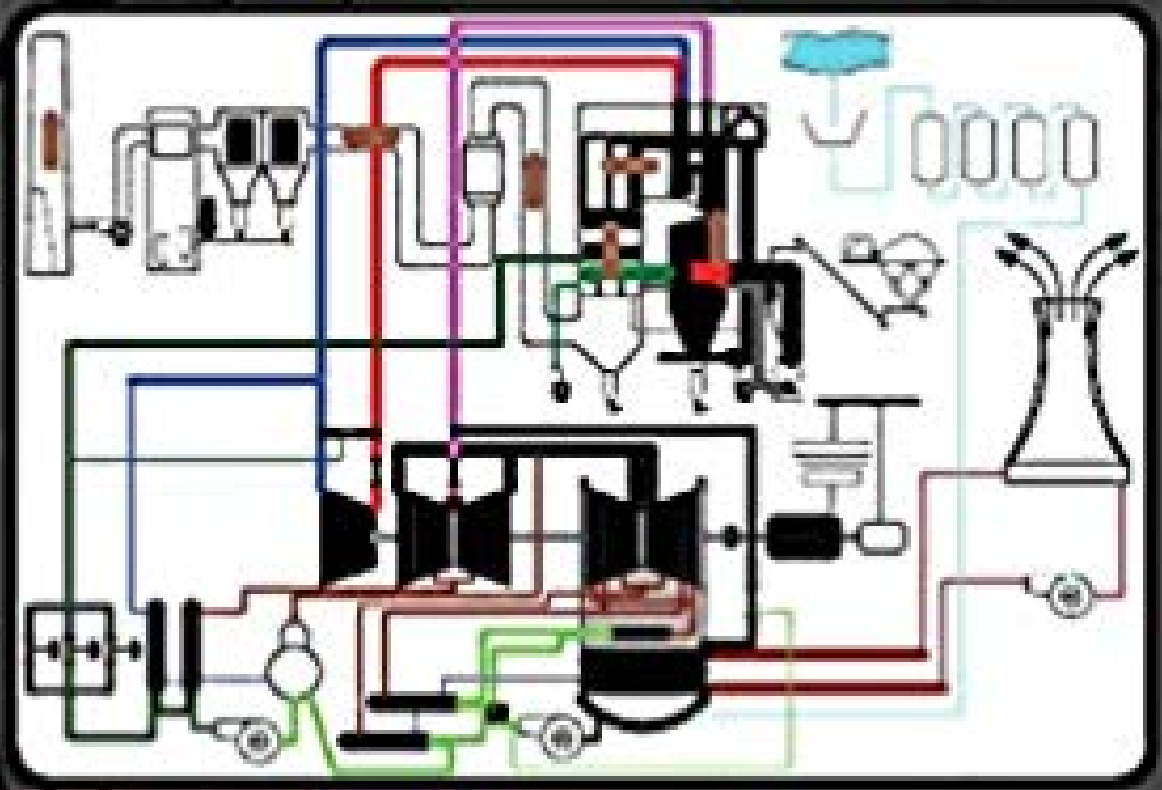
POWER PLANT INSTRUMENTATION AND CONTROL HANDBOOK

A Guide to Thermal Power Plants

SWAPAN BASU AND AJAY KUMAR DEBNATH



www.EngineeringBooksPDF.com

Power Plant Instrumentation and Control Handbook

A Guide to Thermal Power Plants

Swapan Basu
Systems & Controls Kolkata, India

Ajay Kumar Debnath
Systems & Controls Kolkata, India



ELSEVIER

AMSTERDAM • BOSTON • HEIDELBERG • LONDON • NEW YORK • OXFORD • PARIS
SAN DIEGO • SAN FRANCISCO • SINGAPORE • SYDNEY • TOKYO

Academic Press is an Imprint of Elsevier



www.EngineeringBooksPDF.com

Academic Press is an imprint of Elsevier
32 Jamestown Road, London NW1 7BY, UK
525 B Street, Suite 1800, San Diego, CA 92101-4495, USA
225 Wyman Street, Waltham, MA 02451, USA
The Boulevard, Langford Lane, Kidlington, Oxford OX5 1GB, UK

Copyright © 2015 Elsevier Ltd. All rights reserved.

No part of this publication may be reproduced or transmitted in any form or by any means, electronic or mechanical, including photocopying, recording, or any information storage and retrieval system, without permission in writing from the publisher. Details on how to seek permission, further information about the Publisher's permissions policies and our arrangements with organizations such as the Copyright Clearance Center and the Copyright Licensing Agency, can be found at our website: www.elsevier.com/permissions.

This book and the individual contributions contained in it are protected under copyright by the Publisher (other than as may be noted herein).

Notices
Knowledge and best practice in this field are constantly changing. As new research and experience broaden our understanding, changes in research methods, professional practices, or medical treatment may become necessary.

Practitioners and researchers must always rely on their own experience and knowledge in evaluating and using any information, methods, compounds, or experiments described herein. In using such information or methods they should be mindful of their own safety and the safety of others, including parties for whom they have a professional responsibility.

To the fullest extent of the law, neither the Publisher nor the authors, contributors, or editors, assume any liability for any injury and/or damage to persons or property as a matter of products liability, negligence or otherwise, or from any use or operation of any methods, products, instructions, or ideas contained in the material herein.

British Library Cataloguing-in-Publication Data
A catalogue record for this book is available from the British Library

Library of Congress Cataloging-in-Publication Data
A cataloge record for this book is available from the Library of Congress

ISBN: 978-0-12-800940-6

For information on all Academic Press publications visit our web site at http://store.elsevier.com/



www.EngineeringBooksPDF.com

Dedication

This book is dedicated to the promising and growing engineers working in/around or studying thermal power plant instrumentation and control systems who can render services to mankind by providing sparse, pollution-free energy for human progression.

www.EngineeringBooksPDF.com

Foreword

With the advent of technological advancement in all the fields, knowledge and know-how are now available, in bits and pieces, with just a click of the mouse, on the computer. However, it can be time-consuming to find the desired information in a consolidated manner, or it may be difficult to find the exact subject information required.

Modern power plant engineering is a vast subject with different fields of application for all branches of technology. In this book, the authors have included their experiences from a different angle focusing on instrumentation and control systems.

There are number of valuable books available on power plants covering different subjects, but there is a dearth of a single volumes incorporating the majority of the equipment in relation to the process. The chapters of this book cover various subjects on the process and associated instrumentation with alternative arrangements (if any). The text is well demonstrated with facts and figures that make this book easy to understand.

In general, this book accentuates both subcritical and supercritical plants, and there are separate appendices covering supercritical plants as well the emerging demand for the higher efficiency and lower pollution aspects of subcritical plants.

The authors worked for decades with leading consulting firms in India and abroad and keep in touch with modern technology. I truly feel that their experiences will greatly benefit both practicing engineers and students of power plant engineering.

I wish every success to the authors of this book.

S. K. Sen

www.EngineeringBooksPDF.com

Preface

Technical books that have theoretical and practical approaches are available worldwide about several subsystems of thermal power plant instrumentation and controls. This book endeavors to act as a way to balance two extreme lines of thinking, giving a comprehensive approach to plants' measurements and controls.

What is here is primarily meant for professionals working with thermal power plant instrumentation and control systems. Budding (fresh) engineers who start their careers in thermal power plant instrumentation and control engineering, and those practicing professionals of other disciplines, will greatly benefit from the comprehensiveness and practical approaches in this book. It will be a very good reference for engineering students who are pursuing higher-level studies in various branches of engineering.

Highly developed and advanced mathematical deductions are passed up as much as possible; instead physical explanations have been given so that readers get a proper feel of the system so that the book could be kept within a very limited dimension. The text part incorporates an abridged description on the subject being dealt with along with relevant figures and tables to visually show a clear picture of it. In all cases, detailed specifications of the instruments, subsystems, and systems have been included in addition to practical control loops and logistics to enable the book to be "all-time companion" for practicing engineers.

Discussions about both subcritical and super-ultra supercritical power plants, as well as IGCCs, have been included in order to take a look at future trends in power plants. Content keeps pace with development work in the field of electronics and control and communication engineering, with special attention to inclusion of the means and methods of system integration with fieldbus systems, OPC servers, and so on. Application of artificial intelligence and fuzzy logic in power plant instrumentation have been covered in detail.

In an attempt to incoporate this extensive subject area into the form of a book, the authors have carried out a great deal of research over years so as to include the knowledge gained during their decades-long global experience in thermal power plant instrumentation engineering. We wish to convey our sincere thanks to the companies who entrusted us to work in this specialized area of engineering. The authors feel rewarded only when their research work is able to benefit future engineers who can serve the global population by providing scarce pollution-free energy for human development.

Swapan Basu
Ajay Kumar Debnath

www.EngineeringBooksPDF.com

Acknowledgments

At the outset, the authors wish to extend their gratitude to their professors of their engineering institution—Bengal Engineering College, Sibpore (now IIEST)—and their power plant and instrumentation gurus: the late Samir Kumar Shome (former DCL) and the late Makhan Lal Chakraborty (former DCL) for their great teaching in this area. The authors are extremely indebted to Dr. Shankar Sen (former professor at B. E.College) for his encouragement during development the book. While working on the book we were supported with information and suggestions of former colleagues D. K. Sarkar, J. K. Sarkar, D. J. Gupta, S. Chakraborty, A. Thakur, and Arijit Ghosh. In addition, we convey sincere thanks to friends: A. Bhattachariya (Kolkata), A. Sarkar (Norway), A. Tendulkar (Mumbai), N. Kirloskar (Pune), and S. Mohanty (Gurgaon) for their support and sharing of technical information. We would like to thank the authors of the works mentioned throughout the book and the Internet documents that stimulated and helped us write this book. The authors also like to thank the entire team of Systems & Controls Kolkata for infrastructural support. The authors would like to thank the entire team at Elsevier, the publisher, who took all the pains to bring it through to publication.

Last but not the least, we would like to thank our children Idai(Raj), Piku(Deb), Arijita, and Arijit for their continuous inspiration and support. A special thanks to our wives, Bani Basu and Syama Debnath, for managing the family show with care and for encouraging us so that we could dedicate time to the book. The authors sincerely acknowledge that without all these supports it would have been impossible to publish this book.

www.EngineeringBooksPDF.com

Chapter I

Introduction

1. INTRODUCTION

The authors of this book have been associated with the Instrumentation and Control System of Modern Power Plants for more than two decades while working with a leading consulting firm. They are still in touch with modern technology by associating with the engineering and consultancy activities of ongoing projects. We wanted to document their extended experience in the form of a reference book so that professional engineers, working engineers in power plants, and students could benefit from the knowledge gathered during their tenure.

There are so many valuable and good books available on a variety of subjects related to power plants about boilers, turbines, and generators and their subsystems, but it is very difficult to get a single book or single volume of a book to cater to the equipment, accessories, or items along with the instrumentation and control systems associated with them. In this book, there is a very brief description of the system and equipment along with diagrams for a cursory idea about the entire plant. Up-to-date piping and instrumentation diagrams (P&IDs) are included to better understand the tapping locations of measuring and control parameters of the plant.

Various types of instruments, along with sensors, transmitters, gauges, switches, signal conditioner/converter, etc., have been discussed in depth in dedicated chapters, whereas special types of instruments are covered in separate chapters. Instrument data sheets or specification sheets are included so that beginners may receive adequate support for preparing the documents required for their daily work.

The control system chapters VIII, IX and X incorporate the latest control philosophy that has been adopted in several power stations.

This book mainly emphasizes subcritical boilers, but a separate appendix is provided on supercritical boilers because of their economic and low-pollution aspects, which create a bigger demand and need than do conventional subcritical boilers.

It is hoped that this book may help students and/or those who perform power plant-oriented jobs.

2. FUNDAMENTAL KNOWLEDGE ABOUT BASIC PROCESS

Power plant concepts are based on the Laws of Thermodynamics, which depict the relationship among heat, work, and various properties of the systems. All types of energy transformations related to various systems (e.g., mechanical, electrical, chemical etc.) may fall under the study of thermodynamics and are basically founded on empirical formulae and system and/or process behavior. A thermodynamic system is a region in space on control volume or mass under study toward energy transformation within a system and transfer of energy across the boundaries of the system.

2.0 Ideas within and Outside the System

1. *Surrounding*: Space and matter outside the thermodynamic system.
2. *Universe*: Thermodynamic system and *surroundings* put together.
3. *Thermodynamic systems*:
   a. *Closed*: Only energy may cross the boundaries with the mass remaining within the boundary.
   b. *Open*: Transfer of mass takes place across the boundary.
   c. *Isolated*: The system is isolated from its surrounding and no transfer of mass or energy takes place across the boundary.
4. *State*: It is the condition detailed in such a way that one state may be differentiated from all other states.
5. *Property*: Any observable characteristics measurable in terms of numbers and units of measurement, including physical qualities such as pressure, temperature, flow, level, location, speed, etc. The property of any system depends only on the state of the system and not on the process by which the state has been achieved.
   a. *Intensive*: Does not depend on the mass of the system (e.g., pressure, temperature, specific volume, and density).
   b. *Extensive*: Depends on the mass of the system (i.e., volume).

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

6. *Specific weight*: The weight density (i.e., weight per unit volume).
7. *Specific volume*: Volume per unit mass.
8. *Pressure*: Force exerted by a system per unit area of the system.
9. *Path*: Thermodynamic system passes through a series of states.
10. *Process*: Where various changes of state take place.
11. *Cyclic process*: The process after various changes of state complete their journey at the same initial point of state.

2.0.1 Zeroeth Law of Thermodynamics

"If two systems are both in thermal equilibrium with a third system, they are in thermal equilibrium with each other." Thermal equilibrium displays no change in the thermodynamic coordinates of two isolated systems brought into contact; thus, they have a common and equal thermodynamic property called *temperature*. With the help of this law, the measurement of temperature was conceived. A thermometer uses a material's basic property, which changes with temperature.

2.0.1.1 Energy

"The definition in its simplest form is capacity for producing an effect." There are a variety of classifications for energy.

1. Stored energy may be described as the energy contained within the system's boundaries. There are various forms, such as:
   a. Potential
   b. Kinetic
   c. Internal
2. Energy in transition may be described as energy that crosses the system's boundaries. There are various types, such as:
   a. Heat energy (thermal energy)
   b. Electrical energy
   c. Work

2.0.1.2 Work

"Work is transferred from the system during a given operation if the sole effect external to the system can be reduced to the rise of a weight." This form of energy is transferred from one system to another system originally at different temperatures. It may take place by contact and without mass flow across the boundaries of the two systems. This energy flows from a higher temperature to a lower temperature and is energy in transition only and not the property. The unit in the metric system is kcal and is denoted by Q.

2.0.1.3 Specific Heat

Specific heat is defined as the amount of heat required to raise the temperature of a substance of unit mass by one degree. There are two types of specific heat:

1. At constant pressure and denoted as Cp
2. At constant volume and denoted as Cv

Heat energy is a path function and the amount of heat transfer can be given by the following:

$$_1Q_2 = \text{Integration from } T_1 \text{ to } T_2 \text{ of } m\ Cn\ dT,$$

$$\text{i.e., } \int_{T_1}^{T_2} (m\ Cn\ dT),$$

where 1 and 2 are two points in the path through which change takes place in the system, m is the mass, Cn is the specific heat and maybe Cp, dT is the differential temperature, and T_1 and T_2 are the two temperatures at point 1 and 2 of the path.

2.0.1.4 Perfect Gas

A particular gas that obeys all laws strictly under all conditions is called a *perfect gas*. In reality no such gas exists; however, but by applying a fair approximation some gases are considered as perfect (air and nitrogen) and obey the gas laws within the range of pressure and temperature of a normal thermodynamic application.

2.0.2 Boyle's Law and the Charles Law

2.0.2.1 Boyle's Law—Law I

The volume of a given mass of a perfect gas varies inversely as the absolute pressure when temperature is constant.

2.0.2.2 Charles Law—Law II

The volume of a given mass of a perfect gas varies directly as the absolute temperature, if the pressure is constant.

2.0.3 General and Combined Equation

From a practical point of view, neither Boyle's Law nor the Charles Law is applicable to any thermodynamic system because volume, pressure, and temperature, etc., all vary simultaneously as an effect of others. Therefore, it is necessary to obtain a general and combined equation for a given mass undergoing interacting changes in volume, pressure, and temperature:

$$v \propto T/p, \text{ when } T \text{ is constant (Boyle's Law)}$$

$$v \propto T, \text{ when } p \text{ is constant (Charles Law)}.$$

Therefore, $v \propto T/p$ when both pressure and temperature vary

www.EngineeringBooksPDF.com

or

$$v = k.T/p,$$

where k is a constant that depends on temperature scale and properties of gas, or

$$pv = mRT,$$

where m is the mass of gas and R is a constant. This depends on temperature scale and properties of gas: p = absolute pressure of gas in kgf/m^2, v = volume of gas in m^3, m = mass of gas in kg, and T = absolute temperature of gas in degrees K. Therefore $R = pV/mT$ = kgf/m^2 × m^3/kg × K = kgf.m/kg/degree K.

R = 30.26 kgf.m/kg/degree K for nitrogen
R = 29.27 kgf.m/kg/per degree K for air
R = 26.50 kgf.m/kg/degree K for oxygen
R = 420.6 kgf.m/kg/degree K for hydrogen

2.0.3.1 Universal Gas Constant

After performing experiments, it was revealed that for any ideal gas, the product of its characteristic gas constant and molecular weight is a constant number and is equal to 848. Therefore, by virtue of this revelation, 848 kgf.m/kg/degree K is called the Universal Gas Constant.

For example: MR = molecular weight in kg × R

MR = 29.00 × 29.27 ≈ 848 for air
MR = 2.016 × 420.6 ≈ 848.5 for hydrogen
MR = 28.016 × 30.26 ≈ 847.6 for nitrogen
MR = 32 × 26.5 ≈ 848 for oxygen

2.0.4 Avogadro's Law/Hypothesis—Law III

This states that the molecular weights of all the perfect gases occupy the same volume under the same conditions of pressure and temperature.

2.0.5 First Law of Thermodynamics

When a system undergoes a cyclic change, the algebraic sum of work transfers is proportional to the algebraic sum of heat transfers or work or heat is mutually convertible one into the other.

Joules' experiments on this subject led to an interesting and important observation showing the net amount of heat in kcal to be removed from the system was directly proportional to the net amount of work done in kcal on the system.

It is the convention that whenever work is done by the system, the amount of work transfer is considered as +ve, and when work is done on the system, the amount of work transfer is considered as −ve

2.0.5.1 Internal Energy

There exists a property of a system called energy E, such that change in its value is the algebraic sum of the heat supplied and the work done during any change in state.

$$dE = \partial Q - \partial W$$

This is also described as corollary 1 of the First Law of Thermodynamics.

Energy E may include many types of energies, such as kinetic, potential, electric, magnetic, surface tension, etc., but these values, negligible considering the thermodynamic system, are ignored and only the energy due to change in temperature is considered. This type of energy is called internal energy and is denoted by U.

2.0.5.2 Adiabatic Work

Whenever the change of state takes place without any heat transfer, it is called an *adiabatic process*. The equation can be written as follows:

$$\Delta U = W_{ad}; W_{ad} \text{ is the adiabatic work done}$$

It can be established that change in internal energy ΔU is independent of process path. Thus, it is evident that adiabatic work W_{ad} would remain the same for all adiabatic paths between the same pair of end states.

2.0.6 Law of the Conservation of Energy

"In an isolated system, the energy of the system remains constant." This is known as the second corollary of the First Law of Thermodynamics.

2.0.6.1 Constant Volume Process

The volume of the system is constant. Work done being zero, due to heat addition to the system, there would be an increase in internal energy or vice versa.

2.0.6.2 Constant Pressure or Isobaric Process

In this process, the system is maintained at constant pressure and any transfer of heat would result in work done by the system or on the system.

2.0.6.3 Enthalpy

The sum of internal energy and pressure volume product (i.e., $U + pV$) is known as *enthalpy* and is denoted by H. As both U, p, and V are known as system properties, enthalpy is also a system property.

2.0.6.4 Constant Temperature of the Isothermal Process

The system is maintained at a constant temperature by any means and an increase in volume would result in a decrease in pressure and vice versa.

www.EngineeringBooksPDF.com

2.0.7 Second Law of Thermodynamics

There is a limitation of the First Law of Thermodynamics, as it assumes a reversible process. In nature there is actually a directional law, which implies a limitation on the energy transformation other than that imposed by the First Law of Thermodynamics

Whenever energy transfers or changes from one system to another are equal, there is no violation of the First Law of Thermodynamics; however, that does not happen in practice. Thus, there must exist some directional law governing transfer of energy.

2.0.8 Heat Engine

A heat engine is a cyclically operating system across whose boundary is a cyclically operating system across which only heat and work flow. This definition incorporates any device operating cyclically and its primary purpose is transformation of heat into work.

Therefore if boiler, turbine, condenser, and pump are separately considered in a power plant, they do not stand included in the definition of heat engines because in each individual device in the system does not complete a cycle (Figure I/2-1).

When put together, however, the combined system satisfies the definition of a heat engine. Referring to Figure I/2.1-1, the heat enters the boiler and leaves at the condenser. The difference between these equals work at the turbine and pump. The working medium is water and it undergoes a cycle of processes. Passing through the boiler and transforming to steam, it goes to the turbine and then to the condenser where it changes back into water and goes to the feed pump, and finally to the boiler again to its initial state.

2.0.8.1 Kelvin Planck Statement of the Second Law of Thermodynamics

It is impossible to construct an engine that while operating in a cycle produces no other effect except to extract heat from a single reservoir and do the equivalent amount of work. Thus, it is imperative that some heat be transferred from the working substance to another reservoir, or cyclic work is possible only with two temperature levels involved and the heat is transferred from a high temperature to a heat engine and from a heat engine to a low temperature.

2.0.8.2 Clausius Statement of the Second Law of Thermodynamics

"It is impossible for heat energy to flow spontaneously from a body at lower temperature to a body at higher temperature."

2.1 Recapitulation: Various Cycles: Carnot, Rankine, Regenerative, and Reheat

2.1.1 Reversible Cycle: Carnot

Here a reversible cycle was proposed by Sadi Carnot, the inventor of this it, in which the working medium receives heat at one temperature and rejects heat at another temperature. This is achieved by two isothermal processes and two reversible adiabatic processes, shown in the simplified schematic in Figure I/2.1-1.

A given mass of gas (system) is expanded isothermally from point 1 at temperature T_1 to point 2 (after receiving heat q_1 from an external source). So, work is done by the system. The system is now allowed to expand further to point 3 at temperature T_2 through a reversible adiabatic

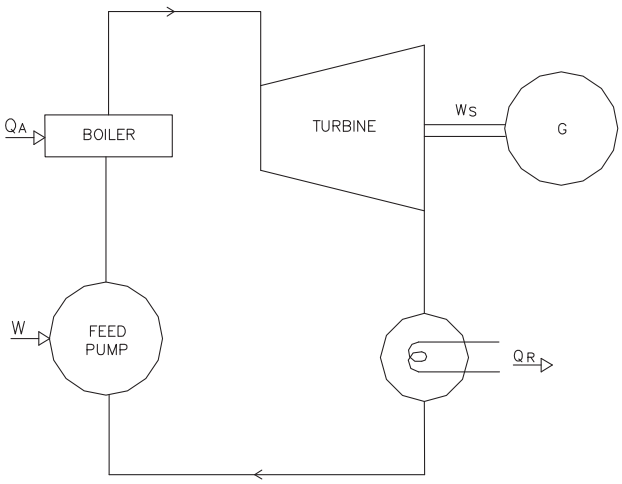


FIGURE I/2-1 Power plant as basic heat engine.

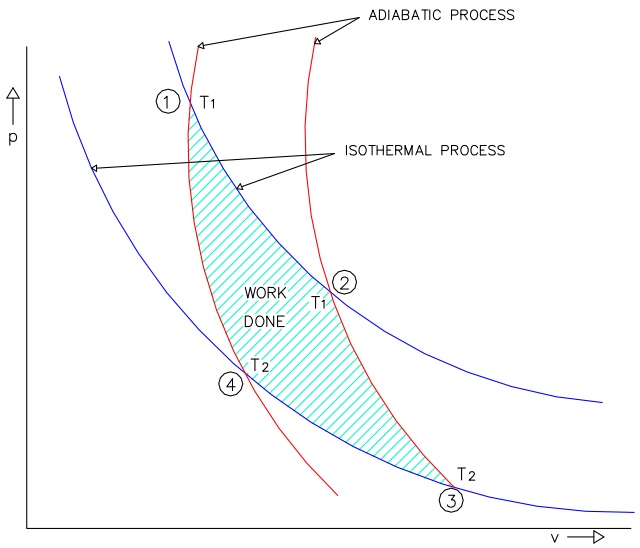


FIGURE I/2.1-1 p-v diagram of a Carnot (reversible) cycle.

www.EngineeringBooksPDF.com

process, meaning no exchange of heat or transfer except work is done due to expansion.

Now the system at point 3 is allowed to reject heat q_2 to a sink at temperature T_2 isothermally up to point 4 by compressing (i.e., doing work on the system). At point 4, the system is again compressed up to point 1, the starting point, through a reversible adiabatic process (i.e., without any heat transfer). Now because the system has completed a cycle and returned to initial state, its internal energy remained the same, as per the First Law of Thermodynamics. Now, $q_1 - q_2 = W =$ work done.

2.1.2 Application of Carnot Cycle in Power Plant

The previous schematic in Figure I/2.1-1 is a classical demonstration of the Carnot cycle. The water–steam flow cycle of a steam power plant is shown in Figure I/2.1-2.

Here the isothermal process or heat transfers take place in the boiler at temperature T_1 and in the condenser at temperature T_2. In these two operations, the fluid is undergoing change in phase; in other words, in the boiler water is transformed to steam at temperature T_1 and in the condenser, steam is transformed into water at temperature T_2.

The reversible adiabatic expansion is performed at the turbine and reversible adiabatic compression takes place in the (boiler) feed pump.

2.1.3 Carnot Theorem or Corollary 2

No engine working between two temperatures can be more efficient than the reversible engine working between the same two temperatures or the Carnot engine (hypothetical). Among all engines operating between fixed temperatures, it is the most efficient.

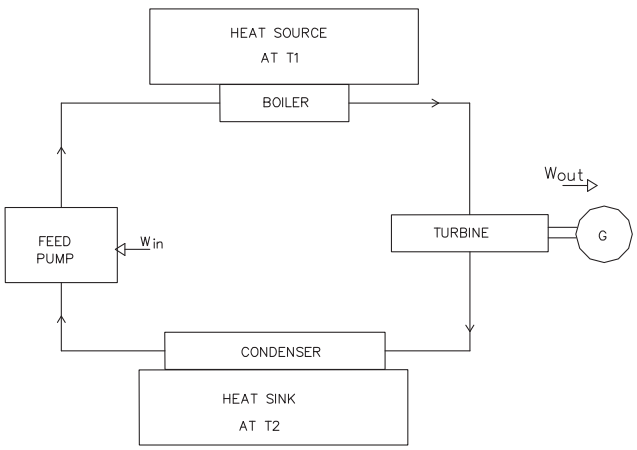


FIGURE I/2.1-2 Water–steam simplified flow cycle of a power plant.

2.1.4 Properties of Steam

Water is introduced into the boiler by a feed pump at a certain pressure and temperature adding some energy to the system. At the boiler, heat is added to raise the temperature at a saturation temperature corresponding to that initial pressure. This is called "sensible heat," as the rise in temperature is evident. When the saturation stage is attained, further addition of heat would change the phase of water to steam without a temperature rise but a sensible change in volume. This stage would continue until dry saturation steam is available. As there is no change in temperature, the heat added is called "latent heat" and is denoted by L.

2.1.4.1 Steam Table

Normally the properties of steam include different parameters, such as pressure, temperature, volume, enthalpy, entropy, etc., and their interrelations are experimentally determined and presented in a tabular form. These values are referred to and required values are obtained from reference tables instead of calculating from the equations, which are very complex.

2.1.4.2 Wet Steam

Wet steam may be described as steam with a mixture of liquid water and water vapor suspended in it. The fraction of steam present in the mixture by weight is called the *dryness* fraction of steam.

2.1.4.3 Superheated Steam

Superheated steam behavior is like a perfect gas; the volume of a given mass can be determined by the Charles Law (i.e., p is constant). All the properties of superheated steam are normally found in reference steam tables, the figures of which were found by performing experiments to explain variations in specific heat and other influencing factors.

2.1.4.4 Entropy

It can be proved that the integral value of change in heat transfers divided by temperature in a cyclic path is equal to zero.

$$\text{Cyclic} \int (\partial q/T)_{\text{rev}} = 0$$

or

$$(\partial Q/T) = dS,$$

where S is called entropy, or change in entropy during a reversible process can be written as follows:

$$\int_1^2 (\partial Q/T)_{\text{rev}} = \int_1^2 dS = (s_2 - s_1) = \Delta S$$

www.EngineeringBooksPDF.com

For unit mass, $\int_1^2 (\partial q/T)_{rev} = \int_1^2 ds = \Delta s$

2.1.4.4.1 Corollary 5 Corollary 5 of the Second Law of Thermodynamics indicates that there exists a property called entropy of a system such that for a reversible process from point 1 to point 2 in a process path, its change is given as

$$\int_1^2 (\partial Q/T)_{rev} \text{ for a unit mass}$$

Therefore it is evident that entropy is not a path function but a point function and change of entropy can be shown as:

$$ds = (dU + pdV)/T$$

or, in another way,

$$Tds = dU + pdV$$

This equation is very important as it is evident that the relationships among all parameters are thermodynamic properties and not path functions such as heat or work. It is interesting that the equation

$$Tds = dU + pdV$$

is applicable to both reversible and irreversible processes, but

$$\partial Q = Tds \quad \text{and} \quad \partial Q = dU + pdV$$

are only applicable to reversible process.

2.1.5 Temperature–Entropy Diagram

As it is known that ${}_1Q = \int_{s_1}^{s_2} Tds$, it can be graphically realized as the area under the curve with temperature and entropy as the coordinates as seen in Figure I/2.1-3. Figure I/2.1-4 also graphically represents the work done in a separate set of pressure and volume coordinates; for example, work done in these coordinates is

$${}_1W_2 = \int_{v_1}^{v_2} pdv$$

By the First Law of Thermodynamics:

$$\text{Cyclic} \int \partial Q = \int dW$$

(i.e., heat transferred to the system is equal to the work done by system). From the previous equation, a very important conclusion can be drawn: the "enclosed area for a reversible cyclic process represents work done by heat transfers on both $p-V$ as well as $T-s$ coordinates. Thus,

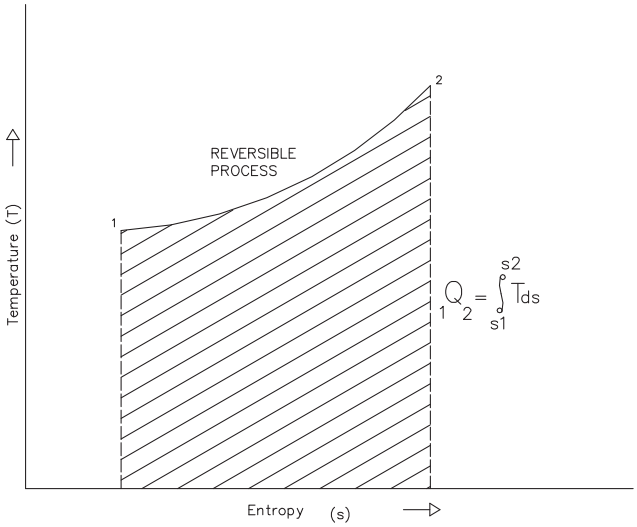


FIGURE I/2.1-3 Temperature–entropy diagram of reversible process.

in the Carnot cycle represented on the $p-V$ or $T-s$ coordinates, the enclosed area denotes work done or heat transfers. From various logical derivations and approximations, it can be said that for an irreversible process, entropy change is not equal to $(\partial Q/T)$, but more than $(\partial Q/T)$; in other words, the (ds) isolated system is ≥ 0, which is known as Corollary 6 of the Second Law of Thermodynamics.

2.1.6 Entropy of Different Phases of Water and Steam

2.1.6.1 Entropy of Water

By definition, $ds = dq/T = Cp.\ dT/T$; therefore, $(s_2 - s_1) = \int_{T_1}^{T_2} Cp\, dT/T = Cp \log_e T_2/T_1$ If 0°C or

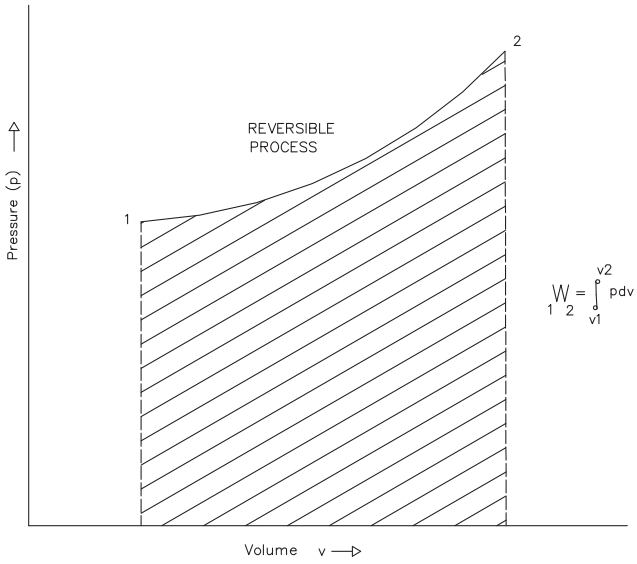


FIGURE I/2.1-4 Pressure volume diagram of reversible process.

www.EngineeringBooksPDF.com

273 K is chosen as the datum for entropy, then entropy of water at any temperature T would be $s = Cp \log_e T/273$ and entropy of water at saturation temperature Ts is $s_w = C_{pw} \log_e Ts/273$.

2.1.6.2 Entropy of Steam

Heat required to convert a unit mass of water to a unit mass of dry saturated steam is the latent heat of vaporization and is denoted by L. Therefore, $s_L = L/Ts$, or, the entropy of vaporization of wet steam is $xS_L = xL/Ts$, where x = dryness fraction of steam; in other words, it is the fraction of dry saturation steam to total mass of the steam. Entropy of dry saturated steam is given by the following:

$$s = s_w + s_L = C_{pw} \log_e T_s/273 + xL/T_s.$$

2.1.6.3 Entropy of Superheated Steam

For unit mass of dry saturated steam to get superheated to temperature T_{sup} at constant pressure, the entropy excursion may be given as follows:

$$s_{sup} - s_s = \int_{T_s}^{T_{sup}} C_p.dT_{sup}/T_s = C_p \log_e T_{sup}/T_s.$$

Therefore, the entropy of superheated steam may be expressed as follows:

$$s_{sup} = C_{pw} \log_e T_s/273 + L/T_s + C_p \log_e T_{sup}/T_s.$$

These equations are very cumbersome and are not used much because these entropy values can be found in reference steam tables.

2.1.7 Temperature–Entropy Diagram of Steam

From the equation $s_w = C_{pw} \log_e Ts/273$, different values of saturation temperature are plotted against values of entropy at different pressures (see Figure I/2.1-5).

In this figure, the portion of graph from point 1 to 2 is considered the water or liquid line. From point 2 to point 3, the path is a straight horizontal line at constant saturation temperature Ts denoting the water and vapor mixture phase. At point 3, the dry saturation stage is achieved. From point 3, if the process follows path 3–4, then different values of dry saturated temperatures are available at lower saturation pressure up to point 4. These two lines or paths when plotted for higher pressure corresponding to a higher saturation temperature would finally merge at point C, which is called the critical point. Here the saturation temperature is 374.065°C and pressure is 225.415 kgf/cm^2. At this point water transforms into the gaseous phase (i.e., dry saturation steam) directly without passing through the two-phase system, and the latent heat of vaporization is zero.

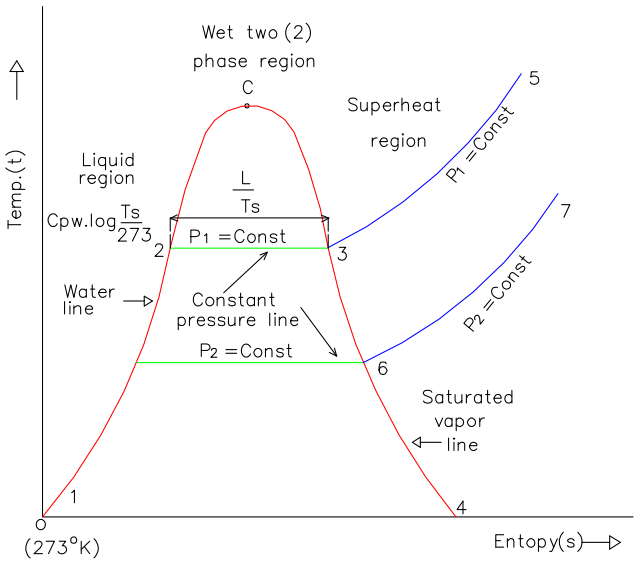


FIGURE I/2.1-5 Temperature–entropy diagram of steam.

In path 3–4, at any point, if the steam is further heated at constant pressure, the process will follow path 3–5 or 6–7 up to the temperatures of superheated steam corresponding to heat added. After this the region is denoted as a superheat region.

2.1.7.1 Pressure–Volume Diagram

The pressure–volume diagram corresponding to the temperature–entropy diagram is illustrated in Figure I/2.1-6.

The critical point C is at 225.415 kgf/cm^2. Liquid, wet, and superheat regions are depicted; 1–2 and extension up to point C is the water line. Line 3–4 and extension up to point C is the dry saturation line. Constant pressure heating is represented by 1–2–3–5.

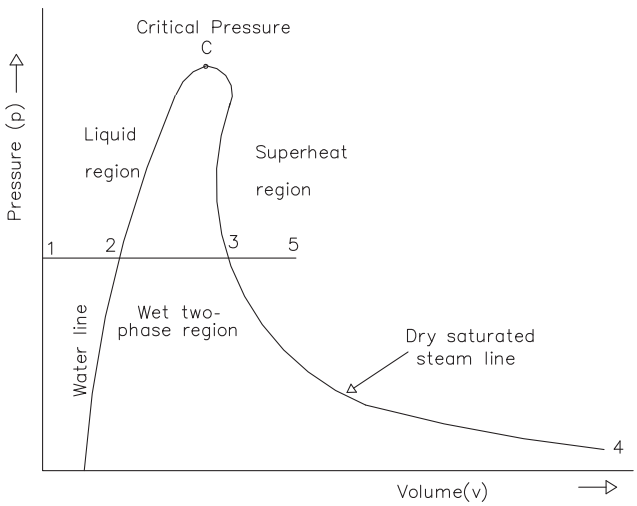


FIGURE I/2.1-6 Pressure–volume diagram of steam.

www.EngineeringBooksPDF.com

2.1.7.2 Steam Generators/Boilers

Steam generators or boilers represent devices for generating steam for various applications:

1. Power generation plant with the help of steam turbines
2. Industrial or process plant, e.g., textile, bleaching, steel, etc.
3. Heating steam as in HVAC system

Boilers are designed to transmit heat through the burning of fuel (e.g., coal, oil, (natural) gas, etc.). The basic requirements to be satisfied are

1. Safe handling of water
2. Safe handling and delivery of steam at desired quality and quantity
3. Efficient heat transfer from external heat source
4. Ability to cater to large and rapid load changes
5. Minimum leakage
6. Minimum refractory material use

2.1.7.3 Boilers Classifications

Boilers are classified mainly by

1. Utilization
2. Tube contents, shape, and position
3. Furnace position and firing
4. Heat source/fuel type
5. Circulation of water

2.1.7.3.1 Use Boilers are primarily stationary and mobile. Stationary boilers are used for

1. Power plants
2. Utility or process plants
3. HVAC plants

Mobile boilers are used for

1. Marine vessels
2. Locomotive engines

2.1.7.3.2 Tube Contents There are two types of tubes: fire and water. Fire tubes contain hot gases inside tubes surrounded by water. These types are of limited use. Water tubes contain water and steam inside the tube with surrounding hot gases. All large plants have this type of boiler. Tubes may be bent, straight, or sinuous and be positioned in a horizontal, vertical, or inclined way.

2.1.7.3.3 Furnace Position and Firing A furnace can be externally or internally fired. For an internally fired system, the furnace region is completely surrounded by water tubes (also called *waterwalls*). The firing system may be front fired, opposed fired, downshot, corner fired, etc.

2.1.7.3.4 Heat Source A heat source may be the combustion of

1. Solid fuels, such as coal, ignite, bagasse, etc.
2. Liquid fuels, such as high-speed diesel oil, fuel oil, coal tar, etc.
3. Gaseous fuels, such as natural gas, hot waste gas as a by-product of some other plant, etc.
4. Electrical energy
5. Nuclear energy

2.1.7.3.5 Forced or Natural Circulation Circulation of water in a majority of applications is done naturally where a natural convection current is produced by applying heat. In forced circulation systems, separate pumps are provided for complete or partial circulation. The Rankine cycle (complete expansion cycle) is considered the standard cycle for comparing steam power plants comprised of boilers, turbines, condensers, etc. (see Figure I/2.1-7). Figure I/2.1-8 illustrates the process with the various components of steam power plants on both $p-v$ and $T-s$ plots for unit mass.

The boiler delivers steam at point 1 as dry saturated steam or at point $1'$ as superheated steam and then to the turbine with the assumption of no heat loss due to transportation through pipelines. The steam expands isentropically in the ideal engine (turbine) to point 2 or $2'$. After that the steam passes to the condenser without any heat loss between turbine and condenser. Steam at point 2 or $2'$ is condensed to completely saturated water at point 3 at pressure p_2. This saturated water is compressed isentropically to pressure p_1 represented by the process path 3D by different pumps. From this, the boiler receives water at pressure p_1 but at a lower temperature, and then heat is added to raise the temperature at T_4 and further transforms

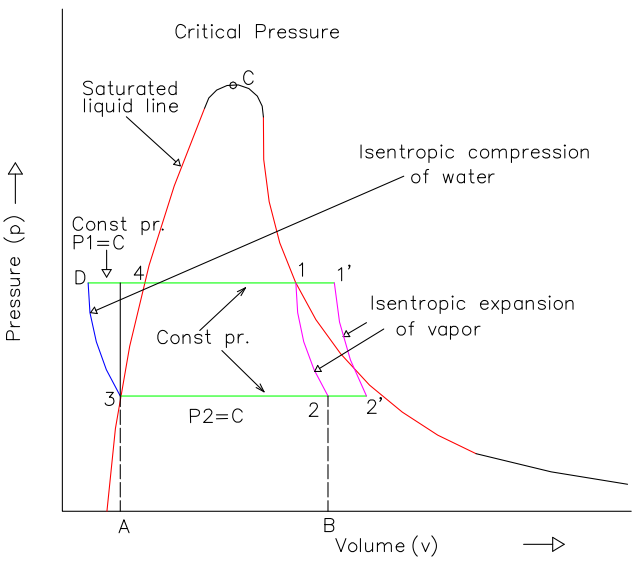


FIGURE I/2.1-7 Pressure–volume diagram of steam in Rankine cycle.

www.EngineeringBooksPDF.com

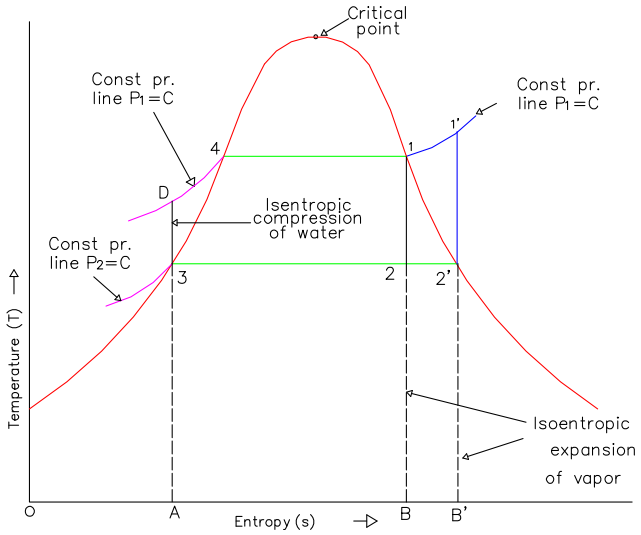


FIGURE I/2.1-8 Temperature—entropy diagram of steam in Rankine cycle.

it to steam at constant pressure (and temperature). It is clear now that D—4—1 (or 1′ for superheated steam) is the process carried out in the boiler.

When an ideal engine receives steam at higher pressure and rejects it at lower temperature after isentropic expansion, the efficiency would refer to the engine alone; this efficiency is called the Rankine Engine Efficiency

2.2 Regenerative Cycle/Heater/Extraction System

2.2.1 Regenerative Cycle

The regenerative cycle is illustrated in Figure I/2.2-1. Before going to the boiler, the condensate, also known as feedwater (FW), after the boiler feed pump (BFP) discharge is heated at various points to avoid irreversible mixing of cold condensate with hot boiler water, which causes loss of cycle efficiency. Various methods are adopted to do this reversibly by interchange of heat within the system, thereby improving cycle thermal efficiency. This method is called *regenerative feed heating* and the cycle is called the *regenerative cycle*. This is implemented by extracting or bleeding small quantities of steam from suitable points throughout the turbine stages utilizing the heat contents of an extracted or bled steam. The vessels where the exchange of heat takes place are called *heaters*. Here the steam totally condenses in the heater shell and is allowed to pass to the next lower pressure heater shell to maintain its own level and to prevent ingress of water into the turbine from the high level in the heater (TWDPS). The outlet water leaves the heater with a higher temperature than the inlet water.

In different cylinders or turbine stages a numbers of extraction outlets are used for regeneration or heating FW through a number of heaters with a suitable temperature and pressure—gland steam coolers (GSC), low-pressure heaters (LPH), and high-pressure heaters (HPH)—to ultimately match the boiler FW inlet temperature. Extraction steam is also provided from the turbine for deaeration of FW and in many plants for a separate BFP driven by a steam turbine in addition to a motor-driven feed pump.

The condensate from the condenser hot well first passes through the GSC to gain heat or temperature and then proceeds to the steam ejector (or a vacuum pump) to gain further heat/temperature (not shown in Figure I/2.2-1).

In GSCs all the gland steams are collected from glands provided at different casings of the turbine to prevent leakage of pressurized steam to atmosphere in high-pressure stages and air into turbine in subatmospheric pressure stages. The heat contained is utilized for condensate heating. An ejector is provided to such air ingress in the condenser to help maintain the vacuum therein by ejecting steam at a very high velocity. Both of these vessels get the initial steam from the auxiliary steam (AS) header at no load or a low-load condition of the turbine and switch over to cold reheat (CRH) steam or extraction steam as necessary.

LPH 1 is normally installed in the steam chest between the low-pressure turbine (LPT) exhaust and the condenser to reduce the load on the condenser and heat gained by the condensate after leaving the ejector.

LPH 2 gets condensate from the LPH 1 outlet and extraction steam from LPT at a slightly higher pressure called Ex 2. Similarly, LPH 3 receives condensate from the LPH 2 outlet and extraction steam from the LPT at a pressure higher than Ex 2 (called Ex 3). Next comes the extraction steam for the deaerator from the intermediate-pressure turbine (IPT) exhaust, which is called Ex 4 or the fourth extraction. It serves two purposes: heating of condensate from the LPH 3 outlet and a very important service called deaeration of condensate. In some power plants, after LPH 3, there is another LP heater (LPH 4), which then receives steam from Ex 4, and the deaerator then receives steam from the IPT exhaust, which is called Ex 5 or the fifth extraction. After the deaerator, condensate goes to the BFP or boiler feed.

Booster pump suction may depend on size of the plant, and has been renamed *boiler feedwater*. The BFP discharge FW then goes to HPH 5 (or HPH 6), then to HPH 6 (or HPH 7), and then HPH 7 or 8 (if any) before finally proceeding to the boiler through an economizer. HPH 5 is provided with the heating steam from intermediate extraction of IPT called Ex 5. HPH 6 is provided with the heating steam from HPT exhaust or the CRH line called Ex 6, or the sixth extraction.

www.EngineeringBooksPDF.com

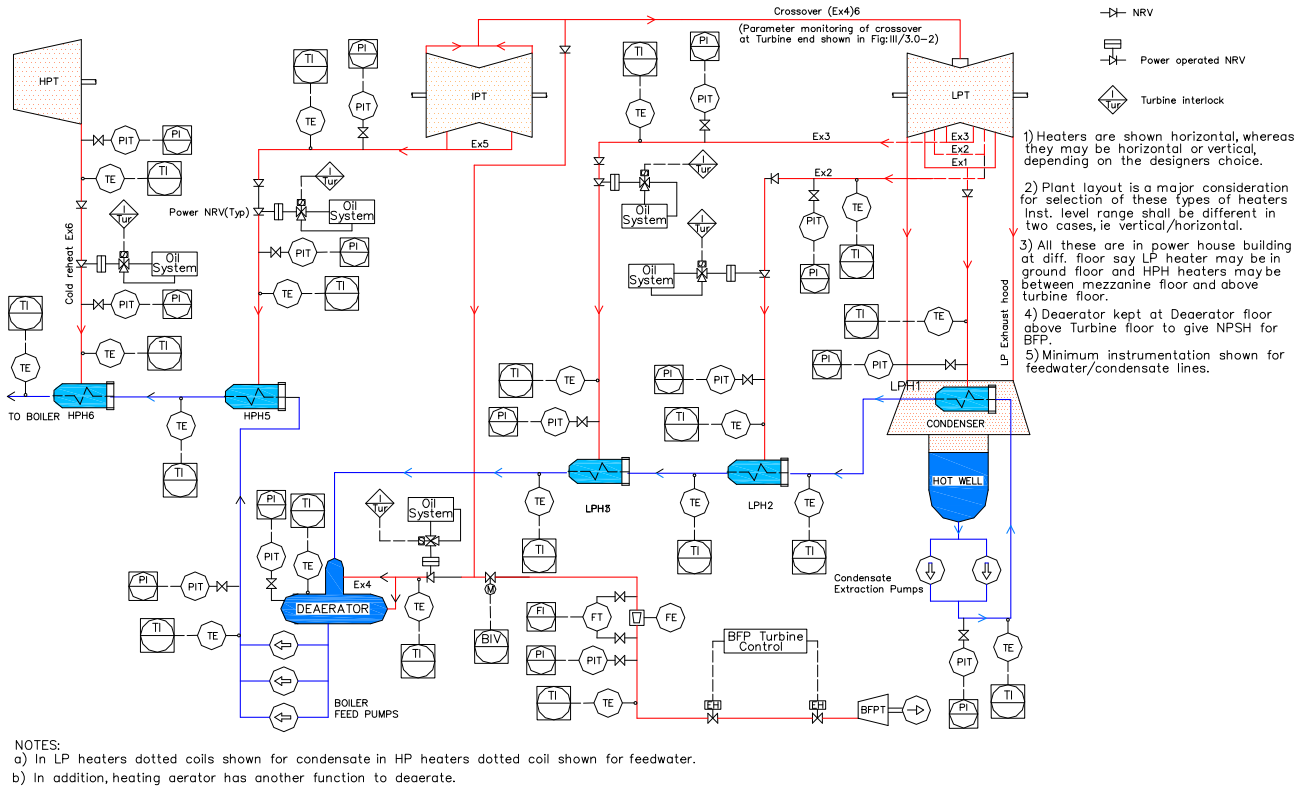


FIGURE I/2.2-1 Extraction steam/regenerative cycle/flow/schematic diagram.

2.2.2 Various Valves and Their Operations

2.2.2.1 Main Steam Stop Valve

The boiler outlet steam passes through the stop valve before going to the consumer/user end called the *main steam stop valve* (MSSV or MSV).The primary purpose of this vital accessory is to isolate the boiler by interrupting steam circuit during startup, shutdown, or in case of an emergency. Normally this valve is motor operated. For a bigger power plant, a small bypass valve is provided to facilitate easy opening of the MSV. During startup, the pressure upstream of the MSV increases while the pressure downstream is almost zero. The differential pressure across the valve and the valve size is very high for high-capacity plants, and the operating thrust/torque required by the actuator is also very high while the valve opens from a fully closed position. To circumvent the situation, a small bypass valve, which opens first with less thrust/torque (line size is small), is provided. As the pressure downstream builds, pressure equalization takes place between the upstream and downstream side and the MSV can then open, requiring less thrust/torque. During normal plant operation the valve remains in full open condition.

2.2.2.2 Nonreturn (Check) Valve

This valve allows the fluid to flow forward under pressure, but checks the fluid flow in the reverse direction. The valve plug moves up from the seat when pressure applied from the bottom of the plug is higher than that of the top of the plug. It will remain in this position as long as the differential pressure multiplied by the plug area is higher than the spring force applied to the plug to keep it the shut-off position. In the reverse condition, when pressure downstream (top of plug) is higher than upstream (bottom of plug), the plug moves down by the force of the differential pressure aided by the spring force and sits tightly on the seat to arrest any flow. Nonreturn or check valves are provided in every flow path, irrespective of steam or water service, wherever there is a chance of return flow under any operating condition. The valve is normally self-actuated—that is, no external power is required. In the extraction line one check valve is a TWDPS requirement. In some instances these may be power-assisted.

2.2.2.3 Startup Vent Valve

This type of valve is in the main steam header and, as the name implies, is required for the startup period only. The valve regulates service, and through it steam is allowed to vent out

www.EngineeringBooksPDF.com

of the system to the atmosphere as required automatically or manually for purging and/or heating of the pipelines. During the initial startup stage the line is drained with the help of the startup drain valve, similar to what was discussed previously. These valves are generally motor-operated.

2.2.2.4 Safety (Pop-Up) Valve

These valves are of immense importance to the safety of the plant and its personnel. Whenever there is a pressure buildup in the pipeline beyond the limit, the valve should operate or pop up to release steam to the atmosphere until the pressure comes down to a safe value. Although a loss of energy and mass of working fluid occurs, it is inevitable during any untoward situation rendered uncontrollable by a normal control system. There are various types of safety valves: electromatic (or relief), spring-loaded, dead weight, fusible plug, etc.

2.2.2.4.1 Electromatic Safety (or Relief) Valve This is a pilot solenoid-operated valve that is energized automatically from the pressure switch at a very high set point, which allows working fluid to operate the actuator of the safety valve. It can be operated through remote manual command as well from the control room/tower.

2.2.2.4.2 Spring-Loaded Safety Valve Normally this valve operates as a last resort to the safety system against high pressure. Under normal plant operation, the spring tension is high enough to hold the valve plug on its seat to ensure a closed position until a very high pressure set point is reached. At this point and above, the force against the spring lifts the plug over its seat to allow extra steam to escape, unless the steam pressure comes down to a normal value. The discharge capacity should be selected so that it is equal to the evaporative capacity to avoid frequent buildup of pressure (actuation of this valve). Other types of safety valves are no longer in use, hence, they are not discussed.

2.2.2.5 Blowdown Valve

This type of valve removes sludge, sediment, and other impurities collected at the bottommost location in the water flow path. It also helps to drain the system completely. There are two types of blowdown valve: continuous and intermittent.

2.2.2.5.1 Continuous Blowdown Valve This valve opens continuously to maintain the dirty material level to a minimum value. The opening of the valve is varied as per requirements with a predefined control signal. The motorized actuator can also receive manual commands; the method of control is the operator's prerogative.

2.2.2.5.2 Intermittent Blowdown Valve This type of valve blows down dirty water as necessary. Its operation may be predefined, based on cyclic or time framed full open/close signal or manual command from the operator with a motorized actuator. Boiler drum conductivity may be one of the parameters to operate this valve in automatic control—not uncommon in medium- to large-size boilers in utility stations.

2.2.2.6 Drain Valve

During the startup of the plant after a prolonged shutdown or a cold startup, the pipelines and various equipment need to be warmed up before loading the boiler. To achieve this, heating steam is admitted phase-by-phase in a very slow manner to avoid dissimilar heat causing expansion of various casings and pipes. While heating metal works, the steam gets condensed and collected at the bottom of the pipeline with a siphon-type of design at various strategic locations. At the bottom, condensed water is drained out through this valve with a motorized actuator when the level in the drain pipe reaches a predefined value to avoid frequent operation. Level switches are provided for automatic operation. The operator is provided a manual command.

2.2.3 Steam Trap

This type of element drains out the condensed water from steam pipes and jackets used for heating, thus resulting in partial condensation, and simultaneously arresting the steam inside from escaping (hence the name). Generally, there are two types of steam traps available: float or bucket and thermal expansion. The operation is self-contained and mechanical; it does not require any external power, therefore, it is not discussed further.

2.2.4 Steam Separator

As the name implies, it separates water particles suspended in generated steam from the boiler and carries the flow of steam to the turbine or engine. To work properly, it should be located far enough away from the steam generator to separate water particles from the steam for most of the transportation line. A drum-type boiler is in the drum where the water particles drop into the water section.

The steam path of the steam separator is guided by a series of baffles. The water particles are heavier and have greater inertia. Because of this, after striking the baffles they fall by gravitational force to the bottom of the vessel. The dry steam is practically unaffected and gets transported out. The collected water is then drained out through the drain line.

2.3 Reheat Cycles in Utility Boiler—Hot and CRH Lines

2.3.1 Reheat Cycle in Utility Boiler

The steam from the high-pressure turbine (HPT) outlet or exhaust is returned to the boiler to reheat the steam at a temperature (generally) equal to the original main steam

www.EngineeringBooksPDF.com

temperature (see Figure I/2.3-1). Reheating is done to avoid wet steam in the turbine blade, which causes erosion because of water particles in wet steam. The international standard moisture limit for steam in a turbine is ~10%. Water particles in the turbine is against TWDPS for the preceding reason.

The modern power plant concept is based on multiple turbine cylinders with the rotors coupled to a single shaft. Figures I/2.3-1 and I/2.3-2 show high-pressure steam, popularly called *main steam*, from the boiler that enters the HPT where it is isentropically expanded from pressure p_1 to p_2 (path 1−2 in the T−s diagram) and removed as high-pressure exhaust. This is normally called *cold reheat*.

This high-pressure exhaust steam is then readmitted to the reheater part of the boiler for reheating, after which the changed steam is at a temperature equal to the main steam and a pressure equal to p_3.The reheated steam from the boiler is known as hot reheat (HRH). It then reenters the turbine intermediate-pressure (IP) cylinder and expands isentropically up to pressure p_4 (point 4 in the T−s diagram). The temperature is maintained at the outlet of the reheater header by providing heaters at various stages, but before entering each heater there are de-superheaters (spray type). These help to avoid overheating and a rise in temperature of the reheated steam to achieve precise control of it by spraying adequate water through control valves. However, in practice reheater temperature is controlled primarily by burner tilt for tangential firing and by operation of a bypass damper or readmission of cold flue gas near the furnace hopper in front/opposed/downshot fired boilers. Spray control is used mostly in emergencies by setting its controller set point slightly higher than the normal reheat temperature controller set point.

By reheating more work is done, that is, more output from the turbo generator as shown in the T−s diagram (Figure I/2.3-2). Without reheat, the steam cycle would follow the path $1-2-5_{Sup}$; however, with reheating, the path followed is $1-2-3-4-5_{Rh}$. The extra work done is in the area vertically under line 2−3, i.e., the area enclosed by the path $2-3-5_{Rh}-5_{Sup}-2$. In modern and/or high-capacity power plants, twin cylinder IP modules (as shown in Figure I/2.3-1) are used for various reasons, although there was only a single cylinder in an earlier design.

The CRH header at the HP turbine outlet supplies steam to the following plant components:

1. Heating steam for HPH 6
2. Turbine-type drive of BFP (if any) during startup
3. Gland seal system
4. Deaerator during startup

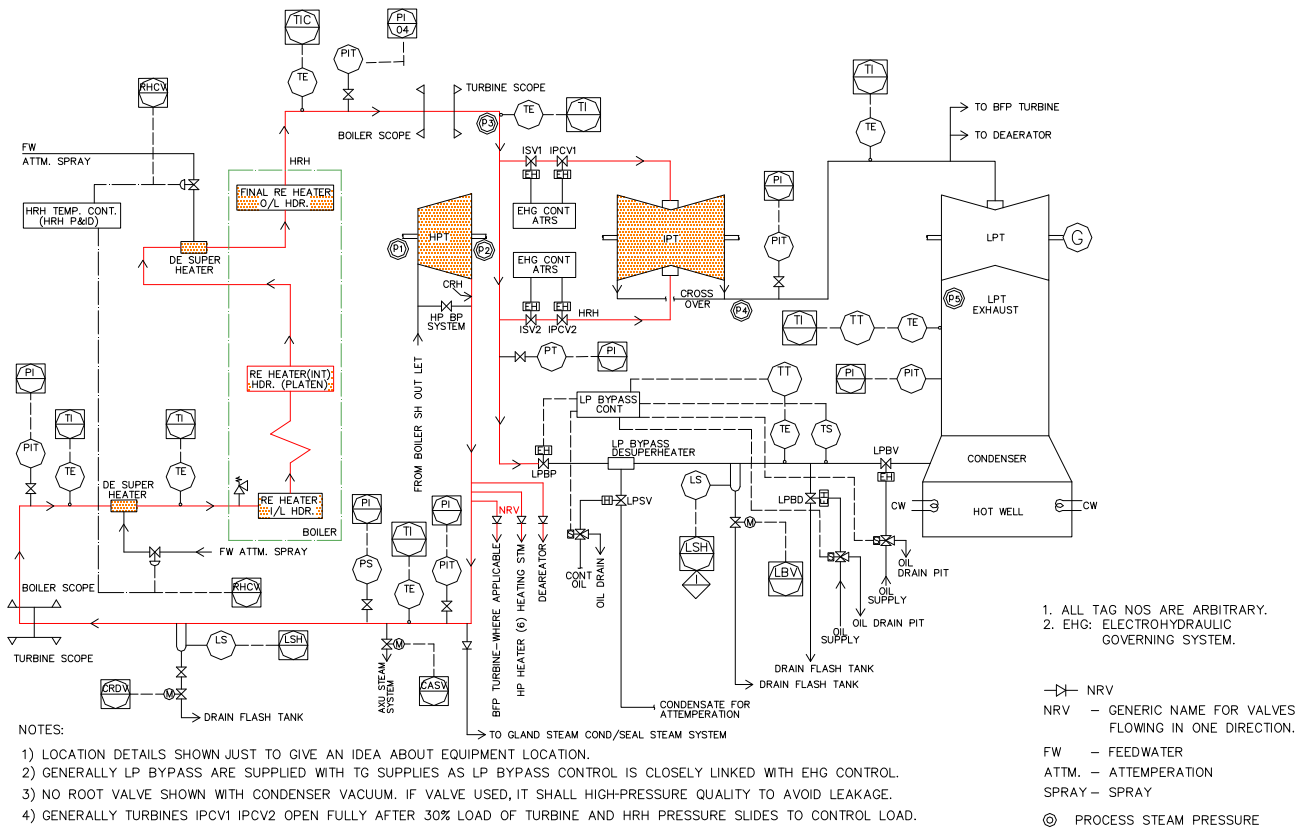


FIGURE I/2.3-1 Elementary flow diagram of CRH and HRH lines in utility boiler.

www.EngineeringBooksPDF.com

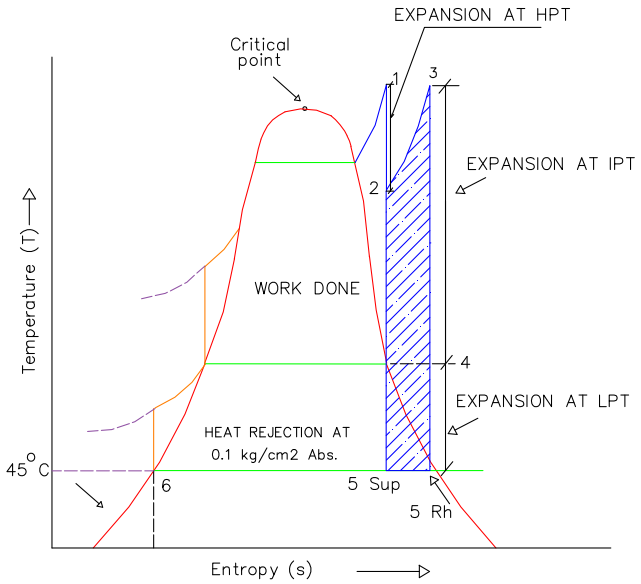


FIGURE I/2.3-2 Reheat steam cycle in modern power plant in T—s axis.

There is another important system, the HP bypass system, which enables the main steam to bypass the turbine to meet the CRH line after suitable temperature and pressure conditioning. If there is turbine tripping (or outage), the steam generation of the boiler cannot stop immediately. As boiler startup is a very time-consuming process, steam generation is kept uninterrupted and diverted to a bypass line by closing the main steam line isolating/regulating valves. This also happens during turbine startup. There is a pressure-reducing valve (PRV) that reduces the steam pressure equal to a simulated pressure set point generated from the control system. After pressure reduction, the steam is cooled by spray water from the FW line through a control valve; thus, a simulated CRH steam condition is generated. The spray water pressure is also regulated so that excess water does not go overpressure by pass line (see Figure III/2.2-1). This is necessary because the boiler is running at the existing load and the reheater must get steam at CRH condition to keep from overheating.

2.4 Gas Turbine Types (Frames)/Black Startup

A gas turbine (GT) is a type of internal combustion engine, also called a *combustion turbine*. Theoretically, basic GTs can be categorized into two classes: open- and closed- cycle. An open-cycle turbine has its main operating fluid and gas/air taken from the atmosphere and returned to the atmosphere after residual heat rejection. In this turbine, fuel is burned with the help of air within the system and combustion products along with the rest of the air form the working fluid. Some part of the exhaust gas may be retained to preheat the inlet air and balance the gas allowed to return to the atmosphere. This system is called a *semi-closed cycle*.

In a closed-cycle system the main operating fluid (e.g., steam in a steam power plant) is not allowed to leave the system and the transfer of heat (work between the system and surroundings) takes place. In other words, it may be categorized as a "hot air engine." Figure I/2.4-1 illustrates this type of mechanical system.

The GT's operating principle, for either an open- or closed-cycle type, is based on the thermodynamic cycle known as the Brayton cycle. In this type of system, the atmospheric air is the operating fluid, which is compressed to accommodate a sufficient amount of air in a given limited-volume combustion chamber to assist in the burning of fuel. When combustion takes place—that is, energy is added to the gas stream in the high-pressure environment of the combustor—the air quickly heats to a high temperature and tends to expand abruptly. The products of combustion are then forced into the turbine section, guided through a set of nozzles mounted throughout the periphery of the rotor, and passed over the adjacent turbine blades. The expansion takes place within the turbine at various stages. The consequent high velocity of the gas flow causes the turbine to spin, which powers the compressor and shaft with mechanical energy. The thermal energy transferred to the turbine comes from a reduction in temperature and pressure and comes out as exhaust gas. The total work developed at the turbine by expansion after subtraction of the amount consumed by the compressor (which normally ranges from 50—60%) is then available for power generation. In a Brayton cycle, the total work developed is proportional to the absolute temperature of the operating fluid passing through a device such as the turbine. It is therefore a natural choice to operate the turbine at the highest operable temperature within the limits posed by the metals subjected to these temperatures. For this purpose, the inlet blades are arranged to be cooled by air or steam (if working in a combined cycle with a heat-recovery steam

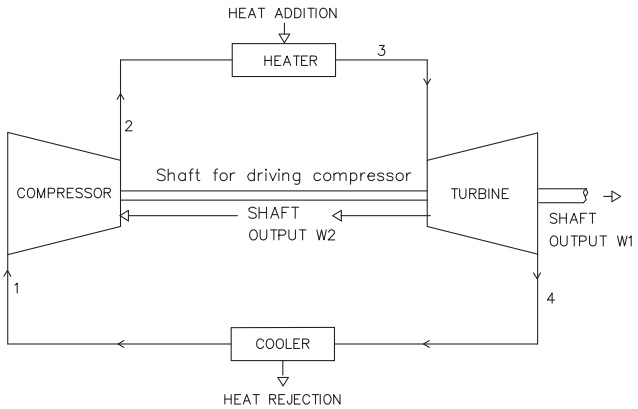


FIGURE I/2.4-1 Closed cycle in GT schematic diagram.

www.EngineeringBooksPDF.com

generator, HRSG) and will be discussed briefly in the latter part of this chapter.

With the tremendous development of GT technology and other factors, the closed-loop cycle has become obsolete and a subject of theoretical interests only. However, the heating of clean air, and it acting like working fluid instead of hot products of combustion, is still in use, but in an open-loop configuration only. The system is briefly discussed in Clause 2.4.9. There is also research that is developing a closed-cycle GT based on helium or supercritical carbon dioxide as working fluid and utilizing nuclear/solar energy as the heat source.

For a smaller engine, the general GT design criterion is that the rotational speed of the shaft must be high enough to maintain blade-tip velocity, because the maximum pressure ratio achieved by the GT compressor depends on the blade tip velocity. The maximum power and efficiency is in turn proportional to the maximum pressure ratio of the engine. To summarize, the maximum powers (close to its own rating) and efficiencies of various machines can be attainable if the blade-tip velocity is constant, which means if the diameter of a rotor is doubled, the rotational speed must be half of its previous value. For example, if a very large jet engine operates at around 10,000 rpm, a comparatively small GT has to run at a much higher speed, such as 100,000 rpm, to attain its maximum (near rated) output and efficiency.

GTs are used in many fields: aviation, power generation, marine vessels, and even in road transport systems. With the advent of aircraft, the GT is broadly classified and developed as a jet engine. When used as an engine for aircraft, GTs are generally called jet engines, not GTs. In this type of GT the available energy, left after driving the compressor and associated components, in the form of high-pressure gas and a huge volume of atmospheric air, is allowed to accelerate, which provides the formation of jet and, consequently, the thrust necessary for desired aircraft operation. Two basic types of jet engines are presently available in aviation technology.

Jet engines optimized to produce thrust from direct impulse of the exhaust gases are called "turbojets." The other type of jet engine has a large fan (driven by the GT shaft) at the air intake of the engine, which supplies a huge amount of air to produce extra thrust in addition to thrust produced by the exhaust gases. This is called a "turbofan" or "fan jet." However, further discussion about aviation engines is beyond the scope this book.

GT thermal efficiency is lower than the thermal efficiency of comparable diesel/reciprocating engines. Thermal efficiency of GTs within a 30 MW rating varies from 35 to 40%. This fact results in ~20% higher fuel consumption in a GT working on single cycle (without heat recovery) mode than that of a comparable reciprocating engine. GT thermal efficiency is proportional to GT output; hence, the thermal efficiency of small GTs, for example, within a 5 MW capacity, normally is not >30%. As far as the capital cost is concerned, the initial investment for a GT engine within a 30 MW range is ~20% higher than in reciprocating engines of similar rating.

In the electric power generation field, two modern basic categories have emerged: heavy duty industrial GTs, which are specifically designed for stationary duty, and aero derivative GTs, which are derived from jet engines. Industrial GTs are different from aero derivatives both in structure and in service, but both are used in electric power generation. For the industrial GTs, the frames, bearings, and different stage blades are heavier compared with aero derivative GT blades. The size of industrial GTs varies widely ranging from small mobile plants to large power-generating plants.

Heavy duty industrial GTs are also known as frame GTs. These are meant entirely for the station-mounted electrical power-generating units with typical average efficiencies of 40%, if installed as a standalone unit.

The efficiency may increase to the typical figure of 60% when waste heat with a very high temperature from the GT exhaust is utilized by an HRSG to power a conventional steam turbine. This is widely known as a combined cycle plant. The waste heat can also be recovered in other ways, such as by heating, cooling, or refrigeration through suitable equipment in co-generation configuration.

The industrial GT has been designed to extract power from the shaft to drive an alternator or AC generator. Normally in this system GT exit pressure is kept very close to the atmospheric pressure with some margin to enable the hot exhaust to reach the desired destination. The typical compression ratio in this type of GTs is 16:1. The electrical power output capacity from the GTs typically ranges from 40 to 350 MW. It is best used as a base load power plant for continuous running.

Lower capacity GTs, usually up to 40 MW or below, may be used for power generation as well as for a mechanical drive, for example, compressors for long distance gas pipelines, air compressors for blast furnaces, for maintaining well pressure in the petroleum industry, or to enable different process plants to work at an elevated pressure environment.

The output power can be extracted from the GT in many forms, such as shaft power to drive trains, ships, etc. The exhaust gas pressure is similar to the atmospheric pressure discussed previously.

The advantages and disadvantages of industrial GT include:

1. Rugged, less expensive, less maintenance time, more availability, less intervals between overhauls
2. Less efficient, heavy structure

The aero derivative GTs are naturally lightweight and thermally efficient with a decreased start-up time.

www.EngineeringBooksPDF.com

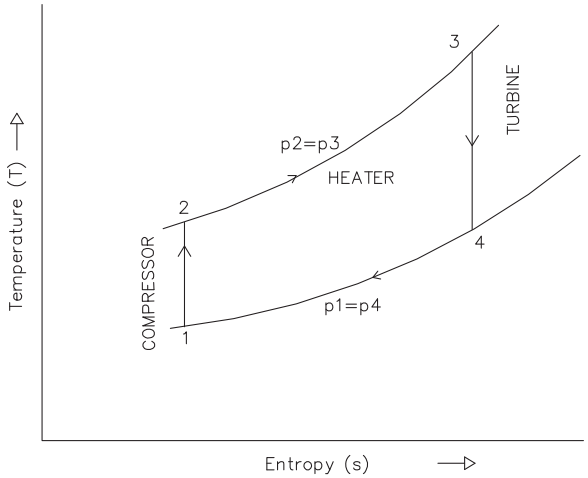


FIGURE I/2.4-2 T–s diagram of basic closed cycle in GT.

The compression ratio may be raised up to 30:1, compared with 16:1 for industrial GTs**.** The capacity rating of aero derivative GTs is available up to 50 MW. This type of machine is slightly more efficient and more costly than the standard industrial GTs. Aero derivative GTs, although expensive, are used in electrical power generation to take up variable load because of their quick start/shut down and they handle load changes more smoothly than industrial machines. Because they are lightweight, they are used in marine vessels.

2.4.1 GT Basic Closed Loop Cycle

Figures I/2.4-2 and I/2.4-3 depict the working principle of this type of GT. Gases passing through an ideal GT undergo three thermodynamic processes. Point 1 denotes the entrance of cold gas/air to the compressor and work is done on the system to raise the pressure of the system, which may be considered as isentropic compression. Point 2 denotes the starting of heat added to the system while passing through the heater, thus raising the temperature. This is considered isobaric (constant pressure) combustion. Point 3 denotes entry to the turbine where expansion of gas/air takes place ultimately to a lower exhaust pressure as isentropic expansion and shaft power develops. Part of it is used to run the compressor and the rest of it is used to run the generator. Point 4 denotes the entry of hot exhaust to the cooler where heat is rejected to reach the initial condition (point 1).With the above assumptions and design parameter, the process may be conceived as an ideal and reversible cycle.

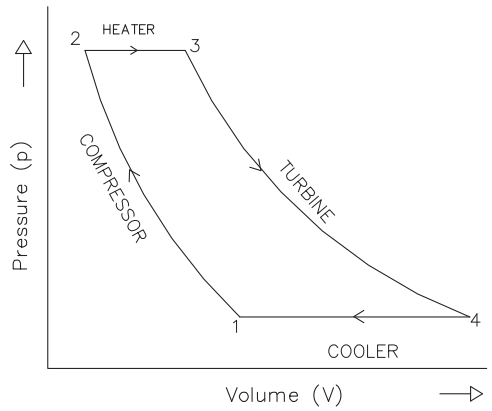


FIGURE I/2.4-3 p-v diagram of basic closed cycle in GT.

2.4.2 GT Basic Open Loop Cycles

2.4.2.1 GT Cycles with Heat Exchangers/ Regenerator

In this type of GT, the fuel-saving system is envisioned as seen in Figure I/2.4-4. The hot exhaust gas is utilized to preheat the cold compressed air by passing through a heat exchanger before going into the atmosphere. With a suitable design, it is possible to raise the temperature of the cold compressed air from t_2 to $t_a = t_4$ and lower the temperature of gas leaving the turbine t_4 to $t_b = t_2$ as shown in the Figures I/2.4-4 and I/2.4-5.

Therefore, it is apparent that the heat transfer has been taking place at each interval of the heat exchanger with a very low, practically negligible temperature difference. With the above assumptions and design parameters, the process may be conceived as an ideal and reversible cycle. The external heat would be less than the amount rejected by the exhaust gas at the heat exchanger.

2.4.2.2 GT Cycles with Intercooling and Reheating

A system with a regenerator improves the cycle's thermal efficiency, but not the work ratio. The work ratio would only be improved by either decreasing the compressor work or increasing the turbine shaft work or both at the same time.

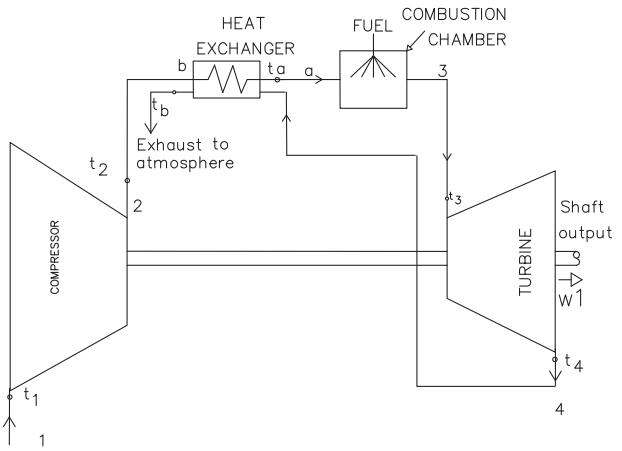


FIGURE I/2.4-4 Schematic diagram of GT cycles with heat exchangers.

www.EngineeringBooksPDF.com

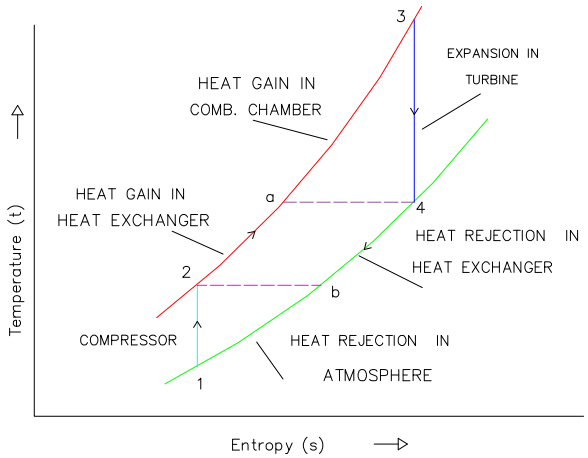


FIGURE I/2.4-5 GT cycle in T−s axis with heat exchanger.

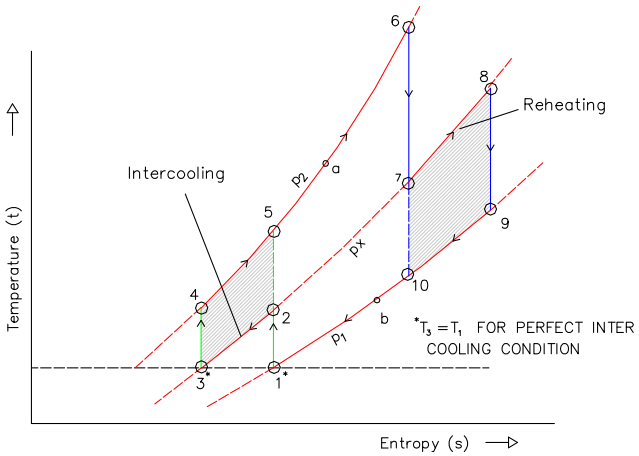


FIGURE I/2.4-7 GT cycles with inter cooling and reheating in T−s axis.

From Figures I/.2.4-6 and I/2.4-7, suppose the process starts at the compressor inlet with atmospheric pressure and temperature at point 1 to point 5 if compression work takes place at a single stage. If the compression work is done at two stages, then the path will be 1−2 and 3−4 instead of 1−5 with cooling taking place at an intermediate constant pressure, p_x. From the series of constant pressure lines, it is evident that the vertical distance between any two such lines on the left side is less than the right side distance. So, the vertical distance 3−4 is less than that of 2−5; the work done on the two-stage compressors are less than that of single-stage compressor.

By suitable design, it may be possible to cool the second-stage cooler inlet temperature at atmospheric condition, i.e., $T_3 = T_1$.This is called perfect intercooling. If the reheat part is analyzed the vertical distance to the right is more than those with less reheating, which means work done by the turbine with reheating is more than that without reheating. From the diagram it is also clear that the total area (work done) with intercooling and reheating is more than that without them. The shaded areas in Figure I/2.4-7 are the additional work available by using the above-mentioned plan.

2.4.3 GT with Single and Double Shaft (Turboshaft)

Generally, GTs can be classified as a single-shaft or double-shaft configuration. A brief description of these two types is incorporated in the following clauses.

2.4.3.1 GT with Single Shaft

A single-shaft GT is normally used when the connected load does not need significant speed variation during the operation range, for example, the alternator or generator. In this configuration, the compressors, along with the turbine and generator, are connected as a single continuous shaft, which means all of them would be running at the same speed.

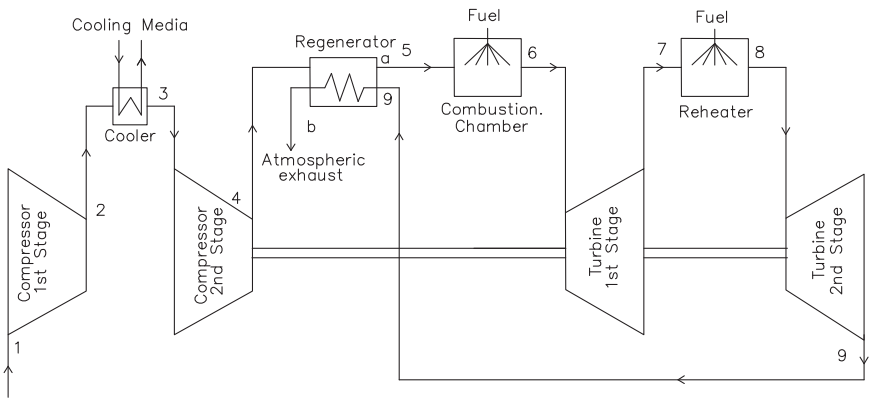


FIGURE I/2.4-6 Schematic diagram of GT cycles with inter cooling and reheating.

www.EngineeringBooksPDF.com

2.4.3.2 GT with Double Shaft (Turboshaft)

In this configuration, the turbine part is mechanically separated into two parts: an HPT and an LPT. Here the compressor rotor and the HPT form a common shaft. The work developed at HPT (also a high speed turbine; often referred to as a "gas generator" or "compressor turbine") by converting thermal energy through kinetic energy is utilized solely to drive the compressor rotor. On the other hand, the LPT (also a low speed turbine; often called the "power turbine" or "free-wheeling turbine") is coupled with the output shaft, which may be a generator or any other load, such as an aerodynamic drive, etc.

The two turbine shafts are separated mechanically but are "aerodynamically" coupled by the hot gases exited from the compressor turbine/gas generator and entering the power turbine. This type of GT is often called a "turboshaft engine," which is used to drive compression trains such as gas pumping stations, natural gas liquefaction plants, marine vessels, etc. This configuration is used to increase speed and power output flexibility. The design of modern helicopters often utilizes the application of this type of GT, and it is preferred because the compressor turbine/gas generator turbine spins separately from the power turbine.

The advantages of a GT with double shaft include:

1. The speed of both turbines can be varied to meet the prevailing demands independent of each other.
2. The starting torque for the load requirement is less than the single shaft as the power turbine is mechanically decoupled from the compressor turbine.

2.4.4 GT Firing Temperature and Pressure Ratio

The two most important parameters for determining the characteristics of a system in GTs based on the Brayton Cycle are the turbine firing temperature and pressure ratio. With the advancement of technology, the modern trend is to operate the turbine at a higher firing temperature and pressure ratio. The combined effect of these two factors is responsible for higher efficiency and specific power, turbine exhaust temperature of the GT, etc. The higher exhaust temperature may range from 425 to 600°C for small to larger sized GTs, respectively. Such high exhaust temperature allows further use of this heat energy through the HRSG in a combined cycle plant.

2.4.4.1 Turbine Firing Temperature

The firing temperature is the highest temperature attained in the system; it is called the turbine inlet temperature or first-stage nozzle outlet temperature. As previously stated, this temperature is proportional to the total power developed by the GT; hence, the higher temperature is a natural trend for a GT.

Restrictions of higher firing temperature and solutions are as follows:

1. Oxides of nitrogen (NO_X) are part of the pollutant gases emitted by the GT. They depend on the combustion temperature (similar to the turbine inlet or firing temperature), so care is taken to restrict them. There are certain methods of firing control by regulating air flow (primary and secondary air, SA) at different locations in the combustion chamber, which assist in maintaining lower temperature.
2. The other restriction for achieving higher temperature is the operating limits of the wetted parts of the turbine materials used. Techno-commercial consideration of the metal selection dictates the temperature.

This problem is also solved by cooling the first-stage nozzles so that the products of combustion entering the turbine blades cool after leaving the nozzle trails. For GTs without HRSG or meant for aerodynamic service, this cooling system employs air injection through the ports of the hollow nozzle walls. The pressurized cooling air enters the hot gas stream and instantly mixes to reduce the entrant gas temperature.

For GTs with HRSG (as in a combined cycle plant), the nozzle cooling utilizes the steam as a cooling medium. In this method, dilution of hot gas with air mixing does not take place. Instead, a fraction of comparatively low-temperature CRH steam from the steam turbine is diverted to travel inside the hollow portion of the adjacent nozzle walls in a closed loop. It exits out back to join the HRH steam line after gaining heat in the IP section of the steam turbine for further cyclic requirement. This type of scheme is illustrated in Figure I/2.4-7A.

2.4.4.2 Turbine Pressure Ratio

This parameter is the ratio of turbine inlet and outlet pressure, which should be the same as the compressor outlet and inlet pressure in an ideal cycle, although the actual pressure ratio is less than what it should be because of loss in the combustion system. The minimum GT pressure ratio is 7 kg/cm^2 for even the smallest available set. For larger machines, the ratio is higher.

2.4.5 Various Sections of GT

Like reciprocating/piston engines, GT engines take the same four steps to accomplish their task, but in four distinctly different sections as stated below (see Figure I/2.4-7B):

1. Inlet (air) section
2. Compressor section with diffuser
3. Combustion section (combustor)
4. Turbine (and exhaust) section

www.EngineeringBooksPDF.com

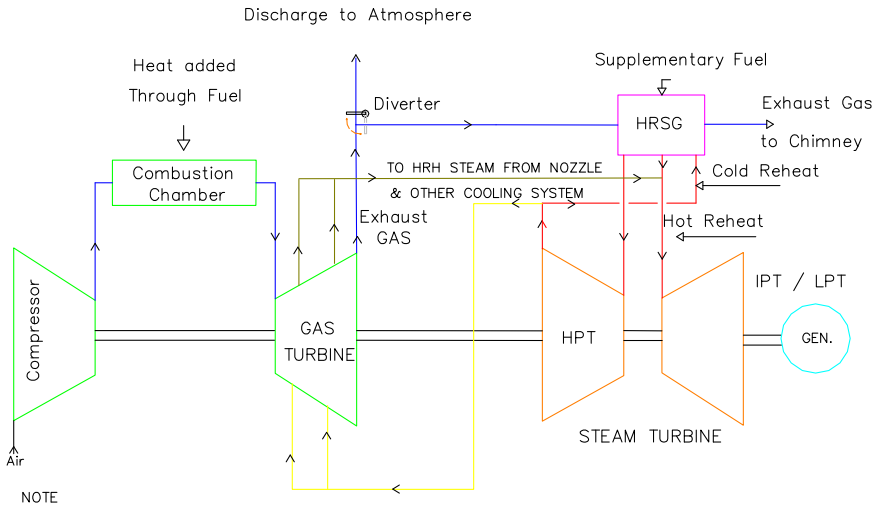
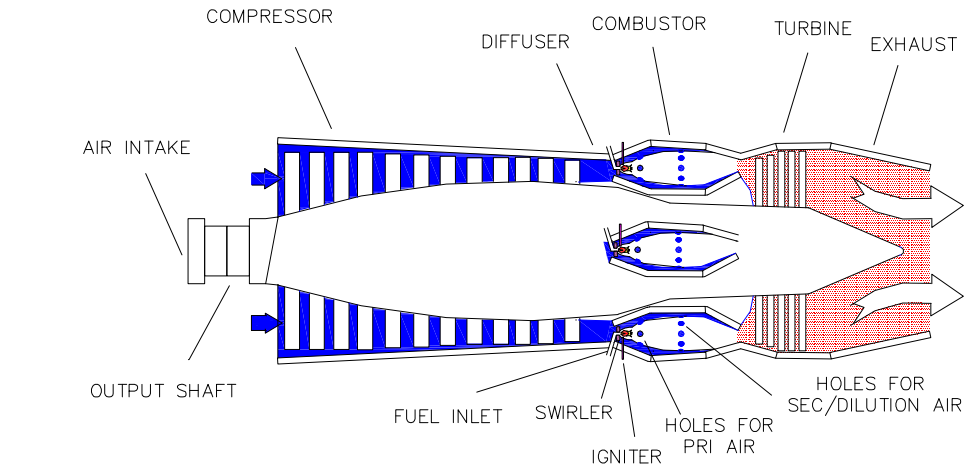


FIGURE I/2.4-7A Schematic diagram of combined cycle plant with GT nozzle cooling.



NOTE
- TYPICAL DRAWING ONLY TO SHOW RELATIVE LOCATION OF VARIOUS SECTIONS.
- ONLY BASIC/ESSENTIAL COMPONENTS ARE INCLUDED FOR CONCEPTUAL PURPOSE ONLY.
- THERE MAY BE PROVISION OF INTERMEDIATE AIR INJECTION HOLES IN BETWEEN PA AND SA
- FOR A POWER STATION, THE LOAD WOULD BE A GENERATOR FROM THE OUTPUT SHAFT.

FIGURE I/2.4-7B Typical location of different sections of a GT.

2.4.5.1 GT Inlet Sections

A considerable mass of air must be supplied to the turbine for the complete system to properly function. This mass of air is supplied by the compressor through the inlet section. It is essential that the air inlet section (ducting) must provide clean, smooth, and continuous air flow to the heat engine to ensure long engine life by preventing erosion, corrosion, and mechanical damage to different GT parts. Mechanical damage may occur through inadvertent suction of small engine parts (nuts and bolts and washers, etc., and even flying creatures like bats, birds, etc.).

2.4.5.2 GT Compressor Section with Diffuser

In a GT (which is a rotary machine), compression is accomplished through aerodynamic activity as the air passes through the different stages of the compressor, contrary to the piston engine, which uses confinement. The compressor has many stages of blades and vanes to suit the

www.EngineeringBooksPDF.com

outlet pressure by using the pressure ratio. It also has inlet and outlet guide vanes for different purposes. The inlet guide vanes (IGVs) allow required air flow to the first-stage compressor blades at the "best" angle. The purpose of the outlet guide vanes is to straighten the air so the combustor is provided air flow in the proper direction.

It is very important that the compressor is fed with smooth air flow to minimize losses due to friction, air leakage, and turbulence to achieve higher efficiency. Pressure builds up in each stage of moving blades and stator vanes and is added up in the last stage according to the required pressure ratio.

A diffuser is provided at the end of the compressor where pressurized air enters through compressor outlet guide vanes. The diffuser, as a divergent duct, converts the maximum part of the velocity component of the flowing air into static pressure. This effect results in a point of highest static pressure and lowest velocity in the entire engine where the outlet of the diffuser and inlet of combustor meets. Apart from rendering this aerodynamic service, the diffuser section is also used for the following minimum facilities:

1. Engine structural support
2. Mounting of fuel nozzles for combustors
3. Support for the rear compressor bearings and seals
4. Oil passages for the rear compressor and front turbine bearings
5. Place for bleed air take-off (if any)

2.4.5.3 GT Combustor with Transition Section

The pressurized air from the diffuser then enters the combustor section (the combustion chamber where combustion of fuel with the presence of air takes place). There are a number of burners called liners/cans located within the annular space between inner and outer combustion cases. They are uniformly distributed throughout the periphery of the round (sectional) combustion chamber and positioned in such a way that the flame produced must avoid direct contact with combustor metal parts. Flame formation takes place at the front end or primary zone of the combustor section with the support of primary air (PA; $\sim$25−30% of total air flow). The SA, the balance of total air (often referred to as dilution air), is injected after the flame-forming primary zone for various purposes:

1. To control the flame pattern and stoichiometric ratio
2. To cool the combustor metals
3. To dilute the temperature of the products of combustion gases at the turbine inlet
4. To increase mass flow according to GT capacity by power requirement.

The latter part or the rear end of the combustor is called the transition section, which is a very convergent-shaped duct. It assists in accelerating the hot gas stream against the reduction of static pressure before entering the turbine section.

2.4.5.4 Turbine Section of GT

The turbine converts thermal energy into kinetic/mechanical energy by expansion of the hot and high-pressure gases to a lower temperature and pressure through many stages, each of which consists of a circumferential row of stationary vanes or nozzles followed by a row of rotating blades. Turbine stage stator vanes and moving blades are placed just in opposite order to that of the compressor. In the turbine, the stator vanes increase hot gas velocity; then part of the energy is imparted to the rotor blades.

The efficiency of the turbine depends mostly on the energy conversion capabilities of the vanes/blades and having the least amount of cross air flow around them instead of a guided and desired gas path. The turbine section of the GT engine has to drive the compressor and all engine accessories, meet the mechanical and electrical losses, and produce usable shaft power output to drive the generator or other load.

The next and last section is the exhaust through which the turbine discharges hot gas. Some amount of energy remains in the exhaust gas and is allowed to discharge in the atmosphere or to the HRSG plant or to produce jet thrust (for aviation services), depending on the design concept.

2.4.6 Black Starting of GT

GT plant black start-up occurs when the plant becomes isolated from the surrounding electric power system and thus must bootstrap itself into an operating state. The degree of difficulty in making a black start depends on the size of the plant and the power needed to drive all of the auxiliary equipment, which must be operating before the plant can start generating electric power.

Fuel supply for the black start comes from the main station's existing storage tank, which must have sufficient stock to supply the main plant and its facility during an emergency. However, it is important that the engine of the black start facility has a separate fuel storage tank big enough for 8 hours of continuous running at full load. It provides operational flexibility in the event of main supply failure and should add little to the overall plant cost.

Black starting a large GT generator with a fuel system is done using a fuel flow control valve to control the GT speed during and after start-up to a predetermined limit at a speed higher than rated and higher than the normal limit speed. In a black start mode a load rate limit is applied to this fuel flow control valve operation when the actual load change step exceeds a predetermined limit amount. It also applies the auxiliary plant loads sequentially to the GT

www.EngineeringBooksPDF.com

set to a predetermined sequence after successful start-up of the same.

The predetermined load limit is adjustable to the allowed load pickup limits of the GT. The predetermined load step limit differs for successive load steps in accordance with the expected size of the actual load steps. A control signal output limit is normally applied to the fuel valve control system and the control signal output limit is raised in this mode setting to permit step load increases to the turbine. Provisions are made for tracking the load step to allow reset of the fuel limit for each step and track ahead for the subsequent step. A temperature limit control is also incorporated into the fuel flow valve control.

There is a full remote control and monitoring system for the automatic alarm annunciation system, remote control, and synchronizing facility with data logging of the plant from the station as well as local service depot. The priority would be restoration of power supplies to essential infrastructure (e.g., lighting loads, sewage works, pumping stations). In the extremely rare occurrence of a total grid failure, it is expected that the transmission system would be restored within approximately 8 hours. The black start facility would provide full load within 60 seconds of start-up. In addition, under extreme circumstances, the facility can operate for up to 72 hours continuously. A suitable control system should provide an immediate and quick start, synchronization, and transient start performance of the black start plant. The connected grid system requirement should test the black start plant on a regular basis, ensuring reliable operation and testing the switching systems.

The electrical power, when finally restored to the external grid, is usually restored gradually to help secure stability of the system. For example, disconnection of electric power for a long period during summer or winter may demand enormous amounts of power at the time of resumption for air conditioning units and heating devices.

2.4.7 Different Steps to Implement Black Start

As previously discussed, black start is the process of restoring power by bringing all the connected power plants back into operation in the absence/failure of the external electric power supply system network. To provide a black start, it is necessary that the power stations have a small diesel generating (DG) set that can be used to start larger GTs, which in turn can then be used to start the main thermal power station generators. The hydroelectric or hydel generating set can also be used to source a black start, as it requires less electric power to start up by itself. A hydel power station requires a very small amount of initial power to start (just sufficient to excite the generator field coils and open the power-operated fluid intake gates) and can put a large block of power online very quickly to allow start-up. Providing such a large standby capacity at each station to facilitate a black start is extremely uneconomical, and power thus generated must be provided to other stations over the designated tie lines. The main power station with steam turbines and fossil-fueled power stations may then use the GT output power, which can supply ~10% of unit capacity for the BFP and forced draft (FD), induced draft (ID), and fuel-related equipment.

A typical black start sequence might be like this:

1. A small battery set starts a small DG set (or hydel generating station if available). Multiple DG sets can be used in parallel to power the emergency auxiliaries and the starting up mechanism and may be used as standby/emergency generators. They were specially designed to handle the high harmonic load. The electrical power from the DG set is used to bring the GT station into operation.
2. Essential electrical connections from the GT to other areas are resumed.
3. Power from the GT is used to start any main unit providing base load.
4. The power from the base load unit is used to restart all of the other power plants in the entire system.
5. For a comparatively bigger electric grid, black start in a particular station may not be useful as it would unnecessarily take much longer to complete the process. In this situation it would be wise to start different power stations (or "islands," each supplying local load areas) with individual black start facility and then synchronize and reconnect these stations to form the complete grid.

2.4.8 Different Systems to Implement Black Start

For simplicity, the DG set is the stored energy source for all types of black starts.

2.4.8.1 Self-Contained Black Start

A self-contained unit consists of an AC generator with GT as the prime mover, and is installed with all the auxiliaries required to operate independently to provide a black start. The system has the following auxiliaries/subsystems as well as both AC and DC drives as back-up (as applicable):

1. Lube oil pump
2. Compressor
3. Fuel oil pump
4. DG set with self-starter motor (battery power requirement)
5. Hydraulic turning gear mechanism for the GT rotor

This system is able to provide a black start even when only battery power and liquid fuel is available. Figure I/2.4-8 is an example of this system.

www.EngineeringBooksPDF.com

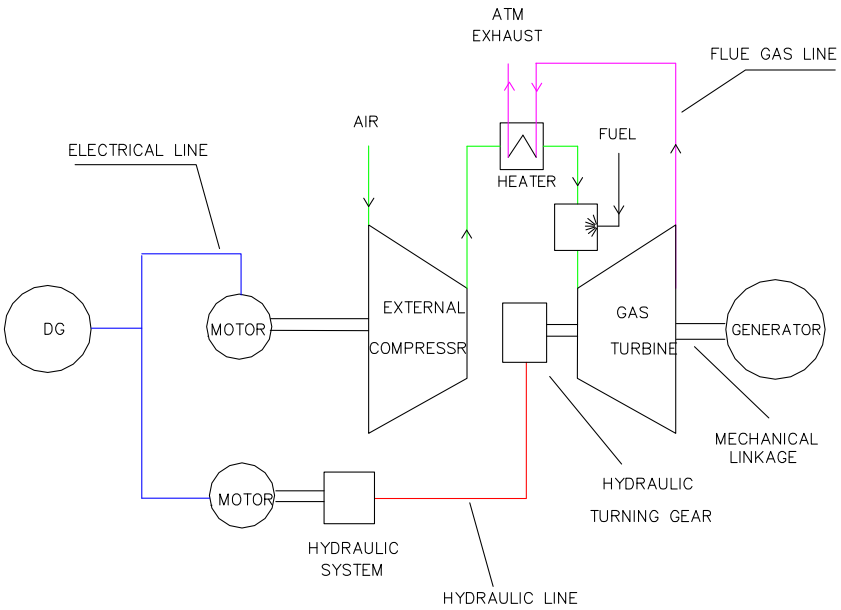


FIGURE I/2.4-8 Schematic diagram of GT black start (self-contained).

2.4.8.2 Black Start through Variable Frequency Drive or Load Commutated Inverter

This system has the following auxiliaries/subsystems:

1. DG set to provide an auxiliary bus, which would supply emergency power, variable frequency drive (VFD), and the GT generator rotor's exciter coil.
2. The VFD/load commutated inverter (LCI) output to drive the GT rotor.
3. Other auxiliary equipment as stated in Clause 2.4.8.1 to run DG sets.

The DG set must be suitable to handle a high harmonic load from the VFD if provided. Figure I/2.4-9 is an example of this system. There are two ways the VFD/LCI output can spin the GT rotor, and they are described below.

2.4.8.2.1 VFD/LCI to Drive the GT Directly In this system the VFD/LCI receives its power supply from the DG set(s) and its output drives the rotor of the GT generator as a synchronous motor to rotate the GT shaft from initial static position up to running speed. Considerations for this system include:

1. Amortisseur or starting windings to support the initial starting torque when the GT acts as a motor. The amortisseur windings are in the synchronous motors, but while the generator acts as a motor, they must be properly sized for high combined inertia loads such as in the gear box, compressor, and turbines.
2. Proper timing sequence must be designed for injecting the rotor field current so that synchronous motor action starts after starting the torque.

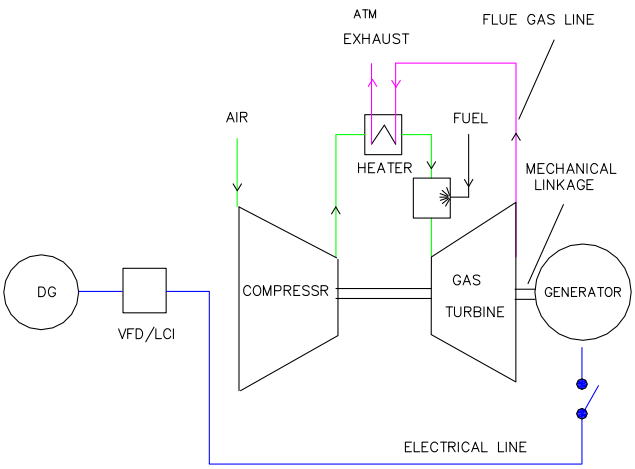


FIGURE I/2.4-9 Schematic diagram of GT black start with VFD/LCI For stator winding.

3. Proper timing sequence to withdraw the VFD/LCI output near the synchronous speed when used as a synchronous generator.

Amortisseur windings are additional windings in the rotating member in the form of bars and occur in the rotor of synchronous motors. These windings are made of copper bars short circuited at both ends, embedded in the head of the pole, close to the face of the pole. They are similar to the skewed, short-circuited bars seen in the rotor of the squirrel cage induction motors. During the static start-up

www.EngineeringBooksPDF.com

condition, the amortisseur windings are used to start the machine under its own power as an induction motor. The synchronous motor is not self-starting; hence, the motor starts initially as an induction motor through the action of these amortisseur windings and takes it unloaded to almost synchronous speed. When sufficient speed has been attained, the excitation to the rotor main winding of the synchronous machine is switched on when the rotor is "pulled in" by the synchronous torque. The motor then runs at the synchronous speed as a synchronous machine. During loaded condition, the function of these windings is to minimize the effect of load fluctuations by dampening the torsional oscillations in the rotor, and for that they are also known as damper windings.

The LCI uses technology involving load-commutated and phase-controlled power thyristors. The AC power supply from the DG set is applied to a converter, which acts as a rectifier and connects the output to an inverter through a DC link inductor (known as load the LCI). This is normally used for controlling the speed of the synchronous motor and incorporates thyristor full-wave bridges and does not need forced commutation at the inverter stage. The automatic thyristor turn-off is achieved with a synchronous motor as the load, if it has a leading phase angle with respect to the load voltage. For a given load, sufficiently increasing the field will produce a leading power factor. These can be referenced in the appropriate textbook.

With the LCI drive there is natural commutation of the thyristors of the inverter bridge(s) by the load and is available over a significant range of motor speed. The overall LCI operation is simple and reliable because of the phase-controlled thyristors and elimination of the forced commutation, which involves a capacitor discharge method to provide reverse biasing of the conducting thyristors. The output power directly connects the stator winding of the GT generator to act as a synchronous motor. The torque of the machine is controlled by the current through a DC link inductor, which controls the machine speed as required.

The inverter output frequency must be high enough to obtain a sinusoidal wave form, otherwise there is a risk of having a square waveform at lower frequencies. The higher frequency, on the other hand, would necessitate a lower turn-off time of the thyristors, which must be lower than the commutation time of the thyristors to obtain reliable functioning of the system. There is an upper limit of the frequency beyond which the commutation would not take place with the undesirable triggering of the thyristors.

The minimum combination of thyristors has a 6/6 pulse at the converter and inverter assembly, respectively, with other variations up to a 24/12 pulse system. The synchronous machine is excited by a field winding supplied with current from an exciter (may be of several types) as discussed in detail in Chapter 10, Clause 3.

2.4.8.3 Black Start through DG with Automatic Voltage Regulator Directly Connected to the GT Generator (without VFD/LCI)

Figure I/2.4-10 is an illustration of this system. Here the DG output is directly connected to the turbine generator

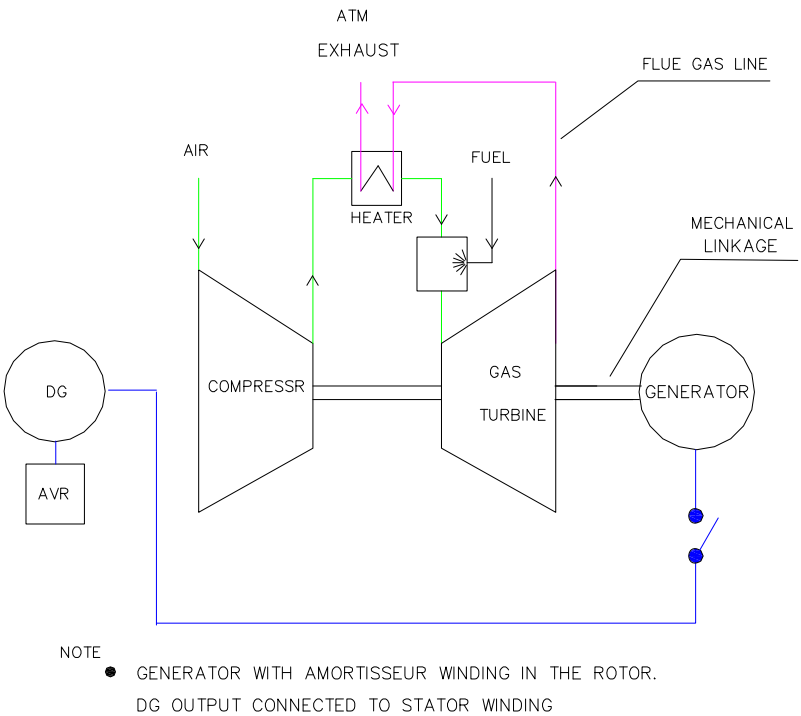


FIGURE I/2.4-10 Schematic diagram of GT black start through DG with AVR.

www.EngineeringBooksPDF.com

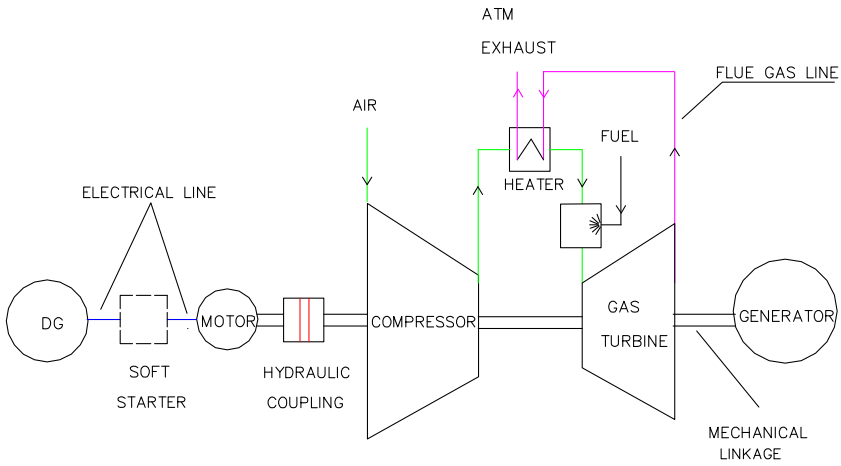


FIGURE I/2.4-11 Schematic diagram of GT black start through hydraulic coupling.

before the DG is started. There is no need for VFD/LCI as the DG would act as a frequency convertor. The automatic voltage regulator (AVR) supplied with the DG set generates an output voltage approximately proportional to the frequency/speed as the DG accelerates from a standstill condition. The DG set must be properly selected to support the start-up and acceleration of the GT generator with amortisseur windings. For such a scheme, two separate DG sets help with the lighting/emergency load and the black start of the GT. This system may be cheaper as the cost of two generators without the static convertor (VFD/LCI) should be less than the cost of one large generator plus a static convertor.

2.4.8.4 Black Start through Hydraulic Drive

This system is similar to what is described in Clause 2.4.8.1. In this system the GT uses an electric motor (induction) to spin the turbine through a hydraulic coupling (for achieving variable speed) up to the rated speed, thus eliminating the use of an external compressor. A soft starter to start the motor may be required for a higher capacity plant. A GT set handles the starting load and the emergency auxiliary powers. Figure I/2.4-11 illustrates this system.

2.4.8.5 Black Start through Electric Drive (Induction Motor)

This method is similar to a black start with a hydraulic drive, but without the hydraulic coupling. Here the GT uses a suitably sized induction starter motor to spin the turbine through a VFD/LCI (for achieving variable speed) up to the rated speed without requiring an external compressor. Additionally with this method there is a limiting inrush current at the instance of switching on. For example, a 15 MW GT set would require a 200 kW induction motor (typical value) and the inrush current may be quite high if started direct online. Modern VFD/LCI usually acts as a load from the DG set output at a power factor close to unity and with minimum harmonics. This would control the voltage amplitude and frequency to produce the slow initial turning and then acceleration required by the connected turbine through mechanical coupling (see Figure I/2.4-12).

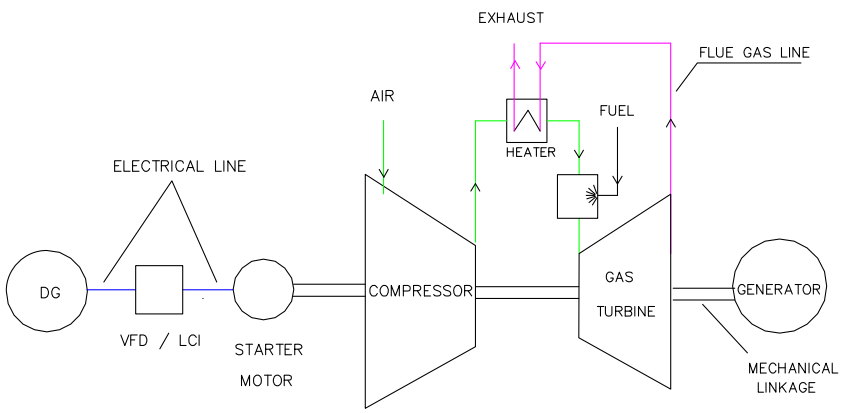


FIGURE I/2.4-12 Schematic diagram of GT black start through VFD/LCI and starter motor.

www.EngineeringBooksPDF.com

2.4.9 GT with Compressed Air Energy Storage Facility

Previously in this chapter, GTs using a compressor or compressed air supply differently were discussed. For example, in Clause 2.4.3.2 the two-shaft configuration has a power turbine without the compressor, and there is a separate compressor turbine that drives the compressor only and its hot gas exhaust is further expanded in the power turbine. In Clause 2.4.8.1 a self-contained GT black start also had a separate starting compressor. More developments have been made toward improving the efficiency of the GT. This is done by separating the compressor and the turbine with a compressed air source and not directly from the compressor. The compressor operates independently with the power supply whenever available, and the compressed air is stored in a separate reservoir. This new design operates more cheaply than earlier configurations.

The compressed air operates the turbine when required. As previously mentioned, the compressor takes about 50−60% of the total developed power from the GT, with an overall improved efficiency. Another advantage is that the energy can be stored when electric power is available during low demand at a low cost and used during high demand. This can be done because the GT has a separate compressed air source.

2.4.10 GT Emissions

As a product of combustion, the oxides are the main polluting agents along with volatile organic compounds (VOC) and particulate matter (PM). The main components of oxides are NO_X, CO, and SO_x, out of which the SO_x percentage is comparatively low as GTs operate on desulfized fuel. Using liquid fuel contributed through ash and metallic additives produces PM. Formation of thermal NO_X is dependent on the operating flame temperature, which is increased at higher loads. Formation of CO and VOC is the result of incomplete combustion, which takes place during low load operation in the GT. The desired condition of pollutant gas emission limits is shown in Figure I/2.4-14.

2.4.10.1 NO_X Control in GT

The control measure of NO_X in a GT is similar to that of a steam generator. As previously discussed, the power developed and efficiency from the Brayton Cycle depend on the firing temperature from the turbine inlet temperature. The GT is designed for a high temperature at the operating load; thus NO_X (thermal) control reduces the flame temperature only and lets the temperature rise further before the hot gas reaches the turbine inlet. The other source of NO_X generation is called "fuel NO_X," because the source is from fuel only and is not dependent on the temperature but is related to the availability of oxygen(O_2). The O_2 reacts with the gaseous state of the nitrogen compounds (NCH and NH_3) to generate NO in the air-rich condition. Under fuel-rich conditions these nitrogen compounds, because they are unstable, produce N_2 gas only.

2.4.10.1.1 NO_X Control of GT through Lean Air/Fuel Ratio Control A portion of total air is mixed with fuel before the flame develops; this is called PA and would be present at ∼25 to 30%. This is called the lean fuel/air ratio, which is much less than the stoichiometric air requirement and the flame produced by this incomplete combustion results in lower flame temperature, thereby suppressing thermal NO_X generation. The balance portion of the air flow or SA is added after to achieve complete combustion.

2.4.10.1.2 NO_X Control of GT through Lean Premixed Air/Fuel Combustion Another way to control NO_X is premixed combustion. Here the major part of the fuel is in a gaseous state and part is total compressed air (typically 50−60%, depending on the combustor design). These are mixed together and injected around the surface of the combustor so that local high-temperature zones are avoided. A small fraction of fuel is injected through the central part of the combustor where the igniter is located. In the absence of the stoichiometric air requirement, the fuel produces a flame but with a lower temperature, and secondary combustion takes place where the premixed air/fuel is injected and later when balanced air flow is injected near the rear part of the combustor. This process creates the flame hot spot temperature and less generation of NO_X. It demands a specially designed mixing chamber and combustor and turbine as well. The NO_X level can be substantially reduced to ∼9 ppm using this method, as claimed by a number of reputed manufacturers.

2.4.10.1.3 NO_X Control of GT through Selective Catalytic Reduction Selective catalytic reduction (SCR) is another method of controlling NO_X percentage in the exhaust hot gas as a part of post-combustion emission control. In this process, ammonia, with a suitable catalytic agent, is sprayed over the exhaust gas to react with NO_X resulting in N_2 and H_2O. Depending on the proper selection and exhaust gas condition, SCR can increase NO_X elimination by ∼80−90%. Generally, there are three types of SCR systems named for the temperature ranges in which they operate:

Low temperature: Works between 150 and 200°C and is located downstream the HRSG exhaust duct. This is not suitable for GT installation without HRSG.
Moderate temperature: Works in the range between 200 and 425°C and is located in between the GT and HRSG

www.EngineeringBooksPDF.com

or may be within the HRSG where the two temperatures (of the hot exhaust gas and catalyst operating range) match each other. This is also not suitable for GT installation without HRSG.

High temperature: Works between 425 and 600°C and is located just at the GT exhaust, irrespective of whether the installation includes HRSG or not.

While SCR application has a number of advantages, there are also a few drawbacks. First, the SCR is considerably more expensive. Second, there can be health hazards caused by the presence of ammonia, which demands *in situ* availability and may leak after prolonged operation.

2.4.11 GT as External Combustion Engine

As previously discussed, most GTs operate as internal combustion engines, but they can also work as external combustion engines. This system may be described as a turbine version of a hot air engine. Another way to describe the system is either as an externally fired GT or as an indirectly fired GT. The process is somewhat similar to the closed loop cycle discussed earlier, but uses fresh air at the compressor inlet instead of recycling the turbine exhaust (see Figure I/2.4-13).

The advantage of external combustion is twofold. Here the heat is added to the system through the heat exchanger; hence, only clean hot air with no combustion products travels through the power turbine. This means the turbine blades are not subjected to combustion products, so they can use cheaper quality fuels of low caloric value. Nonconventional types of fuels such as powered biomass (sawdust, for example) or conventional pulverized fossil fuels may also be used. Due to indirect heat transfer, the thermal efficiency of the external combustion engine is lower than that of the direct type of internal combustion engine.

2.4.12 GT Fuels

This is one of the most advantageous aspects of a GT. The GT is considered a multifuel engine and can operate on almost all of the commercially available fuels, such as gas, diesel, biodiesel, kerosene, natural gas, biogas, propane, and even powdered solid fuel like coal and biomass, with the external combustor. Some of these fuels, like solid fuels, diesel, or kerosene, also require something easily ignitable to start.

GTs operate on gaseous fuel or liquid fuel, and they also can be run on both fuels simultaneously because they are not restricted by their mass flow ratio. However, there are restrictions regarding the quality of the liquid fuel used. The presence of vanadium and sulfur cause high-temperature corrosion of the turbine blades, which ultimately results in loss of engine performance. There are specified limits and different standards for harmful ingredient content (typically 1% for sulfur and 0.5% for vanadium), which avoids deterioration of blade metals. Beyond these restrictions, it is common industrial practice not to use any residual fuel or any kind of cheaper distillates.

2.4.13 GT Control Systems

Other than control loops for auxiliaries, there are four main control loops associated with the GT control systems:

1. Speed/load
2. Temperature

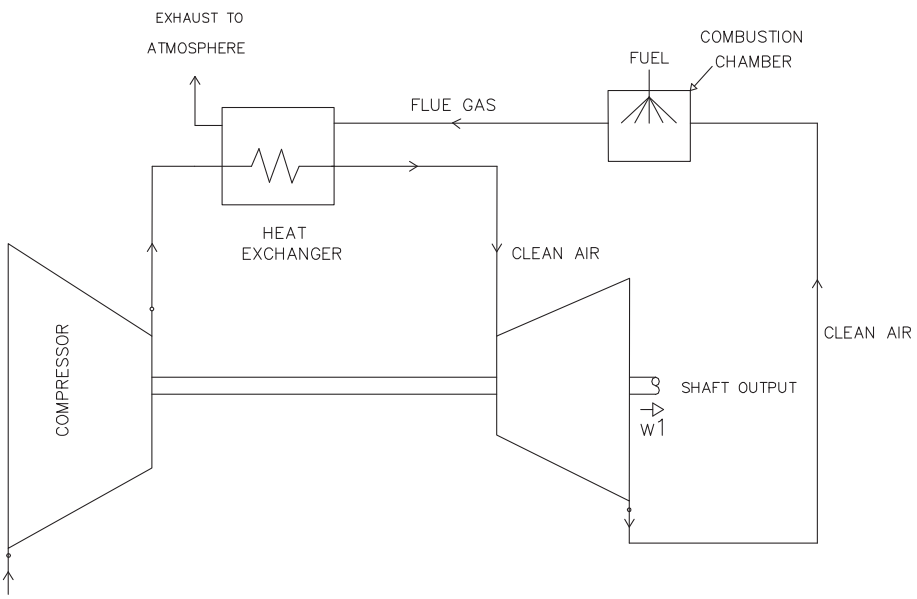


FIGURE I/2.4-13 Schematic diagram of GT with external combustor and heat exchanger.

www.EngineeringBooksPDF.com

3. Fuel flow
4. Air flow

2.4.13.1 Speed/load Control Systems

This control system has the load reference as its set point duly corrected by rotor speed deviation. Actual shaft output is the measured variable; it generates the requirement or fuel demand as the controller output.

2.4.13.2 Temperature Control System

The purpose of this control system is to control the combustor exit or turbine inlet temperature, as discussed earlier, to save turbine metals as well as to limit emission CO and NO_X. The relationship between temperature and emission of these gases is depicted in Figure I/2.4-14. The temperature acts as a measured variable and is compared with the fixed set value of temperature. The output forms the temperature control signal, which influences the "fuel flow control system" without any direct final control element. The controller output also determines the air flow requirement in that loop.

2.4.13.3 Fuel Flow Control System

The fuel flow demand from the speed/load control system is compared with the temperature control system output signal for a low value selection, and the selected lower signal determines the ultimate fuel flow demand. The final control element is the flow control valve, which regulates actual fuel flow to the GT.

2.4.13.4 Air Flow Control System

The air flow demand comes from the temperature control system output signal and acts as a set point against the actual air flow as a measured variable. The controller output adjusts the air flow through a final control element, for example, IGVs of the compressor. This air flow controls the desired gas temperature along with combustion control, as a major part of the inlet air flow is injected at the rear portion of the combustor, which acts as a cooling agent. Normally this temperature set point is kept lower than the GT rated value by ~1% (typically). For a particular GT, the air flow is proportional to the rotor speed. Variation from the maximum rated speed would change the characteristics of the air flow within the compressor.

2.4.14 Effects of Atmospheric Condition on GT Operation

Atmospheric condition plays a vital role in the performance of the GT. As stated earlier, the air flow is proportional to the rotor speed where flow signifies volume flow and not the mass flow. This means the compressor supplies a speed-dependent volume of air to the turbine without any relation to air mass or density. The turbine output depends on the mass of air passing through it; hence, at higher air density the air mass flow would be higher for the same volume of air and, consequently, the power output would be more when air is available at lower density from the atmosphere.

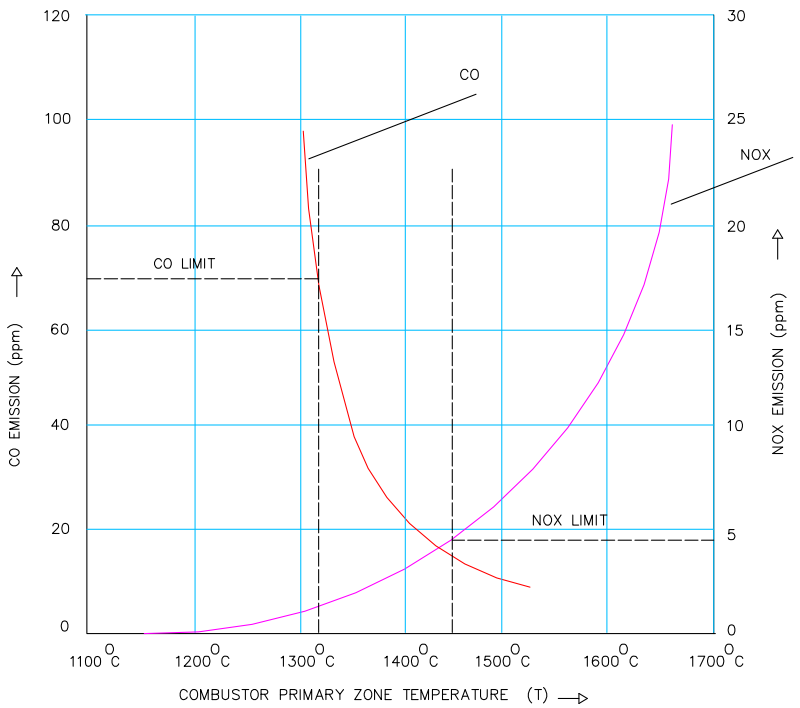


FIGURE I/2.4-14 Emission of pollutant gases presence with respect to temperature.

www.EngineeringBooksPDF.com

2.4.15 Influencing Factors of GT Efficiency and Performance

Efficiency of a GT is primarily defined by the specific fuel consumption of the engine at a given set of conditions. The performance requirement, on the other hand, is mainly determined by the amount of power developed at the output shaft of the GT for a given set of conditions, which includes the standard day conditions with the temperature and pressure duly specified. In general, these data are a datum line with which a variety of GTs can be compared. The majority of GTs are rated at 15°C and 1.033 kg/cm^2.

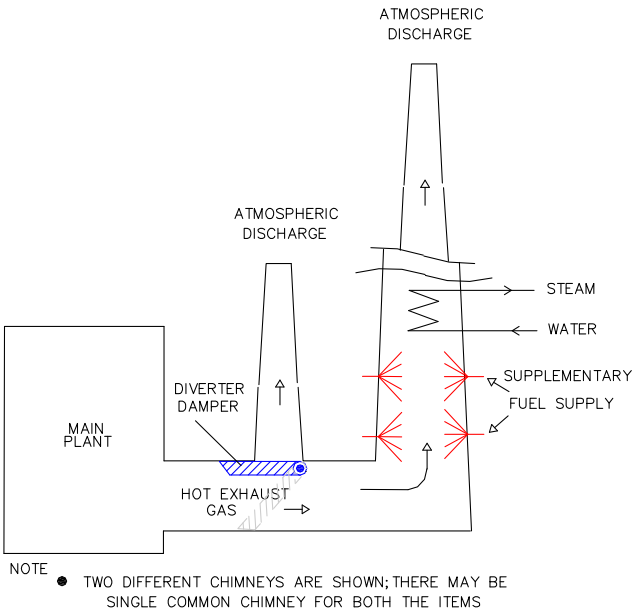


FIGURE I/2.5-1 Schematic diagram of heat recovery steam generators.

The type of operation for which the engine is designed also dictates the performance requirement of a particular GT. There is a number of influencing factors that affect both the efficiency and the performance of a GT, and they are summarized in the following list:

1. *Air mass flow rate* through the turbine determines the machine performance. Any constraint hampering the desired flow condition would jeopardize the overall performance of the machine.
2. *Pressure ratio of the compressor* affects both the performance and the efficiency of the overall GT.
3. *Hot gas temperatures at the turbine inlet* affect both the performance and the efficiency of the overall GT.
4. *Individual accessory/component efficiencies* influence both the performance and the efficiency of the overall GT.
5. *Air/gas leakage* also influences performance and efficiency.

2.5 Recovery Boilers: Introduction

The HRSG is the most popular type of recovery boiler that uses supplementary fuels (see Figure I/2.5-1). Some utility/process plants, especially in industrial applications, produce large amounts of excess heat with exhaust (e.g., flue gas) beyond what can be efficiently used in the process. HRSGs are boilers that reuse or recover this extra energy from hot exhaust gases of combustion chambers from, for example, generation plants, GTs, DGs/engine, etc., for generating steam. HRSGs are found in many combined cycle power plants. A very general schematic diagram is shown in Figure I/2.5-2 for an HRSG used in a combined cycle power plant. Exhaust gases in the main plant (e.g., GT)

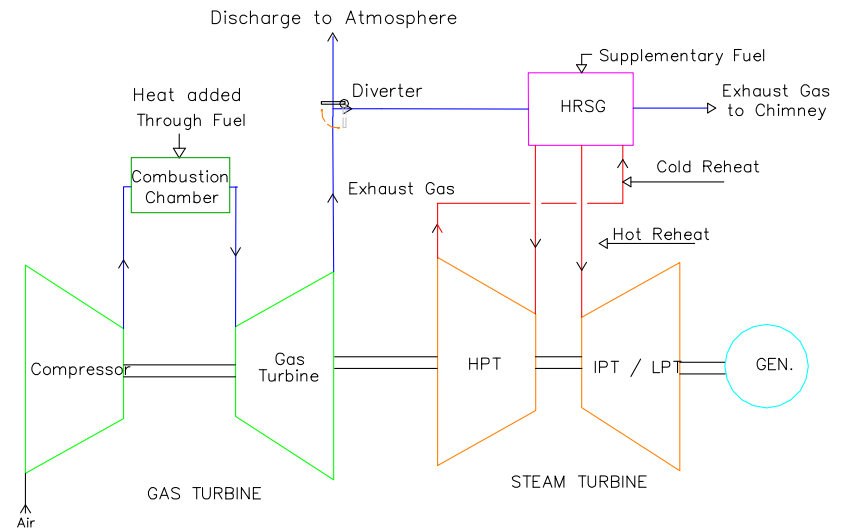


FIGURE I/2.5-2 Schematic diagram of HRSG utilized in combined cycle.

www.EngineeringBooksPDF.com

of ~400–650°C are again allowed to pass through and heat another bank of tubes mounted in the exhaust.

High-pressure and high-temperature water is circulated through the tubes, which produces steam through heat transfer from the hot exhaust gases. One advantage to an HRSG is that it separates the caustic compounds in the flue gases from the occupants and equipment that use the waste heat. In most plants, a flapper damper (or "diverter") is employed to vary flow across the heat transfer surfaces of the heat exchanger to maintain a specific design temperature for the hot water or steam generation rate.

The foremost requirement for an HRSG is that the hot exhaust gases must have sufficient reusable heat to produce steam at the required condition. HRSGs may be designed for either convective or radiant heat sources with horizontal or vertical shell boilers or water tube boilers and be suitable for individual applications ranging from gases from power plant furnaces, incinerators, GTs, to DG/engine exhausts. Where additional steam or pressurized hot water is needed, it may be necessary to provide supplementary heat to the exhaust gas with a duct burner.

While designing the system, it is important that gas-exit temperatures are maintained at a predetermined level to prevent reaching the dew point and properly introducing soot blowing to achieve acceptable thermal efficiency. Today even the small CHP stations would normally incorporate an HRSG/waste-heat boiler. Problems may arise from the source of waste heat (exhaust gas). Carry over from some types of furnaces can cause strongly bonded deposits and carbon from heavy oil-fired engines.

2.6 Process Boiler: Steam Supply at Different Pressures Compared with Steam Turbine Operation for Utility Purposes

Different industries use steam at various pressures and temperatures to make steel, textiles, chemicals, dairy, paper, fertilizer, etc. At the same time captive power plants have been built to meet industry standards, that is, a dual requirement of power and heating and/or process work steam. As the normal turbine exhaust steam pressure is too low to be used for further heating, a back-pressure turbine was introduced to make both ends meet. With suitably designed initial and exhaust pressure of the turbine, it is possible to generate the required power and heating/process steam for a particular industry.

2.6.1 Back-Pressure Turbine

As shown in Figure I/2.6-1, steam is generated at a moderately high temperature and pressure to suit the turbine power requirement and the exhaust steam is normally superheated and not usable in most of the processes for various reasons. These reasons include: (1) a problem in controlling its temperature, since it varies with the initial superheat and (2) the rate of heat transfer from superheated steam to the heating surface is lower than that of saturated steam. To circumvent this situation, the exhaust steam temperature is lowered by using a de-superheater. By spraying water over the superheated steam, the water vaporizes and the steam cools to make saturated steam. This steam is then used by the process heater and comes out totally condensed as water. The exhaust pressure is

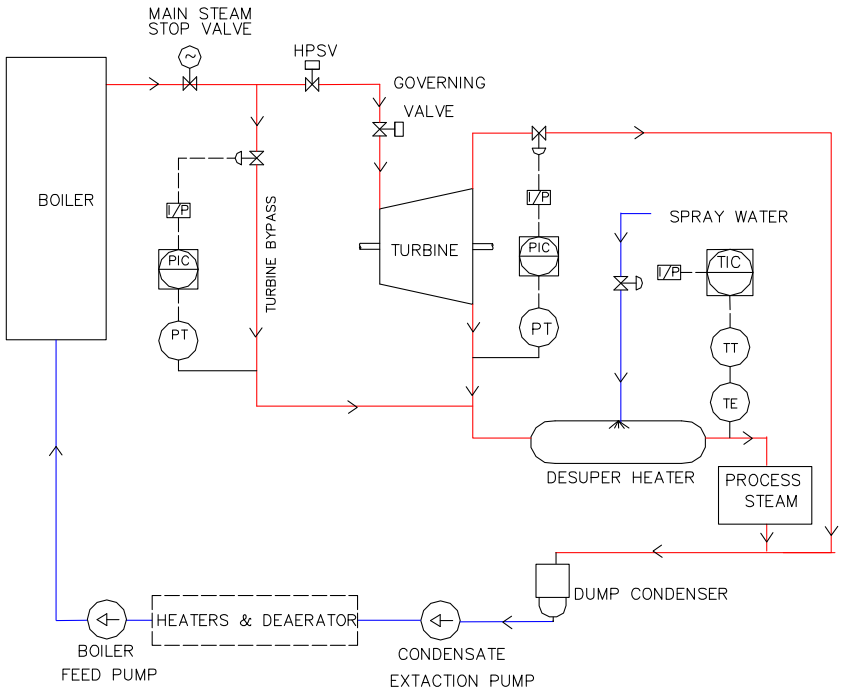


FIGURE I/2.6-1 Schematic diagram of back-pressure turbine.

www.EngineeringBooksPDF.com

controlled to avoid variation in saturated steam temperature.

If the back-pressure turbine is the only power unit, then the quantity of exhaust steam is controlled solely by the load on the turbine. For a low quantity, main steam is allowed to pass through a pressure-reducing valve to the de-super heater to fulfill the process heating requirement. On the other hand, for a larger quantity, an extra portion of exhaust steam is bypassed to another location.

If the back-pressure turbine is running in parallel with other machines, then the output solely depends on the heat load and control of the supply steam pressure is necessary so that exhaust steam pressure is maintained at a fairly constant value. A power station with this type of configuration requires steam conditioning with the help of a steam turbine bypass system to accomplish a fast and smooth start and stop as well as additional protection for the equipment if a turbine trips or there is any other emergency situation. One source of protection is the turbine bypass valve (BPV), which opens very quickly to prevent safety valves from popping up and prevents wastage of steam and heat. Downstream temperature control is also important; it has to match the process application with parameters close to the set point.

The additional but normal tasks done by the bypass system are listed below:

1. Steam to process requirement is supplied through the bypass system when the turbine is out of operation.
2. Turbine operates with insufficient load to fulfill the process steam requirement; that is, it makes up the shortfall of steam supply from the steam turbine compared to system demand.
3. For the back-pressure turbine connected to a generator, process steam is a priority requirement that may demand continuous operation of the bypass system for an allocated period of time.

2.6.2 Pass Out Turbine

There are some cases where the power available from a back-pressure turbine is less than required by the plant (see Figure I/2.6-2). This may be due to a low heating requirement or high back pressure or combination of both. The problem may be overcome in a two-stage turbine, where the main incoming steam expands through the high-pressure stage and supplies the heating steam from the exhaust. The balance steam passes through the low-pressure stage of the turbine to satisfy the power requirement. For any further heating steam requirement at any other pressure and temperature, a number of stages may be incorporated in the turbine for optimum power and heating output.

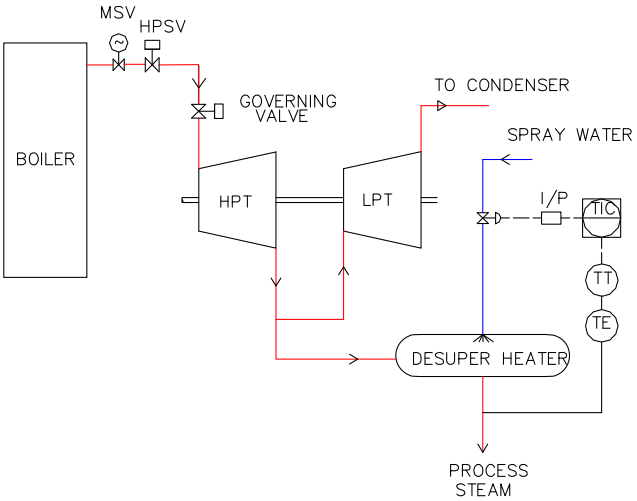


FIGURE I/2.6-2 Schematic diagram of pass out turbine.

2.7 Pressure-Reducing and De-Superheating Station: Purpose and Importance for Process Boilers/Initial Heating Up and Other Purposes

2.7.1 Pressure-Reducing and De-Superheating Station

As the name implies, the pressure-reducing and de-superheating station (PRDS) it a unit that conditions steam from a main system to an AS source of supply by reducing steam pressure and temperature using a pressure-regulating valve and water spray valve. In a process plant, steam is required at different pressure and temperature conditions demanded by different equipment, and the main purpose of this PRDS is to provide a steam supply to satisfy these needs.

2.7.2 Objective of the System

In the PRDS there is a steam header with fixed pressure and temperature (the parameter depends on the plant requirement) for a particular area where steam is supplied to various subsystems within the plant. This process-related steam is called AS. The basic purpose of the PRDS includes:

- Maintaining constant pressure and temperature at the steam header, irrespective of the source of supply for the AS
- Supplying AS to plant auxiliaries at a constant pressure and temperature
- Having more than one PRDS in a plant with a different pressure and temperature, depending on the area and process parameters of plant auxiliaries

www.EngineeringBooksPDF.com

2.7.3 System Description

For the process boiler there are several auxiliary plants and auxiliaries that require steam at different conditions. In addition, there is normally a turbo generator to provide electric power as a captive power plant. High-pressure steam required for the steam turbine therefore must be reduced to the desired pressure set point. This is achieved by a PRV that opens by a controller [may be a single-loop controller or a part of the main distributed control system (DCS) depending on the size and complexity of the plant] to a desired pressure set point. The inlet and outlet of the PRV (Figure I/2.7-1) is controlled with two remotely operated motorized isolation valves (post indicating valves) for isolating the control valve during maintenance.

During this time the system can be made operational by remotely throttling (inching) the BPV, which heats up the line before starting the PRV operation, by crack opening it. After pressure reduction is accomplished at the PRV, the steam is then allowed to pass through the de-superheating station to lower the temperature of the steam to the required value. The attemperation water is sprayed at high velocity through nozzles and at adequate quantity on the de-superheater. The desired value or set point is compared with a PID controller to generate the output signal, which determines the position of the de-superheating control valve (DSCV) by attemperation water flow to the de-superheater. At the inlet and outlet of the control valve (DSCV) there are two isolating remotely operated motorized isolation valves (TIVs) used to isolate the control valve during maintenance. During this time the system can be made operational by remotely throttling the BPV. In Figure I/2.7-1 two PRDSs are illustrated. The number of such stations depends on the requirement of the plants auxiliaries.

2.8 Vacuum and Dump Condenser

Whenever steam is involved in a plant there should be a condenser to prevent venting and reuse of process medium. There are two types of condensers: vacuum and dump. Modern thermal power plants use the former one while the process plants and CHP plants use the latter one. As discussed in Chapter II, Clause 3, the main function of the condenser is to condense the exhaust steam coming out of the turbine or process plant into water and recycle as depicted in the Rankin Cycle. Steam is condensed in a vessel by extracting heat through cooling and converted to water.

2.8.1 Vacuum Condenser

The very name implies that this type of condenser works under vacuum so that maximum boiler heat output is converted into work by the turbine. The typical operating parameters are 0.1 kg/cm^2 absolute, that is, ~0.9 kg/cm^2 vacuum at 45.4°C. The volume shrinkage is so huge that vacuum is created almost instantly. For instance, 1 kg of steam occupying 15,000 L at 0.1 kg/cm^2 pressure becomes only 1.0 L of water. For more details, see Chapter II, Clause 3.

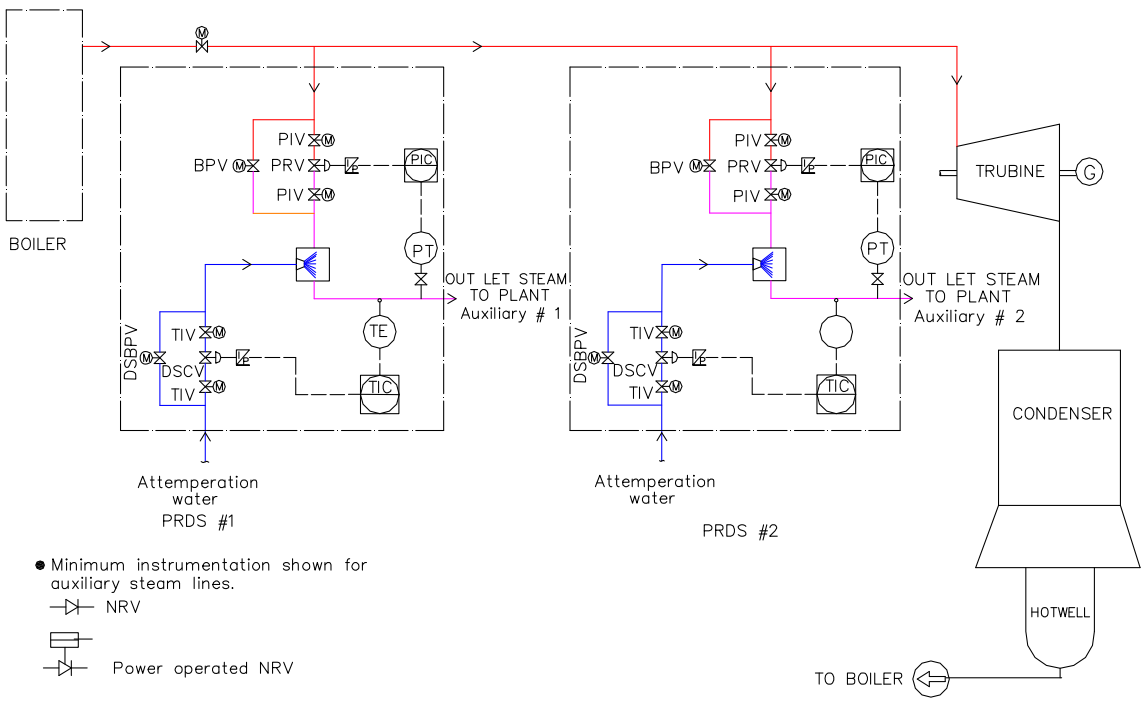


FIGURE I/2.7-1 Pressure-reducing and de-superheating station.

www.EngineeringBooksPDF.com

2.8.2 Dump Condenser

Dump condensers are mainly installed to reuse working fluid, that is, the bulk quantity of steam that might have been wasted by venting. In many power plants dump condensers are provided, in addition to vacuum condensers, to divert the excess steam during turbine start-up, huge load throw off, turbine tripping, or bypass.

In certain plant applications such as combined cycle plants, trash to steam plants, etc., the steam surface (dump) condenser is required to condense the steam that has bypassed the steam turbine. In the bypass scenario, the steam turbine is usually not functioning. The steam from the steam-generating devices bypasses the steam turbine and is admitted to the condenser at a suitable pressure and temperature. Dump condensers can be furnished as a system that may consist of a steam pressure/temperature reducing station and a condensate recovery system, which includes level controls, a condensate pump, and an electrical control panel for automatic operation.

Dump condensers are normally used for process plants and CHP plants when demand requirements, be it steam or turbo generator oriented, may vary and alter the steam pressure condition, which may cause safety valves to pop up. In general plants, such as combined cycle, co-generation, and refuse-recovery plants, where the steam generation is required to be continued while steam turbine maintenance is performed simultaneously, use dump condensers. However, in power plants where process steam is not required, the dump condenser is avoided due to space and extra cost constraints. The operating parameters of a dump condenser depend on the type of plant, which may not be under vacuum condition.

2.8.2.1 Air-Cooled Dump Condenser

Some air-cooled dump condensers are not used for condensing steam; instead they are used to cool hot gases before releasing to the atmosphere during an emergency. For example, plants utilizing residual heat through an HRSG boiler may need emergency cooling if the HRSG is taken out of service for maintenance or it breaks down. There must be some way to absorb the input heat after diverting the heating medium before passing through the chimney. In that situation a fast, air-cooled dump condenser that can immediately be put into service from a standstill condition to operate with full capacity may be used.

2.8.2.2 Water-Cooled Dump Condenser

The water-cooled dump condensers are used when there is a continuous requirement of steam condensation, for example, back-pressure turbine exhaust, power plants with a high-pressure and low-pressure flash tank, or process plants utilizing steam for heating purposes (see Figures. I/2.6-1 and I/2.8-1).

2.8.2.3 System Description of Different Types of Dump Condensers

The basic functions of all water-cooled dump condensers are the same: condense low-pressure steam and convert it to water by taking away the latent heat and a small amount of heat energy with a slight degree of superheat. The pressure of the condensing vessel, which is at saturated condition, varies from plant to plant usage and design criteria.

2.8.2.3.1 System Description of Dump Condensers in CHP Plants In a CHP plant, or co-generation (co-gen) plant, the main purpose is to provide steam to the process plant(s). Generation of electric power is the secondary purpose and the steam turbine (back pressure) passes all of the steam flow as required for the process at an exhaust pressure designed to suit the process demands. Ideally there should be no flow through the steam condensers when everything is running as scheduled and steam is not recovered from the process outlet. Normally the boilers generate sufficient steam in base load operation with the help of supplementary firing, which may be reduced or removed in case of lower demand to avoid dumping of steam.

The problem arises when equipment limitation or outages alter system demand. This may occur any time with no prior warning and cause abrupt and large changes in steam demand, depending on the type of disturbance. When, in case of emergency, the base load steam supply increases above the requirements even after total withdrawal of supplementary firing, the excess steam has to be diverted to the dump condensers for immediate removal from the system. Dump condenser steam temperature control is very important to ensure that vapor locking does not occur during the dumping operation.

2.8.2.3.2 System Description of Dump Condensers in Thermal Power Plants Small capacity thermal power plants normally do not require a dump condenser, as the main condenser handles the steam condensing at very high vacuum. The 500 MW TPS or larger capacity plants with high- and low-pressure flash tanks use a dump condenser (see Figure 2.8-1) High-pressure flash tanks are connected to the drain lines of HPHs for emergency dumping of steam in case of increased levels; LPHs and flash tanks are connected in the same way. Whenever the level of high-pressure flash tanks increases it drains to the low-pressure flash tanks, which in turn drain to a condenser when levels increase. The high-pressure flash tank's steam vent line is connected to move fluid to the dump condenser's steam chest area through a suitable nozzle connection to create necessary design pressure.

www.EngineeringBooksPDF.com

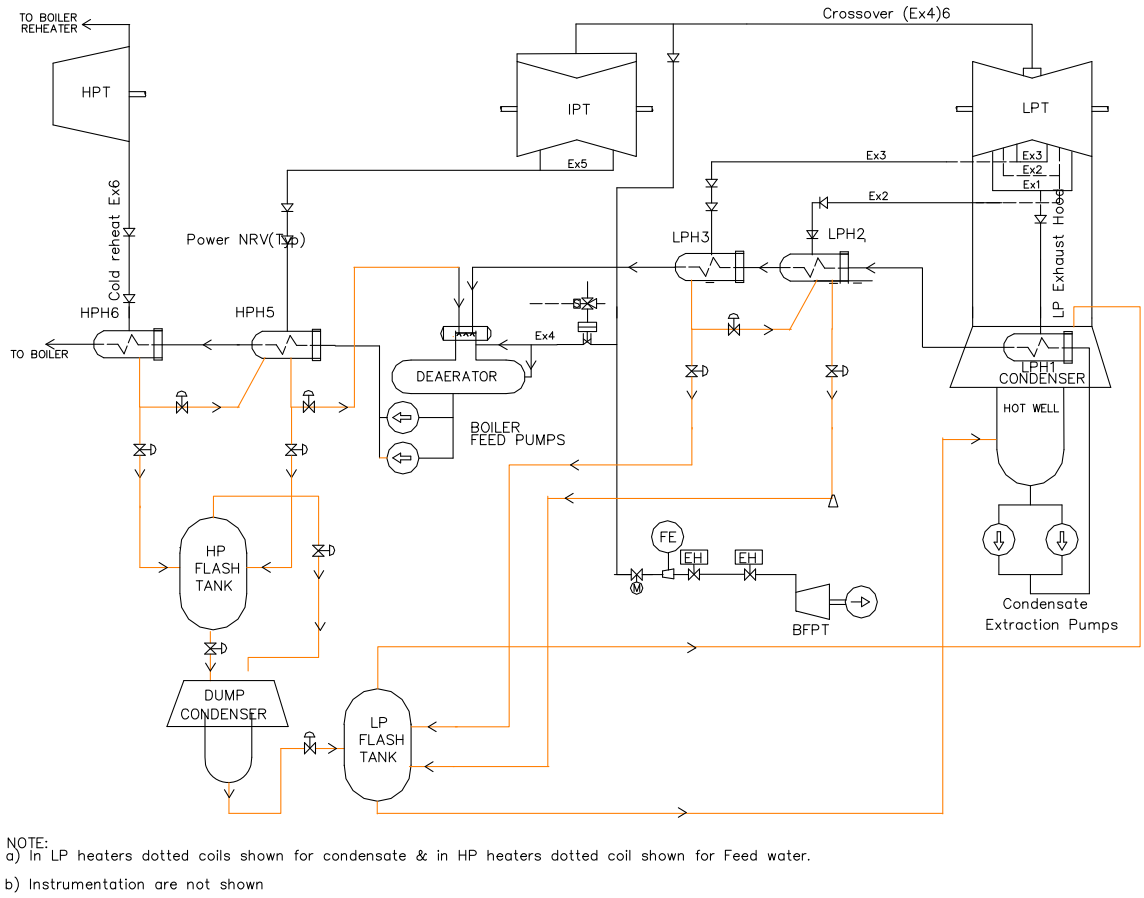


FIGURE I/2.8-1 Dump condenser/HP and LP flash tank flow/schematic diagram.

3. PROCESS PARAMETERS AND RANGES

Parameters are the basic physical and chemical characteristics or properties by which the state/condition of a matter or mass can be described. Some parameters are essential for various control systems, calculations, etc., such as flow or level. There are various process parameters, for example, pressure, temperature, flow, level, etc., which are required for measurement, control, data acquisition for analysis, storage and historical archives, and alarm annunciation systems as well as many other subsystems. All of these systems are provided to ensure safe and uninterrupted operation, maximum efficiency with minimum cost, inventory control, equipment life expectancy, etc. Some parameters are necessary for plant guaranty and acceptance tests with special types of instruments at various strategic measuring points. It is not always possible to directly measure or control properties, so it becomes necessary to deal with variables such pressure, temperature, flow, level, humidity, viscosity, density, etc.

Power plant operation is mainly based on the laws of thermodynamics, which demand instruments for parameters like pressure, temperature, fluid flow for steam and water, and level of and pressure drops across miscellaneous tanks and vessels. Because a turbine is a rotating machine, it requires a different set of parameters, such as speed, vibration, eccentricity, expansion, valve position, etc., as well as conventional parameters. For a generator, parameters are electrical and include voltage, current, power (MW/mega VAR), frequency, etc.

Some analytical parameters are also important for checking the condition of the working fluid, that is, dissolved oxygen, pH, conductivity, hydrazine, etc., for water and dissolved silica, dissolved hydrogen, conductivity etc., for steam. Another set of special analytical parameters is for environmental pollution control. These include smoke/particulate emission, SO_X, NO_X, carbon dioxide, carbon monoxide, oxygen percentage, etc., in flue gas. Typical values of a 210 MW thermal power plant parameters are included in Tables I/3-1 to I/3-3.

www.EngineeringBooksPDF.com

TABLE I/3-1 Typical Pressure Values

Parameters	100% BMCR Turbine VWO	94% BMCR 210 MW	80% BMCR 168 MW	60% BMCR 126 MW	Range	Unit
Steam at boiler outlet	158	—	—	—	200	kg/cm^2
Steam at turbine inlet	150	—	—	—	200	kg/cm^2
Steam at condenser	0.1	0.1	0.1	0.1	0–1	kg/cm^2 a
Steam at HPH 6	37	—	—	—	60	kg/cm^2
Steam at HPH 5	—	—	—	—	—	—
Steam at deaerator	10				15	kg/cm^2
Steam at reheater inlet (CRH)	38	37	29	22	60	kg/cm^2
Steam at reheater outlet (HRH)	35	34	26	19	60	kg/cm^2
Furnace	−3	−3	−3	−3	±25	mm of wcl

BMCR, boiler maximum continuous rating.

TABLE I/3-2 Temperature Values

Parameters	100% BMCR Turbine VWO	94% BMCR 210 MW	80% BMCR 168 MW	60% BMCR 126 MW	Range	Unit
Steam at boiler outlet	540	540	540	540	600	°C
Steam at HP turbine inlet	535	535	535	535	600	°C
Steam at reheater inlet (CRH)	335	330	323	315	450	°C
Steam at reheater outlet (HRH)	540	540	540	540	600	°C
Economizer inlet FW	244	241	231	219	300	°C

BMCR, boiler maximum continuous rating.

TABLE I/3-3 Typical Flow Values

Parameters	100% BMCR Turbine VWO	94% BMCR 210 MW	80% BMCR 168 MW	60% BMCR 126 MW	Range	Unit
Main steam	690	650	552	410	800	Te/Hr
HRH steam	600	571	458	351	800	Te/Hr

BMCR, boiler maximum continuous rating.

3.1 Purpose of Parameter Measurements

Measurements of various parameters are made for different purposes. With the advent of modern and state-of-the art technology, the measurement system is keeping pace with requirements for running plants in a safe and economic way. First and foremost is the plant and operator's safety. Next is the efficient running of the plant so that techno-commercial viability is established. The parameters required for different calculations, for example, plant efficiency, metal stress evaluation, etc., are measured and transmitted to the appropriate software packages. Some measurements are made for diagnostic or postmortem analysis. To circumvent single transmitter/sensor/switch failure, a previously decided plan of action should be

www.EngineeringBooksPDF.com

enacted (1 out of 2 or 2 out of 3 redundancy) depending on the criticality or necessity of the process parameter.

3.1.1 Measurements for Plant Safety

Measurements of plant safety are associated with the parameters whose values must be kept at a particular level; if they go beyond the maximum or minimum limit, there may be a catastrophic result. For example, the normal operating parameter for a furnace pressure is (−)3 mm (g) of water column (wcl). If the pressure goes beyond 200 mm toward the positive side, there is the possibility of an explosion, if it goes toward the negative side, there is the possibility of an implosion. It is too expensive to manufacture a furnace to withstand this higher capacity

Another example is the boiler drum level. Normally the drum level is maintained at a level below the center line of the drum by ∼100 mm. The design parameter does not permit the level to go beyond 150 mm toward the positive or negative side. If there is a positive side increase water could enter the particles inside the turbine. On the negative side, a limit is imposed to avert drum burn out from loss of adequate water to absorb the heat or uneven heat distribution, which causes stress in the drum metal.

The measurements are normally ON/OFF type switches that give binary signals to form start/stop/trip logic (to be implemented in a dual or triple redundant hardware) for almost all the equipment/drive or a central system, which decides the sequential or manually intervened start/stop /trip signals for the equipment/drive as per the present condition of the plant. The other important signals related to this parameter are

Loss of both/all FD or ID fans
Loss of all flame-sensing (ultraviolet or flickering type) scanners
Loss of all fuel (no oil and coal flow)

3.1.2 Measurement for Efficient Running/ Control of the Plant

These measurements are made to control the important parameters that enable the plant to have a continuous and trouble-free operation; this is done with an automatic control system called the DCS. The signals are continuous and generally analog (4−20 mA DC) or digital (through field bus or remote terminal unit).These are called control parameters.

The plant is a thermal power station, so the measurement of steam temperatures is very important as the work done by the turbine depends on the difference between the turbine inlet and exhaust temperature of each stage. The inlet temperature of the HPT is controlled by spraying an appropriate quantity of hot water at the boiler end, and that of IP turbine is controlled by tilting the burner assembly or SH/RH bypass damper (as per manufacturer) beyond their limit, by spraying hot water as a last resort. The turbine low-pressure exhaust temperature, although not controlled through DCS, is controlled by the condenser cooling water from natural resources or using a suitably designed cooling tower system.

The boiler load is maintained by controlling the main steam pressure at the turbine inlet. This control subsystem is called the master pressure control and is used to adjust the fuel input to the furnace. The set point of controlled main steam pressure may be a fixed value or a variable (sliding pressure) depending on the configuration of the boiler, turbine, and other associated equipment. The final control elements (the actuator/drive, through which actual final control action is executed) for fuel are the flow control valve for oil and/or mill/pulverizer (for coal) feeder speed.

The fuel whether oil or natural gas or coal, is heated before going to the furnace for efficient burning by a suitable temperature controller. There are separate controls for oil, which is heated by steam coil and/or mat heaters in the oil day tank and storage tank. After that the oil is heat traced up to the burner with a provision of short and long recirculation. For coal, the mill outlet temperature is the measured variable with a fixed set value of the controller, and the outputs are sent to hot air and cold air dampers to maintain the mill temperature. Mill air flow to carry the coal depends on the boiler load and is done by either the abovementioned hot air damper or the PA fan vane controls, depending on the manufacturer.

Air flow control plays a very important role in the efficient burning of fuels. The exact air flow depends on the quantity and quality of fuel input, which is guided by the stoichiometric ratio. More air flow (for example, 20%) is necessary to ensure complete combustion. This is achieved by measuring the residual oxygen and carbon monoxide percentage contained in the outgoing flue gas; the control system will take corrective action for arranging extra air to the furnace. FD fans provide the combustion air with the help of a variable blade pitch or inlet vane, depending on the manufacturer.

Another very important control is the furnace pressure(draft) control, which is accomplished by ID fans. The pressure transmitters for control purpose are located in strategic positions for representative measurement. Furnace pressure is maintained slightly lower (approximately −3 mm of wcl) than atmospheric pressure to arrest the flame and flue gas within the chamber, thus avoiding operational and environmental hazards. For the boiler drum, level control is very important for reasons stated earlier. Drum levels, as measured by redundant level transmitters, are fed to the controller along with main steam flow and FW flow signals to receive feedback of flow imbalance. There is a fixed set value against which the controller output drives the final control element such as a control valve in the main feed line or the scoop tube of hydraulic coupling to change the speed of the BFP. When the feed control valve controls

www.EngineeringBooksPDF.com

the drum level, the scoop tube controls differential pressure across the valve for smooth control. The problem with the latter control strategy is that there is a continuous energy loss across the valve, which can be eliminated if the valve is kept wide open at higher load with the pump changing speed as per requirement.

Level transmitters are provided for every HPH and LHP for its own shell level control. The flow control valves are in the drain line of each heater to the next lower pressure heater or vessel, for example, HPH 6 to HPH 5, HPH 5 to the deaerator, or LPH 3 to LPH 2, etc. Deaerator level control is achieved in two ways, and which way is chosen depends on the manufacturer's recommendation. The measuring level transmitter outputs are sent to the controller with a fixed set point. According to one philosophy, the main condensate inlet valve after condensate extraction pump's discharge opens or closes as per the controller output, that is, if the deaerator level decreases the inlet valve will open and vice versa. Here, condenser hotwell level control is accomplished by dumping deaerator water into a storage tank called the *condensate surge tank* through a separate line in case of a high level. In turn, the deaerator level decreases and then the condensate extraction pump discharge valve opens more so that the hotwell level becomes normal. For a hotwell low level, condensate from the storage tank is transferred to the condenser hotwell whose level increases to normal.

Another philosophy for deaerator level control is that whenever the level rises condensate is dumped into the condensate surge tank. When the level decreases, condensate from the storage tank is transferred to the condenser hotwell whose level increases. Its controller output then directs the extra condensate to a deaerator through the main condensate inlet valve to replenish its level. In both philosophies, the two valves operate in such a way that one valve will operate when the other valve has reached a full closed condition in either auto or manual position of the controller.

Measuring transmitters for condenser hotwell level control are selected based on its suitability in the vacuum service condition where the operating pressure is 0.1 kg/cm^2 absolute. The output of transmitters after selection/averaging is sent to the controller against a fixed set point. The controller output may be directed to the main condensate inlet valve after condensate extraction pumps discharge the line as per the latter deaerator level control philosophy. If the deaerator level control assumes the latter control philosophy, then the level controller output is sent to the dump control valve in the surge tank if there is a high level; if the level decreases then the condensate make-up valve to condenser opens. The two valves operate in such a way that one valve will operate when the other valve has reached a full closed condition in either auto or manual position of the controller. Here there is another valve in the recirculation line that is fully open at start-up and goes on closing as the load increases, and at ~40% load it is fully closed.

Although the preceding control and plant safety parameters are required for this category of measurement, there are other parameters measured for indication, recording, or data storage purposes. These parameters may be needed for various calculations, post-trip analysis, formation of process graphics, management data preparation, noncritical alarm annunciation signal generation and storing with critical alarms, etc.

3.2 Type of Instruments and Their Selection: Discussion

In a modern power plant, various types of instruments are required that need careful study and ultimately an informed decision is necessary before selecting them. These instruments may include a pressure transmitter or a temperature element/transmitter, etc. A brief discussion about these instruments may help beginners with power plant requirements.

As far as range is concerned, the general notion is that the normal operating value will be approximately two-thirds of the value of the selected range. For example, for a parameter with an operating pressure of 67 kg/cm^2, the range will be 100 kg/cm^2. The trim materials or the wetted parts of an instrument also guide the selection as per the physical or chemical nature of the operating fluid, such as temperature, pH, slurry service or not, whether of an abrasive nature, etc. Selection of an instrument is also dependent on the characteristics of the instrument, such as static and dynamic characteristics. Static characteristics of process variables do not change, such as accuracy, reproducibility, sensitivity, etc., whereas dynamic characteristics of process variables do change, such as responsiveness, fidelity, etc.

3.2.1 Pressure Elements/Gauges/Switches/Transmitters

In a large capacity modern power plant, the operating pressure varies from 0.1 kg/cm^2 absolute to ~300 kg/cm^2 g. The simplest device used to measure pressure is the manometer, which is used for measuring very low pressure. Gauges are used for higher pressure application. Switches are used for alarm generation and binary control purposes, for example, starting, tripping, and interlocked operation of different drive motors and safety relays or equipment. Some sensing elements use the amount of expansion or displacement characteristic of the material when subjected to pressure; these are called elastic deformation pressure elements, and they change shape under pressure. For gauges, switches, and even for a pneumatic pressure transmitter the expansion or displacement characteristic is

www.EngineeringBooksPDF.com

TABLE I/3.2-1 Pressure-Sensing Elements and Corresponding Ranges

Element Type	Minimum Range	Maximum Ranges (kg/cm^2)
Diaphragm	50 mm of wcl	28
Bellows	125 mm of wcl	56
Capsule	25 mm of wcl	3.5
Bourdon tubes	0.85 kg/cm^2	7000
Spiral	1.05 kg/cm^2	280
Helix	3.5 kg/cm^2	700

utilized by different elements: bellows, diaphragms, bourdons, helices, capsules, and spirals depending on the pressure maximum and minimum ranges. Some typical values are indicated in Table I/3.2-1.

Elements such as the ring balance type and wound resistance in varying shapes are now obsolete. For electronic transmitters, different types of elements are used: capacitance, dual inductance, strain gauges, piezo resistive, piezoelectric, silicon resonance, twin resonance, nitinol wires, etc. In capacitance type sensor elements, a diaphragm is used as a primary element with measuring pressure on one side and atmospheric pressure on the other. The diaphragm moves toward the lower pressure side, and this deflection is sensed as change in capacitance and ultimately into a two-wire 4−20 mA DC signal. For a strain gauge, when pressure is applied, the deformation due to stress is converted into an electrical signal. For other operating principles, the change in electrical characteristics due to physical change after applying pressure is sensed and converted into a 4−20 mA DC signal. For smart transmitters, superimposed digital signals proportional to input pressure are also available in the same output terminals. For differential pressure transmitters, the same philosophy applies: two process pressures are connected to the transmitter with higher pressure tapping the impulse line on the high side and lower pressure tapping the impulse line on the low side.

3.2.2 Flow Measurement

There are various was to measure flow: flow switches, flow transmitters and flow gauges. With flow gauges, sight flow glass is used to see that fluid is passing without any calibration. Flow gauges are also called flow meters or rotameters, and there are positive displacement types such as ovalgear meters, nutating disc meters, etc. These meters indicate flow rate as well as cumulative flow value and even have a compatible electrical signal of 4−20 mA.

Flow switches and flow transmitters are also used for flow measurement. There are various types, such as flapper, target, and diaphragm. Switch contacts are available in flow meters, but normally are not used for control purposes. Flow transmitters may be a differential pressure transmitter (DPT) type with two pressure impulse lines connected across flow elements or a differential producer. There are many types of differential producers, such as flow nozzles, orifice plate, and Venturi tubes, and their use depends on the service condition (discussed in Chapter IV, Clause 4). The differential pressure produced is proportional to the square of flow as deducted from Bernoulli's theorem and the transmitter output is calibrated accordingly.

Other types of flow elements are also available that create restriction in a particular section of a specially designed flow path for open channel flow measurement. The flow elements are weir notches (V-shaped or rectangular notches) or a Parshall flume. When passing through this type of restriction or the flow path (Parshall flume), the liquid level increases near the path inlet and this increased level is proportional to the flow. Normally this type of level is measured by an ultrasonic level sensor and transmitter with the built-in software providing flow output.

Magnetic flow meters are based on the electromagnetic property of a conductor. Here, the electro motif force (EMF) generated is directly proportional to flow velocity. The only criterion for the flowing media is that the conductivity must be >0.5 μS/cm. There are other types of flow meters, such as vortex, coriolis, wedge, thermal mass, etc., but they are not normally used in power plant flow measurement.

3.2.3 Level Gauges/Switches/Transmitters

Level gauges are normally called gauge glass, which is located near the vessel. A calibrated glass tube of suitable thickness and material (borosilicate or toughened) is placed vertically with the help of upper and lower limbs (pipes/tubes) covering the level to be observed. Almost all heaters, tanks, and boiler drums are provided with gauge glass for a direct reading. Other types of gauge glass are available for boiler drums with bicolor indicators showing steam as red and water as green.

Level switches of various types are available including conductivity, capacitance, float, magnetic float, displacer, ultrasonic, paddle, and radio frequency. For an open tank, conductivity type switches may be used when the fluid is highly or moderately conductive, and capacitance type switches may be used for low conductive fluid. Level ranges can go up to 5−10 m. Displacer and float types are also used, but the range is limited to 0−2 m for top-mounted switches. Side-mounted float types may be used at any level. Ultrasonic or radio frequency types may be used for a high range up to 30 m. Paddle type switches are used only for solid level service, that is, coal or ash in the bunker.

www.EngineeringBooksPDF.com

TABLE I/3.2-2 Temperature Ranges of Different Thermocouples in Use

Types of Thermo Couples	Iron-Constantan (Type J),	Copper-Constantan (Type T)	Chromel-Alumel (Type K)	Platinum-Platino Rhodium(13%) (Type R)	Platinum-Platino Rhodium(10%) (Type S)
Temperature range in °C	−210 to 1200	−200 to 400	250 to 1372	−50 to 1768	−50 to 1768
Used for measurement parameters			Steam temp. above 300°C	Furnace Temperature ~1000°C	Furnace temperature ~1000°C

For a pressurized tank, side-mounted magnetic float switches may be used at any level, but they are limited to a pressure rating of ~25 kg/cm^2. For very high pressure, a special type of conductivity switch is available called Hydrastep, which is used for boiler tripping from a very high and low drum level.

Level transmitters, when operated on the differential pressure principle at the same pressure or DPT, are used for open tanks or pressurized tanks, respectively. These types are used for level measurements for drums, all heaters, deaerators, condenser hotwells, and condenser surge tanks. Displacer type transmitters are also used for pressurized tanks, whereas conductivity, capacitance, ultrasonic, and radio frequency type level transmitters are used for open tank measurement.

3.2.4 Temperature Measurement

Temperature gauges and switches use the volume expansion characteristics of fluid after heat or the temperature are applied. There is a bulb containing transmission fluid, which is placed at the sensing point. The transmission fluid may be an inert gas like nitrogen or liquid like mercury, alcohol, etc. The receiving side may be bellows, a diaphragm, a bourdon, a helix, a capsule, or spiral-like pressure sensing element. A bimetallic element is also used, which will bend in one direction when heat is applied to two metals of dissimilar coefficient of expansion are joined together.

Unlike the pressure transmitter where the sensing element and processing circuitry are located in the same enclosure, temperature sensors/elements are located separately at the sensing point inside the process. Normally the sensors/elements are isolated from the process fluid, which may have a high velocity of abrasive and/or hazardous nature. This isolation is done using a thermowell, which takes care of process-side problems and is normally threaded and/or welded to the process pipe or vessel. Inside the thermowell there is a female thread to accommodate the sensors/ elements.

Sensors/elements consist of a resistance temperature detector (RTD), thermocouple (THC), thermistor, etc. An RTD uses the property of changing resistance of a wire with respect to change in temperature. The resistance in a medium increases when the temperature rises. It is used in the temperature range of (−)250 to 850°C. There are three types of RTD: copper (53 Ω at 0°C); platinum (100 Ω or 1000 Ω at 0°C), also platinum resistance thermometer (PRT); and nickel (100 Ω or 500 Ω at 0°C). Normally PRTs are widely used in power plants to measure water and air temperature <300°C.

Thermistors also show a similar quality, but in the reverse direction. The resistance of the element decreases when the temperature rises. Thermocouples use the thermoelectric property of EMF in millivolts between two open ends when two dissimilar metal wires are solidly connected at the end and subjected to a higher temperature than the other open ends. Various types of thermocouples are used: iron-constantan (type J), copper-constantan (type T), chromel-alumel (type K), platinum-platino rhodium [two types with 10% (S type)and 13% (R) type) of platinum in the alloy] (see Table I/3.2-2).

BIBLIOGRAPHY

[1] Ballaney, P.L. Heat Engines, vol. I (Mechanical Engineering), sixth ed. Khanna Publishers, India. 1973

[2] GE Gas Turbine Performance Characteristics [GE Power System *GER-3567H*(10/00)]. By Frank J. Brooks, GE power Systems, Schentady, NY (16 pages).

[3] Product Bulletin CEPSI 2008/GTj of Siemens Gas Turbine (SGT-800).

[4] Design Features/Concepts-Transcanada.

[5] Update: Advanced Gas Turbine Technology (February 2004 Modern Power Systems)—GE.

[6] DG Set System. Bureau of Energy Efficiency, Chapter 9. Ministry of Power, Government of India.

[7] Excerpts from Wired For Success by Randy Rundle. Krause Publications, November 1, 1995

[8] Island operation tests in a SCC-800 CHP Plant—an example from an operating plant in Sweden. Paper presented by Göran Tjellander (Siemens, Sweden).

[9] Lesson 40: Load-commutated Current Source Inverter (CSI)-Version 2 EE IIT, Kharagpur.

[10] CHP— Guide to Steam Conditioning. Paper presented by M/s CCI.

[11] Excerpts from Energy Solutions Center, DG Consortium 2004 (Chapter 4/4−3).

www.EngineeringBooksPDF.com

Chapter II

Main Equipment

1. OVERVIEW OF TYPES, FUNCTIONS, AND DESCRIPTION OF MAIN EQUIPMENT

Modern large thermal power plants have evolved as a result of years of research work, experience, and state-of-the-art technologies; however, the basic equipment and/or subsystems are more or less the same, of course, with a lot of sophistication and technological development to increase efficiencies.

There are five (5) fundamental elements, as shown in Figure I/2.1, that may be referred to for an overall idea at a glance; they are the following:

- Boiler
- Turbine
- Condenser
- Boiler feed pump
- Generator

Some other subsystems are, namely, the regenerative heating cycle or offsite packages such as a water treatment plant (demineralization and pretreatment), a coal-handling plant (CHP), an ash-handling plant (AHP), an oil-handling plant (OHP), circulating water (CW) and auxiliary circulating water (ACW) systems, a condensate polishing unit (CPU), and others. This clause briefly describes the functions of the preceding elements vis-à-vis the main equipment with important auxiliaries.

1.1 Boiler

A boiler is a combination of several items that is a means for combustion to provide energy to be transferred to water until it becomes heated steam that is then used for transferring the heat to the turbine. Water is used as the working fluid to transfer the heat to a process because it is not expensive. As a result of the tremendous volume change after the water is converted to steam, it needs careful handling. The main subsystems or system auxiliaries are divided into three (3) principal categories: fuel and air/draft system, feedwater (FW) system, and steam system; each has various supplementary items or equipment to make them suitable for use in large and modern power plants.

1.1.1 Fuel and Air/Draft System

The fuel and air/draft system includes all necessary auxiliary equipment required to make fuel available to create the necessary heat. The equipment needed for the fuel system depends on the type of fuel used in the system. The amount of fuel and air required for steam generation is automatically controlled per steam demand. Mills/pulverizes are used for solid fuels, pumping and heating units are required for liquid fuels, and compressor/boosters are required for gaseous fuels, of course with a suitable type of burner and air supply arrangements. Supplementary equipment and/or items are comprised of the following:

Mills/pulverizers: For solid fuels, mills and pulverizers are supplied with the main equipment so as to achieve higher thermal efficiencies and for spontaneous ignition through burning of finely powdered fuel. The type of mills and pulverizers depends on the type of fuels. Associated feeders and so forth are also a part of this subsystem.

Pumps and heating units: For liquid types of fuels, supply pumps are needed and heating units are also required for a viscous type of fuel such as heavy fuel oil (HFO)/heavy sulfur heavy stock (LSHS) and others.

Fuel burners: This category covers both oil and solid fuel with various designs—for example. low NO_x burners. Burner type also varies with type of atomizer, etc.

Air flow control elements: These are, for example, forced draft (FD) air fans, primary air (PA) fans, air dampers or registers for fuel air, auxiliary/secondary air, overfire air, etc.

Draft system or flue gas system: These include induced draft (ID) air fans and various flue gas dampers for evacuating the product of combustion from the furnace.

Soot blowing system: Periodic cleaning of soot buildup, which damages boiler metals and causes inefficient operation, on the radiant furnace surfaces, boiler tube banks, economizers, and air heaters is accomplished using a soot blowing system that blows hot steam on a regular basis.

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

1.1.2 Feedwater System

The feedwater system provides necessary piping, heat exchangers to preheat water, a recirculation system (if so designed), and feed control valves to control the required amount to meet the steam demand.

Pressurized and preheated water supplied to the boiler as the working fluid to be converted into steam is popularly called *feedwater* in a normal running condition. There are two sources of feedwater: the major part is condensate that is nothing but condensed steam from the condenser and many other heat exchangers used in the processes; the minor part (3∼5%) is the continuous and/or intermittent makeup water (demineralized, DM water) that must come from outside of the boiler.

It also includes blowdown and chemical dosing systems to drain a part of the feedwater when it contains dissolved solids unacceptable to boiler metal, or a reason for scale formation that resists heat transfer causing localized overheating vis-à-vis boiler tube failure, foaming causing carryover to turbine, and so on.

Chemical dosing: This is done to clean the feedwater to avoid blowdown causing both heat and water loss making it slightly alkaline to minimize metal loss due to a chemical reaction.

Boiler circulating water system: In some plants, a boiler circulating water pump (BCWP) is deployed for better circulation of feedwater in the boiler with its suction connected to a steam drum and a discharge connected to a boiler water wall header. Furnace height may be reduced by having BCWP.

1.1.3 Steam System

The steam system includes evaporation of water up to superheating, reheating of cold steam (for a hot reheat system), collection and transfer of the steam through a piping system to the turbine. Throughout the system, excess steam pressure is regulated and/or vented through suitable valves automatically.

1.2 Turbine

The turbine accepts steam from the boiler at a high temperature and pressure, and converts the heat energy into mechanical energy for driving the generator. The following are the associated subsystems:

- Turbine oil system (lubricating, control, and power oil)
- Turning gear/barring gear
- HP/LP bypass system
- Governor and isolation valves
- Gland sealing systems

1.2.1 Turbine Oil System

This subsystem is one of the most important items; it supplies the lube oil to all the bearings, hydraulic control oil, jacking oil, and actuator power oil through individual oil coolers, strainers, redundant pumps, etc.

1.2.2 Turning Gear/Barring Gear

The turning gear (or barring gear) is basically a gear arrangement provided to rotate the turbine generator (TG) rotor shaft at a very low speed before turbine startup and after unit shutdown at low speed (∼1% of rated speed) by the turning the gear until the temperature comes down sufficiently.

1.2.3 HP/LP Bypass System

These subsystems are supplied to protect the boiler reheater from a burnout when no steam is passing through the turbine with the boiler generating steam during start up or running or tripped condition.

1.2.4 Governor and Isolation Valves

These valves are provided for both high- and intermediate-pressure turbines. Both are hydraulically operated and are special valves with high controllability and isolating capability, respectively.

1.2.5 Gland Sealing Systems

Turbine glands are a part of the turbine so that steam cannot escape from the higher pressure parts of it and air cannot enter the lower parts of the turbine. However, many parts of the turbine operate at such a high pressure that it cannot prevent leakage to the full extent. On the other hand, the lower pressure parts operate at a subatmospheric region so air ingress cannot be totally eliminated. This subsystem is provided to seal the glands in such a way that leakage of steam from the high side is controlled at a certain pressure and extra steam from the control valve outlet is diverted to the low-pressure (LP) side glands to arrest air ingress by maintaining a certain pressure.

1.3 Condenser

The function of condenser is to condense the steam coming from the turbine exhaust. High vacuum is maintained to extract steam and then cool it vis-à-vis condensation through exchange of heat with the cooling water from a separate source. The following comprise the subsystems:

- Steam ejectors or external vacuum pumps, vacuum breaker
- Cooling water system or cooling towers

www.EngineeringBooksPDF.com

- Condensate extraction pumps
- Heat exchangers (drain/gland steam cooler, LP heaters)

1.3.1 Steam Ejectors or External Vacuum Pumps and Vacuum Breaker

Steam ejectors or vacuum pumps are provided for maintaining a high vacuum at the condenser. Starting ejectors are meant for the initial operation of the condenser to achieve the vacuum quickly whereas running ejectors are for regular operation. A vacuum breaker is provided for speedy breaking of the condenser vacuum in an emergency condition in order to arrest the turbine from overspeeding in case of problems at the generator side.

1.3.2 Circulating Water Pump System or Cooling Tower

The circulating water is supplied to the condenser by external means. The open-loop configuration allows transfer of seawater or river water through circulating water pump (CWP) and back with a higher temperature after the exchange of heat. The closed-loop configuration allows for a cooling tower (CT) where the hot return cooling water is spayed from a height to exchange heat with the ambient air.

1.3.3 Condensate Extraction Pumps

The condensate extraction pump (CEP) are connected to the condenser hot well to take out the condensate and deliver it to the rest of the water circuit of the whole cycle.

1.3.4 Heat Exchangers (Drain/Gland Steam Cooler, LP Heater)

The CEP discharge line is connected to several heat exchangers, as just stated, in a series up to the deaerator and is popularly termed a *condensate*.

1.4 Boiler Feed Pumps

The outlet of a deaerator is connected to the boiler feed pump (BFP) suction and from there to the popular term of the working fluid—feedwater—to reach the boiler proper. It impels the FW with requisite pressure that dictates the working or operating point of steam generation. BFPs are always supplied in a redundant configuration to avoid interruption of operation. Normally, one motor-driven BFP is kept for startup and emergency situations and one or two turbine-driven BFPs (maybe a motor as well) are kept for operating up to a full load.

1.5 Generator and Exciter

This preceding set is the ultimate equipment to supply electric power, having received the mechanical energy from the turbine and conversion thereof. The following are the two auxiliaries with which the generator is associated for efficient operation:

1. Hydrogen cooling system
2. Hydrogen and seal oil system
   a. Excitation system
   b. Stator cooling water system
   c. Generator inerting system

1.5.1 Hydrogen Cooling System

Generators of modern thermal power plants require very efficient cooling. Hydrogen, with a thermal conductivity that is almost seven times that of air, is generally used as the efficient coolant in its pure form. There are adverse effects if hydrogen purity is detected at a value less than the desired one while the machine is in operation. For example, the most important of them is to forgo the safe operation of the generator. A safe level of hydrogen purity is essential to prevent a potentially explosive mixture of hydrogen and air. The other is the revenue loss due to reduced efficiency. Any drop in hydrogen purity may cause additional windage losses and the reduction in generator efficiency is the ultimate consequence.

1.5.2 Hydrogen and Seal Oil System

As discussed before, hydrogen and air is a very explosive mixture and hence it needs sealing to prevent hydrogen leakage from the generator itself. The same is done through oil sealing applied near the bearings at a higher pressure than that of hydrogen. It is a full-fledged subsystem with redundant pumps, coolers, and strainers.

1.5.3 Excitation System

The generator is a synchronous machine that needs separate magnetic field excitation. The increase or decrease in excitation current dictates the generator's output voltage. There are many types of excitation systems discussed in the relevant Clause 4.2 of this chapter.

1.5.4 Stator Cooling Water System

The generator stator windings are supposed to carry a huge current which means high copper loss; the resultant heat is dissipated by flowing of ultrapure water through the specially designed hollow stator conductor.

1.5.5 Generator Inerting System

It is extremely important that the introduction and removal of hydrogen be done carefully to and from the generator casing while commissioning and decommissioning the system. To avoid the explosive mixture of air and hydrogen

www.EngineeringBooksPDF.com

during commissioning, air is at first purged from the generator casing by an inert gas where carbon dioxide has been dominantly used for years. However, argon or nitrogen is also gaining popularity. The hydrogen is then introduced slowly and continues replacing the purged gas. The reverse is the case while decommissioning the turbogenerator; that is, the purge sequence is reversed.

2. STEAM GENERATOR: BOILER

As discussed very briefly in Clause 1 of this chapter, the steam generation plant, or boiler, forms one of the fundamental units of thermal power plants; it is nothing but the practical and sophisticated representation of a basic heat engine that follows the Rankine cycle. The term *boiler* can be used for subcritical steam generators; however, at pressures above this (i.e., super- or ultracritical application), the term *boiler* is not applicable because there is no boiling at all and the term *steam generator* is the most appropriate.

A boiler is a combination of several items that present a means for combustion to provide heat energy to be transferred to water until it becomes heated steam. There lies the function of the furnace in order to burn the fuel and produce heat. The heat as an intermediate step transferred to water to make saturated steam at a temperature that depends on the pressure above the boiling water and, needless to say, that the rate the steam generation depends on the furnace temperature vis-à-vis its firing rate. The hot steam under very high pressure is then used for transferring the heat to the turbine. Water is used as the working fluid to transfer heat to a process because it is not expensive. There is tremendous volume change after the water is converted to steam, sp it needs careful handling.

The saturated steam is then further heated to a higher temperature and is popularly termed *superheated steam* to reduce suspended water particles, making a given volume of steam carry more heat to produce more work. By this, the higher temperature difference does not allow the tendency of the steam to condense as an effect of pressure and temperature decrease during work done, plus friction and conduction loss with the comparatively colder walls of the steam path including loss across the control valve (HPCV and IPCV). The product of combustion with the residual heat is then guided to pass through the reheater, economizer to preheat the FW before it reaches the boiler and then through the air heater to preheat the air to make it suitable for combustion.

The very names super- or ultracritical steam generators implies that they operate at a higher pressure, ranging ~230 to 254 kg/cm^2 (g) where actual boiling has already ceased to occur just over the critical pressure of 22.64 Mpa or 222.36 kg/cm^2 (g) (i.e., 374°C). This means that the steam generator has no liquid water and steam interface. The steam with very high pressure and temperature passes below the critical point while passing through the HP turbine doing work. Therefore the term boiler may not be used for a super- or ultracritical pressure steam generator, because in reality no boiling takes place.

This process results in less fuel consumption and therefore generates less greenhouse effect. Increases in pressure and temperature in supercritical (SC) and ultracritical (USC) systems increases the efficiency of the Rankine cycle. It has now become possible to increase cycle efficiency from 30% to up to 50% in a USC with the future target of about 52%. The corresponding decrease in CO_2 is expected to the extent of 30%.The details are included in Table: AP5/1 and subsequent discussion of Appendix V of this book.

2.01 Boiler/Steam Generator Subsystems

The boiler system is comprised of three (3) main subsystems: fuel/air/draft, feedwater, and steam. A brief discussion on each system can be found in the following subsections.

2.01.1 Fuel System

The fuel system includes all necessary auxiliary systems/equipment required to make fuel available for producing the necessary heat. The equipment required in the fuel system depends on the type of fuel used. The amount of fuel and air needed for steam generation are automatically controlled per steam demand.

Mills/pulverizers are required for solid fuels, with a primary air fan (AF) so as to make the pulverized fuel into fine powder form that is transportable pneumatically. Feeders with feed control systems are required to convey the solid fuels from a bunker to mills/pulverizers. Figure II/2.1 shows the process for easier understanding.

The drawing shows only a typical view with the interconnection among furnace, mill/pulverizer, PA fan, FD fan, and so on. There are many varieties of options; for example, a PA fan may be mill wise, may have suction from the atmosphere, etc. The draft system as already stated is a very important subsystem to maintain the furnace at a subatmospheric pressure (−3 ~ 5 mm of WCL) and for other important purposes discussed in detail in subsequent chapters.

Pumping and heating units and suitable atomizing medium are required for liquid fuels and compressor/boosters are required for gaseous fuels and, of course, with suitable types of burners and air supply arrangements. Figure II/2.2 may be referred for easier understanding. Fuel burners suitable for each system, with an air compartment and atomizing arrangement, is also provided for liquid fuel.

2.01.2 Feedwater System

This part has already been discussed in brief in Clause 1 of this chapter (Figure II/2.3).

www.EngineeringBooksPDF.com

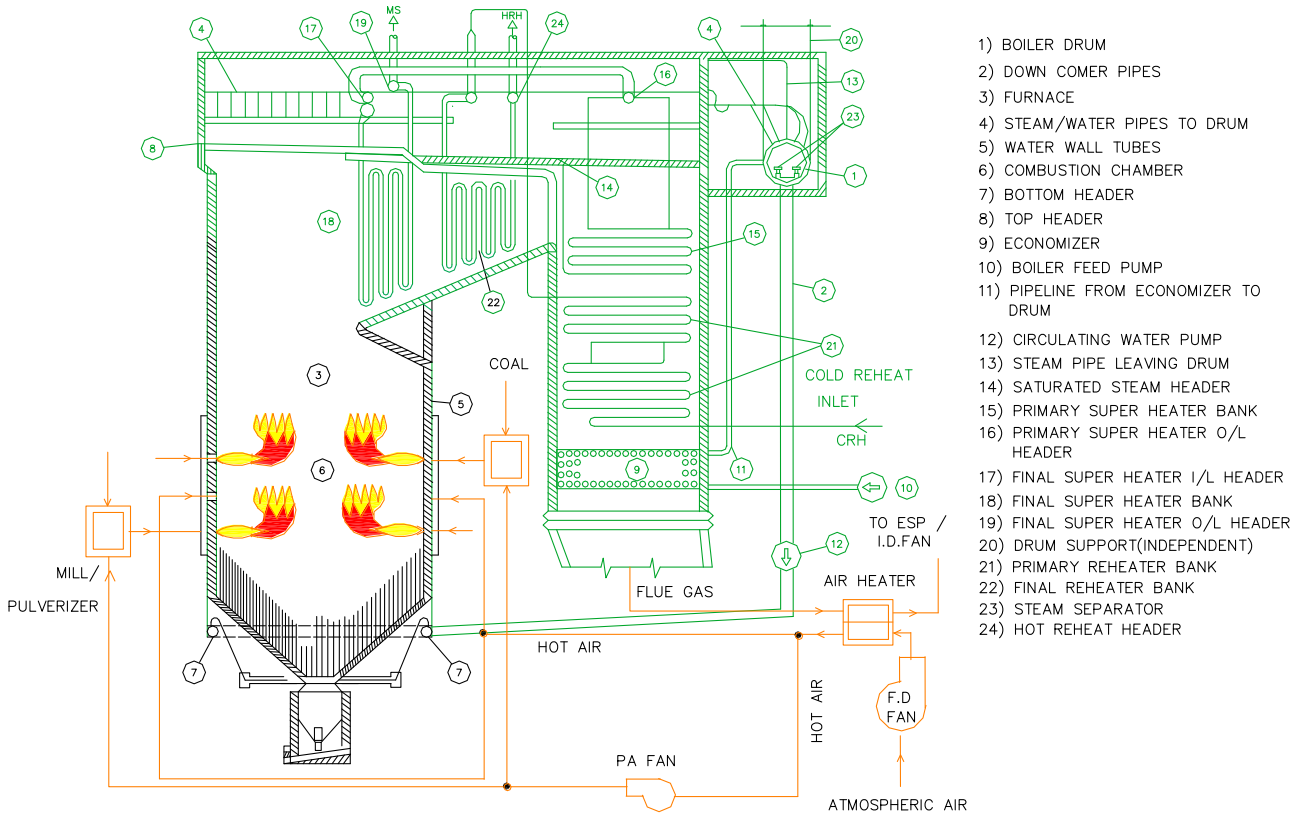


FIGURE II/2.1 Schematic diagram: Solid fuel firing system.

2.01.2.1 Blowdown and Chemical Dosing System

This system enables blowdown of feedwater to the drain if needed when FW is suspected of containing dissolved solids that may corrode the boiler metal, hinder proper heat exchanging by scale formation; this is discussed in Chapter V in detail. It also results in localized overheating and finally causes boiler tube failure, encourages foaming that causes carryover of water to the turbine, and so on. Blowdown is done for the subcritical boiler only because the same is done from the bottom part of the boiler drum or a separate blowdown tank that does not exist in other kinds of boilers.

Chemical dosing is done as a continuous process to retain the harmful contents of the feedwater under control to avoid or minimize the blowdown requirement, causing both heat and DM water loss. In doing that, the water–steam circuit is maintained as slightly alkaline (around a typical pH value between 8.5–9.4) in order to minimize the iron transport and to reduce corrosion. Chemicals dosed are phosphate at a high-pressure zone that is a boiler drum/blowdown tank for pH control; sodium sulfite or hydrazine for oxygen content control; ammonia at LP heater O/L, BFP suction for pH control by measuring and control conductivity, etc. Pumps with automatic stroke control are provided.

2.01.3 Steam System

The steam system collects and transfers the steam produced in the boiler. Transfer takes place through a piping system to the turbine. Throughout the system, excess steam pressure is regulated/vented through suitable valves automatically.

Steam is superheated to get more work and to avoid condensation after work is done at high-pressure turbine parts. A reheater is also provided to superheat the HPT exhaust for the same reason as stated earlier. Figure II/2.4 may be referred to for easier understanding. To avoid congestion, desuperheaters are not shown; only main superheaters and reheaters are shown with their tentative locations. Drums would be replaced with a separator and a storage vessel for a super-/ultracritical SG plant.

2.02 Deaerator

Although not a direct part of the boiler, a deaerator provides mechanical-type deaeration for the removal of the dissolved gases (CO_2 and O_2), which is highly desirable for safe boiler operation. The same is accomplished prior to dose chemical oxygen scavengers (hydrazine) by heating feedwater with steam. This process reduces the concentration of oxygen and carbon dioxide from FW. Being most

www.EngineeringBooksPDF.com

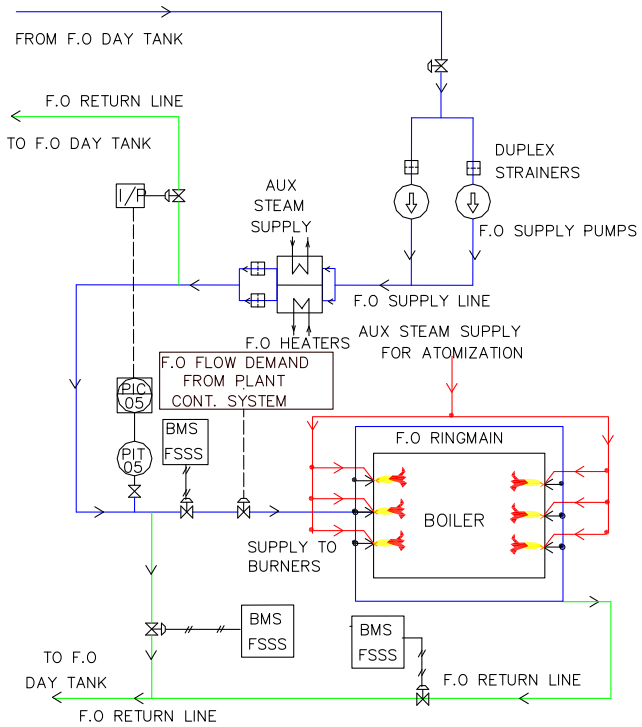


FIGURE II/2.2 Schematic diagram of a fuel oil firing system.

economical, it can reduce the oxygen content up to 0.005 mg/liter. Steam is preferred for deaeration because steam is essentially free from O_2 and CO_2. Readily available steam adds the heat required to complete the process.

2.03 Soot-Blowing System

This system has already been discussed in brief in Clause 1 of this chapter.

2.04 Boiler Circulating Water System

In some plants, boiler circulating water pumps are deployed for better circulation of feedwater in the boiler with its suction connected to a steam drum and a discharge connected to the boiler water wall header. For super-/ultracritical SG plants, this pump is necessary for start up and low-load operation. In normal load operation, it is kept "Off" using an interlocked operation.

2.05 Mills and Pulverizers

For solid fuels, mills and pulverizers are supplied with the main equipment so as to achieve higher thermal efficiencies through burning of finely powdered fuel. The type of mills and pulverizers depends on the type of fuels. Associated feeders and other things are also a part of this subsystem.

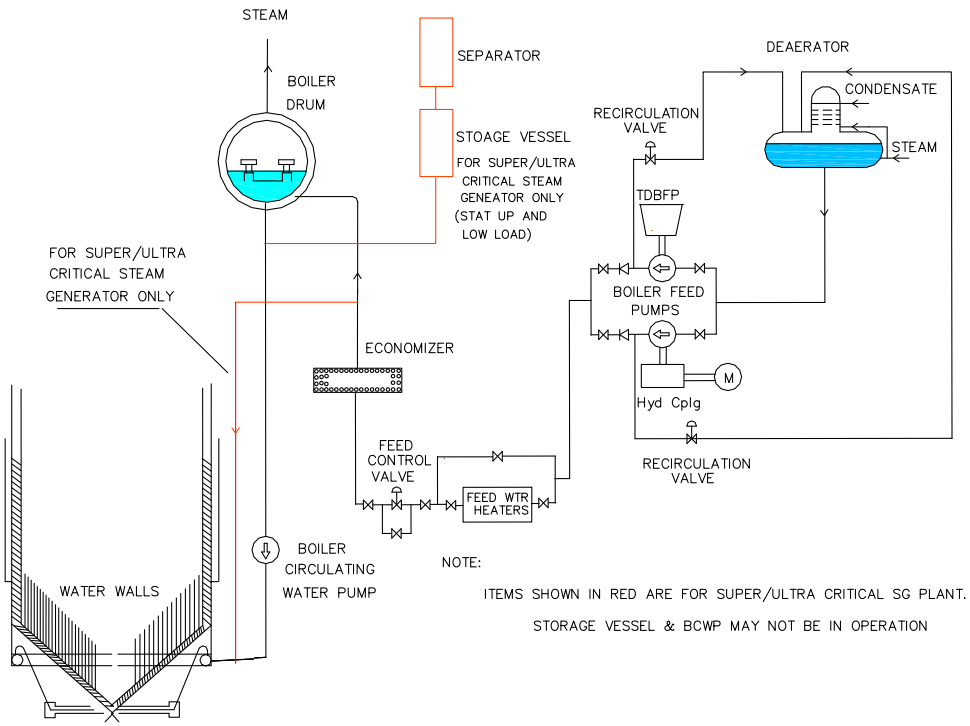


FIGURE II/2.3 Schematic diagram: Typical feedwater system.

www.EngineeringBooksPDF.com

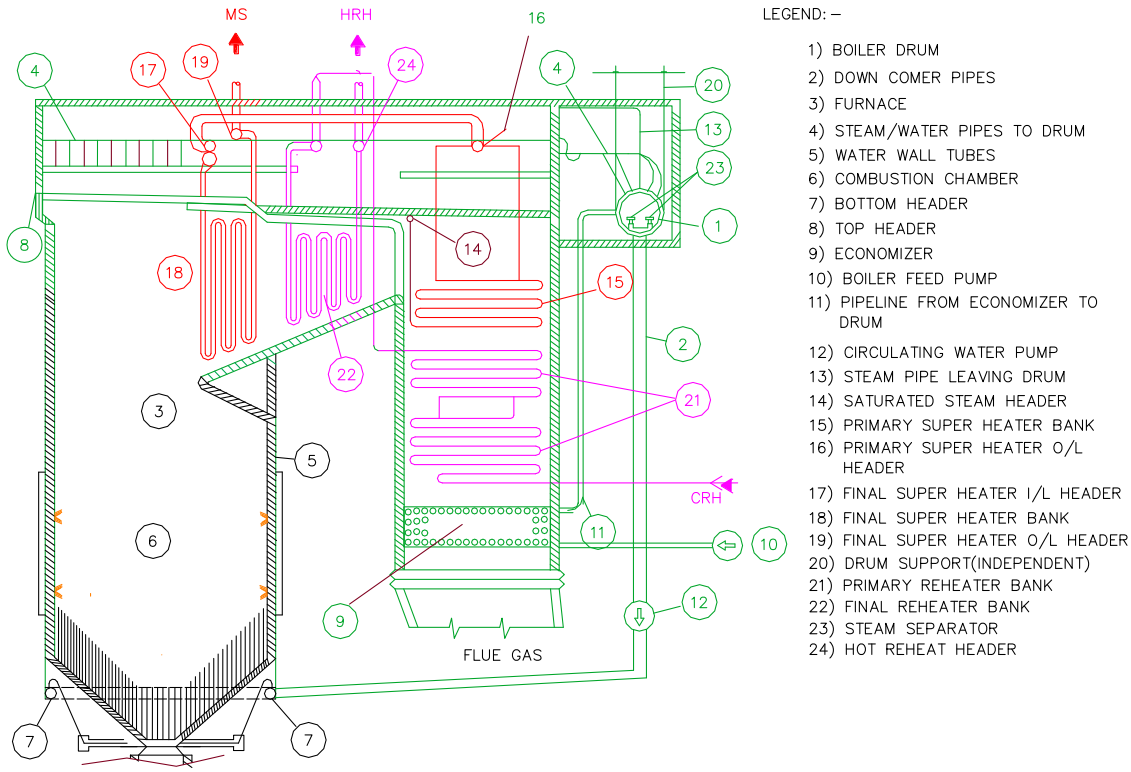


FIGURE II/2.4 Schematic diagram: Steam system.

2.06 Pumps and Heating Units

For the liquid-type of fuels, supply pumps are needed and additional heating units are required for a viscous type of fuel; namely, for HFO, LSHS, and so on.

2.07 Fans

Air is the most desired constituent after fuels for combustion to take place. There are many types of fans used in modern thermal power plants depending on type of fuels.

2.07.1 Forced Draught Fans

The air is supplied through the forced draught fan (FD fan) and air ducts. Before reaching the combustion chamber, air is preheated using an air heater in order to increase the overall efficiency of the boiler. Furnaces usually have a negative pressure for various reasons and automatically controlled dampers are part of this system to control the desired quantity of air, which takes care of the differential pressure of the supply air and the furnace.

2.07.2 Induced Draught Fans

An induced draught fan (ID fan) is provided to maintain a negative pressure in the furnace by sucking the products of combustion from it with a slight positive pressure at the discharge end vis-à-vis the bottom of the chimney/stack. This positive pressure, assisted by the stack effect of the heated chimney (~120°C), causes the flue gas to leave the chimney and mixes it with the surrounding atmosphere. Dampers, automatically controlled, are also a part of the SG plant that maintains the approximate furnace draught within a safe margin.

2.07.3 Primary Air Fans

The function of the primary air fan (PA fan) is to transport the fine grains of solid fuels in the required quantity and at the correct temperature with the automatically controlled dampers; this is done by the proportioning of cold PA with hot PA that is obtained by heating a portion of the PA using air heaters.

2.07.4 Seal Air Fans

A seal air fan (SA Fan) is used to provide air at slightly higher than PA pressure to seal all the dust-laden equipment—namely, the mills/pulverizers with associated dampers, relevant parts of the feeders, and so on.

2.07.5 Scanner Air Fans

The purpose of providing these a scanner air fan (ScA fan) is to cool the flame scanners heads meant for detecting the presence and quality of the fuel flame.

www.EngineeringBooksPDF.com

2.1 Fans: Functions of ID and FD Fans and their Effect on Control Systems and Control Devices

Various fans play vital roles in the SG plant; brief discussions of them has already been given in Clause 1 of this chapter.

2.1.1 Fans

The coal-fired thermal (solid fuel) power plant normally consumes approximately 5 to 8% of the electricity it produces; this is known as the auxiliary load. The auxiliary power requirement broadly includes mills/pulverizers; ID, FD, PA, and other fans; BF pumps (if motor-driven); CW pumps, BCW pumps, and other elements.

Auxiliary drives are designed to operate reliably under every condition, which allows variable load operation almost all the time, to match demand and a variety of operating conditions and process parameters with the help of a number of methods.

Air is the most desired constituent after fuel for combustion to take place. Many types of fans are used in the modern thermal power plant depending on the type of fuel. The supply of air and withdrawal of the product of combustion are handled by the fans.

Speed control technology is an alternative way to mechanically a system to reduce the auxiliary power requirement. Of the previously described drives, fans are the devices used to produce a gas (including air) flow and mainly are associated with the SG package. There are many types of fans available in the industry as indicated next:

- Axial fans or axial-flow fans
- Radial fans
- Cross-flow fans
- Mixed-flow fans

In a thermal power plant, axial and radial fans are the ones most commonly used, whereas cross-flow fans are used extensively in a HVAC system.

2.1.1.1 Axial Fans

The axial fans have blades that force air to flow in line with the shaft on which the blades rotate. The direction of air flow is along the axis of the fan and thus they are so named. Figure II/2.1-1(a) may be referred for easier understanding of the operation of the fans.

This type of fan is used in a wide variety of applications, ranging from small cooling fans for computers/electronics to the giant fans used in very large power plant as an ID fan. The axial fans are characterized by low pressure output with applications from low- to high-flow range.

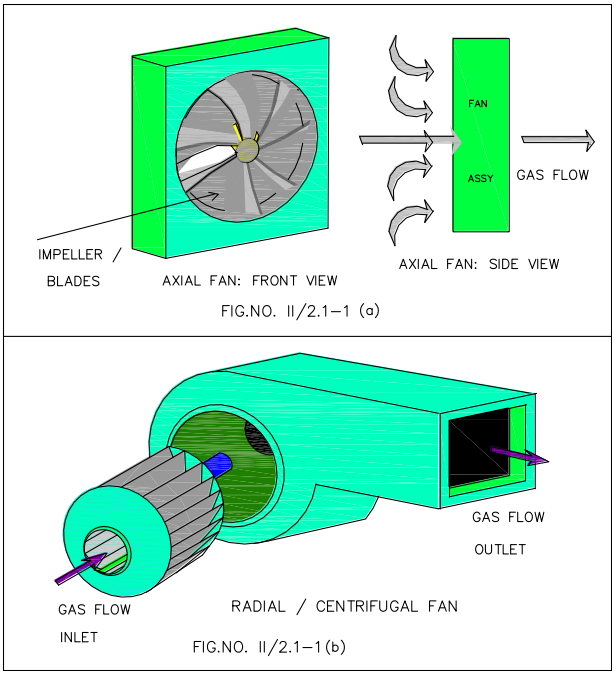


FIGURE II/2.1-1 Schematic diagram of axial and radial fans.

Generally, the axial fans are classified according to their type of wheel blades as follows:

- K-wheel type where blades are fixed (not adjustable). Simple construction.
- A-wheel type where blades are adjustable only under standstill conditions; they are highly efficient.
- C-wheel type where blades are adjustable even under running condition. Highly efficient and air volume is highly variable.

2.1.1.1.1 Axial Fans' Control Devices In general, there are two basic types of axial fan drives—that is, fixed-speed and variable-speed—for which control devices are provided. They are described in the following subsections.

Fixed-Speed Drives.

Variable-pitch control: A variable-pitch controlled fan is used for precise control of static pressure inside the duct or large chamber. The angle of attack of the fan blades can be adjusted to vary the flow of axial fans. The blades are arranged to revolve around a control-pitch hub. The fan wheel rotates at a constant speed and as the angle of attack of the blades increases and the flow increases. This type of control device is applicable to axial fans only and an ID fan, being an axial type, may be provided with this control function.

Outlet damper control: Flow/pressure control is achieved by continuous positioning of the fan outlet damper. This is the method that offers minimum

www.EngineeringBooksPDF.com

efficiency because the system's resistance is the ultimate controlling agent, which when increased lowers the efficiency.

Inlet damper control: Here, the flow/pressure control is achieved by continuous positioning of the parallel inlet damper of the fan. If properly installed, it provides an inlet swirl in the direction of the fan's rotation, causing a reduction of fan power consumption. This method obviously offers improved efficiency compared to the outlet damper control when the damper opens (in the zone of partially close position) in the same direction as that of the fan rotation due to previous rotation of the incoming air's course.

Inlet vane control: The flow/pressure control is achieved by adjusting the pitch of the vanes located at fan inlet. This is another method that offers improved efficiency compared to the outlet damper control, as described before.

Variable-Speed Drives with Hydraulic Coupling. A variable-speed fan has many discharge heads versus flow characteristic curves at each speed; it is similar to a fixed-speed fan that has only one speed. The curve moves up or down with the same shape when the speed is increased or decreased, respectively. Similarly, the efficiency also attains its optimum value at a certain point in the discharge head−flow curve for each speed, whereas only one point is available in the case of a fixed-speed fan. Since the speed can be varied, the best efficiency point can also be adjusted to suit the requirement.

Speed variation can be achieved through hydraulic coupling and a variable frequency drive (VFD); however, for VFD, there is some limitation that is not permitted in cases in which the power requirement is very high. Hydraulic coupling allows the connection between the electric motor and the fan (or pump) through hydraulic arrangements in an oil chamber. The oil level in that oil-coupling chamber determines the speed of the driven equipment. The servodrive deployed for the oil level control is called a *scoop tube* and is widely used for ID fans and BF pump's speed control vis-à-vis suction/discharge pressure control; Chapter VI may be referred to for a detailed discussion.

2.1.1.2 Radial/Centrifugal Fans

The radial/centrifugal fans have an impeller as the moving component; it is nothing but a set of blades or ribs suitably placed around a central shaft. They are also sometimes called a *squirrel cage* or a *scroll* fan.

In centrifugal fans, the air flows at right angles to the inlet air direction and throws the air outward toward the outlet through the action of deflection and centrifugal force. When the impeller rotates, air is allowed to enter the fan around the open space between the impeller and the shaft and is forced to proceed at a right angle to the shaft toward the opening of the fan casing; see Figure II/2.1-1(b). This type of fan produces, comparatively (with respect to axial fans), a higher pressure and less gas flow; they are noisier than axial fans. Radial/centrifugal fans also are classified according to their type of wheel blades as follows:

- F-wheel type where blades are forward curved. Highly efficient.
- B-wheel type where blades are backward curved. Highly efficient and air volume change is negligible with changing pressure. Low noise and low energy consumption.
- P-wheel type where blades are backward and straight. Highly efficient and air volume change is negligible with changing pressure. Self-cleaning.
- T-wheel type where blades are radial and straight. Self-cleaning.

2.1.1.2.1 Control Device of Radial/Centrifugal Fans In addition, for radial/centrifugal fans, in general, there are two basic types of drives—that is, fixed speed and variable speed. These are applicable for control devices that are provided with radial fans. In fact, all the control devices, as stated for axial fans, are applicable for radial fans except the fan blade pitch control; this is a unique control device associated only with axial fans.

2.1.2 Functions of ID and FD Fans

The word *draught* means force is needed to draw something gaseous that may be the result of the differential pressure created or may be the current of gas causing the flow. In any furnace, the first thing to initiate combustion is to supply adequate air along with fuel using forced draught fans; at the same time, extract all the products of combustion with the help of an induced draught fan. In the early days, furnaces may have been designed considering the help from a natural draught. With the emergence of very high-capacity power plants, however, the same is replaced with mechanical draughts because of their more advantageous contribution to proper and efficient combustion and easy supply as well as evacuation of gasses.

2.1.2.1 Functions of FD Fans

2.2 Air Flue Gas Path Equipment

The air and flue gas path is comprised of a lot of equipment such as both a primary and a final superheater (SH), a reheater (RH), an air heater (AH), an economizers, a selective catalytic reduction (SCR) plant, an electrostatic precipitator (ESP); these are a part of the dust-collector system for flue gas, flue gas desulfurization (FGD) plant, etc. The pressure parts are described in Clause 2.4 of this chapter.

www.EngineeringBooksPDF.com

2.2.1 Air Heaters

A combination of economizers and air heaters are often termed a *heat trap*. A detailed discussion on economizers is included in Clause 2.4 of this chapter. An air heater is the last element in the flue gas path where the residual heat contained in the gas is used for air drying before taking part in the combustion chamber to improve overall efficiency; this is done by better and spontaneous burning of fuel and a lower stack outlet temperature per local pollution-control board's stipulations. Air heaters' outlet combustion air temperature is higher compared to a boiler without them affects fuel saving in the range of ~5 to 10%. The preheated air for the combustion process increases boiler efficiency practically at all loads. For larger capacity modern power plants, tubular or regenerative air heaters are the best suited and are used for higher gas and air pressure as per the recent trend.

2.2.1.1 Classification of Air Heaters

The principle of operation dictates the classification of air heaters; they are generally of two kinds—namely, recuperative or regenerative.

2.2.1.1.1 Recuperative Air Heaters These are mostly tubular-type (maybe plate-type too) where the heat input may be from the boiler flue gas or a separate source—namely, other furnaces or steam coils, etc. Here, the heat exchange takes place directly from the source on one side of the heater surface to air on the other side of the surface.

Tubular-type air heaters consist of bundle of vertical tubes through which the flue gas flows upward or downward. Cold air flows horizontally across the external surface of the tubes. The number of traverses is multiplied by putting baffles in the air path for proper heat exchanges. In other designs, the air flows through horizontal tubes and exchanges of heat takes place with the hot flue gas flowing upward or downward across the tube bundle. For efficient heat exchanging, there may be a number of separate horizontal tube bundles, one above the other.

2.2.1.1.2 Regenerative Air Heaters These are normally of two types—rotary and stationary—with the heat source being the boiler flue gas or a separate other furnace, etc. The types are classified according to whether the heating elements are rotary or stationary. The rotary type is depicted in Figure II/2.2-1(a).

Here, the heat exchange takes place indirectly from the hot flue gases to the air through some intermediate medium acts as heat storage. The main advantages of rotary regenerators are economy of space, greater thermal efficiency, and lower capital costs. One major disadvantage of this type is leakage that may be as high as 10%.

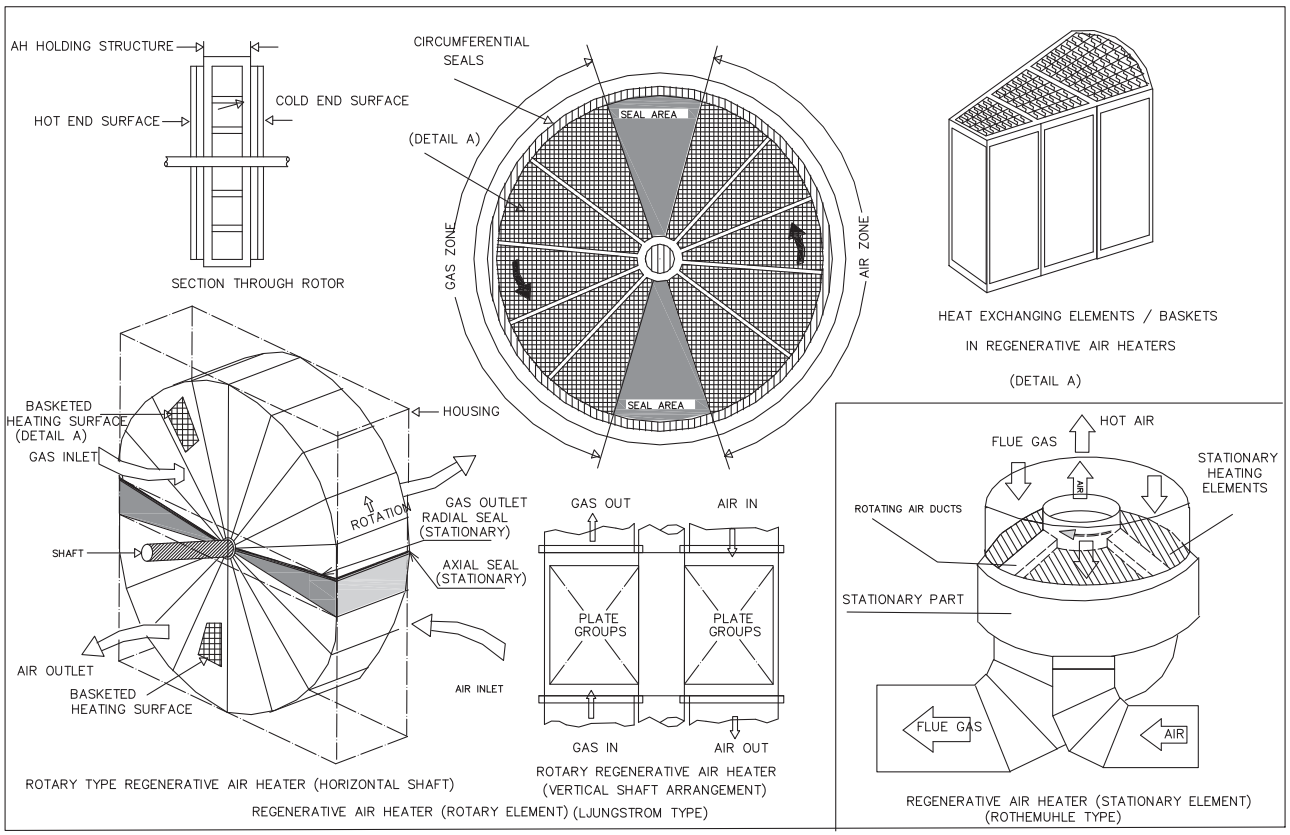


FIGURE II/2.2-1 Various types of regenerative air heaters.

www.EngineeringBooksPDF.com

The stationary plate-type regenerative air heater employs the same basic heat transfer principles as for the rotating-plate regenerative preheater; Figure II/2.2-1(b) incorporates a sketch of an idea for same. The heat-absorbing element or plates in this type of regenerative air preheater is stationary against the rotating air ducts so that they are alternately exposed and heat exchange is accomplished.

Hot flue gas enters from the top of the preheater and heat is absorbed by the unexposed portion of the static plates (not blocked by the rotating air outlet ducts passing above the plates) and flows downward toward the exit. Due to the slow rotational movement of the air ducts, the air inside of it absorbs heat from the static plate as they pass over the hot sections previously exposed. The incoming air is thus heated and flows upward toward the exit.

2.2.1.1.3 Steam Coil Air Preheater and Corrosion Control The steam coil air preheater (SCAPH) is located just before the air heater in the air path so that air temperature increases while entering the air heater. Here steam is passed through the coil whereas air passes through the shell to exchange heat from auxiliary steam to heat up air. During the cold rainy season, or in some cases of startup, this is used to heat air before admitting to the air heater. This system is useful to avoid acid corrosion in the air heater. Here, the average of gas outlet and air inlet temperatures are taken as the measured variables and controlled against a calculated preset temperature, which will not allow the acid condensation.

Corrosion is a common phenomenon that occasionally takes place when air heater metal temperature comes down below a certain level (i.e., acid dew point) particularly at the flue gas outlet/air inlet end. The flue gas-containing sulfur from various types of fuels, moisture, etc. are responsible for very low concentrations of even a few ppm combined with moisture content in the flue gas. This can severely damage metal components when the temperature of the surface exposed to the flue gas falls below the H_2SO_4 dew point temperature. Under those conditions, corrosion occurs because of the presence of a thin film of acidic electrolytes over the surface, giving rise to localized and uniform corrosion. To assess corrosion aggressiveness of the flue gas, several techniques have been introduced:

- By chemical analysis—SO_3 content in the flue gas can easily be determined
- By using electrical conductivity readings—evaluation of the acid dew point of the gas and the rate of acid buildup below the dew point can be made
- By weight-loss measurements taken by inserting probes in the gas stream

  or
- By determining the iron concentration in the corrosion products

These experimental approaches are limited by the short-term characteristics of the readings and by the indirect nature of the variables obtained using the first two techniques and by the average corrosion values obtained during long-term specimen exposure using the third technique. Two or three common methods are applied for the preceding, namely:

- A portion of total air is bypassed so that the heat exchange cannot take place to further lower the metal's temperature.
- Arranging recirculation of hot air from the air heater outlet to the FD fan inlet so that air temperature increases while entering the air heater.

Using the SCAPH located just before the air heater in the air path so that the air temperature increases while entering the air heater. Here steam is passed through the coil whereas air passes through the shell to exchange heat from auxiliary steam to heat up air. During the cold, rainy season, or in some cases of startup, this is used to heat air before admitting to it to the air heater. This system is useful to avoid acid corrosion in the air heater. Here, the average of gas outlet and air inlet temperatures are taken as the measured variables and controlled against a calculated preset temperature value which will not allow acid condensation as discussed earlier.

2.2.2 Dust Collector Units

This is a major part of the air and flue gas path that does not take part in the thermal cycle of the plant but plays a vital role as far as pollution control is concerned. It separates the fly ash part of the flue gas before the chimney on way to the exhaust path.

2.2.2.1 Mechanical Dust Collector Units

Mechanical dust collectors used in some smaller plants (currently most of plants use electrostatic precipitators), utilize three basic forces to bring out clean gas from the dust-laden flue gas: centrifugal, inertial, and gravitational. Dust-laden gas is admitted tangentially through the whirl vanes. Particles admitted are subject to centrifugal force and the dragging force. Clean gas is dragged into the vortex sink and goes out as clean gas. For the dust, the inertial, gravity, and centrifugal forces compel it to be injected into the dust hopper below, as shown in the diagram in Figure II/2.2-2(a)—the mechanical dust collector portion of the main drawing. This type of dust collector is often used in cement plants.

There are various other methods of dust removal also—namely, fabric filter/bag dust filter, wet scrubber, Venturi scrubber, etc. In modern power plants, electrostatic precipitators are the most commonly used.

www.EngineeringBooksPDF.com

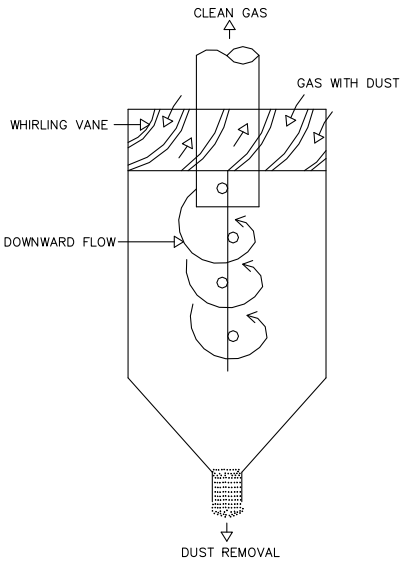


Fig: II/2.2–2a
MECHANICAL DUST COLLECTOR

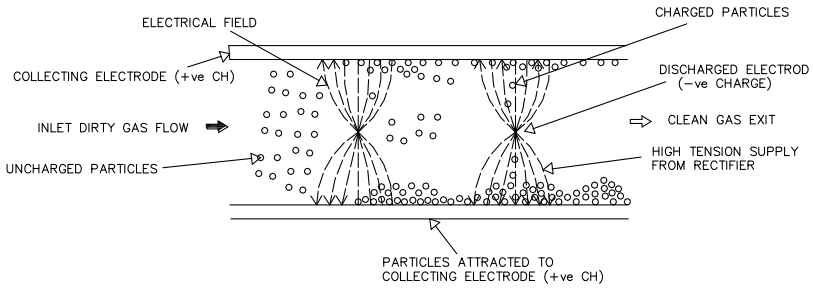


Fig: II/2.2–2b
PRINCIPLE OF ELECTROSTATIC PRECIPITATOR OPERATION

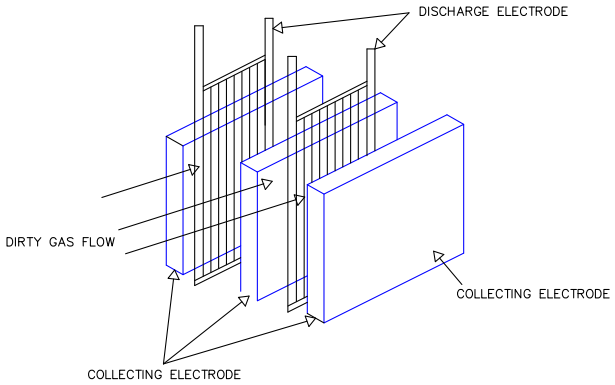


Fig: II/2.2–2c
ESP WITH ELECTRODES & GAS FLOW

FIGURE II/2.2-2 Fly ash separators: Mechanical and ESP.

2.2.2.2 Electrostatic Precipitator

To collect the dust particles, carrier gas is ionized by a high electric field. As shown in Figures II/2.2-2(b) and II/2.2-2(c)—the ESP portion of the main drawing—flue gas is passed through the discharge electrode (basically a row of thin vertical wires); the collector electrodes (a number of large, flat metal plates placed vertically) with a small distance between them are subjected to a highly regulated electric field created by several thousand volts. The gas stream flows through the row of wires connected to the negative terminal of the DC supply and then passes through the collecting plates connected to the positive terminal of the DC supply.

The applied DC voltage is high enough to create electric discharge (corona) and ionizes the gas around the electrodes. Negative ions thus emanated, flow toward the positive plates and the gas-borne particles are charged when coming into contact while passing through. These negatively ionized particles then attracted grounded but positively charged collector plates. The layer does not collapse due to high electrostatic pressure current, though small, flowing into the collected layer.

Dusts are collected at the hopper below by rapping the electrodes. This is popular because it consumes very little power (high voltage but minimal current), is highly effective for dust separation, is coupled with low draft loss with no affect on composition of the gas. Factors influencing collection efficiency depend on:

Collection area or sizing
Hopper design

Gas velocity: One of the factors influencing design, for high sulfur content gases, uses higher velocity—1.5 m/s. Some manufacturers use the term *gas volume.*

Retention time: The time particles spend in the presence of collecting electrodes at design velocity.

Number of fields: For reliability, ESP is divided into independent fields (3, 4, 5, 6) and field strength.

Automatic voltage control: With the help of this, ESP is operated at peak voltage. For this, digital control systems are deployed. Generally, ESP has its own

www.EngineeringBooksPDF.com

independent control room (near ESP) and control system. As a final control element, Thyristor (now a power transistor) controls are deployed. In addition to this, there are a few HT electrical control panels duly integrated with the control system described before.

Power input: It is comprised of the voltage and current in an electrical field. In general ESP efficiency improves with increased input power.

2.2.2.3 Flue Gas Desulfurization Plant

Any type of fuel, in general, contain more or less sulfur in both organic and inorganic forms. In solid fossil fuels, such as all types of coals (e.g., brown coals/lignites, bituminous or anthracite coals, etc.) sulfur is present. Various types of sulphides, bisulphides, and so on are the example of organic sulfur as bound in these fuels. These organic compounds are also found in many unrefined oils and heavy fuel oils (HFO). In natural gases and many raw fuel gases also sulfur compounds generally are found as hydrogen sulphide (H_2S) and carbonyl sulphide (COS). Various types of sulfates (e.g., Na_2SO_4, $CaSO_4$, $FeSO_4$) and pyritic sulfur (FeS_2) are sulfur compounds present in inorganic forms. Biomass fuels, such as bagasse (available from sugarcane fibers after extraction processing), waste wood, straw, etc., contain very small amounts of sulfur.

FGD plants are installed as a pollution-control measure of the main plant where the flue gas contains high SO_2 as a product of combustion of any type of fuels. It acts in such a way that the flue gas discharged to the atmosphere does not contain more than a minimum percentage of SO_2 as stipulated by regulatory authority. For more details, refer to Clause 10.3 of Chapter VIII.

2.2.2.4 Flue Gas Denitrification Plant

There are several methods of flue gas denitrification which is adopted to eliminate the nitrogen oxides (NO_x) from the hot flue gas generated as a by-product of combustion. A selective catalytic reduction (SCR) plant is one of several denitrification methods and the most widely used. This plant also constitutes a significant part of the pollution-control measure. SCR is generally located in between the economizer and AH where ammonia is injected into a catalytic chamber. For more details, refer to Figure VIII/10.3-1 (detail A) and Clause 10.3 of Chapter VIII. The other methods are also briefly discussed in the same chapter. Different subplants in a flue gas path with various combinations are shown in Figure II/2.2-3.

2.2.3 Stoichiometric Air–Fuel Ratio and Excess Air

Judicious amounts of fuel and oxygen are the main constituents of a stable combustion process (Figure II/2.3-1). The combustion products are heat energy, carbon dioxide, carbon monoxide, water vapor, nitrogen, residual oxygen, and other gases. Theoretically, for complete combustion, the requirement of oxygen has a specific value for burning a given amount of fuel. The perfect or ideal fuel ratio is called the *stoichiometric air–fuel ratio*. During the stoichiometric combustion process, no fuel or air are left over. Unfortunately however, in practice, the burning process is never ideal. Therefore, the additional oxygen, which comes from atmospheric air, that is required for ideal combustion has to be supplied for combustion to burn the fuel completely; this ensures safety, better efficiency and pollution control. However, the excess air also accounts for some heat and fanning loss.

For incomplete combustion, which results from an inadequate supply of air to the burner, there are many undesirable events that take place such as unburnt fuel with carbon monoxide, soot, smoke, and others from the boiler. The outcome would be reduced boiler efficiency; reduced heat transfer (for deposition of soot on the pipe surface); pollution (for belching smoke); flame instability; and, ultimately, a potential condition for explosion due to sporadic deposits of unburnt fuel. The term *excess air* refers to the additional amount of air required that is more than the theoretical value. An exact mixing proportion for air and fuel needs to be established for stoichiometric or ideal combustion.

To determine the quantity of excess air needed for the combustion system to operate, the value of stoichiometric air–fuel ratio for that particular fuel should be known. Generally, 20% excess air flow is maintained for pulverized coal-fired boilers whereas 5% excess air flow is quite common for natural gas-fired boilers. However, in the case of a modern control system with fast response and technical advancement, a significant endeavor is needed to bring down this excess air by operating combustion near to stoichiometric point using an oxygen trim control in conjunction with CO analyzer signal injection. Gas turbines' operation calls for a very high value, up to 300%, because the excess air is also used for cooling purposes.

Boilers normally operate at an excess air level not only to ensure efficient running and safe conditions but also to provide protection from nonavailability of sufficient oxygen with the variations in fuel composition and operation snag in the fuel air-control system. It is necessary to bear in mind that excess air would not take participate in the reaction but would take away a portion of heat generated by the combustion of fuel after it leaves the air heater thereby reducing boiler efficiency. Too much excess air may also disturb flame stability. All these aspects may be taken into consideration while deciding on the percentage of excess air to be provided.

www.EngineeringBooksPDF.com

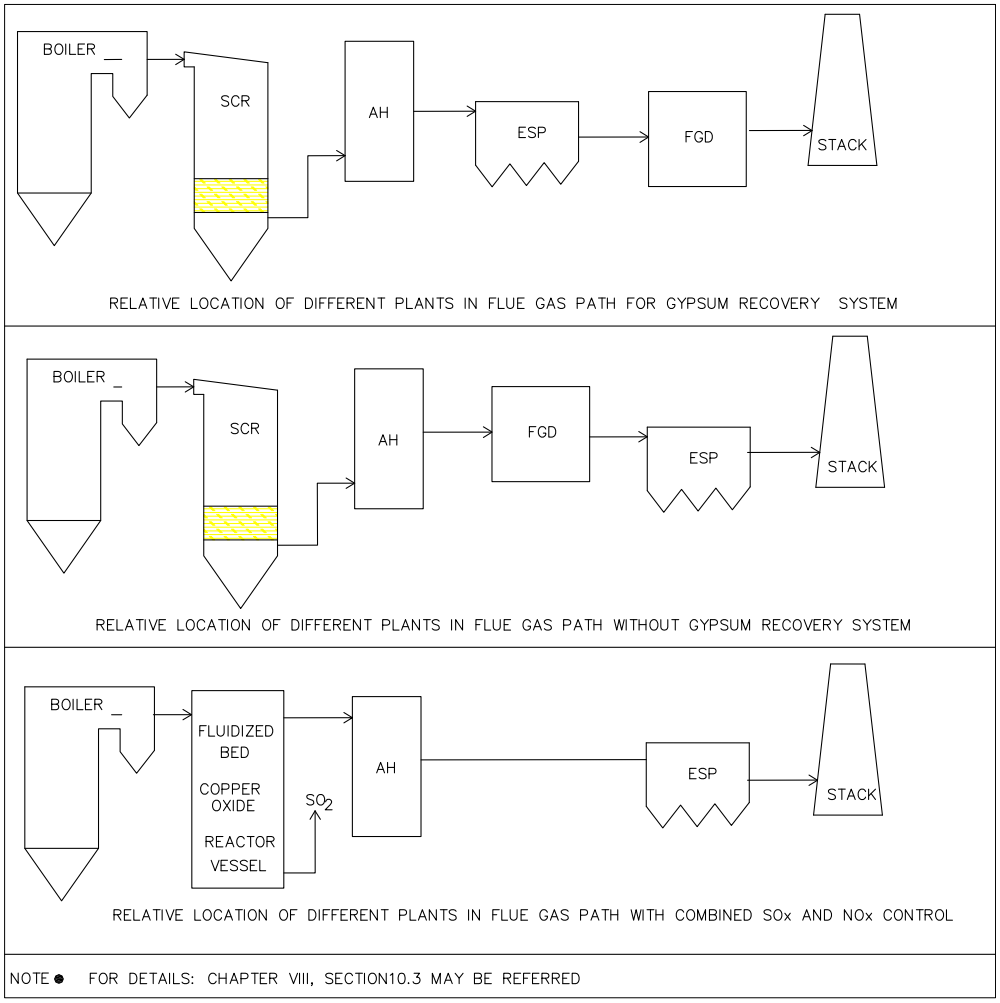


FIGURE II/2.2-3 Relative location of different plants in flue gas system.

2.3 Firing Systems

The various types of firing systems depend on the manufacturer's design. There are many manufacturers that use two major types of firing systems—fixed burners or tilting with corner-fired burners. The detailed control philosophy has been included in Clauses 4 and 5.2 of Chapter VIII.

2.3.1 Type of Firing Systems

2.3.1.1 Fixed-Type Firing

This type is generally used in the Babcock design and also has a variety of options. The following are the types (Figure II/2.3-2):

Front or wall firing: In this type, the burners are placed on the front wall or the side walls of the furnace. Each set of burners connects to one pulverizer to maintain balance. The air required for each burner enters the furnace adjacent to it.

Opposed firing: Here the set of burners is placed on opposite walls in equal numbers and in symmetrical positions.

Downshot firing: In this type of furnace, the burners are placed in such a way that the flames point downward. This system is normally used with anthracitic coals or another type of fuel that takes more time to burn.

2.3.1.2 Corner or Tangential Firing

Here the coal feeds into the furnace at its four (4) corners. This produces a cyclonic effect in the furnace ensuring proper mixing of air and fuel that is essential for proper combustion. Due to this effect a fireball is created with the burners firing tangential to it (Figure II/2.3.3). The combustion air also enters into the furnace tangentially to the fireball above and below these burners. Each pulverizer supplies coal to one level so that the firing is always balanced. In most of the tangential firing systems, the

www.EngineeringBooksPDF.com

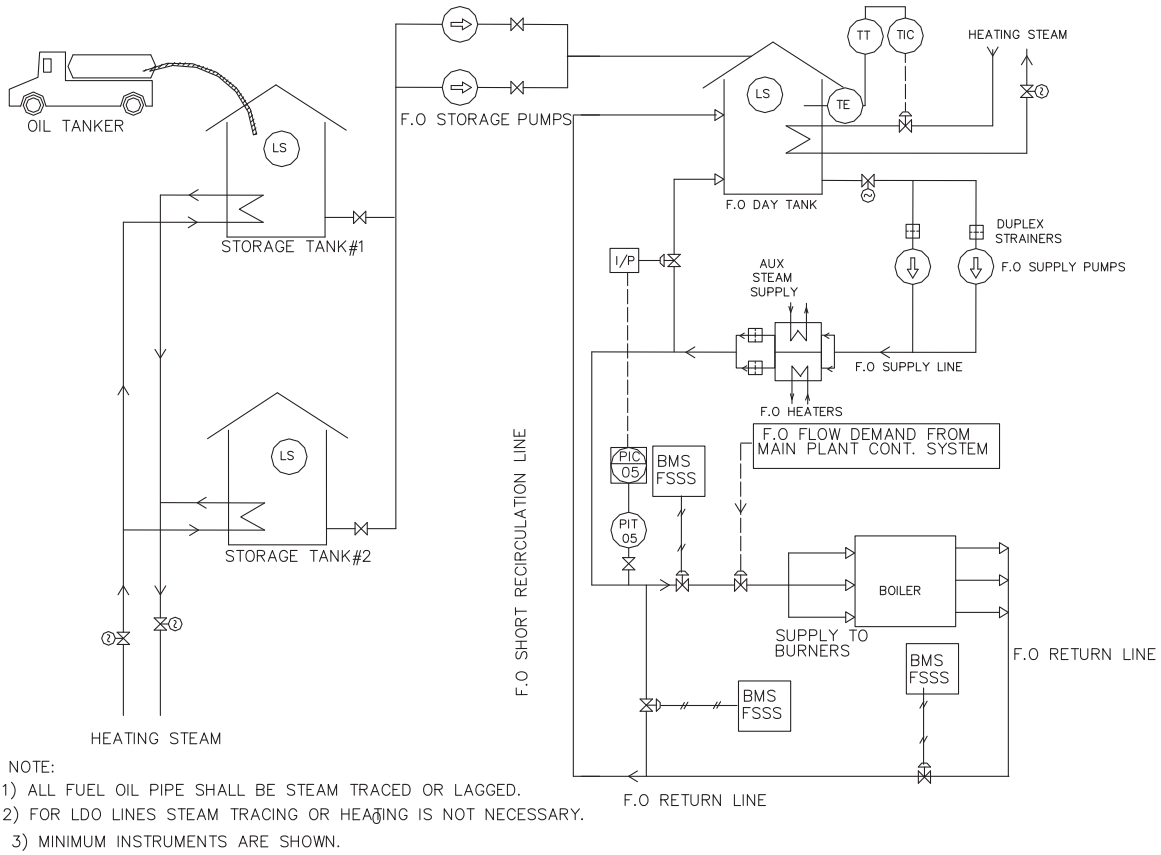


FIGURE II/2.3-1 Fuel oil flow diagram.

burners can tilt 30 degrees up or down, which causes the fireball to move up and down, thus aiding in controlling steam temperature and combustion conditions. These are called *tangential tilting burners*.

2.3.2 Combustion Air

Air supply for combustion of fuels is provided in two parts.

1. Around 25 to 30% of the air is for drying the coal and transporting it—called *primary air*. It enters the furnace along with the coal through the burners. PA header air pressure is controlled by the PA fan and flow is controlled by mill wise dampers.
2. The remaining air enters the furnace adjacent to the burners from air headers or wind boxes, which are air chambers on the furnace walls, and this air is called *secondary air*. An elaborate, dedicated set of control loops (part of the total system) are provided for the control of total air. For Babcock boilers, FD header air pressure is controlled by FD fans and the flow of air through the air registers/secondary air dampers to the burners. For CE boilers, total air is controlled by FD fans and the distribution of this air to respective burners is governed by a secondary air damper control.

The burner tips and the air entry points have splitters, swirlers, and vanes to create turbulence at the burner tip. These arrangements are required with an eye to the target; the most popular term in firing fuels is the *three Ts*, namely:

Turbulence: Ensures proper mixing of the air and coal particles.
Time: Provides sufficient time for the particle to burn.
Temperature: Makes the ignition temperature available to entering coal particles.

The total effect is to prevent the flame from being blown away from the burner while at the same time containing it inside the furnace.

2.3.3 Start-Up Procedure

Since the ignition point of coal is around 300°C, there should be another ignition source to start the firing. This takes place in two stages:

1. The first stage is to use an igniter that provide an electric spark for supplying initial ignition energy to ignite small gas or LDO burners. This is like starting the fire in domestic gas burners.

www.EngineeringBooksPDF.com

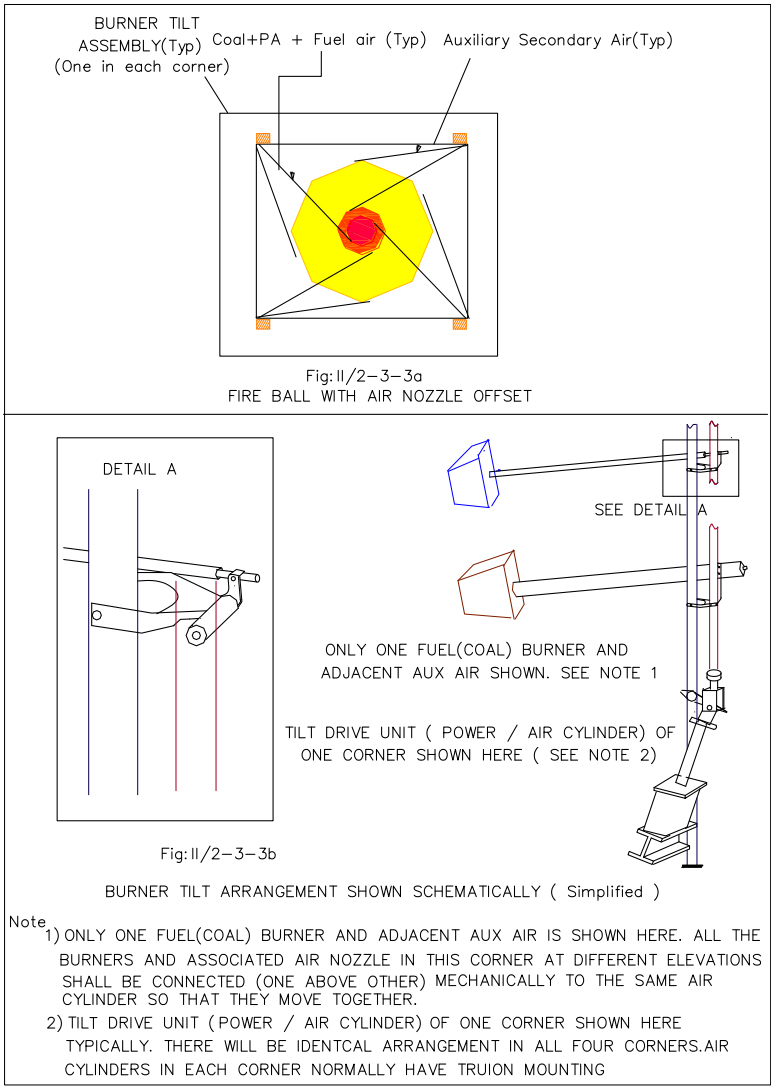


FIGURE II/2.3-2 Tangential fired coal/oil/gas tilting burners.

2. The next stage lights up other higher-capacity oil burners that usually fire HFO. Once these oil burners are burning and the furnace is hot enough, only then is permission given for coal firing. Since sufficient ignition energy is available, the coal particles easily catch fire. Once the coal flame is strong and stabilized, the oil burners are cut off.

However, as an alternative arrangement, direct firing of heavy fuel oil with the help of a high energy arc (HEA) igniter is also available. This is capable of supplying the required energy for HFO ignition.

The type of burner system that is to be adopted depends on the type of coal to be fired. Manufacturer's preferences or license agreements also play a major role in deciding the type of burners to use.

2.3.4 Mills/Pulverizers/Feeders/Primary Air Burners

In a thermal power plant, other than nuclear- or gas-fired ones), the mills/pulverizers are one of the most important pieces of equipment that provide the solid fuels (e.g., coal or lignite) with the correct form or shape to make it suitable for catching the flame appropriately. Details about the mills/pulverizers are discussed in the following and their control systems are discussed in Clauses 4 and 5 of Chapter VIII.

For a plant using coal or lignite (also termed brown coal) as fuel, pulverized forms of it are used as the ultimate firing substance. Coal mills, also known as coal pulverizers, are basically coal crushers. Inside this equipment various grinding arrangements are used to reduce the larger coal size into a smaller size for use in further processing or

www.EngineeringBooksPDF.com

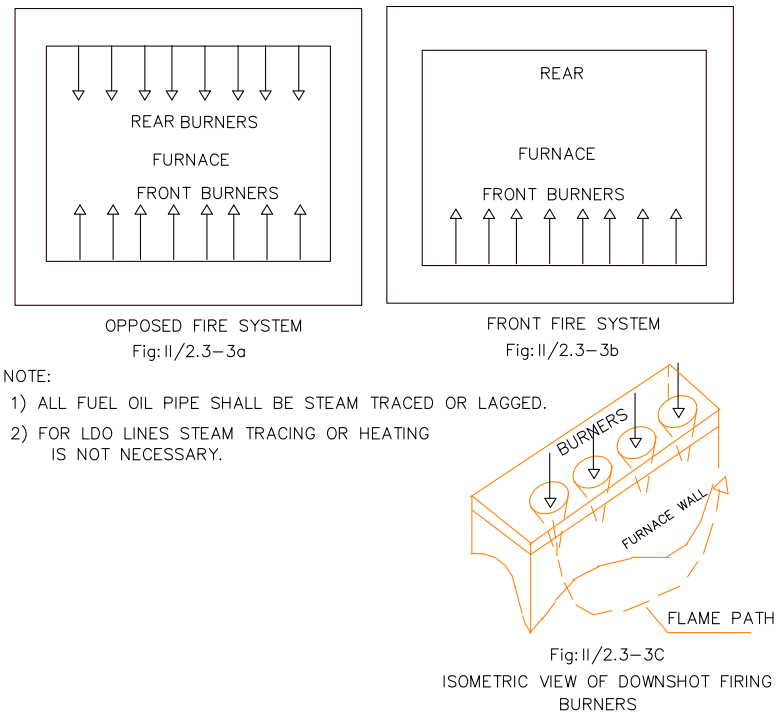


FIGURE II/2.3-3 Opposed fire/front fire/downshot firing system.

transportation by air for burning. Actually pulverizing the coal means, it is, crushed or ground into a fine powder and isj then capable of being burnt in the same way as gaseous fuel burns. This method enables the solid fuel to take part in combustion in a very efficient way.

Although there is a very fine demarcation between pulverizers and mills, they can be taken as the same as far as getting the powdered fuel is concerned. To be more precise, pulverizers often use pressure or collision-oriented force to crush materials; on the other hand, mills are known to apply grinding force to achieve the same end product.

The advantage of efficient combustion has automatically prompted users to prefer coal mills; however, there are some disadvantages as well. Some cannot be eliminated but can be reduced to a lower acceptable level. The main and significant disadvantages include considerable vibrations which may cause damage to its own machineries and both damage/disturbance to machinery in the vicinity, which may result in interruption of plant operations. Proper design improvement and use of appropriate bearing arrangements with a lubrication system vis-à-vis lubricant are the keys to limiting vibrations and significantly reducing any possible disadvantages.

The pulverizing or milling agent may be any of the following four(4) popular ones depending on the type of fuels and, of course, manufacturer's design:

- Vertical roller mill or bowl-type mill for coal.
- A ring-roll and a ball-race mill or ball-type mill for coal.
- Impact- or hammer-type mill for lignite.
- Ball tube-type mill for coal.

A vertical roller mill or bowl-type mill for coal uses heavy rollers that have also been hydraulically loaded in order to crush the coal through application of pressure by means of a continuously rotating table passing underneath of the rollers. In this type of coal mill, hot air is introduced through an opening at the bottom of the mill and is used to transport the pulverized fuel from the top, through a cyclone separator, to the corresponding set of burners.

A ring-roll and a ball-race mill or ball-type mills for coal are basically the same type of mill, except that a ring-roll mill uses rollers and rings and a ball-race mill uses balls and races or raceways. In this type of coal mill, the ring or race is rotating while the different sizes of heavy metal balls or rollers are stationary and springs force the two together to crush the coal.

An impact mill or a hammer-type is a high-speed coal mill. In impact mills, the coal is fed by means an inlet box at the top of it. Crushing occurs in two steps: first, the coal is crushed using primary beater tools at the top of the rotor, then grinding tools are used to crush the coal again at the side of the rotor.

Ball-tube mills are constructed mainly of a rotating tube that contains cast alloy balls. The raw coal is inserted into either side of the mill through two hollow trunnions. In order to pulverize the coal, the tube is rotated and the balls are used as a grinding medium to deform and/or break apart the coal through the use of friction.

www.EngineeringBooksPDF.com

As discussed later in Clause 4 of this chapter, there is a very fine demarcation between pulverizers and mills. Theoretically, pulverizers are often described as equipment that uses pressure or collision-oriented force to crush materials. Mills, on the other hand, are the type of equipment that is known for applying grinding force to make the solid fuel into powder form. However, as the end-product is the same, both can be considered the same as far as pulverized fuel (PF) is concerned.

2.3.4.1 Selection of Equipment

Fuel flow control is an important and vital part of the combustion control system, The selection of mills/pulverizers also plays an important role in a modern thermal power plant. While selecting the type of equipment, the following criteria should be taken into consideration:

- Cost of equipment
- Type of fuel that uses different qualities of coal, lignite, etc.
- Efficiency
- Capacity and space requirements
- Advantages and disadvantages such as power consumption, noise, and vibration, sealing arrangements, capabilities of separating and taking out harmful materials (e.g., magnetic components), and so on.

2.3.4.2 Advantages of Using Mill/Pulverizer

There are numerous functions that can be performed by a mill/pulverizer. The performance of a power plant depends a great deal on the choice of mill/pulverizer. The following items are some of those features:

- Faster response to load-changing because pulverized fuel (PF) burns easily and quickly.
- Transportation of PF through primary air is easier.
- Increased thermal efficiency due to less loss of carbon. There is a provision for lower excess air but that also depends on optimization through proper application of a control system.
- Different sizes and varieties of solid fuels are acceptable when this type of plant is used.
- It is possible to burn PF in combination with other gases and oils.

2.3.4.3 Functions and Controls

A milling/pulverizing plant with associated auxiliaries is installed to perform multifarious activities. Some of the auxiliaries are the mill/pulverizer feeders, PA fans, SA fans, ScA fans, fuel burners, and igniters.

2.3.4.3.1 Mills/Pulverizers The mills/pulverizers duty is to convert raw feed into fine dust particles. For efficient accomplishment of this, a hot air supply to dry the raw feed is necessary. For all types of mills/pulverizers, this is done by proper mixing of hot and cold PA with the help of an automatic temperature control loop. The PA fan's suction may be taken from the atmosphere, then a part of the discharge line is heated using a PA heater. After that it is mixed with the other part of the primary air to get the proper temperature for drying and transporting purposes.

For other types of furnaces, the PA suction is taken from the hot FD fan after use of the air heaters. The automatic temperature control loop is discussed in Clauses 5.1 and 5.2 of this chapter. Apart from this temperature control, there is another automatic control loop that is unique to ball-tube mills. The differential pressure across the mill is maintained at a constant pressure to ensure enough raw feed storage capacity inside the mill. The automatic DP control loop is discussed in Clause 5.3.2 of this chapter.

2.3.4.3.2 Feeders The feeders that have variable speeds are provided to feed the raw fuel. For mills/pulverizers other than ball-tube mills, the speed varies in proportion to the boiler load demand. The raw feed already available inside the mills/pulverizer acts as the storage for meeting the immediate requirement and then the proper feeder speed takes care of the situation by bringing storage status back to within acceptable limits. The automatic feeder speed control loop is discussed later in Clause 4 of this chapter.

For ball-tube mills, the speed does not vary directly with the boiler load. Here, the primary air flow varies with the boiler load and the feeder speed varies to maintain the mill DP level (feed plus ball) at a constant storage quantity of raw feed. The automatic DP control loop is discussed later in Clause 5.2.5.2 of chapter VIII of this chapter.

2.3.4.3.3 Primary Air The primary air does various jobs for the milling/pulverizing plant to make the concept of a direct-firing system possible. The following are the necessary functions:

- Transportation of PF up to the burners; the quantity varies because the boiler load varies.
- Drying of raw feed for conversion into fine particles in an effective manner; hot PA is used for the required function.
- PF and PA mixture as produced at the outlet of a classifier that provides the initial oxygen for combustion.

For all types of mills/pulverizers, the primary air flow varies in proportion to boiler load demand. The automatic PA flow control is discussed in this chapter's Clause 4 for types of mills/pulverizers other than ball-tube mills. The automatic primary air flow control for ball-tube mills is discussed in Clause 5.2.6.4 of chapter VIII of this chapter.

It needs to be noted that a minimum line velocity through the coal conduits has to be maintained to keep the pulverized

www.EngineeringBooksPDF.com

but solid fuel in suspension. Due to the lack of proper fuel–air line velocity, there is a possibility that a dangerous situation, such as solid fuel particles falling out of suspension and being deposited in pipelines in separate fuel slugs, may occur. This untoward deposition may turn into a fire hazard or even an explosion. The mill outlet temperature is an important factor to consider along with other factors (e.g., pipe size, length of pipes, altitude) that may influence the line velocity and thus need to be maintained. There is another control loop for the PA inlet pressure control for ball-tube mills, as discussed in Clause 5.2.6.2 of chapter VIII of this chapter.

2.3.4.3.4 Burners The burners provide the arrangement for further mixing of the PF and the primary air mixture with the secondary air in order to have the desired quantity as needed for a perfect or a near-perfect condition of combustion and delivery of the whole mixture to the furnace.

In some types of burners, a part of the secondary air (called fuel air) is mixed with the PF and primary air mixture and the flow rate varies proportionally with boiler load. The other part of the secondary air (called auxiliary air) is used to control the wind box (WB) to furnace differential pressure. This arrangement of using only a part of secondary air with PF and the primary air mixture is to ensure fuel-rich initial combustion, a precondition for a low NO_x firing atmosphere. Further combustion takes place with the help of other parts of the secondary air.

2.3.4.3.5 Igniters Igniters are required to light the first flame in the furnace with the help of oil and gas as available. Normally, there are spark devices for gas and light oil. HEA or equivalent igniters are used for directly lighting the HFO. When sufficient ignition energy is available by burning gas or oil for enough time and quantity to raise the temperature, the adjacent PF burner can be brought into service because the flame now would be self-sustaining with the main fuel.

When oil is considered for lighting up fuel, it must be atomized to minute particles to create a large surface area that comes into contact with the oxygen available in the air to ensure complete and speedy burning of oils. The same philosophy is applicable for PFs where the particle sizes must be small enough to create a larger surface area for achieving the ideal condition for proper combustion. There is no automatic closed-loop control for the igniters but operating logics are provided in the open-loop control. This includes checking of start permissible signals, starting sequences, and shutdown and tripping sequences in association with the respective flame scanners.

2.3.4.3.6 Seal Air Fans Seal air (SA) fans are used for the purpose of sealing the fuel dust and primary air mixture so that it does not come out of the milling/pulverizing plant. The SA pressure is kept slightly higher than the PA pressure and is supplied to all probable joints/flanges of a plant. Redundant fans ensure uninterrupted supply of pressurized seal air. There is no automatic close-loop control for these fans but safety logistics are provided in an open-loop control.

2.3.4.3.7 Scanner Air Fans Scanner air (ScA) fans are not actually part of process of this type of plant. These fans supply the cooling air to the flame scanners that are provided to check the sufficiency of the flames of the individual burners or maybe of two adjacent burners. The lenses of these scanners need a cooling medium to reduce the high temperatures of the furnace. Because flame scanners are a very important part of furnace safety, the ScA fans are included in the plant. There is no automatic close-loop control for these fans but safety logistics are provided in an open-loop control.

2.3.4.4 Ignition Supports

Ignition supports are not only required to light the initial flame in the furnace but also to provide the oil support needed to help ignite oil or gas as and when necessary. When the main fuel quality is within the design range, there is no necessity of providing additional ignition support because the flame is self-sustaining.

A problem arises when the fuel quality is poor or the number of mills vis-à-vis boiler load is not sufficient to hold the flame as a whole or in the rainy season when higher temperatures may be necessary to sustain a furnace's flame. For these eventualities, the control system must be ready to support supplementary firing if needed.

2.3.4.5 Summary of Coal Mill Controls

To summarize the coal mill controls, they may be divided basically into two major categories:

1. To control the quality of coal being sent to the burners located on the furnace walls. The word *quality* here means the temperature and fineness of the PF. The set temperature values are dependent on the percentage of volatile matter that exists in the main fuel. The controlled temperature is important for many reasons such as stability of ignition, better grindability of solid fuels, better floating ability of suspended PF particles, etc. However, a temperature more than ~65 to 70 is not recommended for various reasons.
2. The mills/pulverizers responses according to the boiler load control include both the PA flow control and the feeder speed control, having the main drive of mills/pulverizers run at a fixed speed.

2.3.5 Fuel Oil Systems

Figure II/2.3-1 in its simplest form, earlier in this chapter, may be referred to in order to get a brief idea about the fuel oil (FO) circuit without going into the actual

www.EngineeringBooksPDF.com

instrumentation system that would be available in the corresponding P and I diagram.

For the FO systems, if utilizing HFO, proper care needs to be taken to maintain the temperature vis-à-vis viscosity throughout the pipeline for which steam tracing or an electrical heating arrangement is necessary. For light diesel oil (LDO), this problem does not arise for its low viscous characteristics. The FO system also demands selection of suitable valves and strainers for smooth and clean handling of the fluid.

Basically, three steps are provided as a complete system in large thermal power plants. These are categorized as:

1. Oil unloading system
2. Storage and transfer system
3. Pumping and heating system

2.3.5.1 Oil Transfer System

A fuel oil unloading system includes unloading of oil from the tankers (may be a roadway truck or railway wagon) through flexible hoses to the adjacent storage tanks. The redundant tanks store adequate oil to cater to the requirement of both startup and emergency oil support. As FO is a viscous liquid, its temperature has to be maintained properly so as to attain the required viscosity for enough fluidity to reach the desired place without getting stuck along the unloading hose.

2.3.5.2 Storage and Transfer System

The storage and transfer system for fuel oil incorporates storage tanks with suitable heaters and temperature sensors for the control system to maintain viscosity to enable storage pumps to transfer the oil to the day tank to meet the day-to-day needs.

Normally, two types of heaters are provided. A floor mat-type heater is located near the lower portion inside tank to regulate temperature; the other one is located near the outlet. The latter is called *suction heater* that ensures the flowability of HFO that is connected to the suction of the transfer pump. The pipelines are also electrically heated or steam is fed through the jacket along the conveying pipe's length. The storage pumps are accompanied by heaters and strainers to keep system fluidity as desired.

2.3.5.3 Pumping and Heating Unit

This unit is a subsection that starts with the day tank outlet, supplying oil to the oil burners and the return oil line up to the suction line of the day tank. This part incorporates redundant heaters (for HFO) and pumps to improve fluidity and then pressurize the oil to a sufficient level so as to reach the far end of the burner elevations and back to the tank; this part is not required for combustion.

Whenever the power plant is in operation, the oil flows in the route just described even if there is no requirement for oil—for example, in the higher load operation of the unit or else. The idea is to keep the oil system in readiness for any eventuality, such as sudden load shedding or runback situation, when a few mills/pulverizers are to be cut off within a very short time and the resultant flame might become unstable thus badly needing instant oil support. The oil pressure is maintained through a pressure control valve in the bypass line more or less diverting oil to the day tank for the dedicated purpose. For details, refer to Clause 10.4 of Chapter VIII.

The FO trip valve (FOTV) is provided at the common inlet of the burners to initiate shutdown of the oil supply instantly in an emergency situation such as tripping of a boiler. The downstream line at the common outlet of the burners is provided with another quick-closing On–Off valve to facilitate oil recirculation during plant running condition. In certain thermal power plants, an OLTV is provided to check whether the HOTV or the oil burners and downstream pipelines are leaking. The details about all these On–Off valves are discussed in Clause 12.1 on BMS/FSSS of Chapter VIII.

The oil route is somewhat different for a unit under a long shutdown condition. There is a small On–Off valve or a regulating valve called a *short recirculation valve* (SRV) at the HOTV inlet and connected to the day tank. In some plants, it opens only when the unit goes on a prolonged shutdown. In some other units, it is always open to ~10% under normal operation of the unit and opens fully in case of long shutdown.

2.3.6 Tangential Tilt Burners

Furnaces having this type of coal burner have the advantage of raising or lowering the burning zone through a burner-tilting mechanism as depicted earlier in Figure II/2.3-3. The burners are corner-fired—that is, located in four corners and focused in such a way that all of them are tangent to a common imaginary circle. **Figure** II/2.3-3 may be referred to for some idea about the system. When firing starts, a huge fireball with swirling action forms. As soon as the burner is made to move vertically upward or downward, the fireball also moves in that direction. Obtain from the manufacturer the optimum position of the burner tilt then it can be set for all loads and an efficient steam temperature control can be achieved.

Such an activity (i.e., repositioning of burners) vis-à-vis the fireball changes the pattern of heat transfer to the SH and RH banks and provides an efficient method of controlling the steam's temperature. Here, the burners arranged in the corner are tilted up or lowered down so that the flame envelope in the furnace can move up or down, causing a good variation in the amount of radiant heat the reheater receives. This is the premier means to regulate reheater temperature in combustion engineering (CE) manufactured boilers.

www.EngineeringBooksPDF.com

The system so far keeps away the requirement of spraying water and is confined to use for fine-tuning and emergency purposes only. In some control schemes, the system is used for controlling the furnace outlet temperature as well. The steam temperature control system thus becomes genetically different in these two types of furnaces—that is, one with a tangentially fired tilting burner and the other having fixed burners.

2.3.7 Reheat Temperature Control by Tangential Tilting Burner Assembly

The firing system in any furnace of a power plant boiler that has reheater banks affects the steam temperature of both the superheater and reheater. It is, therefore, very difficult to control both the steam temperature by a single control system as corrective action for one steam heater bank may have adverse effects on the other bank. To circumvent the situation, separate control strategies have been considered by control engineers in association with equipment designers.

Reheated steam having a low operating pressure is subjected to different thermodynamic conditions than that of superheater steam. A problem may arise as a result of injecting colder spray water and an unwarranted effect may affect the overall efficiency of the power plant. For example, carryover of water particles may conflict with the TWDPS stipulation. In fact for that reason, a spray arrangement is made to inject at cold reheat, never in HRH.

The modern control system for reheater's steam temperature thus normally avoids water spraying and uses a primary control system that would take care of the control of reheated steam, by either adjusting through position control of tilting burners or by apportioning of the hot product of combustion (popularly called *flue gas*) flow through the superheater and reheater banks. The provision of a spray water injection system is also there but as a last resort when the final control element has reached the extreme position; therefore, further influence is not achievable or the temperature has shot up to a particular predefined value when emergency spray is required. This type of control arrangement is normally provided for the boiler when the final SH bank is located in the radiation zone.

2.3.8 Reheat Temperature Control with Gas Dampers

For boilers having gas dampers as the final control element for reheater steam temperature, take the task of apportioning flue gas flow through both the superheater and reheater banks by adjusting the opening of the gas dampers.

2.3.8.1 Gas Dampers in the Main Flue Gas Path

In some boilers, two separate and dedicated sets of dampers are provided in the flue gas path of both the superheater and reheater banks controlling individual flue gas flow. As these dampers are located across the main path, they control the total flue gas volume; proper care has to be taken so that both the dampers do not get a close signal at the same time. In that situation, the flue gas path will be constricted so badly that the overpressurization may damage the structure itself.

To obviate this untoward situation, control philosophy would be such that when one particular set of dampers are fully opened only then can the other set be allowed to throttle. Emergency spray may be necessary here because control through gas dampers is a slow response system; for large units, a sudden rise in temperature following a rise in furnace heat input to cope with the load demand is quite common.

2.3.8.2 Gas Dampers in Bypass Flue Gas Path

Some boilers are provided with SH and RH bypass gas dampers for controlling reheat steam temperature. For any corrective action issued by the controller, the dampers operate in the opposite direction; for example, at a low RH steam temperature, the RH gas bypass damper would close, whereas the SH gas bypass damper would open.

As the water spray is for an emergency or a secondary control system, in the case of reheat temperature control, the spray valves are normally shut unless the temperature at the reheat outlet reaches a predetermined higher set value. The spray valves are provided at the inlet of a reheater so that after spraying the proper quantity, the temperature is lower than the previous value. In addition, after gaining heat input from the flue gas, the outlet temperature is brought back to the normal region vis-à-vis a set value, where the primary control system and final control elements may be put back into action.

In the case of a turbine tripping, the reheater flow would be collapsed and the spray valves must immediately be closed so that cold spray water cannot enter the turbine in any way.

2.3.9 Reheat Temperature Control by a Gas Recirculation Damper

Boilers with a furnace having oil-firing or combined oil- and coal-firing systems, some manufacturers provide a gas recirculation damper at suitable locations of the flue gas path through which a part of the flue gas is circulated back into the furnace at a point that depends on a specific purpose and on boiler design.

In general, when the gas is reintroduced near the vicinity of the primary burning zone and used for superheated steam of the reheater outlet temperature, it is popularly designated as *gas recirculation*; the other choice is to reintroduce the gas at the furnace outlet and the system is often referred to as *gas tempering*. The selection of both take off and injection points of flue gas recirculation may vary according to manufacturer's design depending on the

www.EngineeringBooksPDF.com

type of fuel, size of the plant, etc. Take off points may be from any of the following locations:

- Economizer outlet
- Air heater outlet
- I.D fan discharge

Reintroduction points may also be at any of the following locations:

- Bottom part (through the bottom ash hopper) of the furnace that is closer to the burner or in the near vicinity of the initial burning zone.
- Furnace outlet (first pass) or final SH inlet.
- In the combustion air supply line and sometimes a combination of air line and bottom hoppers for control of temperature and NO_x.

Flue gas recirculation is one of the most efficient methods of altering the pattern of heat absorption or, in other words, distribution of heat inside the furnace/boiler to affect controlling means of reheater outlet steam temperature and reduction of NO_x generation as an effect of lower furnace temperature; details are discussed in Clause 10.3 of Chapter VIII. By controlling the gas recirculation flow, steam temperature of both super heater and reheater may also be controlled. Whatever may be the purpose, the fundamental effect is a change in the pattern of heat absorption throughout the furnace and the rest of the boiler. Normally, this effect is applied to the reheat temperature control and the aftereffects; by doing so, it takes care of the SH temperature control through spray water.

The temperature excursion due to the effect of gas recirculation is totally dependent on the recirculation gas flow when the point of take off and reintroduction is fixed for a particular furnace. For instance, the flow of gas recirculation requirement increases at low load to achieve a reheat temperature at the desired level. On the contrary, the flow of gas recirculation is brought to the lower values when the load increases. The significant advantage of flue gas recirculation is that it changes the pattern of heat absorption only; practically, there is little effect on the total heat absorption or the total flue gas mass which could otherwise reduce boiler efficiency.

When introduction of flue gas is made on the flue gas side, this system experiences the following:

- The total mass flow of the flue gas increases inside the proper furnace and a part of the boiler up to the take-off point and thereby assists in more heat transfer to each heater bank including superheater, reheater, and economizer. The more the recycled gas flows, the more the heat is transferred.
- Due to readmission of a particular percentage of colder flue gas, the overall flue gas temperatures would go down. The flue gas temperature after various types of heater stages following the furnace zone would further go down due to the effect of enhanced heat transfer at each subsequent section.
- As the colder flue gas is injected near the burner, the resultant low temperature would help in generation of less SO_x and NO_x compared to a system without a gas recirculation damper.

2.3.9.1 Flue Gas Recirculation Introduced into Furnace

When the take-off point for the gas recirculation system is at a lower pressure zone than the introduction point, gas recirculation fans are essential to force the part of return flue gas back to the comparatively higher-pressure furnace via the long way and the control damper as well. While providing a gas recirculation damper, it has to borne in mind that the reverse flow of very hot flue gas must be arrested to protect the fans in case of failure (stopping/tripping) of the fan itself.

At the take-off point, if from the ID fan discharge, the pressure would obviously be higher than at any point in the furnace; this arrangement does not call for an additional fan. The typical control philosophy of reheat temperature is discussed in Clause 9.3 of Chapter VIII for this type of take-off point from an ID fan discharge duct.

2.3.9.2 Flue Gas Recirculation Introduced into Combustion Air

Another typical recirculated flue gas take-off point is from the boiler economizer outlet zone or from the outlet duct upstream of the air heater. There are two methods for this type of flue gas recirculation system:

1. The flue gas is reintroduced through a separate line and hot gas fan to the combustion air duct at a suitable location where the recirculated flue gas and the combustion air is thoroughly mixed in the duct by some means.
2. This system eliminates the need for a separate and extra hot gas fan and mixing device. The method is popularly known as *induced flue gas recirculation* utilizes the FD fan to pull (induce) flue gas from the boiler exhaust duct into the combustion air at the fan inlet. The fan also serves as the mixing device and thus this is considered as a very cost-effective method. Control dampers in the flue gas recirculation path are provided to achieve the desired degree of control over the operating boiler load range. However, this system may have some relationship to FD fan design/sizing, thus may be suitably taken care of.

2.3.10 Boiler Tube Failure and Metal Temperature

The pressure parts of a boiler consist of number of tubes and connecting headers containing both water and steam.

www.EngineeringBooksPDF.com

These tubes are often found to be affected by various kinds of failures, having its pressure boundary damaged by a leak or rupture. They also experience loss of metals which may make them prone to being broken due to untoward thinning of the tube metal wall, so boiler inspection needs to be done at regular intervals.

Boiler tube failure, if not properly addressed with the right instrumentation, inspection, and analysis, would occur repeatedly or multiple times in a boiler that has the same failure mechanism and root cause. Some important factors are responsible for boiler tube failure that can be categorized as the root cause related to the following:

- Working fluid chemistry
- Superheater and reheater temperature control
- Combustion control
- Problems in the firing area

Several measuring procedures or methods have been established with the help of the right instruments at the right locations—time using radiography, hydrostatic tests, temperature measurements—that help to prevent or reduce this type of failure. A proper life expectancy calculation is also necessary to enhance residual life of the boiler tube metals and structures.

2.3.11 Major Reasons for Boiler Tube Failure

The following are the major categories that can be responsible for tube failure:

- Tube inside or water-side corrosion
- Tube outside or fireside corrosion
- Tube outside erosion
- Stress rupture
- High-temperature graphitization
- Fatigue

2.3.11.1 Tube Inside or Waterside Corrosion

The problem is most likely to develop during the boiler startup cycles. This type of failure is observed at the inner side of the pipe with wide transgranular cracks that typically take place adjacent to external attachments and weldments, such as buck stay, seal plates, scallop bars, etc. A combination of some damaging factors leads to the breakdown of the protective magnetite of the inside surface of the boiler tube. Corrosion of tube surface then starts in the absence of this protective layer. This type of corrosion typically results from:

Caustic corrosion that may be caused by:
- Random build up by feedwater-borne deposits or preboiler corrosion products at locations of high heat flux.
- Concentration of sodium hydroxide due to chemicals carried over by the feedwater.

Pitting or localized corrosion that is normally affected by:
- Feedwater with a high acidic or oxygen concentration.
- Existence of close-fitting surfaces and deposits where differences in oxygen concentration can be produced.

Stress corrosion cracking (SCC): The combined effect of high-tensile stresses and the presence of corrosive fluids are responsible for this type of failure. SCC failures are distinguished by the brittle type of crack with a noticeable thickness. The failure locations are also observed near the source of higher external stress such as attachments. The corrosive fluid may be a result of carryover from the steam drum into the superheater or may get contaminated during boiler acid cleaning without the faulty superheater protection. Normally, austenitic (stainless steel) superheater tubes are subjected to SCC and can propagate in the tube wall from the inner surface with a transgranular or intergranular crack.

Hydrogen embrittlement: This is a most common type of failure affected by the combined outcome of excessive deposition on inside tube surfaces and the boiler feedwater that has a low pH value. Digression of water chemistry or acidic contaminants—that is, low pH—resulted from, for example, leakage of the condenser particularly with a salt water cooling medium; this may cause further deposition and concentration of the buildup already taking place. The resultant deposit initiates corrosion that releases atomic hydrogen, which propagates into the tube metal wall and reacts with the carbon present in the steel. This phenomenon is called *decarburization* and causes intergranular separation or intergranular microcracking. The final damage done is the loss of ductility or embrittlement of the tube material leading to tube failure resulting in severe rupture.

2.3.11.2 Tube Outside or Fireside Corrosion

There are quite a few types of tube outside or fireside corrosions, namely:

- Superheater fireside ash corrosion
- High-temperature oxidation
- Waterwall fireside corrosion
- Fireside corrosion fatigue

2.3.11.2.1 Superheater Fireside Ash Corrosion Superheater fireside ash corrosion is associated with the ash characteristics of the fuel. The boiler design also constitutes an important factor in this type of tube failure. It is normally the outcome of coal firing although certain types of oil firing also can contribute. The *very high*

www.EngineeringBooksPDF.com

temperatures of combustion gases and metals passing through various types of steam heaters in the convection passes are of immense importance. Molten ash is considered highly corrosive and damage takes place when a certain portion of coal and/or oil ash remains in a molten state on the steam heater's tube surfaces. Ash characteristics are considered during boiler design when establishing the size, geometry, and materials to be used.

The ultimate damage is outerside tube metal loss and, consequently, an increase in tube stress. Affected tubes normally are covered with spots or have a pock-marked appearance when scale and corrosion products are removed.

2.3.11.2.2 High-Temperature Oxidation High-temperature oxidation takes place at any point when the metal's outside surface temperature exceeds the oxidation limit of the tube material. The appearance of this type of tube failure is fairly similar to that of fireside ash corrosion and is often confused with the same. Experts can distinguish the actual root cause between the two types with the help of tube analysis and evaluation of scales and deposits of both inside and outside metal.

2.3.11.2.3 Waterwall Fireside Corrosion Waterwall fireside corrosion is associated with the reduction, or substoichiometric atmospheres, that takes place during the process of burning; the products of combustion pass through the external surfaces of the waterwall tubes. The damage causes external tube metal loss with a consequent thinning of the tube metal wall and increased tube strain.

2.3.11.2.4 Fireside Corrosion Fatigue Fireside corrosion fatigue is the combined effect of thermal fatigue and corrosion. The outside surface of the tube often experiences thermal fatigue stress cycles that may result from different causes such as soot blowing, normal shedding of slag, and normal cyclic operation of the boiler. The thermal effect of load variation, or cycling in combination with the cyclic stress of material over a long period of time, may become the source of a crack on the less elastic external tube scales, thus exposing the actual tube metal wall to repeated corrosion.

Since this type of tube failure develops over a considerably longer period of time, the tube surfaces tend to appear as what has been described as "elephant hide" or "alligator hide" or craze cracking. A series of cracks on tube surfaces thus developed propagates into the tube wall. The long-term appearance is like a series of circumferential cracks over the tube's length. This type of tube failure is normally observed on furnace wall tubes of coal-fired once-through boiler designs; however, occasionally they are also found on tubes in drum-type boilers.

2.3.11.3 Tube Outside or Fireside Erosion

The erosion of tubes' external surface occurs as a result of abrasion from the impingement of various gases and solids on the tube and causes loss of materials to the outside diameter. The erosion medium can be any of the following abrasive materials in the combustion chamber:

- Fly ash
- Coal particle
- Falling slag
- Soot-blowing steam

It has been observed that when soot blower steam is the primary cause, the erosion may be accompanied by thermal fatigue erosion. Because the phenomenon results in metal loss of the tube's outside diameter, the damage would be visible on the impact side of it. Ultimate failure results from a rupture due to increasing strain as tube material erodes away.

2.3.11.4 Stress Rupture

Stress rupture short of tube failure may be categorized in three (3) types as indicated and discussed in the following subsections.

2.3.11.4.1 Short-Term Overheating This type of tube failure often happens during boiler startup because the proper procedure is not followed. Short-term overheat failures are the result of extremely high tube metal temperature due to low or inadequate flow from the cooling medium through the water and/or steam tubes. Tube metal temperatures may even become as high as that of combustion gas temperatures—1000°C or greater—which paves the way for an untoward situation. The cause may be a very simple thing such as accumulation of products of condensation in the superheater tubes during boiler startup, restricting steam flowing to the desired minimum value; this can result in a ductile rupture of the tube metal where the fracture surface becomes a thin edge. The typical physical appearance of the failure may be recognized by what is popularly termed the *fish mouth* opening in the tube.

2.3.11.4.2 High Temperature Creep or Long-Term Overheat Creep is the process where metals exposed to high temperature and sustained stress over long periods of time will gradually become deformed and eventually fail. Long-term overheating related to failures are applicable when tubes are subjected to high temperature over a long period, say months or years. Steam superheater tubes are subjected to operating under high temperatures and may fail due to the "creep effect" after prolonged operation at the end of their life. The waterwall tubes also may fail due to prolonged overheating.

www.EngineeringBooksPDF.com

Problems, such as deposits, scale, etc., causing restrictions in the waterwall tubes may result in very high tube temperatures. Contrasting the physical appearance of the failed tube to that of a short-term overheated one, here the longitudinal split is narrow and swelling is minimal. The buildup or the external scale deposited on the tube surface after prolonged operation also develops secondary cracking.

Superheater and reheater tubes containing steam normally operate at temperatures of 550°C or above. Study and research has revealed that working temperatures of more than 482°C cause metal tube failure due to the phenomenon called *creep-rupture*. Oxide layers are formed on the internal surface of these tubes which restrains heat transfer through the wall and causes the tube metal temperature to increase over operating time.

Heater banks for superheaters, reheaters, and economizers are made of various materials such as carbon steel (CS) in the cooler sections or stainless steel grades in the hottest outlet sections. The allowable stresses in superheater designs using alloy materials for the hottest sections are based on a finite creep-rupture life set by the ASME Code. It is definite that quite a few of these tubes would rupture due to the creep-effect even if some other factor does not cause premature failure of the SH tubes.

For alloy superheater tubes, stress and temperature are not usually constant during a tube's service life. When a tube enters service, the metal in contact with the internal steam begins to form a layer of magnetite (Fe_3O_4) in the form of scales. This oxide grows thicker as the service life increases and its growth over time is dependent on metal temperature. The oxide layer acts as a baffle plate to transfer heat and as its thickness increases, metal temperatures must also increase to maintain a constant outlet steam temperature.

Typically, the tube metal temperature increases more than 1°C) per scale thickness of every one thousandth of an inch or 0.03 mm of ID oxide formation. In addition to the metal temperature increase, tube wall thinning due to OD metal loss for problems, such as erosion, corrosion, or other environmental damaging events, may take place over time. The resulting effect (i.e., the loss or thinning of tube wall) would obviously turn into increased stress on the affected tubes that are operating at a fairly constant fluid pressure.

There are some methods for calculating the creep-life prediction of superheater metal tubes, including measuring the real-time tube metal temperature and scale thickness vis-à-vis tube stress.

2.3.11.4.3 Dissimilar Metal Welds The term *dissimilar metal welds*, or DMW, describes the butt weld where two dissimilar metals are welded—for example, in a power plant, an austenitic material, such as stainless steel, is welded to a metal, say ferrite alloy. The peculiarity of this type of failures is that the damage due to failure at DMW locations takes place only on the ferrite side of the butt weld. Many reasons or factors are responsible for this type of failure, as enumerated next:

- High stress at the austenitic-to-ferrite interface due to dissimilar expansion of the two materials
- Excessive external loading stress
- Excessive thermal cycling
- Creep characteristic of the ferrite material
- Variation or continuous high operating temperatures

The symptoms of failure normally are characterized by no or at least a warning of a tube damage condition. As discussed earlier, the damage occurs at the ferrite side of it throughout the circumference of the weld's fusion line. This type of failure may lead to catastrophic damage in nature as the entire tube will fail across its cross-section.

2.3.11.5 High-Temperature Graphitization

This type of failure is caused mainly as a result of the high temperature of metal tubes at the plant while operating for a long time period. For the part of the boiler tubes made of carbon steel or a similar type of steel with higher carbon content, they may experience a unique type of damage that causes degradation of the steel; this is popularly called *graphitization*. The term *degradation* is used because these materials, if exposed to excessive temperature, would initiate disbanding of the iron carbide molecules in the steel and graphite nodules are formed as a result. The ultimate effect of this phenomenon is lower strength of materials and tube failure with a thick edge brittle-type fracture.

2.3.11.6 Fatigue

Fatigue, as is well known, for causes extensive damaging effects and cyclical stresses in components that are attributable to various factors such as mechanical vibration, thermal cycle, and corrosion fatigue.

2.3.11.6.1 Mechanical Vibration-Type Fatigue The tendency of this type of fatigue is to affect the area of the materials near the vicinity of high stress or constraint. Damage may be noticeable as cracks around the outer side of the tube's diameter. Mechanical vibration-type fatigue damage is initiated by an external source that causes stress. Stress due to external sources of vibration may be transmitted from different origins such as the following:

- High-frequency, low-amplitude stress associated with flue gas flow or soot blowers
- Low-frequency, high-amplitude stress associated with boiler load cycling

As stated in the preceding, fatigue failure-prone areas are near the location of the constraint—for example,

www.EngineeringBooksPDF.com

tube attachments, welds, penetrations, supports, or similar tube assemblies.

2.3.11.6.2 Thermal Fatigue Thermal stresses are responsible for fatigue and have been defined as "stresses in metal resulting from a nonuniform temperature distribution." Thermal fatigue is a continuous process of developing a form of failure that builds up within the metal components where the process is subjected to alternate heating and cooling, resulting in expansion and contraction of the metals.

Whenever there is a difference of temperature between the metal surface and inner metal, it is better to say mid-metal, thermal stress develops. It will be quite significant in cases when the subject metal's thickness is appreciable. Another reason why thermal stress develops is that when the surrounding material or external constraints hinder metal expansion (or contraction).

Expansion of two pieces of metal at various rates (due to different coefficients of expansion) may also contribute to stress development. For example, for weld attachments, where thermal expansion or contraction of one or both pieces happens, metal tensile stress results on the tube's interior or exterior.

The cyclic thermal stress from alternate temperature excursion causes fatigue similar to that of mechanical stress and cracks appear. The reason for a crack is due to the rapid change of temperature in the material that causes thermal expansion or contraction as the case may be. Under thermal fatigue, cracks can initiate, propagate, and eventually failure occurs. This type of failure is quite common in thermal power plants where turbulent mixing and flow of fluids causes fast and unwanted thermal transients in the boiler tubes.

To minimize thermal stress and at the same time to achieve the desired load condition at the earliest possible time, the boiler manufacturers must provide suggestive guidelines on an optimum time frame of heating and cooling for proper startup and shutdown of boilers. Because thermally induced stresses are due to cyclic operation of the boiler fuel firing startup and shutdown, it needs to be noted that stress occurs in every firing cycle with varying magnitudes depending on the startup and shutdown firing procedure.

The causes are due to the resistance offered by the various boiler pressure part metals within the boiler frame to the movement experienced by the thermal expansions and contractions popularly termed *thermal shock*. These metals, such as SH/RH/boiler drum/water tube, etc., are subjected to operation at high temperatures and time-to-time load variations or, in other words. "thermally induced stress cycling" creates metal fatigue. Although the phenomenon is also termed *shock*, which means a sudden impact, the actual effect does not take place all of a sudden but over the period of time.

Each startup and shutdown also may cause metal fatigue and reduce metal life expectancy to some extent depending on its time and type; the resultant effect is ultimately tube failure. Most failures of this type occur after operating the boiler and quite a few starts/stops over a certain period of time, or sometimes after short intervals, depending on the severity of operational glitches and malfunctions of control systems. In general, it has been observed that a considerably longer time period is taken before actual damage becomes evident.

As it appears in reality, these types of failures are not likely to be dangerous in nature as far as damages to the equipment are concerned; however, they may be a costly and a serious affair because of the charges for repair and the revenue loss as a result of downtime. Failures of this type, already described as tube failure, may be described as failure of metals through sectional cracking and may be of different types—for example, leaks between the tube-to-tube sheet joints, cracked tube sheet ligaments, or broken stays (see Table II/2.3-1).

2.3.11.6.3 Corrosion Fatigue Corrosion fatigue is applicable to fireside corrosion fatigue, as already discussed in Clause 2.3.11.2.4.

2.3.12 Measurement of Boiler Tube Metal Temperatures

Boiler tube metal temperatures are very important parameters and thus their measurements have become a necessity as far as boiler tube failure is concerned. During analysis of tube failure, it must be noted that many of the failure factors are related to and/or caused by high temperature or fluctuations in temperature.

Several methods have been adopted to measure the metal temperature of tubes in the gas path. There are even methods for calculations to arrive at metal temperature from measuring other related parameters. These metal temperature values, whether measured or calculated, are normally taken for initial understanding of the boiler behavior under running conditions. This initial observation period may extend up to the first year or two years.

The method, where temperature sensors (normally thermocouples) are used, is used at strategic locations for installing "startup thermocouples" and "permanent thermocouples." Startup thermocouples are meant for the hottest locations where it is assumed, or expected, that the thermocouples would be burnt out after a period of time. The other locations are chosen such that the flue gas temperatures at that area is not so high as to cause burnout of thermocouples.

www.EngineeringBooksPDF.com

TABLE II/2.3-1 Summary of Tube Leakage Types

Leakge Type	Symptoms	Reasons	Remarks
Acid attack	Corrosive attack on internal tube irregular pitting	Poor boiler chemical cleaning and inadequate postcleaning passivation	Same as "Swiss cheese"
Caustic attack	Localized loss ID resulting in stress and strain in tube wall	Excess deposition on ID tube surface—loss of cooling medium flow Local deposit boiling and concentration of boiler water chemicals	Finally results in caustic condition
Dissimilar metal weld (DMW)	Material failure at ferrite side of weld along weld fusion line without warning	When austenitic (SS) joins with ferrites due to high stress at austenitic interface, difference in expansion properties, creep of ferrite due to loading stress, etc.	
Erosion	OD metal loss on impact side of the tube	Impingement of external surface may be due to fly ash or soot-blowing steam which also may cause thermal fatigue	Rupture due to increased strain
Fireside corrosion fatigue	Series of cracks on OD propagates into wall	Combination of corrosion and thermal fatigue. OD experiences thermal stress cycle in addition to subjecting material to cyclic stress	"Elephant hide," "Alligator hide," "Craze cracking"
Graphitization	Brittle with thick edge fracture	Long-term operation at relatively high temperature to damage CS with more carbon Formation of graphite nodules	Dissociation of iron carbide in steel
High temperature oxidation	External tube metal loss excess strain in tube	Local high temperature causes high-temperature oxidations Similar and confused with fireside ash corrosion Best differentiated by tube analysis	
Hydrogen embrittlement	Loss of ductility and embrittlement; finally brittle catastrophic rupture	Deposition on tube ID and low pH Under deposit corrosion, atomic hydrogen is released, which reacts with carbon in the steel and causes intergranular separation	Water chemistry upset may be due to condenser leakage
Long-term overheating	Small swelling and longitudinal split is narrow Tubes often have scale buildups	Long-term* overheating at SH, RH, and stress due to high temperature Also waterwalls fail due to this	
Mechanical failure	OD initiated localized crack due to high stress and constraints	Cyclic stress in component Thermal fatigue affects mechanical damage, with external stress	
Oxygen pitting	Aggressive localized corrosion and loss of tube wall	Presence of excess air may be due to pump air leakage or mainly occurs during a long idle period Failure of operation of preboiler water treatment equipment Mostly in economizer FW inlet and nondrainable surfaces	
Short-term overheat	Ductile rupture of tube metal characterized by "fish mouth"	Occurs during startup, when metal tube temperature may be extremely elevated due lack of steam/water, or SH tubes are not cleared of condensation at startup	
Stress corrosion cracking (SCC)	Thick wall, brittle-type crack in locations with external extra stress	Mainly in austenitic SH material due to high tensile stress coupled with corrosive fluid presence	
SH fireside ash corrosion	External tube wall loss and increase strain in tube	Function of ash characteristic and boiler design Mainly in coal (maybe for oil) Certain constituents of ash in molten state cause high corrosion	
Waterside corrosion fatigue	ID initiated wide transgranular cracks to external attachment	Combination of thermal fatigue and corrosion Breakdown of protective magnetite on ID of the tube	Found in seal plate, scallop bars
Waterwall fireside corrosion	External tube metal loss, thinning, and increase in strain	When reducing atmosphere is created due to combustion., mainly in recovery boiler	Also in burning zone of fossil fuel boiler

**Overheat spread over months and years.*
Source: Courtesy of Babcock library_document.

www.EngineeringBooksPDF.com

During this initial period, the interrelation among the measured values of the startup and permanent thermocouples are drawn so that inferential values of the startup thermocouples can be made use of for further desirable purposes even after the same metal temperature-measuring devices has burned out. In the long run, the number of thermocouples available for this purpose becomes very limited, thus, the inferential value of burnt out thermocouples' measuring points play a vital roll in assessing the tube's failure position.

Another method of calculating the waterside tube metal temperature is from the corresponding water temperature of a particular tube. It is a well known fact that the temperature rise of a metal tube will be much quicker than that of the water flowing through it. As temperature measurements are nothing but indices of internal kinetic energy, which commensurate with the quicker vibration of free electrons associated with the heat imparted to the tube metal.

On the contrary, water does not possess such free electrons and is held within the molecular bonds and thus vibrating movements are restricted. Considering the heat input to the boiler tube as being equal to the heat transmitted to the water inside the tube this causes the temperature rise in both the metal tube and the water for a particular time period. If the temperature rise of the water is measured, the tube's temperature rise vis-à-vis the final temperature can be calculated assuming a suitable mass of water and a metal tube.

2.3.12.1 Measuring Location of Boiler Tube Metal Temperatures

Quite a few measuring locations are selected for both permanent and startup purposes. The locations are at various elevations for mainly water tube walls (normally for 500 MW and above TPS), superheaters, and reheaters. The drum mid-metal temperatures around the periphery are also measured to avert catastrophic disasters in case of low drum level. Data has been acquired for both laboratory stress analysis and field test programs, from which the necessary action can be explored to take care of the power output requirement along with the requirements of the boiler manufacturer's recommendation to protect the structural integrity of the boiler.

The following are the approximate or typical numbers of metal temperatures measured at various strategic locations on the heat transfer elements of a 500-MW TPS:

- Location number alarm value
- Platen SH outlet: 45 nos. 575°C
- Final SH outlet: 40 nos. 590°C
- Final RH outlet: 25 nos. 612°C
- Primary SH outlet: 10 nos. 460°C
- Drum: 10 nos.

In some power plants, economizer metal temperatures are also measured. During startup and shutdown, trends of these measurements are very helpful for operators, especially during startup that is normally monitored in DCS.

2.3.12.1.1 Problems and Solutions of Measuring Boiler Tube Metal Temperatures As environmental or ambient temperatures are very high in these areas, tube metal temperatures are extremely difficult to measure because the object temperature is totally different than that of the environment where the sensor is located. The sensor or probe is supposed to respond to the tip temperature, and thus it is extremely important that proper contact, to eliminate or reduce thermal resistance, be made with the object where the measurement can be conveniently accomplished using only a small area. It is always better if an appropriate (and externally insulated from the environment) heat-sinking compound is used; this would ensure maximum contact vis-à-vis minimum interference. There are methods that follow the preceding guidelines to avoid such harsh environmental problems, as discussed next:

- Provision for using a thermopad, which is nothing but a block of metal suitably shaped and curved to match the tube's curvature. It is meant for pressing the sensor with a metal surface that has a proper fixing arrangement of nuts and bolts or weld.
- A skewer-shaped, pointed-tip sensor is a practical choice but it measurement accuracy is always questionable.
- A spring-loaded arrangement would facilitate good contact.
- A pocket sort of arrangement that is used by drilling or scraping the surface material would ensure better accuracy.
- A thermocoupler made of fine wire of a certain diameter may be used and a layer should be used such that the extension wires are drawn along up to the length of the tube surface; this ensures good contact with the material's body.
- Provision to use a noncontact-type measurement device—that is, radiation thermometry—would also enable avoiding the cumbersome contact type. The instrument used here is popularly called a *radiation pyrometer* and is widely used for industrial measurement purposes. This is noninvasive type of device, so avoids the problem of interference.

There are certain disadvantages of radiation thermometry that must be taken into considered. These may be the background radiation reflected from the surface or the radioactive property that is emitted, etc. Emissivity may change drastically with surface roughness, surface composition, object body temperature, and so on..

www.EngineeringBooksPDF.com

2.4 BOILER DRUM: ITS PRESSURE PARTS WITH LOCATIONS

2.4.1 Boiler Accessories

Figure II/2.4-1 illustrates various very important accessories and equipment of a typical boiler plant of a modern fossil-fired thermal power station of considerably high capacity. The function of these items are described in a brief way to present an overall idea about a plant.

Item 1 in the figure is the boiler drum, which acts as intermediate storage, where boiler feedwater is fed from boiler feed pump (BFP) (item 10) via an economizer (item 9) for onward distribution by the downcomer pipes (item 2) throughout the waterwall (item 4) surrounding the furnace (item 3) vis-à-vis the boiler. In case of a once-through boiler, where there is no boiler drum, a small storage tank and separator tank serves a similar purpose during startup. An economizer is a bunch of water tubes through which cold water from BFP is passed to gain some heat from the flue gas before it goes out of the main boiler structure.

A waterwall is the series of tubes connected together like a wall along the periphery of a boiler/furnace to ultimately form a leak-proof enclosure where exchange of heat takes place. However, the whole surface area of the waterwall is externally insulated by a suitable material to prevent heat loss to the surroundings and then clad for personnel convenience. Water that gets heat input from the products of the combustion chamber (item 6) goes upward as hot water of a lower density; ultimately, it starts vaporizing near the uppermost part of the tubes. This mixture of saturated steam and water is then brought back to the upper part of the drum for separation of steam from water using a steam separator (item 23). Formation of steam in a once-through boiler is little different and discussed in Appendix V.

Saturated steam from the drum is then passed through the primary (/platen) superheater (PSH) bank (item 15) and the final superheater (FSH) bank (item 18) to get the superheated steam dry and ready for the final superheater outlet header (item 19). In some plants, the feedwater from the boiler drum is distributed to the waterwall with the help of a separate set of boiler circulating water pumps (item 12), called a *forced circulation system*; however, the natural circulation system does not utilize those pumps.

Larger plants have steam reheaters meant for heating the steam once again from the high-pressure turbine

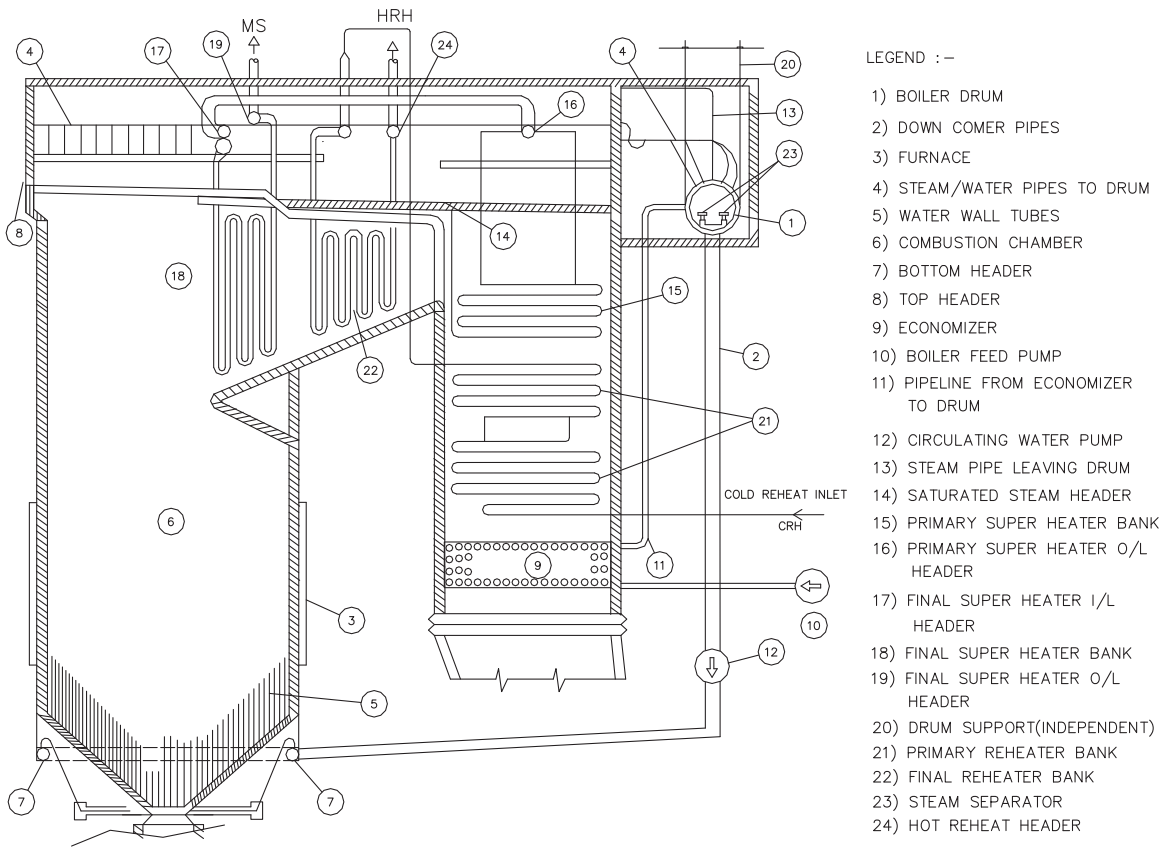


FIGURE II/2.4-1 Boiler drum: Pressure parts and their locations.

www.EngineeringBooksPDF.com

exhaust steam, which is called a *cold reheat* (CRH), for reuse in the intermediate-pressure turbine for increased output. Here, as shown, CRH steam from the turbine is entering the primary reheater bank (item 21); then it goes to the final reheater bank (item 22) so that dry superheated steam is ready leave the outlet header (item 24). This is called hot reheat steam.

In ultrasupercritical steam generating plants more than one reheating system is provided so that they operate at different pressures to achieve a more efficient plant. There may be an additional number of intermediate superheaters and reheaters to meet the steam parameters for external usage. The incoming boiler feedwater may not be arrive directly from the BFP but via the high-pressure water heaters, feed control (valve) station, etc.

There are plants at which the boiler drums are eliminated when appropriately designed and the saturation point occurs at a critical pressure (225.415 kgf/cm^2) and a temperature of 374.065°C. The latent heat of vaporization is zero at this point or, in other words, water is transformed from the liquid phase to the gaseous phase without going through the two-phase condition. These units are called *super critical steam generators* because, in this case, the term "boiler" is a misnomer—no boiling takes place at all. Some brief details are included in appendix V.

2.4.2 Drum Internals

Figure II/2.4-2 illustrates the important internal parts of a boiler drum. It serves many purposes out of which the two main functions are to separate steam and water that comes from the waterwalls and includes an arrangement to provide better quality of outgoing steam and water inside the drum that is ready for circulation.

Apart from that the boiler drum is also considered a high-pressure, intermediate-steam storage unit, though the water level vis-à-vis quantity of drum water is not comparable with respect to the total steam requirement of the plant. In addition, it is capable of repeatedly and frequently receiving waterwall tube fluid, basically a mixture of saturated steam and water that flows at high temperatures and pressures that are different from those of the drum wall. A priority consideration is to design the drum interior with a view to minimizing thermal stress on the drum wall thickness. The approximate and typical range should be 100 to 150 mm depending on the size of the boiler and other parameters.

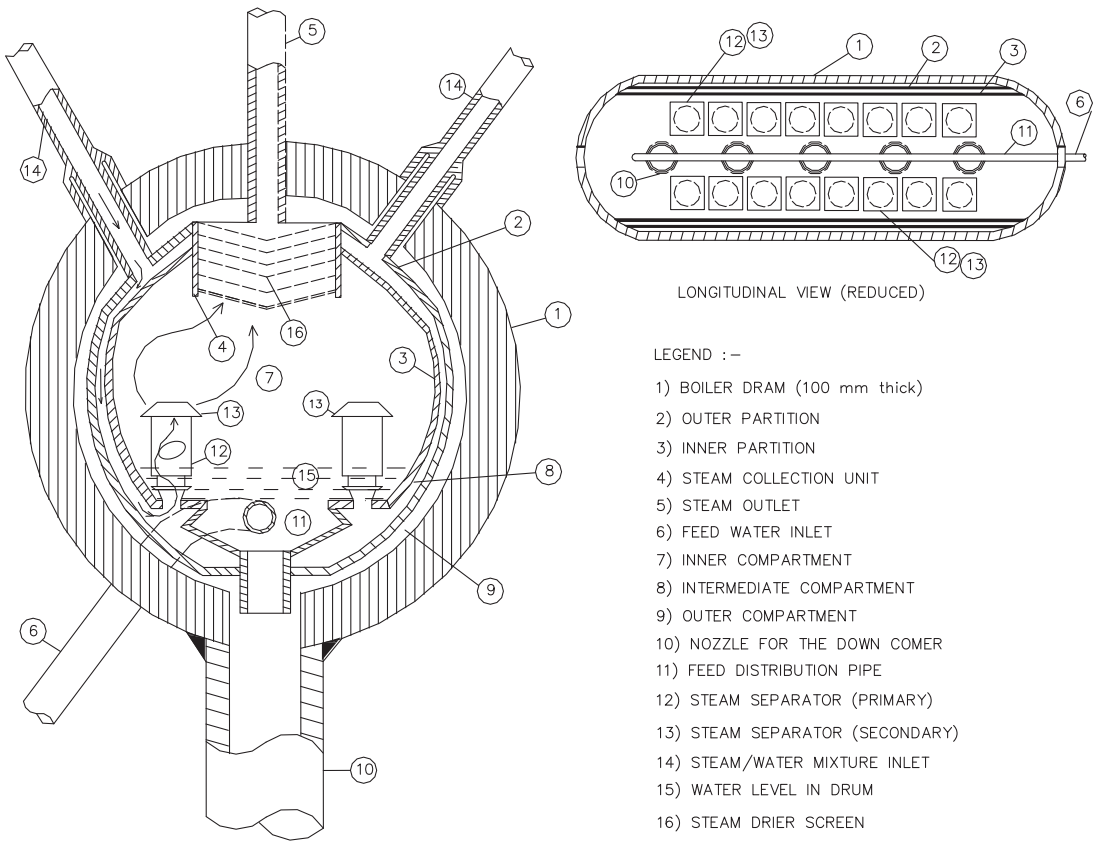


FIGURE II/2.4-2 Internal parts of a boiler drum.

www.EngineeringBooksPDF.com

The baffles are provided in a way to ensure change of direction of the incoming saturated steam–water mixture and to facilitate gravity separation in the inner/open drum space. They also need to assist with the uniform distribution of drum metal temperature to avoid thermal stress during startup/onload conditions. The separators, using a whirling action of the fluid path assist with elimination of water particles from the steam. Steam quality is aided by screen driers that are provided at the top of the drum's internal structure. They are used to heat up the wet steam from the separator and to remove the remaining moisture to achieve dry, quality steam at the drum outlet.

Feedwater lines submerged in water are connected to the boiler drum at the bottom portion; this arrangement enables the comparatively cold fluid to avoid direct contact with the drum metal during admission, thus ensuring minimum thermal stress. Provisions are also made to connect a high-pressure chemical dosing system in order to minimize scales, sludge, and corrosive reactions of feedwater-borne objectionable compounds. Blowdown connections are provided to facilitate both continuous and intermediate removal of a portion of the drum water in order to maintain the water quality vis-à-vis the concentration of feedwater-borne solids.

Drum length normally depends on the furnace's width but for high-capacity units, the steam water separators and purifying equipment, etc., dictates the overall design of the drum. Figure II/2.4-2, shown earlier, illustrates a sketchy view of a major part of the drum's internal arrangement. Baffles or partitions are spaced throughout the entire length so that its interior is divided into three distinct, separate compartments—namely, outer (item 9), intermediate (item 8), and inner (item 7). Partitions are so made as to form a sealed-tight installation that isolates the fluid from the intermediate compartment. The fluid mixture coming from furnace waterwall tubes enters the drum directly into the isolated intermediate compartment through the inlet nozzles (item 13). After entering that compartment, most of the steam–water mixture flows through steam separators (item 12) and into the inner compartment.

The purpose of the outer compartment is to provide thermal isolation between the drum wall and the water–steam mixture's passage to the intermediate compartment and steam in the inner compartment. A portion of the steam–water mixture from the intermediate compartment is allowed to percolate to the outer compartment through holes in the partition between the intermediate and outer compartments. This is done to minimize the pressure difference across the outer partition and thereby to permit only a limited amount of fluid to flow to the outer compartment. The inner and outer compartments are connected to each other near the bottom of the drum; the inner compartment is filled with a controlled level of water. A suction head is created near the multiple downcomer nozzles (item 10) at the bottom of the drum due to the high-velocity water flowing out, thereby ensuring continuous removal of water from the intermediate compartment.

The feedwater is introduced to the drum by means of the feed distribution pipe (item 11) that is located within the inner compartment of the drum; it extends longitudinally as depicted earlier in the transverse sectional drawing of Figure II/2.4-2. The level of feedwater is established initially and thereafter is maintained continuously at a preset value (item 11) by means of external feed water pumps at a pressure that matches the drum's pressure, taking care of the transmission and other losses. The temperature of the inlet feedwater is also important, so is raised by heat exchange through regenerative feed heaters before introducing it to the drum through the feed inlet pipe (item 6).

Because the modern steam-generating units (boilers) operate at very high fluid pressures, in the range of ~150 to 200 kg/cm^2, it is imperative that their pressure components have adequate wall thickness to sustain such pressures over their estimated life. These drums normally have a length in the range of ~20 to 30 meters with a diameter in the range of ~1 to 2.5 meters. Under such conditions, the wall thickness of the drum wall must be more than sufficient—that is, in the range of ~100 to 250 mm.

It is obvious that an increased wall thickness is a necessity as far as pressure criteria is concerned; however, the problem that comes then is the thermal stress of the drum at a saturation temperature corresponding to the drum pressure. While starting up a high-pressure boiler, the foremost consideration demands that a uniform temperature be maintained throughout the length of the drum so that excessive thermal drum wall stress is avoided. It can be accomplished by increasing the pressure of the plant slowly and thereby the temperature of the drum uniformly. This procedure requires considerable time for starting up a large boiler plant; this may not be acceptable to the user from a revenue point of view.

Nowadays boiler drum are designed to operate at an increasing rate of temperature change to reduce the time required for starting up and shutting down a boiler up to say 150°C per hour from the initial moderate temperature value of 40°C per hour. However, it is quite evident that operating in the quick start/stop mode puts severe thermal stress on the boiler drum wall; doing so needs to be weighed against economic advantage. Frequent occurrences of such startups/shutdowns has, in some instances, ultimately resulted in failure of the drum.

2.4.3 Types of Superheaters and Reheaters

It has been observed that if saturated steam is introduced into the turbine, the work done by the turbine results in a loss of energy by the steam associated with its partial condensation (Figure II/2.4-3). The amount of work done by the turbine could have been more had it not been limited by the amount of steam converted to moisture in spite of a pressure drop across this stage. It also is a fact that a turbine

www.EngineeringBooksPDF.com

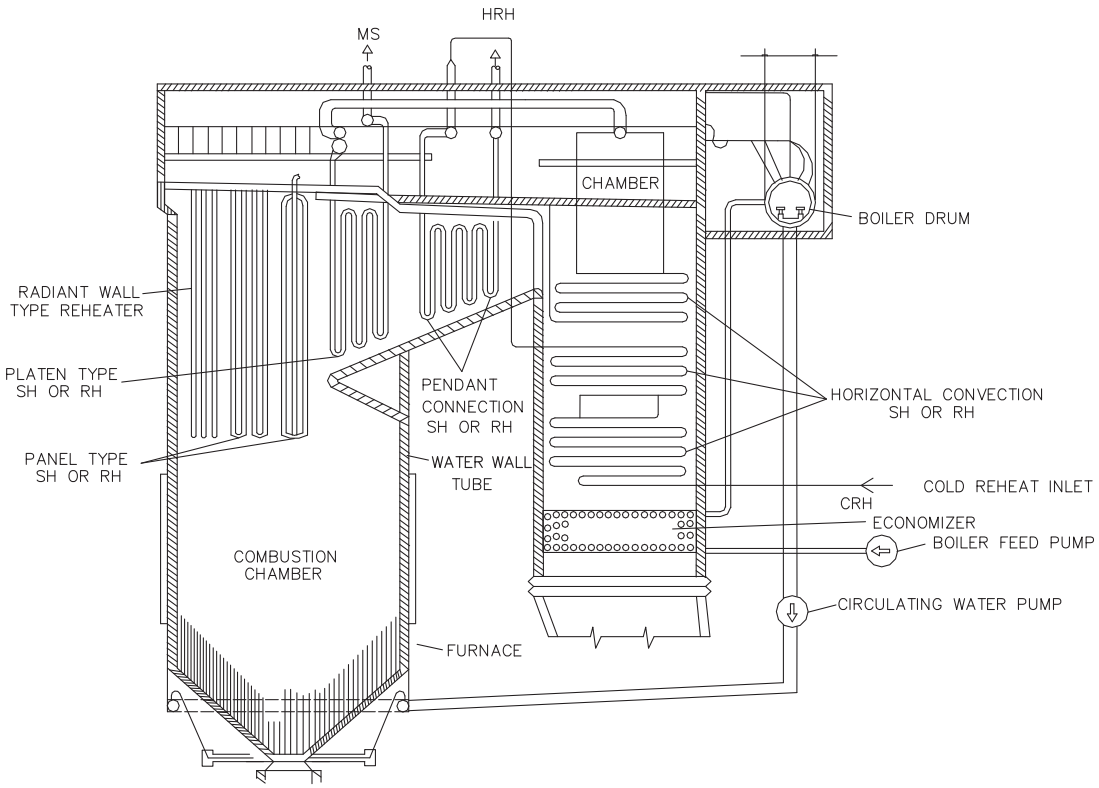


FIGURE II/2.4-3 Types and locations of superheaters and reheaters.

generally converts the heat of superheat to work done without forming moisture, the heat thereof is recoverable in totality. It is economic, therefore, that the admission of steam be to such a degree of superheat that moisture must not be formed at any stage of the turbine to ensure that a maximum amount of work is done in the turbine.

Superheaters and reheaters are the heat exchanger banks used to elevate the steam's temperature above its saturated temperature at a pressure that is effectively the degree of superheat. Before entering the heaters, it is a precondition that the steam's quality be dry saturated. Any addition of heat obviously would increase the steam's temperature depending on the heat input, mass of steam, temperature difference between steam inlet and heating medium, specific heat, duration of heat exchange, etc.

Types of SH and RH depend on the particular requirement of the plant where they are to be installed. Reheaters are also superheaters but the name is so because it accepts the steam from the HP turbine exhaust or CRH steam; it is heated again and sent to the IP turbine to avoid condensation there. There are two basic types of SH/RH popularly known as "convection" and "radiant" superheaters.

2.4.3.1 Convection Type of Heat Exchangers

This is where the heat transfer takes place by convection or movement/mass transfer of fluids. A convection type of design is the original form of superheaters and was initially adopted for relatively low-temperature applications. They are placed in the flue gas path so that direct contact is made between flue gas and the superheater's tube metal surfaces through which the steam is forced to flow. This type of SH/RH is placed in a location where heat transfer by radiation is negligible with respect to the other types; thus, the percentage of heat absorbed in the furnace decreases and more heat is conveyed through the flue gas for absorption in the superheater region in cases of increasing boiler load. This means that when load increases, the temperature at the convection SH/RH outlets is more than that of decreasing loads.

In the convection zone, the superheaters and reheaters are installed in a manner that counters the flow of steam and gas (heating medium), which is established by having a steam inlet at the bottom whereas a gas inlet is at the top of the boiler. In other words, it is from the opposite side to ensure a maximum mean temperature difference between the two opposite-flowing fluids and a minimum heating surface in the primary zone.

2.4.3.2 Radiation Type of Heat Exchanger

This is where the heat is transferred through radiation or electromagnetic waves transmitted by the source. They are located in a place where the flue gas, when traveling needs

www.EngineeringBooksPDF.com

not be in direct contact with them; this means that they receive a negligible amount of heat transfer through convection. The fact regarding radiation energy is that it depends on the heat absorbed in the furnace surfaces, which does not bear a direct proportional relationship with the boiler load; rather, it has a lesser rate when the load increases. The steam outlet temperature of radiant SH/RHs, contrary to the convection type, shows decreasing characteristics as the steam flow at higher load increases but receives lower percentage of heat by radiation. Higher outlet temperature demands more surface area of the heaters—namely, wall-type, pendant- or platen-type SHs and RHs. Those are basically radiant-type heat exchangers and necessarily need to be mounted near the combustion zone where the exchange of heat is by radiation.

For a very high outlet temperature, both locations as well as type of superheaters and reheaters are considered. In general, all high-capacity thermal power stations have both types of SHs/RHs and the combination of these two opposite characteristic curves, and proper coordination of them, provides the considerably flat superheat outlet temperature over a wide range of load variation especially with a higher percentage of loads.

The final SH/RH outlet temperatures are maintained within a very closed limit of set values to avoid overheating of superheater metals and turbine expansion, causing reduced clearance due to the higher steam temperature. Low steam temperature causes moisture carryover and damage to the turbine blades. The outlet temperatures mainly vary due to load changes but also due to formation of an insulating medium such as deposition of ash and slag over the SH/RH tubes.

The final control elements are different in subcritical and super-/ultracritical steam generators' outlet temperature control. For a subcritical or drum-type boiler, attemperation through feedwater spray is done for SH and burner tilt or flue gas recirculation or spray system for RH temperature controls. Firing rate controls do not control the temperature but do the steam pressure and flow vis-à-vis boiler load. For super-/ultracritical steam generators the outlet temperature control, on the other hand, is achieved by the firing rate—that is, the fuel to feedwater ratio—whereas steam pressure and flow (steam generator output) is controlled by boiler feed pumps.

2.4.4 Economizers

The economizer is made up of a bunch of horizontal water tubes usually located in the back pass or second pass (after the primary superheaters and reheaters) of the boiler through which the feedwater enters the boiler to absorb residual heat from the exhaust flue gas and transfer it to the steam production cycle. This process, on one hand, helps improve overall thermal efficiency (thus justifying its name) and on the other hand reduces the stack outlet temperature for better environmental conditions as per various government stipulations. It has been observed that loss (through cooling) of flue gas temperature by every 22.2°C affects boiler efficiency by ~1%. This also means comparatively less fuel would be required to produce the same amount of steam, resulting in lower carbon emission.

According to the location, it is necessarily a convection-type of heat exchanger providing forced and once-through flow path of feedwater, effectively making it heater inside the boiler or steam generator. The economizer tubes may be of different types, such as bare tubes, finned tubes (e.g., spiral or long finned), etc., but bare tubes are preferred, keeping in mind the problem associated with ash fouling. However, the economizer's design has always been guided by economic considerations, the stack outlet temperature, provision of air preheaters, and so on. or a given temperature of the stack outlet. The higher gas temperature at the economizer outlet calls for a smaller size of economizer and a larger size of air preheater. In many cases, the size of an economizer is restricted to make way for the need of increased air temperature vis-à-vis air preheater size for better fuel conditioning and in turn for efficient combustion.

It is preferable that the flue gas from the boiler flows down across the economizer tubes and for the water to go up after entering the boiler at the bottom. This counterflow-type design minimizes the requirement of surface area as well as the draft loss experienced by the flue gas. The concept of an upward feedwater flow direction eliminates the possibility of unstable water flow, assists uniform flue gas distribution, and realization of the idea of steaming economizers that makes provision for generating some steam in the outlet section even.

Steam or vapor formation in the economizer is a common phenomenon and is also advantageous to some extent rather than in the boiler surface. Generally, there is no such restriction for a percentage of vaporization to take place in the economizer but, practically speaking, a maximum limit of ~20% of the feedwater flow at full load operating output is normal.

It is should be borne in mind that the economizer is provided not to just take advantage of waste heat from the by-product of combustion but also to assist, at the same time, with the increased life expectancy of the boiler. Had cold feedwater (without an economizer) been injected into the boiler, the high temperature differential could have caused excessive wear and tear on the boiler over time because all the associated pipes and fittings are subjected to heating and cooling down cyclically. For preheated feedwater through the economizer, the temperature differential is much less and consequently would cause less thermal stress on the boiler metals and thus a longer operating life.

www.EngineeringBooksPDF.com

2.4.5 Boiler Water Circulation

It is needless to mention that water-tube boilers are only used in present day large thermal power plants—that is, shell-type boilers—where water is circulated inside the tubes. The flue gas or the heat source passes through externally to raise water temperature to the desired level. The water-tube boilers are much more advantageous for very high pressure usage as the design employs multiple bunches of small diameter tubes to minimize "hoop stress." Two types of methods are used for circulating the water inside the water-tube boiler: natural circulation and forced circulation.

2.4.5.1 Natural Water Circulation

A large number of water-tube boilers operate on the principle of natural water circulation, which is also known as *thermosiphoning* because the water is circulated by the thermal effect. The reason behind natural circulation can be explained in the following two ways:

1. In natural circulation boilers, the circulation of water depends on the difference between the density of an ascending concoction of hot water and steam and a descending mass of relatively colder and steam-free water. The difference in density occurs because the water expands as it is heated, and thus becomes less dense; in other words, the density goes down when water temperature increases.
2. Natural circulation can be described in another way: it is caused by convection currents due to application of heat to water through the tube metal wall. This results in uneven heating of the total water contained in the boiler.

The boiler drum, waterwalls, and tubes constitute the multi-passage section of the water circuit. There are some large-diameter insulated water pipes connected to the drum and taken out of the boiler and reconnected to the waterwall tubes through a water drum or headers located at the bottom part of the boiler depending on the arrangement of the steam and water spaces. "Drum-type" boilers may have one or more water drums. On the contrary, "header-type" boilers have no water drum and the tubes are connected to many headers that serve the same purpose as water drums. As far as boiler functioning with regard to water circulation is concerned, both are comparable with the only distinction between a drum and a header being the size. These pipes from the steam drum to water drum, or header, are popularly called *downcomers* and form the colder leg of the circulation path as heat is not added here.

On the other hand, the water in waterwall tubes gets heated from the products of combustion in the hotter leg. As the water tubes approach the boiler drum, the water temperature rises and steam bubbles are formed. Comparatively, cold feedwater is introduced into the boiler drum and, because the density of the cold water is greater, it comes down through the downcomer toward the lower part, thus pushing up or displacing the low-density fluid that is a combination of hot water and saturated steam. This sets up a continuous circulation and thus steam is being collected and naturally separated from the hot water in the steam drum and is taken off. The size and number of downcomers installed varies as does the capacity of the plant and from one type of boiler to another.

However, when the pressure in the water-tube boiler is increased, the difference between the densities of the water and saturated steam falls and circulation becomes less effective. At the critical pressure of 225.05 kg/cm^2, the densities of water and steam are the same. The natural circulation is dependent mostly on the height of the water tube, called a *riser*, and the downcomer and, of course, with the difference in the mean density of the fluid in them. To maintain the same level of steam output at the higher design pressures, the distance between the lower part and the steam drum, or in other words the height of the downcomer, must be increased or some means of enhanced circulation must be introduced.

Natural circulation is normally effective up to a pressure of 150 kg/cm^2, which assists with sufficient fluid velocity vis-à-vis heat transfer. The methods to achieve natural circulation may also be of two (2) types: free or accelerated. For a free natural circulation type boiler, the water tubes are installed almost in the horizontal direction, with only slight vertically upward inclination. When the water tubes are installed at a much greater angle of inclination, the rate of water circulation would increase proportionately. Therefore, boilers in which the tubes follow a steep inclination from steam drum to bottom of water headers may be called an *accelerated type*.

2.4.5.2 Forced Water Circulation

As discussed earlier, natural circulation has some limitations in the very high-pressure zone for the plant having a steam drum. This problem could be eliminated by forced or controlled water circulation. This system introduces boiler circulating water (BCW) pump(s) in between the steam drum and the waterwall which enables the cold feedwater from the drum to get an additional pressure head to overcome the limitations experienced through natural circulation. The pump ensures sufficient velocity for the desired heat transfer, making the system independent of any density differences of water/steam and the frictional loss mainly due to water flow through the tubes. Water circulation is assured even before introduction of burners due to an additional pump head.

The advantage of a recirculation pump is that the frictional loss through the tubes may be more by using small-diameter tubes to minimize hoop stress at very high pressures. More small-diameter tubes offers many plus

www.EngineeringBooksPDF.com

points such as less tube weight, reduced tube thickness, increased heat transfer area, lower thermal stress, etc.

2.4.5.3 Water Circulation in Once-through, Supercritical, or Ultracritical Steam Generators

In a once-through boiler, there is no steam drum, thus service of the BCW pump does not arise (except for startup purposes). Theoretically, the boiler here should be merely a piece of tubing through which water enters as input and exits as steam output. In reality, there are a bunch of tubes to provide an effective heat transfer area in a variety of locations to attain the desired temperature at the SH outlet. In fact, the arrangements are almost the same as far as the "after drum tubing" layout is concerned.

A supercritical or ultracritical steam generator (SG) is a special type of once-through SG unit that operates at more than a critical pressure. Unlike a subcritical boiler, the supercritical or ultracritical SGs operate at such a high pressure that actual boiling does not take place at all because the formation of steam bubbles can occur only below a critical pressure and, thus, the SG units have no interphase between water and steam. This type of SG unit is becoming very popular for better efficiency and comparatively less fuel is consumed, thereby producing less greenhouse effect. In fact, the term *boiler* is a misnomer for these types of very high-pressure steam generators, as in reality boiling does not take place.

In the preceding type of SG units, though the steam drum in a general sense is not required, a similar type of concept is provided for facilitating the startup procedure. There are units, called separator and storage tanks, connected in series that function in combination the same as what is done by the steam drum alone. This combination is then connected to a pump that does the same function as the recirculation pump. The initial startup operation with forced circulation continues up to a ~25 to 30 % load of the SG unit and then is gradually bypassed without any recirculation of water.

2.5 MISCELLANEOUS BOILER EQUIPMENT

2.5.1 Main Steam Stop Valve

The boiler outlet steam passes through a stop valve before going to the consumer/user end, called the *main steam stop valve* (MSSV or MSV). The primary purpose of this vital accessory is to isolate the boiler by interrupting the steam circuit during startup, shutdown, or in case of emergency. Normally this valve is motor-operated. For a larger size of plant, a small bypass valve is provided to facilitate easy opening of the MSSV. During startup, the pressure upstream of the MSV becomes higher and higher while the pressure downstream is almost zero.

The differential pressure across the valve and the valve size itself is very high for high-capacity plants; the operating thrust/torque required is also very high while opening the valve from a fully closed position. To circumvent the situation, the small bypass valve opens first with less thrust/torque (line size is small) and when pressure builds up downstream, the MSV can then open, requiring less thrust/torque. During normal operation of the plant, the valve remains in a full open condition.

2.5.2 Nonreturn (Check) Valve

The function of a nonreturn valve is to allow the fluid to flow in the forward direction under pressure but to check the fluid's flow in the reverse direction. Here, the construction of the valve plug is such that it moves up from the seat when pressure is applied when the bottom of the plug is higher than the top of the plug; it remains in that position as long as the differential pressure, multiplied by the plug area, is higher than the spring force applied to the plug for keeping the valve in a shut position. In the reverse condition when pressure downstream (top of plug) is higher than upstream (bottom of plug), the plug moves down by the force of the differential pressure aided by the spring force and sits tightly on the seat to prevent any flow.

Nonreturn or check valves are provided in every flow path irrespective of steam or water service wherever there is a chance of return flow under any operating condition. The valve is normally self actuated that is no external power is required.

2.5.3 Startup Vent Valve

This type of valve is provided in the main steam header and, as the name implies, is required only for the startup period. The valves operate as regulating service—that is, steam is allowed to vent out of the system to the atmosphere as required—determined automatically or manually for purging and/or heating of the pipelines. These valves are generally motor-operated.

2.5.4 Safety (Pop-Up) Valves

These valves are of immense importance as far as safety of the plant vis-à-vis of the personnel is concerned. Whenever there is a pressure buildup in the pipeline that is beyond its limit, the valve should operate or pop-up to release the steam to the atmosphere until the pressure comes down to a safe value Although it results in a loss of energy and mass of working fluid, it is inevitable during any untoward situation that is not controllable by the normal control system. There are various types of safety valves—namely, electromatic safety (or relief), spring-loaded safety, deadweight safety, fusible plug, etc.

www.EngineeringBooksPDF.com

2.5.5 Electromagnetic Safety (or Relief) Valve

This is a pilot solenoid-operated valve that gets energized from the pressure switch at a very high set point; it allows the working fluid to operate the actuator of the safety valve. It can be operated through a remote manual command as well as from the control room/tower.

2.5.6 Spring-Loaded Safety Valve

Normally, this valve operates as a last resort of the safety system against high pressure. Under routine operation of the plant, the spring tension is high enough to hold the valve plug on its seat to ensure a closed position until the very high pressure setpoint is reached. At this point and above, the force against the spring is more to lift the plug over its seat and allow extra steam to escape unless the steam pressure comes down to a normal value. The discharge capacity should be selected such that it is equal to the evaporative capacity to avoid frequent buildup of pressure vis-à-vis actuation of this valve. Other types of safety valves are not in use currently and thus are not discussed.

2.5.7 Blowdown Valves

This type of valve is provided to remove sludge, sediment, and other impurities that collect at the bottommost location in the water flow path. It also provides the means of complete draining of the system. There are two types of blowdown valves: continuous and intermittent.

2.5.7.1 Continuous Blowdown Valve

The function of this valve is to open continuously so as to maintain the dirty material level at a minimum value. The opening of the valve is varied as per requirement with a predefined control signal. The motorized actuator can get a manual command at the operator's prerogative in addition to its automatic controls.

2.5.7.2 Intermittent Blowdown Valve

It is a valve for blowing down the dirty water as needed. Its operation may be predefined based on cyclic or a time frame from a full open/close signal or to a manual command from the operator with a motorized actuator.

2.5.8 Drain Valve

During the startup of the plant after a prolonged shutdown or a cold startup, the pipelines and various equipment need to be warmed up before loading the boiler. To achieve this requirement, heated steam is admitted phase by phase in a very slow manner to avoid dissimilar heating vis-à-vis expansion of various casings and pipes. While heating metal works, the steam gets condensed and collected at the bottom of pipeline with a siphon sort of design at various strategic locations. At the bottom, condensed water is drained out through this valve with a motorized actuator when the level in the drain pipe reaches a predefined value to avoid frequent operation. Level switches are provided for automatic operation. Manual command is provided for operator's action.

2.5.9 Steam Trap

The function of this element is to drain out the condensed water from steam pipes and jackets used for heating, resulting in partial condensation and at the same time arresting the steam inside from escaping, thus the name *steam trap*. Generally, there often are two types of steam traps available: float, or bucket, and thermal expansion. The operation is self-contained and mechanical without requiring any external power, thus are not discussed in detail.

2.5.10 Steam Separator

As the name implies, its function is to separate water particles suspended in generated steam from boiler and carry them by the flow of steam to the turbine or engine. To serve the purpose properly, its location calls for a minimum distance from the steam generator so as not to allow movement of water particles along with steam for the greater part of the transportation line. In the drum-type boiler, it is in the drum itself where the water particles drop into the water section.

Some arrangement is made to guide the steam path to impinge on a series of baffles. The water particles because they are heavier have higher inertia and due to this fact after striking the baffles fall below by gravitational force to the bottom of the vessel. The dry steam, practically unaffected by this, does not get transported. The collected water is then drained out through a drain line.

2.5.11 Swing Check Valve

This type of valve is a variation of the nonreturn or check valve and normally is provided at the turbine end. The specialty of this valve compared to normal nonreturn or check valves is that it requires some external power while opening and after that the forward flow thrust keeps it in a full open position without any external power until the flow is more than some predetermined value. At a very low flow or reverse flow, the valve gets closed automatically due to springs and other actions.

The valve plug is of a circular lid-type connected to the valve's body at a particular point around which it can swing almost 90 degrees. It sits tightly on a ring-type seat matched with main pipe diameter due to spring action and gravitational force; it is also at a low flow and reverse-flow thrust

www.EngineeringBooksPDF.com

due to an untoward situation of sudden loss of forward flow. It is normally installed in the horizontal pipeline and due to swinging action, it remains in a horizontal position in the open condition, which allows the forward flow to pass through and take up a vertical position in the closed condition, inhibiting any flow in the reverse direction.

3. TURBINE TYPES

Basically there are three types of turbines: steam, gas, and hydel. Here, the turbines have been classified by the type of fluid they handle—that is, steam or gas (hot air), water, etc. Gas turbines have been briefly discussed in Clause 2.4. The hydel turbine is a type that operates on the principle of high-velocity water coming from a source located at a higher elevation through a pipeline impinging on the turbine impeller. The steam turbine utilizes high-pressure and high-temperature steam as the prime moving force and is discussed briefly next.

3.01 Steam Turbine Types and Classification

The steam turbine operates wholly through the dynamic nature of steam. Here, steam pressure is allowed to fall in a narrow passage (i.e., nozzle), which results in increased velocity due to conversion of some heat to energy. The high-velocity steam impinges on the moving parts (i.e., blades) of the turbine with a change of direction in motion, therefore causing a change in momentum and ultimately force. The blades move as a result of this force and mechanical work is done. It is known that maximum work is achievable when outlet velocity is half of the inlet velocity. This process of expansion and direction changing may take place once or a number of times in succession.

3.01.1 Impulse Turbine

A simple impulse-type turbine deploys only one set of nozzles, where complete expansion from steam chest pressure to exhaust (condenser) pressure is performed along with the highest velocity (nearly 1000 m/sec) at the outlet of the nozzles vis-à-vis the inlet of moving blade. The result is a very high-rotational speed of the turbine requiring a high reduction gear. The outlet velocity is also very high, causing energy loss of ~10 to 12% of the initial kinetic energy entering the turbine.

This type of turbine is also called a *de Laval turbine*. In this type of turbine, the blade inlet and outlet pressures remain the same and work done is solely due to a change in velocity. Figure II/3.1 depicts the basic functioning of this turbine.

3.01.2 Pressure-Compounded Impulse Turbine

The problems associated with the high-speed (rotational) turbine are eliminated by introducing a single impulse stage at several points in a series connected to the same output rotor. Figure II/3.2 depicts the basic functioning of the pressure-compounded impulse turbine.

Here, the exhaust steam from the first stage that is moving blades (rotor) enters the nozzles of the second stage and so on. The nozzles in each stage are fixed to the diaphragm of a stationary part of the turbine. Each stage can be

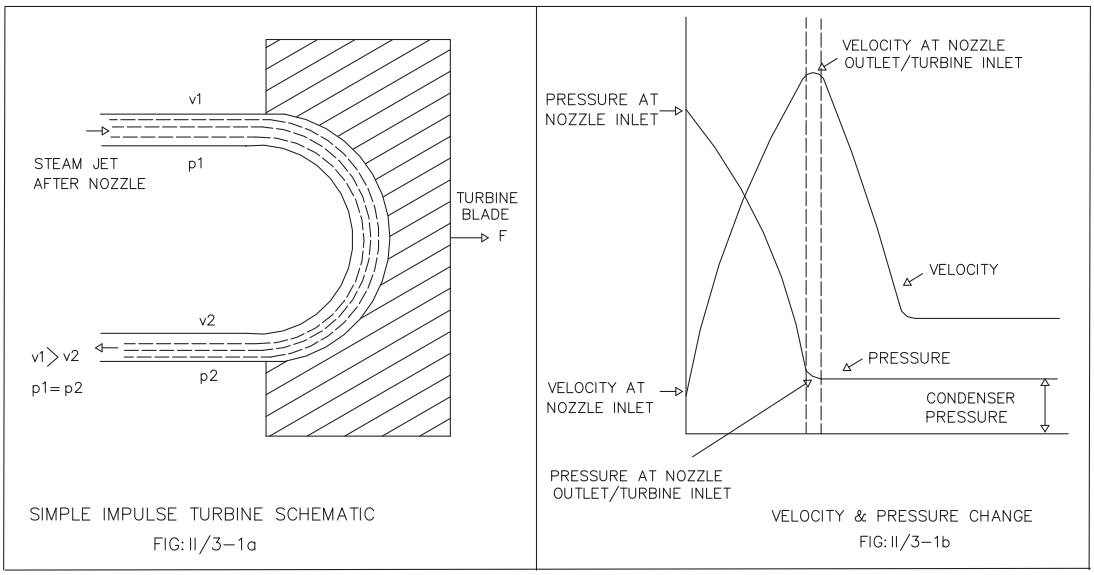


FIGURE II/3.1 Simple impulse turbine schematic and pressure/velocity changes.

www.EngineeringBooksPDF.com

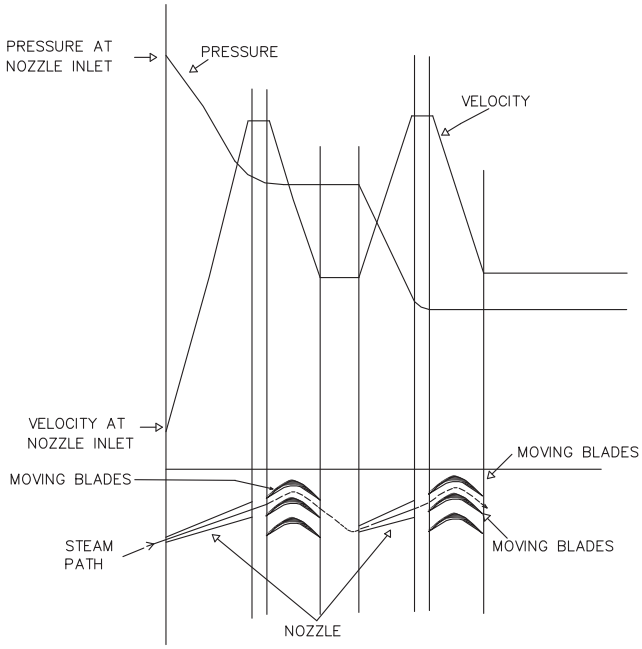


FIGURE II/3.2 Pressure-compounded impulse turbine schematic and pressure/velocity changes.

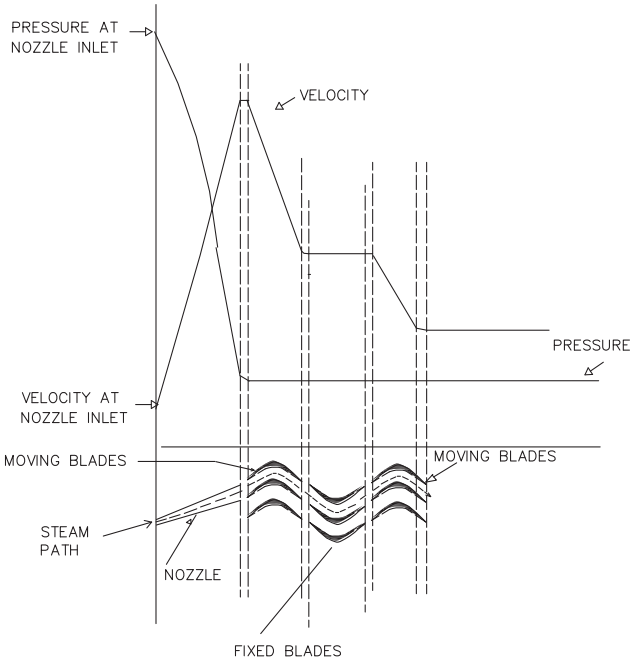


FIGURE II/3.3 Velocity-compounded impulse turbine schematic and pressure/velocity changes.

conceived as a set of nozzles and moving blades that undertakes the splitting up action for a total pressure drop by them. The expansion of steam takes place only in nozzles of each stage. Since the drop in pressure is divided into several stages, the steam velocity at the nozzle outlet vis-à-vis the rotor blade inlet is reduced and thereby the rotor speed is reduced. In fact, the rotor speed can be reduced as per requirements by introducing a number of stages thereby also reducing the leaving loss to ~1 to 2%. This type of turbine is also called a *Rateau turbine.*

3.01.3 Velocity-Compounded Impulse Turbine

Figure II/3.3 depicts the basic functioning of this type of turbine. It consists of only one set of nozzles at the inlet and a number of moving blades (to the rotor) and fixed blades (to the casing) at each stage. The entire expansion takes place in the nozzles and the high velocity (of steam) breaks into several parts at each stage. The fixed blades are provided only to cause change of direction of the steam jet for the next stage. The velocity-compounded impulse turbine is also called a *Curtis turbine.*

Velocity compounding may be achieved with only one rotor using a reentry turbine. The total enthalpy transfer performed in the nozzle itself and results high-velocity steam passing through the moving blades and entering a reversing chamber; this guides the steam to change its direction to pass through another set of moving blades located at a different angular position from the first set of moving blades at various locations. The velocity of the steam decreases gradually providing low speed and high efficiency.

3.01.4 Pressure Velocity-Compounded Turbine

Figure II/3.4 shows the basic functioning of this type of turbine; both the pressure- and velocity-compounded ones combine in different stages. Each stage is identical to a velocity-compounded turbine. The number of stages determines the total drop of pressure that takes place in those stages. This type of turbine was very popular due to its simple construction compared to other types; however, because the efficiency is low, it is rarely used nowadays.

3.01.5 Impulse-Reaction Turbine

Figure II/3.5 depicts the basic functioning of this turbine. In the reaction turbine, as the name implies, the rotor is rotated mainly by the reactive force in place of through the direct impulse or thrust alone. Here, both types of application are done by providing many moving blades in the rotor and the same number of fixed blades in the stationary part—that is, casing or stator.

The fixed blades in this type of turbine act as nozzles because no typical nozzles as such are provided. The blades are projected radially from the stator's inner periphery; they are shaped and mounted in such a manner that the spaces

www.EngineeringBooksPDF.com

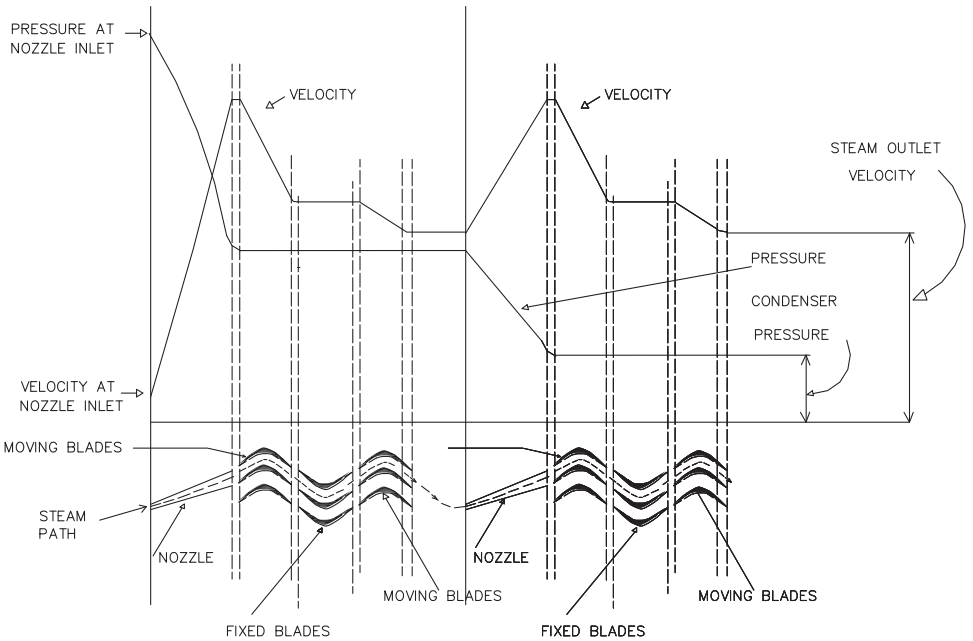


FIGURE II/3.4 Pressure velocity-compounded turbine schematic and pressure/velocity changes.

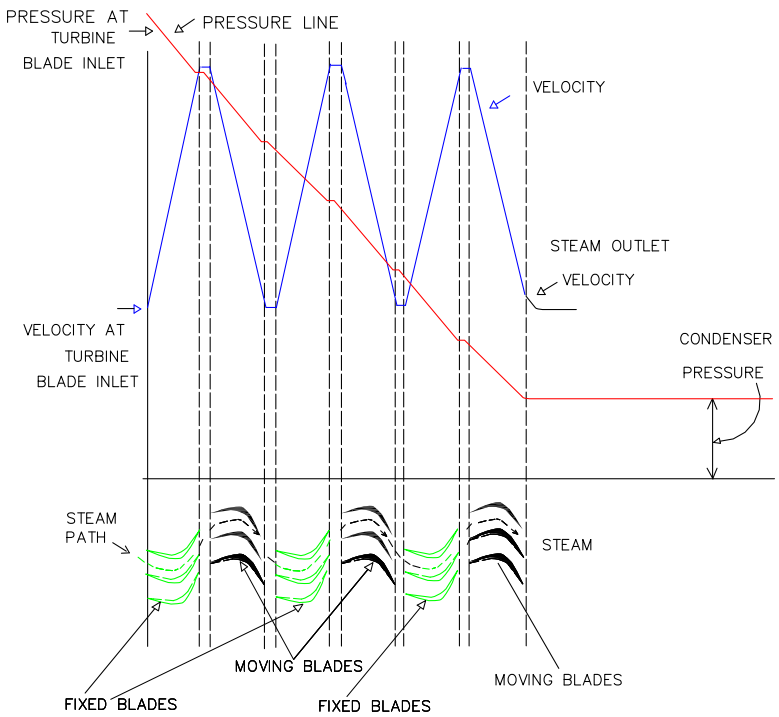


FIGURE II/3.5 Impulse-reaction turbine schematic and pressure/velocity changes.

between the blades are formed just like the shape of the nozzles as can be seen in the cross-sectional view in the figure. Steam is directed onto the rotor by the fixed vanes or nozzles of the stator. In contrast, with only a few nozzles, steam enters into the whole circumference of the inlet chamber, leaves the stator nozzles, and fills the rotor chamber all along. Passing through the first set of fixed blades, there is a small pressure drop and a consequent increase in velocity and the steam is then guided to the moving or free blades.

www.EngineeringBooksPDF.com

The moving blades themselves are arranged in the same manner so that passage in between the blades looks like formation of a convergent nozzle shaped similar to the fixed blades. This particular design allows a small pressure drop and thus increases kinetic energy. The steam that enters into the first set of moving blades imparts torque to the shaft due to a change in direction at the outlet and a change in momentum, thereby impulses to the moving blades. This pressure drop gives rise to a reaction in the opposite direction to that of the added velocity. To analyze the entire action in detail, it can be stated that in the impulse–reaction turbine, the rotor's spinning is caused primarily by three forces:

1. Reactive force produced on the moving blades as the steam velocity increases due to expansion while passing through the nozzle shaped spaces between the blades
2. Reactive force produced on the moving blades during the steam flow path changes its direction
3. Impulse or thrust of the gas that impinges on the blades

Thus, as previously noted, a reaction turbine is moved primarily by reactive force but also, to some extent, by direct impulse/thrust. Impulse and reaction blades can thus be combined to form an impulse–reaction turbine. To summarize, this turbine combines the rotational forces of the previously described turbines; that is, it derives its rotational force or torque from both the impulse of the steam striking the turbine blades and the reactive force of the steam with increased velocity and changing direction. The resultant motive force is the vector sum of these impulse and reaction forces.

As a small pressure drop occurs across both the stator and the rotor, there is a series of continuous and smooth pressure drops throughout the turbine's length. As far as the velocity of steam is concerned, it accelerates through the stator and decelerates through the rotor, with practically no net change in steam velocity across the stage but with a decrease in both pressure and temperature, reflecting the work performed in the spinning action of the rotor.

Generally, this type of turbine is called a *Parson's reaction turbine*; it is characterized by low steam velocity and is popularly accepted worldwide.

3.1 Basic Turbine Type: HP, IP, and LP Cylinders

The modern power plant concept is based on multiple turbine cylinders/rotors, which are coupled to a single shaft (Figures II/3.1-1 and II/3.1-2). As the name implies, the high-pressure steam from the boiler enters the high-pressure (HP) cylinder where it is isentropically expanded from pressure p_1 to p_2 (points 1 and 2 of the T-s diagram) and taken out as HP exhaust—normally termed *cold reheat*.

This HP exhaust steam is then readmitted to the reheater part of the boiler for reheating and the steam condition is changed from p_1 and p_2 in the T-s diagram. Reheating is done to avoid wet steam in the turbine blade, which otherwise would cause erosion, because the standard moisture limit followed internationally for the steam in turbine is $\sim$10%.

The reheated steam from the boiler is popularly known as *hot reheat*; it then enters the turbine intermediate-pressure (IP) cylinder and expands isentropically up to a pressure of p_4 (point 4). In a modern power plant and/or high-capacity power plants, a twin cylinder IP module is also provided for various reasons such as better balancing of heavy mass, etc. After doing its work, steam is taken out of the IP cylinder as exhaust and readmitted to the low-pressure (LP) cylinder;

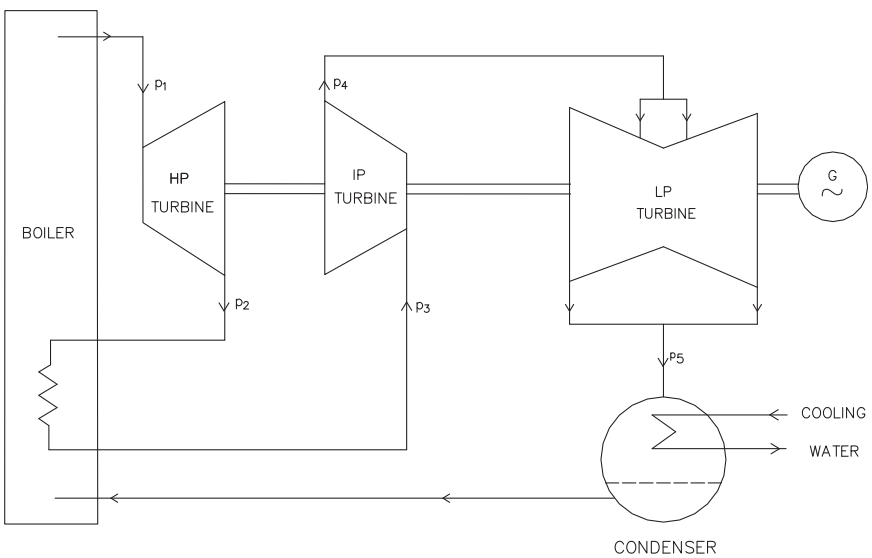


FIGURE II/3.1-1 Schematic diagram of turbine stages.

www.EngineeringBooksPDF.com

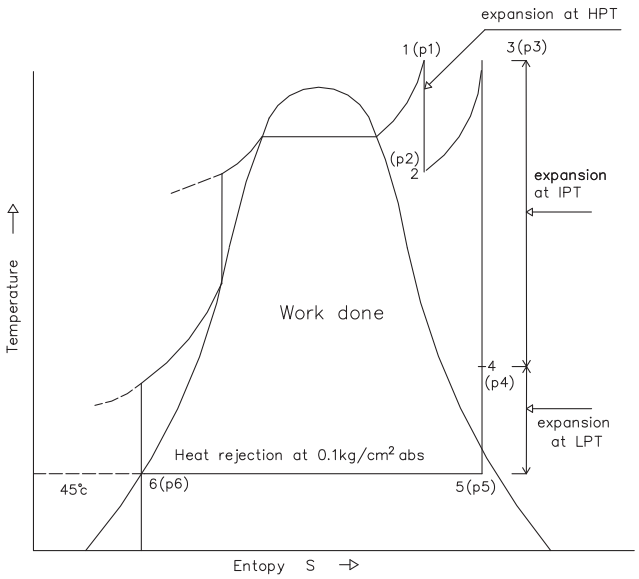


FIGURE II/3.1-2 Reheat steam cycle in a modern power plant with reheated steam in T-s axis.

normally, this is a twin-cylinder configuration with steam admission near the middle portion of it with a symmetrical distribution arrangement.

Here, inlet steam enters at pressure p_4 and further expands isentropically to a p_5 absolute pressure of nearly $\sim$0.1 kg/cm^2. Exhaust from the LP cylinder is then directed to the condenser that is actually responsible for maintaining this very low pressure. Condensation vis-à-vis conversion of a huge volume of low-pressure steam into water takes place through heat rejection to an external cooling agency. In the T-s diagram, the path is shown from p_5 to p_6, which is actually a saturated waterline, and finally taken out of the turbine with the help of a condensate extraction pump (CEP).

The design of turbine part as far as number of stages/cylinders is concerned takes care of many aspects—namely, capacity, plant efficiency, thrust balancing of the turbine as a rotating machine, etc. In various cylinders, there is a number of extraction outlets used for the regeneration cycle. To avoid irreversible mixing of cold condensate with hot boiler water, which causes loss of cycle efficiency, extraction steams are used to heat the cold condensate from a hot well. Before going to the boiler, this condensate, also known as feedwater, is heated at various points by extraction to a suitable temperature and pressure; this is done with heat exchangers called a gland steam heater (GSH), a low-pressure heater (LPH), or a high-pressure heater (HPH) to ultimately match the boiler feedwater inlet temperature. Extraction steam is also provided from the turbine for deaeration of feedwater and, in many plants, for separate BFP-driven by a steam turbine in addition to motor-driven feed pump.

3.2 Turbine Oil Systems

There are three main oil systems as far as turbine subsystems are concerned: lubricating oil, control oil, and jacking oil. The type of oil used nowadays for all purposes is mostly fire-resistant synthetic oil.

3.2.1 Lubricating Oil

As the name implies, it is meant for lubrication purposes for all the bearings of the turbine (Figure II/3.2-1). Any piece of rotating machinery must have clean and dirt-free lubricating oil (lube oil or LO) supplied at the proper temperature, pressure, and quantity under every possible operating condition. Even during the coast-down period following a post-trip condition, a supply of right quantity of lube oil is extremely important.

The turbine rotor shaft that is being subjected to high-speed rotation and a heavy mass is supported on various types of bearings (i.e., journal and thrust) at a variety of places on each cylinder. These bearings require lubrication (lube) and a cooling medium to minimize the effect of friction and dissipation of heat generated due to it. LO serving both purposes is necessarily a closed-loop system consisting of an oil tank, pump, oil cooler, and so on.

Because the duty of this oil system is of utmost importance, the turbine shaft-driven oil pump, popularly known as the main oil pump (MOP), provides the necessary supply pressure during the normal operating condition. There is, of course, a separate motor-driven auxiliary oil pump (AOP) that is supplied with AC and DC motors to provide necessary lube oil during the startup and shutdown period. The oil temperature at all the bearing outlets is measured in addition to measuring the bearing metal temperature at some places; it is controlled automatically by letting more or less water into the oil cooler.

The supply pressure is maintained at a constant value by providing a self-pressure regulating valve (PRV). However, oil from an emergency DC oil pump discharge is connected to the system, bypassing the pressure-control part; in some plants, the oil cooler is bypassed even considering its emergency service requirement. There is also a requirement for a dual filter to remove dirt in the system and provide clean LO. The AC motor-driven AOP (e.g., #1 and 2) starts automatically at the fall of pressure below certain predetermined values, which may be due to some problem in the MOP under running conditions or during the startup/shutdown period AOP failure and/or problem.

If under normal operating conditions, lube oil pressure falls further below some predetermined value, the turbine trip circuits are energized after a short delay and the turbogenerator (TG) is tripped. The DC motor-driven pump, popularly called an emergency DC oil pump rated at $\sim$65% duty, is also made ready as an automatic standby

www.EngineeringBooksPDF.com

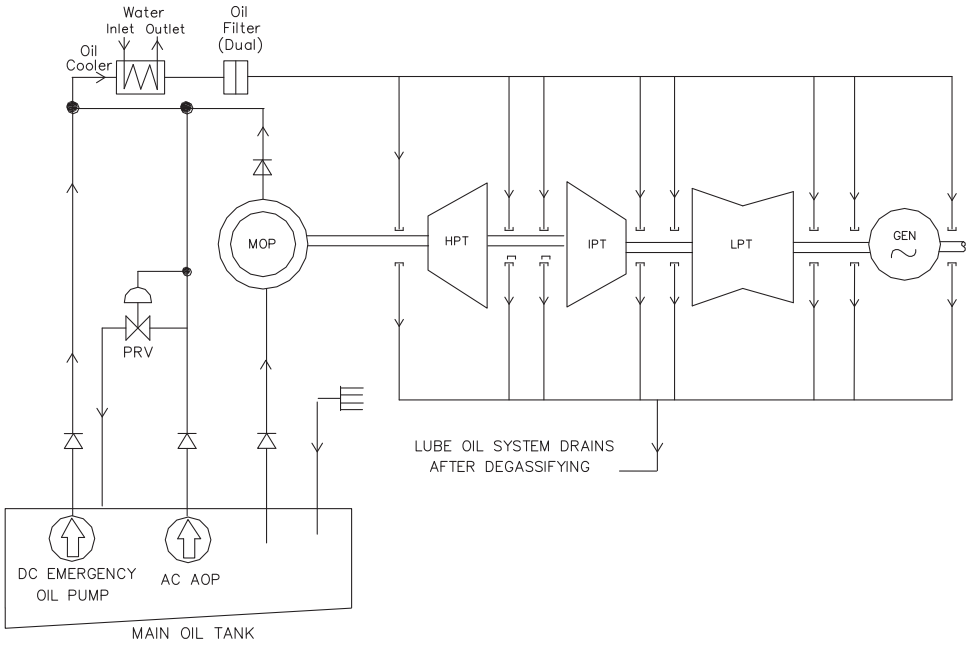


FIGURE II/3.2-1 Schematic diagram of a turbine lube oil system.

to start after a further fall of oil pressure mainly due to failure of the AC motor-driven pump. Normally, additional reliability features, such as a gravity-feed system or an accumulator, are not included in the turbine LO system.

There is a very important mechanism called a *barring gear*, also known as a turning gear, in the turbine subsystem. This mechanism is meant for providing rotation of the TG rotor shaft at a very low speed as a part of startup procedure before actual running of the generator and also after stoppage of the unit as part of the shutdown procedure.

When the unit is going on shutdown or tripped, the steam inlet valve is closed and the turbine coasts down to a dead stop or standstill. Under this condition, when the turbine stops completely, if it remains in one position for a long time there is a tendency for its rotor shaft to deflect or bend. The reason can be attributed to the fact that the heat inside the turbine casing has the tendency to concentrate in the top half of the casing. This phenomenon would obviously result in making the top of the rotor shaft hotter than the bottom. The rotor shaft, therefore, could become warped or bent even to a range of a few microns and would result in an eccentric shaft.

This type of very small rotor shaft deflection can only be detected by highly precise eccentricity meters. It is obvious that however small the magnitude of the eccentricity thus formed would be enough to cause harmful vibrations to the entire TG unit when it restarts. To prevent this, an automatic interlocking system makes the rotor shaft continue turning at low speed (maybe $\sim$1% of the rated speed) by the motor-driven barring (turning) gear unless and until the temperature drops down sufficiently to initiate complete stoppage. The gearing system being used to achieve a very high reduction ratio and to turn a heavy mass requires a continuous supply of lube oil in the gearbox to reduce loss due to frictional force, noise, etc., in addition to cooling purposes.

3.2.2 Control Oil

As the name implies, it is meant for supplying oil to the control circuit of the turbine load and/or speed controller and hydraulic power oil for operating the On–Off interceptor and modulating duty hydraulic governor valves (Figure II/3.2-2). This part of the control and hydraulic power circuit is popularly called an electro-hydraulic governing (EHG) system. It can be described as the blood supply to the EHG system—the brain of the turbine subsystem. Here also, the oil comes from the MOP and AC motor-driven AOP (e.g., #1 and 2) discharge lines connected together with a common self-PRV and control oil supply pressure is maintained at a fairly constant value.

The delivery header of the pressure-controlled oil is supplied to all the electro-hydraulic converters that receive electrical control signals from electro-hydraulic control (EHC) system. The output is then transmitted to the respective servomotors of the various governing valves of the HP and IP turbines as the input signal with a power oil from control oil delivery header. The On–Off interceptor valves also get the required control and power oil from the

www.EngineeringBooksPDF.com

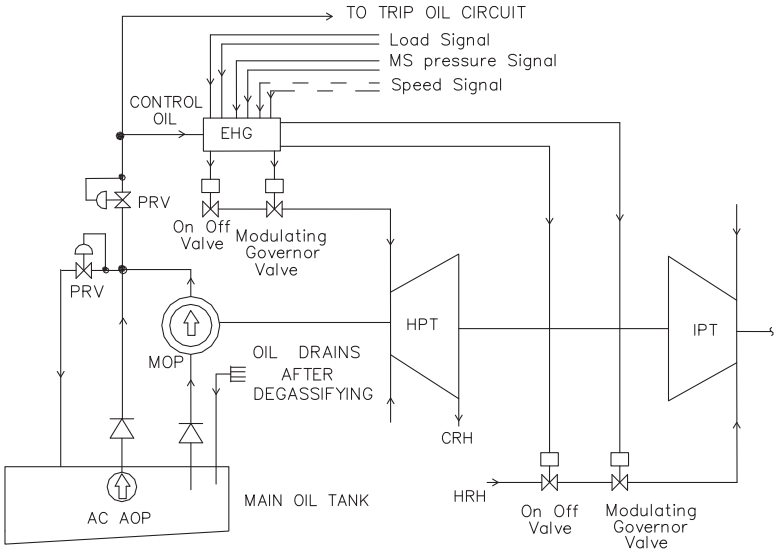


FIGURE II/3.2-2 Schematic diagram of turbine control oil system.

delivery header through solenoid valves and servomotors. The trip circuit is also fed from this header to accomplish automatic tripping of the turbine under extreme conditions beyond which running of the TG is unsafe and may be damaging.

There is another circuit supplied from the preceding system called the automatic turbine tester (ATT).The operation of the various valves are simulated through this system but without actually operating the valves or operating for a very short time so that normal operation of the main power plant, as far as generation is concerned, is not jeopardized.

The automatic interlocked start and stop operation of the AOPs are already taken care of in the part of LO system. The DC-operated emergency lube oil pump has nothing to do with this circuit because the control system is inactive for the turbine; it has already been tripped and the pump is supposed to start after failure of AOPs to deliver adequate oil pressure to carry out emergency services.

3.2.3 Jacking Oil

Figure II/3.2-3 shows the basic purpose of the various oils required in the turbine area. While starting the TG set after long stoppages, there is practically no space between the lower part of the rotor shaft and the bearing part on which the rotor rests. The heavy mass of the rotor may damage itself and the bearing part due to high static friction; just before starting even the LO is supplied because it cannot enter the space in between. To prevent this untoward situation, another oil circuit has been envisaged with very high pressure at $\sim$160 to 200 kg/cm^2 by a separate pump called as jacking oil pump (JOP). It takes its suction from the lube oil header or main oil tank. This HP oil is injected from the bottom of each journal bearing through a special arrangement to virtually float the rotor shaft before turning from the standstill condition.

The thin oil film thus created due to the very small elevated/floated rotor condition helps reduce the damaging frictional effect and then the turbine starts turning at a low speed using the turning/barring gear. Running under this condition for a preset time, and after other prerequisites are satisfied (e.g., turbine gets steam admitted for generating power, etc.), then the turning/barring gear motor stops and the normal LO takes charge of the lubricating system.

3.3 Extraction and Gland-Sealing System

Before going to the boiler, the condensate, also known as feedwater, is heated at various points to avoid irreversible mixing of cold condensate with hot boiler water, which may cause loss of cycle efficiency. A variety of methods can be adopted to do this reversibly by interchanging heat within the system, thereby improving cycle efficiency. One method is called *regenerative feed heating* and the cycle is called a *regenerative cycle*. This is implemented by extracting or bleeding small quantities of steam from suitable points throughout the turbine stages utilizing the heat content of extracted or bled steam. The vessel, where the exchange of heat takes place, is called a *regenerative heater*. Here, the steam totally condenses and the outlet water leaves the heater in a higher quantity and increased temperature.

In various cylinders or turbine stages, there are a number of extraction outlets for regeneration or heating feedwater through heaters with a suitable temperature and

www.EngineeringBooksPDF.com

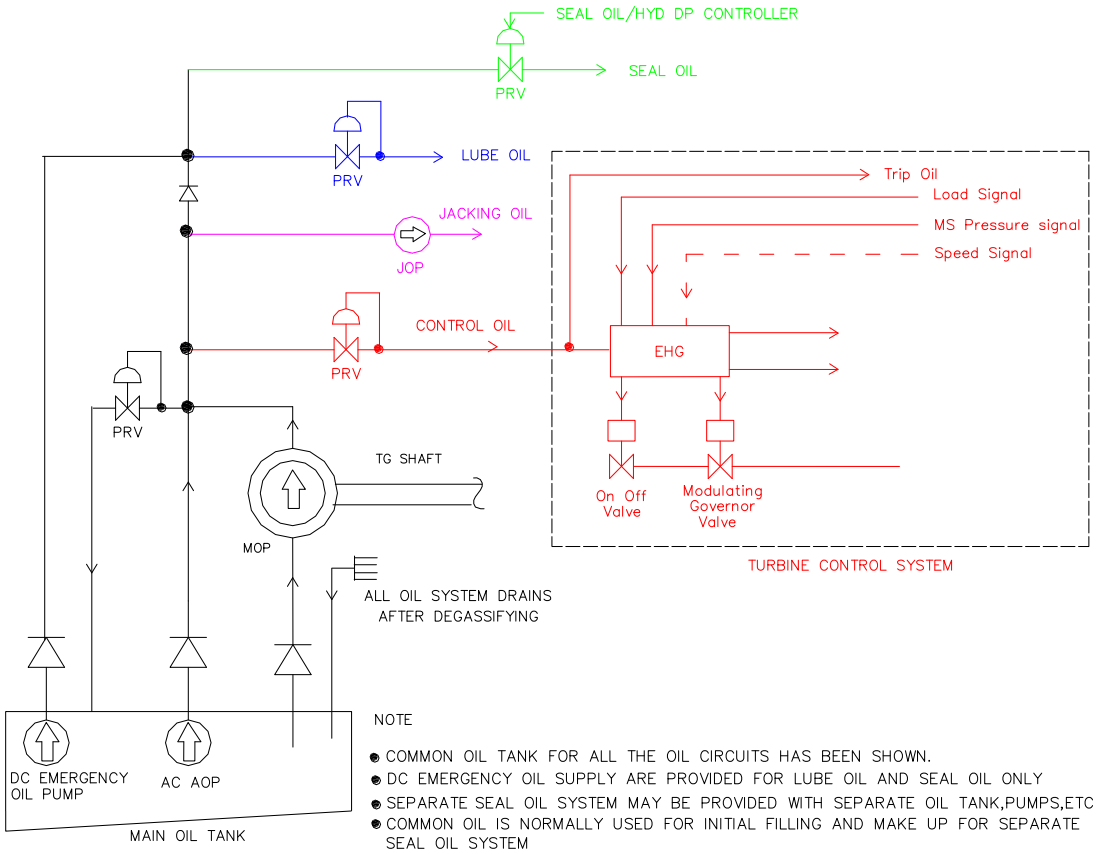


FIGURE II/3.2-3 Simplified schematic diagram of combined turbine control/lube and seal oil system.

pressure; they are known as gland steam heaters, low-pressure heaters, and high-pressure heaters to ultimately match the boiler feedwater inlet temperature. Extraction steam is also provided from the turbine for deaeration of feedwater at the deaerator and in many plants for separate boiler feed pumps driven by a steam turbine in addition to motor-driven feed pump.

The GSH gets heating steam from an indirect bleed steam, which comes out from the turbine gland seals at various places. The gland seals are provided to prevent leakage of steam from the high-/intermediate-pressure turbine casings. Special types of glands, called *labyrinth* glands, are a common choice to minimize the leakage; however, as there must be some amount of steam leakage, it is collected through a header and passed on to the GSH. Here, it is allowed to mix with the main condensate to get a common temperature at the outlet containing a condensate that is more than the inlet temperature.

Initially, steam is supplied to this header from auxiliary steam header (provided elsewhere to meet various requirements, mainly during startup) to prevent air ingress when there is no steam in the turbine for power generation and the condenser is being prepared to establish a vacuum. This steam is maintained at a constant pressure and is called leak-off steam by many manufacturers, whereas the normal operating steam coming out of the turbine is also maintained at a constant pressure that is higher than leak-off steam.

3.4 Condenser and Evacuation Systems

3.4.1 Function

The modern power plant that uses the Rankine cycle has many components of which the most common ones are boiler, turbine, condensate/feed pumps, and condenser. The primary function of the condenser is to condense the exhaust steam coming out of the turbine into water and reuse it as the Rankine cycle does.

The use of a condenser has many more advantages such as:

- Maximization of turbine efficiency by maintaining a proper vacuum.
- Getting through expansion of steam by lowering the steam's exhaust temperature (saturation) much below the atmospheric saturation temperature through

www.EngineeringBooksPDF.com

lowering the exhaust pressure, which increases the vacuum.
- Reduction of steam flow within a given plant output by increasing the work area in T-s diagram to get more work done.

The complete function is achieved in a separate vessel called a condenser, which is directly connected to the turbine's exhaust and causes exhaust steam; by exchanging heat with external cooling water condensation occurs, thus the name "condenser."

3.4.2 What Is a Vacuum?

This is the reading of pressure below the atmospheric pressure. In an enclosed vessel, a vacuum can be created by partially withdrawing the gaseous fluid occupying the given volume of the vessel. Generally, it involves a lot of compression work on the gas; however, in the case of water vapor, it is achieved easily and by doing much less work if it is condensed by cooling. The volume shrinkage is so huge that a vacuum is created almost instantly. For example, at 0.1 kgf/cm^2 pressure (normal condenser pressure), 1 kg of steam occupies 15,000 liters compared to 1.0 liters of only water. It is unnecessary to mention that much less work is needed to transfer condensate from a vacuum to positive pressure.

3.4.3 Type of Condenser

In general, condensers can be categorized into two cooling types: direct (jet/contact) and indirect (surface). The jet/contact type cools water and steam mixes directly with each, whereas in the surface condenser, there is a barrier between the steam and cooling water; both have separate circuits and thus no chance of mixing. Surface condensers are most commonly used in modern power plants. The exhaust steam, after becoming condensed at the outlet, is driven through appropriate pumping to the boiler as feedwater for the next cycle.

The cooling water is popularly termed circulating water (CW) and can be sourced through open-loop/once-through (i.e., from ocean, river, or lake) or closed-loop (e.g., using a cooling tower or spray pond) system.

3.4.4 Operation of the Condenser

As already mentioned, the surface condenser is the type most commonly used in modern power plants and thus is the only one discussed. Here, the main heat transfer takes place at the outside of the tube, thereby cooling vis-à-vis condensing of saturated steam, thus heating the CW inside the tube. Needless to say, the water inlet temperature to the condenser determines the operating temperature/pressure of the condenser. As the temperature decreases, the condenser pressure also decreases. Thus, a decrease in pressure will increases the plant's output and efficiency.

The surface condenser, as discussed earlier, operates under high vacuum and therefore is liable to suck noncondensible gases into itself. These types of gases may comprise most air due to leakage into the cycle from the components operating at that high a vacuum system condition. The gases may result from decomposition of water into hydrogen and oxygen by thermal and chemical reactions and must be driven out of the system.

3.4.5 Evacuation of the Condenser

Evacuation of the condenser is a must for the following reasons:

- It is well known that the total pressure in a system is the sum of the partial pressure of the component gases. If more gas leaks into the system from outside or is generated within the system, the total pressure in the condenser will increase, thus there will be a decrease in turbine efficiency and output.
- Undesirable gases will cloud the outer surface of the condenser tubes, thus seriously hampering the heat transfer of the exhaust steam to the CW resulting in high temperature vis-à-vis pressure, lowering turbine efficiency and output.
- Free oxygen is always hazardous to the metal piping and components in a system for it is corrosiveness by nature. It must be removed from the condenser to improve the life expectancy of the cycle components including steam generators.

For the purposes just listed, air ejectors or vacuum pumps are used; these are the devices instrumental for discharging any leakage air/undesirable gases from the condenser into the atmosphere. Figure II/3.4-1 may be reviewed for a summary of the overall functioning of the system.

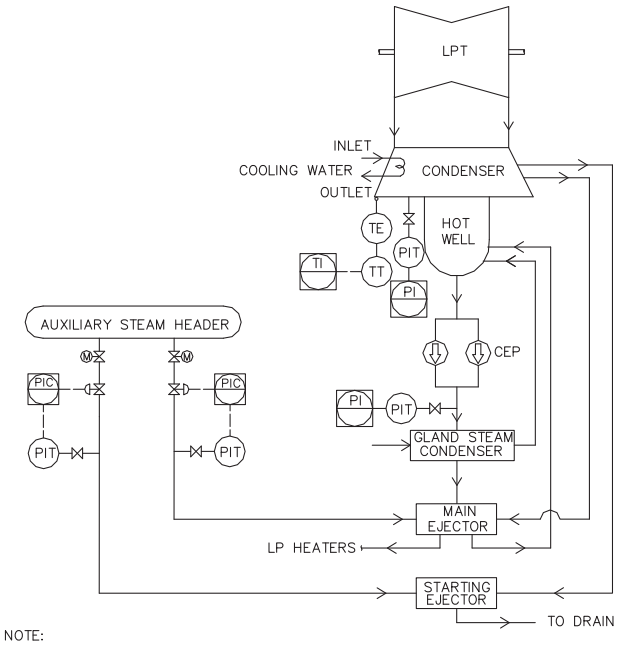
3.4.6 Evacuation Methods

There are two popular methods adopted for the evacuation process of the condenser, thus venting noncondensible gases; they are described in the following subsections.

3.4.6.1 Steam Jet Air Ejectors

Steam jet air ejectors have a low initial cost, so are an economical means and reliable equipment for producing a vacuum. The ejector design has basic advantages such as absence of moving parts and simplicity of operation. The conventional steam jet ejector has four parts: the steam chest, the nozzle(s), the mixing chamber, and the diffuser; Figure II/3.4-2 illustrates ejector operation. A high-pressure motivating fluid enters at the inlet of a

www.EngineeringBooksPDF.com



NOTE:
1) LOCATION DETAILS SHOWN IS JUST TO GIVE AN IDEA ABOUT EQUIPMENT LOCATION.
2) NOTE NO ROOT VALVE SHOWN WITH CONDENSER VACUUM. IF VALVE USED, IT SHALL HIGH PRESSURE QUALITY TO AVOID LEAKAGE.

FIGURE II/3.4-1 Condenser and evacuation system flow diagram.

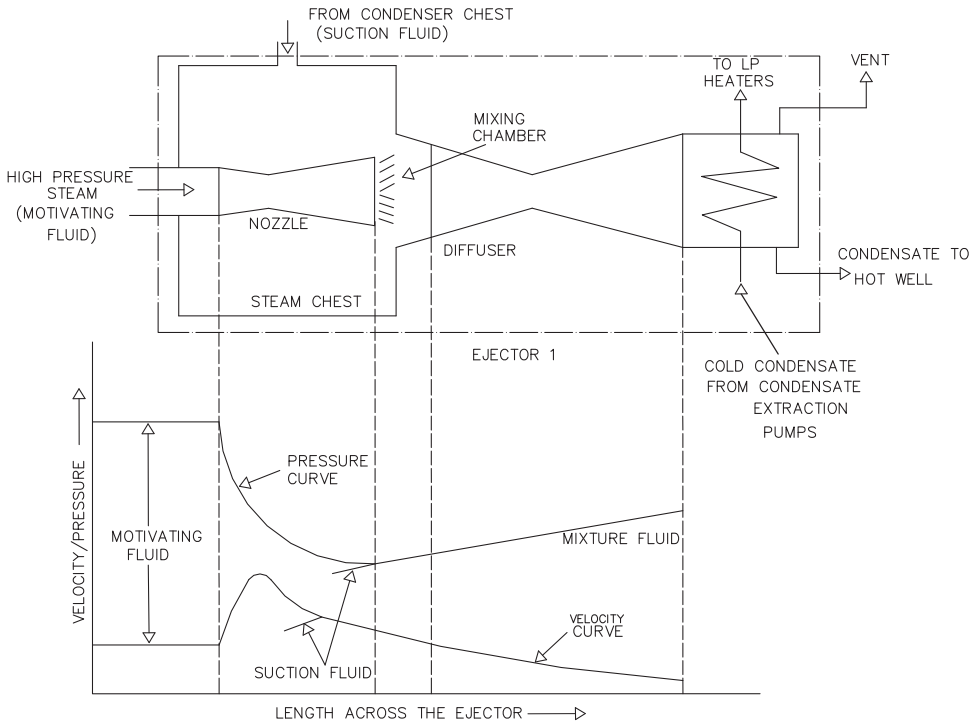
converging–diverging nozzle and expands through it; the suction fluid enters at the steam chest and mixes with the motivating fluid in the mixing chamber; both are then recompressed through the diffuser.

Here, HP steam from an auxiliary PRDS is the motivating fluid to discharge through the nozzle at a high velocity, causing rapid expansion in the ejector steam chest thus resulting in a high vacuum. The ejector suction line being connected to a condenser through a pipeline sucks noncondensible gas or air, thus removing those elements from the condenser. The nozzle described may be of a variety of designs and some of them are discussed next.

3.4.6.1.1 Single-Nozzle Ejectors Single-nozzle ejectors are used for either critical or noncritical flow and are suitable for use only under one set of design conditions.

3.4.6.1.2 Multiple-Nozzle Ejectors Multiple-nozzle ejectors are unique in both design and performance. It is said that the design of this type offers steam savings of 10 to 20% when compared with single-nozzle units designed for the same conditions.

Types. The standard available product of the steam-jet air ejector for condenser is a two-stage, twin-element



NOTE:
1) LOCATION DETAILS SHOWN IS JUST TO GIVE AN IDEA ABOUT EQUIPMENT LOCATION.

FIGURE II/3.4-2 Ejector operation and pressure-/velocity-excursion curve.

www.EngineeringBooksPDF.com

type; however, a one-element type standard product is also available. In these standard types, the two-stage ejector is arranged with the inner cooler and the after cooler, which are common to both. The air ejector type is selected according to the amount of condensed water produced by condensers.

The air ejector, employed in nuclear power-generation plants, uses boiling water-type reactors and has the capacity to extract oxygen and hydrogen gases from the turbine exhaust in addition to air leaking into the condenser. Working steam consists of the turbine's main steam or boiler auxiliary steam. The standard working steam pressure is 14 kg/cm^2.

3.4.6.2 Spindle-Operated Ejector

Spindle-operated ejectors are suggested for use whenever suction or discharge pressures vary. During operation, a pneumatically driven, tapered spindle moves in and out of the nozzle orifice to control fluid flow; otherwise, flow can be controlled by a separate valve.

3.4.6.2.1 Liquid-Ring Vacuum Pump The operating principle of this type uses a liquid compressant to compress the evacuated noncondensible gas or air and discharges them into the atmosphere. The liquid-ring vacuum pump is becoming more and more important in modern power plant practices. The simplified design and operating principle provides many advantages over other types of rotary gas pumps. This type of pump can be used for numerous applications on a very large scale. Figure II/3.4-3 shows how the pump works.

Operating Principle of Liquid-Ring Vacuum Pumps. The figure shows a cross-section across the length of this type of pump. It operates on the principle of a rotary liquid piston. The shaft and impeller assembly (i.e., forming the only moving parts) is mounted eccentrically relative to the pump casing; this means that the centers of the shaft/impeller assembly and pump casing are different as shown in Figure II/3.4-3. As the impeller rotates, the service liquid (i.e., water), which is continuously supplied to the pump, is forced outward by centrifugal force to form a liquid ring that is revolving concentric to the pump casing. By virtue of the eccentric position of the impeller, the liquid ring moves toward the periphery or away from the shaft, resulting in a liquid piston action that displaces the air or gas between the spaces of the impeller blades.

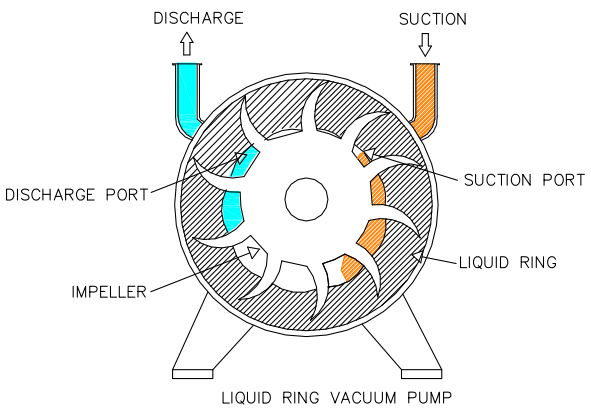


FIGURE II/3.4-3 Cross-sectional view of a liquid-ring vacuum pump.

When the shaft and impeller assembly rotates, the liquid is thrown outward by centrifugal force and air/gas is drawn into the open space through the suction port. As soon as the suction port is crossed, the service liquid is forced back into the spaces between the impeller blades, as depicted in the figure's diagram, and starts compressing the air or gas. When the spaces between the impeller blades reach the discharge point, the liquid ring forces the compressed air between the blades toward the discharge port.

3.4.6.2.2 Dry Vacuum Pump Other than the steam air ejector and the liquid-ring vacuum pump, dry vacuum pumps are devices that need no working fluid. There are two types of pumps—namely, those that use the mechanism of volume reduction or those that mix LP gas with HP discharge gas (as in a root blower).

Unlike the liquid-ring vacuum pump, dry vacuum pumps normally run hot because there is no liquid to absorb the heat of compression; consequently, this increases the temperature of the processed gas. To counteract this, some designs provide for precompression by recycling discharged gas that has been cooled.

3.4.6.2.3 Once-through Oil Vacuum Pump These pumps are a sliding vane-type that uses once-through oil to seal clearances and lubricate moving parts. The vanes are in the slots of rotors and mounted eccentrically to the pump chamber. While rotating, centrifugal forces push the vanes out of the slot and against the walls of the chamber, creating pockets with sizes that vary, similar to those of the liquid-ring vacuum pump. Because of the variation, suction draws processed gas into the pump from a vessel being evacuated and compression takes place as the vanes rotate toward the discharge side of the device; thus, this decreases the area and forces the gas and LO against the discharge valve, which opens slightly above the atmosphere.

In the condensers, an air—cooler section is provided to support the removal of noncondensible gas; the section consists of a bundle of tubes and that are baffled to collect what is being condensed. The volume and size of the air removal equipment is reduced as the volume of the noncondensibles is reduced as a result of the cooling effect.

www.EngineeringBooksPDF.com

3.4.6.3 Mode of Evacuation Methods: Hogging and Holding

There are two modes of operating the noncondensible/air removal equipment termed hogging and holding. It is a prerequisite condition that all the noncondensible gas or air must be removed from the condenser before allowing admission of exhaust steam to it. In hogging mode, a large volume of noncondensible air is removed very quickly from the condenser and thereby its pressure is reduced below atmospheric pressure to a certain predetermined level. The holding mode begins to operate when the desired pressure is achieved after successful operation of hogging to remove all the remaining noncondensible air.

3.4.6.4 Performance

The two-stage, twin-element air ejector (not shown in figure) can extract a specified amount of dry air with its single element and maintain a very high vacuum in the order of say 735 mmHg. This air ejector is designed to extract saturated steam (simultaneously with the air), about 2.3 times the volume of air, from the condenser.

The cooler is divided into the intercooler and the after cooler, which are mounted on the outlets of two stages of the ejector, respectively. It is designed to condense steam. The second-stage ejector extracts air with a small amount of saturated steam, or discharges it into the atmosphere. High-velocity steam jets from the nozzle entrain the air. The diffuser raises the entrained air pressure. The materials for these components differ according to the condition of the steam used. The nozzle is usually made of stainless steel, while the extraction chamber and diffuses are made of steel castings or steel plates.

3.4.6.5 Starting Air Ejector and Priming Air Ejector

When starting the turbine, a special type of air ejector is employed to rapidly discharge a large amount of air from the condenser—called the *starting air ejector*. Another type of air ejector is used to prime the cooling water system of the condenser; it is called the priming air ejector. Clause 3.6 of this chapter discusses it in detail.

3.5 Startup and Thermal Stress

Steam with very high pressure and temperature passes through the turbine to get power output and that is why it is imperative to take care of thermal stresses and keep them at normal values during startup and routine operation. The startup procedure is more important because hot steam would result in stress to the cold turbine metals during the initial entry of steam.

It is extremely important that for large thermal power plants (~210 MW and above) the temperature rises slopes during startup and that large load excursions be limited with a view to restraining the unsteady thermal stresses in the various parts of the rotors (i.e., HP and IP) whether in separate units or integrated HP–IP cylinders. It has long been known that cycling thermal stresses, or low-cycle fatigue, more than design limits can cause rotors to develop a dangerous condition called *cracking*.

It is basically the temperature difference between the hot steam and the cold metal, or to be more precise between the outer surfaces and the middle of the metal body, that causes thermal stress. With a set of specific initial steam temperatures, the flow rate can be regulated at the optimum values for a duration that enables startup of the turbine in the shortest period with a view to maintaining thermal stress within the permissible limit. This procedure is extremely important because thermal stress beyond the limit acts on the life expectancy of the steam turbine and the startup time of the plant also may be jeopardized.

3.5.1 Types of Startup Procedures

A startup procedure is normally of three (3) types: cold, warm, and hot. The cold startup is the most important because the temperature difference is at the maximum in this case and needs careful attention. Cold startup of a steam turbine is applicable after a very long period of shutdown when the turbine's case chest, valves, and rotor temperature are close to the ambient temperature. However, technically, they are considered cold starts when the metal temperature is less than 200°C, which normally denotes the situation after a moderately long shutdown.

Warm startups are when the plant goes for a two-shift operation or resumes operation after the weekend shutdown; here, the temperatures of different metals are not so significant because steam can be entrapped within the turbine. The hot startup conditions are when there is a need to restart the plant immediately after an emergency trip while the turbine is running.

3.5.2 Damage Mechanisms

It has been observed that the damage caused by the cold startups are about three times those caused by warm and hot startups. It has also been found that startup stress becomes lower toward the depth of the metal with proportionate buildup of cracking growth. It is known that two (2) major damage mechanisms are responsible for most of the turbine components' failure, causing a lapse in safety measures and costly maintenance arrangements. These two damage mechanisms are "creep" and "low-cycle fatigue" and mainly associated with high process temperatures and cyclic operation of plants.

3.5.2.1 Creep

In short, this type of failure is a mechanical phenomenon observed on metal bodies caused by the very high

www.EngineeringBooksPDF.com

temperature processing of fluid traveling through them. The damage becomes more aggravated as the rotor metals work under the action of high centrifugal forces. The turbine metals mainly are a special type of steel that undergoes dislocation on the gain boundaries and results in permanent deformation of the affected area.

3.5.2.2 Low-Cycle Fatigue

The phenomenon called low-cycle fatigue is the thermal effect on thick metals when the process temperature varies and, accordingly, stresses develop. The operation of thermal power plants always demands changes in load at any moment and results in development of stress. As the start and stop operations are also associated with changes in temperature, the turbine metals are sure to experience induction of stress.

3.5.2.3 Combined Effect of Creep and Low-Cycle Fatigue

The thick turbine metal component parts, such as HP and IP cylinders, governor control, isolation valve bodies, high-pressure castings, etc., are affected by the combined effect of creep and low-cycle fatigue. The reason is simple: being components of thick section construction, they suffer from stress development—low-cycle fatigue—at the same time by the creep mechanism for handling very high temperatures and pressure.

These two major damage mechanisms, resulting from operation through high temperature and longer runtime periods, engender cumulative, latent destruction of material components that includes reduction in physical properties and distortion/deformation of internal properties. The ultimate outcome is obviously less-efficient running of the turbine until it is noticed and dealt with.

3.5.3 Relationship of Stress, Temperature, and Startups

The temperature rising slopes (heating ramps) must be controlled; this is done by controlling the steam flow rate and quantity by adjusting the openings of various governing valves. In this way there are minimal thermal stresses on the turbine metal, especially of thick components (e.g., steam turbine shafts). It is also important to avoid high differential expansion between the rotor and stator, a case that could tend to make contact between them because of their different thermal inertia. The most critical part of the plant, as far as thermal stresses are concerned, is the turbine shaft that is in contact with the highest temperature steam (i.e., downstream of the first stage of the turbine). The startup control system, therefore, must be capable of keeping the controlled variables within safe allowable limits.

3.5.3.1 Stress and Temperature Curves in Relation to Time

Figure II/3.5-1 shows the temperature distribution in the first section (HP) of the steam turbine shafts and MW excursion with respect to time, and Figure II/3.5-2 shows the corresponding development of thermal stresses with a similar time frame that results in component fatigue and thereby limits its useful lifetime.

Figure II/3.5-1, which displays the different temperatures for the HP turbine, includes the three lower curves that represent the internal, mean, and external rotor temperatures; the two upper curves represent the temperature of

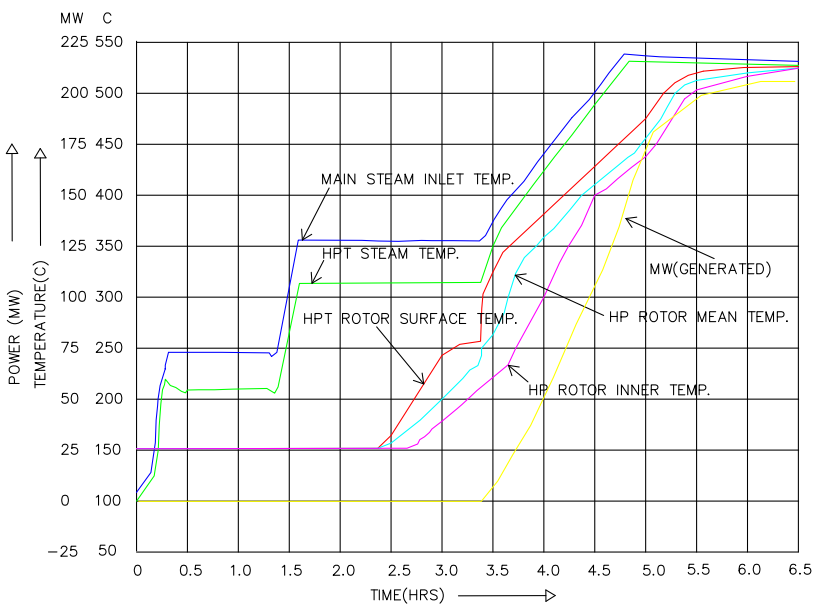


FIGURE II/3.5-1 Change in main steam inlet, HPT steam, rotor temperatures, and MW (gen) with time for normal startup.

www.EngineeringBooksPDF.com

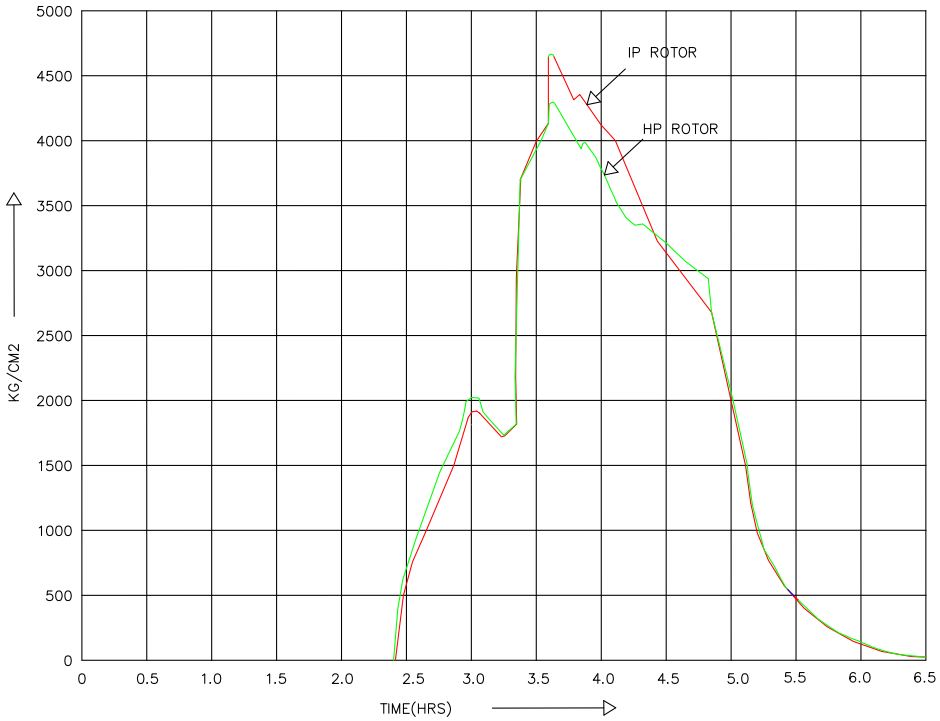


FIGURE II/3.5-2 HP and IP turbine rotor thermal stress development for a normal startup.

the superheated steam at the turbine inlet and the temperature of the first (impulse) stage outlet steam (i.e., downstream nozzles of HPT). This is where the steam first comes into contact with the rotor. During turbine startup, the steam flow, and the heat transfer coefficient, are obviously very low; therefore, the rotor temperatures increase slowly. When, after certain period of time, the HP valves are opened more rapidly, the rotor surface temperature is closer to both the HPT inlet and first (impulse) stage outlet and steam temperature. The temperature and time values, as shown in the graphical representation, are indicative only and vary according to the capacity and design of the plant. At the end of the transient period, all temperatures are more or less equal and the TG set is ready to take up the load.

The possibility of considerable reduction in startup time, however, depends on state-of-the-art knowledge and improvements in steam turbine operation. The warmup procedure, being the first step of the startup procedure, needs much more attention. For the warmup to take place, the turbine needs to admit steam having temperatures above the corresponding metal's temperature. The differential temperature (dT) determines the time to be taken by the warming up process while the approximate or nearest value of the same is absolutely dependent on the time the machine was out of operation. For example, a longer outage would obviously demand lower differential temperatures.

The plant startup process includes a variety of steps such as waiting for proper admission of steam quality, warming up of the turbine metals (e.g., valves and stator/rotor blades), turbine step-by-step acceleration to synchronizing speed, switchover to power-generation mode, etc. All these steps are time consuming and the total time can be reduced if the possibility of doing some steps in parallel could be explored; this may provide operational flexibility and improvement without sacrificing turbine health and life expectancy.

Figure II/3.5-2 shows the corresponding thermal stresses at the rotor surfaces of HPT and IPT. The maximum values, which actually determine lifetime consumption over the startup cycle, would be around a few thousand kilograms per square centimeter (kg/cm^2) and from this point the TG starts to take up the load. The approximate excursion figures, however, indicate the startup procedure in a moderately unadventurous or conventional way to accommodate sufficient safety factors for unpredictable situations that may crop up during plant startup. In other words, more importance is put on plant safety than on efficient running.

Improvement in startup transient behavior can be made with a view to reducing the time needed by either keeping the stress the same as before but taking the generator load earlier or minimizing the stress values. A brief discussion is incorporated in the following.

3.5.3.2 Stress and Temperature Curves in Relation to Longer Soaking Time

After the initial heating ramp, the period called *heat soaking* comes into the picture; this means that heating is

www.EngineeringBooksPDF.com

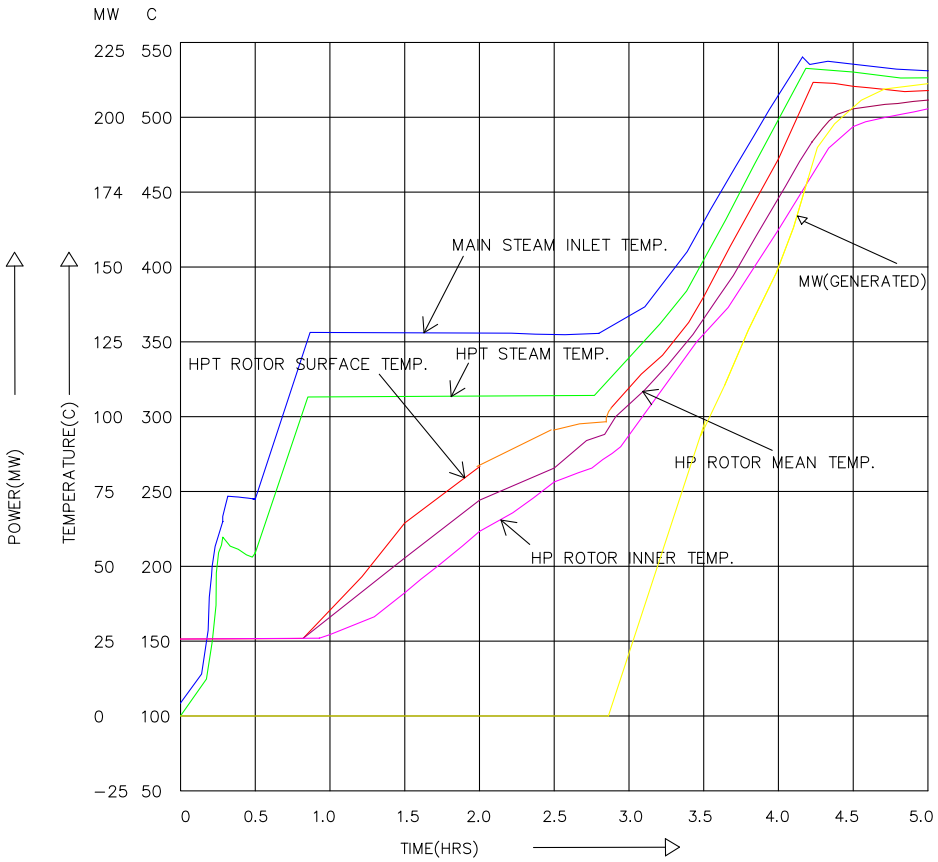


FIGURE II/3.5-3 Change in main steam, HP turbine steam, rotor temperature, and MW with a longer soaking period.

continued for that period of time unless the desired temperature is achieved. Figure II/3.5-3 shows the tentative excursions/trends of the parameters during startup when arrangement is provided to give the turbine more time for soaking. Figure II/3.5-4 shows the tentative excursions/trends of the parameters during that type of startup.

Here, the main objective is to reduce the maximum stress value, which in turn means less lifetime consumption, without increasing the startup time with respect to normal startup transient values. To achieve the same object, it is necessary to reduce the thermal shock at the very commencement of the steam turbine picking up the generator load. This can be done by allowing for a longer soak time for the turbine; that is, once the turbine has reached full speed, it is kept running without taking any load so that the steam flow can heat up the rotor for an extended period greater than that of the time period shown earlier.

Turbine startup is therefore initiated earlier than the normal startup transient, and the turbine is kept idling for say one hour. The load pick-up phase is then started, and the rate of load change is steered in order to get a flat stress curve. After a desired load level is achieved, the rate of change is increased to maximum allowable level. The resulting temperature and stress plots were shown earlier in Figures II/3.5-3 and II/3.5-4.

Here, two thermal stress peaks are observed, each of them contributing fatigue and thereby lifetime consumption. If the peak values are analyzed, it can be seen that the first peak value may be slightly higher than the "elastic limit," and thus correspond to very low additional lifetime consumption. While the second peak is shown to be higher than the first peak, it is, however, well below the corresponding stress value shown earlier for a normal startup. The startup time is also reduced by a considerable value vis-à-vis fuel savings.

3.5.3.3 Stress and Temperature Curves in Relation to a Fast Startup

Figure II/3.5-5 shows the tentative excursions/trends of the parameters during startup when an arrangement is provided to give the turbine less time for soaking. Figure II/3.5-6 shows the tentative excursions/trends of the parameters during that type of startup.

Here, the startup time is minimum and the soaking period is much less as the generator load is connected earlier but with an upper limit stress peak the same as that of the value experienced with a normal startup time period.

www.EngineeringBooksPDF.com

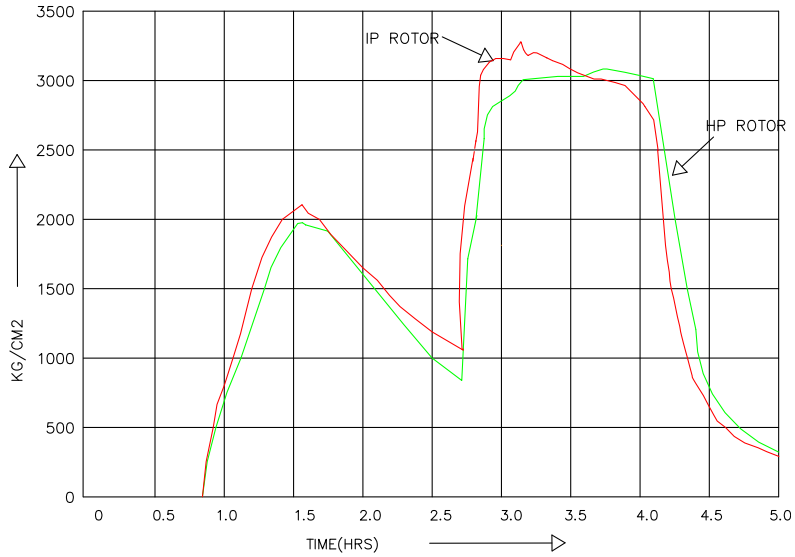


FIGURE II/3.5-4 HP and IP turbine rotor stress development during startup with a longer soaking period.

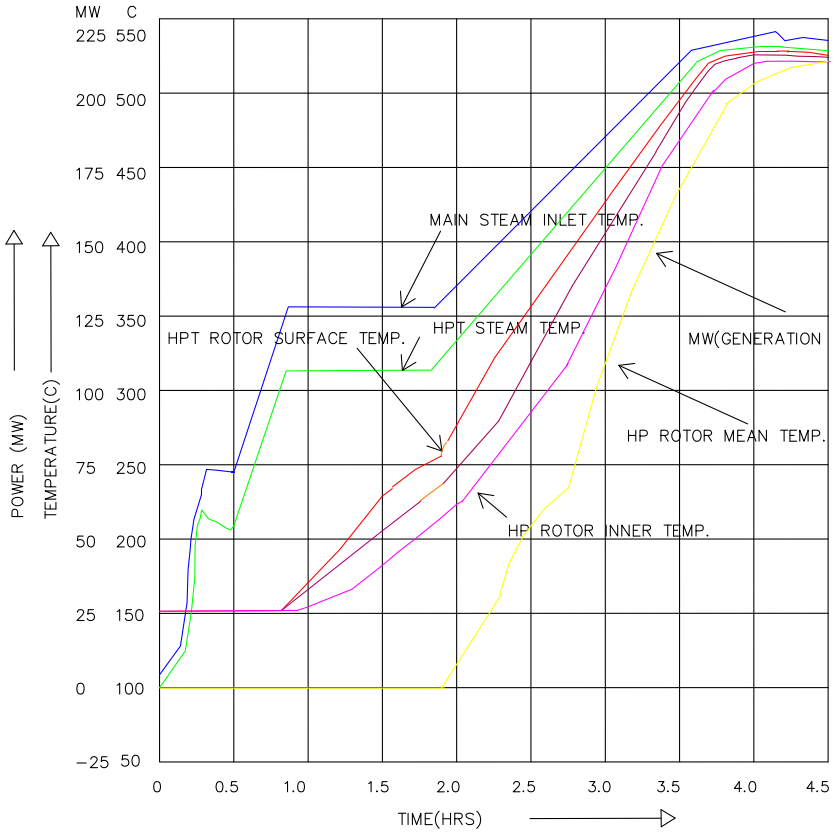


FIGURE II/3.5-5 Change in main steam, HP turbine steam, rotor temperatures, and MW with a fast startup.

The benefit is thus the same lifetime consumption with early load delivery compared to the normal startup time. The net advantage is much less startup time vis-à-vis maximum fuel savings in comparison with normal startup transient values without compromising the stress factor—that is, lifetime consumption.

www.EngineeringBooksPDF.com

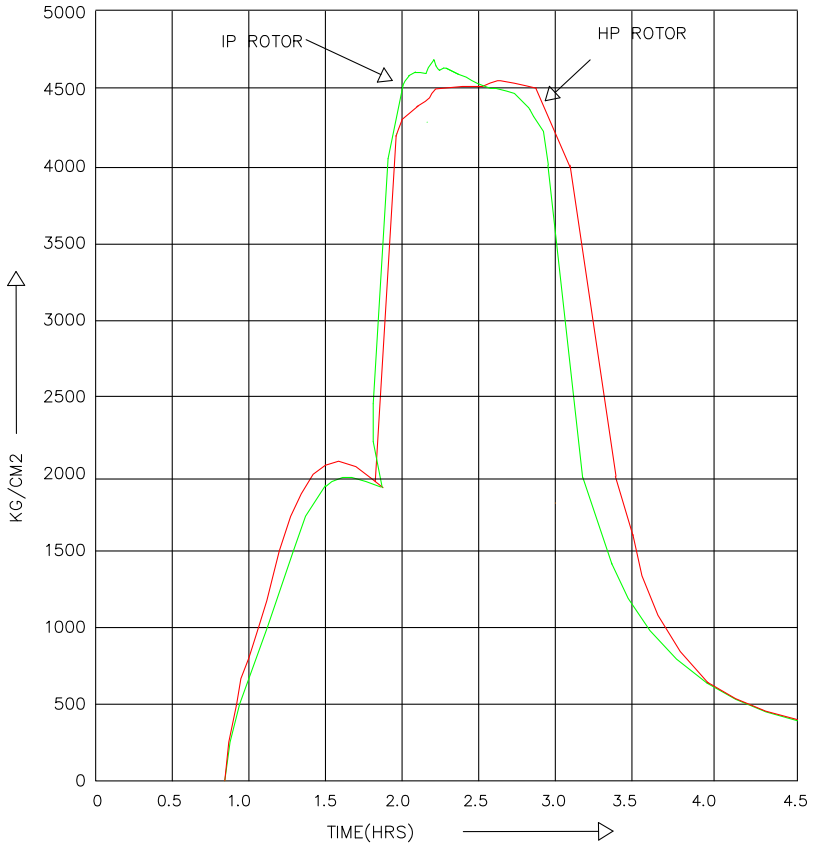


FIGURE II/3.5-6 HP and IP turbine rotor thermal stress developments during a fast startup.

It should be noted that the thermal stress peaks are basically due to the thermal shock at the beginning of the startup phase. Once this peak is attained, lifetime consumption is the same regardless of how fast the stress level goes back to zero.

3.6 Miscellaneous Turbine Auxiliaries

There are many turbine auxiliaries out of which the most important components are discussed in this clause due to space limitation. The component names include, for example, turbine bearings, gland-associated items (e.g., gland packing, gland steam condenser and gland exhaust fan), condenser vacuum with priming system, vacuum breaker, condenser tube-cleaning system, condensate polishing unit, vacuum trip device, etc.

3.6.1 Turbine Bearings

There are quite a few bearings through which the turbine rotor and the mechanically coupled generator rotor are allowed to rotate freely inside the TG casings. The bearings are basically journal type to take care of the weight of the rotor shaft; in addition, there is a thrust-type bearing to take care of the impact of the axial thrust produced during rotation of the huge mass of the shaft.

3.6.1.1 Main Bearing

The main bearing, consisting of a bearing proper and a shell, is a spherical surface, seat-supporting type. It has an elliptical shape, which can be compared to conventional bearings (Figure II/3.6.1-1(a,b)), and offers a much greater effect in stabilizing the shaft during turbine operation. High- and low-pressure rotors of large capacity use tilting pad-type bearings, which provide a greater shaft-stabilizing function. Lubricating oil in the proper volume is fed to each bearing by an orifice installed in the FO tube.

The lower half of shell, which fits into the groove of the bearing stand, is constructed so that its position can be adjusted by an adjusting plate. The upper and lower halves are bolted together to complete the shell stand, which is directly bolted to the horizontal coupling surface of the bearing, and securely maintains the bearing's position.

3.6.1.2 Thrust Bearing

The thrust bearing consists of the bearing proper and a thrust-receiving surface. The surface is a taper-land type,

www.EngineeringBooksPDF.com

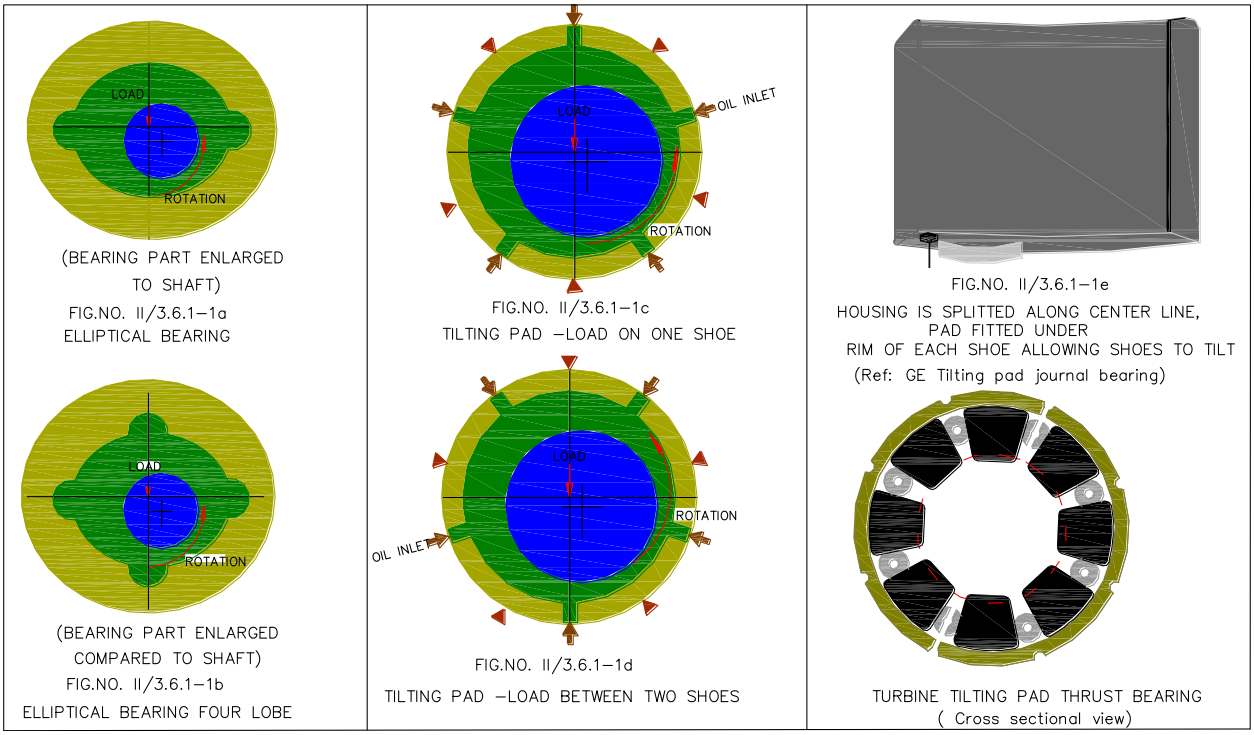


FIGURE II/3.6.1-1 Various turbine bearing types.

which possesses great resistance against pressure. Several radial oil grooves divide the surface into segments, the surfaces of which are radially and circumferentially precision-machined and properly inclined. Various types of thrust bearings are shown in Figure II/3.6.1-1(a–f).

Lubricating oil is supplied from the inner thrust-receiving surface to the oil grooves and is forced into the inclined surface by a rotating collar bearing to form a powerful pressure-resisting surface. Nowadays, old style elliptical or four-lobed bearings are replaced (thus description is not included) by tilting-pad bearings to facilitate of shaft position adjustment. Tilting-pad bearings offer following advantages:

- Total avoidance of oil whirl and dynamic instability
- Increased safety and operability
- Lower amplitude of shaft vibration
- Easier thermoelement placement

The thrust bearing (see Figure II/3.6.1(f) for tilting-pad thrust bearing) is a split-type having adjustable sectional shoes or pads inserted into its back to facilitate adjusting the thrust-bearing gap. During operation, the rotating part of the bearing, through the action of "viscous drag," draws fresh oil into the pad area. Due to fluid pressure, the pad tilts (thus the name) slightly and narrow constriction is formed between pad and the rest of the bearing's surface. Behind this constriction, pressurized fluid builds up in the shape of a converging wedge and separates the moving parts.

This self-renewing wedge or film of oil is not compressible; takes the load; provides shock absorption; helps control vibration; reduces power losses; and extends bearing life over a wide range of speeds, loads, and temperatures. The tilt of the pad adjusts itself with bearing load and speed. Various design details ensure continued replenishment of the oil to avoid overheating and pad damage. Normally, Babbitt metals and polymer-coated (self-lubricated) tilting-pad bearings are used.

The thrust bearing, especially equipped with a thermostat, measures the temperature of the front and rear thrust-bearing metal as a means of sensitivity monitoring of any abnormal condition of its surface. In addition, it is equipped with a protective device for automatically stopping the turbine in case of an unforeseen accident.

3.6.2 Gland Packing, Gland Steam Condenser, and Gland Exhaust Fan

The gland steam system incorporates the gland-sealing system, basically a subsystem of turbine shaft packing, to prevent the leakage of HP-stage steam from or air into the LP stage of the turbine casing along the rotor shaft. The system not only prevents leakage but also provides an arrangement for the removal of gland steam and air, which

www.EngineeringBooksPDF.com

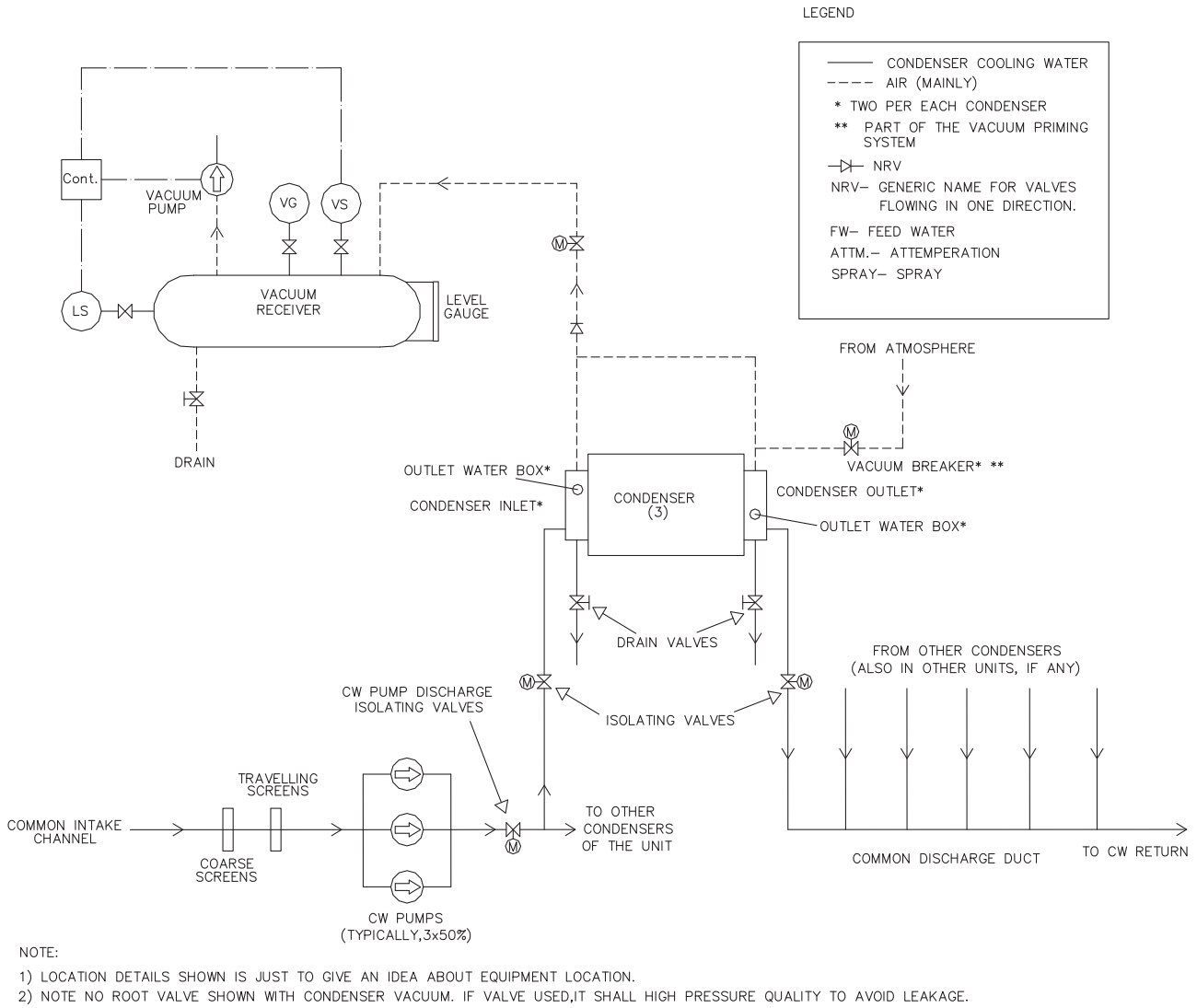


FIGURE II/3.6-1 Vacuum breaker and priming system.

cannot be totally leakproof, from the turbine glands and sends it to the gland steam condenser. The steam is condensed in the form of water drain and sent to the condenser hot well. Leakage air is sent from the gland steam condenser to the atmosphere. The gland steam condenser maintains a partial vacuum in the glands to prevent steam leakage.

3.6.2.1 Gland Packing

Labyrinth gland packing is used for the gland part of the turbine and for the inner surface of the nozzle diaphragm. It consists of several circular segments fitted into the grooves of their mating parts and the equipped labyrinth packing should be in contact with each other; local heating of the rotor due to such contact can be reduced. The labyrinth packing for high-temperature parts consists of an alloy steel labyrinth body inserted with Cr-Mo steel strips, which for low-temperature parts consists of a labyrinth body and strips integrally formed of nickel silver or phosphor bronze stock.

3.6.2.2 Gland Steam Condenser and Gland Exhaust Fan

When the gland seal is a steam seal type, a gland condenser and a gland exhaust fan are installed. Steam leakage and air from the gland are led to the gland condenser, where the steam is condensed, and the air and gases are discharged into the atmosphere by the gland exhaust fan. Turbine condensation is used as cooling water for the condenser to reclaim heat.

www.EngineeringBooksPDF.com

3.6.3 Priming System for Water Box and Circulating Water Pumps

Figure II/3.6-1 shown earlier illustrates the basic functioning of the condenser vacuum system. It is responsible for drawing the CW into the condenser along with the pumps. As the CW intake and discharge points are normally situated at a distant location, it is necessary to suck the air into the long pipeline and create a vacuum that helps draw circulating water through the long pipeline. Removing the air from the system to lift water up into the condenser before the circulating pumps are started is called *initial priming*. Once the flow is established, it continues to run as a siphon effect with the aid of CW pump discharge pressure to cater to the pipeline's frictional pressure drop.

This system is called a *priming system* and vacuum equipment is used to prime the main condenser cooling water pumps by evacuating the water boxes to a vacuum level necessary to overcome the difference in head and remove air released from the cooling water during operation. Continuous priming is also necessary to remove the air liberated from the water during normal operation of the condenser vis-à-vis CW. This vacuum equipment is often also used to remove air pockets from water boxes. Priming valves are often used between water boxes and the vacuum system to protect it from being flooded with cooling water from the main condenser. It is also common to include a vacuum "reservoir" tank to dampen the effects of air surges.

It is obvious that the cooling water temperature will have less of an impact on the priming equipment than the main condenser vacuum equipment. A closed-cycle cooling water loop is usually considered because it will not force the use of exotic materials for the various cooler/heat exchangers. The system may also be considered for a once-through service water arrangement in case of smaller vacuum pumps and when a clean water source is available. This will eliminate the need for a recirculated service water system and its associated maintenance.

A priming valve or stack must be installed at high points in the primed system to allow the air or non-condensible gases to be driven out of the system without excessive water being carried over into the vacuum system. A valve for priming service should also be there to isolate the primed system from the vacuum system when the water level in the primed system reaches a particular value.

Priming valve materials and parts of the vacuum system, which may be in contact (trim or wetted parts) with any carryover, should be designed to be compatible with the CW primed. The use of a dropout receiver tank ahead of the vacuum pump can help to protect the vacuum pumps from corrosive water spray.

For a continuously primed system, the flow of non-condensible gas is relatively small and thus it may be prudent to run the vacuum pumps intermittently for evacuation of a control tank. The pump(s) can be started when the vacuum level drops below a certain point and stopped once a certain level is achieved. The added volume of a control tank helps to prevent frequent cycling of the pump.

3.6.3.1 Priming Devices

3.6.3.1.1 Priming Air Ejector Such an ejector is normally a single-stage, steam-jet air ejector type of operation of which has already been described in Clause 3.4 of this chapter.

3.6.3.1.2 Liquid-Ring Vacuum Pump This type of pump has been described already in Clause 3.4 of this chapter

3.6.3.1.3 Dry Vacuum Pump The dry vacuum pumps are also widely used, the same as the others—steam air ejectors and liquid-ring vacuum pumps. The operating principle of dry vacuum pumps does not use any liquid, such as oil or water, as a sealing fluid. The steam is sucked, compressed, and forced to leave the condenser chamber. Screw-, lobe-, or claw-type pumps have been deployed for these types of applications. Dry vacuum pumps are capable of creating a vacuum range that varies from atmosphere to 2.0 mm of water column.

3.6.3.1.4 Once-through Oil Vacuum Pump Rotary vane-type vacuum pumps are an example of a once-through oil vacuum pump that utilizes oil as sealant/lubricant fluid for extracting clean, dry, nonreactive gases. These types of vacuum pumps are capable of creating a vacuum range that varies from atmosphere to 70.0 mm of water column. The pumps are usually air-cooled, direct-drive, 1750 rpm pumps. Regular maintenance, such as oil changes and periodic vane/filter changes, are required to keep them at maximum serviceability.

3.6.3.2 Selection of the Priming Devices

The following two parameters are important when selecting the priming devices:

1. *Suction pressure:* This is determined by the amount of head required to prime the system and the pressure drops between the vacuum pump and the system.
2. *Capacity:* This is determined by the volume, the lowest operating pressure of the system, temperature of the water being handled in the condenser, and the time allowed to reduce the pressure in the system.

3.6.4 Vacuum Breaker Valve

This is a special type of valve (zero leakage type) in the condenser priming circuit. The purpose of a vacuum

www.EngineeringBooksPDF.com

breaker valve is to quickly allow air into the vacuum space of the condenser as well as into the low-pressure turbine exhaust hood. This valve allows air to be vented into the condenser to reduce the roll-down time of the turbine generator. As a usual practice the vacuum breaker valve is located on the steam turbine (LPT) or on the top of the condenser shell itself.

3.6.4.1 Main Objectives of Providing Vacuum Breaker Valve

The following are the main as well as associated objectives of providing a vacuum breaker valve:

- Reduce or break the vacuum as early as possible
- Decrease the turbine's speed as a result of preceding action; otherwise, there could be a huge acceleration of the steam turbine on loss of load by the generator
- Avert the possibility of turbine rotor vibration going up
- Decrease the loss of turbine LO and hydrogen seal oil pressure

3.6.4.2 Capacity/Sizing of a Vacuum Breaker Valve

There are many considerations for determining the capacity or sizing of vacuum breaker valve. Among the important ones are: total volume of steam space within the LP turbine casing and the steam surface of the condenser and, of course, the time required to reduce the vacuum. The opening time must always be taken into consideration because, in the event of a turbine overspeed running condition, reduction in turbine speed is directly influenced by the vacuum breaker valve opening time and the valve size as well.

3.6.4.3 Types of Vacuum Breaker Valves

Vacuum breaker valves should follow the specifications as described by the original equipment manufacturer unless and otherwise driven by some special consideration. Globe- and Butterfly-type valves are the natural choice.

The sealing of the vacuum breaker valve is very important to reduce any potential threat of air leakage into the condenser; for example, resilient metal seals provide two basic characteristics—elasticity and plasticity—to ensure drop-tight seating. The valves should be rated strictly for vacuum service and, of course, have a tight shutoff-type leakage class. It is always preferrable to go in for an additional water seal system to prevent air in—leakage into the vacuum space while the unit is operating.

3.6.4.4 Location of Vacuum Breaker Valves

While locating the vacuum breaker valves on the condenser itself due to demand from the design criteria, they should be positioned very close to the condenser shell while considering other safety parameters. For example, personnel protection and anticipated/calculated noise levels must also be taken into account during the design stage of the intake piping of vacuum breaker valves.

3.6.5 Online Condenser Tube-Cleaning System

Online cleaning of condensers tubes is necessary for large modern power plants because they handle natural water, especially for the once-through type of CW system, and are subject to mineral fouling. Because the temperature is also the ambient one, biological growth inside the tubes is inevitable. All these phenomena will hamper circulating water flow and lower condenser efficiency via-à-vis plant efficiency and power output. Figure II/3.6-2 depicts the basic functioning of the cleaning of condenser tubes while a plant is online.

3.6.5.1 Principle of Operation

Suitable sizes of rubber sponge balls are injected at relatively high velocity into CW flow circuits at the inlet of the condenser. The sponge balls are circulated through the condenser tubes, where they mechanically remove fouling biological growth, debris, and scales that build up on tube surfaces. Upstream of the injection point, there should be strainer/filter to prevent the balls from escaping the desired route and forced to pass through the condenser itself.

At the condenser outlet, a ball strainer is provided for collection of sponge balls and reinjection at the inlet to continuously maintain the cleaning process. The automatic

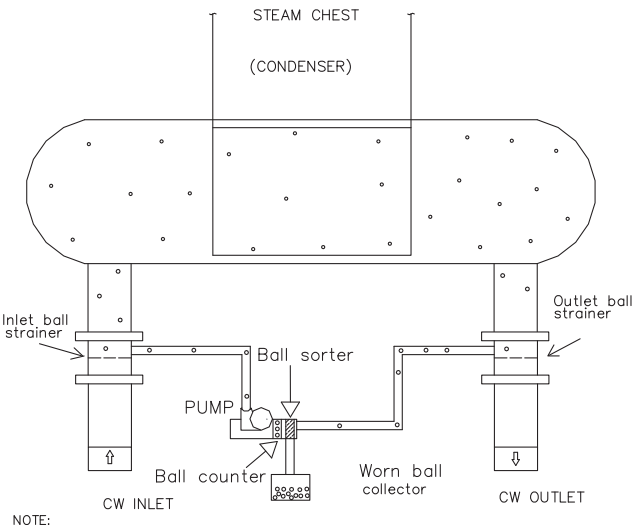


FIGURE II/3.6-2 Schematic diagram of online condenser tube-cleaning system.

www.EngineeringBooksPDF.com

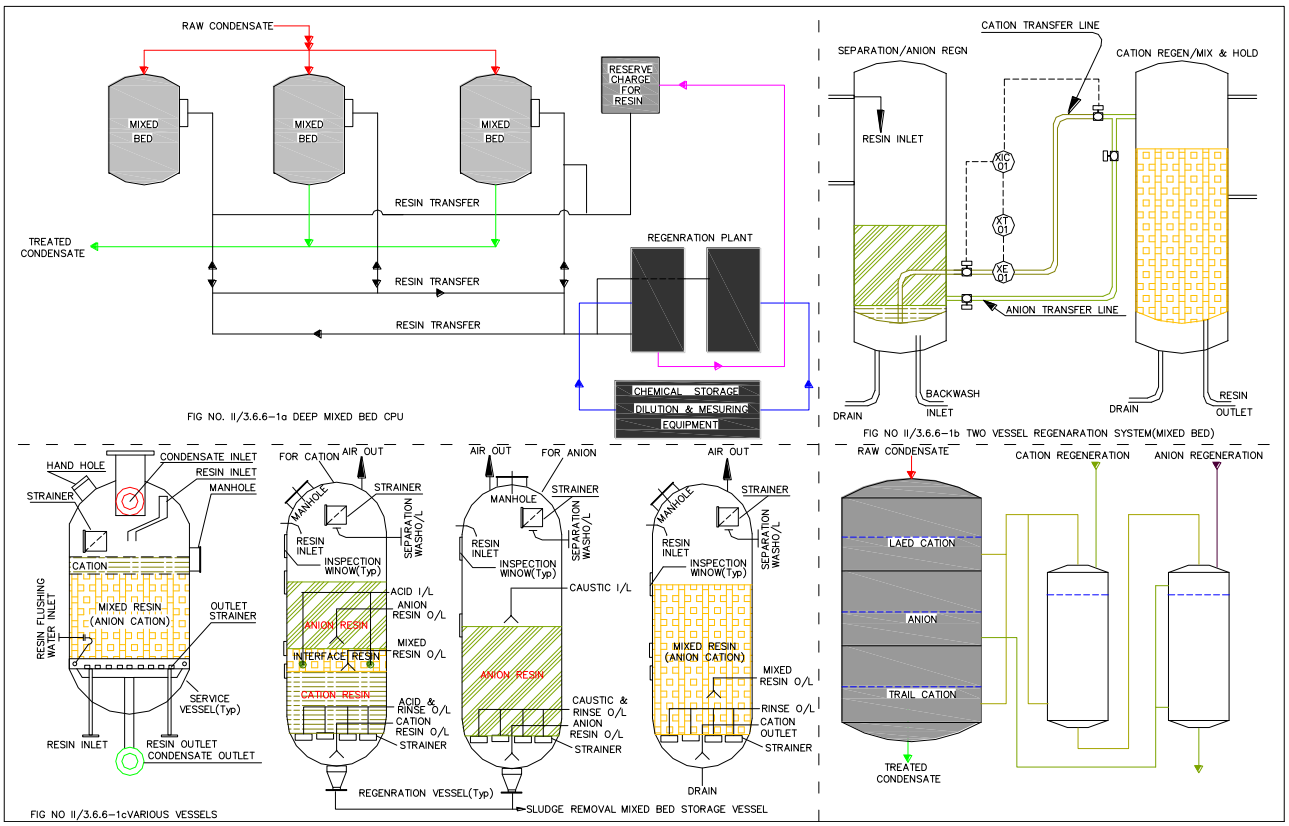


FIGURE II/3.6.6-1 A schematic of a condensate polishing unit.

and continuous operation of tube-cleaning systems has been so designed to permanently eliminate the need for costly plant shutdowns to conduct manual condenser cleaning and/or other methods such as hydrolancing, etc.

3.6.5.2 Basic Objectives

The primary objective is to ensure optimal heat transfer to maintain plant design parameters and thereby raise plant output to the original design specifications. The cleaning system should also reduce fuel consumption/cost. Condenser life expectancy will be better when a plant is equipped with this system and cost effectiveness will be ensured. Online cleaning of condenser tubes is a way to avoid regular shutdowns for manual tube cleaning and reduces expenses related to the use of chlorination.

3.6.5.3 Materials of Construction

Normally, stainless steel or rubber-lined carbon steel is used for construction of the tube-cleaning system, depending on service requirements.

3.6.6 Condensate Polishing Unit

Functional details on the condensate polishing unit (CPU) are discussed in the following subsections. In this connection, refer to Clause 4.0.4 of Chapter V, Clause 4.0, and the details given in Exhibit II/3.6-1 at the end of this clause. For a related drawing, see Figure II/3.6.6-1.

3.6.6.1 Requirements of Condensate Polishing Unit

Boiler pressure is the key factor for determining the requirement of a CPU system (see Figure II/3.6.6-1). For the steam generator plant with low steam pressure (below 40 kg/cm^2), the requirement of a condensate polishing unit is usually avoided. Hard scale formation and boiler metal corrosion can easily be prevented through feedwater treatment before being sent to the boiler proper. Adding suitable chemicals (e.g., phosphate) are more or less sufficient to remove contaminants from the condensate stream.

The requirement for condensate polishing unit becomes a necessity for medium-pressure boilers (40–170 kg/cm^2) and, of course, for boilers with high-pressure (above 170 kg/cm^2) system. In cases of once-through boilers, a CPU is absolutely essential.

It has also been observed that medium-pressure plants can manage to avoid a CPU by controlling feedwater contamination through intermittent and continuous blowdown of boiler drum water. Condensate "scavenging," or cation exchange, is also often used to remove corrosion

www.EngineeringBooksPDF.com

EXHIBIT II/3.6-1 CPU Technology

1. *Factors influencing performance of CPU:* These are discussed in Clause 4.0.4 of Chapter V.
2. The major components associated with a CPU are:
   - **a.** Operating vessel/service vessel
   - **b.** Separator/cat ion regeneration vessel
   - **c.** Anion regeneration vessel
   - **d.** Mixed bed resin/storage tank
   - **e.** Transfer pumps and recovery vessel
   - **f.** Acid- and caustic-handling tanks/measuring tanks
   - **g.** Vacuum pumps
   - **h.** Effluent pumps
   - **i.** Instrumentation and controls (discussed in Clause 4.0.4 of Chapter V)
3. *Basic principles of regeneration:* For the commonly used mixed bed systems, normally there are three service vessels, two working and another standing by. The following are the major steps for regeneration:
   - **a.** Mixed resins are transported from service vessel to separator/cation regeneration vessel in the form of slurry with water supplied by transfer pumps.
   - **b.** Empty service vessel has resin from mixed bed resin/storage tank.
   - **c.** Mixed bad resin in separator/cat ion regeneration vessel is scrubbed with air and backwashed with water to clean and separate resins—light anion resin at the top and heavier cation resin at the bottom.
   - **d.** With the help of water from the transfer pump, anions are transported hydraulically to anion regeneration vessel before regeneration; a portion from the separator/cation regeneration vessel is kept for interface tank to ensure that there is no anion present to improve performance.
   - **e.** Cation resins are regenerated with a diluted acid solution (measure quantity of acid with the help of measuring tank and vacuum pump) piped to separator/cation regeneration vessel at the top. Provisions are kept for sulphation also. For plants with NH^3 cycle or condenser tube leakage exists, sulphation should be done at regular intervals.
   - **f.** Once regeneration is done, acid solution is drained and resin is rinsed with DM water.
   - **g.** Anion is very similarly regenerated with the help of caustic solution.
   - **h.** After regeneration, both cation and anion resins are transported hydraulically to mixed bed resin/storage tank as slurry. The resins are mixed by air and rinsed with DM water. Then they are backwashed to separate the ions again to transport to next service vessel. All of anion and half of cation are transferred and mixed in the service vessel.
   - **i.** Conductivities at various stages are checked to ensure proper regeneration.
   - **j.** Vessel details and various inlet/outlet lines have been elaborated in Figure II/3.6.6-1(c).
4. *TRIPOL® process (a registered trademark):* In this method instead of the mixed bed, there are three layers, as shown earlier in Figure II/3.6.6-1(d). The separate resin movement lines are meant to avoid cross-contamination. The resin volume can be altered to suit the operating condition.

products from condensate returning from the turbine. Since passing through a CPU means there will be a loss of system pressure, and where the contamination level is not that high, use of a partial CPU is also observed with part of the condensate passes through one and the rest goes directly.

Very high-pressure systems are often "zero-solids" systems that require condensate polishing to satisfy the water quality requirements of the major contaminant ions. When condensate from the condenser outlet is passed through various pipelines, heat exchangers, and other equipment in the steam turbine cycle, it is contaminated with different types of impurities. More serious types of contamination that can affect the condensate if condenser cooling water with a high level of total dissolved solids (TDS)—namely, seawater leaks into the condensate stream and leakage of chlorides into the system. Polishing uses ion-exchange resins to remove contaminants from the condensate.

Condensate polishing units are deployed for eliminating impurities from the condensate obtained at the condenser hot well from turbine exhaust or returning steam to the boiler. This is the system requirement for working with quality water/steam to be used as a fluid medium for HP thermal cycles. Polishing units are essential just because the condensate constitutes the major portion of the boiler feedwater.

The risk of persistent contamination of return condensate also calls for the application of a CPU, thus minimizing additional consumption of makeup water. The unit removes impurities such as corrosive materials, dissolved salts, etc. This is a stand-alone system with every hardware, drive, and instrumentation item required for its operation.

3.6.6.2 Presence of Corrosive Materials

Various oxides of metals, such as copper, nickel, and iron, play a major role in corroding the pipe works throughout the cycle and need special attention to deal with them. Their presence is felt in the condensate, generally, of two forms: particulate or suspended matter and dissolved salts. By rigorous and extensive filtration, the affects of these contaminating agents can be arrested.

www.EngineeringBooksPDF.com

3.6.6.2.1 Particulate or Suspended Matter Due to malfunctioning of the condenser, contaminated condensate with organic carbon components, dissolved solids, and materials inflicting turbidity are very much expected. Reusing of condensate in boiler feedwater requires thorough purging of it to match the specified quality for better functioning. The condensate first passes through an activated carbon filter, which removes crud and suspended solids of both organic and inorganic substances. There may be a block with the arrangement for providing a reverse osmosis (RO) process to further clean the condensate before it reaches the main polishing unit. Loaded with hot water membranes for high-temperature operation, the appropriate subsystem reduces the incoming total organic compound (TOC) levels and gets rid of a proportion of the dissolved contaminants in the water.

3.6.6.2.2 Dissolved Salts This type of contamination is caused basically because of leakage of condenser cooling water with the source being river water, seawater, or any type of natural resources. The application of ion-exchanging agents demineralizes or neutralizes dissolved salts and impurities and the bad effects of water can be eliminated.

3.6.6.3 Types of Ion Exchangers

Several types of ion exchangers, as described in the following subsections, are provided as per the requirements of the SG plant and the type of condenser cooling circuit.

3.6.6.3.1 Mixed Bed Exchanger The most common ion-exchanging system observed in a CPU is the application of a mixed bed exchanger, mainly for the plant with low-contamination levels. Mixed bed exchangers consist of a strong acid cation exchange resin and strong base anion exchange resin. Very high-quality demineralized water is expected from the mixed bed exchangers because ion leakage from either cation or anion resin is readily canceled by the other resin. Arrangements are made for maintaining a high flow rate (much higher than general DM plants).

A resin bed depth of approximately one meter (1 m) is provided to maintain a differential pressure across the bed at a techno-commercially acceptable level. Generally, the mixed bed condensate polishing system consists of several vessels—for example, three (3) operating in parallel. This is done to facilitate high flow and maintenance as well. Used resins are transferred to a different mode of operation for cleanup and regeneration. In some cases, disposable mixed bed resins are also used to get rid of the cumbersome regeneration process. A higher level of dissolved salts is responsible for mineral contamination and suggests use of separate cation and anion exchangers. Some plant conditions may also necessitate use of both separate ion exchangers and the use of mixed bed ion exchangers.

3.6.6.3.2 Lead Cation Resin Followed by a Mixed Bed of Strong Cation/Anion Resins When the main feedwater undergoes all volatile treatment (AVT) by using ammonia, hydrazine, and/or other volatile amines to provide a reducing environment to control pH and corrosion to save the metals in a steam generation plant, the resins in the condensate polisher are exhausted at a faster pace. The reason is when an AVT is used in a steam-condensate cycle, the amine is carried over and transported along with the stream of steam and when the amine-laden steam condenses, it builds up amine levels ranging from 0.2 to 1.0 ppm in the condensate cycle. This amine is readily exchanged onto the cation resin during condensate polishing. Eventually, the cation resin becomes exhausted to the amine form and it is needless to mention that the higher the pH, the shorter the runtime.

The improved technique for preventing the early exhaust time length of the mixed bed type polishing unit is to allow the condensate to mix with a hydrogen form cation resin (lead cation resin) to remove the amine before it comes into contact with the resins in the mixed bed. Shifting of this amine load from the mixed bed to somewhere else facilitates a longer runtime of the resins used. This type of polishing unit is, in general, a variation of the mixed bed system and may be termed a *lead cation resin* followed by a mixed bed of strong cation/anion resins. Corrosion products are also removed by this lead cation bed, eliminating contamination of solids in the mixed bed. The added advantage of this system is the regeneration of the lead cation that can be done more frequently on an as and when required basis rather than the mixed bed. The exhaustion time increases the frequency of mixed bed use. As a result, regeneration would obviously be reduced.

The process of having two ion-exchanging beds–that is, cation and mixed—in series would obviously increase the differential pressure across the polishing unit, a permanent loss, and in turn increase the pumping costs. The continuous improvement on the bed size and bed design of different resins makes optimization of the pressure loss features the same.

3.6.6.3.3 Cation-Anion-Cation Stacked Bed Exchanger This type of "cation-anion-cation" stacked bed ion exchanger is the product of a relatively recent development. This process envisages a single tank having individual compartments containing separate layers of cation, anion, and cation resins. The resins, particularly of the second and third layers, are never mixed as used in mixed bed type and each resin goes to its own external regeneration vessel. However, the advantage in this system is that the lead cation resin can be kept isolated without using it until the ammonia break in AVT system is detected by the sensor at a suitable location. Any leakage from the lead cation would be taken care of in the final or third cation resin.

www.EngineeringBooksPDF.com

3.6.6.3.4 Simple Cation Bed Exchanger If the process permits, a cost-effective alternative to simple but not so effective boiler blowdown and costly but effective other types of exchanges discussed previously may select a simple sodium or hydrogen cycle CPU. This type is techno-commercially viable takes into consideration of the savings in operating cost compared to the cost of chemicals and energy requirements.

3.6.6.3.5 Regeneration of Resins It has been observed that the regeneration of the resins outside of the CPU is what can be described as an external regeneration system; it is a comparatively better system as far as maintenance facilities are concerned. Condensate contamination by the regenerating agent itself can be noticeably avoided through proper isolation of the regenerating medium from the recirculating water circuit, with the added advantage of less time requirement that a CPU is forced to remain offline. The only interruption in this case is to take out the used resin and put into the external system for regeneration and, at the same time, introduce already-regenerated resin into the condensate polishing circuit. Using this approach, one regeneration system can be used by multiple CPUs.

3.6.6.3.6 Capacity of the Polishing Unit The capacity of the polishing unit may vary depending on many factors. Plants with partial condensate polishing capacity are often found in large, conventional thermal power systems with a coal/solid fossil firing system. However, in that case, the sizing of the makeup water treatment plant necessitates proper attention to feed the main plant during startup periods most likely apprehending the presence of contaminants at that time. For once-through SG plants, the 100% CPUs are a must requirement as there is no drum where chemicals can be injected.

Sometimes the prevailing other associated parameters are spelt out to facilitate working out the capacity of the plant. For example (typically), as per the condensate flow corresponding to maximum TG output at ~3 to 4% makeup, 0.1 kg/cm^2 (abs) back pressure, and considering all HP heaters out of service. For once-through boilers, both nuclear and fossil fueled, or high heat flux boilers such as oil-fired coastal stations, all of the condensate flow is likely to be treated in an additional plant that is used to provide the makeup water supply.

3.6.6.3.7 Quality of the Polishing Unit The quality of condensate at the outlet of the polishing unit, with reference to that of inlet of the same, determines the quality of the CPU. The running period while in service is also important and needs to be considered when designing the polishing unit. To get a better idea about the water quality expected from the polishing unit, some typical parameters are shown in Table II/3.6-1 (considering the normal conditions in the main plant). See Figure II/3.6.6-2 for specific details about CPUs.

During unit startup conditions, the quality CPU inlet would obviously be different and may be considered; for example, TDS 2000: ppb, Silica: 150 ppb, Crud: 1000 ppb. During a condenser tube-leakage condition, the quality CPU inlet would also vary depending on the type of condenser cooling system.

3.6.7 Vacuum Trip Device and Solenoid

When the degree of vacuum of the condenser drops, the exhaust chamber temperature will rise and there is the

TABLE II/3.6-1 Expected Water Quality at CPU Outlet

Measuring Parameters	Measuring Unit	Inlet	Outlet
Sodium, ppb	ppb	10	2
Iron	ppb	50	5
Silica	ppb	30	5
Chloride	ppb	10	2
Ammonia	ppb	500	*
pH	pH	9.2	*
Conductivity	μ mhos/cm	0.3	≤ 0.1
TDS (excluding ammonia)	ppb	100	25
Suspended solids (crud) **	ppb	50	5

**These values would vary depending on the boiler metallurgy.*
***A sticky coating or an incrustation of filth or refuse*

www.EngineeringBooksPDF.com

CPU Technology: Refer Fig no. II/3.6.6-2

1. **Factor influencing performance of CPU: Discussed in clause nos 4.0.4 of Chapter V .**
2. **Major components associated with CPU are**
   - *a. Operating Vessel/ Service Vessel*
   - *b. Separator /Cat Ion regeneration Vessel*
   - *c. Anion Regeneration Vessel*
   - *d. Mixed bed Resin /Storage tank*
   - *e. Transfer pumps and recovery Vessel*
   - *f. Acid & Caustic handling Tanks/ Measuring tanks, Vacuum pumps.*
   - *g. Effluent Pumps*
   - *h. Instrumentation & controls (discussed in Clause 4.0.4 of Chapter V)*
3. **Basic Principle of Regeneration : Commonly used Mixed bed systems, normally there are three service vessels, two working and other is stand by. Following are the major steps for Regenerations.**
   - ***a.*** **Mixed resins are transported from *Service vessel* to *Separator /Cat Ion regeneration Vessel* in the form slurry with water supplied by *Transfer pumps*.**
   - **b. Empty *Service vessel* is resin from *Mixed bed Resin/storage tank*.**
   - ***c.*** **Mixed bad resin in *Separator /Cat Ion regeneration Vessel* is scrubbed with air & back wash with water to clean and separate resins---- light Anion Resin at the top and heavier Cat ion resin at the bottom.**
   - ***d.*** **With the help of water from the *Transfer pump* Anions are transported hydraulically to *Anion Regeneration Vessel* Before regeneration a portion from the *Separator /Cat Ion regeneration Vessel* is kept for interface tank to ensure that there is no Anion present to improve better performance.**
   - ***e.*** **Cat ion resins are regenerated with dilute acid solution (measured quantity of acid with the help of *Measuring tank* and *Vacuum pump*) piped to *Separator /Cat Ion regeneration Vessel* at the top. Provisions are kept for Sulphation also. *For plants with NH3 Cycle or the condenser tube leakage exists Sulphation shall be done at regular interval.***
   - ***f.*** **Once regeneration is done acid solution is drained and resin is rinsed with DM water**
   - **g. Anion is very similarly regenerated with the help of Caustic solution.**
   - ***h.*** **After regeneration both Cat ion & Anion resins are transported hydraulically to *Mixed bed Resin /Storage tank* as slurry. The resins are mixed by air and rinsed with DM water. Then they are backwashed to separate the ions again to transport to next service vessel. All of Anion and half of Cat ion are transferred and mixed in the service vessel.**
   - **i. Conductivities at stages are checked to ensure proper regeneration.**
   - **j. Vessel details and various inlet /outlet lines have been elaborated in Fig no II/3.6.6-1c**
4. **TRIPOL Process (A registered Trade mark): In this method instead of Mixed bed three layers as shown Fig no. II/3.6.6-1d Lead Cat Ion_Anion, Trail Cat ion. There are separate resin movement lines to avoid cross contaminations. The resin volume can be altered to suit the operating condition.**

FIGURE II/3.6.6-2 CPU technology details.

possibility of the turbine axis becoming out of alignment. If the degree of vacuum drops; for example, to a typical value of 635 mmHg, the vacuum trip device raises an alarm. If it drops further, for example, to 500 mmHg, this device—similar to the emergency device—actuates its three-way valve to stop the flow of feed-oil to the hydraulic system of the safety device and closes the turbine steam valves. The vacuum of the condenser is led to the bellows chamber and converted to motion of a bellows made of phosphor bronze.

This motion is enlarged by the pilot valve and the hydraulic piston, and by disengaging the three-way valve pawl, actuates the three-way valve. This valve can also be actuated by the solenoid or the trip piston of the backup governor. The standard excitation circuit for the solenoid incorporates all electrical stop signals of the breaker for the generator, boiler trouble, protective device against thrust, and so on.

3.7 Turbine Supervisory Instrumentation

Figure II/3.7-1 shows a schematic diagram of the approximate location in and around the TG set. For more details, refer to Figure V/2.0.5-1 in Chapter V. There are important measurements to take and use to get valuable data for safe running, post-trip analysis, archiving, and so on with sophisticated instruments and state-of-the-art technology. These are the main measuring points:

- Eccentricity of the TG shaft near the HP turbine non-driving end
- Thrust position near the thrust bearing

www.EngineeringBooksPDF.com

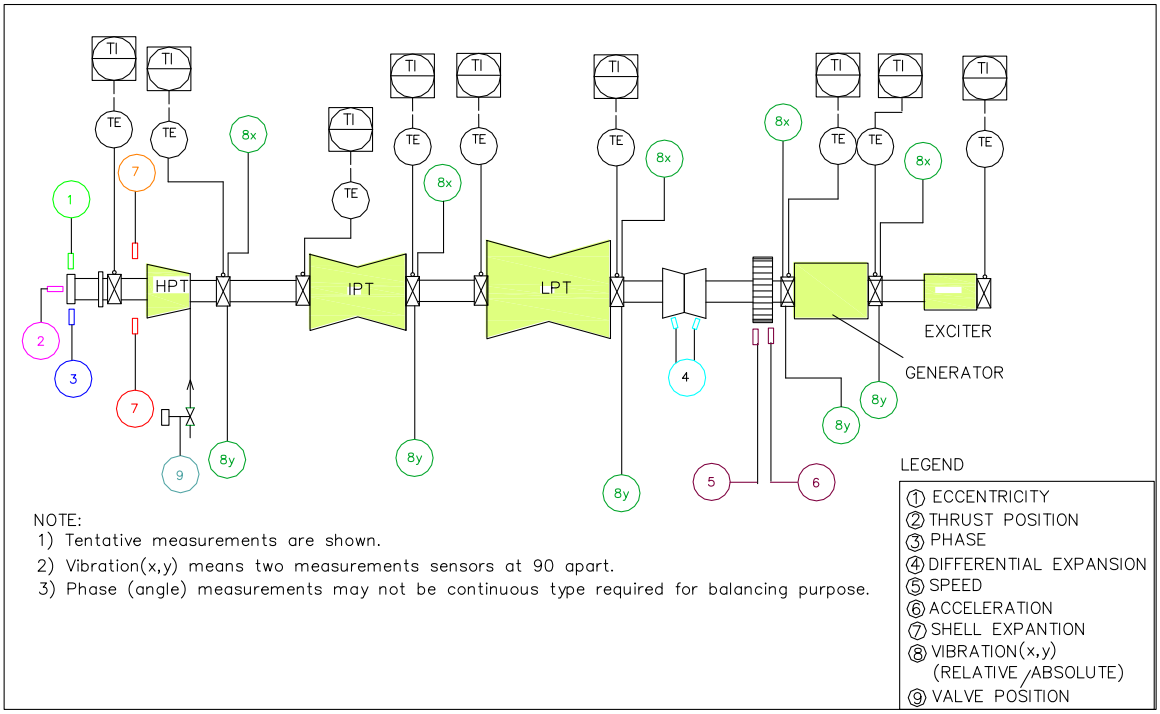


FIGURE II/3.7-1 Turbine supervisory instrumentation.

- Key phasor position near the HP turbine shaft nondriving end
- Differential expansion of the TG shaft with respect to corresponding turbine casing
- Speed and acceleration
- Shell or casing expansion
- Vibration (absolute and relative) at various locations
- Turbine governor valve position
- All the bearing temperatures

The preceding list details the type of instruments. There may be number of similar instruments in different locations for which the instruments list in Clause 2.0 of Chapter V may be referred to. However, actual locations and numbers depend on several factors.

3.7.1 Eccentricity

Eccentricity is the measurement of rotor bow at slow speeds through suitable sensors. The type of sensors deployed to measure eccentricity of the shaft is essentially noncontact pickup ones. They are sometimes popularly called *displacement* or eddy current or even a proximity pickup. Eccentricity may be caused by any or a combination of fixed-mechanical bows (bends), misalignment, temporary thermal bows, or a bow due to gravitational force. It also may be used to calculate shaft attitude angle, which is an indicator of rotor stability.

3.7.2 Thrust Position

Thrust position is the measurement of the axial movement of the rotor with respect to a fixed position when the machine is running under a heavy load. Excessive horizontal movement of the rotor can result in catastrophic damage in mere seconds. It is common to use two or more of the preceding noncontact-type sensors when only one would be used for emergency shutdown or tripping purposes prior to reaching a dangerous level.

3.7.3 Phase or Key Phasor or Phase Angle

Phase, or phase angle, is defined as the angle between the reference point in the shaft and the imbalance is popularly called a *heavy spot* on the rotor. This measurement is a secondary parameter, mainly used for diagnostic and analysis purposes in combination with the vibration data to work out the approximate size and location of the heavy spot and also the critical speed of the machine. The reference point or mark is usually a keyway/notch on the shaft.

The measurements just mentioned are used for establishing the relationship of one vibration signal to another and are expressed in degrees. The once-per-revolution phase reference relates the static coordinate system of the vibration sensor to the rotating coordinate system of the machine. The output signal is generally the measure of shaft speed and is utilized as a reference for measuring the

www.EngineeringBooksPDF.com

vibration phase lag angle. This measurement is a very important tool for diagnosing a machinery problem. It usually is not continuously monitored but is available as a diagnostic aid for vibration analysis and for balancing. In general, it is the indication or warning, suggesting a problem related to shaft cracks, shaft misalignment, or rotor damage/mass loss.

Probing with the noncontact type sensor is typically done to observe a once-per-turn event such as a key or a notch. Phase or phase angle or key phasor measuring is, as already mentioned, a tool to measure the relationship of how one vibration signal relates to another and the resultant signal after the analysis is generally used to calculate the location for placing the balance or counterweight. This parameter is not required to be displayed continuously but is monitored periodically to determine changes in the rotor balance condition, deviations in system stiffness (e.g., a cracked shaft), etc.

The installation requires locating or installing a once-per-turn event, such as a key or notch, that the sensor would detect only one time per revolution of the shaft. The installation of the notch demands special arrangements to cut the notch, but it is convenient for the instrument to view a notch for the installation and adjustment purposes. On the other hand, keys are easier to apply using glues or epoxies but are subject to coming off due to high centrifugal forces.

3.7.4 Measurement of Expansion

As the steam temperature of the thermal power plant varies a lot at different operating points (e.g., startup, running, tripping, and shutdown conditions), the turbine metals in different areas expand in dissimilar ways according to the corresponding steam temperatures. This measurement helps the operator to watch for and to ensure that the measured values are kept within the limits. The unwanted expansion of the turbine casing or rotor shaft may lead to the plant experiencing a disastrous consequence and should trip the machine prior to that limiting condition.

3.7.4.1 Shell or Case Expansion

Case expansion is the relationship of the shell or case to its foundation. The turbine generator sets are tied down at one end and allowed to thermally expand at the other. The LVDT type of sensors, or any other type of position transmitters, are used to measure this thermal growth, which could be of considerable length—in the order of a few centimeters for large machines. In some plants, there are provisions of monitoring thermal expansion of the end position of both sides to ensure that the case expansions take place evenly throughout the length of the machine.

3.7.4.2 Differential Expansion

Differential expansion on a turbine is the relative expansion measurement of the rotor's axial thermal growth with respect to that of the case. Differences in the thermal growth of the rotor to case growth, if it becomes less so as to touch each other, would lead to rubbing and catastrophic failure of the machine and personnel injury as well. The LVDT-type sensors are used to measure this parameter.

3.7.5 Measuring Speed

The previously mentioned type of probe or *magnetic pickup or hall probe* is a sensor for measuring speed. For this measurement, some provisions are made in the turbine shaft (e.g., a key, notch, or toothed gear) so that the sensor can detect revolutions of the shaft. In general, three (3) sensors are provided for two-out-of-three voting and are used for control system, measurement, and plant-tripping purposes. Zero-speed detection for turning gear engagement also can be found using this arrangement.

3.7.6 Measurement of Vibration

Vibration measurement is basically for determining the radial motion of the rotor shaft. The output signal gives all the information about the problem of the rotating machine such as misalignment, cracked shaft, oil whirl, unbalance, or any other dynamic snags. Measuring vibration in a rotating machine provides the most important data for diagnostic purposes. With the limited number of measuring locations due to high cost and minimum availability of space, modern technology has evolved with a proper diagnostician system by several reputed manufacturers to guide the plant management to speedily and accurately assess a machine's condition. Vibration measurement may be provided in a single plane or a two-plane configuration. The latter arrangement envisages the sensors at 90° apart and perpendicular to the shaft cross-section.

3.7.6.1 Relative Vibration of the Shaft

All the bearings provided with the TG unit are basically journal type except for the thrust type. Due to the interaction of various forces with the shaft journal, it can move with respect to the bearing housing. It has been observed that the vibration components of higher frequencies are absorbed/damped considerably through the oil film and may be ignored. The vibration sensors thus are provided to monitor the relative motion between the shaft journal and the bearing housing.

The types of sensors that are deployed to measure the relative vibration of the shaft are essentially noncontact pickup ones. These are sometimes popularly called *displacement* or *eddy current* or even a proximity pickup. This sensor measures not only relative vibration but also relative position of the shaft with respect to the bearing housing to ascertain the clearances between them.

www.EngineeringBooksPDF.com

These sensors measure the dynamic motion (radial vibration) of the rotor shaft relative to the bearing housing. This parameter will detect common machinery problems such as rubs, imbalance, bearing stability, etc. Eddy probes also provide a measurement of the shaft position within the bearing clearance, giving warnings of harmful preloads and misalignments.

3.7.6.2 Absolute Vibration

For machines with a light casing-to-rotor weight ratio, vibration is readily transmitted to the bearing housing. This measurement is also utilized to calculate the absolute vibration of the shaft with the help of the relative vibration of the shaft with respect to bearing housing. An accelerometer or velocity transducer is a cost-effective vibration sensor for these machines.

3.7.7 Turbine-Governing Valve Position

The valve position is measured with an LVDT or any other type of position transmitter that can observe the lift of the governing valve. It is an indicator of approximate turbine load when the TG set is not running in a sliding pressure control mode.

3.7.8 Temperature

The temperature of bearings is a measure of their health in a running condition, determined by sensing how hot a bearing is operating. Several reasons can contribute to overheating of a particular bearing such as partial failure of the lubricating system (e.g., inadequate pressure and/or flow), overloading on the machine, misalignment of the TG shaft, etc. The sensors may be thermocouples or RTDs; however, normally RTDs are preferred for giving better results in a comparatively lower temperature region.

4. GENERATOR

The generator in a thermal power plant is a very significant subsystem driven by the steam turbine and is necessarily synchronous or, in other words, an *alternator* as it is popularly called. It is one of the most important types of electrical equipment and is categorized as the rotating machine that is used for converting mechanical energy into electrical energy or electricity when operated as a generator and vice versa when operated as a motor. In general, they are called a synchronous machine and the name is so given because they operate with a constant speed and are very much synchronized with the frequency of the alternating voltage that appears at the terminals. Synchronous generators are also used in the hydroelectric or hydel plants and gas turbines.

The main generator is based on two major parts: the *rotor*, which is the rotating part, and the *stator*, which is the static part. The rotor is so designed and wire-wound to form a DC magnetic field and made to rotate along the inner periphery of the hollow stator; it is often called a "rotor magnetic field" or "magnetic field" or even just the "field."

When the field is made to rotate by an external agent, the steam turbine, for instance, the magnetic field it produces changes the magnetic field with respect to the static winding in the stator and thus excites them to induce voltages in the stator windings and at the generator output terminals. The DC is required to flow through the field winding to create a constant magnetic field and is much smaller in comparison to the stator winding.

Modern generators are normally either self-excited or with a static excitation system. Figure IX/10.1 shows, in a simplified way, how a self-excited system works when some of the power output from the rotor is used to power the field coils. The static-excitation system (refer to Figure II/4.2-1(c) later in this chapter), on the other hand, envisages generator-produced electric power to excite field residual magnetism (depending on the magnetic material) when the generator is turned off. The same can be achieved with a permanent magnet located on the rotor. When the rotor starts to rotate with no load connected to the generator terminal, the initial weak magnetic field generates a weak voltage in the stator windings. This weak voltage by some means increases the field excitation current and thereby further increases the voltage in the stator windings until the perpetual action enables the generator to develop full terminal voltage. For self-excited generators, it is important to note that the external load is not connected to it during startup because the effect of load current would prevent it from developing of the proper terminal voltage.

The hollow part of the stator is mounted around the rotor with a very small air gap between them. Both the rotor and the stator are made of a ferromagnetic material that is wrapped in a set of coils within the slots distributed throughout their circumference. The stator windings are connected as a three-phase AC voltage system. More details are available in subsequent sections of this chapter and in Clause 10 of Chapter IX.

4.1 Basic Generator Details

There are two significant main subsystems that exist in this type of machine. The rotor (i.e., the rotating part) is also called the field. The other part is the stator, (i.e., the static part) and previously has been called an armature.

4.1.1 Rotor (Field)

This part of the machine is rotates freely (driven by a prime mover) and produces the magnetic field either by a permanent magnet or by a direct current flowing through a coil fixed onto it; this is called *field winding*. The coil is wrapped over a pair or multiple pairs of magnetic cores

www.EngineeringBooksPDF.com

made of ferromagnetic material that acts as magnetic pair of poles producing an electromagnetic field around them when unidirectional current flows. They are so designed to create a constant magnetic field and to interact with the magnetic field produced by the stator winding itself when current flows through it.

The DC flowing through the field winding is much smaller compared to the stator winding. The number of pole pairs may be one or more (up to three pairs) but all the coils must be connected in a series so that the pole strength of each of the electromagnetic poles are necessarily the same. There are two kinds of rotors:

1. Salient pole rotors, which are mainly used for slow-speed machines (e.g., hydraulic turbogenerators)
2. Smooth cylindrical rotors used for GTs and SGTs

The primary function of the field (rotor) is to produce the magnetic field, rotating with a high speed, to excite the machine to induce voltages in the stator windings and ultimately at the output terminals of the stator.

4.1.1.1 Field Flashing

Field flashing of the rotor is often performed when there is a lack of adequate residual magnetism to enable the machine to develop full voltage. This system envisages injection of direct current into the rotor from a separate source for a very short period of time. Due to this fact (i.e., short duration of initial field current), the name *field flashing* is popularly used. The DC source may be fed directly from the station battery or from the suitable AC/DC converter taking its connection from an AC source. On many occasions, small alternators also may need field flashing for initial starting.

4.1.2 Stator (Armature)

A stator, as is evident from the very name, is the static or fixed part of the machine that is mounted around the rotor. The stator is also made of a ferromagnetic material wrapped in a set of coils within the slots distributed throughout the circumference. Stator windings are connected to a three-phase AC voltage system. The winding of the stator is by a star (or wye/Y) connected for the following reasons:

- Star-phase voltage = 58% $(1/\sqrt{3})$ of line voltage. Naturally, the insulation thickness would be less than that required for line voltage; thus, comparatively more space is available for a larger conductor size to carry more current than what is required; the line current required is $\sqrt{3}(1.732)$ times more compared to a Δ-connected stator—thus more power.
- In a star connection, a distorting line to neutral harmonics does not appear because they cancel each other. The neutral point is always connected to a ground with the lowest possible neutral-to-ground line resistance.

It is worth mentioning that efficiency increases with the power rating of the generator; for example, the efficiency for a 10 MW may be ~90%, whereas for a 100 MW, it must be more.

4.1.3 Working Principles

For the generator, mechanical energy is converted into electrical energy. The turbine, be it steam or gas or hydel, supplies the mechanical energy by way of applying torque and thus subsequent rotation of the shaft. Due to the relative motion between the magnetic field produced by the rotor-mounted poles that are duly magnetized, the intensity of the magnetic field passing through the stator windings would change as a function of time. Therefore when the rotor field is energized, electromotive force (EMF) is induced in the generator stator; this is proportional to the rotor speed and rotor field current and is capable of supplying electrical output to the external load. The frequency of this voltage would also be proportional to the rotor speed.

The moment the generator output terminal is connected to the supply bus or, in other words, to the grid, the rotor would be locked to synchronous torque of the network system and its speed would be governed solely by the frequency of the grid. The speed would now be the synchronous speed and, as the frequency of the generator voltage depends directly on the speed of the machine, both the grid and generator voltage frequencies are exactly the same.

The stator coils are distributed throughout the circumference in such a manner that three separate bunches of coils are formed in various combinations (i.e., series, parallel, or both) and termed *three-phase*. The arrangement is made in the way that the three phases of the stator windings are 120 degrees apart electrically and thus the EMF induced obviously would be an alternating three-phase voltage with sinewave characteristics.

The field on the rotor is often called an *exciter* and the DC current through the same is thus called an *excitation current*. It must be borne in mind that the function of the field excitation is only to produce a magnetic field to excite the machine so that the required voltages are induced at the generator output terminals of the stator windings. The actual power handled by the stator is huge compared to that of the rotor. It is also worthwhile to note that in the case of the generator operating as an island concept (i.e., in isolation from the grid or the electrical network system), the field excitation current would be responsible for the generated voltage. However, when the generator is connected to the grid with a number of other generators, forming an infinite bus, the excitement of the field excitation current would control the reactive power generated due to the action of increased armature reactions and so on.

www.EngineeringBooksPDF.com

Generators are designed to produce a moderately high voltage that is a compromise between the high insulation provision and handling of high electric current. For generators up to 50 MVA, the voltage is 6.6 kV; larger-size generators that are above 1000 MW may have voltages up to 32 kV.

4.1.4 Cooling of the Stator and Rotor

Generators or alternators are supposed to deliver electric power at a certain output voltage and current. For a large thermal power station, those values may be very high especially the current, which is reduced afterward by the use of a generator transformer by raising the output voltage, thereby reducing the current flowing through the grid. Therefore the generator windings should be capable of sourcing high-density currents that in turn are responsible for producing enormous heating effects. To overcome/reduce this undesirable heating, the stator windings are made of hollow copper conductors through which the cooling water circulates in a loop, comprising the cooling circuit with redundant coolers.

With this cooling water, the problem often experienced is the formation of scale deposits on the internal walls of the hollow conductors. This deposits decrease water flow as well as heat transfer, both of which are detrimental as far as cooling of the generator stator is concerned; the result is reductions in load delivery capacity and frequent downtime. To get minimum scale deposition, maximum heat transfer and the lowest possible electrical conductivity of the cooling water, a small portion of the normal stator cooling water flow ($\sim$1–10%) is bypassed for rejuvenation through a mixed bed demineralization plant and returned to the original stream.

Another way, as a last resort, to solve this problem is to take the opportunity of the station shutdown and do a chemical cleaning of the hollow conductors using a suitable scale-removing solution. However, the cleaning operations are long-standing process resulting in outage of the machine vis-à-vis revenue loss as well as corrosion of metals that make up the hollow conductors.

The rotor is also subjected to carrying high field excitation current and heat generated due to high centrifugal force. For that reason, pressurized hydrogen is introduced into the generator housing; this enables cooling of both the stator core and rotor elements. It is taken out at a suitable point for reentry after heat release by an external cooling arrangement.

4.1.5 Hydrogen Cooling Including a Seal Oil System

In the early days, electric generators were air-cooled. To cope up with the huge power demand, the size of the generators or the alternators or the machines, as they may be called, started to become increasingly large. Because the bigger machines generate more heat from various sources (e.g., stator windings, rotor windings, windage, and stator core iron), they require more cooling, so the use of air became obsolete as a cooling medium due to its limited capability of dissipating the huge amount of wasted heat. For larger machines, windage losses increased along with more noise generation, and it became very difficult for the cooling system to use air to remove all the heat created by the losses.

In searching for a good cooling medium, helium was considered as a substitute for air but its specific heat can improve the cooling only five times better than air. In addition, helium is not a readily available element, and its cost is too high for cost-effective use. As a further quest to get a better cooling medium, hydrogen was selected in spite of its disadvantages.

Nowadays hydrogen-cooled generators are used at almost all the large power plants. Hydrogen as a coolant has the following qualities, which puts it ahead of other coolants:

- High relative specific heat, which is approximately 14 to 16 times better than air as far as its cooling effect is concerned. This property enables it to absorb a large amount of heat compared to other fluids.
- Hydrogen has a density of 1/14 that of air at the same temperature and pressure, thereby reducing windage losses and noise because hydrogen has the lowest molecular weight. Due to the very high rotational speed of the rotor, the friction (also known as drag) loss, an example of aerodynamic resistance, becomes predominant which is the energy loss specifically termed windage loss. This loss is directly proportional to the velocity square and density of the atmosphere of the rotating mass.
- Highest thermal conductivity of all gases, which means it conducts the absorbed heat efficiently and transfers it more quickly. The outcome is that it behaves as an ideal coolant extracting the heat generated almost 7 to 10 times better than what air can do at the best of times.
- Higher electrical insulation characteristic than air when pressurized.
- Negative oxidizing agent.
- Offers better measurement/detection facility with the use of hydrogen sensors.

Considering these points, it is obvious that a generator with a hydrogen-cooling system would overwhelmingly reduce heat and be much more cost effective compared to its predecessor (i.e, a machine with an air-cooled system).

Against all these plus points, hydrogen has the biggest disadvantage that poses a problem (i.e., fire hazards), which is not applicable to air or helium; it has a wide

www.EngineeringBooksPDF.com

flammability range. However, to the relief of design engineers, it has been experimentally proven that hydrogen does not support combustion when its purity in air is >85% or <3%. With proper handling of hydrogen if its purity can be assured and maintained at a very high level (a low range is not applicable), fire hazards can almost be eliminated; this means that there should be little or no air in the generator casing that could mix with the hydrogen. In that situation, the possibility of an explosion is remote even if there was a spark. Figure IX/9-3 may be referred to understand the need to ensure the purity of hydrogen.

The system for maintaining hydrogen purity in the running generator casing is very important; arrest a leak before it happens and prevent either air or hydrogen from mixing with each other. Care is also necessary to be sure that air does not contaminate the high-purity hydrogen used to fill the generator casing after displacing the air. To facilitate that, carbon dioxide (CO_2) gas is used as an intermediate medium for filling/displacing as much of the air as possible from inside the generator casing before and after running the turbine or whenever it is felt necessary.

4.1.5.1 The Hydrogen System

Presently, most large generators are cooled with hydrogen gas. Almost pure hydrogen, in the range of 99%, is supplied to the generator with a pressure of ~2 to 3 kg/cm^2 g (maybe up to 4 kg/cm^2 g) to prevent air leakage into the generator casing. The hydrogen is circulated within the generator by fans mounted on each end of the rotor. While it is circulating around the generator, there are redundant water coolers and the hydrogen gas is forced to pass through them. After being heated by the generator components, the hydrogen gets cooled down. The heat absorbed by the hydrogen gas is transferred to the water circulating through the cooler. The cold hydrogen at the outlet of the coolers is returned back to the generator casing forming a closed cycle.

A control-loop system is provided to maintain the hydrogen's temperature at the generator inlet. These coolers or heat exchangers for hydrogen cooling normally are mounted on the side or top of the generator frame. Many plants have their own hydrogen-generation system along with a provision for using gas cylinders purchased from external source in case of an emergency or shutdown of the plant's hydrogen-generation system.

The hydrogen, because it is at a higher pressure, still tends to leak into the hydrogen side of the seal (discussed later) where, from the return seal, oil is collected and sent back to the seal oil reservoir. A small amount of hydrogen gas (and also air coming from seal oil) is continuously vented to the atmosphere for purging/scavenging and thus the pressure inside the generator decreases if there is no replenishment. The fact is, however, that most of the H_2 loss results from the leaks out of the generator casing, which causes the pressure to decrease.

To circumvent that situation, a pressure controller may be provided to maintain the pressure by allowing a small amount of high-purity hydrogen gas into the generator casing through a control valve as a continuous feed system. In some plants, manual operation is also done using a batch-feeding system.

A hydrogen purity monitor is provided to detect the condition of purity during operation. This is more necessary in view of the seal oil-borne air if liberated (detailed later) within the generator casing and thus contaminating the purity of hydrogen. It is preferable to monitor the hydrogen's purity at strategic, multiple locations in the generator to ensure that the purity is maintained to prevent a possible explosion or fire.

In case the hydrogen purity drops below a certain level, typically ~85 to 90% or so as recommended by the prevailing standard or manufacturers, then the TG set may be tripped. When putting hydrogen in the generator for the first time or after a long shutdown, the air is first completely replaced with CO_2 and then charged with hydrogen to replace the CO_2 to the desired purity value. Doing this vice versa is recommended when a long shutdown is envisaged; a generator is purged with CO_2 using it as the medium for purging to avoid mixing of air and hydrogen.

Being a heavy gas, CO_2 entry and exit is made at the bottom of generator while that of H_2 is made at the top. The hydrogen purity monitors are usually capable of measuring the purity of the gas at the top of enlargement tanks where from the air/H_2 mixture is vented through the scavenging system. Purity-sensing points are also set to monitor the purity inside the generator casing along with the top part of the enlargement tank.

4.1.5.2 Moisture in a Hydrogen-Cooling System

In its delivered form, whether from an external or internal source, hydrogen gas has a dew point of around −50°C. Normally, the dew point is maintained at <0°C for this type of requirement. Problems may crop up when the generator is in a shutdown condition and hydrogen moisture levels increase beyond this point. The water particles deposit and cause the retaining rings to crack when there is moisture on them. There are some generators that are cooled by hydrogen with dew points of −30°C or lower.

4.1.6 The Seal Oil System

Hydrogen, because it is hazardous if it leaks and mixes with air, there may be a possibility of an explosion. Therefore an idea for preventing leakage along the rotor shaft was

www.EngineeringBooksPDF.com

developed; the method uses a sealing system with the help of oil under a pressure that is slightly more than the hydrogen's pressure. This differential pressure is maintained by dedicated a control loop that is discussed in detail in Clause 9 of Chapter IX. It normally receives makeup oil from the bearing LO system. The seal oil system defines the arrangement provided to arrest not only the escape of hydrogen from the generator casing but also the ingress of air into said casing near the rotor shaft that projects outside of the casing at both ends.

The generator–rotor ends, where the air is supposed to make ingress, are sealed to keep the hydrogen inside the generator. Special seals on both of the shaft ends ensure adequate sealing against axial flow of gas toward the air side. Oil is used as the sealing medium to ensure tight sealing and is injected on the shaft around its entire circumference through the channels and orifices inside the seals. Because the sealing oil is at a higher pressure than the hydrogen inside the generator casing, a portion of the oil flows along the shaft to the air side the generator and some of the oil flows along the shaft into the hydrogen side of the generator. The oil used as the seal oil is generally the same lube oil as that used for the bearings although in some plants, the seal oil system is separate from the LO system.

The oil is supposed to be in contact with air while being transferred from the lube oil tank and also passes through the bearing drains. This air makes froths or small bubbles and somehow can be entrained in the oil. When oil is injected onto the generator shaft, from which air could be liberated, the oil flows into the hydrogen side of the seal area. The unwanted air must be removed otherwise there is every possibility that it could somehow continue to collect inside the generator casing, thus contaminating the hydrogen's purity.

A system provided to remove air from the seal oil into the hydrogen side of the generator seal is popularly called a *scavenging/purging* system. The seal oil that flows into the hydrogen side of the seal area is generally passed to a vessel known as an *enlargement tank*. It is expected that the entrained air liberated from the seal oil, along with a small amount of hydrogen that leaked through the labyrinth seal, accumulates there. As already stated in Clause 4.1.5.1, this small amount of gas (hydrogen and air) is permitted to escape from the seal oil enlargement tank through a vent. It is important that the vent line is long enough so that the discharge of the mixture is made to a safe area around the plant away from any ignition source.

If the seal oil flow rate increases, then the entrained air liberated from the seal oil will also increase and, that being the primary source of contamination, it would result in decreased purity. So, it is very important to keep provide for and monitor of seal oil flow rates to detect an increase for alarm and trip generation. In case there is only one common seal oil flow meter for both generator seals, it may not be possible to detect the defective seal, allowing more oil to flow resulting in liberation of more air. However, a hydrogen purity meter in each enlargement tank would, in that case, indicate any problems with a decreased purity percentage. A more detailed discussion can be found in Clause 8 of Chapter IX.

4.2 Types of Generator Excitation with Advantages and Disadvantages

As discussed earlier, the generator requires a direct current to have its magnetic field energized. The DC field current is arranged from a separate source called the field exciter (Figures II/4.2-1 and IX/10.1). Generally, three types of excitation systems are used:

1. Direct current
2. Rotating type (refer to Figures II/4.2-1(a,b))
3. Static type (refer to Figure II/4.2-1(c))

4.2.1 Direct Current Excitation System

In this type of DC excitation system, mainly used during the earlier stages, the DC generator armature is mounted around the same shaft of the main generator whereas the field is formed by a permanent magnet mounted rigidly on the rotor shaft. The DC voltage as generated is fed to the field-excitation terminals with a proper control arrangement.

4.2.2 Rotating-Type Excitation System

This type of system is again categorized into two types: brush and brushless. The most important difference between them is the technique used for transmitting the DC field-excitation current to generate the magnetic fields. The brush-type excitation system can be mounted on the same shaft as the AC generator armature or can be housed separate from, but adjacent to, the generator. When it is housed separately, the excitation system is rotated by the AC generator through a drive belt.

The distinguishing feature of the brush-type excitation is that static brushes are used to transmit the DC excitation current to the rotating generator field. The current transmission is accomplished via rotating slip rings that are in contact with the spring-loaded brush for pressing against the slip ring for assured contact. Two slip rings are solidly mounted on the generator shaft and both of them are fully insulated from the shaft and each other. Of the two rings, one is meant as positive terminal for the field winding and the other is for the negative terminal. For a brushless-excitation system, Clause 10 of Chapter IX and the associated drawings in Figures IX/10-1 and II/4.2-1(b) may be referred to for details.

www.EngineeringBooksPDF.com

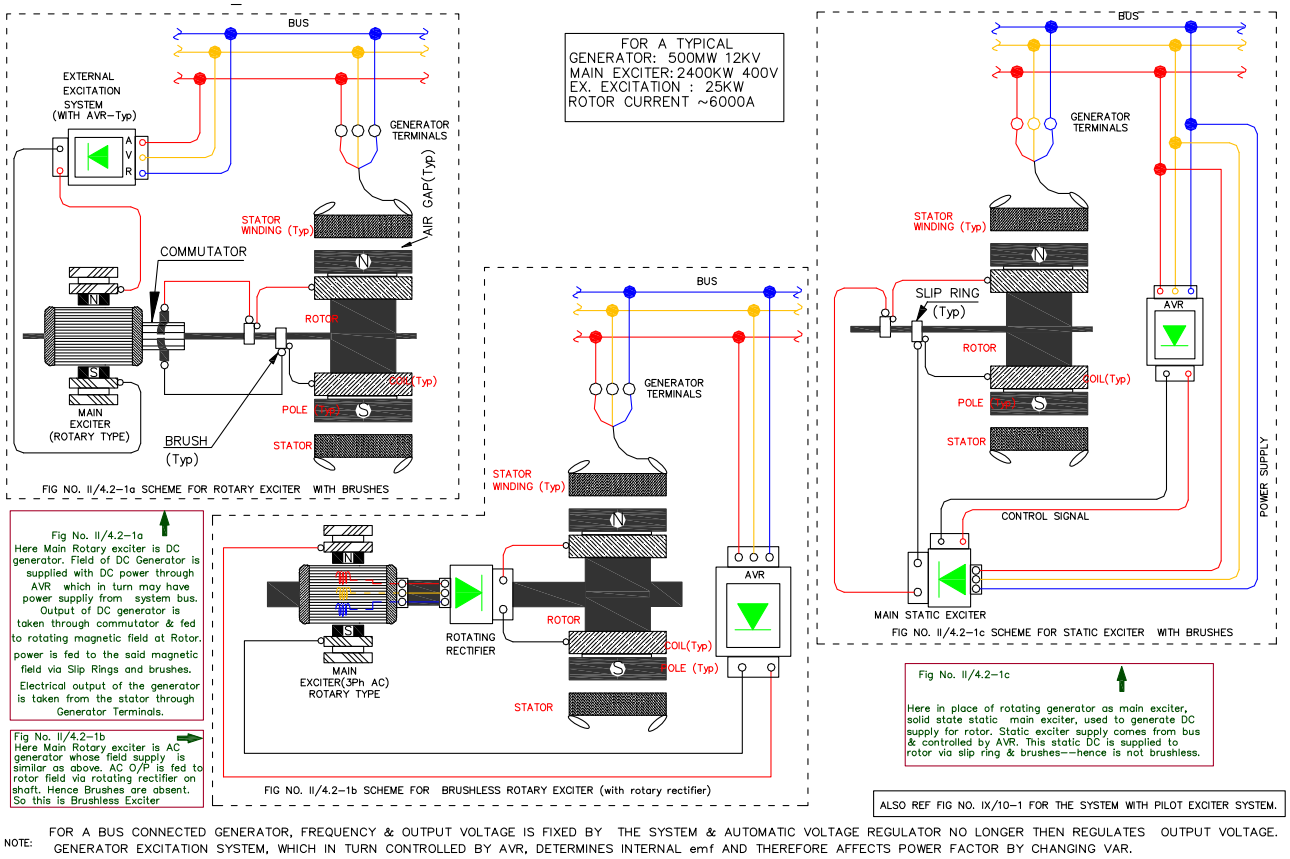


FIGURE II/4.2-1 Schematic diagram of different excitation systems.

4.2.3 Static-Type Excitation System

The static-type excitation system (see Figure II/4.2-1(b)) for generating the magnetic fields involves various options. The types may be classified as per the source of the excitation power taken from the AC voltage of the following:

- Main generator winding, also called a self-excitation
- Auxiliary winding provided with the main generator winding, another type of self excitation
- Station auxiliary system,also called a separate excitation

This system contains no moving parts. Here, the generator output is taken through a suitable transformer and controlled power converters, including thyristors rectifiers, reactors, etc., to convert AC voltage to DC voltage that is then supplied to the field windings through a brush/slip-ring assembly.

At the start, the residual magnetic field of the rotor may be used for startup but due to the strong magnetic field around the high-voltage stator, this natural property may disappear or may be weak; in that case, an external source of DC supply is necessary for initial excitation of the field windings. The initial excitation may be obtained from a station or any other storage batteries. This action is achieved by what is called a *field flushing* system, where DC voltage is taken from either station (or separate) batteries or from a system comprised of solid-state components or from a DC generator with a separate excitation/self-excitation system.

4.2.4 Generator Field Excitation

4.2.4.1 Advantages and Disadvantages of Brush and Brushless Excitation

Synchronous generators (or motors) of small capacity still use brush/slip-ring type electrical sliding contacts for rotor-mounted field excitation connections, as generally was used in the early phases of the invention of electrical machines. The brush/slip-ring type connections are currently not used for large- and medium-sized machines for various reasons; this can be easily understood from the following:

- Unsuitability of use in an explosive or hazardous environment due to formation of an electrical spark when making and breaking contact
- Failure of electrical contact may occur due to contamination caused by dust mixed with oil, grease, or any other sticky material
- Maintenance is very often required due to continuous wear and tear and because of increased downtime and cost of replacement

www.EngineeringBooksPDF.com

4.2.4.2 Advantages and Disadvantages of Permanent Magnets

Normally, high performance, permanent magnets are used for synchronous generators (or motors). They are made of magnetic materials, such as derivatives of neodymium and samarium–cobalt, etc., which offer various characteristics (e.g., high coercivity).

4.2.4.2.1 Advantages The following are the advantages of permanent magnets:

- Do not require an additional DC supply for the field-excitation circuit
- Stable and secure during normal operation
- Higher power efficiency is available:
  - Generally, the brushless field-excitation system (refer Figure IX/10-1) uses the service of a permanent magnet, making it simpler and maintenance free
  - Suitable choice of high-performance permanent magnet materials
  - Air-gap may be designed to a comparatively higher value. Its depth tolerance may improve to ~20% over other types and then the magnetic leakage becomes predominant
  - This facility offers less constraints associated with expansion of generator casings and structures

4.2.4.2.2 Disadvantages The following are the disadvantages of permanent magnets:

- High-performance materials are expensive and sources are limited
- Flux density is limited in spite of quality (e.g., high coercivity). Also are subjected to the influence of higher flux density than what is produced by the torque current magnetomotive force (MMF) and combines as vector quantity. This resultant flux density undesirably magnetizes the permanent magnet which may lead to a higher air-gap flux density and result in magnetic core saturation constraints
- Air-gap flux density is uncontrolled and may cause overvoltage and poor control reliability
- Fields always exist and may pose safety issues (e.g., electrocution) while undertaking construction, assembling, or maintenance job
- Use of them is seem as not environmentally friendly

5. BOILER FEED PUMP AND CONDENSATE EXTRACTION PUMP WITH ASSOCIATED MEASUREMENTS

Modern large thermal power plants have more or less five (5) fundamental elements, as shown earlier in Figure I/2-1, and boiler feed pump (BFP) may be considered to be the same as the heart in the human body. BFPs and CEPs are actually doing the same function in a combined way. The condensate extraction pump is used to do the initial part that draws the condensate under vacuum from the condenser hot well with some positive pressure at the discharge. This water, after passing through several heaters and deaerators, reaches the suction of the BFP that is used to pump water at a very high pressure. It sends the water to the boiler after it passes through a number of HP heaters (Figure II/5.1).

Centrifugal pumps are normally employed for both these services. It is a rotary machine with a set of impellers fixed on the rotating shaft to propel the flow of the fluid by the addition of mechanical energy. The fluid enters the pump impeller along or near the rotating axis and is pushed by the impeller. At the outlet, the fluid comes out flowing radially (i.e., at right angle to the axis of the inlet flow) from where it exits into the downstream piping network.

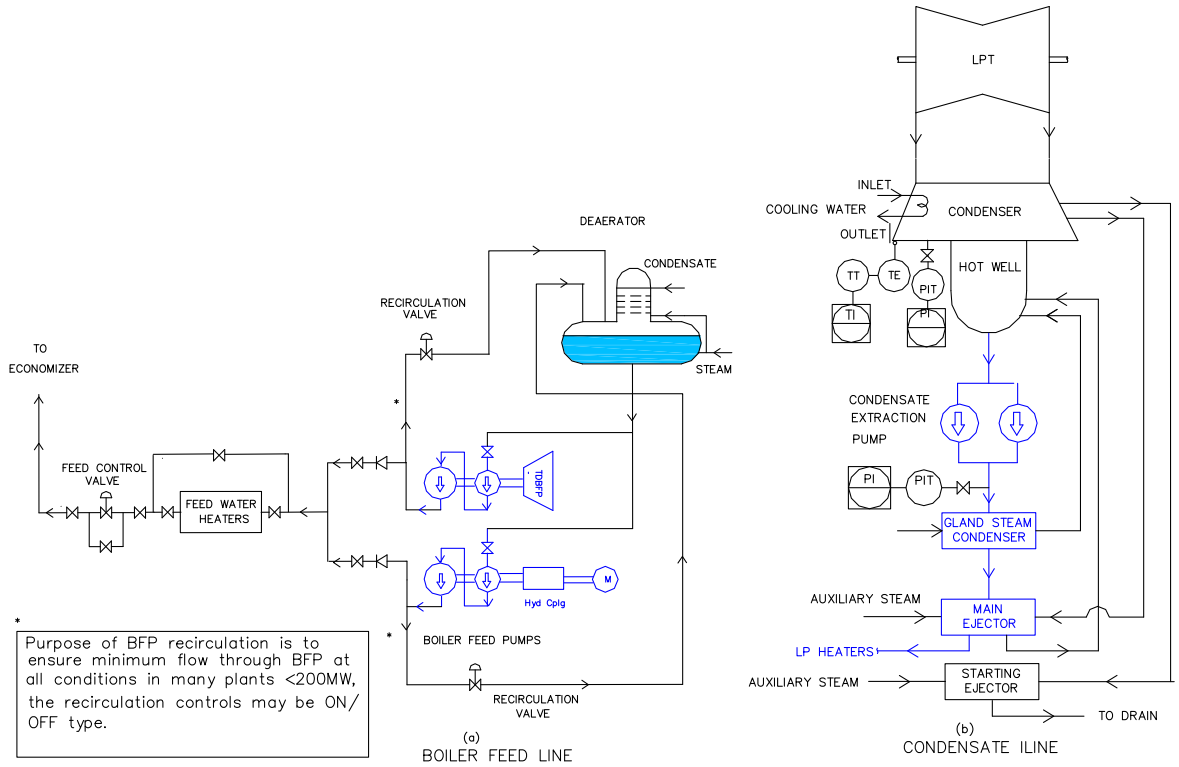
As far as construction of a centrifugal pump, there are three (3) basic components: impeller, diffuser, and volute chamber or casing. A multistage centrifugal pump consists of more than one set of impellers. During centrifugal operation, the pump suction zone of the impeller experiences a negative pressure that enables the fluid to enter the pump at the inlet flange. The fluid, thus, rushes to enter the first, or LP stage, impeller from the suction line. The water gains some positive pressure after coming out of the first-stage impeller and then is guided through the diffuser. Here, vanes are strategically arranged to force the water toward the second-stage impeller. The passage of this stage determines the capacity of the pump. The diameter of the stages is related to the centrifugal force and its relevant stage pressure.

Similarly, in the second-stage impeller, the water becomes more pressurized and enters the next stage. After the final stage, it enters the volute chamber/casing with a design that is arranged to remove the water through an outlet at the appropriate pressure for the system. The impellers can be mounted on the same shaft or on different shafts. If a higher pressure is needed at the outlet, the impellers are connected in series, whereas for higher flow, the impellers are connected in parallel.

5.1 Boiler Feed Pumps

The function of BFPs is to provide water to the boiler. Boiler feedwater pumps are vital components of a power plant because their failure causes unavailability of them in many cases. BFPs are subject to various types of operation such as running at low load during startup, normal coast-down transient, immediate shutdown during plant-trip condition, frequent load transients during normal load operation, etc. It is imperative that designers take care of the BFPs' safe passage while passing through their critical speeds during every occasion. Boiler feed pumps not only supply the feedwater to the boiler but also control it if provided with a variable-speed setting arrangement. BFPs

www.EngineeringBooksPDF.com



NOTE:
** IN CASE OF SUPERCRITICAL BOILERS & LARGE MW SUBCRITICAL BOILERS (WITH DIRECT CONTROL OF BFP SPEED FROM DRUM LEVEL CONTROL) CONTROL) FEED CONTROL STN WILL CONSIST OF LO LOW FEED CONTROL VALVE(30%) & bYPASS VALVE FOR FULL OPEN CONDITION.

FIGURE II/5.1 Boiler feed pump and condensate extraction pump with feedwater and condensate line.

in fact can be used to deliver the desired flow at an appropriate pressure by adjusting the speed through various methods.

5.1.1 Selection Criteria for Boiler Feed Pumps

The following list summaries the criteria to use when selecting BFPs:

Flow of the feedwater: Feedwater flow is one of the most important parameters along with discharge pressure. It is dependent on the rate of the boiler outlet steam flow with some capacity margin as per standards. Normally, the cushion is ∼30% over the maximum flow requirement of the steam generator.

Discharge pressure of the feedwater: Refer to Figure II/5.2 to see that feedwater discharge pressure is another important parameter as stated previously. The BFP discharge pressure is obviously dictated by the boiler outlet steam pressure and friction losses in the pipelines. If the flow control is accomplished by a set of control valves in the discharge line, the pressure would have to be increased by another ∼5 to 10 kg/cm^2 toward the drop across said valve. There are a set of discharge pressures versus flow characteristic curves for every speed as it moves up and down—that is, when speed rises and falls, respectively. The desired operating point can be selected by the correct selection of speed. There is another characteristic curve provided by manufacturers that indicates the minimum discharge pressure in every curve (i.e., for a particular speed) beyond which flow speed should not be increased for the pump's safety.

Temperature of the feedwater: Feedwater temperature is an important parameter for the selection of BFP. Pumps are usually available with temperatures ranges of ∼110°C to 130°C. An external water-cooling facility is provided so that pumps can handle higher temperatures.

Net positive suction head required for the feedwater pump: This parameter is required for protection of the pump. This is the minimum absolute pressure needed at the suction point or inlet of the pump above which it can operate safely. It must be ensured that the available suction head's pressure be greater than the Net Positive Suction Head (NPSH) required to avoid cavitation inside the pump. The deaerator in one way assists the suction head to rise because its feed-storage tank is

www.EngineeringBooksPDF.com

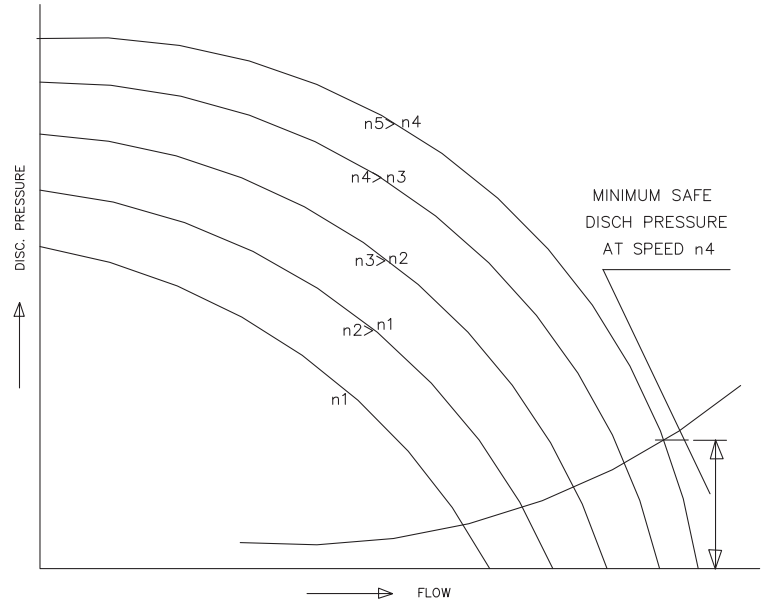


FIGURE II/5.2 Boiler feed pump: Discharge pressure versus flow characteristics curves.

normally located at an elevation of ~20 to 30 meters and is connected directly to the BFP suction; the water level in the feed-storage tank always adds to the pump's safety margin.

5.1.2 Types of Boiler Feed Pumps

Multistage centrifugal-type boiler feedwater pumps are mainly used in steam power plants. This type of pump is available in two broad classifications: equidirectional impellers and opposite-directional impellers. There are several advantages and disadvantages associated with them of which the most important points are efficiency and thrust balancing.

5.1.2.1 Boiler Feed Pumps with Equidirectional Impellers

Impellers, in this design, are set in the same direction throughout the barrel of the pump. This pump is compact and simple with more efficiency compared to other types of pumps. Here, the fluid coming out of each impeller at the outlet is passed through diffuser vanes and then to the inlet of the subsequent impeller. BFPs with this arrangement have a very high axial thrust because the individual axial thrust of each impeller is added as they are unidirectional.

To overcome this problem, a balancing drum, also called a *balance chamber* is provided to balance the axial thrust to reduce the stress exerted on the thrust bearing. It is evident that the balancing drum, in this case, is subjected to a total differential pressure due to all its stages. The drum diameter and clearance must to be greater because the higher axial thrust needs to be balanced. All these factors are responsible for a balance chamber (balancing drum) leak-off flow to be greater than with the other type. The leak-off flow certainly needs to be increased over time because all the clearances begin to increase due to wear and tear of seals and rings. This leak-off flow does not contribute to any energy conversion and therefore efficiency would be reduced.

5.1.2.2 Boiler Feed Pumps with Opposite-Directional Impellers

This design envisages impellers to be divided into two halves that are set in the opposite direction. The outlet of the first group of stages is connected to the inlet of the next group of stages, which lies at the opposite location of the pump through two crossover waterways. The number of impellers in each group of stages is just half of the total number of impellers, or maybe not even as many. For odd numbers of impellers, the first group consists of half of the total number, minus one. Whatever the case, there would be some pressure drop due to this flow crossover arrangement and the system comes down to reduced efficiency. In contrast with the other type of pump design, here axial thrust on the pumps is always well balanced. For obvious

www.EngineeringBooksPDF.com

reasons, the sizing of the balance chamber (balancing drum) is less critical.

5.1.3 Boiler Feed Pumps with Associated Measurements

The following typical and minimum measurements are very important ones that are associated with BFPs:

- Suction pressure
- Differential pressure across BFP suction strainer
- Feedwater flow
- Discharge pressure
- Discharge temperature
- Feedwater flow for all the desuperheaters
- Feedwater temperature after each HP heater
- Feedwater pressure after each HP heater
- Feedwater temperature before economizer inlet

For large boiler feed pumps, some of the recommended integral instrumentation include the following, as a minimum:

- Shaft vibration (both ends)
- Bearing housing vibration (both ends)
- Bearing temperature (at all bearings)
- Axial rotor position
- Balanced water flow

Figure III/6.2-2 may be referred to for easy representation of the system and the purpose of measurements.

5.2 Condensate Extraction Pumps

The CEP is an important component of the total feed cycle as shown earlier in Figure II/5.1. By drawing condensate water from the hot well of the condenser under a vacuum, it delivers condensate water to the next phase of the feed cycle. It acts as a booster pump for the BFP by providing adequate pressure that is also used to overcome the pressure drops across various LP heaters and pipelines up to the BFP suction.

As the condenser hot well is directly connected to the suction flange of the CEP, it is customary for a portion of the pump's delivery to be recirculated to ensure the minimum suction head by way of controlling the condenser hot well level, especially during low-load operation. This is done in such a way that minimum flow through the GSC is also ensured. There are also variations in system design, especially in larger plants where the CEP and GSC recirculation loop is independent of hot well level, which therefore would be regulated independently by makeup and dump valves. A special design is adopted for CEP shaft and other mechanical parts, enabling the volute chamber to hang in the sump and the bearings outside it.

The condensate available from the CEP discharge header is utilized to supply the following major services; this is done by tapping off from the main line before it is connected to the GSC/air ejector:

- Turbine exhaust hood spray
- Gland-sealing system desuperheating

5.2.1 Selection Criteria for Condensate Extraction Pumps

The selection criteria are the same as for the boiler feed pumps, as described in Clause 5.1.1 of this chapter.

5.2.2 Types of Condensate Extraction Pumps

A CEP, as per the general layout of the power plant condenser hot well, is usually a multistage centrifugal pump having a vertical shaft—*vertical centrifugal pump*. They are also referred to as cantilever pumps. The number of stages depends on the pump's discharge pressure vis-à-vis process requirements. These types of pumps are used for the process requiring a high-flow capacity and pressure at the pump's delivery point. The advantage of handling a high-flow capacity is that the pump is able operate with a specific minimum suction head.

CEP types, in general, vary in the shape of the housing of the impellers/diffusers. The options are, although they function basically are the same: bowl type and canister type. Each bowl or canister contains a set of horizontal impellers around its inside periphery and diffuser with integrated guide vanes that direct the fluid to reach inlet of the next stage bowl or canister located just above the previous one. These vertical arrays of bowls or canisters determine the number of stages arranged in the pump barrel.

The CEPs may be categorized by the number of suction facilities: single-suction impeller and double-suction impeller. For a double-suction impeller, the suction head requirement vis-à-vis the safety factor improves.

5.2.3 Condensate Extraction Pumps with Associated Measurements

Typical and minimum measurements are very important; the following are associated with a CEP:

- Condenser hot well level
- Differential pressure across CEP suction strainer
- Discharge pressure
- Discharge temperature
- Discharge flow
- GSC outlet temperature

Figure III/7.2-1 may be referred to see a representation of the system and the purpose of the measurements.

www.EngineeringBooksPDF.com

6. DEAERATORS AND HEATERS

The deaerator is vital equipment in modern, large thermal power plants. From its name it is implied that the primary function is to remove the air, with other objectionable gas ingress, from the main working fluid used by the system.

Feed cycle heaters are popularly called *regenerative feed heaters*. The concept of providing feed heaters comes from increasing the thermal efficiency of the Rankine cycle on which steam power plants operate, thereby saving fuel and lowering air pollution from flue gas emissions. The plain and simple thought behind putting feed heaters in the cycle is to increase the average temperature of the working medium during the process of heat addition and bringing down the fluid temperature while the process is on heat rejection.

6.1 Deaerators

Although a deaerator is primarily used for deaeration (i.e., removal of gases from the condensate water), it functions as a heater located in between LP and HP heaters in the feedwater cycle and storage unit of feedwater; it also ensures the required NPSH for BFPs.

6.1.1 Reason for Deaeration

It has been shown that the presence of contaminants, such as dissolved oxygen, carbon dioxide and other non-condensible gases, in feedwater supplied to the boiler are the main "wrongdoers" affecting the equipment and pipe work metals directly through corrosion. For example, oxygen is the prime element accused for corrosion attack in hot well tanks; feedwater pipelines; BFPs; and, of course, boiler metals. Moreover, the presence of dissolved oxygen is the root cause for rapid localized corrosion in boiler tubes. This is aggravated by the low pH in the working fluid, which means acidic behavior of water resulting from the presence of contaminants such as carbon dioxide.

Carbon dioxide dissolves in water and produce corrosive carbonic acid that is detrimental to boiler metals, causing acid attack; measurement of feedwater pH levels would be indicative for taking appropriate action toward same. The detrimental effect of corrosion is quite visible as pitting-type damage, where deep penetration and perforation can often occur without notice, even if metal loss is nominal. Thus, it is extremely important to remove all dissolved gases from boiler-bound feedwater to keeping it in a healthy condition.

There are two major ways in which removal of dissolved gases in feedwater can be accomplished. One method is to apply chemicals; this is costly and may harm the metals/process if overdone. A mechanical method, on the other hand, proves more economical and thermally efficient compared to the chemical one. Although elimination of dissolved oxygen can be achieved by mechanical methods, in practice, it is usually a combination of both systems that are used. Deaeration is the mechanical process that is responsible for achieving the desired purity level of feedwater, providing an increased lease on life for the boiler.

As stated earlier, the pH level in condensate/feedwater is indicative with regard to the corrosion possibilities if it continues to be above 8.5 to 9. The presence of both of the damaging elements just described can be avoided. It has been shown that above a certain pH level, the presence of carbon dioxide and oxygen are both untraceable. This is the reason for using the chemical method and also suggests application of sodium sulphite, hydrazine, or tannin as an oxygen-scavenging chemical after the deaeration.

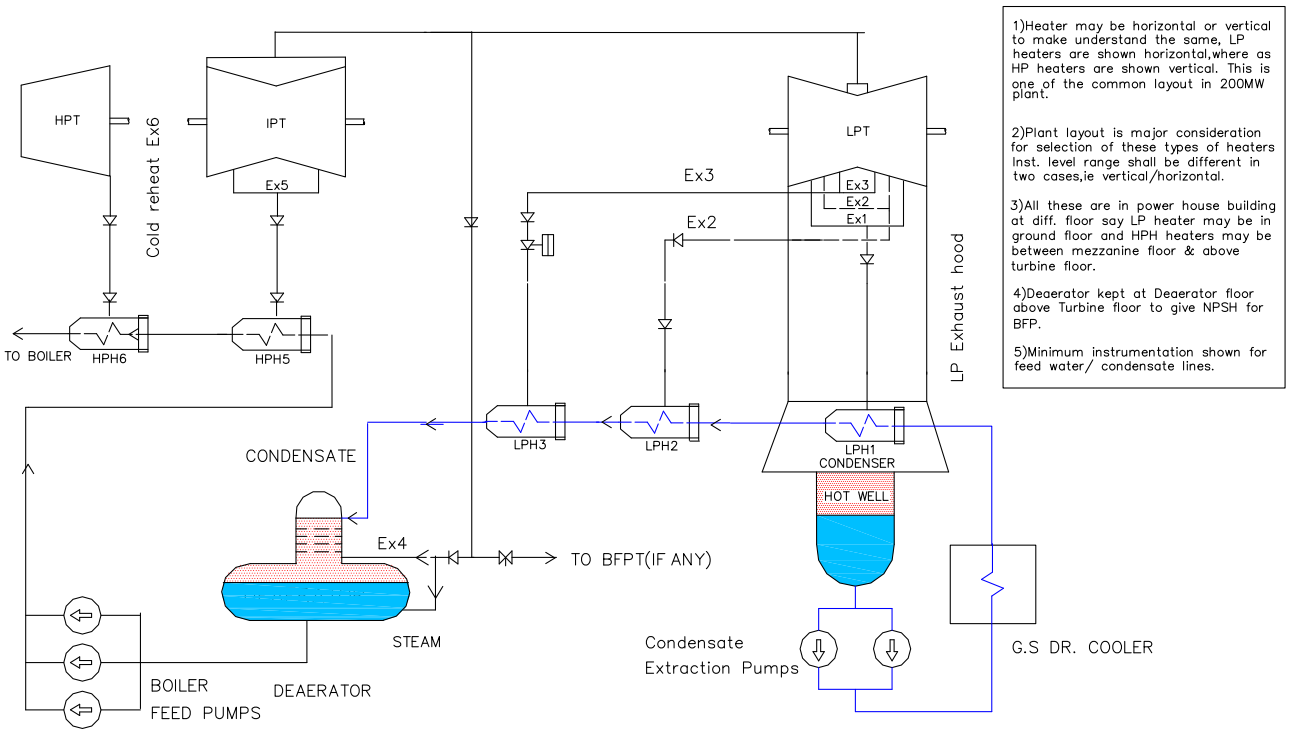
Normally, feedwater temperature is raised to nearly but less than the saturation temperature by supplying heat energy through direct mixing with the steam taken from the fourth extraction line, or the crossover line from IPT to LPT. Operation at higher temperatures than this saturation pressure should be avoided due to the close proximity of saturation temperature that may increase the probability of cavitation inside the BFP. However, this situation can be tackled effectively by installing the feed tank at a very high level to add some pressure above the boiler saturation pressure when the water reaches the BFP suction.

As it is now obvious, by increasing the temperature, more oxygen scavenging is possible; it also needs to be borne in mind that this temperature must be less that the saturation temperature. Thus, the only way to get a higher operating temperature is to increase the saturation temperature of the fluid, which demands increased deaerator shell pressure. Therefore, for units intending to decrease usage of chemicals for feedwater dissolved oxygen content, a pressurized deaerator is the only alternative.

6.1.2 Working Principles of Deaerators

Two different scientific theories paved way to the working principles of deaerators. The first theory, according to Henry's Law, states: "Gas solubility in a solution decreases as the gas partial pressure above the solution decreases." The second theory states: "Gas solubility in a solution decreases as the temperature of the solution rises and approaches saturation temperature." In fact, when a liquid attains its saturation temperature, the solubility of a gas in it is zero but it can be achieved only when the liquid is subjected to turbulence by properly stirring the fluid to ensure complete deaeration. Both of these theories are used in deaerator operation for removal of dissolved gases from boiler feedwater, which at the same time gains some temperature from the heating medium (Figure II/6.1).

www.EngineeringBooksPDF.com



NOTE: In LP heaters dotted coils shown for condensate & in HP heaters dotted coil shown for Feed water.

FIGURE II/6.1 Basic schematic diagram of deaerator operation.

For instrumentation of the deaerator, refer to Figure III/7.2-2. Inside the deaerator a atmosphere of steam is maintained by injecting it in the upper part called the *deaeration area*; the condensate is arranged so that it pass through a special type of spraying system. It, then, comes out in the shape thin films or the water is broken into mist form/minute droplets. This system provides a high surface-to-mass ratio and can be mixed and heated rapidly in contact with steam, thus, a faster heat transfer from the steam to the water; as a result, the fluid inside the deaerator is undersaturated. The important point to note is that raising the water temperature and releasing the gases must take place within a very short period in the deaerator.

This release of dissolved gas is then carried with the excess steam to be vented to the atmosphere. Steam is also injected in the lower part of the deaerator, called a feed tank, for raising the saturated temperature of the system. The gas thus starts to be released from the condensate and in turn is arranged to leave the deaerator's upper chamber through its vent. The combined effect of heating and removing released oxygen and other gasses enhances the gas-liberation process and ultimately decreases gas concentration. The water after deaeration is then available in the feed tank. A thick layer of steam is maintained above the feed tank storage water to ensure that gases are not reabsorbed.

A very efficient deaerator can eliminate a dissolved oxygen concentration equal to or even >0.005 cc/liter (7 ppb). As far as concentration of carbon dioxide is concerned, some manufacturers claim complete elimination of it.

6.1.3 Types of Deaerators

There are two types of water-handling systems in the deaerator that provide a greater surface area; their individual techno-commercial advantages and disadvantages (Figure II/6.2) are the following:

1. *Tray-type:* normally used for power plants with a very high turndown ratio
2. *Spray-type:* normally used for process plants

6.1.3.1 Tray-Type Deaerator

This type of deaerator deploys a series of trays with small holes at the bottom. When pressurized water is passed along the trays, part of it comes out through the holes and is converted to small droplets and/or water mist. They provide more surface area that comes in contact with comparatively high-temperature steam to get heated to a higher

www.EngineeringBooksPDF.com

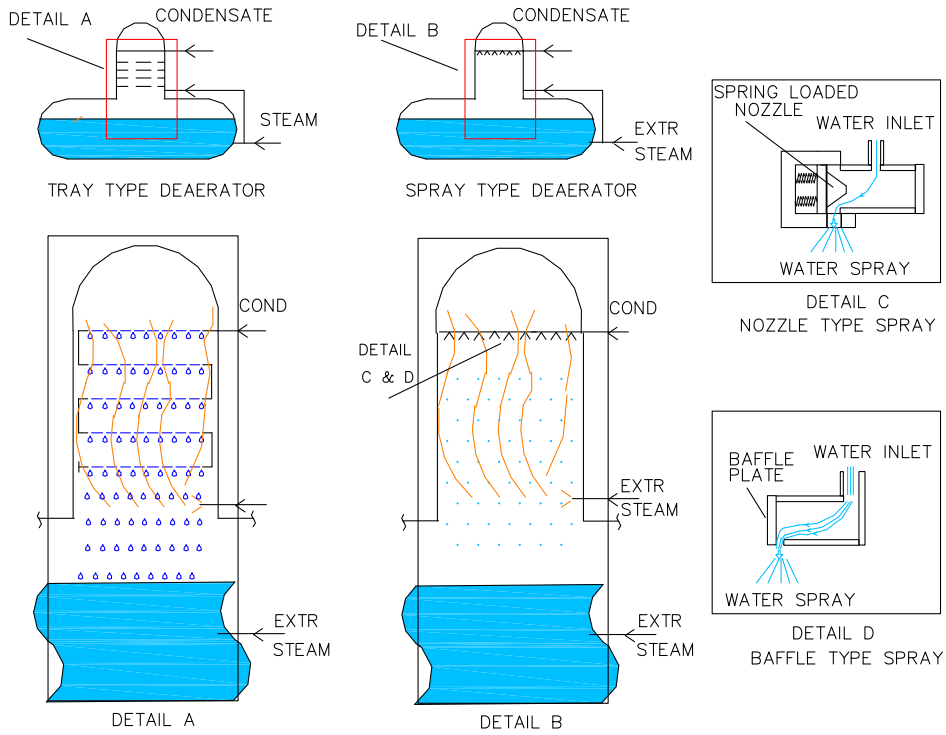


FIGURE II/6.2 Basic schematic diagram of various deaerator types.

NOTE:
In LP heaters dotted coils shown for condensate & in HP heaters dotted coil shown for Feed water.

temperature and releases noncondensible gas, which is vented out to the atmosphere. The major part of the condensed steam falls into the feed tank with a level that is maintained in coordination with the rest of the condensate cycle.

Extraction steam may be injected into the feed tank's waterside also depending on the system's design. This is done to raise the condensate temperature in addition to the preceding arrangement. Pressure fluctuation in this type of deaerator may damage the tray assembly, so the deaerator pressure control needs special attention to keep it within limit.

6.1.3.2 Spray-Type Deaerator

This type of deaerator deploys a number of spray nozzles provided with the manifold where the condensate water enters. Another type may be arranged in such a way that the condensate water is guided to impinge, such as a jet against a baffle plate, so as to come out as if a water spray function is achieved. With a number of such units, the water is converted into fine water particles. They, however, provide more surface area, just like the other type, that comes in contact with steam to get heated quickly and released as noncondensible gas. The extraction steam-heating arrangement is similar to the spray type and also may be provided depending on system design.

6.2 Regenerative Feedwater Heaters

The idea here, as discussed before, is to improve the efficiency of the Rankine cycle. Because the temperature of the condensate from the CEP outlet is low, it is routed through several LPHs and HPHs to increase the water (both condensate and feedwater) temperature. This is accomplished by taking comparatively high-temperature extraction stream from different stages of the turbine to raise the water temperature at multiple points (of the Rankine cycle) through exchange of heat. This idea is termed *regeneration* and the vessel used as the exchanger for transfer of heat from steam to water is called a *feedwater heater*.

Theoretically, there are two main types of feedwater heaters:

1. *Open type*, where the steam directly mixes with the water
2. *Closed type*, where the steam does not mix with the water but an exchange of heat takes place through a metallic barrier in between them

Although both types are available, modern thermal power plants are, in practice, equipped with closed-type feedwater heaters, except a deaerator, which is considered as an open-type. Generally, open-type feedwater heaters are rarely installed.

www.EngineeringBooksPDF.com

6.2.1 Open-Type Regenerative Feedwater Heaters

It is imperative to state, as already discussed, that the open-type feedwater heater is fundamentally a mixing vessel where the extraction steam from the turbine directly combines with the water. In an ideal heat-exchanging condition, the water leaves the heater as a saturated liquid at the vessel's inside pressure. Then, the saturated water is guided to the next heater for further mixing and heating as per the design.

It has been observed that the effect of adding one regenerative heat exchanger in the form of an open system improves thermal efficiency simply by preheating, raising the temperature of the water before it enters the boiler. It has, however, been observed also that at the same time power output is reduced.

6.2.2 Closed-Type Regenerative Feedwater Heaters

Closed-type feedwater heaters, on the contrary, do not allow direct mixing. In a power plant, they are basically shell- and tube-type heat exchangers in which water temperature increases by gaining heat from the tube's metal, which accepts heat from the extracted steam. The extraction steam enters the shell, which contains a bundle of metal tubes, inside which water passes through. The extraction steam then condenses at the outlet of the shell after losing the temperature to the feedwater. Unlike the open-type, here, the two heat-exchanging media are at different pressures because they do not mix with each other.

The piping and instrumentation drawings (P&ID diagrams) relating to feedwater and condensate lines of a steam power plant with a closed-type feedwater heater may be referred as follows:

- Figure III/6.2-2, Feedwater system (overall P&ID)
- Figure III/7.2-1, Condensate P&ID (condenser hot well to gland steam condenser)
- Figure III/7.2-2, Condensate P&ID (condensate through heaters up to deaerator)
- Figure III/8.2-1, Heater vents (HPH and LPH)
- Figure III/8.2-2, HP heater drain system
- Figure III/8.2-3, LP heater drain system

The drawings indicate typical instrumentation systems and the flow path that is summarily described in the following paragraphs.

In an ideal regenerative Rankine cycle with all closed-type heat exchangers (including drain cooler, gland steam cooler, etc.) and feedwater heaters, the condensate, steam drains from the heaters are cascaded to lower-pressure heaters/vessels and, ultimately, to the condenser. The main steam from the boiler is allowed to expand in the turbine to an IP to get work done. While the main part of the steam in the turbine continues to expand to next lower stage, a small part of it is extracted from a suitable point of turbine so as to make thermal balance. The extracted steam is then directed to the feedwater heaters.

The similar process goes on until the steam is expanded to the condenser pressure with several other extractions to heat at various other closed-type feedwater heaters. The water (condensate and feedwater), on the other hand, gets more and more heated through its journey from CEP discharge to boiler inlet. The normal route of the steam condensate drain from any feedwater heater is toward the next lower-pressure heater but is diverted to the deaerator in case of HP heaters and flash tank/condenser, depending on the situation. Some systems allow the condensate from the closed-type feedwater heater to go to a higher-pressure point in the Rankine cycle by suitably pumping it. The heater vent lines are also shown in the figures with three types of possiblities to vent the steam in heaters, if required, during: startup, normal operation, and emergency.

The HP heater vents are sent back to the system through the deaerator in case the first two events; but in emergency, the vents are diverted to an LPH or sump pit to suit the emergency condition. The LP heater vents are sent back to the system through the LP flash tank; in case the first two events were an emergency, the vents are opened to atmosphere through pressure-relief valves.

6.2.3 Comparison of Open- and Closed-Type Regenerative Feedwater Heaters

When comparing the open-type to the closed-type feedwater heaters, it can be stated that the closed-type is more expensive because of its complex design and internal arrangements. Since the two streams are not allowed to mix at all inside the heater, there is no need to provide separate a feed pump for each closed-type feedwater heater to raise the water pressure to be suitable for the next stage. As already stated, modern-day power plants use mostly closed-type feedwater heaters with only one open-type that is a deaerator. Here, one also must keep in mind certain eventualities such as heater tube rupture, which calls for emergency drains. Fortunately, these already are available through high-capacity hot wells and deaerators in the system.

Regarding plant efficiency, it has been observed that the thermal efficiency of the closed-type is more or less equal to that of the open-type feedwater heater. As far as power output is concerned, however, it should be noted that the same is less compared to that of the open-type system. The number of LPHs and HPHs varies to compensate for the capacity and design of the system. In general, however, the number of LPHs are the same for all high capacity power

www.EngineeringBooksPDF.com

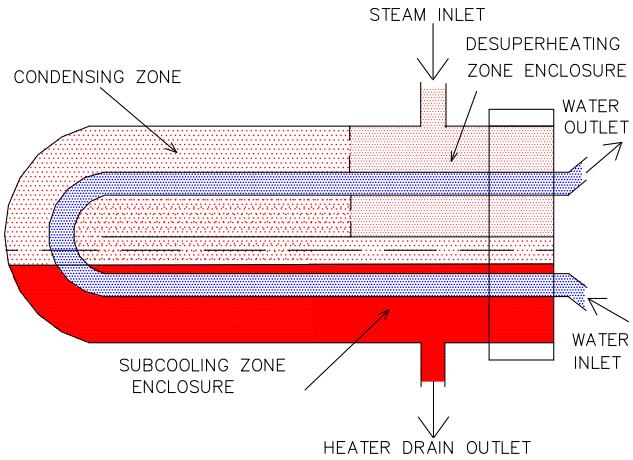


FIGURE II/6.3 Basic schematic diagram of HP/LP heater operations.

plants (i.e., LPH 1, 2, and 3). But the number of HPHs varies capacity even if there are two identical HPHs in each stage (e.g., HPH 6A and B or HPH 7A and B), where either A or B could be isolated in case of any mechanical or operational snag.

6.2.4 Description of Closed-Type Regenerative Feedwater Heater Operation

The bled steam is taken from the suitable extraction point of the HP/LP turbine and then used to heat the comparatively HP feedwater or condensate (Figure II/6.3). The steam is, however, ultimately condensed into a subcooled liquid popularly called *HP/LP heater condensate*. As the two streams are separated mechanically, only a finite temperature difference is a necessary condition for heat transfer to take place. The closed-type feedwater heater is basically a counterflow heat exchanger and the pressurized fluid entering at a lower temperature is heated up to the saturation temperature of the bled steam. There are three distinct heat-transfer zones that can be seen in a typical closed-type feedwater heater, as shown in Figure II/6.3's simplified schematic diagram. Those heat zones are as follows:

Desuperheating zone enclosure: Here, the extraction steam first enters the heater and is cooled while raising the temperature of the feedwater, leaving the heat-transfer zone at a temperature approaching or almost equal to the saturation temperature. In other words, the desuperheating of steam occurs until the saturation temperature is reached by the conduction cooling by the water within the bundle of feedwater pipes.

Condensing zone: This is the largest heat-transfer zone within the heater shell. The greatest part of the heat transfer activity takes place here as the already-made saturated steam condenses due to further cooling; it gives up its latent heat to cooling water thereby raising its temperature.

Subcooling zone: This enclosed zone is a separate, shrouded area within the heater shell to further cool the condensed steam; it is popularly called a *heater drain* while heating the incoming feedwater. The design of heater sizing is done so that the subcooled liquid condensate is reduced to within ~4°C to 6°C (typically) above the incoming feedwater temperature.

7. FUNCTION AND DESCRIPTION OF CW AND ACW SYSTEMS

The requirement of a condenser in a thermal power plant has already been discussed in Clause 2.8 of Chapter I and Clause 3.4 of this chapter. It is evident that when the condenser's internal design is setup to allow the condensate to be cooler, the pressure of the exhaust steam pressure is also reduced according to the saturation condition and efficiency of the cycle (Rankine) increases.

The prime object of a circulating water (CW) system is to cool the LP turbine's exhaust steam to convert it to condensate. Typically, the cooling water causes the steam to condense at a temperature of ~45.4°C (113.7°F) and that creates an absolute pressure in the condenser of ~0.1 kg cm^2. The greatest volume change (negative) that takes place when steam condenses to liquid creates the very low vacuum that enhances the action of taking out the steam.

The limiting factor of the condenser's functioning is the temperature of the inlet cooling water and that in turn is limited by the prevailing average climatic conditions at the power plant's location. Although it is natural that the cooling water temperature would be lower during the winter season, beyond the turbine's limits, this would cause more condensation in the turbine. Plants operating in hot climates during the summer may be subjected to reduced the electrical output if their source of condenser cooling water becomes warmer.

The CW system is provided to supply water not only to the condenser for condensing the LP turbine exhaust steam but also for secondary cooling of the auxiliary cooling water (ACW) systems of various auxiliaries of the boiler and turbine. CW pumps are normally a vertical wet-pit type. The CW system utilizes seawater for both vertical wet-pit type and concrete-volute type pumps.

The ACW system is thus dubbed as a subsystem of the CW system and its primary function is to cool the closed and/or clarified cooling water (CCW) system to take care of the cooling water requirements of all the auxiliary equipment such as turbine LO coolers, H_2 generator coolers, seal oil system, conductor cooling, etc.

www.EngineeringBooksPDF.com

7.1 Circulating Water Systems

There are two major classifications of a CW system that are adopted per the location and design of plants: once-through type or open and closed-cycle type or recirculating using a cooling tower (CT).

7.1.1 Once-through Circulating Water System

This system is used for supplying the cooling water directly to the condenser when it is available in abundance near the plant such as a river or seawater for coastal power stations. The once-through system is always accompanied by a desilting arrangement and traveling water screens of appropriate mesh size.

The purpose of providing traveling water screens is to arrest the entry of debris and biological species from the water source and is installed at the intake section of CW system. When seawater or water from a river is used as the cooling water, suitably sized debris filters (i.e., with an appropriate mesh size) have to be provided upstream of the condenser cooling circuit for enhanced action of debris removal so that fouling with condenser tubes is avoided.

A time-based control system of traveling water screens with backwash facilities is provided. The DP between upstream and downstream of the screens is also a controlling factor for its operation.

7.1.1.1 Once-through Circulating Water System Components

A pump house consisting of a reservoir and pumps with sufficient redundancy draws raw water from the main source (e.g., sea, river, or lake) and discharges it as a cooling medium directly to the condenser (Figure II/7.1). The CW pump house is normally located near the source to avoid additional earthwork to make a canal or other transport area. All instances are indicated and alarmed (for abnormal status) using level switches/transmitters, etc.

The CWPs are provided in a sufficient number to facilitate uninterrupted supply of cooling water to the main power plant(s). Individual pump discharges are connected to a separate header with interlocked operation through a low-discharge pressure and CWP tripping status. The discharge pressure is calculated on the basis of frictional loss due to long runs of the pipelines and the cooling water

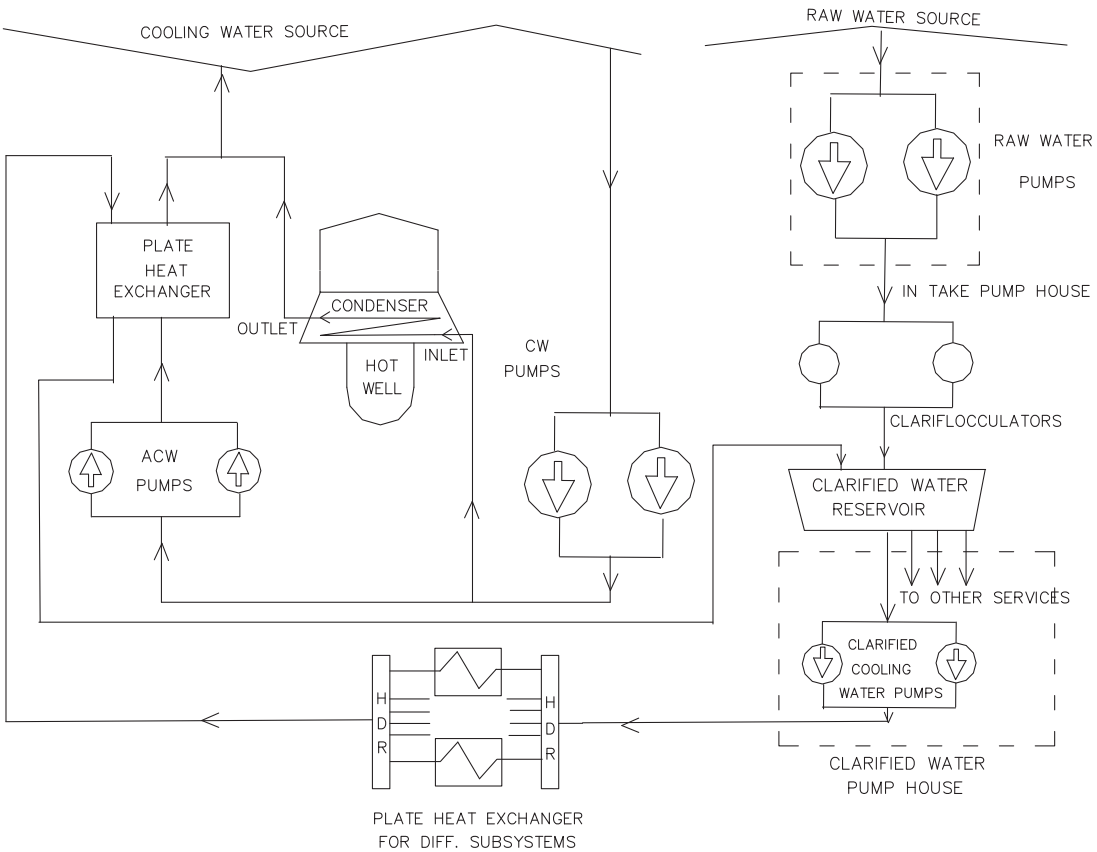


FIGURE II/7.1 Basic schematic/flow diagram of CW/ACW system without cooling tower.

www.EngineeringBooksPDF.com

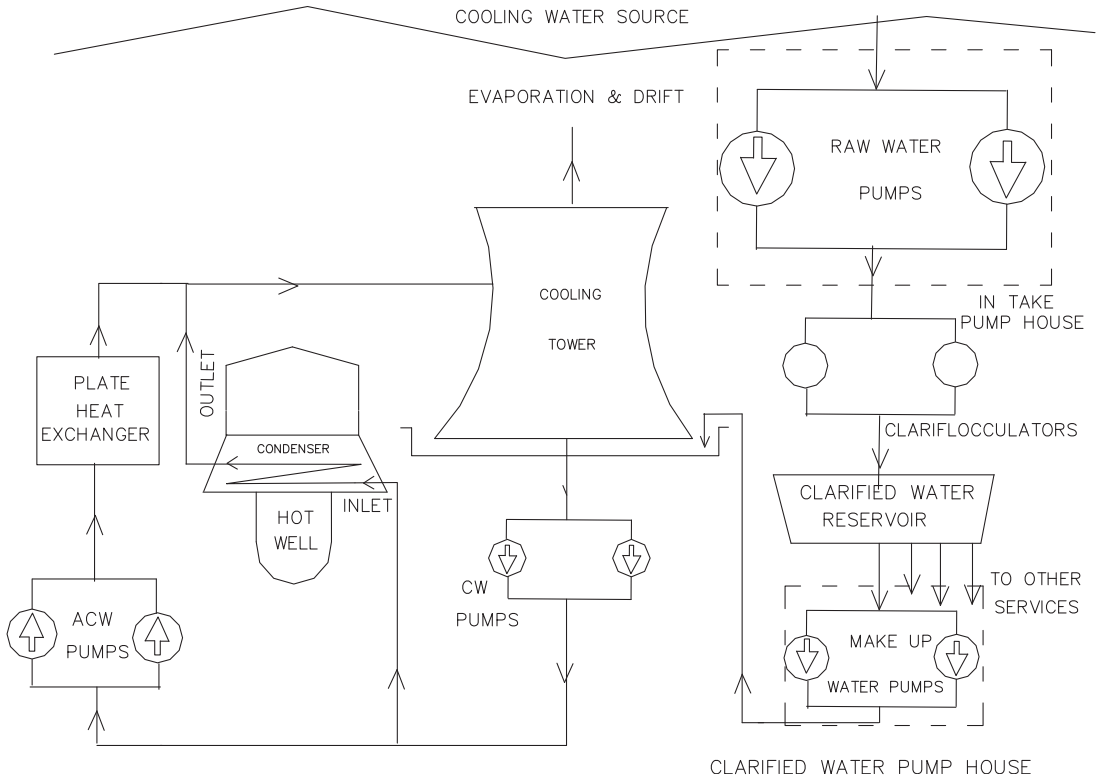


FIGURE II/7.2 Basic schematic/flow diagram of CW/ACW system with a cooling tower.

inlet head near the condenser. Desilting and traveling water screens are provided at suitable locations to prevent unwanted materials from entering condenser cooling circuits.

7.1.2 Closed-Cycle Type or Recirculating Water System

Previously, a once-through or open-type system was allowed to have an upper limit maximum temperature increase of ~20°C compared to the intake temperature; however, there are restrictions in many countries to accept of this type system. As an example, per a government of India Ministry of Environment and Forests (MoEF) stipulation dated February 1, 1999, to meet their water requirements, power plants installed after January 6, 1999, on fresh water sources are not permitted to have a once-through condenser cooling system; this is so companies keep the thermal pollution aspects of the source's water body in mind. This means all inland power plants in countries under this restriction now have to provide cooling towers. Seawater-based cooling towers also have been adopted at coastal sites to acknowledge techno–economic–environmental considerations (Figure II/7.2).

A closed-cycle type or recirculating CW system utilizes the service of clarified water from CTs when this service water is taken from freshwater sources such as a lake, a reservoir, or even when from a river or canal. The freshwater taken from these sources is clarified through a clariflocculator and then transferred to the CW reservoir. The clarifying water pumps are employed to do the transfer action. Once the system starts, transfer takes place for makeup purposes only. The closed CW circuit includes the reservoir receiving cold water from the cooling towers and CW pumps that supply cold water from the CT reservoir into CW pipelines, where it passes through the condensers and plate heat exchangers (PHE) of the auxiliary cooling system. Hot water from the condensers and PHEs is returned to the CTs through discharge ducts/pipe headers.

7.1.2.1 Types of Closed-Cycle or Recirculating CW Systems

Two types of cooling towers normally are available: mechanical induced-draft and natural-draft. Selection of the type of CT is mainly dependent on techno–economic considerations involving capital cost and operating expense. Another important consideration is, of course, related to site-specific aspects.

7.1.2.1.1 Mechanical Induced-Draft Type Cooling Tower As a general rule, a mechanical induced-draft cooling tower (IDCT) is preferred for power plants located near the coal source point (pit head) as a result of

www.EngineeringBooksPDF.com

low running costs due to the lower cost (low coal transportation charges) of power generation. This type of CT may be of single- or double-inlet crossflow or counterflow with fans located on top of the tower.

7.1.2.1.2 Natural-Draft Type Cooling Tower A natural-draft cooling tower (NDCT), on the other hand, is preferred for power plants located near the load centers, which means far from the coal source point because this process works without any rotating equipment (i.e., cooling fans), thereby saving on costly power. The air-flow rate through a NDCT depends on the density difference between ambient air and relatively hot and humid light air inside the tower. For a plant site, where duration of high summer ambient temperature is considerably greater combined with an environment having low relative humidity, an adequate density difference would not be available for suitable performance of a NDCT as per design and operational data. For such sites, IDCT is much a better choice. The natural-draft CT may be of counterflow or crossflow type with draft air flowing through the packing provided by the buoyancy effect of hot and humid air inside the tower shell as compared to outside ambient air.

7.2 Auxiliary Cooling Water and Closed Cooling Water Systems

The ACW system mainly incorporates pumps and valves and is provided with sufficient a number to facilitate uninterrupted supply of cooling water to the coolers for cooling the hot return lines of the system's auxiliary coolers (CCW system) such as H_2 and seal oil coolers, etc., as mentioned before in this chapter. These two systems cater to all the cooling requirements other than the condenser cooling circuit.

7.2.1 Auxiliary Cooling Water System

All the individual suction pipelines are connected to the CW delivery line near the condenser cooling water inlet and discharge lines of ACW pumps are connected to the common header from which supply lines are connected to the secondary sides of the coolers assigned the duty of cooling the closed or CCW itself. The cooling water in the secondary circuit (i.e., the ACW) is connected to the discharge or outlet of the condenser cooling water circuit. The auxiliary cooling water system's components are redundant ACW pumps and plate-type heat exchangers with the necessary valves and temperature and pressure measurement devices and interlocked operation.

7.2.2 Closed/Clarified Cooling Water System

The CCW system takes care of the cooling water requirements of all the auxiliary equipment such as turbine lube oil/control oil coolers, H_2 and seal oil coolers, stator winding water coolers for the generator, BFP auxiliaries, condensate pump bearings, all sample coolers for both continuous measurement, grab sampling, air compressor auxiliaries, etc. For the gas turbine (GT) auxiliaries, CCW is provided with an individual ACW system since the pressure requirements of a cooling water system for a GT are generally greater when compared to that of steam turbine.

The primary part of this CCW system is actually the fluid that utilizes passivated demineralized (DM) water, popularly called *clarified cooling water*, as cooling medium; this is circulated in a closed circuit. CCW basic schemes also have been included in Figures II/7.1 and II/7.2 earlier for both the systems (i.e., with or without a CT).

7.2.1.1 Closed/Clarified Cooling Water System Components

The primary system components of this system are:

- Redundant ACW pumps
- Plate-type heat exchanger
- Overhead expansion tank

The CCW takes away the rejected heat from all auxiliary coolers and is circulated in a closed circuit through plate heat exchangers in series with the help of redundant CCW pumps.

An overhead expansion tank of adequate capacity is provided to ensure positive suction to the CCW pumps as well as to allow the expansion of water in the closed circuit. There is every possibility of losses of water in a CCW system due to leakage near the gland packing at pumps, leakages in flanged connections, at plate heat exchanger seals, etc. The makeup water to compensate for this loss is normally provided from a CEP discharge through interlocked operation. A solenoid-operated level control valve is provided on the expansion tank to ensure a continuous level in tank. During initial fill for the system, makeup water is supplied through pumps with a chemical feed system to provide additional of chemicals to ensure an adequate pH value; this is called *passivation of DM water*.

7.3 CW Makeup and Treatment System

Cooling water quality, in terms of desired cycles of concentration (COC), is maintained by implementation of blowdown operation from the cold water side of CW system (CWP discharge line) and normally is used for comparatively low-grade applications such as an ash-handling (wet) system, coal dust suppression, etc. It is quite natural that loss of water, due to blowdown, evaporation, drift, etc., needs to be replenished by makeup water supplied by CW water pumps installed in the clarified water pump house, as discussed earlier.

Keeping the CW discharge water temperature limitations for coastal power plants in view, the takeup point of

www.EngineeringBooksPDF.com

cooling tower blowdown in general is located near the colder side of the CW system. Or, in other words, from the discharge header of CW pumps; remaining blowdown is discharged back into the sea at a lower temperature.

Scale and corrosion can result even in spite of application of different chemicals at the desired treatment levels as a consequence of improper blowdown. For example, excessive blowdown means suspended solids, scale-forming minerals, etc., are removed and make the cooling water more corrosive. Excessive blowdown may also cause removal of the chemicals already applied for treatment, which may either result in less corrosion protection or increasing chemical costs. On the other hand, if the blowdown is less than the desired value, scale-forming minerals may build up in the system up to a level that could make it difficult for the treatment chemicals to overcome the tendency to form scale deposits.

At a number of plants, blowdown is not taken into consideration as a part of the chemical treatment system but is included as a part of the overall treatment of water-cleaning arrangements. COC, as stated, determines the presence of unwanted chemicals in water without going in for chemical treatment.

The meaning of COC is actually the number of times the constituents in the raw makeup water are concentrated in a CT as water is evaporated. COC is controlled solely by blowdown and is evaluated by the amount of total dissolved solids (TDS) present in the water or by measuring the conductivity of the water. For any cooling tower system, insufficient blowdown, as stated earlier, would cause the COC level to go beyond the highest recommended value and can lead to formation of scale in spite of maintaining the proper chemical treatment levels.

7.3.1 Prevention of Microbiological Growth and Treatment System

For preventing the microbiological growth in the CW system, chlorine dosing is done. Shock dosing with chlorine is carried out in the fore bay of CW pump house. Apart from chlorine dosing of the circulating water, dosing with sulfuric acid, scale inhibitor, corrosion inhibitor, and biocide inhibitor is done, as required, for the control of scale formation, corrosion, and organic fouling in the CW and ACW systems. Side stream (SS) filters are provided in a clarified water-based closed-cycle cooling water system to reduce the turbidity in CW on account of suspended solids in makeup water and atmospheric dust ingress through the CT.

7.4 CW Makeup and Treatment System Using Seawater

Seawater is used as a cooling medium of the CW system (i.e., for condenser cooling purposes) near a coastal area thermal power station. Both the options (i.e., once-through cooling or closed-cycle cooling using CTs) are applicable here. For this type of CW system, the thermal pollution effect on seawater dictates the selection of a system type along with techno–commercial analysis based on the distance between the power station and the sea coast vis-à-vis cost of pumping plus pipelines to transmit seawater. The prime consideration for cooling towers with seawater makeup are CT drift and salt contamination in the environment.

7.4.1 Drift Problems with Cooling Towers Using Seawater

Elaborate study of the problem associated with CT drift has been done, showing that seawater may contain a very high concentration of TDS up to 50,000 ppm, which is suspected of being followed by corrosion of connected equipment. A proper action to be taken to avoid long-distance drift of high concentration salt water to prevent it should be addressed while designing the CW system; this could include deploying low-pressure spray nozzles in the CT, etc.

The manufacturing cost of a CT for a typical seawater application, operating at a COC range of $\sim$1.5, would be higher to accommodate the increase in cooling tower size, which may be up to 10% taller than a similar capacity CW system that utilizes fresh water. The reason behind this is the high salt concentration in seawater that lowers its vapor pressure vis-à-vis a reduction in the evaporative cooling rate, depending on degree of salt concentration. The approach temperature (i.e., the difference between a wet-bulb reading of the environment and the cold water temperature of CT outlet) used during design of towers must consider the effect on tower performance when using salt water. For practical purposes, a 20% increase in approach temperature should be considered for a CT designed for a seawater-based system compared to a fresh water one.

Keeping in view the discharge water temperature limitations for coastal power plants, cooling tower blowdown is affected from the colder side of a CW circuit or, in other words, from the discharge header of CW pumps. The blowdown is partially used for ash-handling, coal dust suppression, plant beautification (gardening), etc., and the remaining blowdown is discharged back to the sea at a low temperature.

7.5 Instrumentation Requirements for a CW System

Other than the interlock and protection system, the necessary instrumentation to be provided for a CW system should include:

- Vibration-monitoring system for pumps and motors
- Bearing temperature (for a larger size motor)

www.EngineeringBooksPDF.com

- Chlorine leakage detection with a chlorine absorption and neutralizing system that comes in to service automatically on detection of a chlorine leak that is more than alarm level
- Cooling water flow
- Hot inlet temperature
- Cold outlet temperature
- Wet-bulb temperature

7.6 Auxiliary and Associated Subsystems of a CW/ACW/CCW System

The following are important auxiliary and associated subsystems that should be provided to take care of various hazards related to a CW/ACW/CCW system. They are listed to give a broad idea:

- Sludge transfer system from the stilling chamber near the source point
- Different dosing systems such as alum, lime, polyelectolyte, etc.
- Chlorination plant
- Service/potable water system
- Fire fighting system
- Effluent treatment plant

8. DEMINERALIZING PLANT'S FUNCTION AND DESCRIPTION

Water is the system's working fluid in any steam turbine generator plant set, be it coal-fired thermal, nuclear power, or combined-cycle. Besides that, water is indispensible for various applications such as condenser and equipment cooling, chemical dosing, ash disposal, service and potable water applications, etc. Each type of application demands that a different type of water be made available with the help of the proper type of treatment accomplished in a particular subsection or plant.

The primary source of water, popularly known as *raw water*, is drawn from a river, lake, or canal based on its availability and/or the geographical location of the plant. Applications vis-à-vis requirements for a particular type of treated water to be used in a thermal power plant are:

- The system's main working fluid requirement is demineralized (DM) water that is available from the DM plant during initial filling and for regular makeup for the Rankine heat cycle.
- CPU to supply the SG plant with better quality water also requires DM water.
- DM water is also necessary for regeneration of the ion-exchanger units of a DM plant, as shown in Figure II/8.1.
- Service water, CT makeup water, potable water after further treatment (i.e., filtration and disinfection), equipment cooling, etc., require clarified water.
- Ultrapure water for generator stator conductor cooling also require DM water with special treatment.

8.1 Necessity for a DM Plant and System Requirements

Water available from any source may be mixed with various types of dissolved salts and dissociates in water that form both positively and negatively charged ions. Positively charged ions are called *cations*; negatively charged ions are called *anions*. These free ions are considered impurities as a boiler working fluid because they influence operating efficiency and cause loss/failure of metal after prolonged use. As discussed in Clause 2.3.9 of this chapter, and in Chapter V, Clause 4.0, overheating caused by the buildup of scales or deposits formed by these impurities, if not taken care of in time, could lead to catastrophic tube failures associated with decreased efficiency.

Buildup of scales or deposits are formed mainly by the presence of calcium and magnesium ions (in the form of carbonates and bicarbonates), which are known as "hardness ions"; they must be removed from the water supply before it is used as boiler feedwater. For that reason, boiler feedwater for high-pressure applications is required to be maintained at a quality by introducing a condenser polishing unit after the condensate is produced to cope with the acquired contamination during cyclic travel. The requirement for very high-quality water (as close as possible to absolute elimination of all ions) is stringent for super-/ultracritical boilers—in general, for all once-through (OT) boilers—that the CPU is designed for a 100% flow capacity.

The DM plant receives water input from the pretreatment plant comprised of a clariflocculator, primary filter (i.e., sand filter), etc., which also supplies the plant with clarified water or filtered water. Drinking water normally is produed from filtered water after chlorination for disinfection. The overall water treatment plant, including pretreatment and posttreatment by the DM plant, is shown in Figure II/8.2. The DM plant consists of an activated carbon filter (ACF) and ion-exchanging system, accomplishing the task of efficient removal of dissolved ions, including carbon dioxide and silica, from the incoming water source.

The type of DM plant to use depends on the source and quality of the raw water available nearby for the plant's requirements. There are quite a number of factors that dictate the quality of what is found in raw water such as suspended solids, dissolved salts, micro-/macrobiotic

www.EngineeringBooksPDF.com

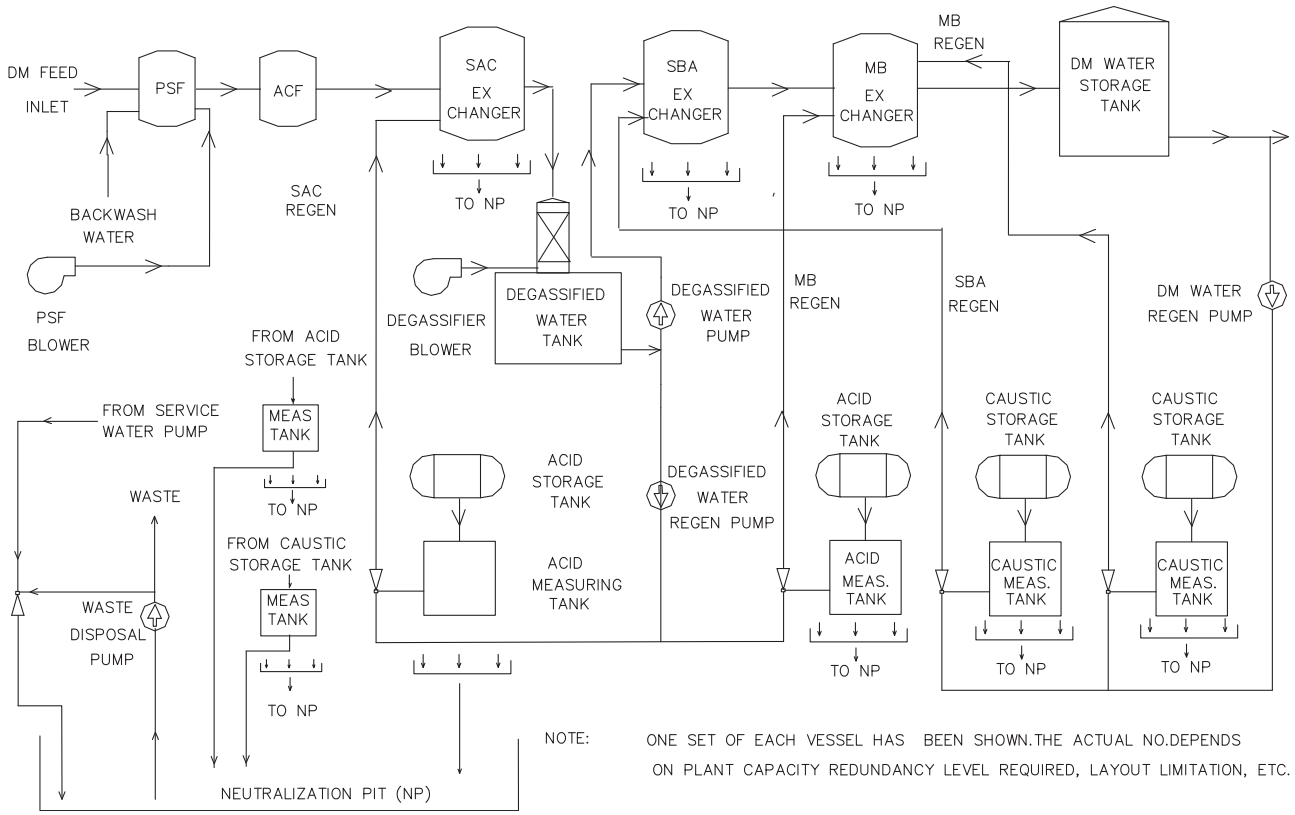


FIGURE II/8.1 Basic schematic/flow diagram of a DM water plant.

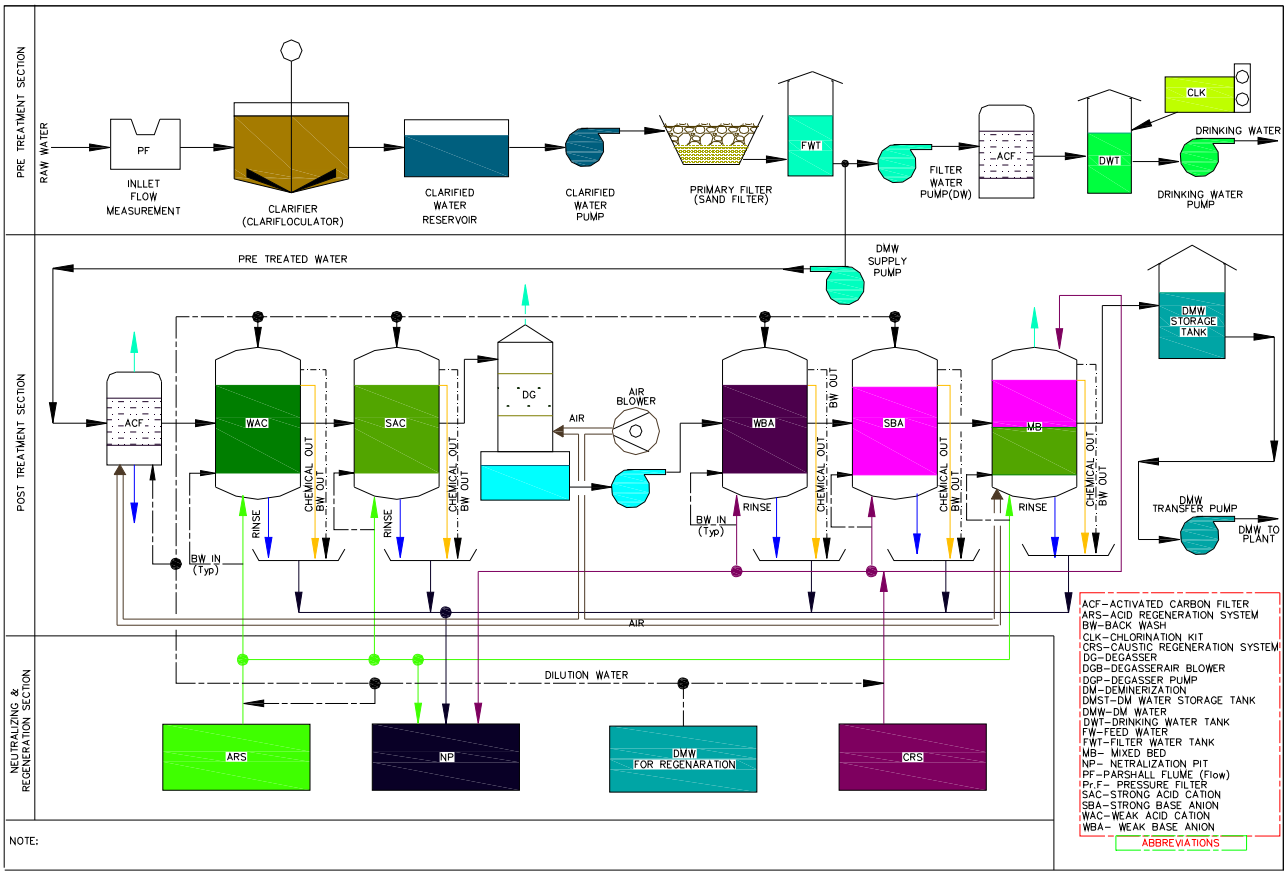


FIGURE II/8.2 Schematic of a water treatment plant's pre- and posttreatment with a regeneration system.

www.EngineeringBooksPDF.com

matter, silica, hardness, etc., and the DM plant must provide the appropriate treatment system. It should be sufficient so that the final product is acceptable according to the plant's technical requirements as well as to the environmental restrictions as stipulated by a local pollution control board or any other regulatory body.

As stated earlier, the primary source of raw water is from what is available naturally (e.g., river, lake, and canal). Where these types of natural resources are not available, seawater is converted—for example, by a reverse osmosis (RO) process (i.e., one-stage or two-stage RO as per application requirements—and then further treated achieve DM quality. There are even instances where raw water has been sourced for a plant from sewage water or other types of water containing high TDS.

8.2 Inlet Water Quality Requirement for DM Plant Operation

In Clause 8 of this chapter, the route of raw water was shown in Figures II/8-1 and II/8-2), starting from the source up to the DM plant inlet. The route includes a raw water reservoir, raw water pumps, and pretreatment (PT) plant, including chlorination, aeration, and clariflocculation through conventional gravity clarifiers or reactor type clarifiers as a standard. The pretreatment plant may also provide an ultra-filtration facility, which separates particles on the basis of their molecular sizes to minimize the effect of raw water that contains high levels of colloidal silica and has a high hardness level.

The quality of the filtered water to be taken into a DM plant for further processing dictates the requirement of chemical dosing in it. The plant is normally designed for continuous and simultaneous operation of all the streams if running more than one steam is envisaged. The outputt of the pretreatment plant is popularly termed *clarified* or *filtered* water and is supplied to DM plant, including other important services such as closed cooling system, cooling tower makeup, potable water plant, service water system, firefighting system, and other miscellaneous services.

8.3 Requirement of DM Water for Other Systems

Demineralized water is required for the following systems or subsystems in a thermal power plant:

- Main working fluid following Rankine power cycle and its makeup after initial filling
- DM plant regeneration
- CPU regeneration
- HP/LP dosing system

8.4 System Operation of DM Plant

Conventional system operation of a DM plant is quite understandable from the very name of the plant that does nothing but eliminate the unwanted mineral salts from water by exchanging of both cations and anions. This is done by replacing the strong and aggressive cations and anions with weak ones that are less or not harmful with more acceptable ions to the process metals. Refer to Figure II/8.1 shown earlier in order to more easily understand the system. The plant's inlet water is guided to through suitable filters and ion exchangers, also called *polishers*, depending on the concentration of various ions in salt form in inlet water.

The ion exchangers put in the water circuit may be of several types—for example, strong acid cation (SAC), weak acid cation (WAC), strong base anion (SBA), weak base anion (SBA), and mixed bed. The basic functions of the various ion exchangers can be described briefly as follows:

- SAC resin neutralizes cations of strong bases and converts neutral salts into their corresponding acids
- SBA resin neutralizes anions of strong acids and converts neutral salts into their corresponding bases
- WAC resins are able to neutralize strong bases
- WBA resins are able to neutralize strong acids.

The last two resins are used for dealkalization, partial demineralization, or full demineralization (in combination with strong resins).

The water passes first through a bed of SAC resin. Replacement of the metal cations—namely, magnesium (Mg) and calcium (Ca)—with it releases the hydrogen ions that lower the solution pH, making the outlet water acidic. The anions—namely, sulfate (SO_4) and chloride (Cl)—can then be removed with a SBA resin because the entering acidic water (H^+ ions) react with the hydroxide ions (OH^-) of the SBA resins. This causes the anions in the incoming water to be absorbed in the resin and H^+ ions with OH^- would react to produce water (H_2O) and the water becomes purer. In some plants, WBA resins are preferred over SBA resins because they require less regenerant chemicals.

As stated earlier in this chapter, if the inlet water is sourced from salty seawater, it needs to be processed separately (e.g., in an RO plant) before it is introduced to the DM plant. In fact, the DM plant can take any type of inlet water with a TDS level of up to a maximum of 500 ppm.

8.4.1 DM Plant Operation Components and Their Functions

Normally, 2 × 100% or 3 × 50% DM streams are provided for a plant. The final product is transferred to the DM water

www.EngineeringBooksPDF.com

storage tanks to cater to the intermittent requirement of various system makeups. Each stream consists of the following components along with the common facility for the regeneration process:

- Pressure sand filter (PSF)
- Activated carbon filter (ACF)
- Ion-exchanger units (with regeneration arrangement)
  - SAC and/or WAC
  - SBA and/or WBA
  - MB
- Decarbonator and degassifier
- Drain neutralization system

The ion-exchanger units, which contain the resin beds, are normally vertical, rubber-lined, welded-plate steel construction and fabricated as per IS: 2825 or equivalent. The vessels are lined with suitable material of an appropriate thickness (e.g., 4.5 mm) to protect the metal of the vessels. Brief discussions for each component are given in the following subsections, along with their dedicated functions.

8.4.1.1 Pressure Sand Filters

Pressure sand filters (PSF) are used in many industrial applications including a DM plant and often are popularly termed *rapid sand bed filters*. APSF consists of a pressure vessel that is normally vertical or horizontal, in rare occasions, depending on the layout of the plant. The filter vessels are generally of welded mild steel construction lined with rubber/epoxy. A minimum of 50% freeboard is provided over the filtering bed depth to enable efficient backwash.

Graded silica quartz sand and anthracite supported by layers of graded underbed, consisting of pebbles and gravels, are provided with a water inlet at the top. Incoming water is distributed uniformly throughout the cross-section of the filter to ensure that there are no preferred fluid paths where the sand may be washed away and jeopardize filter action. The bottom drainage system is kept to collect filtered water.

The selection of the sand's grain size is important because smaller sand grains provide an increased surface area and, consequently, more decontamination at the water outlet that, on the other hand, demands extra pumping energy to drive the fluid through the bed. In an attempt at a compromise, grain sizes are generally selected in the range 0.5 to 1.50 mm. A sand bed depth of $\sim$0.5 to 2.0 m is recommended regardless of the application of which the ratio of quartz sand and anthracite is $\sim$7 to 50.

Raw water flows downward through the filter bed and the suspended matter is retained on the sand's surface and between the sand grains immediately below the surface. Rapid-pressure sand bed filters are typically operated with a feed pressure of 1 to 4 kg/cm^2. The differential pressure (DP) across a clean sand bed usually is insignificantly low. The DP gradually builds up for a given flow rate as particulate solids are captured in the bed; this may not be uniform with depth. For obvious reasons, buildup would be more at the higher level with the concentration gradient decaying rapidly.

This type of filter captures particle sizes down to very small ones. In fact there is no true cutoff size below which particles would not be arrested. Interestingly, the shape of the characteristic curve of efficiency versus filter particle size is a U one with the highest rate of particle capture for the smallest and largest particles, with a plunge in between for mid-sized particles. When the pressure loss, or flow, is unacceptable, it is sensed by a pressure drop across the PSF of $\sim$0.5 kg/cm^2. The filter is then taken out of service and cleaning of the filter is effected by flow reversal or the bed is backwashed or pressure-washed to remove the accumulated particles. Backwashing of pressure filters normally is done once every 24 hours while the system is online.

During backwash, the sand becomes fluidized and the expansion in volume may go up to about 30%, which allows the sand grains to mix, and the particulate solids are driven off as they start rubbing together. The smaller particulate solids are then forced out with the backwash fluid. The fluidizing flow requirement is typically 5 to 30 m^3/hr/m^2 of filter bed area, depending on the depth of the bed, for a short period (i.e., for a few minutes only). The filter backwash fluid is taken to a common inlet chamber of raw water pumps. The backwashing process would cause sand loss though not significantly noticeable, thus requiring periodic top up of sand in the bed.

To assist in cleaning the bed, the backwash operation is often preceded by air agitation through the under drain system. The process of air scouring agitates the sand with a scrubbing action, loosening the intercepted particles. After backwashing, the filter is ready to be put back into service. For a 500 MW TPS, the typical backwashing flow rate would be between 25 to 30 m^3/hr/m^2 of bed area and the air-flow rate would be 50 m^3/hr/m^2 of filter bed area.

8.4.1.2 Activated Carbon Filters

Carbon is used to absorb impurities and is considered the most powerful absorbent and can probably absorb thousands of different chemicals. The very name *activated carbon* is actually because it has a slight electro-positive charge deliberately added to it. The resultant effect is that carbon becomes more attractive to different chemicals and other impurities. When water passes through the positively charged carbon surface, the negative ions of the pollutants are drawn to the surface of the carbon granules.

www.EngineeringBooksPDF.com

8.4.1.2.1 Principle of Operation of an ACF The two physical mechanisms through which filtration by activated carbon removes pollutants from running water are:

1. Adsorption, which helps removal of organic compounds in water.
2. Catalytic reduction, which removes the intentionally applied residual disinfectants such as chlorine and chloramines. Catalytic reduction, as already stated, is a process that takes advantage of the attraction of the negatively charged ions of the pollutants to the positively charged activated carbon.

8.4.1.2.2 Factors Influencing Efficient ACF Filtration The efficiency of activated carbon filtration (ACF) depends on two major factors—the carbon quantity in the vessel and the time period the water remains in contact with the filter. It is quite obvious that more carbon would provide a better result. On the other hand, lowering the flow rate of water means that the pollutants would be in contact with the carbon for more time and that more absorption would take place. The influence of particle size also counts because the smaller the size, the greater the surface area for a particular mass of carbon, thus the removal rate improves.

8.4.1.2.3 Types of Activated Carbon Filters There are two types of ACFs available: granular activated carbon or powdered block carbon. A power plant application prefers the latter one for its higher contaminant-removal ratio although both are effective.

8.4.1.2.4 Materials Used for Activated Carbon Filters Normally, carbon is used for this purpose and is prepared from the raw materials after burning them—the char is used as the carbon. Coal is also used as carbon for an ACF, as well as wood, coconut shells, and bituminous. Of these materials, carbon from coconut shell, as used in ACFs, yields the best results over the others, even compared to its higher cost.

8.4.1.2.5 Specifications of the Activated Carbon Filters The ACF usually has the following parameters:

- Upper ceiling flow velocity range, with a typical value of 15 m/hr
- Bed depth of typically1500 mm and a minimum freeboard (~75%) over the bed
- Anticorrosive lining or coating applied to the vessel to prevent corrosion
- Backwash cycle requirement, using filtered water with a typical value, of once every 24 hours
- Minimum size of particles up to which value the ACF could remove; typical value ranges from 50 microns (least effective) down to 0.5 microns (most effective)

8.4.1.2.6 Advantages/Disadvantages of Using an ACF Activated carbon filters normally eliminate or reduce many volatile organic chemicals including pesticides and herbicides. It also works well against chlorine, benzene, radon, solvents, and trihalomethane compounds, including turbidity, particulates, parasites (e.g., giardia and cryptosporidium). It is at the same time very cost effective.

An ACF requires little maintenance; however, it is very important to ensure that filter replacement is done on a regular basis to be sure of proper filtration at all times. It is imperative that bad tastes and odors do not return to the water; before deciding the filter needs replacement, be aware that these are an indication that the filter is no longer able to completely remove contaminants and that it has surpassed its service life.

Normally, an ACF is not suitable for removal of heavy metals, although sometimes this filter can be used for removal of a few with moderate effectiveness. For example, a high-quality ACF can be deployed for removal of some iron, manganese, and hydrogen sulfide. As far as disadvantages of an ACF is concerned, it already has been stated that ACFs, in general, are not very useful for removing dissolved inorganic contaminants or hardness or scale-causing metal compound/salts, etc.

An ACF usually is not effective for removal of sediment/particulate material. It is always preferrable that a sediment filter be installed before an ACF so as to prolong its life by eliminating gross contaminants that clog the activated carbon surface, thereby reducing the surface area vis-à-vis efficiency of the system. It has been shown that carbon block filters are generally better than granulated ACFs for removing sediment.

8.4.1.3 Filters for Seawater Applications

There are certain types of water; for example, seawater or those that contain a high of pollutants—namely, TDS of <500 ppm and/or that carry antimony, arsenic, asbestos, barium, beryllium, cadmium, chromium, copper, fluoride, mercury, nickel, nitrates/nitrites, selenium, sulfate, thallium, and certain radio nuclides. Removal of these unwanted elements requires either a reverse osmosis water filter system or a distiller.

For production of demineralized water from seawater having a very high TDS in or around 40,000 ppm, a two-stage RO plant followed by mixed bed exchanger is employed. For some applications, a manganese greensand filter also may be useful.

8.4.1.4 Ion-Exchanger Units

The ion-exchanger units constitute an important part of the DM plant. As discussed earlier, the ACF cannot eliminate some unwanted things because the filtered water is forced to pass through various units for exchanging of both

www.EngineeringBooksPDF.com

detrimental cation and anion with weak vis-à-vis harmless ones. In most cases, the term *ion exchange* is used to denote the processes of decontamination, purification, or separation of aqueous and other ion-containing solutions with some special type of exchanging materials. Ion exchanging, in general, can be described as the exchange of ions between two electrolytes or between an electrolyte solution and a complex material.

Ion exchange is a reversible process and the exchange can be regenerated with desirable ions by washing with a solution having an excess of these ions. The basic ion-exchange column consists of a resin bed, which is retained in the column, with inlet and outlet screens, service and regeneration flow distributors, etc. Piping and valves are required to direct the flow and instrumentation is required to control all the sequence timing of other controls. The complete system is typically operated in a time cycle, consisting of the following steps:

1. *Service (exhaustion):* Water solution containing ions is passed through the ion-exchange column or bed until the exchange sites are exhausted
2. *Backwash:* Bed is washed (generally with DM/filtered water) in the reverse direction of the service cycle in order to expand and resettle the resin bed
3. *Regeneration:* Exchanger is regenerated by passing a concentrated solution of the ions originally associated with it through the resin bed, usually, a strong mineral acid or base
4. *Rinse:* Excess regenerant is removed from the exchanger, usually, by passing water through it

Several types of ion exchangers are available—for example, functionalized porous or gel polymer resins, zeolites, clay, and soil humus. There is also a special type of exchanger that has the unique characteristic of being able to exchange both cation and anion simultaneously. This ion exchanger is known as *amphoteric resin*. It exploits the possibility of achieving useful radiochemical separations of both the cation and anion exchange functions of the resin. As there is some limitation in this method, to achieve more efficient action, mixed bed ion exchangers are used for simultaneous exchange of both cation and anion. In fact, the mixed bed ion exchangers contain a mixture of anion and cation exchange resins.

8.4.1.4.1 Different Types of Ion Exchangers The ion-exchanging process is accomplished by passing the polluted solution through an immobile solid particle mass to replace its objectionable ions with similarly charged ions attached to immobile mass. This mass of solid ion-exchange particles is either naturally available inorganic zeolites or organic resins produced synthetically. The latter organic resin is now widely used because of the manufacturing advantage, making their characteristics tailor-made for specific applications.

Polyelectrolytes of high-molecular weight are the best choice for an organic ion-exchange resin. They exchange their mobile ions for ions of a similar charge from the surrounding medium in contact with them. Each resin has a distinct characteristic, which indicates the approximate maximum quantity of exchanges that may take place per unit of resin.

Both anion and cation resins are produced from the same basic organic polymers; they differ in the ionizable group attached to the hydrocarbon network. It is the particular functional group that dictates the chemical characteristic of the resin. Resins as stated earlier in this chapter can be broadly classified as strong or weak acid cation exchangers or strong or weak base anion exchangers.

8.4.1.4.2 Cation Exchanger Resins In a DM plant for a water purification process, the cation exchange resins exchange positively charged hydrogen mobile ions (H^+) for the positively charged ions (e.g., nickel. copper, and sodium) from the polluted water. For example, a resin with hydrogen ions available would exchange them for nickel ions from solution. The reaction can be written:

$$2(\text{R-SO}_3)\text{H} + \text{MgSO}_4 \leftrightarrow (\text{R-SO}_3)_2\text{Mg} + \text{H}_2\text{SO}_4$$

Where,

(R-SO_3) = resin
R = organic portion of the resin (organic compound—any compound of carbon and another element or a radical)
SO_3 = immobile portion of the ion active group (sulfonic acid)

Two resin sites are needed for nickel ions with a plus 2 valence (Ni + 2). Similarly, trivalent ferric ions would require three resin sites. The reaction as indicated in the preceding means that the ion-exchange process is reversible. The degree needed for the reaction to proceed to the right would depend on the resin's preference or selectivity. For example, the reaction shows that the resin group has more of a preference for nickel ions than is its preference for hydrogen ions. The selectivity of a resin for a given ion is measured by the selectivity coefficient.

There are some guidelines regarding service flow rate for a demineralizer range that, generally, falls in the range of 15 to 25 $m^3/hr/m^2$ of resin. Flow rates of more than 25 $m^3/hr/m^2$ of resin may cause increased sodium and silica leakage with certain waters.

Strong Acid Cation Exchanger Resins. They name *strong acid resins* indicates that their chemical behavior is similar to that of a strong acid. The resins are highly ionized in both acid ($\text{R-SO}_3\text{H}$) and salt ($\text{R-SO}_3\text{Na}$) form. It can

www.EngineeringBooksPDF.com

convert a metal salt to its corresponding acid as per the following reaction:

$$2(\text{R-SO}_3)\text{H} + \text{CaCl}_2 \leftrightarrow 2(\text{R-SO}_3)\text{Ca} + 2\text{HCl}$$

Strong acid cation (SAC) resins derive their functionality from the sulfonic acid groups (HSO_3^-). When used for demineralization, SAC resins remove nearly all raw water cations, replacing them with hydrogen ions, by the few reactions, as shown here:

$$2\text{Na}\ 2\text{HCO}_3\ 2\text{Na}\ 2\text{H}_2\text{CO}_3$$

$$\text{Mg}\ \text{SO}_4 + 2(\text{R-SO}_3)\text{H} \leftrightarrow 2(\text{R-SO}_3)\text{Mg} + \text{H}_2\text{SO}_4$$

$$\text{Ca}\ 2\text{Cl}\ \text{Ca}\ 2\ \text{HCl}$$

The hydrogen and sodium forms of strong acid resins are highly dissociated and the exchangeable Na^+ and H^+ are readily available for exchange over the entire pH range. Consequently, the exchange capacity of strong acid resins is independent of solution pH. These resins are used in the hydrogen form for complete deionization and are used in the sodium form for water softening (i.e., calcium and magnesium removal). The specification normally is indicated as: high capacity, strongly acidic, sulfonated polystyrene, macroporous cation exchange resins; this would be in bead to be supplied for a strong cation exchange unit.

Weak Acid Cation Exchanger Resins. Weak acid cation (WAC) resin consisting of the ionizable group is a carboxylic acid (COOH) as opposed to the sulfonic acid group (SO_3H) used in strong acid resins. These resins behave similar to weak organic acids that are weakly dissociated. When operated in the hydrogen form, WAC resins remove cations that are associated with alkalinity, producing carbonic acid as:

$$2\text{Na}\ 2\text{Na}$$

$$\text{Mg}\ 2\text{HCO}_3 + 2(\text{R-COO})\text{H} \leftrightarrow 2(\text{R-COO})\text{Mg} + 2\text{H}_2\text{CO}_3$$

$$\text{Ca}\ \text{Ca}$$

These reactions are also reversible and permit the return of the exhausted WAC resin to the regenerated form.

WAC resins are not able to remove all of the cations in most water supplies. In some plants, to achieve full demineralization, SAC and WAC resins are used in a series combination (as shown earlier in Figure II/8.2 for an economic solution by using a more efficient WAC resin along with the full exchange capabilities of the SAC resin. They alone are used primarily for softening and dealkalization of high-hardness, high-alkalinity waters. The degree of dissociation of a weak acid resin is significantly influenced by the solution's pH and therefore the resin's capacity depends in part on solution pH.

Weak acid resins exhibit a much higher affinity for hydrogen ions than for strong acid resins. This characteristic allows for regeneration to the hydrogen form with significantly less acid than is required for strong acid resins. Almost complete regeneration can be accomplished with stoichiometric amounts of acid. Their primary asset is their high level of regeneration efficiency compared with SAC resins. This high efficiency reduces the amount of acid required to regenerate the resin, thereby reducing waste acid and minimizing disposal problems.

8.4.1.4.3 Anion Exchanger Resins In DM plant applications, the anion exchanger resins exchange negatively charged hydroxide mobile ions (OH^-) for the negatively charged ions (e.g., chloride, sulfate, nitrate) from the polluted water. For example, a resin with hydroxide ions available for exchange would exchange chloride ions from the solution. The reaction can be written:

$$(\text{R-Q})(\text{OH}) + \text{HCl} \rightarrow (\text{R-Q})\text{Cl} + \text{H}_2\text{O}$$

Where,

(R-Q) = anion resin
R = organic portion of resin
Q = immobile portion of the ion active from the quaternary ammonium functional group (discussed later)

The reaction, as just indicated, means that the ion exchange process is reversible. The degree of the reaction to proceed to the right would depend on the resin's preference or selectivity. The selectivity of a resin for a given ion is measured by the selectivity coefficient.

Strong Base Anion Exchanger Resins. Like strong acid resins, strong base resins are highly ionized and can be used over the entire pH range. These resins are utilized in the hydroxide (OH) form for water deionization. They react with anions in solution and can convert an acid solution to pure water. SBA resins derive their functionality from quaternary ammonium functional groups, as follows:

Quaternary ammonium compound: This may be described, in general, as any of a group of compounds in which a central nitrogen atom is joined to four organic radicals and one acid radical. More specifically, it may be a type of ionic compound that can be regarded as derived from ammonium compounds (NH_4) by replacing the hydrogen atoms with two organic groups: (1) R_1 and (2) R_2 $NR_3 + R_4$.

Quaternary ammonium cation: The R (organic) groups may be the same or different alkyl or aryl groups. In addition, the R groups may be connected.

Ammonium cations: Also known as quats, they are positively charged polyatomic ions of the basic structure NR_4^+. The quaternary ammonium cations are permanently charged, independent of the pH of the

www.EngineeringBooksPDF.com

solution it belongs to. Quaternary ammonium salts or quaternary ammonium compounds are salts of quaternary ammonium cations with an anion.

Two types of quaternary ammonium groups, referred to as Type I and Type II, are used. Type I sites have three methyl groups: (1) CH_3, (2) R N CH_3^+, and (3) CH_3. In a Type II resin, one of the methyl groups is replaced with an ethanol group. The Type I resin is more stable and effective with regard to removal of the weakly ionized acids compared to the Type II resin.

Type II resins exhibit a more efficient resin as far as regeneration is concerned. When in the hydroxide form, SBA resins remove all commonly encountered anions as shown:

$$2H_2CO_3\ 2HCO_3$$

$$H_2SO_4 + 2(\text{R-Q})\text{OH} \leftrightarrow 2(\text{R-Q}).\ SO_4 + 2H_2O$$

$$2\text{HCl}\ 2\text{Cl}$$

These reactions are reversible, allowing for the regeneration of the resin with a strong alkali (e.g., caustic soda) to return the resin to the hydroxide form.

The typical specification for SBA generally is stated: "Isoporous/macroprus, Type I in (OH) form, to be regenerated with caustic soda. The attrition loss of the anion resins be limited to ~3 to 4 % per year for the first three years of operation."

Weak Base Anion Exchanger Resins. Weak base resin or WBA resins derive their functionality from primary (R-NH_2), secondary (R-NHR′), or tertiary (R-NR′$_2$) amine groups. WBA resins readily remove sulfuric, nitric, and hydrochloric acids, as represented by the following reaction:

$$2HNO_3\ NO_3$$

$$H_2SO_4 + 2(\text{R-Q})\text{OH} \leftrightarrow 2(\text{R-Q})SO_4 + 2H_2O$$

$$2\text{HCl}\ 2\text{Cl}$$

WBA resins are like weak acid resins with regard to the degree of ionization, which means that it is also significantly influenced by pH. Consequently, weak base resins exhibit minimum exchange capacity above a pH of 7.0. These resins just absorb strong acids but are almost inactive toward splitting purpose of salts. Anion resin is much lighter than cation resin; therefore, the backwash flow rates for anion exchange resins are much lower than those for cation resins.

8.4.1.4.4 Mixed Bed Exchangers The mixed bed exchanger is a very important item used in both a DM plant as well as in a CPU; it is briefly discussed in Clause 3.6.6.3.1) of this chapter. The difference is that in a CPU the MB exchanger is normally used as the only exchanger, whereas in the DM plant, it is used following the cation and anion exchangers in a series combination. The regeneration process is also different in those two systems.

It has been stated already that the mixed bed exchanger has both cation and anion resins mixed together in a single vessel. The same resins are used as discussed earlier; however, the ion-exchange process is repeated many times when water is guided to flow through the mixed resin bed. This repeated exchange causes the water quality to become highly pure and, thus, the process may be termed *polishing*.

More sophisticated equipment having mixed bed systems with a counterflow arrangement is employed to yield purer water than conventional cation–anion demineralizers, obviously at the price of a costlier system. It also calls for more intense operator attention than a standard system when a complicated regeneration sequence is adopted.

8.4.1.4.5 Regeneration of Resins Ion-exchange reactions are stoichiometric, which means they are predictable based on chemical relationships and are reversible. Here, the ion exchangers exchange one ion for another, hold it temporarily, and then release it to a regenerant solution (refer to Figures II/8.1 and II/8.2).

When contaminant water is passed through the resin beds, the capacity of the resins is reached after prolonged "service" operation. The resins become exhausted and are not capable of removing the unacceptable ions any more. There usually are three basic methods followed as an indication of resin exhaustion and that the exchanger should be taken out of service:

1. Time elapsed (timer used)
2. DP crosses exchanger more than a set value
3. Concentration of chemicals at the bed less than set value

Any combination of these could also be used. As stated earlier, the ions become attached to the resin through the replacement of the H^+ or OH^- ions originally attached to the resins. This step is followed by backwashing to expand and resettle the resin bed. The backwash step enables the removal of suspended solids accumulated in the bed during the service step and eliminates channels that may have formed during this period. The backwash flow fluidizes the bed, releases the trapped particles, and reorients the resin particles according to size.

These ions are finally removed with the effluent during the regeneration process step where a strong solution of regenerant, containing the ions originally attached (H+ or OH- ions) to the resin, is passed over the bed. After this step, the rinse step follows by passing water through it to remove excess regenerant from the exchanger.

Cation Regeneration. Strong acid resins may prefer Mg or Ca over hydrogen. Despite this preference, the resin

www.EngineeringBooksPDF.com

can be converted back to the hydrogen form by contact with a concentrated solution of sulfuric acid (H_2SO_4):

$$(R\text{-}SO_3)_2Ca + H_2SO_4 \leftrightarrow 2(R\text{-}SO_3H) + CaSO_4$$

This step is known as *regeneration*. In general terms, the higher the preference a resin exhibits for a particular ion, the greater the exchange efficiency in terms of resin capacity for removal of that ion from a solution. A greater preference for a particular ion, however, will result in increased consumption of chemicals for regeneration.

Regeneration ensures that the resin is converted back to the hydrogen form (regenerated) by contact with a strong acid solution, or that the resin can be rearranged to the sodium form with a sodium chloride solution. Hydrochloric acid (HCl) also can be used for regeneration. Cation regeneration pumps normally draw suction from degassed water storage tanks.

The total concentration of the strong acids in the cation effluent is a measure of the effectiveness of the resin in use. It expressed in terms of free mineral acidity (FMA). During the normal service period, the FMA content is stable for most of the time. The FMA usually is slightly lower than the theoretical value because a small amount of sodium leakage takes place through the cation exchanger. The amount of sodium leaked depends on the regenerant level, the flow rate, and the presence of sodium compared to other cations in the inlet water. Sodium leakage increases as the ratio of sodium to total cations increases and as the regenerant level decreases and flow rate increases.

FMA in the effluent drops sharply when a cation exchange unit nears exhaustion; this means an immediate withdrawal of the service run of the exchanger and regeneration of the resin with an acid solution should begin. Sulfuric acid normally is used due to its cost advantage and availability although improper use of sulfuric acid can cause irreversible fouling of the resin with calcium sulfate. Sulfuric acid is usually applied at a high flow rate and an initial concentration of 2% or less. The acidic concentration is gradually increased to 6 to 8% to complete regeneration. Some installations also use hydrochloric acid for regeneration. This necessitates the use of special construction materials in the regeneration system.

Counterflow cation exchanger regeneration methods have been introduced by some manufacturers to improve on the purity of water. A conventional regeneration method is a cocurrent means to direct water flow; it is the same in both service and regeneration.

After regeneration, some ions, mostly sodium ions, still remain unaffected in the bottom of the resin bed although the upper portion of the bed has been exposed to fresh regenerant and is thus highly regenerated. During service operation, cations are readily exchanged in the upper portion of the bed for the first few periods and then move down through the resin as the bed starts to become exhausted. Sodium ions that remained in the bed after regeneration diffuse into the service water before leaving the exchanger. This sodium leakage enters the anion unit where anion exchange produces caustic, raising the pH and conductivity of the effluent.

In a counterflow method, the regenerant flows in the opposite direction of the service flow. For this, the most highly regenerated resin is located where the service water leaves the exchanger. The newly regenerated resin removes the low level of contaminants that have escaped removal in the top of the bed. This results in higher water purity than cocurrent designs can produce. The same philosophy can be adopted in the case of an MB exchanger.

Anion Regeneration. The anion exchange resins are generally regenerated with sodium hydroxide (48% w/v rayon grade in lye form (as per IS: 252) solution of suitable strength. The need for regeneration is sensed by the output of the continuous measurement of conductivity and monitoring silica analyzers' output readings of anion effluent water quality. In some instances, conductivity probes are placed in the resin bed above the underdrain collectors to detect resin exhaustion before silica breakthrough into the treated water occurs.

The equipment configuration and sequence of operation is similar to that of cation regeneration. Power water pumps provided for anion units draw water from DM water storage tanks. The water used for each step of anion resin regeneration should be free from hardness; to prevent precipitation of hardness, place salt in the alkaline anion resin bed. Continuous conductivity and silica analyzers are used mostly to monitor anion effluent or outlet water quality and to detect the need for regeneration. In some instances, conductivity probes are placed in the resin bed above the underdrain collectors to detect resin exhaustion before silica breakthrough into the treated water occurs.

It may appear that complete removal of the cations and anions is possible; however, in reality some leakage takes place (i.e., mostly sodium leakage from cation exchanger). This sodium is converted to sodium hydroxide in the anion exchanger and to make the effluent pH of anion outlet slightly alkaline. The caustic produced in the anions causes a small amount of silica leakage. The extent of silica leakage from the anions depends on the quality of inlet water and the regenerant dosage being used.

Demineralization using strong anion resins removes silica as well as other dissolved solids. Effluent silica and conductivity are important parameters that dictate the service run period of the system. When silica breakthrough occurs near the end of a service run, the effluent silica level increases sharply with a momentary decrease in conductivity. This is because of exhaustion of hydroxide ions and conversion sodium into sodium silicate (low conductivity) rather than sodium hydroxide. As anion resin nears

www.EngineeringBooksPDF.com

complete exhaustion, the more conductive mineral ions breakthrough, causing a subsequent increase in conductivity.

On detection of the end of a service run, the unit must immediately change over to the next step of operation. If the plant is allowed to remain in the service mode after the breakpoint, the silica level in the effluent can increase beyond that of the influent water as a result of the concentrating of silica that already occurred inside the anion exchanger during the run.

Sodium hydroxide (4%) or a caustic solution is used for regeneration of SBA exchangers, usually heated to 50°C or to the temperature specified by the resin manufacturer to improve on the removal of silica from the resin bed, Silica removal is also enhanced by a resin bed preheat step before introduction of warm caustic.

Mixed Bed Regeneration. During MB regeneration, the resin is separated into distinct cation and anion fractions. The procedure is somewhat different from that of individual cation and anion regeneration. Here, the two resins are first separated by backwashing; this causes the anion resins to settle on top of the cation resin because of their lighter weight. Regenerant acid is introduced through the bottom part of the vessel and caustic is introduced through the top part of the vessel. The two different regenerant streams coming from opposite sides meet at the interface between the cation and anion resin and are arranged to discharge through a collector near the resin meeting plane. After the regeneration step and the following the rinse step, air and water are blown in for intermixing of both the resins (refer to Figure II/8.2). Then, again the resins are rinsed, and the unit is ready for service.

8.4.1.5 Decarbonators and Degassers

This part of the DM plant is included mainly as an economic measure. Decarbonators and degassers are beneficial to the next part of the system where they are installed. As can be observed, the effluent coming out from the cation exchanger contains carbonic acid as a product of the reaction; this, again, needs to be neutralized by the anion exchanger vis-à-vis requirements for an excess amount of caustic for regeneration.

Outlet water from a cation exchanger is split into small droplets by sprays and trays in a decarbonator. The water is then allowed to flow through a stream of oppositely flowing air. Due to this process, the carbonic acid contained in the cation effluent dissociates into carbon dioxide and water. The gas emitted (i.e., carbon dioxide) is separated from the water by the air stream, thus reducing the burden of the anion exchanger. Forced draft or blower-type decarbonators are generally used for removing carbon dioxide (CO_2) to an acceptable limit (e.g., 10–20 ppm). There is a minor problem with this method: the water effluent from a decarbonator is saturated with oxygen.

In a vacuum degasser, which more effectively removes CO_2, the process is slightly different. The water droplets are allowed to pass through a packed column operated under a vacuum. Carbon dioxide is removed from the water due to its decreased partial pressure in the vacuum. The removal of CO_2 can be done up to the level of >2 ppm. The additional advantage of a vacuum degasser is that most of the oxygen is removed from the water. The capital and running cost of a vacuum degasser is greater than that of forced-draft decarbonators.

8.4.1.6 Drain Neutralization System

The drain neutralization system is provided to neutralize the waste drains from all the previously mentioned vessels handling chemicals, including the acid/caustic measuring tanks. The neutralizing pit accommodates all wastes which are neutralized by dosing suitable additive from dedicated acid/caustic measuring tanks. The capacity normally is estimated to be sufficient for storing all wastewater from one cation, anion, and mixed bed unit with ~50% margin and can be of RCC construction in twin compartments. The mixing is done by recirculation of wastes and acid/alkali dosing. The neutralized disposal is made by providing separate pumps for transferring waste to effluent treatment plants.

8.4.2 Advantages and Limitations

High-quality water can be produced by several other methods, including distillation. The cost of a DM plant is comparatively much less than any other system. As the system utilizes the process of ion exchanging, the inlet water quality requirements are maintained for efficient operation of the plant. Some of the system's items are:

- Filtered water required at the inlet
- Iron and chlorine, considered as resin foulants and degrading agents, are to be removed to the maximum extent possible
- Organic materials are considered a threat to anion resins because they attack and cause fouling
- Colloidal or nonreactive forms of silica are not removed using a DM plant. Even if the hot alkaline boiler water dissolves the colloidal material, they form simple silicates that may enter the boiler in a soluble form; as such, they can form deposits on tube surfaces and volatilize into the steam

8.5 Expected Quality of Various Components

As all the components discussed before are selected for their specific contribution to making high-quality water suitable for use for the modern thermal power station, some guidelines

www.EngineeringBooksPDF.com

TABLE II/8.5-1 Expected Parameter Values at Vessel Outlet

Outlet	PSF	ACF	SAC	Degassifier	SBA	MB
Reactive silica					<−0.1 ppm as SiO_2	<0.01 ppm as SiO_2
Conductivity					<5 micromho/cm at 25°C	<0.1 micromho/cm at 25°C
pH					>7.5	6.8−7.2
Sodium			<1 ppm as $CaCO_3$			
CO_2				< 5 ppm		
Free chlorine		Nil				

are provided so that the performance of the components are compared for necessary action. Table II/8.5-1 shows the expected parameter values (typical) of the measuring analyzers provided at the outlets of each vessel.

8.6 Controls and Instrumentation

8.6.1 Controls

A DM plant requires a totally sequential operation, covering the total interlock, protection, monitoring, alarm, data logging, fault analysis, etc., to ensure operability, maintainability, and reliability. The hardware may be programmable logic controller (PLC)-based or a microprocessor-based distributed control system (DCS). Remote I/O cabinets may be provided wherever required depending on distance/location and number of streams vis-à-vis inputs.

8.6.2 Instrumentation

The necessary instrumentation—namely, flow measurements, analyzers (e.g., for pH, conductivity, silica, traces of CO_2), level/limit switches, local gauges, etc.—are included in the complete package of the DM plant.

9. BASIC SYSTEM FUNCTIONS AND DESCRIPTION OF COAL HANDLING

A coal-handling plant (CHP) in a thermal power plant is a front-end facility with a primary function, in a nut shell, that is to receive coal and transfer it to the coal bunker. The proper coal size should be what is acceptable to the mills/pulverizers for further processing.

There are quite a few factors that dictate the design of the CHP (e.g., coal source, coal quality and size, transportation mode, main plant capacity), topography of the area, etc. The coal supplied directly from the mine to the various destinations (e.g., coal preparation plant, coal washeries, steam generation plant) is called *run-of-mine*, or ROM, coal. This coal contains rocks, other minerals, and a variety of contaminations contributed during the mining process; for example, machine parts, used consumables, and pieces of ground-excavation tools (e.g., shovels), among others. ROM coal also comes with a large moisture and particle size variability, depending on the types and locations of mines.

9.1 Influencing Factors of CHP Design

Figure II/9.1 illustrates some of the details about the design of a coal-handling plant.

9.1.1 Coal Source, Quality, and Size

Source and quality of coal are almost synonymous as the quality of coal primarily depends on the source. The source may vary in various ways; mainly, mine coal from the adjacent area or indigenous source. The second one is imported coal that is, of course, costlier but some expect it to be of better quality. The quality of the coal is indicated by the following terms, which also are responsible for assessing a variety of hardware and elements for the CHP:

- Gross calorific value (GCV)
- Hardgrove Grindability Index (HGI)
- Moisture content

There are certain other parameters by which the quality of coal can be assessed, including the amount of impurities that come with the coal and determination of the coal's grade. Those things are complex materials: ash and a variety of elements (e.g., sulfur, sodium, and phosphorus products); they either are not good for reliable heat transfer (i.e., a low efficiency), are detrimental to public health when burnt and residue goes out the chimney (e.g., chlorides, nitrates, and sulfates), or cause corrosion in the boilers. The generally accepted quality or grade can be grossly expressed by the heat available (i.e., useful heat value; UHV) from the coal, as follows:

Grade UHV × Range − Kcal/kg
A > 6200

www.EngineeringBooksPDF.com

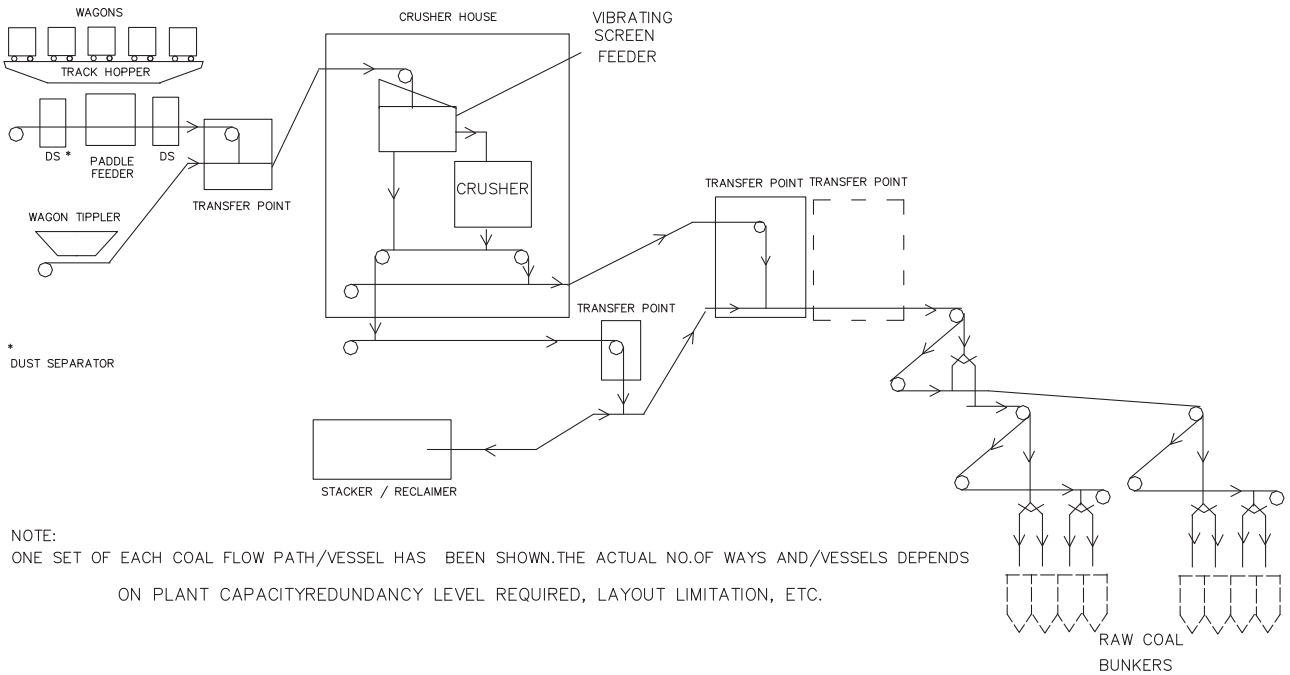


FIGURE II/9.1 Basic schematic/flow diagram of a coal-handling plant.

B > 5600 < 6200
C > 4940 < 5600
D > 4200 < 4940
E > 3360 < 4200
F > 2400 < 3360

According to the major coal grade classification system as far as type of availability is concerned, lignite (aka, brown coal) represents the bottommost position with anthracite at the top position. The subbituminous and bituminous coals are ranked in between. Each rank may be further subdivided according to the closed range UHV. Most of the minerals and traces of the various elements in coal convert into ashes after burning. In fact, ashes are nothing but oxides of the materials (e.g., oxides of iron, magnesium, etc.). The minerals that do not constitute ashes break down into gaseous compounds and go out the furnace's flue—for example, oxides of sulfur, commonly referred to as SO_x.

The mineral content present in coal dictates the type of ash produced after burning. The melting point or the fusion temperature of the ash in turn also influences the design of furnaces vis-à-vis the other parts of boilers. The types of test analyses done to assess the type of coal available in the power plant for producing electricity are shown in Table II/9.1-1.

9.1.1.1 Blending of Coals

Nowadays many operations people in power plants in India accept the concept of utilizing the facilities for blending of indigenous and imported coal because of the shortage of Indian coal. Sometimes the environmental reasons may necessitate coal blending as well, and it can be done in many ways. One method is to provide the facility itself with a coal-handling system in order to lay indigenous and imported coal in alternate layers on the belts while conveying coal to the bunkers; then, the coal layers can be mixed while falling into them. The other method is to stock indigenous and imported coal in layers in a stockyard. The CHP broadly needs to have the following subsystems:

- An unloading mechanism
- Screening, stacking, and crushing equipment
- Storing and reclaiming locations
- A way to transfer coal to bunkers

9.2 Unloading

Normally, the coal received at thermal power stations is unloaded by means of a track hopper, a wagon tippler, or by a combination of both depending on the type of coal rakes used for transportation of coal to a particular plant. There are many variations of transporting wagons and the track hopper at the receiving end has to be suitable for the particular wagon type as per prior discussion with railway authorities while designing the unloading system. Both a wagon tippler and a track hopper perform well for a properly designed unloading system because both systems are proven and time-tested in practice, plus work satisfactorily at many places around the world. Some factors influence the

www.EngineeringBooksPDF.com

TABLE II/9.1-1 Analysis and Assessment of Coal Quality

1	Proximate analysis (in %)	Ultimate analysis (in %)
2	Moisture – 2.6	Nitrogen – 1.5
3	Hydrogen – 5.0	Ash – 15.11
4	Volatile matter – 32.2	Carbon – 67.6
5	Fixed carbon – 50	Oxygen – 9.6
6		Sulfur – 1.2
7		Calorific value – 6,700 Kcal/kg
8		Air-dried loss – 0.3
9		Forms of sulfur: Sulfate – 0.01 Pyritic – 0.66 Organic – 0.55

selection: past experience, preference, groundwater level, cost of underground installation vis-à-vis economic considerations, etc. So, technically, both the systems are workable. The two unloading systems are briefly described in the following subsections.

9.2.1 Track Hopper Unloading System

Here, the coal is received through wagon rakes with a side or bottom opening arrangement. Previously, wagons with side-opening panels were provided and need to be opened manually. Now, with the improved wagon type, a pneumatically or hydraulically operated discharge arrangement is used; coal comes from the bottom so this has become more popular. If a power station is situated in close proximity to the mine, then some clients prefer the bottom-discharge type of wagon with a merry-go-round system for a track-unloading hopper.

The received coal is then unloaded into an underground reinforced concrete cement (RCC) track hopper. Paddle feeders are provided under the track hopper to scoop the coal and feed it onto relevant underground conveyors. A belt-weighing arrangement is provided on these conveyors for measurement of coal-flow rate. The track unloading hopper system by merry-go-round railways was introduced at a later date compared to its counterpart but has found many customers. Many of the existing plants still have track hopper unloading systems.

9.2.2 Wagon Tippler Unloading System

The railways in many countries are not in favor of supplying coal by bottom-discharge wagons. So the only option left is to go for wagon tippler installation by default. In many countries, the number of installed wagon tippler unloading systems is more than that of track hoppers. The coal received from suitable wagons is unloaded in underground RCC hoppers by means of rotary-type wagon tipplers. Side arm chargers are employed for placement of wagons on the tippler table and removal of empty wagons from it after tippling.

Apron feeders are employed under each wagon tippler for extracting coal from the hopper and feeding it onto underground reclaim conveyors. Belt weigh scales are provided on these conveyors for measurement of the coal-flow rate. A provision is maintained for shunting locomotives to place the rakes in position for the side arm charger to handle and to begin the unloading operation.

9.3 Coal Crushing

It has been stressed that the coal supplier should initially crush the materials to a maximum size; however, this is not practical. To circumvent the situation, the crushing provision is kept in the CHP so that the coal bunker receives the materials at a maximum size of $\sim$20 to 25 mm. The unloaded coal in the hoppers is transferred to a crusher house using belt conveyors. There may be different stopovers (e.g., pent house, transfer points) depending on the plant vis-à-vis CHP layout.

Suspended magnets for removal of tramp iron pieces and metal detectors for identifying nonferrous materials are provided at strategic points to avoid unacceptable materials before crushing. There may be arrangements for manual stone picking from the conveyors at suitable locations; the previous two systems are not supposed to render any sort of assistance. The crusher is, however, by-passed if properly sized coal is received, thus coal is sent directly to the stockyard. A coal-sampling unit is provided to evaluate the uncrushed coal. Online coal analyzers are also available; this is costly item and its use depends on budget allocations.

www.EngineeringBooksPDF.com

As stated earlier, the average size of the coal sent by the supplier is expected to be <300 mm but may be something else depending on the agreement or coal tie up. These are designed to convert larger size coal into a small size up to ~20 to 25 mm. Screens (e.g., vibrating grizzly-type or roller screens) are provided upstream of the crushers to sort out smaller size as stipulated and larger pieces coal are guided to the crushers.

An appropriate type of isolation gate (e.g., rod, rack, and pinion) are provided before screens to isolate one set of crushers/screens to carry on maintenance work without affecting the operation of other streams. Screens allow coal particles of <25 mm (typical) size to bypass the crusher and coal >25 mm is then fed to crushers. A set of rod and rack-and-pinion gates is provided before screens to permit maintenance of equipment downstream without affecting the operation of the other stream. The crushed coal either is fed to coal bunkers of the boilers or discharged onto conveyors for storage in a coal stockyard using conveyors and transfer points, if any.

9.3.1 Coal Crusher Classifications

In general, coal crushers are categorized into two types and three types of primary crushers, as follows:

Primary coal crusher: Used for larger coal size. The primary coal crushers may be of different types such as: (1) coal jaw, (2) coal hammer, and (3) ring granulator.

Secondary coal crusher: Used when the coal coming from the supplier is large enough to be handled by a single crusher. The primary crusher converts the feed size to one that is acceptable to the secondary crusher.

9.3.2 Coal Jaw Crusher

This is used for crushing and breaking big or large coal in the first step of a coal crushing plant and is the one applied the most widely in the coal crushing industry. Jaw crushers are designed for primary crushing of hard rocks without rubbing and minimum dust. They may be utilized for various materials (e.g., coal, granites, basalt, river gravel, bauxite, marble, slag, hard rock, limestone, iron ore, magazine ore) within a pressure resistance strength of 200 Mpa. Jaw crushers are characterized by different features (e.g., simple structure, easy maintenance, low cost), evenness of crushed materials, and high crushing ratio. This crusher also offers a high resistance to friction, abrasion, and compression with longer operating lifespan.

9.3.2.1 Jaw Crusher Operating Principle

There are two main components: a fixed and a movable jaw plate. The motor-driven eccentric shaft through suitable hardware makes the movable jaw plate travel in a regulated track and hit the materials in the crushing chamber comprised a fixed jaw plate to assert the compression force for crushing the materials.

9.3.3 Coal Hammer Crusher

A coal hammer crusher was developed for materials having pressure- resistance strength of more than 100 Mpa and a humidity of not more than 15%. Hammer crushers are suitable for mid-to-hard and light erosive materials (e.g., coal, salt, chalk, gypsum, limestone).

9.3.3.1 Coal Hammer Crusher Operating Principle

Hammer crushers are primarily steel drums that contain a vertical or horizontal cross-shaped rotor mounted with pivoting hammers that can freely swing on either end of the cross. While the material is fed into the feed hopper, the rotor that is inside the drum is spun at a high speed. Thereafter, the hammers on the ends of the rotating cross-thrust crush the material, thereby, shredding and expelling it through the screens fitted on the drum.

9.3.4 Ring Granulator

Ring granulator crushers are used for coal crushing to a size that would be acceptable to or suitable for the mills/pulverizers, which then convert it into powdered coal. The essence of using a ring granulator is that it prevents both oversize and undersize coal; this helps with the quality of finished product and improves its workability. Due to the crusher's strong construction, it is capable of being utilized for crushing various materials (e.g., coal, limestone, lignite, gypsum) and other medium-to-hard friable items. Ring granulators are rugged and dependable and specially designed for continuous high-capacity crushing of materials. They are available with operating capacities from 40 to 1800 tons/hr or even more, with feed size of up to 500 mm.

Adjustment of clearance between the cage and the path of the rings is provided to take care of product gradation as well as to compensate for wear and tear of the machine parts and to maintain product size. The unique combination of impact and rolling compression makes the crushing action yield a higher output with less power consumption and a lower noise level. Here, the product is almost of uniform granular size with an adjustable range of <20 to 25 mm, and because the crushing action involves minimum attrition, minimum fines result. Further development from the conventional hammer mill through replacement of hammers by rings makes it possible to minimize both oversize and fines, thereby improving efficiency.

9.3.4.1 Ring Granulator Operating Principle

Ring granulator crushers work on an operating principle similar to a hammer mill, where the only change is that the

www.EngineeringBooksPDF.com

hammers are replaced with rolling rings. This crusher compresses material by impact in association with shear and compression force. It is comprised of a screen plate/cage bar steel box with an opening in the top cover to introduce the material. The power-driven horizontal main shaft passes from frame side to frame side and supports a number of circular discs fixed at regular intervals along its length within the frame.

There are quite a few bars running parallel to the main shaft and around the periphery that pass through these discs near their outer edges. The bars are uniformly located about the center of the main rotating shaft. There are a series of rings, between the two consecutive disc spaces, mounted on each bar that are free to rotate on the bars irrespective of main shaft rotation.

The entire cage assembly, located below the rotor assembly, can be set at a desired close proximity to the rings by a screw jack mechanism that is adjustable from outside of the crusher frame. The rotor assembly, consisting of the shaft, discs, rings, etc., is fixed as far as the main shaft center line is concerned. This main shaft is carried in roller bearings from the box sides. The movable cage frame arrangement is provided so as to set its inner radius marginally larger than that of the ring running periphery.

When coal is fed from the top, the rings also rotate along with the shaft and around their own center line along the bars, which drag coal lumps and crush them to the desired size. After the coal has been crushed by ring granulator crusher, a vibrating screen grades the coal by size and then transports it via a belt conveyor. In this process, a dewatering screen to remove water from the product is optional.

9.4 Coal Stacker and Reclaimer at the Stockyard

The crushed coal is then fed either to the coal bunkers of the main SG plant or discharged onto conveyors for storage in the coal stockyard using conveyors and transfer points. Crushed coal is sent to the stockyard when bunkers are full. Stacking/reclaiming of coal is done by a bucket wheel-type stacker-cum-reclaimer moving on rails. The stacker–reclaimer stacks coal on either side of the yard conveyor. During the stacking operation, coal is fed from stockyard conveyors using a boom conveyor.

When direct unloading from rakes is not in operation, coal is reclaimed by the stacker–reclaimer and fed to the coal bunkers. During the reclaim operation, the boom conveyor discharges coal on the yard conveyor for feeding to coal bunkers through a combination of conveyors and transfer points. The stockyard conveyor can be a reversible type depending on layout requirements.

There may be an emergency reclaim hopper (ERH) to reclaim coal by dozers when a stacker–reclaimer is not in operation. An ERH also may be used for coal blending if such a provision is made. A coal stockpile is provided with the required storage capacity depending on location of the plant as well as coal source. Again, magnetic separators and metal detectors, for removal of metals (i.e., ferrous or nonferrous) from coal already crushed and now reclaimed, are provided at appropriate locations before transferring to bunkers. A coal-sampling unit is provided to sample crushed coal to check for the required size.

9.5 Dust Control and Ventilation Systems

The dust control system has now become an essential requirement of CHP for suppressing the emissions that take place at various locations (e.g., transfer points, feeders, crushers). Dust control is achieved by a dedicated dust suppression and extraction system. There are two widely accepted types—dry fog and plain water—and, in some cases, an extraction system, as follows:

Dry fog dust suppression system: Normally, this is provided for a wagon tippler hopper complex, crusher receipt, and discharge points, for all transfer points, boom belt discharge of stacker–reclaimer. etc

Plain water dust suppression system: This, normally, caters to the area the same as the track hopper and wagon tippler area, stock pile area (with a swiveling nozzle system); this also is very much required from fire-suppression point of view.

Dust extraction system: Generally, this is provided for specific locations (e.g., bunker floors, crusher houses, etc.); the system may be a Venturi scrubber one. One independent dust extraction system for each stream shall be provided.

Dust suppression/admission for all the working areas/locations and buildings/underground structures of a CHP may be available from the mechanical ventilation system/pressurized ventilation system to suit the requirements of a particular area.

The pressurized ventilation system is capable of pressurizing the inside of some closed areas slightly above atmospheric pressure to prevent the dust ingress from outside. Control rooms, offices, and remote terminal unit (RTU) rooms need to have an air conditioning system while the MCC/switchgear rooms of coal-handling plant may be provided with a pressurized ventilation system. The rest of the areas may need mechanical ventilation.

9.6 Other Important Accessories

There are other important accessories except those discussed previously that do take part in the CHP process; some of them are briefly described next:

Apron feeders: These are of robust construction and specially designed for handling ROM coal as normally

www.EngineeringBooksPDF.com

supplied. The additional feature is to have the capability to ward off the choking problem of wet coal that comes during the rainy season. A dribble conveyor is generally provided below the apron feeder for subsequent cleanup activities.

Vibrating grizzly screens: This type of screen is capable of segregating the required size of coal along with coal dust and any other contaminations (e.g., muck and mud) carried in the coal during rainy season. Below each screen, separate hoppers/chutes are provided through which the segregated materials are directly fed to the belt conveyors/feeders.

Vibrating feeders: These generally are provided to feed materials into the primary crusher homogeneously and continuously. At the same time, it is able to act as a screen, thus the crusher load is reduced. Vibrating feeders can continuously and evenly transfer materials to the crusher and roughly screen as well.

Conveyors: Generally, these have motors, gear boxes, couplings, and pulleys; they are like the arteries in a living body and transfer the coal throughout the wide expanse of the power plant.

Yard and boom conveyors: They are a special type of conveyor used for the stacker–reclaimer subsystem.

Side arm chargers: These are used for indexing the rake forward of loaded wagons, placing decoupled wagons on the tippler table and withdrawing from the empty wagons.

Paddle feeders: They are provided to scoop out coal at a guaranteed capacity in both forward and reverse motions.

Electric hoists/manual hoists: They are provided for handling of the equipment during maintenance.

Coal-sampling unit: This unit is included to provide suitable "samples" conforming to ASTM-D-2234 or any other applicable standard for laboratory coal analysis.

Magnetic separator and suspended magnet: The magnets are installed at strategic locations (e.g., before and after the crusher) to separate ferromagnetic materials such as nuts and bolts, MS plates and bars, etc. The strength of the magnet at the specified mounting height is typically 1000 gauss at the center point of the belt. Mounting heights vary depending on the type of location with a typical example of 450 mm before a crusher and 400 mm after a crusher; the height is measured between the top of conveyor belt or bottom of falling material trajectory (already discharged from head pulley) and the surface of the magnetic separator belt.

Metal detectors: These are installed at strategic locations to detect various materials (other than ferromagnetic materials) such as aluminum, brass, copper, stainless steel, manganese steel, bars, scraps, etc.

Chutes and hoppers: Chutes, in general, are used to direct the flow of bulk solids—for example, from one conveyor belt to another in the same or other direction. The minimum valley angle of chutes should be 60 degrees from horizontal. In case of a vertical chute valley, the angle would be >80 degrees. The hoppers are, on the other hand, used for intermediate storage of bulk solids. Here, the flow of material cannot be allowed to take place freely but is controlled to the required rate by some type of feeder. The materials flow from the hopper to the feeder at a continuous but regulated rate. Hoppers and chutes are made of good quality abrasive-resistant steel (e.g., LSLAS07) or equivalent material at more than the minimum thickness, as specified.

9.7 Instrumentation and Control

The sequential logic control system for a CHP normally is accomplished by a programmable logic controller (PLC)-based system or through microprocessor-based distributed control system (DCS) to take care of the huge number of inputs/outputs (I/Os) and associated tasks such as interlock and protection, monitoring, alarm and data logging, etc.

The control system enables selection of any coal flow path beginning from the receiving section to final destination, along with associated equipment such as wagon tippler/track hopper, crushers, screens, feeders, etc., from the CHP control room. A separate PLC-based system may be provided for stacker–reclaimer, wagon tipplers, dust extraction suppression subsystems and then hooked up to main CHP control system via a suitable link.

Local start/stop pushbutton stations and deinterlock switches are mounted near each piece of equipment for starting and stopping during test/maintenance of the system. The communication facility is between the CHP control room and all the important strategic points such as wagon tippler/track hopper control room, stacker–reclaimer control cabin, bunker floor, main unit control room (UCR), etc. The following minimum number of field/process switches, along with the measuring instruments, are provided:

- Belt sway switches
- Pull chord switches
- One no zero speed switch at tail-end for each conveyor
- Level switches in dust suppression system water tanks
- RTDs for conveyor drive motors at crusher motors (for HT motors only)
- Chute blockage switch at a suitable height
- RTDs for conveyor drive motors and crusher motors (for HT motors only)
- Electronic static weighing to measure quantity of coal per wagon on wagon tippler table before and after tippling

www.EngineeringBooksPDF.com

- Vibration monitoring system for crushers and drives
- Electronic belt weighing system for the following locations:
  - Unloading conveyors to determine coal receipt rates
  - Boom conveyor of stacker–reclaimer to determine the coal reclaim rates
  - Belt conveyors to determine quantity of coal reclaimed/blended
  - Conveyor feeding bunkers to deterinem fuel feed rates to coal bunkers

9.8 Brief Details about Conveyor Safety Switches

9.8.1 Pull Chord Switch

These are used to stop the conveyor in case of an emergency. Rope-operated emergency switches can be mounted at equidistant (normally 10 M) places on either side along the conveyor. When pulled, the switch remains in a latched position unless it is manually reset to avoid accidental restart. The rope is tied to the end rings of the lever and is carried opposite to each other. When the rope is pulled from any side, the switch is operated. Normally, the lever is 45 degrees on either side, so when pulled a snap action occurs so that the switch stays put and operates with moderate torque. These are available in an IP 55/65 enclosure (flameproof or commonly a suitable class II enclosure). A contact rating of 10/15 A @500 V AC in changeover contact or 1 NO/1 NC are standard.

9.8.2 Belt Sway Switch

To protect the conveyor from damage due to misalignment, these switches are used. The switches can be mounted at equidistant (normally 25 M) places on either side along the conveyor. In case of excess sway, an edge push operating lever (45 degrees on either side when angle changes, say to 30 degrees) actuates the switch; these may be self-resettable. Normally, belt sway switches are available in an IP 55/65 enclosure (flameproof or a commonly suitable class II enclosure). The contact rating is 10/15 A.

9.8.3 Speed Switch (Zero Speed)

Monitoring of speed is essential in an automation system. In speed control-modulating loops, a continuous monitoring speed is required, whereas a CHP zero-speed switch is required for conveyor operation. Also under-/overspeed switches can be used. Noncontact-type sensors are used for speed monitoring. These are mounted near the rotating device with a metallic flag. Thus, pulses are generated as the flag passes, and same pulse is sent to a conditioning device. When the pulse count goes beyond a set point output, the relay operates to give contact. The speed settings, generally, are adjustable from 5 to 5000 RPM and may be self-resettable. Normally, they are available in IP 55/65 enclosure (flameproof or a commonly suitable class II enclosure). A contact rating of 10/15 A @500 V AC in changeover contact or 1 NO/1 NC are standard.

10. BASIC SYSTEM FUNCTIONS AND DESCRIPTION OF ASH HANDLING

Coal-based thermal power plants require a huge amount of coal to be burnt as a part of continuous process and the consequence is the production of ash, also in a considerable amount and continuously as well. The ash thus produced demands immediate removal to ward off associated hazards caused by its accumulation. A very rough figure suggests that ~200 tons/hr (TPH) of ash production is very likely in a 2 × 250 MW plant using only indigenous coal. The actual quantity, of course, depends on several factors (e.g., gross calorific value, ash content, and other analysis values of the coal received). A brief overview of an ash-handling system is presented in Figure II/10.5.

Ash is basically the unburnable part of coal and the oxides of mainly various metals (e.g., SiO_2, Al_2O_3, Fe_2O_3, CaO, MgO). It is most often sand and clay that somehow gets mixed with the carbon of the coal. Commercially available good-quality coals normally range from 10 to 15% ash, whereas bad-quality coal ranges from 35 to 45% ash. After burning, the ash is either removed from the combustion chamber or from the special equipment called an *electro-static precipitator* (ESP) in the flue gas path that is provided for arresting and collecting the flying ash.

Some part of the ash is produced in the form of very fine grains that fly away with the flue gas, which is thus termed *fly ash*. The other ash part, comparatively coarser, cannot fly away and gets collected in the hopper at the bottom of the furnace; thus, it is called *bottom ash*.

Small quantities of ash are also collected in the air preheater, economizer, and stack. The total system, starting from collection to disposal of this by-product, is taken care of in a separate plant subsystem called an *ash-handling plant* (AHP). Size, percentage contribution, and location of the various kinds of ash in thermal power plants are shown in Figure II/10.1(b). Out of the total ash in the boiler, more than 80% of it is fly ash. Ash from AHP and economizer contributes around 1% each of the total ash. The rest, ~20% of total ash, is mainly bottom ash collected from the bottom of the furnace.

Previously most of the coal-fired power plants made use of the wet slurry system to convey all types of ash from the boiler and accumulated it in ash ponds. This scenario started changing from the late 1970s and dry-type fly ash collection systems began to be accepted by the plant

www.EngineeringBooksPDF.com

authorities. Nowadays, almost all the coal-fired plants are phasing out pond-based systems and adopting fly ash disposal. Even the bottom ash disposal system has grown popularity for semidry or dry ash disposal. The main reason for switching to the dry fly ash system is that its demand as a raw material of cement and asphalt plants, etc., and the capacity constraint of the ash ponds.

In some countries, there is an unambiguous stipulation regarding bottom ash disposal—for example, in India as per the Ministry of Environment and Forests (MoE&F). Bottom ash normally is disposed of in slurry form at almost all power stations. In some of them, semiwet bottom ash disposal is done by using hydrobins; the ash collected is then transferred directly from the bins for end use. Dry bottom ash collection and disposal can also adopt this method if an end-user is available.

For dry fly ash a full-capacity extraction system can be provided to facilitate utilization of fly ash in dry form. In addition, a wet slurry system or high concentration slurry disposal system (HCSD) is often provided to cater to 100% ash; such is used to store the balance of the unutilized fly ash until its full utilization can be achieved. However, in cases where full utilization of fly ash is foreseen from the inception of the power plant on continuous basis, a wet slurry disposal system for it may not be installed.

10.1 PROPERTIES OF ASH

10.1.1 Physical Properties

The color of ash varies from tan to different shades of gray, depending on the presence of carbon particles because of incomplete combustion. The lighter shades of gray generally indicate a higher quality of ash and lower carbon content. A tan color is normally a result of lignite or subbituminous coal use.

Ash in its powdery form (i.e., fly ash or crushed/ground bottom ash) normally has a spherical shape and glassy appearance. Particle sizes vary, however, in accordance with the type, grade, or rank of coal used. The specific gravity of ash may vary in the range of ~2.0 to 3.0.

10.1.2 Chemical Properties

The chemical properties of ash also depend on the type of coal burned as well as the handling and storage of it. As

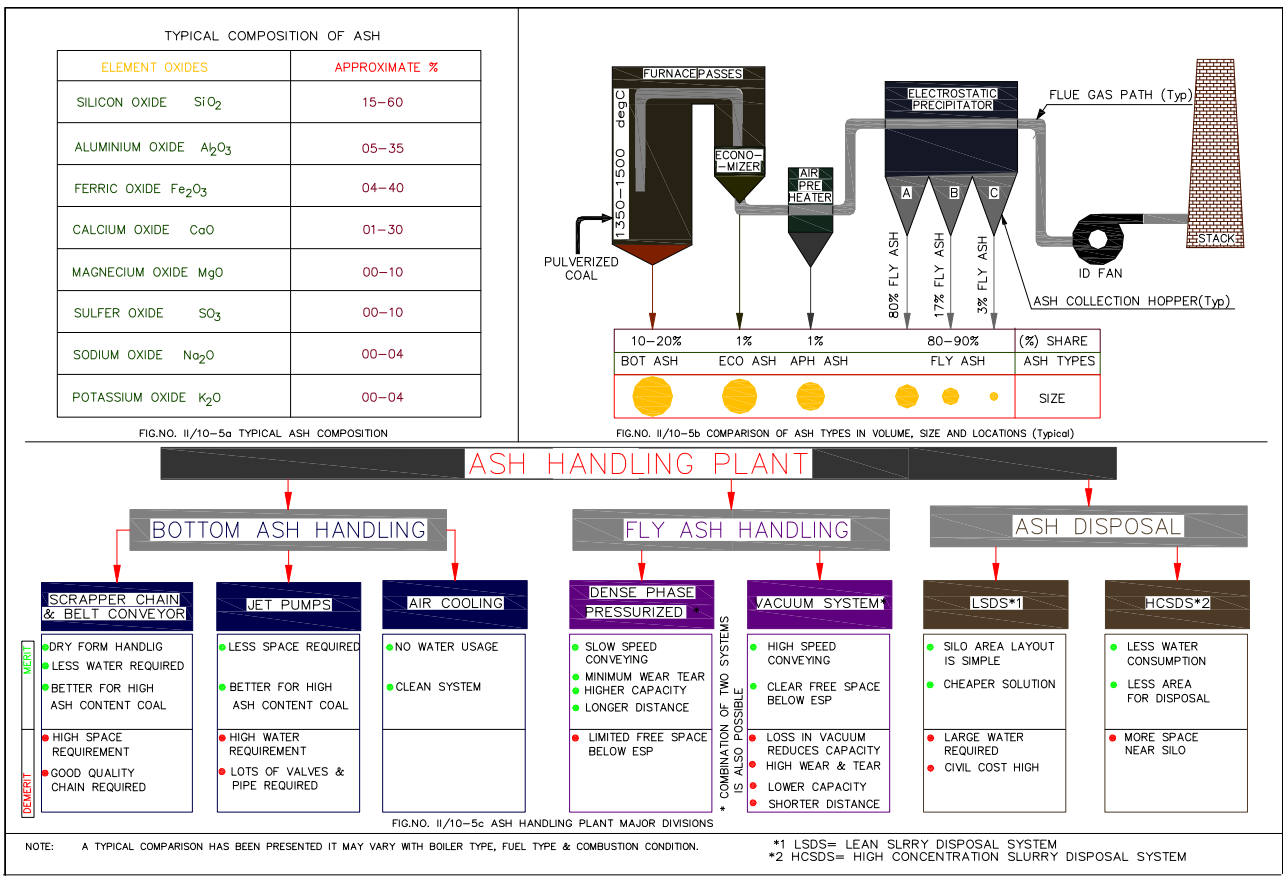


FIGURE II/10.1 Ash-handling system overview (typical).

www.EngineeringBooksPDF.com

TABLE II/10.1-1 Oxide Forms of Various Metallic Elements in Ash

Metal Name	Silicon	Aluminium	Iron	Calcium	Magnesium	Sulfur	Sodium	Potassium
Oxides	SiO_2	Al_2O_3	Fe_2O_3	CaO	MgO	SO_3	Na_2O	K_2O
App. % in ash	15∼60	5∼35	4∼40	1∼30	0∼10	0∼10	0∼4	0∼4

already stated, the main constituents of ash are various kinds of oxides (i.e., silica, alumina), and oxides of iron, calcium, magnesium, sulfur, sodium, potassium, etc. The other important thing is, of course, the percentage of unburnt carbon; this is measured by the loss on ignition (LOI) method, It is considered a significant chemical property of ash and used as a guideline as to the suitability of it for use as a substitute for cement in concrete.

The oxide forms of various metallic elements present in the ash produced in a thermal power plant are given in Table II/10.1-1 as typical examples. The percentage varies due to type of coal burnt (e.g., bituminous, subbituminous, lignite) and other factors—for example, the geographical source of coal. Anthracite coal is rarely used in thermal power plants and therefore not considered here.

10.2 Influencing Factors of AHP Design

There are some major factors that influence the concept design of ash handling in a power plant, including the following:

- Station capacity vis-à-vis total coal requirement
- Gross calorific value (GCV) of coal specified in the design
- Ash content of worst coal

All these factors have a combined effect to determine the total quantum of ash to be handled and thus the sizing of the equipments envisioned or an AHP.

10.3 Mode of Ash Disposal

There are two elemental processes termed *dry ash system* and *wet slurry system*. Another system called a *semiwet system* also exists; it is a combination of the other two. The very name of the systems indicates the nature of the individual process and are discussed briefly in the next subsections. The AHP of a coal-fired thermal power station normally consists of one of following methods for handling the various categories of ash.

10.3.1 Bottom Ash Systems

Bottom ash (BA) is the coarser and heavier part (∼10–20%) of the total ash produced, which, due to gravity action, falls to the bottom of the furnace vis-à-vis the combustion chamber and is collected using this system. The hot ash, when gathered at the bottom of hoppers and cooled, forms into clinkers as a hard deposit. **BA** collection and removal systems may be any of the three processes—wet, dry, semiwet—or a totally dry type. The designer/client selects one per their suitability with reference to the type of ash vis-à-vis coal grade and techno–economic considerations.

10.3.1.1 Wet Bottom Ash System

In this system, the bottom ash is collected and extracted from a water impounded in a specially shaped storage type of refractory lined hopper that facilitates intermittent removal. The hoppers are provided with a water seal trough and dip plates to make them suitable for arresting any air ingress during expansion of the furnace at higher temperatures. The shape of hopper depends on many factors—namely, type of furnace, type and amount of bottom ash produced, etc. (Figure II/10.2). Provisions are there for overflow and makeup of water on a continuous basis to maintain the temperature in the bottom ash hopper at 60°C.

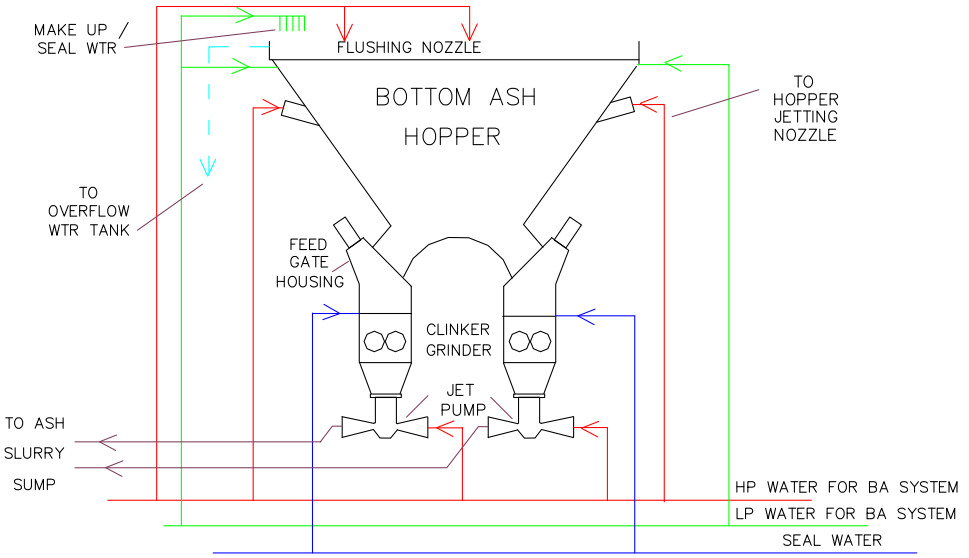
Extraction of ash is done through operation of the inclined feed gate at the bottom of the hopper with an appropriate hydraulic/pneumatic actuator. High-pressure water supplied to the jet pump acts as motive water to pump the bottom ash slurry to dewatering bins/slurry sumps. The clinker grinder at each outlet is provided to convert the clinkers to smaller particles so that a slurry form is obtained for further transportation. When the feed gate opens and the jet pump operates at the hopper outlet, bottom ash slurry arrives at the common ash (fly and bottom ash) slurry sump or dewatering bins, as envisioned by the design, for final transporting to a destination ash pond.

10.3.1.2 Semiwet Bottom Ash System with Submerged Flight Conveyor

In a semiwet bottom ash **r**emoval system, with the help of hydrobins or dewatering bins, the ash collected is disposed of directly from bins in semidry form for end use. A hydrobin is essentially a form of dewatering bin. This system requires extraction of the BA from the ash hopper as a slurry using a slurry pump and transporting it to a dewatering bin located outside for ash–water separation.

As a part of the semiwet bottom ash removal system, this bin separates the BA by dewatering the conveying

www.EngineeringBooksPDF.com



NOTE: ONE SET OF EACH ASH FLOW PATH/VESSEL HAS BEEN SHOWN.THE ACTUAL NO.OF ACCESSORIES AND VESSELS WOULD DEPEND ON PLANT CAPACITY, REDUNDANCY LEVEL REQUIRED, LAYOUT LIMITATION, ETC.

FIGURE II/10.2 Schematic/flow diagram of an ash-handling plant's wet bottom ash disposal system.

supply water from incoming slurry. A submerged flight conveyor (SFC) system is also used to replace existing bottom ash equipment under the boiler with a submerged mechanical chain and flight conveyor. Ash accumulates in the upper trough, which is filled with water to quench and cool the ash. Horizontal flights move the accumulated ash along the trough and up a dewatering ramp. At the top of the ramp, the ash falls through a discharge chute to a truck or bunker. The BA in the bunker is picked up once or twice a day with a front-end loader and put into trucks or may be conveyed to hydrobins for water recovery.

The hydro/dewatering bin collects and dewaters BA solids to ~15 to 20% moisture. The clarified water thus available is stored in a surge tank, recirculated, and reused by introducing it into the conveying cycle. The dewatered and semiwet ash are then arranged for loading into trucks to be taken away to the proper utilization location. The dewatering hydrobin system renders advantages such as elimination of the ash storage ponds, a low initial cost, and avoidance of shutdown for conversion. The disadvantages are running cost and use of a huge quantity of water.

The coarse ash collected from economizer hoppers is connected to the BA hopper top (above the maintained water level) by means of an adequately sized sloping pipe, for transporting slurry by gravity, in the case of a jet pump system. However, if the calcium content is high in the economizer ash or the bottom ash hopper storage capacity is not adequate, the economizer ash is disposed of separately.

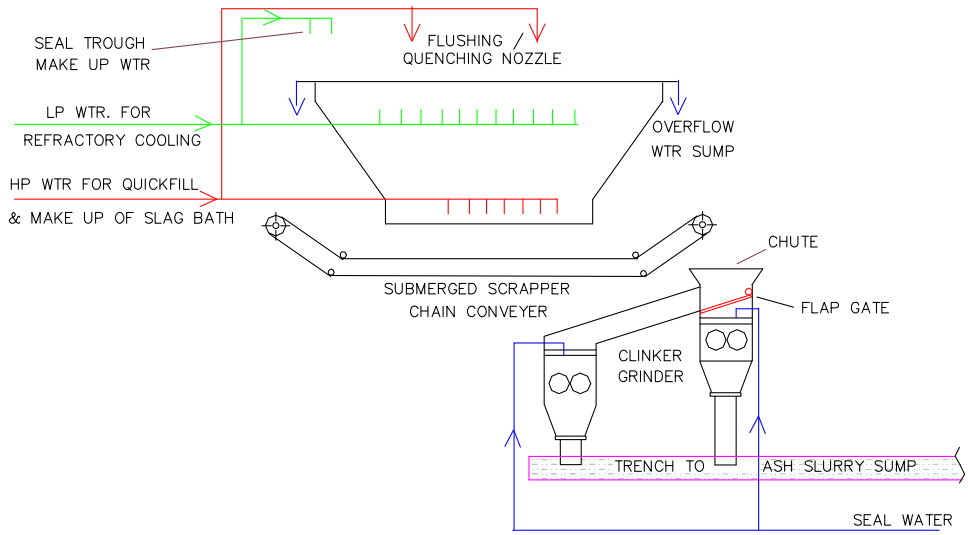
10.3.1.3 Semiwet Bottom Ash System with Submerged Scrapper Conveyor

For plants where intermittent extraction is not acceptable in the design, continuous removal of BA is stipulated. The system here is comprised of a dry-type refractory lined bottom ash hopper (BAH) of adequate capacity and proper shape. The hoppers are provided with a water seal trough and dip plates to make it suitable for arresting any air ingress during expansion of the furnace at higher temperatures. BAH protects the underneath ash extractor conveyor from the direct impact of hot ash. Hot ash is smoothly discharged to the water-filled slag bath of a special type ash conveyer called a *submerged scrapper conveyor* (SCC) below the BAH through horizontal hydro-pneumatically operated discharge gates.

The discharge chute at the hopper outlet remains dipped into the water of the slag bath of the SSC ensuring sealing of furnace's bottom. The design of storage capacity of a BAH would permit sufficient maintenance time for the SSC and, of course, depend on various factors (e.g., type of furnace, type and amount of bottom ash produced, etc.) (Figure II/10.3). Here, also, a temperature of 60°C within the SSC is always maintained by supplying HP water to the slag bath of it.

The SCC collects ash that is continuously falling from the furnace into a water-filled trough in the hopper. The ash in turn is conveyed along the trough by submerged flight bars made of proper quality steel and is then travels up an inclined section to allow the water to drain back into the

www.EngineeringBooksPDF.com



NOTE: ONE SET OF EACH ASH FLOW PATH/VESSEL HAS BEEN SHOWN.THE ACTUAL NO.OF ACCESSORIES AND VESSELS WOULD DEPEND ON PLANT CAPACITY, REDUNDANCY LEVEL REQUIRED, LAYOUT LIMITATION, ETC.

FIGURE II/10.3 Schematic/flow diagram of ash-handling plant's bottom ash hopper disposal system.

trough. After the dewatering at the sloping portion, moist ash is discharged into a clinker crusher for onward disposal through hydraulic sluiceways or belt conveyors.

The BA is then converted into slurry form with the help of a clinker grinder. Using the advantage of gravity flow, if possible, the ash slurry is sent to a bottom ash slurry sump through the ash slurry trench. The slurry is then suitably pumped, if gravity flow is not possible, from bottom ash slurry sump to main ash slurry sump. Accessories envisioned for this system consist of dry-type BAHs, horizontal-type hopper outlet gates, submerged scrapper conveyors, clinker grinders, bottom ash slurry sump, etc. With a submerged scrapper conveyor system, the ash from the economizer is mainly evacuated and conveyed continuously in wet form and the ash slurry is led to an ash slurry pump house through trenches.

10.3.1.4 Dry-Type Bottom Ash System

Bottom ash is collected in a hopper lined with refractory to withstand high temperatures; this also is treated as a transition chute acting as a temporary volume chamber. The ash accumulated at the bottom is evacuated by a special type of extractor connected through an isolating gate/door for maintenance or any other purpose. An arrangement is made so that air can percolate through an extractor with a steel plate conveyor and enter the combustion chamber due to the negative pressure that exists therein. Air travels in a counterflow direction along the surface of the ash, which rests on the steel plates, and encourages a reburning process of the still glowing ash. This reduces the unburnt carbon level and releases additional thermal energy to the air before entering the combustion chamber.

The system does not conflict with the combustion process and the character of the exhaust gas because the controlled amount of combustion air thus added would not be more than a tiny percentage of total air flow. This process cools the ash so that it is better for handling and for protection-associated equipment without requiring any additional fans. Large pieces are crushed small enough to feed into a pneumatic conveyor. Another advantage of this system is that for the remaining glowing ash, when it comes into contact with the fresh air, almost complete coal combustion takes place so that more fly ash rather than BA results for better use of the total ash produced.

The design criteria of the extractor takes care of harsh conditions—for example, exposure to high temperatures, impact loads caused by the fall of large and heavy clinkers, etc. The cooled ash at the outlet of the extractor is then discharged into a crusher for reducing clinkers to a size that is convenient for transporting to a silo.

As this system completely eliminates all water in the bottom ash process, corrosion problems are also eliminated. The boiler becomes more efficient for recovery of most of the heat energy from BA that would otherwise have been wasted. Vacuum pneumatic conveying of dry bottom ash is the most popular system. The process uses a vacuum design to convey ash to the point of shipment for external use. Because of the complete elimination of water, this system provides increased lifetime, reduced cost, and required

www.EngineeringBooksPDF.com

TABLE II/10.3-1 Comparison of Dry and Wet Systems

Dry System	Wet Systems	Remarks
No cooling water consumption	A lot of cooling water required	
No additional water treatment is necessary	Additional water treatment for water recovery/disposal is necessary	Cost saving with dry system
Thermal energy recovered	Significant energy loss	Energy gain with dry system
Reduction of unburnt carbon	Corrosion damage	
Improve boiler efficiency*	Steam may be produced and escape into furnace	
Environmentally friendly, helps reduce coal consumption thus less CO_2 production.	High disposal cost	
Marketable ash available for selling	High maintenance cost	Dry system profitable
Compared to other system, less energy consumption	Significant energy consumption	

**Nearly 0.2% efficiency.*

time. The extractor may be a submerged flight conveyor (moving belt system) or vibrating deck type that moves ash from under the boiler to a crusher where it is fed to a secondary conveyor. A dry bottom ash-handling system is probably more environmentally friendly and economic (from a capital cost as well as maintenance cost point of view). A short comparison of the dry system with the wet system is presented in Table II/10.3-1.

10.4 Fly Ash-Handling System

Out of three general types of furnaces provided in a coal-fired boiler, the dry bottom furnace is the most common, where ~80% of all the ash leaves the furnace as fly ash along with the flue gas. On the contrary, the other two (i.e., wet bottom and cyclone) furnaces yield about 50 and 25% fly ash, respectively.

Fly ash is useful in many applications because it is a pozzolan, which means it is a kind of siliceous or aluminosiliceous material; when in a finely powered form, it combines with calcium hydroxide, from lime, Portland cement, or kiln dust, in the presence of water to form cementitious compounds. In some countries (e.g., India), the maximum percentage (~70–75%) of fly ash generated is used for land filling.

There are two distinctly separate methods available for a fly ash handling system: dry and wet. They are discussed briefly in the following subsections.

10.4.1 Dry-Type Fly Ash Handling System

This type of fly ash handling system is applicable for an ESP and an air preheater (APH) where dry fly ash is extracted from the relevant hoppers through a vacuum-conveying system or pneumatic pressure-conveying system, whichever is felt to be suitable. In some cases, a combination of both vacuum and pressurized systems is used.

Extraction and transportation of dry fly ash from an ESP is accomplished in two phases, as follows, from:

1. ESP collection hoppers to the intermediate surge hoppers or collector tanks by vacuum-conveying or pneumatic pressure-conveying system
2. Intermediate surge hoppers to storage silo, normally located at a distance from the main plant area, by conveying pneumatically

Extraction and transportation of dry fly ash from an AHP and duct hopper ash is accomplished pneumatically and is connected to intermediate surge hoppers or collector tanks of ESPs. Alternatively, ash from AHPs and duct hoppers can be evacuated and conveyed continuously in wet form, and then the ash slurry is led to an ash slurry pump house through trenches.

The advantages and disadvantages of each of the systems are shown in Figure II/10.4(c) and are discussed in the following based on which suitable system is selected:

Pressurized system: Normally, for long-distance and high-capacity conveying, this system is used. The wear and tear of the system is also less compared to the vacuum system. It leaves very little space below an ESP hopper that could be a disadvantage. There are normally two types of pressurized systems, namely:

- *Dense phase:* This can be used for conveying large-capacity (even up to 200 T/H) material over long

www.EngineeringBooksPDF.com

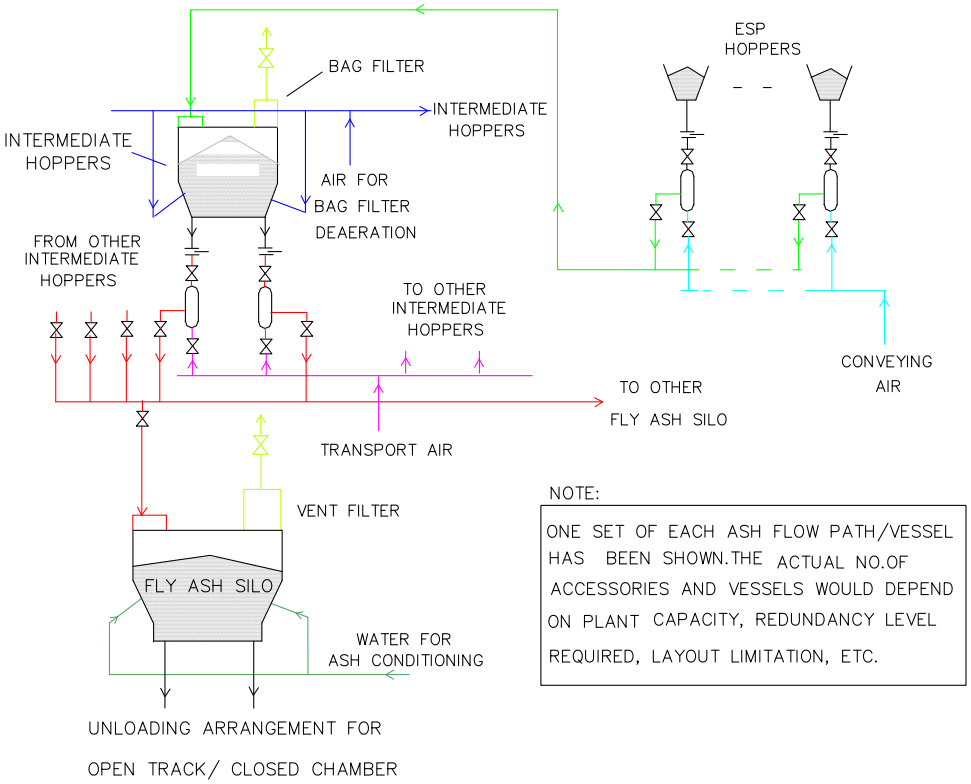


FIGURE II/10.4 Basic schematic/flow diagram of ash-handling plant — pressurized dry fly ash hopper disposal system.

distances (∼2 km). Normally, in this system, the layout below an ESP is a little cumbersome.

- *Lean phase:* In this type, both high-capacity (180 T/H) as well as long-distance (as high as 2.5 km) conveying is achievable.

Vacuum system: With this system, transportation is fast but conveying capacity is not large (∼80 T/H), and it can be used for conveying materials over moderate distances, say ∼1.5 km (Figure II/10.5). The layout is simple but, in case of failure of the vacuum, the capacity will be reduced.

10.4.2 Wet-Type Fly Ash Handling System

A wet fly ash handling and disposal system allows the fly ash to mix with water inside the wetting units to form a slurry with the help of a suitable arrangement. The slurry is thereafter pumped for transportation to common slurry pit with the help of, for example, a jet or suitable pumps. The wet disposal system can be a medium slurry disposal type or HCSD type. The ash for a HCSD type can be taken from a silo or intermediate surge hopper, depending on the site's layout.

10.5 Ash Water System

The entire water requirement of the ash-handling system may be met with circulating water where the plant does not have a cooling tower facility—that is, for a once-through system in coastal stations using lake or river water, or seawater; for the AHP system, water is taken from the return header of the CW system.

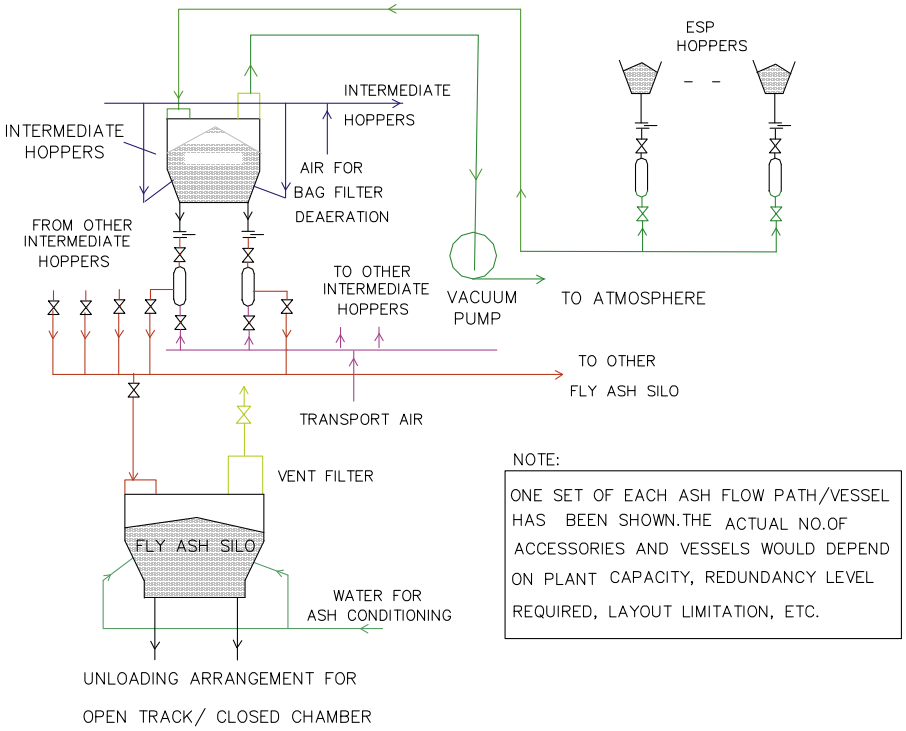
For plants with a CT, AHP water is taken from the CT blowdown water of the station and the recovery water is from the ash pond through decanting. For the latter case, a connection from raw water is also provided for initial, fast fill, and emergency makeup purposes. For AHP equipment sealing and cooling, clarified water is provided. The ash-handling plant's water system consists of HP and LP water pumps, economizer ash water pumps, ash water sump, etc.

10.5.1 Bottom Ash Water System

Both HP and LP water pumps are used in BA handling system and are discussed briefly next.

Bottom ash high-pressure water: These supply pumps are used to extract bottom ash from the furnace/economizer. When a BA handling system deploys jet pumps, the system vis-à-vis HP pumps operates sequentially and in On–Off mode. In cases of a jet pump system, the HP pump supplies water for jet pumps, hopper flushing, seal trough, and gate housing flushing, etc. For AHPs with an SSC system, continuous operation of HP pumps are envisioned. In case there is a SSC

www.EngineeringBooksPDF.com



FIGUREII/10.5 Basic schematic/flow diagram of an ash-handling plant's dry fly ash hopper disposal system (vacuum).

system, HP pumps supply water for quenching, trench jetting, seal trough flushing, gate cooling, sump stirring, and so on.

Bottom ash low-pressure water: The supply pumps are used for a system with a jet pump for refractory cooling, hopper cooling water to maintain water temperature at 60°C, makeup/fill of hopper water, seal trough, slurry sump, etc. LP pumps, on the other hand, for systems with a SSC, supply water for refractory cooling, cooling water for the upper trough of SSC to maintain water temperature at 60°C, makeup/fill of seal trough, ash slurry sump, cooling water to inspection windows, wash water to grinder, etc.

10.5.2 Fly Ash Water System

Fly ash HP water supply pumps are required for wetting heads, air washers, FA slurry/trench jetting, combined ash slurry sump makeup, combined ash slurry sump stirring, etc. Separate seal/cooling water pumps are provided for gland sealing of slurry and vacuum pumps, the sealing water requirement of clinker grinders, and cooling of compressors. Water is a very important medium for a power or process plant, so every effort is taken to preserve it. For example, bottom ash hopper cooling water overflow may be recirculated after treating it in a settling tank or surge tank. For wet ash disposal, water recovery from the ash pond through decanting has been discussed already.

10.6 Ash Disposal System

According to dry and wet systems, the disposal of ash from a plant is also tuned to match with the same. They are briefly discussed in the following subsections.

10.6.1 Wet Ash Disposal System

It has been stated earlier that BA handling and disposal is done either in a wet or semiwet mode. For fly ash systems, on the other hand, both wet and dry disposal is possible.

Fly ash (of wet systems) and bottom ash are made to form slurry and channelized to accumulate into a common ash slurry sump. The same slurry sump is also used to dump the sludge from the pretreatment plant clarifier. The coalesced slurry is then propelled to the final disposal area or ash pond by centrifugal pumps suitable for low-speed ash slurry service. The requirement for ash disposal at long distances and/or higher elevations demands a number of ash slurry pumps in series; a booster station also may be incorporated in case of an excessively high head requirement.

Alternatively, a HCSD system is employed that uses the a slurry concentration between 55 to 70%, depending on the specific slurry rheology (viscoelastic) properties of mud, polymers, plastics, etc. Wet disposal of fly ash is required during any emergent condition when dry disposal is out of service or during commissioning and/or the initial period of a running plant until full utilization of fly ash is accomplished.

www.EngineeringBooksPDF.com

10.6.2 Dry Ash Disposal System

The dry fly ash from ESP and APH hoppers is transported to intermediate surge hoppers. Fly ash collected in there is pneumatically conveyed to storage silos in a separate area, from where it can be transported to outside the plant for further use in road construction, as raw material for a cement plant, at a plantation to increase fertility, and so on.

BIBLIOGRAPHY

[1] Singer, J.G., 1991. Combustion: Fossil Power Systems, 3rd ed. Combustion Engineering Inc, Windsor, CT.

[2] Babcock and Wilcox Company, 1978. Steam: Its Generation and Use, 39th ed. Babcock & Wilcox, New York.

[3] Heat Exchange Institute, 2005. Tech Sheet #113: Condenser Basics—the Rankine Cycle. HEI, Cleveland, OH.

[4] Product Bulletin, Dekker., 2011. Dekker Controller Vacuum System Controller. Dekker Vacuum Technologies, Inc, Michigan City, IN.

[5] Cooling Tower Details. Bureau of Energy Efficiency, India. http://www.beeindia.in/energy_managers_auditors/documents/guide_books/3Ch7.pdf

[6] Golder Associates. 0637567/4.2 SCA/APP.10.1.5/PSD Report Dtd. December 16, 2006.

[7] Sulphur. Zevenhoven and Kilpinen: Dtd. June 1, 2006.

[8] Fast Start-up of a Combined-Cycle Power Plant: A Simulation Study with Modelica. Francesco Casella1, Francesco Pretolani 2. The Modelica Association Modelica 2006, September 4th−5th https://www.modelica.org/events/modelica2006/Proceedings/sessions/Session1a1.pdf.

[9] Babcock & Wilcox. Boiler Tube Analysis: (Power Generation Group).

[10] CIBO Energy Efficiency Handbook, 2011. Power-Gen Europe June 7-9. Fiera, Milano, Italy.

[11] Bielec, M. K., Leopardj, A. J. Tilting Pad Thrust Bearings: Factors affecting performance and improvements with directed lubrication, Paper 13. Made and printed in Great Britain by William Clowfs and Sons Lmited. London,BECCLES and COLCHESTER. http://Tilting_pad_thrust_bearings_performance_directed_lubrication.pdf.

[12] Say, M. G. Performance and Design of AC Machines. 3rd Edition Pitman Publishing Corporation NY 10017, USA The English Language Book Society and Sir Isaac Newton and Sons Ltd. London.

[13] Sen, S. K. Rotating Electrical Machines. 1975. By Khanna Publishers. 2-B Nath Market, Delhi 6.

[14] Sulzer. Product Bulletin: HPT Multistage Barrel Casing Boiler Feed Pump. USA.

[15] Szargut, J. Influence of Regenerative Feed Water Heaters on the Operational Costs of Steam Power Plants and HP Plants. *Int J of Thermodynamics*. ISSN 1301-9724. Vol. 8(No. 3), pp. 137-141, September 2005 http://www.scribd.com/doc/32642580/Optimization-of-regenerative-feed-water-Heaters.

[16] Roth. Product Bulletin:. Rock Island: Roth Pump Company.

[17] Product introduction: The deaerator principle. Spirax Sarco. http://www.spiraxsarco.com/resources/steam-engineering-tutorials/the-boiler-house/pressurised-deaerators.asp.

[18] Urieli, I. Engineering Thermodynamics—A Graphical Approach: November 18, 2013.

[19] Product Bulletin: Ashcon/Drycon System. Clyde Bergemann Power Group/Delta/Ducon Conveying Technology Co. Inc. along with: Ash Handling Options for Coal-Fired Power Plants 02/01/2011 By Lindsay Morris, Associate Editor. http://www.power-eng.com/articles/print/volume-115/issue-2/features/ash-handling-options-for-coal-fired-power-plants.html.

[20] Product Bulletin: Submerged Flight Conveyor. Waukegan, IL: United Conveyor Corporation along with: Ash Handling Options for Coal-Fired Power Plants 02/01/2011 By Lindsay Morris, Associate Editor. http://www.power-eng.com/articles/print/volume-.

[21] Product Bulletin:. Allen-Sherman-Hoff, a division of Diamond Power International Inc. along with : Ash Handling Options for Coal-Fired Power Plants 02/01/2011 By Lindsay Morris, Associate Editor. http://www.power-eng.com/articles/print/volume-.

[22] Cooling power plants-(Updated July 2014) Report on Cooling Water Options for the New Generation of Nuclear Power Stations in the Bristol, United Kingdom: Environment Agency. http://www.world-nuclear.org/info/Current-and-Future-Generation/Cooling-Power-Plants/

[23] Standard Design Criteria/Guidelines for Balance of Plant of 2x (500 MW or above) Thermal Power Project. India: Central Electricity Authority. New Delhi−110066. September 2010 http://cea.nic.in/more_upload/standard_design_bop_sep10.pdf.

[24] Schweinfurth, S. P. An Introduction to Coal Quality: The National Coal Resource Assessment Overview. Chapter C. Professional Paper 1625−F. Edited by B. S. Pierce and K. O. Dennen. Reston, VA: U.S. Geological Survey. http://docs.com/TMX2#!

[25] Smidth, F. L. Fly Ash Handling System Catalog.

[26] Internet Document. Ash Handling System: NTPC Specification and Write up.

[27] Internet Document. CPU. *Purolite Technical Bulletin*. http://www.purolite.com/Customized/uploads/pdfs/Condensate20Purification.pdf.

www.EngineeringBooksPDF.com

Chapter III

Plant P&ID Discussions

1. INTRODUCTION (P&ID)

1.0 P&ID Basics

A piping and instrumentation diagram (P&ID) is probably the most important drawing in a power and/or process plant, and is of immense importance to all the disciplines involved: mechanical (for equipment and details), piping (piping detail), electrical (to list motors and their rating), civil and structural (for structural design and special equipment, for example, for foundation), and instrumentation. It is the starting point of all subsequent designs.

1.1 Instrumentation Symbols in P&ID

Before going in to any details, it is essential to deciphering various instrument symbols used in P&ID (see Figure III/1.0-1 for legends). In most of the cases, ISA S 5.1 (ISA norms) are used. One should keep in mind that although ISA symbol representation is most often used, there are a number of variations in P&ID, such as KKS representation. For simplicity, in this book some times valve tag nos. are shown as Distributed Control System (DCS) tag only; e.g. Boiler start up vent valve in main steam P&ID.

1.2 Piping Representation in P&ID

Also there are certain methods followed in the pipe numbering system to indicate not only the pipe tag but also the size and material of the pipe. One particular method is used in our discussions on P&ID. Why is piping so important? For in-line instrument sizing, the line size is necessary. Also, pipe material codes and schedules

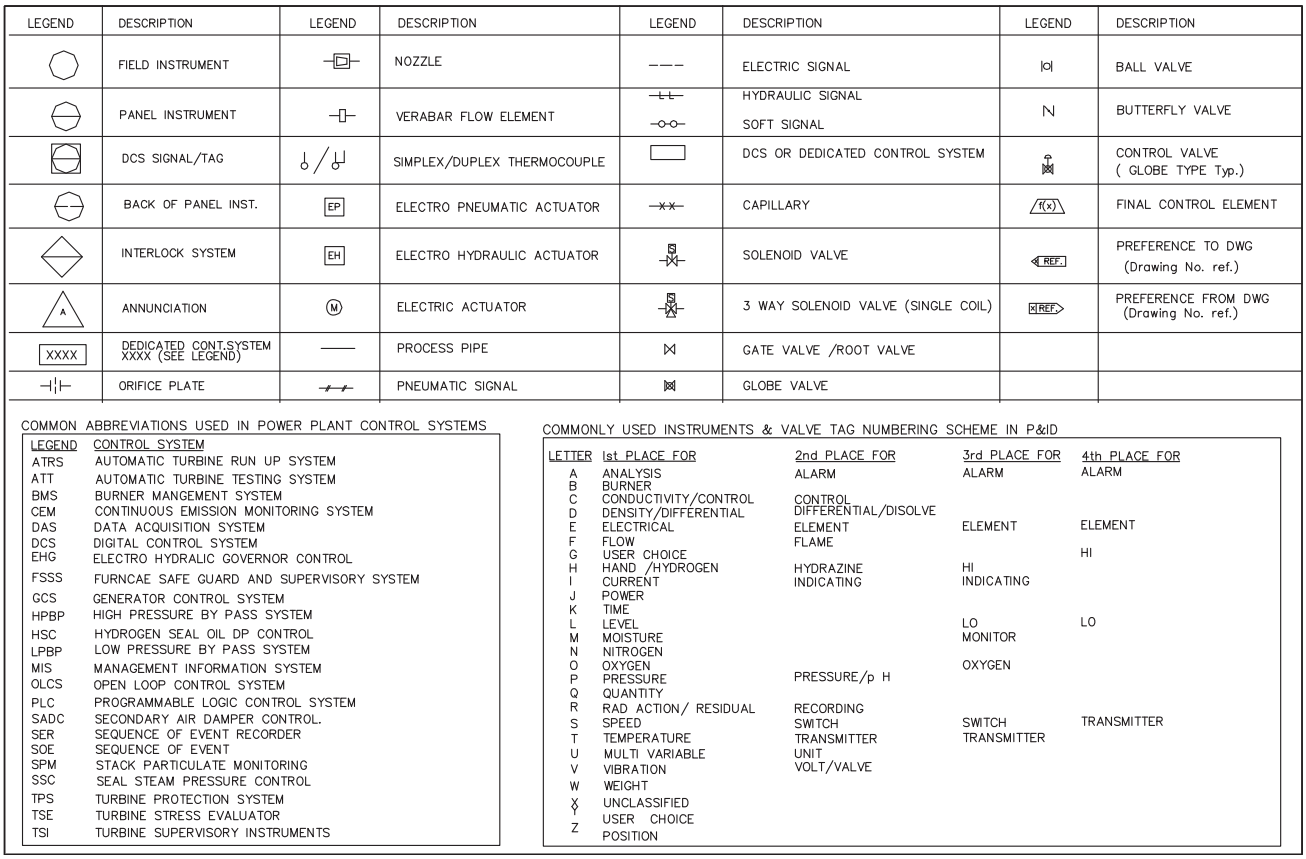


FIGURE III/1.0-1 Symbols and legend for P&ID.

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

FINAL CONTROL ELEMENT(Modulating Service)

Final control elements (detailed discussions in chapter VI), in modulating service, play a great role in the control of all of the parameters.Normally all the final control elements in modulating services have their own positioner to ensure exact positioning of the control element in accordance with the demand signal from the control system. Similarly, the position transmitter (and indicator) of the final control element in modulating service is very important, because in many control systems this position signal is considered as feedback to balance the control loop, while in some other systems this may not be the case. Instead they help operator to assess the actual position. Position signal also helps detect if the actuator is aging. So while discussing P&ID it is necessary to consider that each of the final control elements in a modulating service should have a positioner and a position transmitter (and indicator) with it whether explicitly shown in the P&ID or not. When the electrical actuator is not used as a final control element in a modulating service, then there has to be one I/P (for pneumatic actuator) and I/H (for hydraulic actuator) so that the electrical signal from the DCS can be converted and fed to the positioner of the actuator. In smart actuators these may be built in with the actuator, and in many cases these may be separate. While designing P&ID these aspects shall be taken care of by the designer.

FIGURE III/1.2-1 Note on final control element.

help the reader to decide on the pressure rating and material of an instrument. After going through figure III/2.2-1a, the reader should be able to decipher pipe tag numbering. For in line final control elements (modulating service) note given in fig no. III/1.2-1 may be referred to.

1.3 Process Parameter in P&ID

It is needless to say, process parameter is extremely important for instrument engineers. When such details are available in P&ID, it is helpful to all concerned. While designing a P&ID or while marking instrumentation on the process flow diagram (process flow diagrams show basic system/process flow sequences), it is necessary to furnish all these details. It has been found in many PI&Ds that such details are not very explicit; instead they are read in conjunction with the "heat balance" diagram. If process parameter details are not available in the P&ID, then they need to be incorporated (in the working copy). To prepare an instrument list, such parameters are necessary to select the range of the instruments. In the heat balance diagram generally four parameters are indicated in a box with four cells, as detailed out in fig no.FIGURE III/2.2-1b. Unless specifically stated otherwise, normally SI units are used, but in power station practice certain units are obvious so those units are used. For example, FD discharge pressure is represented by xxx mm wcl, although kg/m^2 is the SI unit for pressure. This is because the value is too small. There are a few other process parameters such as normal level, high and low level, oxygen in flue gas, or conductivity in steam etc., these should be marked in the P&ID wherever necessary.

1.4 Equipment in P&ID

Like instrumentation it is conventional to represent all major equipment, valves, etc., with suitable symbols and associated tag numbers. In many P&IDs (such as Offshore P&ID in NORSOK standard equipment specification) short specification of the major equipment is put in near the equipment. Such information is very useful, e.g., 2 × 3.5MW motor-driven BFP marked below BFP is not uncommon in a P&ID. It is always better to put short specifications for major equipment in P&IDs at suitable place in the top or bottom of the drawing.

1.5 Discussion on P&ID

The following points are covered during discussions on P&IDs.

- Objective and function of the system
- Basic system description
- Major system equipment
- Major parameter monitoring in the system
- Major control in the system
- Redundancy in measurement
- Miscellaneous other points and relationships with other systems

It is important to note that since the discussions are based on generalized terms, various parameter values and major equipment quantity and size will be generalized in and will not match any specific power station, especially small power stations. The main intention is to familiarize the reader with relevant topics. For example, HP bypass control is quite common in larger utility power stations but may not be

www.EngineeringBooksPDF.com

applicable for a smaller one. In process cum power plants there are bypass lines to the bypass turbine, so that when power generation is not possible, the process steam supply remains unaffected. So, Pressure-reducing and de-super heating station (PRDS) are used and this PRDS should not be confused with the HP bypass system. Since downtime cost for large power plants is not the same as that in a small utility station, critical control sensor redundancy is quite common for larger plants. Sensor/transmitter redundancies are discussed at length, in next clause.

1.6 Redundancies for Transmitters (Sensors)

There are a few parameters in power plants where some redundancies are considered at the sensor level. Also, in certain cases redundancies are considered at the controller as well as at the output/display stage. Aspects of controller redundancies are discussed in connection with the intelligent control system in Chapter VII. Here instrument (transmitter/sensor) redundancy is discussed. There are a few types of redundancy implementation techniques depending of the number of sensors and their applications. Some of them as (suggested schemes) are as given below:

- High select
- Low select
- One of two selections—average or Tx1 or Tx2
- Two of three selections by an average or two of three voting circuits

1.6.1 Transmitter (Sensor) Redundancy Considerations

While discussing instrument redundancy, it must be remembered that the transmitters (and sensors) mentioned are two or more for measurement of the same parameter measurement, e.g., two transmitters measuring turbine inlet pressure. However, because of the configuration it is advisable *not* to consider the left-hand side (LHS) drum level transmitter as redundant to that on the right-hand side (RHS). This is because there may be some level difference between the LHS and RHS of drum, such as due drum positioning, (static difference) and there may be difference in level between the LHS and RHS of drum due to nonuniform heating and steaming at both sides. Similarly for boilers with steam outlets at two ends, there may be a difference in temperature readings between the LHS and RHS. So outlet temperatures of superheaters (SHs) or reheaters (RHs) at the LHS and RHS may *not* be considered as redundant.

In those cases at best the average of the LHS and RHS signals can be used to control the parameter, but a close watch, should be maintained so that there is no spurious tripping due to the deviation between the two sides. However, in many small plants, because of the low cost, LHS and RHS transmitters are put in average mode (and practically used as a redundant transmitter—close monitoring of individual levels is important).

1.6.2 Transmitter Monitoring and Inhibiting Selection

High and low limit checks for transmitters has been in practice for quite some time, even when discrete instrumentation was in use. Now with the distributed control system (DCS) it is very easy to monitor out of limits for the transmitter and open circuit and short circuit test for sensors like resistance temperature detectors (RTDs) and thermocouples (T/Cs). Most of the transmitters are monitored for out of limits <4 *or* >20 mA output. Also, since smart transmitters have a diagnostic system, they also can detect fault and isolate themselves from the circuit. In short, whenever a fault in the transmitter is detected selection of that transmitter for any selection is inhibited—*meaning only good transmitters will be selected.* Most of the recent control systems alarms are generated to indicate that one of the transmitters is faulty. If the transmitter is connected via HART/PROFI/Fieldbus, such detections are more explicit and well reported in the system. (Detailed discussions on the above buses will be discussed in Chapter VII).

1.6.3 Redundancy—Two Transmitters (Sensors) for One of Two Selection

There are three kinds of selections in one of two:

High selection: Could be used for two transmitters deployed for measuring the same fuel flow or steam temperature, etc.
Low selection: Could be used for drum level, air flow transmitters, etc.

As discussed earlier, such selections are not redundancy selections in a true sense but are in practice so system designers need to provide a way for individual signals to be monitored. One of two selection is another method for selecting two redundant transmitters, where an average of two can be selected.

1.6.3.1 Two Transmitters (Sensors) in High (or Low Selection)

As shown in Figure III/1.6-1a and b, the two transmitters (one and two) are connected to one Hi *or* Lo select circuit (soft high or low select in the signal processing part of the I/O of the DCS). Output of a high or low selection device passes through a selection switch. Here outputs from individual transmitters are also connected. In *auto mode* normally high or low select output is selected, but if out of two transmitters (sensors) one is detected as faulty (by

www.EngineeringBooksPDF.com

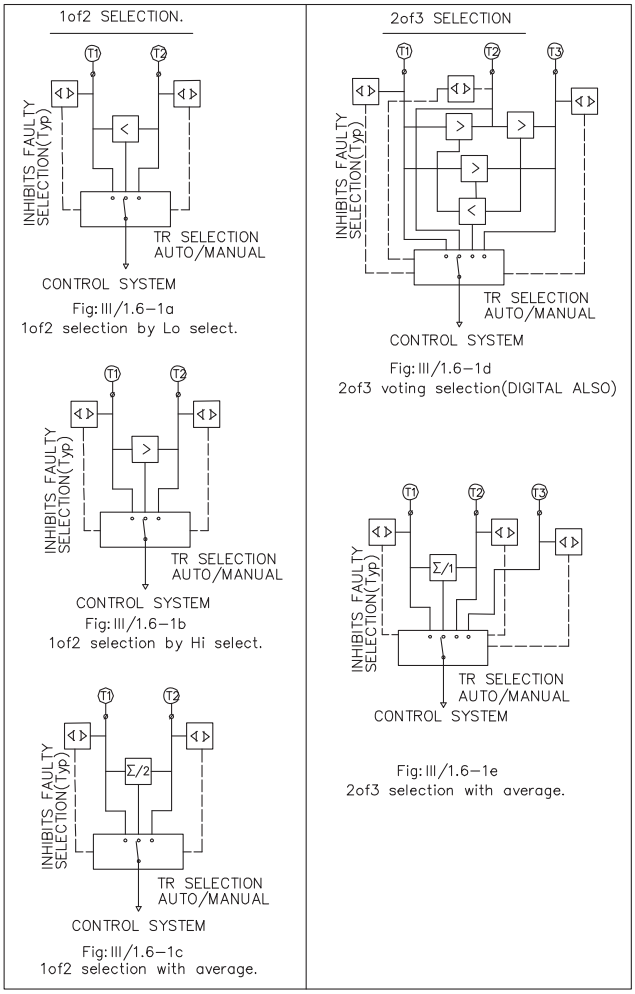


FIGURE III/1.6-1 Redundant instrument selection method.

transmitter diagnostics or by an out-of-range detector), then it will be inhibited so other transmitters will be selected. However, manually any one of the two transmitters or high or low select output can be selected. If there is a fault in any transmitter, it will be alarmed and a healthy transmitter will be selected in auto mode (i.e., if output is not manually selected). For example, with high selection two transmitters are deployed to measure the same fuel flow or steam temperature, and with low selection two transmitters are deployed for drum level and air flow transmitters.

1.6.3.2 One of Two Transmitters (Sensors) Selection with Average

In this mode, as shown in Figure III/1.6-1c, two transmitter signals are fed to an averaging circuit (soft average selection in signal processing part of DCS). The output from the average unit is taken through one selection switch. In auto mode, normally the average output is selected, but if out of two transmitters (sensors) one is detected faulty (by transmitter diagnostics or by an out-of-range detector), then it will be inhibited, so other transmitters will be selected. However, manually any one of the two transmitters or average output can be selected. If there is a fault in any transmitter, it will be alarmed and a healthy transmitter will be selected in auto mode (i.e., if output is not manually selected).

1.6.4 Redundancy—Three Transmitters (Sensors) for Selection

For a number of measurements of great importance in larger utility stations, three transmitters (sensors) are deployed in redundant mode. Some of these measuring points may be those listed below:

- Steam pressure at turbine inlet (steam header pressure—in process cum power plants)
- Steam pressure at turbine first stage
- Furnace pressure
- At drum level there may be some difference in reading between the left and right dished end of the drum, as discussed earlier. Therefore it is better to use one of two on each side of the drum (total $2 + 2 = 4$ transmitters), in place of both side total (two of) three transmitters (because which side of the dished end will the third transmitter be placed). And it will affect true level reading. In certain power plants even a total of six transmitters have been deployed (two of three on each side).
- Feed water (FW) flow (before temperature correction)
- Main steam (MS) flow (before pressure/temperature correction)
- Condenser vacuum
- Deaerator level (not very popular)
- Secondary air flow

The above measurement points are just suggestions and are not sacrosanct, as everything depends on budget provision (the more sugar in the water, the sweeter will be the solution).

1.6.4.1 Three Transmitters (Sensors) in Two of Three Selection

In this mode, as shown in Figure III/1.6-1e, three transmitter signals are fed to an averaging circuit (soft average selection in the signal processing part of the DCS). The output from the average unit is taken through one selection switch. In auto mode normally average output is selected, but if one transmitter (sensor) is detected faulty (by transmitter diagnostics or by an out-of-range detector), then it will be inhibited, so the average output will be from the other two transmitters. In manual mode any one of the three transmitters or average output can be selected. If there is a fault in any transmitter, it will be alarmed and healthy transmitters will be selected in auto mode (i.e., if output is not manually selected).

www.EngineeringBooksPDF.com

1.6.4.2 Three Transmitters (Sensors) In Two of Three Voting Logic

In this mode, as shown in Figure III/1.6-1d, three transmitter signals are initially voted through high selection between two transmitters (soft selection in the signal processing part of the DCS), i.e., high selection between one and two, one and three, and two and three. The output of these three high selections is fed to the low selection. Each of the transmitters, like other systems, is checked for health—either through out-of-range detector or through its diagnostic routine. The faulty transmitter is automatically voted out. The voted transmitter is selected in auto mode. In manual mode it is possible to select any of the three transmitters or the voted transmitter, but in no case is the faulty transmitter selected.

1.7 Analytical Instruments and Control

In the P&IDs discussed below there will be a number of steam and water analysis systems and dosing controls. These are not discussed in the following clauses as they need special attention, but these are discussed at length in Chapter V. Only sampling points are marked and control points are indicated in P&IDs.

2. MAIN STEAM (P&ID)

2.0 Main Steam (MS) System

2.1 Objective and Function of the System

The Main Steam (MS) system provides steam from the source i.e. reactor in a nuclear plant and steam generator (SG; boiler) in a thermal power station. The MS system has the following major functions:

- A source for thermal energy supply to the turbine to carry out mechanical work at the turbine.
- It is the source for many other steam supplies, such as auxiliary steam (boiler auxiliary steam, BAS and turbine auxiliary steam TAS); in many plants the supply for auxiliary steam is taken from the cold reheat steam, (CRH)
- It has the ability to prevent over pressurization of the steam source (if the supply of steam is more than consumption at turbine) by popping up safety valves to release excess steam.
- During start-up, shut down, and huge power shedding by the turbine, the MS bypasses the HP turbine (HPT) and goes to the CRH line after pressure and temperature reduction.

2.2 System Description—MS

2.2.1 Process and Piping: MS

MS starts its journey from the outlet of the final SH. In most boilers the SH outlet comes from the LHS and RHS of the boiler; in these cases, after running for some distance, the outlets may join at a point outside the boiler structure before entering the turbine building (see Figure III/2.2-1). Listed below are a few points to be considered:

- Generally piping up to boiler outlet flange(s) is a part of the boiler itself, and in this part all safety valves, the boiler start-up vent, and drain valves are installed.
- From boiler outlet up to turbine inlet flange(s) is in the scope of piping. This scope part is discussed because design engineers may need to coordinate among various agencies. When MS flow is measured, normally the flow element is placed in the common part of the piping. However, this is not sacrosanct, and there may be two separate lines coming out from boiler and enter the turbine through two/four inlets. In that case, there will be two flow elements (each MS line).
- On piping similar instruments and pipes are tagged for identification, as discussed previously. There are a number of standards for pipe numbering, but that is beyond the purview of this book. A *typical* depiction of pipe tag numbers is shown in Figure III/2.2-1a. This pipe (duct in case of air/flue gas) numbering is applicable for all systems.
- On the process parameter in a P&ID diagram it is customary to indicate the major parameter of the process, including those in the heat balance diagram. Figure III/2.2-1b depicts the process parameter heat balance diagram.
- For the heat balance diagram: P, pressure (in a suitable unit); E, enthalpy (kJ or suitable unit; only in the heat balance diagram, in P&ID enthalpy details are not common); T, temperature (in °C); F, flow (in a suitable unit). There are a few other parameters like level (normal level) that are marked at the place of the storage units. This process parameter depiction is applicable for all systems, so it is not repeated in all system descriptions.
- After the MS line leaves the boiler house, a few outlets may be taken out it, such as tapping for auxiliary steam, etc.
- Generally after entering the turbine building, the main purpose of MS line is to go to the HPT and work there. However, based on plant configurations, there may be some bypass routes. Again depending on the turbine (and the manufacturer) type there may be one, two, or four turbine inlets. Generally HPT is a single-flow turbine with a single or double entry as shown in the Figure III/2.2-1 (double-balanced entry), e.g., the

www.EngineeringBooksPDF.com

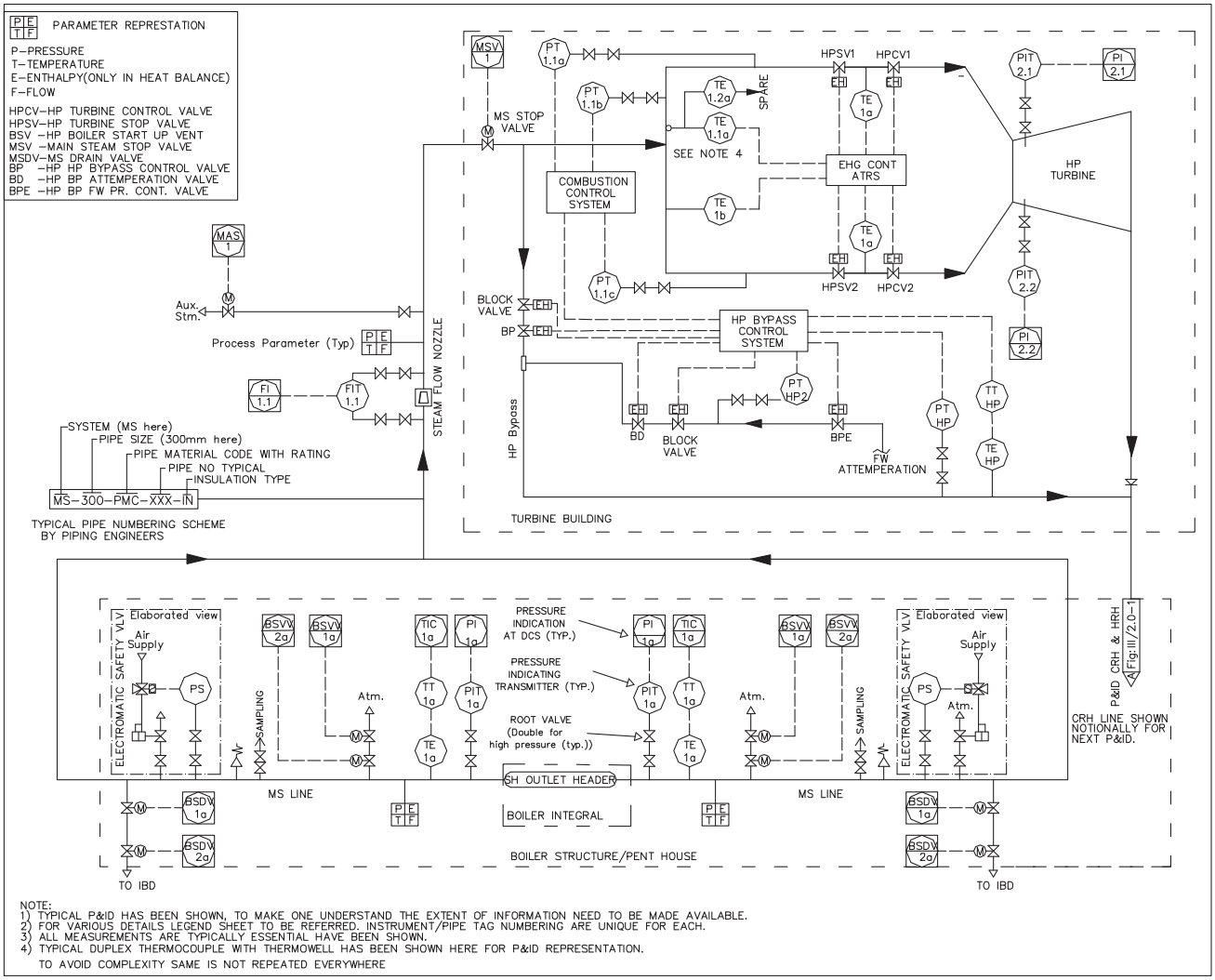


FIGURE III/2.2-1 MS P&ID.

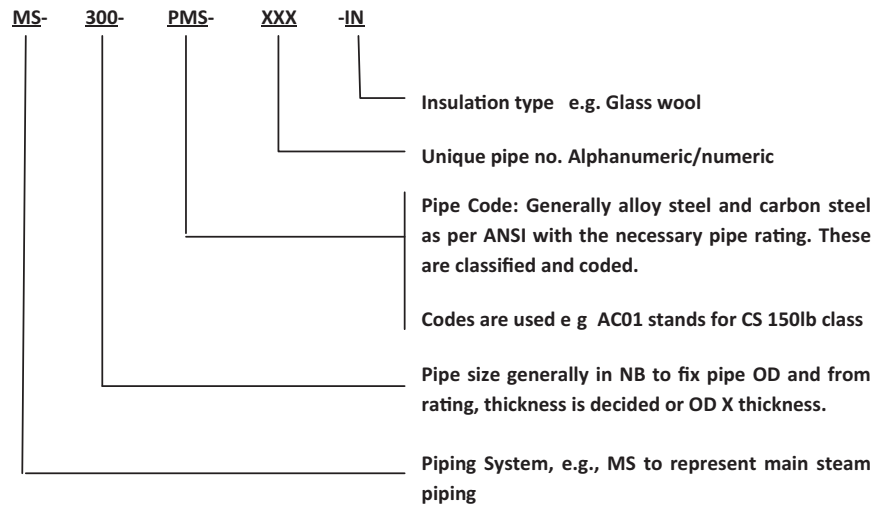


FIGURE III/2.2-1a Typical pipe numbering system.

www.EngineeringBooksPDF.com

Siemens-KWU turbine has a single-flow HPT. However, there are cases where the turbine is double flow with four inlets. Small turbines may have a single entry.

- In Figure III/2.2-1 a box is shown as the boiler SH outlet, but it is quite a big one, as the boiler has a few meters length and breath, so there may be some temperature difference between the two ends. Wherever two outlets are taken from two ends, then temperature (as well as pressure) measurements are done at each end. Turbine 1st stage pressure is also a control parameter e.g. for LPBP control (detailed out in chapter IX). As,this is MS system so control action for this has not been elaborated here.

P	E
T	F

FIGURE III/2.2-1b P&ID process parameter representation.

2.2.2 Bypass Path: MS

In many plants there are bypass routes of the MS line to the turbine, so that the boiler may run without the turbine. In the following clauses, a number of such cases will be discussed.

2.2.2.1 Process Plant Bypass Path: MS

Process cum power plants normally have bypass routes for the MS to bypass the turbine and connect it to another steam header of lower pressure (usually same the pressure and temperature rating as that of the turbine exhaust). Also part of the MS may be sent to the turbine and part to the bypass line. This is done to meet the following criteria:

1. In process plants (such as in paper plants, alumina plants, etc.) there are requirements of steam at various pressures, such as HP pressure, medium pressure (MP), and/or low pressure (LP). The system is designed in such a way that these MP and LP steam pressures are the same as the extraction/exhaust of the turbine, so that some economic benefit (by generating some power through the turbine) can be achieved.
2. If there is a problem in power generation and/or the turbine is not available, there may still be a requirement of MP/LP steam in the plant. To meet such eventualities, these bypass lines in the form of a Pressure Reducing and Desuperheating System (PRDS) are kept for total and/or partial bypass.
3. As stated previously, there can be HP, MP, and LP steam requirements at a process plant. As shown in a typical schematic (see Figure III/2.2-2) the HPMP PRDS station is kept to get MP steam when the turbine

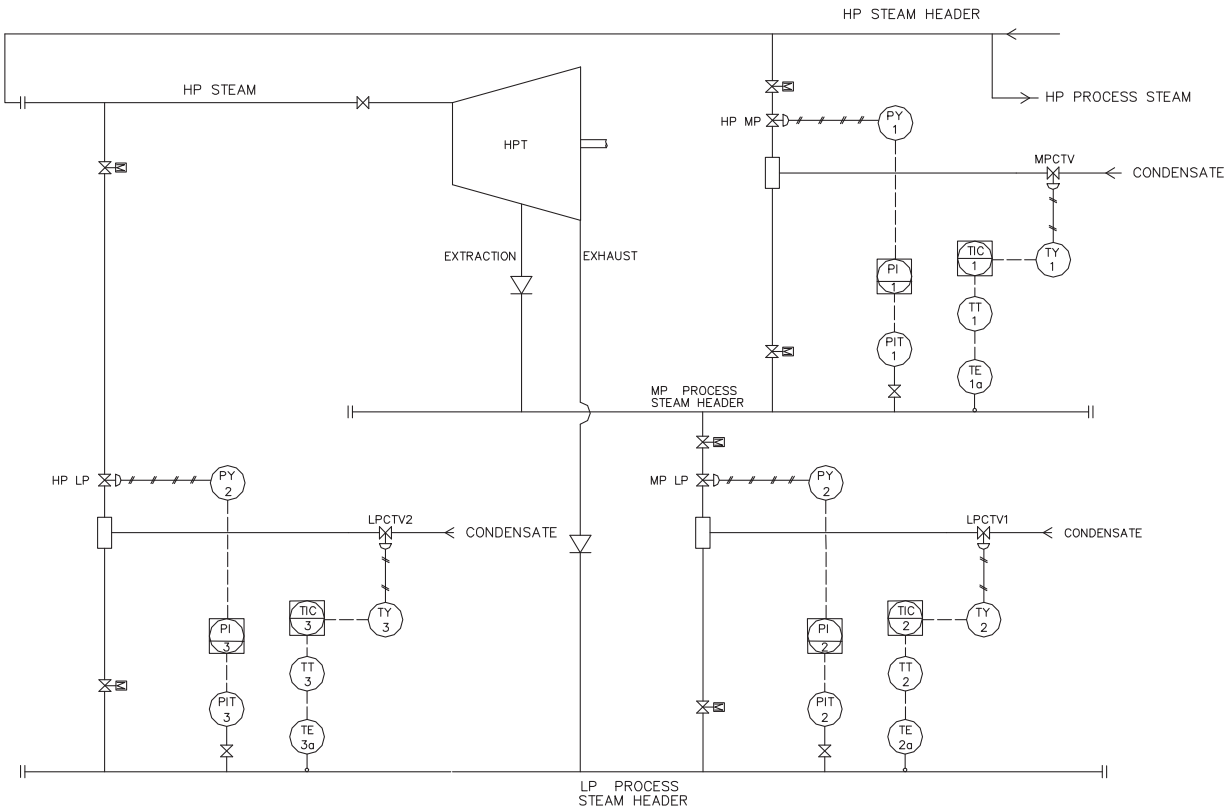


FIGURE III/2.2-2 Power and process plant steam circuit.

www.EngineeringBooksPDF.com

is not in operation. Similarly, MPLP PRDS ensures the LP steam supply in case of nonavailability of the turbine. When there are no requirements of MP steam, the HPLP PRDS ensures the steam supply at the LP header in case of nonavailability of the turbine.

2.2.2.2 HP Bypass: MS

In medium to larger plants (>120 MW), there is one bypass line to bypass the HPT and this is called the HP bypass system. It is used during turbine start-up, turbine shut down, and for large power throw off by turbines. Since a boiler has higher inertia, for certain cases of turbine trip and/or large power-load throw off by the turbine the HP bypass automatically operates sensing pressure at the HP steam line. The set point of HP bypass is set at a point higher than the set point of the inlet pressure. Also, turbine trip automatically starts the HP bypass line through protection input/quick opening criteria. This important system will be elaborated in Chapter VIII.

2.2.3 Sampling Lines

There are sampling lines from the MS line at SH outlet as well as the MS line at the turbine inlet for online analytical instruments as well as for laboratory analysis. These are detailed in Chapter V.

2.3 Major System Equipment: MS

Major system equipment includes the following:

1. *SH outlet header(s)*: It is the header formed at the boiler where various subheaders from the final SH join and normally come out from two sides of the boiler to form the MS header(s).
2. *Start-up vent and drain valve (BSVV, BSDV 1 and 2 in the P&ID)*: Normally there are two sets of remote-operated, semi-automatic motorized valves used during the start-up of the boiler to vent and drain at the initial stage.
3. *Boiler safety valve*: In the SH(s) there is at least one mechanically operated safety valve to exhaust excess steam in case of over pressurization. When the plant is commissioned the safety pop-up function is carried out to set and check the pressure set point through the spring.
4. *Boiler electromatic safety valve*: Apart from the mechanical safety valve, there is an electromatic safety valve operated with the help of a pressure switch, as in Figure III/2.2-1 (set at a pressure near the safety valve set point), to exhaust excess steam.
5. *MS stop valve*: Normally this is a motor-operated, remote semi-automatic valve used to isolate the boiler steam supply to the turbine. Depending on the line size, this valve may have integral bypass (detailed in Chapter VI)
6. *HP bypass system*: This is meant to bypass excess steam at the HPT inlet to the CRH formed from HPT exhaust. There is a dedicated control system (see Chapter VIII) to regulate the pressure at a point slightly higher than that of turbine inlet pressure. Another valve BD is meant to regulate the supply of FW to reduce temperature to match the CRH temperature. A BPE valve regulates the pressure of the FW header used to temperate the HP steam.
7. *HP stop valves (HPSVs)*: These are basically ON/OFF type isolation and stop valves for the entry to the HPT. These are controlled through an electro hydraulic governing (EHG) control system. In some cases, it can be cracked open for heat soaking during start-up in some turbines to meet the starting criteria. Normally these are combined with HP control valves (HPCVs) in a single body.
8. *HPCVs*: These are basically regulating valves controlled by the electro hydraulic control (and/or hydraulic control) system of the turbine to regulate quantity of steam entry to the HPT for varying the load in turbines. The operation of these valves varies with constant pressure and sliding pressure modes of operation of the turbine (detailed in Chapter IX).

2.4 Major Parameters: MS

2.4.1 Process Parameters

A few parameters *typical* for 200 and 500 MW are depicted below (Table III/2.4-1), but these are *not sacrosanct.* It is to be noted that these parameter fixations are done by the thermal engineer designing the system based on the parameters from two major manufacturers [boiler/SG and turbine generator (TG) manufacturers]. Normally 60–100% HP bypass is considered and the system is supplied by either SG or TG supplier as a part of the package. Because of the large distance between boiler and turbine, there will be some pressure loss in the line. Typically in larger plants this pressure loss is as big as 4–6 kg/cm^2. Because of the higher permanent pressure loss, many power plants' (500 MW and above) steam flow is not measured directly, instead turbine first stage (for constant pressure operation of turbine) pressure is considered as the load index for the turbine, while turbine first stage pressure together with the HP bypass steam flow are used to compute the boiler load index.

2.4.2 Monitoring of Process Parameter: MS

It is important to monitor the following MS parameters at the control room in almost all power plants. It is worth noting that the various ranges given here are typical values only and designer needs to adjust them according to the parameters for the particular plant in line with the guidelines given in Chapter IV.

www.EngineeringBooksPDF.com

TABLE III/2.4.1-1 MS Parameters

Steam parameter	Boiler outlet		Turbine inlet		Remarks
Size	200 MW	500 MW	200 MW	500 MW	
Pressure	135–140	165–170	130–135	160–165	For smaller plants: as low as 30–40 kg/cm^2
Temperature	540	540	<540–536	<540–536	For smaller plants: as low as 450°C but superheated steam at that pressure
Flow	~700–800	1600	~700–800	1600	Depends on MW and pressure design.

Units: Pressure in kg/cm^2, temperature in °C, and flow in T/h.

1. *MS pressure and temperature at the boiler outlet*: MS temperature is also a control parameter. With double outlets these measurements need to be performed at each end. Smart indicating pressure transmitters (generally *not* the inserting type) are used. With smart transmitters the calibrated span selection is very easy for high turn down ratio. Typical range for 200 MW plant is 0–150 (160) kg/cm^2, whereas for 500 MW plants it is 0–200 kg/cm^2. However, in supercritical (SC)/ultra supercritical (USC) plants MS pressure is >200 bar, hence the range is to be selected accordingly. Generally for temperature measurements ISA type K T/Cs are used. Depending on the actual parameter of the boiler, the range for the instrument (temperature transmitter) is selected. A typical range is 0–600°C.
2. *MS flow*: Generally flow elements (if used) are placed on the MS line away from both boilers and the turbine end. This is done to ensure straight length requirement for flow nozzle/(orifice plate—for low-rated power plants). As already discussed for *larger plants*, to avoid large permanent pressure loss (may be also for cost of flow-measuring system) instead of measuring steam flow it is computed in various ways such as from the turbine first stage pressure in conjunction with HP bypass flow. Since the pressure is high, a flow nozzle is generally used. Smart differential pressure transmitters (DPTs) are used for head type measurements. Depending on the flow-metering standard, the range is zero to several thousands of millimeters of water column (wcl; typical safe value for the DP ranges from 0 to 10,000 mm wcl—then adjust according to flow and pipe size considerations—this is also very easy for a smart DPT). With smart transmitters the range can be adjusted easily. However, the unit is expressed in terms of kg/h or T/h. Typical flow ranges are 0–900 T/h (duly pressure and temperature compensated to flow calibrated in kg/h or T/h) for 200 MW and 0–1800 T/h for 500 MW plants.
3. *Turbine inlet steam pressure* (steam header pressure in process plants or where there are many boilers supplying to a header and there are many consumers drawing steam from the same header): This parameter (also sometimes dedicated transmitters) is used for HP bypass control. *Typical* range is the same as discussed in item 1 of this list. Generally fixed set points are used to control this parameter. Larger plants, especially in once-through (OT) boilers used mainly in SC/USC plants, have sliding pressure operations within a load band of operations of 70–90% load and fixed set points are used beyond the range of 70–90% load. As a consequence, the HPBP set point in those cases also follows the MS pressure set point raised (plus) by a fixed value.
4. *Temperature measurement at the inlet and outlet of HPSV and HPCVs*: These are generally recommended by the TG manufacturer to compute thermal soaking by turbine metals. They are required for automatic starting and run up of the machine as well as for thermal stress evaluators. Since final temperature reaches ~540°C, ISA type K T/Cs are best suited for this application. However, the range of measurement is decided by the TG manufacturer.
5. *Turbine first stage steam pressure*: After steam enters the turbine the pressure at the first stage pressure is measured. This is very important from a turbine control point of view (especially for LPBP discussed in chapter IX, not shown here). Instrument range for this is similar to the turbine inlet pressure range.
6. *A few other parameters*: There are a few parameters that are not part of MS (but of CRH, hence discussed there) measured at the CRH line that are required for HP bypass control.

2.5 Controls in MS

There are a few controls associated with the MS system including:

1. *MS temperature control*: MS temperature at the SH outlet header(s) of the boiler is an important control parameter. After start-up once the temperature of the

www.EngineeringBooksPDF.com

MS reaches the desired value (i.e., 540°C) is kept constant throughout all operating points of the plant by using FW to attemperate. Initially the fixed set point is kept much lower as there is insufficient steam flow. For SC/USC and OT boilers this is controlled by fuel/FW flow ratio, so its importance in OT boiler cannot overestimated.

2. *Turbine inlet (steam header) pressure*: This parameter is the key parameter that needs to be kept constant (for constant pressure control, see clause 2.4.2, number 3 for sliding pressure operation). Based on this the combustion in the boiler is regulated. Also, this parameter would be used to operate the HP bypass valve (with a higher set point). Steam flow or load index for the boiler is also used as a feed forward signal for combustion control.
3. *EHG control of turbine*: This is the most important control system for the turbine. It interacts with so many other parameters.
4. *HP bypass control*: During start-up/shut down (and sudden load throw off of the turbine) this control plays the most important role in bypassing requisite quantities of steam.
5. *Start-up vent and drain valve*: These are controlled (interlocked) for start-up of the boiler. These are remotely operated semi-automatic operations.
6. *Electromatic safety valve*: This is an interlock-operated valve that pops up when pressure goes over the safety limit in the MS header near boiler.

2.6 Redundancy in Measurement: MS

- For critical parameters like turbine inlet pressure "2 of 3 redundancy," is quite common in larger power plants. In some power plants, dedicated one of two redundant pressure transmitters are used for HP bypass control, but in many places turbine inlet pressure measurement is done with more redundancy, which is also used for HP bypass control. This should be considered while drawing out specifications for HP bypass requirement of the transmitter.
- It is recommended to utilize at least one of two redundancies for MS temperature at the SH outlet on each side (as applicable). For smaller power plants one in each side is also deployed for measurement of MS temperature at the SH outlet.
- In larger power plants (200−500 MW) deployment of two of three redundancies in DPTs for steam flow measurement are not uncommon. However, one of two DPTs is recommended since this is an important parameter.
- Turbine first stage MS pressure is also an important measurement that may call for at least one of two redundancies. This, however, depends on the TG manufacturer, so while specifying instrumentation in a TG specification, the manufacturer needs to be considered.

2.7 Miscellaneous Points: MS

The MS system is closely related to many other systems and controls. Since MS parameters are required by both boilers and turbines, these parameters are controlled from a central monitor in the plant layout. However, these parameters need to be available for both monitors dedicated to SGs and TGs. In conventional layouts this is available in the central desk.

3. REHEAT STEAM (P&IDS): COLD AND HOT REHEAT

3.0 Reheat Steam System

Reheat steam has two parts: CRH and HRH.

3.1 CRH Steam System

3.1.1 Objective and Function of The System

The exhaust from the HPT is the starting point of CRH steam. HPT exhaust represents for that piping section, where steam outlet from both the HPT and HP bypass system come and join. CRH steam may also be generated even when the HPT is not in operation, and sometimes as a combination of both. Depending on the load, CRH steam pressure at the HPT outlet may vary, so when the HP bypass works in tandem, the variations need to be controlled. This system includes the following major functions:

- The steam is sent to the boiler for reheating so that it can be sent back to the turbine to do further work at the turbine.
- It is the source for other steam supply steam such BAS and TAS (in many plants such supply for auxiliary steam is taken from the MS).
- In case of a regenerative heat cycle, CRH is considered as extraction from the HPT (HPT exhaust), as an extraction (say as sixth) steam for the regenerative heater (no. six, —as the heater and extraction steam numbering nomenclature may vary from system to system).
- In many plants, CRH steam is used to heat up the deaerator (through the PRDS) at lower loads when extraction (i.e., from cross over) steam pressure is insufficient.
- Sometimes (depending on the heat balance diagram) it goes to the gland steam condenser (GSC)/sealing steam system.
- It is provided with the facility to prevent over pressurization of steam by popping up the safety valve to release excess steam.

3.1.2 System Description: CRH

The description given below is in conjunction with Figure III/3.0-1. CRH steam starts its journey from the outlet HPT and/or HP bypass (HPBP) station outlet with

www.EngineeringBooksPDF.com

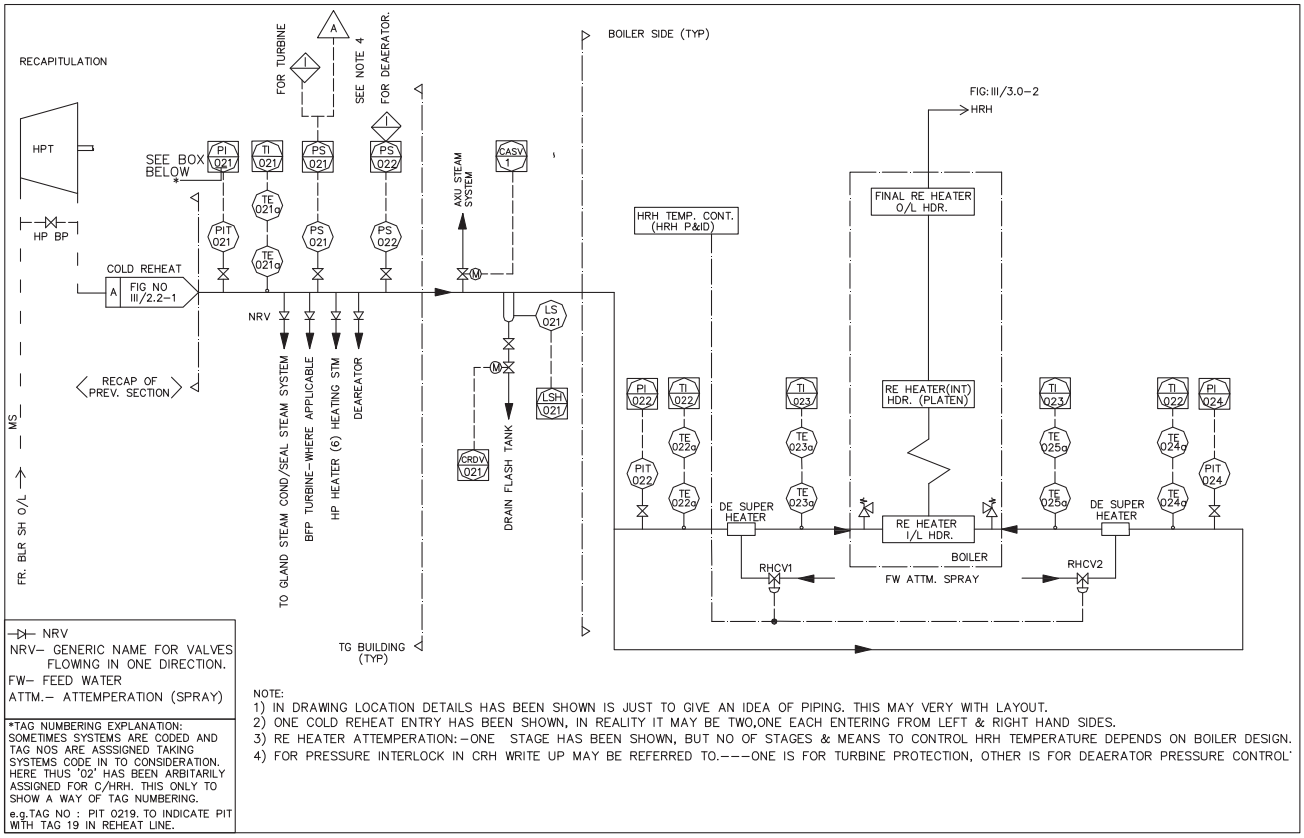


FIGURE III/3.0-1 CRH P&ID.

the aim to reach the RH inlet at the boiler. Like the main MS, there may be single or double CRH line depending on the boiler turbine configuration. With two separate lines, measurement duplication for pressure and temperature is necessary. However, separate monitoring of CRH pressure and temperature at the HP bypass outlet and at the HPT outlet is common. In many cases, the CRH steam line, after running for some distance in a single pipe, bifurcates into two lines to enter the RH inlet header from the left and right side of the boilers. CRH lines have de-superheaters in CRH lines just at or near the entry point of the CRH at each RH inlet header. In the CRH line, there are a few low elevation points from where it is drained to the drain flash tank. In all such points the level is monitored to protect against ingression of water into the turbine. To prevent over pressurization, necessary safety valves are provided in the line.

3.1.3 Major System Equipment: CRH Steam

Major system equipment includes the following:

1. *RH inlet header*: Header where the CRH line(s) from the turbine sides enters the boiler. From here there are several subheaders to form the RH, which get heated from flue gas.
2. *Inlet safety valve*: To prevent over pressurization, there is one safety valve at the RH inlet of the boiler.
3. *Drain lines*: There are a number of drain points during the course of the CRH line. At each of the lowest points there are U traps for draining (the level measurement is done there) to the drain flash tank.
4. *De-superheater*: For several boilers there are stages of attemperation for controlling the temperature of the hot RH (HRH) at the RH outlet. In those cases, the first stage attemperation is kept at the RH inlet header. There is another attemperation in the intermediate stage of the RH.
5. *Miscellaneous supply lines*: As discussed earlier, that there are a number of lines that come out from the CRH line, such as auxiliary steam, HPH 6 supply, gland steam, etc., each with a remote-operated motorized valve.

3.1.4 Major Parameter Measuring Monitoring in CRH Steam

3.1.4.1 Process Parameter: CRH (Typical Values Only)

CRH steam is generally applicable for medium and larger plants as in smaller plants the RH cycle may not be

www.EngineeringBooksPDF.com

TABLE III/3.1.4-1 CRH Parameters

Parameter	RH inlet		HPT/HPBP outlet		Remarks
Size	200 MW	500 MW	200 MW	500 MW	
Pressure*	30–40	47–49.5	31–41	45–47	*Typical value and it may vary
Temperature*	316–340	355–360	316–340	355–360	
Flow	635–720	~1450	635–720	~1450	

Units: Pressure in kg/cm^2, temperature in °C, and flow in T/h.

followed. In Table III/3.1.4-1 we try to put forward a few process parameters at the turbine and boiler end.

Pipe pressure drop between boiler to turbine and vice versa (each side) is ~1–1.5 kg/cm^2. It depends on the actual piping route and sizing, which is beyond the scope of this book. Empirically an ~4 kg/cm^2 pressure drop can be considered from CRH at HPT to HRH. It is noted that the quantity of CRH steam going to the boiler will be less than the MS flow because there will be some consumption at the heater and/or auxiliary steam depending on mass and heat balance diagram for the plant.

3.1.4.2 Monitoring of Process Parameter: CRH Steam

It is important to monitor the following CRH steam parameters at the control room. It is worth noting that the various ranges given here are typical values only and are not plant specific.

1. *CRH steam pressure and temperature at HPT/HP bypass system outlet*: CRH temperature is also a control parameter for the HP bypass system. See Figure III/3.0-1 for these parameter measurement points. Typical calibrated range for larger power plants is 0–50 kg/cm^2. As discussed earlier, actual range setting is very easy with smart transmitters (indicating type preferred), which need to be considered. With double outlets these measurements need to be performed at each end. Generally ISA type K T/Cs are used to measure the temperature. A typical range is 0–400/450°C for instruments (temperature transmitters).
2. *HP bypass steam flow*: In many power plants this parameter is measured, especially where steam flow is not measured (clause 2.4.2). When HP bypass runs in tandem with the turbine then it is necessary to compute the boiler load index. Flow nozzle with a DPT is used for flow measurement. Depending on the flow-metering standard, the range may be zero to several thousands of millimeters of water column (see clause 2.4.2). Depending on the percentage of HP bypass chosen, the range can be selected based on data discussed for typical parameters (see clause 2.4.2).
3. *Pressure monitoring outlet of HPT*: It is important to monitor CRH pressure at the turbine end, so that the pressure does not rise. If it rises then it affects the pressure at the intermediate-pressure turbine (IPT) and low-pressure turbine (LPT) exhaust, i.e., condenser vacuum. For this reason putting a block valve in the HP bypass line is common practice, so if there is high pressure the system flow can be blocked (see Figure III/2.2-1). Also in the attemperation line a separate pressure-reducing valve is introduced so that higher pressure at the FW cannot cause the pressure to rise at the HP bypass line. Also in the attemperation line there is a block valve (see Figure III/2.2-1). A pressure switch is placed to monitor pressure against the high set point. This will generate an alarm, and in some cases this pressure switch causes tripping of the turbine. Protecting the turbine is especially important when other types of protection in the HP bypass line discussed above have not been considered. There may be another pressure switch to sense that CRH pressure is higher than a set value so that CRH steam can be utilized for deaerator heating.
4. *CRH level monitoring*: At all major low points, the level is monitored by float/displacement type level switches in line with recommendations from the Turbine Water Damage Prevention System (TWDPS) to prevent water from entering the turbine.
5. *RH inlet pressure and temperature measurement*: The measurement of CRH steam pressure and temperature measurement is done at the RH inlet, from a boiler performance measurement point of view. As stated earlier, in many boiler there could be a de-superheater at the inlet of the RH as shown in Figure III/3.0-1. In those cases temperature is monitored at both the inlet and outlet of the de-superheater or attemperator.

3.1.5 Controls in CRH Steam

A number of controls associated with the CRH system are listed below:

1. *HP bypass temperature control*: It is a part of the HP bypass control and is discussed at length in chapter VIII. If there is more than one HPBP control

www.EngineeringBooksPDF.com

for each set of HP bypass controls, there will be one spray control valve and maybe one common pressure regulating valve to reduce FW pressure before the FW spray line (see Figure III/2.2-1).

2. *RH temperature control first stage attemperation*: Generally for RH control there is spray water control at the CRH line inlet to the RH. Spray control is used only during emergencies as the same (HRH temperature) is regulated by a burner tilt control or gas bypass damper and/or gas recirculation damper.
3. *CRH line level control*: As stated earlier, at the low points in the CRH line there are drain pots whose levels are monitored and interlocked in such a way that if the level rises above a set value the drain valve is opened to drain to the flash tank. Also level alarms are available at the control room.
4. *CRH supply line valve—remote operated*: There are a few motorized valves (remote operated, semi-automatic) in the CRH supply lines to auxiliary steam, HPH 6, etc., as shown in Figure III/3.0-1.

3.1.6 Redundancy in Measurement: CRH Steam

- For critical parameters like the HP bypass temperature control, one of two redundancy is common (in Figure III/2.2-1 redundancy is not shown).
- For turbine tripping from high pressure in the CRH line, a redundancy of two of three with voting logic may be used.

3.1.7 Miscellaneous Points: CRH Steam

Like MS, CRH is related with many other systems controls. Since CRH parameters are required by both boilers and turbines, these parameters are controlled from a central monitor in a control desk layout. However, these parameters need to be available at both monitors dedicated for an SG and TG. In a conventional layout this is available at the central desk.

3.2 HRH Steam System

3.2.1 Objective and Function of the System

A HRH steam system provides steam from the RH section of the boiler to the IP section of the turbine (IPT) in a thermal power station. Major functions of this system are included below:

- A source for thermal energy supply to the IPT and LPT to carry out mechanical work at the turbine. There may be more than one RH, hence more than one HRH system in the thermal cycle (e.g., USC plant design). It is worth noting that the maximum amount of work is done at the IPT and LPT, so condenser is at vacuum in larger utility power plants.
- It has the ability to prevent over pressurization of the steam source (if the supply of steam is more than consumption at the turbine) by popping up the safety valve to release excess steam
- During start-up, shut down, and large load throw off by the turbine, HRH steam bypasses the IPT and LPT and goes to the condenser after pressure and temperature reduction with the help of the LP bypass (LPBP) system.
- HRH after passing through the IPT goes to the LPT and is known as cross-over steam as well as Ex 4. A part of this cross-over steam is used to heat up the deaerator during normal operation. For plants with steam turbine-driven boiler feed pump (BFPT), this cross-over steam is the source of energy. Cross-over steam is also used as a turbine sealing steam.

3.2.2 System Description: HRH

HRH steam starts its journey from the outlet of the final RH. In many boilers, RH outlet headers come from both LHS and RHS of the boilers (see Figure III/3.0-2). in those cases, after running for some distance, they join at a point outside the boiler structure before entering the turbine building. After running in a single header they may be split into two or four headers to enter into the IPT stage of the turbine. Similar to MS, HRH also has a bypass path known as LPBP to bypass IPT and LPT and HRH steam after pressure and temperature reduction is dumped into the condenser. The LPBP system starts operating during start-up, shut down, and for a large power throw off by the turbine. Usually HPBP and LPBP come into operation at the same time. In most cases the EHG and LPBP go hand in hand, so LPBP is normally in the scope of the turbine suppler. Associated with LP bypass, there are a number of essential temperature protections since it goes directly to the condenser.

3.2.3 Major System Equipment: HRH Steam

Major system equipment for this system include the following:

1. *RH outlet header*: It is the header from which the HRH steam comes out to enter the IPT. As told in connection with CRH, from the inlet header a number of tube bank/panel form the RH, which discharges at this header. It is worth noting that between the inlet and outlet header of the RH there may be a de-superheater where water is sprayed to control RH temperature.
2. *Outlet safety valve*: To prevent over pressurization, there is one safety valve at the RH outlet of the boiler.

www.EngineeringBooksPDF.com

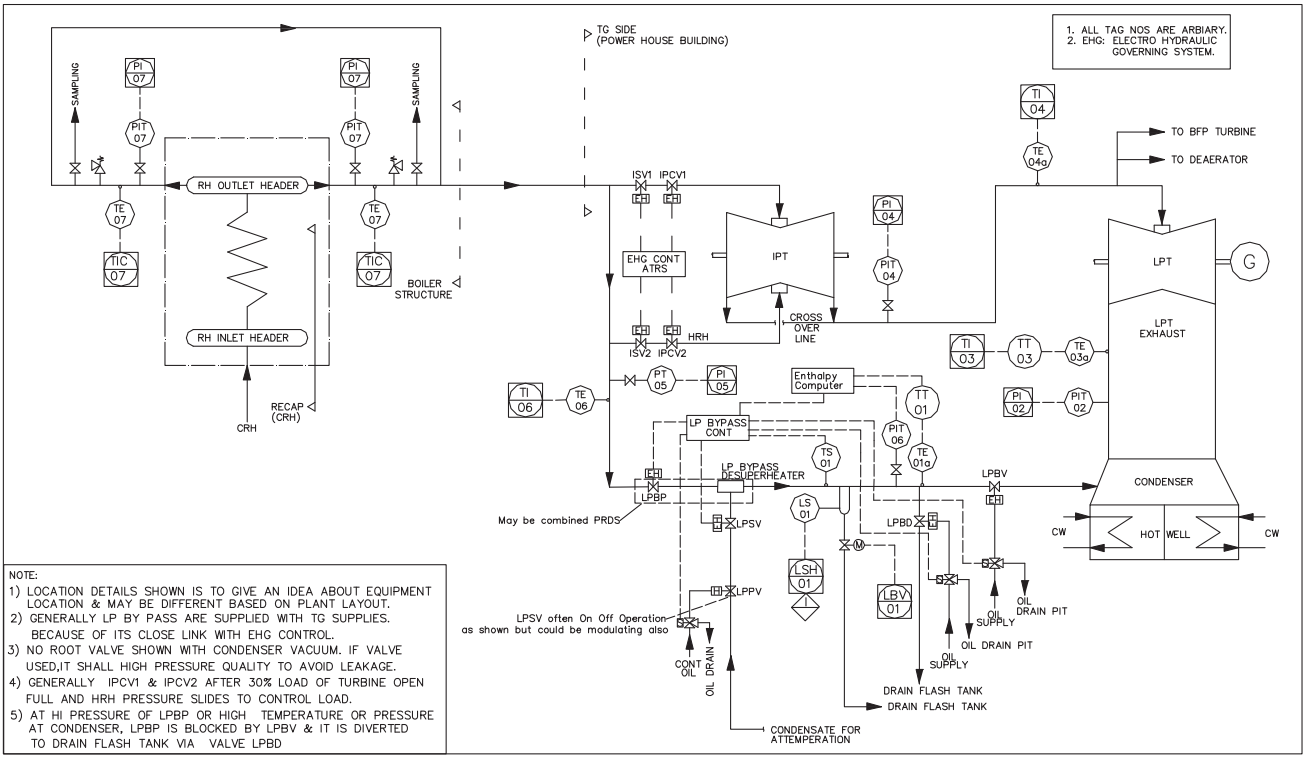


FIGURE III/3.0-2 HRH steam.

3. *IPT stop valve (ISV 1, 2)*: At the turbine inlet there is one in each entry line to the IPT to isolate the steam entry to the IPT (hence LPT as IPT exhaust steam goes directly to the LPT as cross-over steam). This is a hydraulically operated valve under the control of the EHG system of the turbine. Depending on turbine start-up system, these valves can be opened partially through EHG control.
4. *IPT control valve (IPCV1, 2)*: These are regulating valves, which when throttled, the steam admission to the IPT (and LPT) will be regulated. Up to 30% load of the turbine these valves throttle to control the load to the turbine sections. After that they are kept wide open and the steam admission is guided by the HRH flow from the boiler. With variations in turbine design above operational requirement may also vary.
5. *Cross-over line*: It refers to the steam exhaust from the IPT for direct admission to the LPT. In certain cases some extractions are taken from this line to supply steam to the deaerator and the BFPT during steady-state operation.
6. *LPBP and LP stop valve (LPSV)*: These are meant to bypass excess steam to the condenser bypassing the IPT and LPT stages of the turbine. The pressure reduction in this line is done by the LPBP valve. This is effective during shut down and for sudden load throw off. There two distinct situation here. When the LPBP is running in tandem with the turbine, then the LPBP pressure set point is derived from the HPT first stage pressure (since during this time CRH pressure is variable so is HRH pressure). If the turbine is not running but the LPBP is in operation, the LPBP needs to follow the HPBP, hence its set point may be derived from HPBP (pressure-reducing valve position). Based on the above set point, HRH pressure is reduced. The steam at reduced pressure is further cooled in a de-superheater, looking at the enthalpy *not* temperature. Since the temperature at the de-superheater outlet after LPBP is very near (or at saturation temperature), temperature after the de-superheater should not be used, instead fixed enthalpy needs to be maintained. In some designs the control valve and de-superheater are built in one assembly. The spray control in this valve (LPSV) may not exactly behave like a standard control valve at times; it behaves as an ON/OFF valve to ensure that the steam admitted to the condenser does not exceeding a preset value. In case the temperature exceeds that value, it is not admitted to the condenser and is sent to the drain flash tank instead. If necessary the LPBP may be closed in extreme situations. Temperature element and pressure instrument with suitable redundancy may be deployed to compute the enthalpy. Normally fixed enthalpy is maintained(see Figure III/3.0-2).

www.EngineeringBooksPDF.com

7. *LPBV and LPBD*: The purpose of the LPBV is to block the LP bypass steam flow to the condenser in case of high pressure and/or temperature. This is an interlock-operated valve generally connected with LP bypass control. LPBD is also an interlock-operated valve that allows LP bypass steam to the drain flash tank in case LPBV has blocked the flow. This is a typical scheme followed by some manufacturers.
8. *LPPV*: This valve is kept in the line to regulate the pressure of condensate to LPSV. Often it has an ON/OFF control but regulating/modulating controls are also seen.
9. *Drain line*: The LP bypass line going to the condenser has a U drain point to drain to the flash tank.

3.2.4 Major Parameter-Measuring Monitoring in HRH Steam

3.2.4.1 Process Parameter: HRH (Typical Values Only)

HRH steam is generally applicable for the larger plants, as in smaller plants the RH cycle may not be followed. In Table III/3.2.4-1 a few process parameters at turbine and boiler ends have been listed.

3.2.4.2 Monitoring of Process Parameter: HRH Steam

It is important to monitor the following CRH steam parameters in the control room in almost all power plants. It is worth noting that the various ranges given here are typical values and are not any plant specific.

1. *HRH steam pressure and temperature at RH outlet*: HRH at the boiler outlet temperature is also an important control parameter for a boiler. For larger power plants, typical calibrated range for HRH pressure and temperature may ranges from 0 to 50 kg/cm^2 and temperature from 400 to 450°C, respectively.
2. *HRH steam pressure and temperature at the IPT/LP bypass inlet*: Similar as stated above. Here it is worth noting that HRH pressure at the IPT/LP bypass inlet is a control parameter for LP bypass control.
3. *Pressure temperature monitoring at cross-over steam*: Pressure and temperature measurement on this line at the turbine end is important. Typical ranges for smart pressure transmitters is 0−10 kg/cm^2 while Pt100 RTD can be deployed to measure temperature with a range of 0−400/450°C.
4. *LPT exhaust pressure and temperature*: Measurement of both of these parameters is very important. Since this is basically a measurement of condenser vacuum and condenser temperature, it is directly related to plant heat cycle performance. As seen in Figure III/3.0-2, it is to be noted that no root valve is shown for pressure measurement as this is in vacuum. If any valve is to be provided then it should be a high pressure class valve so that there is no leakage. Smart vacuum/absolute pressure transmitter in the short span of 200 mm wcl (0−0.2 kg/cm^2 A) should be used. Whereas a Pt100 RTD should be deployed to measure temperatures ranging from 0 to 80°C.
5. *Temperature and pressure outlet of LP bypass*: With reference to clause 3.2.3, temperature alone at the outlet of the LP bypass (de-superheater outlet) is measured, and but is not taken as a control parameter. Both temperatures and pressures are measured to compute enthalpy. For temperature, Pt100 RTDs and/or copper constantan (ISA type T) etc., are used and for pressure measurement a smart transmitter can be used. For protection, in addition to temperature elements temperature switches are used to trip the LPBV and divert the steam to the drain flash tank. These additional protections are seen in many designs.

3.2.5 Controls in HRH Steam

A number of controls associated with the HRH system are listed below:

1. *HRH steam temperature control*: HRH steam temperature at the RH outlet header(s) of the boiler is an important control parameter. After start-up, once the

TABLE III/3.2.4-1 HRH Parameters

Parameter	HRH outlet		IPT/LPBP inlet		Remarks
Size	200 MW	500 MW	200 MW	500 MW	
Pressure*	29−39	46−47.5	28−38	45−46	*Typical value, may vary in actual case
Temperature*	540	540	540	540	
Flow	635−720	~1450	635−720	~1450	

Cross-over steam (sometimes referred to as Ex 4) has load-dependent pressures and temperatures: 7 kg/cm^2 pressure with >340 °C. LPT exhaust steam is ~0.081 kg/ cm^2 with a temperature of ~ 40—45 °C.
Units: Pressure in kg/cm^2, temperature in °C, and flow in T/h.

www.EngineeringBooksPDF.com

temperature of the HRH reaches the desired value (i.e., 540°C for large power plants) it is kept constant throughout. Initially the fixed set point is kept much lower as there is insufficient steam flow. Later when steam flow is established, a set point is raised or may be set based on load (i.e., air flow). The temperature control for HRH varies from boiler to boiler. In some designs (corner fire) a burner tilt is the primary control element, whereas in wall fire boilers gas bypass dampers or gas recycling dampers can be used as main control elements. Spray water is used during emergencies. In some designs spray water is used as a main control. However, in SC boilers the situation is a little different. Since here FW:fuel ratio is most important, RH spray water is not really used for emergencies, but may be put into operation from the beginning.

2. *EHG control of turbine*: This is the most important control system for a turbine. In the IPT the control valve controls up to 30% of the turbine load. After that it is made wide open from EHG and during that time the steam pressure slides. As discussed earlier there is variation of this also.
3. *LP bypass control*: During start-up/shut down (and sudden load throw off of the turbine) this plays the most important role in bypassing requisite quantities of steam. Since the steam goes to the condenser there is a block valve to protect the condenser during high temperatures.

3.2.6 Redundancy in Measurement: HRH Steam

- HRH boiler outlet temperature measurement is an important parameter so one of two redundancy is generally utilized in utility plants. For two outlet headers this is to be repeated for both sides.
- For LP bypass, generally the control is with the turbine manufacturer/supplier, so while specifying the system-required redundancy at least one of two redundancy may be selected for pressure as well as for temperature measurements. In many plants there are two sets of control, and the same is to be repeated for each control. In larger plants redundancy in temperature switches for turbine protection is also seen.
- LPT exhaust temperature *and* pressure parameters are important. and in larger utility stations one of two redundancy is utilized.

3.2.7 Miscellaneous Points: HRH Steam

Like MS, HRH is inter-related with many other systems and controls. Since HRH parameters are required by both the boiler and turbine, these parameters are controlled from a central monitor in the panel layout. However, these parameters need to be available on both monitors dedicated to SG and TG. In conventional layouts this is available on the central desk.

4. EXTRACTION STEAM (P&IDs): BLEED STEAM

4.0 Extraction Steam System

Extraction steam, also known as bleed steam, is the system for which the regeneration cycle has been made possible. To avoid thermal shock condensate, FW is preheated by extraction steam before admission to the boiler.

4.1 Objective and Function of the System

Out of the total steam admitted to the turbine, a major part is used to do the mechanical work in the turbine, whereas another part is used to preheat condensate and FW. Generally the extraction lines are numbered from low to high pressure (e.g., first three extraction lines from the LPT are numbered as I, II, and III, to heat up LP Heaters 1, 2, and 3, respectively). However, reverse numbering systems are also seen. Number, location, and design parameters of each of these extraction lines purely depends on the heat balance diagram developed for the plant. Basic purposes of extraction Steam include the following:

- In a typical, subcritical turbine plant (i.e., 200−500 MW) there are approximately three extraction lines from the LPT to supply heating steam to three LP heater (LPH) shells to heat up the condensate passing through the coil (e.g., Extractions I−III are meant for heating for LPH 1−3)
- Generally from cross-over pipe (exhaust line IPT going to LPT), extraction steam (numbered as Extraction IV) is supplied for deaerator heating as well as for deaeration function. The deaerator is therefore sometimes referred to as Heater 4. In addition to this, wherever there are turbine-driven BFPs their steam supply is taken from cross-over steam.
- Normally one extraction is taken from the IPT for steam supply to the HPH 5 FW heating. However, there are designs where more than one extraction is taken from the IPT turbine. Based on design considerations, there may be single or double HPHs also.
- FW heater 6 generally is heated by CRH (HPT exhaust). In certain designs there is extraction steam from the HPT also. In some of the designs extraction steam is taken from the HPT (at a pressure higher than HPT exhaust) also to heat up HPH VII.

4.2 System Description: Extraction Steam

The description given below for extraction steam needs to be studied in conjunction with Figure III/4.2-1, where

www.EngineeringBooksPDF.com

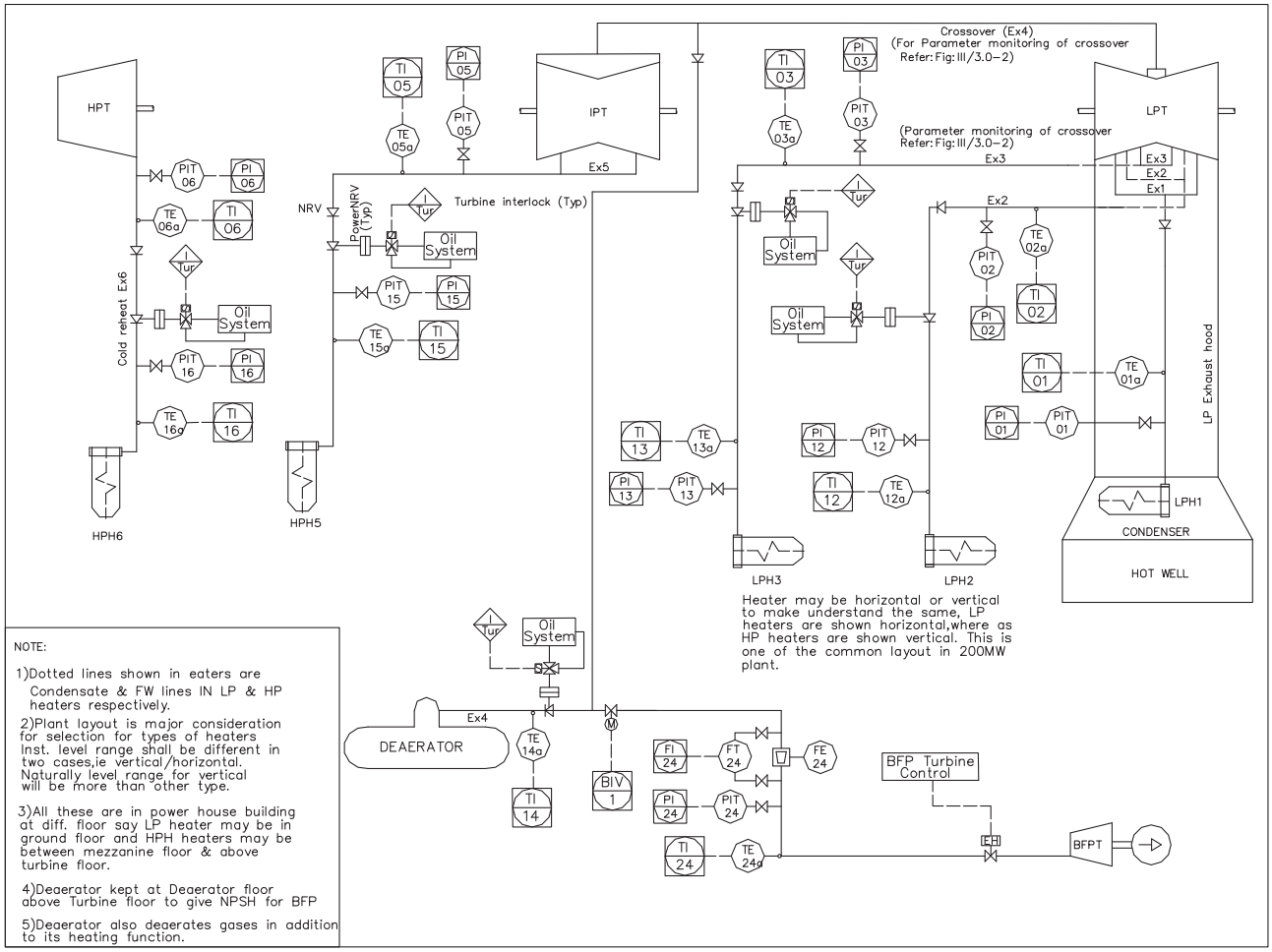


FIGURE III/4.2-1 Extraction steam P&I diagram.

typical generalized configuration is depicted with six extractions numbered from the LPT side.

Extraction steam lines come out at various stages of the turbine. The main function of each line is to preheat the condensate and FW in regenerative heaters. Each line is provided with at least one nonreturn valve (NRV) so that when a high level occurs in the heater, water cannot ingress to the turbine. In extraction lines there are power-operated NRVs that can be closed during certain operations of the turbine. Also by making heaters out, the turbine storage, hence, load shoot up can be made—as is done in SC plants. Some plants use motorized valves in these lines for isolation purposes. The pressure in extraction lines is uncontrolled (meaning it depends on the turbine load). The various extraction lines include the following:

- *Ex 1*: It starts from the bleeding line at the point in the LPT where pressure is slightly higher than the LPT exhaust line and is used for heating condensate at coils of LPH 1 located at the neck of the condenser.
- *Ex 2*: This also is from the LPT, but it has a pressure temperature higher than that of Ex 1 and is used for heating condensate at the coil of LPH 2 located in the ground floor of the power house building. However, in certain designs (where there are seven heaters), this may be at the condenser instead.
- *Ex 3*: This also is from the LPT but has a pressure temperature higher than that of Ex 2. It is used for heating condensate at the coil of LPH 3 located in the ground floor of the power house building.
- *Ex 4*: This is a cross-over line coming out as exhaust from the IPT and going to the LPT as steam input.
  - It goes for heating and deaeration or removes gases (mainly dissolve oxygen) from condensate at the deaerator, which is located at the deaerator floor in the power house building.
  - Plants with BFPTs get the steam supply from this extraction line. This steam is admitted to the BFPT via a steam control valve to control the speed of

www.EngineeringBooksPDF.com

the BFP. (However, there should be at least on motor-operated BFP for start-up purposes).
  - There are also designs, where these extraction steams are taken from two separate extractions; it all depends on Thermal system design.
- *Ex 5*: This line comes from the IPT before the cross-over line with higher pressure and temperature and is used to heat up the FW in the heating coil of HPH 5.
- *Ex 6*: This CRH steam line is used to heat up FW in the coil of HPH 6. When pressure in the CRH line is greater than the set point, this steam is utilized for the BFPT and deaerator until the Ex 4 line is established (TG load, i.e., 55%).

As stated above there are options for additional extractions from the HPT as well.

4.3 Major System Equipment: Extraction Steam

Major system equipment in each of the extraction lines include the following:

1. *NRV*: In each extraction line there will be one NVR that allows extraction steam to flow in to the heater.
2. *Power-operated NRV*: Except in the Ex 1 line, in all other extraction lines there is one additional power-operated NRV for easing out the turbine operation from remote. These power operated NRVs may be under control of turbine run up systems.

4.4 Major Parameter Monitoring in Extraction Steam

4.4.1 Process Parameter: Extraction Steam (Typical Values Only)

For the reader to understand parameter values, some typical values for 200 and 500 MW plants are indicated in Table III/4.1.4-1 at the turbine maximum continuous rating (TMCR) condition.

4.4.2 Monitring of Process Parameter—Ex.Steam

It is important to monitor the following extraction steam parameters in the control room in almost all power plants. It is also important to note that in extraction steam P&ID, measurement of these parameters at the turbine end as well as at the consumer end is quite common, as they can be used for different purposes. As the point of consumption is away from source there may be some drop, so measurements at both ends are done. Also measurements of these parameters at both ends are useful to monitor the performance of the turbine as well as the consuming equipment. It is worth noting that the various ranges given here are typical values.

1. *Ex 1steam pressure and temperature(from LPT to LPH 1)*: Since in many cases this heater is located at the condenser neck, parameters are measured only at one

TABLE III/4.1.4-1 Extraction Steam Parameters

Ex no.	User	Pressure bar (A)	Temperature (°C)	Flow (T/h)	Remarks
For TMCR 200 MW (Typical)					
1	LPH 1	0.5–0.6	82	55	
2	LPH 2	1.2	<150	25–30	
3	LPH 3	2.5–3.0	200–220	25	
4	Deaerator + BFPT	7.0	300–320	85–90	Cross over
5	HPH 5	15–16	425–450	70	
6	HPH 6	30–35	300–320	80	CRH
For TMCR 500 MW (Typical)					
1	LPH 1	0.64	87	79.6	
2	LPH 2	1.6	160	46	
3	LPH 3	3.0–4.0	220–230	47	
4	Deaerator + BFPT.	10.0	350	160	Cross over
5	HPH 5	22	470	95	
6	HPH 6	38–42	340–350	115	CRH

www.EngineeringBooksPDF.com

end. A smart absolute pressure transmitter needs to be used for this purpose. Ranges are typically from 0 to 1.5 kg/cm^2. For temperature measurements an RTD (with smart transmitter, if used) can be deployed. The range of measurement is from ~0 to 100°C.

2. *Ex 2 steam pressure and temperature (from LPT to LPH 2)*: In most of the power plants these measurements are used both at the turbine end and heater end. It is recommended that a smart absolute pressure transmitter is in the range of typically 0–2.5 kg/cm^2. For temperature measurements an RTD (with smart transmitter, if used) can be deployed. The range of measurement is from ~0 to 250°C.
3. *Ex 3 steam pressure and temperature(from LPT to LPH 3)*: Measurements are similar to that in Ex 2. Typical pressure range can be 5 kg/cm^2. Typical temperature range of measurements are from ~0 to 350°C.
4. *Ex 4(steam to deaerator and BFPT) steam pressure and temperature*: Similar to what has been discussed above. At the turbine end smart transmitters in the range of 0–10 kg/cm^2 would suffice. However, at the consumer end the same range would suffice for extraction steam, but since the deaerator/BFPT has steam supply from other sources like auxiliary steam and CRH, another transmitter may need to be selected to cater to those ranges. Instrument for temperature measurement is the same as discussed above and the typical temperature range is ~0–350 to 0–400°C. The BFPT steam flow is measured. In many cases the specifications call for separate steam lines from the CRH (with auxiliary steam until the time the CRH is unavailable) and for steam from Ex 4. In that case separate steam flow measurements are deployed. Steam flow may be in the range of 50–60 T/h. Flow nozzle with smart DPTs are deployed.
5. *Ex 5 steam pressure and temperature (from IPT to HPH5)*: Similar to previous discussions. Pressure range of 0–20 kg/cm^2 would suffice. For temperature measurement ISA type K (with smart transmitter, if used) can be deployed. The range of measurement should be ~0–500°C.
6. *Ex 6(CRH) steam pressure and temperature (from HPT Exhaust to HPH 6)*: Similar to the discussions above, typical pressure and temperature range would be 0–40 (50) kg/cm^2 and ~0–450°C, respectively.

4.5 Controls in Extraction Steam

There is no direct modulating control associated with this system except control for power-operated NRVs. Steam admission to the BFPT has control (as part of the BFPT).

4.6 Redundancy in Measurement: Extraction Steam

Deaerator Pressure measurement is critical as it is used to control auxiliary and CRH steam, but extraction steam is uncontrolled. For that purpose redundancy in one of two mode is quite common.

4.7 Miscellaneous Points: Extraction Steam

Extraction steam measurements are closely related to the turbine system, so these parameters are monitored with turbine end monitors; however, some of these measurements are repeated at the monitors pertinent to control and monitor regenerative cycles, i.e., the central monitor in the control room layout.

5. AUXILIARY STEAM (P&IDs)

5.0 Auxiliary Steam System

As the name suggests, auxiliary steam is the "steam supply" that helps to run various auxiliaries. In a power plant the demand for auxiliary steam is there from initial start-up until the end when the unit is running at its maximum value (rated capacity). It is worth noting that the requirement is higher during start-up of the boiler and turbine and gradually decreases as the unit is loaded to its full capacity. This is because whenever a unit is started it starts with heavy fuel oil [HFO; with a high-energy arc (HEA) ignitor], so for heating and atomizing auxiliary steam is necessary. Even if the unit is initiated with light diesel oil (LDO), steam is still necessary to heat up the HFO so that it can be taken up at any time. When the unit starts loading, the HFO is cut off slowly so atomizing steam is not necessary but heating steam still is on. The requirement is less,– only to keep the HFO in a liquid state through circulation. This is similar to the unit/turbine start-up: steam requirement at starting ejector (wherever applicable) is much more than the normal ejector. Also for deaerator and gland steam there is a requirement of auxiliary steam during start-up, but the requirement reduces as the unit/turbine is loaded and normal ejectors come into operation.

5.1 Objective and Function of the System

There will be a common steam header with a fixed pressure and temperature (parameter depends on the design of the power plant) wherefrom steam is supplied to various consumers within the plant. Major functions of auxiliary steam include the following:

- To maintain constant pressure and temperature at the steam header, irrespective of the source of supply for the auxiliary steam.

www.EngineeringBooksPDF.com

- To supply auxiliary steam supplies to boiler and turbine auxiliaries at a constant pressure and temperature.
- On the boiler side auxiliary steam is supplied mainly to the following:
  - Fuel oil heating—storage/day tank heating, line heating so that highly viscous HFO is in flowable condition.
  - While HFO is fired, it is atomized with the help of auxiliary steam
  - Steam supply to steam coil air preheater (SCAPH) when in use.
  - Supply of steam for soot blowing (SB steam)
- On the turbine side auxiliary steam is supplied mainly to the following:
  - Gland steam supply: during start-up stage auxiliary steam is used to seal gland leakage
  - Deaerator steam pegging with auxiliary steam.
  - Steam supply to air ejector
  - Supply of steam for BFPT (as applicable)

5.2 System Description: Auxiliary Steam

It is important to note that various types and design of the auxiliary steam system exist for various power plants. There are many power stations with lower megawatt size or in process cum power plants, where two separate headers are developed for auxiliary steam: TAS and BAS. Today, in major utility stations with higher megawatts, a common auxiliary steam header is formed. Again, depending on source, there are two types: in some plants MS is taken as the sole source from which to form the auxiliary steam header. In some designs, MS is used as one of the sources during start-up and CRH is used as a main source for formation of auxiliary steam. All of these are shown in Figures III/5.2.1 to III/5.2.4. It is worth noting that in some of the Chinese designs it has been found that they use only pressure reduction to form the auxiliary steam header and temperature reduction is done according to the requirement of the consumers.

5.2.1 System Description: General

For discussions we generally refer to instruments with tag numbers, as shown in Figure III/5.2-1(however, these general discussions are equally applicable to other figures, except the tag numbers may be different). High-pressure steam (MS or CRH) needs to be reduced to the desired pressure set point. This is done by one pressure-reducing control valve (PRV) whose opening is controlled by a controller (part of the main DCS) with the desired pressure set point. At the inlet (PCIV 11) and outlet (PCIV 12) of the control valve (say, BAHPV-1 in Figure III/5.2-1) there are

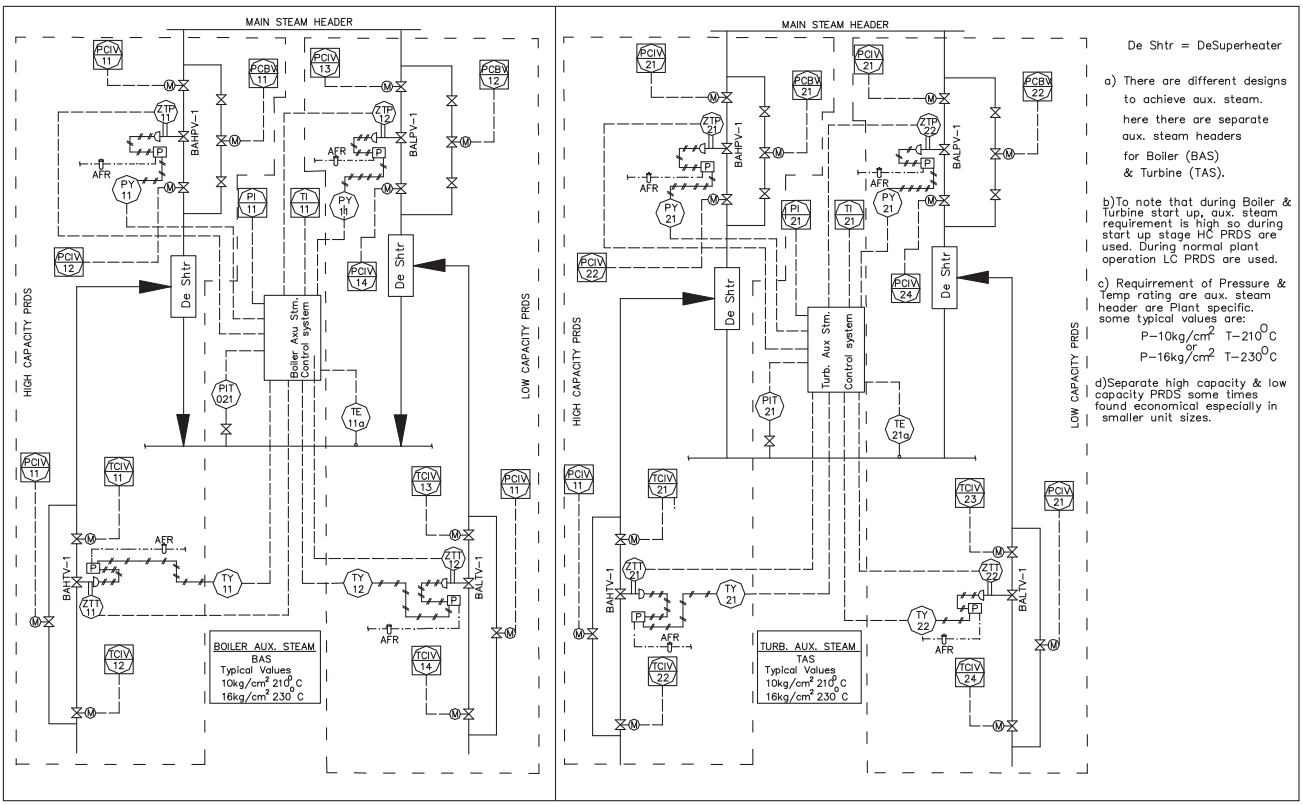


FIGURE III/5.2-1 Boiler and turbine auxiliary steam (high/low capacity).

www.EngineeringBooksPDF.com

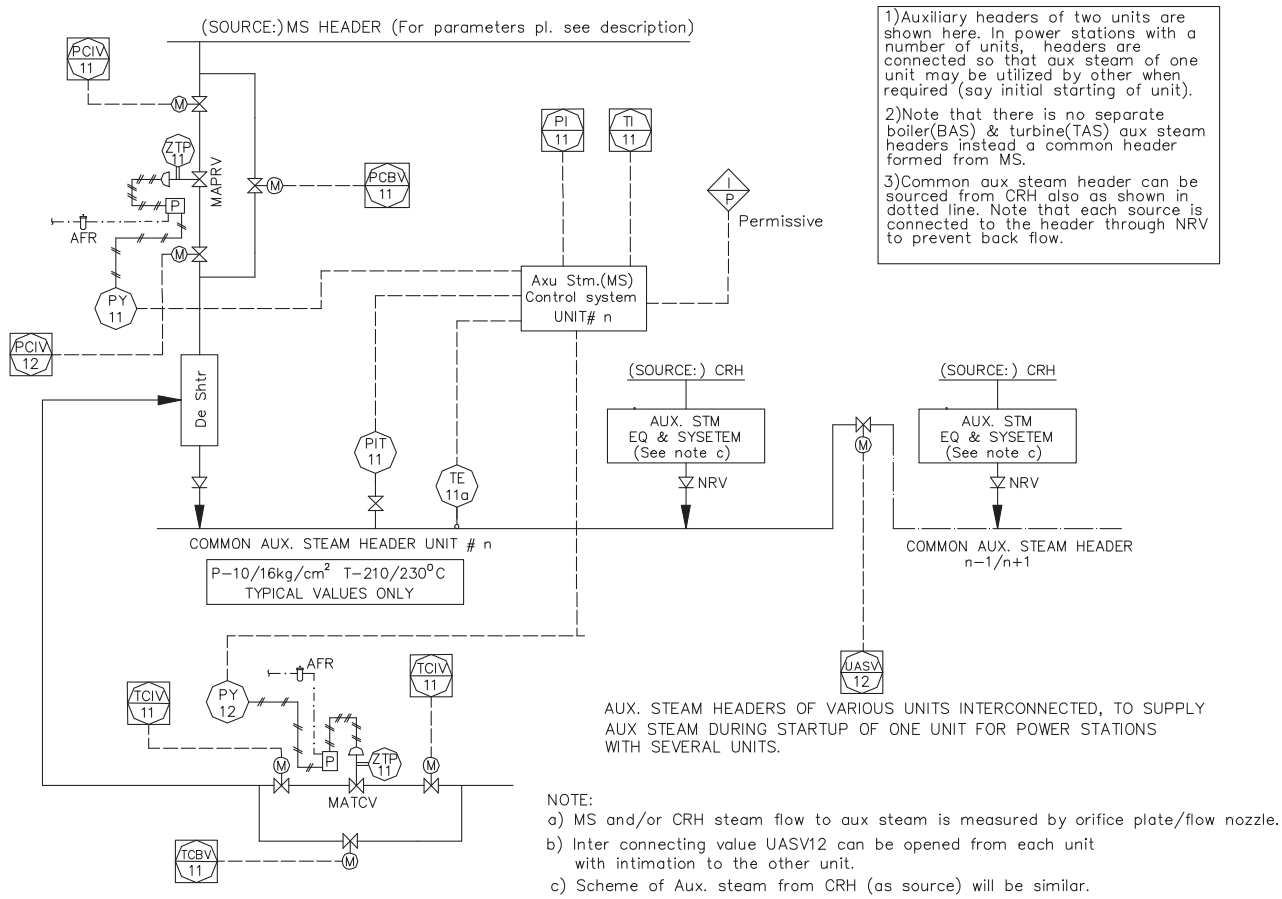


FIGURE III/5.2-2 Common auxiliary steam header (from MS) and interconnections.

two isolating remote-operated, motorized isolation valves used to isolate the control valve (e.g., during maintenance). During maintenance, the system can be made operational by remotely manually throttling (inching) the bypass valve (PCBV 12). The purpose of the bypass valve also is to heat up the line before staring the PRV operation by crack opening of the bypass valve.

After pressure reduction, the steam through one de-superheating station brings down the temperature of the steam to the desired point. The water supply to the de-superheater is controlled by controlling the FW flow to the de-superheater. The desired temperature set point is compared in a PID controller (part of the main DCS) to generate the control signal that regulates the FW flow to de-superheater. Associated isolation & bypass operations are as explained above.

5.2.2 System Description: Separate BAS/TAS

In this type of design, as Figure III/5.2-1suggests, there are two separate auxiliary steam headers. One is BAS and the other is TAS. In these types of systems generally MS is passed through PRDS to generate BAS and TAS headers separately. As stated earlier, because of different flow requirement of auxiliary steam during start-up and at higher load, it may not be possible for a single set of control valves to meet both requirements; hence there may be one high-capacity(HC) PRDS and one low-capacity (LC) PRDSs as indicated in Figure III/5.2-1.

Why two separate headers? For stations only meant for power generation this configuration may not be desirable, because there will be two sets of PRDS stations and each station will have HC and LC PRDS. Had there been one *common header*, there may not have been a requirement for separate HC and LC PRDS stations. When a boiler is starting up (at the pressurizing stage) it has a higher auxiliary steam requirement; at that time the turbine may not need steam at all, especially when there is a bypass in the system. By combing two headers to form a common header is a better option. However, this configuration may be most beneficial in process cum power plants where the steam header consumers may be near the boiler (may be near turbine side also) and the turbine is far off. Therefore, from a layout point of view this could be a better option to minimize energy loss (pressure drop) due to distance.

www.EngineeringBooksPDF.com

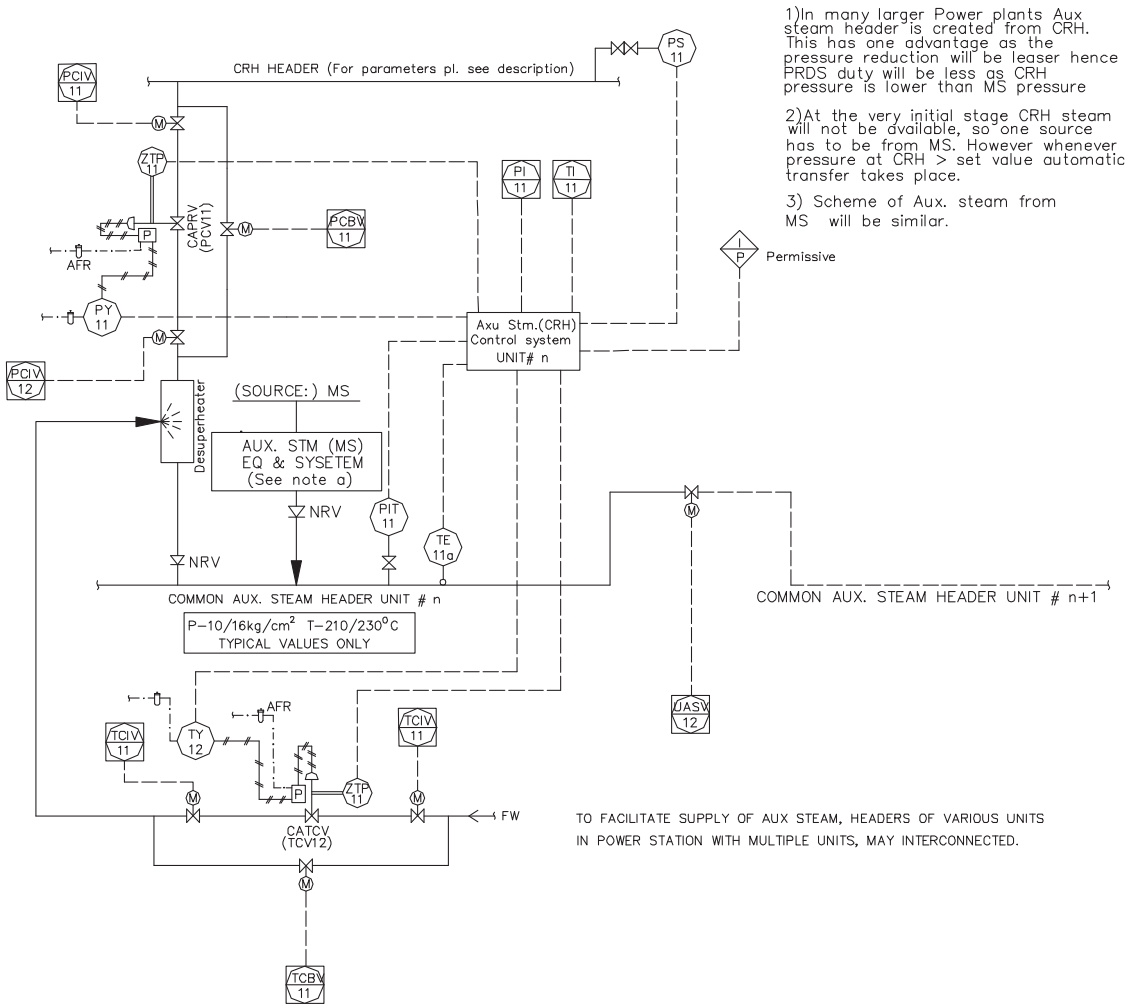


FIGURE III/5.2-3 Common auxiliary steam header (from CRH) and interconnections.

5.2.3 System Description: Common Auxiliary Steam Header From MS

In this system, a common auxiliary steam header is created from MS with the help of PRDS stations (see Clause 5.2.1). It is worth noting that in this type of PRDS station there *may* not be any requirement to have separate HC and LC PRDS. From the MS auxiliary steam can be derived only after the boiler MS pressure reaches a particular set point, i.e., 14 kg/cm^2. Until that value is reached, auxiliary steam cannot be developed from the unit, and in those cases either auxiliary steam is imported from another unit as shown in Figure III/5.2-2 in a station with multiple units or auxiliary boiler needs to be arranged.

Since MS pressure and temperatures are much higher (especially >200 MW) than that for auxiliary steam, it is meaningless to go for such high reduction in parameters to get auxiliary steam. Instead it is economical to use CRH steam (after CRH is available) as a source for auxiliary steam, especially when the power cycle has HP bypass.

5.2.4 System Description: Common Auxiliary Steam Header from CRH Steam

This design is exactly the same as discussed in Clause 5.2.3, only here auxiliary steam is derived from CRH steam. Auxiliary steam can be derived only after the CRH steam pressure reaches a particular set point, otherwise it cannot be developed from CRH. However, at the initial stage auxiliary steam is derived from MS. It is therefore essential to have an interlock operation for such a changeover (see Clause 5.2.1 and Figure III/5.2-3).

5.2.5 System Description: Common Header with Auto Switchover

During unit start-up, as stated earlier, the auxiliary steam needs to be imported from another unit and/or from the auxiliary boiler. When the unit is lit up and the MS pressure is around a set value of 17−18 kg/cm^2 MS pressure is put into the service. Initially isolating valves are opened and the

www.EngineeringBooksPDF.com

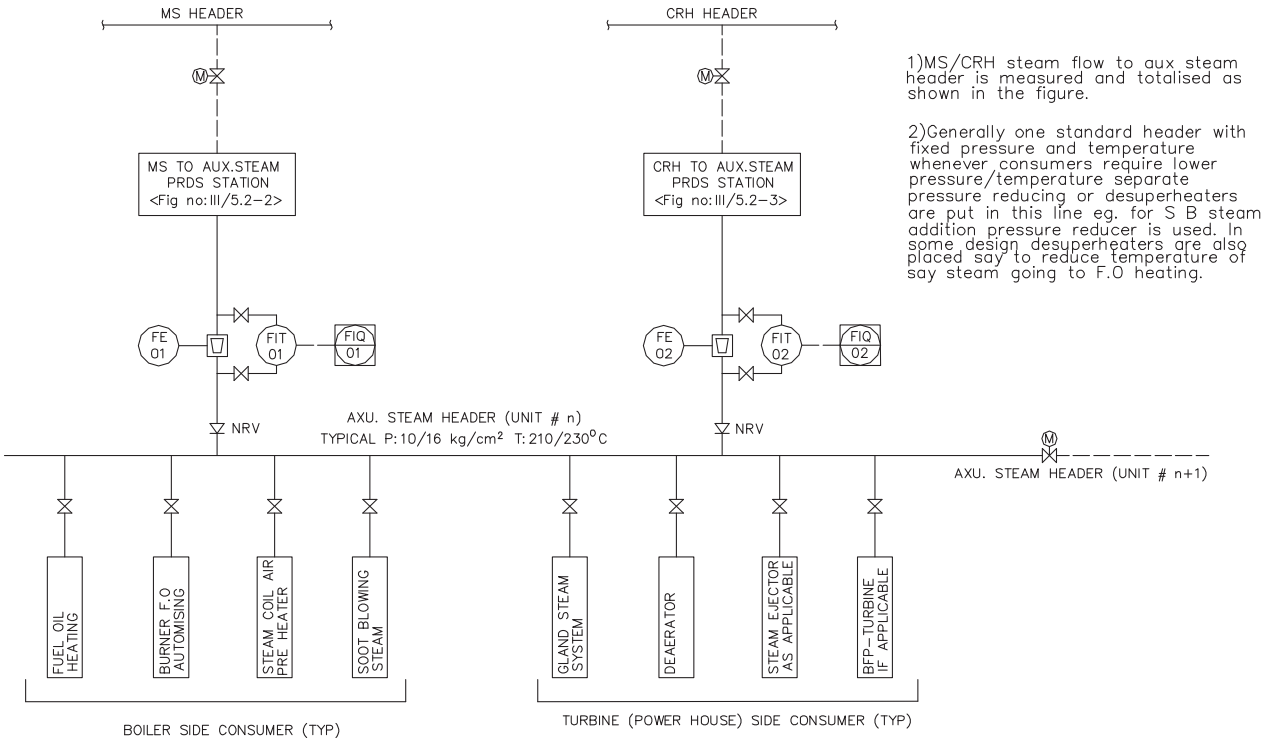


FIGURE III/5.2-4 Auxiliary steam header with consumers.

bypass valve is cracked open to warm the line. Then bypass valve is closed, the required set value is set in the controller for the PRV, and the valve starts opening when in auto. Depending on the auxiliary steam flow requirement the imported supply may be cut off. After the unit is stabilized, CRH pressure is approximately >15 kg/cm^2 and CRH is put in to the service (when CRH is used as a source). Here again in the CRH line to auxiliary steam isolated valves are opened and the bypass valve is used for warming purposes. CRH line PRV to auxiliary steam is set to the desired value, i.e., 16 kg/cm^2 (a little higher than in the MS line to auxiliary line PRV), and put in auto. Naturally the CRH line PRV to auxiliary steam will start opening to a full open condition and auxiliary header pressure is greater than the set point for the MS line PRV set value. This will cause the MS line PRV to auxiliary steam to close and the CRH line PRV will operate automatically. This can be done with sequential interlock. This can be achieved manually also. Two separate temperature control valves are used to keep the auxiliary steam header temperature at the desired value (see Figures III/5.2-2 and III/5.2-3).

5.2.6 System Description as Header Consumers

In Figure III/5.2-4 all the probable consumers of auxiliary steam for both boiler and turbine sides are shown. Also a connection with another unit (a multi-unit power station) is depicted with the help of one motorized valve. This valve can be operated from either unit. Whenever this valve is opened, the other unit is informed through the main DCS.

5.3 Major System Equipment: Auxiliary Steam

Major system equipment in an auxiliary steam line includes the following:

1. *Pressure-reducing control valve*: In each supply line to the auxiliary steam header there will be one pressure-reducing control valve whose function is to reduce the supply pressure to the desired value of pressure at the auxiliary steam header. Depending on the type of valve and its duty, there may be a separate HC and LC valves or a common one.
2. *Temperature control valve*: For cooling, there will be one de-superheater to which FW will be supplied through one temperature control valve. The opening of the valve should regulate the temperature by regulating the FW flow as the set point from the control system. Depending on the type of valve and its duty, there may be separate HC and LC valves or a common one.
3. *De-superheater*: After one pressure-reducing control valve there will be one de-superheater. Here steam

www.EngineeringBooksPDF.com

comes across the cooling FW in the atomizing stage. It is also possible to use combined PRDSs in place of a separate de-superheater

5.4 Major Process Parameters and Measuring Monitoring in Auxiliary Steam

5.4.1 Process Parameter

The parameters in the auxiliary lines are purely a function of plant design and configuration and requirements of various auxiliaries of the boiler and turbine (see Table III/4.4.1-1).

5.4.2 Monitoring of Process Parameters: Auxiliary Steam

Auxiliary steam parameter monitoring and control are done from the control desk. If the power station units have connected auxiliary steam headers, auxiliary steam parameters are monitored in all concerned units. For details, see Figures III/5.2-1 to III/5.2-4. An example of auxiliary steam process parameters are listed below:

1. *Auxiliary steam header pressure measurement*: This is one of the main parameters. It is measured with the help of a smart pressure transmitter with the range of 0−20 kg/cm^2.
2. *Auxiliary steam header temperature measurement*: This is one of the main parameters. it is measured with the help of an RTD (Pt100 typically at 0°C). Along with the RTD, a smart temperature transmitter with the range of 0−250/300°C may be used.
3. *Control valve position signal*: The position feedback signal of each of the control valves is measured. The valve position transmitters may be discrete electrical transmitters with a 0−100% scale with output of 4-20 mA, which is typical. Today smart actuators have built-in smart position feedback.
4. *MS/CRH header pressure measurement*: It is necessary to monitor MS and CRH pressure before choosing one of them for the auxiliary steam header (see Clause 5.2.5). This is done by a smart transmitter with interlock and/or by pressure switch as discussed in Clause 5.2.5.

TABLE III/4.4.1-1 Typical Auxiliary Steam Parameters

MW	Pressure (kg/cm^2)	Temperature (°C)	Remarks
200	13	210	
500	16	230	

5.5 Controls in Auxiliary Steam

1. *Auxiliary steam pressure control*: It is the most important control of the auxiliary steam system. With the help of this control the header pressure is kept constant. Depending on auxiliary steam flow, there may be separate HC and/or LC control valves. If there is a common header from CRH then this control has an automatic transfer of source from MS to CRH.
2. *Auxiliary steam temperature control*: This control is used to keep the auxiliary steam header at a constant temperature.
3. *Miscellaneous control*: There are several consumers that require auxiliary steam at pressures and temperatures lower than that available at the auxiliary steam header. So there will be a number of pressure and temperature control for these requirements. For example, SB steam requirement is at a pressure lower than the auxiliary steam header pressure, so the necessary PRV is put in to reduce the pressure (see Figures III/5.2-1 to II/5.2-4).

5.6 Redundancy in Measurement: Auxiliary Steam

Many utility station units with higher megawatts have redundancy in the auxiliary header pressure measurement and temperature measurements

5.7 Miscellaneous Points: Auxiliary Steam

Auxiliary steam measurements are inter-related to both boiler and turbine systems, so these parameters are monitored at the central/common system monitor. These measurements are repeated at station system monitoring points as well.

6. FEED WATER SYSTEM (P&ID)

6.0 FW System

FW can be defined as return condensate + make-up water. It is the high-pressure deaerated (removal of gases like oxygen and carbon dioxide) water supplied to the boiler from which steam is generated. FW has additional significance in SC and USC boilers. In these boilers there is no drum (storage vessel), so FW flow has direct impact on fuel flow, i.e., both FW flow as well as fuel flow have to be precisely regulated to maintain the FW to fuel flow ratio necessary for proper operation of the plant. It is also important because the majority of attemperation water is supplied from FW. There are several design alternatives available.

www.EngineeringBooksPDF.com

6.1 Objective and Function of the System

The FW system provides treated high-pressure water to the boiler. It has the following major functions:

- To supply high-pressure water (free from dissolved gases like oxygen and carbon dioxide, etc.) to the boiler during start-up and normal and emergency operations.
- To supply attemperation water to
  - De-superheater sprays to control SH and RH (emergency) temperature control systems and
  - De-superheater spray for HP bypass control.
- Ensure minimum flow of water through recirculation control of BFP.
- Regulate flow of feed to boiler to maintain boiler drum level (with a subcritical boiler). With an OT drum level control loop is missing. However Feed water control loop is still there in different form. Also in place of drum level loop, there will be a separator/storage tank level control, which is quite different in control philosophy from drum level control.
- It also accepts chemical dosing to scavenge dissolved gas further as well as to increase pH value of the FW.
- SC boilers need a precise ratio to be maintained with fuel flow to avoid overheating, etc.

6.2 System Description: FW System Variations

Because of variations in BFP and its drives and feed control stations, there are some variations in FW systems from plant to plant. From the pump used (see Chapter II discussions on BFPs) it is nonlinear, and depending on the system resistance an operating point is chosen. As is seen in the curve, when flow is increased pressure falls. In smaller plants this may be acceptable, but in medium-sized plants it is not, because it will affect the net flow as well as the performance of the system. So pump speed is chosen as a variable to change the flow without affecting discharge pressure. Again the speed of the BFP can be varied in different ways, e.g., by hydraulic coupling scoop tube or by variable Frequency Drive (VFD) for motor-driven BFPs. Also instead of motors many plants use turbines as a drive for BFPs, where speed is varied with opening of the BFPT control valve. It is well known that drop across any valve at high flow is a loss of energy, so in higher plants feed control stations at higher load are removed and feed flow is controlled by speed control of the BFP (see Figures III/6.2-1 to III/6.2-5). In an SC boiler the considerations are totally different. Through a low, feed flow control valve normally a minimum of 30% flow is ensured during start-up, and until the Benson point is reached the separator (somewhat like a drum in the subcritical boiler) level is controlled with a boiler water circulation pump (see Figure III/6.0-1a). After a certain load, the FW valve is wide open and feed flow is precisely controlled by BFD speed control, as per set point from the boiler master demand with due consideration to maintaining the FW to fuel ratio to maintain SH temperature.

6.2.1 System Description: General

In this clause the FW system flow path is discussed. FW is supplied from the deaerator (which has multiple functions as discussed in Clause 6.3). The deaerator is located at higher elevations (deaerator floor), which provides the necessary net positive suction head required for BFP (which is generally located at ground floor level). After the feed pump, FW is passed through a series of FW heaters (regenerative heaters—heating steam supplied from extraction steam). FW heaters are shell and tube types. FW is passed through the tubes whereas the steam is passed through the shell. After the heater the main FW is passed through a feed control station, which comprises a set of control valves. Feed control valves are meant to regulate and maintain required FW flow to the boiler. In a drum type boiler these valves help to maintain drum level at a desired (set) point. After the feed control station FW reaches the boiler economizer. A part of the FW from the BFP discharge header is used for the purpose of attemperation, e.g., at de-super heaters, HP bypass control, etc. Sometimes the emergency RH attemperation is taken from the booster stage output (see Figure III/6.2-1a and b). Normally, for SH temperature control, the spray flow is taken from the HPH outlet to avoid thermal shock (because this attemperation water will meet the superheated steam at the de-superheater). However, for HP bypass attemperation flow is taken from BFP discharge—why? This is probably done to have less attemperation water for HP bypass (energy loss) and to ultimately help avoid condenser loading. Also HP Bypass steam does not go to turbine (instead returned to boiler for reheating, hence the fear from water carry over is not there.

However, in case of large SC boilers it is customary to take the spray flow from the economizer outlet because usually MS temperature is higher (to avoid thermal shock). In certain CFBC SC boilers it has been found that SH spray

Point/load at which boiler control is switched from drum (Storage unit) type to once-through type is referred to as the Benson Point/load. At this point the separator/storage vessel levels almost vanish. Typically this load is 25% BMCR. This information will be referred to later in this section.

FIGURE III/6.0-1a Benson point (definition).

www.EngineeringBooksPDF.com

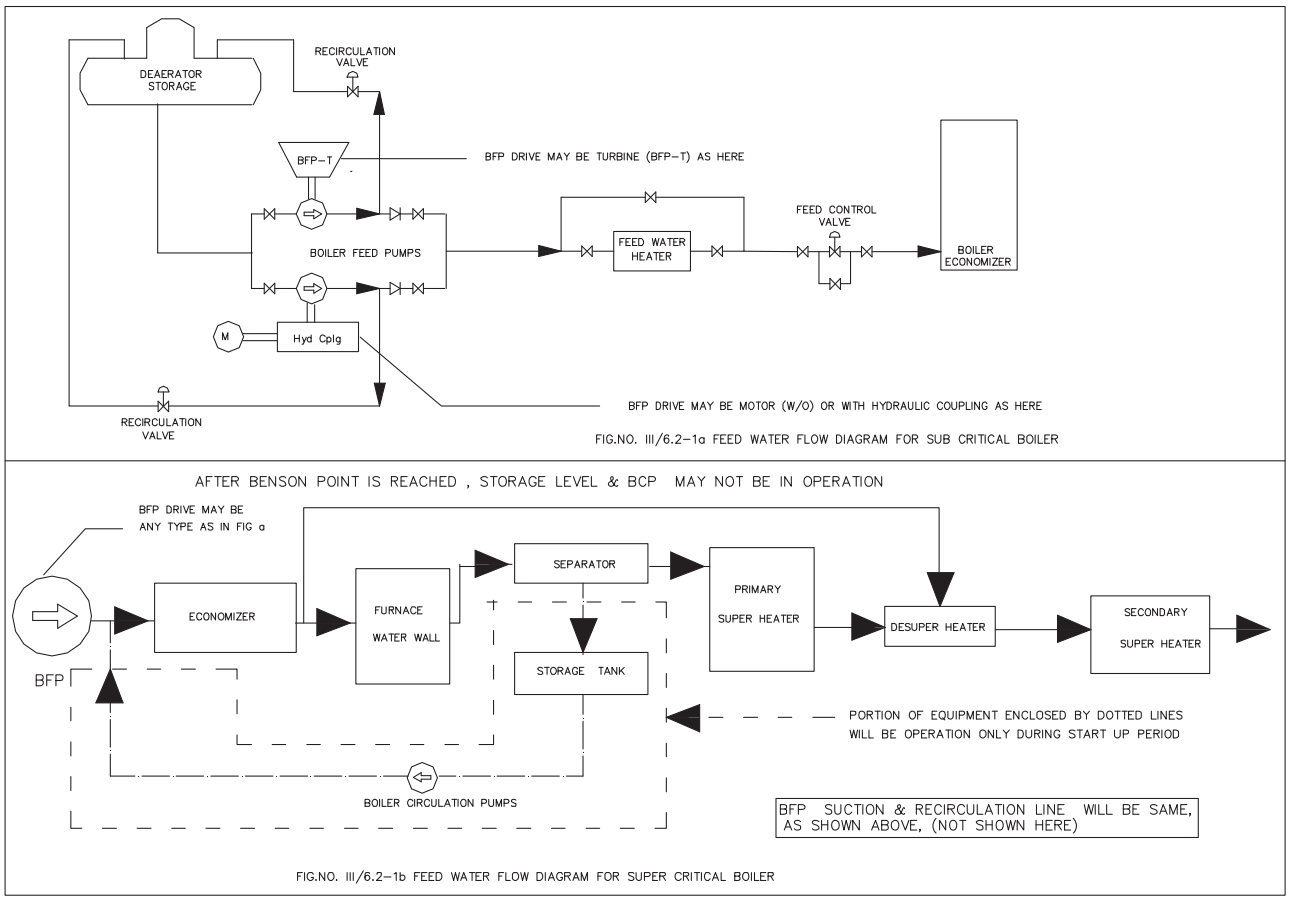


FIGURE III/6.2-1 Typical FW flow diagram.

flow at various stages (of multistage SH temperature control) and FW flows are also taken from the HPH outlet. It should be noted that these spray flow at "secondary stages" actually acts as *trim* control, whereas spray flow from the economizer outlet at the "primary stage" is the main control where maximum spray flow takes place. Also, in SC boilers, steaming takes place in water walls/separator. During the initial startup period water is separated from steam at the separator and water is collected at the storage tank whose level is maintained by regulating the boiler circulation pump (BCP) flow with the help of a control valve (downstream the BCP). During the process of water to steam at the separator inlet, a feed control valve is throttled to maintain a FW flow rate of 25−30% boiler maximum continuous rating (BMCR) through the economizer. Then as the firing increases with load, the steaming at the separator decreases (as it takes place in water walls), and at certain values of steam flow, BCP is stopped and there will be hardly any level in the storage tank. As shown in Figure III/6.2-1a, equipment enclosed by dotted lines becomes nonfunctional at higher load, but the separator will be in service at all times. Therefore, unlike the drum type boiler, there is no storage device in an OT boiler design. Needless to say, FW to fuel ratio is important for proper operation of the boiler.

It is worth noting that a part of each BFP discharge (before the discharge valve) is recirculated back to the deaerator. This is called BFP recirculation. Recirculation control is necessary to ensure minimum FW flow through the BFP under all conditions. Initially when there is no requirement of main FW, this recirculation ensures that total flow (main FW + recirculation) is greater than ∼30% of the full flow of BFP. This recirculation is necessary because the churning effect inside the heavy-duty pump generates a lot of heat, so some minimum water flow is necessary to take away this heat. Flow for individual BFP suction is measured, and a set point of ∼30% of flow is set to operate each BFP recirculation valve. When FW flow through the BFP is more than the set point, the recirculation valve closes. In smaller and medium-sized power plants these controls are ON/OFF type, whereas in large plants >200 MW these controls are the modulating type. However, there is no sacrosanct rule for this; modulating control can also be used in smaller plant sizes as well. From the previous discussion about the SC boiler, it is seen that during initial start-up 30 BMCR FW flow is ensured

www.EngineeringBooksPDF.com

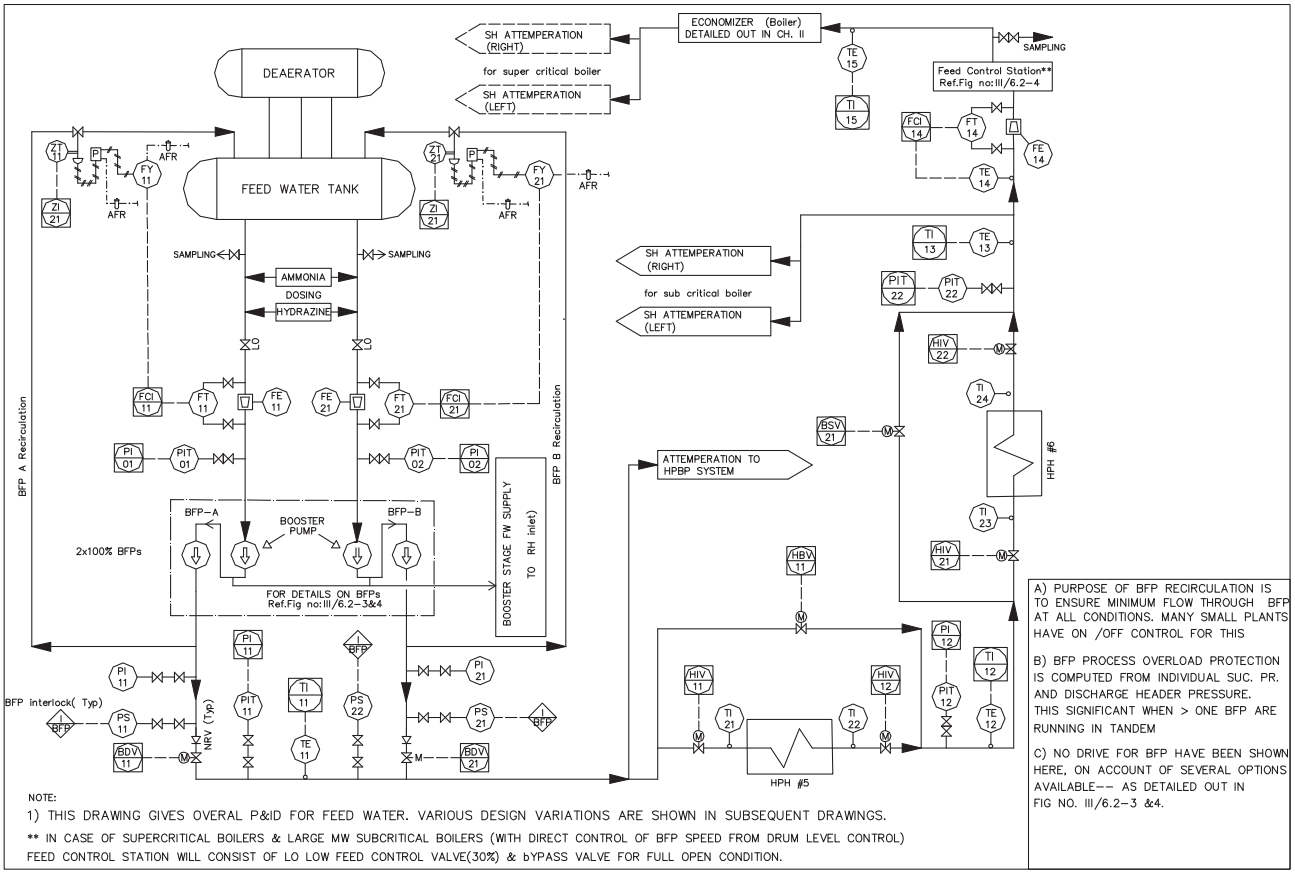


FIGURE III/6.2-2 FW system (overall P&ID).

through the economizer; therefore, in SC and USC boilers, the requirement of BFP recirculation is less important, except for its own starting/testing of the pump.

6.2.2 System Description: FW System Overall

In Figure III/6.2-2 two stages of BFP are shown: booster stage and main BFP. The booster pump is generally located at the ground floor with its suction from the deaerator located at higher elevation to ensure required nominal pump suction head (NPSH). The discharge of the booster pump acts as the suction of BFP. BFP may be located at the operating floor with some piping between two pumps where even the flow elements are placed. However, it is better to place the flow element in the suction line from the deaerator as shown in Figure III/6.2-2 from a straight length availability point of view. In this figure 2 × 100% BFPs are depicted—this is common for large utility stations. There are other options, e.g., 3 × 50%. This means that there will be two 50% pumps running and the third one is a standby. The third pump will cut in automatically in case any of the pumps trips. Based on a reliability study and pump performance data, a decision regarding the number of pump options can be made. For the option, where two BFPs are running in tandem, there is the possibility that one may become over loaded; to prevent this , the BFP protection circuit is developed by measuring FW flow to the individual BFP and associated discharge pressure. This is not really applicable for one pump running at a time. Generally in RH attemperation spray is tapped from the booster stage output and HP bypass water is taken from the BFP discharge. In many cases RH attemperation spray flow is insignificant and may be used during an emergency, yet in case of SC boilers that may not be so.

6.2.3 System Description: FW Sampling System

At the suction line to each of BFP chemicals like ammonia and hydrazine are dosed to increase the pH of FW and to scavenge dissolved gas. There will be sampling lines from BFP suction lines and at FW at the economizer outlet for the steam and water analysis system (SWAS) discussed in Chapter V.

www.EngineeringBooksPDF.com

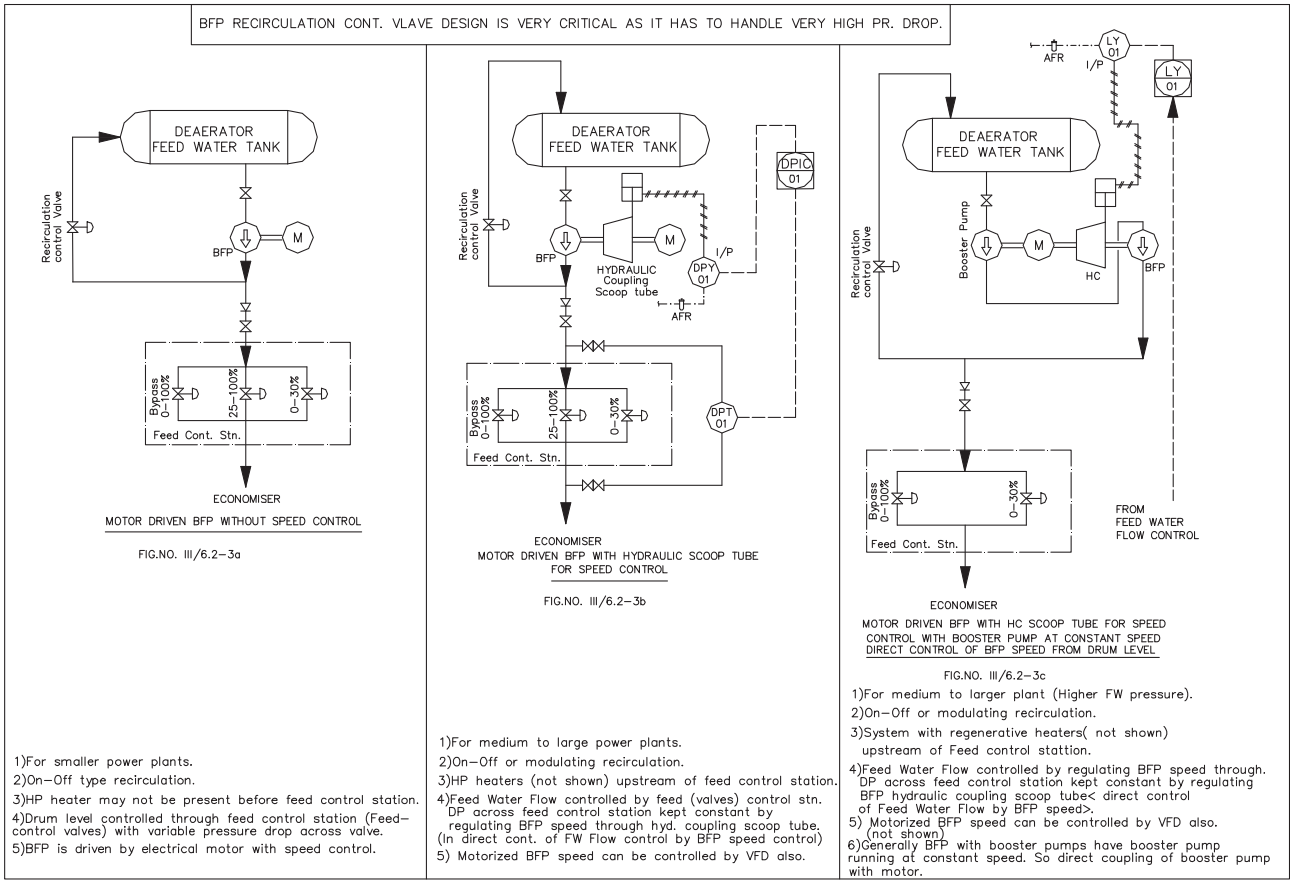


FIGURE III/6.2-3 FW system motor-operated BFP (design variations).

6.2.4 System Description: FW System Motor-Operated BFP

In this clause various aspects of BFPs and types of speed controls are discussed.

1. *Figure III/6.2-3a*: In smaller plant (<60 MW) BFPs are driven by a motor at constant speed and there may not be any way to regulate the speed of the pump. To ensure minimum flow through the BFP; however, there is an ON/OFF type BFP recirculation valve to return FW to the deaerator. Now the drum level is controlled by modulating the opening of the feed control valves. At different FW flow there will be different drops across the feed control valves, so these valves will be selected after due consideration. In the feed control station, there are three control valves: one low load (0–30%), another full load (25–100%), and a bypass valve (0–100%, may be motorized for smaller plants).
2. *Figure III/6.2-3b*: Hydraulic coupling scoop tube is a very popular way to regulate the speed of pumps/fans [e.g., indirect draft (ID) fans]. Constant speed motor is coupled to the pump/fan by hydraulic coupling (turbo coupling is represented in this figure with the symbol of turbine). Depending on the degree of coupling (filling), the speed of a driven item (BFP in this case) is varied. This coupling filling (degree) is varied according to scoop tube position. The scoop tube normally has one pneumatic actuator (or electro hydraulic position control) to vary the scoop tube position as per signal from the control loop. (See Clause 9.2.5, number 2c of this chapter and Chapter VI, Clause 3.4.1 for further details). There are other ways to regulate the speed of a motor-driven BFP, e.g., VFD control of the BFP (see Chapter VI, Clause 3.4.2). Speed of the turbine drive BFP is regulated by regulating steam flow to the turbine. There are two modes of controls for BFP speed as listed below:
   a. In one type the DP across the feed control valve station is kept constant. In this method, feed flow is controlled by regulating the opening of the feed control valve (primary control). Naturally there will be variation in DP across the feed control valves. This DP is compared with a fixed set point (i.e., 10 kg/cm^2), in a controller, to generate a demand signal

www.EngineeringBooksPDF.com

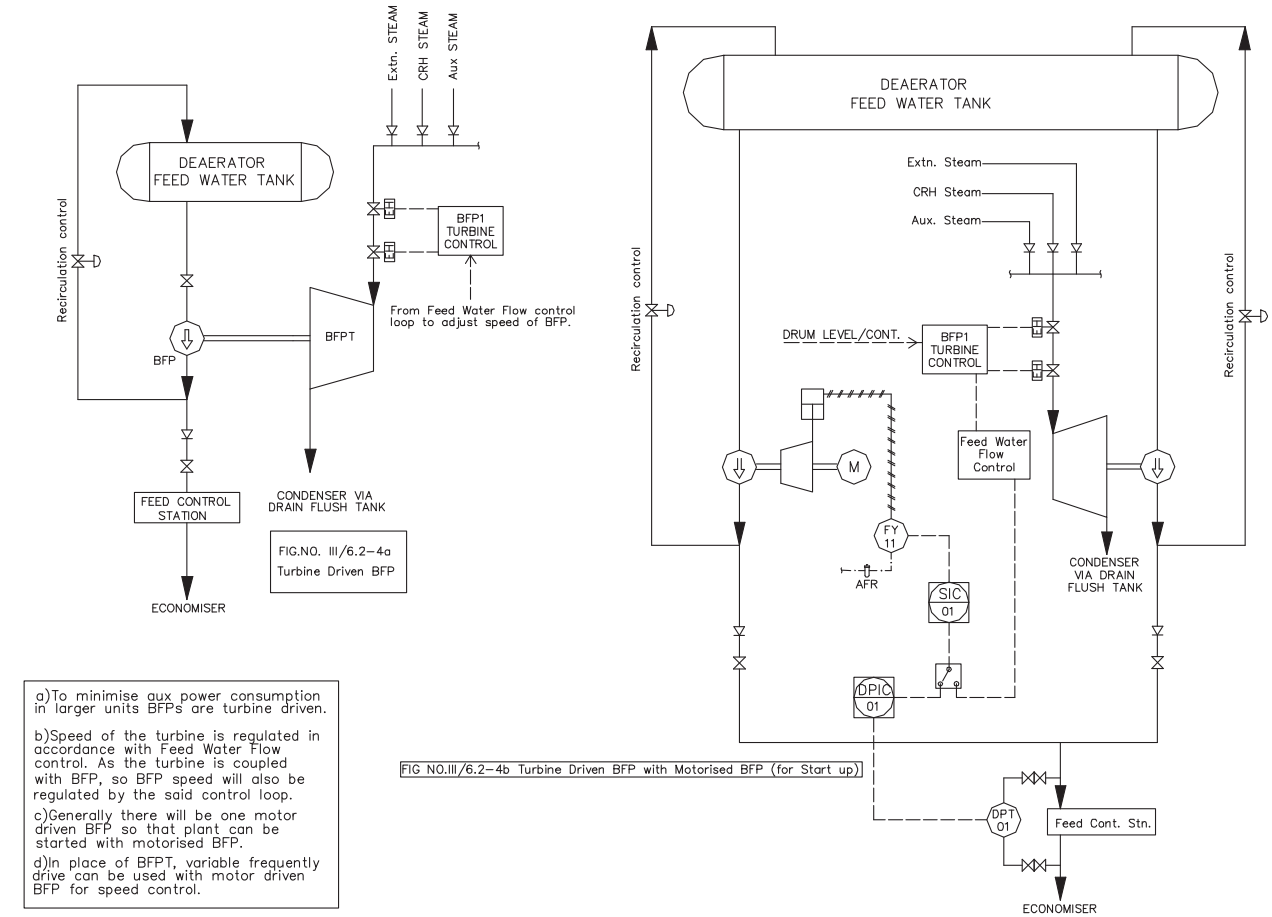


FIGURE III/6.2-4 FW system turbine-operated BFPs.

for BFP speed (secondary control) so that with the required modified speed the FW flow requirement is met and the control valve maintains a fixed DP.

b. In this method feed flow is directly controlled by regulating the speed of the BFP, hence, BFP speed is the primary control. It is worth noting that direct variation of the speed of the BFP is done at BMCR > 25%. At low load this method is not effective; for a low load there exists one low load feed control valve to regulate FW flow. After a boiler load > 25−30%, the bypass valve to the feed control valve opens fully and FW flow is controlled directly by BFP speed regulation. It is recommended that the transfer of control from the feed control station to the BFP speed control is done manually for plant safety (see Figure III/6.2-3c).

c. With OT boilers the feed control valve starts operating during start-up to make sure that the minimum (∼30% BMCR) FW is sent to the boiler. After 30% load the bypass valve is fully open, the feed control valve closes, and the BFP speed is controlled to regulate the flow to the boiler as well as to maintain the FW to fuel ratio at a desired point.

3. *Figure III/6.2-3c*: This was discussed in connection with Figure III/6.2-3b. The difference here is there is a booster pump in addition to the BFP. Here the speed of the booster pump is constant, so the motor is directly coupled, whereas BFP is coupled to the motor via hydraulic coupling as detailed out above.

6.2.5 System Description: FW System Turbine Driven (TD) BFP

In larger units, to reduce auxiliary power consumption and better steam utilization, a steam turbine is used to drive BFP in place of a motor. Extraction steam is the main source of steam supply to this BFPT. In addition to extraction steam, auxiliary steam and CRH steam supply lines are also used so that the turbine can run when the extraction steam supply is not available. Like a normal

www.EngineeringBooksPDF.com

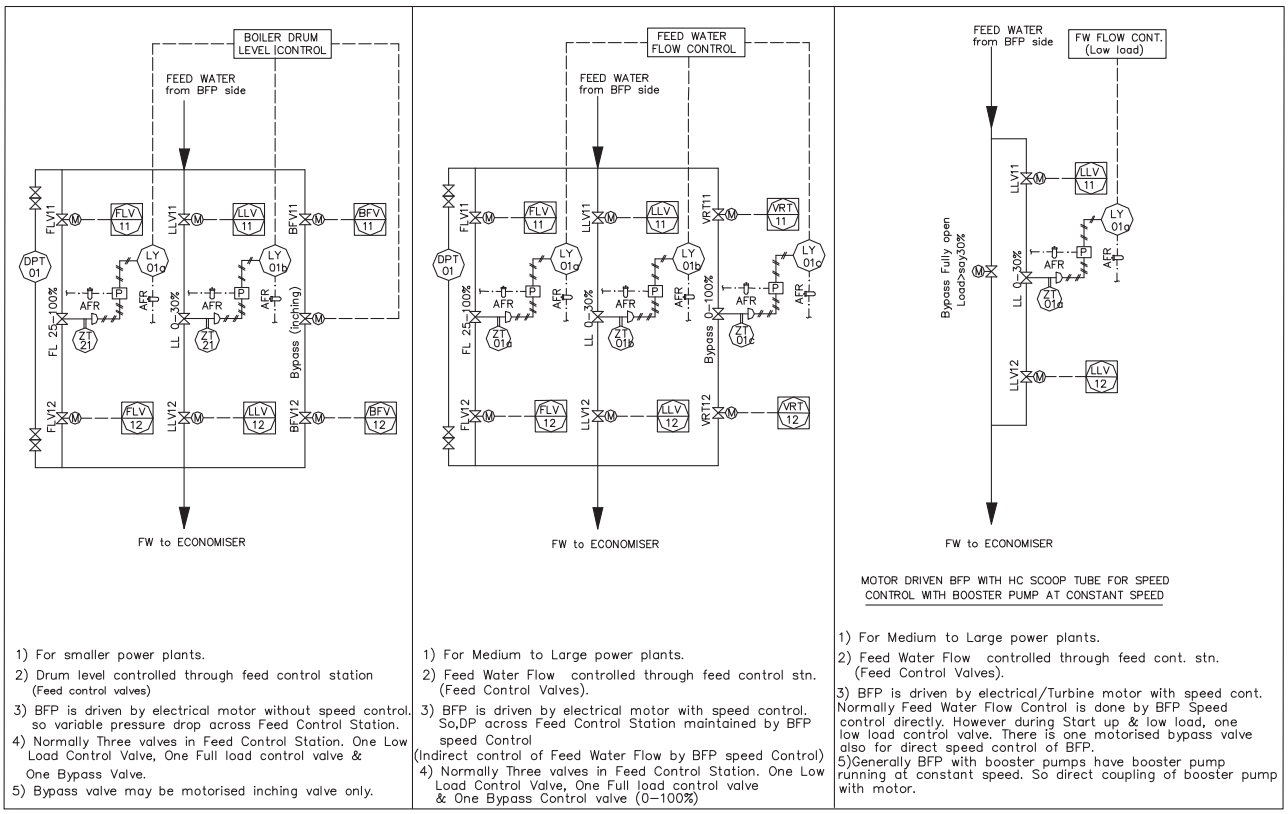


FIGURE III/6.2-5 FW system feed control station design.

steam turbine, the governor control valve is regulated to control the speed; hence, the BFP speed is in accordance with control demand (see Clause 6.2.4, number 2a and b above and Figure III/6.2-4a). The exhaust steam from the BFPT is returned to the condenser via drain flush tank. As stated earlier, in power plants with BFPTs there should be at least one motor-driven BFP to cope with the initial start-up program (see Figure III/6.2-4b).

6.2.6 System Description: FW Feed Control Station

As discussed earlier, the feed control station regulates the FW flow to the boiler as per demand. During start-up and low load (flow) the downstream pressure of the feed control station is negligible (for drum type boiler, until the drum is pressurized; it is only the water head due to boiler drum height), and since the BFP flow is low naturally the head will be high. As a consequence, at low flow there is a very high DP across the feed control station. So at low load the control valve is subject to high DP at low flow. At higher load the drum is pressurized, and as the FW demand is comparatively more and BFP discharge pressure is comparatively less. Thus process conditions at the feed control station under two different conditions are completely divergent. Any single valve handling such a situation has to have a very special design. For this reason, in feed control stations there are separate control valves for low load and high loads. There is also one bypass valve for emergencies if one of valve is in trouble and/or has out for maintenance. The bypass control valve design is also very stringent.

1. *Figure III/6.2-5*: There are three valves with one low-load valve to cater to ~0–30% flow. Overlapping with the this, there is another full-load control valve catering to 25–100% full flow. In smaller units to economize the cost the bypass valves are sometimes chosen as motorized valves for the inching (throttling) operation during an emergency. This confiuration is shown inthe left side figure.
2. *Figure III/6.2-5* (middle part of the figure): This is the same as the system discussed in item 1. The only difference is that the bypass valve is not a motorized inching valve, it is a special type of valve (e.g. variable resistance trim valve or drag valve). It is specially designed to cater to the requirement of a 0–100% load condition of FW. Below are a few points worth noting regarding the changeover of control valves:
   a. Changeover from a low feed control valve to a high-load feed control valve can be done manually or

www.EngineeringBooksPDF.com

automatically. Both systems exist and there are two schools of thought on the issue, because many are of the opinion that if such a changeover is done automatically there may be some bump in the system. However, with advancements in control systems, valves, and actuator technology, auto changeovers are not uncommon.

b. Even under higher load there may be fluctuations in DP across the feed control valves. Also high flow and higher DP give rise to a loss of energy. To prevent damage to the control valves, the DP across the control valve is regulated and maintained at a constant value with the help of the DP controller. The output of that controller changes the speed of the BFP. However, for smaller power plants if the BFP is not provided with a way to it control its speed, then it is not applicable. In these cases control valves need to face fluctuating DP across the valve.

3. *Fig No. III/6.2-5* (RHS): As discussed earlier, that there will be a loss of energy when there is high flow with some DP across the control valve. To prevent such losses in current power plant designs the low-load control valve (0−30%) is kept to cater to the start-up requirements for both OT and subcritical drum type boilers. During start-up and low load, as discussed previously, feed flow is controlled with the help of a low-load feed control valve, because at these conditions speed control of the BFP may not be a good proposition. Whenever the FW flow (load) >25−30% (i.e., the control valve is almost fully open), then the motorized bypass valve receives the signal to open the valve slowly. As the big bypass valve starts opening flow increases and the low feed control valve closes. Also, the feed flow control is transferred from the feed control station to the speed control of the BFP. At low load the DP control to regulate the BFP speed may also be there, but as the control is directly transferred to the speed control of the BFP, DP control (if there) will be nonfunctional. Note that in most of today's designs the bypass valve is considered as a motorized valve with inching operation facility.

6.3 Major System Equipment: FW System

Major system equipment (for further details of selected items, see Chapter II) in a FW line shall include the following:

1. *Deaerator*: This has two basic functions: get rid of dissolved gas and act as a heater. Mechanical deaeration is the preliminary step to get rid of oxygen and other dissolved gases like carbon dioxide. Depending on the deaeration method, the deaerator can be two types—tray type and spray type. While deaerating FW with the help of steam, it also acts as a heater.
2. *BFP*: This is really the heart of not only this system but for the entire cycle. In general, BFPs are centrifugal pumps with low tolerance. They have multistage impellers and call for a minimum of 30% flow of hot water (heated at LP heaters and the deaerator) through it. For C&I engineers a recirculation system and recirculation valve is very important. In some designs, mainly for lager units, booster pumps are used upstream the BFP, i.e., two-stage pressure raising. As discussed earlier, there could be variations in speed control mode and drives for BFPs.
3. *HP heaters*: In the FW system there may be two to three shell and tube type heaters. In the P&ID two FW heaters (HPH 5 and 6) have been considered. As discussed in earleir in connection with extraction system, these heaters are heated with the help of extraction steam from the turbine in to the heater shell, whereas FW is passed through the tube. After heating FW extraction steam is condensed into the heater and it is finally again taken to the system.
4. *Feed control station*: Basically consists of a number of feed control valves along with an associated isolation valve. These are detailed out in Clause 6.2.5.
5. *Economizer*: See Flue gas section Clause 9. Also this is discussed in detail in Chapter II.

6.4 Major Parameter Measuring Monitoring in FW

6.4.1 Process Parameter: FW (Typical Values Only)

Some typical FW values are listed in Table III/6.4-1.

6.4.2 Monitoring of Process Parameters: FW System

For these measurements, refer to Figures III/6.2-2 to III/6.2-5.

1. *Individual BFP Suction flow measurement*: At the suction of each of the BFPs, flow elements are placed to measure the suction flow to each BFP. In some designs with a booster pump, the same flow is measured at the booster pump discharge piping connecting BFP suction. The suction flow is measured in the pipeline from deaerator (preferred location) with flow nozzle and smart DPT(with turn down ratio of 60:1 and a range of 0−10,000 mm wcl). Approximate flow measuring range should be 0−800 T/h (200 MW) and 0−1800 T/h (500 MW). Please note that the flow range given is for 2 × 100% BFP configuration. This will be halved for the 3 × 50% BFP configuration. This BFP suction flow is not the main FW flow measurement (discussed later), but it is used for the following purposes

www.EngineeringBooksPDF.com

TABLE III/6.4-1 FW Parameters (Typical)

Location	Pressure (kg/cm^2)	Temperature (°C)	Flow (T/h)**	Remarks
200 MW				
BFP suction	7.0 + deaerator*	180	800	*Water head
BFP discharge	180–190	180	800	
HPH 5 O/L	175–185*	215	800	*~5 kg/cm^2 drop
HPH 6 O/L	170–180*	248	800	*~5 kg/cm^2 drop
500 MW (drop across heater may be more)				
BFP suction	9.0 + deaerator*	190	1700	*Water head
BFP discharge	200	190	1700	
HPH 5 O/L	190*	230	1700	*~5 kg/cm^2 drop
HPH 6 O/L	~195*	270	1700	*~5 kg/cm^2 drop

***Spray considered after HPH (RH emergency spray flow).*

   a. BFP performance
   b. Generating signal for BFP recirculation control
   c. If there is more than one BFP running (for example, 3 × 50), it helps to compute the overload protection signal for BFP

2. *Individual BFP suction pressure measurement*: At the suction of each of the BFPs the pressure is monitored with a smart transmitter in the range of 0–15 kg/cm^2 to ensure the required NPSH is achieved.
3. *BFP recirculation*: It is necessary to monitor the minimum FW flow through the BFP for controlling BFP recirculation. In many smaller plants separate flow monitors or flow switches with adjustable set points are deployed.
4. *BFP discharge pressure measurement*: The discharge pressure measurement at BFPs are for various purposes as discussed below:
   a. *Each pump discharge before the discharge valve*: Pressure gauge to see pressure locally.
   b. *Each pump discharge before the discharge valve*: Pressure switch to stop the pump if discharge pressure shoots up near shut-off pressure if any discharge valve failed to open.
   c. *BFP discharge header pressure transmitter*: Discharge pressure is measured by smart transmitters in the range of 0–200(/250) kg/cm^2. This signal, in conjunction with individual suction flow, is used to compute protection signals for the BFP.
   d. *BFP discharge header pressure switch*: One pressure switch is kept to see if the discharge pressure drops below the set point. In that case the standby pump may be automatically started.
5. *BFP discharge temperature measurement*: Temperature at the discharge is measured with an RTD (Pt100) to monitor water temperature. Typical range for measurement should be 0–300°C.
6. *Balance leak-off flow measurement*: In some designs BFP balance leak-off flow is monitored for BFP protection.
7. *Local temperature measurement across FW heater*: Input and output of each of the FW heaters is measured locally with the help of local temperature gauges to see the temperature gain across each heater. Typical range for measurement should be 0–300°C.
8. *HPH 5 and 6 outlet temperature and pressure measurement*: Pressure and temperature at the outlet of each HPH is measured to check the pressure drop across the heater and temperature gain. This is done by comparing the two parameters at inlet and outlet. The temperature and pressure ranges at inlet & outlet should be almost the same (as the approximate pressure drop across the heater is 5 kg/cm^2 and temperature gain is ~30°C) so smart pressure transmitters should range from 0 to 200(/250) kg/cm^2 and temperature range from 0 to 300°C for measurement with an RTD (Pt100).
9. *Differential pressure measurement across feed control station*: Significance of this measurement was discussed in Clause 6.2.5. The DP across the valve is measured with the help of a smart type DPT used in the range of 15 kg/cm^2.
10. *FW flow measurement*: FW flow going to the boiler is measured with the help of a flow nozzle and smart DPT. Approximate flow measuring range should be 0–800 T/h (200 MW) and 0–1800 T/h (500 MW).

www.EngineeringBooksPDF.com

This measurement is very important for boiler drum level control in a drum type boiler. In an SC OT boiler this is also extremely important (it is a major controlling parameter). A smart DPT (with turn down ratio of 60:1) in the range of 0−10,000 mm wcl may be selected. In general, at least one temperature measurement for flow compensation (for temperature change) is kept. It is worth noting here that location of this measurement is purely a function of the plant layout. Putting this flow element ahead of the FW control station is better in one sense because it may require less straight length, theoretically. However, sometimes the piping layout from HPH to the feed control station may be a constraint. When it is placed after the feed control station the straight length requirement will be greater (because of control valves) and it may be very difficult. Also heater type (horizontal/vertical) has an effect on this decision. Location wise both options are common. As discussed earlier, generally in SC boilers the spray flow is comes after the economizer, and flow measurement is also done there.

11. *Temperature measurement at economizer inlet*: Temperature at the economizer inlet is important as this is the terminal point for the boiler and is necessary for monitoring as well as for SG performance calculation. RTD (Pt100) may be deployed for this purpose. Typical range is 0−300°C. In some designs this parameter is used in combustion control.
12. *Analytical instruments and control*: The FW system is also an extremely important place to ensure purity of water going to the boiler. For scavenging dissolved oxygen, and to maintain water pH, ammonia and hydrazine dosing take place at BFP suction. From an analysis perspective, sampling points at I/L and O/L of the deaerator and economizer inlet are very important (see Chapter V).

6.5 Controls in FW System

This system is also very important from control point of view, as it is directly and indirectly connected to many of the boiler control systems (see Figures III/6.2-2 to III/6.2-5).

1. *Chemical dosing control*: There is an automatic (medium/large utility stations) control of chemicals at the suction of BFPs as detailed out in Chapter V, Clause 6.0. There are two chemicals for dosing:
   a. *Ammonia*: Dosed to increase the pH value of FW. This is done by measuring the pH in FW at the economizer inlet of the BFP discharge.
   b. *Hydrazine*: Dosed to scavenge dissolve gas (oxygen). This is done by measuring residual hydrazine at the economizer inlet (to allow some retention path) or by measuring dissolved oxygen.
2. *BFP recirculation control*: This control is to ensure minimum FW flow through the BFP. In smaller/medium plants this is done by a flow switch in an ON/OFF type control of the recirculation valve, whereas for larger utility stations modulating control is deployed, utilizing a BFP recirculation control valve. (In one design it has been found that the BFP recirculation line is connected to the deaerator without any valve, meaning constant recirculation. This may call for a loss in the system.)
3. *Attemperation control*: As is seen in the P&ID, a number of attemperation lines (SH, HP bypass, RH, etc.) come out from the FW. So a number of temperature controls by control valves in the water line are necessary, as detailed out in the respective system and not repeated here.
4. *Discharge pressure control*: As discussed earlier, there a number of controls by Pressure Switch (PS) and Pressure Indicating Transmitter (PIT) located at the BFP discharge including:
   a. Individual discharge line pressure switch to prevent the pump getting closer to shut-off pressure (e.g., not opening of the discharge valve).
   b. Pressure switch at the common header is used to cut in the idle the pump.
   c. If there is more than one pump running in tandem, then to prevent overload , protection signals are generated/computed from individual BFP flow and discharge pressure as discussed earlier.
5. *Feed control station*: It is the heart of the FW system as it is responsible for feed flow/drum level control. These valves are modulated in accordance with the demand signal from the feed flow controller. In an OT boiler this valve ensures minimum FW flow through economizer as discussed in Clause 6.2.6.
6. *Drum level control*: It is part of the feed flow control.
7. *Separator storage tank level control*: Part of the start-up control for an OT boiler, and is mainly concerned with BCP flow not feed flow directly.
8. *DP control across feed control station*: The purpose of this control is to limit the DP across the feed control station, as discussed in detail in Clause 6.2.6

6.6 Redundancy in Measurement: FW System

- *Feed flow at HP heater outlet*: Generally in mid/large utility stations where two of three (or one of two) redundancy is deployed.
- *DP control across FW control station*: Since this is used to control the speed of the BFP, wherever applicable, and directly related to FW flow control, it is generally used in utility stations where two of three (or one of two) redundancy is deployed.

www.EngineeringBooksPDF.com

- *BFP common discharge pressure*: This measurement is used where one of two redundancy is deployed in utility stations.
- *Economizer inlet temperature*: This measurement is used when one of two redundancy is deployed in utility stations.

6.7 Miscellaneous Points: FW System

FW measurements are related to the boiler system so these parameters are monitored from the central/common system at the boiler-side monitor. However, the feed control station and speed control of the BFP system are also connected to the boiler, so they must be controlled from the boiler-side monitor.

7. CONDENSATE SYSTEM (P&IDs)

7.0 Condensate System

After work done at the turbine the steam gets exhausted; this exhausted steam is cooled in the condenser to form condensate system. In addition to that, various leakages, drains, and make up finally coming to condenser system constitute the total condensate system. Exhausted steam is cooled at the condenser, then put in to the cycle by condensate extraction pump (CEP). Since it also receives water from other sources, plus possible leakage in the circulating water (CW) system of the condenser, it is possible for the water to be contaminated. Therefore sampling and analysis of water quality at condensate is very important. Condensate also contains higher dissolved oxygen, which is mechanically removed at the deaerator where the condensate completes its journey starting from the condenser and passes into the cycle as FW.

7.1 Objective and Function of the System

These are major functions of the condensate system:

- To supply low-pressure water to the deaerator at all points of operation.
- To supply attemperation water to
  - De-superheater sprays to LP bypass system (as applicable)
  - De-superheater sprays to auxiliary steam system
- It is the source of supply to various systems like the
  - Chemical feed system
  - Pump sealing
  - Gland steam flow seal
  - Flash tank
  - Turbine exhaust hood cooling
- Ensure minimum flow of water through the CEP and GSC
- Regulate flow of condensate to the cycle to the deaerator
- Thermal cycle make up and dump takes place in this system
- It is the source of potential energy through water storage at hotwell and at the deaerator

7.2 System Description: Condensate System

Condenser hotwell- and deaerator-level controls are the major controls in condensate systems. Major variations in this system come from the number of heaters in a regenerative cycle; e.g., some designs call for more than three LPHs. Depending on the layout, these heaters may be horizontal or vertical. In modern large power stations the vacuum in the condenser is created and maintained by vacuum pumps; however, steam ejectors are also commonly used. Basically function and purpose of this vacuum system is to take out air/gases from the condenser and bring them to the vacuum. In the steam ejector auxiliary steam is used to eject out the air and gases. Condenser vacuum system were discussed in Chapter II (Figures II/3.4-1 to II/3.4-3).

7.2.1 System Description: General

Exhaust steam at the turbine is cooled at the condenser to form condensate (see Figure III/7.2-1). Also there are many system drains and leakages put into the condenser to form total condensate. From the condenser (at vacuum) condensate is pumped by CEPs. At the suction of each of the CEPs there is a removable filter to remove dirt from the condensate before it enters the CEP. The filters are provided with a DP switch to detect the clogging of the filter. Since CEPs have the suctions at vacuum, the sealing arrangement at the CEPs is important. There could be redundancy in CEPs with an automatic start-up facility in case of failure or malfunctioning of any CEP. In drawing a $2 \times 100\%$ CEP it has to be considered that a CEP will be running and is capable of supplying 100% flow requirement of the system. In case one pump trips and/or there is a defect in one pump, another can start automatically. Each of two pumps has one NRV and discharge valve, and they are connected to a common header, which goes to the GSC to heat up the condensate utilizing the heat in the GSC. (When ejectors are used in place of vacuum pumps, condensate also passes through main ejector(s) to gain heat, similar to that in the GSC.) One flow element (FE02), upstream of the GSC, is utilized for recirculation control of the CEP and GSC (see Figure III/7.2-2 and discussed in the next clause). In certain cases the condenser may be partitioned, so sample lines need to be taken from both the sides before connecting to the sample pump through suitable

www.EngineeringBooksPDF.com

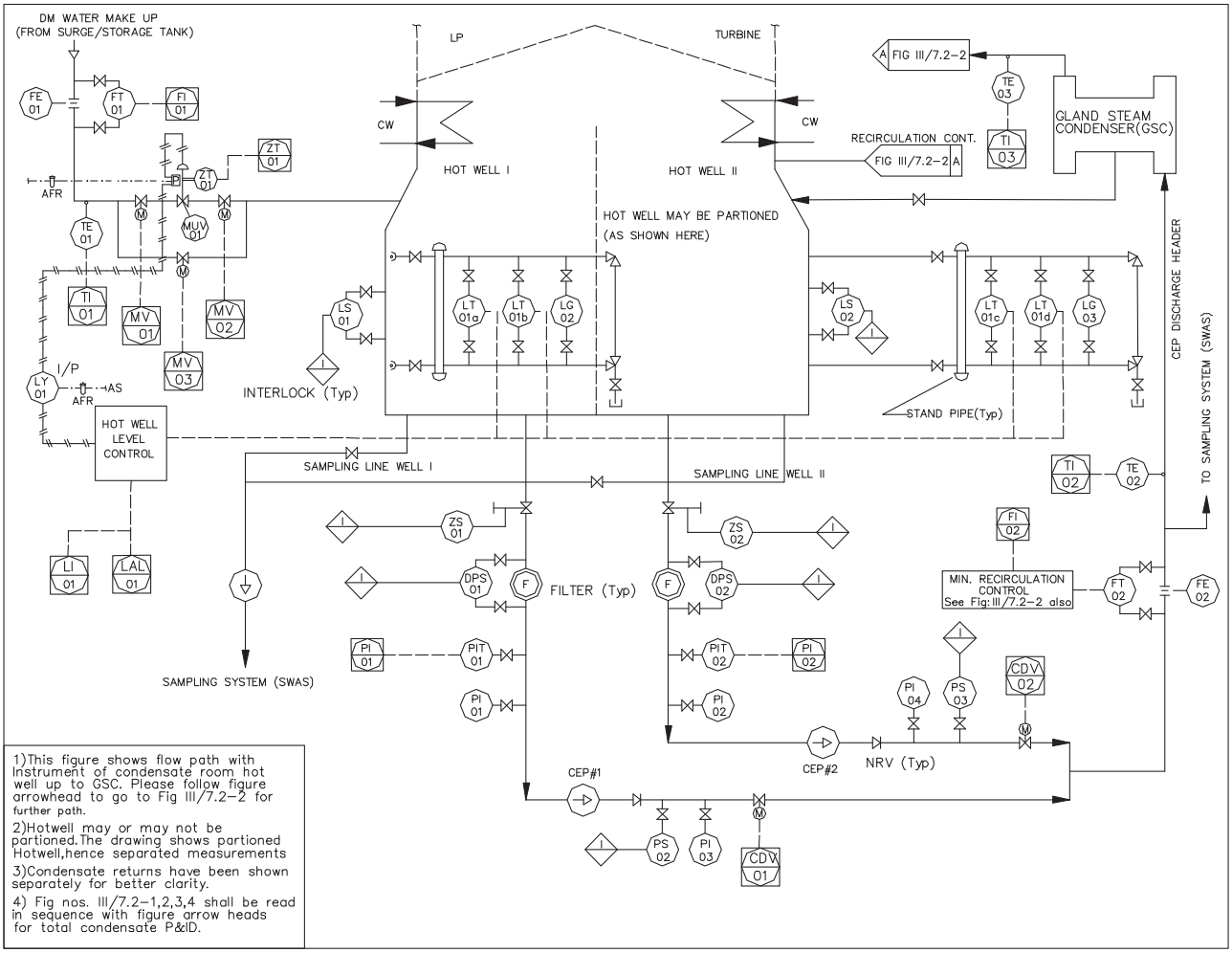


FIGURE III/7.2-1 Condensate P&ID (hotwell to GSC).

> ***MAKE UP and DUMP:*** *It is worth noting that all thermal power plants always need a make up to meet the requirement of leakage loss, evaporation loss, etc. Apart from that, sudden load throw off may require dumping condensate from the system.*

FIGURE III/7.2.1-1 Condensate make-up and dump systems.

valves. Normally the valves are open so that representative samples are available. If there is a portioned operation, it can be collected from the operating side. There is a make-up line with control valve to take regular controlled make up (see Figure III/7.2.1-1).

7.2.2 System Description: Condensate System LP Heaters

Immediately after GSC, there are a number of condensate outlets for consumers like LP bypass spray, auxiliary steam spray, the chemical feed system, vacuum breaker spray, the pump sealing water system, etc. (see Figure III/7.2-2). Also there is CEP and GSC recirculation line with control valve RCV01 to ensure minimum (approximately >30%) condensate recirculation flow through the CEP and GSC. There may be several other schemes for these recirculation controls (see Clause 7.2.4). A sample line is taken after CEP discharge to measure conductivity and pH to assess the condensate quality. As discussed earlier, there is a dump line to dump the excess condensate. This dump line with control valve DPV01 is shown before the main

www.EngineeringBooksPDF.com

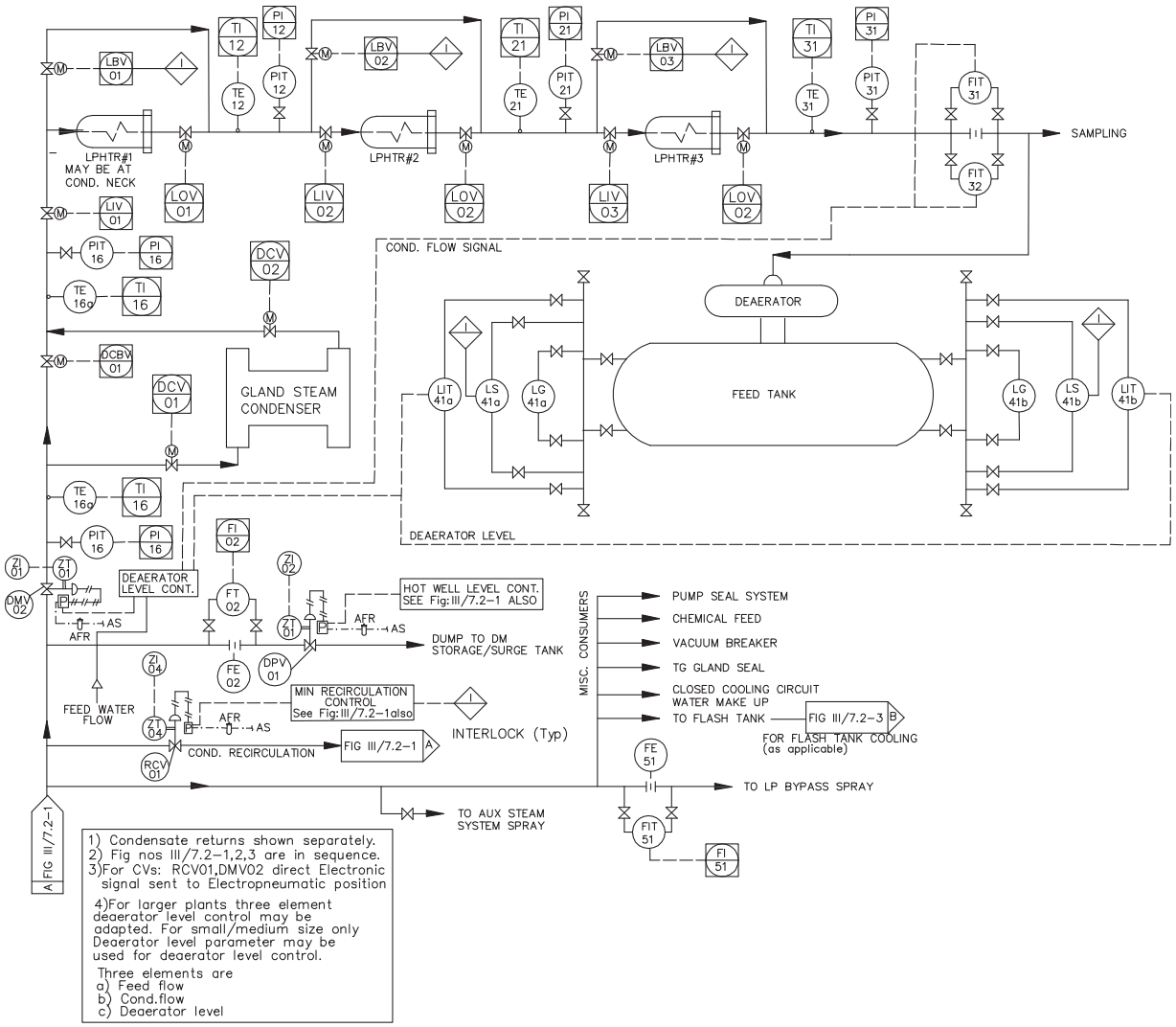


FIGURE III/7.2-2 Condensate P&ID (condensate through heaters up to deaerator).

condensate control valve MCV01. After the main condensate valve , condensate passes through the drain cooler and three LP heaters before reaching its final destination, the deaerator. LPH 1 normally is located at the neck of the condenser. The drain cooler and each of the LP heaters have inlet/outlet isolation valves and a bypass valve so that at any time each of them can be isolated and/or bypassed. Main condensate flow and quality is measured in the condensate line going to the deaerator. In direct mode of control, the hotwell level is maintained by make-up and dump valves, the whereas main condensate control valve regulates the level in the deaerator (see Clause 7.2.4).

7.2.3 System Description: Condensate Return

The temperature of various condensate returns and drains such as the heater drain, etc., are important factors to be considered, so that they can be directly admitted to condenser. If temperature is high, then it may cause the increase in temperature inside the condenser; hence, condenser pressure will increase, meaning lower cycle efficiency. It is therefore general practice to return all of these drains to the condenser via flash tank (HP for HP drains, LP for LP drains). Whenever the level in the flash tank increases, it opens out the drain control valve through the level interlock to drain it to the condenser. There is a pressure interlock associated with the flash tank, so that whenever the pressure inside the flash tank increases through pressure interlock, the spray control valve to the flash tank will open to spray water into the flash tank to lower the flash tank temperature/pressure (see Figure III/7.2-3).

www.EngineeringBooksPDF.com

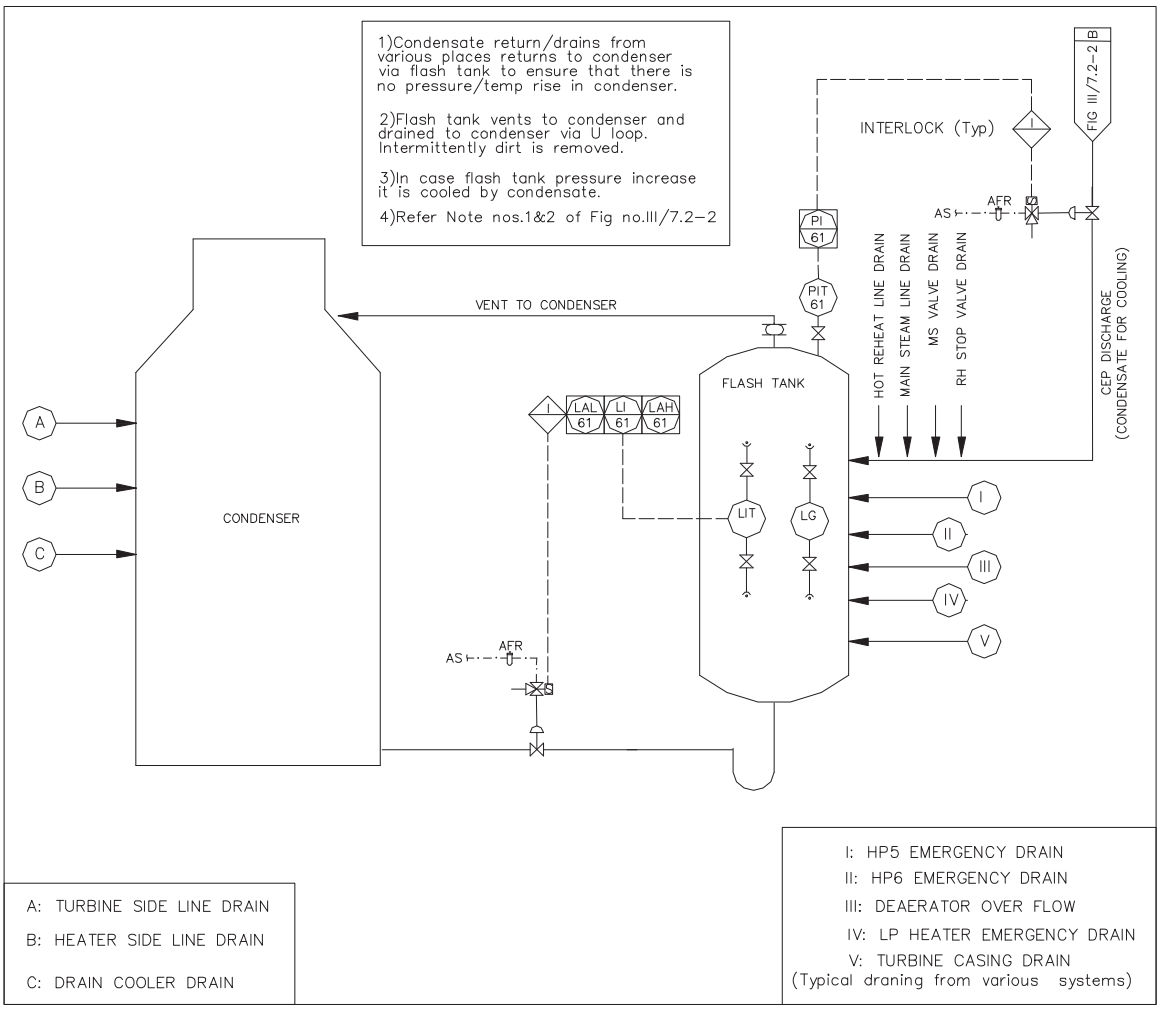


FIGURE III/7.2-3 Condensate P&ID (condensate return).

7.2.4 System Description: Condensate Level Controls

In the P&ID (Figures III/7.2 and III/7.2-1) the following loops have been considered (as shown in Figure III/7.2-4c).

- *Minimum recirculation control of CEP and GSC*: will be done independently by measuring the condensate flow through the CEP and GSC to ensure minimum flow. if main condensate flow increases then from the set point the loop will close the valve automatically.
- *Hotwell level control loop*: Regulates demineralized (DM) make up and dump control. This is also straightforward—when there is excess level in the hotwell (e.g., load throw off) it dumps the excess condensate to a surge tank. Similarly, whenever there is dearth of condensate in the hotwell the control system will open the make-up line control valve for condensate make up.
- *Deaerator level control*: Regulates the main condensate flow to maintain deaerator level.

In Figure III/7.2-4a and b a few other alternatives are seen.

1. *Figure III/7.2-4a*: Hotwell level control loop regulates both minimum recirculation control valve and the main condensate control valve in opposite mode. Whenever the hotwell level rises, it starts opening the MCV to regulate the hotwell level and starts sending condensate to the deaerator. Whenever the MCV opens there is less than a certain value, meaning flow in the main condensate line is less, then recirculation control valve (RCV) will start opening to ensure minimum recirculation flow for the CEP and GSC. Initially when the system starts and the MCV is closed, the RCV will open to ensure minimum recirculation flow for the CEP and GSC. As the system starts drawing the FW from the feed tank, then the deaerator (FW tank) level starts going down, causing make up at the hotwell, which causes the hotwell level to rise. Consequently, the MCV starts

www.EngineeringBooksPDF.com

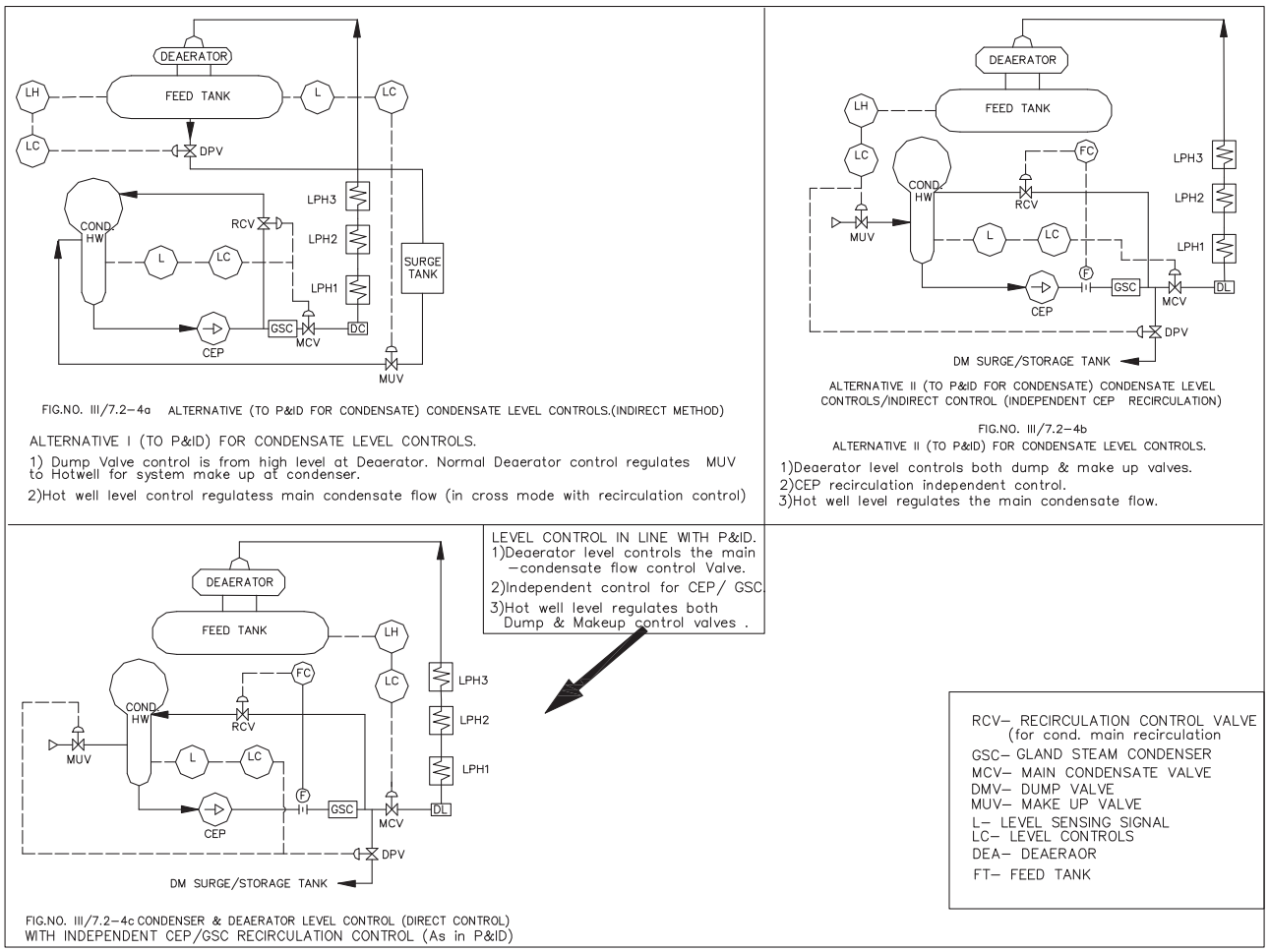


FIGURE III/7.2-4 Various condensate level control modes.

opening and (since RCV and MCV operate in opposite directions) the RCV starts closing. As a result, the deaerator (FW tank) level starts rising. If it rises beyond a desired point then excess will be dumped to the surge tank via a DPV. This mode is a rather indirect way to maintain system balance and levels in the hotwell and deaerator. Because of capacity differences between the hotwell and deaerator (FW tank), this method is sometimes effective.

2. *Figure III/7.2-4b*: These control loops are also alternatives to what has been shown in the main P&ID. This is also an indirect type of control and quite similar to what has been discussed in above. The main difference is here the CEP and GSC recirculation is independent, based on actual flow measurement (similar to that in the P&ID). The condenser hotwell level is maintained by regulation of the main condensate flow MCV. On the hand, the deaerator level regulates the make up to hotwell or dump to the condensate storage (DM) tank.

7.2.5 System Description: Condensate Polishing Unit

See Chapter II, Clause 3.6.6, and Figure II/3.6.6-1 for further details.

1. *Condensate polishing*: Why? And how much?

   In larger unit (>200 MW) super thermal power stations plants it is customary to deploy a condensate polishing unit (CPU). In heat exchangers where steam is condensed, it picks up contamination from environment. Leakage at the heat exchangers and condenser are other sources of contamination. Air leakage and carbon dioxide leakage cause formation of oxides of Fe, Cu, Ni, and Si. For larger power stations, it is *essential* (especially for OT boilers) and *economic*, to use a CPU for better quality water for boiler as well as higher turbine life. This condensate polishing may be partial as shown in Figure III/7.2.5-1, where part of the condensate directly goes to the GSC (main cycle) and part

www.EngineeringBooksPDF.com

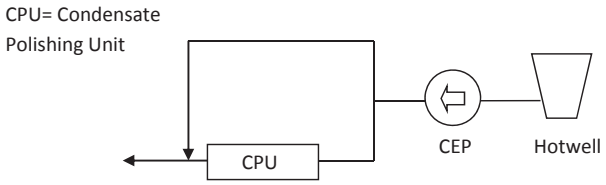


FIGURE III/7.2.5-1 Condensate line with CPU in service.

goes to the main cycle only after passing through the CPU. What percentage of condensate should pass through the CPU is part of the process design and water quality at plant site so it is not dealt with here (see Chapter II, Clause 3.6.6 for more details).

2. Condensate polishing objective: Major objective for using CPU includes but is not limited to the following:
   - Better water quality and cycle clean up
   - Less blow down hence less make up
   - Better heat transfer at boiler
   - Quick start-up and reaching full load
   - Higher turbine life
   - Less pressure on DM plant
3. Types of CPU

   CPUs are basically a series of ion exchange units that may be comprised of the following: (see Chapter II)
   - Strong acid cat ion
   - Weak acid cat ion
   - Mixed bed
   - Strong base an ion
   - Weak base an ion

   The difference in a normal DM plant is the flow rate. If it has a CPU it has to have a high flow rate. Depending on type chosen, regeneration may be *in situ* or external.
4. Instrumentation involved in this system is similar to that in the DM plant.

7.3 Major System Equipment: Condensate System

Major system equipment in the condensate line includes the following:

1. *Condenser*: The purpose of the condenser is to condense turbine exhaust hood steam by taking away the heat of vaporization with the help of the cooling water circuit in the condenser. This condensate collected is stored in the hotwell of the condenser. In conjunction with the flash tank, it provides a collection point condensate drain from various other points of the system. Condenser may be a plate type, direct contact type and shell tube type. Similarly, the cooling system may be an open type (OT) where water is taken from water bodies, e.g., a river and returned to the source at a distance. In some cases these may be a closed type, where cooling water is cooled with the help of a cooling tower.
2. *Flash Tank*: It is basically a storage device kept between the condenser and the condensate drains to ensure that under no circumstances will high temperature go into the condenser directly to raise its temperature. As discussed in Clause 7.2.3, it ensures low-temperature condensate drain.
3. *LPHs*: In the condensate system there may be three (in P&ID LPH 1, 2, and 3) to four, shell and tube type heaters. The condensate in the tube of the heaters is heated by LP-stage turbine extraction steam in the shell. Here heaters are numbered 1, 2, and 3. The lowest heater is 1, which receives the steam from the lowest extraction pressure and so on. However, this numbering system also may start with 3 as the lowest heater.
4. *Drain cooler*: It extracts heat from the various drains it receives from the turbine to heat up condensate and is cooled down before sending it to the condenser.
5. *GSC*: It condenses various leakage steams from the turbine glands. During start-up there will be a requirement of auxiliary steam to seal turbine glands, but as the load increases steam will leak from the glands of the higher pressure stages of the turbine. The steam is collected here, thereby adding heat to the condensate as it passes through in the tube.
6. *CEP*: Pumps out the condensate from the hotwell to the various heaters, other consumers, and deaerator. It is a centrifugal pump, but normally the speed of the pump is not in controlled. Depending on the system resistance, its operating point is decided. Since there are many outlets before the condensate line going to the deaerator, the quantity of water handled in the CEP is more than that of BFP, but with less header pressure (than the BFP).

7.4 Major Parameter Measuring Monitoring in Condensate

7.4.1 Process Parameter: Condensate (Typical Values Only)

See Table III/7.4.1-1 for condensate parameters.

7.4.2 Monitoring of Process Parameter: Condensate System

Monitoring of parameters like the condenser vacuum, level at the hotwell, deaerator, etc., at the control room is extremely important (see Figures III/7.2-1 to III/7.2-3).

1. *Make-up water flow measurement*: In most power stations, the flow of make-up water at the condenser is measured to monitor the actual make up to the system

www.EngineeringBooksPDF.com

TABLE III/7.4.1-1 Condensate Parameters

Location	Pressure	Temperature	Flow	Remarks
200 MW				
CEP suction (condensate vacuum)	0.37* (0.1)	38	800	*Water head
CEP discharge	22	40	800	
LPH 2 inlet	21	62	800**	Less amount for various de-superheating water
LPH 3 inlet	19	87	800**	
LPH 3 outlet	17	125		
500 MW (drop across heater may be more)				
CEP suction (condensate vacuum)	0.45* (0.1)	40	1700	*Water head
CEP discharge	32	40	1700	
LPH 2 inlet	30	85	1700	Less amount for various de-superheating water
LPH 3 inlet	27	115	1700	
LPH 3 outlet	24	135		

Given values may vary with actual values. **Spray for auxiliary steam, LP bypass considered before LPH. Units: Pressure in kg/cm^{2}A, temperature in °C, and flow in T/h.

and check system performance and leakage. For this one orifice plate, in conjunction with a DPT, is used to measure the flow. Under normal conditions, make up should be 3−4% of normal flow for the plant. However, to take care of a sudden change in load, the range of the flow measurement is kept wider, depending on the mass balance and heat balance for the plant. Typical (actual may vary) flow range should be 250 T/h in a 200 MW plant and 450 t/h for a 500 MW plant.

2. *Condensate level at the hotwell*: This is a very important parameter. To avoid too many holes at the condenser body, normally a stand pipe on each side of the condenser, as shown in the P&ID, is used. Various tapping points for level measurements are taken from the stand pipe. LSs are shown *intentionally* direct tapping from the condenser so the reader that knows direct tapping is also possible. LG (Level Gage)s and LT (Level Transmitter)s have ranges covering the allowed very high and very low levels of the condenser hotwell. For control purposes dedicated level transmitters with narrow ranges often are used. As the condenser may be a partitioned type, it is recommended that that the number of transmitters on each side of the condenser will be same. Apart from a closed loop control system (CLCS), there are a number of interlock open loop control systems (OLCS) as well. Hotwell level greater than the minimum set value is taken as start permissive for initial starting of the CEP to ensure required NPSH. Similarly, if the hotwell level is less than the very low set point, the running CEP will trip.
3. *DP across suction filter*: DP across the suction filter of the CEP is monitored, and if there is a "high DP", an alarm is generated to take action to clean the filter.
4. *CEP suction pressure and valve open*: To ensure that the CEP has flooded suction pressure at the suction is measured with the help of a pressure transmitter with a typical range of 0 to 1 kg/cm^2. Additionally, the suction valve open signal is also taken as an interlock/start permissive for the pump.
5. *CEP/GSC minimum flow recirculation*: As discussed earlier, this measurement is done for independent recirculation control of the CEP and GSC. Orifice plate with a DPT is used to measure the flow. Flow range should be >40% of the BMCR.
6. *CEP discharge pressure measurement*: This is done for various purposes as discussed below:
   a. *Each pump discharge before discharge valve*: Pressure gauge to see pressure locally.
   b. *Each pump discharge before discharge valve*: Pressure switch to stop the pump if discharge pressure shoots up near shut-off pressure for any reason, such as the discharge valve failed to open.
   c. *CEP discharge header pressure transmitter*: Discharge pressure is monitored by smart transmitters in the range of 0 to 30(/50) kg/cm^2.
   d. *CEP discharge header pressure switch*: One pressure switch at a common discharge header is used for automatic cutting in of the standby pump.
7. *Temperature measurement at CEP discharge and GSC O/L*: Temperature at the CEP discharge and GSC O/L are measured with the help of an RTD (Pt100) to

www.EngineeringBooksPDF.com

monitor water temperature and for calculation of condensate temperature (heat) gain in each of the heaters. Typical range for measurement should be 0−150°C.

8. *LP bypass condensate flow*: Depending on the system design and requirement of turbine supplier, the spray flow going to LP bypass system is measured in some of the systems, but it is not a mandatory measurement.
9. Condensate dump flow measurement: Because of system disturbances, such as sudden load throw off, it may be necessary to dump a part of the system water to the DM storage/surge tank. Similar to the make-up system, here an orifice plate, used in conjunction with the DPT, is deployed to check overall performance of the system following a load throw off. Typical (may not be actual) range for the measurement could be 250 t/h in 200 MW plants and 450 T/h for 500 MW plants.
10. *Local temperature measurement across LP heater*: Input and output of each of the LP heaters is measured locally by local temperature gauges to see the temperature gain across each heater. Typical range for measurement should be 0−200°C. These gauges may be an integral part of the heater, and are not shown in the drawing. Also terminal temperature difference measurement is necessary for calculation of heater performance for which RTDs may be deployed.
11. *Drain cooler, LPHs outlet temperature, and pressure measurement*: Pressure and temperature at the outlet of each LPH and drain cooler is measured to check the pressure drop across the heater and temperature gain. This is done by comparing these two parameters at inlet and outlet. The temperature and pressure ranges should be almost the same (ΔP and ΔT across the heater will be ∼2-5 kg/cm^2. and ∼25°C, respectively). Smart pressure transmitter should be in the range of 0−25(/35) kg/cm^2 and RTDs in the range of 0−150°C may be deployed.
12. *Deaerator(feed tank) level*: As discussed earlier, for the deaerator (FW tank) level measurement a stand pipe should be used on either side of the deaerator. Various tapping points for LGs, LSs, and LTs (with ranges covering allowable, very high, and very low levels of the deaerator) are taken from stand pipes on either side. For control purpose dedicated level transmitters with narrow ranges often are used. It is recommended that there are the same number of transmitters on each side of the deaerator. Apart from CLCS, there are a number of OLCS controls also. FW tank level greater than minimum set value is taken as start permissive for initial starting of the BFP. Similarly, in the event the FW tank level is less than the very low set point the running BFP(s) will trip. In larger plants, for deaerator level control a three-element control is used: the three parameters include the deaerator level, condensate flow, and FW flow.
13. *Condensate flow measurement*: Main condensate flow going to the deaerator is measured with the help of an Orifice plate (or flow nozzle) and smart DPT. Approximate flow measuring range should be 0−800 T/H (200 MW plants) and 0−1800 T/h (for 500 MW plants). This measurement is very important for deaerator (FW tank) level control as well as mass/heat balance calculations. Smart DPT (with turn down ratio 60:1) in the span of 0−8000 mm wcl (typical value) may be selected for this. It is recommended to have one temperature compensation for the condensate flow measurement from a nearby temperature measurement system.
14. *Sampling points*: Monitoring of water quality at condensate is very important. Major sampling points are at
    a. Each side of condenser
    b. CEP discharge
    c. Deaerator inlet and outlet

From these sampling points, the sample may be taken for manual analysis and/or it can be sent for SWAS (see Chapter V).

7.5 Controls in Condensate System

1. *CEP and GSC recirculation control*: Ensures minimum condensate. flow through the CEP and GSC. This is done independently by measuring flow of condensate through individual CEP and GSCs. As discussed in Clause 7.2.4, there is an alternative method also (see Figure III/7.2-4a).
2. Condenser hotwell level control: As is seen in the P&ID, condensate hotwell level is maintained by regulating two sets of valves.
    a. MUV01 (see Figure III/7.2-1) to take make up when level in the hotwell goes below the set value through modulating control.
    b. DMV02 (Figure III/7.2-2) to dump excess condensate to the DM storage/surge tank, so that the hotwell level does not go above the desired set point.
    c. In an alternative or indirect way (Fig III/7.2.-4) the hotwell level is regulated by regulating the opening of the main condensate line valve, so when the level goes up it opens the valve more, to route more flow to deaerator. In this alternative way the loop also is responsible to ensure recirculation flow (see Figure III/7.2-4a).
3. *Deaerator (FW tank) level control*: In the P&ID the deaerator (FW tank) level is controlled by regulating the main condensate flow control valve to the deaerator. In larger power plants, to achieve better response, three elements may be used. In alternative and/or indirect systems discussed in Clause 7.2.4 (Figure III/7.2-4),

www.EngineeringBooksPDF.com

the deaerator level signal is used to regulate make up and dump valves to regulate the deaerator level.

4. *Flash tank control*: Flash tank is used to prevent draining of hot drains from entering the condenser. It has two controls:
   a. *Level control*: Level in the flash tank is maintained such that whenever it goes higher than the set value, it is allowed to drain to the condenser.
   b. *Pressure control*: There is one line from the CEP discharge taken to spray cold condensate to the flash tank so that its temperature and pressure do not rise. Whenever the pressure inside the flash tank crosses the set point, water is sprayed so that at all times the pressure and temperature are regulated within limits.

7.6 Redundancy in Measurement: Condensate System

- *Hotwell level*: Generally one of two redundancy is deployed for measuring levels on each side of the hotwell. However, if the hotwell is partitioned, it is necessary to have at least one transmitter on each side of the hotwell.
- *Deaerator(FW tank) level*: One of two redundancy is deployed for measurement of the deaerator (FW tank) level on each side.

7.7 Miscellaneous Points: Condensate System

Condensate measurements are related to the turbine system, so these parameters are monitored at the central/common system monitor of the turbine monitor.

8. HEATER DRAIN AND VENT (P&IDs)

8.0 Heater Drain and Vent System

In shell and tube type heaters, after transferring the heat to condensate (LPHs) or FW (HPHs), extraction steam condenses to water, which needs to be returned to the system at the condensate/deaerator through a heater drain and vent system.

8.1 Objective and Function of the System

This system includes the following major functions:

- To condense the extraction steam and to return to the system.
- Heater draining is necessary to prevent induction of water to the TG by draining the water accumulated to the preceding heater, deaerator, and/or condenser.
- By proper selection of drain control valves, possible water hammering between FW heater and condenser is prevented.
- Maintenance of proper levels in the heaters so that the heat transfers to condensate (LPH)/FW (HPH) from extraction steam is ensured.
- To return the noncondensing gases to the condenser.

8.2 System Description: Heater Drain and Vent System

In each of the heaters there are a number of drain and vent paths, depending on the operating points.

8.2.1 System Description: Heater Vent

Excepting LPH 1, all the heaters have three vent lines, these are a start-up vent, an operating vent, and a pressure vent/safety valve vent (operation of pressure safety valve; see Figure III/8.2-1).

1. *Start-up vent*: During start-up the heaters are vented through a motorized valve operated by the plant DCS in automatic/semi-automatic mode. With HPHs these lines return to the deaerator for possible high temperature and pressure. On the other hand, the start-up vents from LPHs 2 and 3 are controlled in the same manner, connected to the condenser. At LPH 1 there may not be a start-up vent.
2. *Operating vent*: Whenever heaters are in operation, there will be some continuous vent from the heaters. Generally these constant vents are done through a restriction orifice, which is sized with lower beta ratio (flow coefficient) so that there is a good amount of pressure drop across it. HP and LP heaters have operating vents connected to the deaerator and condenser, respectively. Drain cooler vents to the condenser through the operating vent line of LPH 1 as shown in Figure III/8.2-1. Depending on the system design, vents and vent lines may be connected to the condenser directly or may be connected via flash tank (see Figure III/8.2-1) to avoid any chance for raising temperature at condenser.
3. *Safety valve vent (pressure)*: Each of the heaters has one safety valve vent or pressure vent. Each heater (except LPH 1) has one spring-operated pressure safety valve where the desired pressure set value is set by the spring. When pressure in the heater is greater than the set point, it will pop up to vent. These pressure vents may be connected to a common header with a vent and drain lines connected to a common drain/sump pit line.

8.2.2 System Description: Heater Drain

As we see in the regenerative cycle, major storage spaces are in the condenser and FW tank (deaerator). The basic

www.EngineeringBooksPDF.com

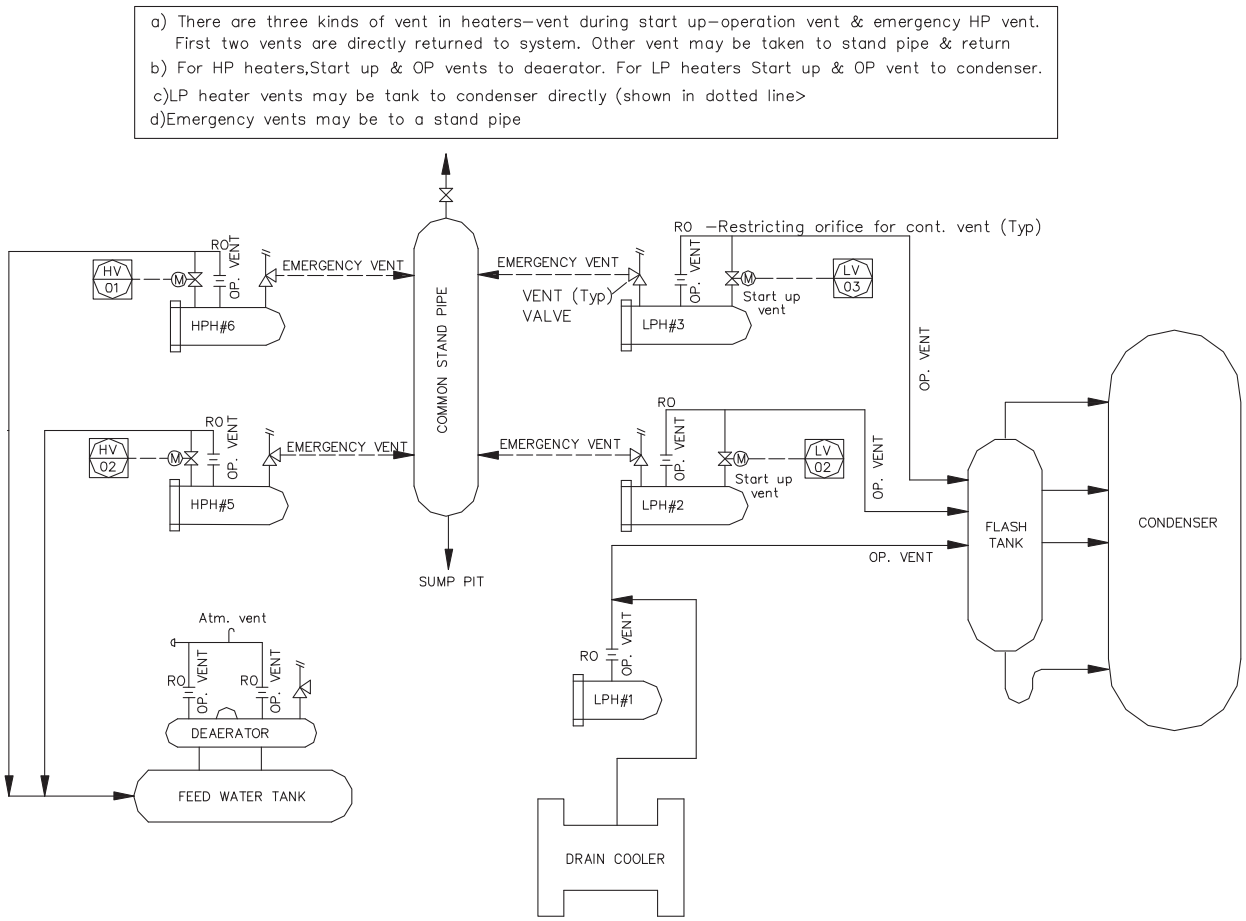


FIGURE III/8.2-1 Heater vents (HPH and LPH).

philosophy behind heater drains is that under normal conditions the heater will drain to the preceding (when considered with respect to (WRT) FW/condensate flow path) heater, so that there is not much change in operating conditions between the draining fluid and where it is drained. However, there are situations when it is not possible for any heater to accept drain from its successor (say heater 5 to accept the same from heater 6) or the heater is bypassed. In those cases the heater may be drained to the condenser or it may drain to the deaerator in case the concerned heater is situated after the deaerator (e.g., HPH 6 to the deaerator). There will be at least two paths for each heater. (Exception: LPH 1 will always drain through the drain cooler and HPH 6 may have three draining paths instead of the two discussed, e.g., normal drain to HPH 5, or to the deaerator, or in an extreme case, to the condenser via flash tank.) Remember that whenever drain to condenser is referred, it is normally through the LP flash tank and may not be directly to the condenser. Although not shown in the P&ID in Figure III/8.2-1, in some design there are HP drain flash tanks (HPDFTs) to accept drain from HPHs to avoid problems due to temperature. These High Presure Flash Tank (HPDFT)s on high levels drain to Low Pressure Drain Flash Tank (LPDFT). All such flash tanks have provision for cooling (see Figure III/7.2-3) the inside temperature through a pressure interlock.

1. HPH drains (see Figure III/8.2-2):
   a. *HPH 6 normal level control*: In HPH 6 there are three draining paths. Under normal situations it drains through HDV06A to HPH 5 to maintain normal level at the desired set point. If there is a problem in HPH 5 (or it is bypassed), for example, the level is already high in HPH 5 (done by level interlock in HPH 5), then it should not be drained to HPH 5. By HPH 5 high level interlock through DCS HDV06A it is closed and HDV06B opens to maintain the level in HPH 6 by regulating the HDV06B drain to the deaerator. The same happens when the extraction pressure to HPH 5 is low (then drains from HPH 6 to HPH 5 will be stopped to prevent water ingress to the turbine extraction line through probable high level in HPH 5). If there is a very high level in the deaerator,

www.EngineeringBooksPDF.com

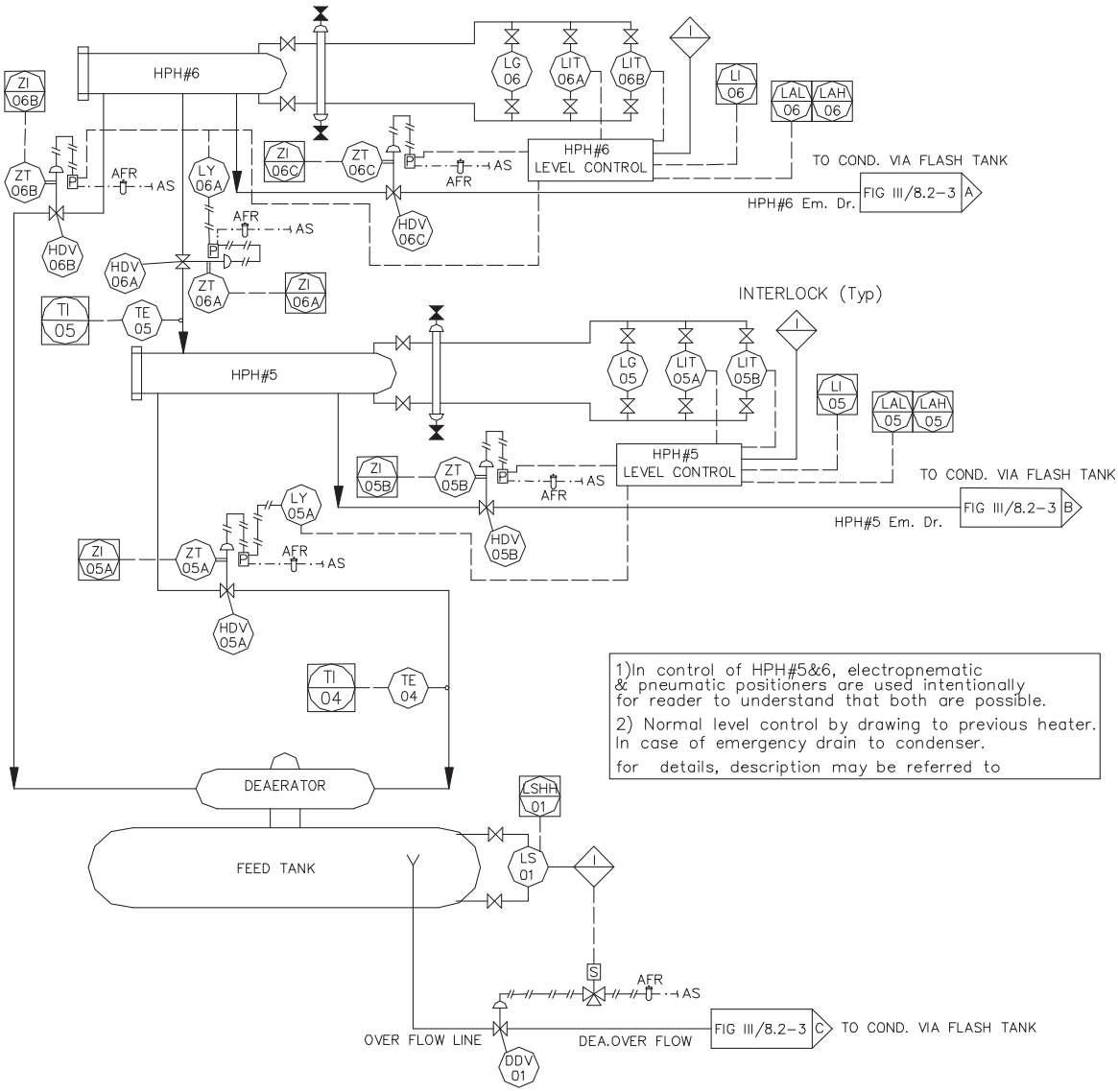


FIGURE III/8.2-2 HPH drain system.

HDV06B may be closed and drain may be sent to the condenser (through LPDFT).

b. *HPH 6 high level control*: There is also a high set point for HPH 6. When the level in HPH 6 crosses that high set point value then HDV06C opens to drain the water to the LPDFT and to the condenser. This may happen if the HPH 6 tube ruptures, causing a sharp rise in heater level.

c. *HPH 5 normal level control*: In HPH 5 there are two draining paths. Under normal situations it drains to the deaerator through HDV05A to maintain normal level at the desired set point. If there is a very high level in the deaerator HDV05A may be closed to drain to the condenser via LPDFT.

d. *HPH 5 high level control*: There is also a high set point level for HPH 5. When the level in HPH 5 crosses that high set point value then HDV05B opens to drain the water to the condenser via LPDFT. This may happen if the HPH 5 tube ruptures.

e. *Deaerator overflow*: If there is deaerator overflow, interlocked with a very high deaerator level (level switch), it will be drained to the condenser by DDV01 (see Figure III/8.2.2.1-1).

2. LPH drains (see Figure III/8.2-3):

a. *LPH 3 normal level control*: Under normal situation it drains to LPH 3 through LDV03A to LPH 2 to maintain normal level at the desired set point. If there is some problem in LPH 2 (or it is bypassed) or the level is already high in LPH 2 (done by level interlock in LPH 2), then it should not be drained to LPH 2. By LPH 2 high level interlock through

www.EngineeringBooksPDF.com

The situation is not always very congenial. This is because HPH 5 or 6 pressure and temperature are quite high when compared the that in the condenser. For these reasons, in many designs HPDFT is introduced and HPH emergency drains may be connected to it. In larger size power stations there may be two HP heaters (i.e., HPH 5 A and B or HPH 6 A and B).

FIGURE III/8.2.2.1-1 Note on HPH drains.

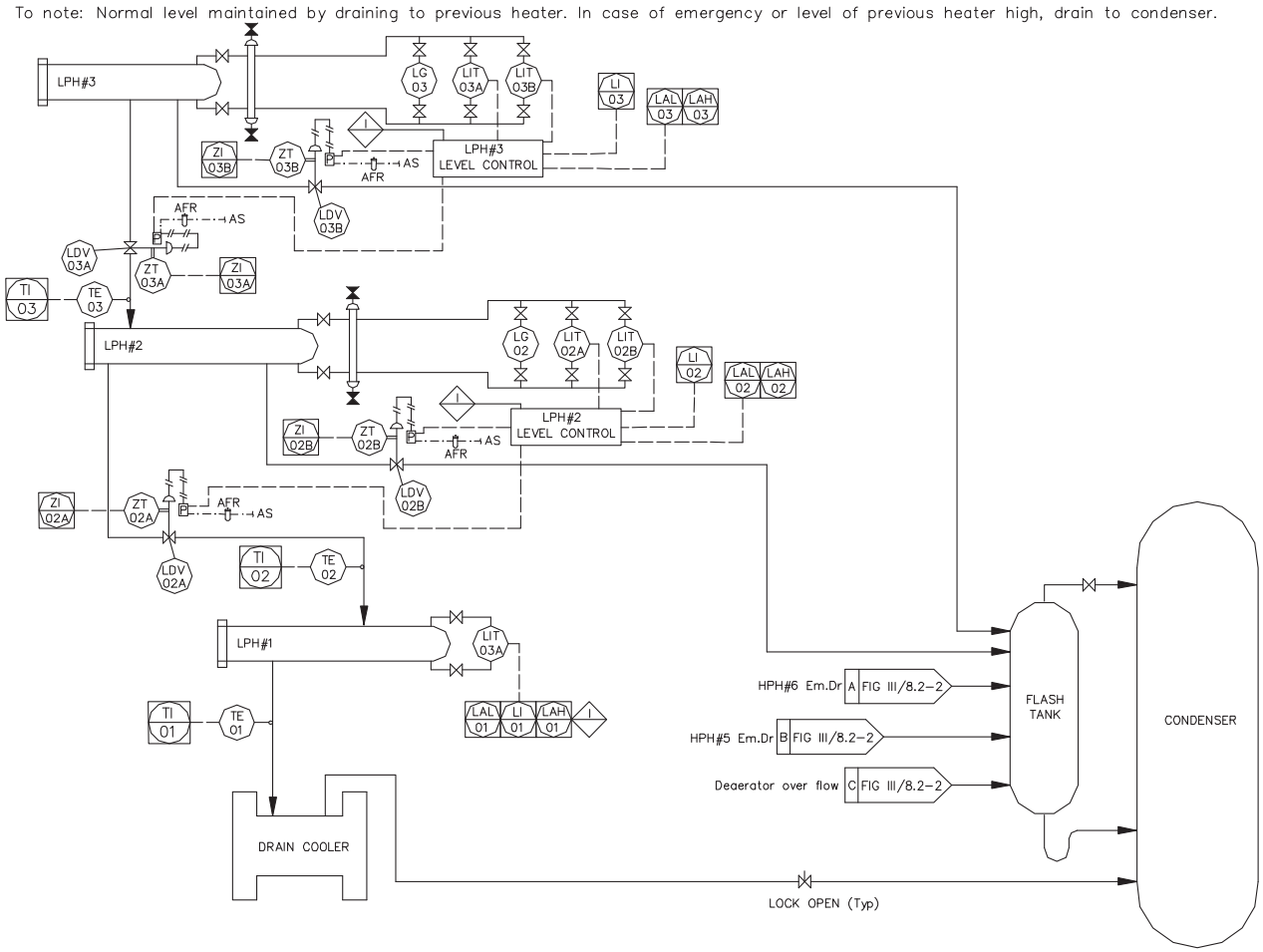


FIGURE III/8.2-3 LPH drain system.

DCS, LDV03A should be closed and LDV03B should be open to maintain the level in LPH 3, by regulating LDV03B drain to the condenser. Also when the extraction pressure to LPH 2 is low, then drain from the cascade drain of LPH 3 to LPH 2 should be stopped to prevent water ingress to the turbine extraction line through high level in LPH 2. This is similar to HPH 5and 6.

b. *LPH3 high level control*: There is also a high set point for LPH 3. When the level in LPH 3 crosses that high set point value then LDV03B will open to drain the water to the condenser. This can happen if the LPH3 tube ruptures.

c. *LPH2 normal level control*: Under normal situation it should drain to LPH 1through LDV01A to maintain normal level at the desired set point. If there is a high level in LPH 1, LDV02A may be closed and drain to the condenser.

d. *LPH2 High level control*: There is also a high set point for LPH 2. When the level in LPH 2 crosses that high set point value then LDV02B opens to drain the water to the condenser. This may happen if the tube ruptures.

e. *LPH 1*: Level in LPH is monitored but it is directly connected to the drain cooler, which in turn drains continuously to the condenser.

www.EngineeringBooksPDF.com

8.3 Major System Equipment: Heater Drain and Vent System

Major system equipment (see Chapter II) includes the following:

1. *Condenser*: Provides collection points of condensate drain from HP and LP heaters, as far as heater drains and vents are concerned. HP heater drains are normally connected via the flash tank.
2. *Flash tank*: A storage device kept between the condenser and various drain points to ensure that under no circumstances does high temperature fluid go into the condenser to raise its temperature.
3. *HP and LP heaters*: There may be three or four LP heaters meant to heat up condensate and there are three to four HP heaters meant to heat up FW by extraction steam lines from the turbine. Depending on the manufacturer and plant layout, these heaters may be horizontal or vertical. On the shell side they receive the extraction steam, which gets condensed after heating up condensate (LPH)/FW (HPH) flowing through the heaters inside the tube. This condensed extraction steam creates level in the heater. To prevent ingression of water to the turbine through extraction lines, it is necessary to monitor the level in these heaters so that it never crosses the high level set points (as per TWDPS). Also to have proper heat transfer to the condensate (LPH) or FW (HPH), it is necessary to maintain the level at the normal set point. For all of this it is necessary to have drains in all heaters. Also there may be noncondensing gases, which calls for a heater vent system to remove them.

8.4 Major Parameter Measuring Monitoring in Heater Drain and Vent System

8.4.1 Process Parameter: Heater Drain and Vent System (Typical Values Only)

The parameters for drain lines are purely a function of the heat and mass balance diagram for the plant. Some typical values are seen in Table III/8.4.1-1.

Heater shell pressure may be the same as extraction pressure. Depending on the terminal temperature difference chosen, the design for the heater's differential temperatures between extraction steam and drain can be estimated. Whereas the flow of drain has been approximated by adding the extraction flow with drain flow from the previous stage.

8.4.2 Monitoring of Process Parameter: Condensate System

For the TWDPS monitoring levels at the heaters is quite important. Also to have an idea about the heater performance drain outlet temperature for each of the heaters is equally important (see Figures III/8.2-2 and III/8.2-3).

1. *HPH 5 and 6 level*: Heater levels at HPH 5 and 6 are monitored. Since the heaters have two set points for control, in larger plants for better resolution, some plants have two different ranges for level transmitters for normal level control and the same for high level control. Some designs have the same set of redundant instruments for both purposes.
2. *LPH 2 and 3 level*: Similar to HPH levels.

TABLE III/8.4.1-1 Heater Drain Parameters (Typical)

Ex number	Heater number	Pressure	Temperature	Flow	Remarks
Typical value TMCR for 200 MW					
1	LPH 1	0.5–0.6	50	115	
2	LPH 2	1.2	82	50–55	
3	LPH 3	2.5–3.0	140–160	25	
5	HPH 5	15–16	~170	150	
6*	HPH 6	30–35	200	80	*(CRH)
Typical value TMCR for 500 MW					
1	LPH 1	0.64	52	175	
2	LPH 2	1.6	90	95	
3	LPH 3	3.0–4.0	140–160	47	
5	HPH 5	22	200	210	
6*	HPH 6	38–42	220–230	115	*(CRH)

Unit: Pressure in bar (A) ,temperature in °C, and flow in T/h.

www.EngineeringBooksPDF.com

3. *LPH 1 level*: Level at LPH 1 is monitored without any control.
4. *Drain line temperature*: Temperature at each drain line is monitored to check the transfer against each of the heaters.

8.5 Controls in Heater Drain System

As discussed in Clause 8.2.2, heater level controls are the only controls in this system. In smaller plants it is quite common to use local heater level controls. However, in larger plants these are achieved through the DCS (see Figures III/8.2-2 and III/8.2-3).

8.6 Redundancy in Measurement: Heater Drain System

Generally one of two redundancies are considered for heater level controls in HP and LP heaters.

8.7 Miscellaneous Points: Heater Drain and Vent System

Heater drain and vent measurements and control are related to the turbine system so these parameters are monitored at the central/common system monitor toward the turbine monitor.

9. AIR AND FLUE GAS SYSTEM (P&IDs)

In this part in addition to Air (Primary & Combustion) & Flue gas, outline of pulverizer instrumentation shall be covered.

9.0 Air and Flue Gas System

In the air and flue gas system, the draft section of boiler plays the most vital role in the performance and firing of boilers It encompasses not only both air and fuel (mill) supply, but also covers the burning of fuel in the furnace and the flue gas it produces. There are classifications of various air in the boiler, such as primary, secondary, combustion, scanner, or seal. Each of these types of air has a specific function to perform and their main purposes are listed below.

Primary air (PA): Air that comes to the furnace along with the fuel, such as pulverized coal. Since it carries pulverized coal, its pressure is more than that of secondary air. PA is supplied by PA fan(s) and may be two types: hot and cold. In the hot PA system a major part of the air at the suction of the PA fan is preheated through the air heater (AH). In hot PA system the fan capacity (mass) is less than that of the cold system (but the same size). In the cold PA system the PA fan handles cold PA, i.e., before being heated by the AH. It is the same size as the hot PA fan, but it has higher capacity. Primary air is responsible for

- Carrying pulverized coal to the furnace
- Removal of moisture from coal so that it can burn spontaneously in the furnace
- Keeping the temperature of the coal pulverizer within the specified limit so there is no chance of fire in the mill (pulverizer)

Secondary Air/Combustion Air (SA/CA): The main air supplied to the furnace for combustion is called combustion air. It is the majority of the total quantity of air supplied to the boiler and quantity wise is more than that of the PA system. This air is supplied to the furnace through a wind box/air register. The distribution of this SA is done as per location of the fuel burner firing (i.e., elevation wise in case of tangential tilt or TT burners). This distribution is controlled through an SA damper control or air register control system.

Seal air system: There are separate fans to supply seal air to the coal mills and coal firing system for sealing coal from coming out. This is done not only to avoid dust pollution, but also as a safeguard against accumulation of fuel. Seal air pressure is higher than PA pressure so that it can seal.

Scanner air system: This air is responsible for cooling the various flame scanners and burners when needed.

9.1 Objective and Function of the System

The air and flue gas system consists of three different sections: flue gas path, secondary (combustion) air path, and PA path. The objectives and functions of this system include the following:

1. *Flue gas*:
   - **a.** When burning fuel in the presence of air, flue gas is produced. It is very hot, and the basic purpose of this gas is to transfer heat to the various pressure parts in the boiler, such as primary and secondary SHs, RHs, economizer, etc., to heat up water and steam.
   - **b.** The transfer of heat to the various parts of the boiler can take place through radiation (platen SH) and partly by convection. Whenever the heat transfer is through convection, flue gas flow plays a vital role in heat transfer.
   - **c.** Another function of flue gas is to preheat the air reaching the furnace (SA) and/or mill (PA) so that spontaneous ignition of fuel can take place.
   - **d.** After all heat transfer the flue gas finally goes out through the chimney. It is very important to see that flue gas at the chimney outlet does not cause pollution, i.e., polluting gases such as NO_X, SO_X, and CO2, need to be well within the prescribed limit set by user's country.

www.EngineeringBooksPDF.com

e. Apart from pollution control, it is also important to make sure there is little unburnt carbon, carbon monoxide, etc., to avoid fire hazard. Also excess air in flue gas and chimney outlet means more energy loss in the form of heat. It is therefore the objective of the flue gas system to ensure that optimum burning is takes place.

f. From optimum plant operation and pollution control, it is important to ensure that flue gas leaving the chimney is not at a high temperature (<120°C), otherwise it could be used for steam temperature control by flue gas recirculation (FGR). Rotary AH heat transfer is more than the recuperating type, so flue gas temperature at the chimney outlet will be much less. Thus gas recirculation, for temperature control, in plants with rotary AHs may not be commonly done (except for NO_X control).

2. *SA (CA)*:

a. To supply adequate oxygen for burning the fuel in the furnace.

b. In AHs, SA absorbs heat from the flue gas to heat itself up to assist in instantaneous combustion of fuel in the furnace.

c. Little excess air is always maintained to ensure complete combustion, so that furnace atmosphere is safe for operation. Otherwise carbon monoxide can accumulate and cause an explosion. Again, excess air should be maintained at optimum levels, so that unnecessary heat/energy is not lost.

d. Depending on the design of the boiler, burners may be at four corners and at different elevations (e.g., corner fired boiler) or they may be arranged in the wall at the front, or in oppose fire mode (wall fire type boiler). The total quantity of SA must be distributed in such a way that all of the burners receive the optimum quantity of SA. While Forced Draft (FD) fan inlet impeller/damper (of fan speed) regulates the *total* CA flow. *Distribution* of air for each burner/over fire air, etc., is regulated by SA damper control (SADC)/air register.

3. *PA*:

a. This is sent to the mills with the help of PA fans. Depending on the boiler design, PA fans may be common for all the mills, e.g., 2 × 100% PA fans servicing all (say six) mills. In these cases, header pressure is maintained at a fixed value by regulating flow through the fan (e.g., the inlet vane control), and individual mills get air supply through a respective hot air (and cold air; mainly for temperature control) damper. In other designs there are as many PA fans as mills, so individual mill air flow is controlled by regulating the individual PA fan control.

b. As discussed earlier, PA may be a hot or cold system. In a cold PA system, PA fans take the suction from the atmosphere or cold discharge header of FD fans, after PA fans, and a part of the air from the PA fan is heated in an AH and sent to the mill after mixing with the unheated part of the PA flow. In a hot PA system, PA fans normally get their suction from SA after mixing of hot SA (through an AH) with cold SA. In these cases normally, the number of PA fans is the same as the number of mills. This system is not very popular for corner fired boilers with bowl mills.

c. In the cold PA system, the Hot Air Damper (HAD) is regulated to meet the total air demand for the mill, whereas the Cold Air Damper (CAD) is modulated mainly for mill temperature control. Conversely, in the hot PA system, with several PA fans, each mill air flow is regulated by individual fan flow control (e.g., inlet vane) and HAD and CAD can be utilized for mill temperature control. In case of tube mills, with the hot PA system, instead of controlling individual side outlet temperatures, the lower temperature of both sides is taken (if both sides are in operation). However, interlock from very high temperatures of an individual side may be provided to avoid fire hazard in the mill.

d. To carry the pulverized coal to the furnace for burning.

9.2 System Description: Air and Flue Gas

9.2.1 System Description: Flue Gas

Listed below is a system description for flue gas (see Figures III/9.2-1 and III/9.2-2)

1. Flue gas is generated at the furnace chamber where the pressure is kept at a little less than atmospheric pressure (e.g., [−] 5 mm wcl). Fire balls are generated in the corner fired boiler with burner titing facilty. Depending on the burner tilt position, the fire ball may go up or down. The furnace wall is basically formed by water tubes (over refractory lining) better referred to as waterwalls. Some amount of heat absorption takes place. Exact heat absorption in furnace and various parts of the boiler is boiler design specific; manufacturer data need to be consulted.

2. Firing takes place at the furnace and from there a part of the heat radiates to the RH or SH, which hangs like pendant (sometimes radiant SHs are called pendant SHs). The heat transfer to steam from flue gas occurs because of radiation, and does not depend on flue gas flow quantity. It is interesting to note that various boiler designs have different configurations of SHs and RHs in the radiation and convection zones. In the P&ID, one typical design of a corner fire boiler has been considered. Thus depending on boiler

www.EngineeringBooksPDF.com

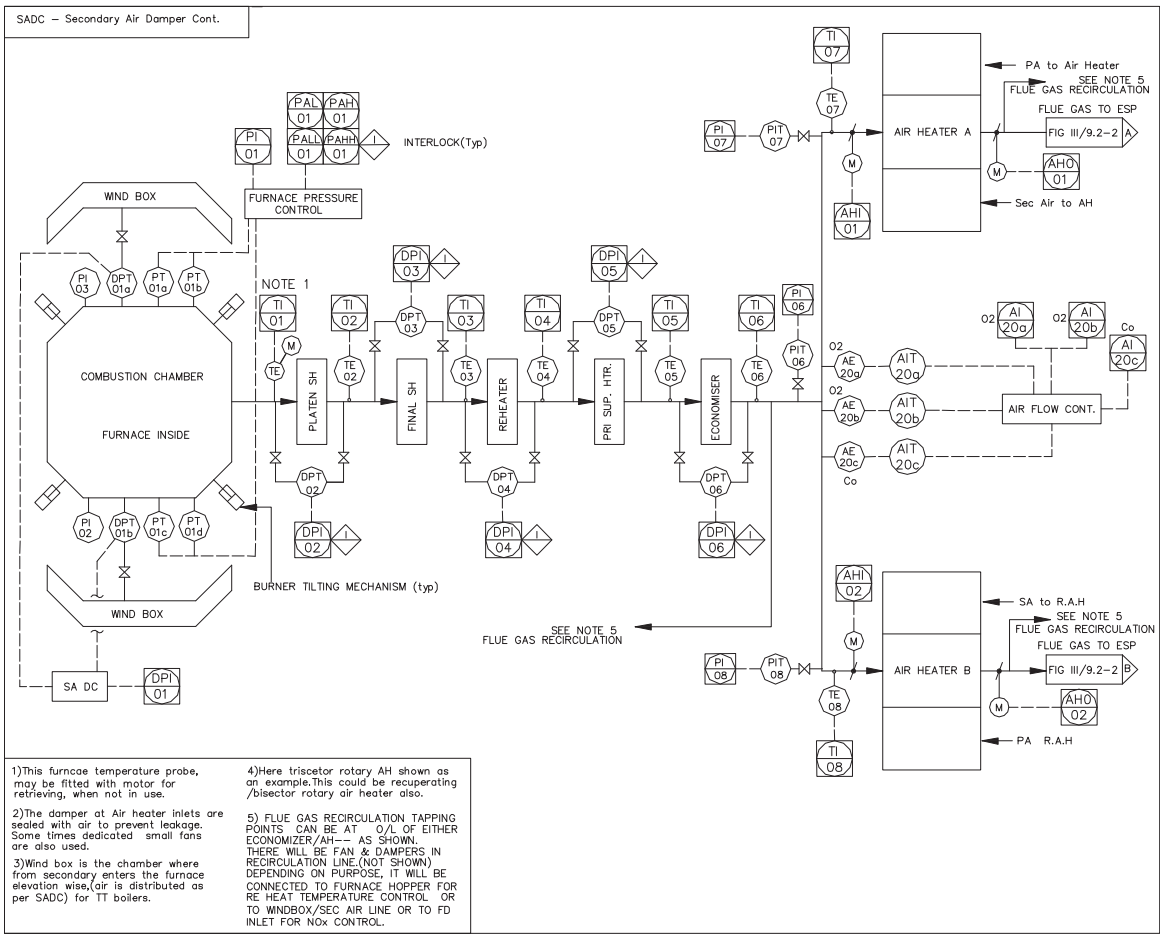


FIGURE III/9.2-1 Flue gas P&ID up to AH.

configuration and design, the means for steam temperature control varies. For a tangential burner, the tilt mechanism of the burner is utilized to regulate RH steam temperature, which also affects SH temperature control also. Again in the case of a wall-fired boiler, gas dampers (may have gas recirculation dampers also) are used to change flue gas distribution between the RH and SH to regulate reheat temperature control (influencing SH temperature control).

3. As the flue gas rises along the height of the furnace it passes over the SH and RH. Near the end of the first pass it passes over the primary SH. In these SHs and RHs heat transfer from flue gas to steam is by convection. Since the convection heat transfer rate is a direct function of flue gas quantity, the total heat absorption increases with boiler output. Therefore the quantity of flue gas and quantity of steam flowing through the coils of these SHs and RHs are dependent variables, i.e., related to each other. For this reason the set point of steam temperature control at the low load is not set at fixed point (i.e., 540°C). During low load, steam flow through the coils of the SH is low so it takes away less quantity of heat transferred by flue gas, and needs to be cooled down by water. Firing is also be regulated, otherwise the SH coil will be damaged. For these reasons the set point in the steam temperature control loop may be derived from air flow, which is an indication of load.
4. In the second pass flue gas comes across the economizer where it heats up FW passing through the coil of economizer. Meanwhile, by transferring heat the temperature of the flue gas comes down (e.g., ~350°C 200 MW).
5. In AH flue gas exchanges heat with air. Here again there are variations in designs of AHs, as discussed in Clause 9.3. In the drawing tri sector Ljungstrom AHs are considered. In the same AH, flue gas heats up both PA and SA. Instead of trisector, Ljungstrom AH could be a bisector (flue gas and either PA *or* SA). In that case, separate AHs are required for PA and SA. For a hot PA system (since PA takes its suction from hot SA air), single set of bisector AH is used. Ljungstrom AHs are rotary type, whereas another

www.EngineeringBooksPDF.com

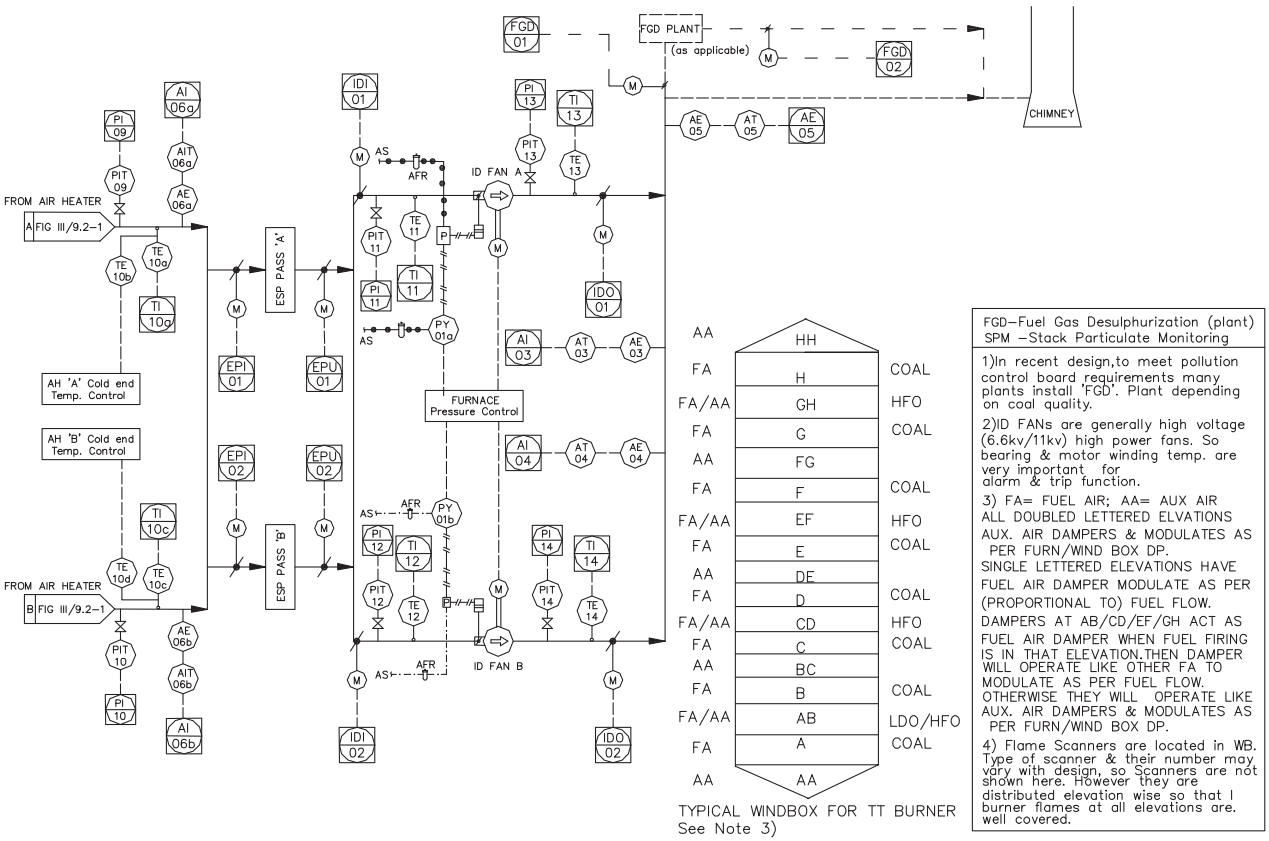


FIGURE III/9.2-2 Flue gas P&ID from AH to chimney.

design is the recuperating, stationary type. Air leakages as well as heat transferring efficiency are high with Ljungstrom/rotary AHs when compared with other versions. For isolating the AH for maintenance, isolating dampers have been provided at the inlet as well as outlets of the air and flue gas paths.

6. The AH is the last stage of heat exchange for flue gas, which finally goes out through the chimney with the help of an induced draft (ID) fan. However, in certain boiler designs further heat recovery is done by recycling a part of the flue gas to the furnace. This method is quite popular for raising the temperature of the reheat steam temperature in wall-fired boilers. Gas recirculation may be used for NO_X control also.
7. In Flue Gas Recirculation—FGR a part of the flue gas at the outlet of the AH or economizer (in some designs, it has been found that flue gas has been recirculated taking tapping at the ID fan outlet to eliminate the need for separate fan) is recirculated back to the furnace with the help of a fan, damper(s), and ducts. It is introduced near the vicinity of the burning zone, i.e., near furnace hopper. With this the total heat absorption may not be affected much, but the pattern of heat absorption in the boiler is changed. In this method, with an increase in percentage FGR, heat absorption at the furnace is reduced, whereas heat absorption in the RH, primary SH, economizer, etc., increases significantly. There is another point where flue gas could be introduced for recirculation. It is near the furnace (first pass) exit. Because of the introduction of recirculated flue gas at this point, with an increase in percentage FGR, flue gas temperature at the furnace exit as well as heat absorption at the secondary SH will decrease, but heat absorption at the economizer and primary SH would increase, with an increase in percentage FGR. (This may signify less attemperation may be required in the second stage attemperation with a two-stage SH temperature control). There could be another advantage of flue gas recirculation. Since part of the heat is recovered from the flue gas, the temperature of the flue gas going to the ElectroStatic Precipitator (ESP) would be reduced over time, and as a result better performance is expected of the ESP. This method is also known as "gas tempering."
8. FGR plays a role in reducing thermal NO_X formation. For effective NO_X control, FGR is used in conjunction with Low NO_X burner (LBN) and/or over fire air dampers. There are two major sources of nitrogen for

www.EngineeringBooksPDF.com

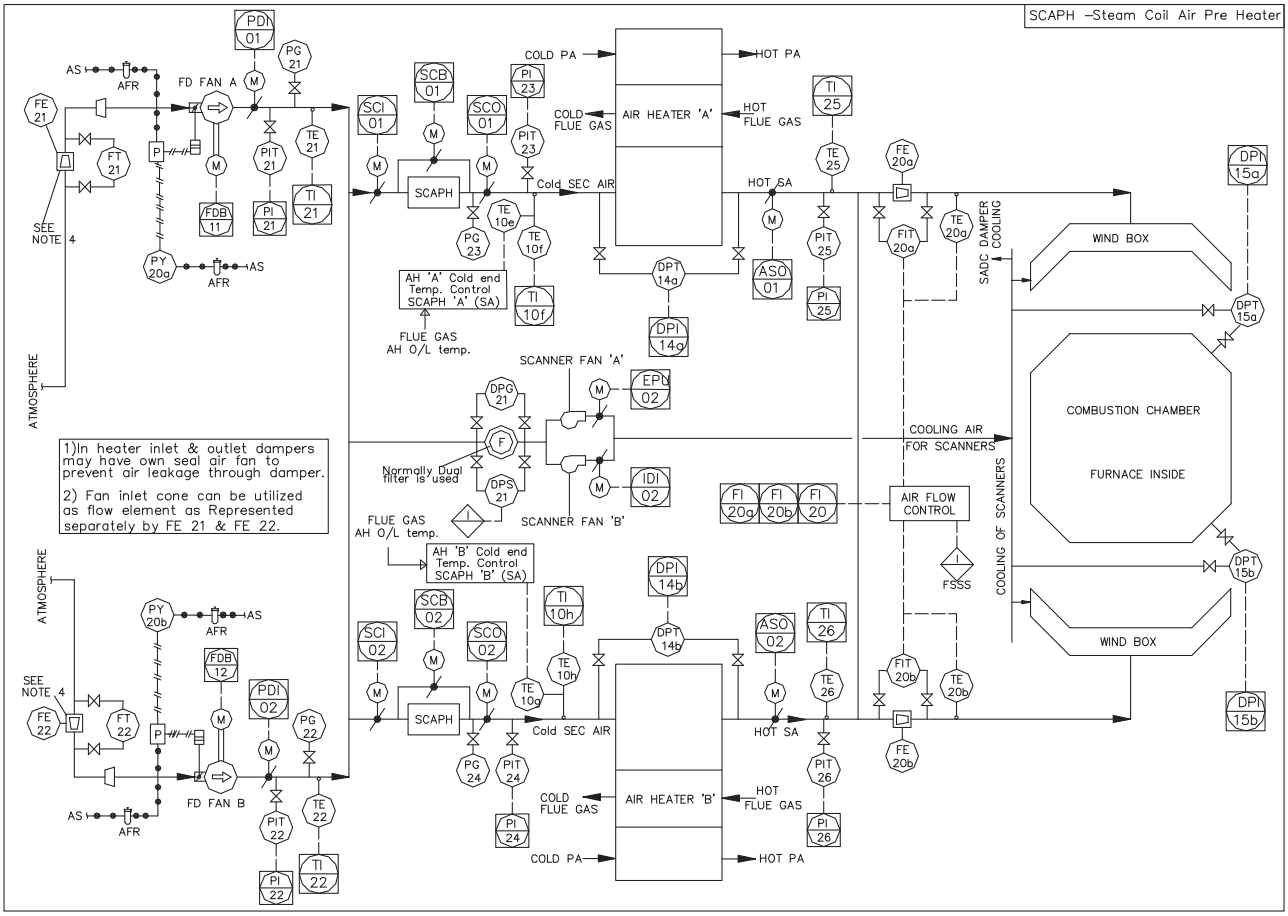


FIGURE III/9.2-3 Secondary air P&ID.

formation of NO_X: one is molecular nitrogen in air used for combustion and the other is bonded nitrogen in fuel. At high temperatures nitrogen is present in air form NO_X—more popularly known as thermal NO_X to pollute the atmosphere. NO_X formation depends mainly on temperature, turbulence (stoichiometric conditions), and time (resident combustion time)— the 3 Ts. To minimize this, decrease oxygen at the combustion zone and reducing combustion gas temperature is necessary. LNBs are designed to mix fuel and air so that there will be a longer and more branched flame, and peak flame temperature is reduced so that there will be less NO_X formation. It also helps to have less oxygen at the hottest combustion part—delayed mixing. In FGR technology 20−30% flue gas at ∼ 350−400°C (may be from AH outlet) is recirculated and mixed with combustion air. This dilution decreases the flame temperature resulting is less thermal NO_X formation. However, this method is more effective in oil and natural gas-fired boilers. For coal-fired utility plants, gas recirculation is effective for temperature control, but may not be that effective for NO_X control (Courtesy: EPA on utility boiler) if used in isolation. For this FGR, an increased rating for the ID fan and/or damper and a separate fan may be necessary. Cost-effective designs are also available where separate fans and wind boxes are not necessary; instead flue gas is induced at the FD fan inlet. However, with LBN and FGR, NO_X reduction >70% can be achieved, provided the boiler design uses "burner out of service" or "Over Fire Air (OFA)." In the OFA port, staged combustion air downstream the combustion zone is introduced. Because of this, TT burner-designed boilers have inherently less NO_X formation. Separate over fire air (SOFA) and Closely Coupled over fire Air (CCOFA) dampers are very common in reducing NO_X levels without using chemicals. This is done with a fuel-enriched condition near the flame zone, with comparatively lower temperature, followed by an air-enriched zone (for complete combustion) by OFA in a staged manner. In TT burners with SOFA, CCOFA reduction levels even can reach nearly 90%. Chemically NO_X is reduced by the selective catalytic reduction (SCR) method.

www.EngineeringBooksPDF.com

Why SCAPH? WHAT IS COLD END TEMPERATURE CONTROL?

Of two types of air heater, tubular and rotary, the rotary type has better heat transfer (but also higher leakage ~10%), therefore the flue gas, after transferring heat to the SA or PA, gets cooled more. If the fuel has sulfur and there is SO_2 in the flue gas because of leakage, air gets converted to SO_3. In the presence of moisture at the cold end (where cold air goes in and cold flue gas leaves the AH) it will form H_2SO_4, which causes corrosion. To prevent this, SCAPH is used to heat up cold, moisture -laden air. This temperature is controlled with the help of regulating steam flow to the coil. This is cold end temperature control—detailed with control loop under the boiler control system. IT IS GENERALLY NOT APPLICABLE FOR TUBULAR AHs.

$SO_2 + O_2 = SO_3\, SO_3 + H_2O = H_2SO_4$

FIGURE III/9.2.2-1 SCAPH cold end temperature control.

No-Load Starting of High Tension (HT) Motors
Big fans, pumps, and mills in general are driven by HT motors (e.g., 3.3/6.6/11 kIV). Now if these motors start, with full load starting, inrush current is very high, i.e., ~5–6 times the full-load current, to avoid such high inrush current. If permitted, it is customary to start these drives under a no-load condition by closing the inlet/outlet damper/valves as applicable. This kind of starting is called no-load starting. However, in certain cases, say for 2 X 100 %BFP, HT drive may have to start in full load. In case one running BFP trips and fails to run, another BFP needs to start in full load to avoid starvation of the boiler.

FIGURE III/9.2.3.6-1 HT motor starting—no load.

9. After the AH flue gas passes through an ESP, whose main function is to eliminate dust from the flue gas before it is discharged to the atmosphere through the chimney by an ID fan. In the past, mechanical dust collectors were used, now ESPs are used for better efficiency. Since these are placed after AHs, all ESPs are cold ESPs.
10. Finally the ID fan takes out the flue gas through the chimney. Today burners are low NO_X designs deployed to reduce NO_X emission. In some designs there are OFA dampers at the wind box to help reduce NO_X emission. Also SCR is another way to reduce NO_X emission. Where coal has a high sulfur content, flue gas desulfurization (FGD) plants are installed. These are detailed subsequently.
11. There will be inlet and outlet isolation dampers for ID fans, which are also used for no-load starting of the fan, similar to that discussed in the next clause.

9.2.2 System Description: SA System

Below is a description of the SA system:

1. SA (CA) to the boiler is supplied by FD fan(s). There may be inlet cones at the suction of these fans, which are nothing but restrictions in the system and could be used as a flow element to measure the total SA (CA) through each fan. The flow through each of the FD fans can be regulated or modulated by (aerofoiled) an impeller or inlet damper (see Figure III/9.2-6b). These regulations are related to the total air control of the boiler. As discussed in Clause 9.2.1. for NO_X control, the FGR line may be connected here.
2. There is also one discharge damper for each FD fan, for isolation purposes. For no-load starting of large, high-voltage (HV) motors for fans (e.g., FD/ID/PA fans), isolating damper(s) are kept close (ref Figure III/9.2.3.6-1).
3. Whenever atmospheric temperature is low and/or it contains more moisture, then it is customary to heat up the air prior to its entry to the AH. This is mainly applicable for Ljungstrom rotary AHs. This preheating is done at the SCAPH (see Figure III/9.2.2-1). This is a coil type heater, where through coil Aux. steam is passed to heat up the air outside. SCAPH has inlet, outlet, and bypass dampers to isolate the system as well as to bypass the system. Same type of SCAPH is utilized in both SA & PA (Cold PA system) system.
4. After the FD fan SA goes to the AH either through SCAPH or directly. There are two types of AH: tubular and rotary. In the AH air is heated up with the help of flue gas coming out from the economizer. In the SA side the AH also has inlet/outlet isolation dampers.

www.EngineeringBooksPDF.com

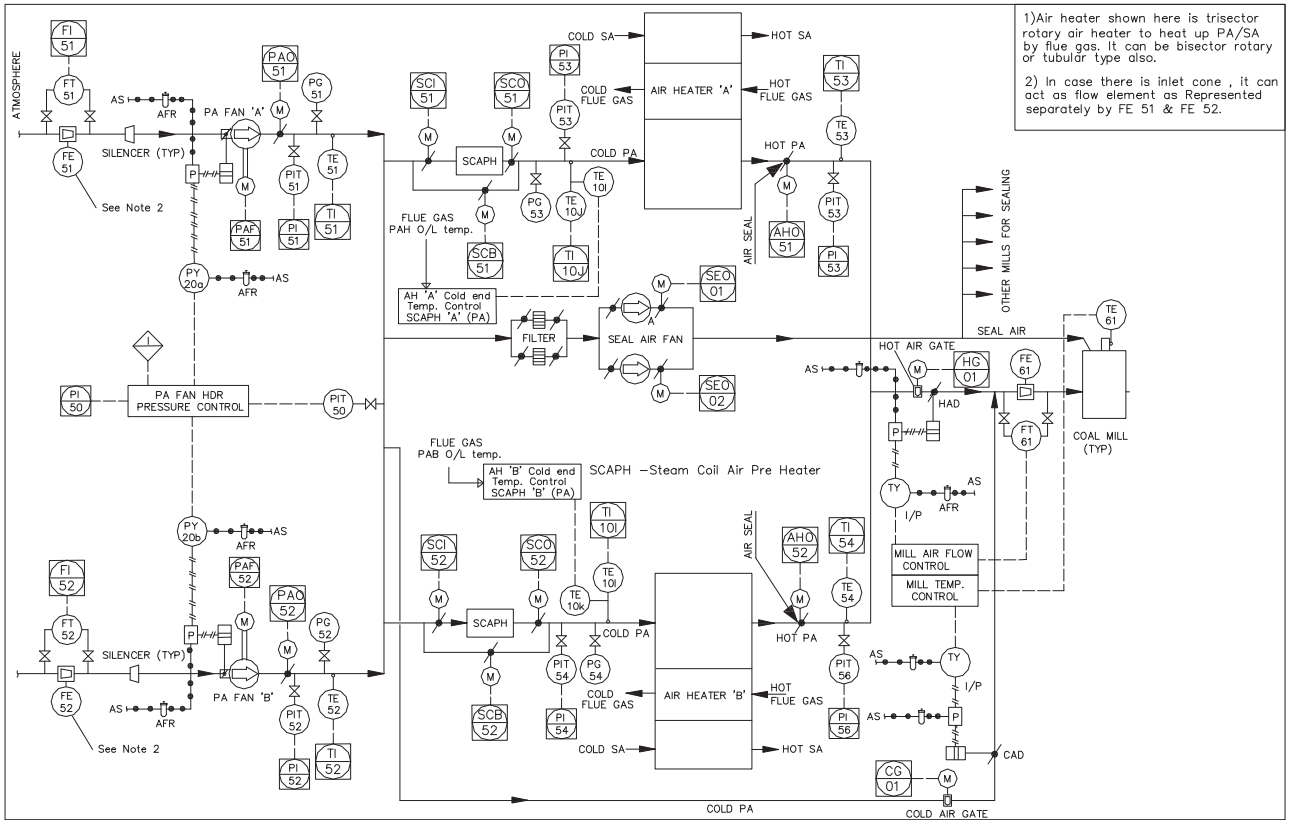


FIGURE III/9.2-4 Primary(combustion air) P&ID.

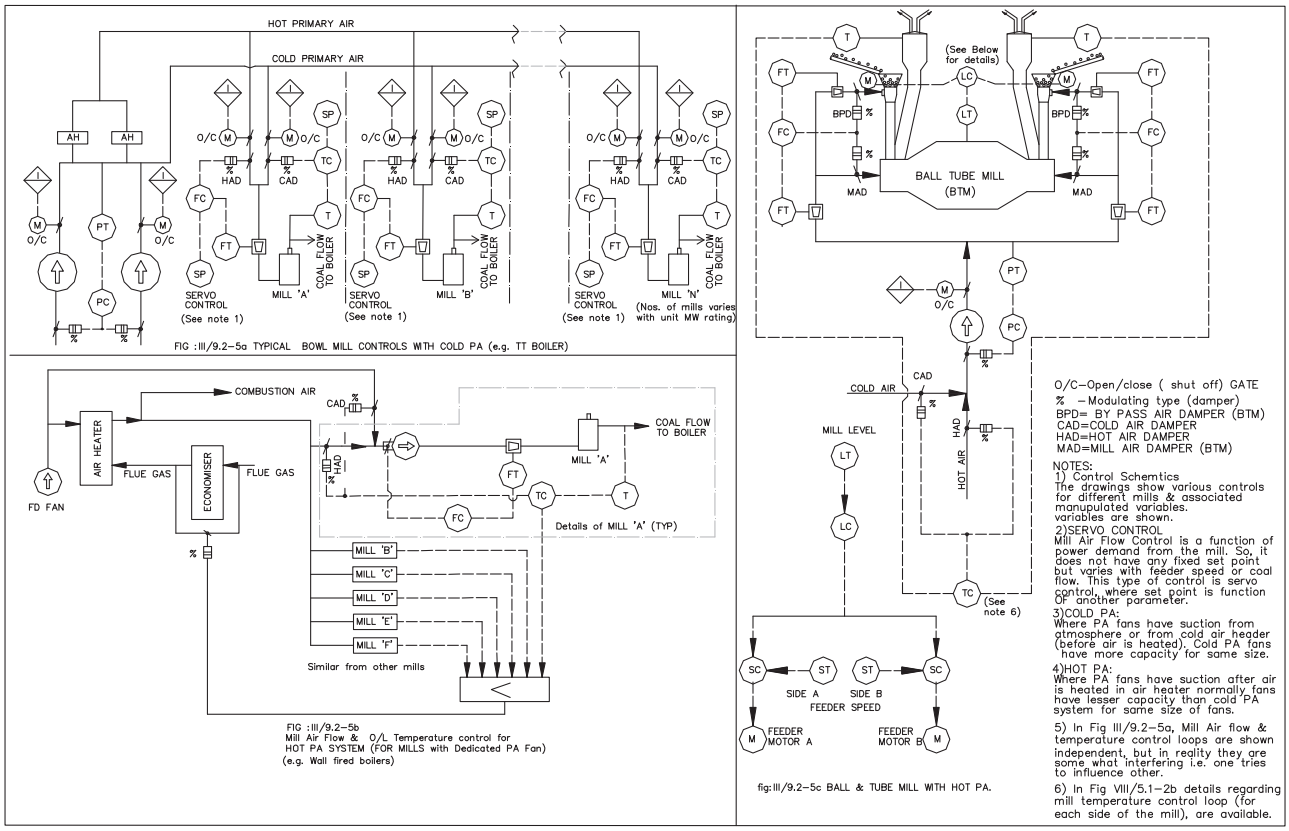


FIGURE III/9.2-5 Mill air flow.

www.EngineeringBooksPDF.com

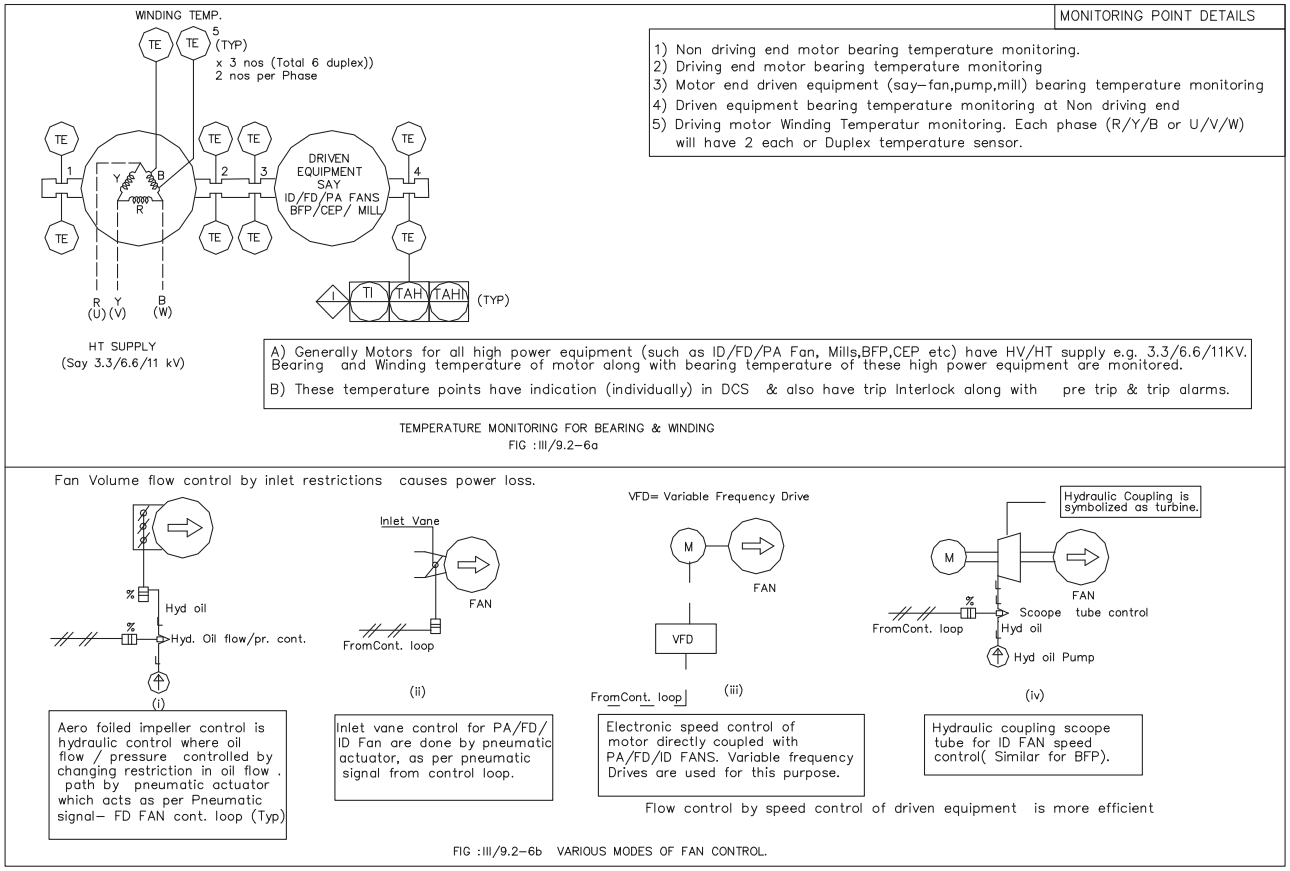


FIGURE III/9.2-6 Various temperature monitoring and types of controls for fans.

5. After the AH, the SA goes straight to the wind box/air register, where there are a number of dampers meant to distribute air to various burners, according to their operational condition and/or to OFA port. In a hot PA system, a part of the SA (both hot and cold) supplies air for the PA system, as shown in Figure III/9.2-5.

9.2.3 System Description: PA System

Reference Drawings: Figures III/9.2-3,5,6:

1. PA to the boiler is supplied by PA fan(s) to carry the pulverized coal to the boiler and perform other functions as detailed out in Clause 9.1. Like the FD fan, PA flow can be measured by inlet cone or pitot tube. PA flow control is done by modulating inlet damper (see Figures III/9.2-4 and III/9.2-6b) or fan speed. For common PA fans to all mills, PA header pressure is chosen as the control parameter to regulate the flow through each fan. See Clause 9.1 for mill total air flow and temperature control. With common PA fans, discharge from both PA fans forms a common header as shown in Figures III/9.2-4 and III/9.2-5a. From this common cold PA header, one line of cold air from each fan goes to an individual mill as cold air through CADs and other lines (to AH directly or via to AH via SCAPH) supply hot air through HADs. As hot air is mainly responsible for carrying coal to the boiler, fuel flow control loop will influence the mill air flow loop.
2. Similar discussions as detailed in Clause 9.2.2 are also applicable here for PA fans.
3. In a cold PA system after PA fan discharge, HADs and CADs are formed, as shown in Fig III/9.2-5a, to supply air to individual mills. This is normally adopted for Tangential Tilt (TT) boilers with bowl mills
4. In the hot PA system, a cold header a hot air header are formed after the FD fan discharge header. After mixing both cold and hot air, it is directed to individual PA fans as shown in Figure III/9.2-5b.

9.2.4 System Description: Scanner Air and Seal Air

1. *Scanner air system (see Figure III/9.2-3)*: The scanner air fan, with its suction from the discharge headers of FD fans, supplies scanner air to cool down the flame

www.EngineeringBooksPDF.com

scanners. Normally scanner air fans have a duplex type suction filter to ensure pure air supply. Also the DP across the filter is monitored for timely changeover of the filter. In modern designs the same air is used to cool down hot secondary air dampers. Each of the scanner air fans has a motor-operated outlet damper with an interlock with burner management system (BMS). In the absence of scanner air, the boiler may be tripped. To ensure proper continuous scanner air supply, DP between the scanner air and furnace is monitored.

2. *Seal air system (see Figure III/9.2-4)*: The basic function of seal air is to seal the dust from the mills and associated devices at various positions. The seal air fan normally takes its suction from the cold PA header in a cold PA system. The hot PA system takes its suction from the discharge headers of FD fans. Normally it has a duplex type suction filter to ensure pure air supply. Also the DP across the filter is monitored for timely changeover of the filter. Each of the seal air fans has a motor-operated outlet damper with interlock to trip the mill in the absence of seal air. To ensure continuous air supply DP across the seal air fan is monitored (see Figure III/9.2-5).

9.2.5 System Description: Monitoring and Controls

Discussions in this clause in connection with large fans and associated drives (motors) are equally applicable for all large equipment (although not discussed separately in respective sections) such as mills, BFPs, and CW pumps.

1. In the most medium to large power plants the power consumed by equipment, such as ID, FD, PA, and Mills (also BFP), is high, so motors to drive this equipment have high tension(HT)/HV supplies to limit the current (see Figure III/9.2.3.6-1). This heavy equipment needs to be monitored for bearing and winding temperature (of motors) by RTD (rarely by T/C) as shown in Figure III/9.2-6a, to ensure protection and smooth operation of the heavy equipment. Similarly, temperatures at each of the three phases of the motor windings are monitored by duplex (or two) RTDs. Generally 0−150°C is the standard range. All the RTDs are connected to the DCS for generation of pre-trip alarm as well as trip whenever the temperature exceeds the set point. This ensures the bearing is not damaged due imbalance and/or motor over load. It is worth noting that these are *in addition* to the current monitoring in each phase. Also all of these fan speeds are also monitored. It is a common practice also to monitor bearing vibration of these fans.
2. In Figure III/9.2-6b, various modes of control of fans are depicted.
   a. In some fans (PA and ID), flow control is regulated by adjustment of the inlet vane as discussed below (see Chapter VI, Clause 3.2 for a detailed discussion).
   b. In some fans there are aerofoiled impellers that are regulated to regulate the air flow to the fan. Because of a heavy design, these impellers are regulated by hydraulic actuators. The pressure and flow to the hydraulic actuators are controlled by controlling the opening/restriction in the hydraulic line. This opening control is done by pneumatic actuator, which in turn is connected to the main control loop (see Chapter VI, Clause 3.3 for a detailed discussion).
   c. Speed control of the fans (Pumps, i.e., BFPs) is another way to regulate flow through each of these fans. These speed controls can be either direct speed control (VFD) of the fan motor electronically (see Chapter VI, Clause 3.4.2) or indirectly by a reliable method using a hydraulic coupling scoop tube (see Chapter VI, Clause 3.4.1). It may be argued that the coupling fill can be varied by means of scoop tube (see Clause 6.2.4 in this chapter).

9.3 Major System Equipment: Air and Flue Gas Path

Major system equipment (for further details of selected items, see Chapter II, Clauses 2.1 and 2.2) in the air and flue gas path is discussed below:

1. *Combustion chamber*: This is where the actual combination of oxygen with combustibles take place. In fuel H_2, C, and S are major combustibles, out of which S is negligible compared to other two. At this chamber following reaction in the simplest form takes place with a generation of huge heat: $C + O_2 = CO_2 +$ Heat; $2H_2 + O_2 = 2H_2O +$ Heat. The furnace chamber size depends on the 3Ts: temperature, turbulence, and time. Hence, these vary with system design. Furnace chamber walls are water cooled for reduced maintenance as well as to reduce gas temperature entering the convection zone, so all walls are generally designed with drainable and weldable panels. The two major firing systems are horizontal and tangential.
   a. *Horizontal/wall firing*: Here coal and PA are introduced tangentially into the coal nozzle and fuel is mixed with CA in the air register individually. In front firing burners are located in a row horizontally on the front wall, whereas in opposed firing, burners are located in a row horizontally both at the front and rear wall of the furnace.
   b. *Tangential firing (Corner firing)*: When pulverized fuel and PA are sent to the furnace from four corner (tangential to an imaginary circle) in a horizontal

www.EngineeringBooksPDF.com

plane, there is huge turbulence take place and intensive mixing occur. In this mode the burners can be tilted WRT horizontal plane. Here secondary air dampers is away from burners, and mix up with combustion air take place in chamber. These tangential burners thus form a fire ball and when these burners tilt the fire ball moves up and down (cause change in heating effect)

2. *SH and RH*:
   a. *SH*: In this, saturated steam gains heat to become superheated. There is some thermal design change between horizontal firing (HF) and TT design, so generalized discussions are included here. With a TT boiler, a large part of heat transfer in SHs is through radiation, whereas for horizontal wall firing, heat transfer is by convection. Hence, steam leaving the SH outlet increases with output of the boiler. Again, in this type of design it has been found that radiant superheat, as a function of load, naturally drops. As a result, overall change in SH outlet temperature is a bit steady but, with load, naturally increases. For this reason, attemperation flow in this type of boiler increases little with load, whereas in a TT boiler attemperation water flow at higher load is minimal. After leaving the furnace chamber, the flue gas first comes across the radiant SH, where major heat is transferred in radiation mode. With the TT boiler the final SH is the vertical, pendant platen type above the furnace. For wall-firing boilers, the final SH is a convection type. The primary SH in both cases is a convection type, which may be located at the vertical pass on the rear side. In the second pass there is a horizontal primary SH. SHs overall absorb about 25% of the heat to raise the temperature from as low as 350−540°C.
   b. *RH*: The RH is in radiant zone of a TT boiler. Reheat steam enters the RH radiant wall inlet header and finally travels into the reheat pendant. In the TT boiler, RHs are mostly the vertical type but horizontal RHs can also be found. In case of a wall HF boiler, the low temperature RH may be located in the second pass in horizontal mode. Heat absorption is ∼20% to raise the temperature from as low 270 to 540°C. Reheat temperature in case of HF firing is controlled by gas damper regulation (gas sharing between SH and RH). For TT boilers this is affected by burner tilt controls. However, in both systems there is a provision for emergency spray at the RH inlet. Reheat steam temperature can also be controlled by gas recirculation (as discussed in Clause 9.2.1).
3. *Economizer*: To improve boiler efficiency by extracting heat from the flue gas after SH, the economizer is deployed. Exact location of the economizer depends on overall boiler design, but it is generally located ahead of the AH in the pass where the horizontal SHs are located. Designed for water and flue gas in counter flow (gas flowing downward across the tube) at temperatures appreciably lower than saturation temperature to prevent steaming in economizer flow from bottom to top.
4. *AH*: This has two functions: cooling the flue gas temperature before discharging to the atmosphere and raising the air temperature of incoming CA and PA (so that coal is dried and transportation of pulverized fuel is possible—in the case of lignite this becomes the primary function). Two principal AHs in used: tubular recuperative type and regenerative, rotary Ljungstrom type. In the former air flow horizontally across tube and gas flows vertically. In the Ljungstrom AH sensible heat in the flue gas is transferred to air through a regenerative heat transfer surface (which turns continuously through gas and air) of the rotor, which is turned by a motor at a speed of 1−3 rpm. Here the gas flows upward and air flows downward (see Chapter II). Between the two types of heaters, both heat transfer and leakage occur more in the regenerative heater. The regenerative air heater could by a bisector (like the tubular type is handling flue gas with either SA or PA) or a trisector type (where flue gas and both PA and SA are handled in one AH). AH cold end temperature control in the Ljungstrom air heater is very important.
5. *Gas recirculation fan*: This draws flue gas from the economizer/AH outlet to recirculate it to the furnace near the vicinity of the burning zone/furnace hopper (when considered for temperature control) or to the air circuit (when used for NO_X control). The duty of the fan is severe because of high dust quantity as well as temperature fluctuation.
6. *SCR*: This converts NO_X with the help of catalyst into N_2 and water. Aqueous ammonia, urea, etc., are added to the flue gas stream to remove NO_X. It is located after the economizer.
7. *Dust removal: mechanical dust collector*: In this method, dust particulates from the flue gas path are removed by centrifugal, inertial, and gravitational forces. Details for this are available in Chapter II.
8. *ESP*: For details see Chapter II. To collect the dust particles, carrier gas is ionized by high-electric field discharge electrodes and collector electrodes. The gas is passed between the electrodes. The gas ions in turn charge the dust particles to be collected at the collecting electrodes. The dust is collected at the hopper below by rapping the electrodes.
9. *ID fan*: ID fan exhaust is the combustion product from the boiler. In creating the exhaust, the fans create a slight negative pressure in the furnace of ∼5−12

www.EngineeringBooksPDF.com

mm wcl. This suction pressure is called "balanced draft." ID fans are generally located downstream the particulate removal system (dust collector/ESP) and are meant for clean service. For ID fan selection due consideration is given to the higher wear resistance due to dust burden, corrosive ash particles, and high temperatures it has to handle. In FGD plants associated with a flue gas system, the ID fan acts as booster fan. Capacity control of ID fans is done generally by inlet vane control (sometimes as coarse control in larger capacity fans) or speed control (sometimes as fine control in larger capacity fans where both the controls are deployed). Speed control in turn is done by hydraulic coupling/VFD—electronic control. Speed controls are always smoother and provide better performance.

10. *FGD plant*: FGDs are installed to reduce the level of SO_2 in the flue gas discharged to the atmosphere. Limestone scrubbing (see Chapter II) is a catalytic chemical process for removal of SO_2, and is the most common method used in FGD plants. In this system sulfur compounds combine with lime (CaO) or limestone ($CaCO_3$) to form slurry.
11. *FD fan*: Air necessary for combustion in the furnace is supplied with the help of FD fans. Normally these are sized for the stoichiometric air plus excess air. If a hot PA system is in use, the fan size should be greater to handle the PA also. Radial aerofoil (centrifugal) fans with impeller control or axial fans with pitch controls are used. Inlet silencer and screen are used for noise and protection of the fan.
12. *SCAPH*: To raise the cold end temperature to prevent acid due formation, SCAPH is used to heat up air (both SA and PA) before it enters the regenerative AH. This is used during start-up, low-load operation, and with low ambient temperature (or highly humid). This is located between the FD/PA fan and AH, and supplied with steam from auxiliary steam. The pressure loss is nominal at ~25 mm wcl.
13. *Wind box*: In corner-fired boilers, pulverized coal is delivered to a row of fuel nozzles in four corners arranged at different levels (one each corresponds to each pulverizer or section of pulverizer for a tube mill). There are a number of SA dampers in each corner in each elevation. These include an auxiliary air damper and fuel air damper and are regulated according Secondary Air Damper Control (SADC) for distribution of SA at various elevations. In case of wall fire boilers, air register serves the purpose of the wind box in distributing SA.
14. *Scanner air fan*: This is a low-voltage fan meant to cool flame scanners and burners. It takes the suction from the cold SA duct.
15. *PA fan*: These are large, high-pressure fans meant to dry and transport coal from pulverizers to the furnace. Located before the AH (before SCAPH also wherever applicable), it draws cold PA from the atmosphere. If a hot PA system is used, the PA has to handle hot air. Inlet vane control is used to control the volume through a PA fan. Inlet silencer and screen are used for noise and protection of the fan.
16. *Seal air fan*: This is a low-voltage fan meant to seal pulverizers and associated equipment. It takes its suction from the cold PA header.

9.4 Major Parameter Measuring Monitoring in Air and Flue Gas

9.4.1 Process Parameter: Air and Flue Gas (Typical Value)

See Table III/9.4.1-1a for flue gas parameters and Table III/9.4.1b for air parameters.

9.4.2 Monitoring of Process Parameter: Air and Flue Gas System

Air and flue gas parameters are immensely important as they are directly related with the firing system and with boiler performance. Major details are of this system include the following:

1. *Furnace/combustion chamber*:
   a. Combustion at the furnace best occurs when it is maintained at a particular point slightly negative (generally never positive, because then hot gas

TABLE III/9.4.1-1a Flue Gas Parameter

Location	Pressure (mm wcl)	Temperature (°C)	Remarks
Furnace	(−)5	1200	
Platen SH	(−)6	1150	
RH	(−)13	800	
Primary SH	(−)33	558	
Economizer	(−)55	338	
AH	(−)188	125	O_2 may be ~5% and CO 100 ppm
ESP	(−)215	125	
ID Fan	150*	120	*At full load condition pressure may drop to ~40–50 mm wcl

www.EngineeringBooksPDF.com

TABLE III/9.4.1-1b Air Parameter

Location	Pressure	Temperature	Remarks
FD fan discharge	174	Ambient	
SA at AH O/L	100	320	
SA at wind box	75	318	
PA fan discharge	850	Ambient	
PA at AH O/L	798	319	
Mixed PA at mill	675	270	~90 T/h flow

These are typical values and instrument span/ranges are for estimation only. We have not mentioned any volume for flue gas here, as it is highly dependent on fuel type, quality, burner configuration, and operating point. PAFdischarge Temp. is for Cold PA system.

comes out of the inspection window). Furnace pressure is a control parameter to regulate the volume flow through the ID fan. It is customary to have one *in situ* pressure gauge near the operating floor. Pressure transmitters deployed are the draft transmitter type. To facilitate better sensitivity, generally transmitters with narrow range are used for control purposes, whereas the transmitters with a wide range (covering very high and very low trip set points) are used for monitoring purposes. Typical range: wide range ±250 mm wcl (tolerance ±10−15 mm wcl,; narrow range ±25 mm wcl. It is customary to have additional dedicated pressure switches for alarms and interlock or trip for furnace pressure. Similarly it has been seen that wide and narrow band dedicated recorders (in addition to the DCS recorder) are installed. In smaller plants such rigorous monitoring may not be possible from a cost perspective.

b. Furnace to wind box and furnace scanner air DPs, are monitored by a DPT as well as by a DP switch (especially for medium/large utility stations). Typical ranges for these are 0−100 and 100−120 mm wcl and 0−450 mm wcl, respectively. Furnace to wind box DP measurement is also very important, especially for corner-fired boilers (see Clause 9.5.2).

c. Temperature in the combustion chamber in some boilers is measured with the help of a retractable temperature probe (ISA type S). This probe is motor operated so it can be put in service during measurement only and would be taken outside with the help of a motor after measurement is over. The temperature span is 0−1500°C for medium/large power plants.

2. *SH, RH, and economizer*: Inlet and outlet temperatures for each platen, final and primary SH, RH(s), and economizer is common. For these, ISA type K T/C, with or without transmitters, are utilized for this purpose. A platen SH (flue gas just outside the combustion chamber) ISA type R or S type T/Cs is preferred. For mid-sized to large plants, the temperature range can be 0−1200°C in the platen and final SH zone, whereas a temperature range of 0−700/500°C would suffice for temperature measurement in a low-temperature SH, economizer, etc. In smaller plants the range may be even less. The DP across each of the heaters may be monitored. If DP is getting high (as per design set point), it will alert the operator to start SB (provided other conditions are okay). In many plants, instead of measuring the DP, I/L and O/L pressure for each of these heaters are measured for the same purpose.

3. *AH (flue gas)*: This is used to transfer heat from flue gas to PA and/or SA. To check how much heat is transferred, inlet and outlet flue gas temperature are measured; 0−400 and 0−200°C are the ranges for I/L and O/L, respectively. ISA type K is quite linear in this range and less sensitive to vibration and other external disturbance, so it is preferred that ISA type K (T/Cs) are used for this parameter. Also, in this measurement averaging of temperature sensors may be required and it is easier to average with T/Cs than with RTDs. AH outlet pressure is monitored by a smart transmitter with a selected span from 0 to (−)200/250 mm wcl. Measurement of O_2 is common at the AH inlet and outlet to compare and monitor air leakage. This is especially so for the rotary AH where leakage is comparatively higher. AH inlet O_2 analyzers are generally the zirconia probe type for better time response (as this signal may be taken to oxygen trim control) and 0−10% by volume is the standard selected range. Carbon monoxide is also measured at the AH inlet for finer control of the air flow loop, and 0−200 ppm the selected range.

4. *ID fan*: Pressure and temperature measurement at the inlet and outlet of the ID fan is common. Pressure ranges at inlet and outlet pressure transmitters are chosen depending on ID fan sizing. Temperatures ranging from 0 to 150 are considered, and an RTD (Pt100 at 0°C) is deployed. At the outlet of the ID fan, NO_X and SO_2 are monitored in many plants. These, along with particulates, are required to be monitored as per Pollution Control Board requirements for medium and large power plants. Speed control of the ID fan is done by hydraulic coupling scoop tube or by VFD. Sometimes inlet vanes are also regulated as course control. Vane control usually means power loss.

5. *ID/FD/PA fan monitoring and control*: See Clause 9.2.5.

www.EngineeringBooksPDF.com

6. *FD fan/PA fan*: At the inlet of FD/PA fans, in some cases there are inlet cones to create negative suction. With the help of the inlet cone, FD/PA fan flow can be measured. DPT and compensating temperature elements, such as an RTD (at inlet for temperature compensation), are used for this purpose. At the discharge header, pressure is measured by a local pressure gauge as well as by pressure transmitter. Range is difficult to specify, as it depends on fan capacity head, etc. At the discharge the temperature is also measured by RTD. FD fan throughputs are regulated by impeller/damper pitch control, whereas the inlet vane may be regulated to control the air flow through the PA fan.
7. *SCAPH and AH*: At SCAPH outlet or AH inlet temperature measurement in SA/PA lines are important ,as these are used for low-temperature control of the AH. For this an ISA type K T/C (Clause 9.4.2) may be used. The pressure loss through SCPH is low, so it is monitored by a smart transmitter (span of ~0−200 mm wcl). At the outlet of AH, pressure and temperature are monitored with the help of an ISA K T/C or RTD and smart transmitter (span of ~0−200 mm wcl), respectively.
8. *Wind box (SA flow)*: From AH, SA goes to the wind box to be distributed properly at different elevations before entering the boiler. (In a horizontal firing boiler air distribution is done through the air register.) Air flow at this point is done to compute total SA flow to the boiler. Aerofoil (a special restriction) or pitot (/piccolo) tube as a flow element may be deployed. The measurement is a head type, smart DP of a suitable range is deployed (as per flow requirement). For corner-fire boilers furnace to wind box DP (transmitter) is very important. As with this parameter, auxiliary air at various elevations (double-lettered elevations) are controlled. A typical TT boiler, burner arrangement is shown in Figure III/9.2-2. Normally all double-lettered elevations have an auxiliary air damper that is modulated as per the furnace wind box DP. Fuel air damper at single-lettered elevations is modulated as per fuel flow (e.g., feeder speed). At double-lettered elevations, where there is HFO and/or LDO (lower level) burners, the control is little different. Normally these elevations' air dampers will be operated as per wind box to furnace DP, yet whenever burners in these elevations are firing then only these dampers will be regulated proportionally as per fuel firing in the elevation.
9. *PA before mills*: PA fan discharge header pressure is monitored by smart transmitters, and this parameter also is a control parameter for PA fan flow control, as discussed earlier. The total PA flow to each mill (hot + cold) is measured with the help of a flow element and smart DPT (or by PA fan DP and then characterization). Flow is duly compensated for temperature. In each of the cold and hot PAs, line pressures and temperature are measured, respectively, by smart transmitters and RTDs.
10. *Scanner air and seal air fan*: Measurement of discharge pressure of these fans is done. Also, scanner air to wind box and seal air to mill DP are monitored by smart DPTs to ensure proper flow.

9.5 Controls in the Air and Flue Gas System

9.5.1 Controls in Flue Gas Systems

There are a number of vital controls in the air and flue gas system (see Figures III/9.2-1 to III/9.2-5).

1. *Furnace pressure control*: Furnace pressure is vital from both an operational and firing point of view. For this purpose the pressure inside the furnace is measured and compared with the set point to regulate the flue gas flow through the ID fan (by speed/vane control). Air flow sometimes is taken as a feed forward signal. Apart from modulating control of the furnace pressure, it also acts as a protection parameter for boiler tripping (for very high/low).
2. *Flue gas O_2 and CO*: Flue gases O_2 and CO are involved in total air flow control to the boiler and for optimizing air flow control (oxygen trimming) to the boiler.
3. *AH outlet temperature*: Flue gas temperature at the AH outlet is measured for low temperature control of the AH.
4. SB: Apart from these controls, the DP across each of the heaters may be considered as the initiating signal for SB control.

9.5.2 Controls in Air Systems

1. *Air flow control*: The total SA flow measured at the wind box and/or at the inlet cone (duly compensated for temperature) is used to regulate total air flow for combustion by regulating impeller control/blade pitch of FD fans. For the purpose of air flow control, flue gas quality (for O_2 trimming) is also monitored as discussed in Clause 9.5.1.
2. *SCAPH steam control*: To maintain temperature of the low-temperature end of the AH (where flue leaves and air enters) at a specified value, steam supply to the SCAPH is regulated by measuring both air and flue gas temperature at the cold end. In bigger plants it has been found that to get representative temperatures a number of temperature elements are put in the flue gas and air duct and the average of these signals is taken for control purposes. Averaging is easier with T/Cs, so an ISA type K T/C can be a better option.

www.EngineeringBooksPDF.com

3. *SADC control*: There are a number of control dampers at the wind box, involved to distribute the total SA at various elevations. For corner-fire boilers furnace to wind box DPT is essential to regulate auxiliary air dampers at various elevations (double-lettered elevations). See Figure III/9.2-2 and discussions in Clause 9.2.4 for details.
4. *PA header control*: The discharge header of PA fans is maintained at a fixed value, and this involves regulation of the PA fan inlet vane.
5. *Mill outlet temperature control*: This is done by regulating (except where there is a dedicated PA fan for each mill where both HAD and CAD are used) the CAD control. In cases of wall-fired boilers, the economizer bypass damper control is deployed for this purpose. For tube mills with a hot PA system, individual sides of the mill outlet temperature are not controlled normally; instead the mill outlet temperature from both sides is used to control O/L temperature (see Figure VIII/5.1-2b).
6. *Mill air flow*: In accordance with the fuel demand the air flow to the mill is regulated by regulating the HAD. (If there is a dedicated PA fan for each mill the vane control of the fan does the same function.) In SC/USC boilers this control is connected with feed flow and feed flow control. With tube mills the situation is a little different (see Figure VIII/4.4-4).

9.6 Redundancy in Measurement: Heater Drain System

1. Two of three redundancy in measurement of the following parameters is common:
   - Furnace pressure (sometimes redundancy is on each side)
   - Air flow
   - Oxygen (trim control) in flue gas
2. One of two redundancy in the following measurement points involved in control loops:
   - PA header pressure
   - PA flow to mill
   - Mill outlet temperature
   - SADC—Wind Box—Furnace DP.
3. These redundancies in measurement are a function of investment, so all such redundancies may not be applicable for smaller plants.

9.7 Miscellaneous Points: Air and Flue Gas System

Air and flue gas system measurements and control are related to boiler system, so these parameters are monitored at the boiler monitor normally kept on the left side of the operator facing the panel/monitor. In conventional/back-up panels, generally these instruments form the leftmost panel.

Below are listed a few points regarding the pulverizer instrumentation:

1. Like other HT-driven fans in pulverizers, the bearing and winding (of motor) temperatures are also monitored by RTDs similar to the discussions in Clause 9.2.5. In Mills there are many bearings, such as upper and lower radial bearing, radial and thrust worm bearing, lower thrust bearing, etc.
2. Measurement of mill DP is also very important to monitor the mill jamming and flow through the mill. For tube mills, DP across the mill is measured for mill level (also the mill level is measured by a sound system). This mill level in the tube mill is a control parameter used to regulate the coal feeder speed. The tube mill coal feeder is not regulated directly as per fuel demand (as is done in Raymond, ball mill); instead air flow through the mill is regulated as per fuel demand. The tube mill maintains a good amount of pulverized coal storage in the form of mill level, which is maintained by feeder speed. As a result of this, mill can run for some time after feeder is tripped.
3. Mill is normally interlocked with the boiler operation through Burner Management System (BMS)/Furnace Safeguard Supervision System (FSSS). In the tube mill, for each side of the mill, there two types of air that go into the mill: one is Air flow through the mill and another is bypass air flow. Bypass air flow has two distinct functions viz. to increase velocity at lower load, and pre heat coal from conveyor. For this reason, Bypass air flow going to the coal feeding pipe, has some higher value initially, but with increase in load as the air flow through the mill increases, Bypass air flow decreases. With tube mills the damper position of air flow through the mill acts as coal flows to the boiler (similar to feeder speed in other mills where there is hardly any storage). For the corner-fired boiler, normally each mill (each side of tube mill) corresponds to one elevation (between two elevations with auxiliary air/fuel oil air damper) and caters to four burners located at the corner of that elevation. In the case of the horizontal fire boiler, depending on design, each mill caters to a few burners in the same elevation. As already discussed, coal flow is a function of PA flow through the mill. In case of SC/USC boilers, coal feed to the boiler is also influenced by feed flow. Therefore these two loops, i.e., fuel flow and feed flow, cannot be seen in isolation. This is because in SC/USC boilers, steam temperature depends on the ratio fuel flow to feed flow.

10. COGENERATION P&ID

This clause discusses the gas turbine (GT) Heat Recovery Steam Generator (HRSG).

www.EngineeringBooksPDF.com

10.0 Cogeneration/Combined Cycle Plants

Cogeneration (Co Gen)and Combined Cycle (CC) plants have one thing in common: electricity is generated with the help of hot flue gas, i.e., generation of electricity with the help of a GT. In a Co Gen plant, in addition to electric power generated by the GT, the exhaust flue gas (from the GT) heat may be utilized to produce steam, with help of HRSG, for other industrial purposes. In combined cycle (CC) plants, in addition electricity generation by GT, the exhaust gas from the GT has sufficient heat (and/or with supplementary firing) to use as a source of heat in the HRSG to generate steam to be used in the steam turbine for electricity generation. A few underlining advantages of a combined cycle are as follows:

A. With integration of an environmentally clean gasification plant (discussed in Appendix VI), it is a low-cost installation needing less time to install.
B. Greater fuel flexibility, coupled with higher thermal efficiency.
C. High degree of operation flexibility such as base load, daily start/stop, mid-size plant.
D. Highly reliable, available, and easy to start.
E. Comparatively more environmentally friendly.

For CC plants two basic configurations are possible:

1. Single shaft CC plant consists of one GT, one steam turbine, one generator, and one HRSG. Here the GT, steam turbine, and generators are coupled to one *single* shaft. This is simple to control and useful for base load operation. This configuration has is discussed in Clause 10.6.
2. In *multiple* shaft configurations a number of GTs and HRSGs may supply steam to one steam turbine via a common Header.

The control and operation of the GT part is most important and demands special attention for equipment-specific control. For this reason, in most of these plants, GT controls are included as a part of GT/Co Gen package [e.g., MARK V control in GE Co Gen plant] with necessary interface to balance of plant control, which may be supplied by an external agency (e.g., instrument vendor). To enhance reliability and availability, these control systems use fault tolerant Triple Modular Redundancy (TMR) redundancies. Before going into any further details, it is necessary to briefly discuss the Brayton cycle (principle on which GTs operate). Explanations are mainly based on GE GTs.

1. *Thermodynamic principles for GT operation—Brayton Cycle*: A short schematic drawing for a simple cycle GT is depicted in Figure III/10.0-1a. At ambient condition air enters the compressor at A where it is compressed to a higher pressure without heating. Because of the compression the temperature increases, so at high pressure and temperature air is discharged from the compressor to the combustion chamber at B. In the combustion chamber the fuel is also injected at constant pressure for combustion. In the combustion chamber at the primary combustion zone high temperatures are reached. The combustion chamber provides a way to mix, burn, dilute, and cool the air (a volume change occurs). Air leaves the combustion chamber at mixed average temperature to reach the turbine at C. In a GT, the energy of the hot gas is converted into mechanical work. In the nozzle section, hot gas expands, hence, heat energy is converted into kinetic energy, in subsequent sections; energy is transformed to rotate the buckets and converted to work. Out of the total mechanical output nearly 50% is utilized to drive the compressor, and the balance is available to meet the mechanical load to drive the generator to produce electricity. Starting devices are deployed for initial start-up.
2. The associated P-V and T-S diagrams are seen in Figure III/10.0-1b and c, respectively.

   Path A to B: This is the pressurization of air in the compressor with the associated rise in temperature, as shown in Figure III/10.0-1b and c.

   Path B to C: This is the combustion part where heat is added in the system at constant pressure. The P-V diagram it is a horizontal line (no change in pressure but change in volume due to combustion) while in the T-S diagram there is gain in S with associated rise in temperature.

   Path C to D: This part represents the expansion occurring in the turbine. Therefore the volume increases and pressure decreases in the P-V diagram and there is an associated fall in temperature in the T-S diagram.

   Path D to A on the Brayton Cycle: There is constant pressure cooling and the gas exhausted to atmosphere in a simple cycle.
3. As stated earlier, air enters the compressor at ambient condition, which may vary with time and place. Therefore it is necessary to have a standard condition: 1.013 bar at 15°C with 60% RH. All calculations are done on this basis.
4. Two parameters characterize the Brayton Cycle: firing temperature and pressure ratio (pressure at B and A). These should be same between C and D, but in reality they are not due to loss. Firing temperature is generally at the reference temperature at the turbine inlet as defined by ISO (Document 2314). Increase in firing temperature increases the thermal efficiency. As the pressure ratio increases the specific power output falls. The effect of these two parameters on MW output per kg/sec is seen in Figure III/10.0-1e. These also affects the efficiencies. A combined cycle (see Figure III/10.0-1d) has less pronounced effect on efficiency, compared with that of a simple cycle.

www.EngineeringBooksPDF.com

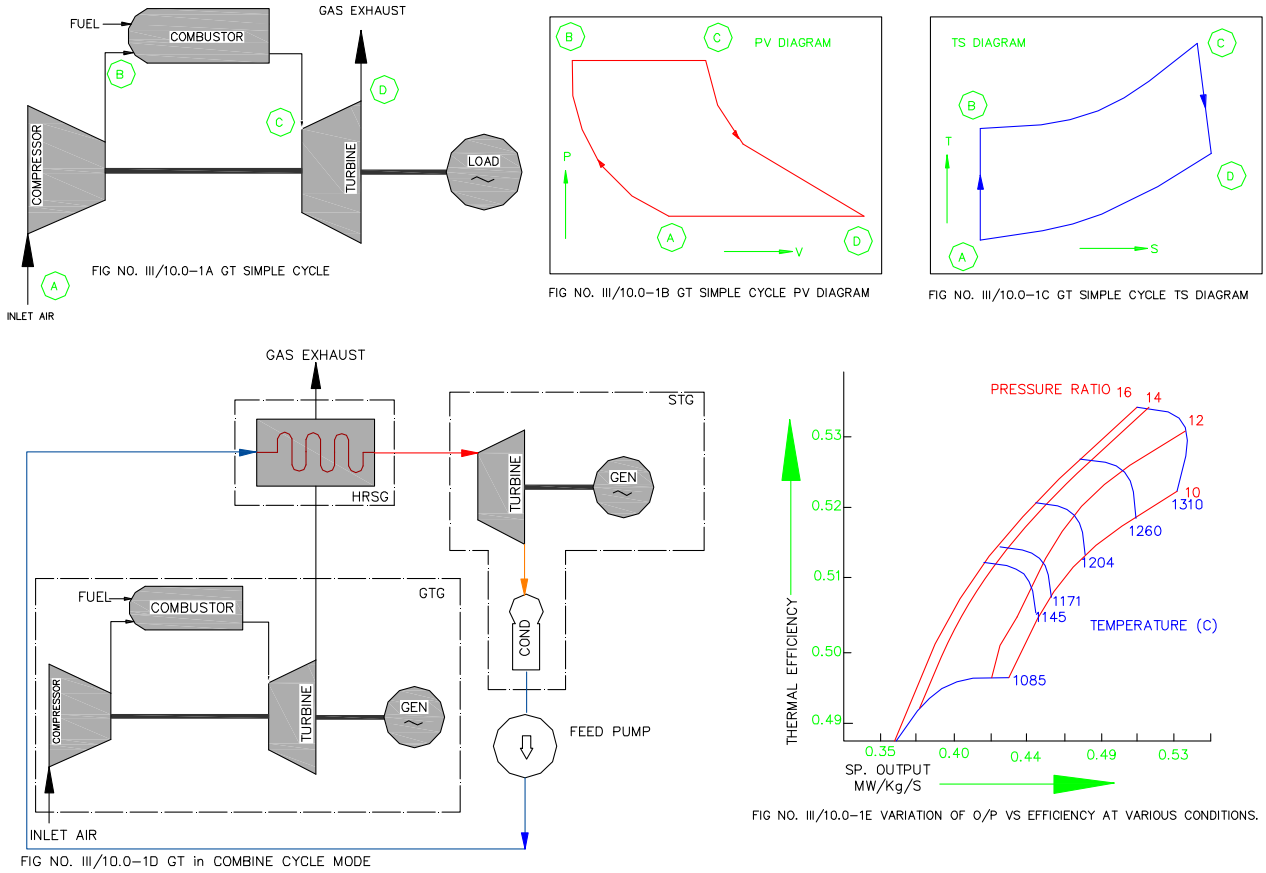


FIGURE III/10.0-1 Thermodynamics of GT in various modes of operation (based on GE document).

5. Inlet guide vane in GT controls the air to the GT to control temperature.
6. All first stage nozzles are cooled by air or steam so that the operating limit of the temperature for the materials is used and not exceeded.
7. The following factors affect GT performance:
   - Air temperature and site elevation
   - Air humidity
   - Inlet and exhaust losses
   - Fuel type
   - Fuel heating
   - Diluents injection (NO_X content)
   - Inlet cooling
   - Air extraction (Integrated Gassification and Combined Cycle–IGCC)

10.1 Objective and Function of the System

Co Gen/CC plants have distinct functions as discussed separately below:

1. *GT*:
   a. *Compressor*: Supplies air to the combustion chamber with higher pressure and temperature. This is connected to the GT shaft.
   b. *Combustion chamber*: Fuel is injected here for combustion with compressed air and supplies flue gas to GT for increased volume.
   c. *GT*: Flue gas generated at the combustion chamber undergoes expansion at the GT, and temperature is decreased by developing mechanical power to drive the shaft connected to the generator.
   d. *Exhaust gas*: From the GT in a simple cycle, with less heat, it is allowed to escape to the atmosphere through the stack. In a Co Gen/CC plant, exhaust gas is partly/or fully sent to the HRSG via a diverting damper (discussed below).
2. *HRSG*:
   a. Used to extract heat from hot flue gas from the GT to heat up water to steam and exhaust the colder flue gas to atmosphere via the chimney.
   b. Depending on the HRSG configuration, there may be supplementary firing to increase throughput of HRSG.
3. *Diverting damper*:
   a. Allows a certain quantity of hot flue gas from GT (as required) to HRSG for to be used as heat in the exhaust gas. It also allows balance gas to be exhausted to the atmosphere.

www.EngineeringBooksPDF.com

10.2 System Description

10.2.1 System Description: Simple Cycle

There are many applications for GTs, but discussion here is restricted to GTs for power generation.

1. Through the inlet guide vane GT brings the air into the compressor, which is connected to the GT proper at the shaft. The compressor and combustion chambers are responsible for supplying hot flue gas to the GT.
2. Because of gas expansion there will active mechanical power available to drive the shaft-connected generator to produce electricity. GT requires cranking power from outside during start-up through starting device, such as a diesel engine, electric motor with torque converter, and even a steam turbine. For larger plants a generator with variable power is used. GTs equipped with diesel engine starting devices are capable of staring at a black-out condition (black start). In these cases the lube oil (LO) supply is established by pump(s) operated by DC (battery) power supplies, which would also power the oil-forwarding pump during black start-up.
3. At the inlet guide vane water or steam injection is regulated to control emission and operating conditions.
4. A simple cycle with exhauster upward may not require purging, and safe lighting can be done. Whereas for Co Gen/CC plants, as a safety measure, purging is necessary. The GT is kept at purging speed until there are five to six air changes done through the combustion chamber and gas path. Typical purging time could be 1−10 minutes. When purging is complete the turbine is decelerated for ignition to start, at a specified ignition speed when ignition is reliable, with less system fatigue.
5. There are sequences to be followed for ignition and firing as per the integral control system offered by the manufacturer.
6. The starting and ignition sequence include (e.g., GE Mark V Courtesy GE WEB documents):
   a. Ignition power supply made available.
   b. Detection of flame by flame scanner opposite the ignitor used to establish completion of firing.
   c. Fuel regulated to warming up.
   d. If there is an unsuccessful firing within a specified time, the purge sequence is repeated and attempts will be made to start a second time.
   e. After a warm-up period, fuel flow is increased allowing the GT to accelerate. At about 40−50% speed the GT will be subject to a programmed rate of acceleration and speed up accordingly.
   f. From speeds at 40% to 80−85%, efficiency of GT will be high enough to become self-sustaining. At 80% speed inlet vane of the compressor may be opened to the full speed. Near running speed synchronization may be initiated.
7. The fuel flow is controlled in accordance with the speed, load, and exhaust gas temperature (capability limit). Inlet vane and injection control of water (or steam) is done to regulate emission. Ambient air temperature has a direct influence on fuel flow as well as start-up operation.
8. Generally GT is controlled by an automatic start/stop sequence, control, and protection integrated in one package (e.g., GE Mark V).
9. NO_X emission control may be accomplished by injection of steam and water into the combustor. This amount of water/steam flow is a function of ambient humidity, fuel flow, and type. Steam flow injection quantity is more than water. Another methods of NO_X control is dry low NO_X technology, where premixing of air fuel is done and combustion takes place at a desired temperature and desired air fuel ratio.
10. The cooling down sequence is another important aspect of GT. The normal cooling down sequence may last from 5 hours to 45−48 hours. However, the cooling down sequence may be interrupted at any time for restart.

10.2.2 System Description: Co Gen/CC Plant

Listed below is the system description for a Co Gen/CC plant:

1. In Figure III/10.2-1 one HRSG and one steam turbine have been added schematically. Typical measurement & control points pertinent to GT has been shown typically in Figure III/10.2-2. This would help the reader to get an idea on the same. Exhaust flue gas from GT is sent to HRSG for heat recovery and generation of steam from the FW sent to the HRSG.
2. After releasing heat at the HRSG the exhaust gas now comes out of the HRSG through the stack.
3. At the HRSG, steam is generated and used as process steam and/or sent to the steam TG. In a CC plant, this steam expands and produces mechanical power to drive the connected generator to produce electricity. In a Co Gen plant, the steam generated at HRSG is utilized for various processes as in industrial plants (e.g., alumina/steel or paper plant). It is possible to have both CC and Co Gen plants together from a set of GT(s) as detailed in Figure III/10.2-3.
4. The steam generated by HRSG can be controlled by a diverter damper as shown in Figure III/10.2-1 and III/10.2-3. Because of limitations in the HRSG, only a part of the exhaust gas may be allowed to enter the HRSG and the balance may be exhausted through the chimney. So there may be two stacks, as shown in Figure III/10.2-3.
5. The exhaust gas now leaves the GT in the range of ~500−550°C, which can be raised to 700−800°C by

www.EngineeringBooksPDF.com

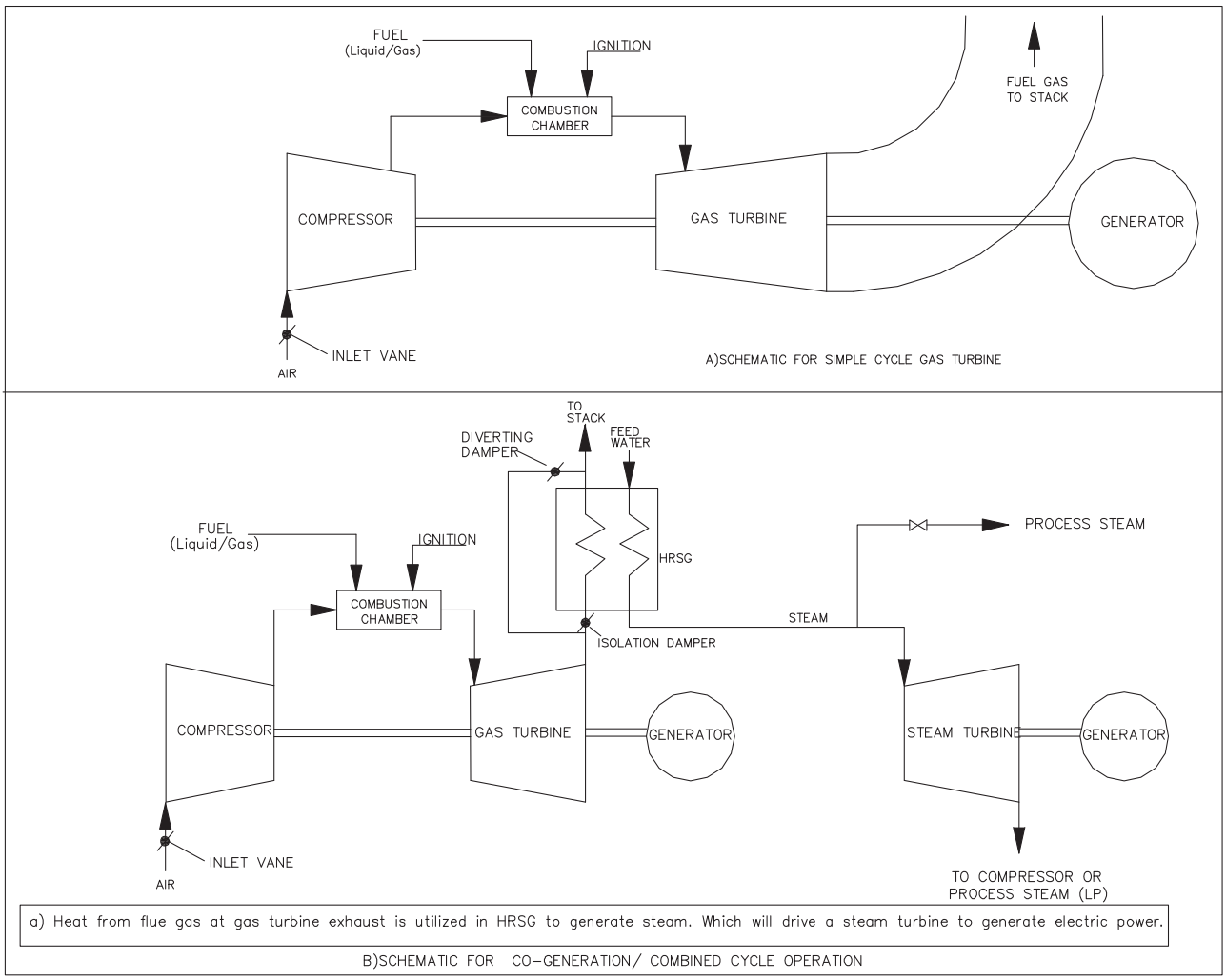


FIGURE III/10.2-1 GT in simple cycle and Co Gen (/CC).

supplementary firing, so that HP superheated steam is available. HP steam temperature can be regulated by attemperation control, as shown in Figure III/10.2-3.

6. Schematic in Figure III/10.2-3 is basically a CC plant, but a part of the steam is exported for process use like in a Co Gen plant. MP steam is sent to the LPT. This steam comes from HPT exhaust. If there is an MP/LP steam header for industrial use, then a part of the HP steam after PRDS could be sent to the MP/LP header so that even if the steam turbine does not run MP/LP steam the header will not starve. This feature already discussed in connection with Main Steam System, in this chapter. The LP header steam supply may be sent to LPT.
7. After expanding in the LPT, steam is sent to the condenser then condensate is sent to the deaerator. For the plant to perform better, condensate may be heated by the GSC and heater. At the deaerator dissolve gases are eliminated. Then the steam is sent to the HP drum by BFP as shown.
8. The hot flue gas is cooled in the HRSG to ~100–120°C, and sent to atmosphere through chimney.
9. Black start is the procedure used to recover power total/partial shut down of electric supply. This is generally provided by a smaller peripheral black-start generating plant. An open cycle GT, diesel engine, and ignition engine are generally used. For GTs a cranking power of 25–30% speed of the unfired GT is given from here. The additional power may be used for gas path purging prior to start-up/ignition necessary for Co Gen/CC plants.

10.2.3 System Description: HRSG

Listed below is a description of the HRSG system:

1. HRSG essentially recovers the heat from the exhaust of the prime mover, such as the GT in a Co Gen/CC plant.

www.EngineeringBooksPDF.com

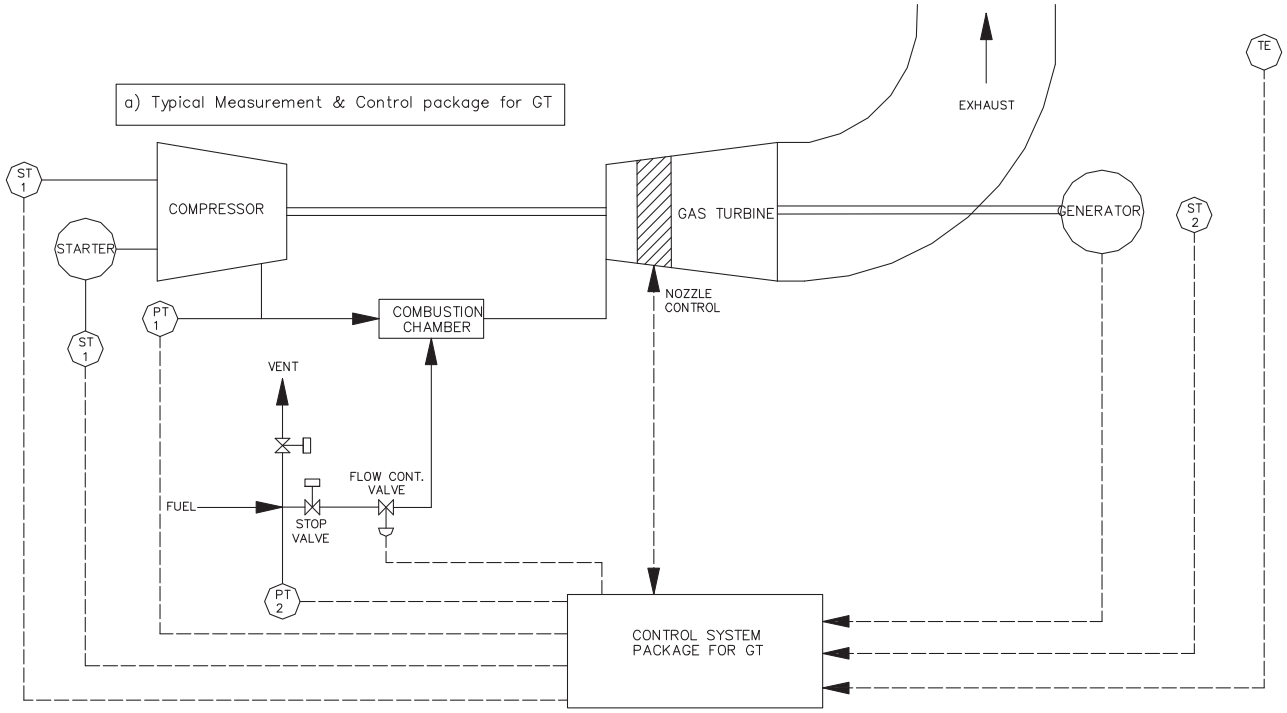


FIGURE III/10.2-2 GT measurements and controls.

2. Waste heat boilers may be horizontal/vertical shell or water tube types to produce steam (hot water also) by radiant or convection heat transfer.
3. The prime function of a waste heat boiler is to use waste gas efficiently, but many of these HRSGs have supplementary firing, which increases the heating capacity as well as efficiency.
4. Greater heat recovery is the primary object of HRSG, as the final exhaust gas temperature is kept and maintained above dew point.

10.3 GT Control System

The control system for GTs is designed to cater to all the requirements of this self-sufficient system. In order to gt an idea, Figure III/10.2-2 may be referred to. Both gas and liquid fuel are used in GT, and fuel flow is regulated in accordance with its speed and load. Temperature control (to fuel flow) limit and inlet air flow control by inlet vane are also important controls. Multistage combustion is necessary, so air fuel ratio and fuel discharge pressure controls are also important. The control system also encompasses the NO_X control system; start-up, shut down, and cooling sequences; and the interlock and protection systems. For generator synchronization, turbine speed (frequency) and voltage control are necessary like any other generator. The control system also includes the operator interface through a color graphic monitor with keyboard and printer. Some of the features found in a typical GT control system (e.g. GE Mark V) include:

- Single failure alarm
- Protection back-up
- Multiple failures to cause safe shut down
- Fault tolerant sensors and processors
- Fault tolerance both hardware and software
- System diagnostic and alarm
- Separation between control processor and communication/data processor

10.4 Major Parameter Measuring Monitoring in Co Gen Plant: GT

The parameters for the GT are very important. Listed below are a few of these parameters:

- Speed and frequency
- Exhaust temperature
- Inlet vane
- Fuel flow(gas and liquid) and pressure
- Water and steam flow
- Actuator stroke
- Vibration
- Flame (scanner)
- Fire (detector)
- Lube and control oil pressure
- LO temperature

www.EngineeringBooksPDF.com

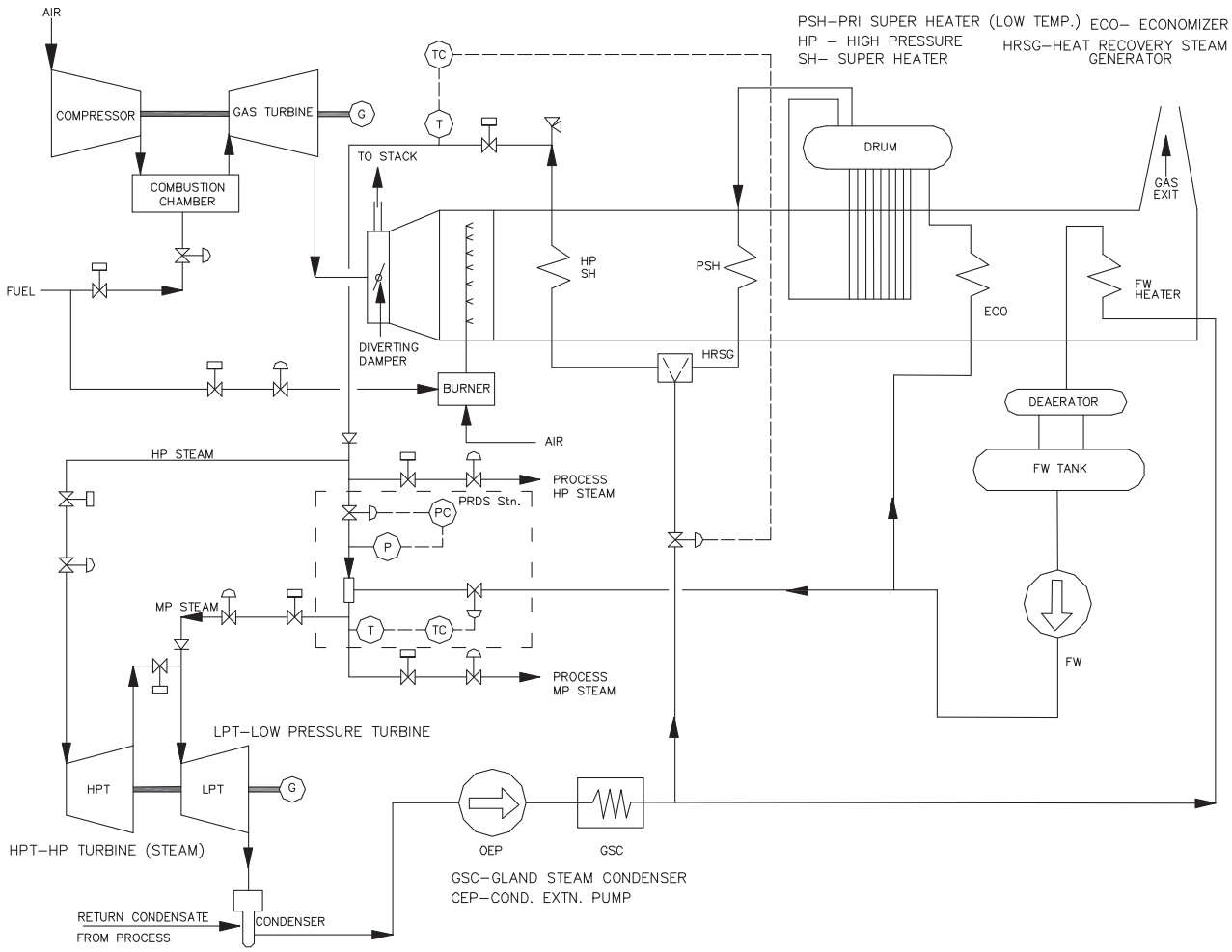


FIGURE III/10.2-3 Co Gen (/CC) typical scheme.

- DP across filter
- Nozzle output

The HRSG and steam turbo generator also have sets of parameters for monitoring and control. These are similar to those discussed in various sections of this chapter, so they are not repeated here. However, these parameters are also equally important for overall performance of the plant.

10.5 Redundancy in GTs

Since control and protection of the GT is extremely important, TMRs are normally adopted for PLCs. Two of three redundancies in measurement of the following parameters is quite common:

- Speed
- Generator output
- Fuel flow(s)
- Actuator stroke
- Water flow
- Low pressure and temperature
- Control Pressure
- Servo solenoids
- Control processor
- Protection processor
- Software

10.6 Single-Shaft CC Configuration

GE S107H and S109H are typical examples of the single-shaft CC configuration. Listed below are some system parameters:

1. This configuration is excellent where the installation and operation of both gas and steam turbines are concurrent. The configuration is simple but efficient.
2. A steam turbine is installed between the GT and the generator. This is done with a solid coupling between the GT and steam turbine with a direct coupled generator with a steam turbine.

www.EngineeringBooksPDF.com

3. Single thrust bearing in the GT compressor and thrust bearing mounted between the steam turbine and generator.
4. Common LO system.
5. From a control and operational perspective, the speed and load control are done through control of the GT fuel flow valve. Steam turbine control valves are closely coordinated. These valves open after sufficient pressure and temperatures are developed. Then they are ramped opened. At this stage, with the valve open the pressure slides with the changes in load.
6. Frequency control is done with the help of GT control. During over speed HP and LP control valves start closing at speeds nearing 103% of rated speed and fully close at 105% of rated speed. IP control valves lag 2% behind.
7. For further details, see "Advanced Technology Combined Cycles" by R.W. Smith, P. Polukort, C. E. Maslak, C. M. Jones, and B. D. Gardiner of GE Power Systems.

11. MISCELLANEOUS OTHER SYSTEMS (P&ID)

11.0 Miscellaneous Other Systems

In this clause P&IDs that form the integral part of turbine, generator, and boiler systems as listed in the Table III/11.0-1 are presented.

In each case the objectives and functions of the system are discussed.

TABLE III/11.0-1 Various Auxiliary Systems

Turbine	Generator	Boiler
LO	Seal oil	HFO
Jacking oil	H_2 cooling	LFO and atomizing air
Control oil	Stator water	Atomizing steam
Seal steam		Burner cooling and ignitor
Evacuation		Boiler circulation

11.1 TG-Related P&IDs

11.1.1 General Discussions

In this part short discussions on various sub systems of TG system has been presented.

11.1.2 System Description and Functions

11.1.2.1 Turbine LO System

1. Being a rotating system turbo generator, there will be some friction at the bearings of the turbine and as a result there will be generation of heat at the bearing. LO is used to take away the heat from the bearing. Major functions include:
   a. Keep bearing temperature $<100-110^{\circ}C$.
   b. Take away heat by conduction—typically the oil leaving the bearing will be $\sim 70^{\circ}C$.
   c. Less friction—between oil film and white metal.
2. Hot LO is cooled in oil cooler outside the bearing housings.
3. While circulating LO in the bearing, it carries a large amount of dirt, which is eliminated with the help of a filter.
4. There are a number of LO pumps: auxiliary oil pumps (AOPs) driven by an AC motor, emergency oil pump(EOP) driven by a DC motor, and shaft-driven main oil pump (MOP). Generally these pumps are centrifugal with sufficient capacity. During initial start-up and shut down, when a shaft-driven oil pump is not available AOPs are used. Depending on unit size, the number and power of AOPs is decided.
5. An EOP is run during shut down if there is system AC failure to save the turbine by circulating oil under this emergency situation.
6. During normal running the oil supply to the various bearings is taken care of by the MOP, which is coupled to the main shaft of the turbine and runs with the turbine to supply LO. Pressure and capacity wise MOPs are higher than AOPs, so when an MOP runs, AOPs are cutoff with an increase in LO pressure above a desired value. In many places there are oil-driven booster pumps (e.g., GE turbine LO system) with a discharge pressure of $\sim 1-2$ kg/cm^2, which acts as suction to the MOP and can deliver oil at $\sim 14-15$ kg/cm^2.
7. All oil pumps, such as AOPs, MOPs (with/without booster pump), and EOPs, have suction from the main oil tank where the level is monitored, as discussed in Clause 11.1.2.3. Before supplying to the bearing, LO passes through an LO cooler and filter to ensure that dirt-free oil reaches the bearing at a temperature less than the desired value. This oil forms a header and from there oil is supplied to each of the bearings individually as shown in Figure III/11.1.2-1.
8. There may be another set of pumps called turning gear oil pumps whose basic purpose is to supply oil to the bearing during turning gear operation of the turbine (see Clause 11.1.2.4). It may share the same suction as used by the EOP. When the turbine runs at higher speed, this pump is automatically put out of service.
9. There are ways to auto start AOPs and EOPs. These can be tested on a periodic basis even when the system is running from a local LO pump discharge panel.

www.EngineeringBooksPDF.com

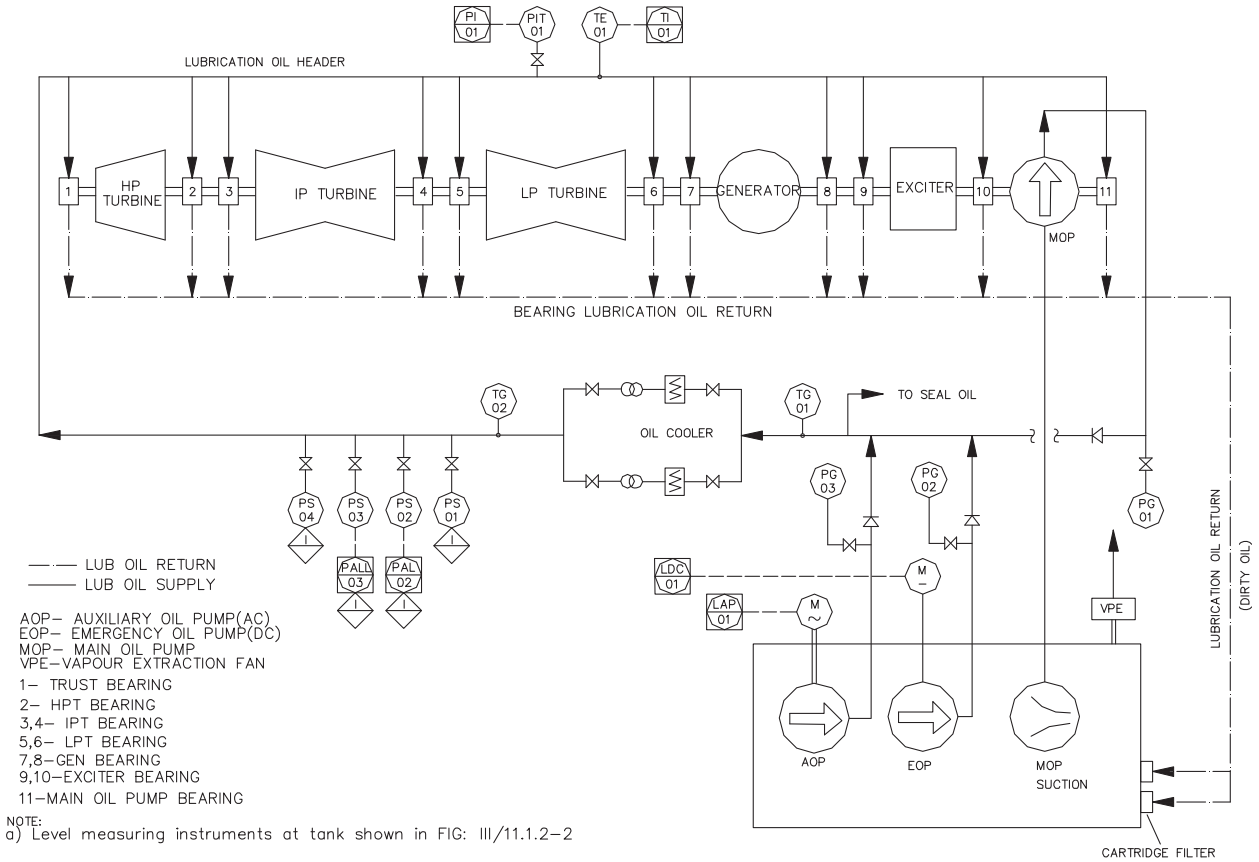


FIGURE III/11.1.2-1 Turbine LO system.

10. Pressure and temperature of LO entering the bearing is monitored by a pressure transmitter and temperature element. There are a number of pressure switches that are effective for changeover of AOP to EOP if desired or cut off of AOP in the event of starting an MOP.
    - **a.** Initially when the AOP is started and if pressure falls below a set point, then another AOP (if any) will be started. When both AC pumps fail then only an EOP will be started. When the turbine reaches the desired speed and the MOP can deliver oil, then the pressure will be greater than a set point and AOP will be stopped automatically. AOP delivers oil at $\sim 2-3$ kg/cm^2, so the pressure range could be $0-5$ kg/cm^2.
    - **b.** If LO pressure is less than a certain value the turbine will be tripped. There is also an LO pressure alarm
    - **c.** Oil tank level is monitored by level switches and level transmitters.
    - **d.** Performance of the oil cooler is monitored by at DCS by an RTD (local temperature gauges).
11. After bearing cooling dirty oil returns to return line and oil tank.
12. Oil Pressure is a criterion in automatic turbine run up system functioning.
13. A part of the LO system it may be taken as seal oil.
14. Normally there is a local panel and gauge board pertinent to the turbine LO system. It may be located near the turbine in the turbine operating floor, whereas the gauge board may be placed at the front pedestal.

11.1.2.2 Turbine Jacking Oil System

1. During start-up and shut down of the turbine, the jacking oil system is comes into operation (see Figure III/11.1.2-2). Before admitting steam, the turbine is turned at a slow speed by turning gear (see number 4 below). During start-up of the turbine, jacking oil is necessary. When the turbine is shut down, the jacking oil system comes into operation so that the hot shaft does not rest on the white metal of the bearing. As discussed earlier, there is a need "separate the white metal in the bearing and shaft" with the help of an oil film. At a low speed of approximately <75 rpm, this separation is achieved by jacking oil. During this time oil at a very high pressure of approximately >200 kg/cm^2 (>350 for higher MW units) is injected from the bottom to lift the shaft. The oil is kept injected until an oil film is developed.
2. Separate jacking oil pumps taking suction from the main oil reservoir are deployed. These pumps are kept

www.EngineeringBooksPDF.com

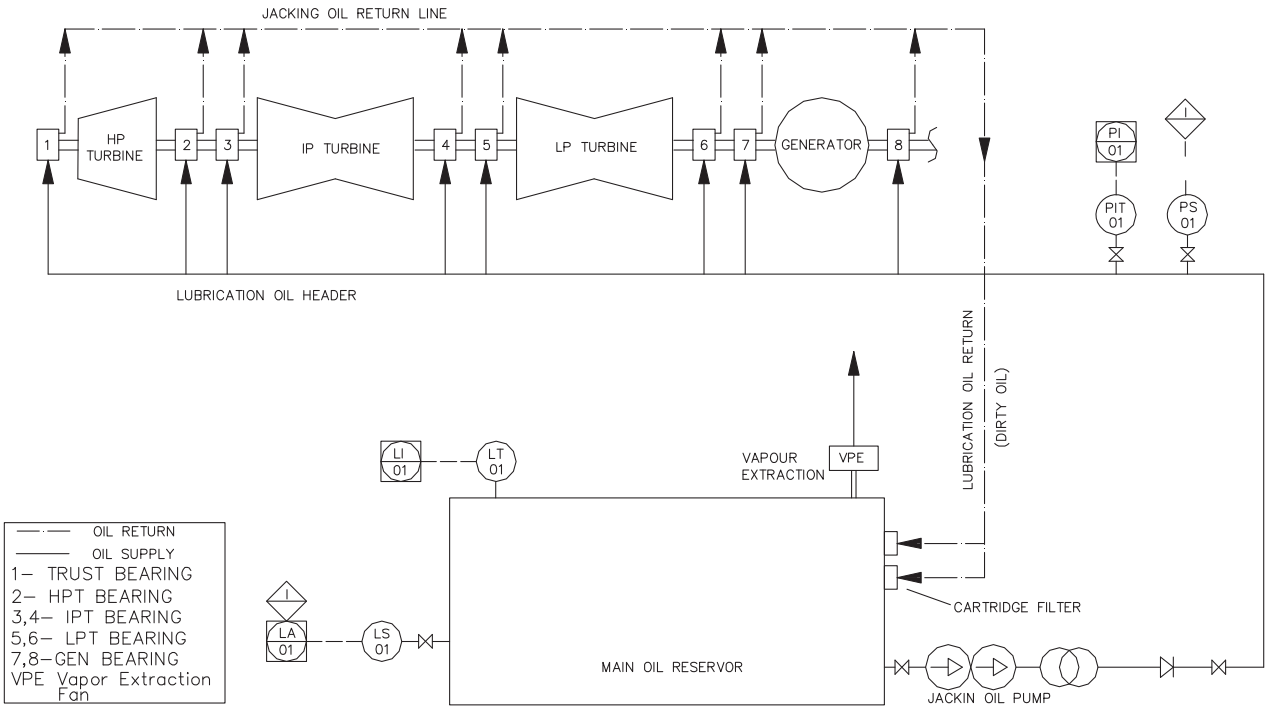


FIGURE III/11.1.2-2 Jacking oil scheme.

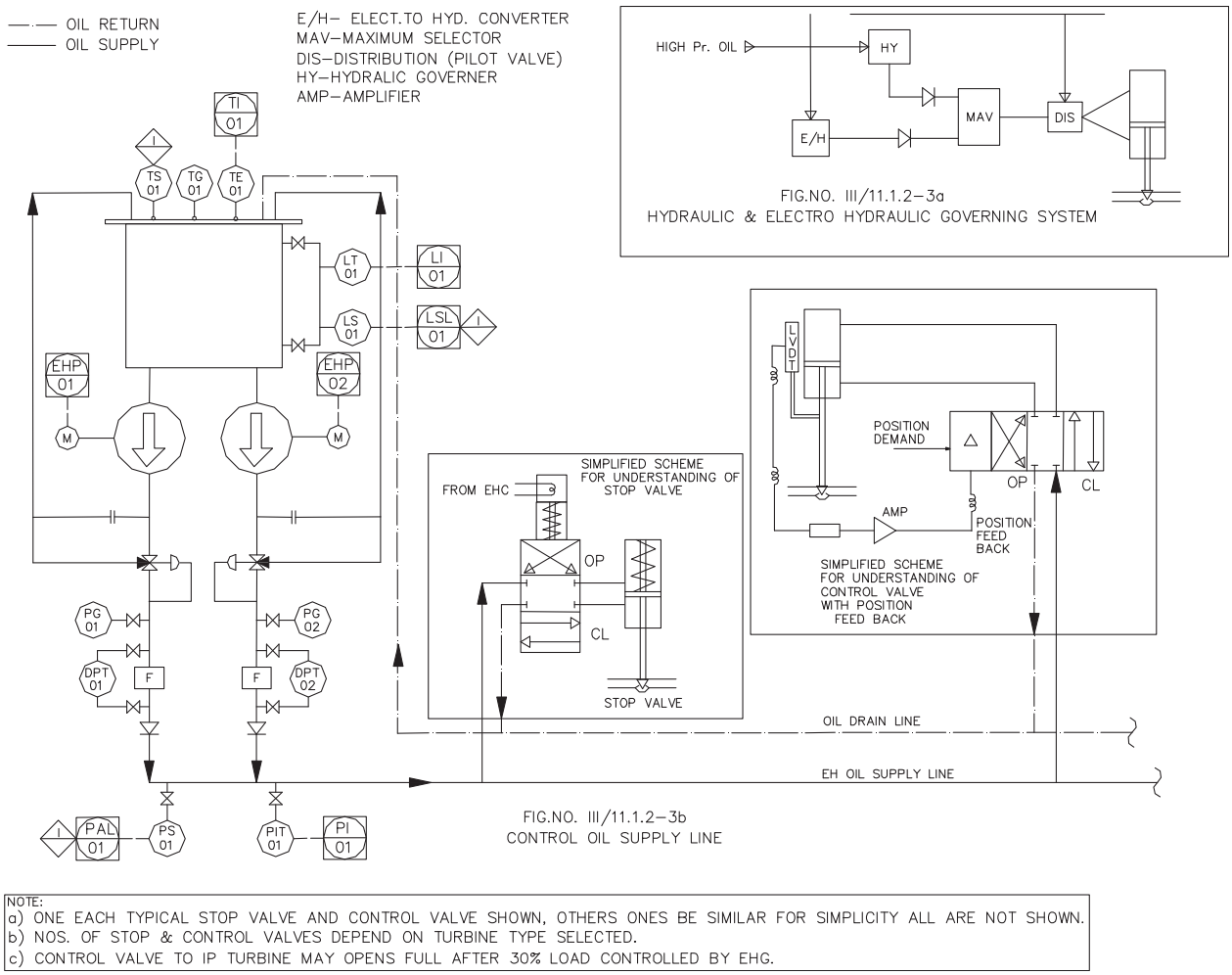
in many places at the bearing pedestal. Because of the very high pressure (sometimes >350 kg/cm^2), safety relief valves are very important for these pumps.

3. Pressure and temperature at the jacking oil header is monitored. Normal range may 0−350 kg/cm^2 for a medium to high megawatt power plants. At the main reservoir the level is monitored at the DCS with the help of a level transmitter. A level switch used for alarm and interlock.
4. As discussed earlier, jacking oil is used during low running of the turbine. During start-up and shut down the turbine rotor is rotated at a slow speed of ∼100 rpm by turning gear. Basically turning gear is driven by a motor and is coupled to, through a series of reduction gears, the main turbine. Turning gear is used to rotate the turbine rotor slowly during start-up and shut down of the turbine to avoid uneven heating/cooling (to avoid shaft deformation). In short, this is the turning gear operation. During this time, the turning gear oil pump may be used to supply oil to the bearings.
5. When the turbine speed crosses ∼200 rpm, the turning gear stops operating. Jacking oil only operates during the time the turning gear is in operation.

11.1.2.3 Turbine Control Oil System

1. The control oil system of the turbine is as important as the circulation system of the human body. It is the same oil system used to operate the HP IP stop and control valves as well as many other control valves such as sets of valves in the bypass system (LP bypass system) using hydraulic fluid. Operation and performance of any control actuator pertinent to the turbine system depends mainly on the Control oil system.
2. Basically, control oil may have two components: high pressure power oil needed to operate the large valves at very high speed (mainly acting as controlled power supply) or relatively lower pressure acting as a signal/control oil to operate pilot valves, solenoids, etc.
3. Since these oil pipelines are (exposed to/or) near close vicinity of high pressure steam pipes, there will a number of fire hazards. For this reason, fire resistance fluids (FRFs) are used. These fluids have long service life as well as good fluidity.
4. Depending on the power plant size, the pressure range of the control oil pumps may be as high as >160 kg/cm^2 and 30 kg/cm^2 on the lower side. There are several control oil lines formed from this FRF line: primary oil, secondary oil, trip oil, etc. Each line them has a separate function. Based on these oil pressures, pilot actuators drain/pressurize the main actuator with the main power fluid. The valves normally open against a spring. Whenever pressurizing fluid drains, these valves close very fast (especially the stop valve) because of the spring force. There will be 3 position × 4-way solenoids to take care of the proportional valve movement in both directions.

www.EngineeringBooksPDF.com



NOTE:
a) ONE EACH TYPICAL STOP VALVE AND CONTROL VALVE SHOWN, OTHERS ONES BE SIMILAR FOR SIMPLICITY ALL ARE NOT SHOWN.
b) NOS. OF STOP & CONTROL VALVES DEPEND ON TURBINE TYPE SELECTED.
c) CONTROL VALVE TO IP TURBINE MAY OPENS FULL AFTER 30% LOAD CONTROLLED BY EHG.

FIGURE III/11.1.2-3 Control oil P&ID (with governor selection).

5. The hydraulic circuit for the governing system is a little complex, but not difficult to understand as long the flow path is followed properly. Figure III/11.1.2-3 illustrates it in its simplest form. Control oil from the electro hydraulic tank is pumped and passed through a filter before sending it to the actuators. The line pressure is maintained by a self-regulating pressure regulator. In some cases a pressure control loop may be deployed for this.
6. In Figure III/11.1.2-3, one 3 position × 4 way solenoid is shown. With no power drain and supply line the two output ports of the solenoid are blocked. When the coil is energized, the solenoid assumes the "OP" position, so that the supply line is connected to the bottom half of the double-acting cylinder, which pushes the piston against the spring force and the valve is opened. (Although not shown in the drawing, there will be feedback from the position signal, so during start-up even the stop valve can be opened at a desired position). When the coil is de-energized (or the close coil is energized—as the case may be) solenoid valve assumes the "CL" position. As a result the supply line is connected to the top part of the cylinder and the bottom part is drained. The actuator closes the valve very quickly by the action of oil pressure as well as by spring force so that closing time is minimal. When any of the two positions is assumed by the actuator, power to the coil of the solenoid may be cut and the solenoid assumes the initial position in which the actuator is locked.
7. The action of the control valve actuator valve is similar to what was previously discussed. As long as there is an error between position demand and position feedback, the solenoid will depart from the initial position of rest (where two ports connected with the actuator are blocked). When the opening demand is more than the actual open position, the solenoid moves to that position so that the top side is connected to the drain and

www.EngineeringBooksPDF.com

the bottom side is connected to the supply (as shown in the left position in Figure III/11.1.2-3), thus the control valve opens. If opening crosses the desired demand position, the reverse action will take place to drain a part of the oil in the bottom part of the actuator (and supply oil introduced in the top part), and the valve will start closing. The opening and closing of the valve takes place proportional to position demand from the governing control system loop.

8. Each turbine has its own governor system comprising a set of valves operating in tandem to give the system unique characteristic specific for the machine assembly. Operational relation and operating points for these valves makes the EHG system uniquely suitable for that particular turbine. This uniqueness is related to the operating parameter and valve actuator characteristics; however, there are several basic features of the governing systems for all turbines, such as speed control/load control, etc. Because of the implementation part of these basic features in the hydraulic system, the performance of governing systems change.
9. In most modern control systems there is a hydraulic and an EHG control system. As shown in Figure III/11.1.2.-3b, either system may selected by max selection.
10. A few major characteristics of this governing system include:
    a. Capability to handle safely full-load rejection without over speed, and to maintain system (grid) frequency.
    b. Speed droop characteristic to share load with other machines.
    c. In some designs, up to low load generally the IPCV is throttled whereas after ~30% load IPCV opens fully rendering the governor in HP control mode for better thermal efficiencies. In cases of sliding pressure operation of the turbine, the HPCV, up to certain load throttles, opens almost fully and the pressure at turbine inlet is not fixed but regulated in coordination with the boiler, up to an upper limit of load. Beyond this load limit, HPCV again throttles (to have cushion in control; see Figure III/11.1.2.3-1).

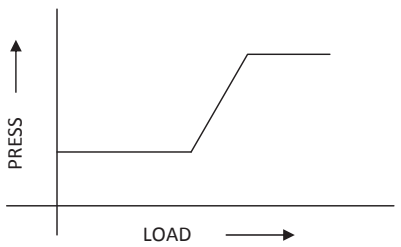


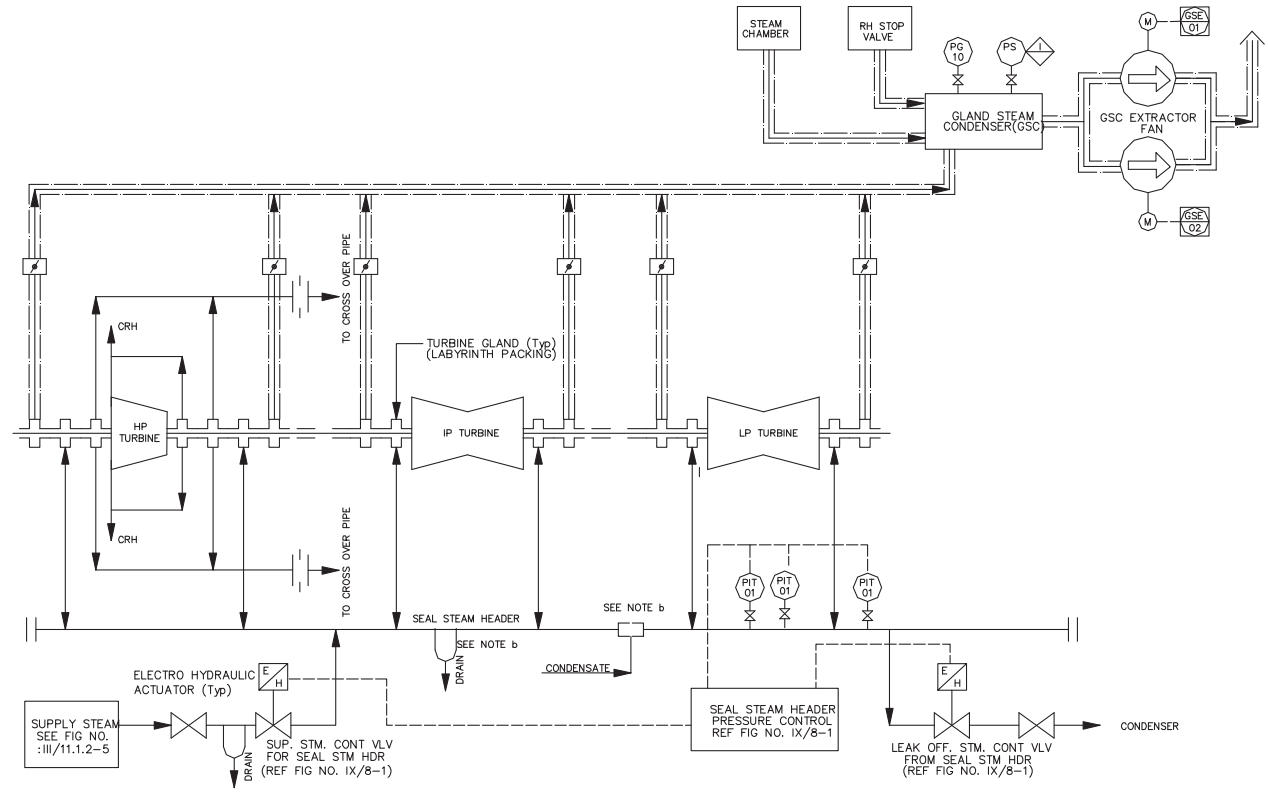
FIGURE III/11.1.2.3-1 Pressure versus load.

    d. In many large machines (e.g., KWU-Siemens) LP bypass is directly related to the EHG system and there may be a common control oil circuit. In these cases the LP bypass control system forms a part of the EHG package and separate controls may not be needed. Also there are systems where separate control systems (as part of the DCS) have been provided for LP bypass control.
    e. Chapter IX discusses this issue in detail.

11.1.2.4 Turbine Seal Steam System

1. The majority of steam turbine use at both ends of the shaft is with rings to prevent any leakage causing reduction of turbine efficiency. As per API, gland sealing is required for all new turbines.
2. This system enables the turbine to be sealed where the shaft comes out of the casing. Sets of labyrinth packing are employed along the rotor where the shaft exists (see Figure III/11.1.2-5b–d. These labyrinths create many chambers causing pressure drop. The DP between atmosphere and inside the turbine causes air leakage in to the turbine on the LP side, whereas the HP side steam escapes (in both cases due labryrith quantity leakages will be much less).
3. During start-up, shut down, and low-load operation, turbine auxiliary steam, assists labyrinth packing in sealing the turbine shaft and air leakage is prevented. During normal running conditions, the steam leakage from the HPT and IPT sides would be used to seal the LP side leakage and excess leakage steam, if any, is dumped. In some designs, the seal steam line for LPT sealing is passed through an attemperator to match the process parameter (see Note b in Figure III/11.1.2-4). In other designs, steam from the HPT is drained to the condenser and the LPT is sealed from leakage steam from the IPT to avoid the need for an attemperator (e.g., Siemens KWU design).
4. As shown in Figures III/11.1.2.-4 and III/11.1.2-5c and d, gland steam at the furthest end of each gland has a mixture of steam and air. This gland steam is taken to the GSC where air is removed by the gland steam extractor fan. The steam chamber and RH stop valve leakages are also taken to the GSC whose pressure is monitored by a pressure switch.
5. Auxiliary steam is supplied to the seal steam header after reducing the pressure and temperature as shown in Figure III/11.1.2-5a.
6. Normally seal steam header pressure is controlled by a dedicated control system, which may be a part of the turbine integral control. There are redundant pressure transmitters (typical range: −100 to + 900 mm wcl) and two sets of valves (e.g., supply steam control valve for seal steam header and leak off steam control valve from seal steam Header) as detailed in Figure IX/8-1.

www.EngineeringBooksPDF.com



NOTES:
a) PRESSURE / TEMPERATURE CONTROL MEASUREMENT & CONTROL DETAILED ONLY IN FIG : III/11.1.2-5
b) IN SOME CASES, TO AVOID TEMPERATURE MISMATCH, ATTEMPERATIONS ARE USED FOR THE STEAM TO SEAL LPT SIDE GLANDS.
c) IN SOME DESIGN, LEAK OFF FROM HPT IS DRAINED TO CONDENSER,& IPT LEAK OFF STEAM IS USED FOR LPT SEALING, HENCE ATTEMPERATER IS AVOIDED (e.g. SIEMENS KWU TURBINE)

FIGURE III/11.1.2-4 Turbine seal steam system

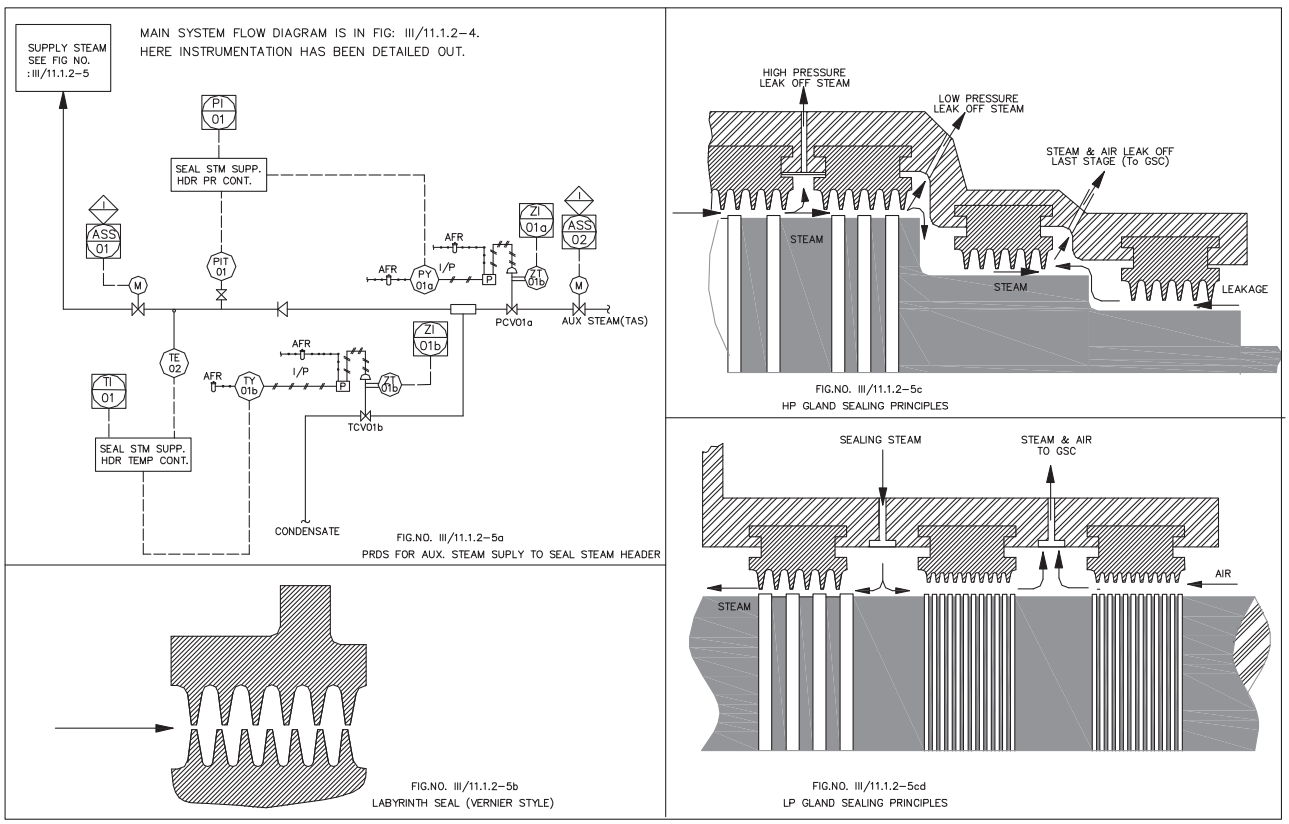


FIGURE III/11.1.2-5 Turbine seal steam system miscellaneous details.

www.EngineeringBooksPDF.com

11.1.2.5 Turbine Evacuation System

1. Thermal efficiency increases when the condenser is kept at vacuum, so the importance of this evacuation system cannot be overestimated. In many systems evacuation is one of the major subgroups in the turbine control system.
2. The vacuum pump and the steam ejector are responsible for maintenance of the condenser vacuum. This system is detailed in Chapter II.
3. The vacuum pump driven by an electric motor draws the air steam mixture from the top of the condenser creating vacuum in the condenser. The air steam mixture is cooled and separated. The air is released to atmosphere and the condensed part is drained.
4. In the steam ejector system, the steam (auxiliary steam) is passed through a nozzle and allowed to expand in one chamber. When the HP steam passes through a nozzle it expands in the chamber and creates vacuum in the chamber; this chamber is connected to the condenser so that the condenser vacuum is created. Out of the mixed air and steam, air escapes to the atmosphere, whereas the steam is cooled by the passing condensate, which absorbs some heat from the steam allowing it to condense (see Figure III/11.1.2-6).

11.1.2.6 Generator Seal Oil System

1. Many of the larger sized generators are hydrogen cooled. When hot hydrogen comes in contact with oxygen/air it is vulnerable for explosion.
2. Seal oil (may be taken from LO oil) is used to seal hydrogen leakage. Seal oil is used at both ends, i.e., the air side as well as in the hydrogen side.
3. There are two sets of seal oil systems. Each system is comprised of a set of seal oil pumps, heater/cooler, filter, one header, and a return oil tank.
4. Since seal oil is necessary at all operating conditions, there are seal oil pumps driven by both AC and DC motors.
5. Seal oil pumps take their suction from the return oil tank. Discharge of the pump is passed through the heating/cooling circuit to keep the temperature at the desired point. This is done by measuring the temperature with a temperature gauge. Seal oil at the desired temperature is then passed through a set of filters. The DP across the filter is monitored and changeover takes place if there is a high DP. There will be one recirculation line to keep the oil running at all times. The recirculation line may be returned to the return oil tank.

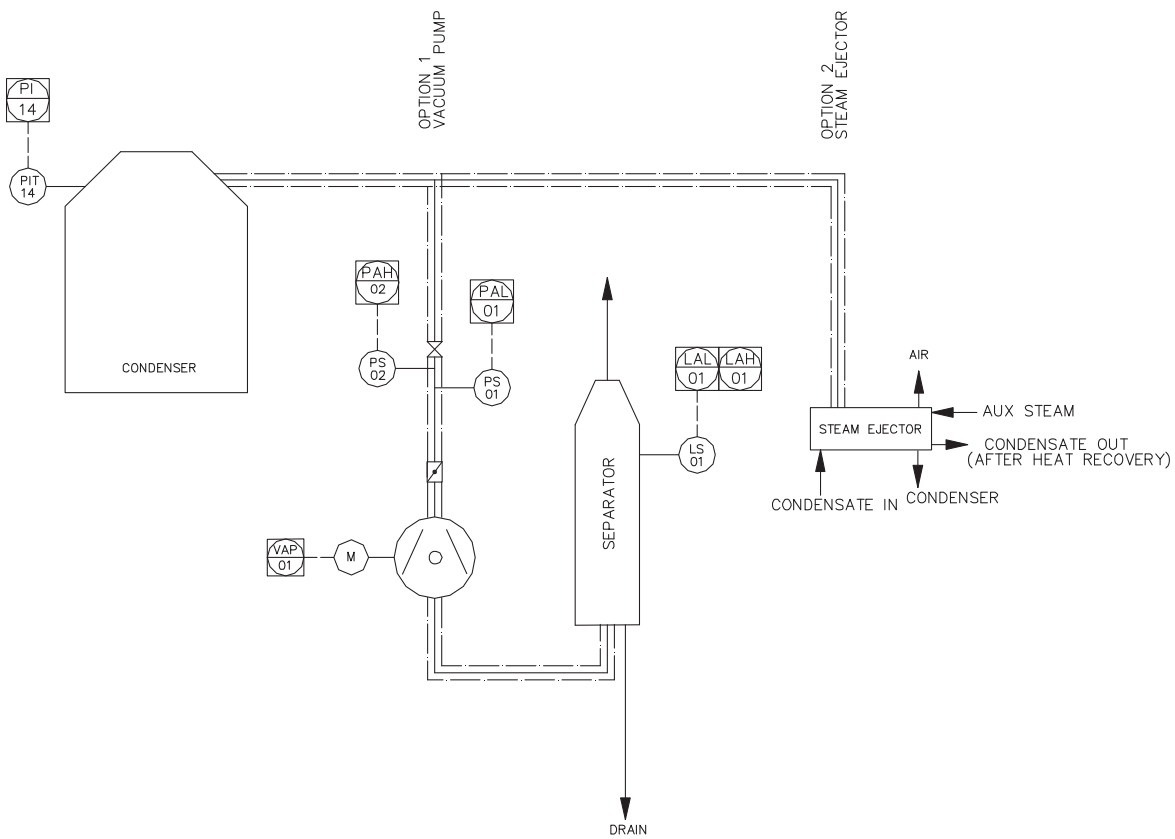


FIGURE III/11.1.2-6 Condenser evacuation system.

www.EngineeringBooksPDF.com

6. Seal oil line after the filter forms a seal oil header. There are two such headers, one for air side and one for the hydrogen side seal oil header.
7. Each of these seal oil headers supplies seal oil to generator at both turbine and exciter ends.
8. The hydrogen side seal oil pressure always maintains a DP WRT the air side seal oil. This is done by measuring seal oil pressure at both ends and connecting these pressures at two sides to two sides of a double-acting cylinder so that the hydrogen side seal oil valve opens to maintain the required DP WRT that at air side (see Figure III/11.1.2-7).
9. Seal oil–hydrogen DP is one of the most important parameters for generator operation and it is measured with redundant sensors and interlocked with generator operation. Generally seal oil is kept at $\sim$1.2 kg/cm^2 above hydrogen pressure.
10. One of the critical things of the seal oil system is to remove entrained hydrogen and other gases from seal oil before the seal oil is again sent to seal the shaft. This is done at the main tank through vacuum operation in the spray nozzle to break the seal oil into fine spray to remove gases. Also after the shaft sealing oil goes through the detraining section. As it passes through this section there is pressure loss, so to take care of pressure loss the DC pump may have to be run.

11.1.2.7 Generator H_2 System

1. Because of better thermal conductivity, low density, and higher specific heat, H_2 has been chosen for rotor cooling in place of air cooling for many larger generators. Air-cooled large generators are also not uncommon. For low-rated generators H_2 cooling may not be applicable.
2. In many power stations, a separate H_2 generation plant is kept for H_2 supply. Also there are provisions for H_2 supply from cylinders for emergencies.
3. There are a number of H_2 driers from where H_2 fills the space in the rotor. The H_2 drying operation is very important, and leak detectors are deployed to monitor the dryness of H_2. Moist H_2 at a lower pressure is sent to the dryer, whereas dry H_2 is sent with higher pressure.
4. H_2 quality and H_2 pressure are very important parameters and are always monitored in the main DCS.

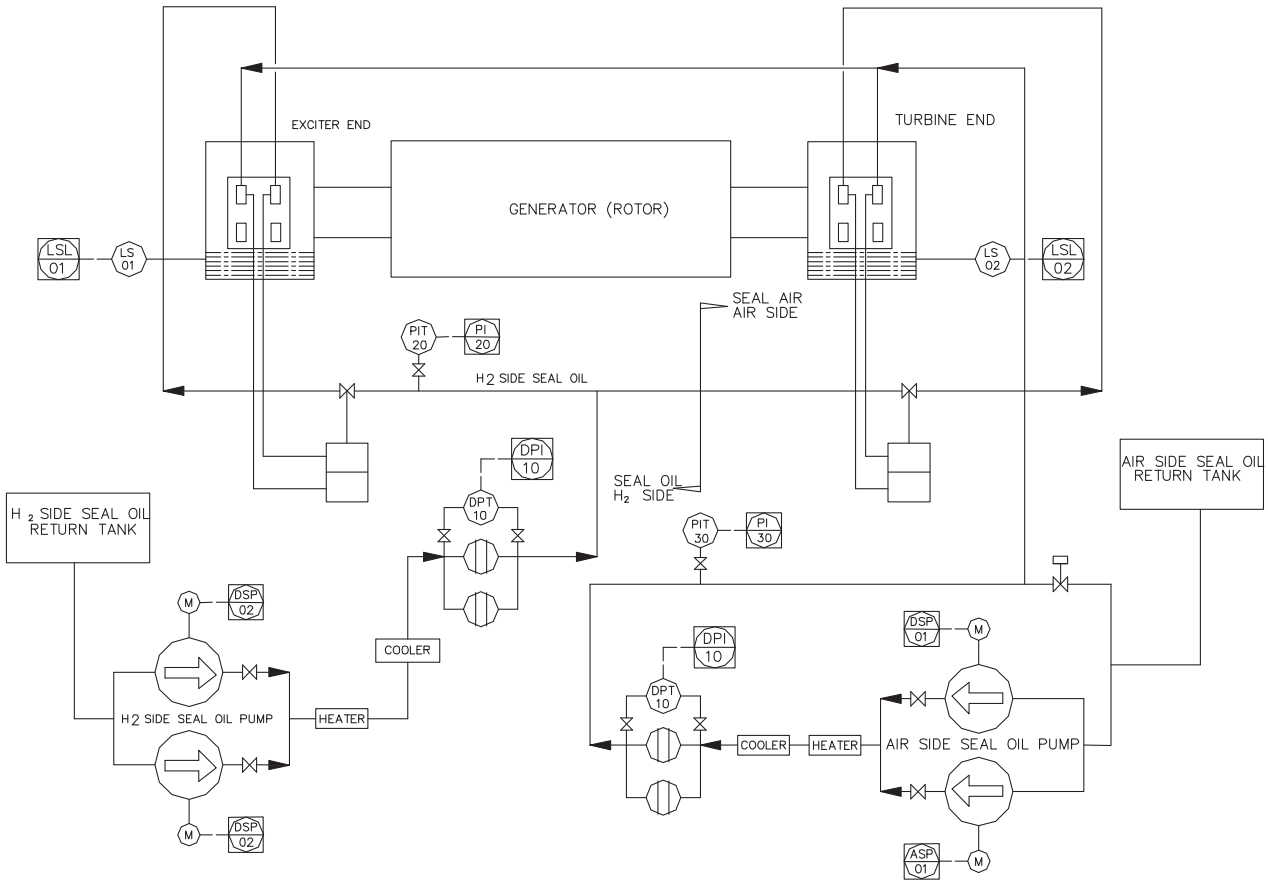


FIGURE III/11.1.2-7 Generator seal oil system.

www.EngineeringBooksPDF.com

5. H_2 is not filled directly in to generator, as there is a chance of H_2 coming in contact with air. At first air is replaced with CO_2 by upward displacement of air, so, CO_2 cylinders are shown in the P&ID (see Figure III/11.1.2-8).When the rotor is completely filled with CO_2 its purity ensured by measuring CO_2 in oxygen analyzer. After ensuring the purity of CO_2 in the rotor, H_2 filling is started. CO_2 is heavier than H_2 so it is filled by downward displacement of CO_2. Proper filling of H_2 is ensured by measuring H_2 in CO_2
6. H_2 is favored as a cooling medium because the generator is completely sealed from a safety point of view, meaning sealed from dust, humidity, salt, etc. Also no oxygen atmosphere exists inside, so HV insulation is safe from stator activity (corona).

11.1.2.8 Stator Cooling Water System

Effective ways to dissipate heat of stator winding is very important in improving the performance of a generator. Larger sized generators have small diameter copper tubes carrying water around stator winding. These are cooled by sending DM quality process water through them.

1. This process water is stored in a tank with a suitable heat exchange circuit, so that a constant temperature is maintained. Stator cooling water pumps take their suction from the tank. The discharge of the pumps is passed through a water cooler to maintain the desired temperature. After passing through the filter, stator cooling water is passed through the hollow copper tubes around stator winding. Water leaving the generator is returned to the tank.
2. The level in the tank is monitored (with high and low alarms) at the DCS by a set of level instruments. Also pressure, temperature, and flow of the stator cooling water line is monitored. Inlet/outlet temperature of stator cooling water is a very important parameter to be monitored.
3. Corrosion is one of the major problems, as copper oxide flakes are formed inside the tube and choke the flow of water. For this either aerated water >2 ppm DO is used to form a CuO layer or deaerated water with <50 ppb DO is used to form a Cu_2O layer to prevent corrosion. As any corrosion is an electrochemical process, electrochemical corrosion potential may be used to detect corrosion due to change in water chemistry.

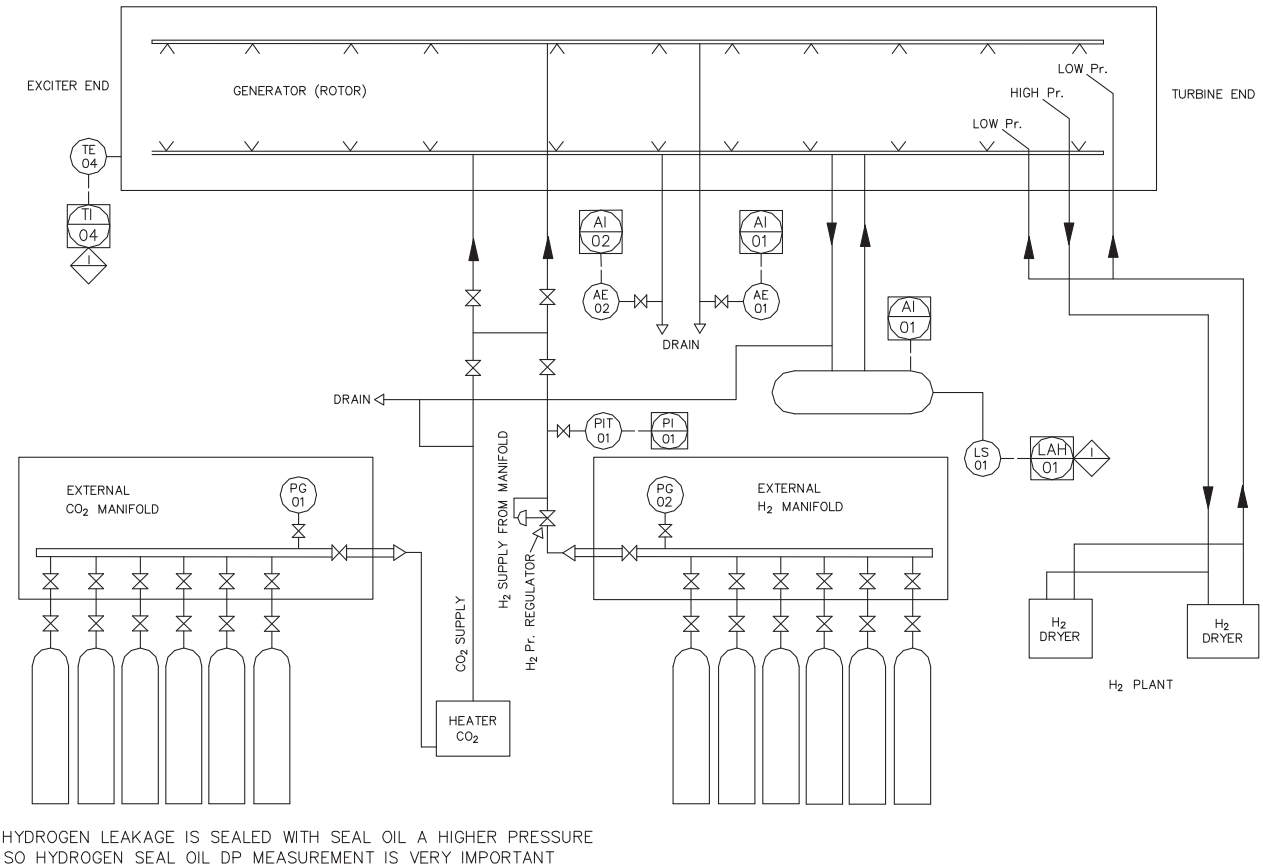


FIGURE III/11.1.2-8 Generator H_2 cooling system.

www.EngineeringBooksPDF.com

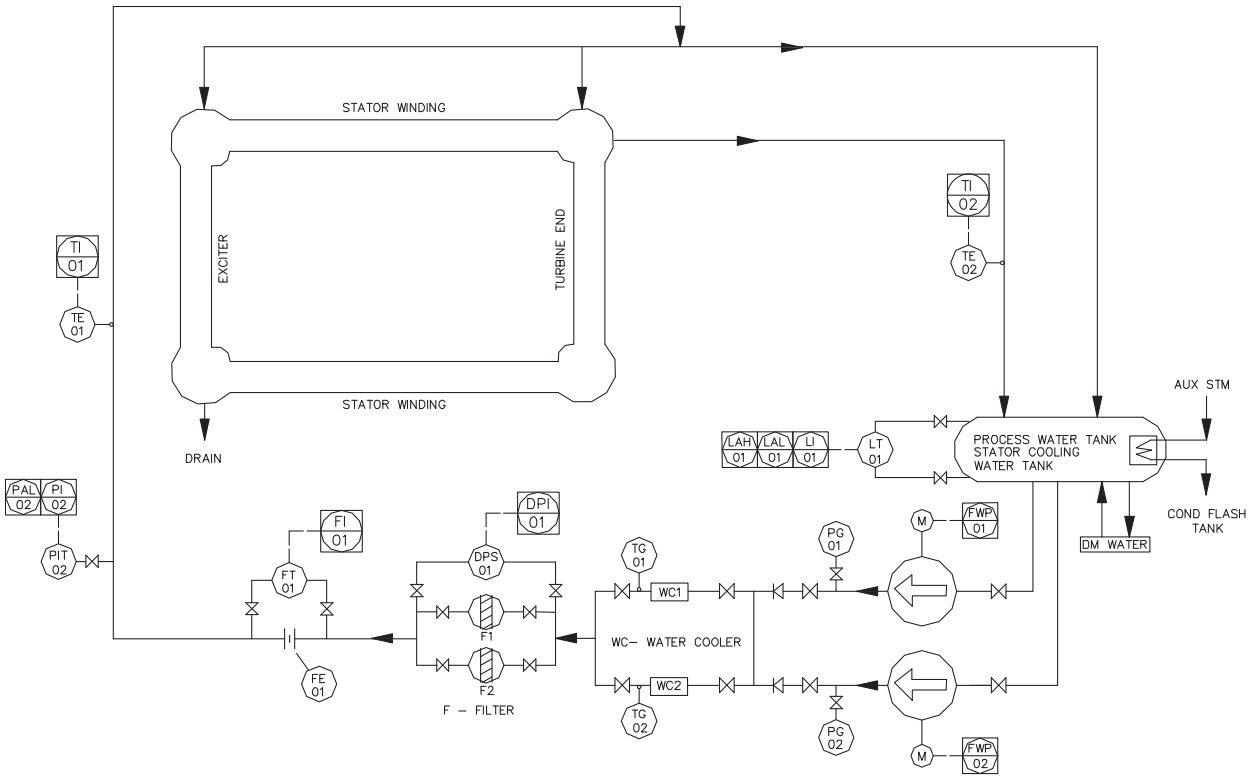


FIGURE III/11.1.2-9 Stator cooling water scheme.

4. Water leakage is a great threat for generator operation, as it can damage insulation. There are suitable leak detectors available (e.g., one from GE;) (see Figure III/11.1.2-9).

11.2 SG-Related P&IDs

11.2.1 General Discussions

In this part short discussions on various sub systems of SG system has been presented

11.2.2 System Description and Functions

11.2.2.1 SG HFO System

See Table III/11.2.2.1-1 for HFO parameters:

1. In an oil-fired boiler HFO can be used as main fuel also. For a pulverized fuel boiler HFO is used as supporting fuel during low-load operation and a secondary fuel for coal flame stabilization. In some boilers this may be directly used as an initial start-up fuel (with HEA ignitor).
2. In thermal power plants there two sections for HFO:
   a. HFO heating and pumping section may be common for various units in a power station. Normally this is located outside the unit power house with a separate control system and panel and a software link with the main DCS.
   b. FO preparation and firing section is mainly connected with oil equipment at the operating floor of the boiler and is controlled from the DCS.
3. Power HFO storage is normally done at two places: HFO storage tank (main storage facility) far away

TABLE III/11.2.2.1-1 HFO Parameters (approximate values)

SL	Characteristic	HFO*	HPS**	LSHS***
1	Calorific value (kcal/kg)	10,000	10,000	10,700
2	Flash point °C	66	66	75
3	Viscosity(cst) at 50°C	370	500	50
4	Specific gravity	0.95	0.9	0.86
5	Sulfur content (% wt)	4.5	4.5	1

**HFO: Heavy Fuel Oil*
***HPS: Heavy Petroleum Stock*
****LSHS: Low Sulphur High Speed*

www.EngineeringBooksPDF.com

from the power house building and HFO day tank (a day's consumption for the unit) very near the power house.

4. HFO is quite viscous and needs heating to achieve flowability. It is therefore essential that all storage tanks have floor coil heaters (steam heating) and heating at the outlet nozzle. This is necessary so that HFO can be pumped and made to flow. In addition to this, the entire flow path of the HFO is heat traced (either by electric or steam tracing). In modern plants there is a continuous recirculation line to keep the oil always in flowable condition to provide quick fuel support.
5. HFO is drawn from the HFO tank by motor-operated, pressurizing pumps. These normally are rotary-positive displacement horizontal pumps with relief valves. The pumps through discharge valves supply the heating unit, which is heated utilizing auxiliary steam. Discharge header pressure is measured and controlled by a recirculation valve to recirculate excess HFO back to the tank. To eliminate dirt the pumps have a suction filter with DP monitoring across it for quick changeover of the filter.
6. Temperature at the outlet of the heater is measured and controlled by regulating the supply of auxiliary steam to the heater to see that the temperature never crosses flash point, which is above a set value to ensure better flowability.
7. The main oil path, after the strainer (filter), flows through the flow meter to measure the amount flown to the boiler (difference between supply flow and return flow computes the oil consumption). A bypass to flow meter is kept if the main path is not available for maintenance purposes.
8. Immediately after the flow meter is the trip valve, which is required to cut off fuel supply to the boiler in the event of boiler trip.
9. After this, oil follows the path to the oil guns. For corner fired boilers there are two paths as shown in Figure III/11.2.2-1. In one path it goes to the boiler operating floor up to the burner. The other path is a constant quantity recirculation back to the tank to ensure that the FO is in running condition at all times. Normally 10−15% recirculation is kept. This is a long recirculation line that traces almost the entire path oil

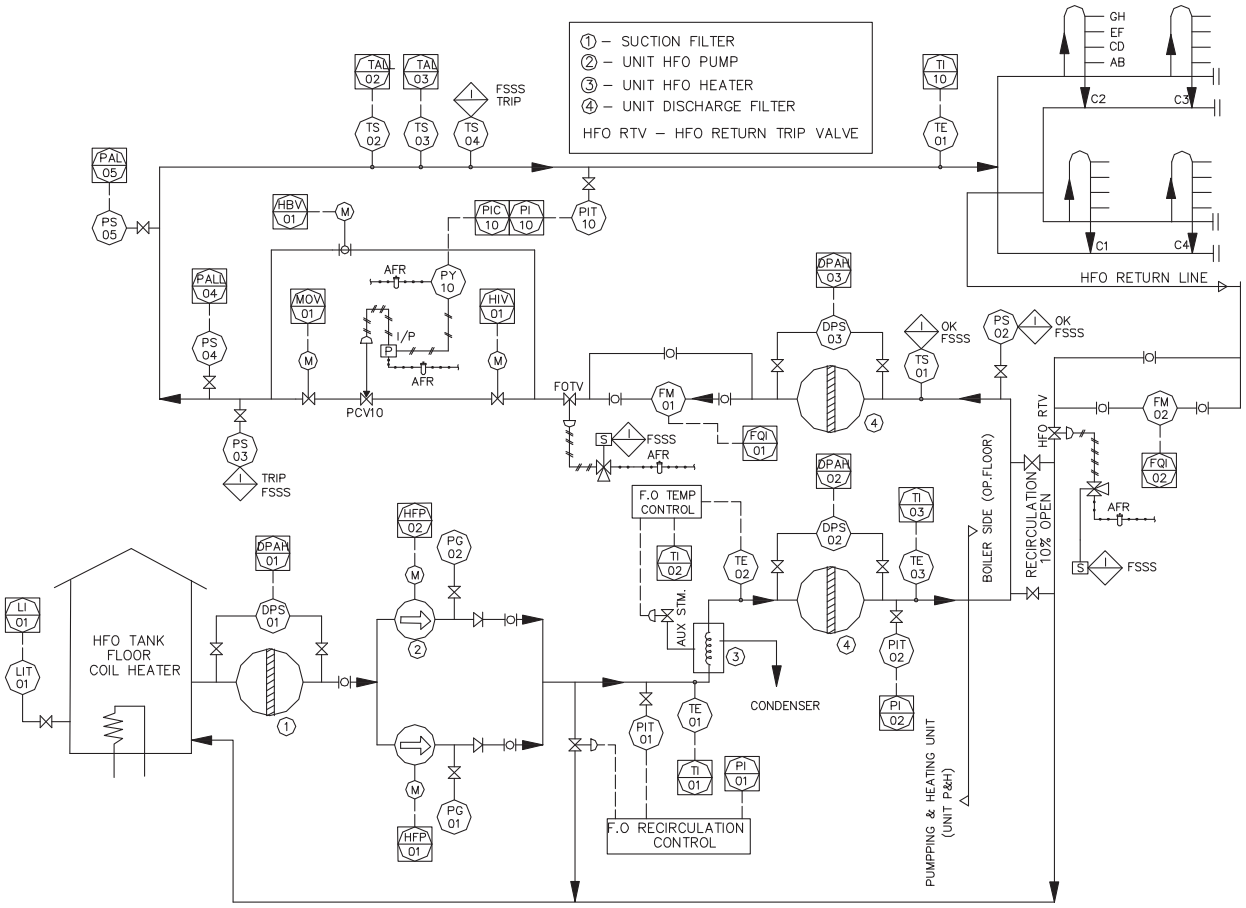


FIGURE III/11.2.2-1 Heavy oil from HFP tank to burner.

www.EngineeringBooksPDF.com

path. This is a scheme followed by a number of manufacturers, if not by all. There is a short recirculation path also where HFO is recirculated from the pump outlet back to the tank, as shown in Figure III/11.2.2-1.

10. For a corner fired boiler, the FO is divided in to four parts to supply all four corners. At each corner, oil line goes up to the highest oil elevation. Also from each of this corner there is a return line as shown in Fig III/11.2.2-1 these return lines meet to form main return line which flow back to the tank via one flow meter. & HFORTV.
11. A pressure control valve regulates the pressure of oil at the boiler front. Depending on boiler demand, flow to boiler will change accordingly. The opening of the pressure regulating valve is necessary so that supply flow changes to take care of changed flow conditions. This is done by measuring the pressure in header at the boiler front (PIC10).
12. Boiler front oil header pressure and temperature are very important for boiler operation. Some of the important parameters include:
    a. Oil pressure okay to start for oil firing
    b. Oil pressure lo trip and alarm
    c. FO temperature greater than set value
13. Because of high viscosity selection of valves, control valves are critical. A ball valve is a good choice, as is shown in the P&ID.
14. In certain boilers (seen in Chinese design) there is a valve parallel to the trip valve known as the leak test valve. This, in conjunction with the trip valve, return valve, and control valve and associated interlocks, checks the leakage in the entire line as well as leaks for the trip valve (see details in Chapter VIII, Clause 12.1).

11.2.2.2 Light Oil and Atomizing Air System

1. LDO
    a. With the help of an HEA ignitor it may be possible to directly fire HFO during boiler start-up. However, with most pulverized fuel boilers LDO is used to fire the boiler when no auxiliary steam is available or as an initial start-up fuel.
    b. LDO is drawn from the LDO tank by a motor-operated, pressurizing pump, which normally are rotary-positive displacement horizontal pumps with a relief valve. Discharge header pressure is measured and controlled by a recirculation valve (it could be a self-regulating upstream control valve) to recirculate excess LDO back to the tank. To eliminate dirt the pumps have a suction filter with DP monitoring across it for quick changeover of the filter.
    c. For LDO long recirculation may not be applicable as it does not have a flowability problem. However, in many designs, especially in Chinese designs, long recirculation is used similar to the HFO line.
    d. Oil normally flows through the flow meter. A bypass to the flow meter is kept in the event the flow meter is taken out for maintenance.
    e. Immediately after the flow meter is the trip valve, which is required to cut off fuel supply to the boiler in the event of a boiler trip.
    f. As discussed in Clause 11.2.2.1no 15, the leak test is also applicable for LDO, and similar leak test valves are used to carry out the leak test as discussed in connection with HFO.
    g. Boiler-front oil header pressure is very important for boiler operation. Some of the important parameters include:
        i. Oil pressure okay to start oil firing
        ii. Oil Pressure low trip and alarm
2. Atomizing air
    a. To burn LDO/HFO at the desired rate, it is necessary to atomize oil, i.e., to disperse oil into the boiler as a mist. In the case of LDO, air is used as an atomizing medium.
    b. Service air from the air header may be utilized for this purpose. The pressure is more than the LDO. This is monitored by a pressure switch in the air line.
    c. The atomizing air line is taken to all corners (or all burners) and elevations of the LDO line for corner fired boiler (see Figure III/11.2.2-2).

11.2.2.3 Atomization: Steam

1. As discussed in Clause 11.2.2.2, HFO is also atomized at the boiler before firing to achieve a high rate of firing.
2. Auxiliary steam is used for atomization. There is one control valve to regulate the steam header pressure so that atomizing steam pressure is kept a little higher than HFO. The pressure at steam atomization line is monitored for low and low low alarm and trip.
3. The basis of atomization is the mechanical type to get small droplets so that they vaporize quickly. There are basically two types of atomization: internal mix and external mix. In the internal mix type lower oil pressure is augmented by the high pressure of the atomizing medium. For the external mix type, atomizing MP need not always be higher than oil, as interaction takes place just before emission out of the nozzle. There is another means to emulsify by water not normally seen in any power plant (see Figure III/11.2.2-3).

www.EngineeringBooksPDF.com

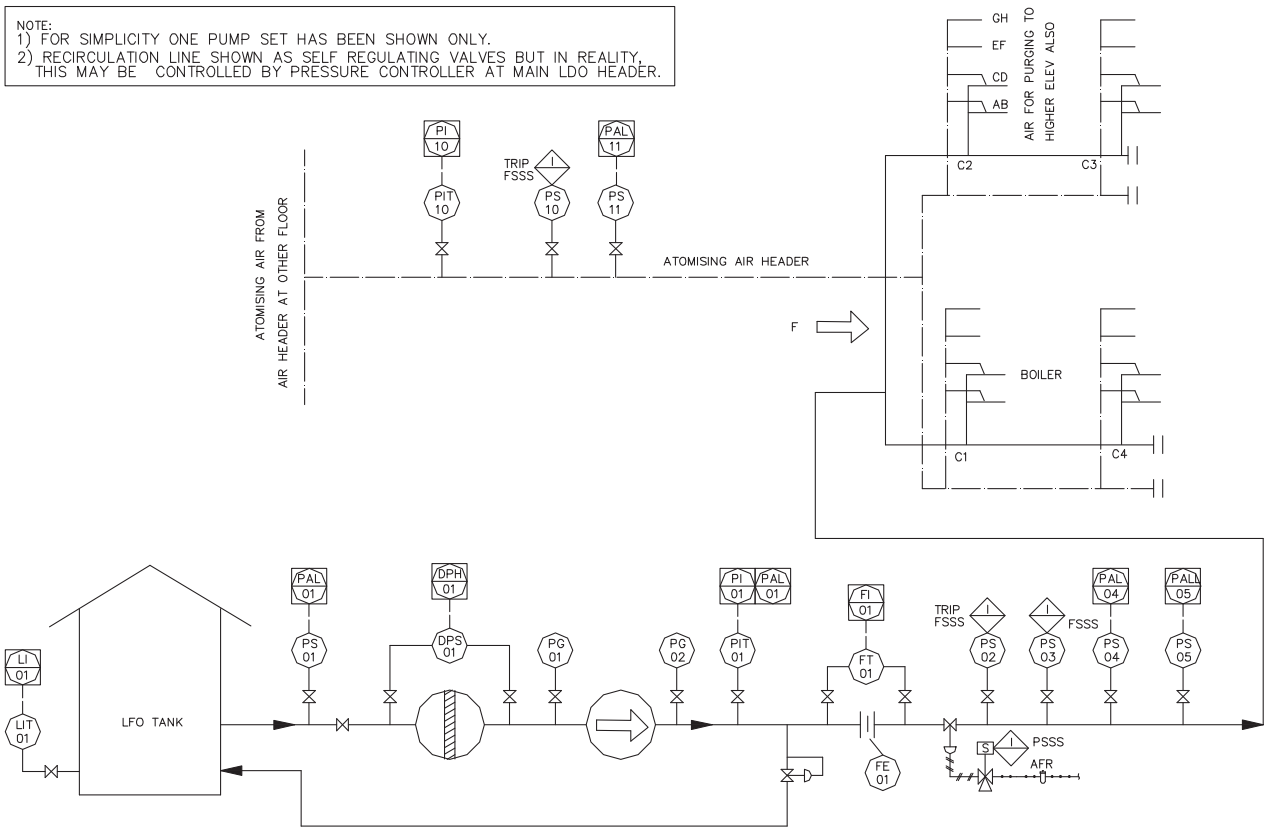


FIGURE III/11.2.2-2 Light oil from LDO tank to burner and air atomizing line.

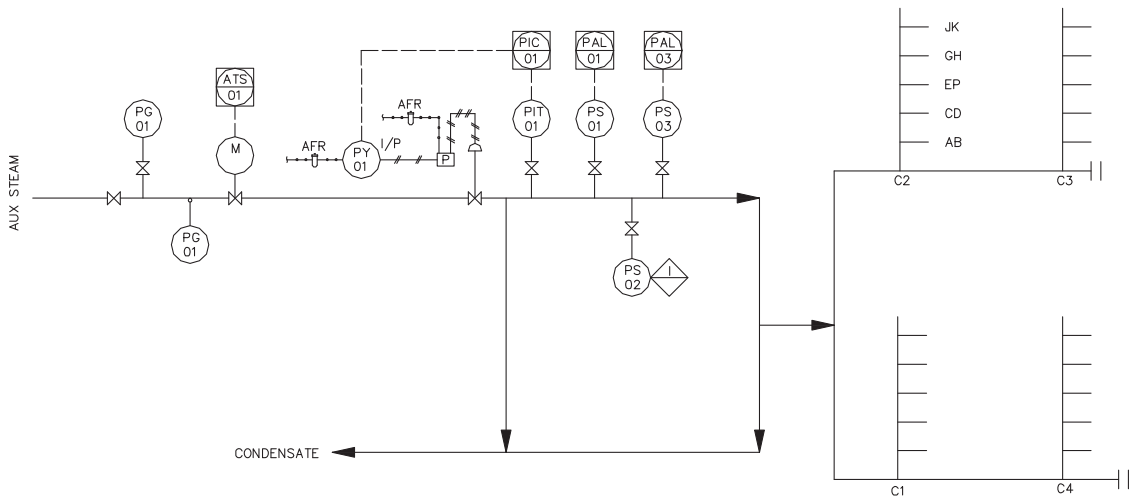


FIGURE III/11.2.2-3 Atomizing steam.

www.EngineeringBooksPDF.com

11.2.2.4 SG Burner Cooling, Ignitor, and Flame Detection System

1. Oil burners are cooled by either steam or air depending on the design.
2. Ignition system mainly consists of the following:
   - **a.** Ignitor, HEA
   - **b.** Warm-up oil
   - **c.** Flame detection system
   - **d.** Control system

11.2.2.5 Boiler Circulation System

1. The boiler circulation is necessary to cool the waterwalls, economizer, etc. Circulation system of OT and drum type boilers are different.
2. There are two types of circulation for a drum type boiler: natural and enforced. In natural circulation the circulation is thermally induced without the use of any pump. In forced circulation, in addition to thermally induced circulation, it is assisted by a Boiler Circulation Pump (BCP).
3. From the economizer water reaches the drum, where, through a downcomer, it reaches the furnace bottom and passes through the water tubes in the furnace wall. When flue gas passes across the furnace waterwall tubes, it heats up the water inside the tube, its density decreases, and it tries to go up. These water tubes/over tubes carry the steam/water mixer to the top, i.e., to the drum through a riser (because while carrying the steam/water mixture through tubes it gets heated by flue gas). In contrast, the same water at lower temperature (hence higher density) will try to fill the gap. Because of the difference in density between cooler water in the downcomer and the steam/water mixture in the riser tube, a natural circulation in the system is established due to convection current. It is important that the flow through the tube must be sufficient to cool the tube and prevent tubes from overheating by flue gas. The greater the heat absorption, there will be more the circulation.
4. In forced circulation, as the name suggests, external mechanical force is produced by pumps located at the bottom (see Figure III/11.2.2-4b). In SC boilers this type of circulation is found when boiler pressure is high with lower static head energy (mainly for higher rated boilers).

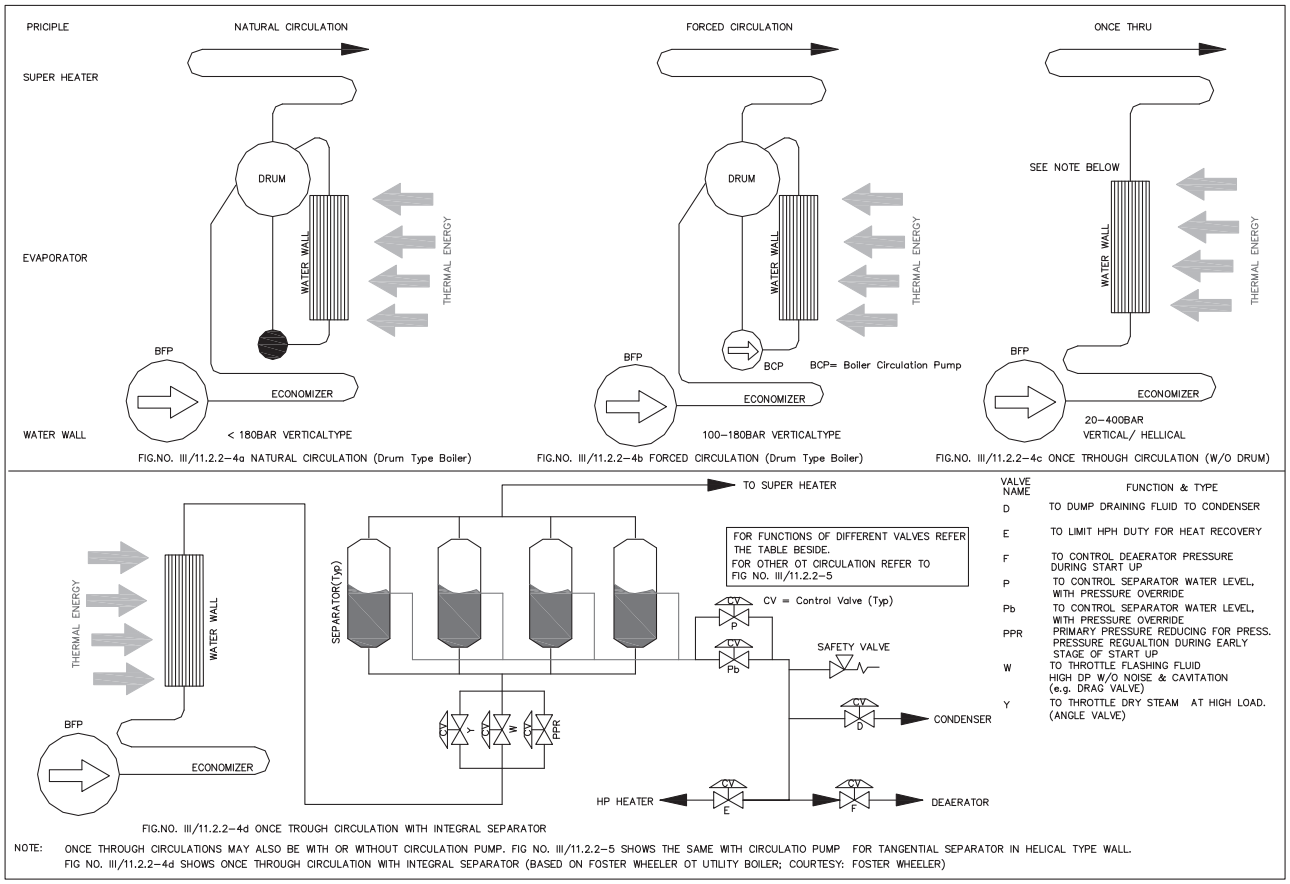


FIGURE III/11.2.2-4 Boiler circulation types.

www.EngineeringBooksPDF.com

5. In a SC boiler water absorbs latent heat to convert itself to steam. As the pressure is increased the amount of latent heat required to convert water to steam reduces. When the pressure is further increased, latent heat of vaporization is zero. The pressure at which such a phenomenon occurs is called critical pressure.
6. At pressure greater than critical pressure, ~225 kg/cm^2 (temperature ~374°C), there is no boiling and water becomes steam directly. This is called an SC boiler. If pressure and temperature parameters are in the range of 300 bar and 620°C, respectively, then the boiler is called a USC boiler.
7. SC boilers are OT in design, meaning that there will not be any stored vessel (i.e., drum) associated with the boiler. Criticality associated with OT boilers is the design of the furnace steam/water evaporator circuitry, the start-up system, and the firing and heat recovery area (HRA). OT boilers have either a recirculation or boiler circulation pump (see Figure III/11.2.2-5) no pump at all.
8. With OT boilers, before fuel is fired, a minimum fluid mass flow rate is established in the evaporator tube to protect it from overheating. This is ensured by the BCP and keeping the feed control valve at a minimum (~25–30% flow rate) opening. This is a basic requirement. In start-up the OT boiler is similar to the drum type boiler control with its storage tank. This is called a Benson load.
9. Before the flow rate reaches Benson point (25–30%), recirculation flow guarantees the safety. After Benson point, a water-cooled wall can be cooled by mass flow rate.
10. Steam and water are separated at the separator, wherefrom steam is put into the SH and through the separator storage tank, and the BCP sends the water back to the economizer. During start-up, if the circulation is improper then there may be a serious temperature difference and damage to the boiler.
11. Safe operation of water circulation is highly dependent on BCP flow control as well as separator storage tank

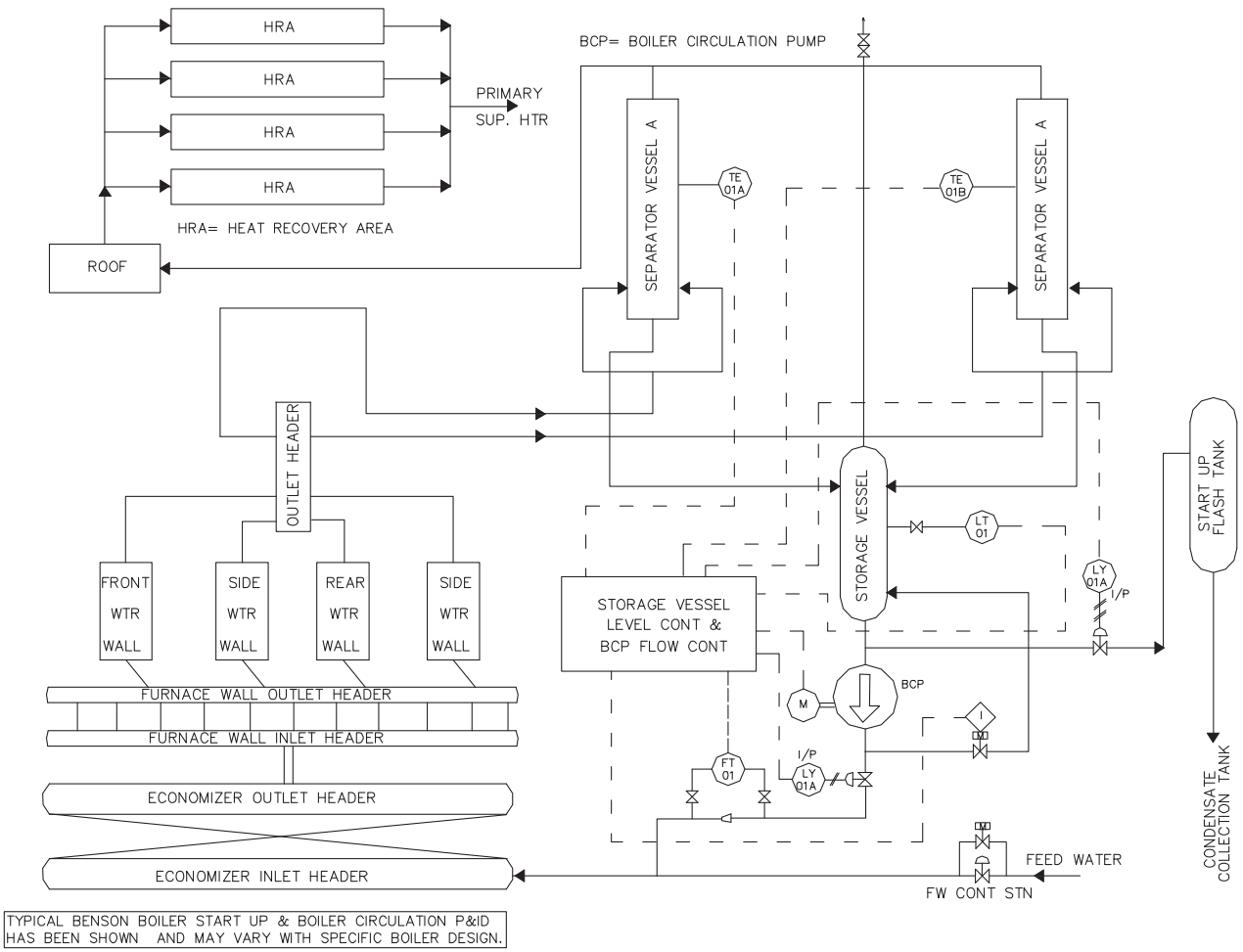


FIGURE III/11.2.2-5 Start-up and boiler water circulation for OT boiler.

www.EngineeringBooksPDF.com

level control. Normally storage level is maintained by BCP flow control. When the storage level is receiving higher then excess flow, it is controlled by draining to the flash tank.

12. When the unit load is near and/or above the Benson point, water level in the separator mostly disappears. Normally the Benson point is passed in rising speed. At a certain point of steam flow the BCP is stopped and automatic FW flow control takes over. FW to fuel flow ratio is very important for OT boilers. Steam temperature is maintained mainly by the firing rate with auxiliary control from spray water flow.
13. Temperature is a function of load. Normally little superheat is kept at the separator. At a low-load combustion rate and decreased feed rate, there may be saturated steam in the separator.
14. OT design is mainly based on the Benson spiral design with a circulation pump. However, there are other designs (e.g. Benson vertical design) where circulation without a circulation pump is possible. Also, Foster Wheeler multipass design does not call for separate circulation pump, but in this case a separator design is different (see Foster Wheeler once through utility boiler technology).

BIBLIOGRAPHY

[1] An analysis of a thermal power plant working on a Rankine cycle: A theoretical investigation : R.K Kaporia, S.Kumar and K.S.Kasana :Journal of Energy in South Africa Vol. 19 no.1 Feb 2008.

[2] Boiler Feed Pump: Sulzer: Pump Catalog.

[3] Boiler Superheater Reheaters: Book: Steam/ its generation & use: Bcock & Wilcox/ Babcock & Wilcox 1972.

[4] Deaerating condenser boosts combined-cycle plant efficiency: R.E. ATHEY, AND E. SPENCER: GRAHAM MANUFACTURING CO.

[5] Economizers & Air Heater: Book: Steam/ its generation & use: Book: Babcock & Wilcox/ Babcock & Wilcox 1972.

[6] Feed Water System: IRI Power plant: Industrial Resources Inc.

[7] Fuel burning system: Book: Combustion Fossil Power systems: Editor J. Singer Combustion Engineering Inc. 1981.

[8] GE Combined Cycle Product line & performance : D.L.Chase & P.T. Kehoe: G.E. New York USA.

[9] Latest Power Plant Control System: T. Kamei, T.Tomura & Y. Kato: Hitachi Documents.

[10] Main Electric Power and Balance of Plant Systems and Equipment of Qinshan Phas III CANDU Nuclear Power Plant : J. Yan, J. Wanggui, H. Ping and S. Varanasi* : East China Electric Power Design Institute * Atomic Energy of Canada Limited.

[11] Mark VIe Control System Product Description: GEI-100600A: G.E.Document.

[12] MS Supply & feed water System: Canteach.candu.org (internet) : Training docu. Jan. 1996.

[13] PIP PIC001: Process industry Practices.

[14] Pipe Symbols: web.cecs.pdx.edu/∼graig/eas199B/PipeSymbols1: Intenet ref.

[15] Power Generation Condensate Polshing Unit: PALL Power generation USA: Catalog.

[16] Preliminary Safety Analysis Report: Lungmen Unit 1&2.

[17] Process Diagram master2 : 30678_12_ch12_p251−270.qxd : Internet ref.

[18] Pulverised Fuel System Fires: Babcock & Wilcox: system Write up.

[19] Pulverizer & Pulverized Coal System: Combustion Fossil Power systems: J. singer Combustion Engineering Inc. 1981.

[20] Simulation of Combined Cyle Co generation Power Plant: W. Pongprasert, S. Kerdsuwan: WIRC King Mongkut Institute of Technology Thailand.

[21] Standard Tech. Specification For Main plant Package of Sub Critical Thermal power plant (500 MW and above): Central Electricity Authority New Delhi : New Delhi India September2008.

[22] Steam and power Conversion System : AP1000 Design Control Document.

[23] Steam generation: Book: Combustion Fossil Power systems: J. singer Combustion Engineering Inc. 1981.

[24] Steam generator Auxiliaries: Book: Combustion Fossil Power systems : Combustion Engineering Inc.

[25] Thermodynamic Analysis of Rankine-Kalina Combined Cycle: R. S.Murugan, P. M. V. Subbarao: IIT New Delhi India.

www.EngineeringBooksPDF.com

Chapter IV

General Instruments

1. INTRODUCTION

Modern thermal power plants are equipped with state-of-the-art instrumentation systems. Advancements in science and technology have transformed instrumentation into a continuously developing system including both measurement and control systems. With the help of measuring instruments, human civilization has learned about the environment, the world, and beyond. By controlling instruments, the quality of necessities and enjoyment of life are not only enhanced but improved. Modernization of and progress in the industrial sector has always depended on precise, modern cost-effective instruments. The power plant instrumentation system comprises various types of measurements. In this chapter discussions are restricted to general types of instruments for pressure, temperature, flow, and level.

1.1 Pressure Measurements

The simplest device for measuring pressure and differential pressure (DP) is the manometer or differential manometer. This is used to locally view low and very low pressure. Gauges are also used for local viewing purposes as well as for remote viewing through an extended impulse line for higher pressure applications. In some cases, low-pressure measurements were also taken remotely. Switches are used for alarm generation and binary control purposes, for example, starting, tripping, and interlocked operation of different drive motors and safety relays or equipment. Some sensing elements use the amount of expansion or displacement characteristic of the material when subjected to pressure. This is called the elastic deformation pressure element, which practically changes its shape under pressure.

For gauges, switches, and even for pneumatic pressure transmitters this characteristic is utilized by different elements, such as bellows, diaphragm, bourdon, helix, capsule, and spiral, depending on the pressure maximum and minimum ranges. Different types of instruments deployed for each kind of measurement are listed in Table IV/1-1. There were many other element types available, for example, ring balance type, wound resistance in varying shapes, etc., but these are now almost obsolete.

1.2 Temperature Gauges and Switches

There are temperature gauges and switches that use the volume-expansion characteristics of fluid after application of heat or the temperature. There is a bulb containing fluid (called transmission fluid) placed at the sensing point. The transmission fluid may be inert gas like nitrogen or liquid like mercury. The receiving side may be a bellows, diaphragm, bourdon, helix, capsule, or spiral-type pressure sensing element. A bimetallic element is also used, which bends in one direction when heat is applied to an assembly of two metals of dissimilar coefficient of expansion joined together. Types of temperature gauge and switch elements are listed in Table IV/1-2.

Pressure spring type temperature gauges are mainly used for remote indication/switch where the indicator/dial case is brought at a distance from the sensing point through a capillary tube. Here the fluid-filled bulb is inserted in the process and a definite amount of volume expansion at a particular temperature pressurizes the internal system fluid, which is sensed by the pressure spring located inside the indicator/dial case. The pressure spring is a hollow spring of simple C-shaped bourdon tube or spiral, although a helix as more often used. A combination of liquid and vapor is also used as a filling liquid, but as vapor does not expand uniformly like liquid and gas, the scale becomes nonlinear at higher temperatures. The range is thereby limited to -180 to 300°C.

1.3 Elements for Remote Pressure Transmitters

The operating pressure in modern power plants varies widely from as low as 0.1 kg/cm^2 abs to higher values around 350 kg/cm^2 g. To take care of this variation, different types of instruments are used with various types of sensing elements for electronic transmitters such as capacitance, dual inductance, strain gauges, piezo resistive, silicon resonance, twin resonance (nitinol) wires, etc. In capacitance elements, a diaphragm is used as het primary element with a higher measuring pressure on one side and atmospheric pressure (for gauge pressure measurement) or vacuum (for vacuum/absolute pressure measurement) on the other side. The diaphragm moves toward the lower

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

TABLE IV/1-1 Type of Pressure Gauge Switch Elements

Type of Measurement	Type of Instruments					
Pressure gauges/switches	**Bellow**	**Bourdon tube**	**Capsule**	**Diaphragm**	**Helix**	**Spiral**
Maximum range kg/cm^2	56	7000	3.5	28	700	280
Minimum range mm of wcl or kg/cm^2	125 mm of wcl	0.85 kg/cm^2	25 mm of wcl	50mm of wcl	3.5 kg/cm^2	1.05 kg/cm^2

TABLE IV/1-2 Type of Temperature Gauge/Switch Elements

Temperature Gauges/Switches	Mercury in Glass	Alcohol, Toluene in Glass	Bimetallic	Gas/Liquid Filled, Pressure Spring Type
Range °C	−30 to 510	−180 to 650	−180 to 425	−250 to 550

pressure side and this displacement is sensed as a change in ratio of two capacitances (placed in such a way that if one increases the other would decrease) and ultimately converted into a two-wire 4-20 mADC signal. For strain gauge, when pressure is applied, the deformation due to stress is converted into an electrical signal. For other operating principles, the change in electrical characteristics due to physical change after applying pressure is sensed and converted into a 4-20 mADC signal. For smart transmitters (highway-addressable remote transmission, HART), superimposed digital signals proportional to input pressure are also available in the same output terminals. Other smart transmitters utilize a full digital signal in Fieldbus systems such as Profibus and Foundation Fieldbus.

The same philosophy applies with a differential pressure transmitter (DPT): two process pressure sides are connected to the transmitter with a higher pressure-tapping impulse line to the high side and lower pressure-tapping impulse line to the low side.

1.4 Elements for Remote Temperature Transmitters

With pressure transmitters, the sensing elements and processing circuitry are located in the same enclosure whereas the temperature sensors/elements are located separately at the sensing point inside the process. The sensors/elements are isolated from the process fluid, which may have a high velocity of abrasive and/or hazardous nature, with the help of a thermowell. This takes care of process-side complications and is normally threaded and/or welded to the process pipe or vessel. Inside the thermowell there is a female thread to accommodate the sensors/elements with a male thread.

Sensors/elements are of various types, such as a resistance temperature detector (RTD), thermocouple (THC) and thermistor. An RTD utilizes the property of changing "resistance" of an electrically conducting wire with respect to change in temperature: the resistance of a conducting wire increases when the temperature rises. The operation of the resistance thermometer depends on the electrical/electronic circuitry. The temperature range covered by different types of RTDs is (−)250 to 850°C. There are three types of RTDs normally in use: copper (53 Ω at 0°C); platinum (100 Ω or 1000 Ω at 0°C), also popularly called the platinum resistance thermometer (PRT); and nickel (100 Ω or 500 Ω at 0°C). PRTs are widely used in power plants to measure water and air temperature <400°C.

Thermistors also show the similar type of quality but in the reverse direction, that is, the resistance of the element decreases when the temperature rises. THCs utilize the thermoelectric property of generating electromotive force (emf) in millivolts (mV) between two open ends when two dissimilar metal wires are solidly connected at the end and subjected to higher temperatures than the other open ends. When the joined ends are heated or subjected to/inserted into a higher temperature, a small but measurable voltage (mV) is generated between the two open and cold ends, depending on the type of wires selected. This varies with hot end and cold ends. Various types of THCs are in regular use: iron-constantan (type J),copper-constantan (type T), chromel-alumel (type K), platinum-platino rhodium [two types with 10% (S type), and 13% (R type) platinum in the alloy]. Table IV/1-3 shows examples of THC temperature ranges.

www.EngineeringBooksPDF.com

TABLE IV/1-3 Type of THC and Temperature Ranges

Types of THCs	Iron-Constantan (Type J),	Copper-Constantan (Type T)	Chromel-Alumel (Type K)	Platinum-Platino Rhodium (13%) (Type R)	Platinum-Platino Rhodium (10%) (Type S)
Temperature Range in °C	−210 to 1200	−200 to 400	250−372	−50 to 1768	−50 to 1768
Used for measurement of parameters	Mill outlet/ bearing temperature		Steam temperature above 300°C	Furnace temperature ~1000°C	Furnace temperature ~1000°C

In all cases types are "ISA type."

1.5 Temperature Transmitters

Temperature transmitters are used to convert the mV output from the temperature elements to 4-20 mADC (with a superimposed digital signal for the smart version). The exact type/model of temperature transmitter has to be selected as per the type of element. The transmitters may be element head mounted, local/field mounted, or element head or cabinet/panel back mounted. As the mV output of temperature elements (for THCs) depends on the temperature difference between the hot and cold junctions, there must be a cold junction compensation facility at the transmitter end to take care of the ambient temperature variation at the location of the transmitter. The cable from element to transmitter needs to be the same specification as the THC element. This is called an extension cable, and there is one with similar characteristics (as a cost-saving measure) called a compensating cable.

As for RTDs, the output is resistance in ohms and the variable signal cable resistance due to variation in ambient temperature would make the measurement unpredictable. Hence, various methods have been applied to obviate this problem by using a three-wire or four-wire compensation system. More detailed discussions on this aspect are available in Clause 3.2. Temperature ranges of THCs not much in use are seen in Table IV/1-4.

1.6 Flow Measurement

1.6.1 Sight Flow Glass

This is used to see that fluid is just flowing through the pipeline without any calibration, whereas flow gauges are provided with flow calibrations. Flow meters and rotameters are types of flow gauges and ovalgear meters and nutating disk meters are flow meters that use positive displacement. These meters are available with indication of flow rate as well as cumulative flow value and even have a compatible electrical signal of 4-20 mA.

1.6.2 Flow Switches

These are also available in various types, such as flapper, target, and diaphragm. Switch contacts are available in flow meters also and are normally provided for alarms, data acquisition systems, or open loop control purposes.

1.6.3 Flow Elements or Differential Producers

These are, to some extent, special types of instruments that are installed inside a flowing channel, such as a pipe or duct, for restriction and as a result a pressure drop proportional to the square of flow is experienced across the element. This pressure drop is taken to the DPT for further use. Many types of flow elements or differential producers are available: flow nozzles, orifice plates, Venturi tubes,

TABLE IV/1-4 Type of Uncommon THCs and Temperature Ranges

Types of THCs	Platinum-Rhodium (30 and 6%) Alloy (Type B)	Rhenium-Tungsten 5 and 26% (Type C)	Nickel-Alloy, Molybdenum (18%), and Cobalt (0.8%) (Type M)	Platinum-Platino Rhodium (Type R)	Platinum-Platino Rhodium (Type S)
Range in °C	50−1800	0−320	0−1400	−50 to 768	−50 to 1768

www.EngineeringBooksPDF.com

aerofoils, piccolo tubes. Usage depends on the service condition and they are discussed in further detail in Clause 4.1.

Other types of flow elements are also available that basically create restriction in a particular section of a specially designed flow path for open-channel flow measurement. The flow elements are weir/notches (V or rectangular notches) or a Parshall flume. When passing through this type of restriction or the flow path itself, the liquid level increases near its inlet and this increased level is proportional to the flow. Normally this type of level is measured by an ultrasonic level sensor and transmitter with built-in software providing output in terms of flow.

1.6.4 Flow Transmitters

These can have DPTs with two pressure impulse lines connected across the flow element or differential producer. The flow is calibrated so that the output is proportional to the square root of DP thus produced across the restriction as deducted from Bernoulli's theorem.

Magnetic flow meters are based on the electromagnetic property of an electrical conductor. Here, the emf generated is directly proportional to velocity from the flow as the area of cross section is constant near the flow meter. The most important criterion for the flowing media is that the conductivity must be more than 0.5 μSiemens/cm. The velocity range is 0.5 m/sec to as high as 15 m/sec, but the practical higher limit is ~5 m/sec.

There are other very special types of flow meters—vortex, coriolis mass flow meter, swirl, thermal mass etc.—but normally they are not used in power plant flow measurement. The coriolis mass flow meter has limited use in oil flow services.

1.7 Level Measurement

1.7.1 Level Gauge

The level gauge, also popularly called as gauge glass, is located near the vessel. This is a very important instrument for boiler drum-level indication without which the Boiler Inspectorate will not allow the boiler to run. A calibrated glass tube of suitable thickness and material, generally borosilicate or toughened glass tubes, are placed vertically with the help of upper and lower limbs (pipes/tubes) connected to the process vessel covering the level to be observed. Almost all of the heaters, tanks, and boiler drums are provided with gauge glass for a direct reading. Other types of special gauge glass are available for boiler drums with bicolor indication with steam as red and water as green.

1.7.2 Level Switch

Level switches of various types are available, such as conductivity, capacitance, float, magnetic float, displacer, ultrasonic, paddle, radio frequency, etc. For open tank, conductivity type (for fluid that is highly or moderately conductive), capacitance type (for low-conductive fluid), displacer, and float type are for top-mounted switches. Side-mounted float types are used at any level. Ultrasonic or radio frequency types can be used for a high range up to 30 m. Paddle type switches are used only for solid level service, for example, coal or ash in the bunker.

For a pressurized tank, side-mounted, magnetic float type switches may be used at any level up to a process pressure of 25 kg/cm^2. For very high pressure, Hydrastep or other similar types are used for boiler tripping purposes from very high and low drum levels.

1.7.3 Level Transmitter

Level transmitters operate on DP principles similar to pressure or DPT, which are used for open tanks or pressurized tanks, respectively. These types are used for drums, all heaters, deaerators, condenser hotwells, condenser surge tanks, etc., for level measurements. Displacer type transmitters are also used for pressurized tanks, whereas conductivity, capacitance, ultrasonic, and radio frequency type level transmitters are used for open tank measurements.

2. PRESSURE MEASUREMENT: VARIOUS MEASURING POINTS AND RANGE SELECTION

Initial introduction of pressure measurements are already incorporated in Clause 1 and Chapter I, Clauses 3.1 and 3.2. Various measuring points in the power plant (typical value of a 250 MW plant) are given in Table IV/2-1 along with the operating/maximum continuous rating (MCR) value and instrument ranges. Normally the calibrated ranges are selected so that the operating or MCR value is ~67 % of the full range. But there may be some cases where the operating or MCR value is closer to the calibrated range, for example, the control range of an instrument.

2.1 Pressure Transmitter: Working Principle, Specification, Supplier, and Special Features

Pressure transmitters are devices that convert low-level electrical outputs from pressure-sensing elements to higher level signals that can be transmitted over a long distance for further processing and use in various systems. Various sensing technologies have been utilized to measure the pressure of liquids and gases. Preliminary discussions in previous chapters (Clause 1 and Chapter I, Clause 3.2) indicated only the types of transmitters that deployed the sensors and the types with working principles, namely

www.EngineeringBooksPDF.com

TABLE IV/2-1 Typical Measuring Points for Pressure Transmitters

SR. No.	Service Description	Operating/MCR Value	Calibrated Range
1	Forced draft fan discharge pressure	250 mm wcl	0–400 mm wcl
2	Secondary air heater outlet pressure	180 mm wcl	0–300 mm wcl
3	Primary air heater inlet header pressure	1000 mm wcl	0–1500 mm wcl
4	Primary air heater outlet pressure	925 mm wcl	0–1400 mm wcl
5	Scanner air fan discharge pressure	400 mm wcl	0–600 mm wcl
6	Flue gas pressure at secondary air heater inlet	−55 mm wcl	−75–0 mm wcl
7	Flue gas pressure at secondary air heater outlet	−145 mm wcl	−150–0 mm wcl
8	Flue gas pressure at primary air heater inlet	−60 mm wcl	−140–0 mm wcl
9	Flue gas pressure at primary air heater outlet	−140 mm wcl	−200–0 mm wcl
10	Flue gas pressure at ESP inlet	−175 mm wcl	−250–0 mm wcl
11	Flue gas pressure at ESP outlet	−200 mm wcl	−300–0 mm wcl
12	Indirect fan discharge pressure	50 mm wcl	0–75 mm wcl
13	Primary air pressure to mill	900 mm wcl	0–1500 mm wcl
14	Furnace pressure	3 mm	−250 to +250 mm
15	Hot air duct pressure	270 mm	0–400 mm wcl
16	Seal air fan discharge pressure	1200 mm wcl	0–2000 mm wcl
17	Mill DP	550 mm	0–800 mm wcl
18	Feed control station inlet feed water pressure	185 kg/cm^2	0–250 kg/cm^2
19	Economizer inlet feed water pressure	175 kg/cm^2	0–250 kg/cm^2
20	Main steam outlet pressure	155 kg/cm^2	0– 200 kg/cm^2
21	Reheater outlet pressure	38 kg/cm^2	0–60 kg/cm^2
22	Reheater inlet pressure	40 kg/cm^2	0–60 kg/cm^2
23	FO pressure at flow control valve outlet	10 kg/cm^2	0–15 kg/cm^2
24	FO pressure at FO pump discharge	15 kg/cm^2	0–20 kg/cm^2
25	LDO pressure at LDO pump discharge	10 kg/cm^2	0–15 kg/cm^2
26	Auxiliary steam pressure for SCAPH	15 kg/cm^2	0–20 kg/cm^2
27	Auxiliary steam pressure for atomization	10 kg/cm^2	0–15 kg/cm^2
28	Auxiliary steam pressure for soot blower	35 kg/cm^2	0–50 kg/cm^2
29	HPT steam chest pressure	150 kg/cm^2	0–200 kg/cm^2
30	HPT governor valve outlet pressure	150 kg/cm^2	0–200 kg/cm^2
31	CRH steam pressure at HPT exhaust	42 kg/cm^2	0–60 kg/cm^2
32	HP; first stage steam pressure	145 kg/cm^2	0–200 kg/cm^2
33	RH (IPT) steam chest pressure	35 kg/cm^2	0–50 kg/cm^2
34	IPT RH ESV outlet steam pressure	35 kg/cm^2	0–50 kg/cm^2
35	LPT inlet steam pressure	5.13 kg/cm^2	0–10 kg/cm^2
36	LPT exhaust steam pressure	1.08 kg/cm^2	0–1.50 kg/cm^2
37	Turbine gland steam header pressure	3 kg/cm^2	0–5 kg/cm^2

Continued

www.EngineeringBooksPDF.com

TABLE IV/2-1 Typical Measuring Points for Pressure Transmitters—cont'd

SR. No.	Service Description	Operating/MCR Value	Calibrated Range
38	Gland steam supply pressure to LPT	0.5 kg/cm^2	0–1 kg/cm^2
39	Condenser shell pressure	0.1 kg/cm^{2}abs	0–1 kg/cm^2 abs
40	Condenser air suction pressure	0.1 kg/cm^2 abs	0–1 kg/cm^2 abs
41	Condenser air extraction pump suction pressure	0.1 kg/cm^2 abs	0–1 kg/cm^2 abs
42	LPH 1 shell pressure	0.5 kg/cm^2 abs	0–1.5 kg/cm^2 abs
43	LPH 2 shell pressure	0.5 kg/cm^2 abs	0–1.5 kg/cm^2 abs
44	LPH 3 bled steam line pressure	2 kg/cm^2	0–3 kg/cm^2
45	L.PH 4 bled steam line pressure	5.7 kg/cm^2	0–10 kg/cm^2
46	Deaerator bled (IP extraction) steam pressure	10 kg/cm^2	0–15 kg/cm^2
47	Deaerator header steam pressure	10 kg/cm^2	0–15 kg/cm^2
48	Deaerator low-load steam supply pressure	3.5 kg/cm^2	0–5 kg/cm^2
49	Deaerator storage tank steam pressure	10 kg/cm^2	0–15 kg/cm^2
50	BFP suction pressure	13 kg/cm^2	20 kg/cm^2
51	Booster pump discharge feed water pressure	0–40 kg/cm^2	0–60 kg/cm^2
52	BFP pressure at discharge valve inlet	210 kg/cm^2	320 kg/cm^2
53	BFP discharge header pressure	205 kg/cm^2	320 kg/cm^2
54	HPH 7 outlet feed water pressure	195 kg/cm^2	0–250 kg/cm^2
55	Boiler drum steam pressure	170 kg/cm^2	0–250 kg/cm^2
56	Primary super heater inlet pressure	165 kg/cm^2	0–250 kg/cm^2
57	IPT bled steam line pressure	21 kg/cm^2	0–30 kg/cm^2
58	HPH 7 (from CRH) steam line pressure	42 kg/cm^2	0–60 kg/cm^2
59	DP across feed control station	7 kg/cm^2	0–10 kg/cm^2
60	Condensate pressure at condenser extraction pump discharge	27 kg/cm^2	0–40 kg/cm^2
61	Condensate pressure at drain cooler inlet	25 kg/cm^2	0–40 kg/cm^2
62	Condensate pressure at LPH 2 outlet	23 kg/cm^2	0–30 kg/cm^2
63	Condensate pressure at LPH 4 outlet	19 kg/cm^2	0–30 kg/cm^2
64	FRF (turbine oil) supply pump discharge pressure	68 kg/cm^2	0–100 kg/cm^2
65	FRF supply filter outlet pressure	66 kg/cm^2	0–100 kg/cm^2
66	CW pump discharge pressure	6 kg/cm^2	0–10 kg/cm^2
67	CW at condenser inlet pressure	5 kg/cm^2	0–10 kg/cm^2
68	CW at condenser outlet pressure	4.5 kg/cm^2	0–10 kg/cm^2
69	Generator stator coolant pump discharge pressure	7 kg/cm^2	0–10 kg/cm^2
70	Jacking oil pump discharge pressure	210 kg/cm^2	0–320 kg/cm^2
71	Lube oil supply pressure to TG bearings	2kg/cm^2	0–3 kg/cm^2
72	Condensate make-up bus pressure	7 kg/cm^2	0–10 kg/cm^2
73	Intake pump discharge pressure	10 kg/cm^2	0–16 kg/cm^2
74	ACW supply bus pressure	7 kg/cm^2	0–10 kg/cm^2

Continued

www.EngineeringBooksPDF.com

TABLE IV/2-1 Typical Measuring Points for Pressure Transmitters—cont'd

SR. No.	Service Description	Operating/MCR Value	Calibrated Range
75	Service water bus pressure	7 kg/cm^2	0–10 kg/cm^2
76	DMCCW suction bus pressure	10 kg/cm^2	0–16 kg/cm^2
77	DMCCW supply bus pressure at heat exchange inlet	7 kg/cm^2	0–10 kg/cm^2
78	DMCCW supply bus pressure at heat exchange outlet	7 kg/cm^2	0–10 kg/cm^2
79	DMCCW supply bus pressure at heat exchange outlet	7 kg/cm^2	0–10 kg/cm^2
80	Stator water cooling supply bus pressure	7 kg/cm^2	0–10 kg/cm^2
81	Auxiliary cooling water pump discharge pressure	6 kg/cm^2	0–10 kg/cm^2
82	Cooling water pressure to compressor	6 kg/cm^2	0–10 kg/cm^2
83	Instrument air compressor discharge pressure	8 kg/cm^2	0–12 kg/cm^2
84	Service air compressor discharge pressure	8 kg/cm^2	0–12kg/cm^2
85	Instrument air receiver pressure	8 kg/cm^2	0–12 kg/cm^2
86	Service air receiver pressure	8 kg/cm^2	0–12kg/cm^2
87	Instrument air pressure at burner area	7 kg/cm^2	0–10 kg/cm^2
88	Instrument air pressure at TG area	7 kg/cm^2	0–10 kg/cm^2
89	DP across gas recycling damper	15 mm wcl	0–20 mm wcl

BFP, boiler feed pump; CRH, cold reheat; CW, circulating water; ESP, exhaust steam pressure; ESV, emergency stop valve; FO, fuel oil; FRF, fire-resistant fluids; HP, high pressure; HPH, high-pressure heater; HPT, high-pressure, turbine; IPT, intermediate pressure turbine; LDO, light diesel oil; LPH; low-pressure heater; RH, reheat; TG, turbo generator; DMCCW, demineralized water clarified cooling water; ACW, auxiliary cooling water; SCAPH, steam coil air preheater.

capacitance, dual inductance, strain gauges (resistive), silicon resonance, piezo electric, twin resonance wire, or nitinol wires.

The main purpose of deploying pressure transmitters is to measure the pressure of various points of interest and to express the values in different units. Gauge pressure is the most common type of pressure measurement relative to the local atmospheric pressure . Absolute pressure is a pressure measurement relative to a perfect vacuum that is −1.0 atm of pressure and whose physical values in different units are 1.033 kg/cm^2, 14.7 lb/sq. in, 1.013 bar, or 760 mmHg. For all practical purposes these values are taken as 1.0 kg/cm^2 (or 10 m of water column head, wcl), 14.22 lb/sq. in, 1.0 bar, or 736 mmHg. Vacuum pressures are lower than atmospheric pressure and can be expressed either in an absolute pressure unit or in a negative gauge pressure. On the other hand, sealed gauge pressure is relative to 1 atm of pressure at sea level. DP reflects the difference between two input pressures. Compound pressure instruments can display both positive and negative pressures. Pressure transmitters are calibrated in different engineering units as per the prevalent standards of the user countries such as in kilograms per square centimeter, pounds per square inch, pascals or kilo pascals, bars or millibars, inches or centimeters of mercury, or inches or feet or meter or millimeter of water.

Pressure transmitters can be classified according to display types and other features made available by the manufacturer. Only a simple visual indication by a needle is provided in the analog meters. Digital display units present numeric or application-specific values in engineering units. These displays may be of different types such as liquid plasma, light emitting diode (LED), liquid crystal displays (LCD), and other types of multiline displays are also available. As far as features are concerned, temperature compensation is provided in smart pressure transmitters as a built-in feature. In some pressure transmitters integral audible or visual alarms and/or output switches with relay contacts or soft logic forms are also available. Explosion-proof or intrinsically safe pressure transmitters are also available, which are suitable for installation in hazardous areas with limited application in power plants.

Various types of electrical signals are available in pressure transmitters as output such as analog voltage and analog current, but the current output(4-20 mA) is always preferred because it is suitable for long transmission coverage and low-attenuation characteristics. Superimposed digitized output signals are also available with the pressure transmitters (smart transmitter type) and are normally encoded with frequency modulation (FM) or some other modulation scheme, such as sine wave or pulse train.

www.EngineeringBooksPDF.com

The universally and widely accepted communication protocols through which the pressure transmitter outputs are transmitted include HART (HART is a registered trademark of the HART Communication Foundation), the Ethernet, the process Fieldbus (Profibus, which is a registered trademark of PROFIBUS International), and Foundation Fieldbus.

There are many criteria constituted as performance specifications of a pressure transmitter and they broadly include, but are not limited to, the following: working pressure, vacuum range, accuracy, response time, dead band, and operating temperature. Working pressure is the maximum, allowable pressure at which pressure transmitters are designed to operate. As a normal practice devices should not exceed 75% of their maximum rated range. Vacuum range, another important measurement, covers the lowest vacuum pressure and the highest vacuum pressure. Accuracy is described as the degree of closeness of the measured value to the true value with respect to the span and expressed in percentage; in other words, it is the difference between the true value and the indication expressed as a percentage of span. In cases where the accuracy differs between the middle span and the first and last quarters of the scale, the largest percentage error is reported. Here accuracy is the overall accuracy including repeatability. Basic pressure transmitters can be divided into two categories: force collector types and others.

2.1.1 Force Collector Types

Devices that respond to variations of applied pressure with mechanical deflection are bourdon tubes, capsules, diaphragms, or bellows, which consist of a highly elastic or flexible element . There are devices also available based on the movements of sealed pistons or cylinders. All of these are categorized as force collector types. The electronic pressure sensors generally use a force collector device to measure strain (or deflection) as a result of applied force (pressure) over an area.

Piezoresistive devices sense shifts of electrical charges within a resistor. Piezoelectric pressure transmitters measure dynamic and quasi-static pressures. They operate in charge mode, which generates a high-impedance charge output, and voltage mode, which uses an amplifier to convert the high-impedance charge into a low-impedance output voltage. Thin-film devices consist of an extremely thin layer of material, usually titanium nitride or polysilicon, deposited on a substrate. Pressure transmitters that use microelectromechanical systems (i.e., variable capacitance) and vibrating elements are also available. More details are outlined in the following paragraphs regarding the principles of operation of the force collector type sensors that use mechanical deflection or strain.

2.1.1.1 Capacitive Type

Capacitive type sensors use a diaphragm and pressure cavity to create a variable capacitance to detect deflection due to applied pressure. A diaphragm is used as a primary element for measuring (high-process side) pressure on one side and atmospheric pressure (for pressure) on the other side (low-process side for DP) or vacuum (for vacuum/absolute pressure). The diaphragm moves toward the lower pressure side and this deflection is sensed as change in capacitance. Ultimately the transmitter part converts it into a compatible output signal. Common technologies use metal, ceramic, and silicon diaphragms. Generally, these technologies are applied to low and medium pressures (absolute, differential, and gauge).

2.1.1.2 Piezoresistive Strain Gauge

The piezoresistive effect of bonded or formed strain gauges detect strain/deformation due to applied pressure. The most common types are silicon (monocrystalline), polysilicon thin film, bonded metal foil, thick film, and sputtered thin film. This is one of the most commonly used sensing technologies for general purpose pressure measurement. Generally, these technologies are suited to measure absolute, gauge, vacuum, and DPs. The piezoresistive effect describes the variation of electrical resistance of a material due to applied mechanical stress. In contrast to the piezoelectric effect, the piezoresistive effect only causes a change in resistance; it does not produce an electric potential. The piezoresistive effect of metal sensors is only due to the change of the sensor geometry resulting from applied mechanical stress.

Metal piezoresistors, i.e., strain gauges, are successfully used in a wide range of applications. The piezoresistive effect of semiconductor materials can be several orders of magnitudes larger than the geometrical piezoresistive effect in metals and is present in materials like germanium, polycrystalline silicon, amorphous silicon, silicon carbide, and single crystal silicon. The piezoresistive effect of semiconductors has been widely used for various sensor devices using all kinds of semiconductor materials indicated above.

The resistance of silicon changes due to applied stress in two ways: from the stress-dependent change of geometry and from the stress-dependent resistivity of the material. For integrated circuits used in analog and digital hardware, silicon is the choice of material and the use of piezoresistive silicon devices is great interest. Easy integration of stress sensors with various electronic circuits makes it technically viable for vast applications, that is, silicon has enabled a wide range of products using the piezoresistive effect. Many industrial instrumentation devices, such as pressure and acceleration sensors, utilize the piezoresistive effect in silicon. Piezoresistors are resistors made from a piezoresistive material and are usually used to measure

www.EngineeringBooksPDF.com

mechanical stress. They are the simplest form of piezoresistive devices.

2.1.1.3 Inductance/Reluctance (Electromagnetic)

Transmitters using these types of sensors are work like capacitive type sensors, which also use a diaphragm and pressure cavity, except capacitive types create a variable inductance/reluctance to detect deflection due to applied pressure. The diaphragm moves toward the lower pressure side and this deflection is sensed as a change in inductance/reluctance. Ultimately the transmitter part converts it into a compatible output signal. Other electromagnetic sensors measure the displacement of a diaphragm/magnetic object by means of changes in the linear variable differential transformer, Hall effect, or by eddy current principle. The latter two are normally not used for pressure measurement.

2.1.1.4 Piezoelectric

Transmitters employing this type of sensor utilize certain materials, such as quartz, which helps the piezoelectric effect to measure the strain on the sensing mechanism due to pressure. Highly dynamic pressure measurement uses this technology.

Piezoelectricity is a property in crystals and certain ceramics that helps generate an electric field or electric potential proportional to perpendicularly applied mechanical stress. The applied stress induces voltage across the material if the two ends are not short circuited or if they are measured by an instrument with very high input impedance.

The generation of an electric potential when stress is applied exhibits the direct piezoelectric effect. Conversely, the generation of stress and/or strain when an electric field is applied exhibits the reverse piezoelectric effect. From the above observation it is evident that the piezoelectric effect is reversible; for example, lead zirconate titanate crystals exhibit a maximum shape change of about 0.1% of the original dimension.

2.1.2 Other Pressure Measurements (Normally Not Used in Power Plants)

2.1.2.1 Optical

The working principle utilizes the property of physical change of an optical fiber to detect strain due to applied pressure. This technology is employed for challenging service applications where the measuring point is located at a highly remote place or the process temperature is very high or systems require high inherent electromagnetic immunity.

2.1.2.2 Potentiometric

Here the strain caused by applied pressure is detected by the motion of a wiper along a resistive mechanism.

The specifications and data sheet applicable to DPTs is seen in Table IV/2.1-1.

2.2 Pressure Switch: Working Principle, Specification, Supplier, and Special Features

A pressure switch is a type of switch that makes or breaks electrical contact when a certain set pressure has been reached at the input. The input is the process pressure connected through impulse line. The process is air, gas, or liquid and would provide ON/OFF switching with adequate current-carrying capacity. The switch can be designed to make contact either on pressure rise or on pressure fall.

Pressure or DP switches are simple electromechanical devices operating on basic principles of deformation/deflection of sensing elements, movement transmitting/multiplying levers/gears, and springs to provide opposing forces.

Process pressure, when applied through the impulse line to the sensing element, creates a force that overcomes the pre-tensioned spring as per the set point and then moves a balancing arm to effect a very small movement required to actuate a micro switch (es).

There are three essential and basic elements, various combinations of which form hundreds of variants to suit a particular requirement of industrial applications. These include the following:

1. Sensing elements like bourdon tubes, bellows, diaphragms (metallic or elastomeric), or a diaphragm sealed piston
2. A spring to determine the range set point
3. A wide variety of snap-acting micro switches

Details of different types of sensor elements used in pressure switch assemblies are discussed in the following clause.

2.2.1 Bourdon Tube-Operated Sensor

This type of pressure switch operates on the very primary principle of electromechanical devices employing bourdon tubes. The essential elements are the bourdon tube for the input section and the micro switch(es) for the output section. These are very simple in construction, utilizing time-proven German "C"/coiled bourdon tubes of 316 SS/phosphor bronze/beryllium copper material.

When process pressure is applied to the input, that is, the sensing element, it creates a force inside the bourdon tube and it bends outward proportional to the applied pressure similar to a pressure gauge. One or two micro switches are fixed (as per the pressure setting) in the instrument and are actuated by the amplified movement of the bourdon end and remain actuated until the pressure decreases.

www.EngineeringBooksPDF.com

TABLE IV/2.1-1 Data Sheet of Pressure Transmitters

SL. No.	Item	Specification	Special Feature
1	Make/model	ABB/Emersion/Honeywell/YEC	
2	Type/output	Smart two wire/4-20mADC/HART/Profibus/FF BUS	
3	Quantity		
4	Accessories	Mounting bracket, nuts bolts	
5	Body	Plated carbon steel/316 SS	
6	Enclosure	IP 66(NEMA4)/IP 67/FM/CSA	
7	Connection	1/2″ NPT for process	
8	Range		
9	Power supply	10.2−32/45 V DC	
10	Adjustment	Span and zero	
11	Sensor	Inductance/capacitance/piezoresistive	
12	Sensing material and medium	316 SS/Hastelloy C	
13	Terminals	1/2″ NPT	
14	Electrical Connection	1/2″ NPT	
15	Damping	Adjustable electrical damping	
16	Output indication	Local integral display	
17	Span adjustability	1:30	
18	Performance	Accuracy: ±0.075% Stability: ±10% of URL Vibration effect: ±10% of URL	

2.2.2 Bellows Sensor

This is the basic pressure switch actuated by a seamless bellows with an adjustable/fixed nonadjustable switching differential. A micro switch is actuated by the movement of the expansion of the bellows through a linkage, thereby providing independent adjustable set points. Multiple set points are available, each with their own setting scale, spring, and switch. The auxiliary mechanism permits switching differential adjustment between 10 and 15% minutes to ∼50% without disturbing the set point.

The materials are wetted parts (i.e., the bellows) such as phosphor bronze bellows with brass wetted parts, 316L SS bellows with 316 SS wetted parts, Monel bellows with Monel Wetted Parts, etc. The enclosures are normally made of aluminum pressure die cast and weatherproof to IP 66 with nitrile gasket.

2.2.2.1 Diaphragm Sensor

Normally used as a DP switch with pressures from two different sources (one may be atmospheric for the pressure switch) of a particular process that are connected to the two inputs. They are placed across a sensing diaphragm, which may either be metallic or elastomeric. The difference of pressure creates a force, which when it overcomes that of a pretensioned spring, moves a balancing arm to effect the small required movement to actuate micro switch(es). High and low pressures are applied on either side of the specially contoured diaphragm and straight away they eliminate the errors due to the difference in area, which is a common problem encountered in two-element pressure differential switches.

Metallic diaphragms may be made of 316 SS, Monel, or Hastelloy C and elastomer diaphragms may be made of nitrile, EPDM, Viton or silicone. This type of pressure switch comprises a thin diaphragm responsive to pressure change with the help of a rigid ring that secures it. The other parts are similar to bellows type sensors.

2.2.2.2 Diaphragm Sealed Piston

This type of switch is used for corrosive type process fluid. The sensing element essentially comprises a time-proven seal diaphragm with a piston for the actuation of the

www.EngineeringBooksPDF.com

micro switch (es). It is versatile because it comes in a variety of combinations of features. Diaphragm chemical seals can be either direct or remote mounted with a capillary and threaded/flanged connection, duly evacuated, and filled with suitable inert type filling liquid. The wetted part material of the switch, including the diaphragm, can be 316 SS or Monel. The diaphragm can be flange connected for low process pressure or welded to the pressure housings to avoid risk against leakage under extreme or specific conditions.

2.2.3 Accessories

The following accessories may be required as optional items:

1. Damping coil, snubber for eliminating effects of process pulsations for increased instrument life
2. Breather/drain for flameproof enclosures
3. Blow out disk for weatherproof enclosure
4. Pigtail siphons for steam services
5. Three-way cock/isolation valves/valve manifold for process isolation and zero checking

2.2.4 ON/OFF Differential/Dead Band of Switch Contact

This is the difference of process value (pressure in this case) between the points at which the switch actuates and de-actuates. For example, for rising pressure a switch actuates at a high set point of 2.0 kg/cm^2 and remains actuated as long as the pressure is >2.0 kg/cm$^{2.}$. If the pressure comes down, the switch does not de-actuate at exactly 2.0 kg/cm^2 but at 1.8 kg/cm^2. This difference of pressure (0.2 kg/cm^2) is called as ON/OFF differential. As another example, for falling pressure the switch actuates at a low set point of 1.0 kg/cm^2 and remains actuated as long as the pressure is <1.0 kg/cm$^{2.}$. If the pressure increases, the switch does not de-actuate at exactly 1.0 kg/cm^2 but at 1.3 kg/cm^2. This difference of pressure (0.3 kg/cm^2) is the ON/OFF differential.

The switches are available with a fixed or an adjustable ON/OFF differential or dead band. The ON/OFF differential for each micro switch depends on the micro switch movement differential and the spring tension setting.

Pressure switches can be set as follows:

1. "Normal or adequate" for system/equipment/pump "start permissive"
2. "Low" or "High" for "alarm annunciation" systems
3. "Very Low" or "Very High" for system/equipment/pump "tripping"

A few parameters are indicated below with approximate operating/ set value for a typical 250 MW thermal power plant. Specifications for DP switches are shown in Table IV/2.2-1.

2.3 Pressure Gauge: Working Principle, Specification, Supplier, and Special Features

Gauges are used for local and remote viewing through extended impulse lines for higher pressure application. Gauge type pressure measuring instruments may be categorized broadly by the magnitude of the pressure it measures. Pressure gauges or vacuum or compound gauges are examples. Many types of gauges have been developed to measurement pressure and vacuum.

The manometers is another instruments used for local viewing. It is usually limited to measuring pressures near to atmospheric or of low magnitude. It is the simplest type of pressure gauge, requiring no hardware and using a graduated glass tube in a straight vertical or inclined configuration or in a U-shape for a hydrostatic liquid column.

A vacuum gauge is used to measure the pressure in a system below atmospheric pressure in a vacuum. The ranges can divided into low vacuum, high vacuum, and ultra-high vacuum.

As already discussed in Chapter I, Clause 3.2 and Clauses 2.1 and 2.2, some sensing elements uses the amount of expansion or displacement characteristic of the material when subjected to pressure. This is called an elastic deformation pressure element because it practically changes its shape under pressure. For gauges, this characteristic is used by bellows, diaphragms, bourdons, helixes, capsules, and spirals, depending on the pressure maximum and minimum ranges.

Although pressure is an absolute quantity, everyday pressure measurements are usually made relative to atmospheric air pressure. In other cases measurements are made relative to absolute vacuum or to some other reference like standard temperature and pressure (STP) or normal temperature and pressure (NTP).

The principle of operation of the sensor element is the same as that of the pressure switch, as discussed in Clause 2.2, in addition to an indicator needle moving or rotating on a graduated scale supported by sector gear, sector gear axle pin, and indicator needle axle. This has a spur gear that engages the sector gear and extends through the face to drive the indicator needle. Due to the short distance between the lever arm link boss and the pivot pin and the difference between the effective radius of the sector gear and that of the spur gear, any motion of the sensor element is greatly amplified. A small motion of the tube results in a large motion of the indicator needle. A hair spring is provided to preload the gear train to eliminate gear lash and hysteresis.

Along with conventional gauges, digital gauges are also available. They provide analog and/or digital output, data logging capability, high accuracy of about 0.08%

www.EngineeringBooksPDF.com

TABLE IV/2.2-1 Specification Sheet of Pressure Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Reputed manufacturer	
2	Range		
3	Sensor type	Bourdon/diaphragm/bellows	
4	Set point	1 or 2 set points	
5	Sensing material	316 SS/Monel/elastomer	
6	Repeatability	± 0.5% FSR	
7	Medium	Gas/air/water/steam/oil	
8	Switch unit	2 SPDT	
9	Rating	5 Amps, 230 V AC	
10	Connection size	1/2″ BSP. If necessary suitable adapter will be used	
11	Casing/casing material	Weather/explosion proof, IP 65, die cast aluminum	
12	Electrical connection	1″ ET/3/4″ ET complete with cable gland	
13	Dead band	Adjustable with narrow/wide band	
14	Quantity	As per BOM	

(0.05% for TEST gauges, alarm contacts, NEMA-4x/IP 66 enclosure, back-lit display).

Specifications for pressure gauges are seen in Table IV/2.3-1.

3. TEMPERATURE MEASUREMENT: VARIOUS MEASURING POINTS AND RANGE SELECTION

Initial introduction of temperature measurements are already mentioned in Chapter I, Clauses 3.1 and 3.2, and Clauses 1.2, 1.4, and 1.5 of this chapter. Various measuring points in the power plant (typical value of a 250 MW plant) are given in chart form (see Table IV/3-1) along with operating/ MCR values and instrument ranges. Normally the calibrated ranges are selected so that the operating or MCR value is ∼67% (but normally not beyond 75%) of the full range. There may be some cases where the operating or MCR value is closer to the calibrated range.

3.1 Temperature Element: Types and Classification, Immersion Length, and Connection Type

3.1.1 Temperature Elements

Temperature sensors/elements (only electrical sensing is discussed) are located separately at the sensing point inside or near the process and outputs are used for further conditioning and converting to standard output, i.e., 4-20 mADC, and/or superimposed digitized signal. Normally the sensors/elements are isolated from the harsh system conditions, which may have a high velocity of corrosive/ abrasives and/or a hazardous nature. This isolation is done by a thermowell of suitable material, which takes care of the process-side complications and is normally welded or flanged to the process through a stub. The element is then connected to the thermowell, which may be threaded for low pressure or welded for medium high pressure or both threaded and welded for very high pressure services. Figures IV/3.1-1 a and b and IV/3.1-2a and b illustrate how different types of thermowells are mounted on the process and accommodate the elements.

There are various types of sensors/elements, namely RTDs, THCs, and thermistors, the application of which depends mainly on the process temperature.

3.1.1.1 RTDs

The electrical resistance of a medium increases when the temperature rises. RTDs utilize this property of changing resistance of an electrically conducting wire with respect to change in temperature. RTDs are widely used in the temperature range of (−)250 to 850°C. There are three types of RTDs normally in use: copper (53 Ω at 0°), platinum or PRT (100 Ω or 1000 Ω at 0°C) and nickel (100 Ω or 500 Ω platinum at 0°). Compared to copper and nickel RTDs, PRTs are in maximum use in power plants to measure water, oil, flue gas, and air temperatures less than ∼400 °C.

www.EngineeringBooksPDF.com

TABLE IV/2.3-1 Data Sheet of Pressure Gauges

SL. No.	Item	Specification	Special Feature
1	Make/model		
2	Range		
3	Case	In die cast aluminum alloy moisture proof; case epoxy powder-coated black	
4	Bourdon material	Ph br, 17-4 SS/AISI 316 SS	
5	Movements	AISI 304 SS	
6	Process connection	1/2″ NPT(M) with bottom entry	
7	Mounting	Direct	
8	Dial size	150 mm	
9	Quantity	As per BOM	
10	Accessories	Snubber for pulsating services; siphon for steam service, isolating valves, 2VM	

TABLE IV/3-1 Typical Measuring Points for Temperatures (250 MW TPS)

SR. No.	Service Description	Operating/MCR Value (°C)	Calibrated Range (°C)
1	Mill outlet temperature	90	120
2	Mill inlet PA temperature	290	350
3	Mill and mill motor bearing temperature	85	150
4	ID fan lube oil temperature	35	50
5	ID fan and ID fan motor bearing temperature	85	150
6	I.D/FD/PA fan/mill motor winding temperature	110	150
7	ID fan hydraulic coupling working chamber oil temperature	35	50
8	FD fan lube oil temperature	35	50
9	FD fan and FD fan motor bearing temperature	85	150
10	PA fan and PA fan motor bearing temperature	85	150
11	FO temperature at FO pump discharge	100	200
12	FO temperature after pump and heating unit	120	200
13	FO temperature at burner front	120	200
14	FO temperature at return line	120	200
15	Auxiliary steam temperature for atomization	210	300
16	Flue gas temperature before primary superheater	800	1000
17	Flue gas temperature before final superheater	1150	1500
18	Flue gas temperature before final reheater	1050	1500

Continued

www.EngineeringBooksPDF.com

TABLE IV/3-1 Typical Measuring Points for Temperatures (250 MW TPS)—cont'd

SR. No.	Service Description	Operating/MCR Value (°C)	Calibrated Range (°C)
19	Flue gas temperature before primary reheater	800	1000
20	Flue gas temperature at economizer inlet	550	1000
21	Flue gas temperature economizer outlet	345	500
22	Flue gas temperature at sec. air heater inlet	340	500
23	Flue gas temperature at secondary air heater outlet	130	200
24	Flue gas temperature at ID fan outlet	120	150
25	Flue gas temperature at primary air heater inlet	350	500
26	Flue gas temperature at primary air heater outlet	130	200
27	Secondary air heater inlet temperature		60
28	Secondary air heater outlet temperature	320	500
29	PA heater inlet header temperature		60
30	PA heater outlet temperature	320	450
31	Feed control station inlet feed water temperature	200	300
32	Economizer inlet feed water temperature	250	400
33	Main steam outlet temperature	540	600
34	HRH outlet temperature	540	600
35	CRH outlet temperature	330	600
36	Reheater inlet steam temperature after de-superheater	315	400
37	Drum outlet steam temperature	362	500
38	Steam at first stage supplemental heater inlet temperature	450	600
39	Drum outlet steam temperature	362	500
40	Steam at first stage supplemental heater inlet temperature	450	600
41	Steam at first stage supplemental heater outlet temperature	500	600
42	Steam at final supplemental heater outlet temperature	550	700
43	Superheater/reheater metal temperature		1200
44	Auxiliary steam temperature for SCAPH temperature control	200	300
45	Auxiliary steam temperature for soot blower	390	500
46	Main Steam at HPT turbine inlet temperature	545	1000
47	HRH Steam at IPT turbine inlet temperature	545	1000
48	Gland seal supply steam temperature (hot start)	450–530	1000
49	Gland seal supply steam temperature (cold start)	250	1000
50	FRF cooler outlet DMCW temperature	30	50
51	FRF cooler outlet FRF temperature	30	100
52	FRF cooler inlet DMCW temperature	50	
53	FRF temperature at FRF tank	40	100

Continued

www.EngineeringBooksPDF.com

TABLE IV/3-1 Typical Measuring Points for Temperatures (250 MW TPS)—cont'd

SR. No.	Service Description	Operating/MCR Value (°C)	Calibrated Range (°C)
54	BFP and BFP motor bearing temperature	85	150
55	BFP motor winding temperature	110	150
56	BFP fluid coup. working oil inlet temperature	35	60
57	BFP fluid coup. working oil outlet temperature	45	100
58	BFP fluid coup. lube oil inlet temperature	35	60
59	TG bearing drain oil temperature	55	100
60	TG lube oil cooler inlet temperature	50	60
61	TG lube oil cooler outlet temperature	35	60
62	Seal oil supply temperature	35	60
63	Generator casing cold hydrogen temperature		
64	Generator casing hot hydrogen temperature		
65	Stator coolant from generator temperature		
66	Stator coolant from generator temperature		
67	HP/LP housing temperature	60	100
68	CEP fan bearing temperature	50	75
69	Generator transformer oil temperature		
70	Generator transformer winding temperature		
71	Unit transformer oil temperature		
72	Unit transformer winding temperature		
73	Station transformer oil temperature		
74	Station transformer winding temperature		
75	Generator rotor temperature		
76	L.PH 1 outlet temperature	70	100
77	LPH 2 outlet temperature	84	120
78	LPH 3 outlet temperature	100	150
79	LPH 4 outlet temperature (if any)	120	150
80	Deaerator condensate outlet temperature	158	200
81	Deaerator steam temperature	365	500
82	HPH 6 outlet temperature	185	300
83	HPH 7 outlet temperature	210	300
84	HPH8 outlet temperature (if any)	235	300
85	Condenser shell inside temperature	40	100
86	Condenser extraction pump discharge temperature	47	100
87	LPH 1 bled steam temperature	82	150
88	LPH 2 bled steam temperature	135	200
89	LPH 3 bled steam temperature	190	300

Continued

www.EngineeringBooksPDF.com

TABLE IV/3-1 Typical Measuring Points for Temperatures (250 MW TPS)—cont'd

SR. No.	Service Description	Operating/MCR Value (°C)	Calibrated Range (°C)
90	LPH 4 bled steam temperature (if any)	250	400
91	Deaerator bled (IP extraction) steam temperature	365	500
92	HPH 6 bled steam temperature	475	600
93	HPH 7 bled steam temperature	330	500
94	HPH 8 bled steam temperature (if any)	390	600
95	BFP suction temperature	165	200

BFP, boiler feed pump; CEP, condensate extraction pump; CRH, cold reheat; FD, forced draft; FO, fuel oil; FRF, fire-resistant fluids; HP, high pressure; HPH, high-pressure heater; HPT, high-pressure, turbine; ID, indirect draft; IPT, intermediate pressure turbine; LP, low pressure; LPH; low-pressure heater; PA, primary air; RH, reheat; TG, turbo generator; DMCCW, demineralized water clarified cooling water; ACW, auxiliary cooling water; SCAPH, steam coil air preheater.

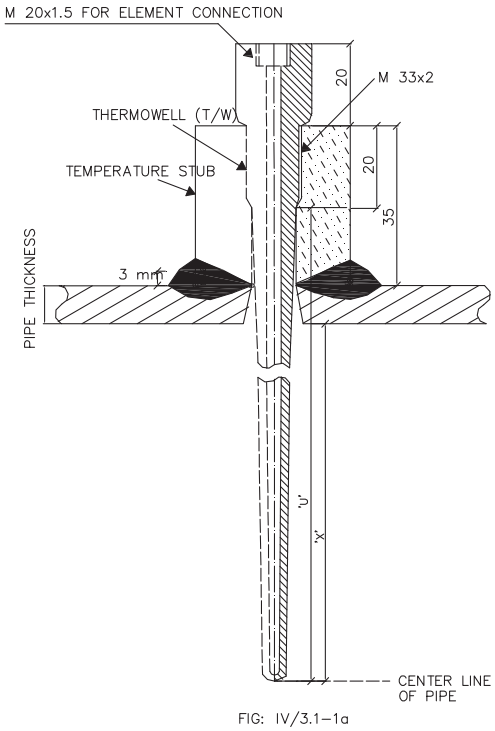


FIG: IV/3.1–1a

TAPPING THERMOWELL/ELEMENT AND T/C & RTD WITH SCREWED T/W DETAILS

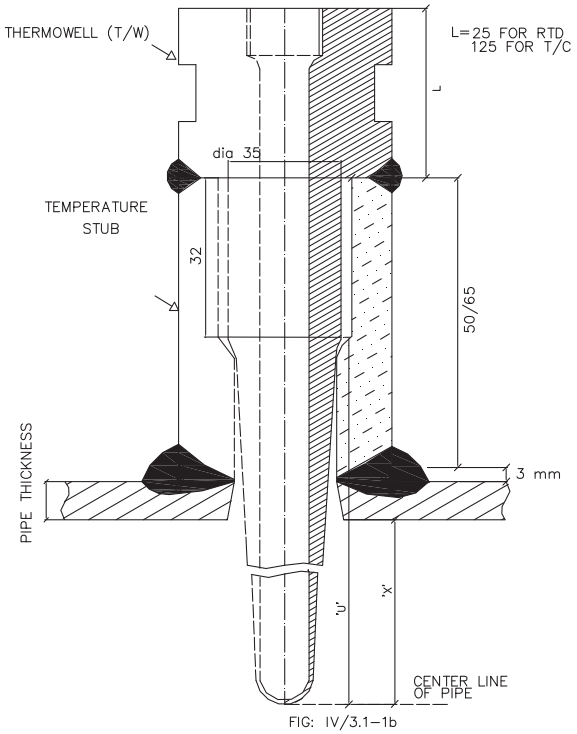


FIG: IV/3.1–1b

TAPPING THERMOWELL/ELEMENT AND T/C & RTD WITH WELDABLE T/W DETAILS

NOTE:
1) ALL DIMENSION ARE IN mm AND APPROXIMATE AND TENTATIVE.
2) MATERIAL OF THERMO WELL CONSTRUCTION SHALL BE SS316 OR DEPEND ON PROCESS CONDITION.
3) FOR PIPE OF 300 dia OR MORE ,INSERTION SHOULD NOT BE MORE THAN 150. FOR PIPE OF 300 dia OR LESS ,IMMERSION LENGTH IN INCREMENTS OF 25 TO BE SO SPECIFIED THAT TIP OF WELL REACH CENTER LINE OF PIPE +/−13. IMMERSION SHALL NOT BE LESS THAN 75 IN A PIPE OF 100dia OR SMALLER.
4)THIS STANDARD IS NOT APPLICABLE FOR GAS AND AIR APPLICATION
5) 'U' IS THE IMMERSION LENGTH, AND'X' IS THE INSERTION LENGTH

FIGURE IV/3.1-1 Thermowell/element details (steam, liquid).

www.EngineeringBooksPDF.com

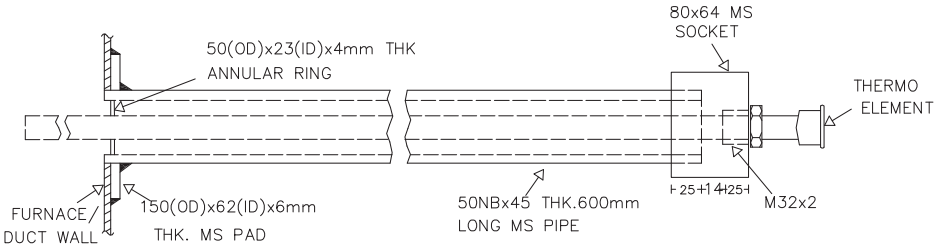


FIG: IV/3.1–2a
TAPPING AND THERMOWELL / ELEMENT WITH FAB T/W C ADJ GLAND FOR
FURNACE OR IN AIR /FLUE GAS DUCT TEMP MEASUREMENT

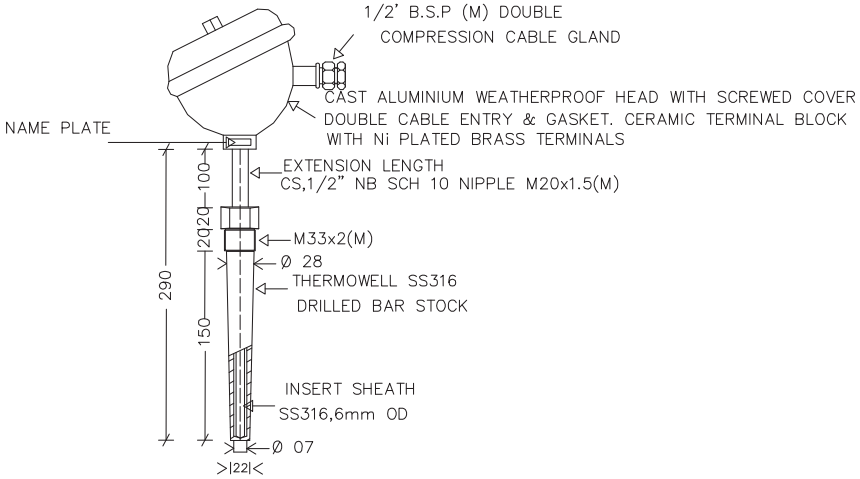


FIG: IV/3.1–2b
ELEMENT CONNECTION WITH THERMOWELL

FIGURE IV/3.1-2 Thermowell/element details (air, flue gas).

RTDs, as used for practical and industrial measurements, are coil element, wire-wound, and thin-film devices (see Figure IV/3.1-3a) that measure temperature because of the physical principle of the positive temperature coefficient of electrical resistance of metals, which means for higher temperatures the electrical resistance between the end terminals of the element or device will increase.

- Coil element RTDs have a wire coil that expands (due to temperatures up to 850°C) freely as a "strain-free" design. The small platinum coil sensor looks like a filament of an incandescent lamp. The mandrel is a hard-fired ceramic oxide tube with equally spaced bores for inserting coil. These RTDs have been largely replaced by wire-wound types.
- Wire-wound RTD design is based on wire wrapping around an insulating mandrel with a round or flat shape. The coefficient of thermal expansion of both the mandrel and the sensor materials matches to avoid mechanical strain, which causes inaccuracy. The lead wire selection ensures that no emf is generated to cause measurement distortion. Temperature range of this type may go up to 660°C.
- Thin-film element RTDs are formed by depositing a very thin layer(1−10 nm) of platinum (mostly) on a ceramic substrate and then coated with epoxy or glass for mechanical protection. This type of element is not as stable compared with the other types. The normal temperature range is 300°C, but may go up to 500°C by suitably taking care of the "strain gauge" effect (mismatching of thermal coefficients).

The relationship between temperature and resistance is nearly linear, and over a wide range of temperatures their measurement has small response times in the order of a millisecond. They show very accurate behavior with resolution and measurement uncertainties (accuracy figured altogether) of ±0.1°C or better in special designs and fall in the category of one of the most precise temperature sensors available. The other main advantage of using RTDs is stable output for a long period of time. They can be recalibrated easily and provide accurate readings even over

www.EngineeringBooksPDF.com

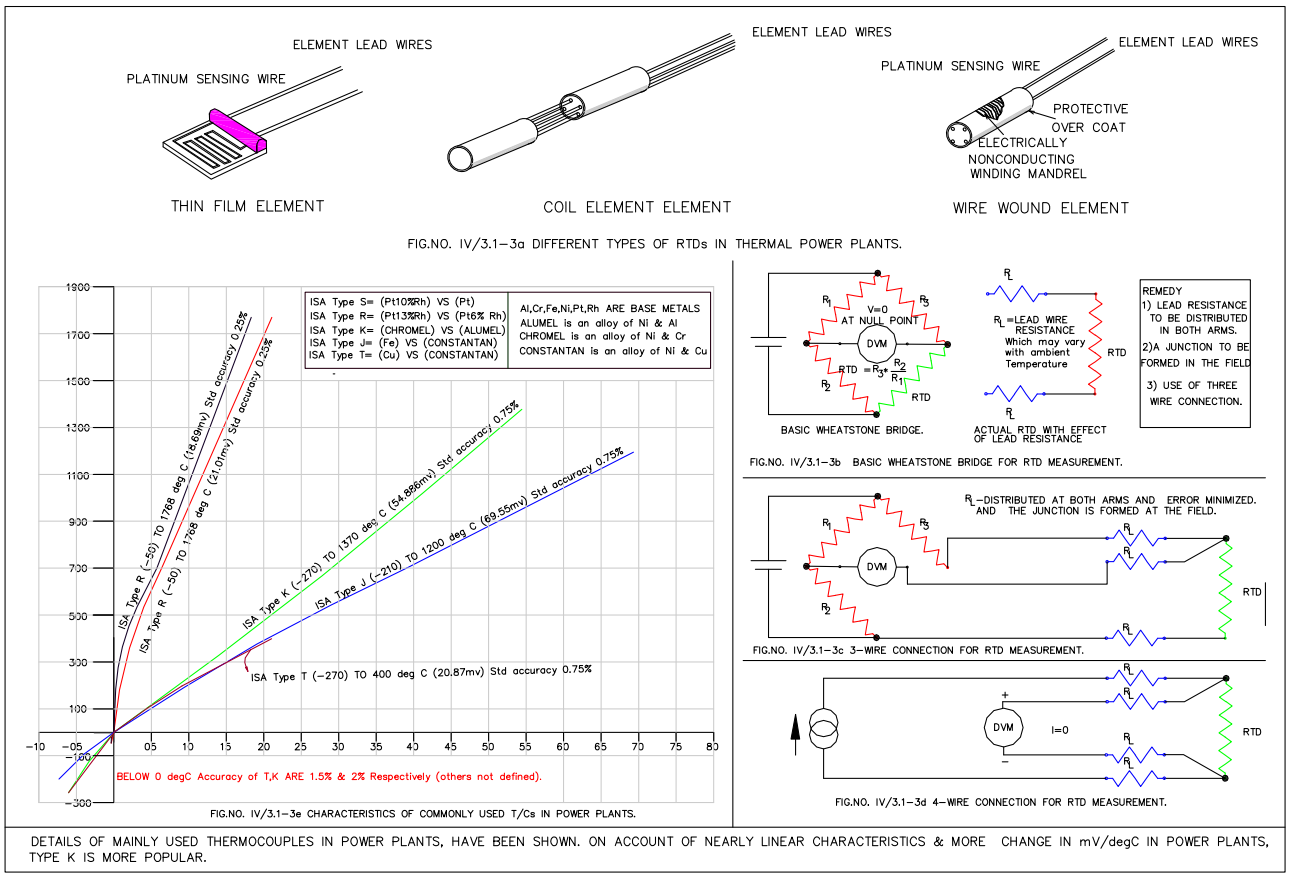


FIGURE IV/3.1-3 Temperature element theory and practice.

relatively narrow temperature spans. Platinum is the preferred material for the most accurate measurement, because in its pure form the temperature coefficient of resistance is almost linear with an accuracy of ±0.1°C, which can be readily achieved at moderate cost. Better accuracy is also possible, but instrument costs escalate to attain smaller error levels.

In a general industrial application, RTDs are provided encapsulated in a very small tablet form within a metal sheath, which is further protected by a probe called a thermowell (discussed above). As per the theory of operation, they belong to the electrical component group and require electrical current to sense the change in resistance by a calibrated standard instrument.

The disadvantage of employing RTDs in comparison to THCs (described later) is mainly the smaller overall temperature measuring range. Inherently, they are not of rugged construction and are failure prone to higher vibration environments .The initial cost is also higher than other temperature-measuring sensors.

Because it is an electrical component, the RTD has lead wires that are required to be connected to the receiving device, such as a temperature transmitter. The lead wires have some inherent resistance that varies with the change in ambient temperature, which would introduce measurement error. The magnitude of error is greater with the long lead lengths required for remote temperature measurement in large-capacity power plants. There are many measuring systems employing three- and four-wire leads from the two end terminals of an RTD to minimize or limit such errors if not be eliminate them completely (see Figure IV3.1-3b–d).

A common way to circumvent the long-lead resistance error problem is to place temperature transmitters near the measuring point. With this system, lead resistance would be minimized and their change in response to varying ambient temperatures is negligible. The temperature transmitters convert the sensor output to an analog current (4-20 mADC as a standard) and/or serial digital signal that can be transmitted over long distances by wire to the receiving device.

Another error of a comparatively minor nature and often ignored is the insulation resistance, which is also a function of temperature and at a reasonably higher temperature the shunt resistance of the insulator may contribute error into the measurement. This error is taken care of by calculating

www.EngineeringBooksPDF.com

the effect of thermal properties of the insulator into the measuring circuit. There are different types of insulator material used, such as powdered magnesia (MgO), alumina (Al_2O_3), and similar compounds. These materials are carefully dried and sealed when encapsulated within the sheath along with the sensor element. ASTM E 1652-00 standard is related to insulation resistance testing to help determine the performance of these sealed elements.

PRTs are a costly element, but here are other provisions for RTDs that are less costly. They are as indicated above and can be made cheaply in copper and nickel, although they have limitations in use due to practical problems. For example, the nickel RTDs show nonlinear characteristics and therefore can only be employed for restricted ranges. The problems with the copper RTDs are well known (oxidation of the wound sensor wire).

Platinum is the preferred material for precision measurement because in its pure form the temperature coefficient of resistance is nearly linear; enough so that temperature measurements within ±0.1°C can be readily achieved with moderately priced devices. Better resolution is possible, but equipment costs escalate rapidly at smaller error levels.

3.1.1.2 THCs

In 1821, renowned German scientist Thomas Johann Seebeck discovered that when any conductor is subjected to a thermal gradient, it will generate an emf. This is now known as the thermoelectric effect or Seebeck effect. To measure this voltage, another conductor to the "hot" end has to be connected and the other terminal has to be brought back to the cold end. This additional conductor will also experience the temperature gradient and will develop an emf of its own in the same direction as that of the former one. As the two conductors of the same polarity are connected to form a hot junction, the emf generated in them will oppose each other. Fortunately, the magnitude of the generated emf also depends on the type of metal used.

Therefore, if a dissimilar metal is used to complete the circuit the two conductors generate different emfs and a small difference in emf between the two cold junction terminals is measured. That difference increases with temperature, and is between 1 and 70 μV/°C) for standard metal combinations.

THCs utilize the thermoelectric property of generating emf in mVs between two open cold ends when two dissimilar metal wires are solidly connected at the end and subjected to higher temperatures than the other open ends. In other words, a THC is a junction between two different metals that produces an emf (mV) related to a temperature difference. THCs are a widely used type of temperature sensor for measurement of indication, recording, controls, etc.

THCs are of rugged construction, less costly, interchangeable, and can measure a wide range of temperatures. The major disadvantage of THCs is a limitation in measurement accuracy. Normally it is very difficult to achieve an accuracy of <1°C. THCs regularly used include iron-constantan (type J), copper-constantan (type T), chromel-alumel (type K), and platinum-platino rhodium [two types with 10% (S type) and 13% (R type) of platinum in the alloy]. The thermal characteristic curve temperature is in mVs, and the accuracy and range of all these THCs are depicted in Figure IV/3.1-3e. From this figure it can be inferred that ISA type K shows a linear characteristic over a large temperature range and produces more mV/°C change in temperature. For this reason, ISA type K gets used more often in power plant applications.

It may be noted that any junction of dissimilar metals will produce an electric potential (mV) related to temperature, but it may not be practical to use all of them as THCs, which must have a predictable and repeatable relationship between temperature and millivolt. For practical measurement of temperature, THCs are made of junctions of specific alloys with the previously mentioned qualities. Different alloys are used for different temperature ranges as seen in Table IV/3.1-1. Other important properties such as resistance to corrosion/oxidation may also be considered while choosing a type of THC; for example, iron-related alloys are prone to formation of oxides and are easily corroded.

3.1.1.2.1 Voltage–Temperature Relationship in THC The nonlinear relationship between the temperature difference (ΔT) and the output voltage (mV) of a THC can be approximated by a polynomial:

$$\Delta T = \sum_{n=0}^{N} a_n v^n$$

TABLE IV/3.1-1 Polynomial Coefficients for K Type THC (0–500°C)

n	1	2	3	4	5	6	7	8	9
a^n	25.08355	7.860106×10^{-2}	$(-) 2.503131 \times 10^{-1}$	8.315270×10^{-2}	$(-) 1.228034 \times 10^{-2}$	9.804036×10^{-4}	$(-) 4.413030 \times 10^{-5}$	1.057734×10^{-6}	$(-) 1.052755 \times 10^{-8}$

www.EngineeringBooksPDF.com

The coefficients a_n are given for n from 0 to between 5 and 13 depending upon the metals. In some cases better accuracy is obtained with additional nonpolynomial terms A database of voltage as a function of temperature and coefficients for computation of temperature from voltage and vice versa for many types of THCs is available online.

In modern equipment this equation is usually implemented in a digital controller or stored in a reference table whereas the older devices use analog circuits. In some electronic instruments linearization of nonlinear outputs of the THC is accomplished to improve the precision and accuracy of measurements.

3.1.1.2.2 THC Connection to Instruments If the measuring tapping point is away from the receiving instrument or device, an intermediate connection, as mentioned earlier, should be made by extension cable wires of the same materials as the main THC wire to avoid any intermediate junction, but this cable is costly. The alternative method is to use a less expensive compensating cable similar to the extension cable. Calibrations of THCs are usually standardized against a reference temperature of 0°C or 273 K. Receiving end instruments or devices integrally incorporate the temperature measurement of the environment and take care of any change in measuring temperature with respect to a reference temperature of 0°C. Practical instruments use electronic methods to adjust the effect of varying temperatures at the instrument terminals. Cold junction compensations are therefore necessary to eliminate the effect of variable ambient temperatures if the THC cold-end terminals are terminated in open ambient conditions for further connection to receiving instruments by cables other than extension/compensating cables.

THCs are widely used in thermal power plant applications for almost all high-temperature measurements as well as for kilns, gas turbine exhausts, diesel engines, and other industrial processes.

3.1.1.2.3 Cold Junction Compensation THCs measure the temperature difference between two points, not absolute temperature. As mentioned earlier, THCs are standardized against this reference temperature, which is 0°C. To measure a single temperature, one of the junctions (normally the cold junction) is maintained at a known reference temperature other than °C, for example, the control room of an air-conditioned environment. The other (hot) junction is at the temperature to be sensed. With a junction of known temperature, the mV temperature difference between the cold and reference junctions at °C can be obtained from the table and the appropriate correction applied. This is known as cold junction compensation. It is worth noting for understanding cold junction compensation methods, that the emf (or the mV) is not generated at the junction of the two metals of the THC, but rather along that portion of the length of the two dissimilar metals that is subjected to a temperature gradient.

There are several methods of cold junction compensation:

- One method depicts termination of extension wires from various THCs in the vicinity (as a cost-saving measure) in a local junction box maintained at a constant temperature, thereby incorporating an artificial cold junction using a thermally sensitive device such as a thermistor or diode to measure the temperature of the cold junction box. From the junction box, less costly copper cable can be drawn up to the input terminals at the instrument with special care taken to minimize any temperature gradient between terminals. The voltage from a known cold junction can be taken care of and incorporated in the measuring circuit. If temperature gradients are the same (which they should be), for these two copper wires from a THC, the millivolt generated by them due to difference in cold and reference junctions will cancel each other.
- Another method uses a THC at the cold junction box and extension wire up to the measuring instrument and adds this voltage to all other THC output of that cold junction box by suitable methods.

Temperature ranges of different THCs are given in Table IV/3.1-2 (but may be extended to upper and lower sides as depicted in Figure IV/3.1-3e).

Table IV/3.1-3 describes properties of several different THC types. Within the tolerance columns, T represents the temperature of the hot junction, in °C. For example, a THC with a tolerance of $\pm 0.0025 \times T$ would have a tolerance of ± 2.5°C at 1000°C.

THC junction types and response times are depicted in Figure IV/3.1-4.

3.1.1.3 Thermistors

Thermistors were discovered first in 1833 by Michael Faraday while working on the semiconducting behavior of silver sulfide. Faraday noticed that the resistance of silver sulfide decreased dramatically as temperature increased. Today thermistors are used as temperature elements, but were difficult to produce earlier and applications were limited. Commercial production of thermistors did not begin until 1930.

A thermistor is a type of resistor whose resistance varies with temperature; that is, thermistors show qualities similar to RTDs. But when used as a temperature element, thermistor characteristics are in the reverse direction, that is, the resistance of the element decreases when the temperature rises. Thermistors also differ from RTDs with respect to the material used; a thermistor is generally made of ceramic or polymer, while RTDs are made from pure metals. Regarding temperature response, RTDs are better as

www.EngineeringBooksPDF.com

TABLE IV/3.1-2 Temperature Ranges of Different THCs

Types of THCs	Iron-Constantan (Type J)	Copper-Constantan (Type T)	Chromel-Alumel (Type K)	Platinum-Platino Rhodium (13%) (Type R)	Platinum-Platino Rhodium (10%) (Type S)
Temperature range in °C	−0 to 700	−185 to 300	0−1100	0−1600	0−1600
Used for measurement parameters	Flue gas	Air and oil	Steam, air/flue gas Temperature >300°C	Furnace Temperature ∼1000°C	Furnace Temperature ∼1000°C

they are useful over larger temperature ranges, whereas thermistors have a temperature range of −90 to 130°C.

Assuming a first-order approximation and that the relationship between resistance and temperature is linear, then:

$$\Delta R = k\Delta T,$$

where ΔR = change in resistance, ΔT = change in temperature, and k = first-order temperature coefficient.

Thermistors can be classified into two types, depending on the sign of k. If k is positive, the resistance increases with increasing temperature, and the device is called a positive temperature coefficient (PTC) thermistor, or posistor. If k is negative, the resistance decreases with increasing temperature, and the device is called a negative temperature coefficient (NTC) thermistor. Resistors that are not thermistors are designed to have a k as close to zero as possible (smallest possible k), so that their resistance remains nearly constant over a wide temperature range.

- Thermistors are used as resistance thermometers in low-temperature measurements of the order of 10 K, that is, −263.2 °C.
- Thermistors can be used as inrush current-limiting devices in power supply circuits. They present a higher resistance initially, which prevents large currents from flowing at turn-on, and then heat up and become much lower resistance to allow higher current flow during normal operation. These thermistors are usually much larger than measuring type thermistors, and are purposely designed for this application.
- Thermistors are regularly used in automotive applications. For example, they monitor things like coolant temperature and/or oil temperature inside the engine and provide data to the ECU and, indirectly
- Thermistors are also commonly used in modern digital thermostats and to monitor the temperature of battery packs while charging.
- PTC thermistors or posistors can be used as current-limiting devices for circuit protection as replacements for fuses. Current through the device causes a small amount of resistive heating. If the current is large enough to generate more heat than the device can lose to its surroundings, the device heats up, causing its resistance to increase and causing even more heating. This creates a self-reinforcing effect that drives the resistance upward, reducing the current and voltage available to the device.

3.1.2 Immersion Length

Immersion length is the length of the temperature element's portion that comes into contact with the measuring fluid. Insertion length is the length of the temperature element's portion that is inserted into the measuring fluid beyond the pipe or vessel wall. Thus the immersion length consists of the insertion length plus pipe or vessel wall thickness plus the length of temperature stub up to which the fluid can fill the gap between the stub and thermowell (see Figure IV/3.1-1a and b).

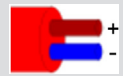
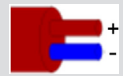
Normally the insertion length should be such that the tip of the element would be around the center (that is the radius of the pipe) when process fluid passes through a pipe. There is some flexibility in the industrial arena; the tip can be away by a maximum ±13 mm from the center so that it can still measure the temperature of the fluid with the tip in the maximum velocity zone. However, for a bigger pipe, the maximum limit of insertion is 150 mm to avoid vibration and damage of the element due to abrasion and erosion . For ducts or vessels with low pressure, the insertion length may be more to suit the application. The minimum insertion length is normally 75 mm. For smaller pipes, the minimum length is maintained with the element mounted in the elbow or expander with suitable length or on a stub fixed at an angle of ∼45° with the pipe.

3.1.3 Connection Types

See Figure IV/3.1-2b for a better understanding of connection details. The elements with a built-in sheath are provided for primary mechanical protection to the fragile elements. The sheath has a male thread for connection with the thermowell with rugged construction normally

www.EngineeringBooksPDF.com

TABLE IV/3.1-3 Properties and Color Codes of THCs

Type	Temp range (continuous)(°C)	Temp range (short term) (°C)	Tolerance class one (°C)	Tolerance class two (°C)	IEC color code	BS color code	ANSI color code
K	0 to +1100	−180 to +1300	*1	**1	 Overall-green + green,- white	 Overall-red + brown,-blue	 Overall-brown + yellow,- red
J	0 to +700	−180 to +800	*2	**2	 Overall-black + black,- white	 Overall-black + yellow,-blue	 Overall-brown + white,- red
N	0 to +1100	−270 to +1300	*1	**1	 Overall-pink + pink,- white	 Overall-orange + orange,- white*	 Overall-brown + orange ,- red
R	0 to +1600	−50 to +1700	*3	**3	 Overall-orange + orange,- white	 Overall-green + white,- blue	Not defined
S	0 to 1600	−50 to +1750	*3	**3	 Overall-orange + orange,- white	 Overall-green + white,- blue	Not defined
B	+200 to +1700	0 to +1820	Not available	**4	No standard use copper wire	No standard use copper wire	Not defined
T	−185 to +300	−250 to +400	*4	**5	 Overall-brown + brown,- white	 Overall-blue + white,- blue	 Overall-brown + blue,- red
E	0 to 800	−40 to 900	*5	**6	 Overall-purple + purple,- white	 Overall-brown + brown,- white	 Overall-brown + blue,- red

Tolerances class one (°C) 0 to +800 and −40 to +900: *1, ±1.5 between −40 and 375°C and ±0.004 × T between 375 and 1000°C; *2, ±1.5 between −40 and 375°C and ±0.004 × T between 375 and 750°C; *3, ±1.0 between 0 and 1100°C and ±[1 + 0.003 × (T − 1100)] between 1100 and 1600°C; *4, ±0.5 between −40 and 125°C and ±0.004 × T between 125 and 350°C; *5, ±1.5 between −40 and 375°C and ±0.004 × T between 375 and 800°C.
Tolerances class two (°C): **1, ±2.5 between −40 and 333°C and ±0.0075 × T between 333 and 1200°C; **2, ±2.5 between −40 and 333°C and ±0.0075 × T between 333 and 750°C; **3, ±1.5 between 0 and 600°C and ±0.0025 × T between 600 and 1600°C; **4, ±0.0025 × T between 600 and 1700°C; **5, ±1.0 between −40 and 133°C and ±0.0075 × T between 133 and 350°C; **6, ±2.5 between −40 and 333°C and ±0.0075 × T between 333 and 900°C.

www.EngineeringBooksPDF.com

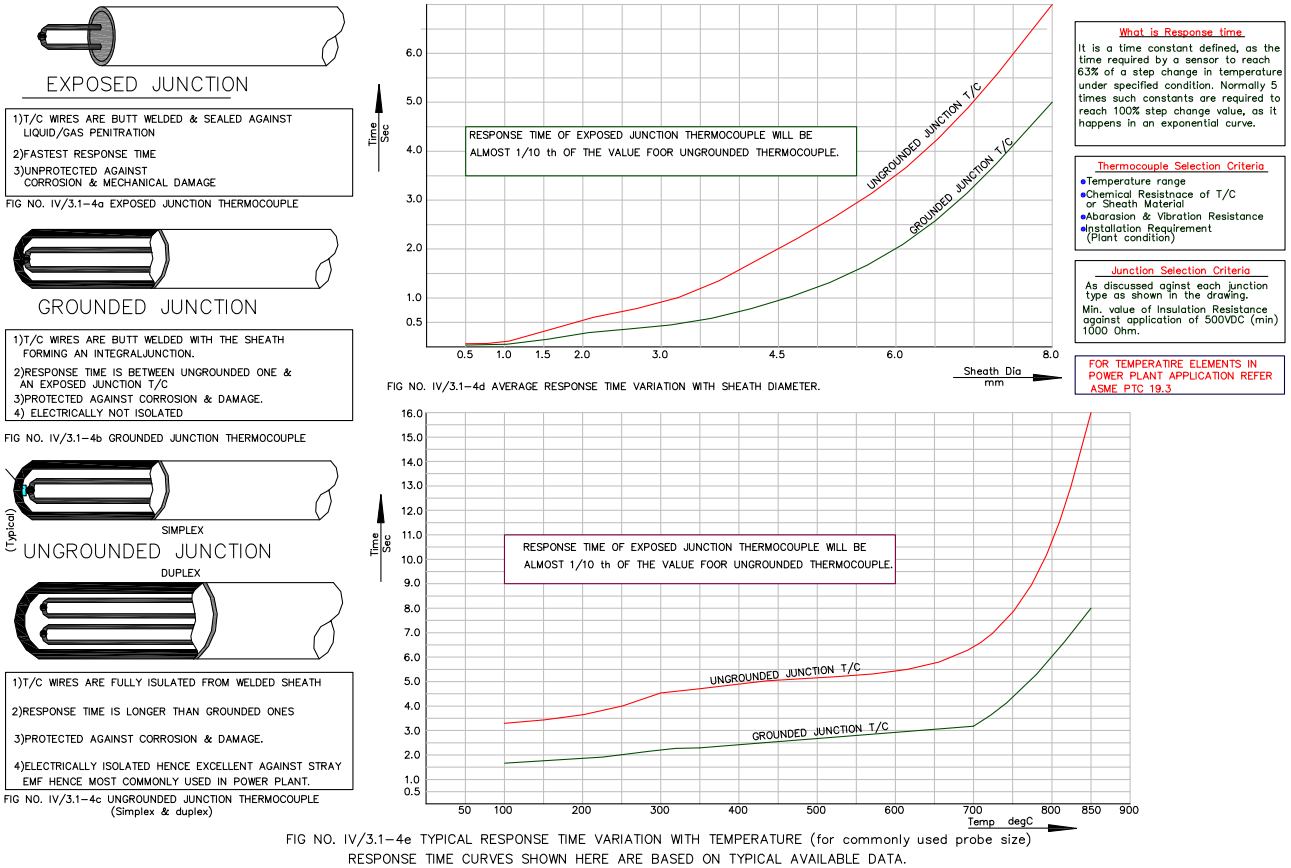


FIGURE IV/3.1-4 Junction types and response time for THCs.

manufactured from solid bar stock with suitable material to suit the service condition. For low pressure, however, the thermowell may be fabricated. Some extension length to the element/sheath is provided after it comes out of the piping insulation to avoid high temperatures through conduction near the electrical connection of the element for remote instrumentation. There is a connection facility on the top of the arrangement called an element head. The head is weatherproof of suitable protection class and material with a screwed cover and suitable gasket. The cover is protected from free falling by a chain fixed to the body of the element. The output wires of the elements are connected firmly at the ceramic terminal block consisting of nickel- or cadmium-plated terminals clearly marking the terminal with universally accepted signs or symbols.

3.2 Temperature Transmitter: Working Principle, Specification, Supplier, and Special Features

The temperature transmitter is an instrument or device used to sense a weak, low-level temperatures in the form of either resistance or millivolts, convert it to a universal output (i.e., 4-20 mA) and/or digital signals (namely HART/Fieldbus signal) representative of the sensed temperature and transmit for remote instrumentation. Similar to the HART/Fieldbus signal, this universal output is a high-level analog signal in the form of a current signal and much more suitable for long-distance transmission through a noisy environment. It is also ready for direct interface with many instrumentation items, such as an indicator, recorder, PLC, DCS, and SCADA system. Current and digital signals are immune to resistance in field-connecting cables or extension wires and stray electrical noise rather than resistance or voltage. This allows accurate signals to be received from a far-away sensor. The 4-20 mA output or digital signal and DC power share the same wire pair. It is not necessary to run power wires to every sensor. Temperature transmitters also linearize the temperature input signal, making them very good and acceptable low-cost signal conditioners.

In large power plants, temperature transmitters are used to control process parameters as well as for plant protection, real-time indication, hard or soft copy recording, analyzing, and historical archiving by sensing a

www.EngineeringBooksPDF.com

temperature of the process and transmitting the information to a remote location for different subsystems envisaged by the end user. The temperature transmitter output can be communicated over the loop to a control room, or the output can be communicated to other process subsystem devices such that the process can be monitored and controlled. The temperature transmitter may located on the top of the sensor (head mounted) or in the field near the sensor, both of which provide minimum effect of variation in ambient temperature. The other location may be in the back of the control panel or rack mounted with due consideration of ambient temperature.

Temperature transmitter types are grouped in two broad categories for RTDs and THCs. There are several methods for making each of these devices.

3.2.1 Transmitter (RTD Input)

The RTD is basically a coil element/wire-wound/thin-film resistance with two end terminals. There are various types that use two-, three-, or four-wire measuring systems (see Figure IV/3.1-3b—d) depending upon the accuracy level desired and the expected cost. The two-wire system has one wire from each end and the three-wire system has one wire from each end and another wire from any end that goes to the measuring circuit. A two-wire system does not provide correct the output due to variation in ambient temperature, as the resistance of the lead wires (both sides) changes unpredictably. The three-wire system is a better way to take care of this problem. The four-wire system has two wires from each end that go to the measuring circuit, which to a great extent eliminates the problem of variation in ambient temperature. In all of the wire measuring systems, the RTD is ultimately connected to a bridge circuit to generate a voltage signal.

There is another four-wire measuring system that is more accurate, in because it almost completely (not 100%) eliminates the ambient temperature variations. The transmitter injects a precise and controlled current into the temperature sensor by two wires, and the with the other two wires the resultant voltage drop across the temperature sensor is used to measure resistance in a circuit, which provides very high input impedance so that minute current flows. With almost zero level current, the lead resistance change will introduce minimum effect and voltage drop across the RTD will be read as an open circuit voltage, even at the remote location. The voltage is then converted into a digital format using an analog-to-digital converter provided by a microprocessor. The microprocessor converts the measured voltage into a digital value representative of temperature. The temperature transmitter generally includes a housing and a temperature probe, which attaches to the housing. To monitor a process temperature, the transmitter includes a sensor, such as an RTD or a THC. An RTD changes resistance in response to a change in temperature. By measuring the resistance of the RTD, the temperature can be calculated.

3.2.2 Transmitter (THC Input)

A thermocouple is placed in the process fluid and provides an output voltage (in mV) in response to a temperature change in the process fluid. Typically, the temperature transmitter is located in the field location and converts the millivolt input signal to 4-20 mADC transmitted to a control room. The connection from sensor to transmitter is made by either a THC extension cable or by a compensating cable for the reasons discussed in Clause 3.1 of this chapter.

Specifications for temperature transmitters are given in Tables IV/3.2-1 and IV/3.2-2.

3.3 Temperature Switches

As described in Chapter I, Clause 3.2.4, most of the temperature switches utilize the volume expansion characteristics of fluid after application of heat or the temperature in turn. The bulb containing transmission fluid is placed at the sensing point .The transmission fluid may be an inert gas like nitrogen or a liquid like mercury or alcohol. The receiving side may be bellows, diaphragm, bourdon, helix, capsule, or spiral type pressure-sensing element.

Bimetallic elements are also used that will bend in one direction when heat is applied to an assembly of two metals of dissimilar coefficients of expansion joined together. One of these is a nickel alloy named Invar, which hardly expands, and another nickel alloy is used that expands considerably. They are welded together and rolled to the desired thickness to form a bimetallic element. The modern type uses a multiple helix or coil within a coil arrangements to accommodate space limitation. Temperature sensors/elements, here the bulb**,** are located separately at the sensing point inside the process and isolated from the process fluid to avoid contact from a high velocity of abrasive and/or hazardous nature. This isolation is achieved through a thermowell, which takes care of the process-side complications and is normally threaded and/or welded to the process pipe or vessel. Inside the thermowell there is a female thread to accommodate the sensors/elements.

Because the temperature switch is a mechanism that is responsive to temperature changes, the movement from expansion of fluid or bending of dissimilar metal coupled together is amplified to open or close a switch by using electrical contacts when a predetermined minimum or maximum temperature is sensed by the responsive element. Temperature-sensitive switches are used for thermal protection of the process or an electrical circuit from overheating . If a device gets too hot or cold (i.e., fuel oil required for burning), the temperature-sensitive switch can

www.EngineeringBooksPDF.com

TABLE IV/3.2-1 Data Sheet of Temperature Transmitters (RTD)

SL. No.	Item	Specification	Special Feature
1	Make/model/type	ABB/YEC/Honeywell/Emersion	
2	Type of input	30WIRE, RTD (Pt.−100)	
3	Process connection	1/2″ Electrical connection	
4	Enclosure	Die cast aluminum, IP 65	
5	Local indicator	(Process/sensor or loop current value) LCD, five-digit, seven-segment sign and floating point Seven-digit alphanumeric characters 6 mm, 14 segments Response time 0.5 s, measuring error ±0.1%	
6	Output	4-20 mADC (maximum load resistance = 750 Ω) with superimposed digitized signal (HART protocol or Fieldbus signals such as Profibus and Foundation Fieldbus	
7	Power supply	8.5−30 V DC	
8	Monitoring	Sensor and self-diagnostic	
9	Signal refresh time	<0.4 sec	
10	Long-term stability	<0.1% PA	
11	Test	Calibration test	
12	Electrical isolation	1.5 kV AC	
13.	Ambient temperature	−40 to 85°C	
14	Humidity	100 RH	
15	Range	As applicable	

be used to generate an alarm or trip the system as per the requirement/severity of the process.

A closed system containing an equilibrium of liquid and vapor of a suitable, volatile chemical or gas is used to sense the process temperature. If the fluid is liquid or vapor, the expected volume expansion of fluid is converted into pressure as the volume of the system is fixed. This pressure within the system is proportional to the applied temperature and is applied to a bellows or diaphragm, bourdon, helix, capsule, spiral, etc., which transmit a force, proportional to the temperature, to an operating bar or beam. The beam is restrained by an adjustable spring. When the force on the bar/beam overcomes the spring tension, it moves and operates a switch or switches. On reduction of the applied temperature, the force applied to the bar/beam also falls and the beam is restored to its original position by the spring and the switch resets.

The switches are grouped into two categories, capillary and rigid stem. The rigid stem type is mounted directly to the process and the capillary type is mounted separately to a nearby wall or local panel.

Care must be taken so that process temperature does not exceed the specified maximum working temperature. Normally accuracy is better than ±0.5%, which is the same as that of the master gauge used. As these switches are meant for outdoor installations, manufacturers make them available with sufficient protections against aggressive environments, for example, explosive gas-laden air, dust, temperature, and water. The instrument is mounted rigidly to avoid shock and vibration so that spurious actuation does not take place.

The case or enclosure must be weatherproof or explosion proof to suit the site condition. The following standards are normally followed in India:

1. Weatherproof to IP 66 IS 2147.
2. Flameproof cum weatherproof (die cast aluminum) CMRI approved to GR.IIA and IIB of IS 2148 1981 and weatherproof to IP 66. GR.IlC.
3. Hydrogen service may be required for a generator cooling circuit.

The corresponding international code, corresponding to CMRI certificates, is also applicable .

Regarding switch configuration and contact rating, the contents of Clause 2.2 applicable and Table IV/3.3-1 is a data sheet of temperature switches.

www.EngineeringBooksPDF.com

TABLE IV/3.2-2 Data Sheet of Temperature Transmitters (THC)

SL. No.	Item	Specification	Special Feature
1	Make/model/type	ABB/YEC/Honeywell/Emersion	
2	Type of input	Type K/T/R/S/J	
3	Process connection	1/2″ Electrical connection	
4	Enclosure	Die cast aluminum, IP 65	
5	Local indicator	(Process/sensor or loop current value) LCD, five-digit, seven segment sign and floating point. Seven-digit alphanumeric characters 6 mm, 14 segments Response time 0.5 s, measuring error ±0.1 %	
6	Output (Cold junction compensated)	4-20 mADC (maximum load resistance = 750 Ω) with superimposed digitized signal (HART protocol or Fieldbus signals such as Profibus and Foundation Fieldbus.	
7	Power supply	8.5−30 V DC	
8	Monitoring	Sensor and self-diagnostic	
9	Signal refresh time	<0.4 sec	
10	Long-term stability	<0.1% PA	
11	Test	Calibration test	
12	Electrical isolation	1.5 kV AC	
13	Ambient temperature	−40 to 85°C	
14	Humidity	100 RH	
15	Range	As applicable	

3.4 Temperature Gauges

A temperature gauge, popularly a thermometer, is a device that indicates the temperature of the process being monitored. The display can be a pointer on a graduated dial or a digital display. THCs, which generate millivolts depending on the temperature, are also used for digital thermometers. By measuring temperature, the thermal condition of a homogenous system is available. Measurement of temperature normally requires direct or indirect (through thermowell) contact between the process and the sensor in such a manner that the sensor responds quickly to the temperature of the process.

Temperature gauges like temperature switches utilize the volume expansion characteristics of fluid after application of heat or the temperature in turn. A bulb containing fluid (transmission fluid) is placed at the sensing point. The transmission fluid may be inert gas like nitrogen or liquid like mercury or alcohol. The receiving side may be bellows, a diaphragm, bourdon, helix, capsule, or spiral-like pressure-sensing element or simply a glass tube with graduated scale. Bimetallic elements are also used that bend in one direction when heat is applied to an assembly of two metals of dissimilar coefficients of expansion joined together, as stated in the Clause 3.1. Suitable measures have been provided to correct errors from changes in casing and capillary expansion due to ambient temperature change. To minimize the capillary expansion effect, an Invar rod is inserted inside the capillary to reduce the fluid volume. The capillary is protected with suitable armor against mechanical damage.

The operating principles are the same as that for temperature switches.

3.4.1 Mercury in Glass

It is the simplest type of temperature gauge there is a sensing glass bulb, basically a small volume reservoir chamber, filled with mercury and placed inside the process. After being heated, the mercury expands much more than the glass (about six times) and is forced to rise along the glass tube. The glass tube is a small tube with a fine bore joined at the opposite end of the bulb. For each particular temperature, the mercury rises to a certain point. The expansion path is then calibrated with a reference temperature bath. The glass tube is not marked but the graduations

www.EngineeringBooksPDF.com

TABLE IV/3.3-1 Data Sheet of Temperature Switches

SL. No.	Item	Specification	Special Feature
1	Make/model		
2	Type	Capillary/rigid stem	
3	Process/electrical connection	M33X2 for thermowell, M20X1.5 for element 1/2″ electrical connection	
4	Enclosure	Die cast aluminum, IP 65(as applicable)	
5	Sensing material	316 SS bulb for fluid-filled type Nickel alloys (Invar and other) for bimetallic type	
6	Set point	Low/high (adjustable)—1 or 2 set points	
7	Repeatability	±1% FSR	
8	Switch unit	2 SPDT	
9	Rating	5 Amps, 230 V AC	
10	Test	Calibration test	
11	Range	As applicable	
12	Medium	Air/water/steam/oil	
13	Ambient temperature	−40 to 85°C	
14	Humidity	100 RH	

are engraved on metal scales with both tube and scale enclosed in a single casing. Mercury in some glass thermometers is calibrated for complete immersion and some with partial immersion. The fluid can be alcohol instead of mercury, which has the coefficient of linear expansion even six times more than mercury.

3.4.2 Mercury or Alcohol in Steel

The principle of operation is exactly same as in Clause 3.1, but has a different final output. In the switch, the output movement of the element is to operate a switch assembly but in the gauge, the output movement is connected to a pointer which moves on a calibrated and graduated scale

3.4.3 Bimetallic Gauges

This is one of the most dependable temperature-measuring instruments. It employs a suitable metal or metal alloy with the required coefficient of linear expansion. One of them is Invar, which expands very little upon application of heat. Welded together with another metal (alloy) that has a better coefficient of linear expansion and rolled to the desired thickness, the combination is used in bimetallic gauges. Alloys with widely differing coefficient of linear expansion values are used for short temperature ranges, whereas for longer temperature ranges, metals (alloys) of closer coefficient of linear expansions are used. The term used to describe the thermal activity of a bimetal is flexibility. The actual movement of a bimetallic strip is proportional to its flexibility. One end of a straight strip is fixed, and the other end of the strip deflects or bends, which varies proportionally with the temperature, to the square of its length and inversely to the thickness. It can be used in a helical configuration and where the angular deflection is determined by the same factors. The pointer attached to the free end is then allowed to show its movement on a properly calibrated scale.

The modern bimetallic gauges/thermometers use multiple helical arrangements or coils within coils. This configuration allows the use of long bimetallic elements in a small space. The fixed end is normally located at the bottom, whereas the free end is located on a shaft to which the pointer is attached. The industrial gauges have a thicker stem. Alarm contacts with secondary pointers for indicating maximum and minimum temperatures settings are also available. A typical specification sheet of temperature gauges is indicated in Table IV/3.4-1.

www.EngineeringBooksPDF.com

TABLE IV/3.4-1 Data Sheet of Temperature Gauges

SL. No.	Item	Specification	Special Features
1	Make/model		
2	Range	As applicable	
3	Type	Alcohol/mercury in glass/steel Bimetallic	
4	Process/electrical connection	M33X2 for thermowell,M20X1.5 for element 1/2″ electrical connection	
5	Style	Capillary/rigid stem	
3.	Medium	Gas/air/water/steam	
4	Accuracy	±0.5% FSD	
5	Ambient temperature	−40 to 80°C	
6	Humidity	100 RH	
7	Case	In die cast aluminum alloy moisture proof Case epoxy powder-coated black	
8	Dial size	150 mm	
9	Quantity	As applicable	

4. FLOW MEASUREMENT, VARIOUS MEASURING POINTS, VARIOUS TYPES, AND RANGE SELECTION

Flow measurement in a power plant is a very important parameter. Whenever the word "total" is used, the mass flow comes into the picture. Everything like ultimate power output, efficiency of the power plant, total enthalpy, etc., depends on the mass flow of steam, coal, and oil. Various kinds of flow meters are shown in Figure IV/4.0-1 with selection guidelines from permanent pressure loss, discharge coefficient variations, etc.

4.0 Units of Measurement

There are two basic types of flow measurement: volumetric and mass flow rates. Both gas and liquid flow can be measured in volumetric as well as in mass flow rates. It is well known that mass of a particular homogeneous material can be calculated by multiplying density of the material with the volume of that material. That means these measurements can be converted between one another if the material's density is known. For liquid, the density is almost independent of the liquid conditions like pressure, although it varies slightly with the temperature. For gas services, the density is a dependent variable of both pressure and temperature and, to a lesser extent, the gas composition.

For liquids, various units are used depending on the application and industry, and also on the country of the users. In most countries the metric (MKS) system is used: tonne/hour (h) or /h (or second) for mass flow and liters/h or cubic meter/h for volume flow. In the United States or UK the flow unit is ton/h or gallons per minute (GPM).

The scenario is different for gases as they are compressible fluids and change volume when undergoing a change in pressure and/or temperature. For a definite amount of mass, a volume of gas under one set of pressure and temperature conditions is not equal to the same gas under different conditions. Therefore, whenever a gas flow rate is involved, references must be indicated to denote the pressure and temperature at which condition this particular volume is applicable. Generally three norms are followed: STP, NTP, ISA.

- *STP*: Defined by the International Union of Pure and Applied Chemistry (IUPAC) as air at 0°C (273.15 K, 32°F) and 10^5 Pa (1 bar). It is commonly used in the imperial and American systems of units with air at 60°F (520°R) and 14.696 psia (15.6°C, 1 atm).
- *NTP*: Defined as air at 20°C (293.15 K, 68°F) and 1 atm (1.0325 bar; 101.325 kN/m^2, 101.325 kPa, 14.7 psia, 0 psig, 29.92 in Hg, 760 torr). Density 1.204 kg/m^3 (0.075 lb/ft^3).

www.EngineeringBooksPDF.com

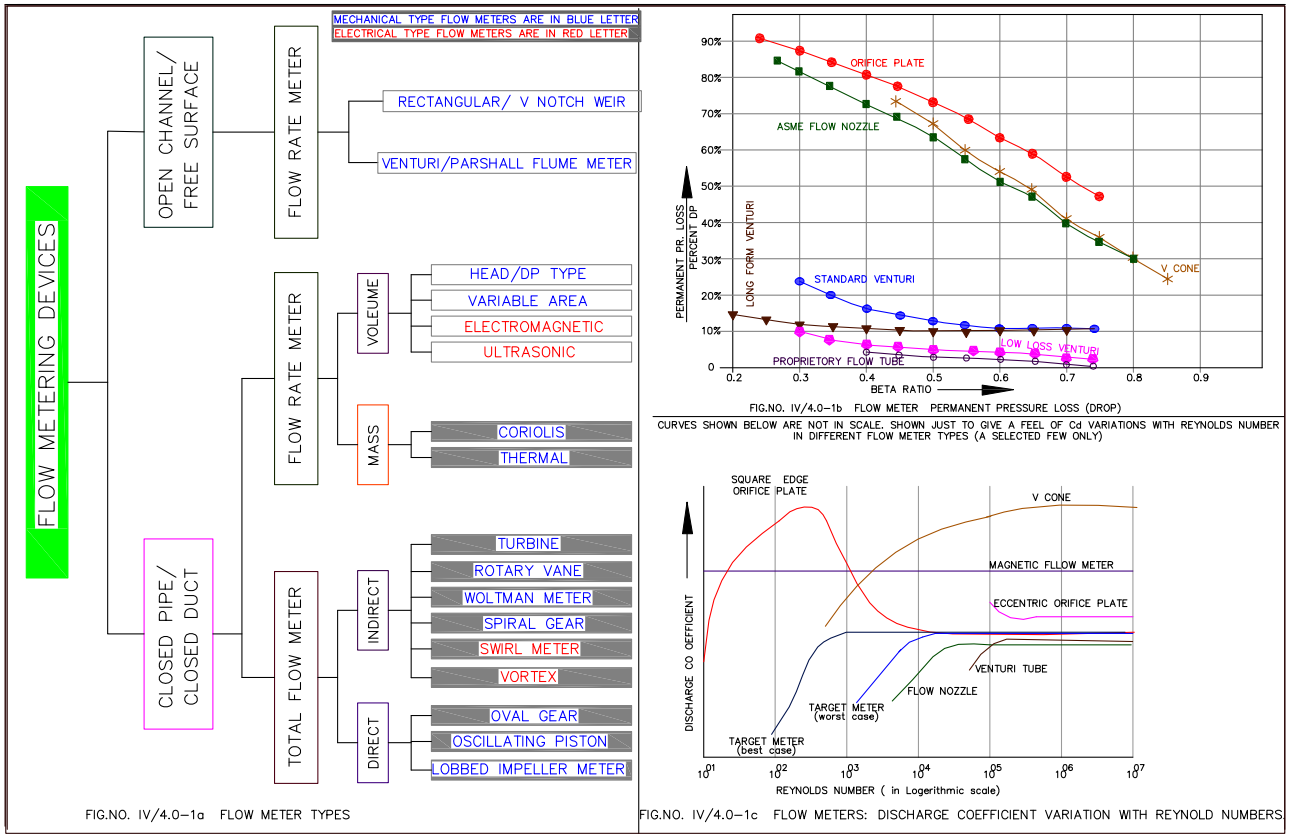


FIGURE IV/4.0-1 Flow meter type and selection.

- ISA: Defined to 101.325 kPa (1 atm, 1.0325 bar), 15°C and 0% humidity.

$$\begin{aligned}[1\text{Pa} &= 10^{-6}\,\text{N/mm}^2 = 10^{-5}\,\text{bar} = 0.1020\,\text{kPa/m}^2 \\ &= 1.02\times10^{-4}\,\text{m H}_2\text{O} = 9.869\times10^{-6}\,\text{atm} \\ &= 1.45\times10^{-4}\,\text{psi}\,(\text{lbf/in}^2)]\end{aligned}$$

The following important measuring points are normally provided for a comprehensive audit of the flow measurements in a typical 250 MW thermal power plant with two-stage superheater attemperation, flue gas recycling from a chimney inlet to furnace hopper, and emergency reheater attemperation (see Table IV/4-1).

4.0.1 Pressure-Based Measurements (Head Type Instruments)

In modern and large-capacity power plants, flow measurements are normally achieved through flow elements based on the Bernoulli's principle, thereby necessitating a differential producer as briefly indicated in Chapter I. The flow transmitter then converts the DP to a 4-20 mADC signal corresponding to flow with a superimposed digitized signal (HART) or other signal through different types of fieldbuses.

Various types of flow meters have been developed, based on Bernoulli's principle, by measuring the DP across a well-designed constriction called a "differential producer." They are popularly called pressure-based instruments. The velocity from the volume flow is proportional to the square root of the DP thus produced. This DP is not permanent. At the down edge of the element, ~60–50% of this DP is recovered while the rest of the 40–50 % is unavailable as permanent pressure loss. The following clauses are examples of these flow elements.

4.0.1.1 Venturi Meter

This constricts the flow in such a fashion that the cross section through the travel gradually decreases from the original one and then becomes steady for a certain length, and again increases downstream up to the original cross section. This method is widely used to measure flow rate in the transmission of gas through pipelines, and has been used since the Roman Empire. The coefficient of discharge of Venturi meters ranges from 0.93 to 0.97.The permanent loss is about 40% of the DP produced and eventually the

www.EngineeringBooksPDF.com

TABLE IV/4-1 Typical Flow Measurement Points (250 MW TPS)

SR. No.	Service Description	Operating/MCR Value	Calibrated Range
1	Total air flow	1800 T/h	2600 T/h
2	Secondary air flow to burner	320 T/h	0–450 T/h
3	Primary air flow to mill	320 T/h	0–450 T/h
4	Flue gas recycling flow	250 T/h	0–350 T/h
5	Main steam flow	750 T/h	0–1000 T/h
6	Feed water flow before feed control station	800 T/h	0–1200 T/h
7	RH steam flow	700 T/h	0–1000 T/h
8	RH attemperation flow	40 T/h	0–60 T/h
9	First stage attemperation flow	140 T/h	200 T/h
10	Second stage attemperation flow	100 T/h	0–150 kg/cm^2
11	Condensate flow after gland steam cooler outlet	800 T/h	0–1200 T/h
12	Gland steam supply header flow	2 T/h	0–3 T/h
13	RFW tank to condenser (in surge)	50 T/h	0–75 T/h
14	Condenser to RFW tank (out surge)	120 T/h	0–175T/h
15	LPH 3 drain pump discharge flow	35 T/h	0–49 T/h
16	LPH 4 condensate to deaerator flow	0–60 T/h	0–90 T/h
17	Raw water flow	3500 M^3/h	0–5000 M^3/h
18	CCW flow to the TG package	2250 M^3/h	0–3200 M^3/h
19	Cooling tower make-up flow	1400 M^3/h	0–2000 M^3/h
20	Stator coolant flow at generator inlet	0–55 T/h	0–80 T/h

CCW, component cooling water; LPH, low-pressure heater; RFW, reserve feed water; RH, reheater; TG, turbo generator.

second lowest among this category. This type of meter can be used for both circular and rectangular cross sections. Also there are two categories/versions of this device: classic long form and short form.

4.0.1.2 Flow Nozzle

This is a modified, shorter version of the Venturi meter that is suitable for circular cross sections with converging–diverging profiles without any straight portion in between. Details are discussed in Clause 4.1.

4.0.1.3 Orifice Plate

This is a plate with a hole through it, placed in the flow path, which allows only fluid to pass through it. The flow path has a smaller cross-sectional area than the original pipe/conduit area and gets constricted. This helps to develop the DP across the plate and measurements of corresponding flow rate can be obtained. It is basically a crude form of Venturi meter, but with higher permanent pressure from energy losses. There are three types of orifices: concentric, eccentric, and segmental. Krell's orifice is also available with a circular target at the center and annular flow encircling it. There are various types of tapping styles available with all these elements.

4.0.1.4 Dall Tube

This is another version of a shortened Venturi meter. Dall tubes are widely used for measuring the flow rate of medium and large pipes when the pressure drop is lower compared with an orifice plate. It has the lowest permanent pressure loss compared with other differential producers.

4.0.1.5 Pitot Tube

This is a DP-measuring instrument used to measure additional stagnation fluid pressure equivalent to flow velocity with respect to the static pressure by impinging the flow straight to the other side or back of the tube wall after entering through the hole. Bernoulli's equation

www.EngineeringBooksPDF.com

is used to calculate the dynamic pressure and hence fluid velocity.

4.0.1.6 Piccolo Tube

This follows the same principle as the pitot tube .Here there are multiple holes in a vertical line facing the flow. Having multiple holes, there is less probability of being affected by choking in a dust-laden service.

4.0.1.7 Multi-Hole Pressure Probes

Multi-hole pressure probes (also called impact probes) are based on the sane theory as pitot tubes. Depending on the type of application, this probe consists of three or more holes on the measuring tip arranged in a specific pattern. More holes allow the instrument to measure the direction of the flow velocity in addition to its magnitude (after appropriate calibration). Three holes arranged in a line allow the pressure probes to measure the velocity vector in two dimensions. Introduction of more holes, e.g., five holes arranged in a "plus" formation, allow measurement of the 3D velocity vector.

4.0.1.8 Aerofoil

This follows the operating principle of the Venturi meter. The construction of the element depicts multiple Venturi meters covering the total cross section of the flow path and they are connected/welded to each other by sealing the path in between so the flow path is divided and passes through each individual Venturi-like passage.

4.0.1.9 V Cone Flow Device

This design incorporates a contour-shaped cone at the center of the pipe with annular passages for the flow passage. V cone flow element is a very accurate (as high as 0.5%) flow device under a head type flow measurement for both dirty as well as clean fluid measurements. It has better permanent pressure loss compared with orifice plates. Details are discussed later in Clause 4.1.7.

4.0.2 Mechanical Flow Meter

A few examples of mechanical flow meters include: variable area meter, piston meter/rotary piston, oval gear meter, turbine flow meter, paddle wheel meter, nutating disk meter, Woltmann meter, single and multiple jet meter. More details are available in Clause 4.2.

4.1 Flow Elements: Selection and Sizing

Flow elements are basic type of instruments that provide an obstacle in the flow path. Some flow measurements, normally for the closed pipe/duct, work on the principle of DP produced across flow elements. Some flow elements work on the principle of level rise over the flow elements for the open channel flow- measuring system.

4.1.0 Flow Measurement by DP Method

The downstream pressure after an obstacle will always be lower than the upstream pressure, producing a pressure drop across the obstacle cum flow element. All these types of flow elements are differential producers and require a DPT to measure the pressure drop and convert it to a compatible linear signal. Flow elements like orifice, nozzle, and Venturi meters constitute a part of this category and ae based on the Bernoulli equation (see Figure IV/4.1.0-1). To have a better understanding it is necessary to look at the Bernoulli equation.

The Bernoulli equation can be expressed as follows:

$$p_1 + 1/2\ \rho\ v_1^2 + h_1 = p_2 + 1/2\ \rho\ v_2^2 + h_2, \qquad (1)$$

where p = pressure, ρ = density, v = flow velocity, and h = elevation heights.

For simplicity's sake, a horizontal flow (neglecting minor elevation differences between measuring points) is assumed by eliminating the upstream and downstream elevation heights h_1 and h_2.

The Bernoulli equation can then be modified to the following:

$$p_1 + 1/2\ \rho\ v_1^2 = p_2 + 1/2\ \rho\ v_2^2, \qquad (2)$$

The continuity equation can be utilized in this connection by further assuming uniform velocity profiles in the upstream and downstream flow. The equation as expressed is as follows:

$$q = v_1 A_1 = v_2 A_2, \qquad (3)$$

where q = flow rate and A = flow area.

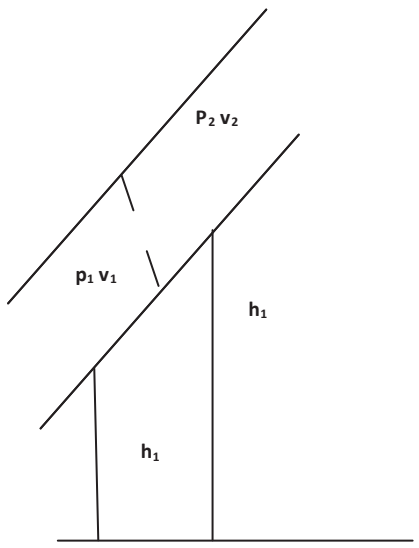


FIGURE IV/4.1.0-1 Bernoulli's equation explanation.

www.EngineeringBooksPDF.com

Combining Equations 2 and 3, assuming $A_2 < A_1$, gives the "ideal" equation:

$$q = A_2\left[2(p_1 - p_2)/\rho\left\{1 - (A_2/A_1)^2\right\}\right]^{1/2} \quad (4)$$

From the above equation it is evident that for a given area and area ratio, that is, geometry of the pipe/tube /duct, the flow rate can be determined by measuring the pressure difference $p_1 - p_2$.

The actual flow rate, however, is less than the theoretical flow rate q due to various geometrical conditions.

The ideal equation (4) thus can be modified with a discharge coefficient:

$$q_{act} = C_d\, \mathrm{X}(q)$$

or

$$q_{act} = C_d A_2\left[2(p_1 - p_2)/\rho\left(1 - (A_2/A_1)^2\right)\right]^{1/2}, \quad (5)$$

where C_d = discharge coefficient and q_{act} = actual flow rate.

The discharge coefficient C_d is a function of the actual minimum jet size, flow element orifice opening, and the area ratio = A_{vc}/A_2 where A_{vc} = area in "vena contracta." Vena Contracta is the minimum jet area that appears physically just downstream the restriction. The viscous effect is usually expressed in terms of the nondimensional parameter Reynolds Number (Re). It is obvious that the velocity of the fluid will be maximum and the pressure will be minimum at vena contracta following the Bernoulli and continuity equations. At the end of this created flow pattern disturbance, the unrest settles down with a steady flow after a short distance from the vena contracta. From this point the velocity of fluid decreases to the same level as before the obstruction (considering the same cross-sectional area of the flow path before and after the flow element). The pressure, however, regains a value near but lower than the pressure before the obstacle and incurs a permanent pressure loss to the flow, which bears a relation in percentage to the measuring pressure drop ($p_1 - p_2$) across the flow element.

Equation 5 can be modified with diameters as follows:

$$q_{act} = C_d\pi/4\, d^2\left[2(p_1 - p_2)/\rho\left(1 - \beta^4\right)\right]^{1/2}, \quad (6)$$

where d = orifice, Venturi, or nozzle bore/throat diameter, D = upstream and downstream pipe diameter, $\beta = d/D$ diameter ratio or beta ratio, and $\pi = 3.14$.

Mass flow for fluids can be obtained by simply multiplying Equation 6 with the density:

$$m_{act} = C_d\pi/4\, d^2\rho\left[2(p_1 - p_2)/\rho\left(1 - \beta^4\right)\right]^{1/2}, \quad (7)$$

Consideration must be given regarding pressure reduction and change in density of the fluid while measuring the mass flow in gases. The above formula is only applicable with the limitations of relatively small changes in pressure and density.

4.1.1 The Venturi Meter

As already discussed in Clause 4, the Venturi meter constricts the flow by gradual change in cross-section throughout the meter travel. The cross-section decreases from the original inlet and then becomes steady for a certain length and again increases downstream up to the original cross section (see Figure IV/4.1-1).

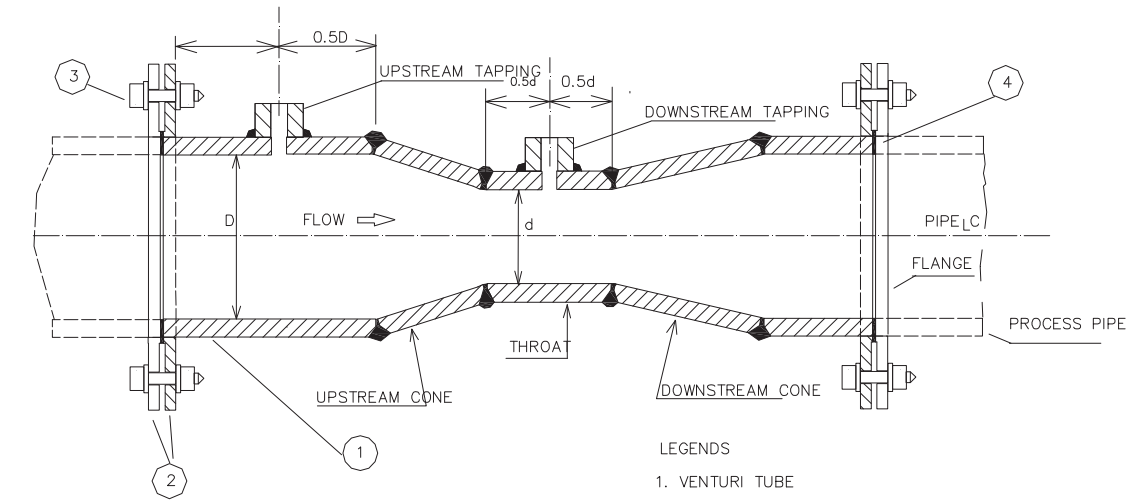


FIGURE IV/4.1-1 Longitudinal cross-sectional view of Venturi tube.

www.EngineeringBooksPDF.com

This long-used method is widely used to measure flow rate in the transmission of gas through pipelines. The discharge coefficient, C_d, of the Venturi meter is comparatively high to other similar types of flow elements and ranges from 0.93 to 0.975. The permanent pressure loss is ~40% of the DP produced and eventually is just higher than the lowest flow meter, i.e., the Dall tube. These types can be used both for circular and rectangular cross sections. In the Venturi meter the fluid is accelerated throughout the inlet due to its converging nature as a cone with an angle of ~15–20° and the pressure difference between the upstream side of the cone and the throat (minimum cross-sectional area) is measured and provides a signal for the rate of flow.

The fluid slows down in a cone with a smaller angle (5–7°) where most of the kinetic energy is converted back to pressure energy. Because of the cone and the gradual reduction in the area there is no vena contracta. High-pressure recovery makes the Venturi meter suitable for the system or process where small pressure heads are available and/or only low permanent pressure loss is admissible .

A discharge coefficient of $C_d = 0.975$ can be indicated as standard, but the value varies noticeably at low values of the Reynolds number (see Table IV/4.1-1).

Venturi tube meters are used in thermal power plants for medium temperature and low-pressure gas flow services, for example, flue gas, primary and secondary air flow, mill air flow, etc. Some manufacturers use Aerofoil, which is a modified version of the Venturi tube as described earlier.

Additional features of Venturi type flow elements include:

1. The Venturi tube is practically suitable for all the services like clean, dirty, and viscous liquid and some slurry services.
2. Straight length before and after the element required varies from 5 to 20 times diameter pipe length (upstream) and 5 to 10 times diameter pipe length (downstream) depending on the layout and installation of items (regarded as constriction) in the vicinity of the element's upstream and downstream pipe length.
3. Typical accuracy is 1% or even lower than full scale range.
4. Rangeability is as high as 4 is to 1.
5. Viscosity effect is high.
6. Relative cost is medium.

4.1.2 Flow Nozzle

As briefly discussed earlier, the flow nozzle is a modified version of the Venturi tube with a comparatively shorter length (long radius nozzle and Venturi nozzle with longer lengths are also used occasionally) flow element (see Figures IV/4.1-2 and IV/4.1-2a). Flow nozzles are used in thermal power plants for high-temperature and high-pressure steam and water flow services, for example, main steam, hot and cold reheat steam, auxiliary steam, feed water and low pressure, temperature services like various condensate flow, etc.

The differences compared with the Venturi tubes include:

1. Flow nozzles are suitable for circular cross section only.
2. Flow nozzles are also designed with a converging–diverging profile but any straight portion in between is not required.

Flow nozzles are used to determine the flow rate of the fluid through pipes with these three different types:

1. ISA 1932 nozzle: This type of flow element was developed in 1932 by the International Organization for Standardization (ISO). The ISA 1932 nozzle is commonly used outside the United States.
2. Long radius nozzle: This type is a variation of the ISA 1932 nozzle.
3. Venturi nozzle: This is a hybrid type of flow element with an inlet convergent clause similar to the ISA

TABLE IV/4.1-1 Different Values of Discharge Coefficient C_d (for Flow Nozzle) in Relation to Different Values of β Ratio and Reynolds Number (Re)

Beta Ratio $\beta = d/D$	Reynolds Number	Reynolds Number	Reynolds Number	Reynolds Number
0.2	0.968	0.988	0.994	0.995
0.4	0.957	0.984	0.993	0.995
0.6	0.95	0.981	0.992	0.995
0.8	0.94	0.978	0.991	0.995

www.EngineeringBooksPDF.com

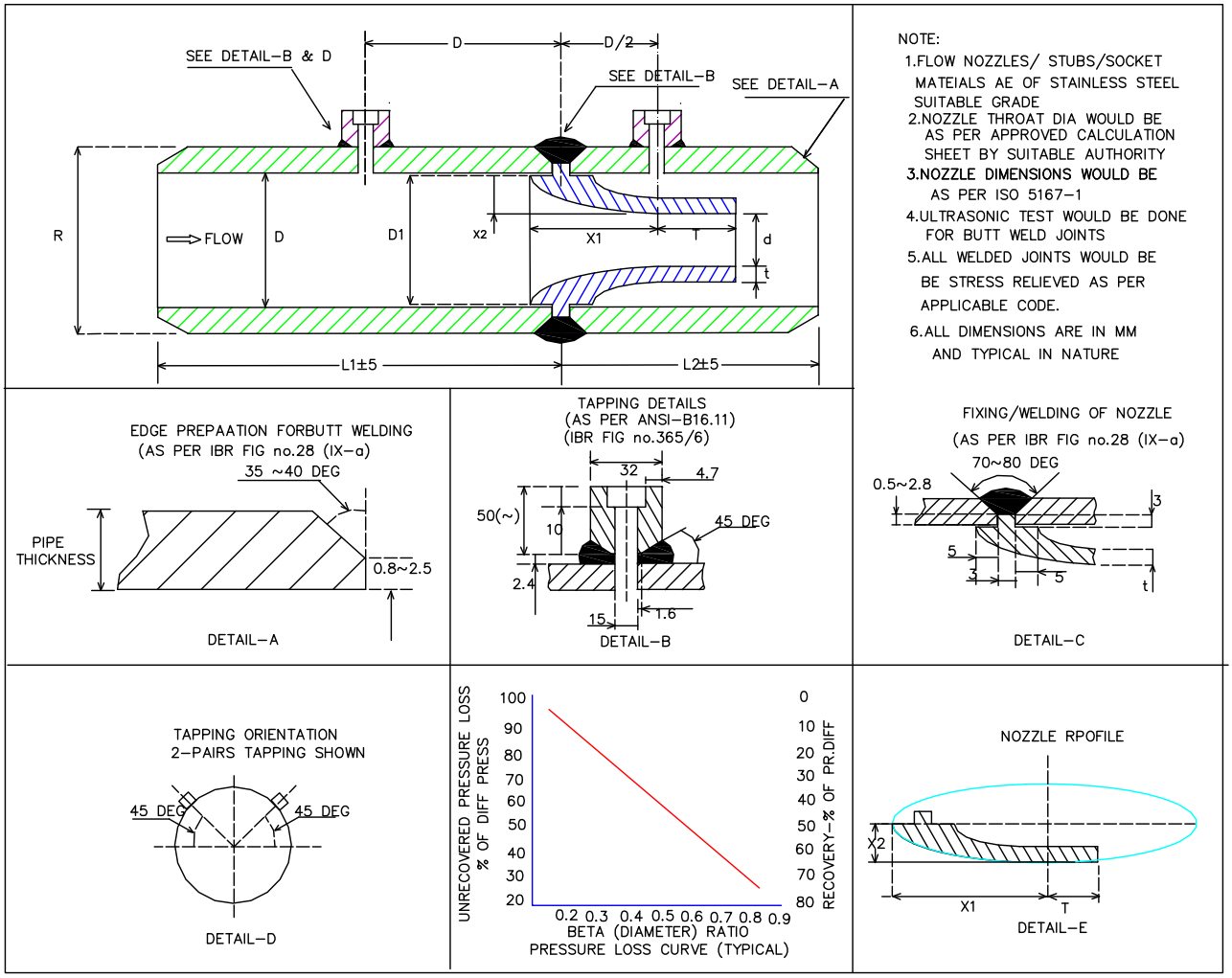


FIGURE IV/4.1-2 Longitudinal cross-sectional view of flow nozzle assembly.

1932 nozzle and a divergent section similar to a Venturi tube flow meter.

Flow elements like the pitot tube (Figure IV/4.1-3) and the Parshall flume (Figure IV/4.1-4; both discussed later in this chapter) are also used for air and open channel water flow measurements, respectively, although they are not popular in power plant applications.

Listed below are additional features of Venturi type flow elements:

1. The flow nozzle is recommended for both clean and dirty liquids.
2. Straight length before and after the element required varies from 10 to 30 times diameter pipe length (upstream) and 5 to 10 times diameter pipe length (downstream) depending on the layout and installation of items (regarded as constriction) in the vicinity of the element's upstream and downstream pipe length.
3. Typical accuracy is 1−2% of full-scale range
4. Rangeability is 4 to 1.
5. Viscosity effect is high.
6. Relative cost is medium
7. Relative pressure loss is medium.

4.1.3 Orifice Plate

The orifice plate consists of a flat circular plate with an outer diameter greater than the inner diameter of the measuring fluid pipe and a thickness of ≥5 mm as per the line pressure and material used. A circular (or a circular segmental) hole is drilled in it which may not be centrally located, for example, an eccentric orifice plate. There is a pressure tapping point upstream from the orifice plate and another just downstream. There are generally four methods of placing the tapping points. The value of discharge coefficient C_d of the meter depends upon the position of tapping points.

www.EngineeringBooksPDF.com

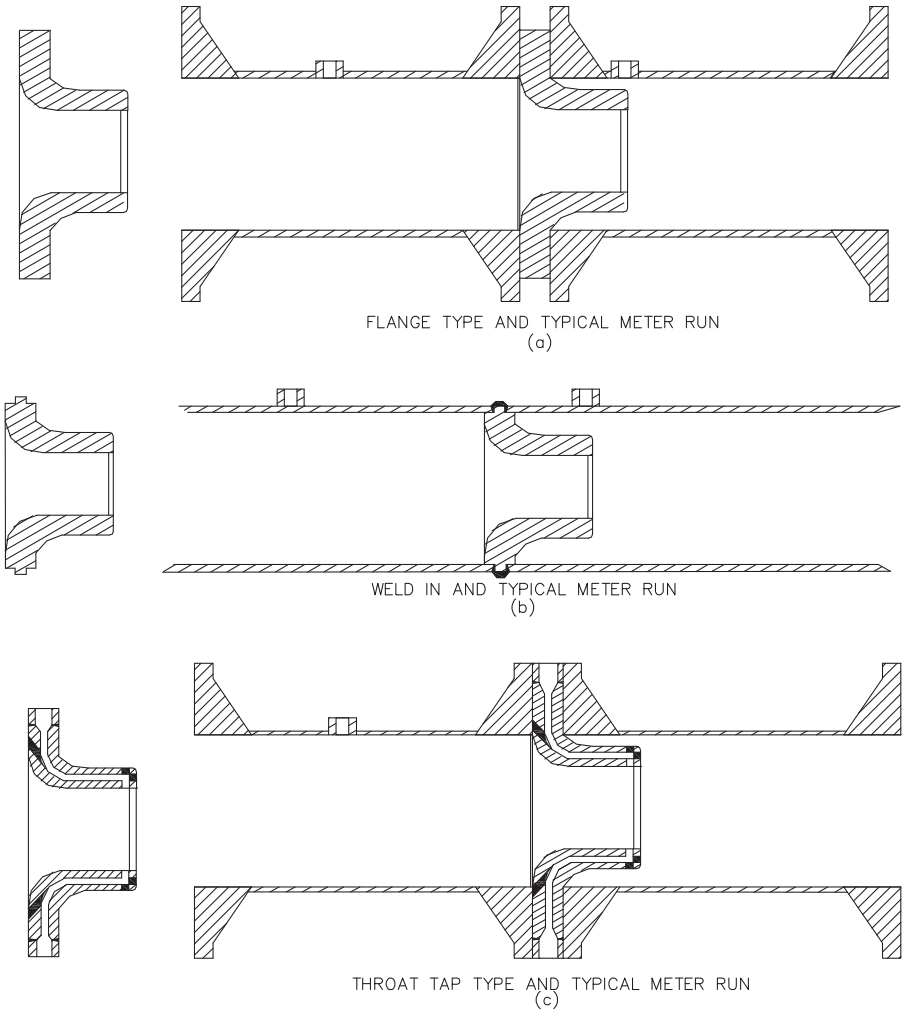


FIGURE IV/4.1-2A Flange or weldable type with D, D/2, or throat tapping of flow nozzle.

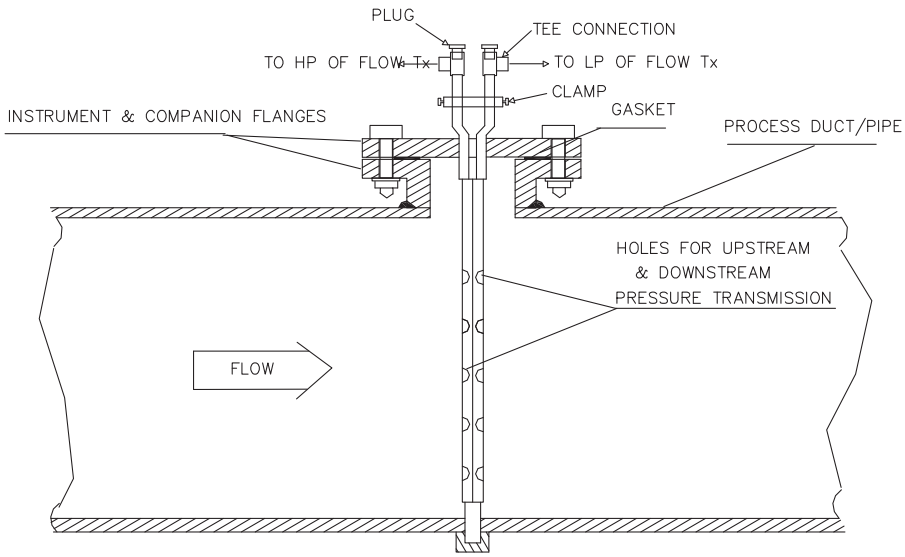


FIGURE IV/4.1-3 Schematic diagram of the construction of a pitot tube.

www.EngineeringBooksPDF.com

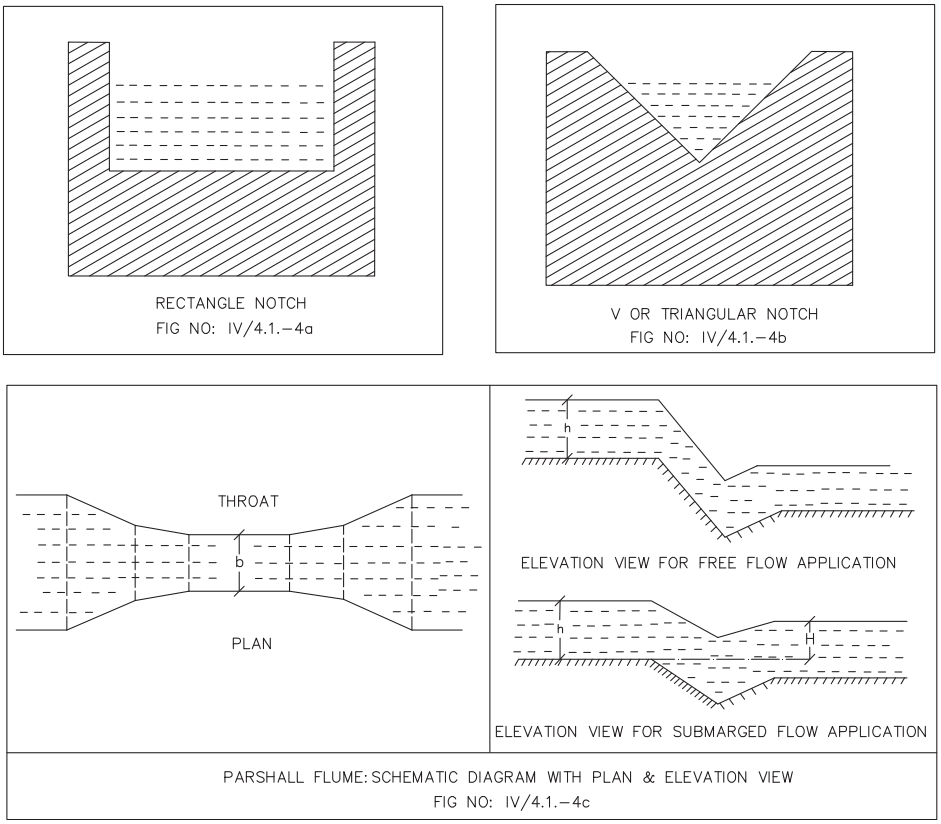


FIGURE IV/4.1-4 Open channel flow-measuring elements.

1. *Flange tapping*: Tapping locations are on the orifice holding flanges,1 inch upstream and 1 inch downstream the inlet face of the orifice.
2. *Vena contracta tapping*: Tapping location 1 pipe diameter (actual inside) upstream and 0.3–0.8 pipe diameter downstream the face of the orifice.
3. *D and D/2 tapping*: Tapping location 1 pipe diameter (actual inside) upstream and 0.5 pipe diameter downstream the face of the orifice.
4. *Pipe tapping*: Tap location 2.5 times nominal pipe diameter upstream and 8 times nominal pipe diameter downstream the face of the orifice.

Carrier ring type orifice plates have been contemplated for small diameter flow pipes where normal flange tapping (i.e., 1 inch upstream and 1 inch downstream the inlet face of the orifice) may be difficult to achieve. The carrier ring is a pair of thick plates/disks suitably grooved to hold the orifice plate in place in between them and make room for drilling flange tapping points. Figure IV/4.1-5 indicates the longitudinal cross-sectional view of the carrier ring type orifice plate.

The discharge coefficient C_d varies considerably with changes in beta ratio (β)and the Reynolds number (see Table IV/4.1-2). A discharge coefficient of $C_d = 0.60$ may be standard, but the value varies noticeably at low values of the Reynolds number (see Figure IV/4.0-1c).

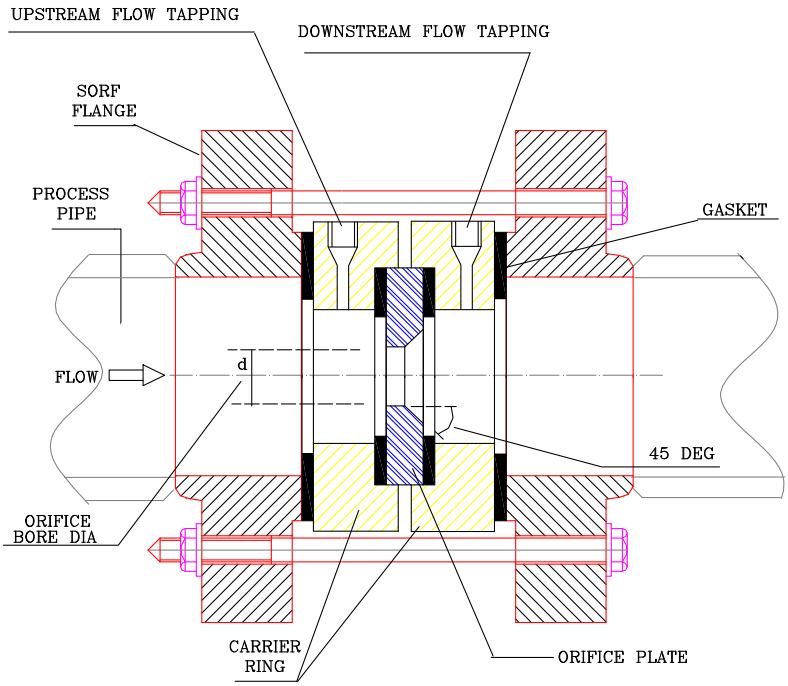
The pressure recovery is limited for an orifice plate and the permanent pressure loss depends primarily on the area ratio. For an area ratio of 0.5, the head loss is about 70–75% of the orifice DP. Orifice plate connections are suitable for flange connections other than carrier ring configurations. The flanges may be the weld type with a weldable neck (Figure IV/4.1-6) or it may be a common type connected to the main process pipe through the counter flange.

There are classifications of orifice plate, such as square-edge orifice (most commonly used), segmental orifice, and eccentric orifice plate—as shown in Figure IV/4.1-7.

Additional features of orifice plate type flow elements include:

1. The orifice meter is recommended for clean and dirty liquids and some slurry services.
2. Straight length before and after the element required varies from 10 to 35 times diameter pipe length (upstream) and 5 to 20 times diameter pipe length (downstream) depending on the layout and installation of items (regarded as constriction) in the vicinity of the element's upstream and downstream pipe length.
3. Typical accuracy is 2–4% of full-scale range.
4. Rangeability is 4 to 1.
5. Viscosity effect is high.

www.EngineeringBooksPDF.com



NOTE
DESIGN AS PER ISO5167–1/BS–1042
ORIFICE WOULD BE MADE OF STAINLESS STEEL OF SUITABLE GRADE
CARRIER RING WOULD BE MADE OF STEEL SUITABLE FOR THE POCESS

FIGURE IV/4.1-5 Longitudinal cross-sectional view of carrier ring type orifice plate assembly.

TABLE IV/4.1-2 Different Values of Discharge Coefficient C_d (for Orifice Plates) in Relation to Different Values of β Ratio and Reynolds Number (Re)

Beta Ratio $\beta = d/D$	Reynolds Number	Reynolds Number	Reynolds Number	Reynolds Number
0.2[a]	0.60	0.595	0.594	0.594
0.4	0.61	0.603	0.598	0.598
0.6	0.62	0.608	0.603	0.603
0.8	0.64	0.614	0.609	0.609

[a]*Normally not applicable for measuring purposes but for the permanent pressure reduction(break down or restricting or restriction) orifice plate.*

6. Relative cost is medium.
7. Relative pressure loss is medium.

The following standards are followed:

1. American Society of Mechanical Engineers (ASME) 2001: Measurement of fluid flow using small bore precision orifice meters, ASME MFC-14M-2001.
2. International Organization of Standards (ISO 5167-1-2003): Measurement of fluid flow by means of pressure differential devices. Part 1: Orifice plates, nozzles, and Venturi tubes inserted in circular cross-section conduits running full.
3. International Organization of Standards (ISO 5167-1) Amendment 1 1998: Measurement of fluid flow by means of pressure differential devices. Part 1: Orifice plates, nozzles, and Venturi tubes inserted in circular cross-section conduits running full. Reference number: ISO 5167-1:1991/Amd. 1:1998(E).

www.EngineeringBooksPDF.com

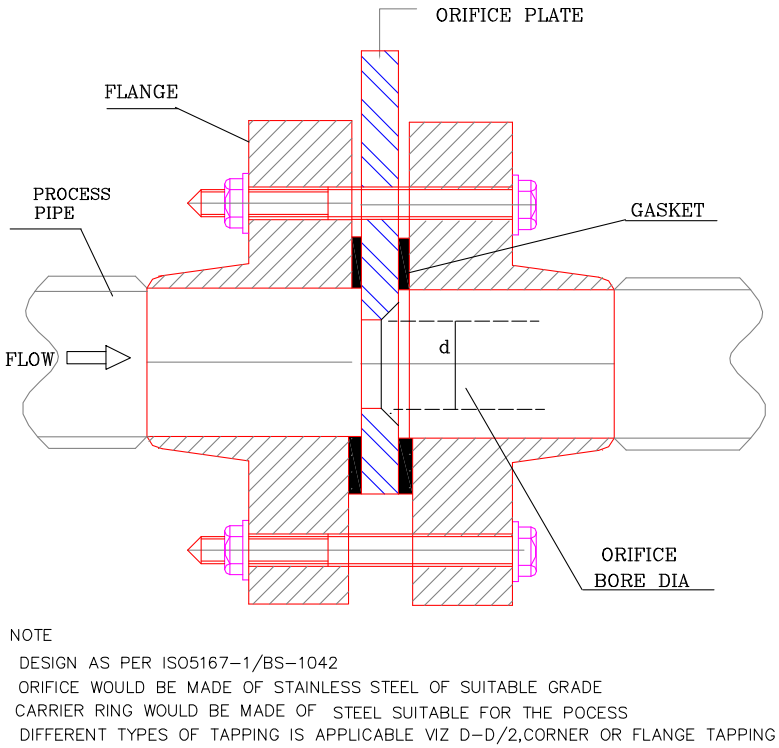


FIGURE IV/4.1-6 Longitudinal cross-sectional view of orifice plate assembly with weldneck type flanges.

4. ASME B16.36–1996 Orifice Flanges, ASME FED 01 Jan 1971 Fluid Meters–Their Theory and Application, Sixth Edition.
5. BS 1042 and BS EN 5167-1.

4.1.4 Krell's Bar Orifice Plate

This was designed by an eminent manufacturer in West Germany (Hartmann & Braun) for the measurement of fluid flow in duct or pipes in a large cross-sectional area. The principle of operation is similar to that of Annubar or pitot tube. The element design claimed to be more suitable for flow measurement of gaseous fluid containing dust.

Its construction (see Figure IV/4.1-8) is just the opposite of the conventional orifice plate but similar to Annubar with a much simpler design. There is a small diameter blind circular plate installed near the central axis of the flow path temporarily restricting the flow. The HP and LP impulse pipes/tubes are welded on two sides of this plate so that their open end is located at the center of the plate.

The fluid velocity becomes zero when it impinges on the plate and is converted into equivalent pressure. The upstream impulse pipe senses the static head plus the dynamic (or velocity) head, whereas the downstream impulse pipe senses the static head only. The DPT connected to this impulse lines generates the appropriate flow signal.

Here the bore of both impulse pipes is comparatively large and thereby problems with dust choking are minimal. The DP produced by this type of element is more than that of Annubar, resulting in high resolution and accuracy.

Additional features for Krell's Orifice plate type flow elements include the following:

1. The meter is recommended for clean and dirty liquids and some slurry services.
2. Straight length before and after the element required varies from 10 to 35 times diameter pipe length (upstream) and 5 to 20 times diameter pipe length (downstream) depending on the layout and installation of items (regarded as constriction) in the vicinity of the element's upstream and downstream pipe length.
3. Typical accuracy is ∼2% of full-scale range.
4. Relative cost is low.
5. Relative pressure loss is medium.

4.1.5 Dall Tube

The Dall tube is a shortened version of a Venturi meter guided by Bernoulli's equation. The pressure drop in this type of instrument is lower than an orifice plate. The tube consists of a short inlet section followed by an abrupt reduction of inlet diameter called an "inlet shoulder." Then come the converging inlet cone and divergent outlet cone, which are separated from each other by a gap, or a slot,

www.EngineeringBooksPDF.com

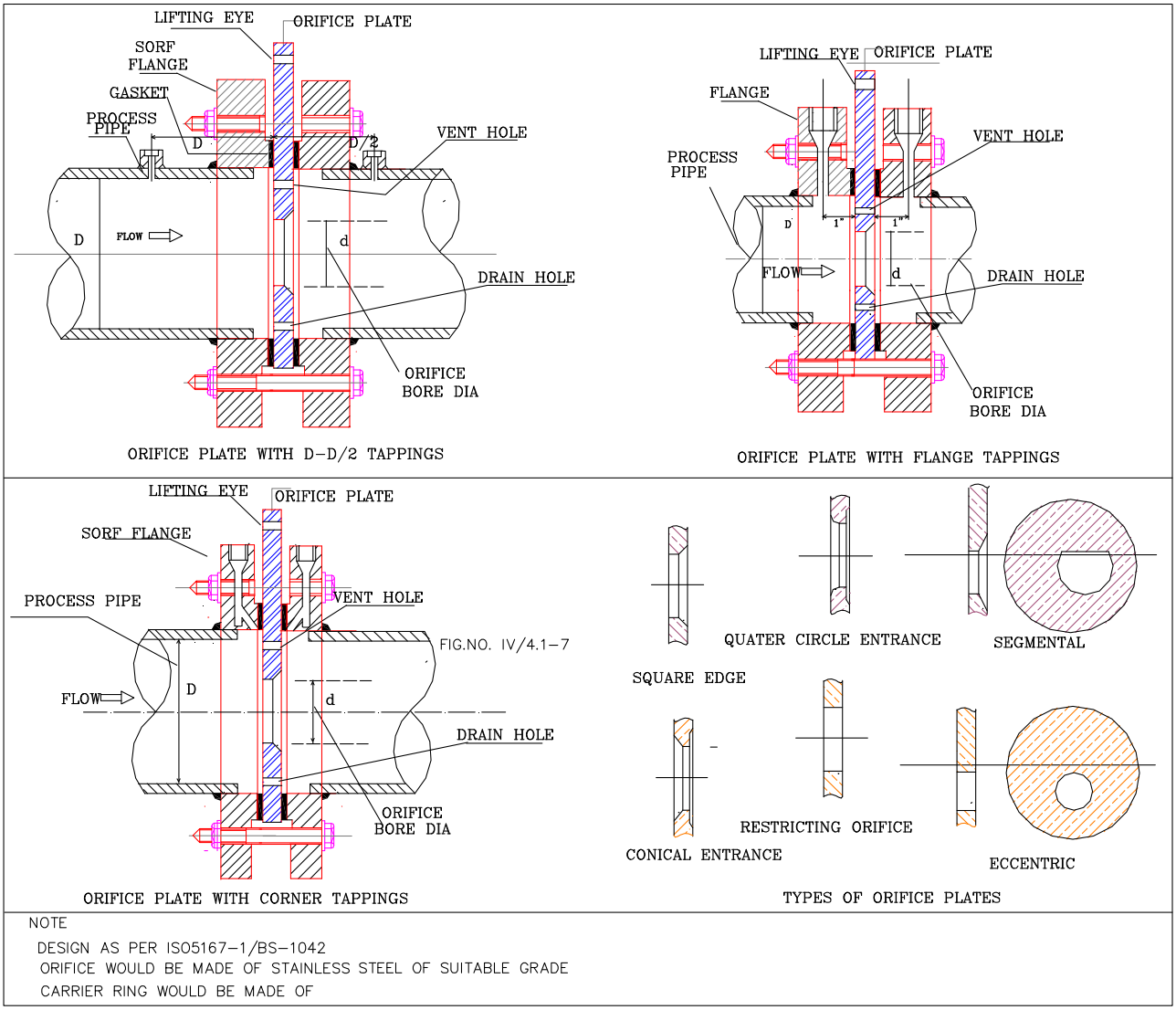


FIGURE IV/4.1-7 Longitudinal cross-sectional view of orifice plate assembly with different types of flow tapping.

called a throat. With these flow meters the flow rate in a Dall tube is determined by measuring the pressure drop across the two tappings with one upstream the edge of the inlet shoulder and the other at the throat. The permanent pressure losses in these meters are lower than orifice meters or, as per some manufacturers, even lower than the Venturi tubes. For medium and large pipe sizes, Dall tubes are normally suitable for measuring the flow rate.

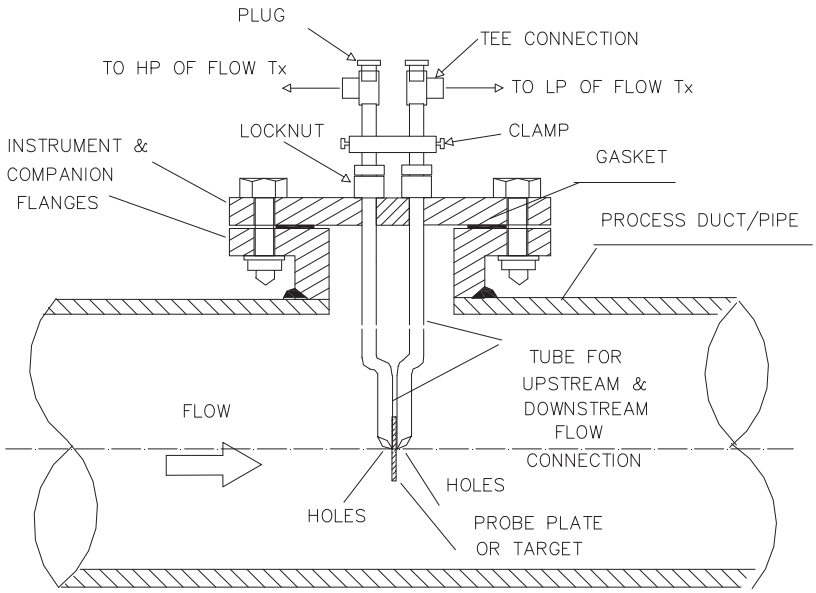
4.1.6 Pitot Tube

A pitot tube is a pressure-measuring instrument used to measure fluid flow velocity by determining the stagnation pressure. Bernoulli's equation is used to calculate the dynamic pressure and fluid velocity The operating principle is similar that for a Krell's bar orifice plate. See Figure IV/4.1-3 for construction of the pitot tube.

4.1.7 V Cone Flow Device

The V cone flow element, as shown in Figure IV/4.1-9 a, is a very accurate (as high as 0.5%) flow device under the head type flow measurement. It can be used for both dirty and lean fluid measurements. In comparison to the orifice it has better permanent pressure loss. The design incorporates a contour-shaped cone at the center of the pipe with annular passages, which direct the flow without impacting it against an abrupt surface thus avoiding wear of edges of the cone by dirty fluids. Because of this feature, recalibration of V cones is rarely required.

www.EngineeringBooksPDF.com



NOTE:
PROBE PLATES TO BE PLACED AT 90 DEGREE TO THE DIRECTION OF FLOW
LOCK NUT IS PROVIDED TO VARY THE INSERTION LENGTH(+_)50 mm TO BE IN LINE WITH MAXIMUM VELOCITY STRATA
ALL METAL PARTS SUBJECT TO BE IN CONTACT WITH THE DIRECT PROCESS SHOULD BE 316SS
OR BEST SUITABLE TO FLUID MEDIUM

FIGURE IV/4.1-8 Schematic diagram of the construction of Krell's bar.

Very short vortices are formed as the flow passes the cone and creates a low-amplitude, high-frequency signal proportional to flow. Pressure loss here is much lower than that of the orifice plate. These flow devices show high accuracy, repeatability, and rangeability with very low permanent pressure loss and short straight-length requirement.

This is a DP type flow element, so one tapping (static pressure) is taken at slightly upstream the cone with the other tapping located downstream the face of the cone itself. The central hole of the cone is connected to a pipe for transmitting the downstream pressure to the flow transmitter.

This type of flow element offers excellent accuracy, repeatability, and rangeability compared with other flow elements and covers the pipe size from 15−3000 mm

4.1.8 Sizing of Flow Elements (Typical)

Various types of flow-element sizing calculation software are available following the standards as stipulated by different organizations as mentioned in the Bibliography. However, a sample calculation is given below so the reader can see how the sizing is normally done (see Table IV/4.1-3).

4.1.9 Flow Measurement by Level Excursion Method (Ref. Fig. VI/4.1-4)

Several types of hydraulic structures are used, for example, notches (rectangular and V or triangular notch), weirs, and flumes (such as rectangular, trapezoidal, or Parshall), for the measurement of flow in the open channel. In the existing channel, notches or weirs can be used since the flow measurement has to be done in the open area where there is a chance of siltation. These elements are removable and cleaning can be done for both the channel and element to restore measurement accuracy. Whenever there is a flow change, the level will change proportionally at the upstream vicinity of the elements, which can be measured normally by an ultrasonic level transmitter with suitable software to convert the level signal into flow.

Notches or weirs are made of thin metal plates, and the general form is either triangular or rectangular in shape. The minimum requirements are

1. Width should be not less than 150 mm.
2. The contraction from either side should be greater than 100 mm.

Parshall flumes are a special shape and size and have to be erected during the construction of the main flow channel

www.EngineeringBooksPDF.com

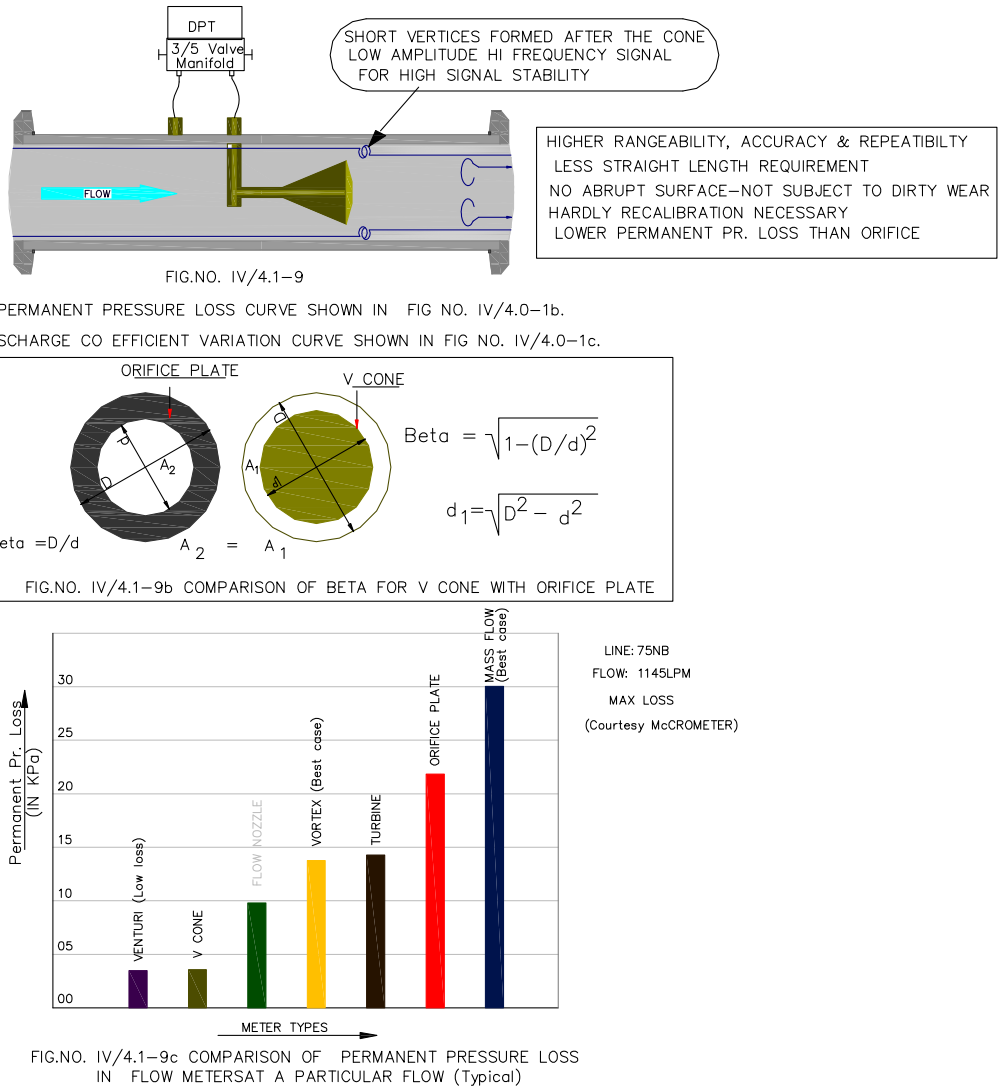


FIGURE IV/4.1-9 V cone flow device.

and cannot be put in the existing one. Level changes as flow changes and ultrasonic level transmitters with suitable software are utilized.

Parshall flume calculation is based on the ISO 9826 (1992) and ASTM D1941 (1991) standards or USBR (1997) standard. Parshall flumes must be constructed in strict compliance with specifications as per these standards as far as shape and their dimensions are concerned. The standard is valid for both free-flowing and submerged Parshall flumes. A free-flowing Parshall flume can be observed physically by the decrement in water head/level at the throat. For submerged flow, the downstream water flows back into the throat over the original head/level making it impossible to identify actual decrement had it been for the free-flow system. Therefore, after developing the empirical formula, the flow calculation of the submerged type of system requires two head measurements: one in the approach channel and one in the throat. On the other hand, only the upstream head/level measurement is required for the free-flow measuring system.

Flumes are also designed to force a transition from subcritical to super critical flow as is done with weirs. For Parshall flumes, the transition is caused by designing flumes to incorporate a constriction at the throat and a sharp drop in head/level in the channel bottom. This transition causes flow to pass through a critical depth in the flume throat and there is a direct relationship between water depth

www.EngineeringBooksPDF.com

TABLE IV/4.1-3 Orifice Plate Bore Calculation as per BS 1042 and BS EN 5167-1

Date:

Tag no. ..... G.A.Drawing no.....

Service of Fluid	DM
Pipe ID	188.40 mm = 0.18840 m (206 OD × 8.8 mm)
Pipe material	Copper
Material of orifice plate	316 SS
Operating temperature (t)	40°C
Upstream gauge pressure (Pg)	3.00 kg/cm^2 = 294198.3 Pa
Barometric pressure (Pb)	1.02 kg/cm^2 = 100027.4 Pa
Operating pressure (Pa)	394225.76 Pa
Specific gravity (σ)	0.992
Flow range (Q_{vr})	360 T/h (6000 LPM)
Dynamic viscocity at operating temperature (Mew)	0.00653170 poise = 0.00065317 Pa/sec
Type of tapping	Flange
DP (h)	5000 mm wcl = 49033.068 Pa

Upstream pipe diameter at operating temperature: $D = 0.1884641$ m
Approximate $CE\beta^2 = 4.Q_v/[\varepsilon .\pi.D^2 \sqrt{(2.h/\rho)}] = 0.36345487$
(assuming $\varepsilon = 1$)
$Nu = \mu$ in Pa/sec/ρ in kg/m^3 = 0.00000066 m^2/sec
Reynolds number: Re at continuous flow,
$Re\ D = 4\ Q_v.0.7/(\pi.D\ Nu) = 724046.08$
Using Table 2 of Clause 1.4, 1992, page 7 and interpolating from ReD column, β = 71909476
Using equation given in 8.3.2.1 of Clause 1.1, 1992:
For β = 71909476, discharge coefficient $C_d = 60272277$
E = 1.168324
Calculating $CE\beta^2$ from C, E, and β just obtained:
$CE\beta^2 = 0.36412735$
By repeating above steps, finally
β = 0.71859276, $C = 0.60275702$, and $CE\beta^2 = 0.36345483$
Bore diameter at operating temperature, $d = 0.13542891$ m
Bore diameter at 20°C, $d_{20} = 0.13538017$ m = 135.3802 mm
Vent hole diameter = 5.0 mm
Modified bore diameter = 135.2786 mm
Pressure loss (Cl.8.4 of Clause.1.1: 1992) = 2334.31 mm
wcl = 46.69 % of DP

and velocity or the flow rate. It is physically very difficult to measure critical depth in a flume because its exact location is difficult to determine and may vary with flow rate. Through mass conservation, the upstream depth is related to the critical depth. Therefore, flow rate can be determined by measuring the upstream depth, which is a highly reliable measurement.

For free flow $Q = Ch^n$, where Q is in m^3/s and h is in m. For submerged flow, ISO equation 12 is rewritten as $Q = C\ h^n - Q_e$, where C and n are found from the above equation based on width (b).

Q_e accounts for the effects of submergence, where m = meters, s = seconds, b = throat width [m], C = Parshall flume constant [empirical units], h = measured upstream head [m], and H = measured downstream head [m].

This is only needed if the flume is submerged or to determine mathematically if the flume is submerged. Usually, one can visually see if there is a hydraulic jump, but determining the ratio H/h is a quantitative method, where H/h = submergence ratio, n = Parshall flume power constant [unit less], Q = flow rate (discharge) through flume [m^3/s], and Q_e = reduction in flow rate due to submergence [m^3/s].

4.2 Flow Transmitters and Meters

The DPT used as a flow transmitter has already been discussed in Chapter I, Clauses 3.1 and 3.2. The nonlinear relationship has an impact on the DPT operating range and requires the electronic DPTs to linearize the signal before transmitting it to the control system. Whatever the operating and ambient conditions, state-of-the art technology in the measurement of flow rate incorporates electronic devices that can correct for varying pressure and temperature, that is, density conditions, nonlinearities, and for the characteristics of the flowing media such as viscosity.

4.2.1 Different Types of Flow Transmitters

4.2.1.1 Magnetic Flow Meters

One of the most common flow meters, apart from DPT and mechanical types, is the magnetic type. A magnetic flow meter is applied to the metering tube, which results in a potential difference proportional to the flow velocity perpendicular to the flux lines. The principle of operation is based on the Faraday's law of electromagnetic induction (see Figure IV/4.2-1).

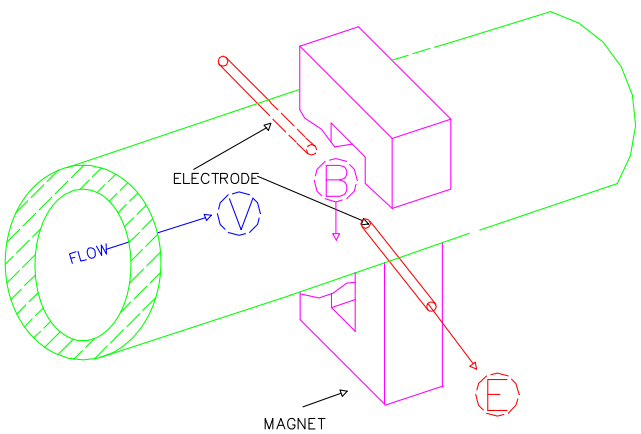


FIGURE IV/4.2-1 Schematic diagram of magnetic flow meter.

www.EngineeringBooksPDF.com

The meter comprises a tube of nonconducting material, for example, a rubber-lined nonmagnetic steel tube. Mounted on the tube wall is a pair of electrodes opposite to each other and making contact or touching flowing media within the tube. The whole arrangement is surrounded by a magnet with its magnetic field just at right angles to the electrode and the flow direction. The flowing media must be an electrical conductor with minimum conductivity of 5 μSiemens/cm (see Table IV/4.2-1).

As the moving fluid (regarded as electrical conductor) flows through the nonconducting tube and through the magnetic field, voltage is induced, which is sensed by the electrode. As per Faraday's law of electromagnetic induction, the magnitude of the induced voltage depends on the

1. Strength of the magnetic field
2. Distance between the electrode
3. Velocity of conducting fluid flowing through the tube.

If the first two conditions are kept constant, the voltage induced will be entirely proportional to the velocity of the flowing media. If the area of the tube is fixed and known the volume flow can be calibrated with respect to the induced voltage. The electronic part of a smart flow transmitter will convert the voltage to a signal like 4-20 mADC and superimposed digital signal (HART) or digital signal through Profibus, Foundation Fieldbus, etc. The velocity range covered by these meters can be 1.0 m/sec up to 10 m/sec without hampering the accuracy.

4.2.1.2 Ultrasonic Type

4.2.1.2.1 Doppler, Transit Time, and Ultrasonic Type This type of ultrasonic measurement employs the difference of the transit time of ultrasonic pulses propagating toward and against flow direction. The average velocity of the fluid and the speed of sound can be calculated along the path of the ultrasonic beam by the transit time difference obtained and their product. Using the two transit times t_{up} and t_{down} and the distance between receiving and transmitting transducers L and the inclination angle α, the equations can be written as follows:

$$\upsilon = L/2 \sin \alpha \times \left[\left(t_{up} - t_{down}\right)/t_{up} \times t_{down}\right]$$

$$c = L/2 \times \left[\left(t_{up} + t_{down}\right)/t_{up} \times t_{down}\right]$$

where υ is the average velocity of the fluid along the sound path and c is the speed of sound.

Ultrasonic flow meters are used for the measurement of natural gas flow, water (any fluid) flow in a closed pipe, ducts, etc. The expected speed of sound for a given sample of fluid can also be calculated and can be compared to the speed of sound empirically measured by an ultrasonic flow meter (see Figure IV/4.2-2a).

TABLE IV/4.2-1 Data Sheet for Magnetic Flow Meters

SL. No.	Item	Specification
1	Make	ABB/Krone L/Foxboro
2	Model/type of transmitter	Remote/head mounted
3	Line size	As per client (15–2600 mm)
4	Display	3 line, engineering unit
5	Metering tube	Stainless tube
6	Earthing electrode	Fitted
7	Maximum detectable velocity	15M/SC
8	Maximum working pressure	6 bar
9	MOC	Electrode: 316 SS/Hastelloy C/titanium/tantalum/platinum iridium/nickel/tungsten carbide Lining: elastomer/Teflon (PTFE)/PFA/neoprene/ polyurethane
10	Test	3 point
11	Protection class	IP 68
12	Power supply	240V AC
13	Process connection	Flat face carbon steel, ANSI
14	Ambient temperature	−10–60°C
15	Totalizer	Integral with membrane keypad
16	Accuracy	1%
17	Range	As per client (0.005–190,000 M3/H)
18	Cable	5–100 m or more
19	Power supply	230 V AC/24 V DC
20	Output	4-20m A(single/dual)/HART/RS 422/423

4.2.1.2.2 Doppler Frequency Shift Method Flow of fluid can also be measured by the help of the Doppler "frequency shift" method. This method uses the characteristics of an ultrasonic beam affected by the movement of a fluid when it is passing through the fluid. An arrangement is made so that while passing an ultrasonic

www.EngineeringBooksPDF.com

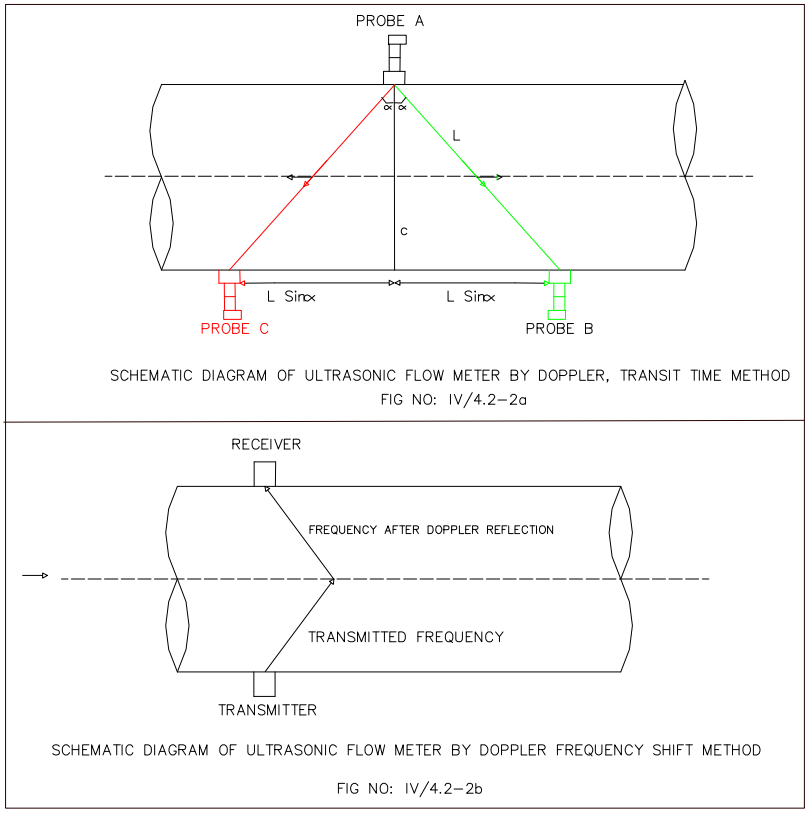


FIGURE IV/4.2-2 Schematic view of Doppler and transit time/frequency shift type flow meters.

beam through the flowing media it will bounce back off a reflective plate at the other end and then after the direction of the beam is reversed and received by the sensor. As the frequency of the transmitted beam is affected by the flowing fluid in the closed pipe, by comparing the frequency of the upstream beam with the downstream beam, the fluid flow through the closed pipe can be measured. The volume flow can be calculated by the mismatch between the upstream beam and the downstream beam frequencies. To make the flow independent of the cross-sectional area of the pipe, the wide-beam sensor is normally selected. It is mandatory that the flow stream must contain sonically reflective materials to act as reflecting plate as described above. The flowing media containing solid particles or entrained air bubbles are suitable for the flow meter to work exploiting the Doppler principle of frequency shifting (see Figure IV/4.2-2b).

4.2.1.2.3 Level Excursion Type The type of flow elements used for this type of measurement were discussed earlier. The level is measured by an ultrasonic level transmitter, which senses the actual level, and not the velocity of the fluid, from the bottom line of the fluid flowing through the channel upstream just near the flow element. An ultrasonic level transmitter is equipped with the appropriate software to convert the level signal into the flow signal according to the flow element design.

4.2.1.3 Coriolis Flow Meters

A coriolis flow meter is basically a mass flow meter for measuring the amount or quantity or the mass of fluid, rather than volume, flowing through a closed pipe or tube. Using the Coriolis Effect, that causes a laterally vibrating tube to distort, a direct measurement of mass flow can be obtained in a coriolis flow meter. The added advantage is that a direct measurement of the density of the fluid can also be obtained with this instrument. Coriolis measurements can be very accurate irrespective of the type of gas or liquid that is measured; the same measurement tube can be used for any gas and liquid without individually calibrating each instrument. As in a conventional mass flow meter, the fluid passes through Coriolis flow meter containing a pair of smooth pipes or tubes without any moving parts, avoiding regular cleaning and maintenance (see Figure IV/4.2-3).

4.2.1.3.1 Coriolis Principles If a moving mass is subjected to an oscillation, perpendicular to the motion, a coriolis force occurs, which depends on the mass flow. Because of this force, sensor(s) at the inlet and outlet are

www.EngineeringBooksPDF.com

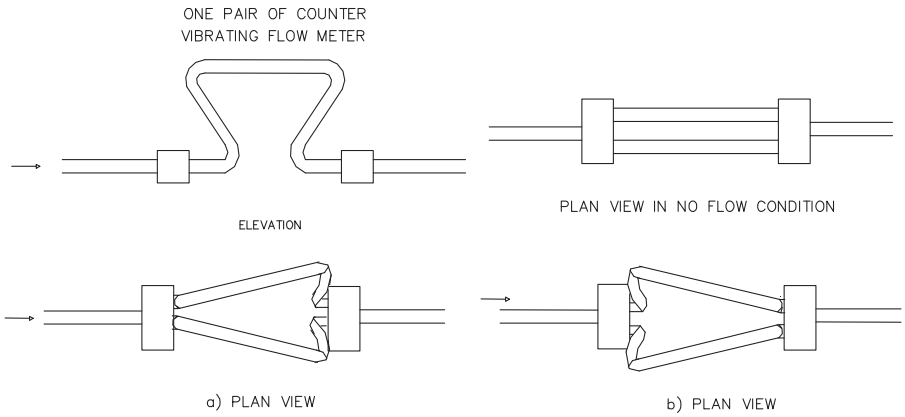


FIGURE IV/4.2-3 Schematic diagram of coriolis flow meter.

subjected to this force differently. At the inlet, because of mass addition, it tries to oppose the vibration, while at the outlet side, mass going out tries to add to the vibration. Naturally there will be a twisting motion in the tubes. The resultant phase shift in tubes' oscillation is a measure of mass flow. Whenever mass of a vibrating system changes, there will be change in vibration frequency. When measuring density, keeping volume flow same, the change in frequency of vibration will be a measure of density (volume flow is the same and meter mass does not change). To eliminate thermal influence on the tube, i.e., volume change of the meter itself, an RTD is used to measure the temperature (see Figure IV/4.2-3a).

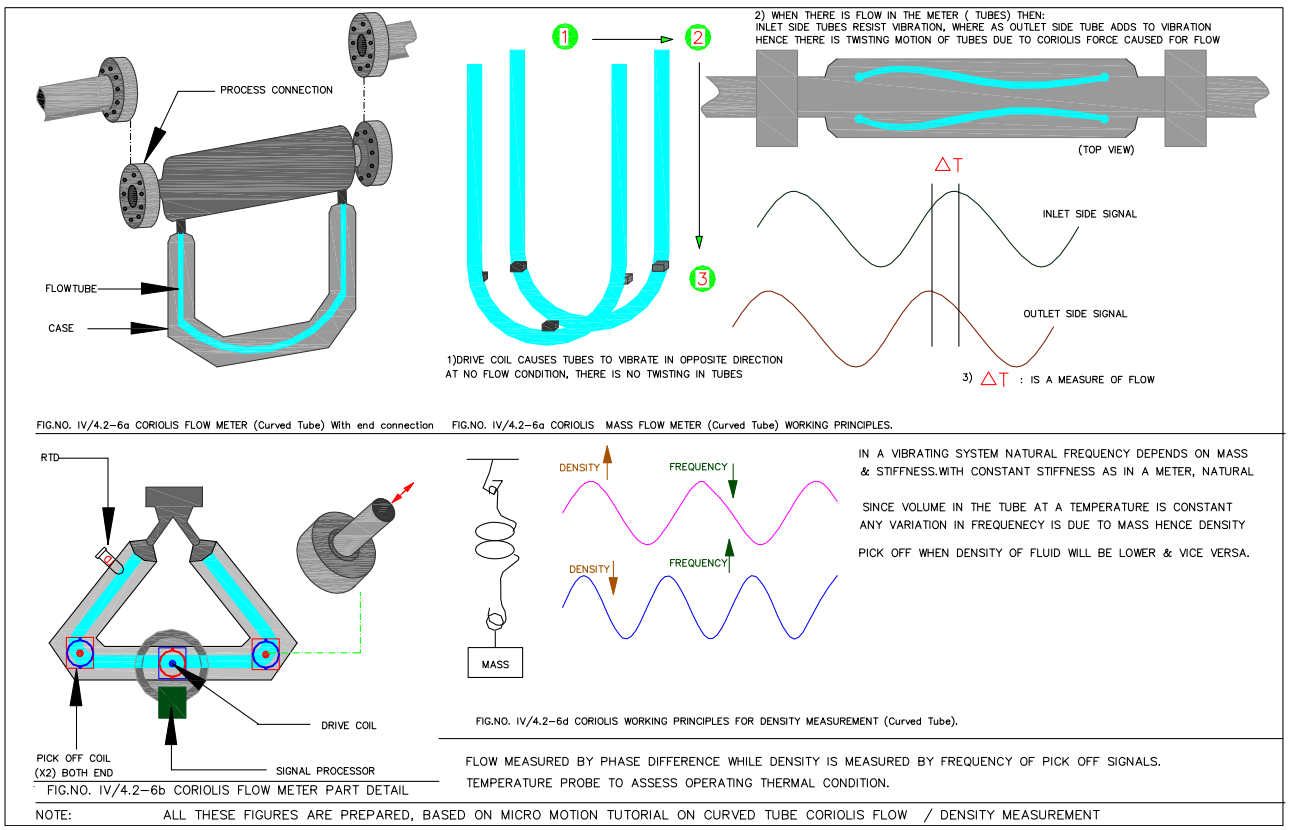


FIGURE IV/4.2-3A Coriolis principles.

www.EngineeringBooksPDF.com

There are two parallel tubes through which the fluid is passed. A mechanical vibrator is arranged to cause vibration in these two tubes. To make the instrument less sensitive to external vibrations, the parallel tubes are made to vibrate to counter each other. The amplitude of the vibration is kept very small, although it can be felt by touching the flow tubes. The vibrating frequency of the tubes solely depends on the size of the mass flow meter, although the ranges may vary from manufacturer to manufacturer in the domain of about 100 to 1000 times per second. When no fluid is flowing, the vibration of the two tubes is symmetrical. The two arms vibrate with the same frequency as the overall vibration, but when there is mass flow the two vibrations shift to a sort of asynchronous situation. The two vibrations are shifted in phase with respect to each other, and the degree of phase shift is a measure for the amount of mass that is flowing through the tubes.

4.2.1.4 Vortex Flow Meter

Vortex flow meters are a direct type of flow-measuring device with operating fundamentals based on the Von Karman Vortex Street principle. In this instrument, a bluff body or shedder bar is arranged at the center of flow path. When the fluid passes through it, disturbances in the flow called vortices are alternately formed on both sides of the shedder. These vortices thus formed are shed just after due to the flow stream forming a vortex street as per Karman Vortex Street principle (see Figure IV/4.2-4).

The frequency of the vortex formation and shedding depends on several factors: velocity of the fluid (υ), width of the shedder (d), Reynolds number (Re). The relationship of velocity with flow and frequency can be given as $f = S \times \upsilon/d$, where S is the Strouhal number.

The Strouhal number (S) is a dimensionless number that defines the quality of the vortex flow rate measurements and bears a relationship with Reynolds number as shown in graph of Figure IV/4.2-4b, which is moderately constant in a long stretch of Reynolds number.

Reynolds number can be expressed as $\mathrm{Re} = \upsilon \times D/\mathfrak{d}$, where D is the inner pipe diameter and ϑ is the kinematic viscosity. The frequency associated with vortex creation or shedding is therefore a dependent variable of fluid velocity only as L is constant and S is fairly constant for a particular wide range of Reynolds numbers and independent of the fluid density and viscosity.

The sensor type employed is often a piezoelectric crystal, the details of which were discussed earlier in the chapter. The local pressure near the sensor, located strategically, changes every time a vortex is created or in other sheds. The pressure changes are sensed by the piezoelectric crystal and converted into a small electrical signal or voltage pulse representing the vortex shedding frequency. Since the frequency of the voltage pulse is also proportional to the fluid velocity, a volumetric flow rate is calculated using the cross-sectional area of the flow meter. The frequency is measured and the flow rate is calculated by the flow meter electronics using the above equation.

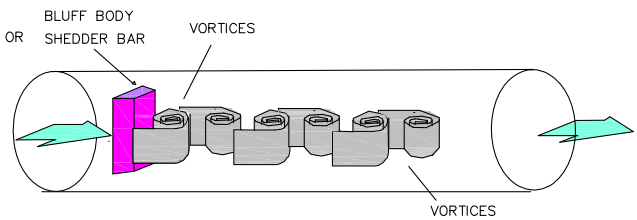


FIG NO: IV/4.2–4a
SCHEMATIC DIAGRAM OF VORTEX FLOW METER

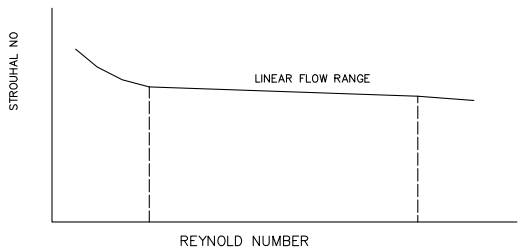


FIG NO: IV/4.2–4b
RELATIONSHIP BETWEEN STROUHAL (S) NUMBER AND REYNOLD'S NUMBER

FIGURE IV/4.2-4 Schematic diagram of vortex type flow meter.

4.2.1.5 Swirl Flow Meters

Another direct type of flow-measuring device is the swirl flow meter. When the flow enters the instrument through the inlet guide body it is forced to swirl or rotate. A vortex core is created in the center of this rotation and is forced again into a secondary spiral-shaped rotation by the back-flow. The frequency of this secondary rotation is fairly proportional to the flow rate .When the internal geometry is designed optimally, the relationship is assumed to be linear over a wide flow range. The sensor type employed is a piezoelectric crystal and its principle of operation is similar to the vortex flow meters.

4.2.1.6 Mass Flow Meters

This device works according to the thermal measuring principle of a hot-film anemometer. This measuring method determines the gas mass flow directly with a result that it is totally independent of pressure and temperature influences. The mass flow meter is used in process plant as well as in the food and beverage industries for flow measurement of gases and gas mixtures (see Table IV/4.2-2).

Thermal mass flow instruments employs different ways to detect the mass flow dependent of cooling a heated resistor as a measuring signal. In a hot-film anemometer

www.EngineeringBooksPDF.com

TABLE IV/4.2-2 Data Sheet for Thermal Mass Flow Meters

SL. No.	Item	Specification
1	Make	ABB/Krone Marshal/ Foxboro
2	Model	—
3	Line size	As per client (25 −200 mm)
4	Operating pressure	40 bar
5	Response time	<0.5 sec
6	Process medium	As per customer
7	Type of transmitter	Head mounted
8	Maximum working temperature	−25−300°C
9	MOC of sensor	Ceramic or metal (316 SS)
10	Accuracy	<0.9% (for air/nitrogen) <1.8% (for other gases)
11	Protection class	IP 65
12	Power supply	230V AC
13	Process connection	DIN/ANSI flanged
14	Ambient temperature	−25−70°C
15	Output	4-20m A
16	Power supply	230 V AC /24 V DC
17	Range	As per client

with differential temperature control, the heated platinum resistor is maintained at a constant over temperature, by controlling power input to the resistor, in relation to an unheated platinum sensor inside the gas flow. The power required for heating the platinum resistor to maintain the over temperature bears a direct relation to the flow rate and the material properties of the gas. With a known (and constant) gas composition the mass flow can be determined electronically by evaluating the heater current versus the mass flow curve without additional pressure and temperature compensation. Another method is employed by using the constant power method. The temperature difference is measured, which results from a constant heating power and depends on the amount of heat dissipated by the gas mass flow. Together with the standard density of the gas, this directly results in the standard volume flow, and an accuracy smaller than 1% of the measuring value is achieved (see Figure IV/4.2-5).

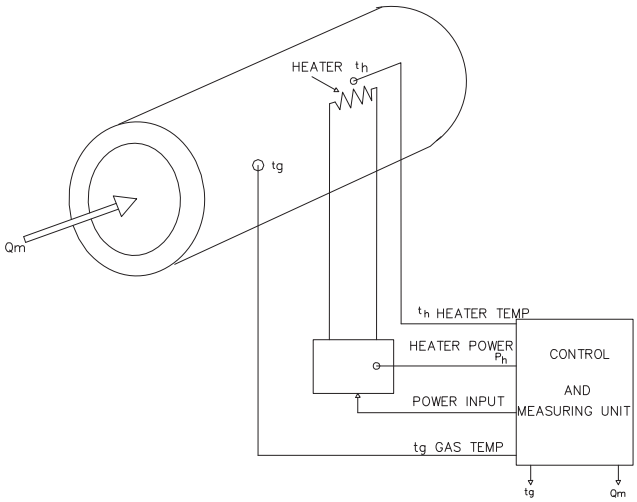


FIGURE IV/4.2-5 Mass flow meter schematic diagram.

The measuring systems are made up of a transducer and a pipe component. The transducer comprises the sensor unit and an electronic transmitter circuit, and it directly delivers an electrically isolated 0/4-20 mA output signal. It is designed as a flange-mounted insertion sensor and is installed in the pipe component in a defined way. The pipe component is available in nominal sizes ranging from 25to 200 mm and in various designs. It is also possible to install the transducer in square ducts or pipes of any size by using a suitable adapter.

4.2.1.6.1 Typical Applications

- Gas flow measurement in thermal power plant
- Gas burner control
- Gas measurement for air separation systems
- Hydrogen measurement in processes

4.2.2 Mechanical Flow Meter

There are several types of mechanical flow meters, such as variable area meter, piston meter/rotary piston, oval gear meter, turbine flow meter, paddle wheel meter, nutating disk meter, Woltmann meter, and single and Multiple jet meter. Those will be discussed briefly in this section, although all of them are not used in a thermal power plant.

4.2.2.1 Variable Area Meter

The variable area meter, popularly called a rotameter is basically a vertically tapered tube, with the small diameter in the downward position. The material of construction is normally made of glass, with a float inside that is pushed up by force offered by the upward fluid flow and pulled down by gravitational force. When the flow rate increases, greater viscous and pressure forces (due to increased DP acting on

www.EngineeringBooksPDF.com

the float area) cause it to rise until it becomes stationary at a location in the tube that is wide enough to restore the DP at the value before rise in flow took place. The two forces balance each other to keep the float stationary at a new position. Floats are normally made of stainless steel in many different shapes, and spheres and spherical ellipses are the most common. Some are designed to spin visibly in the fluid stream to aid the user in determining whether the float is stuck or not. Rotameters are available for a wide range of liquids but are most commonly used with water or air, for example, in demineralized (DM) water. They can be made to reliably measure flow down to 1% accuracy. Remote flow transmissions are also available with this type with the necessary transducer, which is magnetically coupled with the float.

Another type of variable area meter is called as valve type area meter. This type of instrument employs the movement of the spindle containing a plug or a piston of a self-positioning valve. For each flow, there will be particular position of the valve plug or a piston to maintain the DP at a constant value. The valve position is then calibrated against the flow. Remote flow transmissions are also available with this type with the necessary transducer, which is magnetically coupled with the movement (see Figure 4.2-6).

4.2.2.2 Piston Meter/Rotary Piston

Piston meters are also known as rotary piston or semi-positive displacement meters. They are under the category of positive displacement type meter and most common water flow-measuring devices and are used for meter sizes up to 40 mm. The piston meter operates on a piston rotating within a chamber of known volume. Every rotation of the piston ensures a fixed amount of water to go out after passing through the piston chamber. The number of rotations through a gear mechanism is counted, suitably calibrated, and displayed.

4.2.2.3 Oval Gear Meter

The oval gear meter is a also a type of positive displacement meter. The operating principle of the oval gear meter is based on two or more oval-shaped gears configured to rotate always at right angles to one another. It has two sides connected to the inlet and outlet ports. The teeth of the two gears always mesh so fluid is not allowed to pass through the center of the meter. At one position of the inlet side gear, the teeth of the gear close the fluid flow inlet because the elongated gear is protruding into the measurement chamber. At that time, at the outlet side of the meter a cavity is formed that holds a fixed amount of fluid in the measurement chamber.

As the inlet fluid continues to push the gear arrangement, both gears rotate. The fluid in the measurement chamber is then allowed to be released into the outlet port. At the same time the fluid entering the inlet port will be driven into the measurement chamber, which is now open. The teeth on the outlet side then close keeping the fluid from entering back into the outlet fluid. This cycle

Almost all international standard transmitter suppliers have this type of transmitter to enhance the compensation approach for better accuracies. In conventional methods, three separate measuring transmitters/devices were deployed, e.g., DP transmitter, static/absolute transmitter, and temperature elements (with transmitters), that feed these signals to a flow computer in PLC/DCS to get compensated flow as per the following equations: $Q_m = \sqrt{(}\ dp*P/T)$ where dp = DPT output, P and T stand for pressure and temperature compensation signal. However, in this dynamic compensation of flow, which is influenced by factors like discharge coefficient (C), velocity approach factor (E_v). gas expansion factor (Y_1), and density factor (ρ) are taken in to consideration as per the following formula (EN ISO 5167/AG3). $\underline{Q_m = C*E_v*Y_1*d^2 *\sqrt{(dp*\rho)}}$

C:Discharge coefficient is influenced by Reynolds number (velocity profile), which in turn depends on viscosity, density, and velocity of the medium. Re= (v*D*ρ)/υ, where v = velocity, D = internal pipe diameter, ρ = density, and υ = viscosity.

Y_1:Gas expansion factor is applicable for compressible fluids and depends on Beta (β = diameter ratio), isentropic exponent, DP and static pressure of fluid. There are separate formulas for each type of flow elements (such as flow nozzle, orifice plate. etc. (any standard flow-metering book may be referred to for formulae).
E_v: Velocity approach factor depends on β as per the following formula Ev= $\{1/\sqrt{(1-\beta^4)}\}$. Naturally the material of the pipe and flow element and their thermal expansion has influence. Dynamic compensation would result in a better accuracy approach.
P: Medium density directly influences flow rate as stated in the beginning. It is a function of T and P so for gas AGA 8 standard or steam table can be used for superheated and saturated steam, and for liquid ρ as function T may be used.
Normally a PC-based software approach is used while configuring these transmitters. Apart from this Fieldbus or HART 5 or 7 configuration tools can be used.

Even though these multivariable transmitters/sensors individually can offer very high accuracy 0.075% of FSD, actual mass flow measurement accuracy will be little less. The sensor for pressure could be absolute, gage pressure. Normally standard Pt RTD, and/or standard THCs can be used from external sources. The response time could be in the tune of 200–300 mS. Almost all the transmitters have advanced diagnostic features to monitor impulse line block, heat trace, CPU failure, hardware failure, and wrong configuration.

FIGURE IV/4.2-6 Multivariable transmitter for flow measurement.

www.EngineeringBooksPDF.com

continues as the gears rotate and allowing a fixed amount of fluid to pass through the measurement chambers, and the number of rotations is counted, suitably calibrated, and displayed. Remote transmission through magnetic coupling or other suitable devices is also available. This type of instrument is used in thermal power plants for fuel oil, light diesel oil/high speed diesel, or naphtha for problems encountered while using segmental orifice plates.

4.2.2.4 Turbine Flow Meter

The operating principle of the turbine flow meter is based on the rotation of the turbine wheel whose blades are set in the flow path of a fluid stream. When the incoming fluid through the inlet port impinges on the turbine blades, a force is developed that causes the blades to move. The blades are fixed to the rotor and create torque and cause rotational motion. The speed of the meter is proportional to fluid velocity after a steady rotational speed is attained. In this type of meter, remote transmission through magnetic coupling or other suitable devices are also available. Turbine flow meters are used for the measurement of natural gas, air, and liquid flow.

4.2.2.5 Nutating Disk Meter

This type of instrument is commonly used for measuring liquid and water flow. The liquid, enters at the inlet side of the meter and impinges on the nutating disk. The disk is eccentrically mounted within the measuring chamber. Since the bottom and the top of the disk remain in contact with the measuring chamber, the disk starts "wobbling" or nutating with respect to the vertical axis due to the impact of the fluid. The inlet and outlet chambers are separated by a partition. For every nutation, a fixed amount of liquid passes through the chamber and the total number of nutations for a particular period directly indicates the volume of the liquid that has passed through the meter. This instrument provides very reliable measurements within 1%.

4.3 Flow Switch: Working Principle

Flow switches are also available of various types, such as flapper or paddle, target or disk or vane, diaphragm, shuttle, piston, etc. Switch contacts are available in flow meters also and normally provided for alarm, data acquisition systems, or open loop control for interlock and protection purposes. Other types of switches are also available employing the principle of thermal mass flow or vortex type flow measurement with the help of an electronic unit to calculate and provide alarm or tripping contacts.

4.3.1 Flapper or Paddle Type

The flow monitoring switch comprises a paddle/flapper system hanging through a hinge with the flat surface facing the flow direction. To this end a permanent magnet is attached; above this magnet is a reed contact, located outside the flow of fluid. A second magnet with opposing poles generates the force required to reset the switch so that it goes back to its original/normal starting point, that is, at the no-flow position. The paddle/flapper assembly is covered by a gaiter or bellows of suitable material to protect it from a process laden with hazardous components or particles (see Figure IV/4.3-1a).

When the flow increases, the force behind the flow compels the paddle/flapper assembly so that the paddle swings away. This causes the position of the magnet to shift with respect to its relation to the reed contact, activating the contact. If the flow value reduces, the flapper/paddle moves back to its starting position, activating the reed contact again. The force required to push the magnet back to the original position is provided by the two magnets repelling each other. Leaf springs are not usually employed for restoring original paddle/flapper position to get rid of its sensitiveness to pressure peaks. Magnetic forces are considerably more stable in the long term.

Flow switches should be mounted in a horizontal section of cooling water pipe when there is a straight horizontal of at least five pipe diameters on either side of the flow switch to avoid turbulent flow condition. The inlet line should allow free movement of the paddle/flapper in the pipe without rubbing the side. The paddle/flapper must be at the right angle to the flow and the arrow mark on the body must be in the same direction as the fluid flow.

4.3.2 Target or Disk or Vane Type Flow Switch

When there is a fluid flow through a pipe/tube with a velocity that exceeds a particular value, the fluid velocity becomes sufficient to push any object upward if suitably hinged at the top or cause rotation (in case of vane). The flow switch of this type consists of a valve body with a target or disk to sense the velocity of the flowing liquid. The force thus developed against a target, disk, or vane causes it to lift out of the flow path. Disk, target, or vane assemblies of different sizes and shapes for different flow requirements are utilized. They are arranged is an attraction sleeve just at the top of the target/disk/vane assembly. The sleeve then overcomes the pull of the spring and is arranged to move toward a magnet with the switch assembly located outside the sleeve pipe. The moment the

www.EngineeringBooksPDF.com

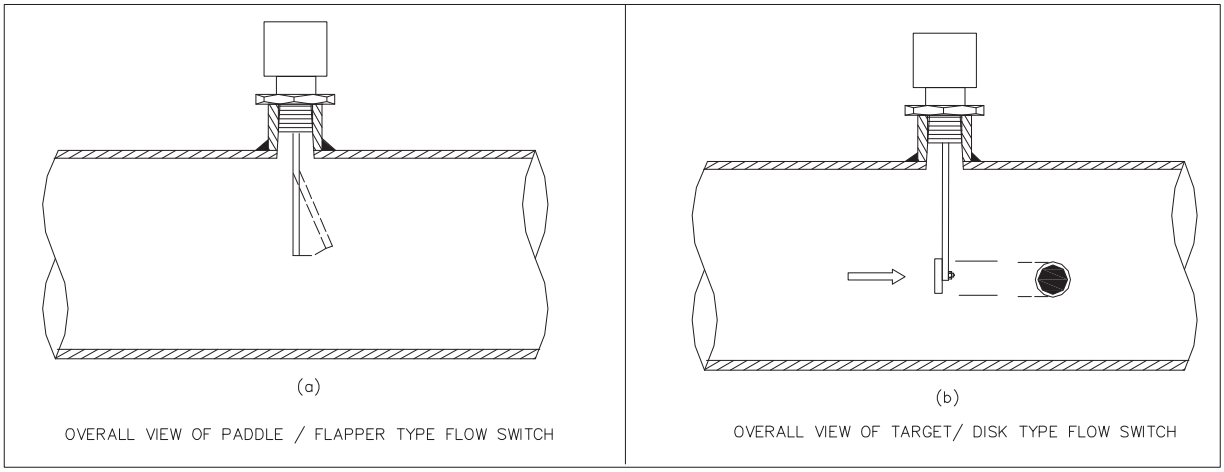


FIGURE IV/4.3-1 Overall view of paddle/flapper/target/disk type flow switch.

sleeve swings into the field of the magnet, the magnet is attracted, actuating the switch. Set point is adjustable and is achieved by adjusting the spring at the top of sleeve pipe (see Figure IV/4.3-1b).

The switch resets when the disk assembly comes down due to fall of flow. Then the spring pulls back the magnet bringing the switch back in to a low- or no-flow condition. With a vane-operated flow switch, the operating principle of the switch is same except that a cam mechanism converts the angular movement of the vane to a suitable movement so the sleeve can operate the magnet by the switch.

4.3.3 Diaphragm Type Flow Switch

The diaphragm type flow switch works by an acting force due to DP on a set of diaphragms (see Figure IV/4.3-2a).

Diaphragm type flow switches are similar in construction to DP switches. The only difference is that there is an opening between the inlet and outlet port letting fluid flow through the switch, whereas it is completely closed in DP switches. The opening acts as an orifice and a DP is developed, which is dependent on liquid flow. The precondition of installing these switches is that the inlet port should be on the same line as the outlet port. When this is

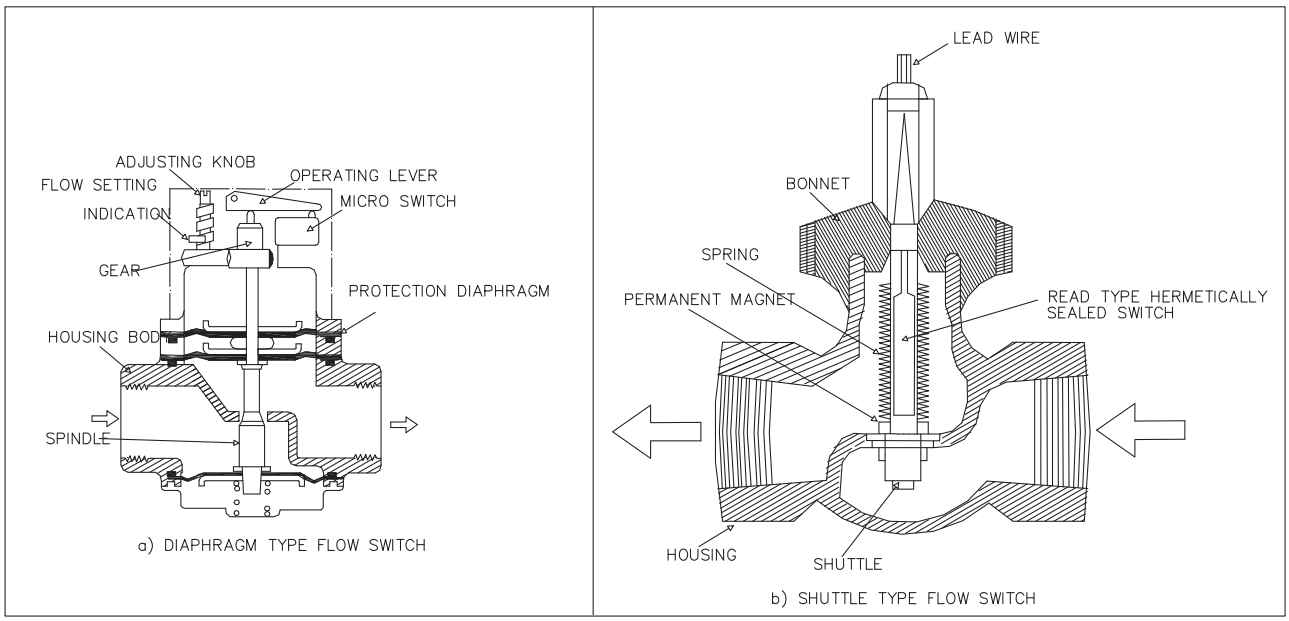


FIGURE IV/4.3-2 Cutout view of diaphragm and shuttle type flow switch.

www.EngineeringBooksPDF.com

done, the liquid flow normally takes a zigzag route inside the switch body. This phenomenon leads to a large pressure drop, which is established when there a liquid passes through the flow switch. Due to the action of DP across the self-created orifice of the switch housing and the compression spring attached to the diaphragm assembly through a spindle, the spindle begins to rise or go down depending on the magnitude of flow. The higher value of flow rate would create a higher pressure drop and cause the spindle to move downward and upward if the flow rate goes down. The top attachment of the spindle with a projected lever is arranged to operate the micro switch. Set point adjustment facility at various flow rates is available. This can be achieved with the help of a knob provided at the gear assembly. This type of switch is sensitive to specifically low liquid flow rates with a minimum of acting components and is capable of withstanding high internal pressures.

4.3.4 Shuttle Type Flow Switch

Shuttle type flow switches work on the principle of an acting force due to DP or the velocity of the liquid acting on a disk. Attached to the disk is a shuttle at the bottom and a magnet just above the disk (see Figure IV/4.3-2b). The upper part of the shuttle body (spindle) moves up against a compression spring or gravitational force. The hollow spindle or stem incorporates a hermetically sealed reed switch within the shuttle.

As liquid flow increases over to the actuation setting, the shuttle is displaced. Upon displacement by fluid flow, this shuttle actuates the reed switch within the unit stem; the shuttle returns when flow decreases and sits on the port seat. The adjustable versions of this flow switch incorporate an internal, adjustable bypass vane by a set point adjuster, which is controlled externally as described in the following clause (see Figure IV/4.3-2b).

4.3.5 Piston Type Flow Switch

In this type of switch, a piston is positioned in the flow path. The piston incorporates a permanent magnet within it and moves along with the piston. When and as long as the DP is high enough to press the piston to the upside against the spring force, the magnet actuates the hermetically sealed reed switch placed outside the mechanical arrangement but coupled magnetically. The piston-metering land diameter dictates the bypass clearance and the actuation point is set (see Figure IV/4.3-3).

Figure IV/4.3-3a shows the operation of the fixed set point type described above. Figure IV/4.3-3b shows the operation of an adjustable set point type where an externally adjustable rotatable vane is provided in the main flow path to determine the bypass flow and the DP across the adjustable vane via the piston for actuation .The magnet-carrying piston is placed in the bypass line and moves as the DP is adjusted.

4.3.6 Thermal Mass Flow Type

This type of flow switch features thermal dispersion technology. Here, the temperature difference is minimum for a full-flow condition and continues to increase as flow reduces for a cooling effect of the heated RTD. Changes in

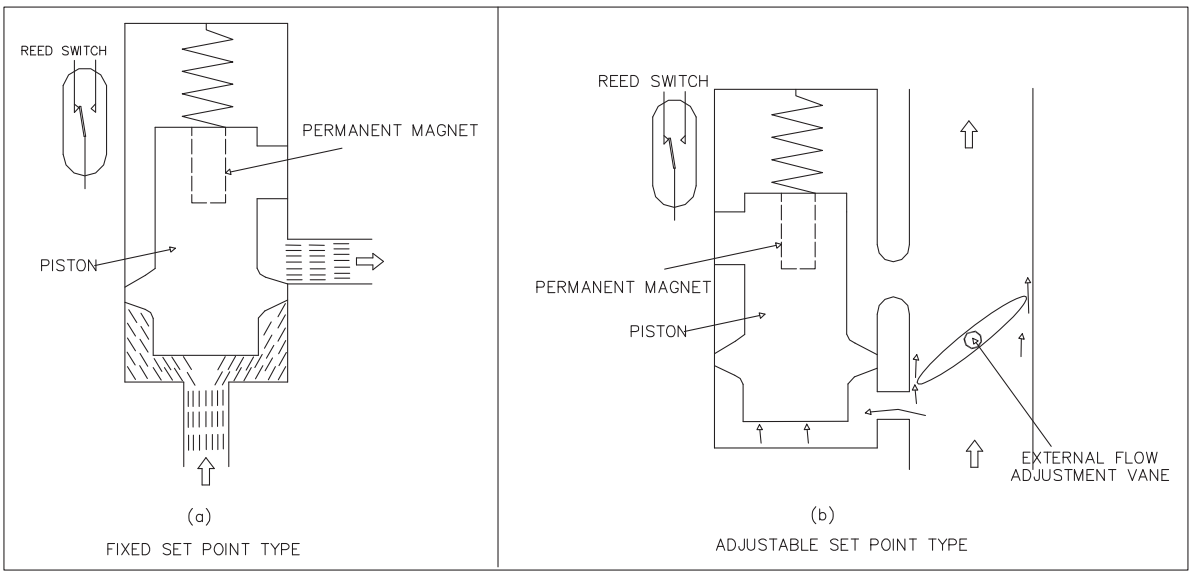


FIGURE IV/4.3-3 Cutout view of piston type flow switch.

www.EngineeringBooksPDF.com

flow velocity directly affect the extent to which heat dissipates and, in turn, the magnitude of the temperature difference between the RTDs. An electronic control circuit converts the RTD temperature difference into a DC voltage signal. Both of these signals are provided at output terminals and are used to drive two adjustable set point alarm circuits. Both alarms are independently field configurable for flow, liquid level/interface, or temperature operations.

4.3.7 Flow Switch with Velocity-Based Actuation

The principle of operation is the same as the vortex type flow transmitter as they both operate on the vortex principle. The obstruction (shedder body) placed in the flow of the liquid sheds vortices downstream at a frequency proportional to the velocity of the liquid. This pattern of vortices is named after the Von Karman Vortex Street. A piezoelectric sensor detects the vortices and generates voltage pulses, which are proportional to the liquid velocity by the flow rate. The instruments may be mounted in any position; the local output meter unit can be rotated. The instruments are supplied with two alarm outputs or with an analog output, thereby operating as a flow switch.

Typical specification sheets for different flow switches are indicated in Tables IV/4.3-1 to IV/4.3-5.

4.4 Flow Gauge

Flow meters are normally used to assess the performance of a system and for calculations of the energy/power or heat rate/efficiency of a plant requiring continuous measurement of flow and the use of electronic flow sensors rather than flow gauges without requiring any power. As already discussed, there are many different methods for measuring flow, and the direct form of those measuring instruments are flow gauges. Generally flow gauges are called as sight flow gauge glasses, which work without any external power supply. Some of the flow gauges can also provide electronic flow sensors for remote transmission (flow meters). Self-contained flow meters or sight flow gauge glasses, on the contrary, rely only on the dynamic characteristics of flow to provide a visual indication of it. Different manufacturers employ different design criteria, which change from one to another, but the basic concept of flow gauge operation depends solely on the principle of dynamic pressure.

Sight flow gauge glasses are the simplest type of flow gauges. They are is basically made of toughened glass or acrylic pipe or tubes, suitably protected from mechanical damage, through which the fluid passes and some sort of mechanism is provided to move a pointer on a graduated scale to indicate the flow rate.

TABLE IV/4.3-1 Data Sheet of Flapper/Paddle Type Flow Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Magnetrol	
2	Range	33–500 LPM (Eq. water)	
3	Set point	Low or high (adjustable)	
4	Sensing material	Brass/316 SS /PVC (for corrosive liquid)	
5	Repeatability	±1–2% FSR	
6	Medium	Liquid/air/gas	
7	Switch unit	2 SPDT	
8	Rating	5 Amps, 230 V AC	
9	Line size	15–300 mm	
10	Maximum velocity	10 m/sec	
11	Process connection	Threaded (25 mm)/Flange (50 mm)	
12	Casing/casing material	Weather proof, IP 65, die cast aluminum	
13	Electrical connection	1/2″ ET/3/4″ ET complete with cable gland	
14	Maximum line pressure	10 kg/cm^2(brass), 30 kg/cm^2 (SS)	
15	Maximum process temperature	100°C (brass), 170°C kg/cm^2 (SS)	
16	Mounting	Horizontal/vertical	

www.EngineeringBooksPDF.com

TABLE IV/4.3-2 Data Sheet of Target/Disk/Vane Type Flow Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Magnetrol	
2	Range	2–50 LPM (Eq. water)	
3	Set point	Low or high (adjustable)–one set point	
4	Sensing material	Brass/316 SS /PVC (for corrosive liquid)	
5	Repeatability	±1–2% FSR	
6	Medium	Liquid/air/gas	
7	Switch unit	2 SPDT	
8	Rating	5 Amps, 230 V AC	
9	Line size	10–50 mm	
10	Maximum velocity	10 m/sec	
11	Process connection	Threaded (25 mm)/Flange (50 mm)	
12	Casing/casing material	Weather proof, IP 65, die cast aluminum	
13	Electrical. connection	1/2″ ET/3/4″ ET complete with cable gland	
14	Maximum line pressure	16 kg/cm^2	
15	Maximum process temperature	110°C	
16	Mounting	Horizontal/vertical	

TABLE IV/4.3-3 Data Sheet of Shuttle Type Flow Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Magnetrol	
2	Range	2–50 LPM (Eq. water)	
3	Set point	Low or high (adjustable)–one set point	
4	Sensing material	Bronze/316 SS/Teflon (for corrosive liquid)	
5	Repeatability	±1% FSR	
6	Medium	Liquid/air/gas	
7	Switch unit	2 SPDT	
8	Rating	5 Amps, 230 V AC	
9	Line size	25–75 mm	
10	Maximum velocity	10 m/sec	
11	Process connection	Threaded/flange	
12	Casing/casing material	Weather proof, IP 65, die cast aluminum	
13	Electrical connection	1/2″ ET/3/4″ ET complete with cable gland	
14	Maximum line pressure	30 kg/cm^2	
15	Maximum process temperature	150°C	
16	Mounting	Horizontal/vertical	

www.EngineeringBooksPDF.com

TABLE IV/4.3-4 Data Sheet of Piston Type Flow Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Magnetrol	
2	Range	0.5—500 LPM (Eq. water)	
3	Set point	Low or high (adjustable)— one set point	
4	Sensing material	Bronze/316 SS/Teflon (for corrosive liquid)	
5	Repeatability	±1% FSR	
6	Medium	Liquid/air/gas	
7	Switch unit	2 SPDT	
8	Rating	5 Amps, 230 V A.C	
9	Line size	8—80 mm	
10	Maximum velocity	2 m/sec	
11	Process connection	Threaded/flange	
12	Casing/casing material	Weather proof, IP 65, die cast aluminum	
13	Electrical connection	1/2″ ET/3/4″ ET complete with cable gland	
14	Maximum line pressure	50 kg/cm^2	
15	Maximum process temperature	120°C	

TABLE IV/4.3-5 Data Sheet of Diaphragm Type Flow Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Magnetrol	
2	Range	10—50 LPM (Eq. water)	
3	Set point	Low or high (adjustable)—one set point	
4	Sensing material	Nitrile butadiene rubber (NBR)/Bronze/SS	
5	Repeatability	±1% FSR	
6	Medium	Water/liquid (noncorrosive)	
7	Switch unit	2 SPDT	
8	Rating	5 Amps, 230 V AC	
9	Port size	10, 15, and 20 mm	
10	Maximum velocity	2 m/sec	
11	Process connection	Threaded/flange	
12	Casing/casing material	Weather proof, IP 65, die cast aluminum	
13	Electrical connection	1/2″ ET/complete with cable gland	
14	Maximum line pressure	12 kg/cm^2, 1—6 kg/cm^2 (op.)	
15	Maximum process temperature	5—60°C	

www.EngineeringBooksPDF.com

They provide a reliable, fast, and low-cost solution to measuring fluid flow. Flow gauges may be of the following type:-

4.4.1 Sight Flow Glass

These types are only for viewing flow or no-flow conditions without any calibrated scale attached to it.

4.4.1.1 Full View Flow

This type is simply a piece of pipe or tube of transparent material through which the fluid passes and the flow is visible from outside just for a confirmatory flow or no-flow signal. The piece of pipe or tube diameter is normally more than the connecting process pipe or tube diameter to avoid any pressure loss due to the instrument.

4.4.1.2 Rotary Type

Rotary type sight flow indicators are used in both transparent solutions and gases. These instruments are equipped with a rotating wheel and are suitable for installation in any position. However, they are also applicable for pipelines with dark opaque solutions where the motion of the wheel is easily detected. These indicators are most suitable for distant viewing purposes.

4.4.1.3 Drip, Ball, and Flapper Types

These are all direct type indicators without calibrated scales.

4.4.2 Variable Area Type

The principle of operation is already described in Clause 4.2.2.1. The rotameter or valve type area meters are generally used as an indicating instrument, but with help of attaching different types of followers with electronic transducer, the remote transmission is very much in use.

4.4.3 Variable Orifice Type

A tapered shaft and a spring-loaded piston are the main components of this type of flow gauge. When there is no fluid flow, because of the action of the actuating spring the piston remains in its seat or initial position. As fluid enters from the inlet side, pressure acts on the piston against the spring and pushes upward to open the orifice formed between the inner diameter (ID) of the piston and outer diameter (OD) of the tapered shaft. For each flow, the piston assumes a particular position to allow the process flow through the corresponding orifice area. At that new position, the spring compression force is equal to the new DP produced by the new flow multiplied by the piston area. The position of the piston is now in equilibrium, when then provides an indication of flow. Flow can be measured directly by attaching a pointer to the piston position to a calibrated scale marked on the flow meter's transparent outer case. For remote transmission, the piston has an embedded magnet that moves a follower that has an electronic transducer.

5. LEVEL MEASUREMENT

Level measurements are very important for any industry or plant as water is required everywhere, but they are specifically important for thermal power plants. All the regenerative heaters, gland coolers, ejectors, deaerators, and most important, boiler drums, require level measurements.

Some typical level measuring points for a 250 MW thermal power plant are given in Table IV/5-1.

5.1 Level Transmitters: Working Principle

The level measurement can be broadly be categorized in two parts: continuous or point values. Continuous level instruments measure levels within a specified range and determine the accurate amount (taking the accuracy figure into consideration) of substance in a certain place. There are two major types of level measurement: direct and indirect. The first one employs a variation of levels directly to obtain a measurement. The other one measures levels indirectly by using a dependable variable that changes with the level. There are several level transmitters and they are grouped in the indirect category. Examples include pressure transmitters, DPTs, and transmitters employing ultrasonic sound waves, radio waves, radioactive signals, bubbler method, load cells, capacitance change, conductivity change, etc.

5.1.1 Pressure or DP Type Level Transmitter

Pressure or DPT transmitters have been used to measure liquid levels of open or pressurized tanks, respectively, with proper calibration taking care of the density value of the subject liquid. These types are used for level measurements of boiler drums, all heaters, deaerators, condenser hotwells, condenser surge tanks, and all dosing tanks.

For open tanks, a pressure tapping at a suitable location is connected, through the impulse line, to the high-pressure port of the DPT with the low-pressure port open to atmosphere. The pressure (or DP) sensed by the DPT is proportional to the level with a known liquid density (ρ) and force due to (earth's) gravity (g). With proper calibration, the potential transform can now be used as a level transmitter.

Regarding the pressurized tank or vessel, single-pressure tapping does not serve this purpose as it senses the pressure of the vessel and the pressure of the liquid level. To balance out the vessel pressure, another pressure

www.EngineeringBooksPDF.com

TABLE IV/5-1 Typical Level Measuring Points

SR. No.	Service Description	Operating/MCR Value	Calibrated Range
1	Boiler drum level (NWL-CL = −100 mm)	±5 mm wcl	−400 to +500 mm wcl
2	HP Heater 7 level (horizontal type) (NWL-CL = −500 mm)	NWL	500 mm wcl ±50 mm wcl (control)
3	HP Heater 6 level (horizontal type) (NWL-CL = −490 mm)	NWL	±500 mm wcl ±50 mm wcl(control)
4	Deaerator level (NWL-CL= +600 mm)	NWL	−750 mm wcl
5	LP Heater 4 level (horizontal type) (NWL-CL = −350 mm)	NWL	−400 mm wcl −100 mm wcl(control)
6	LP Heater 3 level (horizontal type) (NWL-CL = −250 mm)	NWL	−300 mm wcl
7	Gland steamer cooler level	1000 mm wcl	0−1500 mm wcl
8	Cooling water make-up head tank	1800 mm wcl	0−2500 mm wcl
9	DMCW, make-up tank level	1400 mm wcl	0−2000 mm wcl
10	Condensate storage tank level	1800 mm wcl	0−2500 mm wcl
11	Clarified water reservoir level	1400 mm wcl	0−2000 mm wcl
12	CW pit level	3000 mm wcl	0−4000 mm wcl
13	Condenser hotwell level	600mm	0−850 mm wcl
14	RFW tank level	4000 mm wcl	0−5000 mm wcl
15	Ammonia dosing tank level	1500 mm	0−2000 mm wcl
16	MU dosing tank level	2000 mm	0−3000 mm wcl
17	Acid dosing tank level	1500 mm	0−2000 mm wcl
18	Anti-scalant dosing tank level	1500 mm	0−2000 mm wcl
19	Phosphate solution tank level	700 mm	0−1000 mm wcl
20	Sodium solution tank level	700 mm	0−1000 mm wcl
21	Hydrazine dosing tank level	700 mm	0−1000 mm wcl
22	HFO storage tank level	1500 mm	0−2000 mm wcl
23	LFO storage tank level	1500 mm	0−2000 mm wcl

CW, circulating water; HFO, heavy fuel oil; LFO, light fuel oil; LP, low pressure; MU, morpholine; RFW, reserve feed water; DMCCW, demineralized water clarified cooling water; NWL, normal water level; HP, high pressure.

tapping for sensing it is connected, through the impulse line, to the low-pressure port of a DPT so that the output will only be proportional to the liquid level only with known ρ and g.

5.1.2 Displacer Type Level Transmitters

These types of transmitters utilize the buoyancy effect of a submersible matter in a liquid. A cylindrical solid metal body called a displacer is made to hang from a mechanical arrangement to sense the force exerted by the displacer submerged in the liquid of the vessel. The displacer may be located in the tank or in an extended part of the vessel according to the design to create the same level as in the vessel forming the sensing part of the transmitter. With the changes of the liquid level, the displacer is subjected to weight loss and in turn force exerted by the displacer will vary.

With the help of suitable linkage, the force exerted by the displacer is converted into torque and ultimately into 4−20 mADC and superimposed digitized signal.

www.EngineeringBooksPDF.com

5.1.3 Ultrasonic Type Level Transmitters

Ultrasonic type level measurements are used when making contact with the fluid or solid materials is not permitted and these are called noncontact type level measurements. Services, such as measuring the level of deep wells/hazardous areas/lack of tapping facility/highly viscous liquids, bunkers with bulk solids, water treatment applications/open channel measurement, etc., are accomplished through ultrasonic transmitters. The sensors are equipped with hardware capable of emitting high-frequency (20−200 kHz) sound waves that are reflected back to the sensor and detected by its receiving section.

As the velocity of sound is dependent on wave propagation, ultrasonic level sensor outputs are also liable to be contaminated by the changing velocity of sound due to environmental moisture, temperature, and pressures. Modern transmitters are capable of taking corrective actions to the same to improve measurement accuracy.

It is very important that to get best response from reflected sound waves, sensors have to be mounted properly. To avoid unfaithful return resulting in inaccurate output, the bunker, hopper, bin, tank, and vessel should be made relatively free of obstacles such as welding, brackets, or ladders around the measuring point. The modern measurement systems are equipped with a proper "intelligent" echo-processing arrangement to take care of this, but the "line of sight" of the transducer to the target is blocked.

There are several other conditions like turbulence, froth/foam/fumes, vapors of water (steam), or other chemicals and even the changes in the concentration of the process material affect the output of ultrasonic sensors. Turbulence and froth/foam prevent the sound wave from being properly reflected to the sensor; fumes and vapors distort or absorb the sound wave. The amount of energy in the reflected sound waves depends on the concentration of the subject material and any variation therein will affect output response of the sensor. To circumvent those effects, deployment of stilling wells and wave guides are used as a common feature.

It is to be noted here that in this type of measurement, the ultrasonic sensor is designed to be used for both transmitting and receiving sound waves, and it is subject to a period of mechanical vibration popularly known as "ringing." This vibration should cease before the echoed signal can be processed. The net result is a distance from the face of the transducer within which the sensor cannot detect an object and is technically termed as blind or dead zone or blanking zone, typically 150mm to 1m, depending on the range of the transducer.

The low-level signal output from the sensor is then processed in the transmitter, which may be located a few meters away in an accessible place . The transmitter converts the input into 4-20 mADC and superimposed digitized signal in terms of level.

5.1.4 Conductivity Type Level Transmitters

Conductivity type level sensors, consisting of a probe with two electrodes, are used with power sources that have low-voltage and current-limiting capabilities. The voltage is applied across the two electrodes. The power supply is selected according to the conductivity of the liquid. The higher voltage versions will obviously be designed for the less conductive (higher resistance) mediums and vice versa. The electric circuit is completed via the conductive liquid contacting both the longest probe and a shorter probe. Conductivity type sensors are extremely safe because of low voltages and currents and is intrinsically safe for use in hazardous areas. These sensors are very simple and easy to install, but are affected by build-up. They will stop working properly if build-up insulates the electrodes from the conductive medium. Therefore, proper and regular maintenance is required to keep them running.

Conductivity type level sensors are suitable for the point level detection of a wide range of conductive liquids, such as water, and are well suited for highly corrosive liquids such as acids like hydrochloric acid, nitric acid, sulfuric acid and caustic soda, ferric chloride, etc. For those corrosive conductive liquids, the sensor's electrodes should be constructed from 316 SS, Hastelloy B or C, or titanium as per the severity of the corrosiveness of the process fluid and insulated with spacers, separators, or holders of ceramic, polyethylene, and Teflon-based materials. Since corrosive liquids become more aggressive as temperature and pressure increase, suitable measures should be considered while specifying the instruments.

It is interesting to note that, in most of the services like water and wastewater wells, associated ladders, pumps, and other metal installations provide a ground return. However, in chemical tanks, insulated tanks, concrete tanks, and other non-grounded wells, the sensor may be supplied with an earth/ground rod for proper functioning of the instrument.

The low-level signal output from the sensor is then processed in the transmitter, which may be located a few meters away in an accessible place . The transmitter converts the input into 4-20 mADC and superimposed digitized signal in terms of level.

www.EngineeringBooksPDF.com

5.1.5 Capacitance or RF Type Level Transmitters

Capacitance type level transmitters are widely used in sensing the presence of various types of liquids, slurries, and solids. The sensors are equipped with hardware capable of emitting radio frequency signals acting in a capacitive circuit with the process material as the dielectric. Dual-probe capacitance type level sensors are also used to sense the interface between two immiscible liquids where dielectric constants are substantially different such as an "oil—water interface" application. This method of level measurement is frequently and popularly referred to as the RF type because of the application of radio frequency signals.

The advantage of this type of sensor is that it is rugged, simple, easily maintainable, and has no moving parts. Suitable designs for high temperature and pressure applications are also available. However, a problematic area does exist regarding the danger of high-static voltage discharge out of the rubbing and movement of low dielectric materials. This problem can be eliminated with a better design and proper grounding. An appropriate choice of materials as wetted parts in the probe may reduce, if not eliminate, the problems caused by abrasion and corrosion.

Another problem is that the output is also affected by build-up. Point level sensing of adhesives and high-viscosity materials such as oil and grease can result in the build-up of material on the probe; however, this can be minimized by using a self-tuning sensor. Therefore, proper and regular maintenance is required to keep this sensor running.

Capacitance type probes cannot be factory calibrated, instead these are calibrated in place so suitable care need to be taken. Splashguards or stilling wells and other appropriate devices may be necessary where process materials are liable to produce foam or froth and process applications are designed to control splashing or turbulence.

There use of capacitance probes is limited in tall bins storing bulk solids. Long probes and cables may be subjected to mechanical tension and friction due to the weight and abrasive nature of the bulk powder in the bins, which can frequently cause cable breakage.

Capacitance type level sensors can be designed to sense levels of process materials with a wide selection of dielectric constants ranging from 1.1 (coke and fly ash), 50 (sludge and slurries such as dehydrated cake), 88 (sewage slurry), 90 (liquid chemicals such as quicklime), or more. They are widely used in thermal power plants for level measurements of solids in ash hoppers and coal bunkers and liquids in cooling towers, DM plant tank levels, and CW storage wells/pond etc.

5.1.6 Air Bubbler Type Level Transmitters

Air bubbler type level transmitters are used for open type vessels only. The pressure created by a liquid column is used in the bubbler method of level measurement. A pipe is installed vertically in the vessel with its open end downward covering the minimum level. The other end of the pipe/tube is connected to a regulated air supply and a pressure transmitter. A fixed flow of air is passed through the tube. The air supply pressure in the tube is adjusted in such a way so as to keep it slightly higher than the pressure exerted by the process liquid column. This can be accomplished by regulating the air pressure until the bubbles are seen slowly leaving the open end of the pipe or tube. Pressure in the tube is proportional to the depth (and of course the density) of the liquid over the outlet of the tube.

Air bubbler systems contain no moving parts, making them suitable for measuring the level of water with large quantities of suspended solids, sewage, drainage water, etc. The bubbler tube is the only part of the sensor that makes contact with the liquid, which must be compatible for handling with the material under measurement. This technique of level measurement may be a good and natural selection for classified "hazardous areas" if a pneumatic pressure transmitter is used. This type of measurement is not normally used in thermal power plant applications but discussed in view of its popular use in other industries.

In air bubbler systems provision should be made so that high-pressure air can be supplied through a bypass valve to clean the inside of the pipe/tube from solids that may clog the bubbler pipe/tube. This technique is inherently "self-cleaning." It is highly recommended for liquid level measurement applications where ultrasonic, float, or microwave techniques have proved undependable.

5.1.7 Magnetostriction and Guided Wave Radar

Both of these systems utilize a wave guide to measure the level in open as well as pressurized tanks. In power plant applications these types of instruments are quite popular for regenerative heater level measurements. Basic principles and data sheets of these instruments are reviewed in Clause 5.4, so they are not repeated here.

5.2 Level Switch: Working Principle

The point-level or discrete-level sensors only indicate whether the substance is above or below the sensing point. In general, those types are called level switches. Generally the discrete-level type detect levels that are excessively high or low. There are many types of level switches used in thermal power plants.

www.EngineeringBooksPDF.com

5.2.1 Magnetic and Mechanical Float Type Switch

The float type level switches can have different actuating principles of operation: magnetic, mechanical, cable, etc. They are involved in the opening or closing of a mechanical switch, either through direct contact with the switch (micro switch) or magnetic operation of a reed type switch.

In magnetically actuated float sensors, a permanent magnet sealed inside a float rises or falls to the actuation level, thereby the switching takes place through a magnetically coupled reed switch in the switch assembly. With a mechanically actuated float, switching occurs as a result of the direct movement of a float against a miniature (micro) switch. For both magnetic and mechanical float level switches, different factors like temperature, specific gravity/density (ρ), buoyancy, viscosity, etc., affect the selection of the stem and the float. For example, larger floats may be used with liquids with specific gravities as low as 0.5 while still maintaining buoyancy. The type of float used depends on the process fluid. The choice of float material is also influenced by temperature-induced changes in specific gravity and viscosity—changes that directly affect buoyancy.

To protect the float-type sensors a shield can be provided so that the float can operate in a wide variety of liquids, including corrosives. Otherwise chemically compatible floats must be used for organic solvents. Float-style sensors should not be used with high-viscosity (thick) liquids, sludge, or liquids that adhere to the stem or floats or materials that contain contaminants such as metal chips. In these cases a suitable protective below or gaiter must be used. A special application of float type sensors is the determination of interface level in oil−water separation systems. Two floats can be used with each float sized to match the specific gravity of the oil on one hand, and the water on the other. Another special application of a stem type float switch is the installation of temperature or pressure sensors to create a multiparameter sensor. Magnetic float switches are popular for their simplicity, dependability, and low cost. Float switches can be side mounted and/or top mounted. Top-mounted switches may have multiple floats for multiple set points.

5.2.2 Gamma Ray Type Switch

A nucleonic level switch or gamma ray type switch measures the material level by the attenuation of gamma rays passing through a process vessel. The technique is used to sense the coal level in a bunker or level of molten steel in the process of a steel plant. The sensor case is arranged with a source of radiation, such as Cobalt 60 or Cesium 137 on one side and an appropriate detector on the other side. As the level of process material rises in the vessel, less of the gamma radiation is detected by the sensor. This technique falls under the noncontact type measurement category and can be both a continuous and point measurement.

5.2.3 Displacer Type Level Switch

This type of switch utilizes the buoyancy effect of submersible matter in a liquid. and the operating principle was discussed in Clause 5.1.2. A cylindrical solid metal body used as a displacer is provided for one set point. Multiple displacers are used in the same attachment for multiple set points and switches.

5.2.4 Vibration or Tuning Fork Type Level Switch

In this type of switch, a tuning fork is energized by a piezo crystal and vibrates at its resonant frequency of ∼380 Hz. The receiver side incorporates another crystal to detects this frequency. When the tuning fork is covered by liquid, the resonant frequency is reduced by a dampening effect. This change is detected by the integral electronics and converted into a switch signal.

The piezo crystal driving the vibrating tuning fork is either screwed together or glued as per manufacturer's design. The uniqueness of this type switches is that the output is unaffected by changing temperature, pressure, conductivity, density, or viscosity. Suitable design may take care of heavy build-up on forks. Typical applications are in storage and processing (coal level in the feeder bunker/hopper).

With proper selection of vibration frequency and suitable sensitivity adjustments, the following types of solids can be sensed and switching contacts will be available by this instruments:

1. Very fine powders (bulk density: 0.02−0.2 g/cm^3),
2. Fine powders (bulk density: 0.2−0.5 g/cm^3),
3. Granular solids (bulk density: 0.5 g/cm^3 or greater).
4. Highly fluidized powders
5. Electrostatic materials

Single-probe vibrating level sensors are ideal for bulk powder levels. Because only one sensing element contacts the powder, bridging between two probe elements is eliminated and media build-up is minimized. The vibration of the probe tends to eliminate build-up of material on the probe element. Vibrating level sensors are not affected by dust, static-charge build-up from dielectric powders, or changes in conductivity, temperature, pressure, humidity, or moisture content. They are less costlier than other similar types of instruments.

www.EngineeringBooksPDF.com

5.2.5 Rotating Paddle Type Level Switch

Rotating paddle level sensors are a popular selection in various type of bunkers and hoppers in thermal power plants, cement plants, and other material-handling plants. They have been used for many years with proven and established techniques for bulk solid-point level indication. The principle of operation uses a paddle wheel with a low speed rotated by a motor with a gear arrangement that turns the output shaft with the necessary speed. When the solid level reaches the paddle, it will be stalled because the solid materials will not allow the paddle to rotate any more. The motor will still try to rotate with increased torque until a mechanical switch called a torque switch is operated. The build-ups may pose a problem if the process material becomes sticky because of high moisture content in the atmosphere around the bunker or hopper.

Special paddle designs with low-torque motors are used for materials with very low specific density, such as fly ash or bentonite. The paddle can be constructed from a variety of materials, but sticky material not be used to avoid build-up on the paddle.

5.2.6 RF Admittance Type Level Switch

An RF admittance level sensor employs a rod probe and RF source to detect the change in admittance. To eliminate the effects of the changing capacitance of the cable to ground, a shielded coaxial cable is used through which the power is supplied to the probe .The dielectric constant changes with the change in level around the probe. This changes the admittance due to corresponding, naturally formed capacitance, and this change is measured and converted into change in level.

Another type is available in which the probe electronic unit generates an RF signal and creates a field around the probe. The RF environment absorption changes around the electrode when the level changes and is reflected in the changes of generator supply current. When the level rises there is electrical field loss. This is detected by a change in generated current. This change is amplified by a coat guard amplifier (unaffected by external field and deposition over the probe). Typical specification sheets of different flow switches are indicated in Tables IV/5.2-1 and IV/5.2-2).

5.3 Level Gauge: Working Principle

Level gauges form both direct and indirect types of level measurements. Direct type level gauges are do not involve any secondary device, such as the simplest and oldest type like bob and tape and other instruments such as sight level gauges, float and pulley types, displacer types, etc. The indirect type level gauges, on the contrary, require secondary device for processing input signals, which sense the effect of changing levels, for example, conductivity type level gauges and remote bicolor gauges.

TABLE IV/5.2-1 Data Sheet of Float Type Level Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Magnetrol/Leveltrol	
2	Material	Body, external float chamber, and other wetted parts; ANSI 316 SS	
3	Spring	AISI 304 SS	
4	Flange	C.S. ANSI 150 RF	
5	Switch cover	Cast aluminum weather proof, as per IP 66; anti-corrosive painted	
6	Spring pipe	316 SS	
7	Signalization	Hermetically sealed glass encapsulated reed switch/snap or micro switch	
8	Contact form	2 NO + 2 NC	
9	Contact rating	5A to 230V, AC 50 Hz	
10	Repeatability	±2%	
11	ON/OFF differential	45 ± 5 mm (typical)	
12	Hydraulic test	Pressure: 10 kg/cm^2	
13	Maximum working temperature	100°C	

www.EngineeringBooksPDF.com

TABLE IV/5.2-2 Data Sheet of Displacer Type Level Switches

SL. No.	Item	Specification	Special Feature
1	Make/model	Magnetrol/Bestobell	
2	Material	Body, external float chamber, and other wetted parts; ANSI 316 SS	
3	Spring	AISI 304 SS	
4	Flange	C.S. ANSI 150 RF	
5	Switch cover	Cast aluminum weather proof, as per IP 66; anti-corrosive painted	
6	Number of set points	One/two/three	
7	Signalization	Hermetically sealed glass encapsulated reed switch/snap or micro switch	
8	Contact form	2 NO + 2 NC	
9	Contact rating	5A to 230V, AC 50 Hz	
10	Repeatability	±1%	
11	ON/OFF differential	45 ± 5 mm.	
12	Hydraulic test	Pressure: 20 kg/cm^2	
13	Maximum working temperature	100°C	
14	Quantity	As per BOM	

5.3.1 Direct Level Gauges

There are several types of direct level measurements as indicated in the following clauses.

5.3.1.1 Sight Level Gauge Glass

As the name implies, the level can be seen in a graduated glass tube directly connected to the vessel. Normally the glass tube is located near the vessel intended for level measurement. The vessel is provided with two tapping points, covering the entire range of measurement, which are connected to the glass tube by the gauge glass assembly with an integral ball check valve for automatic isolation in case any breakage or damage takes place at the instrument end. As the bottom portion of both the vessel and measuring glass are connected, the liquid level in the measuring glass will be the same (except for very high pressure and temperature services where density plays a considerable role for a mismatch) as that of the vessel. Measurement is a simple matter of directly reading the position of the liquid level on the scale of the sight glass tube. See Figure IV/5.3-1 for a general view of a sight level gauge glass and operation of a ball check valve shown for a boiler drum level service (this also applicable to other services).

In generally, there are two types of sight level gauge glasses: transparent and reflex. For colored liquid, the transparent type is sufficient to show the level, but for colorless liquid the transparent type may confuse the viewer, so the reflex type level gauges are used.

For reflex type gauges, the sight glass plate is grooved in a horizontal saw tooth fashion at an angle of 45° throughout its height. Figure IV/5.3-2 illustrates the operating principle for reflex type gauges with a cross-sectional view of sight level gauge glass.

When the incident light ray reaches the reflex grooves of the glass plate, it is totally reflected if there is steam, vapor, or gas present in the region. As a result, the gaseous space looks like a bright silvery bar. When there is liquid, the incident ray is deviated and will not come back the same way. As a result, the liquid space looks like a black bar.

In some cases when the sight glass is required to be isolated from the corrosive liquid service, there are mica sheets in between the glass and liquid with the same effect as seen in general transparent type and reflex type gauges (see Figure IV/5.3-3).

For transparent type gauges, the incident light ray from a rear-side lamp source reaches the sight glass at an angle of 90°, and there is no special effect of the viewing liquid and gaseous state; these gauges can be used for colored liquid without any problem. For colorless liquid, the axis of the rear-side lamp source and that of the viewer's eyes are

www.EngineeringBooksPDF.com

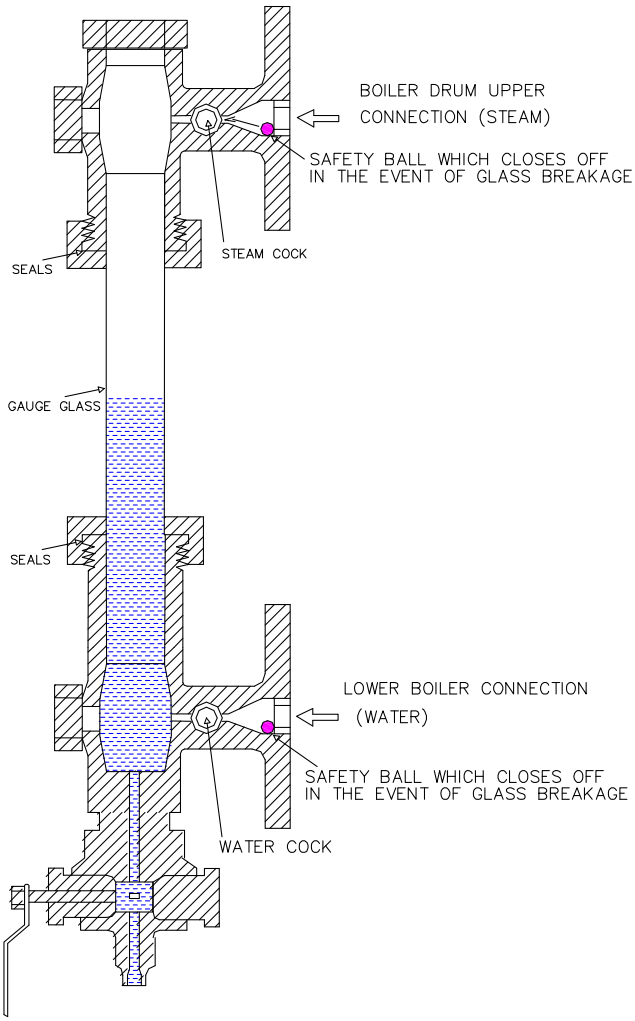


FIGURE IV/5.3-1 Sight level gauge glass: mountings and accessories.

different. The incident light ray from a rear-side lamp source is guided through the two mica sheets at an angle less than 90° and passes the medium in between them. For the gaseous space, the light is guided straight forward and passes through the gas and both mica sheets without any deviation. In liquid space, the light ray passes the liquid medium and the mica sheets at an angle so they are refracted away due to a different index of refraction. The liquid level is visible as a black bar and the gas like a bright silvery bar.

5.3.1.2 Bicolor Level Gauges

Bicolor level gauges are used for boiler drum level measurement in thermal power plants where the steam and water interface is distinctively seen. There are a number of port holes throughout the entire range of measurement for the viewer to observe the approximate water level of the boiler drum. When put into operation, the viewer sees a green light through the port holes located in the water zone and a red light through port holes in the steam zone. With a long glass gauge, that is, without any discrete port holes, a light part green and part red appears on the bezel.

The principle of operation is based on the theory of an optical phenomenon. It is well known that different colors (in this case red and green) have a different index of refraction when passing obliquely through different media like glass, water, and steam in this case (see Figure IV/5.3-4).

To achieve the desired result, the gauge body has a trapezoid section with glasses placed on its nonparallel faces. A lamp or an illuminator with special red and a green filters is fitted on the gauge at the opposite side with respect to the observer. This special illuminator, as shown in Figure IV/5.3-4, conveys light through the filters obliquely to the back glasses of the level gauge.

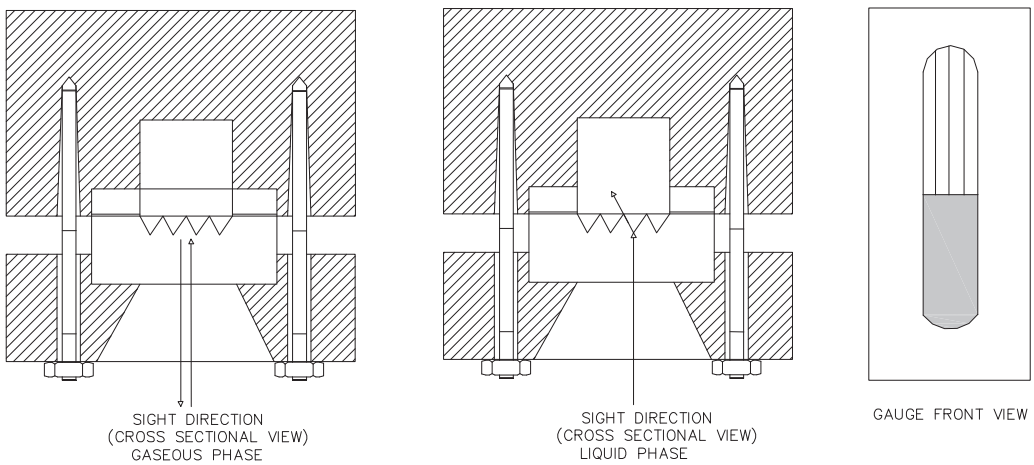


FIGURE IV/5.3-2 Reflex type sight level gauge glass: schematic view.

www.EngineeringBooksPDF.com

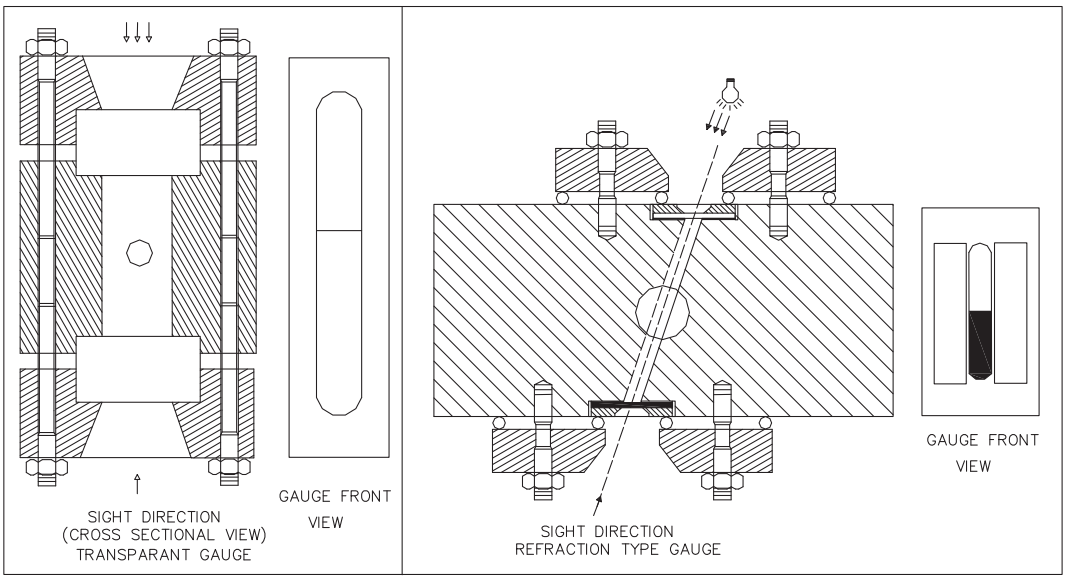


FIGURE IV/5.3-3 Sight level gauge glass with mica sheets: schematic view.

These filters allow crossing only to red and green rays, which reach the media inside the level body through the back glass.

When the gauge port hole part contains steam, green rays are refracted to deviate considerably and are not allowed to reach the observer side; then only red light, whose rays are smoothly deviated by steam, passes through the whole internal hole and reaches the observer. When the gauge port hole part contains water, red rays are refracted to deviate considerably and are lost inside the internal part of the level gauge. Green rays are allowed to reach the observer side glass and are seen by the observer.

5.3.1.3 Float Type Gauge

There are many types of float-operated level mechanisms for continuous direct liquid level gauges. The main and primary device is a float, which by reason of its buoyancy, follows the change in level of the liquid. The other mechanism transfers the float's movement to a pointer movement on a calibrated scale. The float can be of shaped like a hollow metal sphere or disk shaped like synthetic material floats or cylindrical shaped like ceramic floats.

5.3.1.4 Float Pulley Type Gauge

Here the float movement is transferred to the pointer through a string or cable that is wound around a pulley or drum to which the indicating pointer is attached. At the other end of the cable is a firmly suspended weight that keeps the string/cable under tension.

5.3.1.5 Float and Rotary Shaft Type Gauge

In this type of gauge, the float is attached to a shaft that transfers the motion of the float to an indicator. The main disadvantage is that a wide range of level measurement is not permitted. In spite of that, this gauge type does have a mechanical advantage, which may be exploited for control and transmitter purposes.

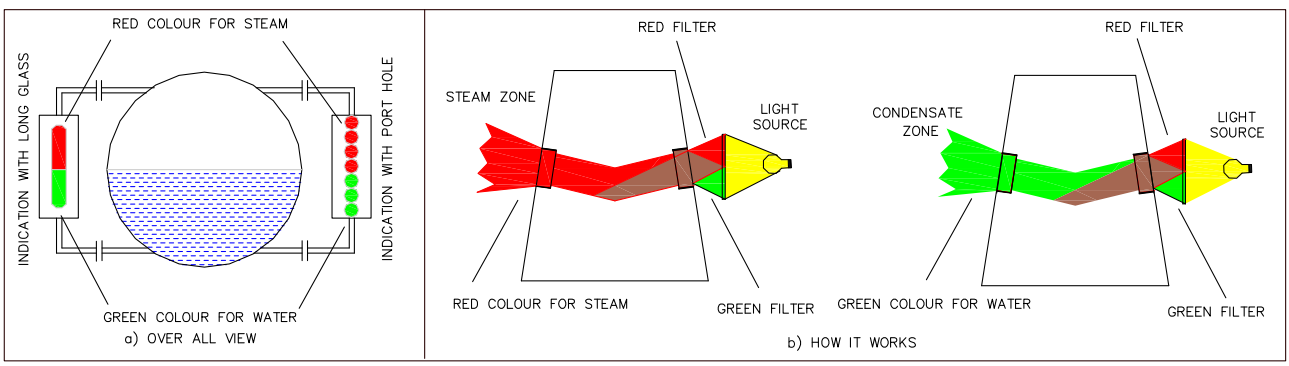


FIGURE IV/5.3-4 Bicolor gauge glass: schematic view.

www.EngineeringBooksPDF.com

5.3.1.6 Float and Magnet Type or Magnetic Level Gauge

A slight variation of the previous float and rotary shaft type gauge is the float and magnet type gauge. In a magnetic level gauge, there is a permanent magnet sealed inside a float, which rises or falls according to the level, thereby actuating a magnetically coupled pointer/indicator outside the vessel and is freely movable on a calibrated scale showing the level of the fluid inside the vessel.

5.3.1.7 Displacer Type Gauge

It is similar to the buoyant float described earlier. With changes in the liquid level, the displacer is covered by the liquid. The more the displacer is submerged, the greater is the force created by the displacer because of its buoyancy. This force is then transferred through a twisting or bending shaft. For every new liquid level, there is a new force on the shaft, causing it to assume a new position. The displacer float is more sensitive to small changes than the buoyant float and less subject to mechanical friction.

5.3.2 Indirect Type Level

Many indirect types of level gauges are available, but the conductivity type level gauge is the most popular.

5.3.2.1 Conductivity Type Level Gauge

These gauges are primarily meant for boiler drum level indication in thermal power plants. This is an indirect type of instrument that detects the electrical conductivity of steam and water by placing electrodes at different levels throughout the range of measurement. They are highly reliable and best suited for very high temperature and pressure conditions (see Figure IV/5.3-5).

The electrodes are connected to the electronic section located in the gauge or indicator, which measures the conductivity between the electrodes and the metallic wall of stand pipe or the water column connected to the boiler drum through two pipes with double valves in each line and vent/drain valves. Each electrode is connected to a separate detection and indication channel. As the conductivity in the media like steam and water are widely varied, the electronic unit can easily distinguish the difference between the two phases.

The number of electrodes is solely dependent on the range or height of the level to be measured. The approximate distance between the electrodes is normally 50 mm. Although the instrument is a type of discrete or step measurement, the advantages are no moving parts, no calibration, easy installation, and no periodic maintenance. Alarm contacts are very reliable from this unit and usually

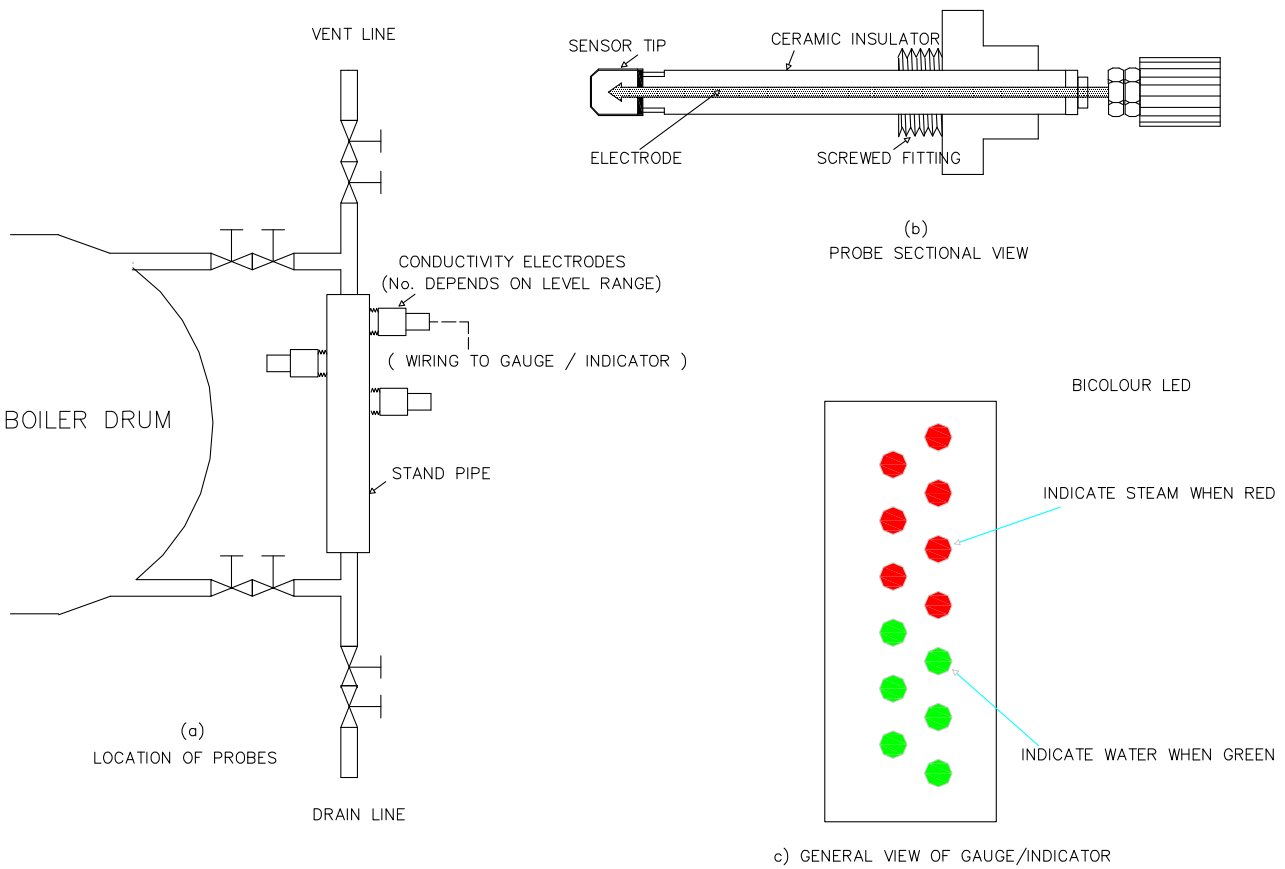


FIGURE IV/5.3-5 Conductivity type level gauge: different views.

www.EngineeringBooksPDF.com

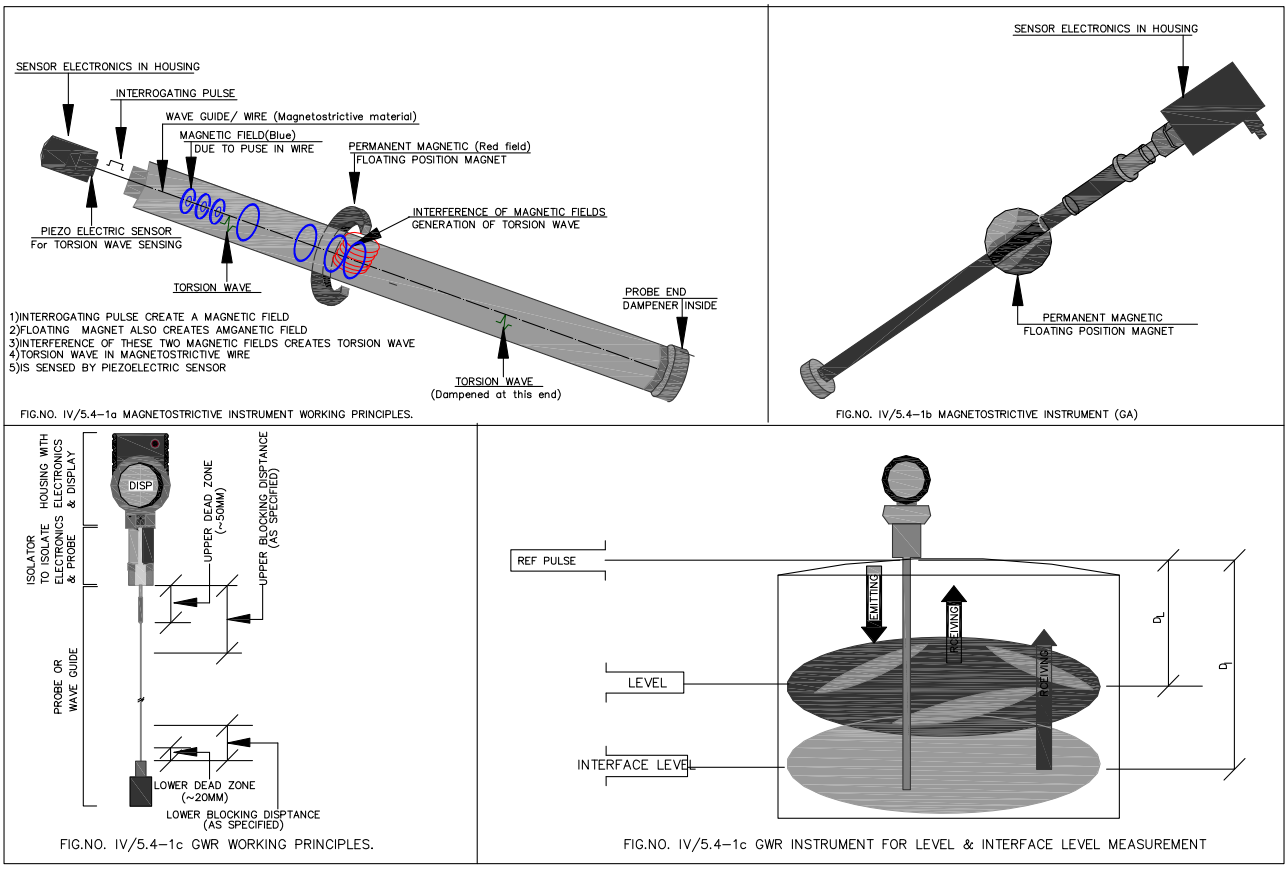


FIGURE IV/5.4-1 Magnetostrictive and GWR instruments.

connected to the master fuel tripping circuit and annunciation system.

5.3.2.2 Pressure Type Level Gauge

The simplest method is to use a pressure gauge with an impulse pipe that has a tapping point at zero level for corrosive material. A transmitting fluid, for example, air, can be used between liquid and the gauge. An Air trap or diaphragm box provide the necessary isolation arrangement. The bubbler methods, as discussed in Clause 5.1.6, is also a proven type of level measurement. For a pressurized vessel, a differential manometer may be used as discussed for DPTs in Clause 5.1.1.

5.4 Magnetostrictive and Guided Wave Radar Level Instruments

5.4.0 Introduction

One of the main ways to improve the efficiency of a plant is to reduce fuel costs. Optimum level control of feed water is one important way to increase the heat and the heat rate and hence the fuel flow. Regenerative heater-level controls in power plants are the major areas where magnetostrictive and guided wave radar (GWR) instruments are mostly applied. These instruments are discussed in this clause (see Figure IV/5.4-1).

5.4.1 Magnetostrictive Instruments

Prior to discussing the magnetostrictive instruments, it is necessary to have some knowledge about magnetostriction and magnetostrictive materials, because they work on the principle of magnetostriction: with like heat it is possible to elongate and shorten a material with a magnetic/electric field. Ferromagnetic materials can be made longer and shorter by application and withdrawal of magnetic fields. Magnetostrictive materials can be magnetostrictive metals, alloys, or ferrite magnetostrictive materials.

5.4.1.1 Working Principles

These instruments utilize magnetostrictive theory to measure liquid levels. Figure IV/5.4-1a illustrates a wave guide made up of magnetostrictive material. The measurement is initiated by an interrogative current pulse through the wave guide/wire (magnetostrictive material). This generates an axial magnetic field (as shown in blue) along the length of the probe. There is a float with a magnet inside with its magnetic field at a right angle to the axial field as discussed earlier (due to current pulse). According to the level the

www.EngineeringBooksPDF.com

TABLE IV/5.4.1.2-1 Data Sheet for Magnetostriction Instruments

SL. No.	Specifying Point	Standard/Available Data	To Be Specified
1	Type	Magnetostrictive	
2	Measuring range	Up to 15 m is possible—consultation with details shown in manufacturer's catalog	To be specified
3	Tube material	316 SS	
4	Mounting	Threaded or flange	To be specified
5	Probe OD	Normally 16 mm (5/8″)	
6	Tr. Housing	Aluminum/SS	To be specified
7	Enclosure	IP 68 or better	
8	Out put	1 or 2 4-20mA DC; also HART, Foundation Fieldbus	To be specified
9	Resolution	0.5 % FSD	
10	Accuracy	0.01% FSD with repeatability ~0.005%	
11	Display	LED/LCD (back lit) and diagnostic display in alphanumeric characters	
12	Power supply	230V AC/24 V DC as the case may be	
13	Ambient conditions	T: −40 to 70°C reheat (100%)	To be specified

TABLE IV/5.4.2.1-1 Data Sheet for GWR

SL. No.	Specifying Point	Standard/Available Data	To Be Specified
1	Type	GWR—rigid rod, flexible cable coaxial, etc.	To be specified
2	Measuring range	Up to 50 m possible—consultation with details shown in manufacturer's catalog	To be specified (as required)
3	Tube material	304/316L SS or Hastelloy C	
4	Isolation material	Teflon/ceramic	To be specified
5	Pressure temperature (°C) and pressure (bar)	As the case may be; also clarify if dynamic vapor compensation necessary	To be specified
6	Pressure connection/wave guide coupler	Threaded or flange	To be specified
7	Probe attachments	Centering disk, centering weight, etc.	
8	Transition housing	Aluminum/SS	To be specified
9	Enclosure	IP 68 or better	
10	Certification	International certification/ SIL requirement	To be specified if applicable
11	Output	1 or 2 4-20mADC, also HART, and Foundation Fieldbus	To be specified
12	Resolution	1.6 mm available	To be specified
13	Accuracy	3/5 mm available	To be specified
14	Display	LED/LCD (back lit) and diagnostic display in alphanumeric characters	
15	Transition zone	Consult manufacturer's catalog	
16	Power supply	230 V AC/24 V DC, as the case may be	
17	Ambient conditions	T: −40 to 70°C reheat (100%)	To be specified

www.EngineeringBooksPDF.com

float moves up and down and has a permanent inside (the float) magnet with its own magnetic field. The interaction of these two magnetic fields generates a mechanical torsion wave from the point of the float (or position transducer) in the wave guide or wire. This wave travels in both the directions. At the probe bottom end there is a damper to dampen the wave, whereas the other side (i.e., toward the probe head) reaches a piezoelectric sensor connected to the wire. Thus at the head, the mechanical torsion wave is converted into an electrical pulse by a piezoelectric transducer located in the sensor housing. The time lapse between the starting pulse and receiving pulse is computed in the probe electronics to calculate the distance and the level. These kinds of probes can withstand harsh environmental conditions and they can be installed and commissioned easily (see Table IV/5.4.1.2-1 for specification and standards for magnetostriction instruments).

5.4.2 GWR

There are two kinds of radar devices used in level measurements: free space (as used in tank gauging) and guided. The guided type is used in power plant applications. Normally microwaves in the range of 1.5 to 26 GHz are used for radar instruments. The lower end, i.e., ~1.5 GHz, frequency range is used for GWR and the higher range is suitable for free space radar. This is based on the simple principle of reflected pulse. If T = total time to travel from device to liquid and back and electromagnetic waves travel at the speed of light C, then the distance (level) is $L = C*T/2$.

The reflection property of the material depends on the dielectric number of the medium. In GWR transmitters direct energy pulses via wire/wave guide to the medium whose level needs to be measured. A major part of the energy is reflected back and measured by the electronics at the probe head; the time difference is a measure of the level. Normally process conditions such as vapor, temperature, and pressure do not affect radar instrument operation. This is true as long as the vapor is not a polar gas whose dielectric number varies with process pressure and temperature, and the speed of microwave pulse may also vary.

It has been found that steam vapor at high pressure and temperature with a dielectric number >1.0 may affect the performance of the radar. However, there are probes with dynamic vapor compensation options used to compensate for changes in vapor space dielectric to get better accuracies. In power plants, GWR is applied for measurement of regenerative heater levels.

Figure IV/5.4-1c depicts different parts of the probe. Electronics, displays, and adjustment devices are usually housed at the top of the probe. An isolation material, such as Teflon, is suitable for low temperature (i.e., ~150°C), which isolates the probe from its electronics to help eliminate high-temperature exposure to the electronics. In a high-temperature application, steam may damage the probe so ceramics may have to be used. It also houses the microwave frequency generators and receivers. The entire probe length cannot be effectively used for measurements since it has upper and lower blocking and a dead zone, as shown in Figure IV/5.4-1c. This instruments also can be utilized for interface level measurements (see Table IV/5.4.2.1-1 for specifications and standards of GWRs.)

BIBLIOGRAPHY

[1] Chapter 6 of "Experimental Methods for Engineers", 6th edition (Pressure Measurement): By J.P. Holman, 1994.

[2] Electronic Pressure Measurement Basics, applications and instrument selection: By M/s Eugen Gaßmann, Anna Gries (technical collaboration of M/s WIKA Alexander Wiegand SE & Co. KG.). First published in Germany in the series Die Bibliothek der Technik Original title: Elektronische Druckmesstechnik © 2009 by Süddeutscher Verlag onpact GmbH.

[3] Product Bulletin for Sight Glass Level Gauges of M/s PHONIX MESSTECHNIK GmbH.

[4] Pubblicazione B09 – 01 – Rev.00. Eng : By M/s CESARE BONETTI S.p.A. Product Catalog.

[5] Machinery's Handbook, 29th Edition. Erik Oberg, Franklin Jones, Holbrook Horton, Henry Ryffel, Christopher McCauley 2800 Pages, Hardcover Published: January, 2012 ISBN: 9780831129002.

[6] Product Catalog of M/s Omega Engineering, Inc.

[7] Product Catalog-2600 Series Pressure Transmitters of M/s ABB Ltd.

[8] Product Catalog-600T Series Temperature Transmitters of M/s ABB Ltd.

[9] Product Catalog-for Multivariable Transmitters (Mass Flow) of M/s ABB Ltd.

[10] Product Catalog-for Thermal Mass Flowmeter of M/s ABB Ltd.

[11] Product Catalog-for Vortex Flowmeter of M/s ABB Ltd.

[12] Product Catalog-for Magnetic Flowmeter of M/s ABB Ltd.

[13] Product Catalog-for Ultrasonic Level & Flowmeter of M/s ABB Ltd.

[14] Product Catalog-for Coriolis Type Mass Flowmeter of M/s ABB Ltd.

[15] Product Catalog-for WEDGE Type Flowmeter of M/s ABB Ltd.

[16] Turbine Supervisory Instrumentation : By M/s SKF cmcp.

[17] Product Bulletin of M/s Burns Engineering, Inc. USA.

[18] Temperature Measurement : By Middle East Technical University Open Course Ware.

[19] Temperature Measurement : By Missouri University of Science and Technology. http://web.mst.edu/~cottrell/ME240/Resources/Temperature/Temperature.pdf

[20] Industrial Instrumentation (C-8\N-IND\BOOK1-6) : By M/s IDC Technologies (India). http://www.idc-online.com/technical_references/pdfs/instrumentation/Industrial_Instrumentation%20-%20Flow.pdf

[21] Product Catalog of M/s Imperil Flange and Fittings Company Inc (For Flow Elements).

[22] LMNO Engineering, Research, and Software, Ltd. USA (For Parshall Flume). Sharp Crested Weirs for Open Channel Flow Measurement, Course No: C02-022 Credit: 2 PDH Harlan H.

www.EngineeringBooksPDF.com

Bengtson, PhD, P.E. http://www.cedengineering.com/upload/Sharp-Crested%20Weirs.pdf

[23] Product Catalog for Ultrasonic Type Flow Measurement : By Fuji Electric Systems Company Ltd. Japan.

[24] Product Catalog for Diaphragm Style Flow Switch : By courtesy of M/s Steven Engineering, Inc.

[25] Product Catalog for Shuttle Type Flow Switch : By courtesy of M/s Clark Solutions, Inc.

[26] Product Information for Glass Level Gauges : By M/s KSR Kubler Niveau-Messtechnik AG.

[27] RF Level Measurement Handbook. 1999: By M/s Princo Instruments Inc. ELS 2005 − Symposium on Unconventional Electrical Machines Suceava 22−23 September 2005. METHOD FOR LEVEL MEASUREMENT IN HYDROENERGETIC ACCUMULATIONS Mariana MILICI, Leon MANDICI, Dan MILICI. http://www.els.usv.ro/pagini/past_editions/ELS%202005/B1-06.pdf

[28] The Principles of Level Measurement October 1, 2000 :By M/s Gabor Vass, Princo Instruments, Inc. http://www.sensorsmag.com/sensors/leak-level/the-principles-level-measurement-941

[29] Product Catalog for RF Capacitance Level Controls (Form 1100) : By M/s SOR Inc.

[30] MaxiFlo ™ Product Catalog : By M/s Seil Enterprise Co : Seoul.

[31] Guided wave radar for level and interference : Vega America Inc.:Catalog.

[32] Guided wave radar Transmitter: www.smar.com: RD 400 catalog The Heat rate imperative : Special Application : Magnetrol Technical brocheure.

[33] Guided wave radar levelTransmitter: MT 5000 ABB Limited catalog.

[34] Magnetostricktive Level Transmitter: AT 2000 : ABB Limited catalog.

[35] Advanced Differential Pressure Flow meter Technology: Macro-meter: ABLE Instruments & Controls Limited UK: Catalog.

[36] Coriolis Flow meter:Micromotion Tutorial: Micromotion- Emerson Process management.

[37] Industrial Flow measurement basic and Practice : ABB Limited : Technical book. 2011 ABB Automation Products GmbH.

[38] Coriolis Flow meter : Endress+Huaser : Catalog.

[39] A Flow Orientation : Flow & Level: Volume 4: Omega instruments USA : Catalog.

www.EngineeringBooksPDF.com

Chapter V

Special Instrument

1. SPECIAL INSTRUMENTS

1.0 Special Instruments: Introduction

1.1 General

Apart from conventional instruments discussed in Chapter IV, there are a number of special instruments used in power plants. Special instruments in this chapter have been categorized under the following subheadings:

- Vibration measurements in various fans, pumps, motors, mills, etc. (mechanical system)
- Turbovisory instruments (mechanical system for turbine)
- Gas analysis (chemical system)
- Steam and water analysis (chemical system)
- Sample conditioning (for chemical analyzers)
- Blow down and dosing control (chemical control)
- Pollution-related analyzer

Working principle, data sheet (as applicable), installation, and application details of these instruments have been covered in the book. Special instruments are quite costly, so it may not be possible for small and medium-sized power plants to acquire all of these instruments. Therefore it is essential to identify the measurement points that are essential and those that can be dispensed with due to cost. Turbine speed and water conductivity measurements are essential, but fan vibration measurements and measuring SiO_2 in steam can be dispensed with due to cost.

1.2 Vibration Measurements

- Vibration is the oscillatory motion of the object; it can be linear or rotational.
- Relative position (proximity sensor), velocity (velocity sensor), and acceleration (accelerometer) are used to measure these parameters.
- Adequate measurement of vibration is a rather complex problem, as a degree of freedom needs to be found. Theoretically, six sensors are necessary for this.

1.3 Turbovisory Instruments

- Turbovisory instruments are provided to determine the deteriorating condition of the machine and to ensure safety to the machine as well as to the operating personnel.
- All these controls and measurements are available as a part of turbine instrumentation package. Major turbovisory instruments include:
  - Pedestal vibration
  - Bearing vibration
  - Shaft vibration
  - Eccentricity
  - Speed
  - Valve position
  - Metal temperature
  - Axial shift
  - Casing expansion—differential expansion (DE)

1.4 Gas Analysis

Gas analysis in power plants is important for two reasons. First, it is directly related to performance of the boiler and turbo generator (TG), e.g., O_2 and CO analysis influence the combustion process, H_2, CO_2, in the generator is related to generator performance, etc. Second, there are a few gas analyzers necessary to monitor pollution like SO_X, NO_X, particulate monitoring, etc.

1.5 Steam and Water Analysis

Chemistry of water and steam plays a great role in the performance and availability of a boiler and TG. If these chemical parameters are not properly monitored, then they would cause corrosion and accelerate deterioration of the plant performance due to depositions and corrosions. The following measuring systems have been discussed:

- Conductivity
- Cat col conductivity
- pH
- Dissolved O_2
- Residual hydrazine
- H_2 in steam
- SiO_2
- Phosphate
- Chloride

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

1.6 Sample Conditioning

There are a good number of instruments that need proper sample conditioning before they can be sent for analysis. Sample conditioning includes removal of dust for gas analysis (say O_2 in a paramagnetic method) and conditioning of pressure and temperature parameters. However, *in situ* gas analyzers like the Zirconia probe for O_2 and IR analyzer do not require such sample conditioning. For steam and water analysis, a central Steam and Water Analysis System (SWAS; a sample conditioning system or water tables) is used for moderate to large utility power stations. The SWAS sampling system includes but is not limited to a sample cooler (primary and secondary), sample drawing pump, pressure reducer, flow rate setter, etc. It also provides a way to take a manual sample.

1.7 Blow Down and Dosing Control System

In any power plant there will be blow down of feed water (FW) to keep the FW quality. There could be continuous blow down and intermittent blow down. At many places conductivity analyzers are used to perform this blow down operation.

To maintain the quality of FW it is necessary to dose chemicals, such as ammonia, phosphate, etc. In low to moderate-sized power plants this may be done manually, but in large plants chemical dosing is part of an automatic control loop and metering pumps.

1.8 Pollution-Related Analysis

In almost every country stringent restrictions have been imposed on the amount of pollution each plant can discharge to the environment following various norms, rules, and regulations set forth by the concerned country. It is therefore important to install gas analyzers to keep track of SO_X, NO_X, etc. in addition to these there are pressure to reduce level of green house gas. Recently in many countries e.g. USA have set target to reduce this level from power plants by appreciable % within a decade.

1.9 Special Instruments

Even though there are many special instruments, only a few are related to the plant control system, yet they can cause reduced plant availability. All of these special instruments are very costly and require close attention to maintenance.

2. VIBRATION AND TURBOVISORY INSTRUMENTS

2.0 Vibration and Turbovisory Instruments

2.0.1 General Idea of Vibration

- Vibration is an oscillatory motion of the object set in a rotating machine because of the imbalance of forces generated and/or acted upon the machine. Vibration transducers provide, in the control room, the condition of the rotating machine, and prevent the machine to be operated in its danger mode to cause damage to it and or surroundings. Vibration frequencies are an integral multiple of shaft speed. The complexity in vibration measurements arises from distribution of the disturbance in a mechanical system.
- If an external (imbalance) force is applied (see Figure V/2.0.1-1a), then it will be set to vibrate, which will decay. If external force is P_i, then output will be given by $P_i = md^2x/dt^2 + c\ dx/dt - k\ x$, where c is the damping factor (say friction) and k is the spring constant. Neglecting damping, the natural frequency will be given by $\omega = (k/m)^{1/2}$.
- External imbalance force may be impressed to cause vibration. Oscillatory motion in its simplest form is shown in Figure V/2.0.1-1b. It is seen that this periodic nature has the time period $T = 1/f$ where f is the frequency. Referring to drawing Figure V/2.1-1b, basic physics is recapitulated to define peak value and root mean square (RMS) values.
- Peak value is the extreme swing with respect to the datum in the positive and negative side, and peak = 1.414 RMS. This RMS to peak conversion is true for a sinusoidal signal, but it will be wrong to multiply 1.414 to the RMS value of vibration meter output to calculate peak value. It is necessary to know, in peak or RMS, in which form the meter output is given.
- Frequency of vibration is also very important. Generally 10−1000 Hz is the range of frequencies encountered in turbine system vibration. In practice it is quite common to measure the vibration indirectly, e.g., the transducer which operates on velocity can be used to get the displacement by simple integration.

2.0.2 Importance of Vibration Measurement

- To determine the natural frequency of vibration and find out the damping ratio associated with it.

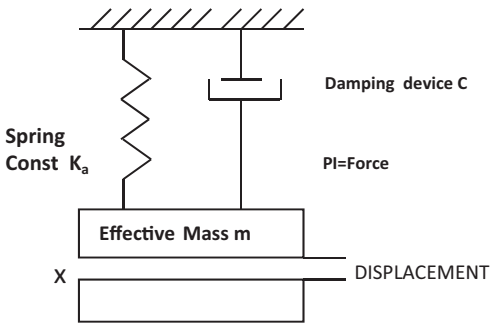


FIGURE V/2.0.1-1a Simple vibration.

www.EngineeringBooksPDF.com

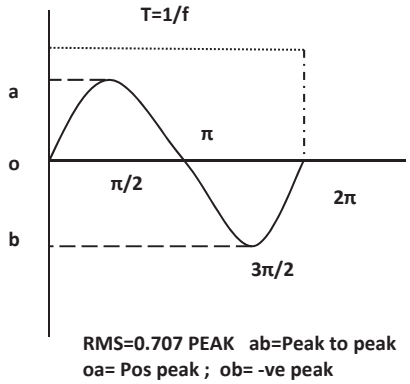


FIGURE V/2.0.1-1b Oscillatory motion.

- Measurement of frequency and force of vibration in a rotating machine is necessary to develop a system to isolate it from vibration.
- At the time of manufacture, all large rotating machines are properly balanced to minimize the chance of vibration, and the vibration frequency and force of vibrations are predicted. However, in reality, because of various reasons (installation problems, linkage problems), the actual data may vary with design data, so it is important to monitor vibration in the machine and compare it with limiting data.
- For machine safety and prevent failure/damage.

2.0.3 Basic Building Blocks for Vibration Measuring System

- *Vibration transducer*: Complete with a preamplifier, the transducer converts the motion (vibration) into an electrical signal. These pickups are used to measure displacement, velocity, and/or acceleration. The transducer pickups come in capacitance/eddy current/linear variable differential transformer (LVDT), or piezoresistive types.
- *Signal conditioning systems*: They convert the signals into a compatible electrical form so that they can be transmitted, displayed, or recorded. Present day signal-conditioning systems also perform computation, communication, and many other software functions through software algorithms helpful for analysis, e.g., fast Fourier transform (FFT) or software links for computer integration. Normally they have an independent power supply, supplied as a package, with their own monitoring system.
- *Display/recording*: There can be a simple monitor to display the vibration data, or it can be a small subsystem connected to its own system by a device net or local proprietary network for display and recording by a display monitor and printer. Normally these are compatible for direct connections with the distributed control system (DCS; i.e., by Ethernet). These systems may be supplied as a package. All such packages have suitable means to communicate with the main DCS, i.e., RS 232C/Ethernet (see Chapter VII).
- Choice of pickup types can be roughly categorized as follows:
  - Displacement measurements are done for very low frequency vibration.
  - For moderately to moderately high frequency vibration, velocity pickup is the choice.
  - When there is very high frequency vibration, and vibrating force is measurable, an accelerometer can be used.

2.0.4 Vibration Measurement Points (Turbine Discussed Separately): Condition Monitoring

In power plants, other than TG, there are other large drives where bearing vibrations are measured with suitable pickups (generally velocity pickup). A typical list with location is presented in Table V/2.0.4-1). Since the bearing and shaft have less clearance, it is important to monitor the vibration at the bearing to avoid a dangerous situation. In

TABLE V/2.0.4-1 Bearing Vibrations for Large Fan Pump Motors

Equipment	Number of points	Location	Remarks
Indirect draft fan	4–6	Nondrive end and drive end of each of fan and motor	Depending on drive type
Forced draft fan	4		
Primary air fan			
Mill	2	At motors	
BFP	4–6	Nondrive end and drive end of each of fan and motor	Depending on configuration
Circulating water pump	4		

www.EngineeringBooksPDF.com

addition to the measurements of vibration in these drives, all of them have speed measurements and interlocks.

Boiler feed pump (BFP) may be driven by a turbine, so naturally there will be more vibration pickups, which is similar to a small turbine.

2.0.5 Turbovisory Instruments: Measuring Points

2.0.5.1 Steam Turbine: Steam Turbine Condition Monitoring

For steam turbine condition monitoring points, see Figure V/2.0.5-1 and Table V/2.0.5.1-1. Most of the possible measurements are listed in Table V/2.0.5.1-1 and not all are applicable for a single machine. Depending on the design and operational philosophy, the manufacturer recommends the most suitable measurement for a particular machine. Any additional measurements can be negotiated with the manufacturer. However, measurements like speed, bearing temperature and vibration, axial shift, valve position, etc., are so important that these are seen for almost all machines. For a few measurements like shaft position, relative expansion, and speed, redundant sensors are common, especially in larger machines.

2.0.5.2 Gas Turbine: Turbovisory Instruments in Gas Turbine

Gas turbine (GT) condition monitoring measurements are listed later in Table V/2.0.5.2-1. Figure V/2.0.5-2 illustrates turbovisory instruments in a GT.

Manufacturers sometimes recommend a few supplementary measurements (e.g., GE's recommendation) for larger frame machines as listed below.

- *Casing vibration*: Measurement for machines with significant motion between bearing housing and free space. This is a seismic vibration measurement, i.e., absolute vibration of casing. For GTs that are not compliant on casing, this is an optional measurement. Probes may be placed on the machine casing (radial bearing housing).
- *Eccentricity*: Large machine with heavy mass causes sagging, Sensors should be deployed to measure residual bow during slow-speed operation.
- The types of measurements discussed above for GTs are similar to those for steam turbo generators (STGs), so measurement and application notes discussed in this clause are also discussed in Clauses 2.1 and 2.2.

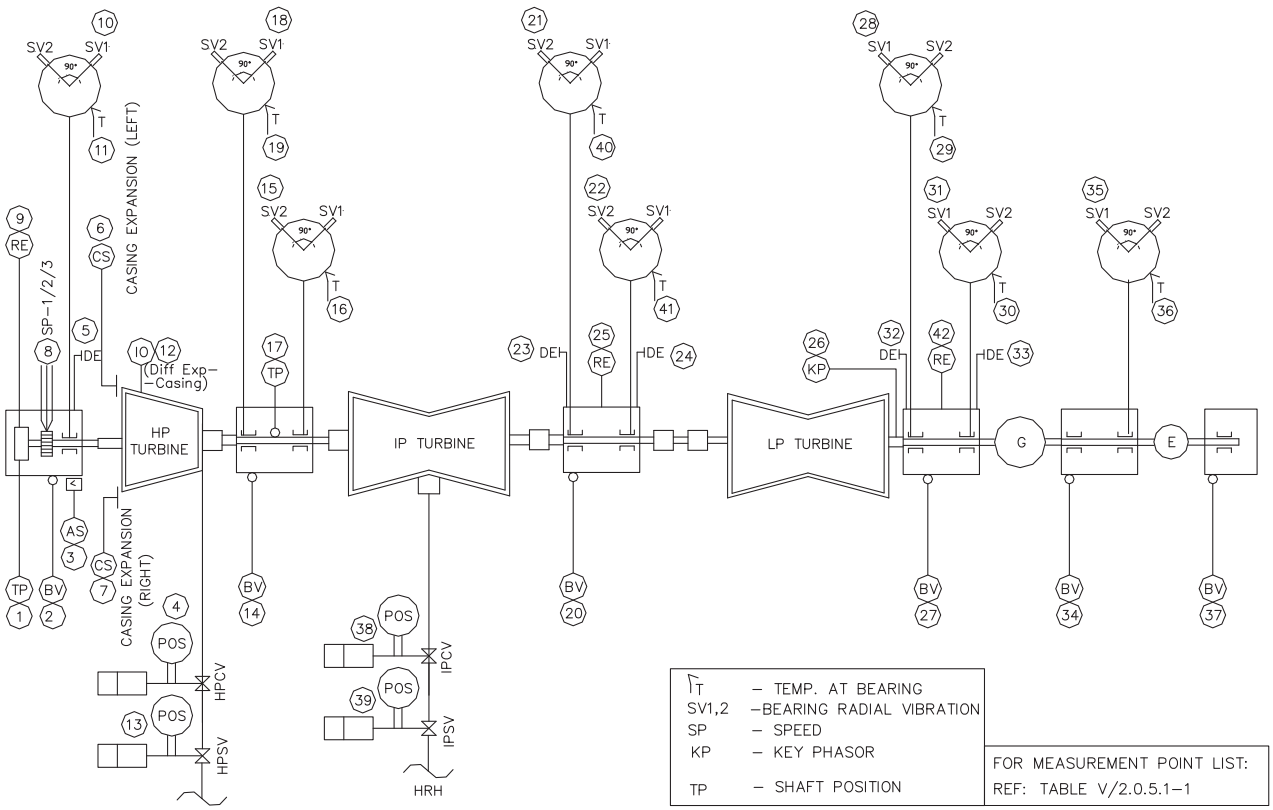


FIGURE V/2.0.5-1 Steam turbine condition monitoring points.

www.EngineeringBooksPDF.com

TABLE V/2.0.5.1-1 Steam Turbine Condition Monitoring

Sl	Measurement Number	Symbol	Measurement	Location	Purpose
1	3	AS	Absolute expansion	Front bearing pedestal	Absolute expansion (Location: fixed end shown one orientation only)
2	11	^T	Bearing temperature	Thrust bearing (HPT front)	White metal temperature of bearing
3	19	^T	Bearing temperature	HPT rear bearing	White metal temperature of bearing
4	16	^T	Bearing temperature	IPT front bearing	White metal temperature of bearing
5	40	^T	Bearing temperature	IPT rear bearing	White metal temperature of bearing
6	41	^T	Bearing temperature	LPT front bearing	White metal temperature of bearing
7	29	^T	Bearing temperature	LPT rear bearing	White metal temperature of bearing
8	30	^T	Bearing temperature	Generator front bearing	White metal temperature of bearing
9	36	^T	Bearing temperature	Generator rear bearing	White metal temperature of bearing
10	10	SV1, SV2	Bearing vibration	Thrust bearing (HPT front)	Shaft vibration at bearing at 90°—*X-Y* axis
11	18	SV1, SV2	Bearing vibration	HPT rear bearing	Shaft vibration at bearing at 90°—*X-Y* axis
12	15	SV1, SV2	Bearing vibration	IPT front bearing	Shaft vibration at bearing at 90°—*X-Y* axis
13	21	SV1, SV2	Bearing vibration	IPT rear bearing	Shaft vibration at bearing at 90°—*X-Y* axis
14	22	SV1, SV2	Bearing vibration	LPT front bearing	Shaft vibration at bearing at 90°—*X-Y* axis
15	28	SV1, SV2	Bearing vibration	LPT rear bearing	Shaft vibration at bearing at 90°—*X-Y* axis
16	31	SV1, SV2	Bearing vibration	Generator front bearing	Shaft vibration at bearing at 90°—*X-Y* axis
17	35	SV1, SV2	Bearing vibration	Generator rear bearing	Shaft vibration at bearing at 90°—*X-Y* axis
18	2	BV	Block vibration	Bearing pedestal HPT-front	Bearing block vibration (Abs)
19	14	BV	Block vibration	Bearing pedestal IPT-front	Bearing block vibration (Abs)
20	20	BV	Block vibration	Bearing pedestal LPT-front	Bearing block vibration (Abs)
21	27	BV	Block vibration	Bearing pedestal LPT-rear	Bearing block vibration (Abs)
22	34	BV	Block vibration	Bearing pedestal generator-rear	Bearing block vibration (Abs)
23	37	BV	Block vibration	Bearing pedestal exchanger-rear	Bearing block vibration (Abs)
24	6	CS	HP casing expansion left	Near HPT front pedestal	Expansion of HP casing (left)
25	7	CS	HP casing expansion right	Near HPT front pedestal	Expansion of HP casing (right)
26	5	DE	Differential expansion	HPT Front bearing pedestal	Expansion of rotor WRT near bearing pedestal

Continued

www.EngineeringBooksPDF.com

TABLE V/2.0.5.1-1 Steam Turbine Condition Monitoring—Cont'd

Sl	Measurement Number	Symbol	Measurement	Location	Purpose
27	23	DE	Differential expansion	IPT rear bearing pedestal	Expansion of rotor WRT near bearing pedestal
28	24	DE	Differential expansion	IPT rear bearing pedestal	Expansion of rotor WRT near bearing pedestal
29	32	DE	Differential expansion	LPT rear bearing pedestal	Expansion of rotor WRT near bearing pedestal
30	33	DE	Differential expansion	LPT rear bearing pedestal	Expansion of rotor WRT near bearing pedestal
31	12	IO	Differential expansion (casing)	HP casing	Differential expansion inner and outer HP casing
32	26	KP	Key phasor	LPT rear bearing pedestal	Angle between heavy spot in rotor and reference mark
33	9	RE	Rotor eccentricity	HPT front bearing pedestal	Eccentricity—sagging of rotor due to uneven heating
34	25	RE	Rotor eccentricity	LPT front bearing pedestal	Eccentricity—sagging of rotor due to uneven heating
35	42	RE	Rotor eccentricity	LPT rear bearing pedestal	Eccentricity—sagging of rotor due to uneven heating
36	1	TP	Shaft position	HPT front bearing pedestal	Axial shift of the shaft (possibility—depends on turbine orientation; redundancy asked for by manufacturer)
37	17	TP	Shaft position	IPT front bearing pedestal	Axial shift of the shaft (possibility—depends on turbine orientation; redundancy asked for by manufacturer)
38	8	SP	Speed	HPT front bearing pedestal	Turbine speed most important parameter (so 2/3 redundancy common)
39	4	PoS	Valve position	HPCV	HP control valve position
40	13	PoS	Valve position	HPSV	HP stop valve position
41	38	PoS	Valve position	IPCV	IP control valve position
42	39	PoS	Valve position	IPSV	IP stop valve position

HPCV, high pressure control valve; IPCV, intermediate pressure control valve; IPSV, intermediate pressure stop valve.

2.0.6 Vibration and Turbovisory Measurement Issues

1. *Speed measurement SP*: Speed measurement is the shaft revolution per minute. In fans and pumps standard speed measuring instruments such as tachometers with transducers or photoelectric transducers are used. A toothed wheel may be used as a typical turbine speed-measuring scheme as shown in Figure V/2.0.6-1. Of various types of sensors for turbine speed measurement, the Hall probe type sensor is popular (e.g., as in Siemens turbine). Other types of transducers are proximity type (from GE), etc. In general, especially for mid to large range turbines, redundant speed sensors are used. These probes (with a preamplifier, if any) are directly connected to a governing control and protection circuits but separately so that they are independent. The protection and measuring circuits may be in triple modular redundancy (TMR) configuration to ensure

www.EngineeringBooksPDF.com

TABLE V/2.0.5.2-1 GT Condition Monitoring

Sl	Measurement No.	Symbol	Measurement	Location	Purpose
1	1	SV1, SV2	Bearing vibration	Compressor end bearing	Shaft vibration at bearing at 90°—*X-Y* axis
2	2	SV1, SV2	Bearing vibration	GT front bearing	Shaft vibration at bearing at 90°—*X-Y* axis
3	3	SV1, SV2	Bearing vibration	GT rear bearing	Shaft vibration at bearing at 90°—*X-Y* axis
4	4	SV1, SV2	Bearing vibration	Generator front bearing	Shaft vibration at bearing at 90°—*X-Y* axis
5	5	SV1, SV2	Bearing vibration	IPT rear bearing	Shaft vibration at bearing at 90°—*X-Y* axis
6	6	ˆT	Bearing temperature	Compressor end bearing	White metal temperature of bearing
7	7	ˆT	Bearing temperature	GT front bearing	White metal temperature of bearing
8	8	ˆT	Bearing temperature	GT rear bearing	White metal temperature of bearing
9	9	ˆT	Bearing temperature	Generator front bearing	White metal temperature of bearing
10	10	ˆT	Bearing temperature	IPT rear bearing	White metal temperature of bearing
11	13	SP	Speed	Compressor shaft	Compressor speed
12	14	SP	Speed	GT shaft	GT speed
13	11	KP	KP	Thrust-bearing pedestal	Angle between heavy spot in rotor and r eference mark
14	12	TP	Shaft position	Thrust-bearing pedestal	TP
15	9	ˆT	Bearing temperature	Generator front bearing	White metal temperature of bearing
16	10	ˆT	Bearing temperature	IPT rear bearing	White metal temperature of bearing
17	13	SP	Speed	Compressor shaft	Compressor speed
18	14	SP	Speed	GT shaft	GT speed
19	11	KP	KP	Thrust-bearing pedestal	Angle between heavy spot in rotor and reference mark
20	12	TP	Shaft position	Thrust-bearing pedestal	TP

IPT, intermediate pressure turbine.

high reliability of protection. In some systems, separate electronic over speed detection systems are available (e.g., electronic over speed system of GE-B&N). Acceleration/deceleration measurement is also important for the operator during rolling of the turbine. The following points may be noted to understand the importance of this measurement:

a. A steam turbine, in its lifetime, is allowed to go into over speed only for a limited number of times (as per manufacturer's data), so speed measurements are very important.

b. In a turbine the gap between stator and rotor is very less (for a larger turbine the gap is narrower), so any over speed can result in havoc to the turbine.

c. During every start-up the operator needs to hold the speed during the heat-soaking period and cross quickly through critical speed (shaft critical frequency).

d. The turbine has to run at synchronized speed, as the generator (which is synchronized with the power system grid at given frequency) is directly coupled with the turbine. However, the scenario is little different for industrial turbines (e.g., BFP turbine; BFPT), which are connected to the driving equipment through gear trains. However, in those cases also speed control is important.

e. During the actual over speed test the governor accurately verifies the operation, so any over speed will cause a protection trip of the turbine.

2. *Electronic over speed detection system (EODS)*: Each manufacturer has its own EODS. In an EODS with SIL3 approval (e.g., KWU), each channel is sent to a voting circuit as open channel whereas same is sent

www.EngineeringBooksPDF.com

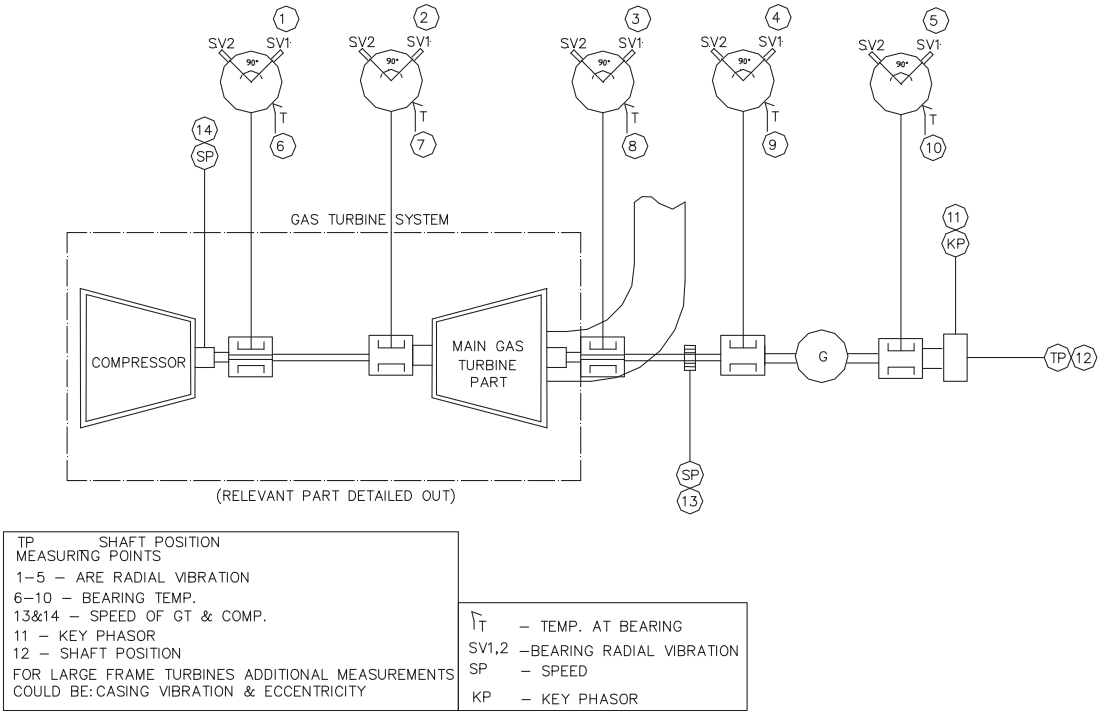


FIGURE V/2.0.5-2 Turbovisory instruments in GT.

through two of three voting circuits (as closed channel) giving three outputs to each of the protection channels—a total of three protection channels (each two of three) for initiating a trip condition (see Figure V/2.0.6-1b) (This is based on SIL 3 over speed protection—a Kraftwerke document '2006).

3. *Bearing vibration measurement (shaft vibration; SV1, SV2; see* Figure V/2.0.6-2a*)*: As the vibration probes are placed radial to the vibration housing, as shown in Figure V/2.0.6-1a, these are sometimes referred to as a radial vibration measurement. Here probes are placed at 90° to each other and placement is radial. Vibration probes may be in one plane or at two different planes. Probes are put in place by a hole (and probe holder) in the bearing housing. Since any force can be resolved into two components at a right angle, by placing the probes at 90° the vibrating force can be assessed better. Radial measurements give firsthand information regarding any unbalance, crack, misalignment, etc.

   If a turbine and any other machine are allowed to run for long with excess vibration, then they may be damaged due to rubbing, fatigue, etc. In turbines this vibration, can be caused by water induction also. Monitoring is important because it provides quick detection that can save the machine.
4. *Bearing block vibration (BV)*: Bearing BV, i.e., absolute vibration is measured for mid to large-sized turbines. These are vibration measurements to detect absolute vibration of the machine casing with respect to (WRT) free space; hence, seismic probes are used (see no. 9 in this Clause.). Where there a light casing to rotor weight ratio exist, vibration is transferred to the bearing housing. To analyze the signals at high frequencies, accelerometers are deployed; otherwise velocity pickup may be sufficient. This monitoring may be performed in all the bearing blocks.
5. *Phase measurement (key phasor; KP)*: In the shaft a key way is kept or a hole is drilled. Magnetic pickup or optical or similar type of sensor is used to measure the angle between the hole or key way and the heavy spot on the shaft. This is important for balancing the machine. Also it can provide early indication of misalignment and/or crack in the shaft, change in blade disposition, loss of mass, etc. (see Figure V/2.0.6-3).
6. *Axial shift/thrust position (TP)*: One of the most important turbine trips comes from this measurement (see Figure V/2.0.6-4). Turbine trip signals are generated from the probe or probes through necessary voting circuits, after each of them crosses the set point. It is similar to shaft position measurement, except that it measures the wear of thrust bearing. In this measurement, the movement of the thrust collar between the active and inactive thrust shoes and their wear and tear are measured. The measurement is carried out by one or two sets of probes on the same or opposite sides of the collar (even two of three is not uncommon in large plants). It measures the movement of the shaft

www.EngineeringBooksPDF.com

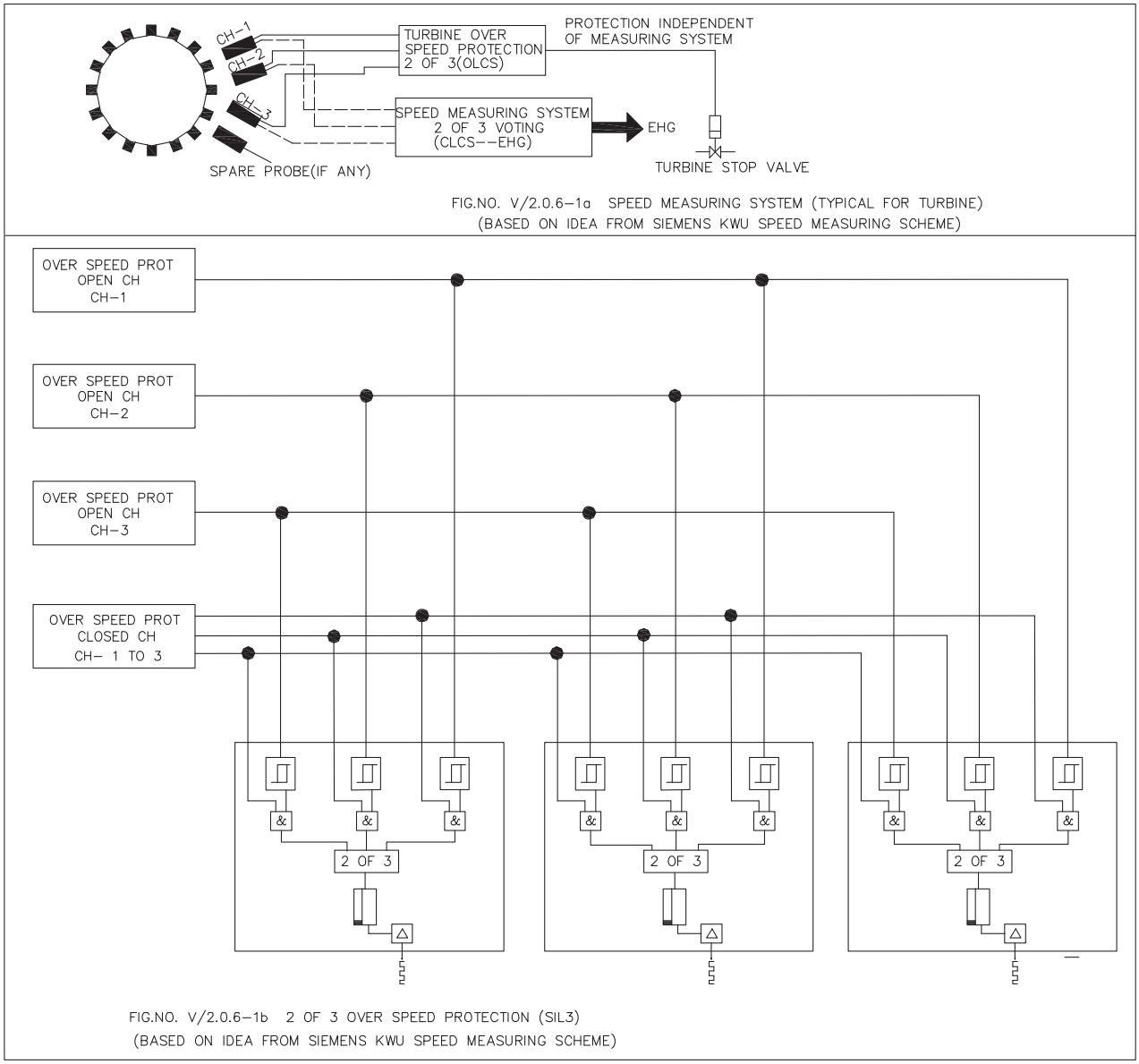


FIGURE V/2.0.6-1 Speed measuring system (typical).

in the axial direction with respect to a fixed reference. Normally the reference is the thrust-bearing support structure or other nearby casing member used as the mounting location of the probe. The thrust collar location with respect to thrust bearing represents the shaft axial shift observed by the probe. TP or axial shift/position measured by proximity probe is in the range of a few millimeters. Since TP measurements are taken within a short range of thrust bearing (normally within 300 mm or as recommended by the manufacturer), thermal expansion needs to be considered. Also instrument range should be suitably chosen for the primary function of monitoring wear of thrust bearing causing axial shift.

Axial shift is important as it indicates a number abnormalities in TG operation such as:

- Axial shift indicates improper operation in the turbine, e.g., a problem in the piping, such as extraction piping.
- Excess wear at the thrust bearing, which may cause severe damage to the turbine through rubbing in seal.

7. *HP turbine (HPT) casing expansion (CS)*: The generator end of HP casing is fixed in an axial direction. So HP casing due to thermal expansion/contraction has only a chance in the front end. It is measured at the supporting end in the front where little axial displacement is allowed without misalignment. From

www.EngineeringBooksPDF.com

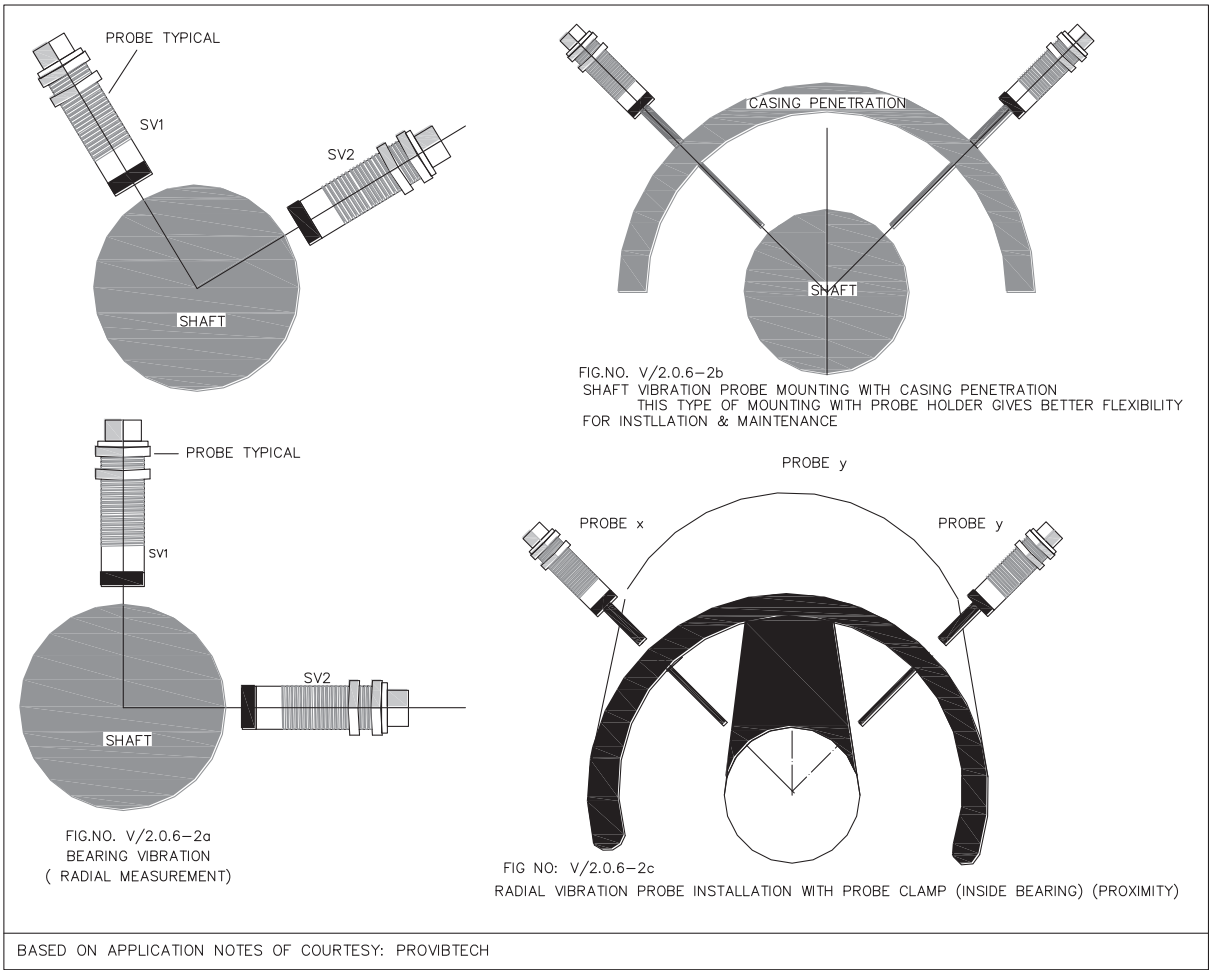


FIGURE V/2.0.6-2 Vibration measurements for bearing (shaft vibration).

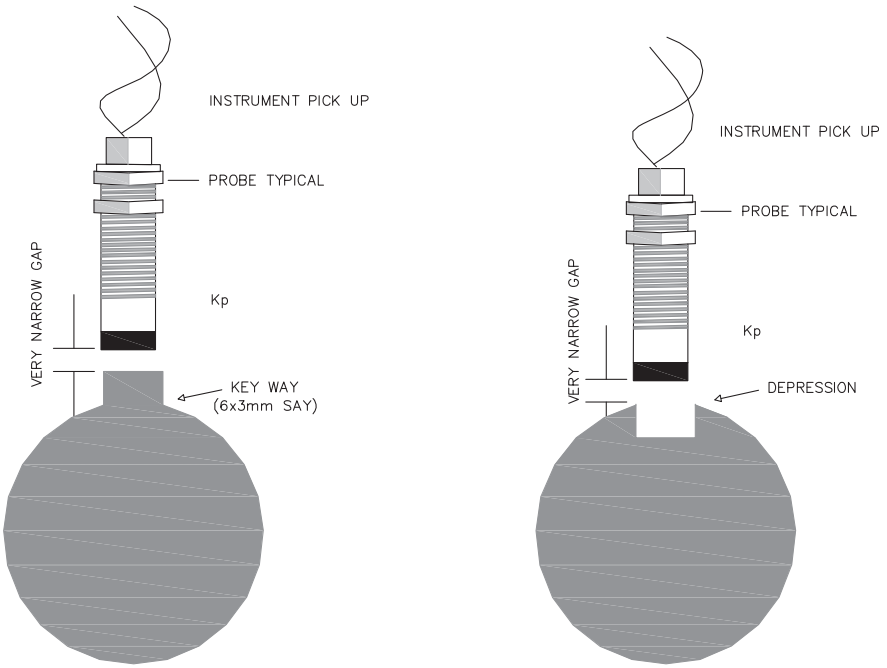


FIGURE V/2.0.6-3 Key Phasor/KP (typical).

www.EngineeringBooksPDF.com

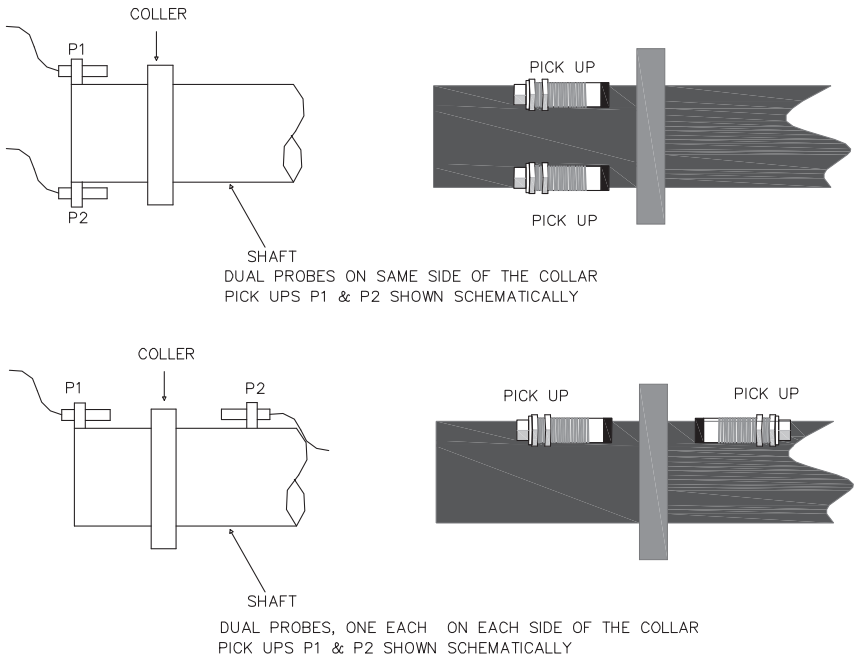


FIGURE V/2.0.6-4 Axial shift/TP.

start-up to operation and shut down there will be a large variation in temperature; naturally there will be chances of expansion. Measurement of this parameter helps operator know about the thermal growth on HP casing. Installation of this is quite critical. The main body part is fixed with the foundation whereas the sensor probe plunger moves by a spring-loaded roller, which is pressed against a support attached to the casing as schematically shown in Figure V/2.0.6-5. The term "cocked case" is popular with this measurement. This occurs when the turbine slider hangs up or sticks on one side of the foundation and continues to grow in the other direction (see Figure V/2.0.6-5). To monitor this, it is necessary to use two LVDTs instead of one. This measurement is important, as it helps to detect excessive resistance of the front casing support to casing thermal expansion. Resistance is marked by jerky movement of the HP casing due to expansion.

8. *Bearing temperature measurement (ˆT)*: Misalignment, insufficient clearance in bearing, excess bearing loading, or improper lubrication at the bearing are major occurrences in many machines, such as fans, pumps, high temperature (HT) motors, and turbines. Therefore it is considered an important measurement not only in TGs but also in machines with big drives. In many turbines suitable ISA type thermocouples are used; others generally use resistance temperature detectors (RTDs) for this purpose. These temperature elements may be brazed with the white metal of the bearing. In some places a few temperature points are monitored together to study the conditions of the turbine: metal temperature, lube oil temperature, exhaust hood temperature. In some cases dedicated temperature scanners with a link to the DCS may be deployed (see Figure V/2.0.6-6)).
9. *Absolute shaft vibration measurement*: This measurement is used to find the motion of the shaft in free space (see Figure V/2.0.6-7). The rotor is much heavier (∼5−6 times) than that of the casing. A seismic probe is used to measure the absolute vibration of the casing (WRT to free space, i.e., with Earth). There will also be another probe to measure relative motion of the shaft WRT casing. These are actually passed through a suitable filter to eliminate noise. These signals are then summed to get absolute shaft measurement.
10. *Rotor eccentricity (RE)*: Eccentricity measurement indicates the deviation of the rotor physical center and theoretical one. Rotor is a very heavy mass on the shaft, and there will be the possibility of sagging or bowing of the rotor. This sag/bow of the rotor are measured by monitoring the RE. Since the hottest part is the HPT rotor, sag/bow would take place at the highest at this part, i.e., susceptibility to thermal deformation would be high. As is clear from the Figure V/2.0.6-8, eccentricity is the maximum difference between the shaft deflections at highest cases. The measurement of RE is possible only when the shaft is rotating. Therefore this measurement is performed at when the turbine is at low speed. This

www.EngineeringBooksPDF.com

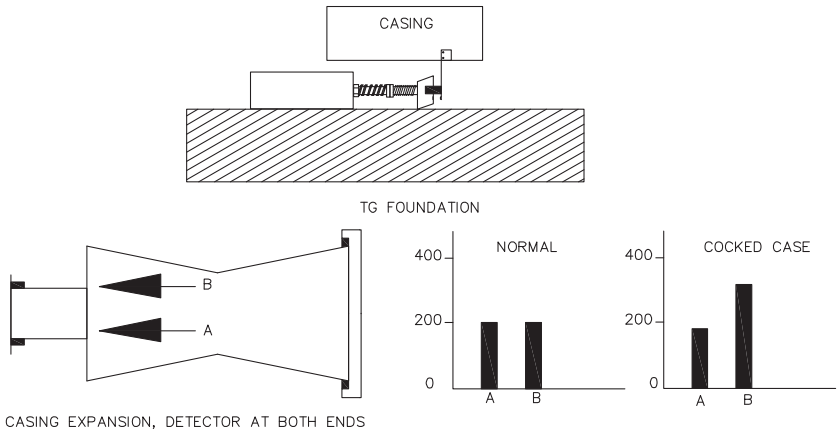


FIGURE V/2.0.6-5 HP casing expansion.

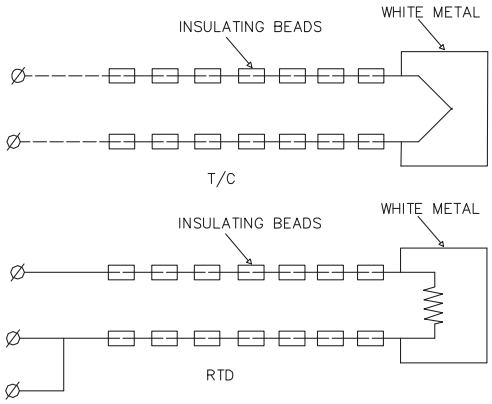


FIGURE V/2.0.6-6 Bearing temperature measurement.

measurement helps the operator bring up the speed without rub or damage.

RE is important for the following reasons:

- Detection of excess deformation at the time of low-speed operation
- To ensure that turbine run up will take place after sagging is straightened

11. *Differential Expansion (DE)*: The thermal expansion/contraction of a lighter hollow rotor is different from the thick casing, so the latter will change at much slower rate than the former one. Because of this, the DE between the rotor and stator casing needs to be measured. This is more predominant during cold start-up of larger turbines. DE is also measured

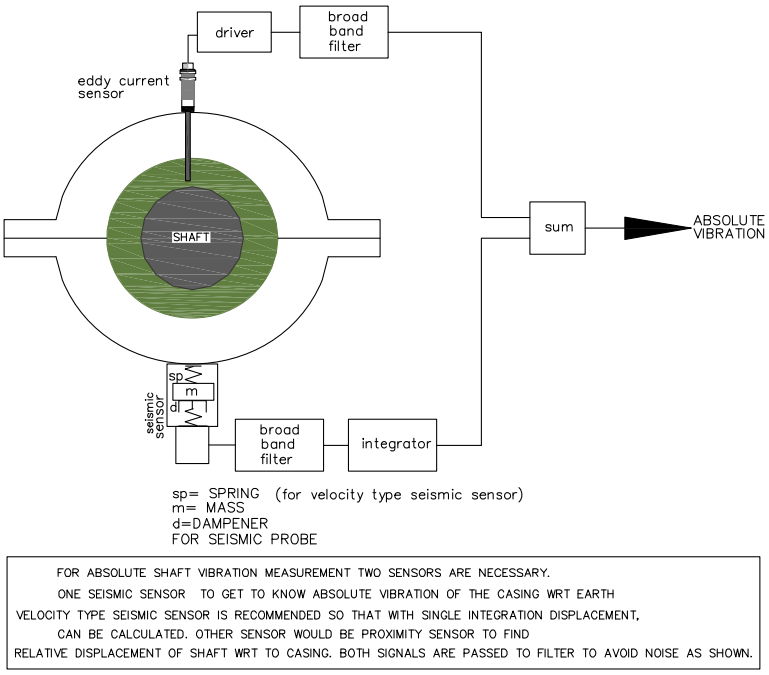


FIGURE V/2.0.6-7 Absolute shaft vibration measurement.

www.EngineeringBooksPDF.com

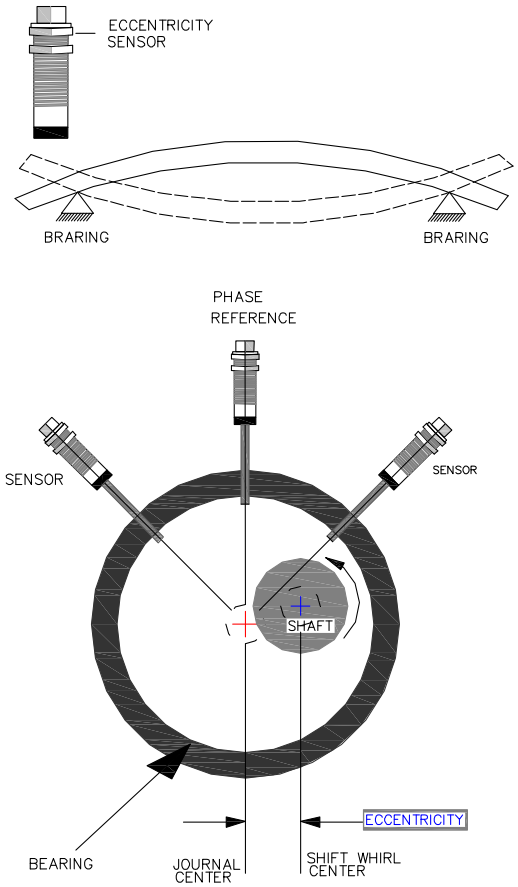


FIGURE V/2.0.6-8 Eccentricity measurement.

when large thermal expansion is experienced. Therefore the operator, with the help of this measurement, has to make sure that the casing has expended sufficiently to avoid rubbing by the rotor. DE measures the axial position of the rotor with respect to the machine casing at some distance from the thrust bearing where the axial shift of the rotor is least. The measurement is typically made with a proximity probe transducer mounted to the casing to measure the axial position of the rotor provided with a collar or special ramp shape given to the rotor (see Figure V/2.0.6-9).

12. Valve position (PoS): Valve PoS measurement is done to know the opening/closing percentage of the valves, mainly the throttling/control valve. However, during heat soaking, for fulfilling certain criteria, stop valves are also cracked opened. Eddy current type, noncontact proximity rotary position transducer, and/or any other type could be used for this purpose (see Figure V/2.0.6-10).

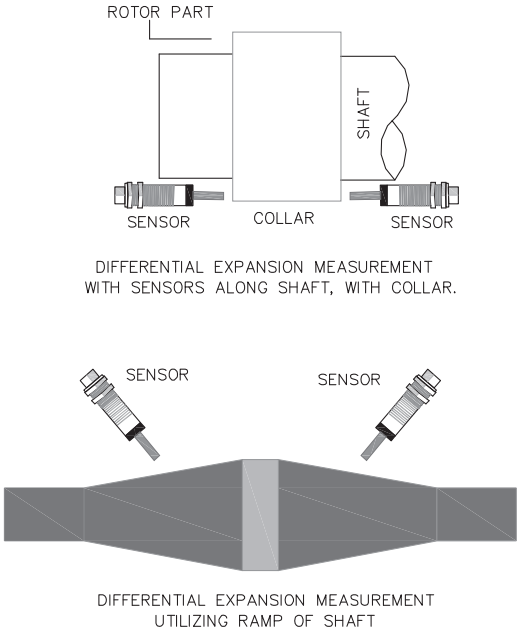


FIGURE V/2.0.6-9 Differential Expansion measurement.

2.0.7 Frequency Range

It has been found that the general frequency range encountered in vibration is from 10 to 1000 Hz. In larger turbines an even lower frequency of vibration has also been found. Since near critical speed there is the possibility of low frequency vibration, for turbines the low-frequency vibration measurement is very important. As the frequency of vibration changes from low to high frequency, the type of sensor changes from a displacement sensor to a velocity sensor to an acceleration sensor. However, by mathematical computation each type of measurement can be obtained from each other, e.g., displacement can be obtained by integrating velocity sensor (practicable for the measurement) output.

2.0.8 Measuring Sensor/Transducer Types

Generally three types of sensors are applied to measure vibration: displacement, velocity, and acceleration and most of the other types are turbovisory instruments.

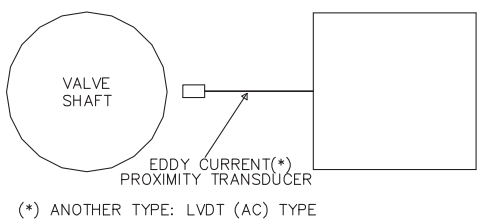


FIGURE V/2.0.6-10 Valve position measurements.

www.EngineeringBooksPDF.com

However, for speed a tachogenerator, photoelectric type sensor, and Hall effect sensor are used.

1. *Displacement type Sensor/transducer*: When there a fixed reference is available and measurement is to be done WRT the same, a displacement type sensor is used, e.g., displacement of shaft with respect to the bearing housing. Sometimes displacement is computed by integrating the output from a velocity sensor. When displacement amplitude is measured, then the sensor is chosen so that its natural frequency is less than the lowest frequency of the vibrating medium in the question. In displacement the transducer total distance traveled by a vibrating body or another piece of moving equipment (i.e., shaft) is measured (normally in micrometers).
2. *Velocity type sensor/transducer*: In this method the velocity of vibration of a moving part is the speed at which it is moving at any instant of time. Normally RMS value is chosen for vibration in mm/sec as the unit of vibration. In this type of sensor/transducer Faraday's law is used to generate voltage (e) $= -N\ d\Phi/dt$ where N represents the number of turns of the sensor coil and $d\Phi/dt$ is proportional to the velocity of vibration. The transducers used are a moving coil type, moving magnet type, or change of reluctance type, with relation to a fixed coil. Thus velocity of vibration is the speed at which the vibrating part is moving at any instant, and output voltage is proportional to velocity vibration. To measure a very low frequency (10 Hz) of vibration, the natural frequency of the transducer will also be lower (<8 Hz). At a vibration frequency above the natural frequency when the coil would remain stationary with respect to Earth reference, so it is called seismic transducer. Output is mV/mm/sec.
3. *Accelerometer* In most of the acceleration type measurements, Newton's second law, $P = m*f$ (where P = force, m = mass, and f = acceleration) is used. In this method either spring compliance shows displacement of the mass relative to the casing is proportional to the acceleration is used or piezoelectric transducers are used (where charged developed is proportional to the force applied). In modern turbines piezoelectric type transducers are used to measure pedestal vibration.

2.0.9 Factors Influencing Vibration Measurements

Factors that influence vibration measurements include the following:

1. *Cross-axis sensitivity.* The sensitivity of an instruments is greatly influenced by the vibration occurring perpendicular to the sensitive axis of the instrument. As a result there may be an error in measurement, since it depends on the sensitivity of the instrument. Internationally it is recommended to keep error at <10%.
2. *Capacitance effect*: In the piezoelectric sensor the charge produced due to force is measured; therefore it is very sensitive to the stray capacitances coming from the cable and preamplifier. Also a variation in relative humidity may affect the measurement. For these reasons, the use of charge amplifiers and special cables may be recommended by the manufacturer.
3. *Sensor loading*: The sensitivity of the vibration sensor falls with less mass; whereas the addition of mass would create loading of mass of the vibration system and problems of frequency response would be predominant. Therefore the sensor should be chosen carefully.
4. *Coupling*: The sensor and the surface at which the sensor is coupled should be very stiff to avoid any spurious vibration at low frequency.
5. *External influence*: Temperature, external magnetic field, damping, etc., affect vibration readings. A system with lower damping takes more time to come to equilibrium after a disturbance.

2.0.10 Interpretation of Vibration Measurements

Vibration measuring instruments are of different category e.g. monitoring, machine diagnostic, and portable type instruments. Also among these the reading types are different; some are time peak overall, average overall, FFT overall, etc. As discussed previously (Clause 2.0.1) the relationship between the RMS peaks of a simple sinusoidal wave is different from the same from a vibration signal, which may not be a simple sine wave.

In Figure V/2.0.10-1, in curve A RMS = 0.707 peak, but this is not valid for curve B. The main intension of this discussion is to conclude that there may be mismatch between the computed value of an RMS reading by an instrument and a peak-detecting diagnostic instrument. Most instrument engineers try to equate them, but this may not be correct. It is always advisable to use an oscilloscope to compare where these can be checked. It is therefore necessary to have detailed discussions with the manufacturer before declaring the instrument reading right or

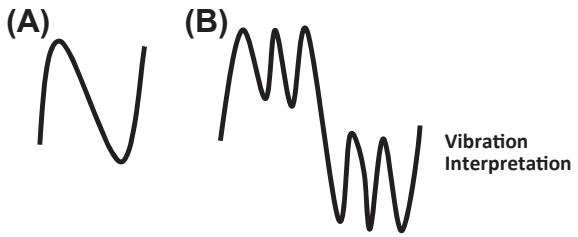


FIGURE V/2.0.10-1 Vibration interpretation.

www.EngineeringBooksPDF.com

wrong. All manufacturers (GE: B&N) have suitable standards written for reference.

2.1 Vibration Measurement

A few common sources of vibrations are discussed n Table V/2.1-1. In this clause an effort will be made to discuss various kinds of vibration measuring systems. Since this type of sensor is used to measure various kinds of measurements (even other than vibration), discussions will be made based on the type of instrument, e.g., proximity type eddy current sensor can be used for both shaft vibration measurement at bearing as well as eccentricity measurement. Data sheets based on renowned manufacturers are included with suitable application note/cross reference for each type of sensor

Monitoring of shaft vibration in orthogonal *X-Y* axis (radial) is common; however, this alone is insufficient. Casing vibration measurement is also necessary and important. Casing vibration is more useful when rotor mass is sufficient to transfer vibration energy to the bearing. Phase measurement is helpful in analyzing the signal.

For casing vibration, all three types of sensors can be used. A general guideline is to select the sensor type according to machine rpm. So, for casing vibration, the displacement type sensor is the better choice when M/C rpm $<$ 600, whereas for 600 $<$ M/C rpm $<$ 60,000 a velocity type sensor is the better choice. However, acceleration type sensors with an integrator are often in use.

2.1.1 Proximity Probes

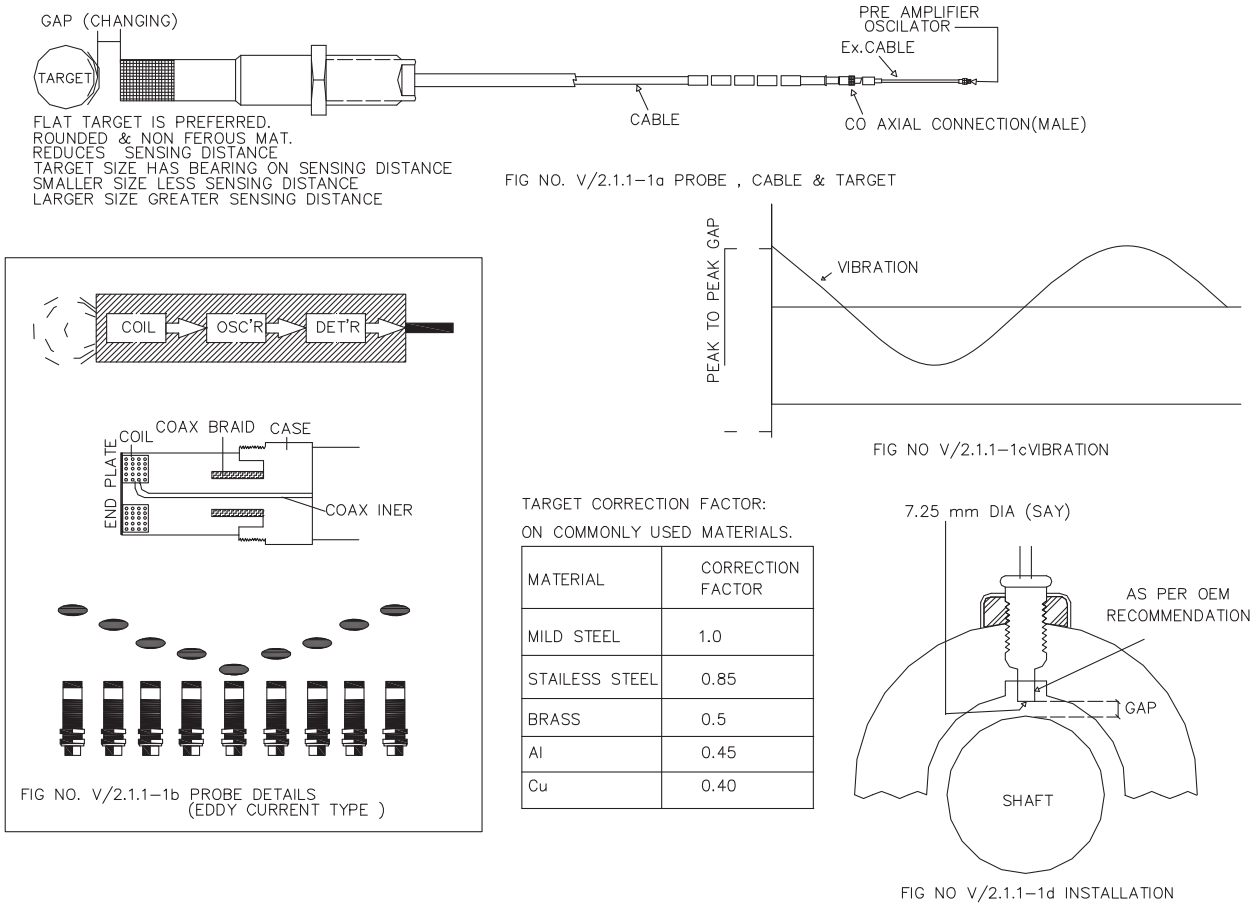
In proximity types of sensing, the change in the air gap between the target and the sensor is measured to give suitable or voltage output. An eddy current type of proximity sensor is the most popular one, but the mutual inductance type can be used as a switching device also.

- *Eddy current sensing principle*: In this system, as shown in Figure V/2.1.1-1a and b, there is a transducer coil at the tip of the probe. Along with the coil, the sensor consists of an oscillator, power to drive transducer oscillator, and detector (demodulator). The oscillator generates the high-frequency (1−3 MHz) signal through the transducer coil. This forms a changing magnetic field in the nearby vibrating target, and, consequently, a high-frequency magnetic field is generated on the target. Therefore an induced voltage is generated in the target body (as per Faraday's law), which causes the eddy current to flow. Eddy current in the conducting shaft changes the amplitude of the high-frequency signal from the probe. The energy loss due to eddy current (in the vibrating target) changes the oscillator operating point. This change is detected at the detector or pickup coil. When the target is at a fixed position there will be DC at the detector, meaning a new, unchanging amplitude of high-frequency signal due to the fixed target. Because of vibration and shaft, the target changes position and the amplitude of the high-frequency signal changes in proportion to the air gap between the sensor and target. Eccentricity or shaft vibration causes gap changes, and the amplitude change in carrier frequency current (original signal) caused by eddy current is detected after being demodulated. Pickup coil signal is amplified and given as output. This type of sensor signals for vibration amplitude or displacement.
- *Change of reluctance sensing principle (mutual coupling)*: This type is another possibility, but it is not popular. It consists of two coils: a primary coil excited by ∼10−20 kHz and secondary coils. These two coils are placed across a metallic core. The second coil receives the voltage because of the mutual coupling between them. These arrangements are placed on one side of the diaphragm forming a part of the path for magnetic flux. The whole assembly is placed near the target, which when it vibrates changes the air gap between the target and the sensor. The voltage generated in the second coil is a function of air gap and is proportional to the air gap.

TABLE V/2.1-1 Common Sources of Vibration

Cause	Indication	Remarks
Bent shaft	High axial	Unsteady (in TG)
Misalignment	High axial	Axial amplitude high, higher vertical or horizontal reading
Unbalance	Radial steady	Most common vibration cause
Gear mesh	Radial high	Typical acceleration due to high frequency
Resonance	At machine critical speed amplitude is high	Original equipment manufacturer guideline for quickly passing the speed.
Looseness	Proportional to looseness	Often coupled with misalignment

www.EngineeringBooksPDF.com



MATERIAL	CORRECTION FACTOR
MILD STEEL	1.0
STAILESS STEEL	0.85
BRASS	0.5
Al	0.45
Cu	0.40

FIGURE V/2.1.1-1 Proximity probe.

2.1.1.1 Eddy Current Proximity probes

1. Because of the eddy current there is a small voltage in the pickup coil. As long as the gap does not change the coil the voltage does not change. Hence, a DC voltage proportional to the average gap between the target and the sensor is available at the output due to the demodulation and signal conditioning action of the sensor output circuit.
2. When the shaft rotates without vibration/eccentricity, there will be DC voltage from the average gap as stated above.
3. When the shaft vibrates (or there is eccentricity), there is AC voltage (due to the loss of eddy or change in mutual inductance) because of the vibration (or eccentricity), and this voltage (at detector after demodulation) is proportional to the amplitude vibration or eccentricity.
4. Only AC voltage is measured to note the vibration, eliminating the DC voltage after demodulation.
5. Depending on the coil size the range could be 10 mils (0.25 mm) to 2.0 mm (80 mils)
6. Some of the special features preferred when selecting a system include but are not limited to the following:
   - Interchangeability of probes, cables, and extension cables in the system.
   - Compliance with requirements of API 670 Standard/ ISO 10816/ISO 7919/European CE marking/IEC, ATEX, CSA, etc. Possible for hazardous application.
   - Immunity to radio frequency interference (RFI) and electromagnetic interference (EMI).
   - Some manufacturers offer a click lock (finger-tight connector), e.g., GE-B&N.
   - High temperature capability as high as 260°C.
   - Sensor face can be plastic or stainless steel (ability to withstand harsher environmental conditions). Sometimes full epoxy encapsulation is used to protect against shock and contamination.
   - Protection against reverse polarity and short circuit.
   - With a vibration sensor mild steel is considered as a standard target. If other materials are used then a correction factor can be used to ascertained the actual range (nominal sensing range*correction

www.EngineeringBooksPDF.com

factor for material = actual sensing range). Factors for various materials ae shown in Figure V/2.1.1-1 (courtesy Rockwell).

- To order, the following need to be specified:
  - Length for overall probe, cable, and extension cable
  - Approving authority
  - Accessories
  - Contact type and rating for switches only
  - Application note: For measurement of the following:
  - Shaft/bearing vibration—radial vibration
  - DE transducer (TG)
  - Eccentricity (TG)
  - Axial shift (TG)/thrust or axial position
  - Speed/zero speed/reverse rotation protection

2.1.1.2 Eddy Current Proximity Probe Data Sheet (Typical Value for Idea Only)

See Table V/2.1.1.2-1 for the eddy current, proximity sensor data sheet.

2.1.2 Velocity: Seismic probes

The velocity probe measures the velocity of vibration. It involves measurement of both the amplitude and frequency.

2.1.2.1 Velocity Probe: Seismic Probe Working Principle

As per Faraday's law, whenever there is a change in magnetic flux there will be induced voltage, which is proportional to the rate of change of flux. The seismic

TABLE V/2.1.1.2-1 Data Sheet: Eddy Current Proximity Sensor

Sl	Specifying point	Standard/available data	To be specified
1	Number of inputs	One per sensor standard	
2	Power supply	24V DC standard	
3	Sensitivity	Varies with supplier, 1—2 mV/V input	
4	Output resistance	<50 Ω	
5	Probe length and total length	0.5—10 m (with extension wire)	To be specified as per application
6	Extension cable	2.0—9 m available	
7	Gap/range	0.5—2.5 mm	
8	Extension cab capacitance	Supplier specific: ~70 pF/m typical	
9	Extended temperature range	Standard available: 120°C	
10	Minimum target size	15 mm flat or 50 mm diameter shaft—for continuous (or minimum of one side face equal to probe diameter for switches)	
11	Probe diameter	5—12mm diameter (may be greater for switches)	
12	Probe tip	Plastic (PPS) with casing SS/stainless steel, with epoxy painting	
13	Probe cable	Manufacturer standard	
14	Compliance and certification	Manufacturer standard (Some international authorities could be ABS, EMC, IEC, or ATEX and CSAETC for hazardous approval)	
15	Environmental conditions	Available commercially: T = 177°C, OP range 100°C RH: 93%(IEC standard test)	
16	Field wiring	Standard triad cable	
17	Enclosure	IP 67/65, etc.	
18	Output	Voltage For continuous monitoring (linear)/for switch: contact type, number, and rating	
19	Approval	As per project standard	To be specified

www.EngineeringBooksPDF.com

velocity transducer works on this principle. It has a fixed conductor length and magnetic field strength so the generated voltage is proportional to the velocity at which magnetic flux is cut in the coil. As shown in Figure V/2.1.2-1a, a permanent magnet is attached to the casing, whereas the coil assembly (coil with core considered as mass) is suspended by spring with dampening. The mass of coil assembly along with spring is chosen/designed in such a way that the natural frequency of the assembly is lower than the frequency of machine vibration, which in power station drives is ~10 Hz. At these frequencies, the probe almost remains stationary in the space, i.e., with respect to the reference frame of Earth, so it is called a seismic type. When the instrument casing is fixed with the bearing housing (pedestal) and there is vibration in the pedestal, there will be relative motion of the magnet with respect to the fixed point, i.e., the coil. Therefore voltage will be induced in the coil and is directly proportional to velocity of relative motion. Therefore the output is proportional to the velocity of the casing vibration. Displacement can be obtained by integrating the output. Sensitivity is expressed in terms of mV/mm/sec.

2.1.2.2 Velocity Probe: Seismic Probe

1. The instrument is a self-excited system.
2. After a particular frequency the change in output drops because then the transducer operates near damped natural frequency.

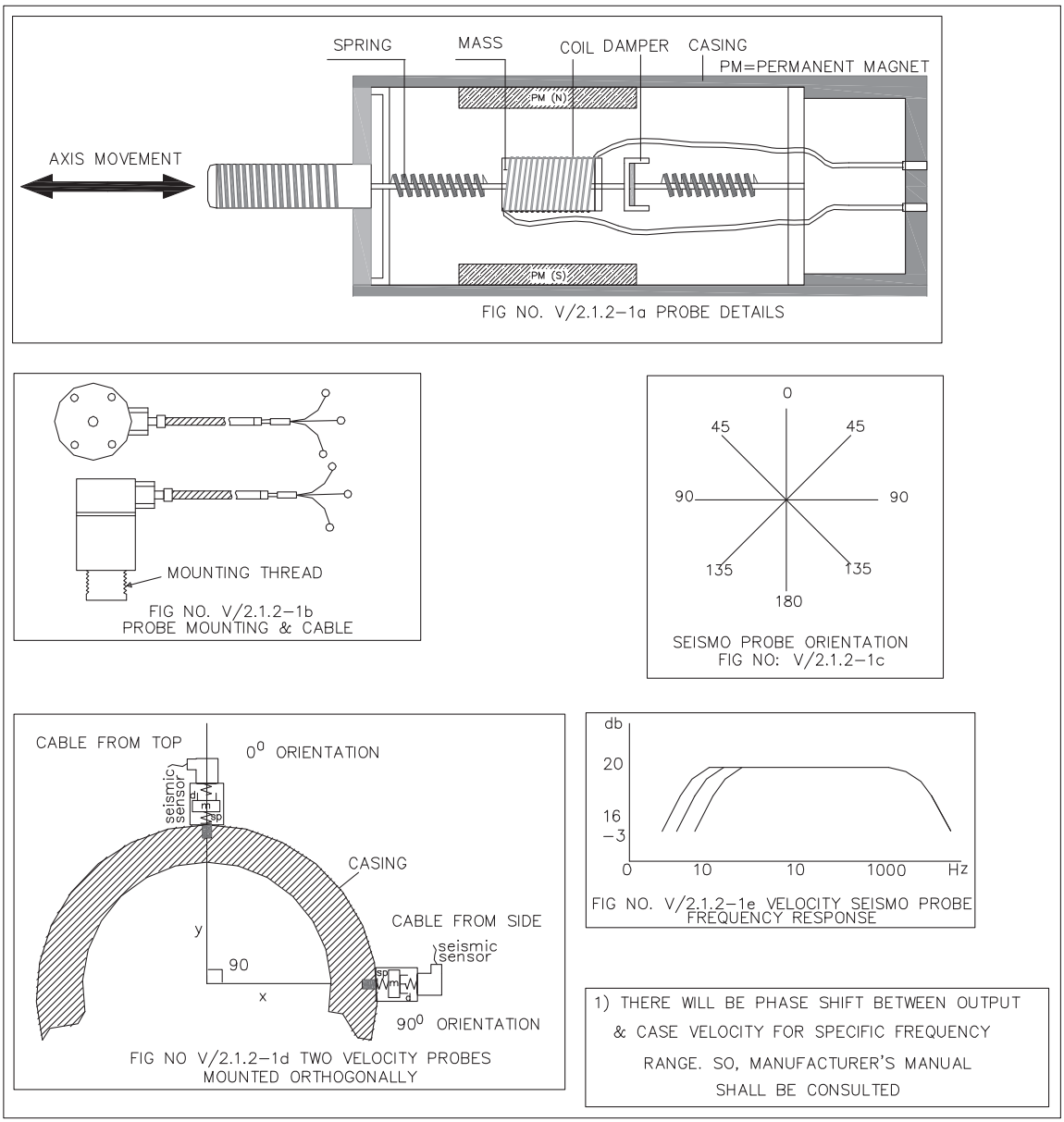


FIGURE V/2.1.2-1 Siesmo velocity probe.

www.EngineeringBooksPDF.com

3. Since the magnetic field around the main generator can be picked up, it is recommended that a magnetic screen be used.
4. Physical installation of the transducer is very important to avoid an erroneous result.
5. A large portion of vibration occurring at the rotor, due to misalignment and imbalance, is transmitted to the bearing housing or pedestal. Therefore with this instrument vibration can be monitored and the machine can be protected.
6. For accurate results and proper location, physical installation of the transducer is done in consultation with the manufacturer/original equipment manager.
7. Orientation of the probe is very important.
8. With respect to phase angle measurement, there are phase differences between output and case velocity. This is a function of frequency, so for analysis this should be considered.
9. Some of the special features preferred in selecting this system include but are not limited to the following:
   a. *Two-wire configuration*: The transducers are available in s two-wire configuration with linear output.
   b. *Impact*: These are less sensitive to impact and impulsive excitation, but can be affected by an external magnetic field, so a magnetic screen should be used.
   c. *Power supply*: As no external supply is necessary, it is used in a portable configuration.
   d. *Minimum frequency range*: Up to 10 Hz frequency range is available on the lower side.
   e. *Compliance*: With requirements of API 670 Standard/ISO 10816/ISO 7919/European CE marking/ IEC, ATEX, CSA, etc. Hazardous application is possible.
   f. *Orientation*: As shown in Figure V/2.1.2-1c.
   g. *High temperature*: **T**ransducers available to cater to temperatures up to 200°C.
   h. *For ordering*: The specifications include desired information regarding the following:
      i. Transducer frequency range
      ii. Orientation of mounting
      iii. Mounting drawing preferable
      iv. Mounting base and accessories
      v. Electrical connection details
      vi. Authority approval
   i. *Application*: Casing vibration.

Typical specification of seismic velocity sensors are seen in Table V/2.1.2.2-1.

2.1.3 Acceleration: Seismic Probes

A seismic sensor **a**cceleration probe is mainly used for high-frequency vibration measurement. Normally compressive force is measured with the help of a known proof mass (seismic mass) and from there acceleration is measured. This may be integrated to calculate velocity and displacement of vibration.

2.1.3.1 Acceleration Sensor: Working Principle

For the seismic sensor mass (m) and spring (s) are fixed. $P = m*f$ where P is the force for mass m having acceleration f. Again spring compliance shows that relative displacement of mass WRT case is proportional to acceleration. Transducers based on this principle show that at the low-frequency end the displacement produced is too low with very low output, which may be suppressed by background noise. This type of sensor is not popular for measuring vibration in power plants where there is low-frequency vibration.

The piezoelectric sensor is the most popular type of accelerometer used in power plants to measure the compressive force due to vibration. When force is applied (or applied force changes) to a certain kind of crystalline substance, e.g., quartz, charges develop (or change) between the two surfaces of the properly shaped crystal. These charges are proportional to the applied force, which in turn is proportional to the acceleration (as $P = mf$ and mass is constant). By integrating the output the velocity (and double integration—displacement) can be obtained. Double integration poses a serious problem to the signal-to-noise ratio vis á vis the frequency range. Velocity is normally used as a result of the one-time integration from the output of the instrument. There are several design types available, such as shear, bending, and compressive force (see Figure V/2.1.3-1b). Here the force is applied to the tripod (for three directions) where piezoelectric crystals are embedded. When the accelerometer is attached to a vibrating object, the piezoelectric elements experience a vibrating force (changing in nature due to vibration). A seismic body is placed against a spring so it will experience a changing compressive force. This produces a varying charge at the quartz. This signal is processed by a charge amplifier and other electronics to produce an output as shown in Figure V/2.1.3-1d. This a self-generating system. In view of this, it can be considered as a variable capacitance with a variable voltage. The charge $q = P*a*K$—where q is the charge developed due force P, K is spring constant for displacement (m/N), and a is material constant—depends on material, geometry of the crystal, and position of the electrodes. Now P in a spring is proportional to displacement X_i, so $q = K_q*X_i$, where K_q is the overall constant (see Figure V/2.1.3.1-1).

The most common quartz is lead zirconate titanate "($Pb[Zr_xTi_{1-x}]O_3$; $0 < x < 1$ are also known as PZT (ref Wikipedia). PZT is temperature dependent for charge sensitivity and capacitance value. It is a self-generating device with a high source impedance. Signal conditioning

www.EngineeringBooksPDF.com

TABLE V/2.1.2.2-1 Velocity Sensor(Seismic) Data Sheet: All are Typical Values

Sl	Specifying point	Standard/available data	To be specified
1	Frequency response	0-(−)3 dB for minimum to 15 kHz	
2	Frequency range	±2.5 to 10 kHz	Choice of span
3	Electrical connection type and orientation	Terminal block/coaxial connector (copper/silver-plated brass) and top or side	
4	Mounting angle	0/(±)45/135/180, etc.	Choice of angle
5	Mounting base	Circular/rectangular/isolated plate	
6	Agency approval	API 670 Standard/ISO 10816/ISO 7919/European CE marking/IEC, etc.	To be specified as per project standard
7	Mounting	Screwed/as per base selected	
8	Operating temperature	Up to 200°C	
9	Humidity	95% RH	
10	Casing/adapter	Anodized aluminum	
11	Sensitivity	25 mV/mm/sec to 4 V/mm(frequency > 5 Hz)	
12	Probe dimension	Manufacturer standard	
13	Output	Voltage for continuous monitoring (linear)/for switch: contact type, number, and rating	
14	Lead wire	100/300 m available	
15	Transverse sensitivity	±10%	
16	Field wiring	Standard triad cable	
17	Enclosure	IP 67/65, etc.	
18	Hazardous class	To specify (intrinsic safety ATEX, etc.)	As applicable

is done by charge amplifier as typically shown in Figure V/2.1.3-1c. The output voltage is proportional to displacement so it is also linear with force or acceleration. Sensitivity is expressed in terms of charge per unit acceleration (pC/g or mV/g).

2.1.3.2 Accelerometer: Seismic Probe

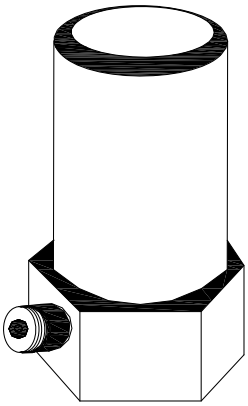
1. Three zirconate titanate elements used as piezoelectric material may be placed in delta as shown in the drawing.
2. Clause 2.1.2.1, items 5 and 6 also are applicable here.
3. Some of the special features preferred in selecting this system include but are not limited to the following:
   - **a.** *Two-wire configuration*: The transducers are available in a two-wire configuration with linear output.
   - **b.** *Power supply*: 24V DC for standard configuration.
   - **c.** *Minimum frequency range*: Up to 15 Hz frequency range is available on the lower side.
   - **d.** *Compliance*: With requirements of API 670 Standard/ISO 10816/ISO 7919/European CE marking/IEC, ATEX, CSA, etc. Hazardous application possible.
   - **e.** *High temperature*: Transducers available to cater to temperatures up to 200°C.
   - **f.** *For ordering*: The specifications to include desired Information on the following:
     - **i.** Mounting thread/stud details
     - **ii.** Agency approval
     - **iii.** Cable length and type
     - **iv.** Details of accessories
     - **v.** Electrical connection
   - **g.** *Application*: Casing vibration in acceleration and velocity

Typical values for a number of accelerometers are listed in Table V/2.1.3.2-1.

2.1.4 Application Note

1. *Bearing vibration (radial vibration)*: Turbine, BFPT, indirect draft (ID)/forced draft (FD)/primary air (PA) fans; applicable probe choice to be specified based on the previous discussion. Proximity type also may be a choice.

www.EngineeringBooksPDF.com



(COURTESY BRUEL KJER)

FIG NO.V/2.1.3–1a ACCELERO METER

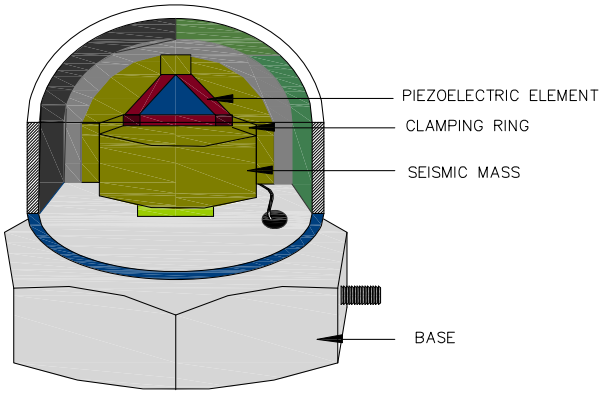


FIG NO.V/2.1.3–1b INTERNAL DETAILS OF ACCELARO METER (PIEZO ELEC TYP)

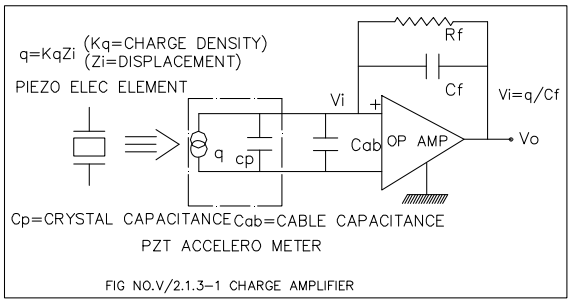


FIG NO.V/2.1.3–1 CHARGE AMPLIFIER

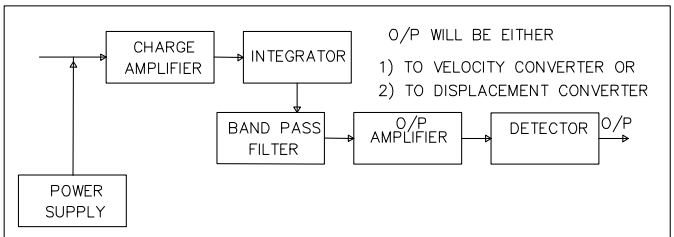


FIG NO.V/2.1.3–1d BLOCK DIAGRAM OF ACCELERO METER MEASURING SYSTEM

1) VIBRATION MEASUREMENT BY ACCELEROMETER IS NORMALLY USED FOR HIGH FREQUENCY VIBRATION MEASUREMENT
2) PIEZOELECTRIC TYPE ACCELEROMETER MAY BE SHEAR TYPE, COMPRESSION TYPE & BENDING TYPE.
NORMALLY COMPRESSION TYPE IS MOSTLY USED AND SHOWN HERE.

FIGURE V/2.1.3-1 Accelerometer details.

Charge amplifier: Charge amplifier (shown in Figure V/2.1.3-1c) is used to minimize the capacitance effect of cable. Since operational amplifiers have very high input impedance, current through the feedback circuit is due to V_i to produce output V_o. With integrating operational feedback, output is integral of input current, which is the charge, so it is called a charge amplifier. In negative feedback OP Amp amplifier, $V_o / V_i = - Z_f / Z_i$ Where $Z_f = C_f$ and $Z_i = C_p$ parallel C_{cab} or $Z = C = C_p + C_{cab}$ so $V_o / V_i = - C / C_f$ $(z = 1/\omega C)$.

Therefore $V_o = - C / C_f * V_i$ or $V_o = - C / C_f * q/C$ or $V_o = -q / C_f$ or $V_o = K_q X_i / C_f$ (since $q = K_q * X_i$).

Thus it is seen that

- **O/P voltage is linearly related to displacement caused due to acceleration.**
- **O/P changes instantaneously with I/P without distortion.**
- **Sensitivity, K_p, and time constant are independent of cable capacitance and C_p**
- **Disadvantage: It has a lower S/N ratio and natural frequency is lost due to loss of stiffness. Also in practice the feedback capacitance has some resistance (not considered in the calculation), which would have some minor impact on the amplifier performance. Normal value of C_f is 10 to 10^6 pF and Rf 10^{10} to 10^{14}. Ω could be a better choice.**

FIGURE V/2.1.3.1-1 Charge amplifier.

www.EngineeringBooksPDF.com

TABLE V/2.1.3.2-1 Accelerometer Data Sheet: Typical Values

Sl	Specifying point	Standard/available data	To be specified
1	Frequency response	±2dB for minimum to 15 kHz	
2	Frequency range	±2.5 to 15 kHz	Choice of span
3	Acceleration range	490 m/sec^2 for frequency range up to 15 kHz	
4	Linearity and noise	±1% within range, noise: 0.039 m/sec^2	
5	Transverse sensitivity	<4–5%	
6	Magnetic sensitivity	0.4 g/Tesla	
7	Temperature	−55 to 250°C (high temperature)	
8	Humidity	>93%	
9	Shock peak to peak	5000–20,000 g	
10	Capacitance	1200 pF(typical value)	
11	Cable length (m)	Up to 350	
12	Grounding	Isolated from case to case	
13	Mounting stud	Manufacturer standard	
14	Cable connection	Manufacturer standard	
15	Case material	304l SS/manufacturer standard	
16	Accessories	Mounting base and others	To be specified
17	Agency approval	API, CE marking, hazardous etc.	As applicable

2. *Casing vibration*: Turbine, generator, BFPT, etc.; seismic, velocity, or accelerometer (with or without integrator) as required for specific parameters to be measured.
3. A typical guideline for choosing a sensor based on frequency. The choices include: displacement, velocity, acceleration, 0–200 Hz (eddy current), 2–20 kHz (electromagnetic), and 0 to >20 kHz (piezoelectric).

2.1.5 Machine Health/Condition Monitoring System

Almost all major monitoring systems available commercially from reputed manufacturers are not only meant for vibration but are commonly used for vibration and other related systems, such as KP, speed, DE, eccentricity, etc. In the following clauses, discussions are presented regarding common machine health monitoring systems (Figure V/2.1.5-1).

2.1.5.1 Concept of Monitoring and Analysis

In power plants any severe condition of the turbine can cause a complete trip of the plant. Also failure in other major auxiliaries such as FD/ID/PA fans and BFPs would result in drastic reduction or complete stoppage of generation. Higher protection strategies such as SIL3 or API 670 standards are prescribed to protect these machines. With suitable machine conditioning and analysis systems, it is possible to predict such failures and in most cases preventive action can be undertaken to avoid such catastrophic situations. Monitoring gives the ability to record and identify the "vibration and allied parameter signature." This makes the technique very powerful. Some of the features of condition monitoring include the following:

- Complete mechanical health monitoring and feedback to be integrated with the main control system. Apart from vibration, there will be flexibility in accommodating other parameters like DE, eccentricity, speed, KP, etc.
- Generation of predictive alarm based on analysis
- Internal/external intrinsic safety (as applicable)
- Provide suitable display
- High accurate and high sensitive transducer (e.g., 0.1 mV/measuring unit or better)
- Communication gateway and software support, e.g., MODUS communication over standard link or Ethernet support, etc.
- Normal alarm and trip based on protection standard (such as API 670/SIL1 or SIL3)

www.EngineeringBooksPDF.com

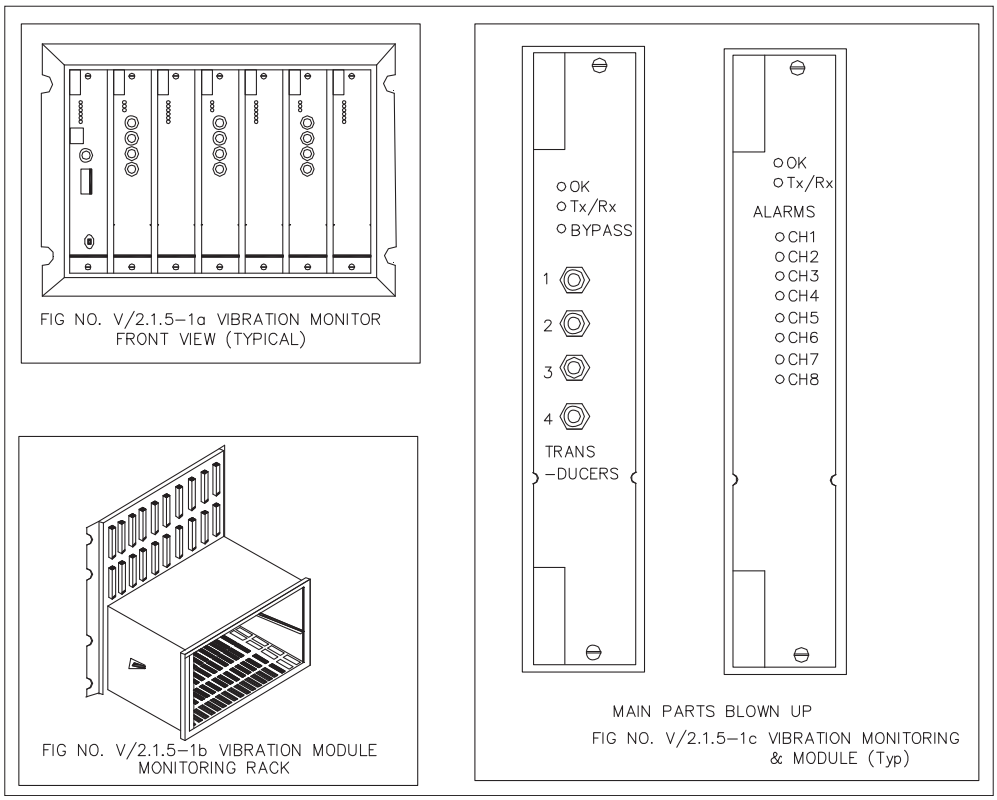


FIGURE V/2.1.5-1 Vibration monitoring system.

2.1.5.2 Condition Monitoring System Components

Commercially there are several variations of machine health/condition monitoring systems (see Figure V/2.1.5.2-1). However, basic functional components or subsystems in almost all them include the following: instrument rack, power supplies, rack interface module, communication module, monitoring modules, relay module, display module (PC compatibility), safety barrier (if any), supporting software, and networking capability (if any). This is discussed in greater depth in the following clauses.

1. *Instrument rack*: A basic rack where various modules are housed that could be connected to each other using a back plane connector.
   - **a.** *Standard available*: 19" EIA rail mounted rack
   - **b.** *Various I/O module mounting*: At the rear or one above the other
   - **c.** *All modules connection*: Back plane connector
   - **d.** *Enclosure*: NEMA 4X (IP 66) available for field application
   - **e.** *Layout in the rack*: Manufacturer standard
2. *Power supply*: This is essential for all manufacturers. Features include:
   - **a.** Standard AC (/DC) supplies compatible with standard instrumentation power supplies of the country in voltage as well as frequency.
   - **b.** Line protection and noise filter are standard
   - **c.** Dual supplies are available in many designs with the same or different voltage. However, with the same voltage a different source is preferred.
   - **d.** In case of redundant sources, one is always primary while the other is a back-up with changeover facility.
   - **e.** Self-testing facilities of power supplies to ensure correct voltage.

No of modules, I/O channels, communication modules, and their relative disposition in the instrument rack are purely based on manufacturer's design. In reality these may vary WRT to description here. This is general guidelineonly, based on data from a reputed manufacturer.

FIGURE V/2.1.5.2-1 Condition monitoring system guideline.

www.EngineeringBooksPDF.com

3. *Rack interface function (the first interface of the system)*:
   - **a.** For functionally there is an interface to the configuration, display, and monitoring software.
   - **b.** Configuration software actually configures the rack, while display software retrieves data from the rack for display.
   - **c.** It may supply a self-monitoring feature as well as one for the entire rack, even if provided by any module.
   - **d.** There may be several LEDs to indicate various functions, such as OK (health) and transmitting/receiving mode: T_x/R_x (courtesy: B&N module).
   - **e.** Entire rack configuration can be done from this module with the help of any portable configuring unit. There may be some security level (may be hardware as well as software) to configure the rack.
   - **f.** It can provide permanent connectivity as well.
   - **g.** There may be a dedicated module for this function (courtesy: B&N module) or it may be a functional part of any other module.
4. *Communication module*: It is the gateway in the rack to digitally transfer the vibration data and status to the outside world, e.g., to the DCS. The function of this gateway module is to support a number of industry standard links and protocols (e.g., RS 485 and MODBUS protocol; Courtesy of 6600 Series of Entek by Rockwell). Based on the importance, redundancy can be incorporated in the communication channel. For assessment of communication capability, the baud rate and distance (of communication), communication channel traffic mode, and rush of traffic can be used. Also, the communication module should be designed in such a way that it does not interfere with the monitoring system and other functions. Support of the Ethernet, wireless, and serial links are important features.
5. *Monitoring module*: In power plant condition monitoring system there are a variety of modules supporting measurements of various kinds and number of channels in each of the modules. Many channel types provide advanced datasets, e.g., gap voltage/filtered voltage, etc., in addition to the amplitude of vibration. Some of the modules may provide buffered output (4-20 mA) at the module. Some of the modules are capable of providing data like frequency response of the channel. These parameters from the various modules are available commercially and they are used purely as per manufacturer's standard (e.g., 3500/40M of Bently Nevada has four channels to include different parameters or 3500/42M provides buffered output; Courtesy B&N). Monitoring modes have been seen in many standard power plant specifications that calls for measurement of both velocity as well as displacement. A probe (seismic or proximity type) needs to be provided, and others may be found by signal conditioning.
6. *Relay module*: Relay modules provide relay contacts necessary to generate alarms and for tripping. These relay modules, in conjunction with supporting software, provide simple relay output to very complex logic sequences. It may be a simple danger output of a particular channel or it could be a Boolean logic expression combing various channels in AND OR logic. The type and number of contacts and current rating of the relay module may vary with manufacturer. These relays may be used to trip equipment, such as tripping a turbine from over speed, so redundancy may have to be built in. Generally TMR relay modules are deployed for SIL3 protection (TUV certified); (e.g. ref Figure V/2.1.5.2.6-1).Other standards include the API 670 system. While selecting these relays or any other module, authentic certification from a concerned authority is necessary. These relays may be used directly to trip the system.
7. *Display module*: Currently several display choices are available. Some of these displays are LED/back lit LCD/back lit high-resolution dot matrix VGA/laptop or computer displays. Except laptop type displays, these can be mounted on the front of the monitor or can be put in a cabinet some distance away from the monitor. These displays can be used in configuring the system, to monitor the status of various channels, bar graph display with text for parameters, etc. Distance limitation is based on the type of link it has with the system. Also, there could be a separate workstation attached to it, or a laptop or other PC can be hooked up to the system with necessary supporting display software. Based on the requirement, these display systems may have suitable authority approval for hazardous applications.
8. *Safety barrier and isolation*: For applications where transducers are located at hazardous locations, an intrinsic barrier (e.g., as an offsite of a refinery) needs to be located at the safe zone. Generally for such cases external barriers are used. There is not much application for this in a power plant; however in many places it is necessary to have some galvanic isolation. In most

FIGURE V/2.1.5.2.6-1 Note on SIL for condition monitoring.

For example "FS" category of Bently Nevada 3500/53 module has SIL3 protection. Similarly 3500/42, 40M, etc., both have SIL 1 for case vibration and SIL3 certifications for over speed. –For these one needs to consult the manufacturer's catalog.

www.EngineeringBooksPDF.com

cases external isolators are used in conjunction with the monitoring system.

9. *Supporting software system*: Today, almost all monitoring systems are the intelligent type (even up to the card level). Most manufacturers have their system software to support their system and making it capable of communicating with a main DCS. "Plant WEB" from Emerson and 6600 series monitoring system from Entek (Rockwell) are examples of this. Apart from module configuration, there is system software for display management, control configuration, etc. Alarm management, self-diagnostic functions, prediction control software, communication software, etc., are all supporting software systems. Power predictive analysis tools, priority assignment, history data management, graphic support (GUI) etc., are results of system software support. Display support software also decides on data capturing and display strategies.
10. *Networking capability*: Some commercially available monitoring systems have the capability to support networking. Many DCS suppliers have in their systems OPCs (ref: Chapter VII) to support direct integration with the main network. With predictive intelligence, a monitoring system in a networking environment allows the operator to track the condition of the machine at all operating conditions.

2.1.6 Machine Vibration Analysis System

Vibration analysis is useful tool for performing a number of functions including:

1. Usefulness of vibration analysis:
   - Evaluating machine condition
   - Diagnosis of machine fault at various operational condition
   - Monitoring and trending of machine conditions over time and prediction of fault
2. Some of the methods are
   - *Casing vibration*: This gives the permissible limits if a machine crosses limit and is not permitted to do so. Through analysis this condition can be checked.
   - *Radial vibration*: This enables detection of a fault in the rolling element of the bearing. There are software programs by which the bearing fault condition and vibration at the surface can be detected and analyzed.
   - *FFT*: Mathematical algorithm for transforming the vibration in time domain to frequency domain. Amplitude versus frequency is useful for fault recognition. Power plants use data from either peak or RMS in time domain. Unless the fault has advanced, changes may not be noticed, whereas a frequency domain signal not only registers the problem at an early stage, it also predicts the fault. It is used to detect faults like misalignment, unbalance, or eccentric component. For such an analytical approach FFT and bearing condition spectrum need to be implemented on a periodic basis (e.g., monthly). Digital signal processors are used to analyze various vibration parameters that are collected periodically.
3. *Standards*: Standards like VDI 2056 are available to assist this analysis program.
4. Portable FFT analyzers are used in many plants where, on a daily basis, data are collected and stored. This also may be used to analyze and predict a fault.

See Table V/2.1.5.4-1 for a data sheet on machine condition monitoring.

2.2 Other Turbovisory Instruments

The basic scheme for steam and gas instruments (turbine supervisory instruments; TSI) was presented in

TABLE V/2.1.5.4-1 Machine Condition Monitoring: Analysis System Data Sheet (Typical)

Sl	Specifying point	Standard/available data	To be specified
1	Instrument rack size	Based on manufacturer's data, specify if any depth limitation	
2	Orientation of modules	Top/bottom, or in wider rack based on layout space available	To be specified
3	Termination	Extension marshaling/back of rack	
4	Power supply	Single/dual, AC, DC voltage, frequency to be specified.(to specify additional power)	
5	Configuration	1. Method of configuration, rack interface module if any. 2. Configuration means, from front or any other place, any security protection 3. Security level	

Continued

www.EngineeringBooksPDF.com

TABLE V/2.1.5.4-1 Machine Condition Monitoring: Analysis System Data Sheet (Typical)—Cont'd

Sl	Specifying point	Standard/available data	To be specified
6	Communication	Types of links and protocols Other like wireless communications If any, network support to specify Please specify the redundancy in communication channel if any	
7	Module types	Whether single or multi measurement type; number of channels allowed	
8	Output	Analog output if any, also from which channel and available where	
9	Status indication	Healthy status LED, T_x, and R_x on during communication Alarm LED, transducer LED	
10	Relay module	Number of channels, status indication of each	
11	Software	Configuration, display support, analysis software, FFT, and other mathematical support software	
12	Grounding	Isolated from case to case.	
13	Display options	Type and area of display, lines of display, information for display	
14	Standard (as applicable)	SIL3/SIL1, API 670, etc., to be specified	
15	Authority certificate	TUV For SIL3 and others for hazardous area, if any	
16	Intrinsic safety/ isolation	If required please specify and specify method, e.g., external or internal	
17	Environmental condition	Ambient temperature, humidity, etc.	To be specified
18	Other special feature		To be specified

Figures V/2.0.5-1 and V/2.0.5-2. Normally all of these form a part of the integral instrumentation package of the turbine. Short discussions on the various requirements of the instruments and application notes are presented below.

2.2.1 STG TSI Specification

While specifying TSI for STGs, the following requirements should be considered.

1. TSI, a part of the steam turbine condition-monitoring system, should be one complete package including sensors, transmitters, converters, limit value monitoring (alarm/trip) amplifier and other signal-conditioning and analysis module, power (dual) supplies, and all special cables and junction boxes as terminal point.
2. A list of TSIs for medium to large size plants were presented in Table V/2.0.5.1-1. Actually TSIs are per manufacturer's recommendation mainly in consultation with the owner's representative. Also redundancy criteria should be considered for individual measurements.
3. TSI system(s) should be provided with all necessary suitable hardware and software so that the system is able to distribute the signal within the system as well as establish communication with the main DCS.
4. For metal temperature measurement, duplex (or two simplex) RTD 100 Ω at 0°C or ISA type K (e.g., in KWU turbines thermocouples are mainly used) should be deployed.
5. Other common sensor types used are
   a. Proximity type sensors (Clause 2.1) are used for radial vibration, axial/TP, DE, and eccentricity.
   b. Seismic probe (velocity type piezoelectric; Clause 2.1) for absolute vibration at casing block.
   c. LVDT type for casing Expansion and valve position; LVDT are available in different ranges. For details about casing expansion and valve position monitoring systems, see Clauses 2.2.3 and 2.2.4.
   d. Hall probes are commonly used to measure the speed in a turbine (e.g., KWU turbine).
6. Systems are intelligent enough to cater to the following requirements:
   a. Data storage for analysis
   b. Online/spectral/harmonic analysis
   c. FFT analysis

www.EngineeringBooksPDF.com

   d. On-site calibration and configuring facility
   e. Software support for configuration, display, and communication
7. After Studying catalogs of various systems, it is necessary to specify the system based on the generalized requirements listed above.
8. Sometimes there are separate system monitoring cum analysis systems specified for utility stations. These intelligent systems may operate independently but have the capability to communicate with the main control system and TSI systems. These systems are capable of diagnosing machine faults by suitable monitoring and analysis, so that operator can take preventive action prior to the actual fault. System monitor and associated software support should include the various features discussed in item 6 above and also support the following features:
   a. The offered system needs to meet the reliability requirements specified in API 670 or better. For protection the requirements of SIL3 need to be met. Also certification from a competent authority (e.g., TUV) is necessary.
   b. There should be high overall system accuracy (e.g., typical values 0.01 mV) as per the project standard.
   c. The intelligent module may accommodate a number of channels with a mix of different kinds of measurements in one module.(e.g., ProvibTech PT2060/10).
   d. All of these modules should have the capability of digital signal processing and are easily configurable/programmable with the capability to communicate with the other systems. It is possible to integrate the two systems seamlessly through suitable networking.
   e. Systems normally provide suitable relays with redundancies for protection inputs and have redundant power supplies.

2.2.2 Smaller Utility Turbines or BFPT TSI Specification

Possible measurements for smaller turbines and/or BFPTs are listed below:

1. Axial shift—TP (minimum of two sensors)
2. Triple redundant speed measurement
3. Over speed protection
4. Differential Expansion
5. Casing overall expansion
6. Control valve position
7. Bearing radial vibration (orthogonal sensors)
8. Casing vibration (if recommended)
9. Bearing and casing metal temperature
10. Possibility for integrating with DCS

2.2.3 Casing Expansion

This was previously discussed, but now discussions will include measurement principles, installation.

1. The turbine shell is anchored at one end to the foundation, and the other end is allowed to expand due to thermal expansion. As shown in Figure V/2.2.5-1a and b, the LVDT is used to measure casing thermal growth. The body of the LVDT is designed to be attached to the turbine foundation, whereas a spring-loaded roller is pressed against a bracket attached to the turbine case. The roller tip of the plunger is allowed to ride freely without creating any problems with the turbine operation. Considering the convention of instrumentation, as the plunger goes in to the LVDT the body signal output will grow. Depending on direction of installation of the LVDT, when there is thermal expansion of the casing, either positive or negative, the signal in the LVDT will increase (in the Figure V/2.2.5-1a the positive signal will increase).
2. LVDTs (see any standard instrumentation/sensor textbook) are electromagnetic devices with three coils, as shown in Figure V/2.2.5-1b, on a hollow tube. The primary coil is excited with supply voltage, which on account of induction, will induce voltage onto the secondary coil as the plunger moves in and out of the hollow tube. Secondary coils are so wound that as the plunger is in the center the induced voltage in both coils is the equal in magnitude but opposite in sign so that net voltage across the secondary coil (in differential mode) is zero. As the plunger goes in either direction, there will be an increase in one of the secondary coils, and decrease in the other one and we get a voltage across the secondary coil. LVDT can be AC or DC type. AC has some carrier voltage for operation.
3. Casing expansion specification (standard specs for guidance only):
   a. *Operating range*: 0—25/50/100 mm
   b. *Core magnetic material*: (Ni-Fe core common)
   c. *Scale factor*: 0.14/.34/.4 V/mm
   d. *Linearity*: 0.5% full-scale division (FSD)
   e. *Stability*: 0.12% FSD
   f. *Environmental condition*: (−)18 to 80°C, 0—93% RH
   g. *Ordering information*: Linear range/scale factor, spring action

2.2.4 Valve Position

Correct valve position is necessary for efficient operation of the steam turbine. Potentiometric and LVDT are the most common methods deployed to generate such signals. Potentiometric is where a standard resistor can be supplied

www.EngineeringBooksPDF.com

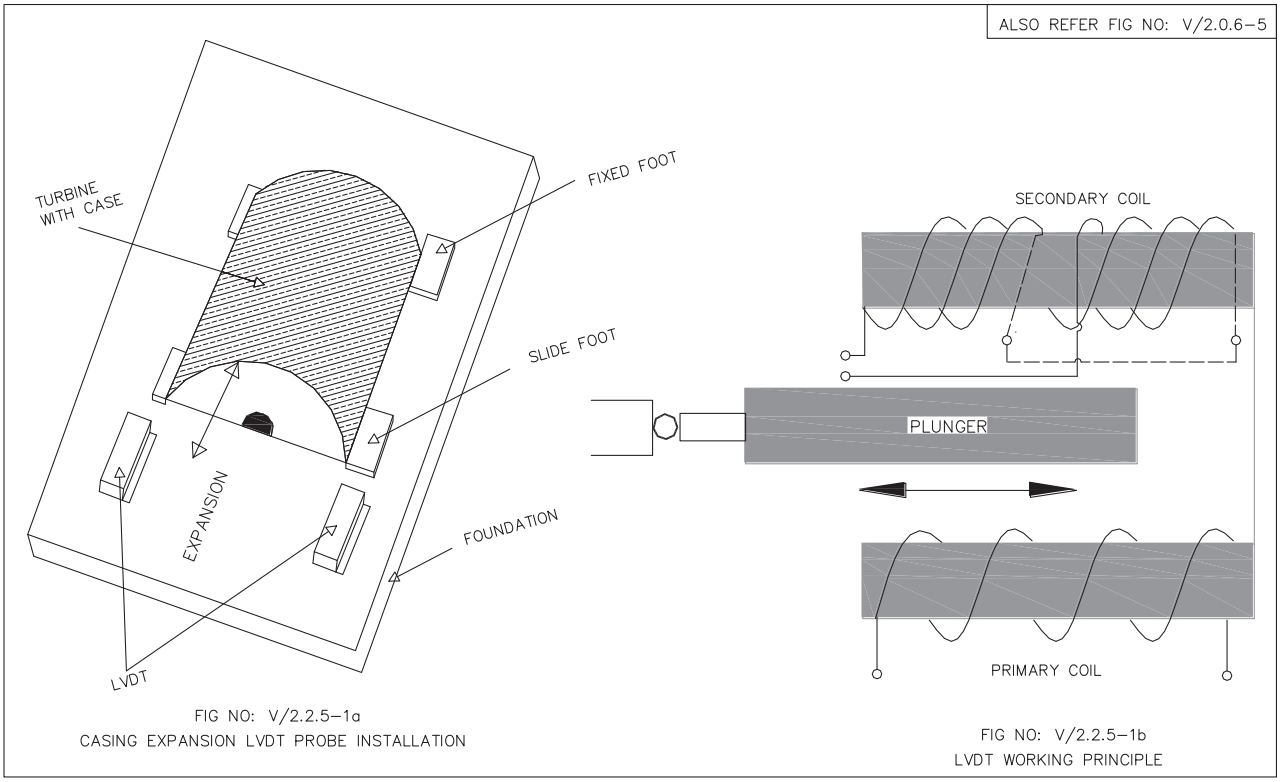


FIGURE V/2.2.5-1 Casing expansion LVDT probe installation.

with a constant voltage and as the valve changes position, the slider across the resistance changes and there will be a change in output voltage. With the help of a V/I converter the standard 4-20 mADC can be achieved. Valve position transducer specification is also available in chapter VI. Another type of valve position transducer used, the AC LVDT type, is discussed above, where the rod inside the LVDT body moves as per valve position.

LVDT valve position sensor specification for TSI application (a standard spec, for guidance only) is listed below.

1. *Type*: Single or dual AC LVDT
2. *LVDT internal core*: Magnetic material (Ni-Fe core common)
3. *Core connecting rod material/length*: To be specified (aluminum with length 6−15″ standard available)
4. *Linear range*: To be specified (available 25−500 mm)
5. *Linearity*: 0.25% or better
6. *Environmental condition*: T = (−)50 to 150°C, 93% RH
7. *Ordering information*: Application, length of rod, and linear range

2.2.5 Application Notes on Installation

1. *X-Y vibration*: In a shaft perpendicular to it is called radial vibration, and the sensors are placed orthogonally. Sometimes probes are installed inside the machines with a probe clamp as shown in Figure V/2.0.6-2b and c. In these cases adjustable penetrations are available (courtesy: ProvibTech sensors).
2. *Thrust measurement*: Proximity probes are mounted in the fixed casing structure, and the probe is used to measure the movement of the thrust collar as shown in Figure V/2.0.6-4. In power plant practices two or more probes are installed for this as it is a very critical measurement. The probes can be located one on each side or on the same side.
3. *Absolute casing vibration*: Seismic probe velocity or accelerometer are used for this purpose. For casing vibration measurement probes are mounted in horizontal and vertical axes as shown in Figure V/2.1.2-1d.
4. *Phase reference*: As shown in Figure V/2.0.6-3 magnetic or optical pickups are used to detect the marking in the shaft for phase reference.
5. *DE*: Similar to TP, It measures the axial position of the rotor with respect to the casing. These measurements are also done by measuring the gap between the collars and the proximity sensors fixed at the casing as shown in Figure V/2.0.6-9. This can be measured utilizing the ramp of the shaft as shown in Figure V/2.0.6-9. This is more important at the time of start-up and at the time of shut down when there is a change in expansion between the rotor and the casing.

www.EngineeringBooksPDF.com

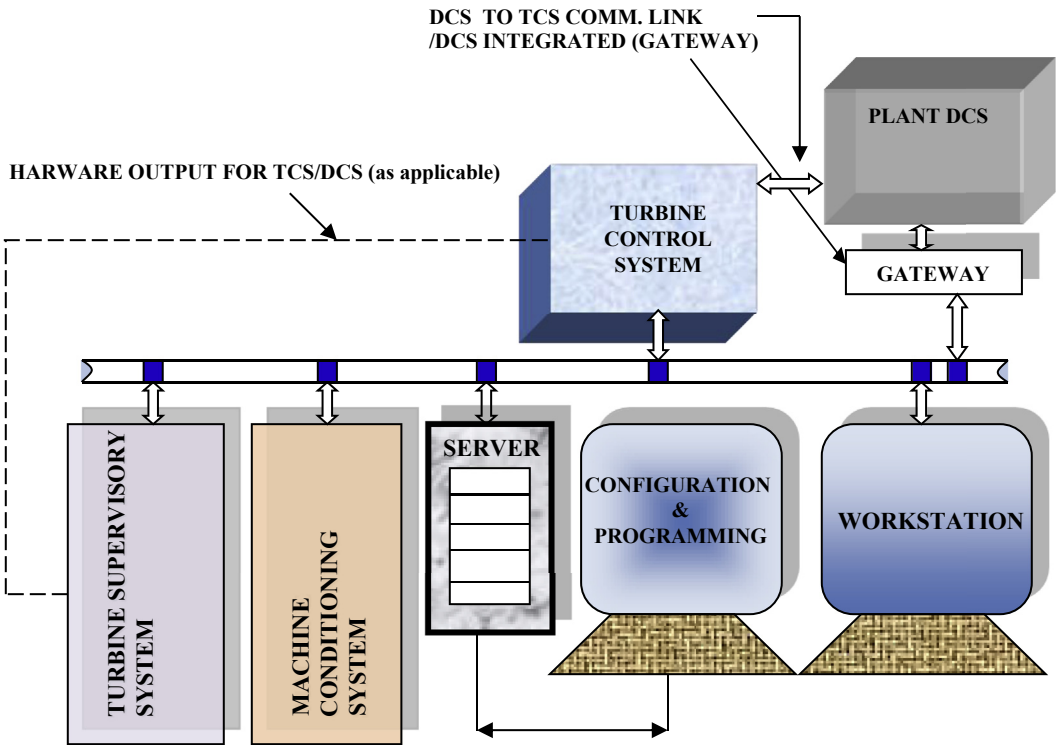


FIGURE V/2.2.6-1 Turbine supervisory system configuration (typical).

6. *Casing expansion*: As discussed previously and shown in Figure V/2.2.5-1a, the body of the LVDT is fixed with the foundation, whereas the rod is touched with the sliding foot of the casing. The casing expands or contracts during start-up and shut down. The position of the rod/plunger is used to measure the casing expansion/contraction.
7. *Eccentricity*: As discussed earlier, eccentricity indicates the deviation of shaft center from the center of the journal bearing. This bow type can be fixed mechanical (within limits), temporary thermal, or gravity. This deviation has to be very minimal so that the start-up can be done without much damage to the turbine. As shown in Figure V/2.0.6-8, there will be two proximity pickups set orthogonally to measure the positive and negative extreme of the bow of the shaft; their difference will indicate the eccentricity with which the operator decides the time of slow rolling and heating to remove the eccentricity.

2.2.6 System Configuration

Generally this condition monitoring system forms a part of the TG package, so that the turbine control system (TCS) can be configured in a common system network (see Figure V/2.2.6-1). The sensor outputs are connected to the monitoring modules, which today are generally intelligent types. The monitoring and analysis systems are also intelligent and could reside in the same network as that of the TCS. Also most of these monitoring and control systems offer hardware analog and relay outputs so that the TCS can receive hardware signal as well. TCS and the main DCS may be integrated and then these can be in the same network through the Ethernet, etc. Other machine conditioning systems may be integrated into the same network.

3. GAS ANALYZERS

3.0 Gas Analyzers for Power Plants

3.0.1 Gas analysis requirements and types

1. *Basics*: In thermal power plants the chemical energy of fuel is converted to the thermal energy of steam, which is converted to kinetic energy in turbines acting as prime movers to generate electrical energy. Overall conversion percentage efficiencies in power plants include: subcritical 30-40, supercritical (SC) 40–45, and ultra supercritical (USC) ~50.

   By utilizing various techniques such as using oxy-fuel technology, SC/USC plants with IGCC 55%efficiency is achievable (see Figure V/3.0.1.2-1). All of these technological developments also help to lessen pollution due to CO_2, NO_X, etc., to a great extent (in oxy-fuel technology NO_X emission is almost zero).

www.EngineeringBooksPDF.com

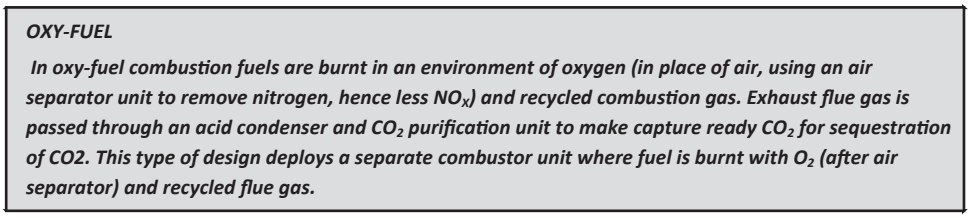


FIGURE V/3.01.2-1 Oxy-fuel.

Waste gas generated in power plants cannot be released directly to the atmosphere without purification. Analysis of flue gas plays an important role not only in increasing efficiency of the boiler, but also in maintaining the outside air quality within limits. In modern power plants, in addition to the de-dusting plants (e.g., electrostatic precipitator; ESP), desulfurization and de-nitrification plants are also installed. These new plants, in addition to controlling pollution, could also offer commercial benefit to the plant owner (e.g., production of gypsum from the desulfurization plant). Also to get the maximum benefit in terms of efficiency, it is necessary to optimize vol% of oxygen (excess air) in flue gas. Therefore it is can be argued that gas analysis in power plants is necessary for combustion control to prevent hazards (e.g., CO in ESP) and for maintenance of atmospheric air quality (e.g., NO_X, SO_X, particulate monitoring, etc.). Apart from these, there are other types of gas measurements involved in power plants, e.g., H_2 purity measurement in the TG is required to get better efficiency from the TG. Therefore the basic objective of gas analyzers are

- To improve economics—efficiency (optimization of excess air)
- Eliminate man and machine hazards (CO measurement in ESP)
- Environmental protection (to regulate emission of particulate, greenhouse gas CO_2, NO_X, SO_2, etc.)

2. *Flue gas purification*: Optimization of oxygen, use of low NO_X burner, etc., are a few methods under taken in modern power plants to improve efficiencies and reduce pollutions. Contrary to the above, de-dusting, desulfurization, and de-nitrification are major post-combustion steps in the modern power plants used to purify flue gas before it is discharged.
   - *De-dusting*: Dust collectors, bag dust filters, and ESPs are the normal way to de-dust flue gas. Out of them ESP is the most popular. It works when an action of force on charged particles in an electric field is used to remove dust (see Chapter II, Clause 10).
   - *Desulfurization*: For removal of SO_X, desulfurization plants based on liquid purification are mostly used. The core of such a plant is spraying of limestone water to form gypsum and thus removeSO_2 (see Chapter II, Clause 10.3).
   - *De-nitrification plant*: Selective catalytic reduction (SCR) process is commonly used to remove NO_X (see Chapter VIII, Clause 10.3). During removal of NO_X ammonia is formed and exact metering of NH_3 is very important.
3. *International standard*: Coal-based power plants rank top in air pollution. All countries have started setting target to reduce emission level for green house gas and other polluting gases (e.g. USA has already set tough target for future directly impacting thermal power plant). Environmental Impact Assessment showed that because of pollution created in large combustion plants, there have been serious impacts of various constituent matters on the air quality. For thermal power stations, suspended particulates, oxides of sulfur (SO_X), oxides of nitrogen (NO_X), and carbon dioxide (CO_2) are the major pollutants. Clear Act 1990 raised concerns over trace concentration metals in flue gas from power plants and other places. Now traces of heavy metals, particularly mercury, are also monitored. International standards specify the emission limits and methodology for monitoring the pollution constituting items. In Europe a 2001 directive 2001/80/EC came into effect concerning large combustion plants. The European Committee for Standardization caused the Comité for Eurpéenne de Normalisation (CEN) to be created. Some of its features include:
   - Stricter measure for particulates and limit of SO_2 and NO_x.
   - Monitoring of Hg (solid fuel), Total Organic Carbon − TOC has been introduced.
   - Mandatory use of EN 14181 and EN ISO 14956.
   - EN14181is "Stationary source emission—Quality assurance of automated measuring systems," which provides guidelines concerning features of automated measuring instruments, their installation, and maintenance. The quality assurance levels for such instruments are
     - *QAL1*: Suitability of the measuring instruments for the task. As per ENISO 14956.
     - *QAL2*: Drift control.
     - *QAL2*: Installation, calibration, uncertainty, etc.

www.EngineeringBooksPDF.com

- ENISO 14956 deals with definition of suitability of an automated measuring system and procedural details.
- Some of the other international standards/certifications followed are UK, MCERT; United States, EPA requirements; Japan, JIS.

Limiting value and associated range of instruments, meant to monitor these air polluting gases in thermal power plants, varies with standards as well as with type of fuel (solid/liquid gas, etc.; see Table V/3.0.1.3-1).

4. *Various gas compounds*: Major gaseous compounds generated during combustion of fuel (coal) include:
   - *CO*: Generated mainly due to incomplete combustion. Can be minimized by regulating excess air. This also accounts for system loss; it is always desirable to keep the stoichiometric ratio at a value where CO generation is at a minimum. Practical achievable minimum value could be $\sim$50 mg/m^3.
   - *CO_2*: Formed because of complete combustion of carbon in excess air. Apparently this is not harmful, but has a greenhouse gas effect, hence, it needs to be lowered by capturing (see Figure V/3.0.1.4-1) and/or CO_2 sequestration (seizure). There have been several methods used all over the world to reduce CO_2 emission. CO_2 generation in SC and USC boilers is much lower than in subcritical boilers. The most popular technology to reduce CO_2 emission is oxy-fuel combustion, where oxy-fuel combustion cycle fuel is burned with oxygen in the presence of recirculated flue gas. In this cycle CO_2 is made ready for CO_2 capture. This method is auxiliary power intensive due to the O_2 separator.
   - *NO_X*: Oxides of nitrogen are formed during burning of fuel in air. Use of low NO_X burner reduces formation of NO_X. The addition of separate over fire air (SOFA) or closely coupled over fire air (CCOFA) dampers injects air above the combustion zone for complete combustion, while there will be low air in the burner zone (Lower than the stoichiometric ratio), so that the flame temperature is low and there will be less thermal NO_X as well as NO_X formation due to bonded nitrogen in fuel (see Chapter III, Clause 9 and Chapter VIII, Clause 10.3). The arch-fired burner approach (low volatile coal) of FWC, and ultra low NO_X approach of ALSTOM drastically reduces the NO_X formation. The most popular post-combustion methodology for removing NO_X from flue gas is SCR, where NH_3 reacts with NO and NO_2, so NH_3 monitoring needs to be done in addition to monitoring of NO_X.
   - *SO_2*: Sulfur content of coal forms SO_2 when coal is burned. The major part is SO_2; however, a part of SO_2 is oxidized to form SO_3, which may combine with water vapor to form H_2SO_4—alike cold end corrosion at the air heater (AH). SO_2 is major part so naturally SO_2 analyzers (UV or IR type) are used to monitor this polluting gas. Post-combustion flue gas desulfurization plants are deployed (see Chapter VIII, Clause 10.3) to get rid of SO_X.
   - Apart from the above heavy metals, currently after the Clean Air Act, trace elements like mercury and other heavy metals in flue gas are also monitored. Also NH_3, as stated above, is monitored.
5. *Oxygen analysis*: Air supply to the boiler ideally should exactly what is required for complete combustion, i.e., where stoichiometric ratio $\lambda = 1$. However, depending on the burner design, there may some places where the fuel may escape the main firing zone and remain without getting completely burned. This will give rise to the chances of formation of CO, which is explosive, especially when CO containing flue gas passes through the ESP where there will be electric discharges. To ensure safe conditions excess air is maintained to make sure there is complete combustion. Now there are two contradictory situations. If air is not in excess, there is a chance of incomplete combustion and the associated hazard. If excess air is more then there will be loss of heat due excess air going out with the flue gas. Also more excess air means more NO_X formation at a high temperature. It has been found that at the value of stoichiometric ratio λ is a little (slightly) >1, i.e., where CO is minimum is the optimum point. Also at this point concentration change of CO is maximum

TABLE V/3.0.1.3-1 Gas Components Limit and Range

Item	Limit value*	Expected range	Unit	Remarks
CO	150/100 (GT)	0–125/625	mg/m^3	*Lower for fuel:liquid and gas
SO_2	200	0–600	mg/m^3	
NO_X	200	0–300/1500	mg/m^3	*For GT 50 and gaseous fuel 100
Par#	97–100	0–200	mg/nm^3	#Par = particulate
Hg	0.1		µg/m^3	

The top three are in line with 13 FEPL Germany, whereas the bottom two are as per the EPA.

www.EngineeringBooksPDF.com

CO_2 capture means basically storage of CO_2 for future sequestration. Sequestration can be done by geo engineering, mixing with oil storage in the sea (as done in the North Sea), or by chemical means of formation of carbonate of metals from oxides of metals

FIGURE V/3.0.1.4-1 CO_2 capture.

(<100 ppm). The objective of oxygen trim control (Chapter VIII) of air flow control is to achieve that point. To have better control, fine tuning of the loop may be done through a CO analyzer (see Figure V/3.0.1.5a and b).

Calculation for excess air in % is rather easy, it is Excess Air in % = {(O_2 in %)/(21 − O_2 in %)}*100.

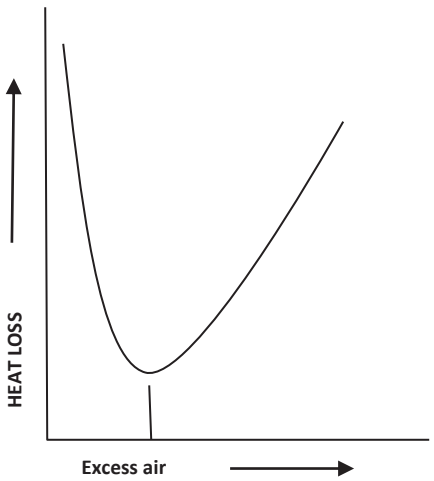


FIGURE V/3.0.1.5-1A Heat loss versus excess air.

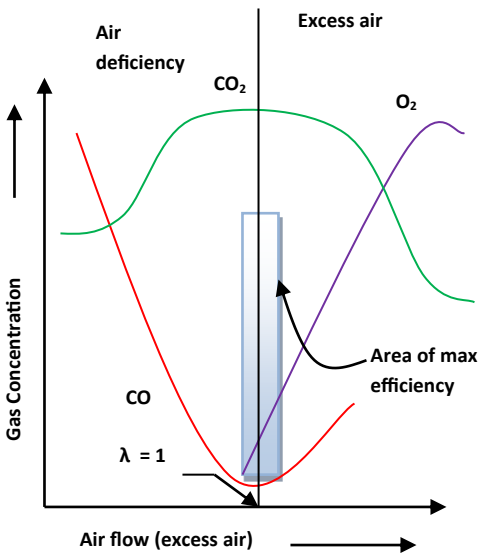


FIGURE V/3.0.1.5-1B Optimal operating point.

Although the area of maximum efficiency is shown around the vertical line (λ = 1), the overall operating point can never be on the left side of the vertical line as in that case there will be deficiency of O_2, which is unacceptable. So the operating point has to be only on the right side of the vertical line. This strategy is implemented in oxygen trim control by measuring O_2 by zirconia probe, which is an *in situ* type analyzer with moderate accuracy and excellent response time. Because of the following reasons, it is recommended that the zirconia probe be located at the economizer outlet in the flue gas path:

- AH leakage, especially in the Ljungstrom (regenerative) AH, is high so may not get a representative value, and the probe cannot be located.
- Oxygen probe can be placed near the combustion zone, but because of high temperature the proposition is very costly and instrument availability will be restricted. However to find air leakage in an AH, O_2 is measured at AH O/L.

6. *Gas Analyzing types*: Analyzers used for gas analysis include the following (see Table V/3.0.1.7-1):
   - *Extractive principle*: Where a gas sample is taken from the process flow. Here the analyzers are kept at a little far-off place. Samples are drawn from the duct by the steel (better to use stainless steel SS 316/320) sampling probe of nominal bore ∼20 mm. The number of such probes in a duct depends on duct size and gas stratification. If multiple probes are used, then there will be an automatic method to select the probes one after another. Prior to admitting the probe to the analyzer, the sample is conditioned and prepared. The gas is drawn up to the conditioning system with the help of a stainless steel tube—10 mm diameter could be optimum. This preparation means drying the gas by cooling so that moisture is removed. For dust removal, various kinds of filters are utilized. Ceramic filters are used to remove coarse dust while membrane filters are used for finer particles. Sometimes water mists are used to remove dust. Standard cooler and/or special coolers like electric coolers to bring down the temperature ∼2−5°C are used. Take-off points are also very important (e.g., take-off points should be pointing downward toward the duct so that dust can flow in to the duct due to gravity). The choice of sampling tube (after

www.EngineeringBooksPDF.com

TABLE V/3.0.1.7-1 List of Gas Analyzers in Power Plants (Typical)

Location	Mea	Range (typical)	Unit	Remarks/(purpose)
Economizer O/L	O_2	0–10	%	Accuracy: 0.5% FSD (E), 5% reading (I)/(zirconia type used for O_2 trim control).
AH O/L	O_2	0–10/0–5*	%	Accuracy: 0.5% FSD (E), 5% reading (I)/EX (e.g., paramagnetic for AH leakage).
	CO	0–300/500	mg/m^3	Accuracy: 2% reading/for fine-tuning of O_2 trim control (I) Usually *in situ*
Stack	NO_X	0–1500	mg/m^3	Accuracy: >5% reading/(pollution)/(I).
	SO_2	0–400	mg/m^3	Accuracy: >5% reading/(pollution)(I)
	SPM	0–20	mg/m^3	Accuracy:> 5% reading/(pollution)/(I) (0–100% for opacity)
De-nitrification plant*	NO_X	0–1500	mg/m^3	*De-nitrification plant as applicable. Accuracy: 1% FSD/pollution control
	NH_3	0–10/25	mg/m^3	*De-nitrification plant as applicable Accuracy: 2%/NH_3 slip monitoring from de-nitrification plant(I)
Desulfurization plant*	SO_2	0–4000	mg/m^3	*Desulfurization plant as applicable Accuracy: 1% FSD/pollution control
ESP I/L	CO	0–300/500	mg/m^3	2% reading/ESP protection(I)
	NH_3	0–10	mg/m^3	Accuracy 2%/de-nitrification control wherever applicable and ESP protection(I)

(I), *in situ* type is possible; EX, extractive type; FSD, full-scale division.

the probe) diameter is also crucial. When the diameter is too small, then sample volume change will be less and one can expect to get better representative samples. But there will be chances of frequent choking of the tube by dust-laden flue gas. If the diameter is bigger, then the chances of choking are less probable, but time for volume change may be greater; hence, less representative samples will be available. If extraction type instruments are used, then a number of analyzers can be connected to one sampling line. Also there would be would be a provision for cleaning the probe in periodic intervals. Depending on principle of sample extraction, typical response time is 10–20 sec.

- *In situ*: This principle analyzer is put directly at the point of measurement. This is done when fast response (5–10 sec) is desired, e.g., zirconia probe for O_2 online IR analyzers and opacity monitors.

7. Measuring points of flue gas analyzers a in power plant:
   Gas analysis in GT: CO, CO_2, NO_X, and SO_2 SPM are commonly measured in GT plants. As per EPA, measurements are done at GT exhaust/heat recovery steam generator (HRSG) inlet as well as the HRSG outlet. In case of natural gas, SO_2 and SPM will be minimal and hydrocarbons are also measured.
8. *Generator cooling gas analysis*: The efficiency of a generator depends highly on its cooling system. Because of the following, H_2 has been chosen as the cooling medium for the generator rotor:
   - H_2 Shows higher thermal Conductivity,
   - H_2 has higher heat capacity
   - Low frictional loss for rotating parts
   - High dielectric breaking strength

   However, fire hazard is associated with the use of H_2, as it forms an explosive mixture when it comes in contact with air. The requirement of analyzers and purity value is guided by IEC 60842 and EN 60034. In power plants the H_2 purity analyzers are used to measure H_2 in air and H_2 in CO_2. CO_2 purity in air is also measured.

3.0.2 Analyzer Selection Criteria

To select an analyzer for a particular application, the system designer should consider the following criteria:

1. Whether extractive or *in situ* type
2. The same parameters may be analyzed by a number of methods; for example, O_2 can be measured by a zirconia probe or by the paramagnetic/thermo magnetic method. Similarly SO_2 may be analyzed by IR and

www.EngineeringBooksPDF.com

UV. Range, installation facility, provenness of the instrument in the application, and international certification should all be considered
3. Desired accuracy
4. Calibration method and frequency of calibration needed
5. Analysis frequency
6. Sampling method (as applicable)
7. Data handling
8. Display and recording details
9. Maintenance issue
10. Cost

3.0.3 Component and Analysis Types

Table V/3.0.3-1 is a list of various measuring methods. System designers need to choose the correct one as per the above discussions. Gas analysis with the cheaper, electrochemical cell method may not be very accurate and is less popular in utility stations.

3.0.4 Absorption Principle for Analysis

1. *IR method of detection (typical wavelength: 2.5−10 μm):* Hetero atomic molecules such as CO, CO_2,SO_2, NO_X, etc., show the property of absorption in some region in the IR spectrum. These gas components show distinct behavior in their absorption pattern to a particular frequency, so selection of the proper optical filter based on frequency of absorption is very important. A typical schemes is shown in Figure V/3.0.4-1. IR radiation from a common hot filament source is passed through an optical filter sensitive to the desired IR frequency. This filtered radiation is then passed through both reference sources as well as through the cell/chamber containing sample gas. If the sample contains the desired gas the energy absorption will be different than that in the reference cell, which contains non-IR-absorbing gas (N_2). This causes half of the detector cell to have a different pressure on the pressure-sensitive diaphragm, causing deflection of the diaphragm (higher gas concentration, higher the deflection), hence, a response in the condensing microphone pickup. To have AC pickup in the condenser microphone, the beam is chopped. This scheme is shown in Figure V/3.0.4-1a. There will a variation of this kind of pickup where the sample gas is passed through a fixed volume chamber at a preset time interval and the chamber is then sealed with the sample gas trapped inside. The IR radiation is pulsed into the chamber via an IR transparent window. The pulsating pressure change is measured by the microphone as a frequency change, which produces the signal (see Figure V/3.0.4-1b).

In both the cases, the pickup signal is amplified and rectified to detect the presence of the desired gas in the detector as a ratio of the two signals. The above method of detection is generally referred to as the photo acoustic method. The other kind of detector, based on opto pneumatic detection, is popularly known as a LUFT detector (named after inventor Karl Luft; see Figure V/3.0.4-1c−f). In the detection part there may be two chambers; if they are connected then a thermal mass flow sensor (a resistor) may be placed in between the two detection chambers. If the two detection chambers are not connected, then because of pressure variation, there is deflection in the diaphragm, which causes a change in differential capacitance similar to a normal capacitive pressure sensor/transmitter. Figure V/3.0.4-1c shows a single measuring chamber through which sample gas is

TABLE V/3.03-1 Gas Analysis Types

Component	Location	Types of measurement	Remarks
CO_2	Flue gas	IR/EC/TC	IR preferred, TC types are also in use
CO_2	Generator	IR/EC/TC	TCs are used mostly
CO	Flue gas	IR/EC	IR preferred
H_2	Generator	TC	
H_2	Main steam	TC (katharometer)	
SO_2/SO_X	Flue gas	UV/IR	
NO_X	Flue gas	Chemiluminescence/IR	
NO_2/NO	Flue gas	Chemiluminescence/IR/UV	
O_2	Flue gas	Para or thermo magnetic/zirconia	Zirconia for control loop
NH_3	Flue gas	Absorption spectroscopy (near-IR)	Also possible by chemiluminescence method

EC, electrochemical cell; TC, thermal conductivity.

www.EngineeringBooksPDF.com

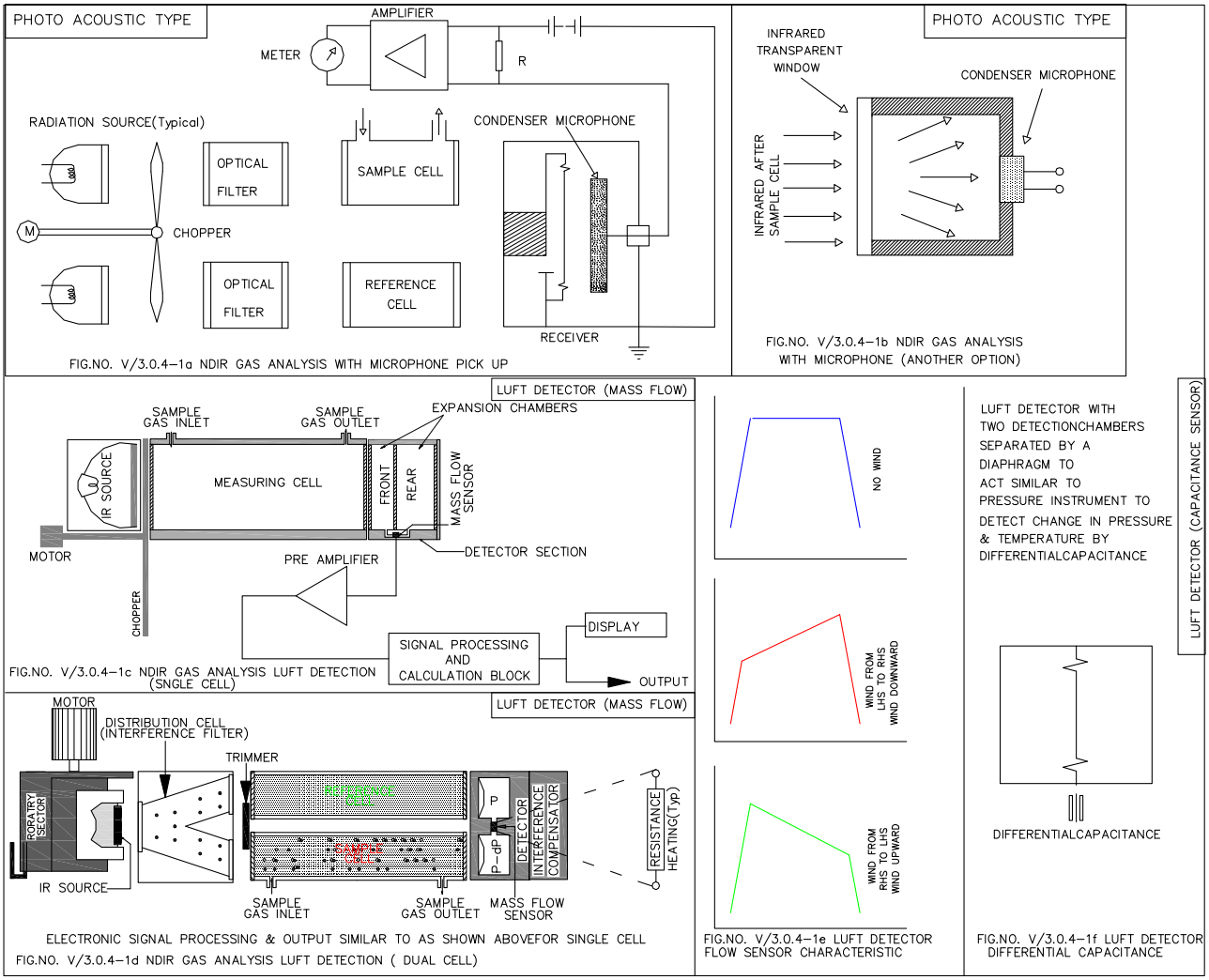


FIGURE V/3.04-1 NDIR principles for gas analysis.

passed. An IR source passes IR radiation through the chamber. Based on gas concentration, IR radiation of the required frequency is absorbed by the measuring chamber. To have AC sensing the IR radiation is chopped by the chopper. When the radiation is allowed to pass through, it will send energy (less absorbed by sample gas), which will increase the temperature and pressure in the front detection chamber. To balance the pressure it will push the pneumatic mass to the rear chamber through the opening containing a thermal mass flow detector (resistance) to detect pneumatic mass flow. The higher the concentration of desired gas in the sample the less will be the mass flow as more energy will be absorbed. To have an AC pulse, as stated earlier, radiation is interrupted when naturally, when there is no ration, there will be extra pneumatic mass flow from the rear to front detection chamber to balance the pressure. In place of a single chamber there could be two chambers, as shown in Figure V/3.0.4.1d. Figure V/3.0.4.1e depicts a no-wind characteristic curve that is flat, whereas during one-way flow (say left to right) the temperature variation goes in one direction; in reverse flow variation in goes in the other direction, meaning that on because two-way flow (by chopping the IR radiation) there will be better response (change in temperature) of the mass flow detector. This variation in temperature is measured in the LUFT detector as gas concentration. If the two chambers are not connected, but sealed by a diaphragm, the pressure variation will cause variations in differential capacitance as shown in Figure V/3.0.4.1f. This type of detection is also possible in the extractive type of analyzer.

2. With *In situ* type instruments, a transmitter and detector are placed across the duct. In the *in situ* analyzer

www.EngineeringBooksPDF.com

system, the transmitter and receiver are placed opposite to each other in the duct/stack as shown in Figure V/3.0.4-2. There is one IR source at the transmitter, which beams IR through a chopper and lens to the flue gas in the duct to reach the receiver located at the opposite end of the duct/stack. IR, after passing through flue gas, reaches the receiver where two beams of exactly the same wavelength are created by a beam splitter (which receives the radiation through a lens in the receiver). The Receiver a employs gas cell and optical filter to filter out interfering signals (placed ahead of splitter). There are two solid-state detectors, side detector (SD) and end detector (ED), to detect the radiation (after absorption by the desired gas in flue gas). SD detects the IR coming from flue gas; the remaining part is passed through the gas cell containing the desired gas of known concentration. So from the SD and ED a ratio signal can be created, which in electronics is compared with the calibrated ratio to detect the concentration of the gas component in flue gas.

3. *UV method of detection (typical wavelength: 200–600 nm)*: SO_2, NO, and NO_2 in flue gas can be measured by this principle. The radiation spectrum required for measuring gas as well as for reference is generated in the filter wheel box from the UV lamp (see Figure V/3.0.4-3). There is an interference filter in the filter wheel box. Two interfering filters with different characteristics are put into the beam path for accurate measurement. The beam splitter directs filter radiation to both reference chambers as well as the sampling chamber. UV detector (diode array or spectrophotometric detector) behind each of these chambers detects the radiation to calculate the quotient received by detectors. *In situ* instruments with integral control and calibration units are also available. In resonance absorption spectrometer principles, NO, NO_2, and NH_3 can be measured without an NO converter. Using this principle, NH_3 slip in SCR can be measured.
4. *Laser type absorption detection*: A few analyzers in the market use single-line molecular absorption spectroscopy utilizing a diode laser emitting near-IR light. LDS 6 of Siemens is an example of this type of laser (see Figure V/3.0.4-4—Schematic developed based on Siemens LDS 6 analyser—courtesy Siemens). This is an *in situ* multichannel analyzer utilizing a laser beam.

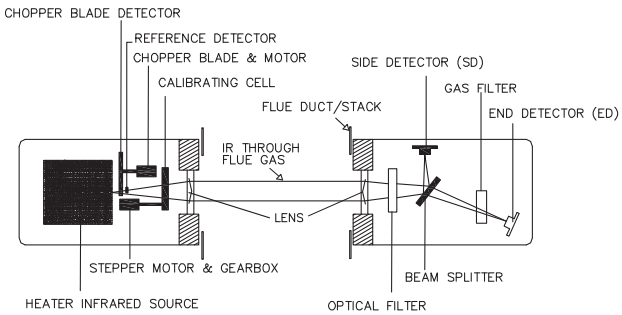


FIGURE V/3.04-2 IR gas analysis (*in situ*).

3.0.5 Chemiluminescence Type Analysis System

This type of analysis system may be deployed to detect NO_X, NH_3, etc. When NO reacts with ozone (O_3) to produce NO_2, a part (10%) of electronically excited NO_2 reverts back to NO and gives away illumination. The light emission is directly proportional to the concentration of NO present in the gas (since each NO molecule produces light). The volume of sample gas and excess ozone are carefully regulated. The emitted light is measured by photomultiplier and electronics. As is clear from the previous discussion, it

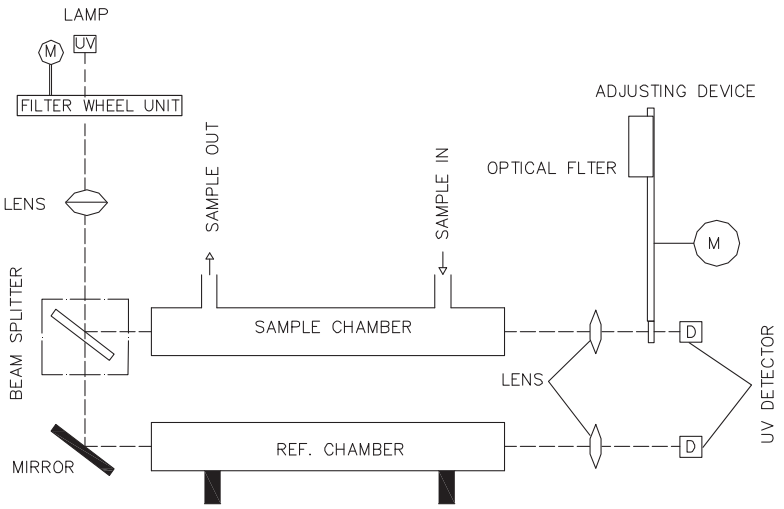


FIGURE V/3.04-3 UV gas analysis.

www.EngineeringBooksPDF.com

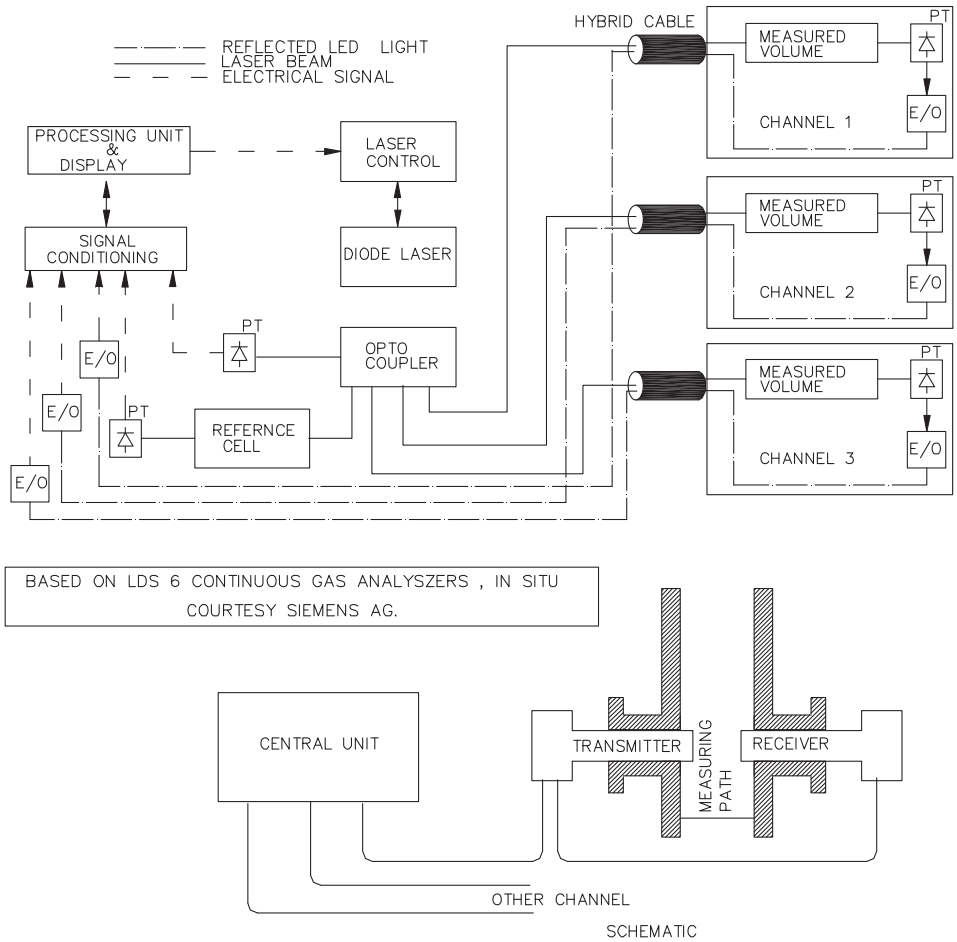


FIGURE V/3.04-4 Laser gas analysis.

is basically for NO, so for measurement of NO_2/NO_X a suitable converter is necessary to convert NO_X to NO concentration.

This conversion is normally achieved by passing the sample over a heated catalyst to convert all oxides of nitrogen to NO before the main reaction chamber. Some instruments are able to perform the automatic switching of the catalyst in and out of the sample path so that the resulting signal may be used to measure NO only by indirectly measuring NO_2 produced by the reaction with ozone. A similar technique may be used to perform measurement of ammonia (NH_3) but by oxidizing reaction (e.g., $NH_3 + O2 ==> NO + H_2O$) before the main reaction chamber.

3.0.6 Paramagnetic and Thermo Magnetic Oxygen Detection System

While most of the common gases are diamagnetic (repelled out of magnetic field), oxygen is strongly paramagnetic. Magnetic susceptibility of the O_2 principle is used to measure O_2 present in the sample to give an indication of O_2 concentration by volume.

Paramagnetic: Normally a set of two glass spheres (filled with N_2 or another diamagnetic gas) is kept suspended by a thin wire with a metal piece acting as a mirror and kept in balance in a magnetic field (see Figure V/3.0.6-1). A light source focuses on the metal piece, which reflects the light to two photodiodes (connected in reverse mode) placed to receive the reflected light. At balanced condition both the photodiodes receive the same amount of light. Thus any movement of the metal piece can be detected by the photodiodes due to variation in the amount of light. When O_2 molecules with magnetic susceptibility start flowing, it displaces the spheres, which are moved away from the magnetic field. The metal piece/mirror rotates, and as a result the light detected by the two photo detectors is different. Photodiodes are connected to a differential amplifier, which causes unbalanced current flows through the feedback coil mounted on suspension. Because of the interaction of this magnetic field due

www.EngineeringBooksPDF.com

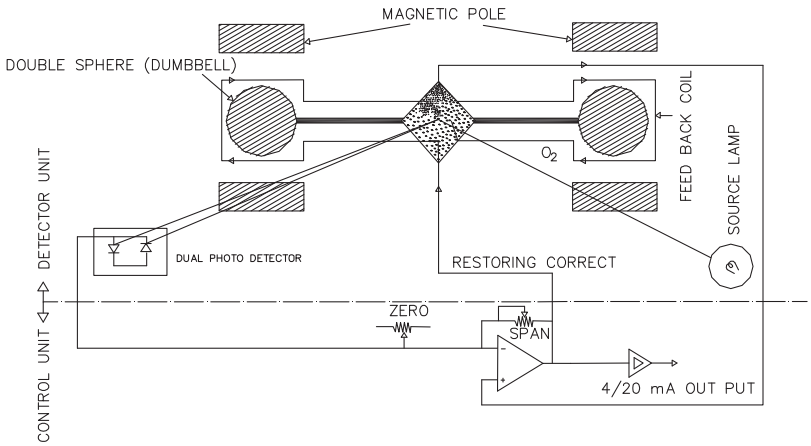


FIGURE V/3.0.6-1 Paramagnetic oxygen analyzer.

to current in the coil and permanent magnet, the sphere is brought back to the original balanced position. So the feedback circuit current is proportional to the concentration of O_2 in the sample. Manufactures like Fuji Japan, Siemens, ABB, etc., have instruments of this type.

Thermo magnetic: The magnetic susceptibility of O_2 also depends on temperature. In this analyzer there will be one (or two) platinum wire(s) heated by external source and connected to a Wheatstone bridge (see Figure V/3.0.6-2). A magnet is placed across *one* platinum wire. When sample gas containing O_2 is introduced, because of oxygen's affinity toward magnets, it will be attracted toward the magnet and pass over the hot platinum wire. As soon as it passes over the hot magnet it loses susceptibility and moves away. This place will be filled in by a fresh sample. Thus a magnetic wind will be established. This magnetic wind takes away the heat from the platinum wire. The amount of heat taken away is proportional to oxygen volume, which is measured by change of resistance in the Wheatstone bridge discussed above (which may compare this resistance change with respect to other platinum wires that are not subject to a magnetic field when two wire s are used). ABB has an analysis system based on this principle. A similar system utilizes two thermistors that are located in such a way the magnetic wind cools down one on the inlet side of the magnetic wind and the other is located at the outlet side of the magnetic wind and gets heated by the same. They are connected to a Wheatstone bridge. Additional sensor elements are used to measure gas heat capacity and viscosity to calculate the oxygen percentage accurately by the microprocessor-based transmitter to arrive at the resulting signal proportional to oxygen concentration. This type is available with APX, (Panametrics) under GE Industrial, Sensing.

3.0.7 Zirconia Oxygen Detection System

In situ oxygen detection method, based on the Nernst relation for zirconium oxide, is used in the zirconia probe oxygen analyzer (used for boiler air flow O_2 trim control because of its better response time). When heated at ~700°C zirconium oxide (because of oxygen vacancy in the ceramic lattice) is selectively conductive to oxygen ions (see Figure V/3.0.7-1). When two gases differing in O_2 concentration are on opposite sides of the zirconium oxide membrane a DC voltage is generated as per Nernst, who established this relationship (see Figure V/3.0.7-2).

The generated voltage is not linear with O_2 concentration hence the linearization circuit is necessary. Also as log of zero is infinite, the sensor cannot measure zero concentration. Again from the equation it is seen that it is dependent on temperature, which needs to be maintained precisely to get an accurate result. The reference air (~500−1000 ml at 1 bar) can be supplied by a pump or regulated instrument air supply through an inlet port in the probe terminal head. There is also suitable venting of reference air in the return path. In most of the cases heaters in the probes are used to maintain the temperature. High-temperature versions of these probes do not require heaters and they can be put close to the combustion point, which is desirable. There is a calibration gas inlet port to check the probe with test gas.

3.0.8 Thermal Conductivity Gas Detection System: Katharometer

In a katharometer the concentration of a particular gas in the sample is measured, utilizing thermal conductivity of the particular gas (see Figure V/3.0.8-1). Generally the thermal conductivity of gas is inversely related with its molecular weight as is seen in Table V/3.0.8-1. H_2 has the

www.EngineeringBooksPDF.com

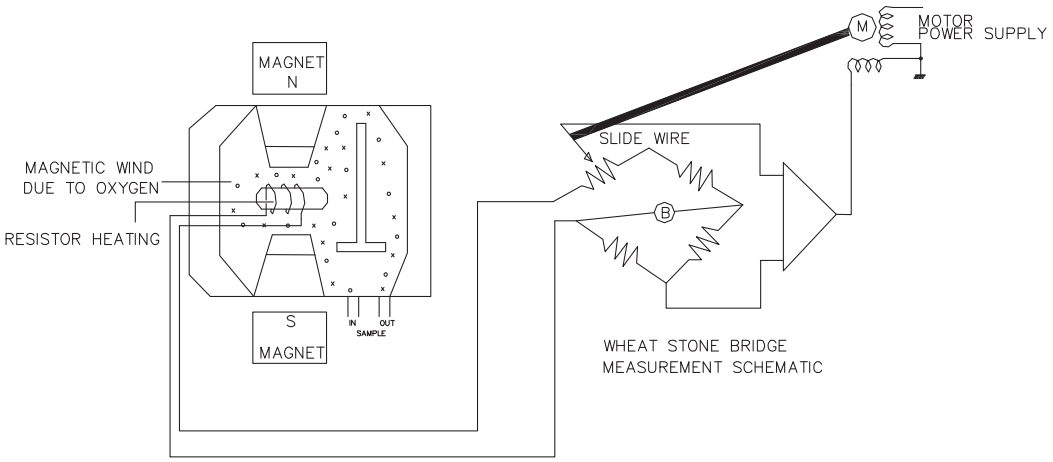


FIGURE V/3.0.6-2 Oxygen measurement by thermo magnetic method.

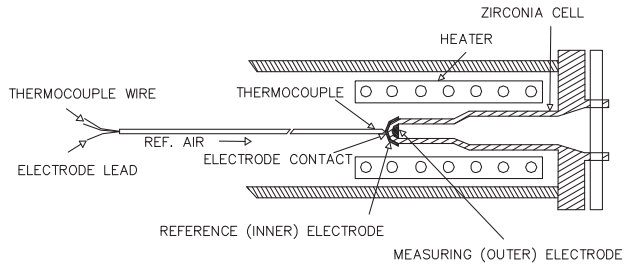


FIGURE V/3.0.7-1 Zirconia probe for oxygen measurement.

Therefore there will be an imbalance in the Wheatstone bridge circuit causing imbalanced current, which is measured by the DC amplifier and other circuits. Thus there will be 4-20 mA current proportional to the percentage concentration in a known volume of gas measured. In the katharometer matched platinum wire filaments are used as resistance in the Wheatstone bridge. H_2 and CO_2 are the major gases measured in this principle.

NERNST EQUATION: $E = (RT/nF)\ln(P_1/P_2)$

*Where **E** = measurable voltage DC; **R** = universal gas constant (8.314 J/mol K; **T** = temperature in K; **n** = number of electrons transferred; **F** = Faraday constant; P_1 = partial pressure of referred gas (air ~20.9%), P_2 = O_2 partial pressure in sample gas. Empirically the relationship has been simplified to*

$E(mV) = F(= 0.0496)*T*(\log_{10} P1/P2) \pm C(mV)$ where C = cell constant.

FIGURE V/3.0.7-2 Nernst equation—discussions.

highest conductivity with the least molecular weight, whereas SO_2 has high molecular weight but less thermal conductivity.

When current is passed through an electrical conductor surrounded by gas in a chamber, temperature will rise until equilibrium is reached. At this point the energy supplied to the conductor matches the thermal loss due to surroundings provided the loss due to radiation, end conduction, etc., are minimal. The thermal conductivity difference between the measuring gas and reference gas causes the difference in heat loss—hence the temperature difference between the two resistances. It is known that the electrical resistance is proportional to the temperature.

3.0.9 Combustible Analyzer

Combustibles like CO + H_2 are analyzed using the catalytic combustion method. In this method platinum is used as a catalytic sensor for detecting CO + H_2. This is useful for detecting incomplete combustion. Combustibles are measured in terms of 0−2000 ppm.

3.0.10 Gas Chromatograph

For GTs, special instrumentation like gas chromatographs (GC) provide a cost-effective analytical package. A GC is an analytical instrument that measures the content of various components in a sample.

www.EngineeringBooksPDF.com

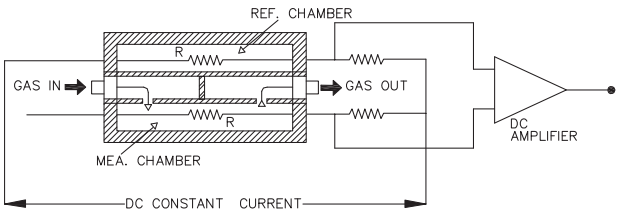


FIGURE V/3.0.8-1 Thermal conductivity analyzer (katharometer).

calculate the Hydrocarbon dew point of fuel gas at various pressures and help mitigate damage from this.

3.0.11 Extractive Multi-Analysis System

In this type of analysis system a number of gas components are analyzed utilizing a single probe. The sampling system faces many challenging demands for the process conditions such as changing pressure and temperature and dust-loading

TABLE V/3.0.8-1 Comparison of Thermal Conductivity of Gases

Gas	Comparative thermal conductivity to air at 0°C	Reference gas
SO_2	→	
CO_2	→	N_2, air, Ar
CO	→	
NO	→	
N_20	→	
H_2	→	$N_2(CO_2)$

3.0.10.1 Principle

The sample solution injected into the instrument enters a gas stream (helium or nitrogen), popularly called a carrier gas. It transports the sample into a separation tube known as the "column." The constituent components are separated inside the column. The detector measures the quantity of the components that exit the column. When a sample with an unknown concentration is measured, a standard sample with known concentration is first injected and then the standard sample peak retention time (or the appearance time) and area are compared to the test sample to calculate the concentration

- *Gas composition*: Operates the plant at stoichiometric point, so that all C is converted to CO_2, S to SO_2, and H_2 to H_2O so that there is no unburned constituent in the exhaust gas. This also helps reduce NO_X to a minimal value without use of high-cost low NO_X burner. GC helps in accurately determine the gas composition so that the burner can operate efficiently at the stoichiometric point.
- *Wobble index (WI)*: Gas burners get damaged from varying flame dynamics. This can be controlled by using WI, which relates the energy content of the gas per unit volume at normal temperature pressure divided by square root of specific gravity. GC can calculate WI to provide reliable data for GT operation.
- *Hydrocarbon dew point*: When the natural gas temperature falls below the hydrocarbon dew point, then heavier hydrocarbon components start dropping, which results a catastrophic (flash back) situation for the GT. GCs can

conditions. In power stations such instruments are used to monitor gas components like CO, CO_2/NO,N_2O, NO_2, $NO_X/SO_2/O_2$. A few typical features of these instruments from some well-reputed manufacturers are presented below:

1. Measuring gas components with ranges:
   a. *CO*: 0−125/600 mg/m^3
   b. CO_2: 0−40% V
   c. *NO/NO2/N2O/NOX*: 0−100/1000 (1500) mg/m^3
   d. *SO2*:0−75/1000 mg/m^3
   e. *O2*: 0−10% V
2. *Number of gas components*: 3−6 available
3. *International certification*: As per the applicable standard (as discussed in Clause 3.0.1; e.g., QAL 1/2/3 for European systems)
4. Analysis technology such as photometer, UV type, nondestructive IR (NDIR), paramagnetic, flame ionization detection, etc., to measure the gas components
5. *Number of analyzers*: Normally 3−4 analyzers in one single system
6. *Overall accuracy*: 1-2% Full Scale Division—FSD (depends on individual instrument accuracy as discussed later)
7. *Analyzer performance specification*: To be specified (some guidelines have been given in this book against individual analyzer type)
8. Sample probe and sampling system:
   a. *Dust retention factor*: >99% with heating to avoid clogging
   b. *Probe length*: As per requirement

www.EngineeringBooksPDF.com

   c. *Probe material*: High-temperature stainless steel
   d. *Temperature withstand capability*: up to 1000°C
   e. Sample line size and heating (to specify temperature)
   f. Sample feeding pump and or extraction method
   g. Sample gas cooler
9. *Power supply system*: 230 V AC, 1 Ph, 50 Hz (110 VAC, 1 Ph, 60 Hz) or DC power supply, etc., as applicable/available
10. *Output*: Analog/digital, alarm for each channel
11. *Contact rating*: As applicable (e.g., 30/50 VA, etc.)
12. *Calibration method*: Currently auto calibration methods are available for most cases, from the analyzer front panel
13. *Display type*: Digital read out/graphical
14. *Built-in system software*: To handle sampling system, etc., other system software for networking as applicable; in-house graphic generation, history logging, data storage, sampling of data, etc.
15. *Interface*: HART/Profibus/Fieldbus/MODBUS Ethernet, etc.
16. *IT compatibility*: Whether Industrial computer is compatible/Web browser access, etc.
17. *Examples*: ABB ACX/AO 2000 Rosemount X Stream, etc.

3.0.12 In Situ (Modified) Multi-Analysis System

Here one probe to diffuse the flue gas into the sensor is put at the end of the probe. There are a number of stainless steel filters to eliminate high dust from the flue gas. The sensor used is a NDIR type. A few typical features of this type of instrument are presented below (see Figure V/3.0.12-1):

1. Measuring gas components with ranges:
   a. $CO/NO/NO_2/N_2O/NO_X/SO_2$: 0–3000/6000 ppm
   b. CO_2: 0–25% V
   c. *Measuring unit options*: % or mg/m^3
2. Number of gas components: Up to five
3. *Overall accuracy*:1–2% FSD.
4. *International certification*: As per the applicable standard
5. *Analyzer performance specification*: To be specified (see Data Sheets)
6. Sample probe and sampling system:
   a. *Dust retention factor*: >99%
   b. *Probe length*: 1000/2000 mm
   c. *Temperature withstand capability*: Up to 1000°C
   d. *Diffusion cell*: 1 m
7. *Power supply system*: 230 V AC, 1 Ph, 50 Hz (110 V AC, 1 Ph, 60 Hz) or DC supply etc., as applicable/available
8. *Output*: Analog/digital, alarm 4-20mA + SPST contact for alarm
9. *Contact rating*: As applicable (e.g., 30/50 VA).
10. *Calibration method*: Auto calibration with span/zero gas.
11. *Display type*; Digital read out/graphical
12. *Built-in system software*: For networking as applicable; in-house graphic generation, history logging, data storage, sampling of data, etc.
13. *Interface*: HART/Profibus/Fieldbus, etc.
14. *Special feature*: Pressure and temperature measurement for normalization
15. *Examples*: Codel G-CEM 4000

3.0.13 In Situ Multichannel Analysis System

There are several *in situ* single-line analyzers connected to a central analysis system used to measure a number of gas components in the flue gas (see Figure V/3.0.13-1). Each set of transmitter/receiver units form a channel. The Siemens LDS 6 analyzer is an example of this kind of analyzer. Power plant ammonia trace can be measured in similar way.

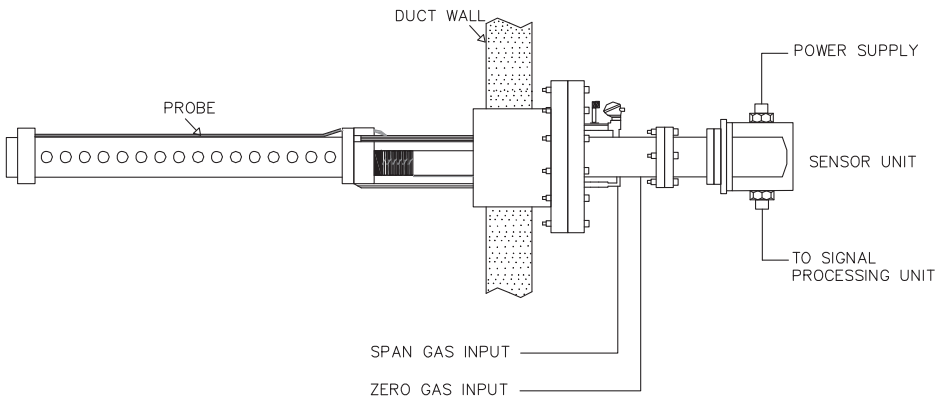


FIGURE V/3.0.12-1 Multigas analysis probe.

www.EngineeringBooksPDF.com

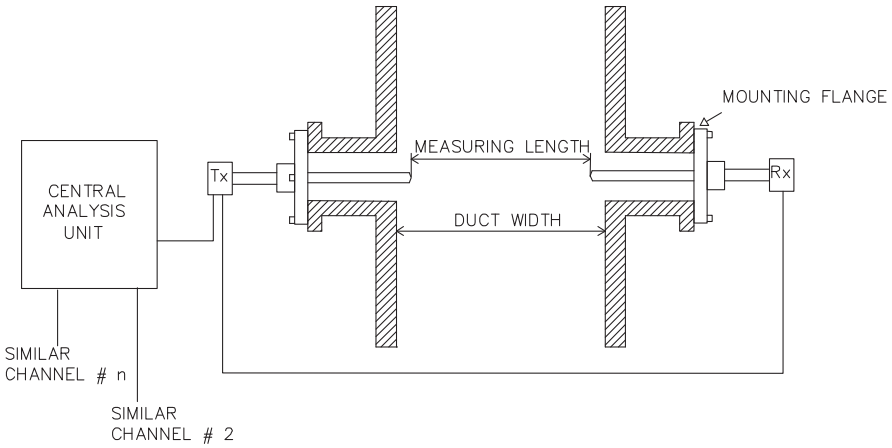


FIGURE V/3.0.13-1 Multichannel *in situ* analyzer.

3.0.14 NO_x Analyzer

For a data sheet on the NO_X analyzer, see Table V/3.0.14. An example of a chemiluminescence type is shown in Figure V/3.0.14-1.

3.0.15 SO_2 Analyzer

For a data sheet on the SO_2 analyzer, see Table V/3.0.15-1.

3.0.16 Opacity/Particulate Monitoring

To keep the environment clean particulates, such as unburned coal and fly ash, coming out of the stack need to be monitored properly. Essentially it is desirable to maintain 0.15 mg/m^3 dust in the exhaust gas. The particulates in flue gas are measured in either mg/m_3 or as % opacity (see Figure V/3.0.16-1a and b). Transmittance and opacity has been described in Figure V/3.0.16.1-1. Some the measuring principles of particulates are discussed below:

1. Working principles:
   - **a.** *Transmissiometer (light extinction)*: Measures the loss of light intensity (visible range) across a particulate-laden flue gas, as a function of dust concentration.

     In the instrument a collimated beam of visual light is put across the gas path in the duct or stack directed toward the receiver at the opposite end. Receiver measures the loss of intensity as discussed to convert it into output signal. For better accuracy, a dual-pass transmissiometer is used with a mirror on the opposite side of the stack. For a particulate monitoring instrument an RED/near-IR light source is used instead of visual light.
   - **b.** *Optical scintillation*: Another popular method, here the receiver measures the modulation of light due to the dust particles. The greater the dust concentration the greater will be the momentary interruption of light beam, hence, variation in amplitude of the light received. After manual gravimetric sampling it can be calibrated as mg/m^3.
   - **c.** *Light scattering:* Light is both absorbed as well as scattered by the particles in the path of the light and the amount of such scattering is a function of dust concentration and size, shape, and color of the particles. Light scatter type instruments measure the amount of light in a particular direction (forward/backward) and *output is proportional to the dust concentration,* i.e., particulate matter in the flue gas. The light scattered by the particles is focused by the receiving optics. Receiving the light by the receiver/detector generates a current proportional to dust concentration. The angle of source to receiving optics and the characteristic of the optics determine the volume of gas to be covered.
   - **d.** *Beta attenuation technique*: Beta rays are passed through the material; part will be absorbed and reflected and part will be passed. Attenuation of intensity is a measure of particles present in the path. Basically the sampling instrument measures the energy absorbed from beta particles as they pass through the particulate collected at the filter. The two major items are beta source and detector. From a safety point of view and good half-life ^{14}C is chosen as the source. The detector does the beta count as beta particles pass through the particulate in the filter. The output is mass concentration. These instruments also measure the volume of gas extracted and give a reading in mg/m^3.
2. *Suppliers*: Rosemount/Lear Siegler/Durag
3. *Opacity instrument*: Most *in situ* opacity instruments work on a double-pass transmissiometer (see Table V/3.0.16.3-1 for examples).
4. *Dust measuring instrument*: See Table V/3.0.16.4-1.

www.EngineeringBooksPDF.com

TABLE V/3.0.14 NO_X Analyzer (Chemiluminescence) Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Working principles	Chemiluminescence (Che)/IR/UV(NO, NO_2)	
2	Span	0–25/1500 mg/m^3/(IR) 0–5000/6000 ppm (Che)	Selectable range may be specified
3	Drift (zero/span)	Per week: Z: 2% FSD S: <0.5%	
4	Accuracy	<0.1 ppm/1–2%(IR) FSD	
5	Response time	Typically 60–200 sec as per type	
6	Output	4-20mA DC + high/high-high aluminum	
7	Contact details	SPST/SPDT 50 VA or 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
9	Probe details	Length (i.e., 1–2 m) Material: SS (norm)	To be specified
10	Sampling	As applicable to specify pump, flow rate, pressure temperature	To be specified
11	Display	Back-lit LCD 32 channel alphanumeric/$4_{1/2}$ digit display	
12	Connectivity	RS 232/485/MODBUS/Profibus/HART/Ethernet, etc.	
13	Power supply	230 VAC/24 VDC as the case	
14	Housing protection/ material	IP rating (67)/epoxy-painted aluminum	To be specified
15	Ambient condition	Temperature/humidity	To be specified
16	Accessories (sampling, if any)	Mounting flange/air and other requirements, if any, for cleaning, sampling system (as applicable)	To be specified
17	Software detail	For data storage, networking, sampling, etc., as applicable	To be specified depending on need

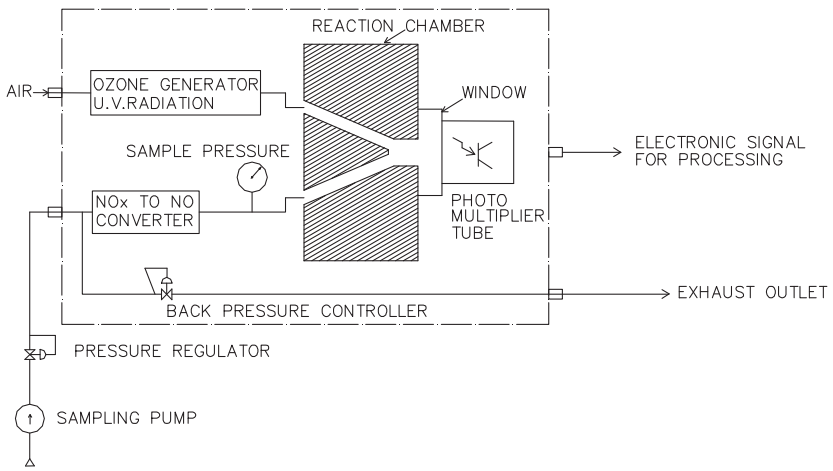


FIGURE V/3.0.14-1 NOx analyzer (chemiluminescence type).

www.EngineeringBooksPDF.com

TABLE V/3.0.15-1 SO_2 Analyzer

Sl	Specifying point	Standard/available data	To be specified
1	Working principles	IR/UV/Thermal conductivity	
2	Span	0–25 ppm/0–75mg/m^3	Selectable range may be specified
3	Drift (zero/span)	Per week: Z: 2% FSD S: <0.5%	
4	Accuracy	1–2% FSD IR (2%)	
5	Response time	Typically 200 sec	
6	Output	4-20mA DC+ high/high-high aluminum contact	
7	Contact details	SPST/SPDT 50 VA or 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
9	Probe details	Length (i.e., 1–2 m) Material SS (norm)	To be specified
10	Sampling system	As applicable to specify pump, flow rate, pressure temperature condition	To be specified
11	Display	Back-lit LCD 32 channel alphanumeric/$4_{1/2}$ digit	
12	Connectivity	RS232/485/MODBUS/Profibus/HART/Ethernet, etc.	
13	Power supply	230 VAC/24 VDC	
14	Housing/material	IP rating (67)/epoxy-painted aluminum	To be specified
15	Ambient	Temperature/humidity	To be specified
16	Accessories (sampling, if any)	Mounting flange/air and other requirements, if any, for cleaning, sampling system (as applicable)	To be specified
17	Software detail	For data storage, networking, sampling, etc., as applicable	To be specified depending on need

N.B.:ABB/Rosemount/Honeywell/Siemens/YEL are some of the standard suppliers.

3.0.17 Ammonia (in Flue Gas) Analyzer

Generally measurement of NH_3 in power plants is done as part of a multi-analyzer system, both extractive type (ABB Limas11HW) or *in situ* (e.g., SiemensLDS6). For a data sheet on the ammonia analyzer, see Table V/3.0.17-1.

3.0.18 Mercury in Stack Gas Analyzer

This analyzer is a part of continuous emission monitoring (CEM). There are two popular types of mercury analyzers: atomic absorption spectroscopy (AAS) and atomic fluorescence spectroscopy (AFS).

- *AAS:* This system includes a thermo catalytic converter positioned inside the sampling probe. Its purpose is to reduce the ionic mercury compounds to elemental mercury vapor. The mercury is finally measured in a UV atomic absorption photometer.
- *AFS*: This system utilizes the phenomenon of releasing stored energy in atoms in the form of light (there are variety of other ways), which is known as fluorescence. It measures this emitted light, the wavelength of the which indicates the identity of the atoms. The intensity of the fluoresced light is directly proportional to the concentration of atoms and the intensity of the excitation source. Cold vapor AFS is specific to mercury and is without interference from SO_2 or HCl (see Table V/3.0.18-1 for the mercury stack gas analyzer data sheet).

www.EngineeringBooksPDF.com

TABLE V/3.0.16.3-1 Opacity Instrument

Sl	Specifying point	Standard/available data	To be specified
1	Light source details	Solid-state light modulation, high-intensity LED (~650 nm) Expected life (~5 years) with aging computation	To specify selected feature
2	Span	Full scale in % or in mg/nm^3	To be specified
3	Drift (zero/span)	0.1% opacity/month a typical value	
4	Accuracy	1%-FSD or 0.2 % opacity	
5	Response time	Typically 10–15 sec	
6	Output	4-20mADC + high/high-high aluminum contact	To be specified
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	See Clause 3.0.1 for country requirement	To be specified
9	Path length/gas condition	Length: 0.5–12/15 m Flue gas temperature: >400°C	To be specified
10	Calibration	Automatic and manual zero/span calibration Also to compute build-up	
11	Display	$4_{1/2}$ LED with diagnostic display	
12	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
13	Power supply	230 VAC/24 VDC	
14	Housing/material	IP rating (65)/epoxy-painted aluminum.	To be specified
15	Ambient	T: Up to 50°C RH (93%)	To be specified
16	Accessories sampling, if nay	Mounting flange/air purge system/service module	To be specified
17	Software detail	For data storage, networking, remote control/calibration, etc., as applicable	To be specified
18	Special feature	Service module for diagnostics	Optional

TABLE V/3.0.16.4-1 Dust Measuring Instrument

Sl	Specifying point	Standard/available data	To be specified
1	Working principle	Forward scattering of light (or laser)	.
2	Span	0–10/200 mg/m^3(or nm^3)	To be specified
3	Accuracy	2%-FSD	
4	Response time	~10 sec	
5	Output	4-20mADC + high/high-high aluminum contact	To be specified
6	Contact details	SPST/SPDT 50 VA 50 V 1A	
7	International certification	See Clause 3.0.1 for country requirement	To be specified
8	Length/temperature	Length: 0.5–5 m Temperature: >200°C	To be specified
9	Function test	Automatic	
10	Air purge	Integral, to be provided.	
11	Display	LED with diagnostic	
12	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	

Continued

www.EngineeringBooksPDF.com

TABLE V/3.0.16.4-1 Dust Measuring Instrument—Cont'd

Sl	Specifying point	Standard/available data	To be specified
13	Power supply	230 VAC/24 VDC	
14	Housing material	IP rating (65)/epoxy-painted aluminum	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	
16	Accessories	Mounting flange/air purge system/service module (as applicable), shutter	To be specified
17	Software detail	For data storage, networking, remote control/calibration, etc., as applicable	To be specified
18	Special feature	Diagnostic module/laser protection	Optional

TABLE V/3.0.17-1 Ammonia Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Working principle	Absorption spectroscopy (UV/laser)/chemiluminescence	
2	Span	0—10/25 0—200 ppm	To be specified
3	Accuracy	2% measured value	
4	Output	4-20 mADC + high/high-high aluminum contact	To be specified
5	Contact details	SPST/SPDT 50 VA 50 V 1A	
6	International certification	See Clause 3.0.1.for country requirement	To be specified
7	Sampling details	SS 2-4 M probe + heater/cooler	If applicable
8	Display	5 digit LED + diagnostic display	To be specified
9	Response time/laser protection	<3 sec/class I laser protection	For laser type
10	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
11	Power supply	230 VAC/	
12	Housing material	IP rating (65)/epoxy-painted aluminum	To be specified
13	Ambient	T: Up to 45°C RH (93%)	To be specified
14	Accessories	Mounting flange/sampling system (if applicable), shutter	To be specified
15	Software detail	For data storage, networking, remote control/calibration, etc., as applicable	To be specified
16	Sample gas	*In situ* and extraction type	To be specified
17	Special feature	Diagnostic module/laser protection	Optional
18	Some Suppliers	ABB/Maihak/Siemens	

TABLE V/3.0.18-1 Mercury in Stack Gas Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Working principle	Absorption UV spectroscopy after converting Hg vapor or fluorescence	.
2	Span	0—45/500 µg/nm^3	To be specified
3	Accuracy	1—2% measured value	

www.EngineeringBooksPDF.com

TABLE V/3.0.18-1 Mercury in Stack Gas Analyzer Data Sheet—Cont'd

Sl	Specifying point	Standard/available data	To be specified
4	Output	4-20 mADC + high/high-high aluminum contact	To be specified
5	Contact details	SPST/SPDT 50 VA 50 V 1A	
6	International certification	See Clause 3.0.1.for country requirement	To be specified
7	Sampling details	SS 2-4 M probe + heater/cooler	As applicable
8	Display	5 digit LED/LCD (back-lit) + diagnostic display	To be specified
9	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
10	Power supply	230 VAC/24 VDC	
11	Housing material	IP rating (65)/epoxy-painted aluminum	To be specified
12	Ambient condition	T: Up to 45°C RH (93%)	To be specified
13	Accessories	Mounting flange/sampling system (if applicable), shutter	To be specified
14	Software detail	For data storage, networking, remote control/calibration, etc., as applicable	To be specified
15	Process temperature	<250°C	To be specified
16	Some suppliers	Durag/Gasmet/Opsis/Applitek	

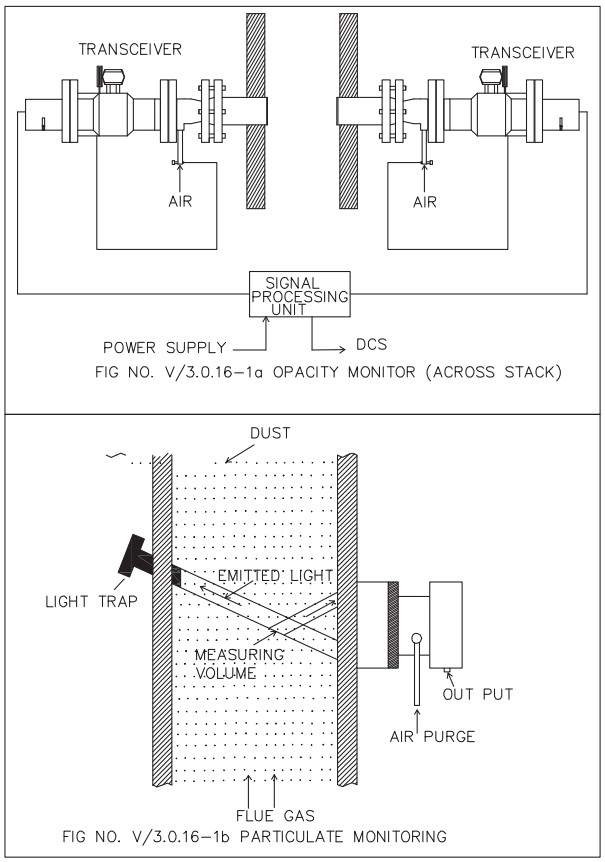


FIGURE V/3.0.16-1 Opacity monitor and particulate monitoring (across the duct).

3.1 Oxygen Analyzer

3.1.1 Oxygen Analyzer Types

The two most commonly used types of oxygen in flue gas analyzes are paramagnetic and zirconia. Since oxygen in flue gas is a vital parameter, dedicated analyzers are used in power plants.

1. *Zirconia probe*: Special features of this instrument include:
   - **a.** Figure V/3.0.7-1 shows the zirconia cell (available from ABB, Emerson, etc.) as a part of the probe inserted into the flue gas duct. Zirconia probe ceramic filters are built in to reduce the particle content. For a high-temperature version, ceramic aluminous porcelain, Inconel (<1000°C), and Alumina (<1900°C) sheaths are used. Flame-arrester porous ceramic filters are common in this type of instrument. Some of the analyzers have inherent intrinsic safety features also.
   - **b.** Zirconia probe mounting is shown in Figure V/3.1.1-2. There is another type as shown in Figure V/3.1.1-1, where a diffusion-based sampling system is used to draw the sample to the zirconia call located outside the probe to reduce particles in to the analyzer. Heater block at the inlet of the sampling line reduces the chance of corrosion and helps to draw the sample in as well as to maintain temperature (analyzers from GE and Ametek).

www.EngineeringBooksPDF.com

If the intensity received at the detector is I and the reference intensity is I_0 then,

Transmittance $T = I/I_0$, while opacity = 1-T, and optical density (D) = log(1/T).

After manual gravimetric sampling, opacity can be related to dust concentration in mg/m^3.

FIGURE V/3.0.16.1-1 Transmittance.

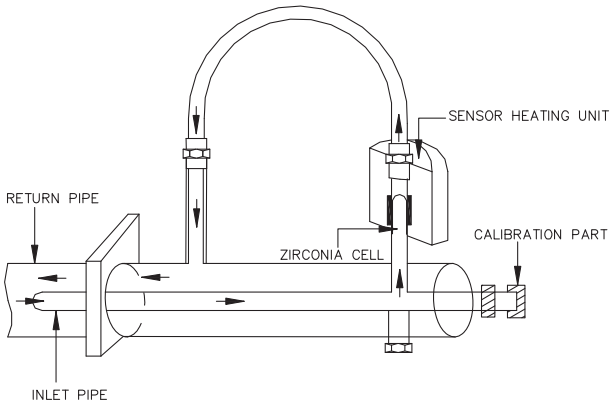


FIGURE V/3.1.1-1 Zirconia O_2 analyzer by diffusion sampling.

c. For the zirconia probe there is a requirement of reference air and this can be supplied by a pump or from instrument quality air.
d. Output is temperature dependent; hence it is regulated by a heater. Also, analyzer output is logarithmic, so output linearization is necessary
e. As per flue gas duct size, probe length needs to be specified to get a representative signal (especially for the type shown in Figure V/3.1.1-2).

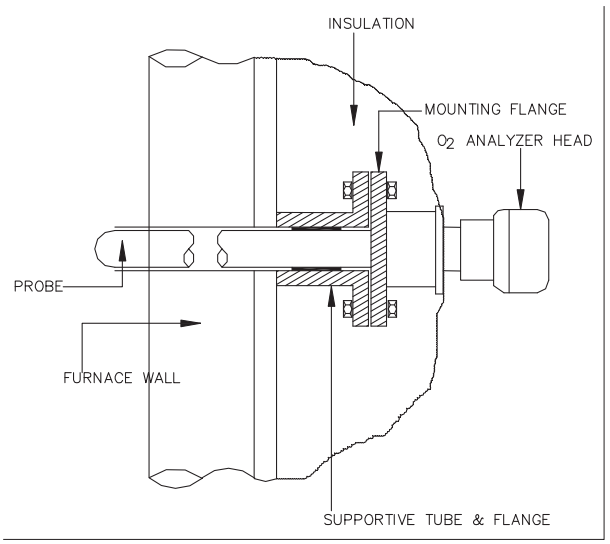


FIGURE V/3.1.1-2 Zirconia probe mounting.

f. Because of warm-up time, the probe has some start-up time. A few diagnostic features like power failure, thermocouple open circuit, heater open circuit, etc., may be considered for specification of the instrument.
g. In some of the types by using a catalyst, combustibles can be measured as an optional feature to monitor incomplete combustion.

2. *Paramagnetic type*: Some features of paramagnetic oxygen analyzers include:
a. As no reference gas is necessary running cost is less
b. Requires elaborate sampling system, hence, routine maintenance is essential.
c. Linear output and better accuracy
d. As there is a strong magnetic property, oxygen is utilized; hence, interfering gas has very little effect
e. Zero and span gas are necessary for analyzer calibration

3.1.2 Zirconia Oxygen Analyzer

See Table V/3.1.2-1 for zirconia oxygen analyzer data sheet.

3.1.3 Paramagnetic Oxygen Analyzer

See Table V/3.1.3-1 for paramagnetic oxygen analyzer data sheet.

3.2 CO and CO_2 Analyzers

3.2.1 CO Analyzer Features

Most of the CO analyzers used in power plants are based on the NDIR type. CO analysis may be part of a composite CEM or as dedicated instrument.

1. Multiple component Gas Analyzers features to be considered.
a. Sampling: Pressure, temperature and probe material, heating, and drying considerations
b. Automatic probe cleaning
c. Central processing and calculation unit
d. Periodic auto zero span calibration
e. Combustibles monitoring as an optional feature for CO
f. Dedicated user-friendly software with networking facilities

www.EngineeringBooksPDF.com

TABLE V/3.1.2-1 Zirconia Oxygen Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	0–25 5 by volume available, but for power plant 0–10% by volume	
2	Probe length (m)	0.5–2.0	To be specified
3	Process temperature limit	600–1900°C available	To be specified
4	Accuracy	±1% or reading	
5	Response time	Typically 10–15 sec	To be specified
6	Output	One or two 4-20 mADC + high/high-high alarm contact, HART + diagnostic alarm	To be specified
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
9	Probe materials	Depending on temperature (see Clause 3.1.1, number 1a)	To be specified
10	Calibration	Automatic and manual zero/span calibration possible in some instruments	
11	Display possibility	LED/LCD display with diagnostic display in alphanumeric character, microprocessor based	
12	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
13	Power supply	230 V AC/24 V DC as the case may be	
14	Housing protection	IP rating (65)	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	To be specified
16	Accessories	Mounting flange/air source, flame arrestor, filter	To be specified
17	Software detail	For data storage, networking, remote control/calibration, etc., as applicable	To be specified
18	Zirconia type	*In situ*/diffusion sampling/fast response/high temperature version, etc.	To be specified
19	Special features	Special cable and cabling details, etc.	Any other

TABLE V/3.1.3-1 Paramagnetic Oxygen Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	0–25 5 by volume available, but for power plants 0–10% by volume	
2	Probe length (m)	0.5–2.0	To be specified
3	Process temperature	600–1900°C available	To be specified
4	Accuracy	±0.1% O_2/1% FSD	
5	Response time	~20 sec	To be specified
6	Output	One or two 4-20 mADC + high/high-high alarm, HART + diagnostic alarm	To be specified
7	Contact details	SPST/SPDT 50 VA 50 V 1A	

Continued

www.EngineeringBooksPDF.com

TABLE V/3.1.3-1 Paramagnetic Oxygen Analyzer Data Sheet—Cont'd

Sl	Specifying point	Standard/available data	To be specified
8	International certification	As per country requirement (see Clause 3.0.1., number 3)	To be specified
9	Sampling system	316 SS or better for probe material; SS tubing for sample line; sample pressure, temperature and flow rate limit specs	To be specified
10	Calibration	Zero/span calibration with respective gas	
11	Display type	LED/LCD display with diagnostic display	
12	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
13	Power supply	230V AC/115 V AC, as the case may be	
14	Housing protection	IP rating (65)	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	To be specified
16	Accessories	Complete sampling system, zero span gas, mounting flange, etc.	To be specified
17	Software detail	For data storage, networking, remote control/calibration, etc., if applicable	To be specified depending on need
18	Zero/span drift	<2%	To be specified
19	Special features	Other special features, if any	Optional

g. Display and operator console with selection of analyzer

2. General points for single and/or multiple component gas analyzers:
   a. International certification
   b. Type and number of outputs, alarm contacts
   c. Easy installation
   d. Diagnostic feature
   e. Operator's friendliness
   f. System connectivity/networking, e.g., HART, Fieldbus, Link RS 232

3.2.2 CO Analyzer

For a CO analyzer data sheet, see Table V/3.2.2-1.

TABLE V/3.2.2-1 CO Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	0–50/6000 ppm/0–75mg/m^3	
2	Probe/path length (m)	0.5–2.0 m (for sampling type)/6–8 m path length (*in situ*)	To be specified
3	Temperature	< 1600°C (material as per temperature)	To be specified
4	Accuracy	±2% measurement	
5	Response time	<10 sec	To be specified
6	Output	One or two 4-20mADC + high/high-high alarm contact, HART + diagnostic alarm	To be specified
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
9	Zero/span drift	<2% zero/0.5% span/week	
10	Calibration	Automatic and manual zero/span calibration possible in some instruments	
11	Display possibility	LED/LCD display with diagnostic display in alphanumeric character, microprocessor based	

www.EngineeringBooksPDF.com

TABLE V/3.2.2-1 CO Analyzer Data Sheet—Cont'd

Sl	Specifying point	Standard/available data	To be specified
12	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
13	Power supply	230 VAC/24 VDC, as the case may be	
14	Housing/material	IP rating (65)/aluminum	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	To be specified
16	Accessories	Mounting flange, special cable if any	To be specified
17	Software detail	For data storage, networking, remote control/calibrations, etc., as applicable	To be specified
18	Other gases (as applicable)	Also to specify number of such gases	To be specified
19	Special feature	Integrated flow/temperature measurement	Optional

3.2.3 CO_2 Analyzer

Both thermal conductivity and NDIR types are used. (Features in Clause 3.2.1 may be considered here also, as applicable.) See Table V/3.2.2-1 for a CO_2 analyzer data sheet.

3.3 H_2 (Purity) Gas Analyzer

3.3.1 H_2 (Purity) Analyzer in TG

Normally purity analyzing in TG is done by a complete system in place of an individual instrument.

1. TG efficiency is directly linked with the purity of H_2 gas used for cooling the generator. If there is drop in H_2 purity there will be drop in generator efficiency.
2. Two sets of analyzers are required: H_2 in CO_2 and H_2 in air.
3. For safety international standard IEC 842 and EN 60034-3 are followed. Intrinsic safety and two-stage alarms are not uncommon. When H_2 concentration is less than the set point (e.g., 95%) an alarm is generated.

3.3.2 H_2 Analysis System (Complete Analysis System)

See Table V/3.3.2-1 for an H_2 analysis system data sheet.

TABLE V/3.3.2-1 H_2 Analysis System Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	80–100%vol H_2 in air 0–100%vol H_2 in purge gas 0–100%vol air in purge gas	Range selection switch
2	Gas inlet condition	Pressure in kPa, temperature °C and flow rate L/min	To be specified
3	Cabinet	IP 54 cabinet for continuity and operation	To be specified
4	Accuracy	±0.25% FSD	To be specified
5	Response time	<10 sec	To be specified
6	Output	One or two 4-20mADC + alarm contacts with adjacent set point, + diagnostic alarm	To be specified
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3), also for intrinsic safety, if any	To be specified
9	Zero/span drift	<1% zero/0.5% span/week	

Continued

www.EngineeringBooksPDF.com

TABLE V/3.3.2-1 H_2 Analysis System Data Sheet—Cont'd

Sl	Specifying point	Standard/available data	To be specified
10	Calibration	Automatic and manual zero/span calibration possible in some instruments	
11	Display	LED/LCD display with diagnostic display	
12	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
13	Power supply	230 VAC/24 VDC	
14	Housing/material	IP rating (65)/aluminum	To be specified
15	Ambient	T: Up to 50°C RH (93%)	To be specified
16	Accessories	Mounting flange, special cable if any	To be specified
17	Software detail	For data storage, networking, remote control/ calibration etc., as applicable	Need-based specification

4. STEAM AND WATER ANALYSIS SYSTEM

4.0.1 Basics of Steam and Water Chemistry with Measurements and Controls

Modern power plants, especially steam turbines, have extremely low tolerance for any deposition and contamination. Water chemistry plays a vital role in achieving maximum efficiency with minimum downtime. To make the discussions on SWAS more meaningful, it is better to discuss steam and water chemistry beforehand. Contaminations in FW mainly comes from the following:

- Make-up water from demineralization (DM) plants (malfunctioning)
- Circulating water (CW) from condenser leakage (severe for sea water cooling)
- Conditioning chemical such as NH_3/N_2H_4 (residual to be removed)
- Corrosion products (Fe, Cu, etc.) formed in FW system
- Recycling of boiler water (mainly SiO_2)

For studying boiler chemistry following points need to be considered:

1. *Corrosion and deposition*: Basically these two phenomena are related to each other. Corrosion produces solid metallic oxides and hydroxides, which are carried away by the system flow to be deposited at another place (see Figure 4.0.1-1). Also high concentrations of deposits cause corrosion. Most of the common metals used in power plants are susceptible to corrosion in a favorable environment to form metallic oxides by reacting with atmospheric oxygen and/or with water, etc. Carbon steel (CS) is a common material used in boilers and the medium is water, so there is every possibility of a high degree of corrosion. At higher temperature, in alkaline medium, insoluble iron hydroxides are formed. Also mild steel readily corrodes in water, and the rate of corrosion is controlled by pH value. In a typical iron corrosion magnetite will be formed: $3Fe + 4H_2O = Fe_2O_3 + 4H_2$. This black iron oxide, a typical product of corrosion, inhibits further excess corrosion by forming a magnetite layer. Also copper and copper alloys form a protective layer of cuprous oxide. Some metals like aluminum, chromium, and titanium can form protective oxide layers when they come in contact with air and moisture. For this reason, cast aluminum is used as the casing of many instruments. The stability of these protective layers depends highly on pH value. To maintain pH value, ammonia is added, but it corrodes copper alloys. So pH value needs to be maintained at a moderate value. Dissolve oxygen (DO) may cause pitting. This is especially important at closed heaters and at economizers, where temperature rises rapidly. At higher temperature, even small concentrations of DO could cause severe corrosion and economizer tube failure due to pitting. Variations in pH are another big cause for corrosion. Other boiler corrosions include:

   a. Chloride corrosion—acidic attack
   b. Stress corrosion
   c. Scale formation on heat transfer surface
   d. Caustic corrosion

   Deposition could be caused by carryover from softener, ion exchange, condensate system leakage, etc. Boiler deposition takes place (1) at the drum, the hottest area where steam is formed, i.e., where nucleate boiling occurs; (2) in the whole boiler system there exists a thermal gradient so at the hottest point deposition takes place; and (3) at the region of low flow. Deposition in the tube of superheater, etc., can lead to tube failure or leakage due to overheating. Carryover can cause damage to the turbine blade or may

www.EngineeringBooksPDF.com

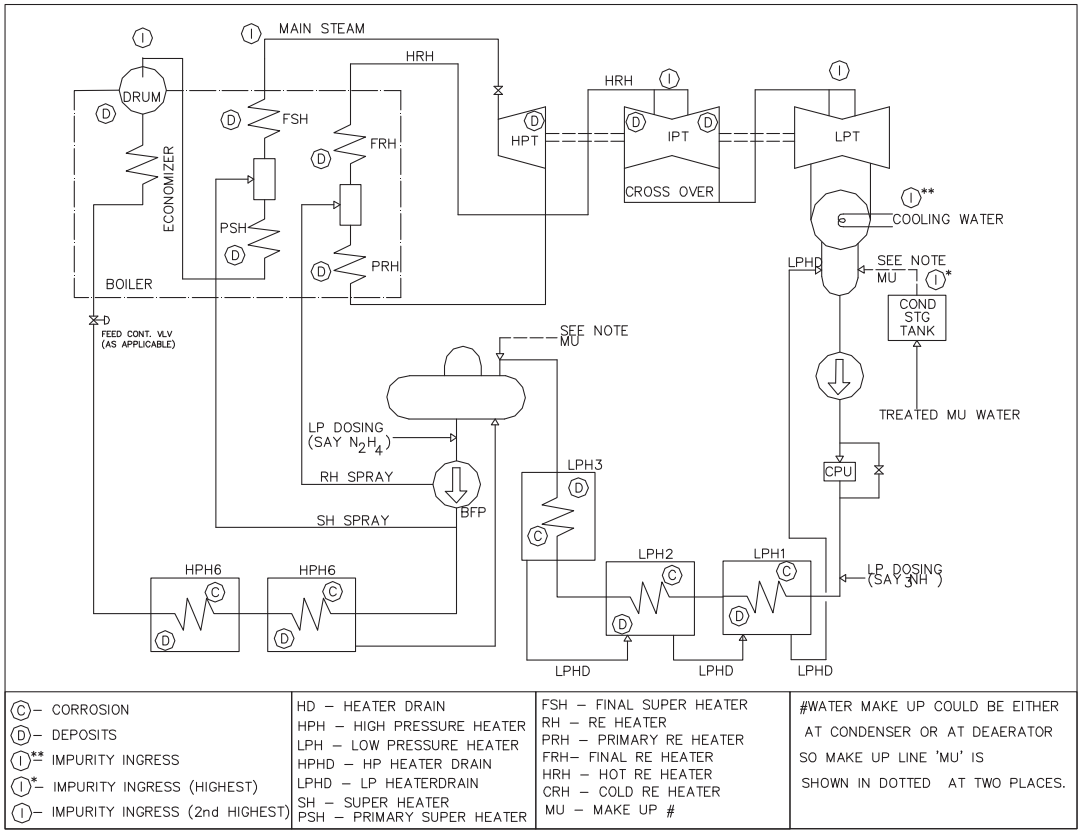


FIGURE V/4.0.1-1 Typical corrosion and deposits in power cycle.

cause sticking of the stop/governor valves and may lead to catastrophic damage to the turbine due to over speed. Silica is an important factor. CW is one of the sources of silica. It also needs to be controlled at DM plants. Operating conditions may lead to chemical damage to the system such as foaming, synthetic contamination, etc.

2. *Sources of contamination*: The major source of water contamination in power plants is the leakage of CW circuit in condenser and other heat exchangers. Chemical quality of CW influences the scale formation and corrosion in boiler. Sea water containing Ca/Mg ions reacts with the boiler to form mineral acids. Early indications of such failure are possible by cat ion conductivity at condensate extraction pump (CEP) discharge. Make-up water is another source of contamination. One of the major equipment/systems installed in medium/large power plant (to improve the quality of water) is the full or partial condensate polishing unit (CPU). Maintenance of water and steam purity is extremely important to prevent
   - **a.** Corrosion in water and steam systems in boiler and turbines
   - **b.** Formation of any deposit and/or scale in the tubes and pipes and turbine deposition
3. *Hydrogen embrittlement*: Sometimes referred to as Hydrogen induced cracking, it is the process by which metals, mainly high-strength steel, become brittle on exposure to Hydrogen. At high temperature the solubility of hydrogen increases and allows hydrogen to diffuse into the metal. These hydrogen atoms recombine in the void of the metal space to form hydrogen molecules and create pressure from inside. When this pressure is increased to the level that is high enough to overcome tensile strength of the metal, cracks start. These may occur in the metal during the manufacturing process or any of the processes like cathodic protection, phosphating, pickling, etc., or during operation, e.g., decarburization (when carbon steel is exposed to temperature $>500°C$ and pressure >100 kg/cm^2). Decarburization at steam side may be: $3Fe + 4H_2O = Fe_3O_4 + 4H_2$ resulting in hydrogen damage of the steel. For this reason H_2 in main steam is monitored by a katharometer (see Clause 3.0.8).
4. *Treatment requirement*: It is necessary to treat the boiler water to produce the protective coat on the tubes required for good quality water and steam. For this it is necessary that the water has low controlled alkaline, a very low level of DO, and a very low presence of ions like Cl^-. Silica from CW is another damaging

www.EngineeringBooksPDF.com

factor as it deposits on the turbine. Silica needs to be controlled at the DM plant as well. The percentage of impurity allowed in boiler water/steam is a function of boiler-operating pressure, so it is more critical for high-pressure boilers.

Two basic ways to regulate corrosion in water are all volatile treatment (AVT) and oxygenated treatment (OT). Two types of AVT are (1) AVT (R) using ammonia (NH_3) and as a reducing agent say, hydrazine (N_2H_4) and (2) AVT (O) is the same as AVT (R) minus the reducing agent, (i.e., N_2H_4). Ammonia is a commonly used cheaper material to maintain pH in boiler water. N_2H_4 is used to scavenge DO and protect copper alloys from ammonia. It may be good for Cu alloys, but it forms a thick, harder magnetite layer. In OT ammonia is used to control pH and remove oxygen, but the slightly oxidizing environment is maintained to promote formation of the oxidizing layer on the metal surface. In SC and subcritical plants (with CPU), after start-up OT is done. This treatment feeds oxygen to the condensate and FW to arrest corrosion as well as internal scale formation; hence, there is less chemical cleaning. Normally after start-up during operation OT is done to reduce internal scale formation at operating temperature. Further details are available in Appendix V. Oxygen may enter into the system from air in leakage through the LP turbine and condenser. Also oxygen may come from make-up water and/or from return condensate. Oxygen removal is done by mechanical deaeration, chemical injection, and by catalytic deaeration. Deaeration of water at the deaerator is done to remove DO, carbon dioxide, and other noncondensable gases as well as to heat the water to the temperature where solubility of undesirable gases are at a minimum. It is possible to bring DO to 3–40 ppb and almost zero (free) carbon dioxide. The rest of the DO is scavenged by chemical means such as hydrazine (or ascorbic acid/diethyl hydroxylamine): $N_2H_4 + O_2 = N_2 + 2H_2O$. This also controls pH, because at high temperature and pressure NH_3 breaks down and increases pH. On account of health hazard, many do not prefer hydrazine. Instead many use DEHA which has nearly 40 times less toxicity when tested in animals. Diethylhyrdoxylamine (DEHA) has unique properties such as volatility, passivating steel surface, coupled with low toxicity makes DEHA a good Oxygen Scavenger in modern days power plants. Some of the features of DHA shall include:

Rapid scavenging of O_2 at FW temperature and pH control,

Passivate internal surfaces of boiler.

Volatility with steam similar to neutralizing amine with ability for distilled of boiler and protects steam and condensate equipment.

Under heat it yields two neutralizing amines to raise pH value.

Low toxicity hence less health hazard.

Reaction with Oxygen: $4(C_2H_5)_2NOH + 9O_2 = CH_3COOH + 2N_2 + 6H_2O$. In hydroxide alkalinity of boiler acetic acid does not pose any problem and acetates are formed. Only shortcoming is its sluggishness in reaction kinetics of oxygen capture at lower temperature. This is circumvented by use of coscavenger Hydroquinone (HQ) used with DEHA. There is a direct relation between pH and conductivity as shown in Figure 4.0.1-2.

Dosing is done at the high-pressure boiler. All these exercises are done to minimize depositions. Otherwise, silica, sodium salt, etc., are carried over with steam to the turbine where, with a fall in pressure and temperature, the solubility falls and gets deposited at the turbine.

5. *Treatment requirements for high-pressure, high-temperature plants*: For Chemistry control in OT boilers, the following considerations are important:
   - **a.** No phase-separating device like a boiler drum
   - **b.** FW, boiler water, and steam is a continuous fluid stream
   - **c.** Sliding pressure operation (fixed pressure is less susceptible to corrosion)
   - **d.** Like subcritical boilers, FW treatments are AVT and OT

   As discussed, AVT (R) forms a thick layer, which may give rise to an increase in metal temperature, especially in SC boilers so they require frequent cleaning. AVT (O) excludes the use of any oxidizing agent so electro chemical

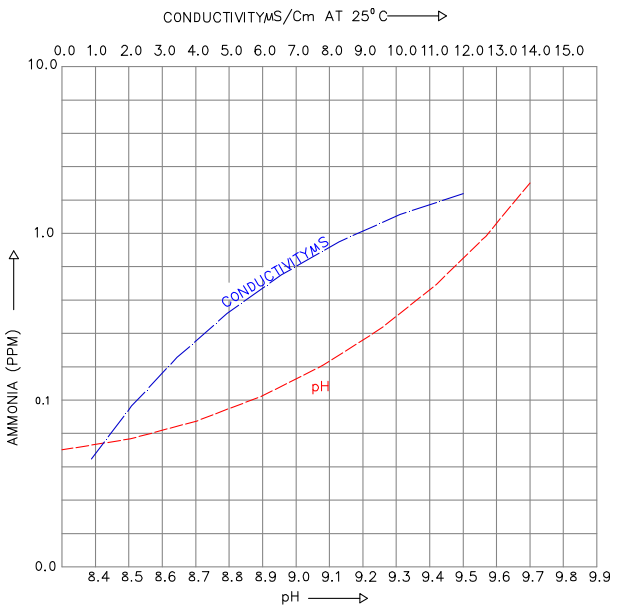


FIGURE V/4.0.1-2 Variation of pH and conductivity WRT ammonia.

www.EngineeringBooksPDF.com

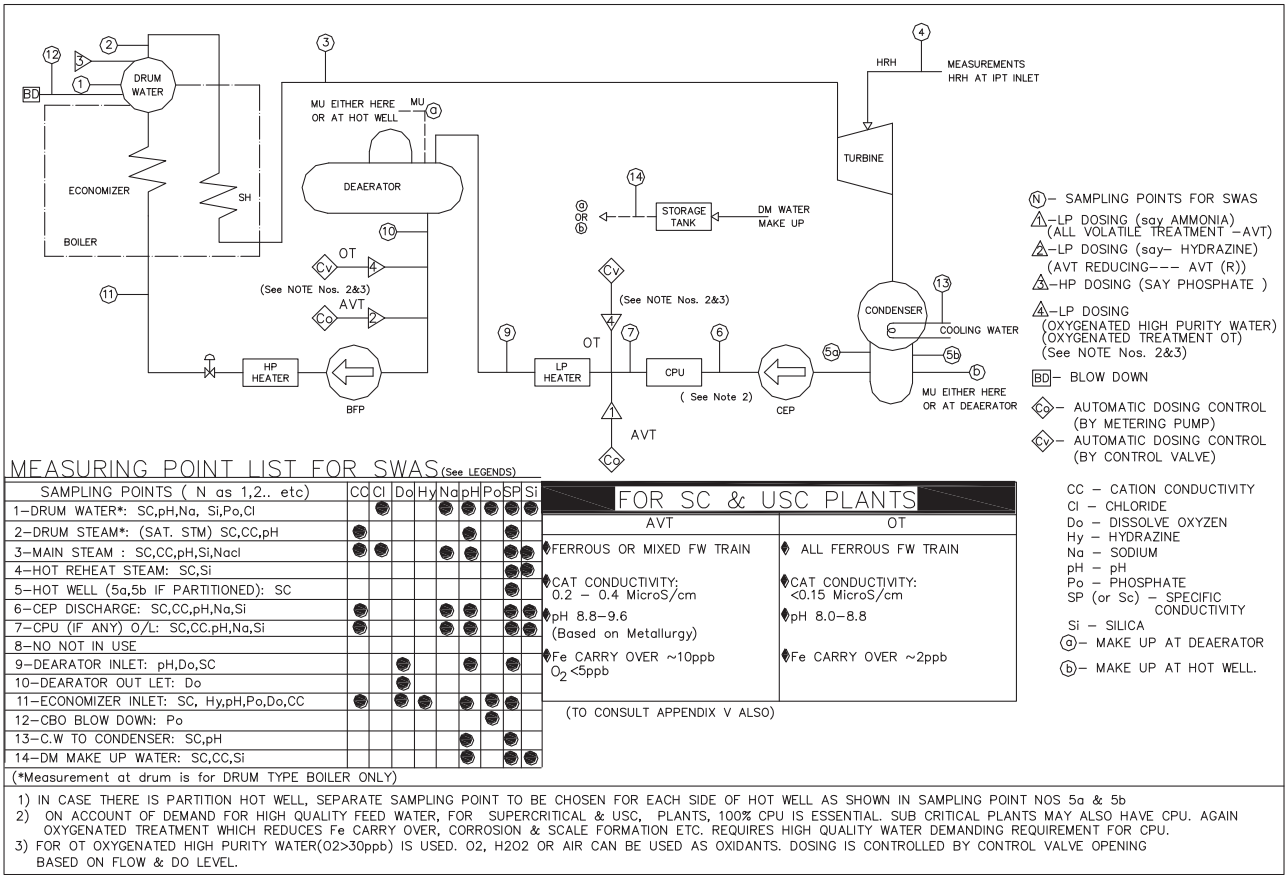


FIGURE V/4.0.1-3 Power cycle sampling, dosing, and blow down points.

potential (ECP) will be higher. It also favors formation of hematite (which is less soluble) on the top of magnetite. This layer is thinner and minimizes orifice fouling. On the other hand, AVT (O) provides more ECP, which forms a hematite layer that is stable, and there will be less iron oxide in the FW. Major systems use OT (e.g., Hitachi design for 1000 MW boiler), but a disadvantage is that when oxygen is coupled with anions it is highly corrosive.

6. *Sodium (Na) measurement*: Generally sodium is present as chloride and sulfate and can come to the system through:
   - **a.** Condenser tube leakage.
   - **b.** Na^+ is the first cat ion that breaks when a bed is exhausted (at CPU or DM)
   - **c.** In drum sodium triphosphate is added to remove scaling effect, so this could be a source

   It is important to maintain the sodium balance between condensate and in the steam. Excess sodium results in a problem of deposition in superheater tubes and turbine blades. In an OT boiler the requirement is more stringent, making almost all modern large power plants have Na^+ monitoring. Also Na^+ measurement is sensitive to changing pH and temperature.

7. *SWAS measuring points dosing control and blow down*: A detailed picture of the overall system is presented in Figure V/4.0.1-3. Tables V/4.0.1.8-1 through V/4.0.1.8-13 presented below give the various

TABLE V/4.0.1.8-1 MP1: Service: Drum Water

Parameter	Limit/target/range	Unit	Remarks
Chloride (Cl)	<200/<20/0–200	µg/kg or L	$OP
pH	8.8–9.2		
Phosphate (PO)	<1*/Range: 0–10	mg/L	*EPT
Silica (Si)	<<200/<20/0–100	µg/kg or L	
Specific conductivity (SP)	/3/0–10	µS/cm	At 25° ℃
Sodium (Na)*	<100/5–10/0–10/100	µg/kg or L	*$

www.EngineeringBooksPDF.com

TABLE V/4.0.1.8-2 MP2: Service: Drum Steam

Parameter	Limit/target/ range	Unit	Remarks
Cat conductivity (CC)	<0.8/<0.08/0 −1/10	µg/kg or L	Multirange for continuity
pH	8.8−9.2		
Specific conductivity (SP)	/2−3*/0−10	µS/cm	At 25°C(*$)

TABLE V/4.0.1.8-3 MP3: Service: Main Steam to HPT

Parameter	Limit/target/ range	Unit	Remarks
Cat conductivity (CC)	<3/<0.08/0 −1*	µS/cm	
Chloride (Cl)	<100/<2/0 −20/200	µg/kg or L	*$
pH	>9*		*AVT treated
Silica (Si)	<<100/<5/0 −50/100	µg/kg or L	
Specific conductivity (SP)	/2−3/0−10	µS/cm	At 25°C
Sodium (Na)	<100/5−10/0 −10/100	µg/kg or L	*$

TABLE V/4.0.1.8-4 MP4: Service: HRH Steam to IPT

Parameter	Limit/Target/ Range	Unit	Remarks
Silica (Si)	<<100/<5/0 −50/100	µg/kg or L	
Specific conductivity (SP)	−/2−3/0−10	µS/cm	At 25°C

TABLE V/4.0.1.8-5 MP5: Service: Hotwell (Two Sets if Partitioned)

Parameter	Limit/target/ range	Unit	Remarks
Specific conductivity (SP)	11/3/0−20/50	µS/cm	At 25°C

TABLE V/4.0.1.8-6 MP6: Service: Condensate at CEP Discharge

Parameter	Limit/target/ range	Unit	Remarks
Cat conductivity (CC)	<3/<0.2/0−1	µS/cm	
pH*	>8.8−9.3		*AVT mainly
Silica (Si)	<<100/<20/0 −50/100	µg/kg or L	
Specific conductivity (SP)	~15/3/0−10	µS/cm	At 25°C
Sodium (Na)	<100/5−10/0 −10/100	µg/kg or L	*$

TABLE V/4.0.1.8-7 MP7: Service: CPU (if Any) O/L**

Parameter	Limit/target/ range	Unit	Remarks
Cat conductivity (CC)	<3/<0.08/0 −1/10	µS/cm	
pH	>8.8 −9.3(9.2*)		*AVT mainly
Silica (Si)	<<100/<5/0 −50/100	µg/kg or L	
Specific conductivity (SP)	~1/0.08/0−1	µS/cm	At 25°C
Sodium (Na)	<200/<2/0 −10/500	µg/kg or L	*$

MP8 is not in use.

TABLE V/4.0.1.8-8 MP9: Service: Deaerator Inlet

Parameter	Limit/target/ range	Unit	Remarks
DO	<200/<50/0 −50/100	µg/kg or L	
pH	8.6−9.0		
Specific conductivity (SP)	15/2.5/0−550	µS/cm	At 25°C

www.EngineeringBooksPDF.com

TABLE V/4.0.1.8-9 MP10: Service: Deaerator Outlet

Parameter	Limit/target/range	Unit	Remarks
DO	<100/<10/0–50/100	µg/kg or L	Value also depends on deaeration type

TABLE V/4.0.1.8-10 MP11: Service: FW at Economizer inlet

Parameter	Limit/target/range	Unit	Remarks
Cat conductivity (CC)	<3/<0.08/0–1*	µS/cm	
DO	<100*/<5–20/0–20/200	µg/kg or L	*Time dependent and possible for OT
Hydrazine (HY)	–/<10–20/0–50	ppb	
pH	>9*		*AVT treated
Phosphate (PO)	/<5–20/0–50/100	µg/kg or L	
Specific conductivity (SP)	<12/2–3/0–10	µS/cm	At 25°C

TABLE V/4.0.1.8-11 MP12: Service: CBD

Parameter	Limit/target/range	Unit	Remarks
Phosphate (PO)	<20/0–50/100	µg/kg or L	

TABLE V/4.0.1.8-12 MP13: Service: CW to Condenser

Parameter	Limit/target/range	Unit	Remarks
pH	<8.3*		*Above this acid may be injected
Specific conductivity (SP)	1.2	mS/cm	At 25°C

TABLE V/4.0.1.8-13 MP14: Service: DM Make Up

Parameter	Limit/target/range	Unit	Remarks
Cat conductivity (CC)	–/<0.1/0–1	µS/cm	
Silica (Si)	–/<20/0–50/100	µg/kg or L	Silica (Si)
Specific conductivity (SP)	–/<0.1/0–1	mS/cm	At 25°C

sampling points and parameter details such as approximate value (or approximate safe range). NA stands for not applicable (i.e., parameter not measured/relevant).

a. Notes on the list of measurements for SWAS:

i. Parameters depend on operating condition of the boiler (on pressure), so these data are indicative/typical values only.

ii. Specific conductivity depends on dissolved solids, and the presence of NH_3 and CO_2 can change the value significantly. It also depends on pH.

iii. Selectable ranges in instruments are indicated by "/" in UP range.

iv. Symbols used: **$**, depends on operating condition and local decision; EPT, equilibrium phosphate treatment (among the various phosphate treatment means EPT is very effective at maintaining desired boiler pH), MP, measuring point.

v. pH value varies little with AVT/OT treatment of water.

Ammonia low-pressure dosing systems are shown in plants without CPU, ammonia (LP) dosing is seen at CEP discharge. For plants with CPU, ammonia (LP) dosing is done at the CPU outlet.

b. *Typical parameters for SC boilers* (EPRI Recommended targets are more stringent):

i. *DM water*: Specific conductivity: < 0.1 µS (0.1–0.2 alarm), TOC < 300 ppb, SiO_2: < 10 ppb (>10 alarm), Na < 5 ppb, Fe < 20 ppb

ii. *Hotwell outlet*: Specific conductivity: 2.5–10, cat conductivity < 0.2 µS (0.2–0.5 alarm), pH 9.0–9.6, Fe < 20 ppb. see Table V/4.0.1.8-14 for FW chemical corrosion parameters

iii. *Main steam/RH steam*: Specific conductivity (µS) 2.5–7.0, cat conductivity (µS) < 0.2, pH 9.0–9.6, Na/K (ppb) < 5, SiO_2 (ppb) < 20, Fe (ppb) < 20.

www.EngineeringBooksPDF.com

TABLE V/4.0.1.8-14 FW Chemical Corrosion Parameter (Alarm)

Parameter	AVT	OT	Remarks
Specific conductivity (μS)	4–10	2.5–7	
Cat conductivity (μS)	0.2(0.2–0.5)	<0.2 (>0.2 –0.5)	
pH	9.2–9.6 (<9.2, >9.6)	8.5–9.0	
Na/K (ppb)	<5 (>5)	<5	
SiO_2 (ppb)	<20 (>20)		
Oxygen (ppb)	<10 (>50)	50–150	
Hydrazine(ppb)	Trace		
Fe (ppb)	<20		

8. Chemical dosing control (see Clause 6) and blow down:
   a. *LP dosing control*: One ammonia dosing is used to control pH of the condensate; two hydrazine (or other O_2 scavenger say, DEHA) dosing (AVT-R) at BFP suction to scavenge DO.
   b. HP dosing control: Three phosphate dosing at drum for controlling Na.
   c. Blow down: Point #12: from boiler drum.

4.0.2 HRSG

Some MPs at HRSGs for combined cycle/cogeneration plants are seen in Table V/4.0.2-1.

4.0.3 Cause and Effect of Some Impurities in Water

For a list of these, see Table V/4.0.3-1.

4.0.4 CPU

For higher size and SC plants the requirement for a CPU is essential. Details on CPUs were presented in Chapter II, Clause 3.6. During normal operating conditions with a steady flow rate corrosion may be at minimum due to chemical dosing. When the unit is in shut down, the corrosion rate increases rapidly (due to oxygen entry). So, during start-up, a great deal of blow down may be necessary, resulting loss of time and water. The CPU helps to rapidly start the system. Traces of soluble impurities entering the system become concentrated within the system in high-pressure boilers. In SC and USC plants a single-phase fluid exists, so all the boiler fluid enters the turbine. These may deposit on turbine blades leading to inefficiency and mechanical damage. So OT boilers (especially for SC boilers) 100% CPU is essential. Depending on operating conditions CPU may be partial (50%) or 100%. CPU in condensate line would cause a pressure drop at a very high flow ($\sim$1550m^3/h for a 660 MW plant is typical) leading to system loss. The 3 × 50% vessel combination in the CPU is the most popular configuration. Original specifications for water quality at the CPU outlet for fossil fuel SC units were conductivity < 0.1 μS/cm at 25°C and Na < 5 μg/kg. Even better water qualities are available now at the CPU outlet. Major factors influencing CPU selections are

- Flow rate
- Quality of the water to be treated
- Regeneration procedure and conditions
- CPU O/L water quality and quantity.

Operationally CPU is sequential, so for sequential operation there is a dedicated PLC, or open-loop regeneration mode initiation could be selected by the following:

- Manual
- Time based (timer)
- Differential instrument
- Flow

TABLE V/4.0.2-1 Chemical MPs for HRSG (Typical)

Sampling points	CC	DO	Na	pH	Si	SP	Remarks
Condenser hotwell						X	For symbols see tables above
Condensate pump discharge	X	X				X	
LP/IP evaporator water				X		X	
LP steam	X				X		
HP evaporator water				X	X	X	
HP/IP steam	X		X		X		
Other steam				X		X	

www.EngineeringBooksPDF.com

TABLE V/4.0.3-1 Cause and Effect of Some Impurities in Water

Item	Effect	Remedy	Remarks
CO_2	Corrosive to form carbonic acid	Deaeration—neutralized in alkaline medium	
DO	Corrosion, pitting, failure of boiler tubes, turbine blade	Deaeration—mechanical means, hydrazine dosing chemical means	
Sedimentation and turbidity	Sludge, scale carryover	Clarification, filtration at pretreatment plant; also condensate blow down	<5 ppm
Organic matter	Deposits, clogging, etc.	Chemical treatment at DM plant after pretreatment	
Hardness	Scale formation, thermal inefficiency, low heat transfer	Softening plant, internal treatment at boiler	
Na	Formation of carbonates, corrosion, even embrittlement	Deaeration, of make-up water, ret. condensate and ion exchange deionization and acid treatment of treatment of make-up water	
SO_4	Scale formation	Deionization	Treatment through CPU as well
Cl_2	Priming, salt deposits at boiler tube and turbine	Deionization	Treatment through CPU as well
Si	Hard scale and deposit at turbine blade	Deionization	Treatment through CPU as well

Some of the major control initiations are

- Sequence selection mode Man/Semi/Auto
- Regeneration mode selection Auto/Manual
- Local remote selection
- Transfer initiate
- Transfer interrupt
- Regeneration initiation, etc.

Control systems of DCS are normally used. The mode of operations could be the following:

- Manual from local panel
- Semi-automatic mode with manual mode selecting (e.g., regeneration), then automatic steps in the selected mode
- Automatic mode where mode selection as well as all sequences in the steps are automatic

4.1 Conductivity Analysis System: Conductivity Measurement

Conductivity measurement is done in power plants to get an idea about the soluble salts in condensate and FW. In power stations, two types of conductivity measurements are done: specific conductivity and cation conductivity, as discussed. Various features that need to be considered are discussed below:

- For measurement of conductivity by analyzer it is necessary to fix up the cell constant. Table V/4.1-1 lists some details.
- Standard solution of 7.4 g KCl/L at 20°C for cell constant ~1.0 is used, whereas 0.74 g KCl/L at 20°C for cell constant ~0.1 is used. These are approximate values.

TABLE V/4.1-1 Conductivity Selection Guideline

Conductivity range (μS/cm)	0–20	1–100	10–200	10–1000	100–20,000
Cell constant	0.01	0.05	0.1	1	10
Remarks	Each sensor set has a selectable two-cell constant in the range 1–10—but this is the rule of thumb, and is not fixed.				

www.EngineeringBooksPDF.com

- Size, shape, position, etc., of measuring electrode in a conductivity cell determines the cell constant of the conductivity cell.
- Measurement of conductivity depends greatly on temperature. As conductivity in solution increases with a rise in temperature. It is therefore necessary to consider temperature compensation.
- In conductivity measurement with direct **e**lectrical contact, polarization effect also affects the reading. Polarization depends on the *surface of the electrode and frequency* of AC excitation. Use of a carbon electrode is very helpful in eliminating the polarization effect.
- The conductivity-measuring electrodes should be located away from the high temperature and vibration and shocking zones.

4.1.1 Conductivity Analyzer Description

1. Various types of conductivity cells include: insertion, screw, flow cell, retractable with valve, etc. In the central SWAS panel, flow cell type is the most popular. However, for condenser hotwell application, many plants use the insertion type to measure the conductivity online to avoid use of vacuum pumps to bring the sample to the panel.
2. In case of insertion and dip types, the length of insertion needs to be specified and in all types the connection size and style need to be specified as well.
3. Most materials used by major manufacturers include:
   a. *Electrode*: Carbon/graphite, stainless steel 316, titanium, platinized (commonly used in power plants, but it may have problems associated with mechanical cleaning)
   b. *Body*: Epoxy resin, stainless steel, brass-epoxy resin flow cell is commonly used
   c. *Monitor material*: ABS, epoxy-painted aluminum, carbon steel, etc. (manufacturer standard)
4. Most often a sensor is connected to the transmitter by cable, which forms the part of the instrument to be supplied. Cable length desired to be coordinated with manufacturer and to be specified.
5. Maximum allowable operating pressure and temperature should be specified and/or selected from the manufacturer's data sheet.
6. Temperature sensor generally used is the Pt100 RTD. Temperature compensations are automatic, and compensation range is to be specified. In SWAS the sample is generally conditioned to 25°C.
7. Apart from contact type conductivity instruments, there are also toroidal conductivity instruments. This type of instrument has one driving coil and one pickup coil. The driving coil is excited by AC voltage, and due to induction there is current in the pickup coil. The amount of pickup depends on the solution conductivity. This is shown in Figure V/4.1-1. Since in this method direct contact is unnecessary, it is good to measure conductivity in oily and sticky material. In SWAS this may not find much application.
8. Cell constants 0.01, 0.1, and 1.0 μS/cm are generally used.
9. The self-diagnostic feature in the transmitter is common for all systems. Both remote and local alarms can be generated from a diagnostic program.
10. Most of the transmitters are the smart programmable type with integral display. Most of them are capable of ON/OFF control functions and can provide requisite alarm contacts.

4.1.2 Conductivity Analysis Working Principles

A conductivity cell consists of two electrodes made of carbon or metals. In contact with the electrolyte (sample) the two electrodes are excited by an AC source as shown in the adjacent figure. The electrolyte basically offers resistance to this current flow. Naturally the amount of current flowing through the sample is proportional to the conductivity (inverse of resistivity) of the sample. The measurement of conductivity depends on cell constant, which is a function of length, surface, and geometry of electrode. Cell Constant (c) is the current response of a sensor due to sensor dimension and geometry. Its unit is cm^{-1}. The relation between specific conductivity K and cell constant is $K = c/R$, where R = resistance across electrodes. Since R is temperature dependent, K is also dependent on temperature. For this, conductivity is generally expressed at a specific temperature, normally 25°C (see Figure V/4.1-2). Also see Figure V/4.1-1 for various types of conductivity measurement types.

4.1.3 Accessories for Conductivity Analyzer

See Table V/4.1.3-1 for a list of major accessories for the analysis system. A conductivity sensor and transmitter are depicted in Figure V/4.1-3.

4.1.4 Conductivity Analyzer

Table V/4.1.4-1 is a data sheet for a conductivity analyzer.

4.1.5 Conductivity: pH

As discussed in Clause 4.0, there is a direct relationship between conductivity and pH. This relationship has been utilized for pH calculation by differential conductivity instruments. One of these instruments is the Polymetron 9123. Here conductivity before and after the cation is measured and based on a built-in algorithm, the pH calculation is done.

www.EngineeringBooksPDF.com

What is Conductivity?

When current is passed through an electrolyte then it generally obeys Ohm's law, and the ability of the electrolyte to conduct electricity is the conductance of the electrolyte. Conductivity of any electrolyte is due to the presence of ion in the electrolyte, so it cannot detect the material nor the concentration. In certain cases, the concentration of an electrolyte in solution can be determined by conductivity, if the composition of the solution is known (as is sometimes done in DM plants). Its unit is Siemens/cm (or mho/cm). For convenience it is expressed in terms of µS/cm.

Why catIon Conductivity? What is it?

The disadvantage of using specific conductance is that some gases common to steam (such as carbon dioxide and ammonia) ionize in water solution. Even at extremely low concentrations, they interfere with measurement of dissolved solids by increasing conductivity. Low concentrations of dissolved solid may give rise to low conductivity, but this may be increased due to dissolved gases such as CO_2 or NH_3. Now when this is passed through Cat col. (acting in cation exchange principle)it can help to detect dissolved solids. Now when there is chemical reaction inside the Cat col., when there is dissolved ammonia:

R-H + NH_4OH R-NH_3 + H_2O --------(1)

Whereas, the reaction when it contains salt will be

R-H + NaCl R-Na + HCl----------(2)

Cations replace NH_4 ions and the outcome is water, i.e., conductivity of NH_4 is eliminated as it is pure water. On the contrary, in Equation 2 the outcome is HCl, thus, in this case conductivity is almost three times more than imparted by NaCl, i.e., highly increased. So in normal operation if after cation conductivity reading is increased it suggests that there is contamination (due to leakage, for example).

FIGURE V/4.1-1 Concept of conductivity.

4.2 pH Analyzer: *pH Measurement*

In 1909 Soresen coined the term pH. Here "p" stands for the mathematical symbol of negative logarithm, and H" stands for the chemical symbol for Hydrogen. The formal definition of pH $= -\log_{10}[H]^{+}$. From chemical dissociation principles it is known that in any aqueous solution, the concentration (molar) of the hydrogen ion multiplied by the concentration of hydroxide ions is constant; $K_w = [H^{+}][OH^{-}]$ where K_w is the dissociation constant and dependent on temperature. $K_w = 1$ when T = 25° C; normally pH is defined at 25°C. Acid water concentration, with hydrogen ion concentration 1.0×10^{-4} has a pH value of 4 as per definition of pH (see Figure V/4.2-1). The simplified Nernst relationship equation is as follows:

$$E_g = E_g^0 + \{(2.303RT)/n * F\} * \log_{10} a,$$

where E_g = sum of reference potential and liquid junction (LJ); $E^{o}{}_g$ = potential when $a = 1$; a = hydrogen ion activity, for hydrogen number of mole $n = 1$; T = Abs

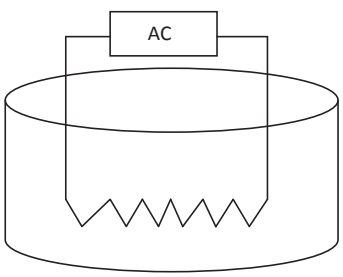


FIGURE V/4.1-2 Conductivity analysis working principles.

TABLE V/4.1.3-1 Accessories for Conductivity Analyzer: Major Accessories for the Analysis System

• Temperature sensing probe	• Coaxial and other cable
• Electrode holder	• Junction box
• Flow cell	• Receptacle, cab gland and other electrical accessories
• Cat column (if any)	• Any other as required

www.EngineeringBooksPDF.com

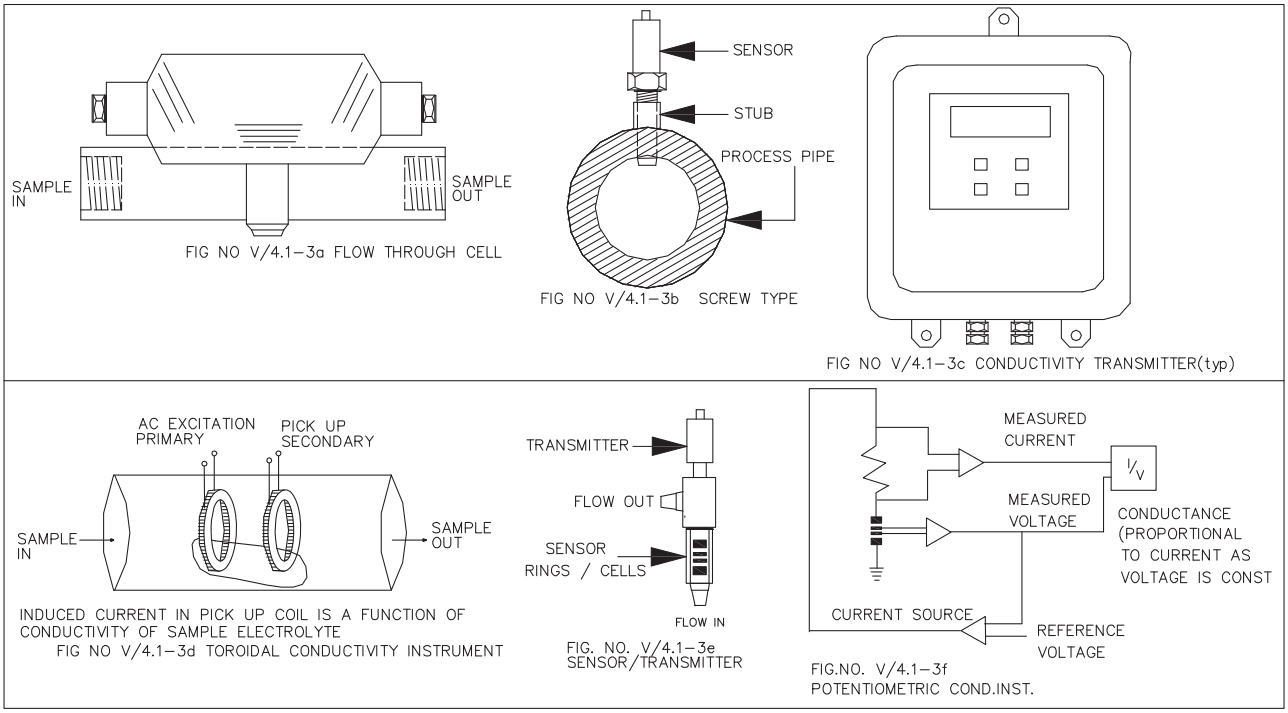


FIGURE V/4.1-3 Conductivity sensor and transmitter.

TABLE V/4.1.4-1 Conductivity Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Type	Insertion/screw/dip/flow cell/retract able type	To be specified
2	Output	1 or 2 4-20mADc + alarm contacts	To be specified
3	Temperature compensation	Automatic temperature compensation	To be specified
4	Accuracy/linearity/repeatability	±1% FSD/0.1 FSD/0.3 FSD	
5	Process condition	To specify + pressure and temperature conditions	To be specified
6	Contact details	SPST/SPDT 50 VA 50 V 1A	
7	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
8	Materials	Manufacturer's standard	To be specified
9	Calibration	Automatic and manual zero/span	
10	Display	LED/LCD (back-lit) and diagnostic	
11	Connectivity	RS 232/485/MODBUS/HART/Profibus/Ethernet, etc.	
12	Power supply	230 VAC/24 VDC	
13	Housing	IP rating (65)	To be specified
14	Ambient condition	T: Up to 50°C RH (93%)	To be specified
15	Accessories	Discussed separately above	To be specified
16	Process connection	To specify based on project standard	l 1/2" or 3/4" NPT(typical)
17	Software detail	For data storage, networking, remote control (FTP)/calibration, etc.	To be specified depending on need
18	Special features	Programming feature, RFI effect standard	To be considered

www.EngineeringBooksPDF.com

What is pH? What is pH scale?

Acidity and alkalinity of a solution is indicated by pH. It may be defined as the logarithm of the reciprocal of hydrogen-ion concentration in gram atoms per liter. pH = (-)$log_{10}[H^+]$ - $log_{10}(1/[H^+])$.

pH scale is defined between 0-14 division with pH 7 (neutral distilled water). pH values >7 are basic and pH < 7 is acidic in nature. HCl(1), H2SO4 (1.2) is at the extreme end in the acid side with NH4OH(11) and NaOH(13) at the other (basic) end of the pH table with distilled water at the middle(7). In power plant boiler feed water pH is kept a little alkaline. Note that pH has direct influence on conductivity and measurement is temperature dependent.

FIGURE V/4.2-1 pH measurement.

temperature in K; $R = 1.986$ cal/mol degree; and $F =$ faraday (col per mol). Finally $E = E^0 + 0.059$ V pH.

There are a few terms associated with pH measurements that need to be properly understood. A few of them are briefly presented below. As the detailed theoretical part is beyond the scope of the book, for further details please refer to standard textbooks

- *Reference electrode*: Maintains stable constant potential independent of solution under test, but it depends on concentration of KCl solution. Ag wire with AgCl coating in close contact with KCl solution is the reference electrode used in most cases.
- *LJ*: KCl electrolyte of the reference electrode has to have a contact with the solution under test to complete the electrical path. This is done through a salt bridge or LJ, which is a porous plug that restricts the flow of electrolyte from the reference electrode to maintain constant potential. The type of LJ influences response time of the electrode. LJs again come in different shapes, like flushed, notched, and recessed types. It is recommended to consult the manufacturer for their use in a particular application. One of the major problems associated with pH is the plugging of the LJ (to cause the drift in reading), especially if there are suspended particles. If the pores are smaller, particles cannot accumulate in the pore (as they cannot get into the pore) and diffusion takes place. Double junctions help avoid plugging from KCl and also prevent poisoning (see Figure V/4.2-2b).
- *LJ potential*: Diffusion of KCl makes the electrical contact. An LJ potential exists when two dissimilar electrolyte solutions come in contact (through a salt bridge) but are not allowed to mix. Because of the difference in concentration there will be diffusion, which drives the ion from one side to the other. Since K^+ and Cl^- have different mobilities, during diffusion there will be potential because charge separation increases. This is called LJ potential. When dissimilar electrolytes come in contact there will be a potential, LJ potential, whose only aim is to keep the potential low and constant.
- *Glass membrane shape and types*: Different shapes offer different properties. These are detailed in Figure V/4.2-2e. There are different types of membrane glass for accurate measurement of pH at different applications. The resistance of the measuring electrode can change in electrode response. This pH electrode resistance depends on the composition of glass, thickness, and shape.
- *Electrode selection*: Length of time necessary to get a stable reading from the instrument when the sensor is changed from solution to other (or if temperature varies) is the response time, which depends highly on the electrode selection. Also the LJ directly affects the flow rate of electrolytes from the reference electrode into the sample, thus the LJ potential varies. Therefore the electrode selection is of immense importance.
- *Calibrating buffer*: Calibration buffer has to be of known pH at 25°C. Selecting the buffer solution is necessary to select an accurate pH. It is customary to use two known buffers for calibration as there are variations in commercial buffers. The difference between the two buffers should be minimal. Some pH meters have the ability to recognize the buffer, so it is better to consult the manufacturer for buffer pH values.
- *Electrode storage and use*: Dry electrodes are supplied by the manufacturer, and they need to be conditioned as per the manufacturer's recommendation or place them in HCl acid solution for 12 hours. pH electrodes should not be allowed to dry out, instead they may be kept in DM water at a temperature close to the temperature to which they would be subjected.
- *Scale and slope controls*: It is recommended that these should be done in line with the manufacturer's recommendation. In modern smart instruments these also can be done at the meter. (Slope is the mV response of the sensor per pH of the sample.)
- *Na^+ error*: Ideally pH versus mV should be a straight line, but at higher pH values it is not so. This is because, ideally, glass electrodes need to respond to H^+, but it is also affected by Na^+. As pH increases H^+ starts decreasing and Na^+ become more prominent. It is

www.EngineeringBooksPDF.com

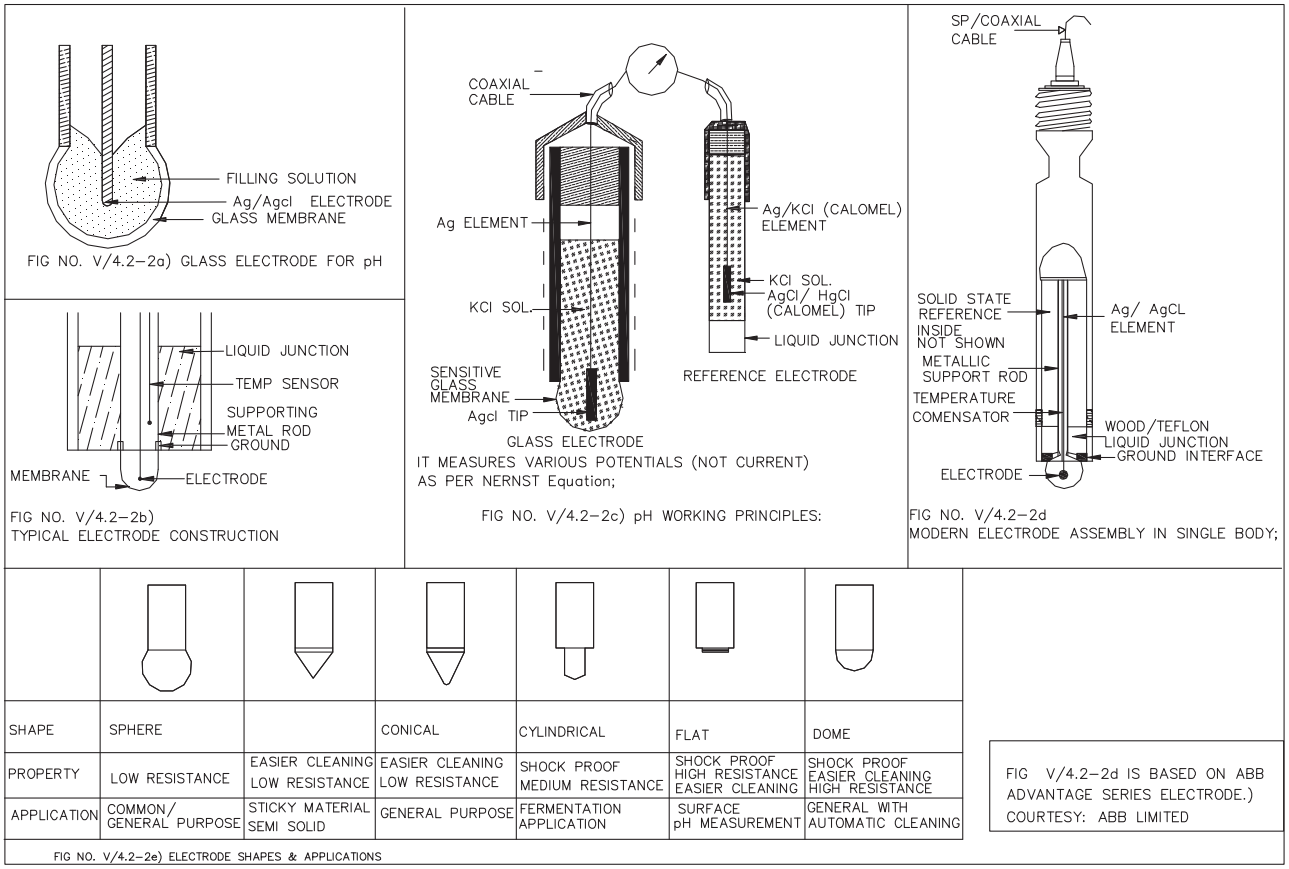


FIGURE V/4.2-2 pH sensor types.

more so in boiler water, which contains Na^+ in some form. It is recommended to calibrate boiler water in an alkaline buffer.

- *Stirring*: For a well-buffered solution stirring is not required, but for a poorly buffered solution stirring yields a faster response.

4.2.1 pH Analyzer: Description

1. pH is measured by measuring the potential between the measuring electrode and reference electrode. For industrial use, manufacturers offer a variety of pH sensors and transmitters. Table V/4.2.1-2-1 is a selection guide for material selection.
2. There are pH electrodes with solution ground by rods of different materials such as 316 SS, titanium, and Hastelloy.
3. The LJs could be of wood, Teflon, ceramic/glass frit (ceramic), etc.
4. Sensors can be flow cell, inline, insertion, retractable, and submersible types. with the insertion type, the insertion length needs to be specified such as 1/2/3 inch insertion length. Flow cell materials needs to be specified.
5. Specifying the operating temperature is very important as pH is temperature dependent.
6. All transmitters are provided with temperature compensation. There may be variations in the mode of compensation. Temperature compensating elements can be Pt100 RTD, BalcoRTD (alloy of Ni and Fe at 7:3) identified temperature at 25°C, and/or another type.
7. Most of the sensors are provided with integral cables to connect the transmitter with the sensor. There are a number of options available for types of connection and cable types as well as length to allow the designer to suitably locate the transmitter away from the sensor. However, in the case of a central sample table, such an option does not have much impact.

TABLE V/4.2.1.2-1 Sensor Material Selection

Flat glass	Coat resistance glass	Metallic, e.g., platinum/ antimony	Totally solid inner chamber charged with KCl, has a solid state reference electrode

www.EngineeringBooksPDF.com

8. Smart transmitters, with self-diagnostic features to generate remote and local alarms are common today.
9. Transmitters have integral local displays. In general all of these transmitters are programmable and capable of doing ON/OFF control and can provide alarm contacts.

4.2.2 pH Analyzer: Working Principles

Measurement of pH is made with glass electrodes, and the EMF is measured with respect to the reference electrode (see Figure 4.2.2c). The H^+ sensitive electrode consists of a thin glass membrane on to which a glass tube is sealed. This glass electrode consists of an inert glass tube with a pH-sensitive glass tip, in various shapes, blown onto it by glass blowers. The thickness of the glass determines its resistance and affects its output. Sealed inside the tube is a solution of potassium chloride buffered at a pH ~ 7. Silver wire coated with a silver chloride tip is inserted in to the solution and acts as a measuring electrode. Through a complex mechanism, an electrical potential, directly proportional to pH of the liquid, develops at each glass liquid surface. The overall potential of the measuring electrode is the sum of internal potential at the glass surface plus potential at the glass membrane surface outside (out of this inside potential is known as it as a known liquid). So measuring potential varies proportionately with the pH of the liquid. The reference electrode actually used to complete the circuit in measurement and potential is considered as reference. The reference electrode is silver wire coated with silver chloride in contact with KCl solution (or may be gel) held in a glass or plastic tube. Porous LJ (defined earlier) is an integral part of reference electrode, and provides electrical connection between the reference electrode and the liquid whose pH is to be measured.

1. A reference is required to develop a potential independent of the solution under test, but would depend on concentration of KCl.
2. For operation of the reference electrode, without loss, it has to be hydrated. So a salt bridge is necessary. This salt bridge is a porous plug that restrictively allows KCl to flow out of reference electrode to establish electrical contact and maintain constant potential for the reference electrode.
3. When there is a difference in concentration between two electrolytes of different concentration there will be diffusion through the porous plug—LJ. As mobility of $Cl^-$and K^+ are different so they will move through the LJ differently and there will be a charge difference, hence, the LJ potential.
4. Potential is discussed with respect to a fixed point (for example, ground). Thus net potential developed as per the Nernst equation (for measuring purposes) will be $E = E_{IR} + E_S + E_J + E_E - K^*T$ pH, where all Es indicate potentials, E_{IR} = internal reference electrode, E_S = at selective junction, E_J = at LJ, E_E =at external electrode, and T is the temperature in Kelvin, K constant = 0.1984. Here all the terms of the Es are independent of the pH of the test solution. So E is measured as a proportional signal to pH with dependence on temperature.

4.2.3 Accessories for a pH Analyzer

See Table V/4.2.3-1 below; for a list of major accessories for a pH analysis system.

TABLE V/4.2.3-1 Accessories for pH Analyzer: Major Accessories for the Analysis System

Temperature sensing probe	Flow cell (as applicable)	Electrode holder
Coaxial and other specific cables	Junction box	Receptacle and other electrical accessories

4.2.4 pH Analyzer Specification/Data Sheet (standard 0–14, special ranges, e.g., 9–12)

See Table V/4.2.4-1 for a pH instrument data sheet.

TABLE V/4.2.4-1 pH Instrument Data Sheet (To Specify Range)

Sl	Specifying point	Standard/available data	To be specified
1	Type	Insertion/submersible/flow cell	To be specified
2	Electrode cleaning	Auto cleaning (as applicable)	To be specified
3	Electrode type	From the above discussion	
4	Output	1 or 2 4-20mADC + alarm contacts	To be specified

Continued

www.EngineeringBooksPDF.com

TABLE V/4.2.4-1 pH Instrument Data Sheet (To Specify Range)—Cont'd

Sl	Specifying point	Standard/available data	To be specified
5	Temperature composition	Automatic	To be specified
6	Accuracy	±0.02 pH/0.01 pH*	*Repeatability
7	Stability	0.02 pH/week	
8	Resolution	0.01 pH	
9	Contact details	SPST/SPDT 50 VA 50 V 1A	
10	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
11	Materials	Manufacturer's standard	To be specified
12	Calibration	Automatic and manual zero/span	
13	Display	LED/LCD (back-lit) and diagnostic	Display
14	Connectivity**	RS 232/485/MODBUS/HART/**	
15	Power supply	230 VAC/24 VDC	
16	Housing	IP rating (65)	To be specified
17	Ambient condition	T: Up to 50°C RH (93%)	To be specified
18	Accessories	Discussed separately above	To be specified
19	Process connection	To specify based on project standard	l 1/2″ or 3/4″ NPT (type)
20	Software detail	For data storage, networking, remote control (FTP)/calculation, etc.	To be specified depending on need

***or Fieldbus such as Profibus, Foundation Fieldbus, etc.*

4.3 DO Analyzer: DO

DO is responsible for oxidative corrosion, mainly in the form of pitting in the boiler. The deaerator is used to mechanically drive away gaseous substances from condensate and DO is monitored at the deaerator outlet.

4.3.1 DO Analyzer: Description

1. DO measurements in power plants can be done by (1) amperometric principle (major suppliers include: ABB/Rosemount/Polymetron) and (ii) optical (major suppliers include: Polymetron and YSI).
2. In amperometric instruments the diffusion of oxygen depends on temperature, so a temperature element is used with the system to compensate for temperature variation. (see Figure V/4.3.2-1). Some manufacturers minimize the distortion on the membrane to keep the pressure equal to the sample pressure to eliminate the influence of pressure on the measurement. Many use a constant head unit before the flow cell.
3. Use of a flow through cell is quite common for DO measurement in amperometric sensors.
4. Some amperometric instruments use a disposable type of sensor to make maintenance easier.
5. The majority of DO analysis systems consist of sensors and smart transmitters with self-diagnostic features that support various protocols/Fieldbus systems. Normally sensors and transmitters are connected by special (or integral) cables forming a part of the instrument.
6. Typical sample parameter is pressure: ~0.3 kg/cm^2, F:100−50 0ml—this depends on a sample drawing system, T: 5−50°C (consult the manufacturer's data sheet), sample particulate <8 μm.
7. In amperometric sensors (galvanic cell) the cathode is silver, whereas the anode will be gold (or lead for disposable sensors, e.g., manufactured by ABB).
8. The optical system utilizes luminescence lifetime detection. In some instruments a single blue-light LED is used in conjunction with luminophore, while some use both red and blue lights to measure the DO level (see Figure V/4.3.3-1).
9. Description of analyzers types:
   a. *Amperometric*: Sensors are mounted in the flow cell with a temperature element as show in

www.EngineeringBooksPDF.com

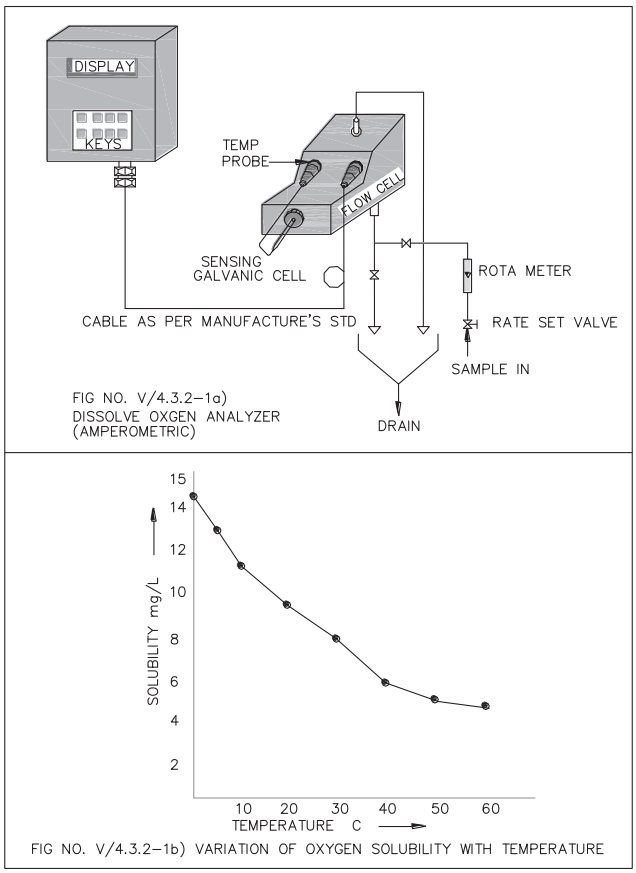


FIGURE V/4.3.2-1 DO analyzer (amperometric).

Figure V/4.3.2-1. If there is a gold electrode then a Teflon membrane is stretched over it (e.g., Rosemount). A silver cathode is used.

b. *Optical*: There are sources of light (e.g., LED) used. In some cases only blue light is used with luminophore and a color filter. In some case two sources of light (red and blue) are used with a dye layer.

c. *Transmitter*: Small signal from the sensors is amplified and conditioned at the smart transmitters with integral display and various connectivity as discussed above.

4.3.2 Amperometric DO Analysis: Working Principles

1. This galvanic cell consists of a gold (or lead) anode and a silver cathode (see Figure V/4.3.2-2). The gold anode is covered with stretched Teflon. When oxygen diffuses, because of the voltage applied, the reactions at

$$\text{Cathode: } O_2 + 2H_2O + 4e^- \longrightarrow 4OH^-$$

$$\text{Anode: } Au \longrightarrow Au^+ + e^- \text{ OR } Pb \longrightarrow Pb^{2+} + 2e^-$$

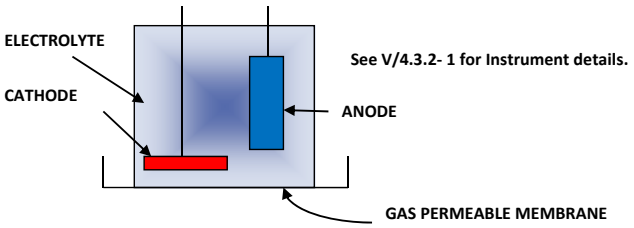


FIGURE V/4.3.2-2 Polarographic DO cell.

2. Because of the above reactions, there will be a current directly proportional to the concentration of DO in the sample.

4.3.3 DO Analyzer: Working Principle (Optical Type)

1. Oxygen as a triplet molecule (the triplet state is the most stable of oxygen molecule) is able to quench efficiently the fluorescence and phosphorescence of certain luminophores. This effect (first described by Kautsky in 1939) is called "dynamic fluorescence quenching." The *degree of fluorescence quenching* is related to the *frequency of collisions*, which means related to the *concentration*, *pressure*, and *temperature* of the oxygen present in the sample.

The optical DO sensor utilizes this property and has a blue light directed to an oxygen-active compound called a luminophore, which has been stabilized in an oxygen-permeable polymer. The blue light causes electrons in the luminophore to be excited to a higher energy level and return to their original level after emission of red light. When the luminophore comes in contact with elemental oxygen, the O_2 molecules absorbs the energy, resulting in reduced intensity of red light emission, i.e., the fluorescence is quenched by oxygen. When the polymer-sensing surface is exposed to water, oxygen diffuses into the sensing surface according to the amount ("partial pressure") of oxygen in the water. In this method one LED light source is used, and there are two identical photodiodes, one with a red filter and another with a blue filter, to detect red and blue light, respectively (see Figure V/4.3.3-1).

2. There is some initial difference in the reading of these two detectors when there is no DO. Let this difference be the base value. When oxygen diffuses into the system and absorbs red light, then the difference between the two detectors is different from the base value, which is a measure of concentration of DO. In reality this is done with a precision measurement of phase difference of the two detectors and from there DO concentration is calculated.

3. Sometimes a red dye layer is used. Once it is used with red light and does not cause any reaction on the dye,

www.EngineeringBooksPDF.com

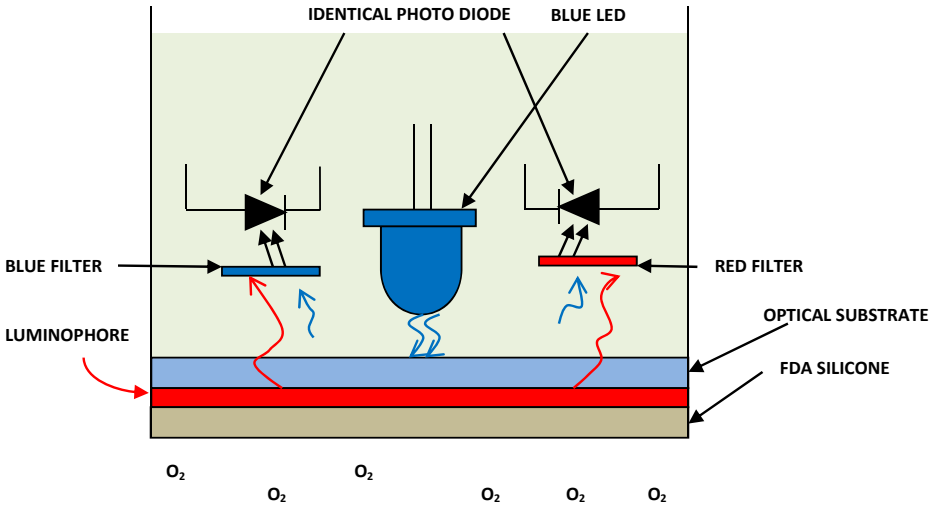


FIGURE 4.3.3-1 Optical DO sensor.

TABLE V/4.3.4-1 Accessories for DO Analyzer

Temperature sensing probe (Pt100)	Auto calibration	Cable gland and other electrical accessories
Spare sensor for disposable type	Constant head unit	

then it is taken as reference. This dye is then flashed with a blue light.

4.3.4 Accessories for the DO Analyzer

See Table V/4.3.4-1 below; for a list of accessories for the DO analyzer and Table V/4.3.5-1 for a DO analyzer data sheet.

TABLE V/4.3.5-1 DO Analyzer Data Sheet

Sl	Specifying Point	Standard/Available Data	To be specified
1	Type	Amperometric/optical	
2	Measuring range	0–20/200/20,000 µg/kg	To be specified
3	Electrode	Ag cathode, Au/Pb anode	
4	Output	1 or 2 4-20mADC + alarm contact	To be specified
5	Response time	Typically <1 min	To be specified
6	Accuracy	±5% reading	
7	Electrolyte life	Manufacturer's standard	Shelf life
8	Resolution	0.1 µg/kg	
9	Contact details	SPST/SPDT 50 VA 50 V 1A	
10	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
11	Materials	Manufacturer's standard	To be specified
12	Calibration	Automatic and manual zero/span calibration	
13	Display	LED/LCD (back-lit) and diagnostic*	*Alphanumeric
14	Connectivity	RS 232/485/MODBUS/HART/FB**	To be specified

www.EngineeringBooksPDF.com

TABLE V/4.3.5-1 DO Analyzer Data Sheet—Cont'd

Sl	Specifying Point	Standard/Available Data	To be specified
15	Power supply	230 VAC/24 VDC, as the case may be	
16	Housing protection	IP rating (55)	To be specified
17	Ambient condition	T: Up to 50°C RH (93%)	To be specified
18	Accessories	Discussed separately above	To be specified
19	Software detail	For data storage, networking, remote control (FTP)/calculation, etc., as applicable	To be specified depending on need
20	Special features	Salinity and pressure correction, cable length, etc.	To be considered

***FB, Fieldbus like Profibus Foundation Fieldbus.*

4.4 Residual Hydrazine Analysis System: Residual Hydrazine

Hydrazine helps to maintain a protective magnetite layer on steel surfaces, so uses of hydrazine as an oxygen scavenger in modern power plants are quite common.

4.4.1 Hydrazine Analyzer: Description

1. Hydrazine measurements can be done on the basis of the wet chemical colorimetric principle (analyzers of this kind are available from suppliers like Rosemount), as well as by measurement of potential in electrochemical cells—amperometric sensing (analyzer of this kind is available from ABB, Emerson, and Polymetron). Each of these analyses involves addition of a chemical reagent to obtain the desired result. The system response time for a hydrazine analyzer is 3−10 minutes depending on the type selected.
2. In both of these systems there are standard solutions as part of the instrument.
3. Colorimetric analyzers can be multistream and utilize a pump for reagent delivery. In electrochemical cell type analyzers, reagents like caustic soda to adjust pH are mixed with the sample through a porous disk and a constant head unit to ensure the required pressure.
4. Channel selection and calibration in most of the cases are automatic.
5. A self-diagnostic feature is common for all hydrazine analysis systems.
6. Sample parameter is pressure: ~0.3 kg/cm^2, F:100−500ml—depends on sample drawing system. T: 5−50°C (consult manufacturer's data sheet), sample particulate: <60 μm.
7. Sections of the analyzer include:
   a. *Analysis module (colorimetric type)*: Section of the analyzer where the actual analysis takes place in the sample cell; present between the light source (LED) and photo detector.
   b. *Transmitter and control module*: Small signal from sensors is amplified and conditioned at smart transmitters with integral display, multistream selection, and various connectivity.

4.4.2 Electrochemical Type Hydrazine Analyzer: Working Principles

1. It consists of an outside jacket filled with silver oxide or gel into which there is one porous ceramic cylinder (see Figure V/4.4.2-1). A silver wire acting as a cathode is wound round the outer surface of the ceramic cylinder. The sample is admitted from the bottom of this cylinder. Before sending the sample to the sensor, it is necessary to pass it through a constant head unit to ensure desired pressure and flow. While the sample is admitted in the system, caustic soda used as an alkali reagent is mixed with the sample through a porous disk to raise the pH level for an enhanced reaction in the alkaline environment (pH 10.2−10.5). From the bottom of the cylinder the sample flows out from the top. Platinum wire acting as an anode is introduced in the cylinder at the center. The electrical path between two electrodes is complete via ionic transport through the porous ceramic cylinder. The resultant current is proportional to hydrazine presence in the solution. The measurement is temperature sensitive so a temperature element is inserted.
   The reactions that take place at the electrodes are as follows:
   Pt Anode: $N_2H_4 + 4OH^- \Leftrightarrow N_2 + 4H_2O + 4e^-$
   Ag cathode: $4H_2O + 4e^- \Leftrightarrow 2H_2 + 4OH^-$
2. Some of the instruments use three electrodes (e.g., Hach instruments). The third electrode is a reference electrode kept at a constant potential difference with the anode. The measuring principle based on a three-electrode amperometric is also an electrochemical method. Here the platinum anode used is the working electrode, while

www.EngineeringBooksPDF.com

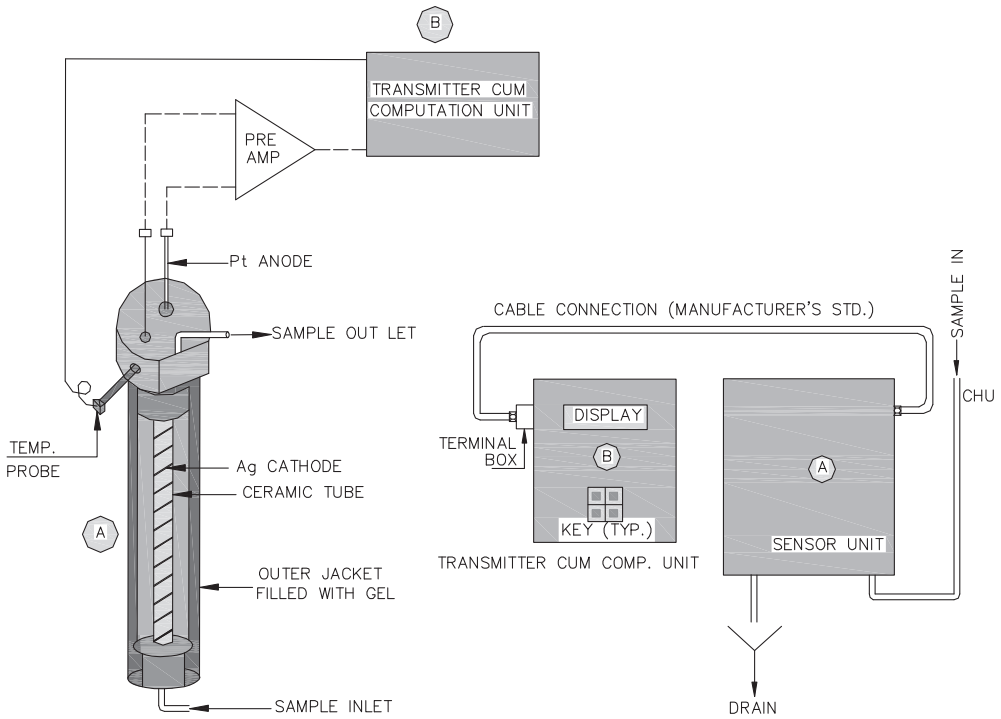


FIGURE V/4.4.2-1 Hydrazine analyzer system.

the stainless steel cathode is the counter-electrode. A small polarization voltage is applied between the anode and cathode. The anode−cathode potential is kept constant with respect to a third Ag/AgCl electrode called the reference electrode. The system avoids interference effects, namely voltage drift, resulting from changes in water composition that may appear in a two-electrode system.

Hydrazine is oxidized at the surface of the anode (the platinum working electrode). The resulting current is directly proportional to the hydrazine concentration.

The sample is made alkaline with a pH of 10.2−10.5 by a dosing reagent like the analyzer with two electrodes. The chemical reaction is the same as stated above. A temperature sensor for automatic compensation is provided. In some systems, Teflon bids driven by the sample circulate on the surface of the anode to clean any deposits on it.

4.4.3 Colorimetric Type Hydrazine Analyzer: Working Principle

This system is similar to the system connected with silica and phosphate analyzers discussed in the next clause. The sample along with reagents is mixed after the reaction time and put into the measuring cell. The measuring cell is placed between the LED light source (sending light with wavelength 450−480 nm) and photo detector. The amount of light absorption is proportional to the amount of hydrazine present.

At first a reference measurement is done to take care of various interfering factors, such as color of the sample and different reagents, turbidity, refractive index variations, etc. After reagent mixing and color development another measurement with the sample is taken. The concentration is measured with the absorbance calculated based on the difference between the two measurements and the stored calibration parameters. For a high-range measurement, a mixing pump is required to mix the sample with distilled water (dilution process). There should be separate pump sets for the reagents and the sample.

4.4.4 Accessories for a Hydrazine Analyzer

See Table V/4.4.4-1 below; for a list of accessories for a hydrazine analyzer.

TABLE V/4.4.4-1 Accessories for Hydrazine Analyzer

Standard solution	Sample tubes and fittings	Cable gland and electrical accessories
Reagent (built in)	Temperature sensor (compensation)	

www.EngineeringBooksPDF.com

TABLE V/4.4.5-1 Hydrazine Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring principle	Colorimetric/electrochemical cell	
2	Measuring range	0—100/200/1000 ppb with selection	To be specified
3	Number of streams	Single or single/2/4/6 (colorimetric)	To specify
4	Reagent and standard solution	Typically one and standard solution	To be specified
5	Output	1 or 2 4-20mADC each stream (or timescale) output + alarm contact	To be specified
6	Accessory	±5% reading/±01.5% reading*	*Repeatability
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
9	Materials	Manufacturer's standard	To be specified
10	Calibration	Auto and man zero/span calibration (frequency and timing as per manufacturer)	
11	Display possibility	LED/LCD (back-lit) with diagnostic display, microprocessor based	
12	Connectivity	RS 232/485/MODBUS/HART/FB**	
13	Power supply	230VAC/24VDC	
14	Housing protection	IP rating (55)	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	To be specified
16	Software detail	For data storage, networking, remote control(FTP)/calibration, etc.	To be specified
17	Accessories	Discussed separately above	To be specified
18	Special features	Reagent consumption, filling, drain, etc. Type, material. and number of electrodes Temperature probe	To be considered

***FB, Fieldbus like Profibus Foundation Fieldbus*

4.4.5 Hydrazine Analyzer Data Sheet

See Table V/4.4.5-1 for the hydrazine analyzer data sheet.

4.5 Miscellaneous Special Analysis Systems

4.5.1 Special Analysis Systems

In this clause a few special analyzers and their associated data sheets are discussed.

4.5.2 Silica and Phosphate Analyzers: Description

1. Silica and phosphate measurements are done on the basis of the wet chemical colorimetric principle (determining the intensity of a color and relating it to the concentration of solution is who the colorimetry principle works). Each of these analyses involves the addition of a number of chemical reagents and a number of reactions at various stages. Therefore it is a semicontinuous (rather than batch processing) system and each cycle may take ~10—15 minutes. Normally these analyzers have a system with a panel (approximate size H × W × D 1000 × 500 × 300 mm—with space for reagents). Normally analysis systems are comprised of three main sections: basic analysis system (wet part), reagent supply lines, and control and display unit (dry part). Analyzers may be a single or multichannel type.
2. The reagents are drawn to the system by a peristaltic pump and/or by a pressurizing system and a solenoid valve. Built-in reagent systems are complete with the necessary pumps and valves and a sample chamber (there are separate systems for the sample and reagent).

www.EngineeringBooksPDF.com

3. In most cases, the channel selection and calibration are automatic. There can be up to six channels in one analyzer system. An analog and alarm output corresponding to each channel is provided. Self-diagnostic features are quite common.
4. Sample parameter requirement is the same as that for the hydrazine analyzer.
5. Clauses of the analyzer are

a. *Analysis module*: In this clause, actual analysis takes place in the sample cell, which is present between the light source (LED) and photo detector.
b. Reagents are supplied by peristaltic pumps/pressurizing system with a solenoid valve to regulate the flow.
c. *Display and control module*: This analyzer is a microprocessor-based program controlled for mixing reagents and cleaning, etc., as well as for stream selection, display, and output control.

4.5.3 Silica Analyzer: Working Principles

1. Heteropoly blue colorimetric analysis (molybdenum method) is used to detect the reactive silica trace. Sample pumps and solenoid valves are used to draw the sample and regulate its flow. A sample cell is placed between a light source and photo detector to measure the amount of absorption from the light of the wavelength in the range of 450 to 820 nm.
2. Acidic molybdate solution is first mixed with the sample to form molybdosilicic/(molybdophosphoric) acid by reacting with traces of silica (/phosphate).
3. Citric acid/surfactant reagent is added to mask molybdophosphoric acid and react with excess molybdate (to prevent molybdate from producing interfering blue color). The surfactant wetting agent minimizes air bubble formation on sample cell walls. Light absorbance at this stage through this solution is measured, which gives the *reference signal* at zero silica condition. Color formed at this point is *identical* to the final color of a sample without any silica content and compensates for any background turbidity color of the sample, changes in light source, or contamination of the sample-cell walls.
4. In next stage amino acid is added to reduce molybdosilicic acid to blue-colored solution. Now the blue color is the measure of the amount of Si in the sample. This is measured physically by a light (~ 800 nm)-absorption method. This absorption is compared with reference absorption (discussed in Clause 4.5.3, number 3).
5. Silica content in the sample is related to the ratio of absorption by reference and by the sample. This relation is not linear but is proportional to the log of the ratio of the reference sample. Standard solution is used to determine the constant of this relation.
6. Instrument calibrations could be programmable and repeated after a fixed cycle (e.g., twice a week to three weeks), which varies with manufacturer.

4.5.4 Silica Analyzer Accessories

Silica analyzer accessories, in addition to cable glands and electrical accessories, are listed in Table V/4.5.4-1.

TABLE V/4.5.4-1 Silica Analyzer Accessories

All reagents required (for desired period)	Standard solution	Tubes and fittings
Cleaning solution and air Source	Chilling unit, if any	Temperature probe for compensation

4.5.5 Silica Analyzer Data Sheet

See Table V/4.5.5-1 for a silica analyzer data sheet.

4.5.6 Phosphate Analyzer: Working Principles

In power plant steam/water cycles, inorganic phosphorus is present in the form of phosphate and is normally referred to as orthophosphate or soluble reactive phosphorus available chiefly as ions of HPO_4^{2-} and with a small percentage present as PO_4^{3-}. These are called orthophosphate ions and result from dissociation of orthophosphoric acid (H_3PO_{4-}).

1. This analyzer is based on molybdophosphoric acid colorimetry (as suggested in ASTM D 515). Upon mixing a reagent with a sample, a color change indicates the presence of orthophosphate. Here ascorbic acid is used to measure the orthophosphate. Surfactant is added to minimize bubble formation the surface wall. Light absorption is measured through the solution in the sample, and is considered a reference absorbance value similar to that discussed above for silica. Molybdate reagent is then added to react with orthophosphate, to form heteropoly acid. To reduce the heteropoly acid, ascorbic acid is added and the molybdenum blue color is formed. After complete reaction, light absorbance is measured. This increased absorption is due to orthophosphate. The ratio of the final absorption and reference absorption is proportional to orthophosphate present in the sample. Reactions include:

   Phosphate + Molybdate → Phosphomolybdic Acid
   Phosphomolybdic Acid + Ascorbic Acid → Reduced Phosphomolybdate complex Blue
2. When vanadate molybdate reagent is used, it forms orthophosphate vanadomolybdophosphate and gives a yellow color. The rest of the method is the same.
3. Instrument calibrations could be programmable and repeated after a fixed cycle (e.g., twice a week to three weeks), and varies with manufacturer.

www.EngineeringBooksPDF.com

TABLE V/4.5.5-1 Silica Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	0–20//500/5000 ppb multiple ranges available, upon selection	To be specified
2	Number of streams	Single/2/4/6	To be specified
3	Reagent and standard solution	Typically four and standard solutions at regular pressure	To be specified
4	Output	4-20mADC + alarm contact/stream	To be specified
5	Accuracy	±0.5 µg/L/1% reading	
6	Repeatability	±01.5% reading	
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
9	Materials	Manufacturer's standard	To be specified
10	Calibration	Auto/man zero/span calibration Frequency and time period—manufacturer standard	
11	Display	LED/LCD (back-lit) with diagnostic*	*Alpha numeric
12	Connectivity	RS 232/485/MODBUS/HART/FB**	
13	Power supply	230 VAC/24 VDC	
14	Housing protection	IP rating (65)	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	To be specified
16	Software detail	For data storage, networking, remote control(FTP)/calibration, etc., as applicable	To be specified
17	Accessories	Discussed separately above	
18	Special feature	Reagent consumption, filling, drain, etc.	To be specified

***FB, Fieldbus like Profibus/Foundation Fieldbus.*

4. If A_{SD} and A_Z denote the absorption by standard solution at full strength and zero, corresponding to standard PO_4 (µg/L), the slope will be slope = standard PO_4 (µg/L)/($A_{SD} - A_Z$) so, PO_4 (µg/L) = $A_{SA} \times$ slope − instrument constant (reagent blank), where A_{SA} = absorption by sample solution.
5. Phosphate analyzer accessories are similar to those given in Clause 4.5.4.

4.5.7 Phosphate Analyzer Data Sheet

See Table V/4.5.7-1 for a phosphate analyzer data sheet.

4.5.8 Sodium Analyzer

1. The measurement of Na is based on direct potentiometric technique utilizing a highly sensitive ion-specific electrode (ISE). The potential difference between the reference electrode and ISE is directly proportional to the *logarithm of Na concentration.*
2. This instrument is sensitive to changes in *temperature* as well as variation in *pH.*
3. This ISE glass electrode composition contains sodium and is sensitive to H^+ but less sensitive to Na^+. The buffer solution contains a fixed level of sodium ion. Therefore the difference in Na^+ in both sides of the glass electrode would result in potential.
4. Because of high sensitivity to H^+ ions of the measuring electrode, it is necessary to maintain the sample with constant pH (preferably around pH 11) by adding pH adjusting reagent for measurement. Therefore pH conditioning liquids are included in the measuring system through a three-way valve. This is done before sending the sample to the measuring cell to ensure accurate and repeatable Na^+ measurement (see Figure V/4.5.9-1).
5. It is necessary to reactivate the analyzer from time to time so that it is not a sleeping element when measuring ultra pure water for a long time. For this, the instruments are programmed with automatic reactivation, just like the automatic calibration program. For this standard solution and reactivate solution are included in the liquid-handling section of these analyzers.

www.EngineeringBooksPDF.com

TABLE V/4.5.7-1 Phosphate Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	0−1/5/15 ppm ranges with selection	To be specified
2	Number of streams	Single/2/4/6	To be specified
3	Reagent and standard solution	Typically two and standard solution	To be specified
4	Output	4-20mADC + alarm contact/stream	To be specified
5	Accuracy	±1% FSD4% reading	
6	Repeatability	±01.5% reading	
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	As per country requirement (See Clause 3.0.1, number 3)	To be specified
9	Materials	Manufacturer's standard	To be specified
10	Calibration	Auto/man zero/span calibration frequency and time period—manufacturer standard	
11	Display	LED/LCD (back-lit) with diagnostic*	*Alphanumeric
12	Connectivity	RS 232/485/MODBUS/HART/FB**	
13	Power supply	230 VAC/24 VDC	
14	Housing protection	IP rating (65)	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	To be specified
16	Accessories	Discussed separately above	To be specified
17	Software detail	For data storage, networking, remote control (FTP)/calibration, etc., as applicable	To be specified
18	Special features	Reagent consumption, filling, drain, etc.	To be specified

***FB, Fieldbus like Profibus/Foundation Fieldbus*

6. Two sections of the instrument are the electronic control section for display and the transmission unit liquid-handling section.
7. As the measurement is temperature sensitive, the standard solution is kept *in the range of temperature of the sample line*. This is done with the help of a heat exchanger in the standard solution, so that during calibration it is almost at the same temperature as the sample.

4.5.9 Sodium Analyzer: Working Principle

1. As discussed above, it is an ISE potential measurement after pH conditioning.
2. Sample is injected in to an overflow tank to ensure constant head for the sample line. This is done because the sample is mixed with pH conditioning reagent as it flows down to the measuring cell. pH conditioning is done to ensure *constant pH* value. There are three wells to house the thermistor (temperature compensation), ISE, and reference electrodes. Electrodes are connected to a preamplifier where the difference potential is measured and sent to the transmitter, which also receives signal from the thermistor for temperature compensation.
3. After a fixed time, reactivating fluid is put into the well of the measuring cell to make it sensitive at all times. After sending reactive fluid, it is rinsed with sample so that it is sensitive (otherwise response time at a later date will be very sluggish).
4. For calibration a standard solution can be injecting into the system as shown in next page Figure V/4.5.9-1 (standard solution may be heated as discussed above).
5. Sample parameter requirement is the same as discussed for DO (Clause 4.3.1, number 6).

4.5.10 Sodium Analyzer Accessories

For a list of sodium analyzer accessories, see Table V/4.5.10-1.

www.EngineeringBooksPDF.com

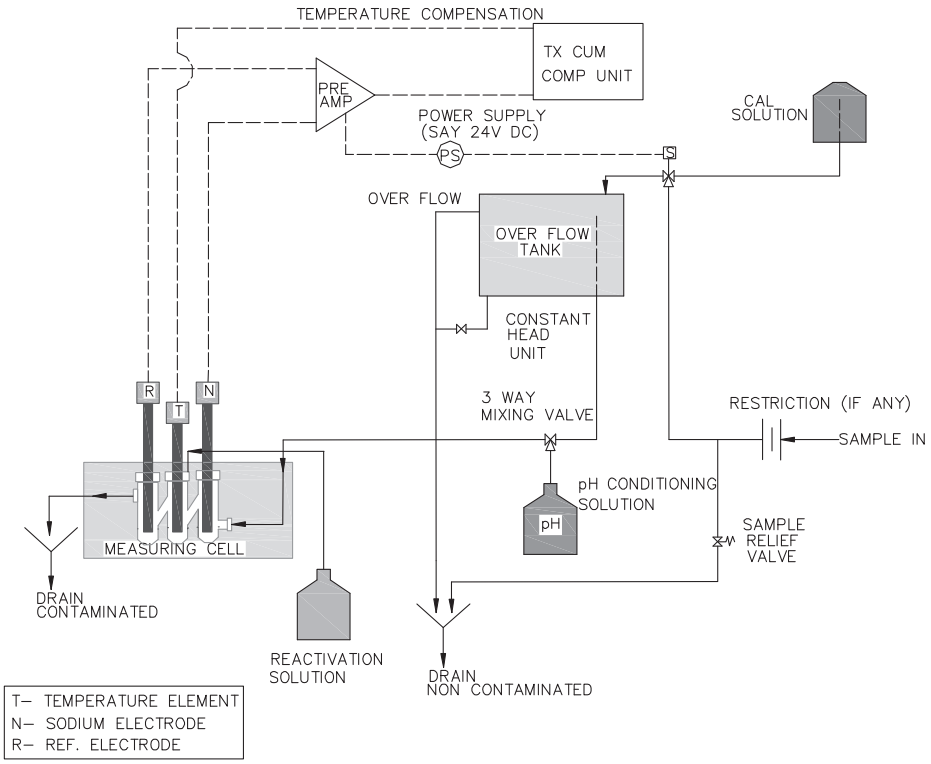


FIGURE V/4.5.9-1 Sodium analyzer working principles.

4.5.11 Sodium Analyzer Data Sheet

A sodium analyzer data sheet is seen in Table V/4.5.11-1.

4.5.12 Chloride Analyzer

1. Chloride analyzer in a power plant application utilizes ion-selective chloride electrodes.
2. This analysis system also requires temperature compensation.
3. For calibration the standard solutions are injected in the system as shown in Figure 4.5.13-1 through two solenoid valves.
4. Calibration and measuring cycles are preprogrammed and are automatic.
5. Ammonium acetate used as reagent may be drawn through a multichannel peristaltic pump and mixed. Reagent and standard solutions are available in a complete system.
6. Sample requirements are the same as those given for a DO analyzer (Clause 4.3.1, number 6).
7. There are two sections: liquid handling and electronic.
8. Electrodes are placed in a temperature-controlled flow cell where there is a heater to eliminate the effects of temperature variations in the sample and in ambient conditions.
9. Electronics are placed on the back side of the instrument. There is a front display and key panel to operate the analyzer in manual as well as in automatic mode.

TABLE V/4.5.10-1 Sodium Analyzer Accessories

All reagent solution is in the same enclosure	Standard Solution	Tube fittings and drain Lines
Reagent for 3M trouble-free operation.	Heat exchanger	Grab sampling system
Flow regulator restrictor	Cable gland and other electrical accessories	

4.5.13 Chloride Analyzer: Working Principles

There are a three methods for determining chlorine ions: ISE, coulometric and colorimetric.

Coulometric: With this method very low levels of silver ions are generated by passing a constant electrical current between the cathode (silver wire) and another electrode. Silver ions in turn react with the chloride ions of the sample solution to form silver chloride and change the sample conductivity measured by voltage between the electrodes.

www.EngineeringBooksPDF.com

TABLE V/4.5.11-1 Sodium Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	0–10/100/10,000 ppb selectable	To be specified
2	Number of streams	Single/2/4/6	To be specified
3	Reagent and standard solution	Typically one and standard solution at regular temperatures	To be specified
4	Output	4-20 mADC + alarm contact/stream	To be specified
5	Response time	Typically 3–6 minutes	
6	Accuracy	±5% FSD	
7	Repeatability	±1.5% reading	
8	Contact details	SPST/SPDT 50 VA 50 V 1A	
9	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
10	Materials	Manufacturer's standard	To be specified
11	Calibration	Automatic and manual zero/span calibration frequency and time period as per manufacturer's standard	
12	Display	LED/LCD (back-lit) with diagnostic*	*Alphanumeric
13	Connectivity	RS 232/485/MODBUS/HART/FB**	
14	Power supply	230 VAC/24 VDC, as the case may be	
15	Housing protection	IP rating (65)	To be specified
16	Ambient condition	T: Up to 50°C RH (93%)	To be specified
17	Accessories	Discussed separately above	To be specified
18	Software detail	For data storage, networking, remote control (FTP)/calibration, etc., as applicable	To be specified depending on need
19	Various keys	Menu key, up/down key, selection key, a/m	To be specified
20	Special features	Reagent consumption, filling, drain, battery back-up, if any, etc. Type and material of electrode Temperature probe	To be considered

***FB, Fieldbus like Profibus, Foundation Fieldbus.*

Colorimetric: Similar to silica/phosphate measurement, this method also uses the time-based mixing of reagents for developing the color of the solution after reaction. First, a measurement is taken as a reference to eliminate interfering factors such as sample or the reagent's own color, turbidity, refractive index variations, etc. The second measurement is taken after the reaction is over and the concentration is measured by the absorbance of light by the color sensed by a combination of light detector and sensors. The final result is computed on the basis of the difference between the two measurements and the stored calibration parameters. This semicontinuous method takes nearly 15 minutes to achieve results.

ISE: This system uses chloride-sensitive, solid-state polycrystalline membrane at the electrode tip designed for the detection of chloride ions (Cl^-) in aqueous solution. The voltage develops across the membrane in relation to an Ag/AgCl double-junction reference electrode (with a typical outer filling solution of KNO_3 or CH_3COOLi). The two electrodes may be separate or may be combined in a common probe assembly. ISE may be affected by numerous *analytical interferences* that can be minimized or eliminated by adding appropriate chemical reagents to the sample. For better results at low concentrations of chloride, a standard method for making measurements with ISEs is to add *ionic strength adjuster* solutions (for example, $NaNO_3$) to each of the standard solutions and samples. Temperature variations affect electrode potentials and are either maintained at a fixed value by a heater or temperature compensation is applied. pH range is

www.EngineeringBooksPDF.com

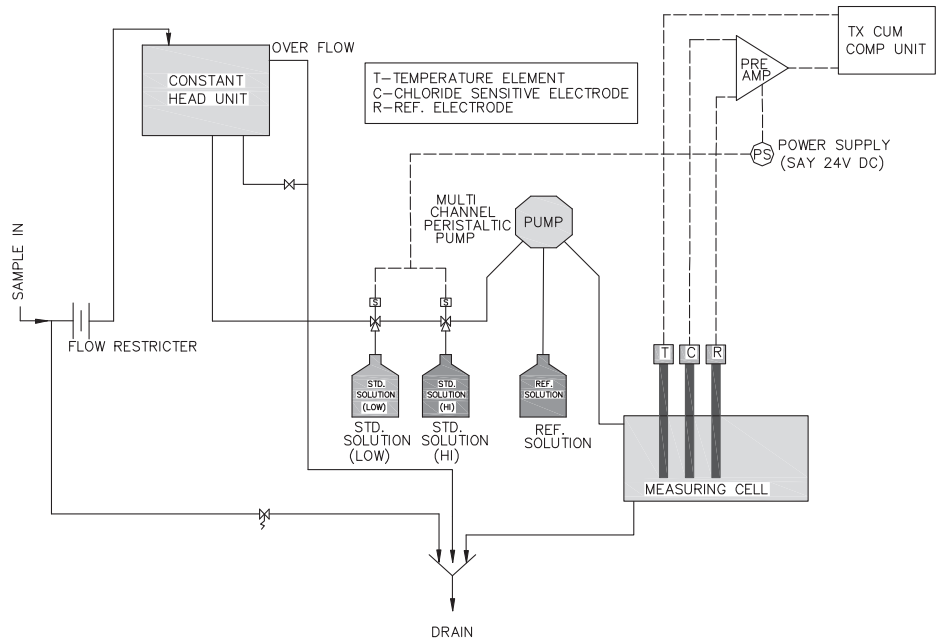


FIGURE V/4.5.13-1 Chloride analyzer system (ISE).

wide (2−12 pH). The slope of measurement at 25°C is ~54 ± 5 mV per decade.

1. Here also sample is fed through to the overflow tank (see Figure V/4.5.13-1) to ensure constant pressure. On the way to the measuring cell the sample passes through set of solenoid valves, which are used during calibration to admit standard solutions in the low and high range. Reagent ammonium acetate is mixed through a multichannel peristaltic pump.
2. There are three wells that house the thermistor (temperature compensation), ISE, and reference electrodes.
3. The difference in potential between the two electrodes is a function of chloride ions.
4. Calibration is controlled by the built-in microprocessor.

4.5.14 Chloride Analyzer Accessories

For a list of chloride analyzer accessories, see below Table V/4.5.14.

TABLE V/4.5.14-1 Chloride Analyzer Accessories

Complete reagent	Junction box	Compensating temperature probe
Standard solution	Solenoid valves	Tube fittings, electrical accessories

4.5.15 Chloride Analyzer Data Sheet

The chloride analyzer data sheet is listed in below Table V/4.5.15-1.

TABLE V/4.5.15-1 Chloride Analyzer Data Sheet

Sl	Specifying point	Standard/available data	To be specified
1	Measuring range	0−10/100/1000 ppm selectable	To be specified
2	Number of streams	Single	
3	Reagent and standard solution	Typically one and two standard solutions	To be specified
4	Output	4-20 mADC + alarm contact/stream	To be specified
5	Response time	Typically 3−6 minutes	

Continued

www.EngineeringBooksPDF.com

TABLE V/4.5.15-1 Chloride Analyzer Data Sheet—Cont'd

Sl	Specifying point	Standard/available data	To be specified
6	Accuracy	±5% FSD ±1.5–2% reading*	*Repeatability
7	Contact details	SPST/SPDT 50 VA 50 V 1A	
8	International certification	As per country requirement (see Clause 3.0.1, number 3)	To be specified
9	Materials	Manufacturer's standard	To be specified
10	Calibration	Automatic and manual zero/span calibration frequency and time period	Manufacturer's standard
11	Display	LED/LCD (back-lit) with diagnostic*	*Alphanumeric
12	Connectivity	RS 232/485/MODBUS/HART/FB**	
13	Power supply	230 VAC/24 VDC, as the case may be	
14	Housing	IP rating (65)	To be specified
15	Ambient condition	T: Up to 50°C RH (93%)	To be specified
16	Accessories	Discussed separately above	To be specified
17	Software detail	Same as that for Na^+ (Section 4.5.11, number 18)	
18	Special feature	Same as that for Na^+ (Section 4.5.11, number 20)	

***FB, Fieldbus like Profibus/Foundation Fieldbus.*

5. SAMPLE CONDITIONING SYSTEM

5.0 Sample Conditioning

For optimum operation of a power plant, monitoring steam and water chemistry is extremely important. For such monitoring, it is essential that samples are taken from the strategic points in the plants and to condition the samples before sending the analyzers. Today, all sample points, pertinent to SWAS throughout the main power plant and associated places, are drawn to a central place sometimes are referred to as the "SWAS Room." This is where the samples are conditioned and analyzed (exception: conditioned hotwell conductivity, which may be monitored at the field to avoid complexity of sample drawings). Normally all samples are brought to a common pressure and temperature (so that they can be interpreted in a better way on the same platform): P = ~2 kg/cm^2 and T = 25°C.

1. Sample conditioning depends on the sample pressure and temperature condition. There may be two kinds of sample conditioning: primary and secondary. Secondary sample conditioning is necessary for *all* samples, even if primary sample conditioning has already been done. In sample conditioning systems, pressure reduction is done after sample cooling, i.e., coolers are placed upstream the pressure regulator.
2. Sample line flow rate is guided by a grab sample plus the number of analyzer(s) connected with the sample line in question (with minimum sample flow requirement of each analyzer). As a guideline for a sample cooler selection as well as line size selection, consider the following conditions:
   a. *Analyzer flow rate*: As per manufacturer's recommendation only, otherwise 50–70 cc/min (typical value)
   b. *Grab sample*: Maximum 500 cc/min (typical value)
   c. *Sample line flow velocity*: ~2 m/sec (typical value)

5.1 Primary Sample Conditioning

This is necessary for the samples at either P > 100 kg/cm^2 *or* T > 100°C. For Primary sample conditioning major components include mainly those items listed below. These may be placed in a rack at a suitable place in the field and may not be in the SWAS Room, to avoid congestion.

1. Sample isolation globe valve
2. Breakdown/restriction orifice
3. Primary sample cooler
4. Sample line relief valve
5. Cooler shell relief valve
6. Pressure-reducing valve (PRV; pressure > 100 kg/cm^2)
7. Coolant sight flow indicator
8. Tundishes/sink

www.EngineeringBooksPDF.com

5.2 Secondary Sample Conditioning

All samples should have secondary sample conditioning. Major components needed for each sample line for secondary sample conditioning mainly include those listed below:

1. Isolation globe/needle (low temperature) valve
2. Blow down valve
3. Secondary cooler
4. Shell relief valve for cooler
5. Sample line relief valve
6. Sample filter
7. Pressure regulator
8. Coolant water isolation valve
9. Coolant flow sight flow indicator
10. Solenoid block valve (with facility for manual operation)
11. Pressure gauge
12. Pressure switch
13. Temperature gauge
14. Temperature switch
15. Rate set valve (one for each analyzer)
16. Rotameter (one for each analyzer)
17. Chiller unit (+ temperature controller)
18. Three-way ball valve (for grab sampling and draining)
19. Cat column (for cat conductivity analyzer)

5.3 Primary ample Conditioning P&ID

Three distinct cases have been considered here (see Figure V/5.3-1).

5.3.1 When P >100 kg/cm^2 and T > 100°C

If the sampling point is located at an inaccessible place or far away from the primary sample-conditioning rack, then safety valves are recommended. As a safety measure, relief valves are considered and the break down orifice is used to further reduce the pressure. The primary cooler takes the supply of the coolant from the equipment cooling water (DM water supply). Generally the primary coolers are designed to bring the outlet temperature to ∼45−50°C**.** In

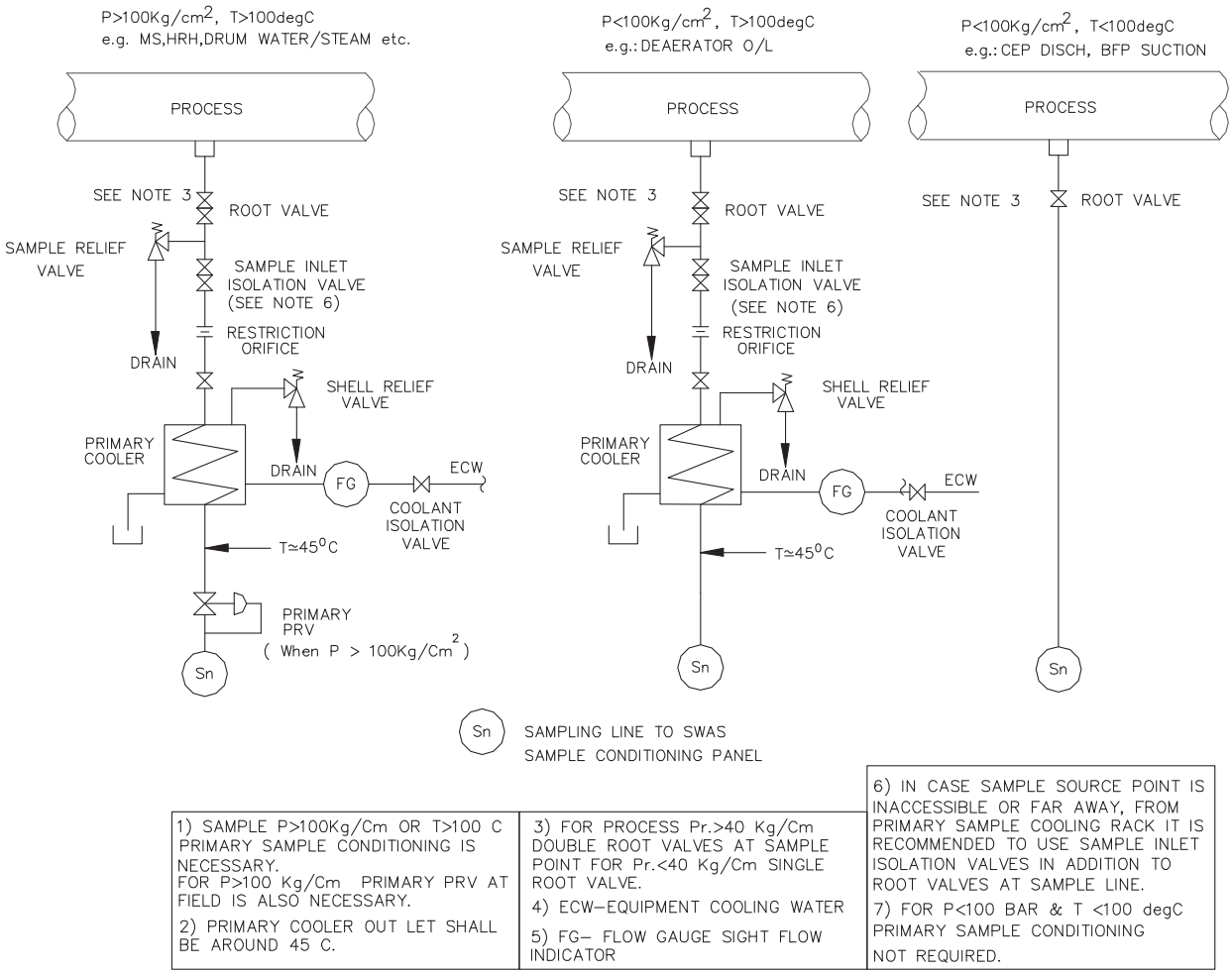


FIGURE V/5.3-1 Primary sample conditioning (at field).

www.EngineeringBooksPDF.com

mid/large-sized plants, the following sampling points would be seen: drum water/drum steam, blow down, FW at economizer inlet, MS to HPT, HRH to IPT.

5.3.2 When $P < 100$ kg/cm^2 and $T > 100°C$

It is same as discussed above, only the PRV may not be necessary. The Deaerator outlet is a sampling point that falls under this category.

5.3.3 When $P < 100$ kg/cm^2 and $T < 100°C$

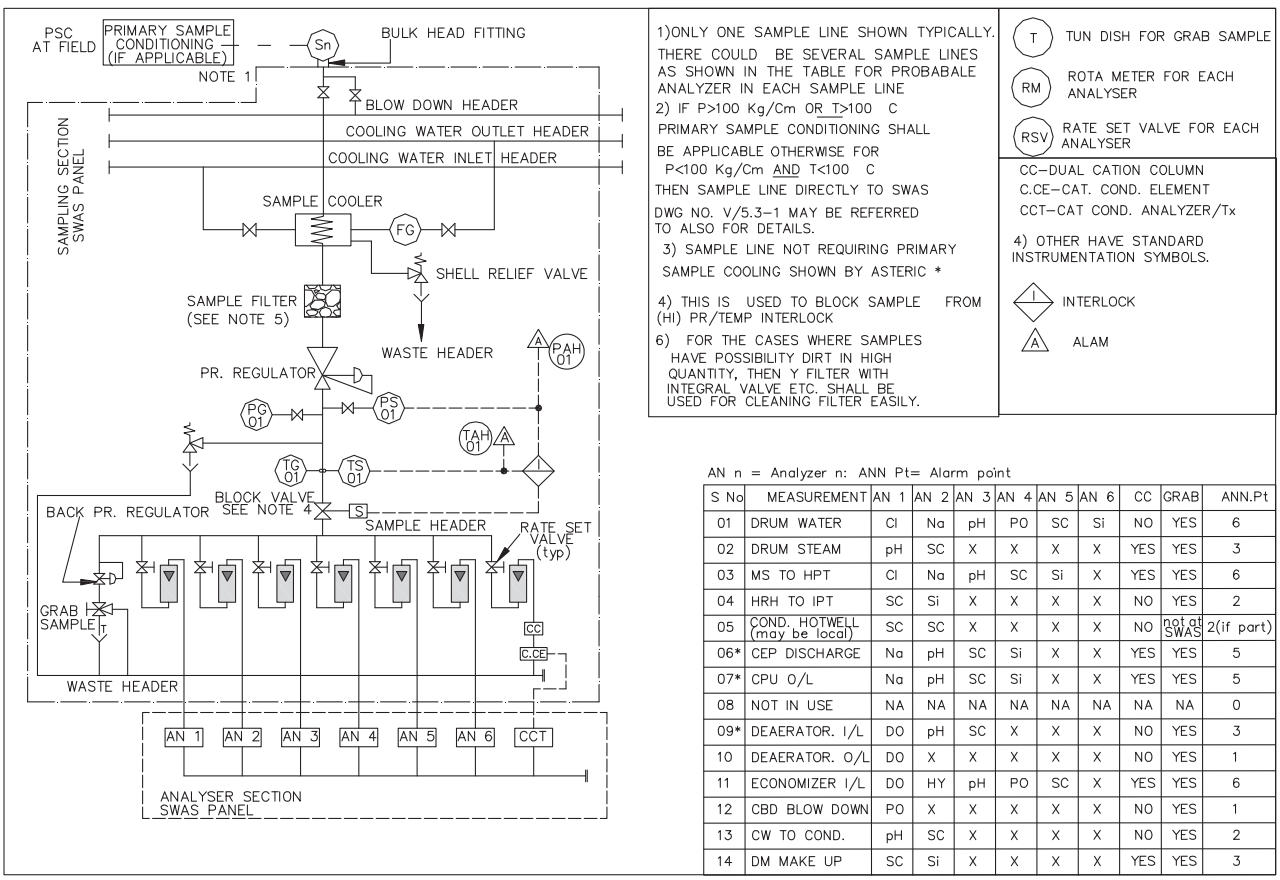
Primary sample conditioning may not be applicable. CEP discharge, CPU outlet, DM make-up water, CW to condition, etc., may fall under this category.

5.4 Secondary Sample Conditioning P&ID

Generally secondary sample conditioning is done in the sample conditioning panel (SCP) of the SWAS. After primary sample conditioning, or directly (as applicable), the sample line (designated by "Sn" for *n*th sample line) in Figure V/5.3-1 is connected to the SCP via bulk head fitting. For this reason, in Figure V/5.4-1 the primary conditioning circuit is shown by a dotted line. Normally the closed blow down valve shown is used to drain/blow down the line. The secondary cooler (or isothermal bath) is cooled by a chiller to ensure the sample O/L temperature is $<25 \pm 1°C$. Self-regulating PRV downstream from the filter ensures that the sample pressure at the outlet of the PRV is 2 kg/cm^2. Solenoid-operated (with manual intervention) block valve (temperature shut-off valve) downstream to the PRV blocks the sampling flow, when temperature or pressure exceeds the set limit, through interlock. In the grab sample line there is a back pressure valve to ensure suitable back pressure at all times in the sample line. The needle valves associated with rotameters adjust the sample flow to the analyzers, so these are called rate set valves. Normally analyzers are placed in a separate panel located beside the SCP. In the cat conductivity analyzer, the cat column only is located in the SCP.

5.5 Sample Conditioning Components

All pipe fitting and other wetted parts are generally chosen as 316 SS to avoid any contamination. The discussions



AN n = Analyzer n: ANN Pt= Alarm point

S No	MEASUREMENT	AN 1	AN 2	AN 3	AN 4	AN 5	AN 6	CC	GRAB	ANN.Pt
01	DRUM WATER	Cl	Na	pH	PO	SC	Si	NO	YES	6
02	DRUM STEAM	pH	SC	X	X	X	X	YES	YES	3
03	MS TO HPT	Cl	Na	pH	SC	Si	X	YES	YES	6
04	HRH TO IPT	SC	Si	X	X	X	X	NO	YES	2
05	COND. HOTWELL (may be local)	SC	SC	X	X	X	X	NO	not at SWAS	2(if part)
06*	CEP DISCHARGE	Na	pH	SC	Si	X	X	YES	YES	5
07*	CPU O/L	Na	pH	SC	Si	X	X	YES	YES	5
08	NOT IN USE	NA	NA	NA	NA	NA	NA	NA	NA	0
09*	DEAERATOR. I/L	DO	pH	SC	X	X	X	NO	YES	3
10	DEAERATOR. O/L	DO	X	X	X	X	X	NO	YES	1
11	ECONOMIZER I/L	DO	HY	pH	PO	SC	X	YES	YES	6
12	CBD BLOW DOWN	PO	X	X	X	X	X	NO	YES	1
13	CW TO COND.	pH	SC	X	X	X	X	NO	YES	2
14	DM MAKE UP	SC	Si	X	X	X	X	YES	YES	3

FIGURE V/5.4-1 SWAS sampling and analysis.

www.EngineeringBooksPDF.com

below is brief and general. If there is any special requirement the designer needs to take care it appropriately.

5.5.1 Sample Isolation Valve (Both Primary and Secondary Sample Conditioning)

1. *Type*: Globe-type forged construction
2. *Pressure rating*: As per ANSI B16.34 standard to match upstream the sample line pressure at maximum sample temperature
3. *Material*: SS (ASTM A 182)
4. *Flow*: As per system design; for guideline see Clause 5.0, number 2.
5. *Body size*: As per sample line design
6. *Plug and spindle*: Single piece; guided plug
7. *Accessories*: Suitable handle

5.5.2 Blow Down Valve

Same as above with special features like a slow opening type valve and a throttle area separate from the seating area.

5.5.3 Break Down Orifice

1. *Material*: 316SS
2. *Break down Ratio*: As per requirement
3. *Standard*: BS/ISO
4. *Beta ratio*: Project standard (<0.5)
5. *Mounting*: Welded/flanged of suitable rating and standards

5.5.4 Primary Cooler

1. *Type*: Shell and submerged helical (coil counter flow design)
2. *Coil material*: 316 SS/Monel/Inconel
3. *Shell Material*: 304 SS
4. *Standard*: ASTMD 1192 or equivalent
5. *Inlet temperature*: As per sample temperature, may be >600°C
6. *Special feature*: Capable of withstanding *simultaneously* high temperatures and pressure of sample
7. *Preferred outlet temperature*: ~45−50°C
8. *Pressure rating*: Suitable as sample pressure rating as per ANSI
9. *Flow*: Sample line flow (see Clause 5.0, number 2).
10. *Capacity of cooling*: Within 5°C of cooling water used
11. *Cooling water*: Equipment cooling water of the plant (DM water)
12. *Relief and check valve*: Shell and cooling water header relief valve and cooling water outlet check valve
13. *Construction*: Removable shell, and no welding in sample coil
14. *Accessories*: Shell relief valve of suitable rating
15. *Location*: Sampling rack at a suitable location outside or field

5.5.5 Sample Relief Valve (Both for Primary and Secondary Sample Processing)

1. *Application*: Primary sample conditioning high pressure and temperature and secondary sample conditioning moderate pressure.
2. *Pressure setting*: From outside
3. *Connection*: Threaded/flange (ANSI/DIN, etc.)
4. *Pressure/temperature rating*: More than corresponding sample cooler rating
5. *Set pressure*: Sample pressure + 20%
6. *Material*: Body SS 316, disk SS 410/431
7. *Spring material*: X12CrNi177 (typical)

5.5.6 Primary PRV

1. *Type*: Piston self- regulating type for downstream pressure containing PRV.
2. *Pressure rating*: As per ANSIB16.34
3. *Temperature rating*: >600°C
4. *Material:* 316 SS body and internal/wetted parts
5. *Output pressure setting*: Wide range from outside
6. *Output pressure regulation*: Desired output pressure setting is an aspect of system design but <<100 kg/cm^2 (e.g., 35 kg/cm^2)
7. *Flow*: Sample line flow (see Clause 5.0, number 2)
8. *Size*: Design as per sample line size

5.5.7 Coolant Flow Indicator

Sight flow is as discussed in Chapter IV, Clause 4.4.

5.5.8 Secondary Cooler

1. *Type*: Shell and submerged helical (coil counter flow design)
2. *Coil material*: 316 SS/Monel/Inconel
3. *Shell material*: 304 SS
4. *Standard*: ASTMD 1192 or equal
5. *Inlet temperature*: 45 ± 5°C
6. *Outlet temp*: ~25 ± 1°C
7. *Pressure rating*: As per ANSI to suit pressure after primary conditioning
8. *Flow*: Sample line flow (see Clause 5.0, number 2)
9. *Capacity of cooling*: Within 5°C of CW
10. *Cooling water*: Chilled water, e.g., 20°C
11. *Relief and check valve*: Shell and cooling water header relief valve and cooling water outlet check valve
12. *Construction*: Removable shell and no welding in sample coil
13. *Accessories*: Shell relief valve of suitable rating
14. *Location*: Sampling rack beside SCP

5.5.9 Sample Filter

1. *Type*: Cartridge type
2. *Body*: SS 316

www.EngineeringBooksPDF.com

3. *Element removal*: Easy removal
4. *Particle size*: Up to 40 μm
5. *Location*: Secondary sample conditioning before PRV

5.5.10 Secondary PRV

1. *Type*: Piston type/spring-loaded diaphragm, self-regulating for downstream. pressure containing PRV
2. *Pressure rating*: As per ANSIB16.34 for valves
3. Material: 316 SS and internal/wetted parts
4. *Output pressure setting*: From outside
5. *Temperature rating*: Greater than the highest sample temperature at the highest sample pressure
6. *Output pressure regulation*: 2 kg/cm^2 sample output for analyzer
7. *Flow*: Sample line flow (see Clause 5.0, number 2)
8. *Size*: Sample line size design

5.5.11 Solenoid Valve

1. *Type*: Single coil, normally open type
2. *Number of ways*: Two Ways,
3. *Coil voltage*: 240/110 VAC or 24 VDC as per project requirement
4. *VA rating*: To be specified (∼10−15 W)
5. *Insulation Class*: F
6. *Material*: SS 316
7. *Size:* Sample line size
8. *Pressure/temperature rating*: As per system design
9. *Operation*: Interlocked (to prevent high pressure/temperature to reach analyzers) with manual intervention to close manually from SWAS panel

5.5.12 Pressure Gauge

A 4" dial pressure gauge (SCP/rack front) is used. See Chapter IV.

5.5.13 Pressure Switch

A blind type with set point and dead band adjustment from front of switch (inside SCP/rack) is used. See Chapter IV.

5.5.14 Temperature Gauge

A 4" dial bimetallic temperature gauge (SCP/rack front) is used as discussed in Chapter IV.

5.5.15 Temperature Switch

Blind Bimetallic type temperature switch with set point and dead band adjustment from front of switch (inside SCP/rack) is used. See Chapter IV.

5.5.16 Rotameter

One for each analyzer in all sample lines. Short borosilicate glass type with 316 SS float type (normally located one after another in the front of the SCP). See Chapter IV.

5.5.17 Rate Set Valve

This is a needle valve and comes as an accessory with the rotameters and is used to set the desired flow to the individual analyzers. The valve should be made of SS 316.

5.5.18 Chilling System and Isothermal Bath

1. *Function*: To cool each sample by chilled water at 20°C
2. *Type*: Direct Expansion type with refrigerant tube in the shell
3. *Capacity*: Redundant 100% capacity
4. *Performance*: To maintain sample temperature at 25 ± 1°C at maximum flow samples, at their maximum temperature condition. Chilled water output 20°C of the quantity as demanded by the system concerned
5. *Condenser*: Water cooling at temperature 40 ± 2°C
6. *Condenser design standard*: ASME design code
7. *Compressor*: Low noise, easy access complete with motor along with all electrical protection for the same; should also include auxiliaries, such as lubrication system, discharge valve, etc.
8. *Chiller pump*: Chiller water pump motor, etc., continuous operation
9. *Other auxiliaries*: Electrical panel, storage tank, etc., complete with all necessary instruments like temperature gauge, level gauge, etc.

5.5.19 Grab Sample and Three-Way Valve

Grab sample is collected via a three-way ball valve of SS 316 construction. There should be sufficient flexible shall to grab the samples. Grab sample flow should be directed to the sampling trough, which drains to the waste header. The function of the three-way valve is to allow the sample drain prior to collection. Also through this the entire line can be flushed.

5.5.20 Back-Pressure Regulator

The back-pressure regulator maintains upstream pressure constant, during fluctuation of flow in the sample header at the time sample collection. This, in conjunction with the pressure regulator, provides a stable pressure and flow condition to the analyzers connected with the sample header.

5.5.21 Resin Column (For Cat Conductivity)

1. *Function*: Cat ion column
2. *Type*: Duplex cat column

www.EngineeringBooksPDF.com

3. *Connection*: Quick release connector (SS) for easy removal/change
4. *Accessories*: Regeneration panel

5.6 Sample Pipes, Tubes, and Fittings (Typical)

1. *Standard*: ISA SP 77.70 (latest)
2. *Power piping*: ANSI B 31.1 PTC 19.11
3. *High Pressure and high tension tubing*: SS 3/8" (10 mm) OD ASTM A213 bulk head fitting type 316H, 16 BWG tubing
4. *Secondary sampling*: SS 1/4" (6 mm) OD ASTM A213 BH fitting Type 316H, 16 BWG tubing
5. *Blow down header*: 80/160 as per pressure flange 2"ANSI B16.5, Class 300/600 lb RF
6. *Closed cooling water pipe*: 2" (50 mm) SS ASTM A312 type, 304 SCH, 40 flange; 2" ANSI B16.5, Class 150 lb RF
7. *Drain header*: 2" (50 mm) SS ASTM A312 type, 304 SCH, 40 flange; 2" ANSI B16.5, Class 150 lb RF

5.7 SWAS Rack/Panels

1. *Sample conditioning rack*: To house various components for sample conditioning. This may be an open rack and/or a closed enclosure with a corridor in between.
2. *Analyzer panel/rack*: The purpose of this is to house all analyzers.
3. *Instrumentation cum electrical panel*: A closed panel to house electrical components, recorder/controller power supply system, etc.

5.7.1 SCP/Rack

1. *Type*: Open rack type/closed corridor type, with easy access for adjustments.
2. *Material*: CRCA sheet ~ 2.5 mm thick should be deployed.
3. *Mounting*: Floor mounting with suitable foundation on base channel (e.g., 100 mm). The mounting should be without vibration, if necessary with suitable antivibration pad.
4. *Enclosure class*: As applicable depending on type, should be NEMA 12 minimum.
5. *Surface preparation painting*: All surfaces should be cleaned, shop blasted, and painted with enamel painting. Also, other surface finishings are as per manufacturer's standard. Exterior and interior paint color should be as per project requirement (e.g., brilliant white paints for interior color). The paints should be anticorrosive types.
6. *Finish* All sharp welds and corners should be ground smooth. Both internal and exterior should be free from scale, cutting, welding spatters, etc.
7. *Accessibility and maintainability*: Easy access without obstruction, and easy removal maintainability. There should not be any crossing of tubes and obstruction from front or back of the analyzer and or sampling component.
8. *Completeness*: Complete in all respect at the factory booth in tubing/piping as well as for electrical connections.
9. *Location*: SWAS Room (SCP and analyzer panel should be in close proximity).
10. *Headers*: There should be a number of headers such as cooling water headers and waste water headers. All of



Inside Sample conditioning panel—Courtesy: Forbes Marshall Pune India.

www.EngineeringBooksPDF.com



Courtesy: Forbes Marshall Pune India.

these should be properly dressed and mounted in the SCP. Suitable drains, sink, etc., should be provided.

11. *Arrangement*: All the monitoring instruments, such as the pressure gauge, temperature gauge, rotameter, etc., should be mounted at the front of the panel. Rate set valves should also be in the front. Various headers, coolers, etc., should be arranged suitably inside the panel.

5.7.2 Analyzer Panel

Various features discussed in Clause 5.7.1.2 through 5.7.1.9 also are applicable for this panel.

1. *Type*: Free-standing enclosed panel.
2. *Analyzer mounting*: As far as possible there should be front surface mounting.
3. *Arrangement*: The electrical connections and electrical devices are arranged as per logical functions. All drains and electrical and other connections should be placed in the rear side of the panel. The sample line bulk head should be at the top rear side.
4. There will be a common drain line to collect the liquids leaving the analyzers.

5.7.3 Instrumentation cum Electrical Panel

Various features discussed in Clause 5.7.1.2 through 5.7.1.8 above also are applicable for this panel.

1. *Type*: Free-standing enclosed panel.
2. *Location*: SWAS room.
3. *Major components*: Power distribution breaker, recorders, controllers, analyzers, etc.
4. *Devices*: Apart from the electrical devices stated above, there may be a recorder and annunciator in this panel. Also isolators, etc., exchanging signals with the DCS.
5. *Analyzer output*: Analyzers normally have 4-20 mADC, which may be connected to the recorder in this panel, as well as output may be sent to the DCS system of the main plant. Many analysis systems offer a high + low alarm, which can be annunciated in this panel and/or could be sent to the DCS as a binary signal. In case the numbers of contact are insufficient, relays may be used or contacts may not be sent to DCS as from the analog signal alarms can be generated in the DCS.

6. BLOW DOWN AND DOSING CONTROL

6.1 Blow Down

6.1.1 Functional Requirements

As the steam is generated from the boiler, the total dissolved solid (TDS) starts rising and forms deposits and scales at boiler parts such as the tube. When these are carried by the steam, they will form deposits elsewhere, e.g., turbine. Therefore whenever the TDS level crosses the limit set by the manufacturer blow down is necessary. The basic purpose of blow down is to regulate the boiler

www.EngineeringBooksPDF.com

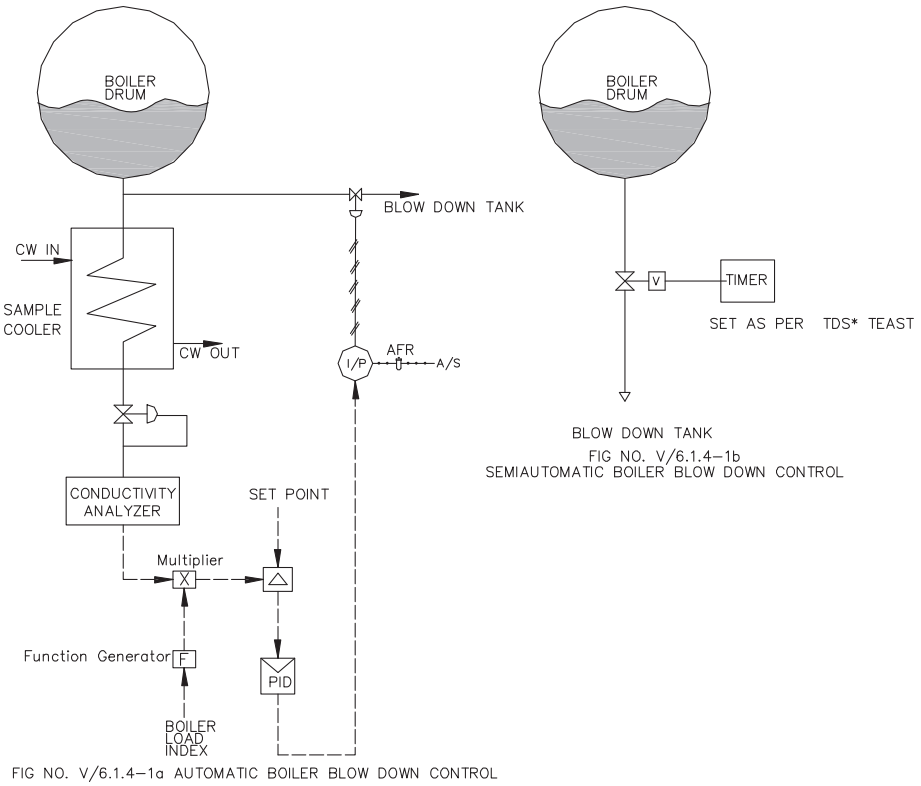


FIGURE V/6.1.4-1 Boiler blow down control.

parameters within the prescribed limits to minimize, "carryovers," "corrosion," and "scale formation" and to drive out the "suspended particles." So, TDS, alkalinity, and silica suspended solids are the major factors based on which blow downs are carried out.

6.1.2 Range

Blow down quantity depends directly on the maintenance of water chemistry in the system concerned (also on quality of water available). Apart from this, factors like the boiler design, turbine requirement, and boiler-operating condition determine largely the blow down quantity (as a percentage of FW quantity). The range of blow down lies somewhere between 2 and 20% of total FW quantity. Also, see ASME's "A Consensus on Operating Practices for Boiler Blow Down".

6.1.3 Blow Down Types

Blow down may be manual and intermittent or continuous and automatic. Manual short-time blow downs are taken from the lowest point of the drum. The continuous blow down system, a part of FW, is always discarded. It offers advantages for large heat recovery.

6.1.4 Blow Down Control

In an automatic blow down system, the blow down and its rate are regulated in relation to the concentration of dissolved solids present to maintain the proper water chemistry. Various ways to automatically control blow down are as follows:

1. Automatic blow down control using conductivity (see Figure V/6.1.4-1a):
   - **a.** *Objective*: To blow down drum water in relation to dissolve solids. Since TDS, alkalinity, silica, etc., directly affect the *conductivity*, it may be taken as a parameter to control blow down
   - **b.** *Loop*: In this method a conductivity probe is used to measure the boiler conductivity and compare it with the set point, which is set based on the allowed total contamination level. However, the rate of blow down should maintain a relation with the amount of FW input to the boiler. So actual conductivity signal, for error generation, is duly multiplied by FW quantity, i.e., by boiler load index, to take care of changes in load. The error thus generated is fed to the blow down PI controller, which generates a demand signal for the amount of blow down, i.e.,

www.EngineeringBooksPDF.com

blow down should be varied with the load in the boiler.

2. As shown in Figure V/6.1.4-1b, there is another way blow down can be controlled. A TDS test is carried out before blow down. Based on the test result, the blow down valve opening is controlled by a timer to keep the valve open for a specified time. This is a very easy method, but it is not accurate. For utility stations of moderate size this may not be suitable. Also it does not take care of load fluctuations.
3. A combination of timer and conductivity analyzer and control is also possible. "Boiler boss" from Rosemount is an example of this.

6.2 Dosing Control

Normally in power stations dosings are done at two places: low pressure condensate and in the boiler drum, i.e., in high-pressure dosing control.

6.2.1 LP Dosing

In low-pressure condensate ammonia and hydrazine are dosed at the CEP discharge and at the suction of the BFP, respectively. However, plants with OT, N_2H_4 dosing is absent (see Clause 4.0.1, number 4). In plants with a CPU dosing may be done at the CPU outlet in place of CEP discharge. The purpose of ammonia dosing is to control the pH of water; pH is kept slightly alkaline to avoid corrosions from chloride and other salts, whereas DO is scavenged by dosing hydrazine. A very low ppb of DO can cause severe corrosion by pitting. Therefore a slight residual of hydrazine is kept in the system.

1. Ammonia dosing control (see Figure V/6.2.1-1):
   a. *Objective*: This is a loop is used to regulate the pH in the system by dosing Ammonia. As shown in Figure V/4.0.1-2, there is direct relation between pH and specific conductivity, so specific conductivity has also been used through the function generator.

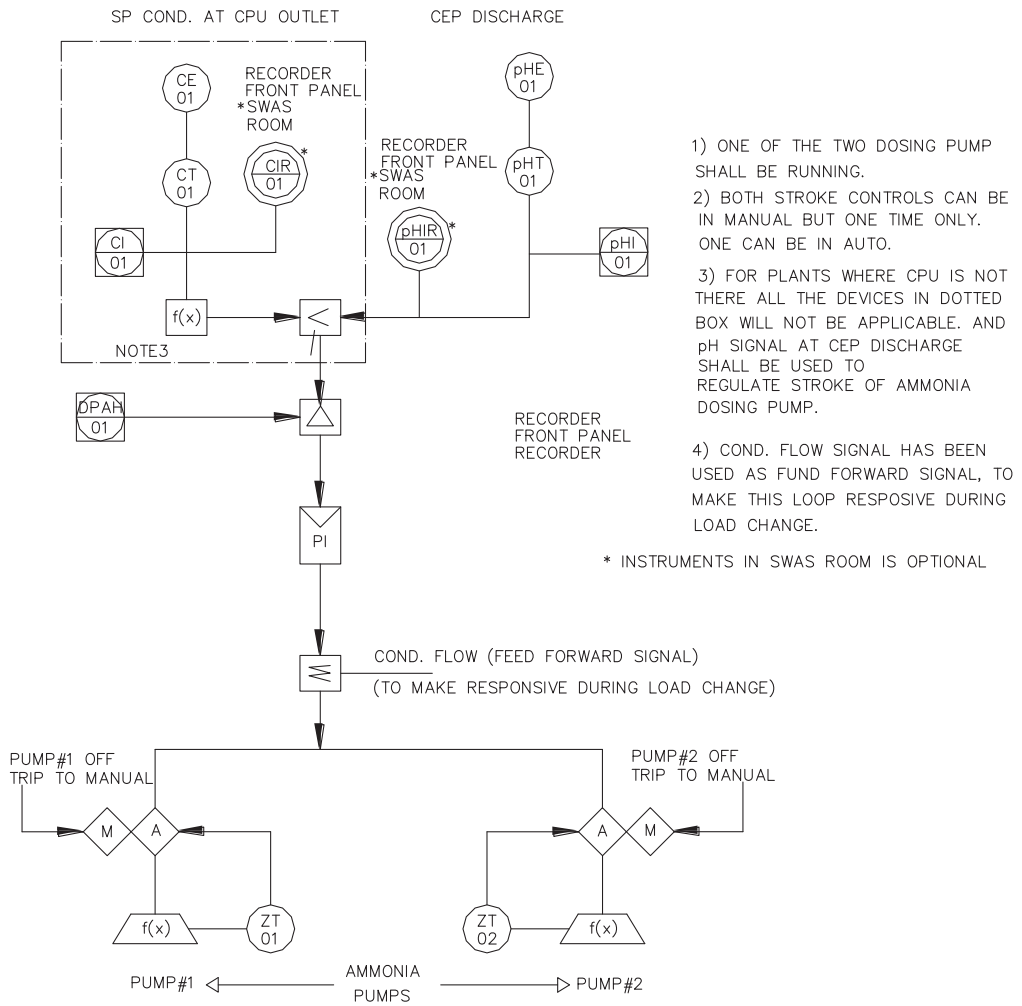


FIGURE V/6.2.1-1 Ammonia dosing control (LP dosing).

www.EngineeringBooksPDF.com

b. *Loop*: pH set point is compared with lower actual pH and derived pH from specific conductivity or directly from pH instruments as detailed in the loop (with notes). The error thus generated is fed to the PI controller to control the stroke of the running ammonia-dosing pump. To make the loop more responsive, condensate flow has been taken as feed forward signal.

c. *Interlock* (1) Normally only one pump is in operation, so the auto/manual (A/M) station of the operating pump should be in auto. (2) When any pump is not in operation the corresponding A/M station should trip to manual. (3) In a DCS the A/M station should be a soft A/M station in the operator's console.

2. Hydrazine control (see Figure V/6.2.1-2):

a. *Objective*: This loop is used to scavenge DO to the extent possible. As discussed earlier, that on account of toxicity, in modern power Hydrazine is replaced by DEHA etc. so similar loop is applicable for DEHA also. This loop may not be applicable for a plant with an OT (see Clause 4.0.1, number 4).

b. *Loop*: DO here have been expressed as a *function* of residual hydrazine. The lower this signal the actual residual hydrazine is considered as the measuring signal, which is compared with the set point for residual hydrazine to get PI output from the controller to regulate the stroke of the hydrazine-dosing pump. The output of the controller is summed with FW flow (may be BFP suction flow), which acts a feed forward signal to make the loop responsive at a changing load.

c. *Interlock*: Same as Clause 6.2.1, number 1c.

6.2.2 HP Dosing Control

Alkalinity in the system is maintained with phosphate dosing (see Figure V/6.2.2-1). Sodium compounds influence phosphate dosing. Alkalinity of the drum water is well maintained when it is done in conjunction with pH based on NaOH. Phosphate, either by itself or with NaOH, can elevate pH.

1. Phosphate dosing Control:

a. *Objective*: This loop is used to operate the boiler at the desired pH.

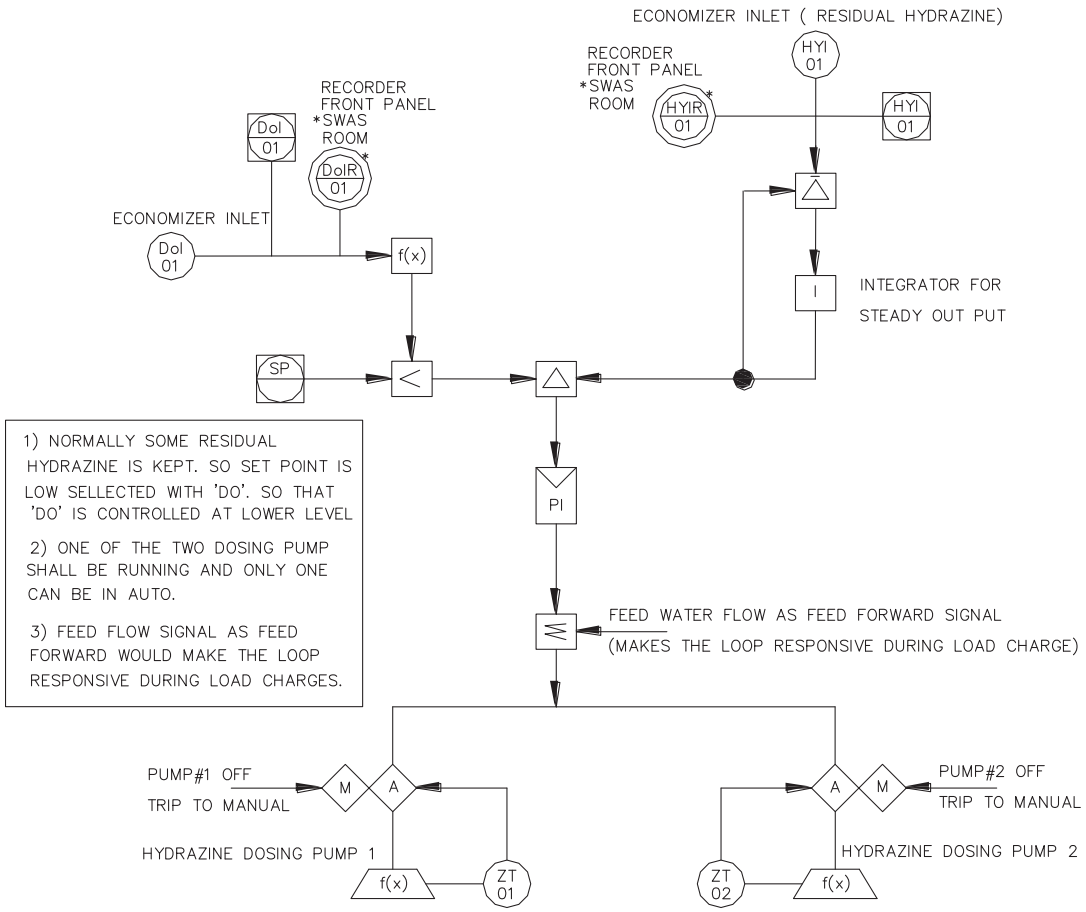


FIGURE V/6.2.1-2 Hydrazine dosing control (LP dosing).

www.EngineeringBooksPDF.com

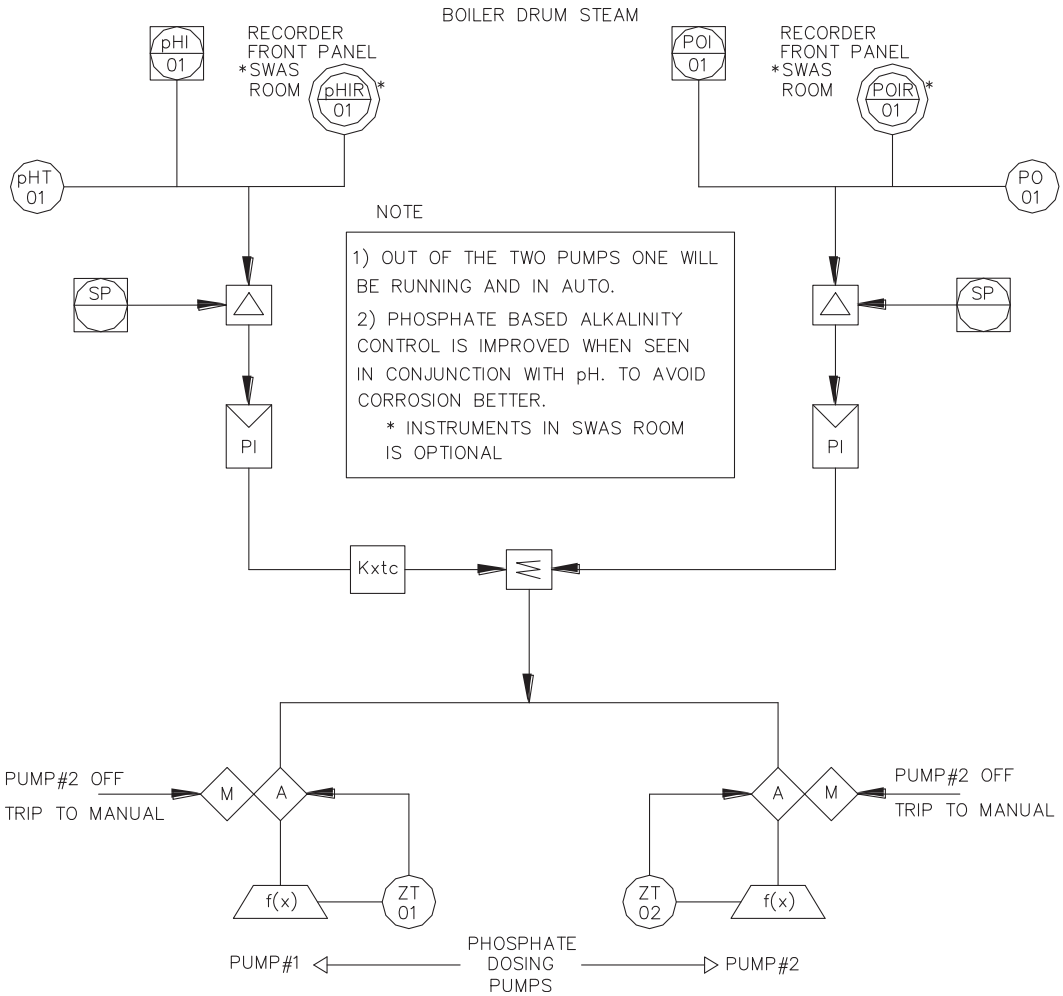


FIGURE V/6.2.2-1 Phosphate dosing control (HP dosing).

b. *Loop*: In this loop the actual value of pH and PO are compared in separate controllers to generate demand for each parameter. PO demand in conjunction with pH from the drum water pH controller is used to regulate the stroke of the phosphate dosing pump. The output of the controller is summed with FW flow as load of the system, which acts as a feed forward signal to make the loop responsive at changing load. pH and FW signals are put into the loop through scaling and bias units to normalize the signal.

c. *Interlock*: Same as Clause 6.2.1, number 1c above.

7. ANALYZERS FOR AIR POLLUTION MONITORING AND CONTROL (NO_X CONTROL)

7.0 Pollution Control

In power plants there two kinds of pollution that need attention. Pollution because of various gases along with dust emitted from the boiler and the other major pollution contribution comes from liquid pollution from various effluents.

7.1 Gas Analyzer for Pollution

These have been discussed in detail in Clause 3.0. Also see Chapter VIII, Clause 10.3, for further details.

7.2 Effluent and Treatment

Power plants produce a great deal of waste products from water treatment plants, regeneration and resin water, sludge, cooling tower blow down, boiler blow down, and waste from various drains. Based on local and national environmental regulations, there are certain guidelines such as the effluent guidelines by the Environmental Protection Agency. Treatment is needed, which should include but is not limited to aeration, sludge treatment, chlorination, and neutralization of pH. Acid and alkalis are

www.EngineeringBooksPDF.com

added to the system for pH neutralization. A number of measurements, such as pH, conductivity, and DO are done. All of these analyzers were discussed previously.

BIBLIOGRAPHY

[1] 3300 Rotary Position Transducer (RPT): Bently Nevada.
[2] 3500 System Overview: Asset condition Monitoring: Bently Nevada.
[3] 6600 Series Machinery Protection Monitors: Entek– Rockwell Automation.
[4] Application Note_ Power generation: Provitech (200MW STG) : www.provitech.com.
[5] CSI 6000 machinery Health Monitor: Emerson Process Management.
[6] Gas Turbine Vibration Monitoring – an over view: Mel Maalouf application Engineer Bently Nevada Products (GE energy):.
[7] Inductive Proximity Sensors: Rockwell Automation.
[8] Machinery Protection System: G E Energy: 3500 series.
[9] Piezoelectric Accelerometer and vibration Preamplifier Handbook: Bruel & Kjaer : Denmark 1976.
[10] Piezoelectric Accelerometer Product data : Bruel & Kjaer:.
[11] Power Generation Handbook: P. Kiameh MC.GRAW-HILL HANDBOOK AUG '2002.
[12] Principles of Vibration Measurement andAnalysis : Bruel & Kjaer:.
[13] Real time Condition Monitoring System usingVibration Analysis for Turbine Bearing: A. Bandopahyay, S.K.Dasmondal and B.Pal: ER & DCI Calcutta.
[14] Signal Conditioning : Turbine speed: e.on Kraftwerke.
[15] STI Field Application note– turbine supervisory instrumentation: STI Vibration monitoring inc.
[16] Turbine Run Monitoring Signals for turbine protection: e.on Kraftwerke.
[17] Turbine Supervisory Instrumentation: SKF (CMCP): Field Apllication Note.
[18] Turbine Supervisory Instrumentation Selection Guide: Rockwell Automation: Technical literature (Internet document).
[19] Understanding Discrepancies n Vibration Amplitude reading between Different Instruments: S. Sabin, A.Hamad, R.Chitwood, M.Qureshi:G.E. Energy.
[20] Understanding of Vibration Analysis: IN-PLANT SERVICES, INC: GREENVILLE, SC.
[21] Vibration (P.H. Sydenham) : Instrumentation Reference Book: Edited by: Walt Boyes.
[22] Vibration Application guide Metrix Vibration Condition :Monitoring & protection.
[23] Vibration Measuring Instruments: Dr. B.K. Sridhara: Mysore India.
[24] FCC Flue gas Emission Control Option: P.K. Niccum, E. Gbordzoe, S.Lang FCC: NPR A2002 Annual meeting March 2002.
[25] Advance Cemas NDIR (multicomponent measuring system): ABB limited:Catalog.
[26] Advance Optima High performance measuring technologu Limus 11UV: ABB Analytical : ABB Catalog.
[27] Advance Optima the integrated Anlyser system Solution: ABB Analytical : ABB Catalog.
[28] Advanced Pollution Instrumentation: Teledyne advanced Pollution Instrumentation: Product data sheet.
[29] B&W NOx Reduction System and Equipment at Moss Landing owner station: B.Becker(B&W), D. Tonn (B&W), N.Stephenson (Cormetech USA), K Speer (Moss Landing USA):.
[30] Continuous Emission Monitoring: Codel international limited UK: Product Data Sheet.
[31] Continuous Gas Analysers in Situ: Siemens: LDS 6 Catalog.
[32] Cross Duct Co Analyser: Codel international limited UK: Product Data Sheet.
[33] DEFOR Extractive UV Gas Analyzer: SICK sensor intelligence: Catalog.
[34] Environmental Assessment Report: Jhajjar Thermal Power Project: Januarry 2009.
[35] EPA CICA Fact sheet: EPA USA: EPA-452/F-03–034.
[36] Flue gas Oxygen Analysers: GE sensing & Inspection Technologies:.
[37] High temperature Zirconia Oxygen probe: ABB limited:ZGP2.
[38] Improving performance of N G fired asset in power plant with process Chromatographs: Emerson Process management: Application Note.
[39] Modular continuous Gas Analysers: ABB limited: AO2000 series.
[40] NDIR TYPE INFRARED GAS ANALYZER (4-COMPONENT ANALYZER): Yokogawa Electric Corporation Japan: Product Data Sheet.
[41] NOx Analyzer: Rosemount Analytical: Catalog.
[42] Opacity Dust Density Monitor: Emerson process Management: Catalog.
[43] Opacity Monitor: Lear Siegler Australia: Catalog.
[44] Paramagnetic Oxygen Analyser: Fuji Electruic systems co Ltd:Catalog.
[45] Particulate Measurement System: PCME CO UK: QAL181.
[46] Principles of operation: MEECO Inc.
[47] Putting Combustion Optimization to Work: N.Spring Sr. Editor :2009.
[48] Reduction of NOx through Combustion Optimization: J. Cahill :Emerson Process Management.
[49] Specific Ion Analyser: Honeywell :Specification.
[50] Stand Alone type Infrared Gas Analyser: Fuji Electric co ltd : Catalog.
[51] Superior Technology, quality & Reliability from World leader in Hydrogen Measurment: ABB Limited UK.
[52] Use of process analyzers in fossil fuel-fired power plants Solutions from Siemens: Power Industry – Siemens : Write up.
[53] Conductivity Sensor: Emerson Process Management : Product Data Sheet.
[54] A measure of success in the fight against corrosion: N.Kirloskar, Forbes Marshall : Power Engineering (PEI).
[55] Advantage series Two wire two electrode cond. Tx: ABB limited : Conductivity & pH.
[56] After Cation Conductivity (ACC) and De-gassed Cation Conductivity (DCC)analyzer: Luchan Enterprises Co., Ltd : Catalog.
[57] Alternatives to Hydrazine in Water Treatment at Thermal Power Plants: S.Tsubakizaki, M.Takada, H Gotou, K Mawatari, N. Ishihara & R. Kai : Mitsubishi Heavy Industries Technical Review vol. 46 No. 2 (June. 2009).
[58] An Introduction to steam boiler and steam raising: NEM Bussiness Solutions (Internet document): cip.ukcenter.com.
[59] Analytical Solutions: Honeywell:System Write up.
[60] Automatic Blow down control Medium and high Pressure blow down system: Forbes Marshall India : Application Note.

www.EngineeringBooksPDF.com

[61] Boiler Feedwater / Condensate Chemistry Control: KANUPP - IAEA Training.
[62] Boiler Steam and water Sampling System: LECOL.
[63] Characteristics of Boiler feed water : Lenntech : Application Note.
[64] Chloride Analyser: Sherwood UK :926.
[65] Clean Coal Technologies: K Ravikumar Director: Bharat Heavy Electricals Ltd. : 9th Assochem Energy Summit.
[66] Conductivity in power plants: Kemtron: Application Note.
[67] Conductivity Instrument: Polymetron: Product data sheet.
[68] Controlling Chemistry During Start up and commissioningof Once Through Supercritical Boilers: K.Kirschenheiter, M.chuk, C.Layman, K. Sinha—Bechtel Corporation: December 2008.
[69] Dissolve Oxygen Analyser:ABB limited :4600.
[70] Dissolve Oxygen Analyser:HACH Ultra:Hach 9182.
[71] DO Sensor:Rosemount Analytical:499A.
[72] Dual Timer Automatic Boiler Blowdown Control System:-Rosemount Analytical: Boiler boss 1000.
[73] Electrochemistry Theory & Practice :Dr. A.Bier :Hach Ultra.
[74] Enhanced Phosphate Treatment for Drum Recirculating Boilers:J.Stodola (Ontario hydro), M.D. Silbert Marvin Silbert and associates.
[75] First for Liquid analysis :ABB Limited :Indutrial Liquid Process Analyser.
[76] Handbbok of industrial water treatment:GE Power & water :Water & process technologies.
[77] Hydrazine Analyser :Hach Ultra Switzerland:9186.
[78] Handbook of industrial water treatment:GE Power & water :Water & process technologies.
[79] Hydrazine Analyser :Hach Ultra Switzerland:9186.
[80] Importance of Good Bolier Feedwater treatment:Vogt power international:Technical bulletien (HRSG).
[81] Install an Automatic Blowdown control System:Energy efficiency and Renewable Energy :DOE USA.
[82] Instrumentation for monitoring and control of cycle chemistry for the steam-water circuits of fossil-fired and combined-cycle power plants:The International Association for the Properties of Water and Steam:Technical Guidance Document.
[83] Investigating a Proven Alternative to Phosphate Treatment for Low-Pressure HRSG Units Operating with Demineralized Water:-G.J.McGiffney, BetzDearborn:GE Energy.
[84] Lecol Boiler SWAS: Luchan Enterprises Co., Ltd: Catalog.
[85] Modern Power Plant Practices Vol F: Book— British Electricity International: Elsevier.
[86] Monitor for Fluoride, Ammonia, Nitrate & High Level Chloride:Honeywell on line water chemsitry:8230 Series.
[87] On line Hydrazine Aalyser :Emerson Process Management: CFA3018.
[88] On line Hydrazine Analyser :Emerson Process Management: Product Data Sheet.
[89] Online Water Chemistry measurement for power Plants :Honeywell on line water chemistry.
[90] On-line Water Quality Parameters as Indicators of Distribution System Contamination:J.Hall A.D.Zaffiro, R.B. Marx, P.C Kefauver, E Radhakrishnan, R.C.HaughtJ.G. Hermann.
[91] Optical DO measurement Principles:Forbes Marshall India:VISIFERM Sensor.
[92] Optical DO measurement Sensor:polymetron 9123:Catalog.
[93] pH /ORP sensors for process Monitoring:ABB limited:TB(X) 5 series.
[94] pH Calculated by differential conductivity:polymetron 9123:Catalog.
[95] Phosphate analyser:ABB Limited:Navigator 601.
[96] Phosphate analyser:ABB Limited:Navigator 601:Hach.
[97] Principles & Guidelines of pH Measurement :S. Rupert:Intech March 2005.
[98] Sample Sequencer :Sentry equipment Corp. USA: Catalog.
[99] Silica Analyzer :ABB Limited:Navigator 600.
[100] Silica Analyzer :Hach :Catalog 60000—18.
[101] Silica Analyzer :Polymetron :Product Data Sheet.
[102] Silica Monitor :ABB limited :8240.
[103] Single channel Sodium Analyser poly metron.
[104] Sodium Analyzer :Hach: 9245.
[105] Sodium Monitoring in the water and steam cycle of power plants:E. Basset, S.Conan, P. Dudouit, P.Guillou, E.L.Hostis, R.Qarbi, G.Stehle:Hach Ultra Analytic SA Switzerland.
[106] Sodium Monitoring on Power plant : ABB limited:Tech. note.
[107] Specification for SWAS:http://specswas.blogspot.in/ : Nov.30th 2009.
[108] Standard Design Criteria/ Guideline for Balance of plant (2X500 MW TPP):Central Electricity Authority:New Delhi 2010109.
[109] Steam and Water Analysis Brochure:Emeson Process Management:write up (Sentry USA).
[110] Steam and Water Analysis system overview:Forbes Marshall India:System write up.
[111] Steam and Water Sampling:Sentry equipment Corp. USA.
[112] Steam generation in power plants:Hach Ultra :Application Note power no 12113.
[113] Theory and Practices of pH measurement:Emerson Process management:Decemeber 2010.
[114] Total Chlorine Analysis Sysetm:Emerson Process Management :TCL Prod. Data Sheet 115.
[115] Two wire transmitters for pH, Conductivity, Oxygen and chloride:Emerson Process Management :Product Data Sheet.
[116] Water chemistry Aspects in Supercritical Unit:V Chandrashekharan:en. Sipat NTPC India.
[117] Water quality — cooling tower make up water quality:tom baker:en.allexpert.com.
[118] Water treatment :Honeywell Analytical Solutions.
[119] Water treatment hand book by Degrimont.
[120] The Analyst 2001 winter: Diethylhydrxylamine: a volatile oxygen.
[121] DHA as oxygen sacvenger for boiler treatment by a. Khera, N. Anbunanthan: ion Exchange India.

www.EngineeringBooksPDF.com

Chapter VI

Final Control Element

1. VALVES AND ACTUATORS

1.0 Introduction

A control loop consists of process sensor(s) for measurement, controller subsystem, and final control element (FCE) to regulate the manipulated variable to control the desired parameter at a desired value. Optimal control of the process depends on the performance of all control components; without an FCE process control may not be feasible. In almost all cases the basic purpose of the FCE is to regulate flow (even in a heating control current flow is controlled). Dampers, impellers, vanes, blade pitch, variable frequency drives (VFDs), coupling control (for control of pump/blower/fan speed control), and control valves are all examples of an FCE. The most common FCE is the control valve. Hydraulic coupling scoop tube and VFDs are common for induced draft (ID) fans and boiler feed pumps (BFP; in case of BFP turbine the control valve is the FCE).

Currently, there are a number of factors, such as high competition, low environmental impact, and economics, which compel a designer to develop control systems with a very high degree of performance, safety, and reliability. Needless to say, it is important to select the proper FCE. By putting too much importance on the control loop, often the FCE becomes a weak link. However, for better control performance FCE performance has to be good as it is in service in both manual and auto modes, and without an FCE process control is impossible. There are several issues related to FCEs: gain, dead band, and system lag. Of these, gain is directly related to the FCE viz. control valve. It is critical to choose the FCE gain precisely (e.g., within a range of 2−3%); otherwise, if gain is too high then, for a small change in the process it will be multiplied by the gain to change the valve position.

How should we judge the FCE's performance? In simple language—it is the ability of the FCE to control a process efficiently in response to the demand created by the controller, without any backlash, dead band, or system lag. In this definition one important aspect is missed—gain. The gain should be optimum so that the system can reach a stable position without much oscillation (due to overshoot/undershoot). Whenever FCE is discussed, it basically consists of the actuator and the valve (or damper/impeller, etc.). While time-based parameters, such as backlash, dead band, and system lag, are a contribution of the actuator; gain is a function of the control valve/damper, etc.

From the previous discussion it is clear that control valves need to offer constant gain, which is a time-independent proportional response to controller output, whereas the actuator is responsible for time-based parameters. Ideally a linear (first-order) control system is considered, but in reality there will be deviation. In this clause various terms related to control valves have been discussed. Figure VI/1.0-1 shows various parts of the control valve. For FCEs, nominal pipe size and pressure ratings are important and these aspects are detailed in Clause 1.11.

1.1 Control Valve and Actuator: General

The most important aspects related to control valves are as follows:

- Control valve size
- Trim characteristic
- MOC of various valve components
- Selection of correct actuator with/without positioner
- Proper accessories

Improper selection of control valve type will result in the wrong gain for the system, and improper characteristics will also result in erroneous gain, degrading the control loop performance. A properly selected actuator will result in very little backlash, dead band, etc. Often it is found that when the valve/FCE starts/ stops it does so with jerks. This is because of *stiction*, which is the resistance offered to start a motion. Because of stiction, position of the air cylinder overshoots jerkily and may move with jerks. This happens when the static friction *exceeds* dynamic friction. When there is stiction then there will be overshoot and oscillation may take place. Valve fluctuation not only causes poor performance, but it may result in degradation of plant performance and may be responsible for mechanical damage, wear, and tear of main mechanical equipment in addition to damaging the valve. All these result in loss for the plant and poor return on investment.

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

FIGURE VI/1.0-1 Control valve and actuator parts.

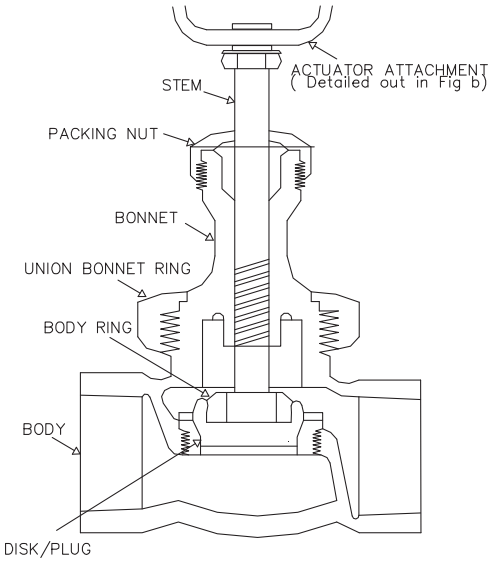


FIG NO. VI/1.0–1a
VARIOUS PARTS OF A CONTROL VALVE

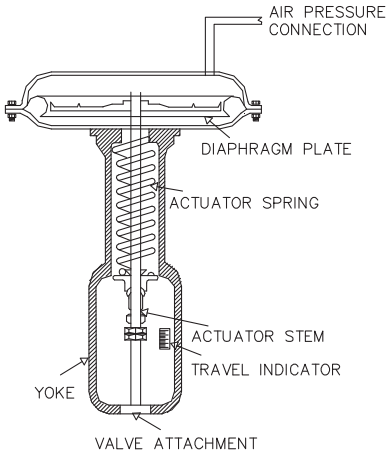


FIG NO. VI/1.0–1b
TYPICAL DIAPHRAGM ACTUATOR WITH SPRING

When a product is selected, then it is hoped that the total system will have a trouble-free performance. For a control valve, there must be proper selection of sizing, materials, characteristics, rating, etc. For further details, refer to Control Valve Technical Specification published by ISA. Basically, all control valve sizing is derived from the ISA S75.01 Standard (IEC 534-2-1 and 543-2-2 standards are also very similar to the ISA standard). Details about control valve sizing is available in the aforesaid standard, sizing catalogs published by manufacturers, and in most textbooks. A short discussion on the same is presented in Clause 1.2. However, before this discussion, it is better to consult for definitions of a few terms related to control valves and actuators in Table VI/1.1-1.

1.2 Control Valve Sizing

For specifying control valves ISA form S20.50 (control valve data sheet) may be filled out. Detailed instruction for filling out S20.50 also is available from ISA. Discussions on control valves are started with sizing so that the reader can see various terms and their implications related to control valves. Sizing and selection of control valves is incomplete without any discussion on control valve characteristics, which are presented in Clause 1.3.

- *Desired valve design*: To specify pressure class trim characteristic, valve type, etc.
- *Process fluid*: To specify gas, oil, steam, water, etc.
- *Service conditions*: Use symbols (Sym) and meanings are as per ISA Guidelines.

In Table VI/1.2-1 various constants are defined with a pressure base of 101.3 KPa/1.013 bar and all pressures in absolute (abs) pressure. A few factors, such a F_L, x_T, and C_d (defined in Clause 1.2.1), are available in the manufacturer's table for representative sizing coefficients (guidelines available in ISA standard calculation). The valve sizing basis followed is mainly as per ISA S75.01 and IEC534-2-1 and IEC534-2-2.

1.2.1 Sizing for Liquid Services

For definition of symbols, refer to Table VI/1.2-1.

Sizing formula for volume flow:

$$C_v = q/NF_p\left(\Delta P/G_f\right)^{1/2},$$

where $N = 0.0865$ (when q in m^3/h, p in KPa); $N = 0.865$ when q in m^3/h, p in bar); and $N = 1$ if all in FPS (Foot Pound Second–imperial system).

Sizing formula for mass flow:

$$C_v = w/NF_p(\Delta P * \gamma)^{1/2},$$

where $N = 2.73$ (when w in kg/h, p in KPa and γ in kg/m^3); $N = 27.3$ (when w in kg/h, p in bar, and γ in kg/m^3), and $N = 63.3$ if all in FPS.

Based on the above C_v, valve size is selected from the manufacturer's table. Then, F_p is determined to finally get an accurate C_v value. Pipe geometry F_p can be calculated as per the formula below, if it is not available from the manufacturer's data:

$$\mathrm{F_p} = \left[1 + \sum \mathrm{K/N}\left(\mathrm{C_v/d^2}\right)^2\right]^{-1/2}$$

www.EngineeringBooksPDF.com

TABLE VI/1.1-1 Commonly Used Control Valve Terminologies

Terminology	Definition	Remarks
Actuator	An externally powered device that supplies the motive force required for control valve movement. It can be electrical, hydraulic, or pneumatic.	
Bonnet	Part of the control valve that holds a packing box and stem seal and can guide the stem movement.	
Bonnet extension	Bonnet with greater dimension between the bonnet flange and packing box. Used in very hot/cold service for better heat transfer	
Capacity	Rate of flow through a valve under stated conditions.	ISA
Control valve assembly	Includes all the components mounted on the valve body required for its operation. Valve body assembly, actuator, positioner, air set, air lock relay, limit/torque switches, position transducer, etc., form a part of it.	
Dead band	Range through which input can be varied upon reversal of direction, without any observable change in output signal, i.e., the amount of controller output without observable change in process variable.	
Diaphragm pressure range	High and low pressure applied to the diaphragm to produce rated valve plug travel with atmospheric pressure in valve body, often referred to as bench set.	
Enthalpy	Sum of internal energy and product of volume and associated pressure.	
Entropy	In thermodynamic process it is the measure of energy that cannot be transformed in to mechanical work.	
Flow characteristic	Relation between the fluid flow through the valve and the percentage of rate travel (0—100%)	
Flow characteristic Inherent	Flow characteristic when constant DP is maintained across the control valve.	
Flow characteristics EQ percentage	Inherent flow characteristics of the valve, which causes EQ percentage change in flow in the existing flow for equal change in travel.	Clause 1.3
Flow characteristics linear	Inherent flow characteristic represented ideally by a straight line in a rectangular plot of Flow versus percentage of travel	Clause 1.3
Flow characteristics quick opening	Inherent flow characteristics in which there is maximum flow for minimum percentage travel	Clause 1.3
Hysteresis	Maximum difference in output, for any single input, while input is increasing and decreasing in a calibration cycle.	
Installed valve gain	Ratio of change flow through the valve to the change in percentage travel of the valve under actual process conditions.	
London pressure	Amount of pressure required to position a pneumatic actuator.	
Process gain	Ratio of the change in the controlled process variable to the corresponding changes in the controller output	Control valve
Maximum flow rate	This flow condition is consistent with plant or equipment operational maximum flow condition. The maximum flow condition is generally governing case for required maximum C_v	ISA Guide, pp. 486—487
Minimum flow rate	This flow rate is consistent with plant turndown requirement or equipment turndown capability. The minimum flow condition generally subjects control valve to the highest DP condition. Minimum flow conditions are generally the governing case for the required trim performance.	
Normal flow rate	A flow condition generally referred to as the design flow or material balance flow.	
Range ability	Ratio of maximum to minimum flow within which inherent flow characteristics do not change the stated limit.	

Continued

www.EngineeringBooksPDF.com

TABLE VI/1.1-1 Commonly Used Control Valve Terminologies—cont'd

Terminology	Definition	Remarks
Rated C_v	Value of flow capacity at full open position.	
Seat	Area of contact between the closure member and the associated mating surface that causes complete shut off of the valve. It is related with valve leakage. Net contact force determines the seat load.	
Time constant	Time parameter defined as the time interval between first detectable change and output; reaches 63% of the final steady-state value from a step change in the input.	
Valve cage	Part of valve trim that surrounds closure member.	
Valve plug	The whole closure assembly.	
Valve port	Orifice of the control valve that controls the flow (there may be a difference in size between body size and port size).	
Valve trim	Internal component of a valve that modulates the flow of the controlled fluid. In a globe control valve this includes seat ring (sitting surface for closure member), cage, and stem along with closure ember.	ISA

where $N = 0.00214$ if d and D are in millimeters, or $N = 890$ if d and D are in inches.

$$\sum K = K_1 + K_2 + KB_1 - KB_2$$

where K_1 and K_2 are resistance coefficients of upstream and downstream fittings. KB_1 and KB_2 are Bernoulli's coefficients for inlet and outlet. If inlet and outlet pipe size of the control valve is same then KB_1/KB_2 [$KB = 1 - (d/D)^4$] will be equal and, hence, may be omitted.

For inlet reducer

$$K_1 = 0.5\left[1 - \left(d^2/D^2\right)\right]^2, \text{ and}$$

for outlet reducer

$$K_2 = \left[1 - \left(d^2/D^2\right)\right]^2$$

TABLE VI/1.2-1 Legends for Standard, Commonly Used Symbols for Control Valves

Symbol	Meaning	Symbol	Meaning	Symbol	Meaning
C_v	Valve flow coefficient	G_g	Gas specific gravity	M	Molecular wt
d	Nominal valve size	P_1	Upstream abs static pressure	N	Numerical constant for unit conversions
D	Pipe ID	P_2	Downstream abs static pressure	q	Volume flow q_{max} (choked flow at upstream pressure
F_F	Liquid critical ratio factor	P_c	Abs critical pressure	$T1$	Temperature in K
F_k	Ratio of specific heat factors	P_v	Vapor pressure—Abs	w	Mass flow rate
F_L	Rated pressure recovery factor	ΔP	Pressure drop ($P_1 - P_2$)	x	Ratio $\Delta P/P_1$
F_{Lp}	Combined pressure recovery factor and geometry factor with fittings attached	ΔP_{max}	Maximum allowable pressure drop (liquid) ΔP_{max} LP same, but valve with fittings	x_T/x_{TP}	Rated pressure drop factor without attachment. If there is an attachment then it is X_{TP}
F_p	Pipe geometry factor	γ_1	Specific weight at inlet condition	Y	Expansion factor
G_f	Liquid specific gravity	k	Ratio of specific heat	Z	Compressibility factor

www.EngineeringBooksPDF.com

Relative Valve capacity : $C_d = C_v/d^2$ is useful factor in establishing the effect of geometry of different valve design which affects the pressure loss for a given flow. Thus it indicates pressure recovery in different style and design of valves. Larger the C_d value higher will be Pr. Recovery , naturally more possibility for choke flow.

FIGURE VI/1.2-1 Relative valve capacity factor.

For the choke flow condition, maximum flow with allowable drop is determined by the following:

$$q_{\max} = N * F_L * C_v * \left[(P_1 - F_F P_v)/G_f\right]^{1/2},$$

where $N = 0.865$ when q in m^3/h, p in bar, and $N = 1$ if all in FPS) and

$$F_F = 0.96 - 0.28(P_v/P_c)^{1/2}.$$

If there are attached fittings then F_L should be replaced with

$$F_{LP}/F_P \text{ where } F_{LP} = \left[\{(K_1 + K_{B1})/N\}\{C_v^2/d^4\} + (1/F_L)^2\right]^{-1/2},$$

when $N = 0.00214$ if d or D is in millimeters, $N = 890$ if d or D is in inches.

Note: The liquid pressure recovery (also refer figure V/1.2-1) factor F_L is a function of the ratio between valve pressure drop and pressure differential between inlet and pressure at vena contracta. $F_L = [(\Delta P)/(P_1 - P_{vc})]^{1/2}$ values of different F_L for various valve designs are available in manufacturer's tables for a particular design (available ISA standard for valve sizing).

$$\text{Allowable } \Delta P_{\max} = F_L^2(P_1 - F_F * P_v)F_F = 0.96 - 0.28(P_v/P_c)^{1/2}$$

if $\Delta P_{\max} < \Delta P$ then there is a choke flow condition. So C_v is to be recalculated replacing ΔP with $\Delta P_{\max}$ to avoid cavitation.

1.2.2 Cavitation($P_2 > P_v$): Related to Pressure Recovery Factor for Control Valve in Liquid Services

While controlling the flow, a control valve creates a pressure drop in the fluid. As the pressure drops the velocity head increases due to restriction. In the flow path, at a point where the fluid reaches maximum velocity, its pressure is minimum. This point is called vena contracta, where pressure is minimum with highest velocity. If this minimum static pressure goes below liquid vapor pressure, then at the given temperature liquid bubbles will be formed. Past the vena contracta the fluid decelerates and pressure recovery takes place as shown in Figure VI/1.2.2-1. As the static pressure recovers and goes above the liquid vapor pressure, the bubbles will immediately collapse back to liquid. This phenomenon is known as cavitation. The collapse of bubbles produces a high-energy implosion, which creates high-impact force and metal fractures causing erosion. In globe valves $P_1 - P_{vc}$ is about 125% of ΔP, if $P_{vc} > P_v$ (vapor pressure) this will not occur.

Major negative effects of cavitation include :

- Restriction of fluid flow
- Generation of high noise
- Erosion/pitting of metal surface
- Cause vibration/ hammering to cause damage plug/cage and guide

The effect of cavitation is quite destructive even lookwise also. The time required for such destruction depends on the severity of the cavitation as well as on the material used. Since inlet pressure is proportional to energy available for cavitation, higher inlet pressure will cause more damage from the cavitation (if it happens). When the calculated F_L is more than the rated F_L for the valve the cavitation effect is more destructive. Some of the special design trim such as Self-Drag(R), Flash Flo(R), etc., available commercially are meant to fight cavitation.

All anti cavitation design valves are designed and tested with water as medium, but it may not be the same for different liquids used in the industry. Since water has a defined vapor pressure and collapses instantaneously, the

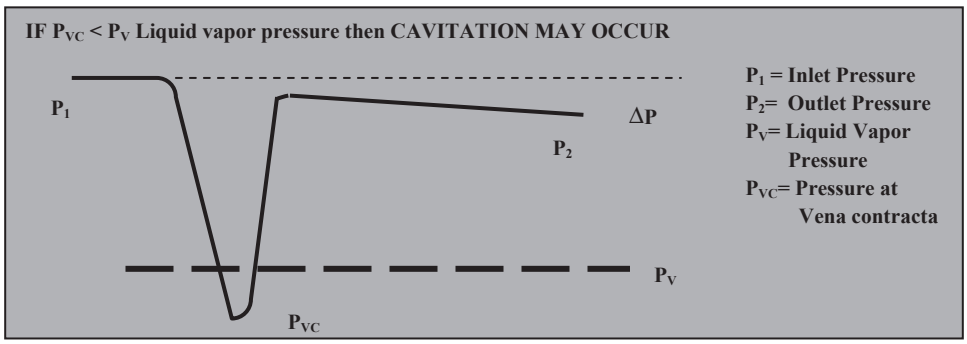


FIGURE VI/1.2.2-1 Pressure profile in a control valve.

www.EngineeringBooksPDF.com

effect of cavitation in water is more severe when compared with hydrocarbons (may not have defined vapor pressure). However, for power plants such problems are mainly in water application.

Cavitation restricts the flow. The vapor bubbles formed at vena contracta increasingly try to restrict flow until the flow is completely choked. Normally, when ΔP is increased, then flow increases. In the choked flow condition liquid flow will not increase, even if ΔP is increased. Until the point of incipient cavitation, $(\Delta P)^{1/2}$ is proportional to flow. From the point of incipient cavitation, with an increase in $(\Delta P)^{1/2}$, the flow curve starts bending and at choked flow condition it is completely horizontal (—choked flow condition). Since it is almost impossible to define the point of damage, the critical pressure drop factor $F_L(F_{LP})$ is used to rate the trim type.

A few suggested methods to eliminate cavitation include:

1. *Materials*: Use of hardened materials can avoid erosion due to cavitation. Some of the materials, such as Stellite 6B and Stellite 6, have very high anticavitation resistance, as well as excellent corrosion resistance materials, but are rather costly. Whereas stainless steel 410 and stainless steel type 17-4 PH have good anticavitation resistance with excellent corrosion resistance at moderate cost.
2. *Revised process condition*:
   a. To reduce operating temperature (so that vapor may not form) to eliminate cavitation.
   b. To install the control valve with a chance of cavitation at the lowest point with low ΔP. Also, the control valve is placed as close as possible to the pump.
3. *Valve selection*: In case of cavitation, selected valves should be designed to have less pressure recovery factor, i.e., to require F_L less than rated F_L. The selected trim should be designed to cause pressure drop in stages.
4. *Installation*: A number of control valves in series to eliminate chance of cavitation.
5. *Choked flow*: Reduced trim design is recommended as in ISA technical guideline.

1.2.3 Sizing for Compressible Fluid Services

Sizing formula for volume flow with specific gravity of gas is specified (see Table VI/1.2-1 for symbols):

$$C_v = q/C_1 * \left(x/G_g * \mathrm{T1} * Z\right)^{1/2},$$

$$\text{where } C_1 = N * F_p * P_1 * Y.$$

N (for normal condition of $T_N = 0°\mathrm{C}) = 3.94$ (with q in m^3/h P in KPa) or $= 394$ (with q in m^3/h P in bar) when temperature in K;
N (for standard condition of $T_S = 15.5°\mathrm{C}) = 4.17$ (with q in m^3/h P in KPa) or $= 417$ (with q in m^3/h P in bar) when temperature in K; and
N (for standard condition of $T_N = 60°\mathrm{F} = 1360$ (with q in scfh P in psia) when temperature in R.

The expansion factor Y is important for compressible fluid valve sizing and Y factor is affected by

- Pressure drop ratio x
- Internal geometry of the valve
- Reynold's number
- Factor k
- Ratio of port area to body area—x_T is responsible for this, for valve geometry, and pressure drop ratio

$$Y = 1 - (x/3 * F_k * x_T),$$

where $F_k = k/1.4$ and x_T is pressure drop ratio to produce critical flow (with $F_k = 1$). Condition of critical pressure drop occurs when $x > F_k{*}x_T$ (or x_{TP}, see Table VI/1.2-1). At that condition: $Y = 1 - 1/3 = 0.667$.

It signifies that at constant P_1, flow will not increase even if ΔP is increased due to critical pressure condition. This means $Y > 0.667$.

Sizing formula for volume flow with molecular weight of gas (compressible fluid):

$$C_v = q/C_2 * (x/M * \mathrm{T1} * Z)^{1/2},$$

$$\text{where } C_2 = N * F_p * P_1 * Y$$

N (for normal condition of $T_N = 0°\mathrm{C}) = 21.2$ (with q in m_3/h P in KPa) or $= 2120$ (with q in m^3/h P in bar) when temperature in K;
N (for standard condition of $T_S = 15.5°\mathrm{C}) = 22.4$ (with q in m^3/h P in KPa) or $= 2240$ (with q in m^3/h P in bar) when temperature in K; and
N (for standard condition of $T_N = 60°\mathrm{F} = 7320$ (with q in scfh P in psia) when temperature in R.

Y factor is the same as discussed above in connection with volume flow with specific gravity.

Sizing formula for mass flow with molecular weight (compressible fluid):

$$C_v = w/C_3 * (x * M/\mathrm{T1} * Z)^{1/2},$$

$$\text{where } C_3 = N * F_p * P_1 * Y$$

$N = 0.948$ (with w in kg/h P in KPa) or $= 94.8$ (with w in kg/h P in bar) when temperature in K and
$N = 19.3$ (with q in lb/h P in psia) when temperature in R

Y factor is the same as discussed above in connection with volume flow with specific gravity.

Sizing formula for mass flow with specified weight γ_1 of gas:

$$C_v = w/C_4 * (x * P_1 * \gamma_1)^{1/2},$$

$$\text{where } C_4 = N * F_p * Y$$

$N = 2.73$ (when w in kg/h, P in KPa and γ in kg/m^3);
$N = 27.3$ (when w in kg/h, P in bar and γ in kg/m^3); and

www.EngineeringBooksPDF.com

$N = 63.3$ if all in FPS.

Y factor is the same as discussed above in connection with volume flow with specific gravity.

Determination of X_{TP}: If the control valve has attached fittings then this factor can be determined from $X_{TP} = X_T/F_P^2[1+(X_T{*}K/N)(Cv^2/d^4)]^{-1}$ $K = K_1 + K_{B1}$, where $N = 0.00241$ when d or D is in millimeters, or $N = 1000$ when d or D is in inches. This is determined to accurately calculate C_v.

1.2.4 Flashing Liquid:($P_2 < P_v$)

Whenever the downstream pressure of the control valves becomes equal or below the vapor pressure of the liquid, then the liquid will flash, i.e., it turns into vapor, $P_2 < P_v$. This is similar to cavitation, but not exactly the same, because downstream pressure will not recover and the bubbles will not collapse. However, this phase change may result in high velocity, causing erosion of the metal. While sizing the valve for flashing application, it is necessary to size the valve at choked flow condition. Also refer figure no VI/1.2.4-1. Downstream pipe should be large enough to accommodate additional volume. It is necessary to calculate vapor fraction—the velocity of this vaporized mixture (see ISA control valve sizing standard). Due to erosion, the thickness of the body will be reduced (less than acceptable code) so body material will be chosen accordingly. Chrome molybdenum (WC6) steel may be used and the body may be angular. Cage control trim/multiple orifices may be used. In flashing services with $\Delta P < 3.5$ kg/cm^{2,} hardened trims may suffice. In power plants, while sizing steam drain valves and heater drain valves (especially draining to condenser), due consideration is given to hardened trims. Reduced trim design could be a better option.

1.2.5 After the C_v Calculation

After the C_v calculation the body size needs to be found by matching the calculated C_v with the characteristic curve of the valve to see that calculated C_v meets the criterion set by ISA or is better. As per ISA technical specification trim capacity should meet the following parameters:

1. An equal percentage trim should open a maximum 95% travel to meet the maximum flow.
2. For linear/quick opening it should open 90% travel to meet the maximum flow.
3. In general designs are a little conservative so that at a later date a small capacity increase will not need to change the control valve to accommodate the flow.

1.2.6 Reduced Trim Applications

Control valves with reduced trim are considered for the following application as per ISA guidelines:

- Pressure drop > 5170 KPa
- Choked flow
- Flashing flow> 5% weight of liquid
- Erosive fluid
- Future capacity increase
- Gas flow with outlet velocity 0.3 Mach (99M/S)
- Noise >85 dBA (measured 1 m from source)

1.3 Control Valve Characteristics

1. The relationship between control valve capacity and valve travel is known as flow characteristics of the control valve. Control valve characteristics, rangeability, gain, and turn down ratio are all inter-related. As per B.G. Liptak (9), all of these "describe the personality of the valve." These are important in the sense that all of these parameters in conjunction with different elements in a control loop decide the performance of the entire loop.
2. One control loop with various elements is shown in Figure VI/1.3-1, where: K_a = actuator gain, K_c = controller gain, K_p = process gain, K_s = sensor gain, and K_v = valve gain; overall gain of the loop is $K = K_a{*}K_c{*}K_p{*}K_s{*}\ K_v$. As long as the overall gain is constant it is stable. It is clear that if controller gain is independent of load then as long as $K_p{*}\ K_v$ is constant, the system is stable as the overall gain is constant, meaning that changes in process have a direct impact on control valve gain (assuming the controller is not changing with load change—nonadaptive). In other words, control valve gain is again related to the control valve characteristics. Before any discussion on control valve characteristics, it is necessary to discuss control valve gain.

***ISA recommendation for "Cavitation, Choked Flow and Flashing*: ISA S75.01 -ISA guide and Seller's valve Cavitation index data shall be used for determination of severity of Cavitation, choked flow or Flashing condition. Following techniques for Cavitation resistant valves may be followed (REF; p.191 ISA GUIDE)**

- **"Reduce the pressure in multiple stage"**
- **"Direct flow away from valve body, pipe wall"**
- **"Break the flow in many small streams"**
- **"Force the flow through multiple turns or tortuous path"**

FIGURE VI/1.2.4-1 ISA recommendation for flashing.

www.EngineeringBooksPDF.com

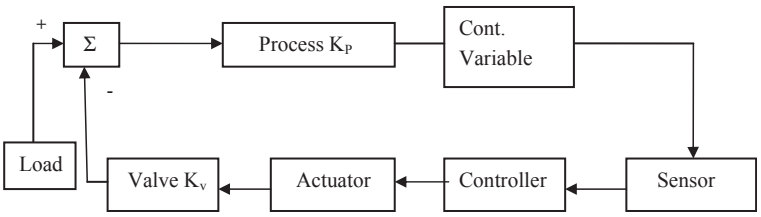


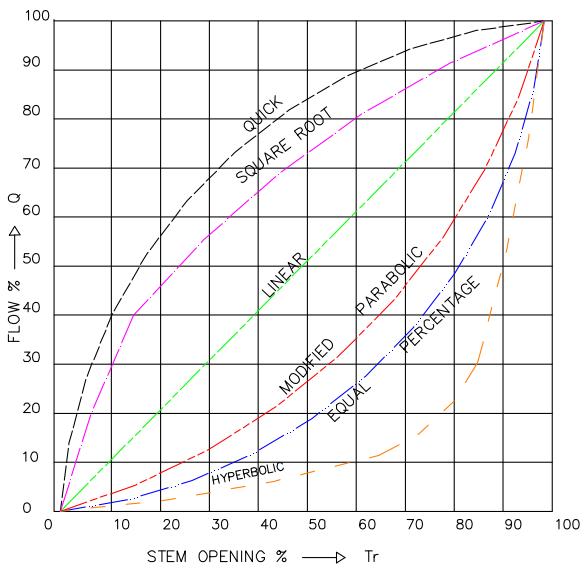
FIGURE VI/1.3-1 Control loop.

When the control valve gain varies at a constant rate with load (flow), the valve gain is called equal percentage. If the control valve gain drops with load/flow, then it is the quick opening type. If there is no variation of valve gain with flow/load (i.e., the load and gain is related in a constant gradient relationship), then it is linear. If the valve gain shows some other nonlinear characteristic with load, then it may be called square root, parabolic, hyperbolic, etc., as shown in Figure VI/1.3-2a.

The valve gain is the slope of the chracteristics of curve, i.e., $\Delta Q/\Delta T_r$. Valve gain is influenced by valve size, pressure drop, and valve characteristic, as well by flow. In Figure VI/1.3-2b the pump characteristics along with system resistance illustrate how the control valve needs to change its opeing to provide necessary system resistance. The pump discharge pressure drops with an increase in load or flow. As the ΔP of the valve increases with flow, the valve gain drops with load. This suggests that after installation the valve gain changes. This is called installed valve gain. When actual flow is plotted against a corresponding valve opening, installed valve characteristics are obtained and they are quite different from the theoritical characteristics where seen in testing.

3. Tuning the controller is done at nominal load of the loop with the assumption that the loop gain (except an adaptive gain controller) will not change with load. In practice, this is not the case; when the loop gain changes with process load, something needs to be done to compensate for the deviation, i.e., the control valve characteristics need to match the process type. Proper selection of a control valve for a specific application is not easy and requires experience. However, the rule of thumb for selecting a valve characteristic is presented in Table VI/1.3.2-1 (level), Table VI/1.3.2-2 (Flow) to be read in conjunction with Figure VI/1.3-3 and Table VI/1.3.2-3 in line with a number of standard suppliers to make selection easier (for flow application also see Figure VI/1.3-3).

For temperature application equal percentage characteristics are good, because they have a higher time constant. Quick opening valves are used mainly for ON/OFF service, in a batch or semicontinuous process,



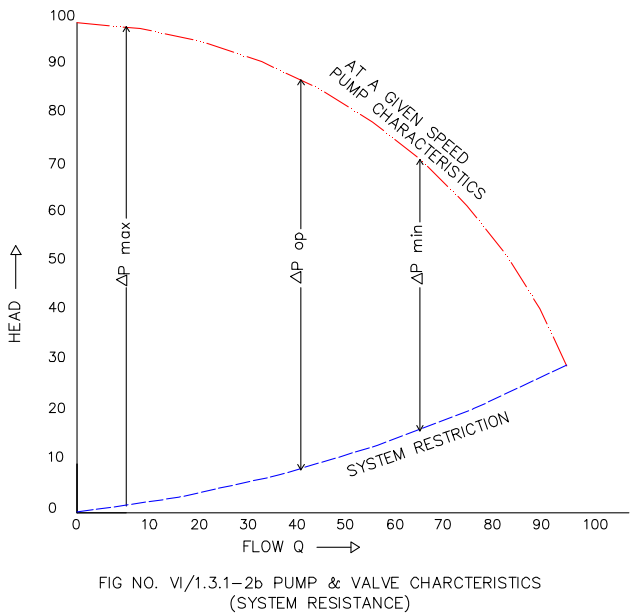


FIGURE VI/1.3-2 Valve characteristics and system resistance.

www.EngineeringBooksPDF.com

TABLE VI/1.3.2-1 Control Valve for Level Application

ΔP	Load condition	Inherent characteristic
Constant	All Load	Linear
ΔP at maximum load >20% of minimum load ΔP	ΔP decreasing with load increasing	Linear
ΔP at maximum load <20% of minimum load ΔP	ΔP decreasing with load increasing	Equal percentage
ΔP at maximum load >200% of minimum load ΔP	ΔP Increasing with load increasing	Quick opening
ΔP at maximum load <200% of minimum load ΔP	ΔP Increasing with load increasing	Linear

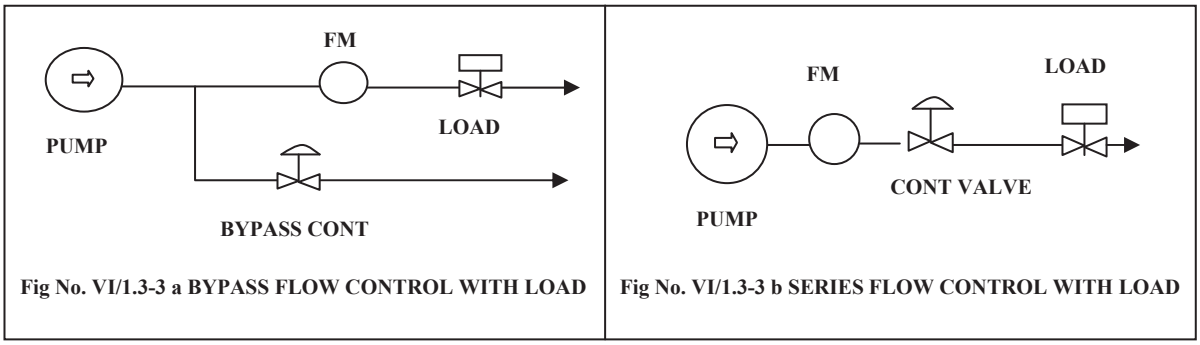


Fig No. VI/1.3-3 a BYPASS FLOW CONTROL WITH LOAD

Fig No. VI/1.3-3 b SERIES FLOW CONTROL WITH LOAD

FIGURE VI/1.3-3 Pump and valve configuration types.

TABLE VI/1.3.2-2 Control Valve in Flow Application**

Flow signal to the controller	Location of control valve in relation to flow meter (Figure VI/1.3-3)	Recommended Inherent characteristic	
		Wide set point range	Small flow set point ranges[a]
Proportional to flow	Series	Linear	Equal percentage
Proportional to flow	Bypass	Linear	Equal percentage
Proportional to flow square	Series	Linear	Equal percentage
	Bypass	Equal percentage	Equal percentage

[a]*With large ΔP change with increasing load.*
***(Location of the control valve and flow signal to the controller are important parameters).*

where there may be a large flow requirement. Rangeability (R) and turn down ratio (T) are quite close but still different: Rangeabilty = (maximum controllable flow)/(minimum controllable flow) and turn down ratio = (normal maximum flow)/(mininimum controllable flow). Generally normal maximum flow is considered 0.7 maximum controllable flow (as in flow element calculation). Average flow is considered 0.7 times maximum flow; so $T = 0.7\ R$.

4. In power plants there are a few applications where it is necessary to use low-capacity (LC) and high-capacity (HC) control valves in tandem, such as auxiliary steam. During the start-up period, the flow demand of auxiliary steam is greater than during normal running at higher load. During start-up time the valve has to face comparatively low differential pressure (DP) with higher demand of flow. On the other hand, when the unit is running normally the demand for auxiliary steam is

www.EngineeringBooksPDF.com

TABLE VI/1.3.2-3 Control Valve for Pressure Application*

Fluid	Time constant	Valve ΔP	Recommended Inherent characteristic
Liquid	Fast	Irrespective of ΔP	Equal percentage
Liquid	Slow	$\Delta P_{Qmax} < 0.2\ \Delta P_{Q\ min}$	Equal percentage
Liquid	Slow	$\Delta P_{Qmax} > 0.2\ \Delta P_{Q\ min}$	Linear
Gas	Fast	Irrespective of ΔP	Equal percentage
Gas	Slow	$\Delta P_{Qmax} > 0.2\ \Delta P_{Q\ min}$	Linear

**(Process fluid & time constant is important) Fast : Short pipe length (Liquid flow in pipe) Slow : Large volume (long distribution line,Tank, Receiver)*

low but the DP may be higher. For these reasons LC and HC valves are used. How should these valves be switched? Figure 1.3-4a shows that during switching from large capacity to small capacity there is a large flactuation if the switching over is abrupt. For this reason the loop is changed to manual and the LC valve is slowly closed down and the LC valve is opened up.This can be done by using a split-range arrangement, as shown in Figure 1.3-4b. When the LC valve is near full open position, the HC valve would be near closing position. Suitable dead band between the two can also be done for better control. By using the floating control method, when the HC valve is opened slightly the LC valve, which has a small capacity, closes to meet the

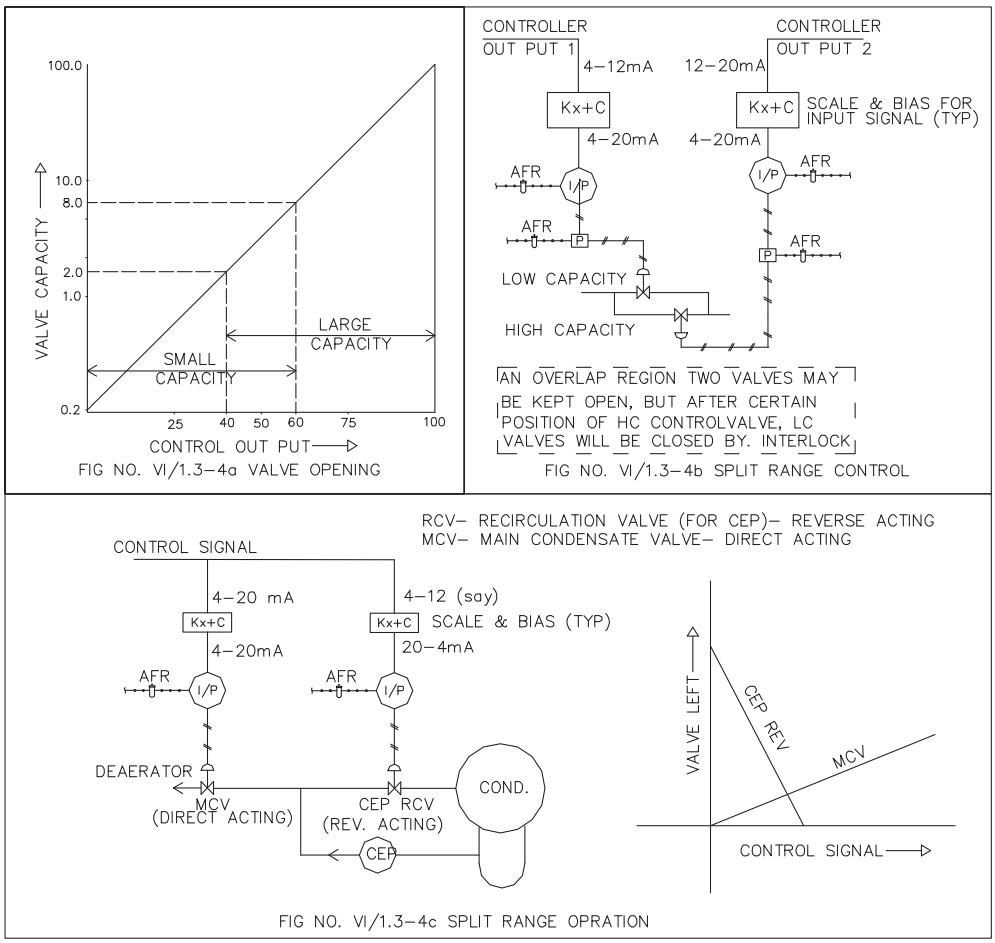


FIGURE VI/1.3-4 Small and large capacity valves—split range.

www.EngineeringBooksPDF.com

demand. The LC valve may be closed by interlock after the HC valve achieves a certain position. The swiching method can be done by electronic circuitry, which is easier to achieve, but can also be done pneumatically. As shown in Figure VI/1.3-4c, there is another kind of split-range controls sometimes encountered in power plants. In this system one valve is a reverse-acting type, and the other is a direct-acting type and they meet the same control strategy.

1.4 Seat Leakage Classification

1. Classifications are denoted by the quantity of fluid passing through a valve assembly when the valve is in fully closed position with pressure differential (static pressure) and temperature as specified. Control valves are classified according to ANSI B16.104. Control valves are designed for throttling, yet they are expected to offer some type of shut off.
2. The shut-off characteristic depends on many factors, such as valve type, seat material, guiding, actuator thrust, type of fluid (higher the flow ability more chances for leakage), pressure drop across the valve, etc. A new control valve will conform to the leakage specification of the supplier, but after use sometimes the leakage value may change. This may be due to the temperature gradient between the trim and body or strain in pipe/valve. Also, when a valve operates below the specified temperature, leakage could occur. Listed below is a sample of leakage classifications (for more see Tables VI/1.4.3-1 and VI/1.4.3-2).
   - **a.** *Valve leakage classification*: Class I through VI
   - **b.** *Special name Class IV*: Metal to metal is the kind of leakage expected from metal plug and metal seat.
   - **c.** *Special name Class VI*: Soft seat where either the plug or seat or both are made from a soft composition material, such as Teflon.

1.5 Actuators and Sizing

Before going into much detail, a few fundamentals of actuators and sizing should be discussed, such as how valve orientation and actuator orientation influence the actuator sizing.

1.5.1 Basics of Actuator (Sizing)

In a spring diaphragm actuator any valve position is achieved by making the total force on the stem equal to zero. For subsequent discussions, the following letters have been assigned to a variety of variables: A = area of the diaphragm, P = air pressure, K = spring constant, X = spring displacement, ΔP = valve process pressure drop at shut-off pressure, and A_v = effective valve area (orifice). The

TABLE VI/1.4.3-1 Control Valve Leakage Class (Leakage as Percentage of Rated Full Capacity)

Class	Leakage%	Test medium	Service ΔP/temp.	Typical construction
I		No shop test		Same as Class II, III, IV
II	0.5	Air 45 to 60 psig	50 psig/3.4 bar in temperature range 50 to 125°F, whichever is lower	1. Balanced single port single graphite piston ring, metal seat low seat load 2. Balanced double port, metal seats, high seat load
III	0.1	Same as above		1. Balanced double port, soft seats, low seat load 2. Balanced single port single graphite piston ring, lapped metal seat, medium seat load
IV	0.01	Same as above		1. Balanced/unbalanced single seat Teflon or multiple graphite piston ring, lapped metal seat, medium seat load
V	$<5 \times 10^{-4}$ml/min/inch orifice diameter per psi DP	Water at 100 psig or operating pressure	Service DP 50 to 125°F	1. Unbalanced single port soft/lapped metal seat, high seat load 2. Balanced single port, Teflon piston ring, soft seat, low seat load
VI	See below Table VI/1.4.3-2	Air/N_2 < 50 psig or operating pressure at 50, 125°F		Unbalanced single port low seat load

www.EngineeringBooksPDF.com

TABLE VI/1.4.3-2 Class VI Leakage Values

Port Diameter		Bubble per minute	ml/min	Port Diameter		Bubble per minute	ml/minute
in.	*mm*			*in.*	*mm*		
1	25	1	0.15	4	102	11	1.7
1 1/2	38	2	0.3	6	152	27	4
2	51	3	0.45	8	203	45	6.75
2 1/2	64	4	0.6	10	254	63	9
3	76	6	0.9	12	305	81	11.5

general practice is to consider the maximum upstream pressure as ΔP, unless ensured by a back pressure downstream. During this discussion, downward forces are arbitrarily chosen as positive.

In Figure VI/1.5-1a the process flow comes from the bottom of the plug, and goes to the outlet from the top, i.e., the process flow assists in opening the valve. Again, air supply is from the top, so air will push the plug to close the valve by compressing the spring in the actuator. The force of the acting air is in a positive direction (direct acting) and is opposed by spring compression force and force due to process flow:

$$P_a * A - \Delta P * A_v - K * X = 0 \quad \text{or}$$
$$P_a * A = \Delta P * A_v + K * X. \quad \text{(a)}$$

The minimum force required to overcome is the sum of the two opposing forces. But if the orientation is changed, then what happens?

According to Figure VI/1.5-1b, the process flow comes from the bottom of the plug, and goes to outlet from the top, i.e., the process flow is opposing the valve opening. Again, air supply is from the bottom, so air will pull the plug to open the valve by compressing the spring in the actuator. The force of the acting air is in a negative direction (reverse acting), and it is opposed by the spring compression force and force due to process flow:

$$-P_a * A + \Delta P * A_v + K * X = 0 \quad \text{or}$$
$$P_a * A = \Delta P * A_v + K * X. \quad \text{(b)}$$

The minimum force required to overcome is the sum of the two opposing forces. This occurs because both process flow and actuator orientation have been changed.

As seen in Figure VI/1.5-1c, the process flow comes from the bottom of the plug, and goes to the outlet from the top, i.e., the process flow assists in opening the valve. Again, air supply is from the bottom, so air will pull the plug to open the valve by compressing the spring in the actuator. The force of the acting air is in the negative direction (reverse acting), and it is opposed by spring compression force, but assisted by force due to process flow:

$$-P_a * A - \Delta P * A_v + K * X = 0 \quad \text{or}$$
$$P_a * A = \Delta P * A_v - K * X. \quad \text{(c)}$$

The minimum force required to overcome is the difference of forces for process flow and spring compression, hence it will be less than in Equations (a) and (b).

In Figure VI/1.5-1d the process flow comes from the top of the plug, and goes to the outlet from the bottom, i.e., the process flow opposes the opening of the valve. Again, air supply is from the top, so air will push the plug to close the valve by compressing the spring in the actuator. The force of the acting air is in a negative direction (reverse acting), and it is opposed by spring compression force and force due to the process flow:

$$P_a * A + \Delta P * A_v - K * X = 0 \quad \text{or}$$
$$P_a * A = K * X - \Delta P * A_v. \quad \text{(d)}$$

The minimum force required to overcome is the difference of forces for spring compression and process flow, hence, it will be less than in Equations (a) and (b).

1.6 Materials of Construction and Associated Tables for Pressure and Temperature Ratings: Data Presented Are Mainly as per ASME B16.34

1.6.1 Major Control Valves

Major control valves in the main power plants are discussed in the following clauses. A typical list of control valves in main power plants is presented in Table VI/1.6-1. The materials listed are just suggestions. The reader is advised

www.EngineeringBooksPDF.com

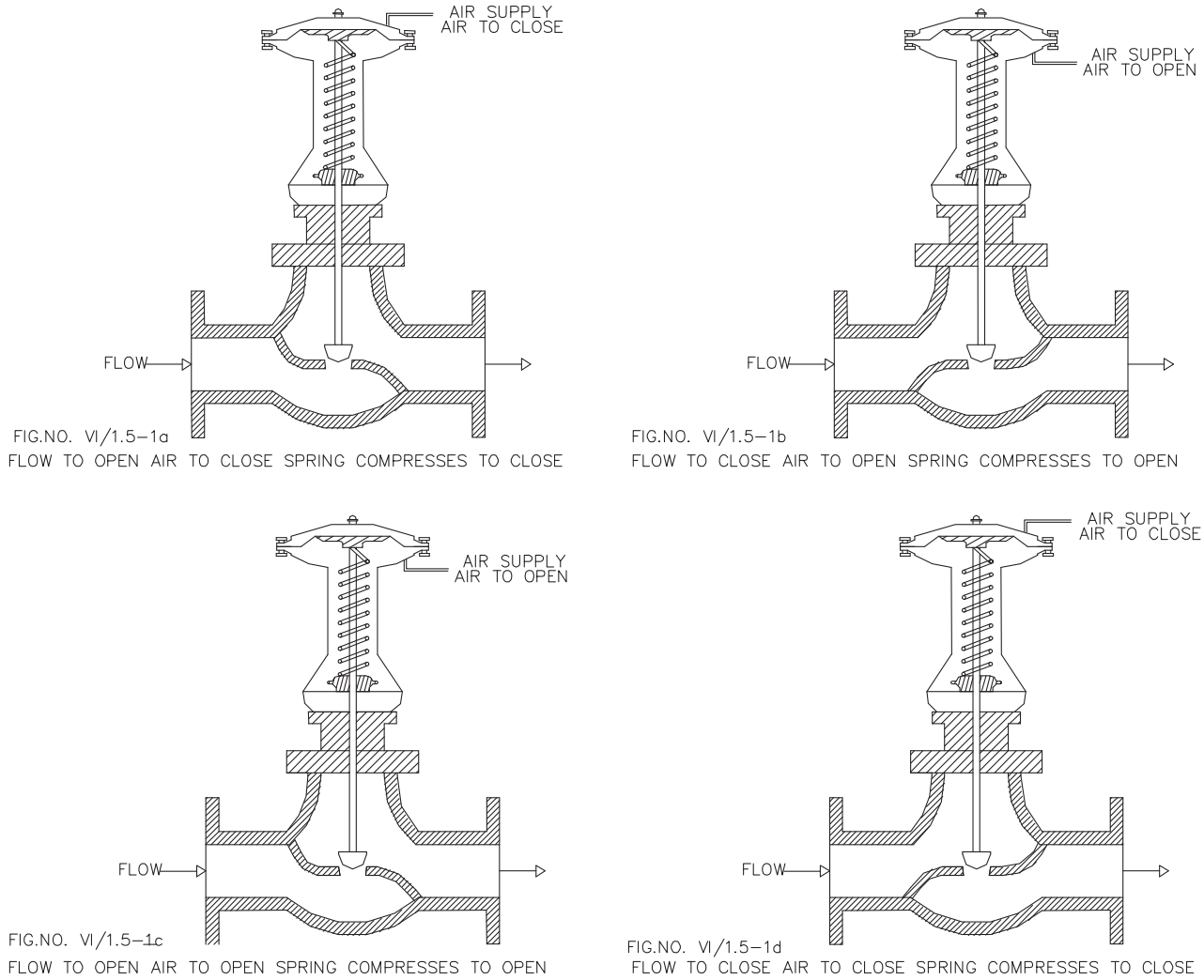


FIGURE VI/1.5-1 Basics of actuators.

also to review the necessary standards for pressure and temperature ratings and the necessary de-ratings at different conditions.

1.6.2 Valve Body and Trim Materials Composition with Temperature Limit

Valve Body and Trim materials commonly used in power plant applications are listed in Tables VI/1.6.2-1 and VI/1.6.2-2. There are many other materials available for which the standard book on control valves may be consulted. Major compositions and temperature ratings are as per international standards.

1.6.3 Seat Materials

Some of the common seat materials with temperature limits are listed in Table VI/1.6.3-1.

1.6.4 Valve/Flange Pressure Temperature Ratings

The pressure withstand capability of each of the materials discussed above needs to be de-rated as per the operating temperature. This is done based on the pressure class selected for the valve and operating temperature. For example, the working pressure for a valve (150 lb) of ASTM A216-WCB at 200°F (93.33°C) is 260 psi (18.2798 kg/cm^2), whereas a valve with the same rating when used in temperature at 600°F (315.5°C) would have the maximum working pressure of 140 lb (9.8 kg/cm^2). This means that corresponding to each material specification and pressure rating (class of the valve) there would be a maximum pressure that the material can withstand at a particular temperature (range). These can be found in ASME B16.34 Table 2-1.1 or relevant standard of the country or from flange/valve suppliers.

www.EngineeringBooksPDF.com

TABLE VI/1.6.1 List of Major Control Valves in Power Plants with Suggested Materials (Quantity of Valves in Each Service Depends on System Design)

Control valve	Body material.	Trim material (SS)
Low/high range feed control valves (also bypass valve)	ASTM A 217GR C5	17-4 PH
SH or RH or other spray control valve	ASTM A 217GR C5	440C
HP or LP heater normal level control valve	ASTM A 217GR WC6	17-4 PH
HP or LP heater high/emergency level control valve	ASTM A 217GR C5	17-4 PH
BFP recirculation control valve	ASTM A 217GR C5	440C
CEP/GSC min Flow Control Valve	ASTM A 217GR C5	17-4 PH
Auxiliary steam or CRH to deaerator valve	ASTM A 216GR WCB	Type 316 Stellite
Normal or emergency make-up to condenser valve	SS Type 316	Type 316
Condensate flow to deaerator valve	ASTM A 216GR WCB	Type 316 Stellite
Deaerator drain to condenser valve	ASTM A 217GR C5	17-4 PH
Drain cooler Level control valve	ASTM A 217GR WC6	17-4 PH
Steam pressure valve for atomizing	ASTM A 216GR WCB	Type 316 Stellite
Control valves in PRDS for auxiliary steam	ASTM A 216GR WCB	Type 316 Stellite
CBD tank level control valve	ASTM A 217GR C5	Type 316 Stellite
Condenser spill valve	ASTM A 217GR WC6	17-4 PH
SCAPH steam control valves	ASTM A 216GR WCB	17-4 PH
SCAPH drain valve	ASTM A 217GR C5	17-4 PH
Gland sealing supply valve	ASTM A 217GR WC6	17-4 PH
F.O heating and pressurizing valves	ASTM A 216GR WCB	Type 316

TABLE VI/1.6.2-1 Valve Body Material Composition (a Few Materials Commonly Used for Control Valves in Power Plants;— in %) and Temperature Limit (in °C)

Casting	Forging	Other major composition (%)	Low temperature limit (°C)	High temperature limit (°C)	Remarks
A216 Gr WCB	A105	C = 0.2—0.24; Cr = 0.2; Mn = 1.0—1.35; Mo = 0.06; Ni = 0.2; Si = 0.15—0.3	−29	535	Moderate temperature and corrosion noncritical
A217 Gr C5	A182 F5	C = 0.15(M); Cr = 4.0—6.0; Mn = 0.3—0.6; Mo = 044 —0.65; Ni = 0.5(M); Si = 0.5(M)	−29	590	Moderate corrosion
A217 Gr WC6	A182 F11-CL2	C = 0.1—0.15; Cr = 1.0—1.5; Mn = 0.3—0.8; Mo = 044—0.65	−29	535	Minimize graphitization
A217 Gr WC9	A182 F22-CL3	C = 0.15(M); Cr = 2.0—2.5; Mn = 0.3—0.6; Mo = 0.87—1.13; Si = 0.5	−29	565	Elevated temperature and strength, greater than F11

www.EngineeringBooksPDF.com

TABLE VI/1.6.2-2 Valve Trim Material Composition (in %) and Temperature Limit (in °C)

Type	Other major composition (%)	Low temperature limit (°C)	High temperature limit (°C)	Remarks
316 SS Casting: A351CF8M Forging: A182 F316	C = 0.08; Cr = 18.0–21.0; Mn = 1.5(M); Mo = 2.0–3.0; Ni = 9.0–12.0; Si = 1.5 (M)	−250	815 (316°C as trim)	High temperature and corrosion resistance
316L SS Casting: A351CF3M Forging: A182 F316L	C = 0.035; Cr = 16.0–18.0; Mn = 2.0(M); Mo = 2.0–3.0; Ni = 10.0–14.0; Si = 1.0 (M)	−250	454	
TYPE 17-4PH ASTM A564 Gr 630UNS S17400	C = 0.07(M); Cr = 15.0–17.5; Mn = 1.0 (M); Ni = 3.0–5.0; Si = 1.0(M)	−29	343(427°C as cage)	Less impact on loading
Type 440C	C = 0.95–1.2; Cr = 16.0–18.0; Mn = 1.0; Mo = 0.75; Si = 1.0(M)	−45	315(427°C as cage)	

1.7 Special Considerations

There are some special considerations for various applications as listed below:

1. *High pressure*: A forged body is used for greater strength. Erosion-resistant materials are selected for these services. Special seal and higher stem diameters are some of the considerations.
2. *High DP*: High force may develop across the valve and internal parts causing instability of the valve. High-velocity droplets may lead to erosion. For erosion, aberration, or cavity SS 440C may be used. Also, in globe valves there may be excessive stem thrust. For "flow to close" type valves high DP may damage the seat, whereas "flow to open" type valves will open against the actuator! For high DP there may be a sharp drop in outlet temperature, which may cause the material to be brittle.

TABLE VI/1.6.3-1 Commonly Used Seat Materials with Temperature Limits

Materials	Lower limit in °C	Upper limit in °C
High density polyethylene (HDPE)	(−) 54	85
Neoprene	(−) 40	82
Nitrile rubber	(−) 29	93
Nylon	(−)51	93
PTFE	(−) 268	230

3. *High temperature*: Where $T > 230°C$, material temperature limitations discussed in Clauses 1.6 must be considered, as well as temperature limitations due to packing. Packing material limitations include: Teflon, 230°C; metallic packing, 480°C; graphite packing, 399°C.

1.8 Control Valve Noise

From Pollution point of view, noise is the third greatest menace after air and water pollution, and noise is a kind of loss to the system. Valve noise is expressed in terms of decibels (dB). Valve noise, more precisely aerodynamic noise, is defined in terms of sound pressure level (SPL). SPL in dB is defined as follows:

$$\text{dB} = 20\log_{10}\left(\text{measuring SPL } 2 \times 10^{-4}\text{microbar}\right)$$

$$\text{dB} = 20\log_{10}\left(\text{measuring SPL}/2 \times 10^{-5}\text{N}/\text{M}^2\right)$$

1.8.1 Sources of Noise

There three types of noise encountered in control valve:

1. *Mechanical vibration*: Caused by the response of valve internal components to turbulence through the valve. Turbulent strike, vortex shedding causes such vibration. These could also be due to improper design. This kind of vibration indicates tonal frequency vibrations. Problems occur when these induced vibration frequencies match with the natural frequency of the trim causing resonance. This can result in trim failure due to fatigue. Generally, guided valves have less noise. Should any noise happen at all, it can be checked by changing the valve design or reducing clearance between the guide and plug.

www.EngineeringBooksPDF.com

2. *Aerodynamic noise*: Arises as a result of the direct conversion of mechanical energy of flow into acoustic energy as the turbulent flow passes through the valve orifice. This noise is more predominant compared with noise from mechanical vibration. The point at which sonic speed is reached at vena contracta is a function of valve design and F_L (rated pressure recovery factor). IEC standard IEC-534-8-3 is followed to predict aerodynamic noise. The basic process for noise prediction consists of the following:
   a. To calculate the trim outlet velocity and find the noise source strength; sound power is generated in the fluid inside the valve and pipe because of throttling pressure
   b. To calculate the part of sound energy generated at the valve that is propagated to downstream piping
   c. To calculate how pipe wall attenuates the noise as it passes from inside to outside transmission loss due to piping
   d. To estimate the weighted SPL at a distance of 1 m from the pipe
3. *Hydrodynamic noise*: The major sources of Hydrodynamic noise come from the following:
   a. Turbulent flow
   b. Cavitation
   c. Flashing
   d. Mechanical vibration for above

   The problem associated with hydrodynamic noise comes from erosion as well as corrosion. The IEC-534-8-4 standard may be used to measure them both.
4. *Noise predictions*: Different types of noise predications are discussed below.
   a. Aerodynamic noise:

      i. To calculate the total stream power at vena contracta W_m use kinetic energy equation stream power due to mass flow "m":

      $$W_m = 1/2 * mU2$$

      Where U is the velocity at vena contracta calculated using the First Law of Thermodynamics.

      ii. The acoustic efficiency is calculated, for each flow regime discussed below, as $\eta = M_{vc}^{3.6}$ where M_{vc} = Mach number at vena contracta and peak frequency $f_p = 0.2\text{U}/d_{vc}$ where d_{vc} is the orifice diameter at vena contracta. This varies with the flow regimes discussed below:

      iii. There are five defined flow regimes for a particular valve depending on inlet pressure P_1, outlet pressure P_2, fluid physical parameter, and F_L for the valve. These flow regimes are
      - Subsonic
      - Sonic with turbulent flow mixing
      - No compression but with flow shear
      - Shock cell turbulent flow interaction
      - Constant acoustical efficiency

      iv. Thus in each regime efficiency is defined and calculated. Thus the sound power is calculated from the total power with the help of the efficiency in each regime.

      v. Only a portion of the sound power is propagated downstream, and this is designated by r_w, which is a function of valve style. Typical values are listed in Table VI/1.8.1.

      vi. Next is to convert the sound power to SPL, which is done by the following:

      average SPL across pipe cross section

      $$= 10 \log 10(3.2 * 109 W_a \rho_2 c_2) \Big/ \left(d_p^2\right),$$

      where W_a = sound power, ρ_2 = downstream vena contracta gas density, c_2 = downstream vena contracta sound speed, and dp = down stream pipe ID.
      Downstream noise propagation is given by the following:

      $Lg = 16 \log_{10}[1/(1 - M_2)]$ where M_2 is the Mach number at outlet

      vii. The net sound level at pipe wall is given by $L_{\text{pAe}} = 5 + L_{pi} + TL + L_g$, where L_{pi} is pipe internal SPL and TL is transmission loss, which is dependent on flow peak frequency. These transmission loss regimes are determined from TL versus peak frequency.

      viii. Finally, noise at 1 m from pipe wall is SPL = $\text{L}_{\text{pAe}} - 10\log_{10}[(dp + 2tp + 2)/(dp + 2tp)]$ where tp is pipe thickness. In the above calculations only basic steps have been discussed. Standards and handbooks with standard curves are also available for detailed calculations.

TABLE VI/1.8.1 Factor for Noise Calculations

Valve type	r_w
Globe/rotary globe	0.25
Butterfly/ball	0.5
Expander	1

www.EngineeringBooksPDF.com

b. *Hydrodynamic noise prediction*: The main factor is associated with cavitation. There are two situations: choked flow and nonchoked flow. Again, for flashing fluid there a variety of situations. So noise prediction is rather complex. For details, please refer to standard IEC-534-8-4.

5. *Noise control means*: Noise can be controlled by source treatment and path treatment.

a. Source treatment for noise control

i. Size of fluid jet affects the noise generation. By reducing the size efficiency of conversion of mechanical energy to sound it shifts the energy to high frequency and curtails the transmission through the pipeline. Small size and proper spacing reduce the shock eddies.

ii. For adiabatic flow with friction, the flow area of valve trim is gradually increased in downstream sections to compensate for expansion and more or less constant velocity. Thus, a sharp fall in enthalpy is arrested.

iii. Multipath, multistage, and a combination of the two, are the major source treatment. LO DB and cage style can also be used as source treatments.

iv. For high DP, the $\Delta P/P_1 > 0.8$ series restriction approach to split the pressure drop between the control valve and restrictor downstream is effective.

v. Hydrodynamic noise is mainly associated with cavitation, hence, if the cavitation is predicted and eliminated then noise is reduced drastically.

b. The following are methods used for path treatment:

i. *Silencer*: This way is effective, but there are a few problems associated with it, such as flow velocity, which makes this ineffective in HC services where the operating condition may be too severe for its use.

ii. *Pipe schedule increase*: This means higher wall thickness, which is good but needs to be maintained throughout downstream length as noise once generated does not dissipate quickly (and the system may be costly too).

iii. *Pipe insulation*: This is effective, but has the same limitations as previously discussed. Also, the insulation must be properly wrapped without any gap/void.

1.9 End Connection for Control Valve

In power plants there are three common control valve end connections:

1. *Screw type*: These are common in small valves and economical. The threads are female with different standards such as NPT and BS. Generally, these connections are restricted to low-pressure applications and area as large as 50 mm NB. Maintenance is not easy.

2. *Flange connection*: In this type, the valve is connected with pipe by mating the flange set with a gasket in between and the two flanges are bolted (see Figure VI/1.9-1). These can be used for a wide range of pressures and temperatures (up to 800°C). This connection is a natural choice for easy removal of the valve. There is no difficulty in matching both end dimensions as long as an international standard like, DIN, ANSI, BS, and JIS, is followed. In these standards, corresponding to the flange nominal size and pressure class for a particular material, there will be standard tables specifying all other required details such bolt diameter, pitch, thickness, etc. There are three kinds of flanges for connections:

a. *Flat face*: There is full face contact of the two matching flanges with a gasket in between. This is used for low-pressure applications.

b. *Raised face*: There is a raised face in contact with the raised face of the matching flange with a gasket in between. The inner diameter of the raised face matches the outside diameter of the valve opening somewhere near but less than the bolt diameter. The raised face has a concentric groove to accommodate the gasket and prevent gasket blow-out. Pressures up to 400 bar and temperatures up to 815°C can be withstood with this type flange. The temperature pressure table should be consulted for each material and pressure class.

c. *Ring-type joint*: This is similar to the raised face type, but there is one U-shaped groove and a metallic elliptic/octagonal-shaped gasket is used to put the ring-type gasket in the groove when the bolts are tightened (see Figure VI/1.9-1c). Pressure sealing up to 1000 bar is possible, but is rarely used for high temperature.

3. *Weld type*: Weldable valves are leak tight but difficult to remove. Also care must be taken during welding that high-temperature trim and other parts are not damaged. There are two types of welding connections as shown in Figure VI/1.9-2.

a. Socket weld ends are prepared on each side of the valve by boring a socket type space where the pipe slips into the socket, rests there, and is welded as shown in Figure VI/1.9-2a. These are used for pipe up to 50 mm NB.

b. Butt welding connections are used generally for line >65 mm NB. There is end preparation at each end of the valve, i.e., beveled. The pipe is also beveled and welding is done as shown in Figure VI/1.9-2b.

www.EngineeringBooksPDF.com

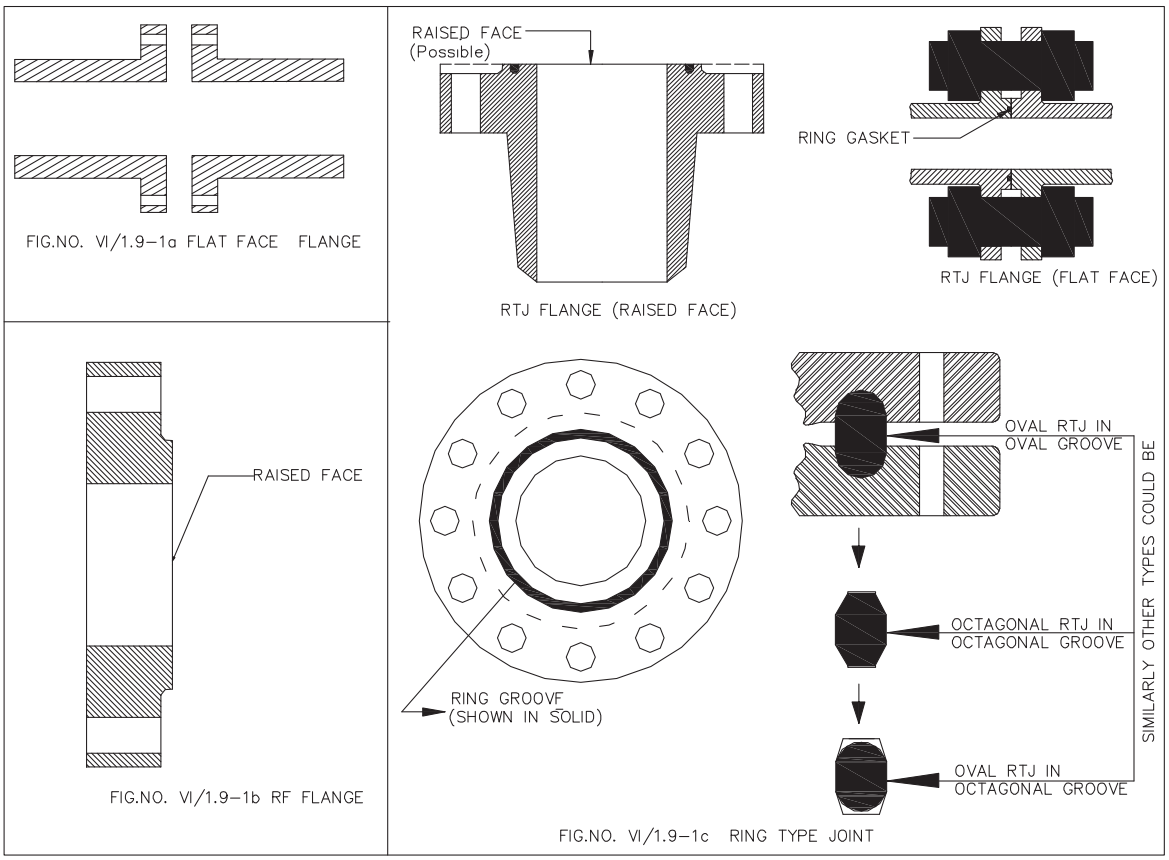


FIGURE VI/1.9-1 Flange type valve end connection.

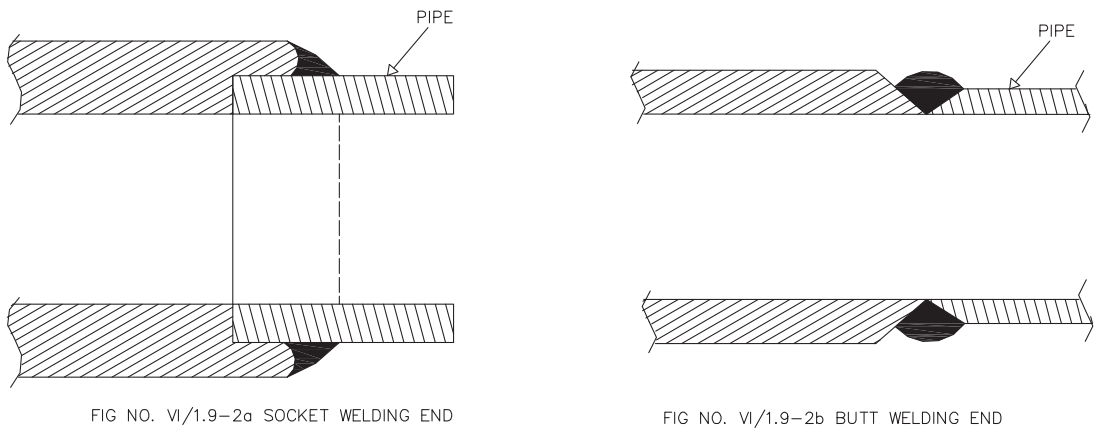


FIGURE VI/1.9-2 Weld end connection.

1.10 Control Valve Face-to-Face Dimension

ISA developed standard ISA S 75.nn (where nn stands various values, e.g., ISA S 75.03, ISA S 75.03.12, ISA S 75.15, ISA S 75.03.16, ISA S75.22, etc.) to specify the face-to-face dimensions for various kinds of connections based on their pressure class, connection type, etc. This standard covers face-to-face dimensions for flanged globe style control valves for classes 125, 250, 300, and 600, etc. (these dimensions are in accordance with ISA S75.03).

www.EngineeringBooksPDF.com

TABLE VI/1.11-1 ANSI Class Rating and Pressure Nominal (at Standard Temperature)

ANSI class rating	Pressure (lb)	Pressure nominal (PN)	Remarks
150	290	20	PN is the rating designator followed by a designation number approximately pressure rating in bar 1 bar = 1 × 1.105; pa = 14.5038 psi. So PN 20 stands for 20 bar = 14.5 × 20 = 290lb
300	750	50	
400	1000	64	
600	1500	100	
900	2250	150	
1500	3750	250	
2500	6250	420	

TABLE VI/1.11-2 NPS and DN Equivalence (in Power Plants)

NPS (in.)	DN (mm)	NPS (in.)	DN (mm)	NPS (in.)	DN (mm)
1/4	8	2 1/2	65	20	500
3/8	10	3	80	24	600
1/2	15	4	100	28	700
3/4	20	6	150	32	800
1	25	8	200	48	1200
1 1/4	32	10	250	56	1400
1 1/2	40	12	300	60	1500
2	50	16	400	72	1800

NPS, normal pie size; DN, diameter nominal.

Face-to-face dimensions are end-to-end dimensions of the valve. The basic purpose for this standard is to provide valve face-to-face dimensions for flanged and flangeless control valves without giving special consideration to the equipment manufacturer used. Thus instrument engineers can help their piping engineers with these data. For each type of valve, each valve size, and valve pressure class end connection there will be unique face-to-face dimensions per ISA S75.03. The reader is referred to this standard as well as the manufacturer's handbook when specifying face-to-face dimensions of any end connection.

1.11 Nominal Pipe Size and Pressure Rating

A control valve is a line device, therefore, nominal pipe size and associated pressure ratings are very important. Pressure ratings are normally specified either in terms of ANSI (class, in psi) or as per ISO 7268 as "pressure nominal" (PN, in bar). Similarly, pipe size is defined either in terms of nominal pipe size (NPS, in inches) in North American standard, or in ISO 6708 in diameter nominal (DN, in millimeters). The most common standards and their equivalents normally found in power plant are presented in Tables VI/1.11-1 and VI/1.11-2.

2. CONTROL VALVE TYPES

2.0 Introduction

It is indeed a big task to select the control valve best suited for a particular application. Control valves that work in power plants might not be appropriate for process plants like refineries and paper plants. In this clause we discuss the types of valves normally encountered in a power plant; however, some special types of valves might also be discussed, depending on their application. Since in power plants there are many applications where cavitation and/or flashing fluid might occur, a term C_d ($= C_v/d^2$) as defined in figure VI/1.2-1 is very useful for calculating the pressure

www.EngineeringBooksPDF.com

TABLE VI/2.0-1 Valve Selection Guide (3)

Feature	Ball	Butterfly	Digital	Globe (1)	Globe (2)	Saunders
Maximum pressure class common (lb)	2500	600	2500	2500	2500	150
Service	Mainly ON/OFF	Throttling	Throttling	Throttling	Throttling	Throttling
Minimum/maximum size (mm)	6/1200	50/1800	6/250	6/750	6/750	6/1800
Minimum/maximum temperature °C	(−)55/350	(−)30/550	(−)30/650	VL/675	VL/675	(−)50/250
Maximum cap C_d $C_d = C_v/d^2$	25−40	−40	13	12	15	20
Pressure recovery F_L	0.6	0.65		0.85−0.9	0.85−0.9	
Characteristic	Good	Fair	Very good	Very good	Very good	Fair
High DP(>15 bar)	Low (4)	Low(4)	High PD possible	High PD possible	High PD possible	NA
ANSI leakage CL	IV	VI	V	IV	IV	V
Abrasive service	Ceramics	NA	Bad	Good	Good	Good
Anticavitation	Fair	Fair	Fair	Good	Good	NA
Flashing service	Bad	Bad	Fair	Good	Good	NA
Viscous service	Good	Good	Fair	Good	Good	Good
Comparative cost	0.8	0.7	2.4	1(Ref)	1.25	0.65
Special feature	a) High capacity b) Good range-ability c) Tight shut off d) Lightweight	a) High capacity b) Lightweight	a) Precise/ high-speed control	a) Good sealing b) Easy trim change c) High capacity d) Good rangeabilitytrun -1 e) Low noise		a) Self-cleaning b) Good for water treatment service

PD, pressure differential. 1) Globe valve single port 2) Glove valve double port 3) Data presented in the table are data from commonly available in the market in connection with power plant application. 4) Generally Lo DP, but Hi DP is also possible

recovery factor. Generally, higher C_d means higher pressure recovery value; hence, while selecting a control valve for applications where cavitation or flashing fluid is a possibility, care must be taken to select the proper type. Data presented in the are from valves commercially available in connection with power plant application.

However, before that a few details about other important types of valves will be discussed. Pressure ratings and sizes have been discussed in terms of NPS, ISO, and ANSI. The equivalence between NPS/ISO and ANSI/ISO is detailed in Clause 1.11.

2.1 Ball and Butterfly Valves

Both of these valves belong to the quarter turn family, and are mainly used as ON/OFF valves, but have some modulating application. They both have quite good tight shut-off characteristics.

2.1.1 Ball Valves

As the name suggests, a ball valve has a sphere with hole in the middle. When the hole is in line with the pipe axis there is full flow, but when it is at 90° with the axis of the pipe the flow is zero. So within 90° it has to complete full flow. Ball valve action has been detailed out schematically in Figure VI/2.1-1b. Because of its high-pressure recovery factor, it has the possibility of cavitation and noise. Also, the opening versus the actuator rotation is nonlinear. For all these reasons a ball valve is not commonly used as a control valve in a power plant application; however, it is used as a control valve in paper and other industries. It can offer a tight shut-off characteristic—ANSI CL IV (metal seat) and VI (soft seat)

1. There are four kinds of ball valves:
   a. *Full bore*: The ball is oversized so that the hole in the ball matches with the pipe ID so that full flow can pass.

www.EngineeringBooksPDF.com

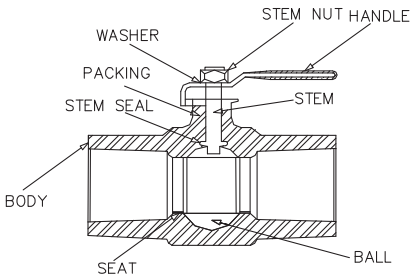


FIG NO VI/2.1–1a BALL VALVE SECTION

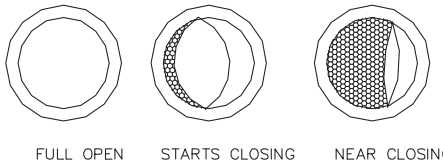


FIG NO VI/2.1–1b BALL VALVE THROTTLING ACTION SECTION

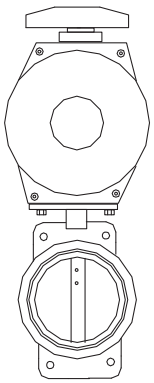


FIG NO VI/2.1–1c BUTTERFLY VALVE & ACTUATOR (WAFER TYPE)

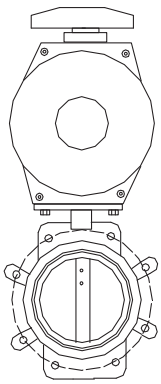


FIG NO VI/2.1–1d BUTTERFLY VALVE & ACTUATOR (LUG TYPE)

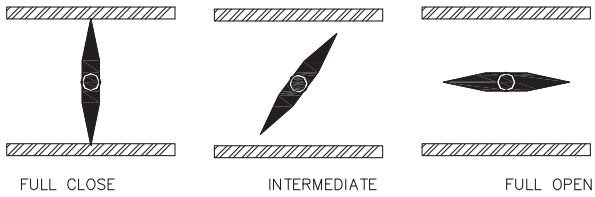


FIG NO VI/2.1–1e BUTTERFLY VALVE THROTTLING ACTION

FIGURE VI/2.1-1 Ball and butterfly valves.

b. *Reduced bore*: Flow through the valve is one pipe size smaller than valve's pipe size.
c. *Characterized type*: This is a V or U notch ball valve. Used in paper industries.
d. *Cage type*: The ball is positioned by a cage.

2. Conventional ball valves may be two-way and three-way with a T port and/or L port to be used as diverting, mixing valves as well as for a selective use of path (refer to the standards book).
3. Ball valves are available from 12 mm to 1 m with pressure rating from 150 to 2500 lb, with temperature of 260°C.
4. Ball valve data sheet in a power plant application (typical one may vary with application):
a. *Type*: Conventional full bore
b. *Size*: 15–50 mm(typical)
c. *No of ways*: 2/3 (in HVAC)
d. *O ring*: Viton (Hi Temp; Kalrez)
e. *Material*: Body: SS 316/CI/Bar stock brass; ball: SS 316 or better seat: Buna N, natural rubber.
f. *Maximum design pressure/temperature*: As per application.

2.1.2 Butterfly Valve

As stated earlier, butterfly valves and ball valves operate similarly. Here in place of a ball there is a metal disc mounted on a rod. When the disc is parallel with the pipeline there will be full flow, but when it is at 90° flow stops as shown in Figure VI/2.2-1e. Generally, it also turns a quarter to allow full flow.

1. In the disc hard facing materials are applied. Depending on design and seat configuration it can be
a. Resilient BV with a rubber seat with a pressure withstand capability of ~25 kg/cm^2 (e.g., Keystone Dubex RMI) and size up to 1200 mm. Another kind of high-performance butterfly valve is the high shut-off lined valve with excellent throttling capabilities at low torque. Pressure can be as high as 50 kg/cm^2.
2. Again, depending on type of mounting/installation, butterfly valves are categorized as follows:
a. *Wafer design*: Meant for unidirectional flow, by using suitable seals, with a flat valve face on both the sides. It is put between two sets of flanges (see Figure VI/2.1-1c).

www.EngineeringBooksPDF.com

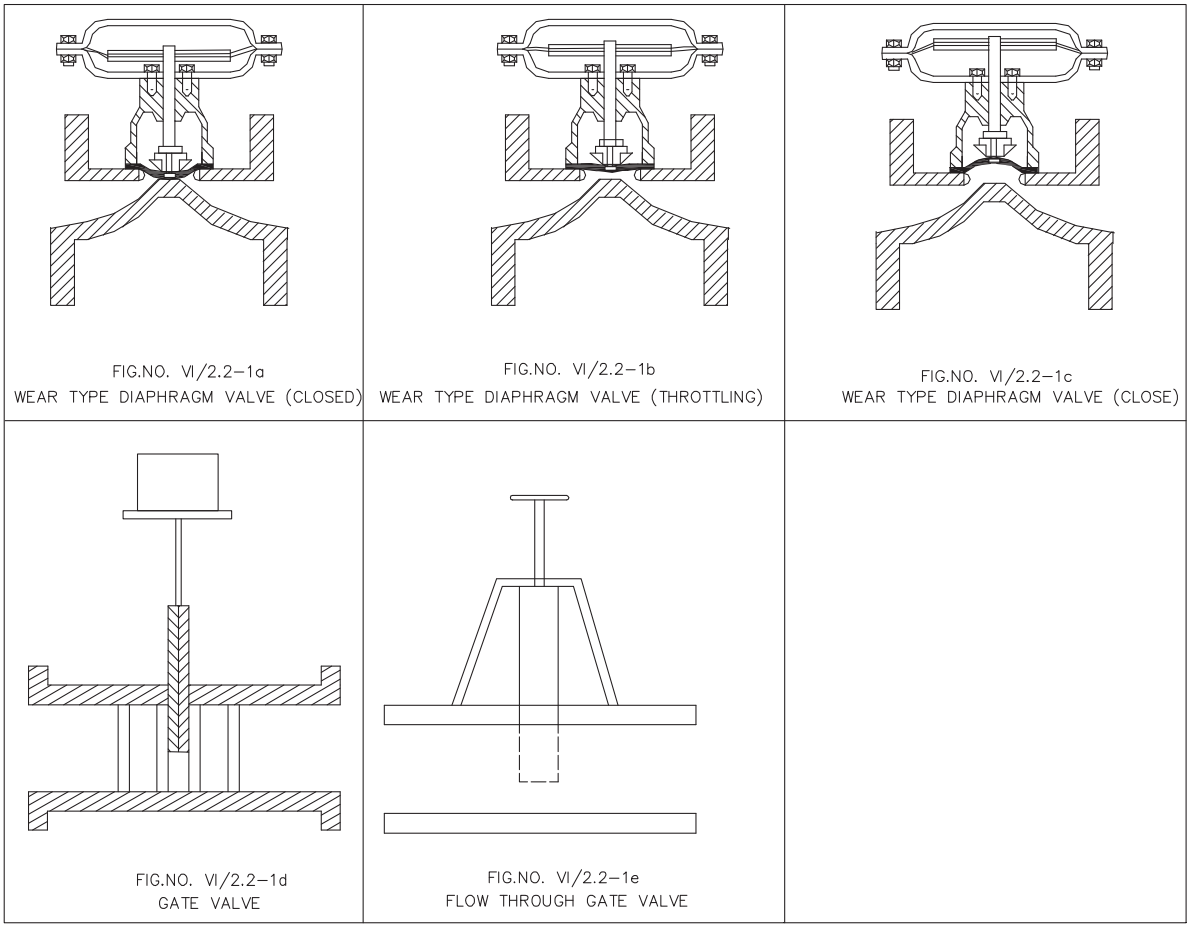


FIGURE VI/2.2-1 Diaphragm and gate valve.

b. *Lug type design*: Has threaded inserts on both sides of the body, and is also placed between two flanges. Butterfly valves have a wide range of temperature designs up to 530°C (see Figure VI/2.1-1d).

3. Butterfly valves are used in the circulating water system of a power plant.
4. Butterfly valves data sheet in power plant application (typical one may vary with application):
   a. *Type*: Double-flanged, double/triple eccentric resilient seat
   b. *Size*: 300–1200 mm (typical)
   c. *Material*: Body: ductile iron (epoxy lining possible), Seat: PTFE, natural rubber
   d. *Maximum design pressure/temperature*: Depends on application, pressure < PN 25 temperature < 100°C
   e. *Leakage*: ANSI CL VI, (CL IV if metal seat selected)
   f. *Connection*: ISO/ANSI/DIN flange

2.2 Other Miscellaneous Valves

A few other types of valves used in power plants will be discussed in this clause. Some of these are used with actuators (e.g., diaphragms) and some are without actuators [e.g., rate set valves in steam and water analysis systems (SWAS), or simple isolation gate valve, etc., without any actuator]. However, linear actuators will be used for the diaphragm and gate valves discussed below.

2.2.1 Diaphragm Valves

These valves are also known as "Saunders' valves." Diaphragm valves are applied for corrosive fluid slurries (see Figure VI/2.2-1a–c).

1. The valve consists of a moving or elastic diaphragm that is moved upward or downward to regulate fluid flow. The valve stem moves the diaphragm to restrict the flow as shown the Figure VI/2.2-1a–c. In operation, there are similarities between these valves and pinch valves.
2. In the context of a power plant these valves are extensively used in water treatment plants; 25–100 mm valve sizes are mostly used.
3. Body materials may be ductile iron, SS 316, etc., and the diaphragm materials include Teflon, Buna N, or neoprene.

www.EngineeringBooksPDF.com

4. Most of these valves have a quick opening characteristic.
5. Depending on construction, there are three types:
   a. Straight through
   b. Weir design where there is wear toward which the diaphragm is compressed to create restriction
   c. Dual range with two compressing units to produce a better flow characteristic
6. Diaphragm valve data sheet in a power plant application (typical one may vary with application):
   a. *Type*: Weir/straight through
   b. *Size*: 15–100 mm (typical)
   c. *Material*: Body: SS 316(CF8)/DI/CI/bar stock brass diaphragm, Buna N, natural rubber, EPDM
   d. *Maximum design pressure/temperature*: Depends on application; PN 10/16, temperature 160°C
   e. *Connection*: Screwed, flanged
   f. *Body lining*: Natural rubber

2.2.2 Gate Valve

It is the most common valve and is used in most industries. It has undergone many changes in the last century. Generally, it is not used as control valve.

1. Most of their application is in stop/block valves, because in partial opening position it may give rise to vibration and it offers practically no resistance to flow during open condition, hence, it offers the lowest pressure drop. For various gate valve design see figure VI/2.2-1 d–e
2. There are two basic design of disc/gate: parallel and tapered or wedge gate. Wedge type gates are used as gate dampers or coal chute outlet dampers.
   a. *Solid wedge*: Have very little flexibility, and if there is any distortion it cannot cope.
   b. *Flexible wedge*: Has a slot around it so that it can withstand temperature changes.
   c. *Split wedge*: When at closed position two pieces meet.
3. Because of their bonnet design, gate valves can be the following types:
   a. *Screw design*: Inexpensive bronze valves
   b. *Union joint*: Same as above with flexibility to disassemble
   c. *Bolted joint*: Most popular kind
   d. *Pressure seal type*: For high-pressure service; extensively used for high-pressure, high-temperature application
   e. *Welded joints*: High-pressure uses
4. Like the V notch ball valve, gate valves also can have a V insert.
5. There is another kind of gate valve called the "position disc" type (Figure VI/2.2.2-1). In the open position, the rotating disc with holes matches up with a stationary disc with holes to allow full flow. In closed position they are at 90° to stop flow. This also can be used to control flow.

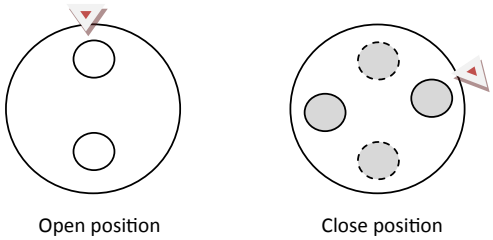


FIGURE VI/2.2.2-1 Disc positioning gate valve in two positions.

6. Gate valve data sheet in power plant application (typical one may vary with application):
   a. *Type*: Parallel slide knife edge
   b. *Size*: 15–500 mm (mechanical steam service application)
   c. Material: Body: ductile iron/SS 316/CS in some applications with hard facing (epoxy lining possible), Seat: metal to metal or PTFE
   d. *Maximum design pressure/temperature*: Depends on application, up to 4500 lb class available (e.g., L&T)
   e. *Leakage*: ANSI CL II or better with soft seat possible
   f. *Connection*: Screw/flange/weldable

2.3 Globe Control Valves

In most of the process industry as well as in power plants, globe control valves are the most popular, even if their design does not offer a tight shut-off characteristic. It is the most commonly used FCE and has probably the maximum design and type variations. Major reasons for its popularity are

- Simplicity design and sizing
- Relatively lower dead time
- Low noise, cavitation effect, etc.
- Simple linear actuators such as spring diaphragm/piston cylinder/(also electrical actuator)
- Special design variations available to be used in abrasive, corrosive, high-pressure, high-temperature application—almost all types of fluids.
- Variations in flow characteristics like linear, EQ%, QC, parabolic, etc.

Limitations include higher cost for C_v, low speed, and low stiffness.

2.3.1 Parts of a Control Valve

Various parts of control valves and actuators were depicted in Figure VI/1.0-1a and b. The Valve stem is coupled with the stem of the actuator. Various parts shown are typical, but vary with the types of valve. In the following clauses, various trim and body designs will be discussed.

www.EngineeringBooksPDF.com

2.3.2 Various Kinds of Globe Valve Design

The major pressure drop in the control valve takes place in the trim part. Depending on the flow characteristics discussed (see Clauses 1.3) earlier, the shape of the plug varies. These are shown in Figure VI/2.3.2-1a–c for EQ%, linear, and quick opening. Most of the modern valves have a contoured plug, ported plug, etc., to achieve the desired flow characteristics. For various kinds of plug designs used in power plant, figure no VI/2.3.2-1 a–i may be referred to. A valve mainly comprises body assembly (which includes bonnet and top and bottom closure) and trim (which includes plug stem guide bushing, etc.). Body configuration determines the trim style to meet the process requirement.

1. *Single seated valves (with discussions on cage type trim)*: This type of globe valve is most popular and available in numerous forms. Single seated valves offer the following features and advantages:
   - Simple in construction
   - Manufactured from bar stock, forged, split body, etc.
   - Generally offer tight shut-off characteristic (soft seating/metal-to-metal seating-available)
   - Less susceptible to vibration (because of less mass in comparison to double seat)
   - Actuator sizing is critical due to unbalanced force over the entire port at high pressure

   For proper performance and alignment with the seat, it is necessary to guide the plug. The various kinds of guide for the valve plugs include: stem guided (when the guide bushing in the bonnet acts on the valve stem), top guided (here the plug is aligned by a single guide bushing in the bonnet as shown in Figure VI/2.3.2-2a), or top and bottom guided (the plug is aligned by guide bushing in the bonnet as well as at the bottom flange; as shown in Figure VI/2.3.2-2b) for a double seat valve. However, it is possible to have a top and bottom guided single seated valve. Cage guides (outside diameter is close to the inside wall of the cylinder cage with opening) are finding new popularity because of their better controllability in complex situations. They retain the seat ring and provide a guide for the plug. Various kinds of cage guides are depicted in Figure VI/2.3.2-1h and i. Cage guides with balanced and unbalanced plugs are shown in Figure VI/2.3.2-1f and g. In one system the cage opening construction is different, i.e., windows of the wall of the cylinder determine flow characteristics. In this type the interchange of the cage will change the flow characteristic without changing the seat plug. By interchanging the cage, special trim design such as low noise/low cavity trim is achievable. The other design has a plug characterized as per required flow types and the cage has a large opening to allow flow. The plug surface next to the ring is responsible for achieving the flow characteristic, i.e., unobstructed flow area changes in size and shape as per plug design. With cage guides it is possible to easily

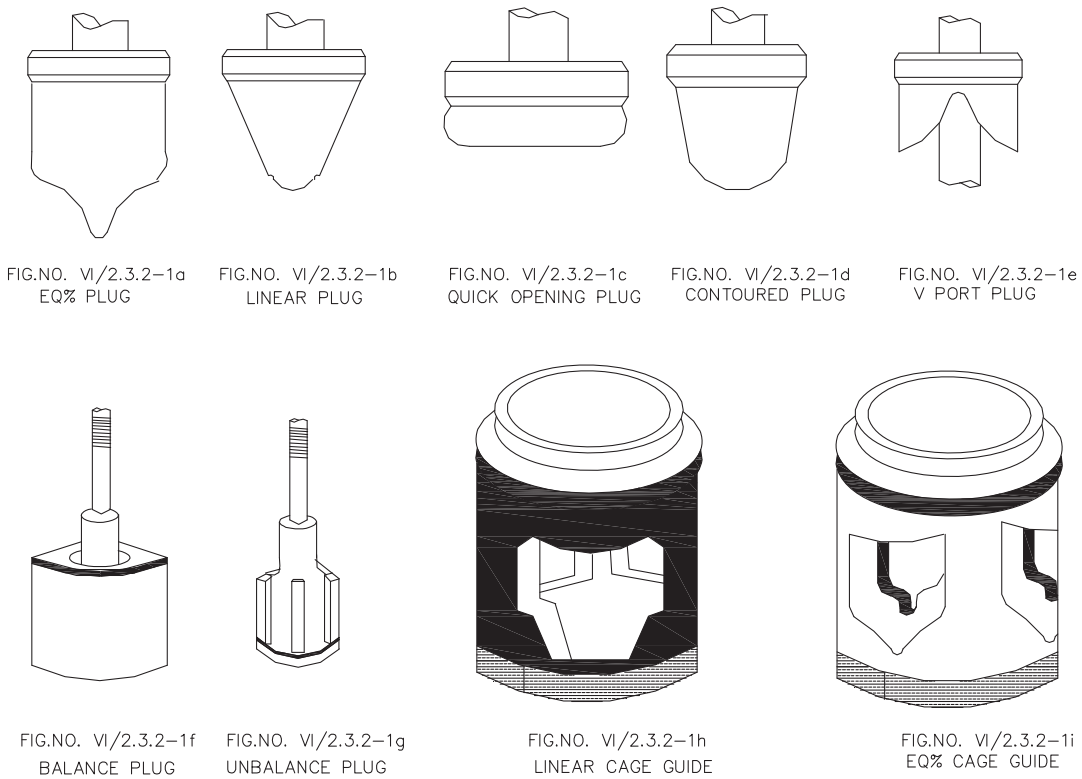


FIGURE VI/2.3.2-1 Types of plug and cage (globe valve).

www.EngineeringBooksPDF.com

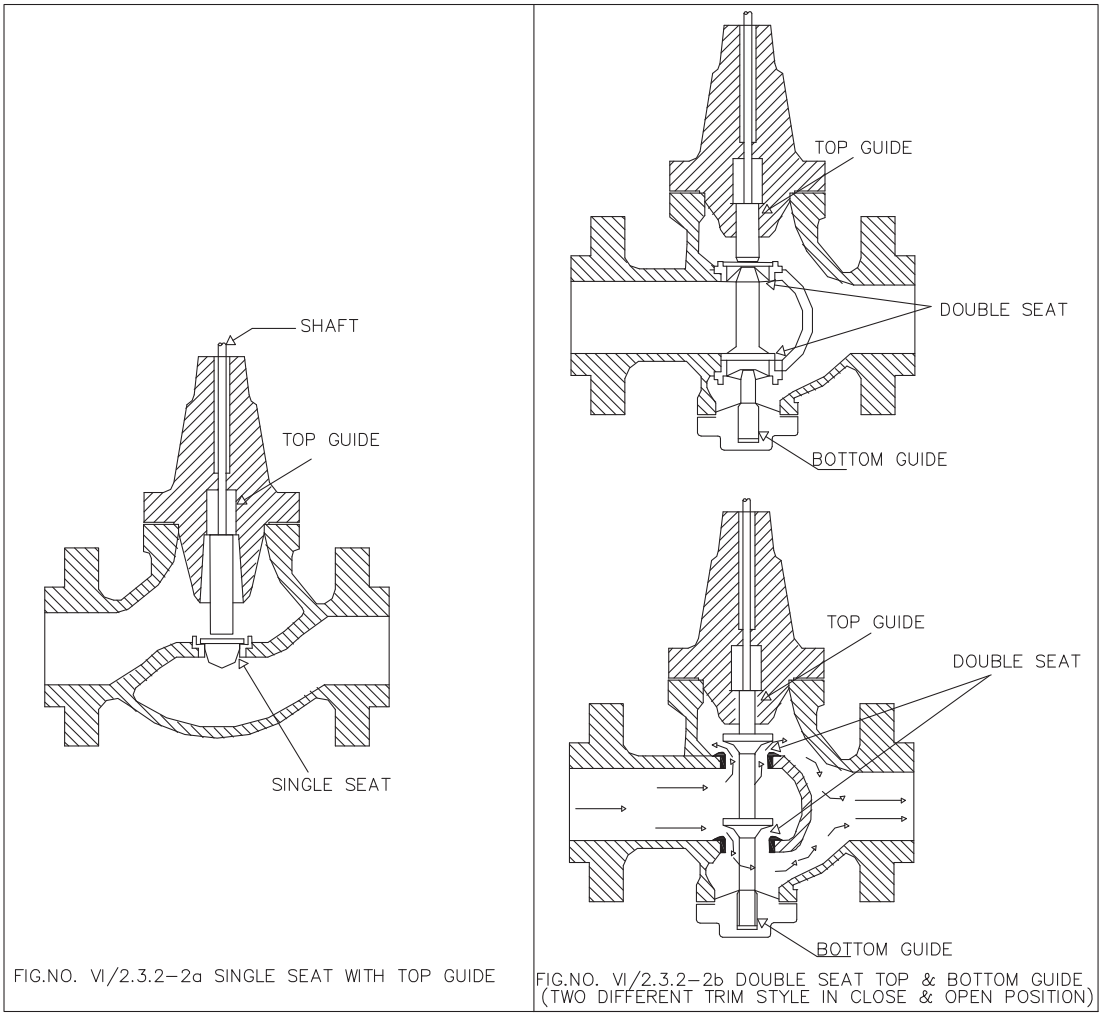


FIGURE VI/2.3.2-2 Globe valve single and double seat.

modify various trim parts to achieve various requirements, such as low noise, reduction in cavitation, etc. If the plugs are balanced then there will be less force necessary from the actuator, whereas if the plugs have an unbalanced force then the shut off will be better because of the unbalanced force. In a cage type valve design both are possible. The balanced plug cage guide is popular as it has a lower actuator force requirement in a single seat. In this sliding piston the plug seals the upper portion of the plug and cage wall and seals high-pressure end leakage. Downstream pressure acts on both sides at any position. As a result the actuator size required will be lower, as it has to overcome the reduced unbalanced force. Thus it has various advantages like single seated, better shut off, and because of the balanced plug a lower actuator force. Cage style trim design in angle valves is used in feed water and heater drain valves. These are also single seated valves.

2. *Double ported/seated valves*: These valves are heavier and larger and have lower shut-off characteristics. Leakage class is Class II or Class III. As shown in Figure VI/2.3.2-2b, a double ported valve has one advantage; it can be converted from push to close to push to open by opening the bottom potion, the bonnet, and inverting the assembly. As seen from Figure VI/2.3.2-2b, the force on the upper plug always tends to cancel the force on the bottom one. Because of dynamics of hydrostatic force, this valve is not totally balanced, hence, it is called a semi-balanced valve, and lower size actuators can be used. Normally these are used for >100 mm valve sizes.
3. *Special design valves*: Below are a number of special valve designs that are examples of the various kinds available commercially for power plant application. These are just examples and not recommendations.
   a. *High temperature (Courtesy Fisher Valve data book)*: Boiler feed water application, superheater control, and bypass control in power plants require

www.EngineeringBooksPDF.com

TABLE VI/2.3.2.3-1 Material Guidance

Temperature °C	Material used	Source
T > 538	Cr-Mo steel	Courtesy: Fisher Control Valve
T = 593	ASTM A217 Gr WC9	
T < 816	ASTM CF8M	

special considerations due to their high-temperature applications. These valves may have a special bonnet design (see later discussion), and need special attention due to their materials. Standard gasket and elastomer are not suitable. These valves use a metal-to-metal seat. Graphite packing material may be used (see Table VI/2.3.2.3-1 for different types of materials and their uses).

b. *Lo dB trim valve*: Designed for severe service application in compressible fluids. The design reduces the unbalanced force to minimum requiring low actuator torque. There are various types of designs: single Lo dB trim with or without diffuser and multistage Lo dB design are meant for anticavitation. There is a rotary globe valve with Lo dB trim. Dresser Masoneilan valves also have this kind of design (Figures VI/2.3.2-3 and VI/2.3.2-4a).

c. *Variable resistance trim VRT valves (Courtesy Dresser Masoneilan)*: Provide a good solution for cavitation protection in high-pressure liquid application. A boiler feed water control valve is one example. Here process fluid is passed through a series of axially stacked plates with drilled holes and positioned to provide the required level of cavitation protection with required flow rate.

d. *Drag valve (Courtesy CCI)*: Drag type trim ideally suited for minimizing noise at required flow capacity. The valve design is a multistage design. Based on leakage requirements, either a hard or soft seat can be used. This valve is suitable for BFP recirculation control where there is a requirement for very high-pressure breakdown without erosion/cavitation or vibration, and leak tight at required flow rate (Figure VI/2.3.2-4b).

e. *Reduced trim*: There are applications where it is necessary to have a larger valve body but with reduced trim. As per the ISA Guide (p. 112–161), reduced trim design may be considered for the following applications:

- Pressure drop in excess of 5170 KPa
- Gas/vapor outlet velocity >0.3 Mach
- High noise >85 dBA
- Choked flow
- Flashing exceeding 5%wt of liquid being vaporized
- Erosive fluid
- Future capacity increase anticipated

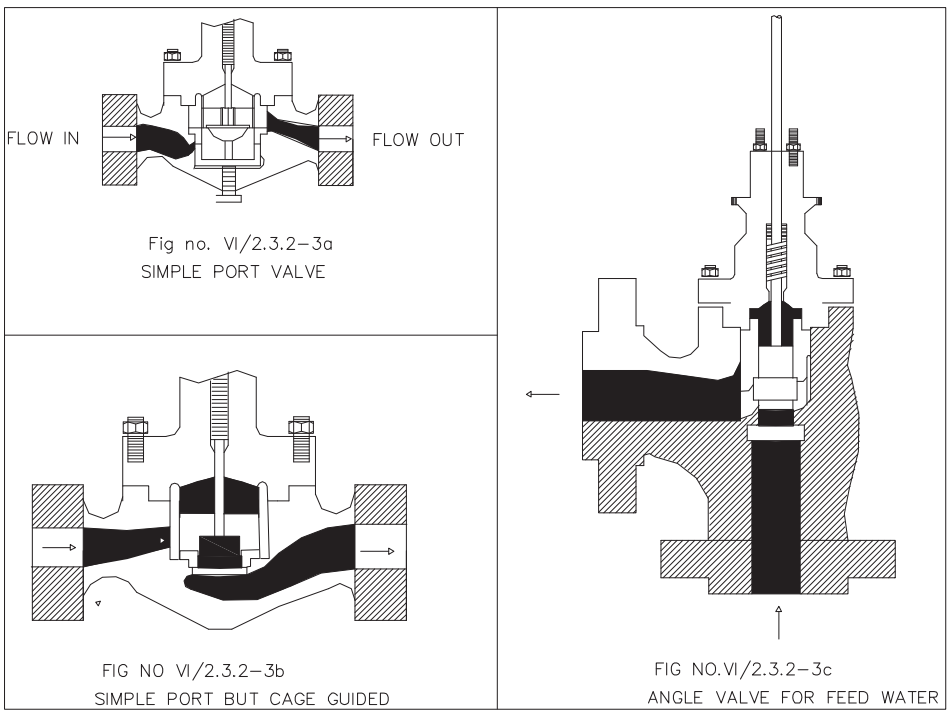


FIGURE VI/2.3.2-3 Single port globe control valve.

www.EngineeringBooksPDF.com

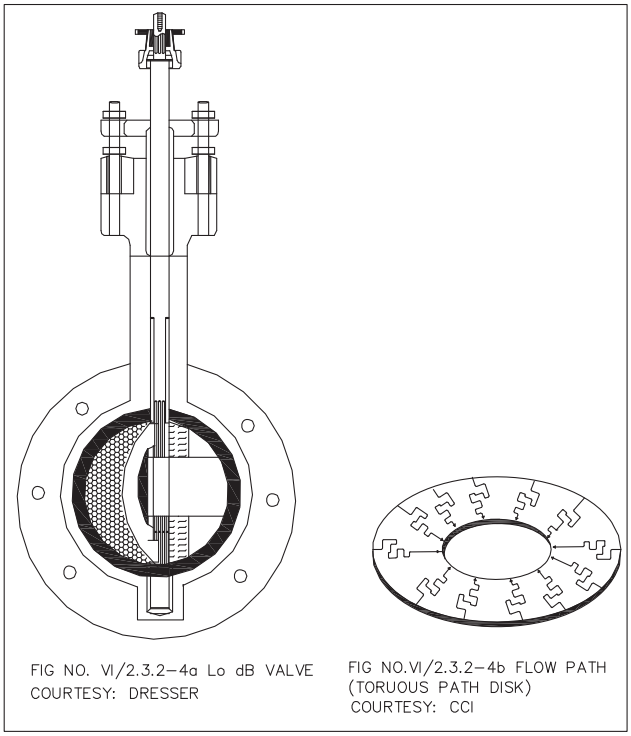


FIGURE VI/2.3.2-4 Special globe control valve design.

2.3.3 Control Valve Bonnet

There are three main types of bonnets: standard, extended, and bellow seal. The bonnet mainly serves the following functions:

- It is the pressure-retaining top closure assembly, and the plug stem/rotary shaft moves through it
- The actuators are mounted on it
- Provides seal valve trim against process fluid

The pressure-retaining part design calculation is based on ASME or other international standard codes. Most often the bonnet is the bolted flange type as shown in Figure VI/2.3.2-3a and b. In designs with cage trim, the bonnet applies force to prevent leakage from the valve body through the bonnet flange as well as seat ring

1. *Standard bonnet*: With standard seal packing and gasket materials it can withstand:
   a. *Pressure class*: ANSI 150-2500
   b. *Temperature*: −30 to 230°C but can be used up to 300°C with special packing materials. ISA recommends at >230°C or <0°C an extended bonnet is to be used.
2. *Extended bonnet*: These are used for very high- (as in power plants) and low-temperature applications. The advantage of this type is that it enables packing to be placed far away from extreme temperature conditions so that the temperature is within the range acceptable for the packing materials. Sometimes fins are used on the bonnet to dissipate heat. For a high-temperature application a cast type extension is preferred. Stainless steel (<800° C) is preferred to CS (<400° C) due to lower thermal conductivity for heat dissipation.
3. *Bellow seal bonnet*: Used where there is toxic fluid, volatile/radioactive fluid, etc.

2.3.4 Control Valve Packing

To prevent any leakage through stem to atmosphere there is a stuffing box at the upper part of the bonnet. The stuffing box is fixed with the valve by flange connection in most cases. It consists of packing follower and a packing retainer. Packing materials should have the following characteristics:

- Compatible(nonreactive) with process fluid
- Ability to seal stem
- Offer low friction
- Capability to withstand process temperature
- Offer good service life

Most popular are packing materials are Teflon, laminated or filament graphite, and asbestos.

1. *Teflon*: This is a plastic material with low friction available in V ring, ring or cup, and cone ring. It is resistant to almost all process fluids. It is suitable for temperatures ranging from −40 to 230°C). In extended bonnet design the temperature can be raised up to 400°C. (Frosting in stem is not good as it may cause cracking in the packing.) It is better suited with a smooth finished stem. A PTFE V ring is a coil type system usually used for $P < 20$ bar and $T < 93$°C. Performance and service life is good coupled with low friction. Seal PTFE packing with live spring load is suitable for environmental application $P < 50$ bar and T < 230°C; in nonenvironmental case it is used for high-pressure temperature application. This type gives good performance, long life, and friction is low. Kalrez (with PTFE) is suitable for environmental and high-temperature application
2. *Graphite*: Suitable for high-temperature application up to 650°C; however, the extension bonnet is better for temperatures >400°C. It has high service life and high thermal conductivity, but has medium to high friction. Valve manufacturers use laminated or filament graphite rings, and care should be taken to see that there no air is trapped. There are environmental seals in graphite also. This type gives good performance and long life.
3. *Asbestos*: Old material used as asbestos rings. This is largely replaced by Teflon packing.The prolonged inhalation of asbestos fibers can cause serious illnesses including malignant lung cancer. The European Union

www.EngineeringBooksPDF.com

has banned all use of asbestos. For high-temperature application reinforcement wires are used. Asbestos packing is used with lubrication.

2.3.5 Steam Conditioning Control Valves (PRDS) in Power Plant Applications

In power plants and steam generation plants there are a number of pressure reduction and de-superheating stations (PRDS). What is a steam conditioning application? This system deals with simultaneous reduction of pressure and temperature of the inlet steam to the required level; for example, main steam at 150 bar at 540°C may have to be reduced to steam at 16 bar at 210°C. Since there is simultaneous reduction of both the vital parameters, forged type valves are best suited for the application. In these applications valves are available up to the 4500 lb class. Some of the advantages of the combined valves include:

- Because of turbulent expansion zone the mixing may be better
- Higher rangeability
- Because of spray of water the noise generation is less
- Less space and easier installation

However, the characteristics of these valves vary greatly with the applications. There are some special trim designs that can accommodate rapid change in temperature following turbine tripping. To improve the heating efficiency it is necessary to precisely control temperature, so it is necessary to inject a controlled quantity of spray water. Proper selection of a de-superheater is essential. Because of complex thermal and flow dynamic variables involved in the process of de-superheating, there are a number of physical, thermal, and geometrical factors on which the selection success of a de-superheater depends. Factors affecting the performance include:

- *Orientation of spray*: Proper placement of the de-superheater has great impact on performance. Vertical orientation with flow going up is a good selection for better mixing. Downstream fittings also play a role in performance.
- *Spray water temperature*: The higher the temperature of the spray water the better the heat transfer, because increased temperature drops size distribution; the latent heat of vaporization, rate of vaporization, etc., improves, hence, better performance of the de-superheater.
- *Spray water quantity*: This directly affects the time for vaporization and, since heat transfer is time dependent, would depend on the quantity of spray water.
- *Steam velocity*: Velocity directly affects the residence time, which highly affects the mixing. If the velocity is too high, then there is not enough time to mix. On the other hand, if the velocity too low, water droplets will try to drop out in want of turbulence. Maximum velocity could be 46−76 m/sec and optimum minimum velocity may be 9 m/sec. This is in line with recommendations from manufacturers.
- *Pipe size*: As the pipe size affects the velocity, it affects penetration and the coverage area for the flow.

Quantity of spray water can be calculated from the quantity of inlet/outlet steam flow and enthalpies of inlet and outlet steam as well as from the enthalpy of water. These are available in any standard sizing handbooks. Based on the quantity of spray water needed, C_v for the de-superheater is calculated. There are a number of de-superheater designs including:

- *Fixed geometry nozzle*: Simple mechanically atomized de-superheater with single/multiple spray nozzles. Generally used for constant load operation rangeability 5:1. These are fixed by a suitable flange on branch pipe.
- *Variable geometry nozzle*: This is also a mechanically atomized de-superheating system, only it has variable geometry activated by back pressure. Because of this configuration it has a rangeability of 20:1.
- *Self-contained design*: This is another kind of mechanically atomized design. It has variable geometry and is activated by back pressure.
- *Steam atomized design used mainly for systems with low-velocity steam*: The atomizing steam pressure is nearly twice that of Inlet steam.

3. DAMPERS AND MISCELLANEOUS OTHER FCEs

3.0 Introduction

In power plants, dampers/louvers, vanes, and impellers are used to control the flow of gas through fans and/or ducts. Butterfly and guillotine dampers are similar to the butterfly and gate valves previously discussed. In this clause, dampers will be discussed from the perspective of their use in a boiler draft system in a power plant. Fan controls will be emphasized more than various dampers. Also, there will be brief discussions on other fan/pump controls, such as hydraulic coupling scoop tube and VFDs, to cover miscellaneous FCEs. Also discussed will be various dampers such as multiple blades/louvers, and radial vanes. Controls for fan blade pitch as in axial fans (and the speed controls of fans), which are also used to control the gas flow through fans, are also mentioned.

3.1 Control Dampers

A control damper basically consists of a frame, blade, axels, and linkage seals. Normal parallel dampers (see

www.EngineeringBooksPDF.com

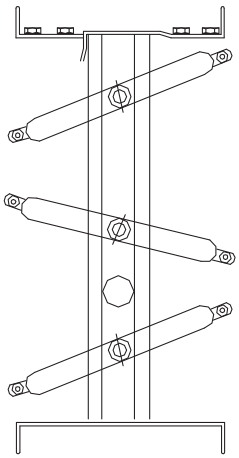


FIG VI/3.1–1a CONTROL DAMPER IN OPPOSED ACTION

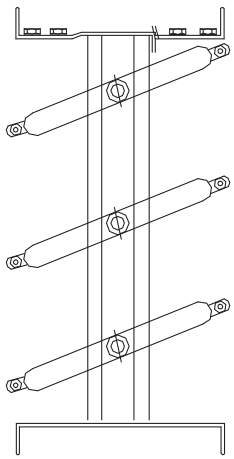


FIG VI/3.1–1b CONTROL DAMPER IN PARALLEL ACTION

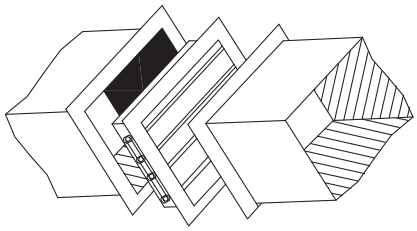


FIG VI/3.1–1c DAMPERS IN DUCT

FIGURE VI/3.1-1 Control damper.

Figure VI/3.1-1b) are similar to butterfly valves and direct the flow toward the parallel opening (Figure VI/3.2-1b). In opposed blade configuration, as in Figure VI/3.1-1a, flow direction is straight similar to Figure VI/3.2-1a. Opposed blade dampers allow better control over the entire range of control, whereas parallel blade dampers are better suited for control of ~70–100% flow. These control dampers are generally installed in the duct by flanges, as shown in Figure VI/3.1-1c. There is a special kind of control damper known as an airfoil control damper, which is used when extreme low leakage is desirable for a system with medium to high pressure and velocity. In power plant application some considerations are given while designing the control damper and damper actuator—a multiple burner tilt actuator requires extremely high torque, whereas long stroke length is necessary for damper actuators in an air application.

Dampers/vanes connected with various types of fans need special attention and these are discussed separately with types of fans. In power plants the large fans like forced draft (FD)/ID/primary air (PA) fans are generally centrifugal fans (outlet flow at 90° with inlet flow) or axial fans with flow parallel to the shaft around which the blades rotate. Air flow through these fans can be controlled by fan speed and inlet vane or fan pitch control.

3.2 Vane/Damper Control

There are dampers sized to handle maximum air velocity. Outlet dampers used to throttle air flow can be an opposed as well as a parallel type, as shown in Figure 3.2-1a and b, respectively. When the outlet dampers are throttled due to resistance there will be a drop in fan pressure, which is not a good use in utility boilers. Generally, outlet dampers are used in utility boilers as an ON/OFF damper for low load starting of the fan, i.e., as an isolating damper. Inlet box damper for fans is used in all types of boilers, but are mainly used in a clean air application. Parallel blade inlet box dampers have less power efficiency than variable angle inlet vanes, so they are used more often in utility boilers. These inlet vanes could be the nested type (used when there is no duct and space constraints) or an external variable Inlet vane.

3.2.1 Variable Inlet Vane

This control is used for centrifugal fans with fixed speed to control air flow through the fan. This can also be applied to fixed speed, fixed pitch axial fans (or fans with higher pressure and velocity; Figure VI/3.2-1c). In most cases these are external to the fan for accessibility to linkage and for maintenance and flexibility in mounting location.

www.EngineeringBooksPDF.com

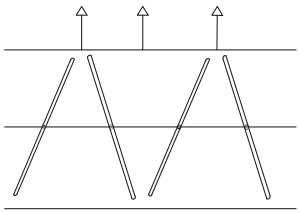


FIG.NO. VI/3.2–1a OPPOSITE BLADE EFFECT ON FLOW

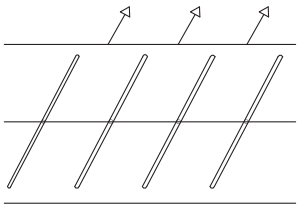


FIG.NO. VI/3.2–1b PARALLEL BLADE EFFECT ON FLOW

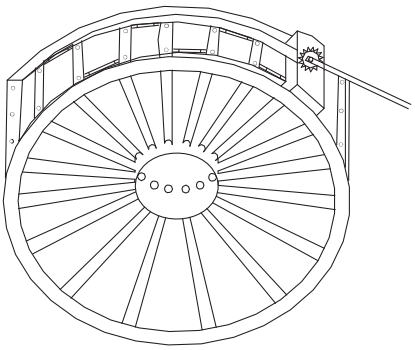


FIG.NO. VI/3.2–1c VARIABLE INLET VANE FOR CENTRIFUGAL FANS

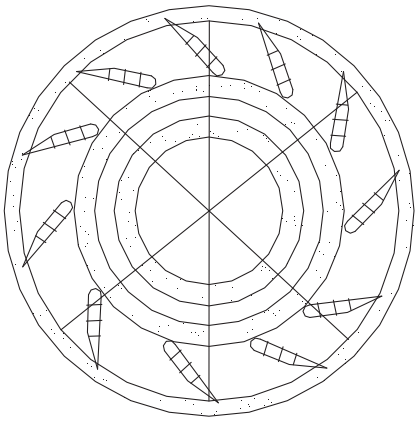


FIG.NO. VI/3.2–1d AEROFOIL IMPELLER

FIGURE VI/3.2-1 Dampers, variable vanes, and impellers.

Variable inlet vanes can alter the fan performance by pre-swirling the gas before it enters the impeller (in contrast to loss of power associated with conventional dampers). When the vanes are fully open it offers extremely low resistance. As the vanes close (change in angle), the air enters the system in the direction of rotation as the impeller. This causes reduced total pressure generated across the impeller and a reduction in power. The variable inlet vane is an energy saver when compared with conventional dampers. Depending on the operating condition and damper size, there are two options available:

- *Cantilevered blade*: Used in high-temperature flue gas containing corrosive and abrasive materials. The vortex vanes are designed to offer the least resistance. In corrosive application, they are used with an inlet cone, and the vanes throw the air to the eye of the impeller for accurate and better control. Single and double vane designs are available.
- *Center hub supported blade*: This option is used for comparatively clean air as it has higher velocity and pressure (see Figure VI/3.2-1c).

In a variable vane-controlled system, the fan selection is generally done with full pressure and flow with no vane in place. When a vane is in place, maximum performance is decreased. It is worth noting that the variable inlet vane control is extremely sensitive at lower load, meaning that with a slight change in angle there will be larger flow change, whereas the same characteristic is reversed at a higher load. This means the variable vane is not linear like axial fan control, discussed below.

3.3 Blade Pitch Control

Blade pitch control is applied to axial fans with fixed speed to control air flow (see Figure VI/3.2-1d). The blade angle is adjusted, with the help of a hydraulic actuator (fixed with the shaft), from minimum to maximum position to ensure maximum possible efficiency. It is worth noting that in these cases some important and critical items are the LO system, sliding bearing, and suitable oil control sealing, especially the stationary hydraulic control valve and rotating hydraulic cylinder. Flow change with change in blade angle is proportional, so linear characteristics are possible. The response time of this type of control is quite good, approximately <30 sec or better. This design is used for FD (may be also for PA/ID/flue gas desulfurization) fans. Aerofoil-shaped blades are fixed to a hub mounted for axial sliding motion on a drive shaft. The other end of the link is connected via linkage to the driving shaft of the hydraulic actuator. As the hub moves axially, a rotational movement is transmitted through the pin and link arrangements to the fan blades to vary their pitch. This force is balanced at the actuator by the spring force. This way of controlling the gas flow is linear with the angle of the impeller.

www.EngineeringBooksPDF.com

3.4 Speed Control (Applicable for Both Fans and Pumps)

The most energy-efficient way to control flow through a fan is speed control. As the fan speed control is only possible with the help of an external system, any inefficiency of the system is introduced into the overall efficiency of the system. Also cost needs to be considered as the unit sizes increase, but the electrical method seems less costly (for medium voltage application, but for high-voltage, large size fans this may not be true). There are various methods to control fan speed including:

- Two-speed motor
- Fluid drive speed control
- Variable speed drives

Of these three methods, the last two are used extensively in power plants.

3.4.1 Hydraulic Coupling for Speed Control

Hydraulic coupling working on the hydrodynamic principle consists of one pump (an impeller) and a reaction element (turbine, generally known as a rotor) enclosed in suitable casings, as shown in Figure VI/3.4.1b. For a better understanding of the scheme, see Figure VI/3.4.1a. Both the impeller and rotor face each other with an air gap. An impeller with shaft is connected to the prime mover motor of constant speed. A rotor with shaft is connected to driven equipment (e.g., ID fan or BFP in case of a power plant general application) through a suitable arrangement. Oil is filled in the coupling. There is a fusible plug that blows off and a drain in case of sustained overloading. There is no mechanical coupling between these shafts. The power is transmitted from drive to the driven equipment by virtue of a fluid-filled coupling. The rotation of the impeller imparts kinetic energy to the fluid in a closed circuit, and this energy is converted in the rotor in to mechanical energy to rotate it, as shown in Figure VI/3.4.1b and c. Fluid flow in a closed circuit from impeller to rotor is through the air gap at the outer periphery, whereas the same from rotor to impeller is through the inner periphery. To establish a flow of fluid from impeller to rotor there is a head difference, hence, there will be a difference in speed due to the slip developed. Essentially this difference in speed is known as

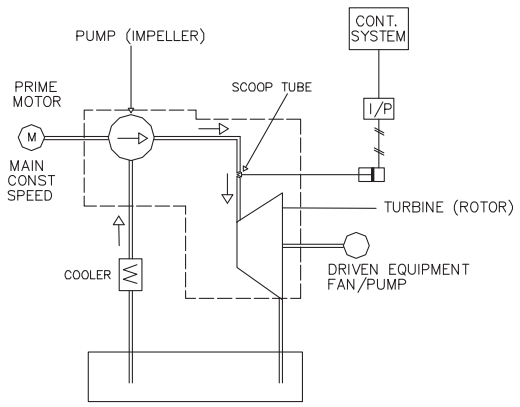


FIG.NO. VI/3.4–1a SCHEMATIC TO EXPLAIN BASIC PRINCIPLES

1)COUPLING REGULATED BY CHANGING THE QUANTITY OF FLUID BETWEEN IMPELLER & TURBINE i.e. TO REGULATE FILLING LEVEL OF COUPLING WITH THE HELP OF SCOOP TUBE/VALVE/ NOZZLE

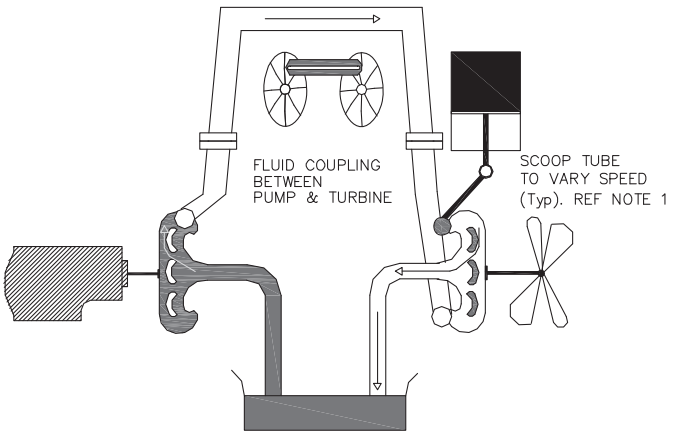


FIG.NO. VI/3.4–1b ELABORATE SCHEMATIC HYDRAULIC COUPLING (WITH SCOOP TUBE)

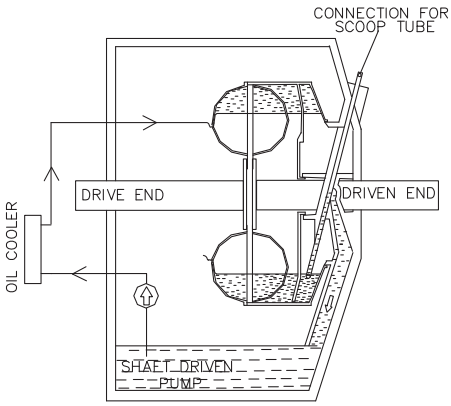


FIG.NO. VI/3.4–1c HYDRAULIC COUPLING WITH SCOOP TUBE FOR SPEED CONTROL

FIGURE VI/3.4-1 Hydraulic coupling scoop tube.

www.EngineeringBooksPDF.com

slip and is an important factor and inherent characteristic of the coupling. As the slip increases there is more and more fluid so more torque is transmitted. The system is not linear in power transmission, but proportional to the cube of speed of the driving machine. Both sides develop torque in proportion to the square of the speed of the respective driven member. One advantage of the system is that it can develop high output torque at low output shaft speed, even when the speed of the drive motor is high. Efficiency is inversely proportional to slip. With the speed control of a fan (ID fan) or a pump (BFP), there will be one sliding scoop tube entering through a clearance in a coupling rotating casing to vary the oil quantity. According to the position of the scoop tube, the fluid above it is drained out and as a result the amount of coupling changes. The speed of the driven machine depends on this and is very accurately controlled. This system offers smooth control of the speed. From the control loop the electronic signal, after being converted to a pneumatic signal, regulates the stroke of the power cylinder used to position the scoop tube (as shown Figure VI/3.4-1a–c).

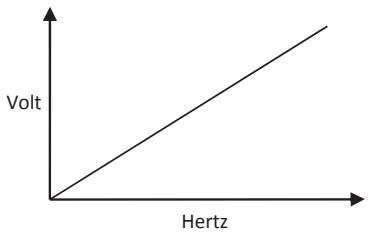


FIGURE VI/3.4.2-1 Torque development.

3.4.2 VFD for Speed Control

Figure VI/3.4.2-2 illustrates the basic building block for a VFD. AC motor speed (S) is given by: $S = (120*f)/(P)$, where f = frequency of the supply, and P is the number of poles. Out of the two parameters responsible for motor speed, P is not changed as it calls for physical change in the motor and rewinding, but it is easier to change the frequency of supply.

As long as the f/P ratio is maintained, the rated torque can be developed. This indicates that whenever speed of an induction motor is controlled both frequencies as well as voltage are controlled to get different torque (see Figure VI/3.4.2-1). This ratio is varied in input, which consists of an isolation transformer, a rectifier circuit, and a DC bus section comprising a suitable filter, *di/dt* arrestor, etc. An isolation transformer isolates the system from the input supply. It also helps in developing a multiphase rectifier circuit as shown in Figure VI/3.4.2-2, which shows twelve diodes in multiphase rectifier circuit to convert the AC supply (50/60 Hz) to a DC circuit. There is a filter to smooth out the DC voltage; the multiphase rectifier circuit is used to get better DC voltage. The smooth DC is fed to the inverter section. In the inverter DC voltage is transformed into AC voltage (see the standard book on power electronics for

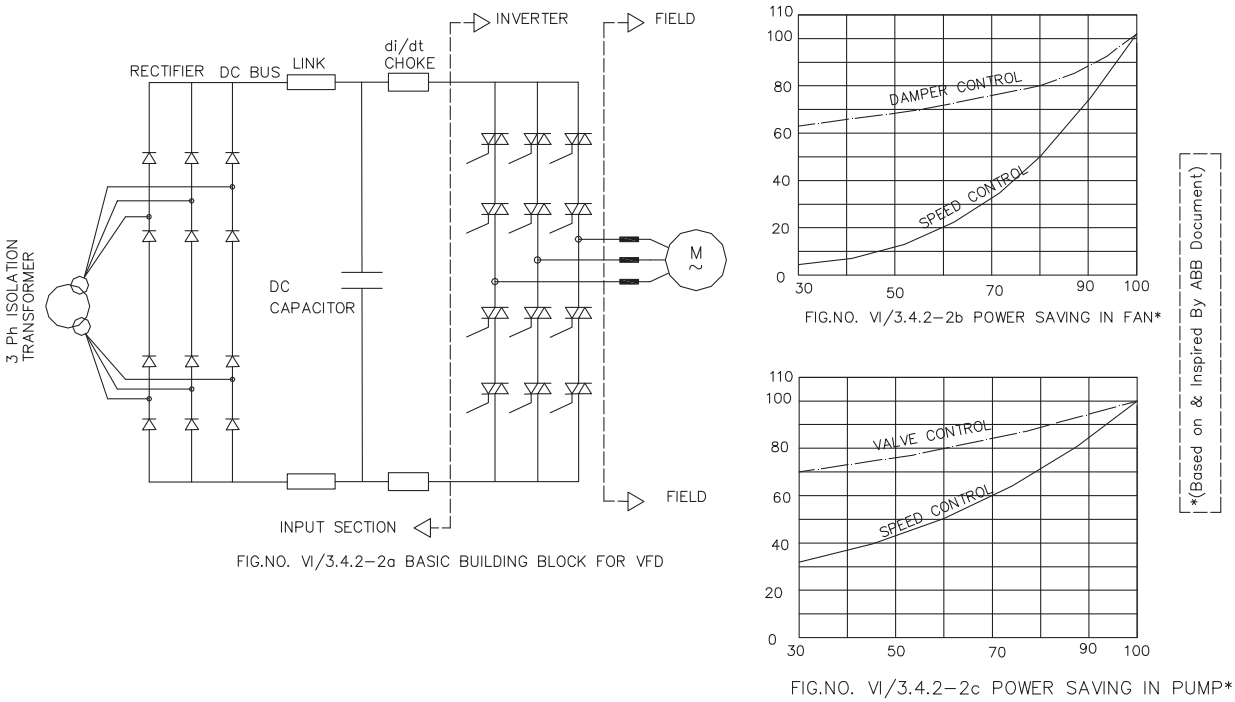


FIGURE VI/3.4.2-2 Basic block diagram for VFD (3Ph) and power-saving diagram.

www.EngineeringBooksPDF.com

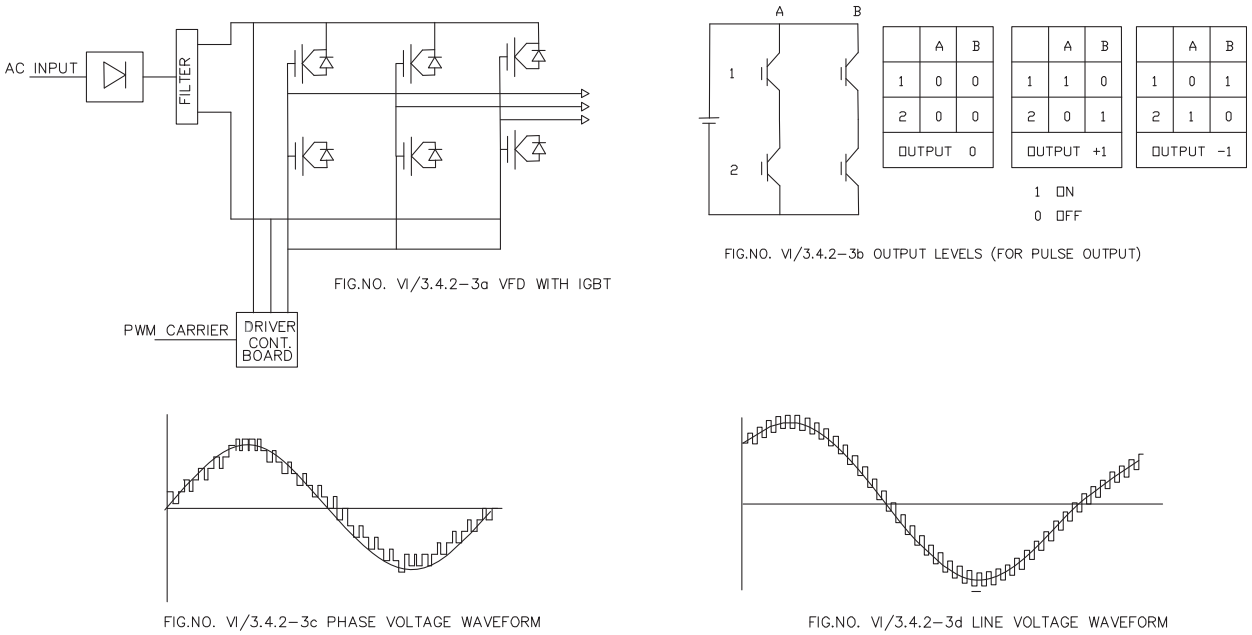


FIGURE VI/3.4.2-3 Inverter circuit and waveform.

inverter action), with the help of a silicon-controlled rectifier or an insulated gate bipolar transistor (IGBT), which is an advanced three-terminal power semiconductor switching device working on a minority carrier. IGBT has high input impedance combined with the capability to handle high bipolar current. It combines the advantages of MOSFET and BJT—it is a voltage-controlled device. IGBT is used to turn the DC voltage on and off, and the DC voltage provides bipolar pulses of equal magnitude. In the control board the set point is compared, and it regulates turning on the waveform positive half or negative half of the power device. The longer the device is on, the higher the output voltage and the higher the frequency. The shorter the power device in on the lower the output voltage and the lower the frequency. The power device is made ON/OFF by a carrier frequency, also known as switching frequency. The higher the switching frequency the higher the resolution of pulse width modulation (PWM), so it is the smoother waveform of the AC signal. The typical frequency is 3–4 KHz. Figure VI/3.4.2-3a and b shows the inverter cells and output conditions. Typical waveforms have been depicted in Figure VI/3.4.2-3c and d. Here each inverter cell generates a voltage level. Typical energy savings in fans and pumps are shown as a percentage in Figure VI/3.4.2-2b and c. Power savings are more prominent in fans at lower loads.

4. ACTUATORS

4.0 Introduction

An actuator in FCEs accepts the external signal from the control system in response to the same to regulate the motion (or position) of the FCE to modify its position and achieve the desired control. It has two functions: (1) to accommodate various accessories associated with the assembly so that desired movement of the FCE can be achieved and (2) to respond to the external control signal. In power plants all three types of actuators, electrical, hydraulic, and pneumatic, are used. In many plants electrical actuators with power amplifiers are used for regulating functions to overcome excess inertia problems associated with electrical actuators. However, electrical actuators are used more often in ON/OFF functions in power plant applications. In many control applications such as turbines [high pressure (HP)/intermediate pressure (IP)] stem control valves, HP/low pressure (LP) bypass valves, aerofoil controls of FD fans, etc., hydraulic actuators are more common. These actuators, however, normally come as a part of the main equipment supply. A pneumatic actuator is the most common in power plant applications, and it is also recommended by ISA. Actuators can be classified as linear actuators and rotary actuators. Electrical actuators, such as servo motors, are rotary actuators, whereas other actuators types could be either type. In power plants the majority of hydraulic and pneumatic actuators are linear (rotary actuators are used with butterfly valves/dampers).

4.1 Actuator Sizing

Generally actuator sizing is performed by the control valve manufacturers and is properly documented to be reviewed by the system engineers. All manufacturers have their own

www.EngineeringBooksPDF.com

catalog and selection guidelines based on the actuator. As discussed in Clause 1.5, the force required for an actuator varies with valve and actuator orientation. Next various forces and actuator sizes will be discussed.

4.1.1 Forces for Actuator Sizing

There are a number of forces that need to be considered including:

1. *Unbalanced force at plug*: This results from the fluid pressure (ΔP) at shut off. Generally, maximum upstream pressure is considered. The unbalanced area (UA) is chosen carefully, and it depends on the configuration. Even for a balanced trim there will be some unbalanced force. These data are obtainable from the manufacturer. As a rule of thumb, the following may be considered: UA for balance trim may be $(\pi/4)$ $[(\text{Cage ID})^2 - (\text{Seat ID})^2]$ and UA for unbalanced trim could be $(\pi/4)$ $(\text{Seat ID})^2$.
2. *Seat Load (SL)*: This is calculated from the shut-off requirement of the valve. A list of recommended seat load needs to meet the requirement for ANSI/FCI 70.2 or /IEC534-4 leakage tests has been presented. The data given below are based on standard manufacturer data and are available from all manufacturers. Based on standard differential pressure (DP) the seat load calculation basis is listed below.
   Leakage Class I: As required there is no test recommended.
   Leakage Class II: 20 lb per lineal inch of port circumference
   Leakage Class III: 40 lb per lineal inch of port circumference
   Leakage Class IV: 40 lb per lineal inch of port circumference; size $<$ 4 3/8 inch port diameter
   Leakage Class IV: 80 lb per lineal inch of port circumference; size $>$ 4 3/8 inch port diameter
   Leakage Class VI: 300 lb per lineal inch of port circumference
   For Optimum performance of boiler feed water service a seat load of 1000 lb per lineal inch for any DP should be considered.
3. *Packing friction (PF)*: Table VI/4.1.3-1 lists the packing frictional force for commonly used packing materials.
4. *Miscellaneous other forces*: There may be several other additional forces like seal friction. The manufacturer needs to share this information with the system designer. Plug seal friction force can be calculated as follows:

$$\begin{aligned}\text{Plug seal force (SF)} &= 2\pi(\text{Cage ID}) \\ &\quad + (0.02355)\left[(\text{cage ID})^2\right. \\ &\quad \left. - (\text{Seal Groove})^2\right] * \Delta P\end{aligned}$$

5. *Actuator output*:
   a. actuator output (FLOW TO CLOSE VALVE) = allowable ΔP*UA + SF +SL + PF
   b. actuator output (FLOW TO OPEN VALVE) = allowable ΔP*UA + SL + PF (unbalanced trim) Remember to ensure that the pressure class of the valve is higher than the allowed pressure drop.
   c. As discussed in Clause 1.5:

$$\begin{aligned}\text{direct actuator output} &= A(\text{effective diaphragm area}) * \\ &(\text{air pressure} - \text{final spring pressure, i.e., spring pressure} \\ &\text{when travel reaches full travel valve})\end{aligned}$$

$$\begin{aligned}\text{reverse actuator output} &= A(\text{effective diaphragm area}) * \\ &(\text{air pressure} - \text{initial spring pressure, i.e., spring} \\ &\text{pressure when valve starts moving})\end{aligned}$$

For a rotary type actuator, torque, which is sum of all torque, is calculated. Power cylinders for dampers have their dynamic torques calculated based on mounting type and style. From the linkage arrangement the force is

TABLE VI/4.1.3-1 Packing Material Selection

Packing material	Temperature range (°C)	Sealing	Life	Packing friction (kg)[a]	Remarks
Single PTFE	(−)46 t0 230	Good	Long	9−45	Depending on pressure class and stem length
Double PTFE	(−)46 to 230	Good	Long	13−70	−DO−
Graphite	(−)198 to 538	Good	Long	45−450	1) −DO− 2) High-pressure withstand capability

[a]This is to be chosen in consultation with the manufacturer.

www.EngineeringBooksPDF.com

calculated, and, finally, from the above calculation power cylinder area is calculated.

4.2 Some ISA Guidelines on Actuators (Control Valve Technical Specification)

After gathering some knowledge on actuator sizing, this clause will concentrate on some of the guidelines set forth by ISA. The Discussions presented below is based on some of important ISA guide line and not always exact quotes. At the end of each guideline the guideline reference is shown in parentheses. This allows the reader to check data regarding the selection of an actuator. (Courtesy of Control Valves—Practical Guide For Measurement and Control.)

"Actuator systems should be a pneumatic type … other than pneumatic shall be applied on exception basis only" (ISA Guide, p. 101). It should be pointed out that in power stations, there are a few control valves where it is conventional to use hydraulic actuators, such as turbine (HP/IP) control valves and all control valves in the HP/LP bypass system. In general they form a part of the main equipment supply.

"Valve body size greater than 2" and pressure drop in excess of 4000 KPa, a diaphragm shall not be used" (IAS Guide, p. 101).

"Supply air pressure shall be < 930 KPa g" (IAS Guide, p. 101). It may be better to specify a little lower value while specifying air supply pressure and to include an air filter regulator.

Material for pneumatic tubing fitting, valve shall be a minimum 316 SS (carbon steel, Cu, bronze, SS 304 shall not be used; IAS Guide, p. 101).

"Valve travel position total accuracy shall be <2% … and … overshoot during testing (shop or field) shall not be greater than 2%" (IAS guide, p. 101).

Air failure position shall be accomplished without aid of process pressure. (IAS Guide, p. 101)

"All applications need to be verified for the actual stroke speed requirement. … Boosters may be used to stroke time requirements but stroke movement shall be stable at 20, 50, and 80% control signal steps" (IAS Guide, p. 470).

Bolted yoke assembly shall not be used (IAS Guide, p. 470).

4.3 Pneumatic Actuator Selection

See Table VI/4.3-1 for the selection of pneumatic actuators.

4.4 Piston Cylinders

In power stations, piston actuators are used in linear applications mainly. As shown in Figure VI/4.4-1, the piston actuator can be used in a linear as well as in a rotary application with suitable linkage, feedback spring, and cam. In a control application piston cylinders are used with a positioner. At steady-state condition of the pilot valve, air supply ports to both sides of the main piston are closed and exhaust ports are also not connected. Based on the control signal, at the diaphragm, it will push or pull the arm. As a result, the pilot valve will be moved up or down.

TABLE VI/4.3-1 Points for Pneumatic Actuator Selection

Feature	Diaphragm (linear)	Piston (linear)	Rotary diaphragm	Rotary piston
Thrust	Moderate	High	Higher torque possible	Higher torque possible
Speed	Slow	Faster	—	Faster
Stroke	Short	Longer	Short	Longer
Fail safe	Possible without additional accessories	No fail safe without accessories	Possible without accessories	No fail safe without accessories
Design	Simple compact	Simple, mounting may be special	Complex with mounting, sometimes special	
Air pressure	Low to moderate	Higher	Moderate	Higher
Control	Excellent with/without control device	Excellent with control device	Good control with suitable device	Good control with suitable device
Other features	Lack in stiffness	Higher stiffness	Easily reversible	
Application	Control linear valves	Linear valves and Damper	Rotary valves, e.g., ball, butterfly	Rotary Valves of higher sizes

www.EngineeringBooksPDF.com

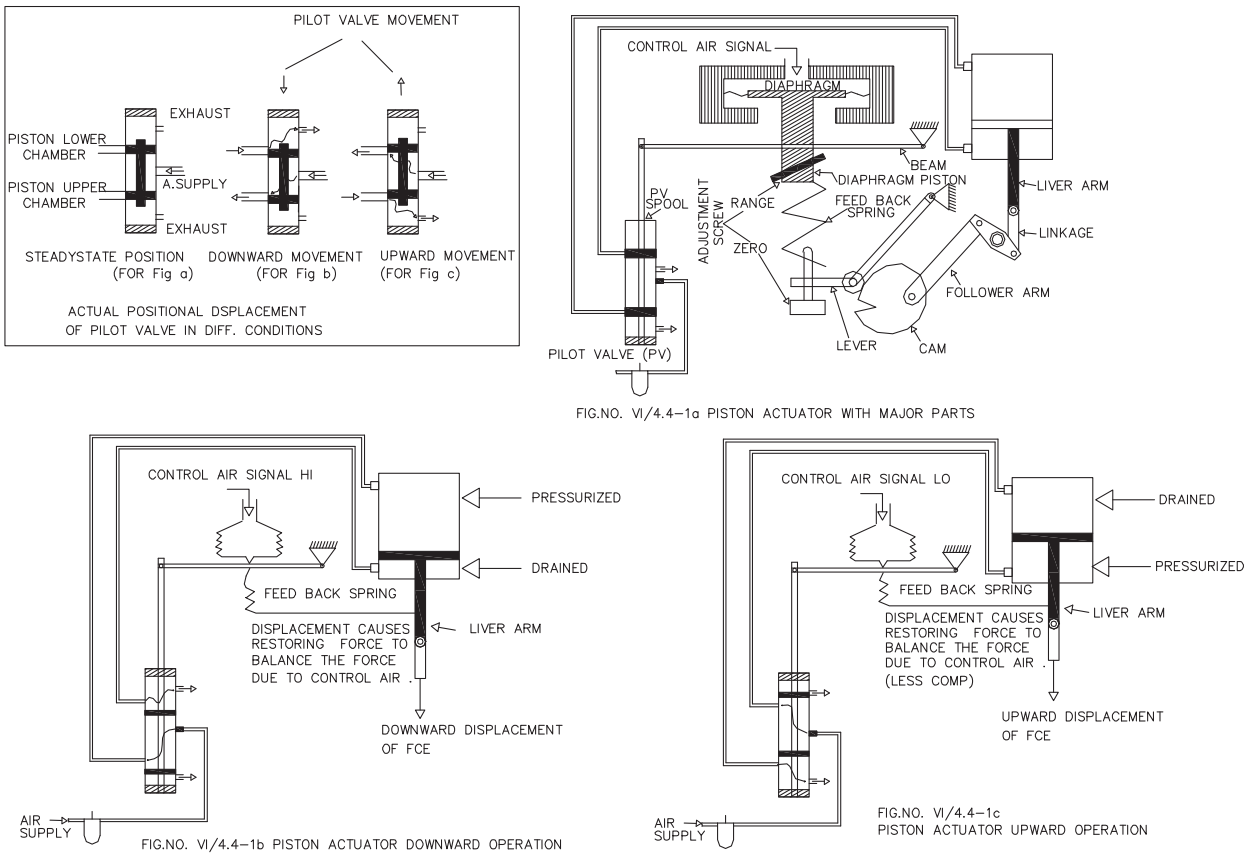


FIGURE VI/4.4-1 Piston actuator with feedback spring and cam.

When the diaphragm is pushed down due to a higher control air pressure signal, the pilot valve piston is also pushed downward to proportional to the additional control air pressure. As a result of this, the exhaust port of the lower side of the pilot valve will remain closed, and the air supply port will open while the exhaust port on the upper side will open proportionately and the air supply port will remain closed (Figure VI/4.4.-1b). For detailed view, pilot valve positions in the box of figure VI/4.4-1 may be referred to. During this period supply air will be connected to the lower part of the piston. This will cause the upper part of the piston cylinder to become pressurized, and the lower part is drained. As a result the lever will move downward to change the position of the FCE. When there is displacement of the lever arm, there will be feedback to the main beam via linkage, lever, and feedback spring (getting compressed; Figure VI/4.4-1a and b). This displacement of the FCE will stop when the force due to air pressure on the beam will be balanced by feedback spring. It will be reversed when there is low pressure in the control air pressure, as shown in Figure VI/4.4.-1c. Through a suitable linkage arrangement the same actuator can be used in a rotary application. For zero and range adjustment there are separate screws for calibration. There are various mounting arrangements of the power cylinders, including straight mounting/fixed mounting and trunnion. Trunnion mounting is generally used when load moves in an arc, as in various damper controls, to transfer complete thrust. The cylinder sizing is also influenced by the type of mounting possible at the site.

4.5 Safe Failure

There are a number of options available when choosing a fail safe mode. Generally, there are three types: fail open (FO), fail close (FC), and stay put (meaning maintaining old position prior to failure) or fail lock (FL). Out of these three schemes, the first two are achieved by suitable air connection only, whereas the FL condition can be achieved with some accessories. As shown in Figure VI/4.5-1a–d, there could be four combinations possible.

4.5.1 Direct Action: Air to Close: FO

Air pressure is applied from the top of diaphragm, so on increasing pressure, the stem lowers. This is referred to as direct acting and will compress the spring to close the valve (direct acting valve), i.e., the air is required to close (air to

www.EngineeringBooksPDF.com

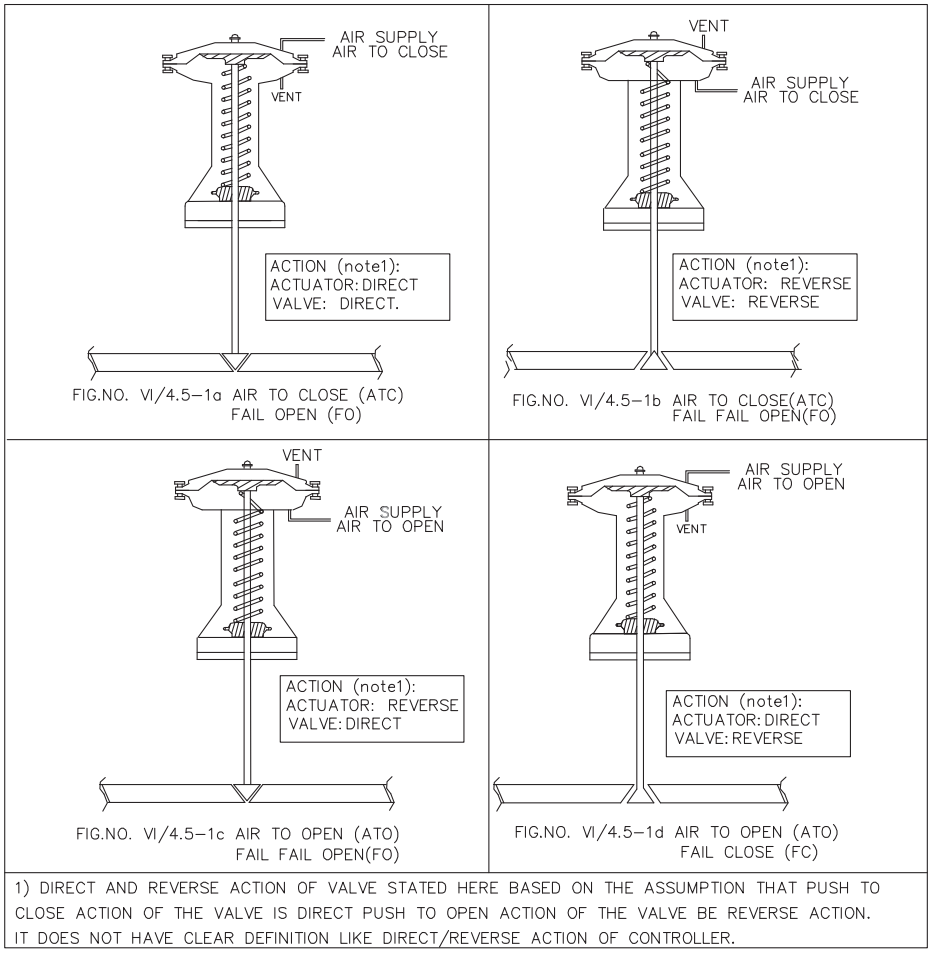


FIGURE VI/4.5-1 Fail safe condition for linear actuators.

close; ATC). This is FO, because when there is air supply failure the valve opens due to spring action and returns to the original position (Figure VI/4.5-1a).

4.5.2 Reverse Action: ATC: FO

Air pressure is applied from the bottom of the diaphragm, so on increasing pressure, the stem rises. This is referred to as reverse acting, and will compress the spring to close the valve (reverse acting valve), i.e., the air is required to close (ATC). This is FO because during air supply failure the valve opens due to spring action, and returns its original position (Figure VI/4.5-1b).

4.5.3 Reverse Action: ATO: FC

Air pressure is applied from the bottom of diaphragm, so on increasing pressure, the stem rises. This is referred to as reverse acting, and will compress the spring to open the valve (direct acting valve), i.e., air is required to open (ATO). This is FC because during air supply failure the valve closes due to spring action, and returns to its original position (Figure VI/4.5-1c).

4.5.4 Direct Action: ATO

Air pressure is applied from the top of the diaphragm, so on increasing pressure, the stem lowers. This is referred to as direct acting, and will compress the spring to open the valve (reverse-acting valve), i.e., the air is required to open (ATO). This is FC because during air supply failure the valve closes naturally due to spring action, and returns to its original position (Figure VI/4.5-1d).

4.5.5 Rotary Actuators

These actuators work similarly to FC/FO. In power plants many dampers are required to be done like the same; however, in most cases piston actuators and/or electrical actuators are used.

4.5.6 Fail Lock

In power plants many of the valves and dampers are required to attain FL condition (especially in a modulating application), i.e., the stay put condition. In case of air failure, to achieve FL condition it is necessary that the air pressure at the diaphragm

www.EngineeringBooksPDF.com

(or air pressure on each side of the double acting piston cylinder) is locked at the value where it was prior to air failure. This is done with the help of an air lock relay.

1. *Air lock relay*: It is a pressure sensing valve, as shown in Figure VI/4.5.6-1a. With the help of a pressure-adjusting screw the spring pressure can be set. As long as pressure on the diaphragm is above the desired pressure value, it can compress the spring to keep the valve open. As soon as the air pressure falls below the spring compression force, the spring will try to go back to its original position and the valve will close isolating input and output ports, i.e., isolating the valve or closing the valve port so that it maintains its position prior to air failure (air locked condition shown). Air lock relay has a minimum of three ports: input/output and supply port. There are a few other versions available that have solenoid valves (3/5 port versions from Rotex).
2. *Air lock (AL) connection and functions*: An air lock relay is placed between positioner (where in use) output and FCE input. Air supply to the positioner and air lock is supplied through a separate air filter regulator (AFR). However, the supply to these AFRs is from the nearest air header as shown (see Figure VI/4.5.6-1b–d). Upon air failure AL closes the path to the FCE so that it maintains position to achieve FL. If there is a double-acting piston cylinder then two ALs are used.
3. FL during electric signal failure is achieved by using a separate solenoid valve in series with the AL, as shown in Figure VI/4.5.6-1e and f. Electrical signal failure may be generated from the distributed control system (DCS; may be electric power failure or output port failure). Upon generation of an electrical signal failure the interlock solenoid valve is closed; air pressure in the actuators remains unchanged to ensure FL.
4. It is worth noting that it is not possible to keep this locked position for long unless accumulators are used. However, measures discussed above could be an immediate solution so that there is no bump in the system. Also, if the valve is at partial position, exact position retention is not predictable for certain, as there may be some deviation.

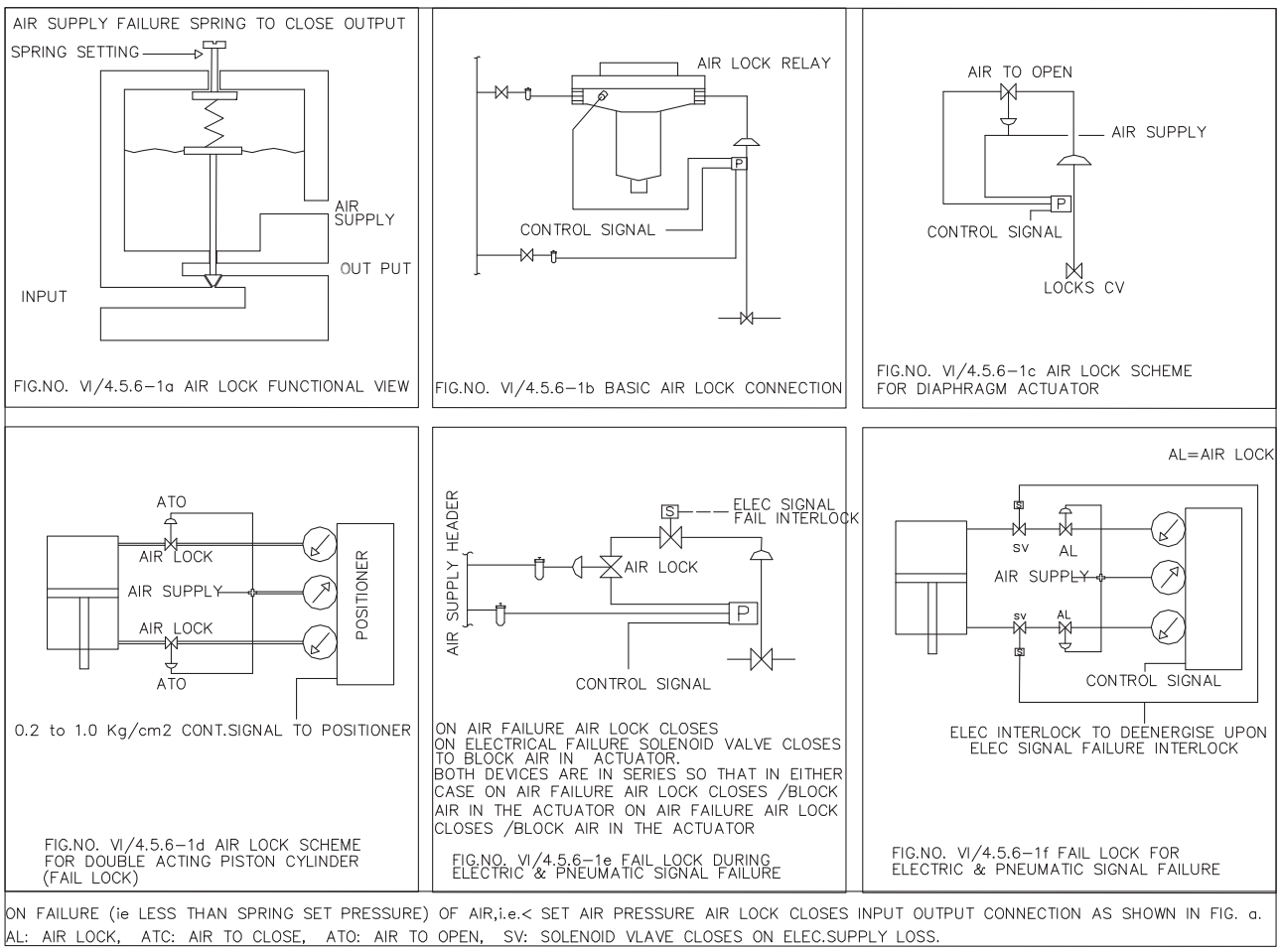


FIGURE VI/4.5.6-1 Air lock: miscellaneous fail lock condition.

www.EngineeringBooksPDF.com

4.6 Electro Hydraulic Actuator

Because they have a very fast response, high thrust, excellent throttling ability, and better stiffness, electro hydraulic actuators are extensively used in power plants. In spite of having these major advantages, there are a few limitations, such as high cost, it is heavier, its performance depends on temperature of operating oil, the system is rather complex, and tuning is not easy. These actuators are used in a turbine generator system application, HP bypass system, and in some cases for impeller control of fans. These have been discussed at length in connection with turbo generator controls in Chapter IX, Clause 2, so they are not repeated here.

4.7 Electrical Actuators

Electric actuators are a combination of a servo motor with worm gear to prevent reversal of drive direction by an unbalanced load. Generally, three-phase AC motors that deliver higher torque (ranging up to >80,000 NM) are deployed. However, single-phase AC or DC motors have also been used, but infrequently. These can be used for both linear and rotary drive. Electric actuators are compact in design and can deliver high torque. Slower speed (due to inertia) and limitations due to the duty cycle make it less popular in modulating applications, but with the latest technology the majority of these problems have been overcome. Based on functions and movement, mechanism actuators can be classified as follows:

- *Multi-turn actuator*: Used for gate valves and damper applications.
- *Part turn actuators*: Used for butterfly and ball valves and damper application. The torque delivery may be part revolution, e.g., 90°.
- *Linear actuators*: These are mainly used for globe valves; however, because of low cost and simplicity of the pneumatic actuator, they enjoy an edge over their electrical counterpart.

4.7.1 Some Essential Parts of Electrical Actuators

1. *Worm gear*: Is in the form of a screw to prevent damage due to unbalanced forces. The worm gear and worm wheel have axes at 90° to each other, so power transmission is at 90°, which is different from spur gear. In a single start worm, for a 360° turn of worm gear the wheel moves one turn. Worm gears are mainly used for large gear/speed reductions in the range of 20:1 and even up to 300:1. Worm gears possess a unique feature: when connected to the drive motor, they can easily turn the gear, but the gear finds it difficult to turn the worm. This happens because the angle on the worm is very shallow, and when the gear connected to the FCE tries to rotate it, the frictional force between the gear and the worm does not allow any worm movement. It is a self-locking system, and reverse movement is prevented.
2. *Limit switches*: When the dampers/valves reach the end position, the actuator needs to be stopped. For this purpose limit switches are used. This is limited seating and the actuator has to move with definite torque to ensure positive seating.
3. *Torque switch*: This prevents actuator overload due to over torque, as a consequence it may stop at any intermediate position whenever torque exceeds the set torque value. This helps positive seating of valve/damper and at the same time helps the actuator from being overloaded.
4. *Motor control center (MCC), Motor starter, and integral control*: The control action of the actuator needs to be controlled with the help of contactors/thyristor. There are a number of options available, and with the advent of Fieldbus technology, the choices are enhanced. A few of the control strategies are discussed below:
   a. *MCC control in combination with PLC/DCS*: The power circuit (with provision for MCC operation) is a part of the MCC. Normally the interlock and remote operation manual command and/or auto interlock are cooked at PLC/DCS. In MCC there are draw out/non-draw out type modules to accommodate electrical control for a number of motors (some may be an ordinary LT motor).There should be bus bars R,Y, and B, phases and neutral. In Figure VI/4.7.1-1a short specification for the bus bars are given. It should be noted that as this is a typical diagram, data mentioned, e.g., 415 V 50 Hz, etc., are only to indicate that for specification all details like voltage, frequency, number of phases, fault level, and bus bar material (e.g., Cu or Al) need to be mentioned to enable manufacturers to design the system. Voltage level also could be 380, & frequency may be 60 Hz etc. meaning that these parameters may vary from country to country.
   b. *Intelligent MCC*: Today there are MCCs that are intelligent (e.g., in the sum of ABB), so that these can be directly hooked up with the PLC/DCS for exchanging data, i.e., supervision control. These provide cost-effective protection and control for LT motors. It also helps that they save the cost of cable and the cost of discrete elements in the MCC. RS interface, status LEDs, and the availability of a local interface make them quite popular. In Offshore desins these are used extensively, in power plant also they are gaining popularity.
   c. *Built-in starter with the actuator*: A built-in starter module on the head of the actuator is used to accommodate contactors and external connections to PLC/DCS for manual/auto command, as discussed above.

www.EngineeringBooksPDF.com

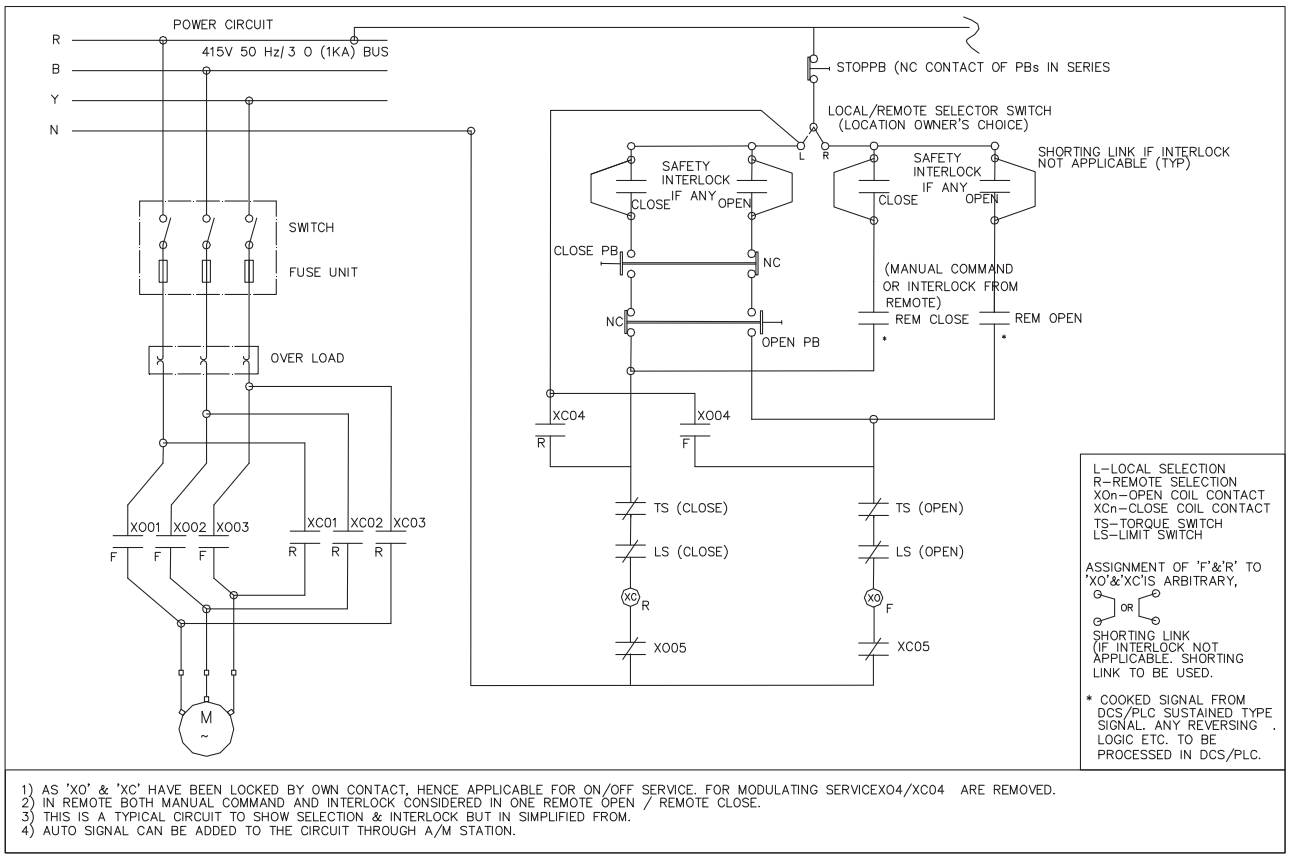


FIGURE VI/4.7.1-1 Electrical schematic for electrical actuator.

d. *Smart actuators*: These are either pneumatic or electric. Electrical actuators are available not only with a starter but with a necessary control circuit that communicates with the DCS or the rest of the system through a Fieldbus system. See Clause 4.8 for further details.

e. A short description of the system is presented below (also see Figure VI/4.7.1-1). In the circuit there is a typical three-phase AC servo motor, which will reverse its direction of the motion whenever any two phases are altered (Swapped). In this case the R and Y phase has been reversed with the help of X_o (F) and X_c (R). The assignment of forward (F) and reverse (R) is purely arbitrary, only intended to name two relays. Here there are two selections, local and remote, which indicate that the actuator can be operated from two places. In reality there may be many other selections, such as local, remote, MCC, unit "n"(a valve in common systems like the CW system may be operated from unit 1 or 2, for example). There may be a selection for test (to test the contactor operation) and normal operation, etc. There may be a series interlock (one assigned as a safety interlock) that cannot be bypassed even during local operation (e.g., fuel shut-off valve cannot be opened before some interlocks are satisfied, say, PR.OK). In a remote circuit this may be any safety interlock and/or sequential interlock in a series. Similarly the "REM Close" or "REM Open" could be a combination of manual command and/or auto interlock (whenever one FD stops its damper closes). As discussed above, the FCE will stop operating as soon as the end position is reached or torque is greater than the set value. In this circuit X_o (F) and X_c (R) have been locked with self-contact, so it is in ON/OFF service, as the FCE cannot be cut off at an intermediate point unless STOP PB has been operated. If such self-locking contact is removed then the circuit could be used in modulating (*inching*) service. In that case the STOP PB may be eliminated, because if there is an inching operation (without self-locking contact) the actuator will operate as long as opening/closing command is available (by the push button/or from the auto circuit). As a standard practice, a thermal switch has been put in series in the power circuit.

5. *Special considerations for electrical actuators in modulating services*: In power plants electrical actuators are quite common; in fact they are preferred for isolation

www.EngineeringBooksPDF.com

**** Super Capacitor : This is one of the latest device (in this millennium) often referred to as electrical Double Layer Capacitor. Unlike Normal capacitor it has electrolyte and electrodes like battery. Ordinary capacitors are specified in Micro, Nano, Pico Farads. Super capacitors are specified in Farad. It has energy density in the range of 1-10Wh/Kg. For high voltage connections these capacitors are used in series. It could to used in Actuator control to hold energy in case of main power failure. These can be recharged and discharged many times. Unlimited cycle time, Rapid charging and low impedance are the major advantages of the device..***

FIGURE VI/4.7.1-2 Super capacitor.

services, e.g., isolating dampers for fans or main steam stop valves, etc. In modulating services FCEs need to be operated all the time depending on the output of controllers. As a result of this there is the possibility of overheating the gear and the motor. Another problem associated with an electrical actuator is its inability to go to the desired position (full open/close) upon failure of motive power. This is because the spring size needed would be much higher considering the power delivered by the electric motor. However, it is inherently stay put, which is an advantage in many services. With advancement of technology, some of these problems have been overcome such as:

- Failure to go to desired positions. This is achieved by the super capacitor (see Figure VI/4.7.1-2), that can not only go to the end position but any desired position can be achieved.
- Use of accurate sensors and advanced technology. It is possible to circumvent the problems discussed above and an overall resolution, coupled with high speed of response, is possible, e.g., with power amplifiers it is possible to have much better response time by circumventing the inertia problem. Avoidance of dead time (in the pneumatic actuator some time is necessary to overcome the static friction, and in case of small changes in modulating loop this is significant) and small amount of overshoot is a great advantage of electric actuators over its pneumatic counterparts.
- Enclosures available in IP 67/68.
- Intelligent actuators are possibilities.
- Self-diagnostic features.
- Low-power device that could be used even in conjunction with solar power.

4.8 Intelligent Actuator

Intelligent actuators are actuators with built-in intelligence to work in tandem with other devices in a third-party network based on open systems like Fieldbus, Profibus, etc. The heart of such actuators is the micro controller, which allows improved positioning and communication with the external world.

Because it is intelligent, it can provide electronic positioning, and with the help of a PID controller it can operate on an external analog/digital set point. Salient features include:

1. System can provide field supervisory system, and can provide additional data for system optimization.
2. Self-diagnostic feature for critical applications.
3. Built-in PID control for external set point tracking and critical control.
4. Easy adaptable of control loop configuration.
5. Retrofitting where additional hardware otherwise would take more space.
6. Huge saving in cost of cable when connected in a two-wire system of connections.
7. In some configurations, a number of such actuators are connected to a valve control master station, which actually communicates with an external DCS deployed to control a number of valves, dampers, etc. (see Figure VI/4.8-1a). In this configuration complex control algorithms of the field units reside in a master station, which exchanges data and command with the DCS. Cable cost is significantly reduced but major control is in the field.
8. Intelligent actuators are also available that support open connect systems such as the Foundation Fieldbus as shown in Figure VI/4.8-1b. This connection methodology includes a terminator at the two ends. Also, systems can support Profibus, Device Net, MODBUS, etc., to connect the intelligent actuators to open systems.

5. ACCESSORIES

5.0 Introduction

Major accessories required for satisfactory operation of actuators is necessary. Table VI/5.0-1 outlines the functionalities of these items. Based on the function desired, a designer can choose the required ones for a particular application.

5.1 AFR

In a power plant there is one common instrument air pressure line throughout the plant. This pressure is

www.EngineeringBooksPDF.com

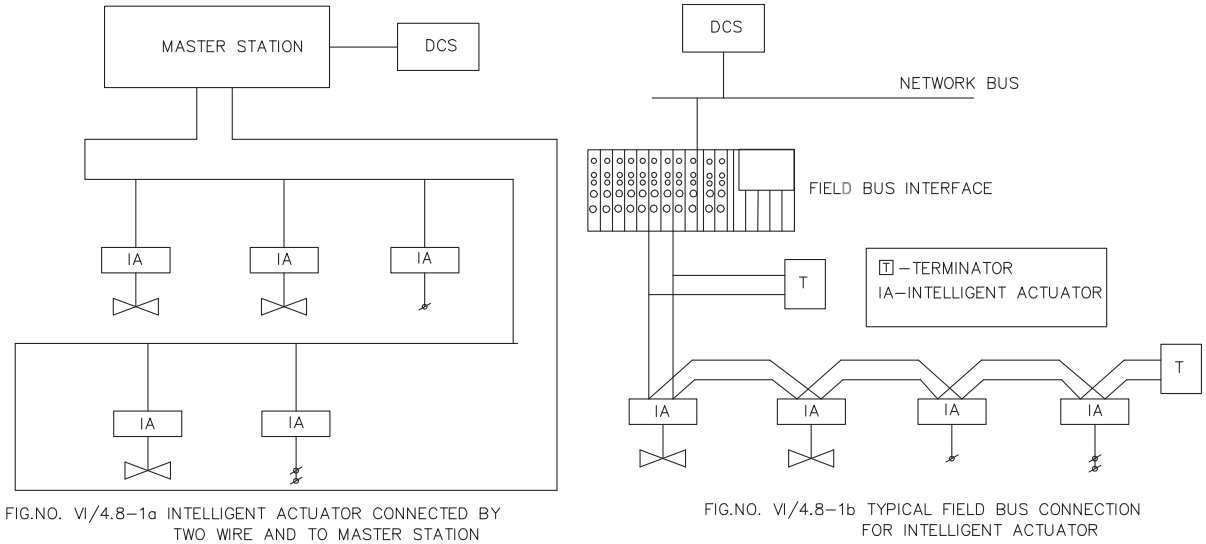


FIGURE VI/4.8-1 Intelligent actuator connections.

TABLE VI/5.0-1 Functions of Various Major Accessories for FCE

Accessories	Function	Remarks
Air filter regulator (Air set)	To supply air to the instrument, the FCE and its accessories are at the desired pressure. It filters out the air and helps to remove dust and moisture.	Often called Air set: selection of appropriate range for service is essential
Air lock relay	On air failure, it holds the last position of the FCE	FL operation.
E(I)/H or E(I)/P converter	Converter used with an FCE to convert standard electrical control signal to hydraulic/ pneumatic standard control signal	E/H converter discussed in connection with turbine (see Chapter IX).
Hand wheel	To provide local manual control, override control	Side/top mounted
Limit switches	To indicate the end and intermediate position, also used to stop FCE at the desired position.	Essential for ON/OFF services
Positioner	Primary function is to ensure that the FCE accurately reaches the desired position, which is demanded by the controller/control system.	It has a few other functions as well as the positioner
Position indicator	Local indication of FCE, generally mechanical (scale pointer type)	For local indication.
Position transmitter	Device used to transmit FCE position at remote place (e.g., voltage, 4-20 mADC & even pneumatiic signal say*)	(*) 0.2–1.0 kg/cm^2 also used.
Solenoid valve	When used as an accessory, it is used generally for ON/OFF operation. For interlock and/or to attend the FL position in case of electrical signal failure and modulating services.	
Torque switch	To stop electrical actuators of FCEs when allowable torque limit is just exceeded.	Safety for electrical actuators.
Volume booster	To amplify pneumatic signal in volume, pressure, and/or both. Mainly used when a number of pneumatic actuators are to be operated through one pneumatic signal.	

generally kept close to 7 kg/cm^{2}g, whereas the air supply requirements for control valves, power cylinders, and I/P converters vary (see Table VI/5.3.1-1). AFR is used to supply air to the pneumatic device at the required pressure. The other main function of AFR is to remove oil, moisture, and other contaminants from the air supply to save the costly pneumatic instruments/actuators. It also helps to remove pressure surges and protects the devices from low

www.EngineeringBooksPDF.com

TABLE VI/5.1.1-1 Air Set (DS)

Sl	Specifying point	Standard/available data	To be specified
1	Fluid	Compressed instrument quality air	—
2	Inlet pressure (bar)	15–20	—
3	Outlet pressure (bar)	0.4–2.1 or 0.7–4.2 or 2.8–8.8 adjustable	Square head screw/hand wheel
4	Temperature maximum °C	(–)40–100°C	—
5	Filter size	5 μm (in general)	—
6	Filter element	Sintered bronze/polypropylene	—
7	Body	Die cast aluminum	—
8	Seals	Neoprene	—
9	Mounting	Pipe line, panel, on actuator assembly with bracket.	—
10	Accessories	Over pressure vent/drain port	—
11	Connection size	6/15 mm	To be specified
12	Pressure gauge	Yes (in dual scale) as accessories	To be specified

temperatures or high dew points. Various parts of AFR are detailed in Figure VI/5.3-1a.

5.2 Air Lock Relay

In many applications an air lock relay is used to lock the actuator of the FCE at the last position where it was when air supply failure occurs (e.g., rupture in the line). With a double-acting cylinder there will be two such air lock relays, whereas in other applications, e.g., diaphragm actuator, one will suffice. A schematic of an air lock is depicted in Figure VI/4.5.6-1a with application details in Figure VI/4.5.6-1b–f. There is an air lock data sheet in Table VI/5.2.1-1.

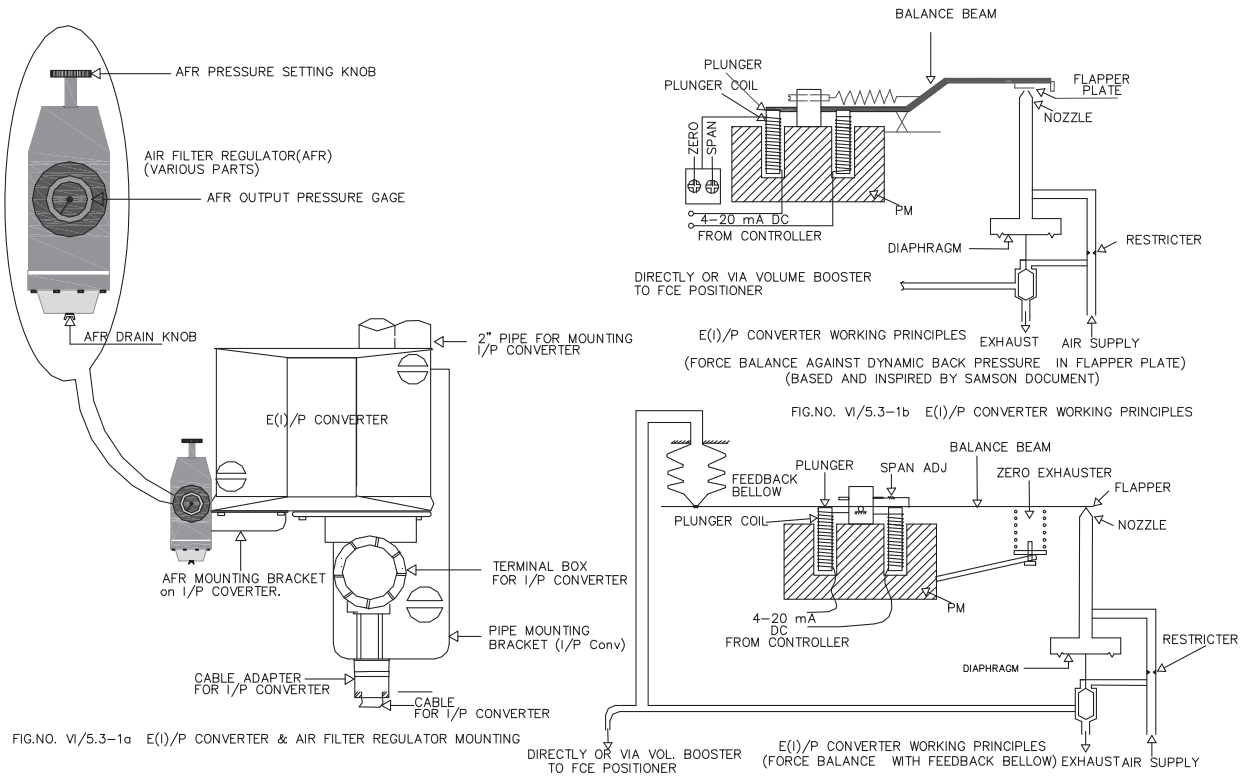


FIGURE VI/5.3-1 E(I)/P converter.

www.EngineeringBooksPDF.com

TABLE VI/5.2.1-1 Air Lock Relay (DS)

Sl	Specifying point	Standard/available data	To be specified
1	Fluid	Compressed instrument quality air	
2	Pressure (bar)	As the supply pressure: (for example) 7	
3	Temperature	(−)30 to 90°C	
4	Diaphragm	Reinforced rubber	
5	Trim	Brass with rubber sheet	
6	Body/ connection	Brass, aluminum/ 1/4′″ or 6 mm	
7	Switching point	Adjustable in 1.2−3.0 kg/cm^2	

5.3 E(I)/P Converter

The E(I)/P converter converts the electrical control signal into a pneumatic one. In an intelligent positioner, this forms part of the positioner. Of the various types of E(I)/P converters available commercially, the simplest and most popular is the one that works on the force balance principle. For mounting details and working principles, see Figure VI/5.3-1a and b. There is a plunger coil near a permanent magnet, with two poles on the opposite side of the fulcrum. When the system is in a balanced condition the balance beam is in equilibrium to produce a pneumatic output proportional to the current in to the device. When the current input to the plunger coil increases, the right side coil of the plunger is pulled toward the right side, so the flapper is pushed toward the nozzle. As a result, there will be increased back pressure and pressure in the diaphragm, which will try to close the exhaust, and the output air pressure of the E/P converter increases. This also causes increased feedback below to bring the balance beam to its equilibrium position, as soon as the forces are balanced. There is a zero adjusting bellow and span-adjusting spring. There could be other possibilities where plunger coil force is balanced by the dynamic back pressure as shown in Figure VI/5.3-1b (in the upper part of the drawing; based on a SAMSON document). There is an E(I)/P converter data sheet in Table VI/5.3.1-1.

5.4 Hand Wheel

This FCE accessory is used to operate the valve manually at site (field). The mounting of the hand wheel may be at the top and/or side. When mounted on the side there must be a suitable link and clutch arrangement for it to operate. Normally hand wheels have a neutral position, when the

TABLE VI/5.3.1-1 E(I)P Converter (DS)

Sl	Specifying point	Standard/available data	To be specified
1	Input	0/4 to 20mADC (for split operation 4−12 or 12−20mADC may be available (e.g., model no. TEIP of ABB)	To be specified
2	Output	0.2−1.0 kg/cm^2 or 3−15 psi, or 0.2−1.0 bar intermediate/higher ranges such as 6−30 psi, etc., are also possible (e.g., model no. TEIP of ABB)	To be specified
3	Ex proof approval	Possible if applicable to indicate the desired certification standard	To be specified
4	Characteristics	Linear−direct/reverse	
5	Air supply/capacity/ consumption	1.4−5.4 bar (supply pressure)/∼2.0−8 N m^3/h (capacity)/0.16 N m^3/h (consumption)	All figures mentioned here are typical only.
6	Enclosure class	IP 65/NEMA 4	To specify
7	Hysteresis/sensitivity	0.3%/0.1% of FSD	
8	Accuracy	<0.5% FSD	
9	Influence variables	Air supply/vibration/mounting position	Manufacturer standard
10	Connection	6 mm/1/4″ NPT etc.	
11	Materials of construction	Die cast aluminum/plastic manufacturer standard	
12	Accessories	Mounting bracket for 2″ pipe mounting/wall mounting	
13	Environmental	(−)20 to 80°C 97% humidity	
14	Special feature	Construction ruggedness, vibration effect lightweight, and dynamic response	Split range if desired (to be specified)

www.EngineeringBooksPDF.com

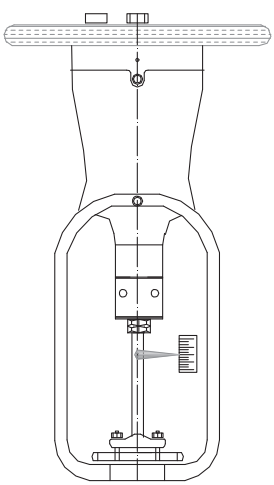


FIG.NO. VI/5.4–1a HAND WHEEL (TOP MOUNTED) WITH LOCAL POSITION INDICATION

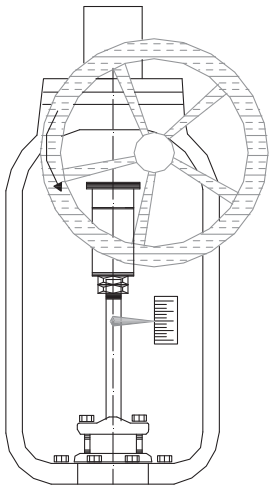


FIG.NO. VI/5.4–1b HAND WHEEL (SIDE MOUNTED) WITH LOCAL POSITION INDICATION

FIGURE VI/5.4-1 Hand wheel and local position indicator.

TABLE VI/5.4.1-1 Hand Wheel (DS)

Sl	Specifying Point	Standard/ available data	To be specified
1	Material	Ductile/cast iron	
2	Mounting	Yolk attached to the valve body	
3	Maximum travel	Valve specific	
4	Maximum thrust	Valve specific	

actuator can be operated remotely. Generally, clockwise rotation of the hand wheel closes the valve and ante clockwise rotation opens the valve (see Figure VI/5.4-1). See Table VI/5.4.1-1 for a hand wheel data sheet.

5.5 Limit Switches

As stated earlier, this FCE accessory is essential for electrical actuators to stop the motor at the end point. Also limit switches are necessary for FCEs in ON/OFF service to know the FCE position for all types of actuators. It is necessary to specify a few data for this particular application. In case of an intermediate position, this position is to be specified (in percentage; see Table VI/5.5.1-1).

5.6 Positioner

In its crudest form, a positioner is basically a proportional controller with integration action to nullify offset and to ensure that the FCE takes the desired position as per position demand from the control system. The positioner helps avoid error caused by packing friction or any other jamming. Split range operation is possible with the help of a positioner. A properly designed position will have optimum gain to achieve desired position without overshoot and improve control loop performance. There are two types of positioner: pneumatic and smart pneumatic.

5.6.1 Pneumatic Positioner

As shown in Figure VI/5.6-1, when input signal changes (increase), the position diaphragm will then be pushed downward through pilot valve. As a result, the supply line to the valve will connect to the air supply line with the exhaust line remaining isolated. This will cause more air pressure on the diaphragm to push the valve to close with the additional force. As the valve closes, a positioner feedback cam will be pushed up to compress the spring to balance the force due to the air pressure. This will continue until the position spring force balances input signal pressure multiplied by the sensing diaphragm area, so that both forces balance at the new assured position of the valve. During this time, the supply line of the valve is connected to the air supply line pushing more and more air in the system to increase the pressure on diaphragm actuator until the desired position (sensed by feedback cam) is reached. The operation is similar when the valve is to be opened; the only difference is the supply line to the valve is connected to the exhaust line and the main air supply line remains isolated. Thus the displacement of the actuator diaphragm is minimum, but valve position changes because of the change of spring compression force. The operation is similar to the positioner for a double-acting cylinder (see Figure VI/4.4-1). When the control pneumatic signal changes the diaphragm is pushed (or pulled up), the pilot valve is also pushed downward, and the air supply connects to the upper part (Figure VI/4.4-1b) of the cylinder (space

www.EngineeringBooksPDF.com

TABLE VI/5.5.1-1 Limit Switch (DS)

Sl	Specifying Point	Standard/available data	To be specified
1	Function	Accurate poisoning of actuator	
2	Enclosure class	IP 67/NEMA 4X etc.	To be specified
3	Ex proof approval	Classification as per NFPA/ATEX	If applicable
4	Contact type	Single pole double throw/COC, etc.	
5	Contact material and type	Silver-plated Cu/self-cleaning type	Snap acting.
6	Contact rating	AC 3A at 240V 1 Ph 50 Hz; DC 0..3A at 220V etc.	
7	Insulation resistance	>100 MΩ	
8	Actuator strength	4–5 times operating force <1 min	In a direction
9	Mechanical resistance	High shock and vibration resistance	
10	Life	>1 million operation	
11	Environmental	(–)20 to 50°C, 97% humidity	
12	Termination	Suitable for upto 2.5 mm^2 cable	
13	Speed of operation	Fast but not damaging the actuator	
14	Manufacturer	Reputed manufacturer as the actuator safety depends on it	

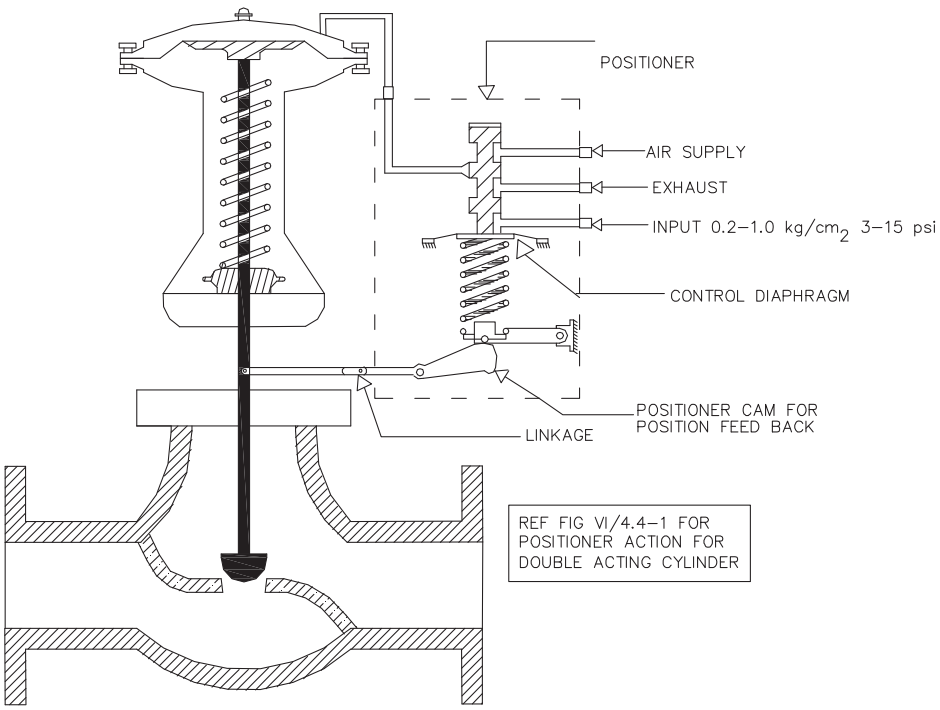


FIGURE VI/5.6-1 Valve positioner with diaphragm actuator.

above the piston), whereas in the space below (Figure VI/4.4-1a) the piston connects to exhaust, and as a result the piston of the power cylinder starts moving down. As it moves down the feedback spring is compressed through the cam. This compression of the spring will try to bring the diaphragm back in its original position by balancing the signal air pressure. Until the diaphragm returns to its original position, air will be pushed into the cylinder, i.e., at balanced condition air lines to the cylinder will blocked. Thus the accurate position is ensured by pushing more and

www.EngineeringBooksPDF.com

TABLE VI/5.6.1.1-1 Pneumatic Positioner (DS)

Sl	Specifying point	Standard/available data	To be specified
1	Input	0.2–1.0 bar/3–15 psi /0.2–1.0 kg/cm^2	
2	Air supply	Manufacturer's standard: >1.4 to <10 bar	
3	Split ranging	To specify range	If applicable
4	Accuracy/hysteresis	<1%/<0.5% FSD	
5	Action/characterization	Direct/reverse and cam characteristic	To be specified
6	Stroke length	15–100 mm standard	To be specified
7	Materials	Case: Die cast Al; Flapper Nozzle, Bellow and Cam: SS	To be specified
8	Gage	40 mm diameter, 3 gauges (Supp/Inst/OP)	
9	Environmental	(–)20–80°C, 97% humidity	

TABLE VI/5.6.1.2-1 Electro Pneumatic Smart Positioner (DS)

Sl	Specifying point	Standard/available/indicative data	To be specified
1	Input	4-20mADC*/digital inputs	*If no network
2	Air supply	0.5–7 bar(≤actuator pressure)	Manufacturer's standard
3	Air consumption/capacity/OP press	4–12 Nl/min (based on air pressure)/4.5–10 N m^3/h/ 0–6 bar (as per actuator)	Manufacturer's standard
4	Travel length/time/speed/limit	10–100 mm/0–100% travel time/0–200 sec in each side/0–100%	To be specified
5	Valve action/characterization	Direct or reverse/to specify FCE characteristics	
6	Communication/link	HART/Fieldbus/any link necessary	To be specified
7	Accuracy/hysteresis	<1%/<0.5% FSD	
8	Sampling/sensitivity	10–20 ms/0.3% (typical)	
9	Environmental	(–)20 to 80°C, 97% humidity	
10	Connections	Pneumatic 6 mm or 1/4" and electrical 1/2"	To be specified
11	Electrical classification	Agency approval certification	When applicable
12	Materials/enclosure	Case: Al ; Elastomer: Nitrile/IP 65	To be specified
13	Accessories	Mounting kit, pressure gauge block, local indicator, AFR, PC, and other adapter/feedback module, wireless adapter, etc.	To specify as applicable
14	Mounting	Direct on actuator	To be specified
15	Software and special feature	To specify if any special feature is desired	

more air one side of the cylinder (see Table VI/5.6.1.1-1 for a pneumatic positioner data sheet).

5.6.2 Smart/Electro Pneumatic Positioner

A few big advantages that make the smart positioner more and more popular are as follows (see Table VI/5.6.1.2-1 for a data sheet):

- Simple to use and very reliable.
- Microprocessor-based self-tuning, self-calibrating controller with PID configuration possible (helpful for valves in special application). Noncontact type position sensor is available.
- Smart positioners are a low-cost digital communication through a two-wire system that reduces large cable costs.

www.EngineeringBooksPDF.com

- The actuator can be protected by the positioner against burn out when jammed.
- Remote calibration and configuration to change critical parameter to improve performance (e.g., HART, field bus, etc.)
- In addition to collecting position data, many other types of data, such as pressure, differential, flow, etc., also can be collected
- Diagnostic features such as total stroke, max travel speed, etc.
- Very easy to integrate the systems, and FCE performance management is possible.
- With use of a wireless adapter (e.g., Smart Wireless THUM) integrating with a control system is possible at low cost.
- Any position locking is possible; valve characterization may be customized.
- Because it is self-tuning, it is easier for commissioning.

Figure VI/5.6-2 illustrates a basic block diagram of a smart positioner. The heart of the system is the motherboard comprising the CPU and EE PROM, which continuously runs the set control algorithm. Like any other microprocessor-based system, it consists of an I/O interface through which the controller input analog signal (if any 4-20mADC) and other digital I/O signals necessary for various controls and interlocks are fed into the system. Normally these positioners have a position sensing block to accept input from even noncontact type position sensors. As discussed earlier, the I/P converter is built in to the system. Output of the I/P controller is fed through a pneumatic relay to boost the signal when necessary. The position sensor continuously monitors the pneumatic output for proper operation of the positioner. Normally the smart positioner has a communication board to establish communication with external devices such as the HART communicator, PC programming, etc. or for online calibration/programming. There will be on board display drivers and an optional board for displays as well as various optional features. It receives two power supplies: an electric power supply (say 24VDC) and air supply. Not explicitly shown, these controllers inside the positioner have options for auto as well as local manual operations. Major Important parameters of the smart positioner include:

1. *Operating parameter*: These parameters need to be set and adjusted if necessary.

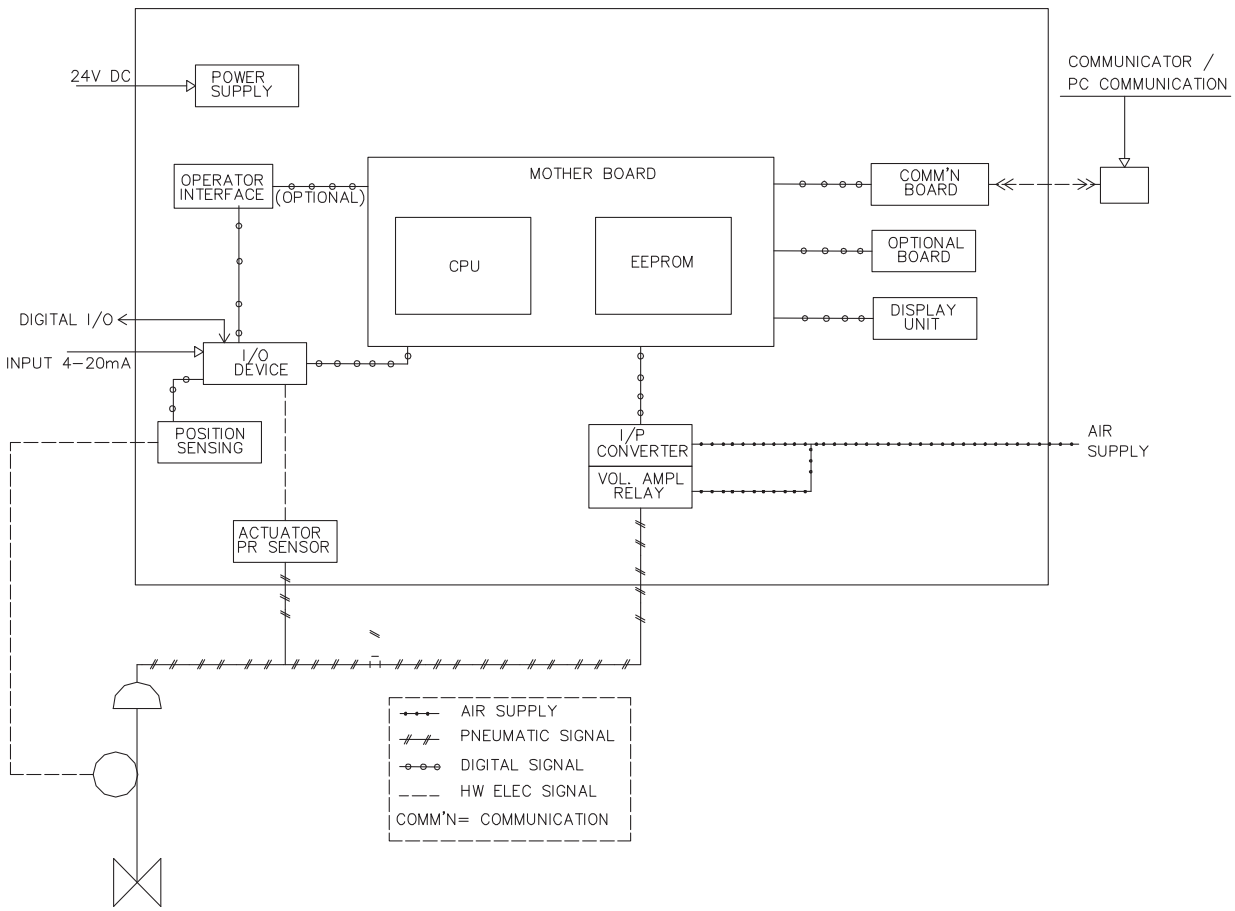


FIGURE VI/5.6-2 Smart positioner block diagram.

www.EngineeringBooksPDF.com

- *Signal range*: Input signal (if any option) and split range signals (say 4−12 or 12−20 mA).
- *Valve action*: Direct or reverse
- Flow characterization
- *Travel limit*: If other than 0−100%
- *Sensitivity limit*: If necessary to adjust other than factory setting within the specified limit of the manufacturer
- *Speed of operation*: Time to travel 0−100%
- *Digital input*: To hold at a FL condition, for example

2. *Adjusting parameters*: Valve range (0−100%) effective direction (air to close/open), display parameters, and their ranges. Various control parameters needed for controls.
3. *Monitoring parameters*: Performance monitoring parameter (to be set during start-up):
   - Alarm limit minimum/maximum position
   - Leakage detection in the system
   - Watch dog alarm
   - Signal out of range <4 or >20 mA
   - Position out, time out
4. *Other monitoring and diagnostic conditions*: Number of control actions performed, total stroke distance, maximum travel speed, stick slip, etc., to help the operator in assessing the service condition of the system. Also, it monitors performances of each electronic circuit and overall performance of the system in line with predefined program.
5. *Communication*: Each of these positioners has at least one communication port to set up remote operation and/or communication with other systems such as a PC (through serial link, e.g., RS 232/MODBUS). A number of these can be configured to form a network run by some special program (e.g., IBIS of ABB). For remote operation, an established system can be used, such as HART, Fieldbus, etc. New parameters can be set and may be put in to action immediately upon downloading the parameter values, etc.
6. Wherever called for, the devices should be intrinsically safe. Certifications are available also from standard manufacturer.

5.7 Position Indicator

On the valve (FCE) there are local mechanical and other types of local indicators to help commissioning and other personnel operating the valve (FCE) locally. In its basic form it could be a small pointer attached to the valve shaft that moves on a graduated scale (0−100%) to give a local indication (similar to those seen in Figure VI/5.4-1). For a rotary actuator/valve there may be a gear shaft-driven mechanical device to give valve position in a mechanical digital reading. This could be a small gauge type device also. There are local digital indicators available for electric actuators.

5.8 Position Transmitter

There are two basic types of position transmitters used in the industry: standard conventional and smart type. There are also two types of sensing transmitters: physical contact and noncontact. All of these types can be applied to both linear as well as rotary actuators.

5.8.1 Standard Electronic Position Transmitter

In this type a multi-turn potentiometer is mechanically connected to the device sensing the mechanical position. This resistance change is sensed in a bridge circuit excited by an AC supply. The change in resistance is sometimes converted to a 4-20mADC signal in the signal conditioning unit of the transmitter. Normally these instruments are provided with travel limit sensing to generate high and low alarms if travel exceeds the set positions (see Table VI/5.8.1-1 for a standard electronic position transmitter data sheet).

5.8.2 Smart Noncontact Position Transmitter

Noncontact position transmitters are used frequently with smart positioners. These are contact valve position transmitters with digital communication with, for example, a HART protocol. These are highly accurate (<0.5%) and can be used with both linear as well as rotary actuators. The valve position sensing is done with a simple magnetic pick-up avoiding mechanical contact arms, etc. These sensors could be proximity type, LVDT, or capacitive type. Even a Hall effect type (see Figure VI/5.8.2-1 for Hall effect details) can be deployed. However, a proximity type with a self-diagnostic feature, available with FM/intrinsic safe circuitry, is the most popular (see Table VI/5.8.2-1 for a smart noncontact type position transmitter data sheet).

5.9 Solenoid Valve

Functions of a solenoid valve as an accessory to an FCE include (see Figure VI/5.9-1):

- Interlock operation in a modulating control loop is shown in Figure VI/5.9-1a. Here when interlock I operates, the FCE (valve) goes to a preset opening. Normally when there is no interlock (logic0) the solenoid valve (SV) is de-energized, and FCE (valve) is fed with the signal from the I/P converter to open accordingly. On Interlock (Logical 1) the solenoid valve is energized, and the FCE (valve) is fed with the preset signal to open the FCE (valve) to the preset value. In this circuit an SV energization action can be reversed by interchanging the ports. The same action, however, also can be achieved electronically in the control loop. For this reason the reader is advised to compare Figure VI/5.9-1b.

www.EngineeringBooksPDF.com

TABLE VI/5.8.1-1 Standard Electronic Position Transmitter (DS)

Sl	Specifying point	Standard/ available/ indicative data	To be specified
1	Input	Single/dual multi-turn potentiometer	
2	Signal Output	4-20mADC with Hi and Lo Alarm	
3	Power supply	24VDC standard	Manufacturer's standard
4	Span	Depends on application, 9–110 mm travel	To be specified
5	Overall accuracy	±1% FSD	
6	Alarm contact and rating	2X COC/3Aat 240AC/0.3A at 220VDC	To be specified
7	Mounting	On actuator	
8	Materials/ enclosure	Case: Al; Steel Mounting bracket/ IP 65	To be specified
9	Environmental	(–)20 to 80°C, 97% humidity	
10	Connections	Electrical 1/2″ NPT	To be specified
11	Electrical classification	Agency approval certification	When applicable
12	Electromag-netic comp.	EN 61326-1	
13	Accessories	Mounting kit, local	To be specified
14	Special feature	To specify if any special feature is desired	

- For ON/OFF action, pneumatically this can be achieved by use of the solenoid valve as shown in Figure VI/5.9-1c for a double-acting cylinder (for diaphragm actuator or single-acting cylinder a three-way valve would suffice).
- As discussed in Clause 4.5.6, the solenoid valve can be used to achieve FL condition due to electrical signal failure.
- In electro hydraulic circuits in turbine control there are a number of applications of the solenoid valve to achieve various trip and interlock operations. In those circuits the port positions change depending on energization of coil, so that the desired port connects to a different position. That is why solenoid valves are specified as 3/2 or 4/2, etc., specifying the number of the port and the position.
- Solenoid valves may be single or double coil. In boiler BMS/FSSS circuits double coil solenoid valves find their application, so that in case of power failure the valve does not change position suddenly.
- SS solenoid valves are generally used as FCE accessories. However, the Cu solenoid valve is also popular for instrumentation (see Table VI/5.9-1).

5.10 Torque Switches

Torque switches are an important accessories for an FCE. They are essential for electrical actuators to stop the motor at end point when desired torque is reached (see Table VI/5.10.1-1 for a torque limit switch data sheet).

5.11 Volume Booster

As the name implies, the volume booster boosts the volume, hence, pressure in an enclosed space. The term booster relay can, in general, be used as volume boosting, pressure boosting, or both. The term booster relay is normally used when the input pressure is scaled up or down at the output as per requirement. The term volume (capacity) booster is more specifically used when the volume boosting of air with output and input pressure remain the same (that

**** Hall effect:** This is a semiconductor device. A transverse electric field perpendicular to both magnetic field as well as to the direction of current) will be generated in a semiconductor carrying an electric current , placed in a magnetic field perpendicular to the current.*
In Semiconductors holes and electrons are charge carriers, and collision of these charge carriers with impurities are in a straight path, in absence of magnetic field but in presence perpendicular magnetic filed the collision path deviates towards transverse direction due to Lorentz force.
Thus on account of Hall effect these charges move to one end in the transverse direction giving rise to electric potential across the device. Applying this effect many sensors have been developed some of them used in power plants are Position sensing, speed sensing(Turbine) etc.

FIGURE VI/5.8.2-1 Hall effect.

www.EngineeringBooksPDF.com

TABLE VI/5.8.2-1 Smart Noncontact Type Position Transmitter (DS)

Sl	Specifying point	Standard/available/indicative data	To be specified
1	Sensor type	Proximity/LVDT/Hall effect	
2	Signal output	4-20mADC with HART/Foundation Fieldbus communication	
3	Power supply	24 VDC standard	Manufacturer's standard
4	Span	Depends on application, 5–110 mm or more travel	To be specified
5	Accuracy/repeatability	< ±0.5%/0.4% FSD	
6	Electrical classification	Agency approval certification	As applicable
7	Mounting	On actuator	
8	Materials/enclosure	Case: Al /SS/Steel Mounting bracket/IP 65	To be specified
9	Environmental	(–)20 to 80°C, 97% humidity	
10	Connections	Electrical 1/2″ NPT	To be specified
11	Turn on/update time	100/25 ms	
12	Electromagnetic comp.	EN 61326-1	
13	Accessories	Mounting kit	To be specified
14	Special feature	To specify if any special feature is desired	

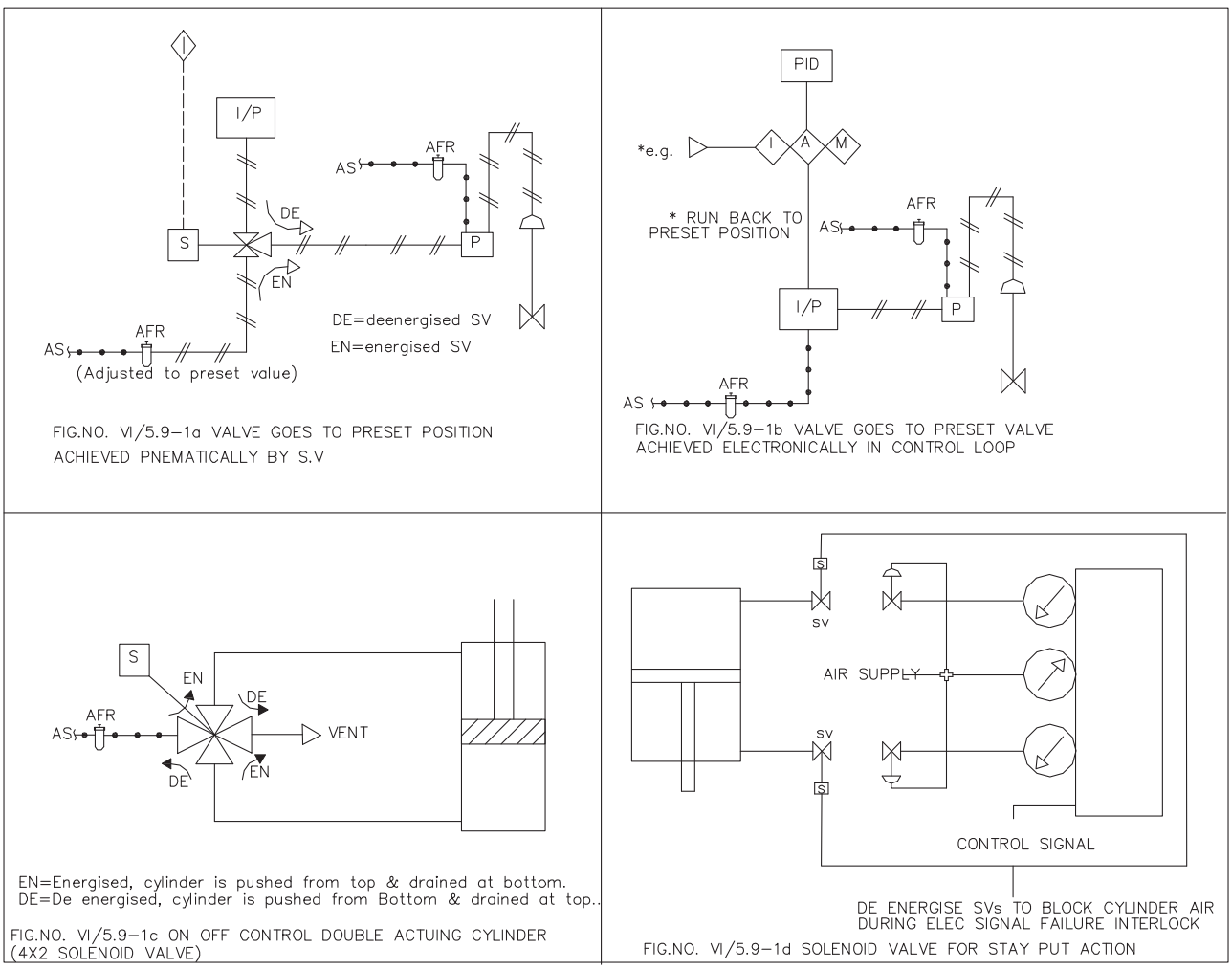


FIGURE VI/5.9-1 Use of solenoid valve as solenoid accessories.

www.EngineeringBooksPDF.com

TABLE VI/5.9-1 Solenoid Valve (FCE accessories) (DS)

Sl	Specifying Point	Standard/Available /Indicative Data	To be specified
1	Fluid	Air/hydraulic fluid	To be specified
2	Pressure rating	To specify (in case of pneumatic system >10 bar)	
3	Size	1/4″ or 6 mm generally for pneumatic application—to specify	
3	Differential pressure/flow/temperature	To specify(2−10 bar at 800l/m—typical value/30°C)	
4	No of coils	Single/double	
5	Coil voltage	Power supply available can be 240VAC/220VDC/24VDC	To be specified
6	Number of ports and Position	To specify depending on requirement, for example,3/2 etc.	To be specified
7	Material body/core tube, plug, etc.	SS preferred	To be specified
8	Connection type and size	1/4″ Air side/ Electrical : $^1/_2$ ″ NPT	To be specified
9	Insulation class	Class H (for high temp)/F	
10	Environmental	(−)20 to 80°C, 97% humidity	
11	Any other special feature	Electrical certification necessary	If applicable

TABLE VI/5.10.1-1 Torque Limit Switch (DS)

Sl	Specifying point	Standard/available data	To be specified
1	Function	To stop the drive at torque limit	
2	Area classification	Agency approval certification	If applicable
3	Contact type	Single pole double throw, etc.	
4	Contact material	Gold alloy plated/self-cleaning type	
5	Operating torque	To specify based on actuator	
6	Enclosure class	IP 67/NEMA 4X, etc.	To be specified
7	Contact rating	AC 3A at 240V 1Ph 50 Hz DC 0..3A at 220V	
8	Insulation resistance	>100 MΩ	
9	Life	>1 million operation	
10	Mechanical resistance	High shock and vibration resistance	
11	Environmental	(−)20 to 50°C, 97% humidity	
12	Termination	Suitable for 2.5mm^2 cable	
13	Speed of operation	(1−360°/sec—typical)	
14	Environmental	(−)20 to 80°C, 97% humidity	

is with a ratio of 1:1) within the permissible dead band. This is basically a regulator where the input actually supplies the loading force. This works on the force balance principle. Again, since force is equal to the pressure multiplied by the area by changing the ratio of area on the input and output side, the required output pressures can be varied as area ratio × input pressure. If input side pressure (1 bar) is to be balanced by output side force and if input

www.EngineeringBooksPDF.com

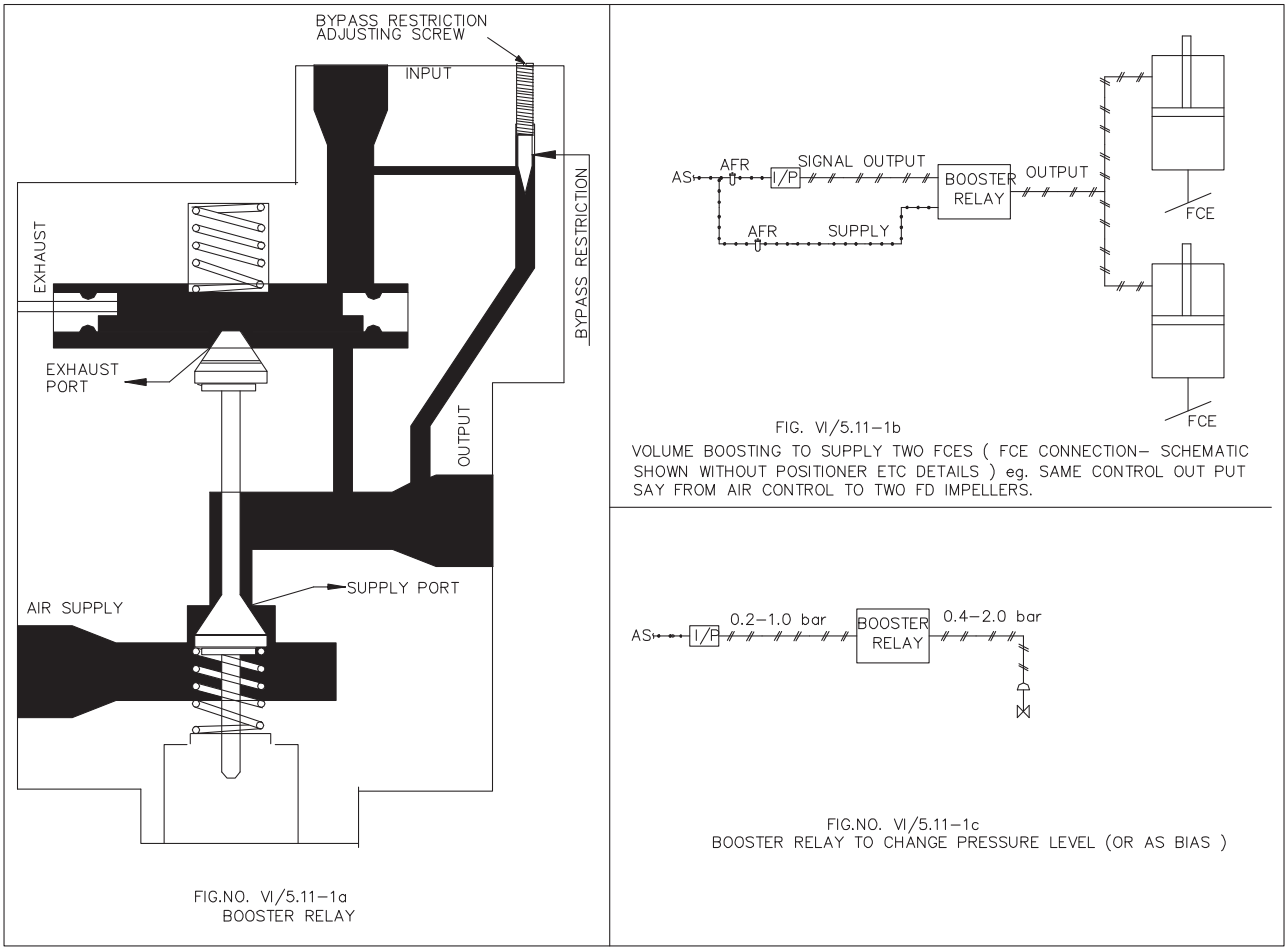


FIGURE VI/5.11-1 Volume booster and its application.

diaphragm area (6*A*) is six times than that of output area (*A*), then input force = 6*A* × 1 bar = 6*A* unit of force. This force can be balanced by 6 bar pressure at the output as the output side area is *A*. So by making the input side area less than the output side area the pressure ratio also can be reduced (see Figure VI/5.11-1).

Thus it is clear that the booster relay can be used to change the pressure level (Figure VI/5.11-1c) and/or for bias. Application of volume boosting is depicted in Figure VI/5.11-1b. Here the same control signal is distributed to multiple users with a 1:1 pressure ratio. For large actuators, volume boosters are used between positioners and actuators to improvise the speed of response or even used when a positioner is not. As shown in Figure VI/5.11-1a, at balanced condition both supply and exhaust ports as shown will be closed. Now when input pressure increases there will be downward pressure on the input side diaphragm to maintain a closed position of the exhaust path, and further force will push the valve downward allowing air supply to come in the output chamber. Since air supply pressure is more, there will be air flow increase in the output chamber, hence, flow to the actuator. This will continue until the output side pressure acting on the diaphragm balances the force in the input side diaphragm (= input diaphragm area X input side pressure). When balance is reached, force on both diaphragm's air supply line is closed. If the input pressure falls the valve will go up and air from the actuator will be exhausted and the actuator supply line will remain closed to bring down the output pressure. During this time, due to higher pressure in the outer diaphragm, it will bring the port assembly up, and output side air will escape through the exhaust port. From here it is clear that extra output side air volume is supplied by the relay. Also by varying the input/output diaphragm area the output pressure can be varied with respect to input (see Table VI/5.11.1-1 for a booster relay data sheet).

www.EngineeringBooksPDF.com

TABLE VI/5.11.1-1 Booster Relay (DS)

Sl	Specifying point	Standard/available data	To be specified
1	Function	To boost volume/vary pressure/to apply bias	
2	Input	0.2–1.4/0.2–3.5 bar (typical value)	If applicable
3	Supply pressure	2.1–4.0 bar (typical values)	
4	Gain ratio	To specify as per Requirement	To be specified
5	Consumption (typical)	200 L/min	Manufacturer's standard
6	Capacity output	~ 150 L/min	
7	Action	Proportional	
8	Connection	1/4″ NPT	
9	Supply pressure effect	<3% FSD per 1 bar change in supply pressure	
10	Environmental	(–)20 to 50°C, 97% humidity	

BIBLIOGRAPHY

[1] Application and Selection of Control Valves:B.G. Liptak, A. Balint:Book-Process Control and optimization Vol II (B.G.Liptak).

[2] Cavitation in Control Valves: Samson AG: Technical information.

[3] Control Valve Characteristics: www.maintenanceresources.com/referencelibrary: Cashco Catalog.

[4] Control Valve hand Book:Emerson Process Management:4th Edition (Fisher).

[5] Control Valve Selection and Sizing :K.L.M Technology Group:-Engineering Design Guidelines.

[6] Control Valve Technical Specification:G.Borden jr& P.G.Friedmann:ISA 1998.

[7] Control Valves For Power Plants :MIL Controls Limited:Application Handbook.

[8] Ease Control Valve Selection :T. Bishop, M.Chapeaux, L.Jaffer, K. Nair, S.Patel:CEP Magazine Nov 2002.

[9] Guidelines for Selecting th proper Valve characteristic:Valve magazine : Vol. 15 no 2.

[10] KCP&L Increases Plant Capacity by retrofitting New Control Valves1/30/2014D. Crawford, B.Tally, B. Beckmann, G.Knoch (KCP&L) & J.Wilson (fisher):Power Engineering Magazine.

[11] Key Design Component of Final Control Elements :ISA: Intech-March/April 2010.

[12] Leakage Classification of Control valves :The Engineering Tool box:www.engineeringtoolbox.com/control-valve-leakage.

[13] Noise Control Manual : Dresser flow control: Masoneilan.

[14] Seat Leakage Classifications:www.maintenanceresources.com/referencelibrary: Cashco.

[15] Standard Design Criteria/ Guideline for Main Plant Package (2X500 MW TPP):Central Electricity Authority New Delhi 2010.

[16] The Control Valve's Hidden Impact on the bottom Line :B.Fitzgerald & C.Liden: Valave Magazine (Fall 2003).

[17] Valve Sizing:Swagelok: Technical Bulletin.

[18] Valve Sizing and Selection Technical Refernce:WarrenControl.

[19] Valves Noise Calculations Prediction & reduction: H.D.Baumann, J.B.Arnet, B.G. Lipatak, F.M.Cain:Process Control and optimization Vol II (B.G.Liptak) CRS press/Taylor & Francis 2006.

[20] Ball Valve Options/Details:Autoclave Engineers: Catalog.

[21] Butterfly and rotary Process Valve:Tyco Flow control: Keystone Catalog.

[22] Condensed Catalog :Dresser Masoneilan.

[23] Cross - Reference of ASTM Material Specifications covering Cast and forged valves, fitttings, flanges and union:Rare Energy : Matrials Catalog.

[24] Diaphragm Valve:AquaMatic Catalog: Comercial Control valve Pentair water tretment.

[25] Dirty Service Anticavitation Trim:Fisher Emerson Process management:Product Bulletin October 2009.

[26] Drag valve (BFP Recirculation):Control component Inc.:Catalog.

[27] Drag Valve for boiler Feedwater Control Application:Control component Inc.:Catalog.

[28] GSI Series Weir Style Diaphragm Valves:Swaglok: Catalog.

[29] High Capacity Anti-Cavitation Solutions :The Dresser Masoneilan : Technical write up.

[30] Know your Valve:S. Brame (Emerson process management): Hydrocarbon Engineering July 2005.

[31] Packing Selection Guidelines For Fisher Sliding Stem Valves:Fisher Emerson Process management: Product Bulletin.

[32] Power Plant Applications:C. Sterud:Control Componenet Inc. Document.

[33] Replacement of BFP Recirculation control valve solves a maintenance problem in Baldwin Unit 3:M.E.Liefer (illinois Power) H.L. Miller and R.E.Katz (CCI):Control Componenet Inc. Document.

[34] Sunder's Diaphragm Valve:C.E.Gayler, B.G.Liptak :Process Control and optimization Vol II (B.G.Liptak) CRS press/Taylor & Francis 2006.

[35] The Ever Popular Gate Valve:G.Johnson: Internet Write up.

[36] Types of valves and UsageTLV.Co.Ltd:Dorot Control Valve:Internet write up.

[37] Valve Types : Butterfly Valve:C.E.Gayler, B.G.Liptak & J.B.Arant:Process Control and optimization Vol II (B.G.Liptak) CRS press/Taylor & Francis 2006.

[38] Valve Types :Globe Valve:H.D.Baumann, J.B.Arnet, B.G. Lipatak, F.M.Cain:Process Control and optimization Vol II (B.G.Liptak) CRS press/Taylor & Francis 2006.

[39] CombustionFossil Power Systems:Combustion Engineering Inc.:Steam generator Auxiliaries.

www.EngineeringBooksPDF.com

[40] Consider variable pitch fans:R.C.Monroe:Hudson Product Corporation USA.
[41] Energy efficient design of Auxiliaries in Fossil Fuel Power plants:ABB Limited:Technical Paper.
[42] Fluidomat:www.fluidomat.com:Technical Paper.
[43] Hydro- kinetic Drives...Hyadraulic coupling:N.A.D'arcy:Internet document.
[44] Hydrodynamic Couplings Principles | Features | Benefits:Voith Turbo I Hydrodynamic Couplings 5:Technical Catalog.
[45] Impellers with Airfoiled blades :TLTTurbo.
[46] Increasing efficiency of the conventional auxiliary systems of power plants (Reduction of Life Cycle Cost by operational excellence):T. Schmager, P. Mannistö, P.Wikström ABB Switzerland Ltd: Technical paper.
[47] Inlet Outlet Dampers for Centrifugal fans: GreenHeck:Catalog.
[48] Installation and Maintenance manual for Scoop Coupling:Elecon Engineering Co. Ltd India: Technical Manual.
[49] Variable fill fluid Coupling:Transfluid transmissioni industriali:Technical Catalog.
[50] Variable Speed Control :Hivectol HVI: Internet Paper.
[51] Variable speed drive theiry:L.M. Photonics Limited.
[52] Variable-Pitch Axial Flow Fans for Thermal Power Stations:L. Müller, Zweibrücken:www.troxtechnik.com/.
[53] Vortex Damper (Variable inlet vane damper):Process barron USA: Technical Write up.
[54] A precision electric actuator is unaffected by valve stiction and can track closed loop controller demand almost perfectly without dead time lag,or overshoot.:K.C.Meyer, S. Kempf:Intech December 2006.
[55] Actuator and Control Valve Selection:Prof. D.R.Yang: Korea University.
[56] Actuator Sizing Manual :Flow Serve :Worcester Controls.
[57] Control Valve Fail Safe Position:www.maintenanceresources.com/referencelibrary:Cashco Catalog.
[58] Electrical Actuator:Rotork Process Controls.
[59] Electrical Actuator for industrial process Controls:BECK: Technical Bulletin.
[60] Pneumatic & Electric Actuator:Elomatic (emerson Process management):Product Guide (DS).
[61] Pneumatic Actuators & Positioners / Mobile Type Air Cylinders:Rexroth Bosch Group: Catalog:Limitorque Actuation Systems.
[62] Valve Actuators and Control Systems:Limitorque Actuation Systems: Technical Catalog.
[63] Valve Automation:ABB Automation Inc. USA: Technical Bulletin.
[64] Air Filter Regulator:Worcester:Product Specification.
[65] Air Lock Relay:Rotex: Catalog.
[66] Air Lock:Yamatek Corporation: Product specification.
[67] Air Supply Filter Regulator:ABB Limited: Technical Catalog.
[68] Analog Position transmitter: Siemens AG: Catalog.
[69] Digital Position Transmitter:Westlock Controls:Tyco.
[70] Digital Positioners and I/P Signal Converters:ABB Instrumentation: Technical Bulletin.
[71] Electropneumatic Converters for Direct Current Signals:Samson AG: Product Specification.
[72] Electro-Pneumatic Positioner TZIDC: ABB Limited:Tecnhical Catalog.
[73] Field type I/P Converter:Yamatek Corporation:Product Specification.
[74] Field view Digital Valve controller:Fisher Emerson Process Management:Product Bulletin (Feb'10).
[75] Flame proof Limit Switches:Yamatek Corporation:Specification.
[76] Handwheel Actuator:Fisher :Catalog.
[77] I/P Converter :Pneucon Valve pvt Ltd:Product Specification.
[78] I/P Converter TEIP11ABB Instrumentation:Catalog.
[79] Low Torque basic Switches: Omron: Catalog.
[80] Mechanica Position Indicators:Mission Inductries Inc.: Product Specification.
[81] Pneumatic Positioner: HNL Engineering Limited:Catalog.
[82] Position Transmitter:Fisher Emerson Process Management:Product Bulletin (Apr'09).
[83] Relays and Volume Boosters:Marsh Bellofarm:Product Catalog.
[84] Smart Position Transmitter:SMAR.
[85] Smart Valve Positioner:Yamatek Corporation:Product Specifiction.
[86] Smart Valve Positioner:Yamatek Corporation:Catalog.
[87] Smart Valve Positioner:Fisher (Emeson Process Management): Product Bulletin (Oct'09).
[88] Solenoid valve :Asco: Catalog.
[89] Valve Position Indicator: Proximity:Specification.
[90] Valve Position Monitoring and Smart Discrete Controls:J.Difranco:Valve Magazine 2007.
[91] Valve Position trnsmitter:Cal Val Canada: Product specification.
[92] Valve Positioner:www.maintenanceresources.com/referencelibrary:Cashco Catalog.
[93] VBL Volume Booster: Fisher: Product Bulletin (Jan'13).
[94] Volume Booster :: Fisher: Product Bulletin (Oct'12).
[95] Volume Booster Relay: Robertshaw: Product Bulletin.

www.EngineeringBooksPDF.com

Chapter VII

Intelligent Control System

1. BASICS (DISCUSSION ON INTELLIGENT NETWORK SYSTEM)

1.0 Preamble

Intelligent systems are normally encountered in power plants to control the process. What is a system? A system is a part of the universe within a certain domain in space and time. What is an environment? Outside the frontier of the system is the environment. What is an intelligent system? Conceptually an intelligent system learns how to act in a given environment to reach its objective. An intelligent system has a temporary object that it has derived from the main objective. It has a few senses to gather knowledge about the given environment to reach to objectives. The system then stores these sense impressions as elementary concepts. Working on these concepts it develops a new one and stores the relationship and enriches the "concept." To continue with the internal information it checks the inputs for an update and builds up the present situation. Also, it looks to its memory to find the set of rules and chooses the best suited (rule-based) one for the application and performs the action. A smart transmitter keeps in its memory the family of the characterization curve at various ambient temperatures. So a smart transmitter can sense the environmental changes and can correct itself with the stored curve to offer better accuracy of measurement. An expert operator can establish a relation among various parameters, so if one parameter is upset, based on knowledge, the operator directly adjusts the actuator and/or adjusts other parameters to control the system precisely. Similarly, in an expert system a few parameters and their relationships are stored based on a set of rules. The expert system regulates the system to achieve precision control.

Only essential basics of various systems can be covered in a discrete manner to limit the volume of the book. Because of this, the reader can develop an idea about the basics of the systems and can become familiar with various terms used so that subsequent discussions could be meaningful.

1.1 Signals and Signal Processing

In control systems there are a few types of signals that first need to be conditioned before they can be processed. The majority of these signals can be classified as in the Table VII/1.1-1.

TABLE VII/1.1-1 I/O Signal Types

Signal types	Signal class	Remarks
Analog	Hi level	4-20 mADC
	Lo level	T/C, RTD, mV, etc.
Digital/ binary	Potential free	Contact rating important
	Wet signal	Such as TTL, voltage O/P for relay
Pulse		Variations in frequencies, widths, etc.

For analog inputs, A/D conversion, and analog output D/A conversion is essential. Successive approximation types of A/D converters are more popular. However, because of prohibitive costs, an individual A/D or D/A is not feasible, so these are sent to/from the system with the help of a time division multiplexer (TDM). A time-shared multiplexer scans the signals (either random or) sequentially to the control system. Major design consideration for multiplexers should include but not be limited to the following: sampling rate, accuracy, size, and number of channels (recommended restricted to 16), noise, cross talk, single-ended (nondifferential signals, one end is common ground so one end may be terminated) or differential and/or with screen, signal level, polarity and so forth. A solid-state FET multiplexer can scan a channel in 5 μS. Binary inputs are generally status inputs, whereas binary output gives the ON/OFF control of the external device. Normally such binary signals are potential free contacts (or, e.g., TTL etc., as in Table VII/1.1-1). Digital inputs in a group are treated as a word of variable length. The correspondences between bit position and field status functions in digital signal are maintained by software (bit processing). This is one of the reasons why it is easier to interface digital signals with third-party devices. The pulse signal may have to be shaped, before further processing. Pulse inputs are normally fed to the counter before they are sent for Distributed (digital) Control System DCS/Programmable Logic Control (PLC) to process them. As detailed in Table VII/1.1-1, all signals are not the same so it is necessary to condition the

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

signals to make them compatible with the signals acceptable to the PLC/DCS. For analog signals, impedance matching, signal conversions for low-level signals, etc., are necessary. Similarly, for digital signals the voltage level may have to be matched (especially when interrogation voltage is different, see Clause 2.0.1, number 1). Noise consideration is a big issue. Common mode and normal mode noise considerations are made for system design as well as cable selection and cabling. With these basics in mind, a few design considerations, especially for power plants, are discussed below.

1.1.1 General Considerations

Depending on plant size, there are variations in the configuration of the control system. Some plants may want the PLC system automated, while some may use a DCS or a mix of this and automation in an integrated system. Also, at field instrument level some plants may want hardware connections for the sensor/transmitter and actuator (even with a smart device), while others may opt for devices with a HART or Fieldbus system. Naturally the considerations would be quite different, so, we start our discussions on general considerations for I/O signal conditioning are discussed.

1. *Spare capacity*: While considering the I/O capacity it is recommended to consider an ~10% fully wired module of each variant, terminated up to the final termination point up to a marshalling rack (if applicable) to support the expansion ability of the system. In addition to this, sometimes spare space with wiring for an additional module insertion is recommended. These are recommended more often when **Field bus** etc. systems are *not* considered. For Fieldbus systems addition and deletion of input/output may not pose much problem.
2. *Signal processing*: Depending on the application, basic signal processing may include the following:
   - Optical/galvanic isolation as applicable
   - Transmitter power supply with fuse and other protections
   - Interrogation voltage (if different, suitable isolation)
   - Various computations
   - Square root and flow computation (e.g., pressure/temperature computation)
   - Linearization of various signals (e.g., thermocouple, T/C)
   - Reference junction compensation
   - Include and delete any input for scanning based on operator action.
   - Redundancy selection (ref: Chapter III)
   - Short circuit/open circuit/noncoincidence (COC) fault detection
   - Diode auctioneering for output redundancy
   - Filtering for noise reduction/attenuation
   - Filtering of digital signals (delay: 10−15 ms) to prevent spurious action
   - I/O data validation and reasonability check
   - Online ADC gain drift check
   - Self-surveillance and diagnostic (channel and module level).
3. *Remote cabinet location*: If a Fieldbus is considered this is fine, otherwise cabling also can be reduced by utilizing remote I/O cabinets or a remote terminal unit (RTU) and connecting it to the system through various links/buses. For power plants there are few places where there is a cluster of measuring points, such as metal temperature measurements at the boiler platform. Some recommended places for such remote I/O locations *could be* as listed below
   - Boiler platforms
   - Boiler outside area (outside−fan area)
   - Mill area
   - Boiler feed pump (BFP) area
   - Turbine area
   - Steam water analyzer system (SWAS) room
   - Switchgear room
   - Transformer area
4. *Acquisition timing*: The time at which these data are acquired, validated, and processed depends on the system chosen, so it is not specified here. However, in the system the all signals should be updated at 250 ms or better. Digital and SOE inputs the update times, which should be ~30−50 ms and 1 ms, respectively, depending on the systems and use.

1.1.2 Critical Measurement

For critical measurements modules may have facility to use fault tolerant mode (discussed later). Common such Faults may arise from: Power supply (main and stand by) fault, Sensor/Transmitter module failure etc.

1.1.3 Signal Grouping Philosophy

In some systems, design philosophy calls for a division of whole systems into group, subgroup, subloop, and drive control devices (e.g., ATRS from Siemens/KWU). In such systems connection of the I/Os are connected to the respective part, e.g., limit switch contacts and/or contacts from the MCC are connected to the drive module, whereas any input required for various subgroup drives are connected to the subgroup level. This is to avoid unnecessary traffic in the subsystems. However, it all depends on the plant control philosophy and on the design of the selected control system. Also there are variations in control system philosophy from manufacturers regarding mixing input and output in one module for analog as well as digital signals. Some manufacturers prefer combing inputs and outputs to make a loop self-contained, whereas others believe in

www.EngineeringBooksPDF.com

segregating input from output and combining redundant signals in two different modules. This grouping is not restricted to the I/O level alone, but may be at the controller level also. A controller may take care of both modulating as well as sequential control for drives, for example, FD fans in the Procontrol P 13 system. Whereas there are systems where Modulating controls are kept separate from interlock operations.

1.1.4 I/O Intelligence

Barring a few small manufacturers, most of the major suppliers support intelligent I/O systems. Also they use Fieldbus in place of hardwired I/O.

1.1.5 Common Mode and Normal Noise Rejection

Usually modules are designed to withstand a common voltage of 500 V peak to peak/DC for short periods. Typical, common mode rejection ratio (CMRR) is ~100 dB at 50 Hz (or 60 Hz) with source imbalance, and normal mode rejection ratio (NMRR) is 60 dB at 50–60 Hz (see Figure VII/1.1.5-1).

1.2 Network Basics

A number of computers connected together form a network. When this network is owned privately for a particular purpose it forms a Local Area Network (LAN). Similarly, a number of real-time systems (controllers) in plants form LANs, e.g., two or three PLCs may form a LAN. In a similar manner, even in a system, for example, a DCS with a number of control processors, workstations may form a LAN. Such a network in a building or number of buildings may have some distance limitation such as 1–2 km. If a completely integrated system in a power plant is considered, then it can stretch over kilometers of a LAN. When a LAN is developed through wireless means, it is known as a wireless LAN (WLAN). When this length limit goes beyond ~100 km, it will form a Wide Area Network (WAN).

Over the entire globe various networks are connected via the Internet. Thus in a plant starting with a small control system it can grow to a completely integrated LAN, which again may be connected with a larger system over the Internet. LANs often are implemented by TCP (Transmission Control Protocol) as an IP (Internet Protocol) subnet (discussed later in clause 1.2.2). Why these discussions now? In a plant there are different control systems [for steam generators (SGs)/turbo generators (TGs)/offsites] from various manufacturers. Each of these manufacturers naturally would not like to divulge his control strategies to other; however, it is necessary that these systems communicate with each other for data exchange and/or with a central monitoring and control system. Because of this, protocols need to be established so that these different systems can form an integrated control system, otherwise an operator's life will be miserable.

What is a protocol? In connection with networking, a protocol can be conceived as an agreed upon formally defined unambiguous convention for communication. In other words, it is set of rules, system hardware and software must follow to be recognized and understood by other system(s) in the network. Fundamental details on networking and protocol are presented below. A standard textbook on networking may be consulted for further reading.

1.2.1 ISO–OSI Reference Protocol Model

The International Organization for Standardization (ISO) developed a reference model Open System Interconnection (OSI), which is not any particular network architecture, but it defines general seven layers for a protocol. These seven layers include: application, presentation, session, transport, network, data link, physical (for remembering, a good mnemonic is: *all people seem to need data processing*). The arrangement and data flow using this model is depicted in Figure VII/1.2.1-1 and the basic purpose of each layer is given in Table VII/1.2.1-1. Out of the seven layers, the physical, data link and network layers are often referred to as the *media layer* as they are more concerned with medium, address, and path. Whereas other layers, like transport, session, presentation, and application, are more connected with the hosts so they are often called *host layers*.

1. *Physical layer(1)*: It is responsible for transmitting raw bit over communication channels, and to make sure the if a node sends "one" receiving node it gets "one" and not "zero". The electrical, mechanical, and

CMRR: It is a measure of the capability of a device to reject a signal that is common to both input leads; it is measured in decibels, the effectiveness to reject a common mode voltage. It is a ratio of A_v/A_{vcm} when expressed in dB. Here A_v and A_{vcm} stand for differential and for common mode gain.

NMRR: It describes the ability of the instrument to reject a normal (differential) signal between the input leads. It is also expressed in dB.

FIGURE VII/1.1.5-1 Common and normal mode rejection ratio.

www.EngineeringBooksPDF.com

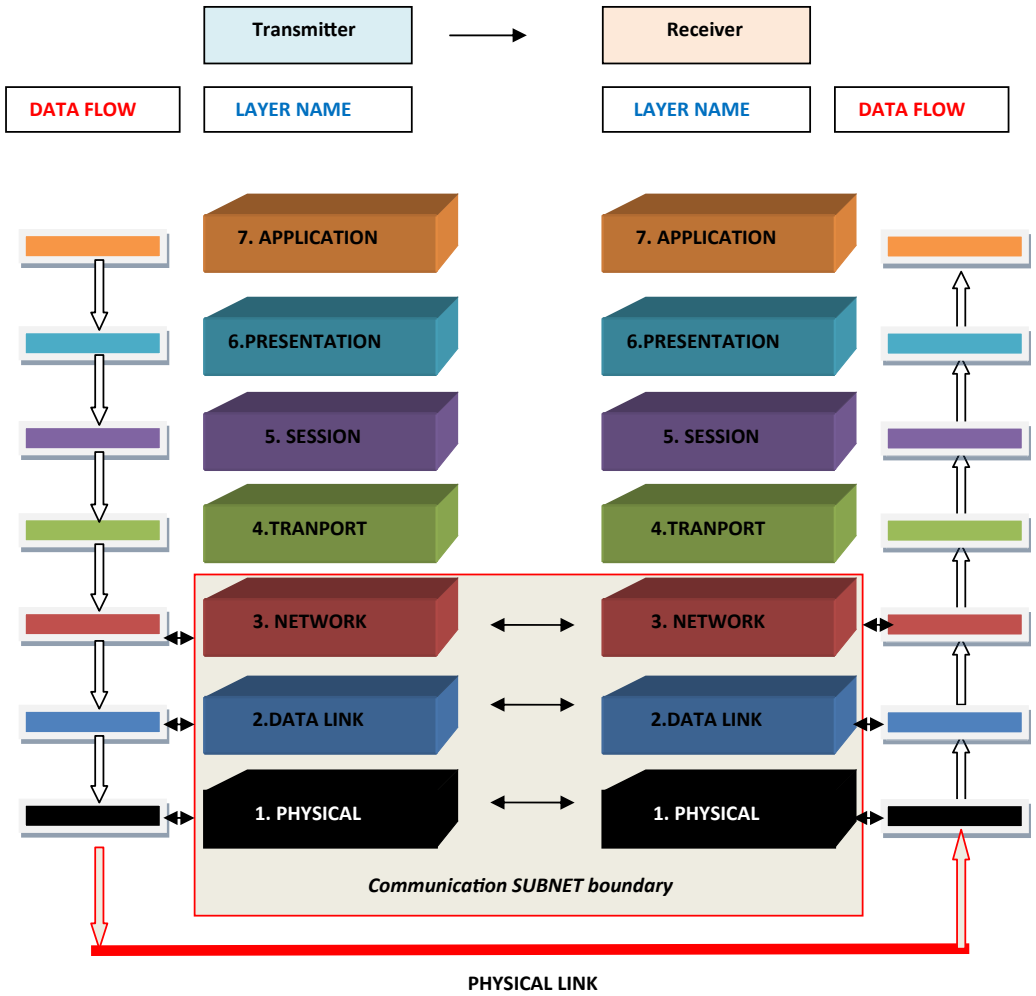


FIGURE VII/1.2.1-1 ISO–OSI model.

TABLE VII/1.2.1-1 Layer Functions

Layer number	Layer name	Main function
1	Physical	Signal level and connection, media type (e.g., FO/wire)
2	Data link	Source/destination, data transmission, and checksum
3	Network	Determination of data path in network
4	Transport	Error checking
5	Session	Opening/closing of communication path for specific purpose
6	Presentation	Building block of data and encryption
7	Application	Data meaning— purpose

physical medium below it is its main concern. It defines cable type, connector type, and so forth. This layer is concerned with signal, binary transmission, and media—issues including physical interface, bit rate, distance etc.

2. *Data link layer(2):* This layer develops a data frame from the raw data to convert raw data in a line without any transmission error to the network layer. Transmission speed is a great concern here. For communication between slow receivers with fast transmitters, this layer ensures the buffering space in the receiver. It has two sublayers: media access control (MAC) and logical link control (LLC). It is responsible for physical addressing and actual communication in a network. Here the issues include: framing, addressing, header trailer bits etc. (e.g., Ethernet).
3. *Network layer(3)*: It is concerned mainly with *path/route finding* and *determination of logical addressing* for data transfer. It regulates the subnet and looks for

www.EngineeringBooksPDF.com

the path and how packet data can reach from source to destination. In a complex network with too many nodes, finding an easy, sure route is a major task. Too many data packet transfers without a suitable route results in a traffic jam, causing delay, and in the meantime more and more data continues to come. So, the network layer has to find an alternative route. Issues include: packet header, virtual path (e.g., IP).

4. *Transportation layer(4):* It is a layer for *fragmentation* and *reassembly.* It receives data from layer 3 and splits it into many data packets (to facilitate network layer action) and makes sure that these are correctly received at the other end. At the receiving end this layer needs to reassemble the data packets. It uses message headers and control messages to make sure that the end user gets the message in the order it was sent. It also decides the type of service to be provided to the session layer. It shields the upper layers from changes in hardware technologies. It ensures end-to-end connection. Issues include: headers, error detection, reliable communication, etc. (e.g., TCP/UDP—User datagram protocol).
5. *Session layer(5)*: Any discussions without a specific agenda may turn out to be unending. Similarly in a session layer, *process-to-process* communication takes place between the nodes in a network. Here dialog control (tracking who is to speak and who is to listen) is token management, which is to prevent two sets of parties from doing the same operation at the same time. Synchronization of check points, etc., takes place in this layer, for example, an inter host communication in NetBIOS (a protocol for functions like browsing and communication between servers).
6. *Presentation layer(6)*: When communication between the two nodes takes place there should be some defined syntax and semantics of information exchange. This layer looks after the this communication. The processors communicating may have different data representation, so someone has to define the it. It is the responsibility of this layer to carry this out. Issues include: conversions, encryption, and compression, e.g., Simple Mail Transfer Protocol (SMTP) in e-mail.
7. *Application layer (7)*: E-mail and File transfer Protocol—FTP are examples of an application layer, i.e., this layer that offers service to the user (user interface layer). Issues include: type of service.

1.2.2 TCP/IP Reference Model

TCP/IP is another reference model for radio and satellite network systems. It is a set of protocols used to communicate over the Internet. Because of its flexibility and wide functionality, it is in a control network as well.

TCP: In the suite of protocols TCP/IP, TCP is a reliable connection-oriented delivery service where data are transmitted in segments.

IP: Is a connectionless, unreliable datagram mainly responsible for routing and addressing packets between the hosts/nodes. Here connectionless means that no session is established; it is used by shared devices. Since delivery is not guaranteed it is unreliable. A TCP/IP

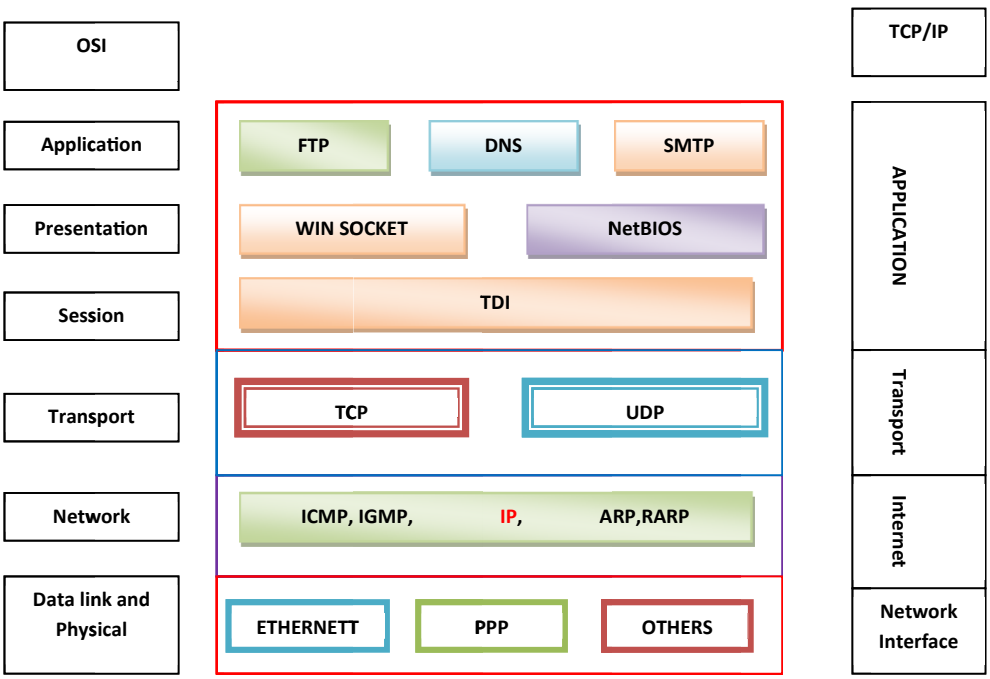


FIGURE VII/1.2.2-1 TCP/IP reference model.

www.EngineeringBooksPDF.com

reference model consists of a few layers as shown in Figure VII/1.2.2-1 (two models compared side by side). There are four basic layers. When compared with OSI, it is clear that some OSI models have been clubbed together. Also here the Internet layer is sometimes referred to as the transport layer.

1. *Network interface*: This layer sometimes referred to as link layer , Physical layer etc. Basically when compared with OSI model comprise both Physical and data link layer. This layer is transparent to the user. Basic responsibilities shall include:
   - Error checking of incoming data packets
   - Tagging outgoing data packets for error checking
   - Computer network interface
   - Acknowledgement of data, and resend in case of non-acknowledged data bit

   Several support protocols and networks should include but are not limited to the following:
   - *Ethernet*: A network based on IEEE 802.3 (discussed later)
   - *CSLIP*: Compressed SLIP
   - *PPP*: Point-to- Point Protocol is a serial line data encapsulation that is better than SLIP.
   - *SLIP*: Serial Line Internet Protocol used to send data across a serial line. It places data packets in a data frame to transport across the network.
2. *Internet layer*: Above the network interface, it is the Internet layer created for the packet-switching network layer (equivalent to the network layer of the OSI mode). IP address and address resolution take place within the Internet layer. It consists of the following protocols.
   - *Internet Protocol (IP)*: A connectionless, unreliable data gram protocol. IP provides mechanism software to address and manage data packets sent to computers. There are several headers associated with the IP, such as source IP address, destination IP address, identification (inform destination host whether to be passed on to the transport layer protocol TCP/UDP), and protocol check sum (to check integrity of data).
   - *Address Resolution Protocol (ARP)*: Used to convert a logical address to a physical address. It is used to find a specific address (hardware) from a specific IP number.
   - *RARP*: Reverse ARP is used to resolve IP address without having its own storage media.
   - *Internet Control Message Protocol (ICMP)*: This protocol is used to report connection status back to the computer and to retry the connection. It is also used for error reporting.
   - *Internet Group Management Protocol (IGMP)*: Used by multicasting the router for tracking group memberships.
3. *Transport layer*: Next to the network layer is the transport layer used for network connectivity. It is intended that data sent are received by right node/machine as well as for right application. Error checking, flow control, verification of integrity, completeness, etc., are functions of this layer. It has two protocols: TCP and UDP.
   - *Transmission Control Protocol (TCP)*: A reliable connection-oriented delivery service where data are transmitted in segments. It is used for transport by some applications. Reliability is achieved by assigning a sequence number to each segment sent. Several sequence numbers of TCP headers are source port, destination port, sequence number (sequence number of first byte of data), TCP check sum, etc. It is worth noting that there are separate port number for several applications, such as TCP port numbers 20 and 21 are assigned for File Transfer Protocol (FTP) for data and control, respectively. Numbers 80 and 139 are for HTTP and NetBIOS, respectively. A TCP connection is done by three-way (client TCP segment server send back TCP segment with initial segment sequence number. and client sends back acknowledgment) handshaking.
   - User Datagram Protocol (UDP): Connectionless, unreliable protocol UDP is told by the application layer to which machine it is supposed to transmit. It is a fast but *not* guaranteed transfer. Three headers of UDP are included: source port, destination port, and UDP check sum. The port functions as a multiplexed message and tells where the message is to be sent, e.g., UDP port numbers 53 and 137, used for Domain Name System (DNS) and for NetBIOS, respectively.
4. *Application layer*: Contains network applications and services that users interface to use networks (Internet). Application layers also have utilities like printers. Some of these protocols are FTP, HTTP, and SMTP.

1.2.3 Miscellaneous Network Devices

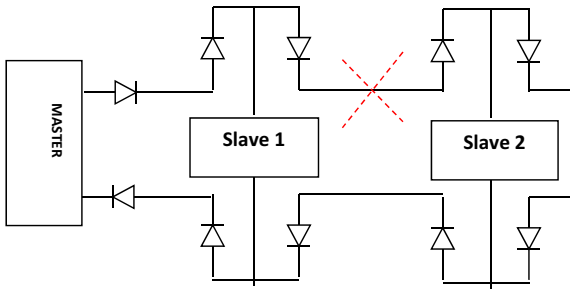
Major network-connecting devices are

- *Repeater (physical layer)*: Extends hardwired connection and copies bit from one network to another.
- *Bridge (data link layer)*: Copies data frame from one network to another ((looking at header).
- *Router (network level)*: Copies packet from one network to another and makes decisions about the route.
- *Gateways (network and above layers)*: As a simple router, it uses data conversion, encapsulation, translation, and encryption.

1.2.4 Common Link Connections

These are also used in Fieldbus (e.g. PROFIBUS uses RS 485) and MODBUS protocol may be used with RS 232. Since Recommended Standard (RS) is not truly maintained by manufacturers, these were defined by the Electronic

www.EngineeringBooksPDF.com



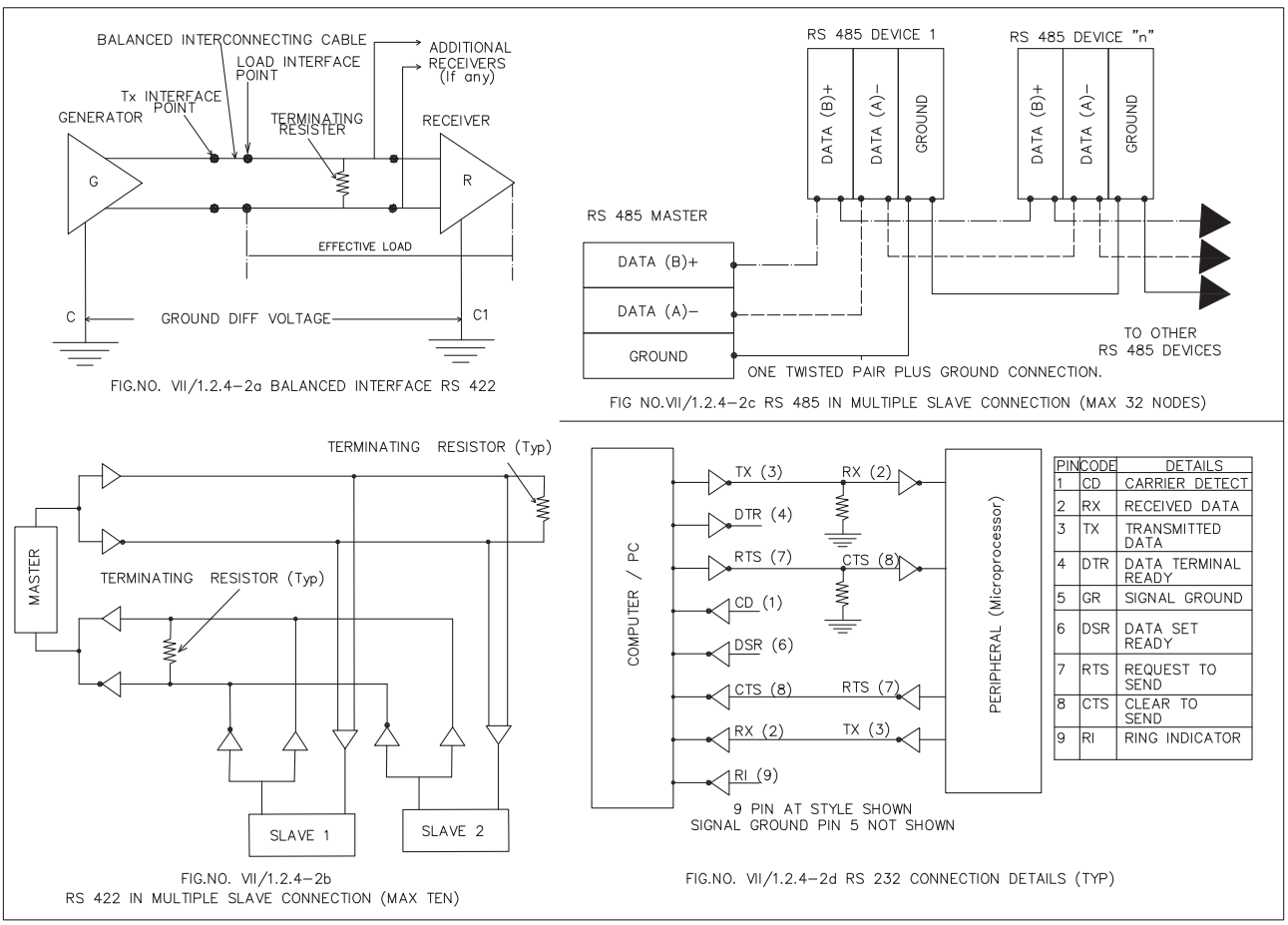
Typical RS232 connection details shown in Figure VII/1.2.4-2d

FIGURE VII/1.2.4-1 Daisy chain connection for multiple slave connection.

Industries Alliance (EIA). For further details, pin connection/allotment, etc., standards may be consulted.

1. *RS (EIA) 232*: RS 232 has been defined as an electrical interface for serial transmission of data. This is used to send data over a short distance for point-to-point communication. Normally a communication rate <20 Kbps is used; however, today's faster drivers are also accommodated (e.g., MAX3225E). However, it is possible to connect multiple slaves to a master ("N" numbers of SLCs to a control system) in a daisy chain connection as shown in Figure VII/1.2.4-1. There is one disadvantage to this system: if there is a break (as shown by a dotted break line) in the chain in daisy connection, then all downstream devices will be disconnected. Typical connection of RS 232 has been shown in Figure VII/1.2.4-2d Standard defines a few characteristics:
   - Electrical characteristics include: voltage Level, signaling rate, timing, slew rate, voltage withstand capability short circuit behavior, and maximum load.
   - Pluggable connector and pin definition and function of each circuit in connector
   - Interface circuit for telecom application

   The standard does not define external power supply, character encoding (i.e., ASCII), protocol, framing character, and error-checking method. Some of the standard data should include but are not limited to the following:
   - *Binary 0*: +5 to 15 VDC (Tx) and +3 to 13 VDC (Rx)
   - *Binary 1*: (−)5 to 15 V (Tx)and (−)3 to 13 VDC (Rx)



PIN	CODE	DETAILS
1	CD	CARRIER DETECT
2	RX	RECEIVED DATA
3	TX	TRANSMITTED DATA
4	DTR	DATA TERMINAL READY
5	GR	SIGNAL GROUND
6	DSR	DATA SET READY
7	RTS	REQUEST TO SEND
8	CTS	CLEAR TO SEND
9	RI	RING INDICATOR

FIGURE VII/1.2.4-2 Link connection details RS 232/422/485.

www.EngineeringBooksPDF.com

- Slew rate is 4−30 V/μS
- *Approximate load/output resistance*: 3−7 kΩ/300 Ω
- *Start bit binary 0*: Stop bit binary 1
- Data 5−8 bit
- Parity even, odd, mark, or space
- *Leading and trailing idle bit*: Binary ones

Since there is no guideline for cable selection, the decision needs to be made on the basis of what is to be connected and the PIN connection (in RS 232 9/25 D plug connectors are used) and gender of the plug. In some cases a 4 pin are is in use. IBM PC AT connection is 9 pin.

2. *RS 422*: A balanced voltage interface with better data rate and distance, when compared with RS 232 Although defined mainly for communication between DTE and DCE, it finds its use in point-to-point interconnection of digital equipment. It defines the characteristic requirement of balanced line drivers and receiver, but not signal name operation. In its simplest form it can be used as an extension of RS 232 for conversion of RS 232 to RS 422 and back. A typical baud rate of 100K is achievable over a 1.2 km distance (normal maximum cable length), but baud rate falls in logarithmic scale with increase of distance (maximum 10 Mbps is possible for 12 m typical for 24 AWG twisted pair cable). Interconnecting length is decided based on the data rate necessary. Combination of generator and receiver potential difference with ground is common mode voltage and it should be <7 V. A 37 pin in D SUB plug connector are commonly used. A typical RS 422 connection is shown in Figure VII/1.2.4-2a. A single master can accommodate up to 10 slaves via RS 422 interface as shown in Figure VII/1.2.4-2b.
   - *Open circuit O/P voltage*: ±10 VDC(Max)
   - *CMV at R_L 100 Ω*: ±3V
   - *Loaded O/P voltage*: +2 VDC (Min)(R_L 100 Ω)
   - *Differential receiver voltage*: ±10V(±12V capability)
   - *Max out current*: 150 mA
   - *Receiver input resistance*: 4 kΩ
3. *RS (EIA) 485*: Because there is transmission over a twisted pair (*half duplex*) cabling, RS 485 is less costly and less sensitive to noise, at the same time it allows a bidirectional, asynchronous serial transmitter over a distance of 1.2 km at a baud rate of 100 Kbps (in 10 m maximum and 35 Mbps is possible). Unlike RS 422, it can accommodate multiple node (up to 32) linear topologies in peer-to-peer communication as depicted *in* Figure VII/1.2.4-2c (where connection with a twisted pair cable and ground wire is seen). There is one variant of RS 485 in a four-wire connection in Master Slave mode and for duplex communication (like RS 422). Like RS 422, it also uses differential balanced line (three wires, even though transmission is over two wires and the third wire is reference voltage). However, ground is important to avoid data loss. Cables are terminated with a resistor to minimize noise effect. It has 9 pins in a D SUB plug connecter (consult standard for pin details). RS 485 is widely used in many protocols for electrical interface, e.g., MODBUS, PROFIBUS. Some of the specification data are as follows:
   - *Open circuit O/P voltage*: 1.5−6 VDC(±)
   - *Short circuit out current*: ±250 mA per output
   - *Receiver sensitivity*: (−)7 < V < 12: ±200 mV
   - *Receiver input resistance*: >12 kΩ
   - *Common mode voltage*: ±3V
   - *Loaded O/P voltage*: 1.5−6 VDC (±) at RL 100 Ω

   RS485 handles some software like Addressing, *Turn Around Delay* etc. Latter one is important in two wire system as during this time other transmission may take place.

1.2.5 Network Transmission Technologies

There are two major and popular modes: broadcast and point to point:

Broadcast mode: A short message called a packet is sent by a machine (node) over the communication channel shared by and listened to by all other machines (nodes) in the network. The packet contains an address. Intended machine/node(s) check the address field and process it, while others ignore the message. With the use of specific code, the transmitting machine (node) can send the message to all destinations at a time and each machine (node) checks to process the call. Multicasting is different from broadcasting because it has a subnet of machines (nodes) that can be addressed. Any machine (node) in the network can become a member of the subnet to receive the group message, something like a group SMS or e-mail. Broadcast may be bus type or ring type, as shown in Figure VII/1.2.5-1a and b, with each box representing a node. On a round robin basis each channel may be allocated a time slot on the basis of time interval division. This type of allocation is static and uncalled for time is wasted. In a centralized dynamic allocation system there is a central node that decides the time allocation to different nodes.

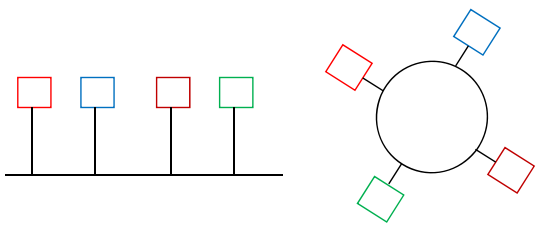


Fig no. VII/1.2.5-1a: BUS system Fig no. VII/1.2.5-1b Ring system

FIGURE VII/1.2.5-1 Bus systems.

www.EngineeringBooksPDF.com

In a decentralized dynamic system a machine decides when it wishes to communicate. To avoid any chaos, various standards have been developed to handle the this, e.g., collision detection.

Point-to-point mode: In this mode, at any instant, there will be transmission between a pair of machines (nodes). Naturally a packet in this network may have to travel intermediate nodes, so a routing algorithm plays a vital role.

As a general convention it has been found that broadcast mode is used for networks with limited geographical spreading, whereas larger networks use point-to-point mode. IEEE has set forth a few standards based on these network:

Ethernet (CSMA/CD) IEEE 802.3 Standard	Token bus (IEEE802.4)	Wireless LAN (IEEE802.11)
	Token ring (IEEE 802.5)	Wireless MAN (IEEE 802.16)

1.2.5.1 Ethernet (IEEE 802.3)

Ethernet refers to standard IEEE 802.3. One interesting feature in Ethernet is that it does not utilize straight binary encoding (i.e., 5 V for 1 and 0 V for 0). Manchester (or differential Manchester) coding (refer to any standard book) is used. This makes the bandwidth double. There are two modes of operation in Ethernet: (1) half duplex (bidirectional communication but not both at the same time) and (2) full duplex (bidirectional communication may take place at the same time). Ethernet consists of basically three parts:

- Physical layer is the physical medium to carry on the communication among various computers (nodes)—is discussed below.
- MAC rule is a part of the data link layer embedded in the Ethernet allowing multiple machines to access the network. Data link control of ISO is divided into two IEEE sublayers as shown in FIGURE VII/1.2.5-2 below.

2	DATA LINK	LLC (or LLC + SNAP)
		MAC

FIGURE VII/1.2.5-2 Data link layer and sublayer.

- Where LLC stands for Logical Link Control and SNAP stands for Sub Network Attachment Point is mainly found in the Apple Macintosh network. MAC has the following functions:
  - Data encapsulation (including frame assembly) before transmission, frame parsing (analyzing), error detection after transmission.
  - *MAC*: Initiation of frame recovery after failure of transmission.
  - MAC—client sub layer, which is mainly related to LLC may be as follows:
    - LLC (IEEE 802.2) is an interface between Ethernet MAC of upper layer.
    - Bridge entity (LAN-to-LAN connections: Ethernet-to- Ethernet or Ethernet-to-token ring)

    Ethernet frame: Protocol structure for Ethernet
  - IEEE 802.3 (10/100 Mbps): for MAC data frame—LLC Format see Figure VII/1.2.5-3). Ethernet Frame (Data packet) is seen in Figure VII/1.2.5-4 and contains the following:
    1. *Preamble*: 7 byte (8 byte for Digital Intel Xerox version—DIX Ethernet) is an alternate pattern of 0 and 1 7 bytes (Octets.) used to tell receiving stations a frame is coming and provides a way to synchronize the frame reception portion of receiving a physical layer. It has a 10 MHz square wave (5.6 μS).
    2. *Start of frame delimiter (SFD)*: It is 1 byte and also an alternate pattern of 0 and 1 with two consecutive 1s to indicate the neat bit is the leftmost bit of the leftmost byte.
    3. *Destination address (DA)*: This is 6 bytes long and the DA identifies the receiving station. Here first higher bit indicates 0 for ordinary address and 1 for group addressing in multicast mode for multiple machine addressing ,i.e. to be received by all the stations in the group. If all the bits are 1s it is broadcast mode that all stations to receive. Bit number 46 (adjacent to higher order bit—6 byte meaning $6 \times 8 = 48$ bit $- 2 = 46$) distinguishes between local address and global address. If it is 0 it is a local address decided by the LAN administrator and no body outside the LAN is interested in it. If 46 bit is 1 it stands for a global address assigned by IEEE to have a unique address for each of the stations (in the order of 7×10^{13})
    4. *Source address (SA)*: It is 6 bytes long and SA identifies the sending station and is similar to DA.
    5. *Length type*: It is 2 bytes and indicates MAC data bytes in a data field or frame type ID. When transmission speed increases then frame size must increase or cable length is decreased. Maximum length of the frame is mainly limited by the RAM size of the receiving end. There is also a limit in the minimum length of frame (size fixed at 64 byte from destination station to checksum including both). Why is there a minimum byte length? It is clear from the Figure VII/1.2.5-5 bit collision.

www.EngineeringBooksPDF.com

Discussion on LLC (IEEE 802.2)

LLC and SNAP are found in the IEEE 802.2 standard.

IEEE 802.2 is identical to all networks. It provides the interface between different protocols (TCP/IP, etc.) and network types (such as Ethernet, Token ring, etc.). LLC provides the following functions to the upper network layer:

- ★ ***TYPE 1: Unacknowledged connectionless (meaning no idea about what is going on) mode---to single destination, (point to point), multiple destination (multicasting), and to all destination (broadcasting)***
- ★ ***TYPE 2: Connection-oriented operational mode---a connection-aware link between LLCs of end stations (using sequence numbering for frame receipt guarantee).***

LLC frame format consists of Destination Service Access Protocol (DSAP), Source Service ACCESS Protocol (SSAP), control field, and information field as shown below:.

DSAP Address	*SSAP Address*	*Control Field*	*Information Field*
8 bits	*8 bits*	*8 or 16 bits*	*N*8 bit*

DSAP: 1 I/G: 0 individual or 1 group and 8 address bit

SSAP: 1 C/R: 0 Command or 1 response and 8 address bit

Control has separate structure format to include fields like Information, supervisory, and unnumbered. Information: LLC data or higher layer protocol.

FIGURE VII/1.2.5-3 LLC format.

Bytes →	7	1	6	6	2	0-1500	0-46	4
Frame →	Preamble	SFD	Destination address	Source address	Length type	Data	PAD	Checksum

FIGURE VII/1.2.5-4 Ethernet frame.

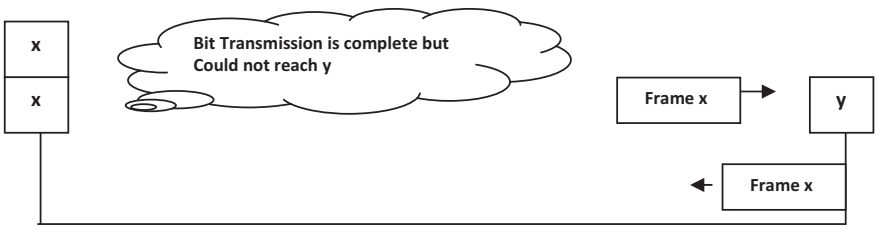


FIGURE VII/1.2.5-5 Bit collision (minimum frame length).

As is clear, if the frame size is too small then by the time the first bit reaches the distant receiver y, from x, frame transmission from x may be complete and at that time seeing no transmission. y may like to transmit and this will result in a collision that will curtail the current frame and there will be bit pieces of frame in the cable. This is why IEEE decided to have 64 bytes as a minimum.

6. *Data field*: A sequence n bytes of any value (0−1500), it is seen or specified with PAD.
7. *PAD*: A field that is filled when data that is less than 46 bytes, so it is padded to make a total frame of 64 (hence may have 0−46 bytes).
8. *Checksum*: This is 4 bytes. This sequence contains a 32-bit cyclic redundancy check (CRC). It is created by sending MAC and is recalculated by receiving MAC to check for the damage.

www.EngineeringBooksPDF.com

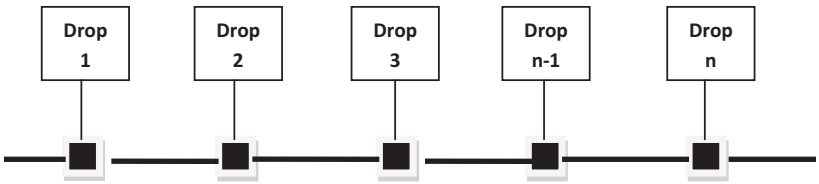


FIGURE VII/1.2.5-6 Multidrop network.

1.2.5.1.1 Physical Medium Multiple computers may be connected over a single channel in a multidrop way (see Figure VII/1.2.5-6). Here the common channel is shared by all the drops (computer/node). This channel may be coaxial cable, twisted pair cable, and fiber optic cable. Even though these nodes are physically connected in a star pattern by a repeater, logically it is still a single channel, so logical topology is more important than the physical topology. In this method each machine/computer/node is authorized to communicate over the bus/channel at *any time* but *one at a time*. There is no priority. All nodes or computer on an Ethernet are connected by a common channel, and communication is carried out using Carrier Sense Multiple Access/Collision Detect (CSMA/CD).

1.2.5.1.2 How Does CSMA/CD Work? This works somewhat like a meeting room where there are several speakers, and each wants to air their voice (meaning multiple access). To avoid noise in the room each speaker speaks one after another. This is like carrier sensing, i.e., when one is airing a voice all others listen to the speaker. During discussions if two speakers start speaking, as a courtesy both stop speaking and give each other a chance to speak. This is how collision detect works.

- Before transmission each machine/node verifies that there is no communication in the line.
- If two machines/nodes/computers transmit simultaneously, then there will be a collision (i.e., there will be several data frames in the line). In that case both machines send a jam signal to all the devices connected preventing all from communicating. A collision detector could be releasing its own signal (24 mA) or there is an error in the CRC. Also all the machines/nodes/computers will interrupt their communication and wait for a random period. After that period lapses one may start checking the channel freeness and can communicate. Will there be a specified data packet size as discussed above and a waiting time? Also for one collision there is time, if there is another collision will the machine wait for two waiting times and so on?
- CSMA/CD is applicable for a shared channel and for a half-duplex mode of communication, whereas switching Ethernet is something different and could be used for a full duplex.

In the Ethernet names are specified by x BASE y, where x stands for speed of communication in Mbps, and y stands for a physical medium-type symbol as detailed in Table VII/1.2.5-1.

1.2.5.1.3 Switched Ethernet The physical topology remains a star, but it is organized around a switch very similar to a gateway.

- In an Ethernet switch there are 4−32 line cards and each may have approximately eight connectors. These connectors are connected at the back plane for very high speed (more than Giga bits per second) communication utilizing its own protocol. Because this is used for internal switching action and is not related to the outside network protocol of which is immaterial. What is important is the speed. Each of these connectors could be connected to a host computer/node/machine, etc. Thus it is possible to connect $4 \times 8 = 32$ to $32 \times 8 = 256$ machines nodes, etc (see Figure VII/1.2.5-7).
- There is another very similar device known as an Ethernet hub. Since the hub is involved in collision and binary back off and the cost of switches is falling, hubs are almost obsolete.
- The switch inspects the source and destination address message to draw up a table that allows it to know which machine is connected to which port. Knowing the recipient port switch transports the message on the appropriate port.
- If one of the nodes connected to switch 1 wants to communicate, the switch will examine whether it belongs to the same card. If this is the case, it will pass the it. If not, it will pass it to the next card through a high-speed back plane to the destination card. What if more than one machine out of eight (for example) wants to communicate? Then CSMA/CD will be used. So one card will have one collision domain (restricted to eight). Alternatively, it may have suitable RAM to buffer the input data. When buffer RAM is there, send and receive can go simultaneously in full duplex mode. In that case there is no need for CSMA/CD.
- When the Ethernet acts on full duplex mode there will be separate set of connections for send and receive, i.e., in duplex mode; for example, 100BaseTx Ethernet has two pairs of cables.

www.EngineeringBooksPDF.com

TABLE VII/1.2.5-1 Ethernet Types

Name	Cable	Max seg (m)/PORT (m)	Node/ seg	Connector	Remarks
10Base5	Thick coax	500	100	Vampire tap	Original now obsolete
10Base2	Thin coax	200	30	BNC	Cheap (no hub)
10BaseT	Twisted pair (CAT 3 or 5)	100	1024	RJ45	Easiest set up and cheapest; common for Ethernet switch (or hub); each node connected to each port; use two different voltages (−)2.5, +2.5 V
10BaseF	Fiber optic	2000	1024		Long distance
100BaseFx	Fiber optic(type 62.5/125)	2 km			Fast Ethernet
100baseTx	2P twisted pair Cat 5	100		RJ45	Known as Fast Ethernet, uses three different voltages (−)1, 0, +1 V
1000BaseLX/ SX	Fiber optic (multi/mono)	550			Single (10μ) or multiple (50, 62.5 μ) L = Long wave (∼1350 nm) S = short wave (860 nm)
1000BaseCX	2p STP	25		GG45/RJ45	Cat 7/Cat 5e/tough Cat 5 STP
1000BaseT	4p UTP (Cat 5)	100		RJ45	(Cat 5) IEEE 802.3(40) 2006
10 GB BaseT	Cat 7	100		GG45	

- Thus in a network with an Ethernet switch there may be several communications going on simultaneously without any collision. In full duplex mode in the same card even transmit and receive actions may go on simultaneously. Therefore it is not possible to predict which action is going on in a port.

1.2.5.1.4 Gigabit Ethernet As the name signifies, the speed of the Gigabit Ethernet is a minimum of 10,00 Mbps. This is achieved with the help of Ethernet switches as shown in Figure VII/1.2.5-8. Here with respect to the switch and any node there is only one sender so there is no collision, hence, CSMA/CD is not utilized. Also when a switch is sending data it is done through a separate line, hence, full duplex mode possible. Except for the *physical limitation* of the medium, a switch does not have a distance limitation so it can be applied to large area network. As of today various technologies such as 10BaseT, 100BaseTx, 1000BaseT, or 1000baseTx use the same connector RJ45 to be connected to the same switch. This intermixes various types and poses serious disruption problems that could be addressed by auto negotiation (N way). It is also covered in IEEE 802.3 1998. Mostly in power plants the network speed of 100 Mbps is used, but it may not be much longer until a higher speed will be in demand, so a Gigabit Ethernet has been considered.

Here 10/1000 stands for Mbps speed. 5/2/T/F stands for cable type specified. BASE here stands for Base Band

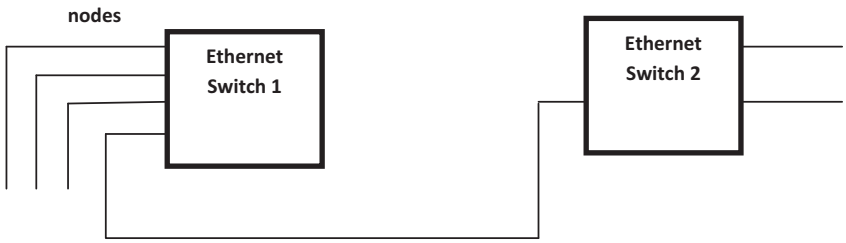


FIGURE VII/1.2.5-7 Ethernet switch and network.

www.EngineeringBooksPDF.com

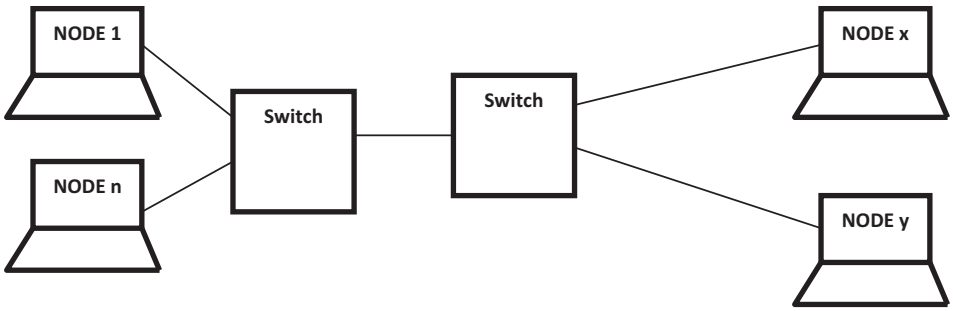


FIGURE VII/1.2.5-8 Giga bit Ethernet.

transmission. All 10/100/1000 Ethernet speeds are available in a half as well as full duplex configuration. The "X" after T and F stands for different standards, e.g., both 10baseT and 100baseTx use only two pairs of Cat 5 cable, yet, they have different standards (i.e., 10baseT, IEEE802.3(14) 1990 and 100baseTx, IEEE802.3(24) 1995). 100 and 1000 Mbps Ethernets are covered by IEEE 802.3u and IEEE 802.3z, respectively. 40Gbase-CR4 and 100Gbase-Cr10 belonging to IEEE 802.3ba are new Ethernets of the year 2010. LAN cable details are available later in this chapter. At this time most manufacturers have integrated systems based around the Ethernet, e.g., ABB, Siemens etc.

1.2.5.2 Token Passing (IEEE 802.4 and IEEE 802.5)

When compared with CSMA/CD, the token passing system is deterministic and has the advantages like higher throughput and priority setting. There are two different topologies used: token passing bus (IEEE802.4) and token passing ring (IEEE802.5). The basic scheme of operation in token passing systems is listed below:

1. Only one device/node can talk at a time.
2. Node/device waits for a free token to communicate over the channel.
3. Token circulates among the node until one wants to communicate.
4. If a station does not have any data to transmit it passes the token to the neighbor.
5. Token is held for a specified time.
6. When the node/device grabs the token it takes the following actions:
   a. Sending device/node sets the token busy and adds information and a trailer packet.
   b. The entire message is sent over the channel for communication.
   c. Every node examines the header packet or frame to check if it belongs to it or to ignore in case it is not meant for it.
   d. Intended node/device copies the message set bit in the trailer field to acknowledge and send back. The sender then checks the message received back to check if it's properly received. Then it frees the token in case it is not required.
7. The most popular is Fieldbus, like Foundation Fieldbus, and Profibus, which utilize token passing media access.
8. Its advantages include:
   a. High throughput at higher network load (number of nodes) when compared with CSMA/CD but saturates after a certain number of nodes in network.
   b. Deterministic
   c. Priority setting (up to six)
9. Its disadvantages include:
   a. Complicated protocol and software
   b. Higher bandwidth expensive cable and hardware

1.2.5.3 Token Bus (IEEE 802.4)

A Fiber Distributed Data Interface (FDDI) is a 100 Mbps LAN based on token passing bus (IEEE 802.4). Token bus is a protocol suite for physical and data link layers with two subdivisions, such as MAC and LLC. Its features include the following::

1. Physically it is a bus network, logically it has to be a ring network.
2. Stations are organized in a doubly linked list.
3. It uses MAC address for distributed polling
4. It can broadcast or it may go for point to point.
5. Possible central station to manage and monitor the network.
6. It has logical ring maintenance including:
   a. Initialization of ring
   b. Addition and deletion to and from ring
   c. Periodic token holder call to others to join if outside ring
   d. Maintenance of address of predecessor and successor once the ring is formed

See Figure VII/1.2.5-9 for Token bus, where SD/ED = Start/End Delimiter, FC = Frame Control, and FCS = Frame Check Sequence Max from SD to ED is 8191 bytes. Westinghouse WDPF uses a token bus system.

www.EngineeringBooksPDF.com

No. Of Bytes →	≥ 1	1	1	2or 6	2or 6	>0	4	1
Frame →	Preamble	SD	FC	Destination Address	Source Address	LLC	FCS	ED

FIGURE VII/1.2.5-9 Typical frame format of token bus.

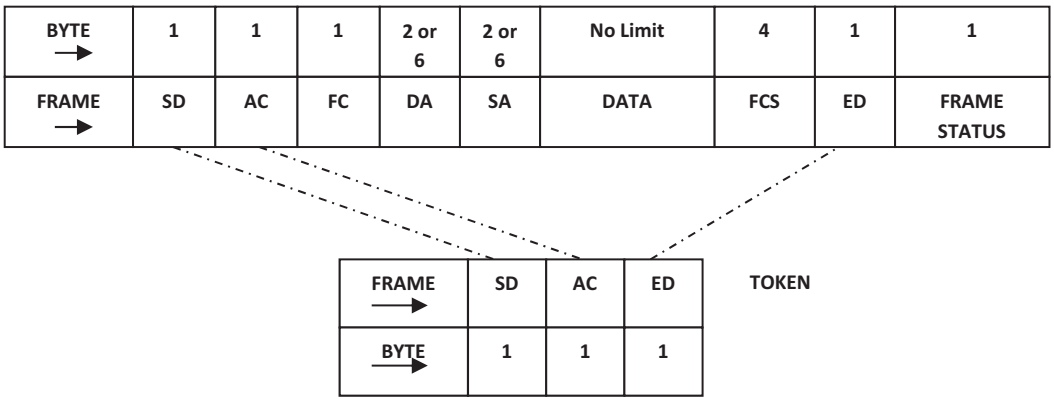


FIGURE VII.1.2.5-10 Token ring data frame.

1.2.5.4 Token Ring (IEEE 802.5)

In 1970 IBM first developed this system, which is quite compatible to the standard IEEE 802.5. In the original system topology a medium was specified as Star and twisted pair cable, respectively. In IEEE 802.5 this is not specified; however, it does specify the data rate as 4−16 Mbps and the station per segment as 250. Signaling should be base band and token passing uses differential Manchester encoding. As discussed previously, when a station/node possessing a token wants to transmit information, it seizes the token, alters 1 bit of the token (which changes the token into a start of frame), appends information, and sends it to the next station/node. The next station/node sees and sends it to next station. In this fashion, the information circulates in the ring until it reaches the destination. The destination station copies the information and again circulates the token in the network until it reaches the sender. It then checks whether the information is copied. The token is then finally removed from the network.

The token ring uses a sophisticated means of priority management. The token ring has two fields, priority and reservation, which control priority. Only a station/node with a priority value equal to or higher than the priority value contained in the token can seize it. The token ring deploys several means for fault management. A central station or any of the stations may be assigned to perform the timing and ring maintenance management function. When a station fails, its token may be circulating in the ring, which prevents others from continuing communication in the network. Such fault management can be done by the station assigned for network maintenance. A typical IEEE 802.5 and token ring is shown in Figure VII/1.2.5-10. SD/ED = Start/End Delimiter and SD alters each station on arrival of a token. ED is the end of token or data. AC = Access Control byte, which is for priority control (first three higher bits), and FC = Frame Control byte, which states data or control.

This byte specifies the type of information. FCS = Frame Check Sequence filled in by a source with a calculated value dependent on frame contents. Destination station recalculates this to check if there is any damage. Frame Status: 1 byte data are for field terminating a command/data. The frame status field includes an address-recognized indicator and frame-copied indicator as discussed above.

1.3 HART Protocol

Highway Addressable Remote Transducer or HART is an open, bidirectional communication protocol, utilizing a Frequency Shift Keying(FSK) standard, to exchange data between intelligent field devices with the host system. In a true sense HART is *not* a fieldbus but a protocol. In HART technology a 4-20 mADC signal can be sent simultaneously with digital information in a superimposed manner. Some of the systems may have necessary OPC servers (see Clause 1.6) for system integration, e.g., HART OPC Server ABB800xA system. Figures VII/1.3-1 and VII/1.3-2 may be referred to for HART communication and data frame.

www.EngineeringBooksPDF.com

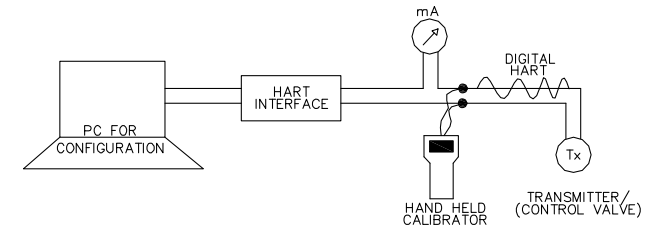


FIG NO.VII/1.3–1a HART COMMUNICATION ANALOG & DIGITAL (POINT TO POINT)

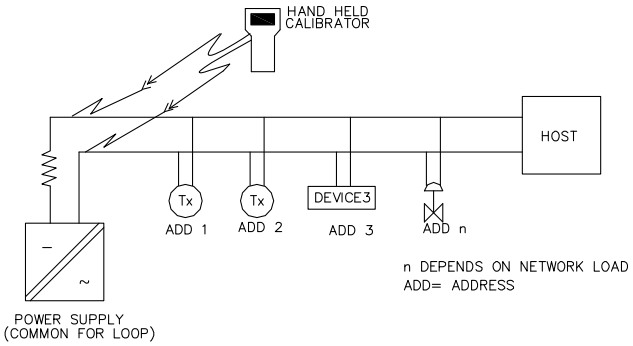


FIG NO. VII/3.1–1b HART COMMUNICATION MULTIDROP WITH HOST & POWER CONNECTION

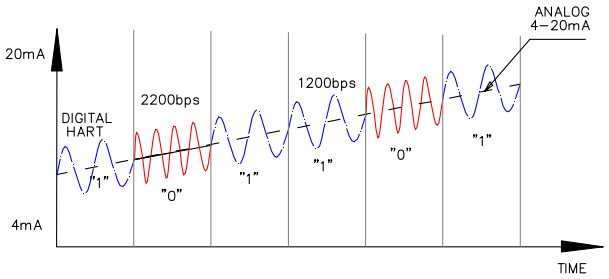


FIG NO.VII/3.1–1c HART SUPER IMPOSITION OF DIGITAL OVER ANALOG

FIGURE VII/1.3-1 HART communication.

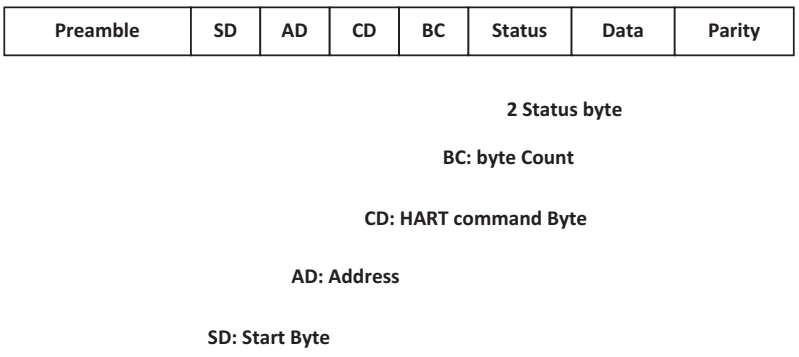


FIGURE VII/1.3-2 Typical HART telegram timing.

1.3.1 HART Protocol Features

Major features of the popular HART protocols are as follows:

1. Technological advantage to support the user such as:
   - Standard wiring for 4-20mADC, but also digital data transmission
   - Complete usefulness of intelligent devices to improve operational performance
   - Early warning generation for variation in performance of process, device.
   - Quick troubleshooting by identification and problem resolution
   - Continuous validation of loop integrity and automation strategy
   - Gateways to communicate with fieldbuses.
2. System and plant availability features:
   - Robust and accurate protocol for risk reduction for failure as well as avoidance of costly shut down of the system
   - Ability to detect device and connection problem in real time and early warning of deviations
   - Ability to integrate devices and systems
3. Advanced diagnostics and maintenance cost:
   - Quick validation of the loop and configuration, so any change quickly reported for action coupled with remote diagnostics (at host)
   - Predictive maintenance and reduction of spares inventory.
4. Regulatory compliance
5. Integrated safety level (SIL)
6. Cost-effectiveness

www.EngineeringBooksPDF.com

7. Enabled for record keeping and possibility of testing shut-down conditions
8. Broader selection of product from multiple vendor support

1.3.2 Characteristics of HART Protocol

1. *Technique*: Superimposition of digital signal with 4-20mADC signal.
2. *Technology*: Bell 202 standard FSK.
3. *Communication speed*: 1200 bps.
4. *Number of device supports*: Could be as many as 100, but based on allowed load impedance it is typically15. Powering provision and one of the most important factors is that each new unit is a contributor of noise. All of these limit the number of devices in a loop.
5. *Configuration*: Master slave mode. It can support two masters, e.g., the host as a primary master and handheld configurator can be a secondary master, whereas intelligent devices, e.g., Tx/Control valves, could be the slaves (see Figure VII/1.3-1b).
6. *Communication modes*: Peer to peer, multiplexing type, with one PC (for example), connected via multiplexer or it can be a multidrop type configuration, as shown in Figure VII/1.3-1b.
7. *Cable*: Normal Instrumentation twisted pair cable is sufficient. Depending on the distance coverage the specification may change, e.g., up to 1500 m, 0.2 mm^2 conductors with a common shield, whereas for ~3000 m the same cable is used but with individual shielding. For shorter distances unshielded cables may be possible; however, it is recommended to use screened cables.
8. *Data exchange*: Status, diagnostics, calculated value, etc. Some of the generic parameters include: PV reading, analog output reading, secondary variable reading, change (tag, data, PV unit, range, damping, output transfer function, and polling address), output trimming, loop checking data, zero and range change, modem action, etc.
9. *Load limit*: A 1100 Ω provision of powering (as shown in Figure VII/1.3-1b) the entire loop.
10. *Noise immunity and error detection*: Online devices can be added or removed without much degradation of performance. Noise immunity conforms to IEC 801-3 (radiated, radio frequency, and electromagnetic field immunity) and IEC 801-4 (electrical fast transient/burst immunity) Class 3. It can detect up to three corrupt bits in a telegram as error detection
11. *Hazardous application*: IS compatible and Exi.
12. *Addressing*: Special long format addressing format is used. During configuration mode in peer-to-peer mode tag and bus address are set.

TABLE VII/1.3-1 Typical HART Telegram Timings (Based on Samson Document)

Parameter	Calculation	Value
Byte/Telegram		25 Message +10 cont ch.
Telegram size	35ch X11	385 bits
Time per bit	1/1200	0.83ms
Transaction time	385X 0.83	0.32S
User data rate %	(25(M)X 8)/ 385	52 (%)
Time/user data	0.32/25	13ms

1.3.3 Telegram

Typical structure is as shown in Table VII/1.3-1. These are in UART characters with a start, a stop, and parity bits. HART telegram timing has been shown in Figure VII/1.3-2.

1.3.4 OSI Model versus HART

When compared with the OSI 7 layer model, it is found that the layers 1, 2, and 7 are distinctively present, while session (5) and presentation (6) layers are missing. Also network and transport layers are present but not so distinctive.

1. *Layer 1 physical layer*: Here the transmission is in Bell 202 FSK with "0" represented by a 2200 bps signal and "1" represented by a 1200 bps signal (Figure VII/1.3-1c).
2. *Layer 2 data link layer*: Function of this layer is to ensure communication from one device to another. System consists of master (two permitted) and slave. Slave communicates only when it is called. For admitting two masters, a primary after each command gives a pause to allow for a secondary master to communicate. Here one of the major problems is to control noise when a new one is added, because each unit is a contributor of noise.
3. *Layer 3 network layer*: Not prominent, main functions include routing and end-to-end security. There is a service to transport layer.
4. *Layer 4 transport layer*: Not very prominent, used to ensure communication is successful.
5. *Layer 7 application layer*: Various commands like universal (common to all devices), common to many devices, device family/generic command, device-specific command, response data type, and status report are the major functions of this layer. Some commands and conformance relationships are presented in Table VII/1.3-2.

www.EngineeringBooksPDF.com

TABLE VII/1.3-2 Layer 7 Command Relations (HART)

Command field development	Data flow	Conformance for master
Universal command	→	Read measured variable
Universal command	→	Read universal information
Common practice command	←	Write common practice parameter
Common practice command	←	Write selected parameter
Device SP. command	→	Read device-specific information
Device SP. command	↔	Read and write entire database

1.3.5 HART for System Integration

In integrated systems HART devices can be connected via Intelligent HART-enabled I/O, controllers, etc. These can be connected through a multiplexer as well. Integrated systems have Field management tools to configure and access data, e.g., managing remote I/O, TOPOLOGY planning up to the field level, etc., from field devices. OPC servers are developed as part of a system-integration package (e.g., HART OPC for the ABB 800xA system). The OPC (discussed later in this chapter) server is used to access specific field devices; to utilize various device libraries; and to configure, parameterize, and operate the device communication. Device type managers are available for management of HART devices.

1.3.6 HART Hand-Held Configurator

HART is an open communication protocol between the master and the field devices. This openness, interchangeability, and manufacturer independence is possible as long as communication is done using universal and common practice commands. To eliminate the problem with device-specific command problems, a device description language (DDL) was developed. Basically, a HART configurator consist of the following components as its basic building blocks:

- Microprocessors with associated memory
- *RAM*: Temporary memory to execute the program
- E^2PROM program and basic data
- *Keyboard*: For operation, calling data, etc.
- *Display*: For value and parameter display
- *Modem*: To communicate over the two wire with various devices
- RS 232C communication with PC and other host devices

There are VDI guidelines for the communication structure of this. Some of these features include but are not limited to the following:

- All protocol-defined commands must be implemented and can be selected.
- Device description can be implemented.
- User interface provides all extended communication, information. and control options.

General features and specifications for the universal HART hand-held configurator shall include but not limited to those elaborated below:

1. *Function*: Clone/upload/download configuration, off-line mode for developing/reviewing configurations
2. *Major keys*: Quick Menu access, HART menu, and home-dedicated text edit
3. *Extensive store*: >200 configurations, full alpha-numeric keypad
4. *Edit function*: From review/edit mode
5. Programmable lock-out settings of commission devices
   - Step-by-step configuration
   - Document as-left configuration
6. Operations:
   - Reconfiguration for process changes
   - Reconfiguration for batch runs
   - Document as-found and as-left configurations
   - Populate DMS database software
   - Thumb key for up/down/side selection
7. Device Maintenance
   - Troubleshoot devices with HART
   - View device error messages
8. *Devices support*: Normal available configurator with >600 device support s
9. *On-site update*: Via Internet
10. *User interface*: 10-3 line display, high-resolution pixel with back-lit display
11. *Power*: Lithium/alkaline battery back-up
12. *Housing*: Plastic case
13. *Certification*: CE/ATEX, etc.
14. *Firmware language*: Multilanguage
15. *Major suppliers*: ABB, Emerson, YEL, etc.

1.4 MODBUS Protocol

In 1979 Modicon developed this protocol for communication among Modicon PLCs. Later it became the de facto standard for connecting various devices with a control system as well as communication between networks. It is basically an application layer protocol for connecting

www.EngineeringBooksPDF.com

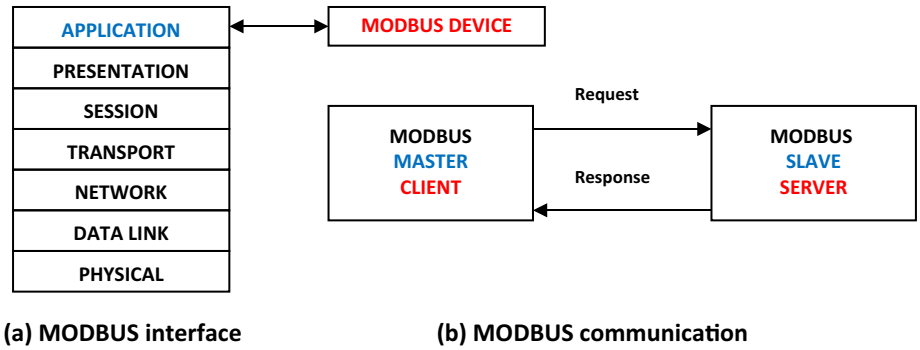


FIGURE VII/1.4-1 MODBUS system.

devices (see Figure VII/1.4-1a). It works on a master–slave basis, which is similar to an HTTP. A transaction takes place upon *request* from the master (client), and the slave (server) *responds* as shown in Figure VII/1.4-1b. An exception response is sent for error.

1.4.1 Transaction Methodology

Transaction methodology in MODBUS has two types: a transaction over the MODBUS network and transaction over a different kind of network. In the former method, the master has established a data format for master's query by placing "device address, a "function code" defining the action, any "data" to be checked, and an "error" checking field. Slave message in MODBUS protocol contains field "confirming action," any "data" to be returned and an "error" checking field. For different networks it uses built-in port, network adapter, etc., to communicate in a "peer-to-peer" communication mode, in which the master initiates the request. Multiple internal paths are often provided for concurrent communications. As stated earlier, the master sends the query (or request) containing a few fields as shown in Figure VII/1.4.1-1.

QUERY: Function code tells the slave (being addressed) the action to perform and any additional information, data byte field information to slave regarding register to start and how many registers to read, etc. Error check is for the slave to validate the data.

RESPONSE: Function code echoes the function code in query. Data byte contains the data collected. In case of error, the function code is modified to indicate error.

MODBUS communication is based on packets of data called Protocol Data Units (PDUs) comprising query and response as discussed above. There is another PDU known as an exception response PDU used to indicate error where function code of query + 0X80 (error code) and a code-specifying exception. The specification defines a number of functions, each with a number function code (1-127 and 128-255 for error code). A new release has function codes such as "public," "user defined," and "reserved." MODBUS data types should include read-only data types for discrete input/output (each single bit), input register, and holding register (each 16-bit word).

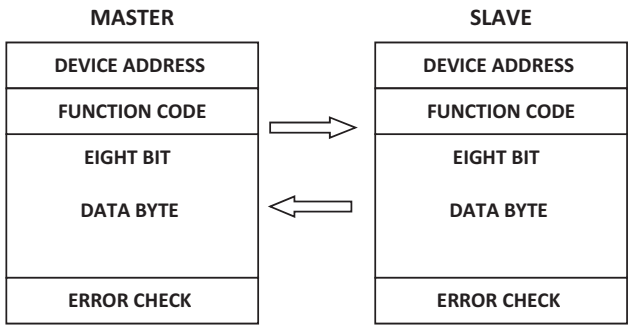


FIGURE VII/1.4.1-1 Master slave query response with different fields.

1.4.2 Implementation Methods

MODBUS has been implemented in all physical media such as wire, fiber optic, and radio. They are mainly implemented utilizing (1) serial asynchronous master–slave and (2) IP master–slave.

1. *Serial link: RS 232 (EIA232)*: Valid for short distance (i.e.,15 m) and point-to-point communication RS 422. This link can be used for bidirectional communication over comparatively longer distances (<1.2 km) in point-to-point mode as shown in Figure VII/1.4.2-1.

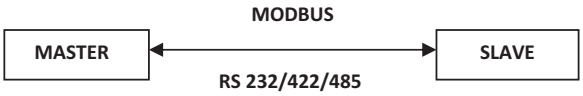


FIGURE VII/1.4.2-1 Point-to-point communication between master and slave.

www.EngineeringBooksPDF.com

TABLE VII/1.4.2-1 ASCII and RTU Encode

	ASCII		RTU	
Name	Length	Explanation	Length	Explanation
Coding system	NA	Hexadecimal, ASCII	NA	8-bit binary, hexadecimal
Start	1 ch	Start with ":" colon (3A in ASCII)	3.5 idle	Minimum 3.5 ch time in silence
Address	2 ch	Station address	8 bit	Station address
Function	2ch	Function code (i.e., to read coil etc.)	8 bit	Function code (i.e., to read coil, etc.)
Data	N ch	Data + variable length as per message type	N*8 bit	Data + variable length as per message type
Check	2 ch	LRC error check	16 bit	CRC error check
End	2 ch	Carriage return, etc.	3.5 idle	Min 3.5 ch time in silence

2. *RS 485*: As shown in Figures VII/1.4.2-1 and VII/1.4.2-2, MODBUS is applicable to RS 485. In actual implementation, the PDU is transformed into an application data unit (ADU) by adding a header and error check sum with a maximum 256 bytes, as shown in Figure VII/1.4.2-3.

   There exist two methods of serial communications: ASCII and RTU. Encoding differences between them are given in Table VII/1.4.2-1.

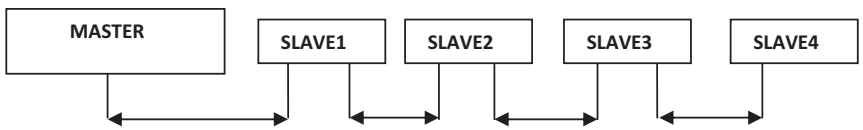


FIGURE VII/1.4.2-2 Multiple slave communication in RS 485.

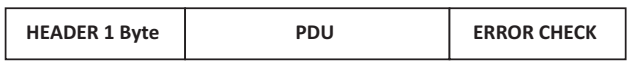


FIGURE VII/1.4.2-3 IP method of MODBUS implementation.

3. *IP based*: In a TCP/IP-based MODBUS implementation with multi-master system, bidirectional communication is possible. It uses TCP/IP stack for communication and extends the PDU with an IP-specific header. MODBUS TCP frame format is shown in Table VII/1.4.2-2.

1.4.3 Discussions

MODBUS Plus is an extended version of MODBUS, but it is proprietary. MODBUS can be used in a 20 mA current loop also for a distance of ~1000 m. Transmission speed is 19.2 Kbps, based on link type used and distance. So , it can be concluded, that this protocol can be used in a variety of means & methods.

1.5 Fieldbus Requirements

What is Fieldbus? Why is it so important? Fieldbus may be conceived as a digital communication system for various field devices such as sensors, actuators, and field control systems. This definition is incomplete, because the Fieldbus

TABLE VII/1.4.2-2 TCP Format

Name	Length	Explanation
Transaction/ invocation identifier	2 bytes	Message synchronization between client and server
Protocol identifier	2 bytes	Zero for MOD BUS/ TCP
Length field	2 bytes	Number of remaining bytes
Unit identifier	1 bytes	Slave address (255 if not used)
Function code	1 bytes	Function code
Data byte	N bytes	Data as response or command

www.EngineeringBooksPDF.com

TABLE VII/1.5-1 IEC 1158-2 Features

Features	Requirements	Features	Requirements
Data transmission	Digital Manchester bit synchronized	Data security	Preamble, error-free start, and end delimiter
Speed	31.25 Kbps voltage	Cable	Two wire-shielded twisted pairs
Explosion protection	IS EExia and ib EEx d/m/p/q	Number of stations	32/segment (maximum could be 126 address available)
Topology	Line/tree or combination	Repeaters	4

has to address a few needs, such as device addressing, two-way communication to exchange data related to the parameter as well as status of the field device, communication speed, etc. Obviously Fieldbus cables should *not* be looked as "just wire." In an integrated system it can be compared with one of the main arteries in the human body. There are a few advantages of Fieldbus that include but not limited to the following:

- Significant reduction of cable wiring, cable tray, and tray layout.
- Easy to use and easy future expansion and modification.
- More extensive data exchange to and from the field devices at a much faster rate
- Reliable, cost-effective, and deterministic.
- Greater flexibility in system design and layout.
- Openness and interface capability makes it possible to integrate multiple products from different vendors in a system.

The IEC 61158-2 standard was developed for interconnection of various automation system components. Some of the salient features of IEC 1158-2 related to transmission technology are presented in Table VII/1.5-1.

The following are basic transmission features noted from this standard combining with the field intrinsically safe concept (FISCO):

- Each segment should only have one power supply.
- No power fed to the bus when a station is sending.
- In steady state all field devices consume constant current
- Field devices are passive current sinks.
- Passive line termination at both ends of the main bus line.
- Linear, Tree, and Star topology allowed.

1.6 PROFIBUS

PROFIBUS is one of the most proven and popular Fieldbus standards. It was introduced in 1989 in Germany in line with the DIN18245 standard. It has been incorporated into international standard IEC 61158-2. PROFIBUS supports more than 15 million devices over a million networks worldwide with 2200 products (type).

TABLE VII/1.6-1 PROFIBUS Application

Application area	Applicable industries
Simple to large low-cost distributed control and automation application	Factory automation, robotics
High-speed, time-critical application	Process control and power industries
Complex communication tasks	Building automation, warehousing, and material handling
Hazardous application and process automation	Smart devices

1.6.1 PROFIBUS Family and Application Area

The PROFIBUS systems consist three compatible versions that operate all together seamlessly.

- *PROFI FMS (Field Message Specification)*: This is a high-end application level communication. It provides object-oriented transmission with structured data, loading, and control programs. The extension of other family members such as PROFIBUS DP and its suitable integration with the Ethernet gave rise to PROFINET, which made FMS less important and less popular.
- *PROFIBUS DP (Decentralized Periphery)*: Low-cost field and controller level communication. Majority of PROFIBUS devices belong to this category.
- *PROFIBUS PA (Process Automation)*: This is a cost-effective, two-wire connection used for field devices to communicate.

For safety critical applications, PROFIBUS has PROFISAFE, and for IT application and networking there is PROFINET. Table VII/1.6-1 gives a clear picture of the application of PROFIBUS.

www.EngineeringBooksPDF.com

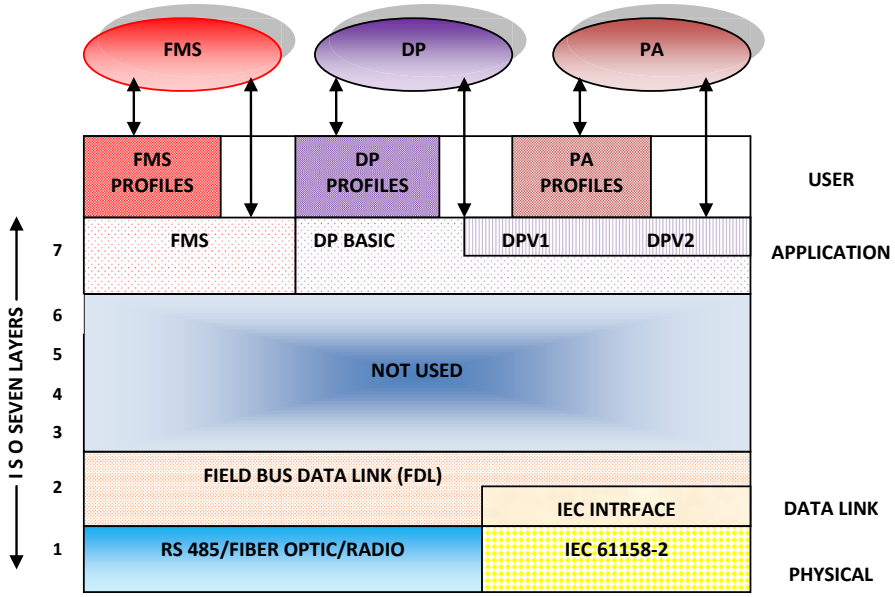


FIGURE VII/1.6-1 PROFIBUS layer structure.

TABLE VII/1.6-2 PROFI BUS Transmission Techniques

Transmission technique	FMS/DP	PA
RS485	Twisted pair or with four wires with power supply speed: 9.6 to 1200 Kbps	
Optical	High-speed communication with electrical Isolation	Not applicable
IEC 61158-2	Not applicable	Shielded twisted pair cable at 31.5 Kbps; supply and data on the same cable (IS possible)

1.6.2 PROFIBUS Structure

The two layers, physical and Fieldbus Data Link Layer (*FDL*). in all three types of PROFIBUS are nearly identical (see Figure VII/1.6-1). When compared with the ISO/OSI model, it is clear that layers 3–6 are missing in PROFIBUS where FDL handles Transmission Protocol, data security, and error detection. Original DP has been extended to include these functions, referred to as DPVs, which are found in the application layer. Various PROFIBUS variants are seen in Figures VII/2.0.3-3b and VII/2.0.3-4 where it is very clearly shown that PROFIBUS DP and PROFIBUS PA have been connected through couplers.

1.6.3 Physical Medium and Transmission

Three ways to realize transmission techniques in PROFIBUS are detailed in Table VII/1.6-2.

1.6.4 Topology and Communication

Of 0–128 device numbering, 126 is reserved for generic devices and 127 is used for broadcast messages. But the limit from IEC 61158-2 and RS 485 is only 32 per segment. Address setting means (HW and SW) are as follows:

- Hardware is by local binary dip switch or rotary switch.
- Software setting over PROFIBUS.
- Special software and serial link by hand-held device or control system

Topology can be linear in RS 485 in daisy chain and can be made a tree as per IEC 61158-2. The circuits can include repeaters, couplers, and optical link modules (for transforming optical signals into electrical signals) as shown in Figure VII/1.6-2.

1. *Signal coupler*: Provides the following features:
   - Electrical isolation between safe and IS bus
   - It is like a slave to PROFI DP
   - Baud rate adaption (PA; 31 Kbps) is faster (1200 Kbps)
   - Powering of PA Bus
   - Adaption of IEC 61158-2 technique for transmission in PA when other side is RS 485

   Installed between PROFIBUS DP and PA, is a signal coupler, which is necessary as both systems

www.EngineeringBooksPDF.com

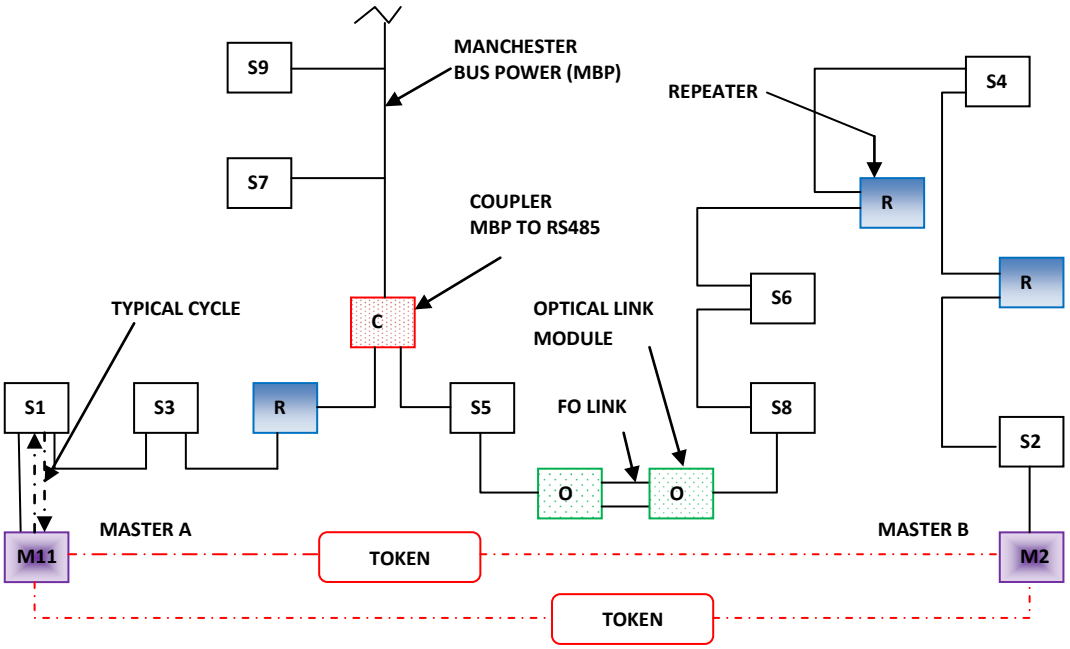


FIGURE VII/1.6-2 PROFIBUS configuration and communication.

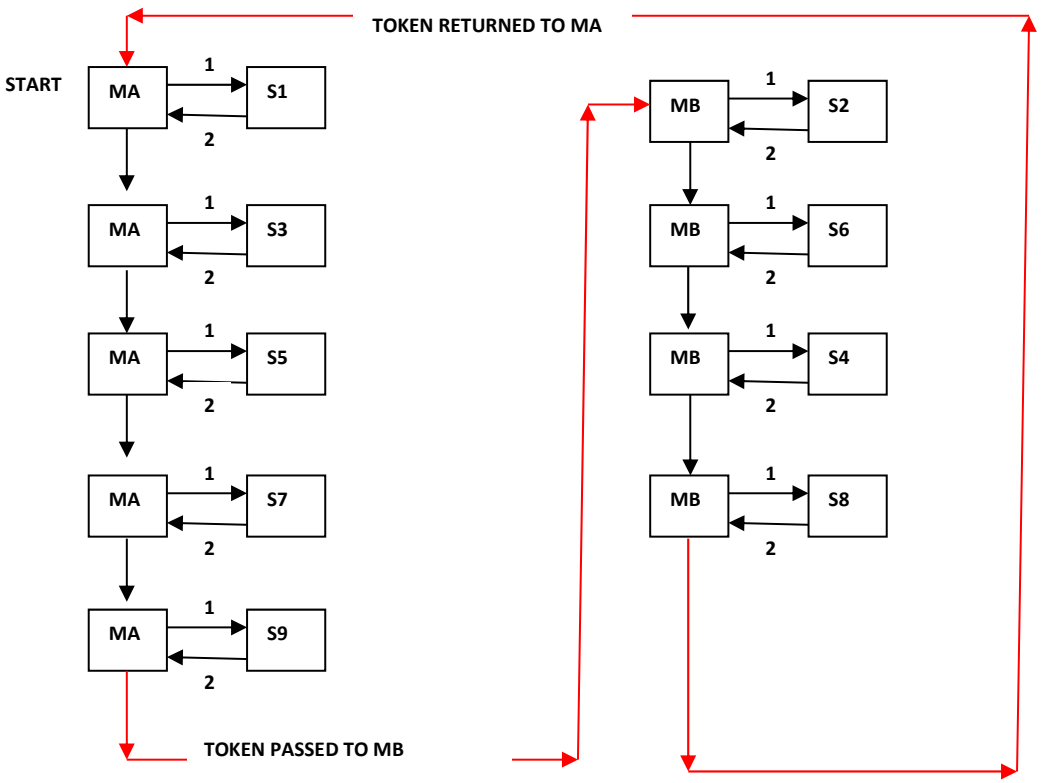


FIGURE VII/1.6-3 Token passing and communication (PROFI).

have different techniques for using IS and transmission as well as a powering scheme.

2. *PROFIBUS operational aspects*: PROFIBUS operates in a master–slave mode with more than one master. Master stations control the network communication and the slave responds to the call from the master. Each of the masters can communicate with a number of slaves. The system is highly democratic, meaning

www.EngineeringBooksPDF.com

TABLE VII/1.6-3 Master Classification (PROFI)

Functions	Class 1 master	Class 2 master
Designation	DPM1	DPM2
Processing and operation	Information processing to and from slave during normal operation	Engineering functions such as configuration tool, diagnostic, engineering, etc.; it is used for operation and monitoring purpose and during start-up
Authority	One master can write to the outputs of a particular slave	Can read and write to the outputs of any slave even when it is under control of a master
Communication	It communicates with slave in *cyclic* operation due DPV1 function of extended DP	It uses *acyclic* communication for access

that all masters have equal rights while all the slaves connected to any master have equal rights. In the case of a multi-master system, communication is regulated by the token passing method (see Clause 1.2.5.2). The master with the token takes over control in the bus. A simplified method of communication and token passing is shown in Figure VII/1.6-3. There are two classes of masters, Class 1 and Class 2 (see Table VII/1.6-3).

3. *Cyclic and acyclic communication*: As shown in Figures VII/1.6-2 and VII/1.6-3, the normal communication system in DP is cyclic. A master with a token (*token holding time* is calculated and specified by the user) talks to all its slaves in a cyclic manner, e.g., MA to S1 followed by S1 to MA then to S3 (under control of MA), etc. After the communication is complete, it is passed on to the next master (e.g., MB) when MB does its communication and MB to S2 is followed by S2 to MB then to S4 (under control of MB), etc. Cyclic communication is transparent. When a master requires any information from a slave it simply writes it in the appropriate part of the memory of the master for the slave to retrieve. The slave puts the required information in the appropriate part of the memory of master to be retrieved by the master. Slaves always monitor the bus, utilizing a watchdog timer to check the inactivity in the bus. If a message is not received within specified time, it senses error in communication and goes into *fail-safe condition.* During the cyclic operation, the Master checks the health of the slave making sure that it responds to all the calls from the master. Acyclic operation is unique for DPM2 to access to the network and read/write to any slave during configuration and start-ups.
4. *Network configuration and start-up*: Like any other network, the PROFIBUS network needs to be configured first. During configuration, the master is notified about the basic characteristics of the slaves. This is done with the help of software supplied by the PROFIBUS master manufacturer. During configuration the token holding time is also set. General Station Description (GSD) files discussed in Clause 1.6.5 help in such configurations. When the master device is initialized, the master (Class 1) sets the parameter into the slaves, i.e., it provides the slave with required settings and locks itself to the master. This is called parameterization. Next, it is important during start-up to check the configuration by the master to confirm that the slave is configured as per the requirement set forth by the master. At the final stage, a diagnostic request is sent by the master (Class 2), which is responded to by the slave satisfying to the master that the slave has no problem.

1.6.5 GSD Files and Associated Parameters

To ease the configuration, all supporters of PROFIBUS are standardized, and these are called general station descriptions. These GSD files are a tremendous help during interoperability. During the planning stage GSD files are loaded to the master. Basic data supplied by GSDs include but are not limited to the following:

- Device manufacturer and device identification number.
- Transmission rate and bus parameter.
- Number and format of the data cyclic communication.
- Device profile standardizes the PROFIBUS so that all device function and parameters are standard, and it determines access method. These include dynamic process value and status report. There are a few acyclic

TABLE VII/1.6-4 PROFIBUS IS Parameter

Maximum parameter	EEx ia IIC	EEx ia/ib IIB
Power	1.8	4.2
Current	110 mA	250 mA
Device	10 (depends on total current)	22 (depends on total current)

Supply current = sum of individual current + 9 mA (MCoding) + FDE fault (0–9mA).

www.EngineeringBooksPDF.com

read write functions such as operating and standard parameters. There us some manufacturer-specific information, and it is accessible only if the Class 2 Master has any knowledge about them.

- Function block provides a uniform application interface for various blocks and their functions are required to be defined.
- There are two kinds of profiles: Class A and B. These are mainly transducer blocks, which describe the coupling of signals to process characteristic curves and sensor types. The Class A profile is limited to absolute necessary information and Class B extends this to the available scope of the function of devices.
- Two specifications are used to enable the Class 2 master manufacturer-specific feature and operating functions,. electronic device description (EDD) and the field device tool (FDT)

1.6.6 PROFIBUS Wiring

1. *IEC 1158-2*: IS requirement and cable as per specifications below (see Table VII/1.6-4):
   - *Design*: Braided shielded* twisted pair
   - *Conductor*: 0.8 mm^2 (AWG18)
   - *L Loop resistance*: 44 Ω/km
   - Impedance: At 31.25 kHz 100 Ω ± 20%
   - *Wave attenuation*: 3dB/km
   - *Capacitance*: 1nF/km
2. *RS 485*: Preferred connector could be 9 pin D SUB plug for RS 485. Termination is necessary at both ends, preferably one with master. First and last segments can have 31 stations and the rest is restricted to 30. Wires are color coded and the shield may be connected to the body.
3. *Optical connections*: Long distance use of optical module including Optical Link Module (OLM). Line ring star configuration possible.

1.6.7 PROFIBUS DP Features

Salient features of PROFIBUS DP are presented below:

1. Probable baud rate is 9.6/19.2/45.45/93.75/187.5 Kbps and 1.5/3.0, 6.0, 12 Mbps
2. Device support per segment is maximum 32 including masters
3. Up 244 byte I/P and O/P per station
4. Data can be read by controlling and Class 2 masters
5. Alarm acknowledgment
6. Communication is cyclic and only one master can write in slave for safety reasons

TABLE VII/1.7-1 PROFINET Facilities

IT integration	Utilization of industrial wireless LAN	Transfer of large volumes of data
Real time	Distributed automation	Comprehensive diagnostics

1.6.8 PROFIBUS PA Features

1. Transmission technology is IEC 1158-2 (2W data and power)
2. Maintenance and diagnostics from available instruments
3. Distance <1900 m, maximum of four repeaters
4. Manchester coding without mean value at ±9 mA
5. 126 addressable devices but up to 32 per line segment
6. Remote DC voltage maximum of32 V

1.6.9 Telegram

Profibus telegram is presented in Figure VII/1.6-4. SD = Start Delimiter, SA = Source Address, DA = Destination Address, FC = Frame Control, DATA UNIT = Data, LE (LEr) = Length Byte (repeat), FCS = Frame Check Sequence, and ED = End Delimiter.

1.7 PROFINET

One may argue that PROFINET is an extension of PROFIBUS DP and its integration with Ethernet gave rise to the open bus Referred to as PROFINET. PROFIBUS internationally defined PROFINET as the universal standard, which opens up new facilities like those listed in Table VII/1.7-1.

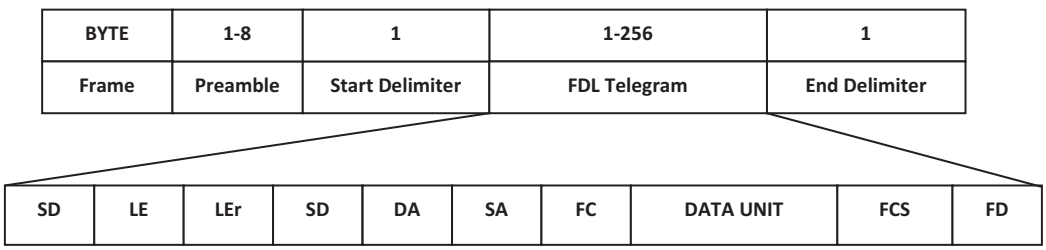


FIGURE VII/1.6-4 PROFIBUS telegram.

www.EngineeringBooksPDF.com

TABLE VII/1.7-2 PROFINET Layer Features

Physical layer	Data link	Application
Standard: IEC8802/IEEE 802.3		Standard: IEC 61158
Power and communication: number	Link type: token passing	Data transfer: PROFI DP
Speed: 100 and 1000 Mbps	Error check: 16-bit CRC	Alert and trend: in-field device
IS: no	Deterministic: not really	
Distance: 100 m maximum	Comm. Type master–slave	Field control: no
Number of devices: unlimited		

PROFINET in accordance with IEC 61158 and IEC 61784 is an open industrial Ethernet. It simultaneously supports TCP/IP Ethernet, OPC (Clause 1.10), and XML. In addition to PROFIBUS, it also supports other fieldbuses through proxy technology. For better availability, PROFINET can be configured in a ring using redundant cabling, so with the help of the Media Redundancy Protocol (MRP), changeover (time: 200 ms) can be made effective. Also It supports isochronous mode to synchronize acquisition with output, which is helpful for motor control flow measurement, etc. (see Figures VII/2.0.3-3 and VII/2.0.3-4)

1.7.1 Layer Features

Since PROFINET is basically extended from PROFIBUS, it has three well-defined layers (see Table VII/1.7-2).

1.8 Foundation Fieldbus

According to Fieldbus foundation "Foundation Field is an integrated total architecture for information Integration—FOUNDATION field bus is an all-digital, serial, two-way communication system." It consists of H1, which interconnects field equipment and high-speed Ethernet (HSE 100 Mbps). Link device is an HSE device to connect one or more H1 links. It has been incorporated in international standard IEC 61158-2.

1.8.1 Foundation Fieldbus Family and Application Area

As stated earlier, that Foundation Fieldbus has two types of bus systems:

- H1 bus based on IEC 61158-2 standard uses field devices like sensors, transmitters, and I/Os.
- HSE bus is an HSE bus that provides integration of high-speed controllers, subsystems via link device, data servers, and workstations.

1.8.2 Foundation Fieldbus Benefits

Foundation Fieldbus offers the following benefits:

1. *H1 bus*:
   - Reduced wiring, marshaling, cabinets, and equipment room size.
   - Common power supplies and IS.
   - More data/multivariables from each device.
   - Distortion-free digital communication enables control capability at the field level.
   - Better performance for self-diagnostic and communication capability.
   - For distributed control at field, reduced Hardware requirement.

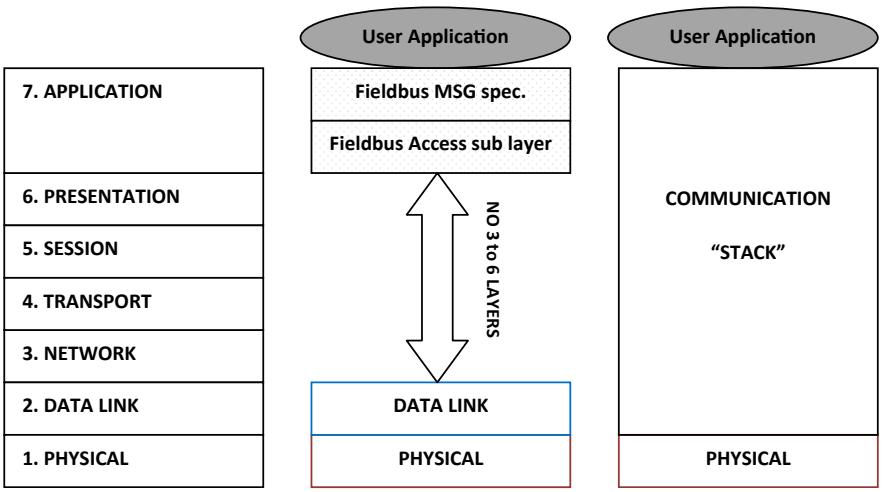
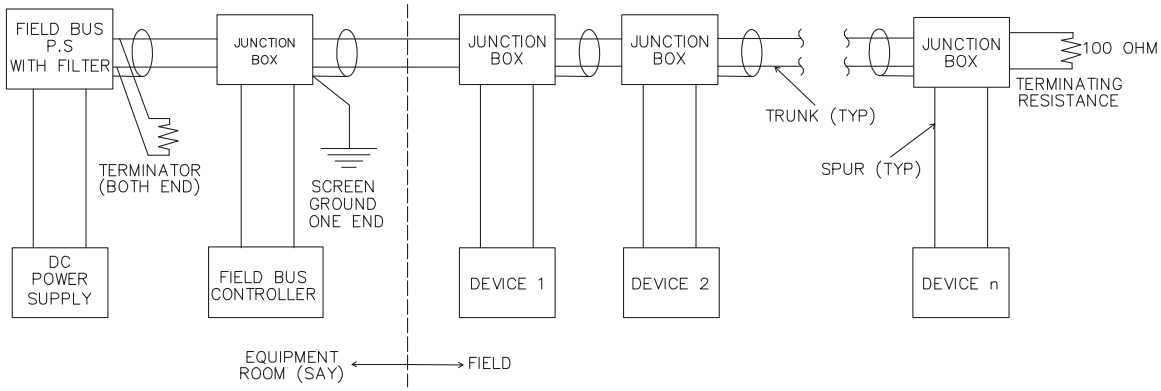


FIGURE VII/1.8-1 Foundation on Fieldbus model.

www.EngineeringBooksPDF.com



SPUR LENGTH TABLE (LENGTH IN METER)

NO OF DEVICES	1 DEVICE/SPUR	2 DEVICE/SPUR	3 DEVICE/SPUR	4 DEVICE/SPUR
1–12	120	90	60	30
13–14	90	60	30	1
15–18	60	30	1	1
19–24	30	1	1	1
25–32(MAX)	1	1	1	1

PREFERRED CABLE FOR FOUNDATION FIELD BUS :– SHIELDED TWISTED PAIR AWG 18 (0.8 mm2) MAX LENGTH : 1900 mtr.

FIGURE VII/1.8-2 Foundation Fieldbus cabling.

- Higher flexibility and sophistication.
- More information for operation.

2. *HSE bus*: The benefits discussed in in the previous list are applicable to an HSE bus also. Additionally, it offers the following benefits:
   - Asset management functions like diagnostics, calibration, identification, etc., help make proactive, high-performance management actions
   - Since the system is an open system, it is interoperable enabling user to mix various subsystems to form an integrated system.
   - Same functional blocks of H1can be used here, eliminating the need for proprietary programming languages. The same language system can be used over the entire system.
   - Peer-to-peer communication enables communication between two devices without a central computer system. It is possible to bridge information between HI networks.
   - Since it is standard Ethernet, there is no need for any special tools and cables.

1.8.3 Fieldbus Model and ISO–OSI Model

Foundation Fieldbus specification is based on a layered communication model as shown Figure VII/1.8-1. Foundation Fieldbus H1 consists of three layers: (1) physical, (2) data link, and (3) user application, as shown in Figure VII/1.8-1. Layers 3–6 are *missing*. The use application is made up of a function block and device description (see Clause 1.8.10), and it is directly based on the communication "stack" shown.

1. *Physical layer*: H1 bus complies with IEC 61158-2 physical layer. Upon receiving a message from the communication stack, the physical layer converts it to a physical signal for transmission in the medium and vice versa. The conversion includes additional removal of start/end delimiters, preambles, etc.
2. *Communication stack*: Comprises layers 2–7. The Data Link Layer (DLL) regulates the message on to the bus through the deterministic Link Active Scheduler (LAS, see Clause 1.8.8). The field access scheduler uses scheduled time-restricted data and unscheduled data (on request, alarm) to provide services to the Field Message Specification (FMS). FMS services allow user applications to send messages to each other.
3. *User application*: Consists of a number of blocks as per Foundation Fieldbus. Each of these blocks represents different functions, such resource block, transducer block, and function block. While the first two blocks

www.EngineeringBooksPDF.com

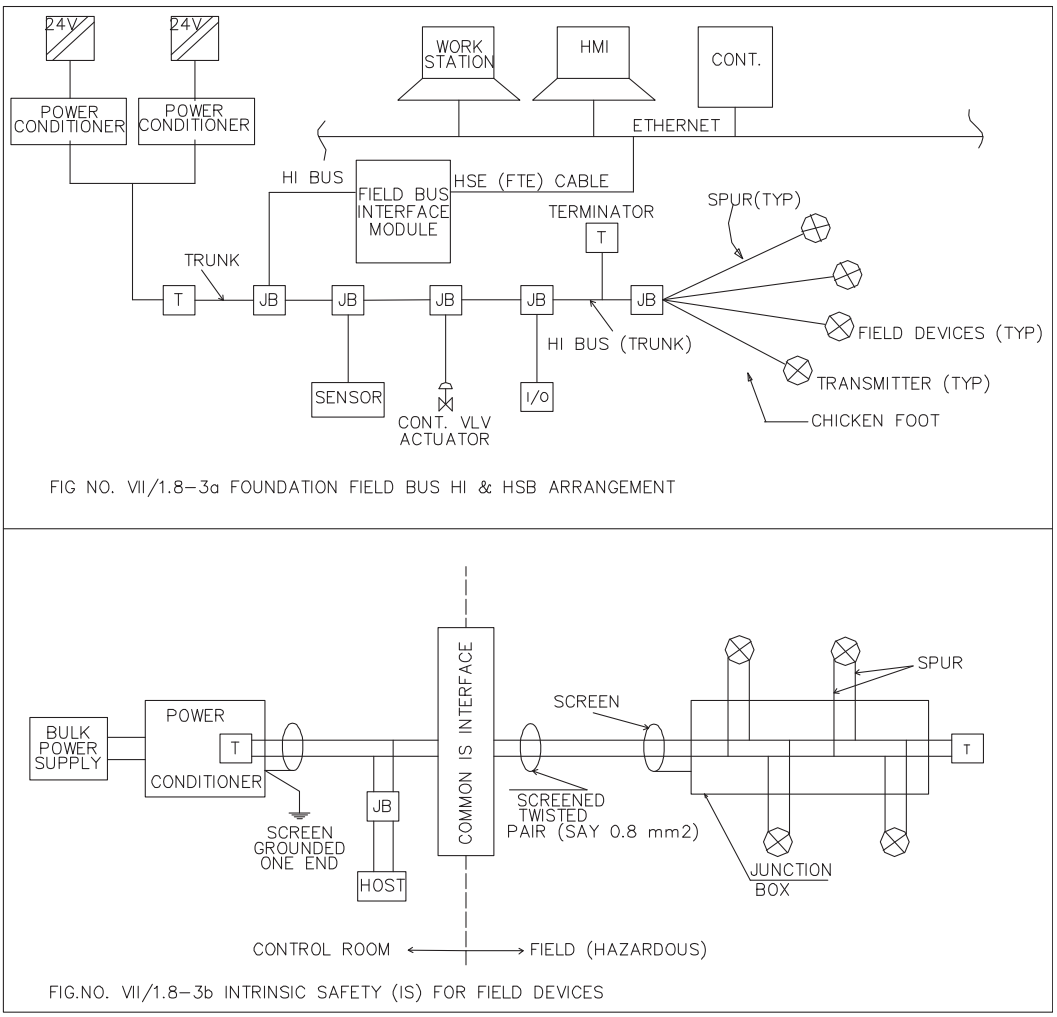


FIGURE VII/1.8-3 Foundation Fieldbus configuration.

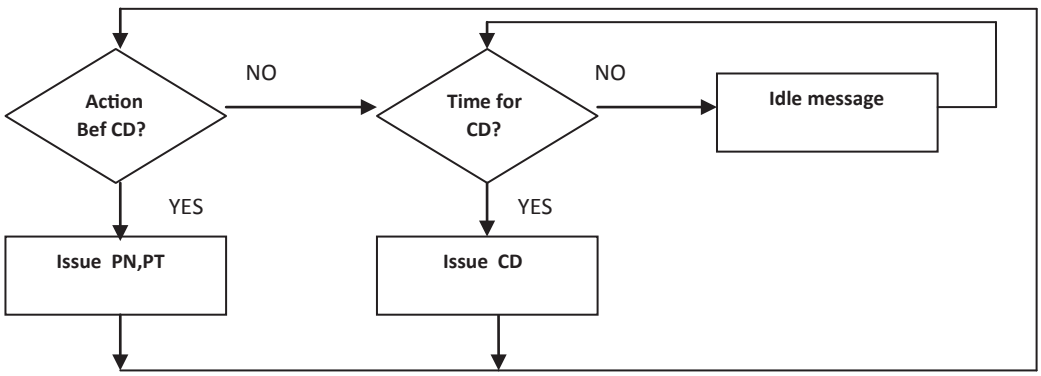


FIGURE VII/1.8-4 Communication schedule.

are used to configure various devices, the function block is used to develop control strategy.

4. *Telegram*: Complete telegram for Foundation Fieldbus is shown in Figure VII/1.8-5.

1.8.4 H1 Bus Features

The H1 bus is quite similar to PROFIBUS PA, with certain features:

www.EngineeringBooksPDF.com

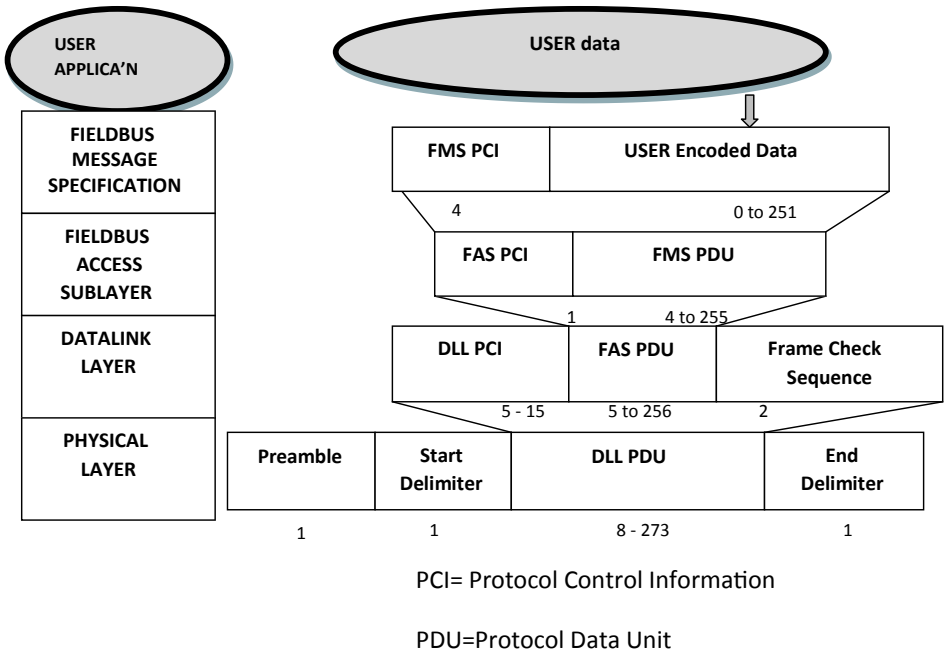


FIGURE VII/1.8-5 F Fieldbus telegram.

- For the common power and IS (where applicable) for the H1 bus minimum voltage for communication is 9 V. H1 bus communication speed is 31.25 Kbps with Manchester-encoded data; Standard is IEC 61158-2. Token passing is the communication mode deployed in an H1 bus**.** Basic units like sensor, transmitters, and I/O devices can be connected to the H1 bus.
- There are *two* types of devices in the H1 bus: basic unit and link master. The link master can assume responsibility of the LAS (see Clause 1.8.8). Max 32 devices per H1 Bus in line, tree, and star topology. The maximum number of units in hazardous units are reduced because of power supply limitations (<<32). When a number of devices are connected to a common junction box they form a chicken foot as shown in Figure VII/1.8-3.
- Although daisy chain is allowed, it is preferable to connect devices including the link master through the junction box (JB). The connection between devices to JB is called a *spur*, whereas JB-to-JB connection is called a *trunk***.** A number of devices connected to a common JB form the chicken foot.
- Maximum length of H1 bus (sum of trunk and spur) is 1900 m without a repeater with the maximum possible spur length of 120 m (see Figure VII/1.8-2). Maximum of four repeaters allowed, so the maximum possible distance is 9500 m (with four repeaters). A 1900 m connection length is possible with shielded twisted pair cables with a 0.8 mm^2 conductor. The screen of the shielded cable should be ground at one end and both ends properly terminated by resistors as shown in Figure VII/1.8-2.
- Standard bulk power supply is not fed; instead it is fed through a filter conditioner to avoid AC short circuit during data transmission (see Figure VII/1.8-3a and b)

1.8.5 HSE Bus Features

HSE is based on standard Ethernet topology with a high speed of 100 Mbps for communication-(for other features see no 2 of clause 1.8.2).

1.8.6 Linking Device

This is a device that connects one or more H1 buses to the HSE device/network, and acts like a gateway for field device access (FDA), FMS, and system management (SM) services to the H1 bus. There is a difference in speed between the H1 bus and HSE bus, so conversion of data transfer rate and telegram need to be done at this device.

1.8.7 Gateway and Host Devices

The gateway device is used to link the Foundation Fieldbus to interface with other standard bus systems like Device Net and PROFIBUS. Host devices are OPC DA so that non-HSE devices can communicate with the HSE network.

www.EngineeringBooksPDF.com

TABLE VII/1.8.8-1 LAS Functions

Activity	Discussions	Remarks
SC	All time-critical tasks have strict schedules created during configuration. Compel data are sent to the device. Cyclic data are sent according to a list. Each device has a different schedule based on its function and task.	Device (i.e., sensor) publishes specific data upon receipt of compel data and it can be received by others (i.e., CV). In SC point of time and sequence is well defined.
USC	On request device parameters, diagnostic data are sent. LAS passes token to all in the bus	Sent between break of SC. LASs grant permission to access the bus when the token is given to it. Each device can send data until the time is expired or it finishes the data transmission.
Live list	Maintains a live list to recognize the device sending data upon token passing.	
Synchronization	All devices have exactly the same time as in DLL, due to time synchronization.	
Redundancy	In case of more than one link master, if LAS fails another takes over.	

TABLE VII/1.8.9-1 VCR Types

Client/server	Report distribution	Publisher/subscriber
Operator communication	Event notification, alarm, trend	Data publication
Changes for set point, device data remote diagnostics, display access	Operator alarm, trend to historian	Actual value or PID block to OP console

1.8.8 Communication Stack

In H1 bus there are a few services available such as:

- Devices in the H1 bus that can exchange data one with other.
- Devices that are served in definite time.
- No two devices can access the bus simultaneously.
- Token management for scheduled communication (SC) and unscheduled communication (USC), the latter of which is executed in break time between SCs.

All such services are controlled by LAS responsible for control and scheduling of communication over the bus. Any link master can become LAS. There can be more than one link master in a network, and it is possible to operate the system with redundant LAS. If one LAS fails, another link master will become LAS. LAS controls many functions with the help of a series of commands it broadcasts over the bus, e.g., it broadcasts the time distribution (**TD**) signal to synchronize various operations. There are basically two kinds of communications: scheduled and unscheduled. Time-critical tasks such as process controls, etc., fall under SC. On the other hand, functions like parameterization and diagnostics are USCs. These are executed in break time between two SCs. The major functions of LAS have been tabulated in Table VII/1.8.8-1. Many of these functions of LAS are SM functions. Since LAS continuously polls the unassigned device, it is possible to include any device at any time by special command probe node (PN) and probe response (PR). Before any operation LAS refers to the list to check any scheduled task. Depending on the device, there are separate schedule times for different actions so devices know precisely the task to be performed. It waits for the idle time to start SC as shown in Figure VII/1.8-4. Here PT stands for passing token. LAS waits for a precise time to send Compel Data (CD) to activate the schedule operation.

1.8.9 Application Layer Functions

Field access sub layer (FAS) and FMS services are extremely important for functionality and performance of the Fieldbus, but are invisible to the user.

1. *FAS:* Creates the virtual communication relationship (VCR), which is like the speed-dialing system in telephone. After configuration the VCR number is entered to communicate with another field device on the bus. There are different types of VCR (see Table VII/1.8.9-1)
2. *FMS*: Standard message format used to send data across data sent over the Fieldbus as an "object description" where index 0 stands for the dictionary header, and numbers 1−255 define standard data types. FMS also defines the virtual field device (VFD) used to make the object or device description (DD) of a field device as well as the associated data available to the network. These two are used to access remotely.
3. *User application*: It is based on three types of blocks to represent different application functions: resource,

www.EngineeringBooksPDF.com

TABLE VII/1.9-1 World FIP

Features	Specification
Media	Twisted pair and fiber optics
Speed	31.25 Kbps/2.5 Mbps (maximum)
Access	Bus arbiter
Physical layer standard	IEC 1158-2/yes powering
Communication technique	Producer/ consumer—deterministic
Bus power and "IS"	Yes power and "IS" possible
Distance (m)	2000/4000 with repeater
DLL	Synchronous + message
Number of nodes	256/network in bus topology
Standard	EN50170

transducer, and function. Devices are developed based on the first two blocks, whereas function blocks are used for control strategies.

- *Resource block*: *Characteristic* of the device such as device name, manufacturer, and serial number.
- *Transducer block*: Used to *configure* the device, read sensors, and command output value.
- *Function block*: It is the *control strategy* builder input and made out of function blocks are linked over the Fieldbus. There may be many function blocks in a control strategy and these are scheduled. AI, AO, DI, DO manual

  loader, PID, and bias gain are the standard ones. *Control strategy building at the Fieldbus is unique with Foundation Fieldbus.*

1.8.10 Device Description and Common File Format

For configuration and operation, actual physical, Device Description (DD), and common file format (CFF) are important. DD and CFF are furnished by the device supplier or host. Parameters and capabilities are defined in these files and used for offline configuration. DDs help operate devices from different suppliers to work on the same bus. CFFs are standard ASCII text files used to describe capabilities and functions of the device.

1.9 World FIP

This is another available Fieldbus. Some of its basic features are presented in Table VII/1.9-1.

1.10 OPC

What is OPC? This is another tool for system integration. OPC is open connectivity in industrial automation for interoperability supported by creation and maintenance of open standards and specification. In the days of DOS-based systems, for printing in a printer, one would have to write the driver of the printer. In Windows-based systems printer support is built in to the operating system (OS). Individual printer manufacturers have CDs for run to specific data into the printer support of the OS. The idea of OPC is similar to that; OPC is a standardized interface for accessing process data.

Object linking and embedding (OLE), component object model (COM)/distributed component object model (DCOM) was developed by Microsoft. When this is applied to the process control, OPC (OLE for process control) is developed. OPC is based on the Microsoft COM/DCOM standard and has been expanded according to the manufacturer's requirements when they need access to the data in

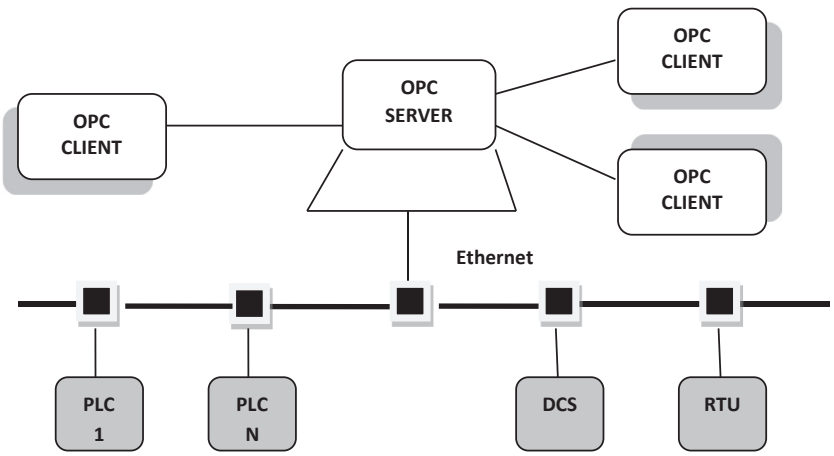


FIGURE VII/1.10-1 OPC client server architecture.

www.EngineeringBooksPDF.com

the area of automation. Industrial automation product manufacturers can write OPC data access servers and software and could become an OPC client. Typically OPC clients are programs for the acquisition of operating data. OPC servers are provided for PLCs and Fieldbus cards. An OPC server is an *executable program*, which is started when the connection between the server and client is made. Because of DCOM characteristics, it is possible to access the OPC server even if it is another computer. Also due to COM characteristics, different languages such as C++, JAVA, and Visual BASIC can be used. Some of the features of an OPC are below:

1. *OPC data access*: Used to move real-time data from control systems like PLC, DCS, and RTU to a Man Machine Interface (MMI) or any other client.
2. *Alarm and event*: Alarm and Event notification such as process alarm, operator's action, information messages, tracking, etc., are provided to the client on demand and on event happening.
3. *OPC batch processing*: Special requirement—not so relevant for power plants.
4. *OPC data exchange*: This is most the important part for interoperability in a multivendor environment, in the form of data exchange between server to server and client server. This service includes but is not limited to add remove, diagnostics, monitoring, and management systems across the Ethernet and Fieldbus system as shown typically in Figure VII/1.10-1.
5. *OPC historical data access*: This gives access to the stored data for trending. Historical data archiving has set rules.
6. *OPC security*: OPC specifies the controlling rules for the client access to the server to safeguard the sensitive information as well as to prevent unauthorized modification.
7. *OPC XML data access*: XML is a language for encoding information in a machine-readable form, mainly used on the Internet. XML DA provides a simple, generalized, and flexible consistent rule for exposing plant data.
8. *OPC unified architecture*: This is not based on Microsoft but on a unified system that provides standards for cross-platform capability.
9. *OPC certification*: Self-certification, interoperability workshop, and third-party testing are ways to get certification for an OPC-compliant system.

TABLE VII/1.11-1 Characteristics and Implementation Methods for Fault Tolerant System

Characteristics	Implementations methods
A number of single points of repair	Replica
FA fault isolation	Redundancy
Fault limiting	Diversity
Available redundant or diverse route	Fault tolerance

1.11 Fault Tolerance

Fault tolerant systems continue to run in the event of failure of some component (or due to one or more fault). Fault tolerance may mean graceful degradation of the system, but it continues to run as a degraded system, and operating-quality degradation is proportional to severity of failure. Fault tolerance may not be restricted to one machine or to an entire system. In TCP/IP (see Clause 1.2.2), packet switching is continued even if the link is improper, resulting in degradation in communication. Fault Tolerant features are described in Table VII/1.11-1).

In *intelligent systems* the fault tolerance needs to be treated a little differently. The fault may occur both in software and hardware. It may be argued that the software faults are *almost* all due to design failure, such as error in interpretation of the specification or error in implementation of the algorithm. In software, fault tolerance can be conceived as a way to provide redundancy service to comply with the specification, in spite of the fault. This is true when the error is not due to design fault. Otherwise design fault would be replaced in multiple places. This means that emphasis is put on the specification in defining whether it is fault or not. This puts a great deal of pressure on the designer Now it is to be judged whether this is an exception handling or fault tolerance. Therefore fault tolerance in software is not a solution in itself. Software fault tolerance is the ability of the software to detect and recover from a fault that has happened either in the software or in the hardware (in which the software is running), in order to provide service as per the specification. Therefore fault tolerance can be implemented by software, embedded in hardware, or a combination of both. In different Hazard analysis of the system e.g. FMEA LOPA etc. it is possible to detect such software design faults but this is beyond the scope current discussions.

When a control system provides satisfactory performance even in the presence of variations from its original model without change in structure and parameter of the control loop, then the control system is *robust*. This may be due to any fault in the original model could not be used and a diversified model has been used instead (without change in structure and parameter of the control loop). Now if the control loop's structure and parameter can be changed in the event of failure, then the control loop is said to be reconfigurable. Therefore, a fault tolerant control system can be characterized as robust, reconfigurable, and/or a combination of both.

www.EngineeringBooksPDF.com

Fault tolerant systems provide improved system reliability, survivability, and maintainability. To achieve a high degree of automation, the controller must be have the capability of additional performance requirements over a conventional control system whose major task is to track and regulate. One such additional task, high-degree autonomy, requires that the system is fault tolerant—meaning adaptation to the changes in the plant, environment, and control objective, i.e., to achieve reliability it must detect failure, isolate it, and if possible, contained it. So far discussions have been restricted to fault tolerance to a few loops or control systems in the network. Vendors have now come out with a Fault Tolerant Ethernet, which is included in Appendix IV.

1.12 Control Intelligence

What is artificial intelligence? It is the branch of control engineering (discussions restricted to control systems only) that makes intelligent systems, especially intelligent computer programs used to solve control system problems. Both conventional as well artificial intelligence strive to harness mathematical models and a logical approach. Power plants keep on expanding in terms of size, geographical area assets management, and penetration of new technologies. Naturally with conventional control theory the optimum performance may not be achievable, because in those cases the plant is often considered as a linear system, with little or no interaction. Nonlinearity coupled with plant dynamics makes it impossible to get a complete solution with conventional control theory. In power plant applications expert systems and fuzzy logic have more application. Our discussions will be restricted to these systems. A few application areas of expert systems and fuzzy logic in power systems are listed below:

- Power system operation including economic dispatch, load power flow, and maintenance schedule
- Power system planning, including generation expansion and reactive power planning
- Power system control such as voltage control, load frequency control, etc.
- Power plant control, such as complete control of boiler and turbine, including coordinate control
- Power system automation, heuristic

The complexity of a dynamic system model and the increasing demand for closed control loop performance for power plants necessitates the use of complex and sophisticated control systems. As stated earlier, deterministic feedback control is suitable for a linear power plant system, with high noise in applications, and suitable Kalman filter. Other filter arrangements and loop performance can be improved. When there is significant variation in plant parameters, the robust (see Clause 1.11) control loop alone is not suitable, so the control system needs to be adaptive also. For highly complex control systems, a self-learning/heuristic approach may be necessary.

1.12.1 Expert System

Expert system is an artificial Intelligence computer program that achieves expert-level competence in solving problems in specific task areas by ringing a model of knowledge about that specific task. So this is a knowledge-based system or expert system. In most cases the knowledge-based system is built around the knowledge base used by a human expert. Each system has a domain of operation called a task domain, which needs to be well defined. Some of the basic task definitions are given in Table VII/1.12-1.

All the tasks defined above need to be cyclical and dynamic, which can reconfigure the control system in real time. Expert systems in control applications are normally rule-based systems with a database, rule base, and an interpreter known as an *inference engine*. Expert systems draw the inference based on the knowledge base. These inferences are expressed as parameters. These parameters are rule or external to the system. IF THEN rules develop the premise, whereas other parameters are connected by logical AND/OR. Abnormal behaviors, when detected, are reported. One of the major disadvantages of the system is that it suffers from the bottle neck of adapting to a new situation. However, it has following advantages:

- Permanent and consistent
- Can be transferred and reproduced
- Easy documentation and development

1.12.2 Fuzzy Logic System

Fuzzy logic developed by Zadeh was created to address uncertainty and imprecision, which widely exists in engineering problems. From experience it is found that an experienced operator controls a plant boiler by monitoring all major parameters and adjusting a number of them. When steam

TABLE VII/1.12-1 Some Expert Task Definitions

Task	Requirement
Interpretation	Complete analysis of data, correctly, consistently
Monitoring	Alarm/event reporting
Diagnostic	Fault finding and analyzing
Prediction	Forecasting future based on knowledge in time
Planning	To define action for result to achieve goal
Design	Creating object and satisfying requirements specified

www.EngineeringBooksPDF.com

temperature is falling, the expert operator not only controls the spray valve at the same time, but is also looking at the feed water flow control. Similarly when a plant is loading, by increasing the air flow there will be effect on furnace pressure. Just like in daily life, various parameters have to be adjusted precisely in an up and down manner to get the optimum result.

Fuzzy logic is based on generalized set theory. In a fuzzy set the degree of association of an element continuously varies. The beauty of fuzzy logic is that it is also understood by a nonexpert. Other advantages of fuzzy logic include softer constraints and more precise operational constraints. Coordinate control, steam temperature control, and feed water flow control are classical examples where fuzzy controls can be deployed. As discussed earlier, steam temperature control is coupled with feed water flow control, but by using fuzzy logic the control system can be decoupled by decoupling strategies such as a decoupling controller, gain scheduling, etc.

1.13 Firewall

A firewall traps inbound and outbound information packets, analyzes them, and then either allow them to establish communication or discards them. The firewall is a subsystem of computer hardware and software that intercepts the data packet before allowing it in and out of the LAN/server. It is a kind of security used mainly for networks in the public domain. A firewall is one type of security (or check point?), but control systems may have vendor-specific separate security systems as well. General discussions on firewalls are presented in Appendix IV.

TABLE VII/1.14-1 Security Issues in Control System and IT

Security issues	IT	Control systems
Antivirus and mobile code	Commonly used	Almost impossible to use for Vulnerability
Time-critical contents	Delay accepted, generally	Real-time, no delay
Availability	Some delay/ interruption generally acceptable	Unacceptable has to be 24/7
Security awareness	Moderate in all sectors	Not much developed except physical means
Physical security	Secure (server room)	Remote unmanned—secured
Patch application	Regular interval	Rare, in some cases vendor specific

TABLE VII/1.14-2 Control System Security Attack Types

CSS attacks	Discussions
Backdoor intruders	1. Holes for intruding discovered by the attacker due to unintentional error or overlooking of system architecture perimeter design or fixing boundary for capabilities of the system. 2. To provide better connectivity, many times the security perimeter of the control system is compromised and/or deployment of robust access technologies, such as Public Facing services, etc., are required without proper security analysis of the control system. 3. For Wireless communication there is a problem called "residual effect." Once an attacker discovers an access point in wireless communication, which have been made better without a proper security check, he will gain privileges to tamper or gain control of the network. 4. Many intruding problems in an IT network can be managed by patches. This is extremely difficult in CS, especially when there are remote locations. 5. Many networks, such as for an electric company, need to share some data in the public domain, but these are generated in CS, e.g., electric power generation, frequency of operation, etc. In such cases it is better that CS shares the data with a business server (with a firewall) that may share a server with a Web server through proper firewall access. This is because many times an attacker collects important information from public servers. A firewall must separate a public server from an internal network.
Attack through field devices	1. Most of the field devices available are IT compatible (e.g., transmitters), Many modern devices have embedded file servers to provide operational and maintenance data. Operators and administrators have a secondary access. These were initially made for trusted network use only. In an integrated system, attackers gain control over these field devices by creating a tunnel path to the control system to access viable targets connected to network security-related issues. 2. When a device is compromised an attacker may gain control and even attack the master controller.

Continued

www.EngineeringBooksPDF.com

TABLE VII/1.14-2 Control System Security Attack Types—cont'd

CSS attacks	Discussions
SQL data injection attack	1. Database is an important aspect in CS. In the traditional use of these systems, the security-associated computer and software of the related devices were looked over. 2. In an IT network, the database is mainly managed with SQL. 3. When these two networks are connected an attacker may gain access to control data via an IT database, which may share CS data. While making such an intrusion, an attacker may disregard the protection mechanism for the control system, and may gain control over the control database.
OPC attack	1. OPC is extensively used in control systems for connectivity. 2. OLE, COM, and DCOM are used in common computing environments. 3. Convergence of isolated control systems with a business network poses a big problem and CS becomes vulnerable to attackers. The use of patches, as in IT, is a big challenge in a control network.
MITM	1. ARP helps maintain a route with a mapping network address to the physical address. 2. Attackers poison this ARP table and can force all network traffic, including control traffic, through the computer of the attacker. All resources on the network would talk to the attacker without knowledge. 3. In open architecture, data in transit is a major concern. MITM is exceptionally dangerous to a CS as it can stop the process and can capture, modify, and falsify information showing good data to the HMI and wrong data to the field device.

ARP, Address Resolution Protocol; CSS, control system security; MITM, man-in-the-middle attack; SQL, structured query language.

1.14 Security in the Control System

Control systems evolved from standalone systems to interconnect networks that coexist with IT networks. Since these two environments, IT and control systems, are not the same, such integration at times introduces various security threats to the control network. With embedded firmware there is less impact from the mobile code in the form of a virus. On the other hand, a complete integrated network is easily affected with mobile codes like a virus, similar to IT networks. With complete integration of different networks, such as a corporate network, Web server, etc., with a control system in a TCP/IP environment this is not uncommon (it may be economical too). However, this gives rise to cyber or technological vulnerability for the control systems. Keep in mind that traditionally control system communications have *less security* (for isolated operation earlier) and the system administrator needs to be aware of the *capabilities* of the security supplied by the system vendor. The threats to the open architecture can mitigate to the control system domain as an unauthorized intruder for gathering data either through or around perimeter defenses. To develop a proper security system for the control network, it is essential to know about different security threats (see Table VII/1.14-1). Large networks as a whole have their own security, but these may *not* be sufficient for control system vulnerability, because they are mainly based on IT security, which may not suit some control systems. Some of the unique features of the control system are compared with IT systems in Table VII/1.14-1)

1.14.1 Types of Threats for Control System Security

Today people place more emphasis on business facilities, so in many cases networks are connected to each other including the control and operational network. Also open systems are the state of the art for control networks, which often makes the system vulnerable if adapted without proper security checks. Some of the probable sources of cyber attacks are discussed in Table VII/1.14-2.

2. PLC SYSTEM: INTRODUCTION

What is PLC system? A programmable control system is a digital computer deployed for automation and monitoring of electromechanical and/or electrochemical processes. The applications of PLC in power plants includes a burner management system (BMS)/automatic turbine run up system (ATRS) etc. Because of its versatility often people refer to them as the "Cinderella of control."

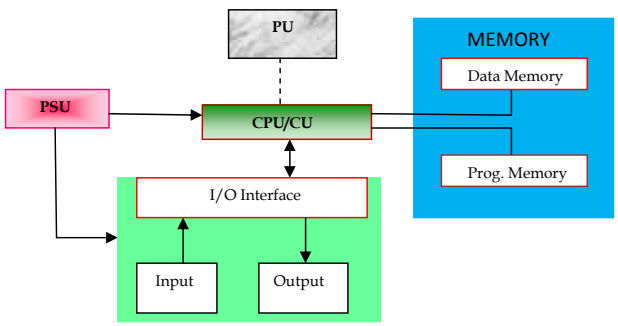


FIGURE VII/2.0.1-1 Basic PLC configuration.

www.EngineeringBooksPDF.com

Normally when ratio of the digital to analog signal is high, PLCs find their applications from an economical point of view. On the other hand, DCSs are used for data acquisition systems (DASs), PIDs, and other complex control algorithms, and naturally the response and reaction time in a DCS could be more when compared with a PLC. For these reasons PLCs are popular in the ATRS, BMS, and soot blowing (SB) controls in power plant. However, in mid- to large-sized power plants a DCS is more poplar when compared with a PLC. Today, the capability of the PLC has increased so much that it is rather difficult to really distinguish between a DCS and a PLC. If one analyzes the systems very closely, PLCs may have a few advantages when compared with DCS, as listed below:

- Flexible, modular, and smaller physical size
- Less complicated application with easier programming and reprogramming
- Easier networking and interface with third-party devices
- Easier expansion and system modification provision
- Low to moderate cost

2.0.1 PLC Basics

In its basic form a PLC may be conceived as combination of five basic units connected via a bus in a configuration shown in Figure VII/2.0.1-1.

- Power supply unit (PSU)
- I/O system has I/O devices
- Central processing unit (CPU)
- Memory is program memory and data memory unit
- Programming unit (PU)

Apart from these basic units, there are a few other features to be supported, e.g., operator workstation (WS), interface to third-party devices, and/or connection to the main plant control system. To achieve these, a communication module and interface devices would be necessary. All of these give rise to variations in the system configurations and intelligence.

1. *PSU*: Generally the power supply is a separate module in the chassis, but it could be an integral part of each module also. The basic purpose of the PSU is to provide

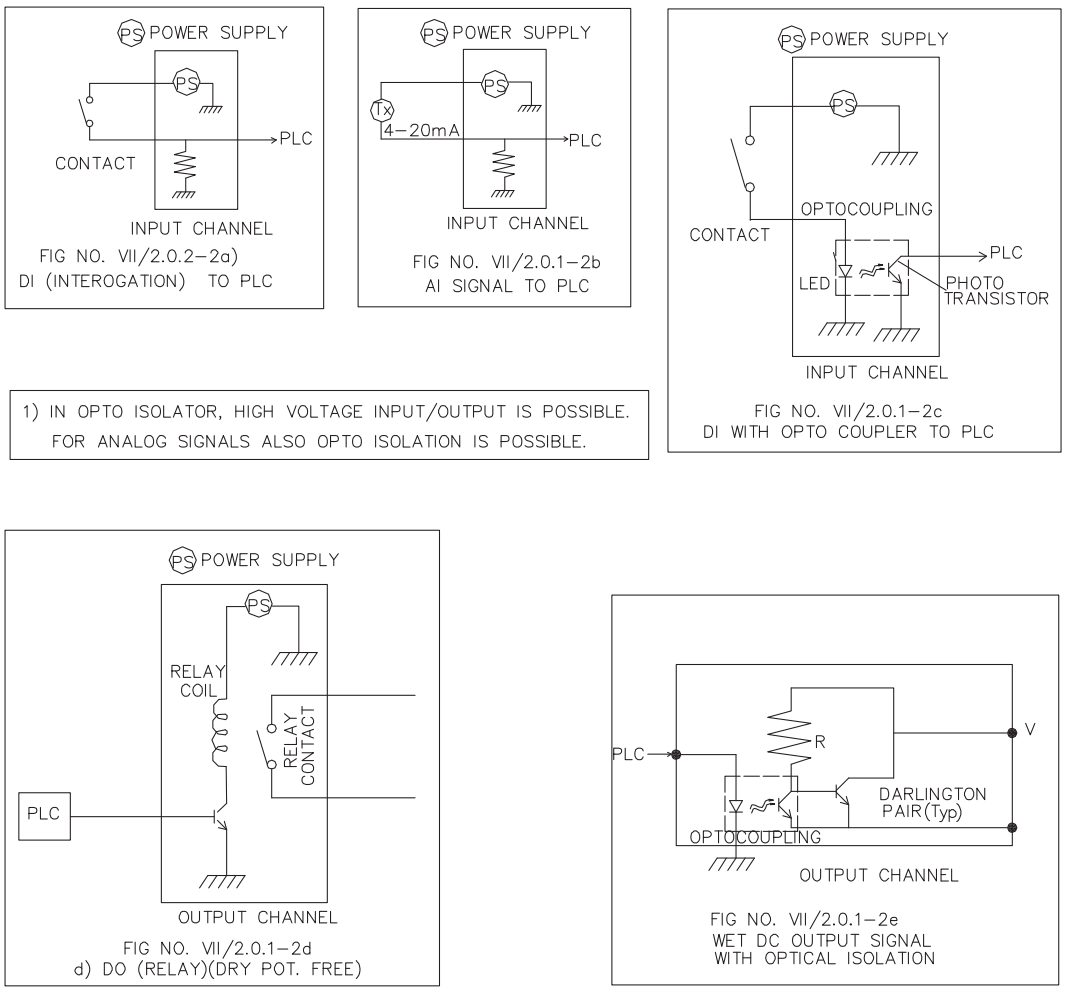


FIGURE VII/2.0.1-2 PLC I/P output signals.

www.EngineeringBooksPDF.com

a power supply of desired quality (voltage, type, etc.) to the modules so they function properly. These power supplies generally include necessary isolation and protection from line disturbances. The PSU must have the necessary heat-dissipation capability and should be rated suitably to supply the necessary driving power to all modules. If there are remote I/Os, then a separate power supply in the remote I/O chassis is necessary. A common power supply is 24 VDC; however, each manufacturer specifies the power supply required for its system. It is quite common to use separate interrogation voltage (may be higher than the power supply voltage) to avoid channel noise. What is interrogation voltage? It is the voltage of supply from the PLC by which input contact status is sensed in the system. In cases higher interrogation voltage is used, such interrogation voltage must be available for I/O devices.

2. *I/O system*: Comprised of input (I) and output (O) devices. Input devices are momentary or permanent digital signals from various contacts, such as from process switches, electrical switches, push buttons, and/or registering inputs such as from a thumbwheel (BCD), etc. In addition to digital inputs, there are analog and pulse inputs, e.g., RTD/TC, 4-20 mADC from process transmitters, and pulse input from flow meters. While choosing the required input module, it is necessary to decide the number of inputs in one module, interrogation voltage level (for larger distances higher interrogation voltage may give better noise immunity), and type of input (single or differential mode). It is also important to decide whether the input should have any isolation circuitry like optical/galvanic isolation, etc. Output devices, like input devices, can be digital output for a solenoid valve, MCC, or analog output to drive the final control actuator. There may be registering type output to drive panel meters also. While choosing the required output module, it is necessary to decide on the number of outputs in one module, output voltage level, type of output, allowable load, etc. Output could be a potential free contact (contact rating and type is an important aspect here), wet output (e.g., TTL), direct AC output, analog output, and/or special output for motion control and/or servo positioning control. Typical I/O interfaces are depicted in Figure VII/2.0.1-2a–e.

TABLE VII/2.0-1 CPU Tasks

Step	Function	Explanation
1	Input scan	To scan all the inputs connected to the PLC and present the data to the CPU
2	Program scan	To execute the user program to perform PLC functions
3	Output scan	Present the result of the program to the output devices to energize and de-energize output devices
4	Housekeeping	Internal diagnostics and communications.

3. *CPU or control unit (CU)*: This is the heart of the entire system. It performs all the tasks meant for the control system. Major tasks of the CPU include the following:
   - Scanning inputs and allocating outputs
   - Execution of the Program
   - Driving Peripherals and communication with external devices
   - Traffic control on system data hi way
   - System Diagnostics etc.

   The microprocessor, along with main board memory, forms the major intelligent unit of the system that carries out all of these tasks in a faster and more flexible manner. The CPU internal program enables the PLC to execute control instructions embedded in the user's program. This is stored in nonvolatile memory or memory with battery back-up so that nothing is ever lost. Housekeeping (such as to check the health of

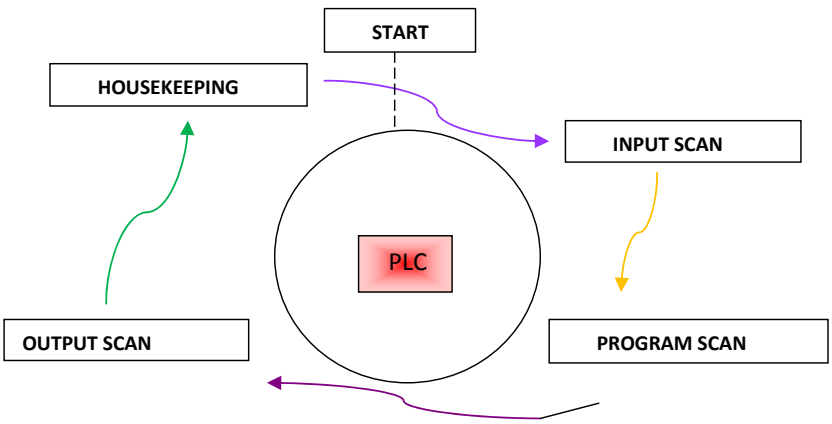


FIGURE VII/2.0.1-3 PLC operating principles.

www.EngineeringBooksPDF.com

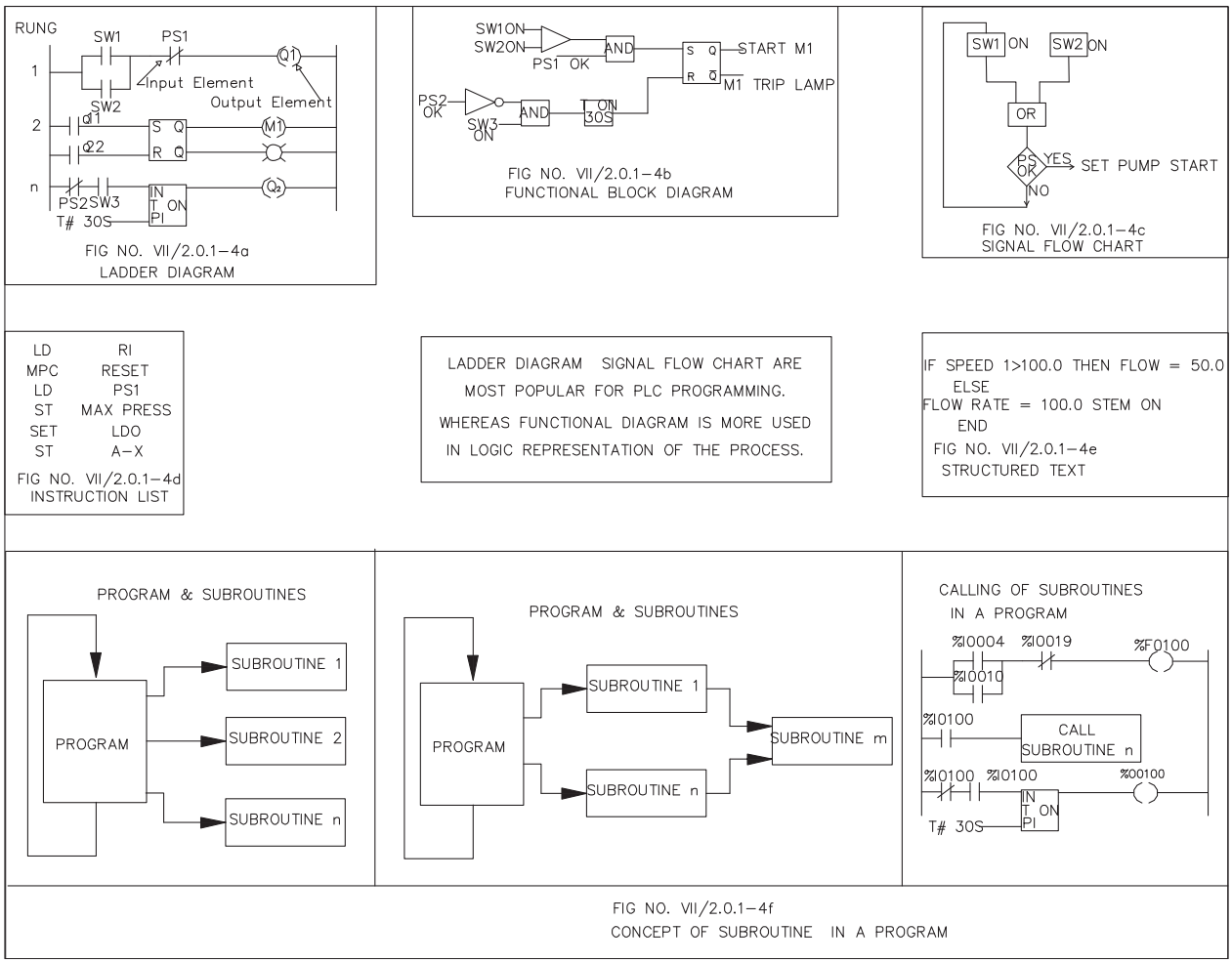


FIGURE VII/2.0.1-4 Programming language types.

the devices, internal communication with other systems, etc.) is another important task the CPU performs.

When the system starts after initialization, it performs four main steps (as given in Table VII/2.0-1) in a cyclic manner as shown in Figure VII/2.0.1-3.

Word size and scan time actually gives indications about the performance of a PLC. Word size from 8–32 bits and a scan time of 0.1 ms is typical for PLCs.

4. *Memory:* The memory unit plays a large role in the functioning of a PLC. One part of the PLC memory is used for PLC's executive program or OS necessary to execute the user's application program and interruption handling. There are two basic parts of the memory, program memory where the user's program resides and data memory where process data from I/O is stored. Volatile memories are backed up with a battery. The division of memory between data and program enhances performance of the PLC. Size of the main memory is guided by the CPU selected. Integral RAM should be sufficient to store small programs, whereas for a large PLC memory can be augmented to 64 MB. These may be battery backed up too.
5. *PU:* The interface between user and PLC during program development and loading. Starting from a small calculator-sized hand-held unit, a PU can be a full CRT-based system also. Many manufacturers utilize a PC with a programming tool for program development. Program development can be both on and off line.
6. *Miscellaneous units:* In addition to the basic units discussed so far, there are other units called peripherals for operational aid such as color graphic CRTs and printers. There is program aid such as a PC-based system with a license for special software, remote I/O, etc. Also there can be specialized panels for the operator to operate the plant. Other operation aids include interface devices such RS 232, RS 422, etc., to link with other devices.
7. *Program language:* Programming languages and methods normally used include but are not limited to the following:

www.EngineeringBooksPDF.com

- *Ladder diagram (LD)*: A graphical programming language to show opening/closing of relay, counters, timers, flip flops, shift registers, etc., as shown in Figure VII/2.0.1-4a.
- *Functional block diagram*: As shown in Figure VII/2.0.1-4b, this is a graphical language used to depict the functional relationship among various functional blocks. This is very useful for control loop and logic representations.
- *Signal flow chart (sequential function chart; SFC)*: It is a special Block representation with suitable direction graphics to elaborate the logical function. It consists of branches and nodes, as shown in Figure VII/2.0.1-4c.
- *Instruction list (IL)*: Like an assembler language, it uses instruction sets to bring out PLC logic (see Figure VII/2.0.1-4d).
- *Structured text (ST)*: As shown in Figure VII/2.0.1-4e, it is a high-level text language similar to PASCAL.

8. *PLC operational aspect*: CPU tasks in Table VII/2.0-1 are discussed below
   - *Input scan*: At this portion the scanning of inputs takes place when input data are stored in appropriate storage, provided the CPU is not in STOP mode and I/Os are enabled. Scanning is skipped when the I/O is not enabled.
   - *Program execution*: Immediately after the input scan program execution or logical operation is implemented when CPU is in run mode. In this part of the program, the application program will be executed according to the logic and the output will be updated. Ladder logic should be executed and/or subroutines (see Figure VII/2.0.1-4f) should be called if necessary in the program until the end of the program is reached.
   - *Output scan*: Outputs are scanned immediately after program execution. Outputs are updated. At this stage, if the application calls for it, global data should be updated also.
   - *Program communication*: This is executed when the program device is connected and there is a service request from the programming device. Thus communication with the programming device is established.
   - *System communication*: When there is a service call from intelligent modules, this is executed. If there are time-consuming requests, they may be distributed in several cycles of the program.
   - *Reconfiguration*: In this part, the CPU checks the actual hardware configuration with a configured system. Empty module and faulty modules are not scanned. If the CPU detects a module not working it will replace it with a good one or an added module. Then it will reconfigure itself to include this in scan cycle. During this period, it recognizes changes in configuration.
   - *Checksum:* It is the last stage in each program cycle. It calculates the check sum and compares it with the reference check sum. In case of mismatch, its reference value will be flagged as a program failure. It has the following functions executed at the initial stage:
     - Calculation of each program cycle time
     - Schedule start of next program cycle
     - Update fault table
     - Set/reset watchdog timer
     - Diagnostics
9. Basic points for selection of PLCs in one application may include:
   - PLC powering voltage type, value, and system current rating
   - Scan time and word-processing capability
   - Available memory to cater to the application
   - Software and programming language
   - I/O capability including analog signal-handling capability
   - Remote I/O handling capability
   - Environmental requirement (especially for remote I/Os)
   - Programming and connection of user with PLC
   - Networking and Fieldbus capabilities.
   - Third-party device integration OPC
10. *PLC in power plants*: It is likely that various control systems supplied for a power plant may be from different vendors, e.g., steam generator suppliers may include integral control systems for BMS, SADC, SB control, HP bypass, etc. Similarly turbo generator suppliers may supply integral controls systems like ATRS, automatic turbine testing (ATT), TSE, etc. Third parties supply the main DCS. Also there is a number of off sites whose suppliers may also supply different controls. So it is quite *improbable* that the same system from a single supplier could be selected for all of these control systems. It is necessary to connect different systems from different suppliers. This integration is not an easy job, because in the case of intelligent systems compatibility of electrical connections alone will not suffice. It requires compatibility in physical connections, protocols, networking speed, etc. It is extremely difficult to integrate them unless all of the systems offer openness and transparency in communication. This may be difficult, but it is not impossible. Today everybody looks to curtail cost, so one way to do integrate is to use Fieldbus systems to cut cable cost. It seems that many important pertinent criteria need to be considered before one a PLC is selected.

www.EngineeringBooksPDF.com

2.0.2 Salient Features of PLC

For mid to large power plants integrated system is a call of the day. Some these features include the following:

1. *Availability*: The system to be designed should be available at all times. Down time in the PLC or in any automation will cripple the entire process and may lead to a catastrophic situation. This may result in a costly loss. A few considerations toward that would include:
   - There is redundancy in a system controller, I/O server, etc., so that lost capability can be overcome.
   - A typical problem associated with redundancy is finding suitable means and methods for such a change over and associated cost. Systems need to be configured and designed in such a way that such a changeover is smooth and scalable in critical areas so that the system is cost-effective.
   - Early fault detection.
   - Online change of configuration/system parts.
   - Fault tolerance can be characterized robust, reconfigurable, or both. So a fault tolerant system has better reliability, availability, maintainability, and survivability.
2. *Down time reduction—diagnostic*: Automation system should have an integrated self-diagnostic feature in modules so that the diagnostic feature is distributed throughout the plant. These may have features like
   - Module identification
   - Time stamping
   - Error message in Man Machine Interface (MMI) with different degrees of detailing and status
3. *Flexible I/Os for various plant conditions*: I/Os suitable for various conditions include SIL (discussed later) rated I/O modules, IS I/O (if called for), etc. These are needed for applications like BMS ATRS, etc.
   - SIL rating as applicable with possibilities of intermixing standard I/Os with a fail-safe I/O to have a compact, completely integrated automation system with international certification.
   - IS I/O if applicable, with necessary international certification
   - I/O intelligence
   - Configurable I/O modules
   - Scalable I/O system
4. *Security*: Seamless exchange of data and IT compatibility to access data from any location in an open system. Naturally there should be comprehensive (see table VII/1.14-2 also) security at all levels. Some of the applicable features for PLC may include:
   - IT Standard security like micro firewall (to prevent all unauthorized access to the PLC devices without obstructing valid PLC control commands), Virtual Private Network (VPN; for authentication of communication between genuine partners to avoid unauthorized data modification and disclosure of system data and encryption), and Wired Equivalent Privacy (WEP) in a wireless network as part of IEEE 802.11 protocol for confidentiality.
   - Physical separation and accessibility at various levels should have self-autonomy.
   - System management for all securities without interrupting the main operation.
   - For control system security see Clauses 1.13 and 1.14 and Appendix IV.
5. *Open architecture*: It is preferred that the systems have open architecture to integrate various networks as well as have an industry standard Fieldbus such as Foundation Fieldbus, PROFIBUS, etc. IT-enabled systems make it possible to integrate various systems together such as drives and MCC also.
6. *Communication*: One complete integrated system comprises various levels such as field, controller, operator management, and corporate levels. This type of system must have a highly developed communication capability to transparently exchange data at all of these levels. Some of these features include but are not limited to the following:
   - Combination bus system such as PROFIBUS and Foundation Fieldbus
   - IT compatibility
   - Integration of office system
   - Integrating communication of wireless LAN
7. *Engineering and software:* Control system software should be capable of meeting the specific needs of different control applications for power plants, with special attention to safety and complexity of applications (with expert solution as applicable). Major key features are
   - Block wise modularity
   - Data consistency
   - Shared configuration for the entire plant automation
   - Open data interface (e.g., GSD OPC etc.)
   - Standard programming language, e.g. IEC 61131-3 compliant
8. *Expandability, scalability, and cost-effectiveness*: A system with a modular flexible design can start with a single controller with a few modules then, depending on application, can be built into a giant system. A large system can be integrated utilizing several controllers, field devices, and workstations—communicating over Fieldbus and Ethernet. This means that the system has the flexibility coupled with capability and power to integrate. In a scalable system there will be a wide selection of CPUs and I/Os, to meet the system requirement, and system availability without incorporating unnecessary redundancy in the system. This means that common

www.EngineeringBooksPDF.com

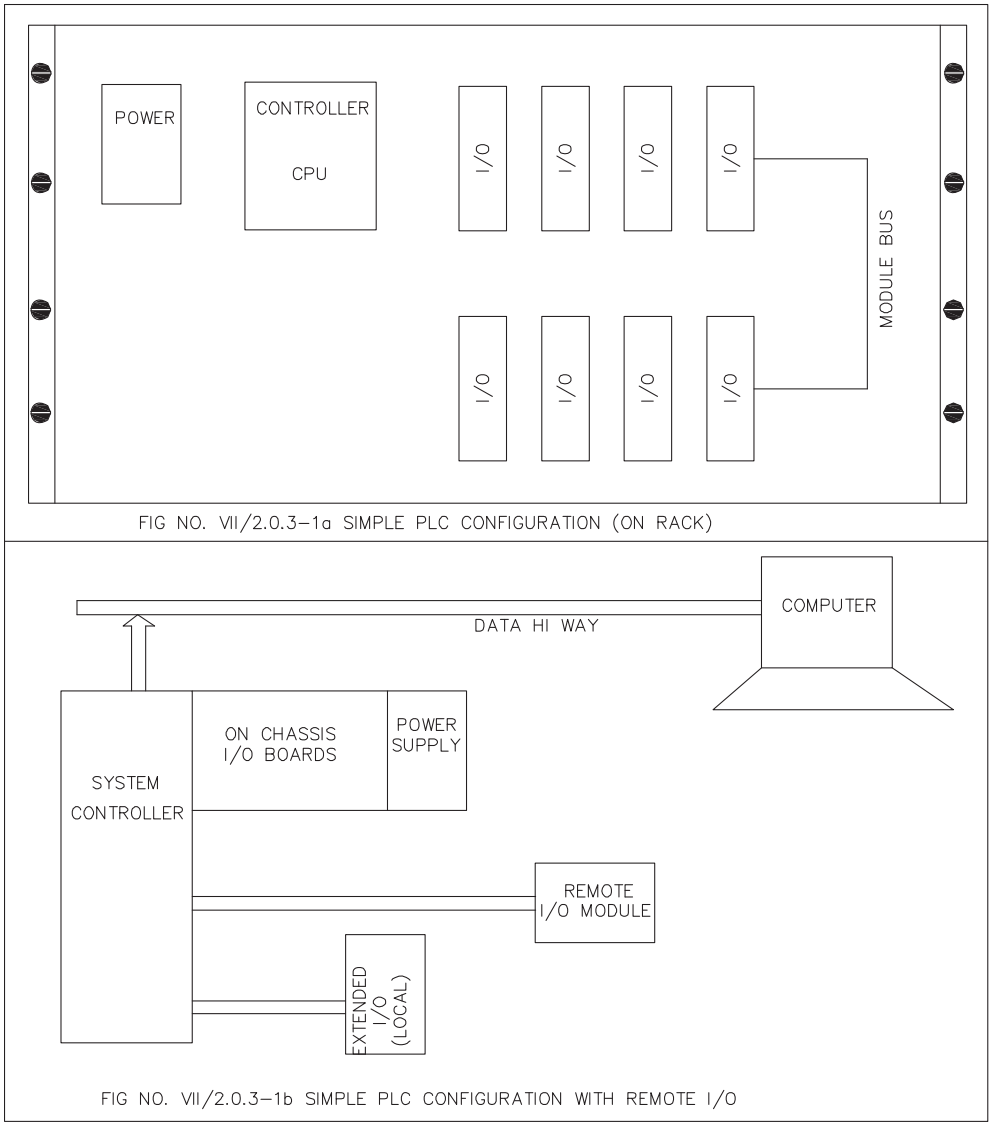


FIGURE VII/2.0.3-1 Simple PLC Configurations.

hardware and software (freely configurable modules) would be used for both small and large systems.

2.0.3 PLC Configurations

Some commonly used configurations are discussed below:

1. Simple *PLC configurations*: In Figure VII/2.0.3-1a, a PLC with on-chassis I/O cards and power supply system (based on layout, the chassis can be single or dual) is shown. Here all I/Os are local to the PLC controller. Based on selection of the CPU, there will be a limit of such I/Os. Normally 512/1024 I/Os are supported in this simple PLC. Such configuration may be suitable for control systems in a circulating water system (CW) and auxiliary cooling water (ACW) in power plants as long as they are working independently. If this needs to be connected to the main control system, then some extent of modification may be necessary. In Figure VII/2.0.3-1b, a modified higher system with remote I/Os is depicted. When the application demands additional I/Os, then a limited number of I/Os can be added as extended I/Os. The volume of such an extension depends on the type of PLC chosen. In this configuration extended I/Os are connected to the PLC controller, but they could be connected to the system with the help of an extension module in the main chassis. Sometimes it is desirable to have a remote I/O connected to the PLC. A typical application of remote I/O in a power plant could be in the raw water pump house I/Os or pretreatment plant I/O connections to a demineralized (DM) plant PLC. In these cases all I/Os are terminated at the remote I/O

www.EngineeringBooksPDF.com

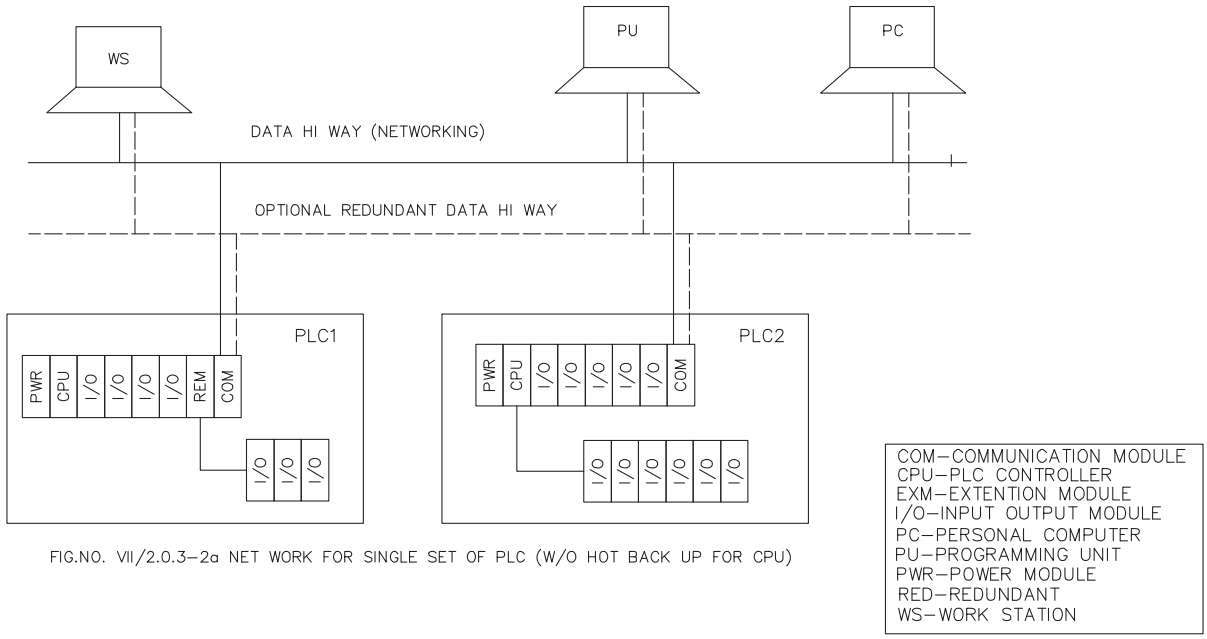


FIG.NO. VII/2.0.3–2a NET WORK FOR SINGLE SET OF PLC (W/O HOT BACK UP FOR CPU)

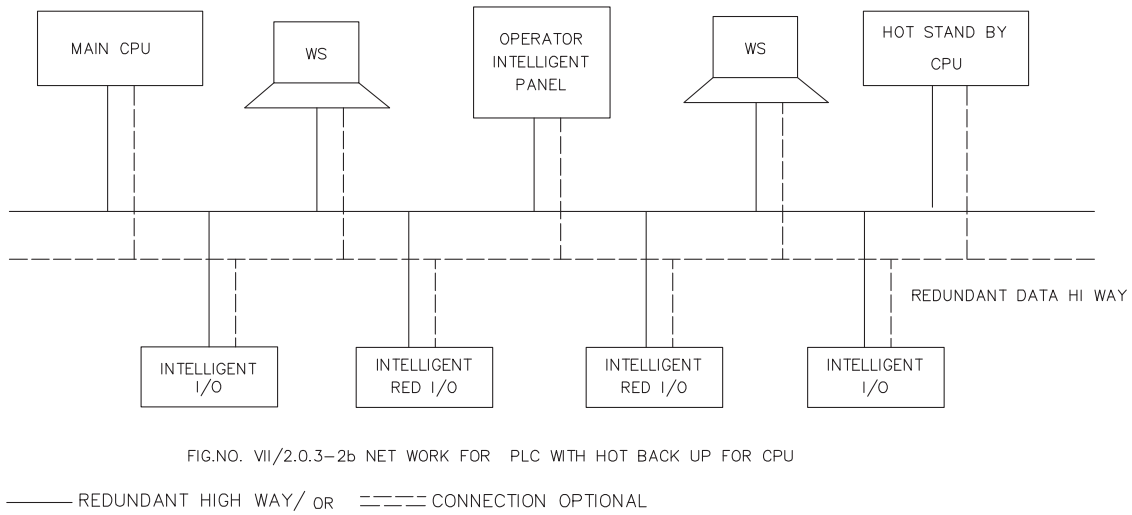


FIG.NO. VII/2.0.3–2b NET WORK FOR PLC WITH HOT BACK UP FOR CPU

REDUNDANT HIGH WAY/ OR CONNECTION OPTIONAL

FIGURE VII/2.0.3-2 PLC networking.

cabinet/terminal board, which is connected to the PLC through a serial link. This can be done with the help of a Fieldbus also. In this configuration, a data highway is shown to connect a computer. Here there could be a workstation(s), a programming station, and/or another PLC of the same family, as shown in Figure 2.0.3-2a. "DH +" of AB/Rockwell is an example of the same. In the data highway other computer systems can be networked in the form of the Ethernet. Such standalone PLCs could be suitable for off-site plants like water treatment plants and coal-handling plants as long as they meet the system requirements. Presently, however, people look for an integrated system with connection to the main control system.

2. *PLC network—redundancy and safety considerations*: To increase the I/O-handling capability and/or to integrate several PLC systems, it is necessary to form a network with the PLC, as shown in Figure VII/2.0.3-2a, where two PLCs complete with the I/O power supply units in independent configurations that have been connected via the control network (e.g., Ethernet). These I/Os to PLC may be distributed over a few chassis and can be connected to the host/main PLC by Fiber Optic and/or by Fieldbus or may be connected to host/main in a dedicated way as shown. A common WS, PU, and/or any PC can be connected to the same network. Also, it is possible to share common input/outputs by the PLCs in the network. Note that here a dedicated communication processor has been deployed to

www.EngineeringBooksPDF.com

reduce the load of the PLC main processor. The data highway may be redundant to enhance system availability. Redundancies as options are available at various PLC sublevels such as at I/Os, controllers, and communication subsystems.

In Figure VII/2.0.3-2b two controllers, one as a main controller and another as a hot standby, are connected in the network. In mid- and large-sized power plants in most of the applications, redundant systems (except for very noncritical services), are chosen. Standby controllers also share the critical control information. Both are updated in a regular manner, i.e., both share the same information over the bus but stand by controller output only when the main controller is out of service. In many systems any of the two controllers can be set a primary controller, if one fails (diagnosed by system diagnosis program), Hot standby takes over without bounce (as both are updated simultaneously) to the process. Upon rectification of the primary controller it may be put in to service. In cases where a controller is not pre-assigned as "primary," this controller will start functioning as "standby." Otherwise this controller will take over as primary, and the working one will again be in the system as standby. I/Os and data highways can be redundant as shown. Presently, it is possible to integrate various products from different manufacturers also. Another feature in Figure VII/2.0.3-2 is that I/Os have built-in intelligence to be supported in the bus. Also they can support the Fieldbus. In these I/O modules, parameterization, free configuration, etc., are possible. There are a few special intelligent modules available for encoders, high-speed counters, servo controller, servo positioning, etc.

The fault tolerance of PLC and I/O provides maximum availability of the system for single-point failure. Using industrial grade electronics suitable for harsh environments, with limited loading, coupled

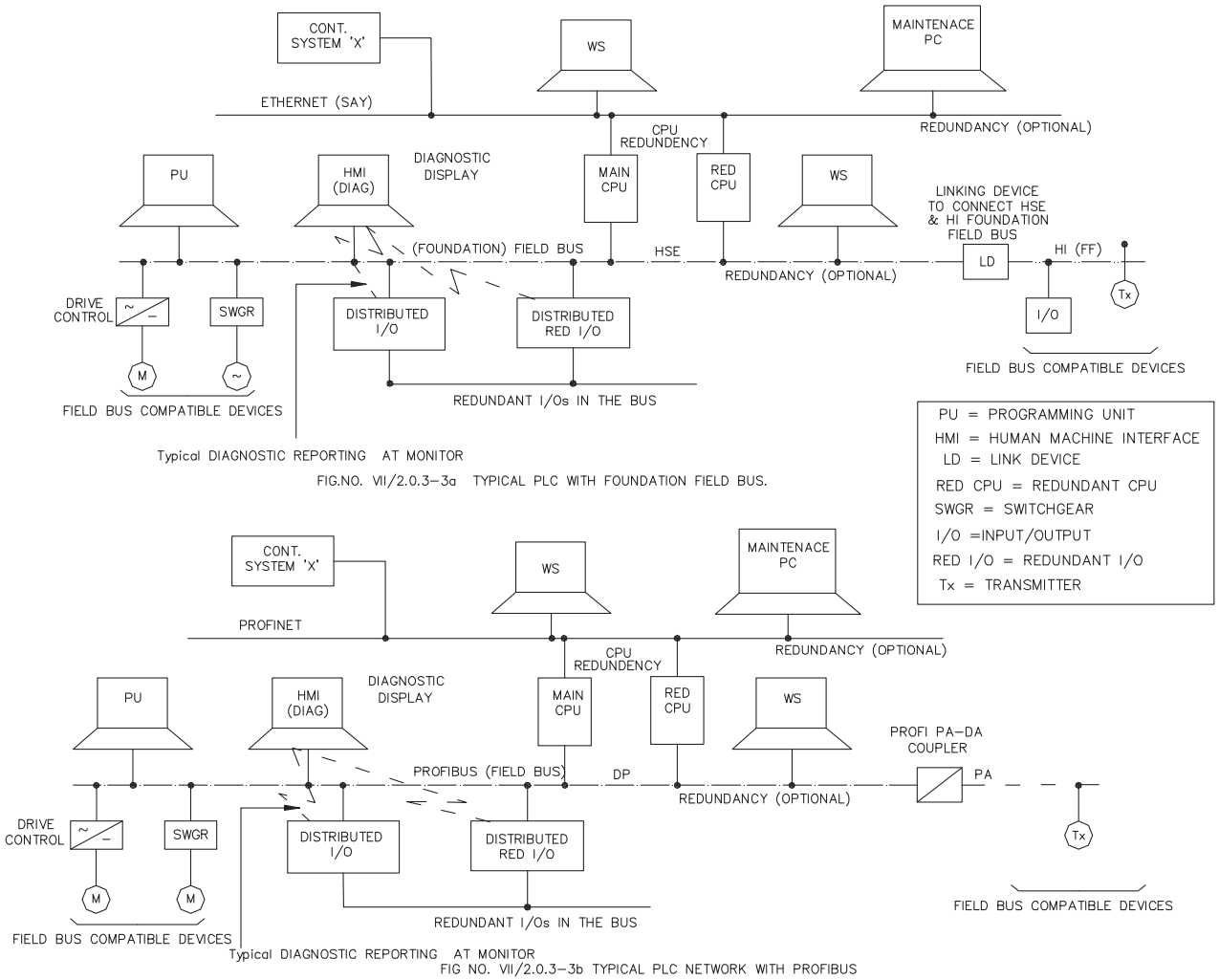


FIGURE VII/2.0.3-3 PLC with Fieldbus systems.

www.EngineeringBooksPDF.com

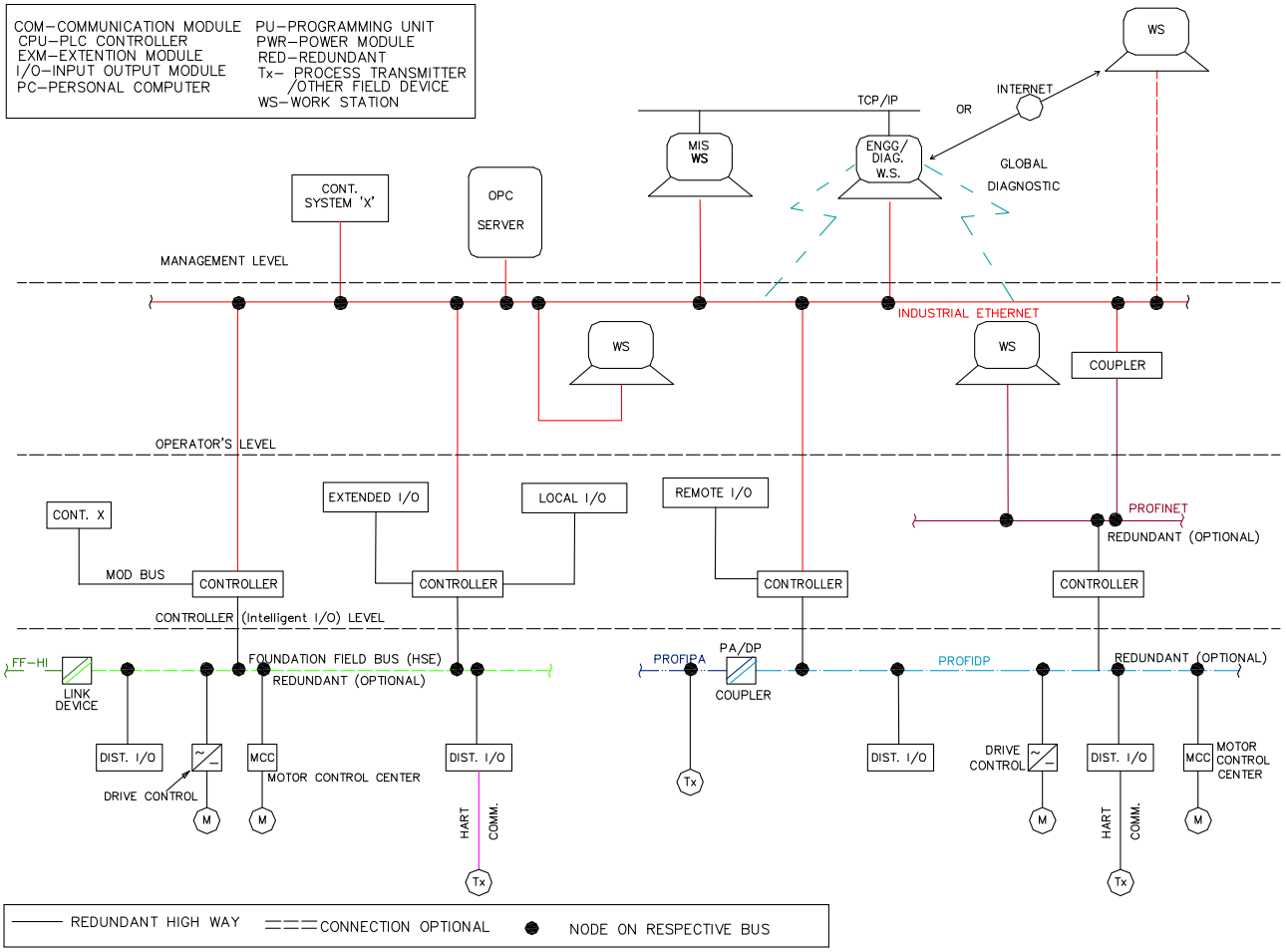


FIGURE VII/2.0.3-4 Integrated plant control system.

with low-power consumption and/or forced cooling makes the system more reliable when used in fault tolerant mode. In a fault tolerant system redundancies are available at the controlled network, Fieldbuses, CPUs, I/Os, etc., to achieve bumpless transfer. For noise immunity fiber optics may be used. In several fault tolerant PLCs, like the ABB AC880M Control module, application and hardware settings may be changed online during operation. Fault tolerant PLCs have international certification (e.g., TUV). For safe systems, as applicable, IEC 62061 SIL certification may be used. Fault tolerant and/or SIL rated PLCs may be useful for BMS/ATRS/Digital EHG (DEHG) applications. For certain systems, designers go for triple modular redundant (TMR) PLCs (e.g., in GE gas turbine controls). TMR PLC increases safety, reliability, and system availability coupled with avoidance of nuisance tripping. In a TMR PLC error detection is easier and a fault tolerant situation is achieved.

3. *System integration*: In the past PLCs were connected with systems with the help of interfaces like RS 422 to enable main control systems to poll certain data/status from PLC. Today, PLCs (intelligent systems) have become so open that parameters can be monitored from a location even at a places thousands of kilometers apart. Also now the integration of systems is not restricted to a few vendors, but all most all products can be integrated to the system. There also has been

MPI: It Stands for Message Passing Interface, a standard for writing message passing program. This is an interface attempt for practical, portable, efficient and flexible standard for message passing. It is done on C++ /FORTAN language for shared and distributed memory. This is useful for global diagnostic feature also.

FIGURE VII/2.0.3.3-1 Note on MPI.

www.EngineeringBooksPDF.com

huge cost reductions and freedom of choice for the products. This feature increases the life cycle of the system as any off-the-shelf products can now be integrated into the system and the system can survive. Integration of field devices to a controller is a demand and can be achieved with the help of Fieldbuses like PROFI BUS and Foundation Fieldbus as well as supportive systems such as TCP/IP and OPC. Almost all available intelligent systems can support these.

In Figure VII/2.0.3-3a and b, such features are shown. Within the limited scope of the book, a brief discussion on system integration is presented below:

- *Foundation Fieldbus integration*: In Figure VII/2.0.3-3a various systems are integrated with the help of the Foundation Fieldbus HSE in which distributed I/Os, electrical drives, and switch gear/MCC (for various pumps, and fans) are integrated (with the controllers and CPUs residing on the same HSE FF). Several other control systems (designated as "X"), PC-based systems, workstations, and MIS workstations can be connected to the PLC/intelligent controllers through high-speed Ethernet. At the lower field level, field devices such as transmitters, sensors, other I/Os, etc., also are integrated with the system via H1 FF. These two Fieldbuses are connected by a linking device).
- *PROFIBUS integration*: In Figure VII/2.0.3-3b various systems have been integrated with the help of PROFIBUS-PROFI DP in which distributed I/Os, electrical drives, switch gear/MCCs (for various pumps and fans) are integrated with controllers on the same PROFI DP. Several other control systems (designated as "X"), PC-based systems, workstations, and MIS workstations can be connected to the PLC controllers through the PROFINET/industrial Ethernet. At the lower field level, field devices such as transmitters, sensors, other I/Os, etc., are also integrated with the system via PROFI PA, which is connected to PROFI DP via PA-DP bus coupler (see Clause 1.0).
- Thus a seamless integration of systems is possible, and by utilizing suitable object-oriented software it is possible to exchange information to process monitoring and visualization. Therefore data exchange with other control systems and intelligent devices is possible with the help of PROFINET, industrial Ethernet, and Message Passing Interface (MPI; Figure VII/2.0.3.3-1). So, with integration, it is possible to develop a large communication network over a common bus to curtail additional costs for complex proprietary communication processors. In such connections parameterization and optimization of field devices is possible. Also it is possible to integrate Industrial IT, which enables the systems to utilize the benefit of comprehensive diagnostics and troubleshooting from remote places.
- A More comprehensive integrated system is shown in Figure VII/2.0.3-4, and each subsystem has a different communication standard. This is a typical system architecture to show how the systems can be integrated. The entire system architecture is divided into four levels: management, operator, controller, and field. These level divisions are purely arbitrary for better understanding. Here wireless WAN is not shown, but the system can be integrated with it as well.

  Field level: Field devices with Foundation Fieldbus H1 have been integrated to FF HSE by link device, whereas field devices using PROFI PA are integrated to Fieldbus PROFI DP by a PA-DP coupler. Various I/O subsystems accepting HART have been utilized to put field devices with HART into the system. For integration of HART devices, a HART OPC server may be developed for the system (e.g., 800xA of ABB). So at field level, a few Field us systems have been well integrated at controller level via the Ethernet.

  Controller level: Here there are separate controllers. These controllers may be two different scalable controllers or they could be redundant. At the controllers direct I/Os can be connected in a local I/O, extended I/O, or as a remote I/O as shown. Even these controllers may accept the MODBUS device. There are separate controllers for two different Fieldbus systems, e.g., PROFI DP and FF HSE. These controllers also connect/integrate the system to PROFINET or an industrial Ethernet for operator/management interface. PROFINET and industrial Ethernet can be connected by a coupler or a switch, as shown.

  Operator level: Here there are various WSs connected to PROFINET and the industrial Ethernet.

TABLE VII/2.0.3-1 Security Levels

Security level	Accessibility
Zero protection	Allow full access without password
Write protection	Read only access to HMI/CPU or network Communication without password No access to CPU for writing and mode changing
Read/write protection	Same as above plus reading data in CPU is password protected

www.EngineeringBooksPDF.com

There will be seamless flow information to the operator through PROFINET and the industrial Ethernet.

Management level: Connected to the industrial Ethernet is the MIS WS and engineering/diagnostic WS. One server for the system is connected. The server may include an OPC server for various third party/system for seamless transfer of data and system management. Third-party systems are represented by Cont. syst. "X". For IT compatibility (IEC 61131-3 standard), TCP/IP and Internet connections are shown so that the system also can be accessed from a distant place.

4. *Diagnostics and security*: Mid-to large-sized PLCs integrate diagnostic function to quickly detect fault and can eliminate system fault to increase system availability. Controllers and I/Os have a comprehensive self-diagnostic to quickly identify the fault. Fault LED in the front panel facilitates quick and easy module isolations. Also the report can be generated from these diagnostic programs to the central maintenance monitor, as well as diagnostic alarm in HMI/MMI (as shown in the Figures VII/2.0.3-3 & 4) is quite common. As discussed earlier, Industrial IT interface enables the system to utilize Web server facilities for global diagnostics and remote troubleshooting. In a large network there is seamless transfer of data at various levels. However, it is not desirable that everybody has access to all these data as well as access to modifying the data, so there are several security levels built in to the systems for accessing and modifying data. Some data accesses are allowed for the plant operator (e.g., control bias), whereas in the same architecture some data are only accessible by an instrumentation technician (e.g., controller setting). Data access levels are arranged in a hierarchical pattern. A typical PLC security with password for a standard PLC is listed in Table VII/2.0.3-1.

2.0.4 Hardware Considerations

Depending on application in the power plant, there will be wide variations in I/Os as well as controllers for a PLC/intelligent system. A coal-handing plant mainly handles digital I/Os in sequential operations in various subgroups, whereas in DM plants there will be a good mix of digital and analog I/Os and also a sequential operation. PLC in a BMS requires meeting the high-safety requirements of NFPA; although NPFA specifically does not call for SIL certification, it is becoming necessity to go in for SIL as a safety requirement in larger power plants for BTG controls. Again PLC in ATT/ATRS/BMS may have fewer I/Os when compared with PLCs for a total ash-handling plant, but more critical from a safety and security point of view. Naturally the size and type of PLC application in each of the above cases will quite different. Most of the big manufacturers offer a wide range of products from with the designer can choose. ABB, GE, Honeywell, Mitsubishi, Omron, Phoenix contact, Rockwell (AB), Siemens, and Triconex are a few of the major suppliers of PLCs in the world. A few pertinent features of various subsystems of PLCs are presented below:

1. *I/O subsystems*: Major considerations for I/O subsystem include the following:
   - *Category*: Direct to the controller (local I/O, extended I/O, remote I/O), Distributed I/O over bus such as in FF Bus, PROFIBUS, Control Net, device net or support of HART Protocol.
   - *I/O type*: Digital (signal level, output type: potential free, TTL, etc.), Analog (types: 4-20 mADC, T/C, RTD, and HART support), pulse (voltage/frequency), registering I/O (thumbwheel), serial/parallel module. For analog inputs whether single or in differential mode, and for analog outputs driving load impedance, etc.
   - *Power supply (AC/DC) and interrogation voltage*: To specify voltage level and quality of power supply requirement and interrogation voltage level if other than power supply voltage.
   - *I/O density*: Number of channels in each module. Normally I/Os are available in 8/16/32 I/Os in one module. There are separate input and output modules, but mixed I/Os are not uncommon.
   - *System isolation*: Optical isolation and galvanic isolation for I/Os.
   - *Connection medium*: Supported connection types such as cable types, fiber optic, etc.
   - *Module mounting and connectivity*: DIN mounting, etc., cabling plug/fiber optic termination, and adapter module (e.g., extension module) bus isolation wherever applicable.
   - *Intelligence and special I/O*: I/Os can be intelligent, special modules for encoder, a high-speed counter, linear/servo positioning, motion control, etc.
   - *Event time stamping*: Depending on applicability, critical I/Os with time stamping facility.
   - *Module feature for safety*: Standard or fail-safe module (as applicable).
   - *Diagnostic features*: Details of diagnostics built in, e.g., watchdog timer, etc.
   - *General fault detections*: Such as wire breaking, short circuit and non concidence error for change over contact (COC) etc.
   - *Remote I/O link*: Link to the controller by serial link or by a network such as data hi way, Control Net. In case of link type and associated protocol (e.g., RS 422/485 MODBUS Protocol).

www.EngineeringBooksPDF.com

- *Accuracy*: Depends mainly on ADC resolution, and high accuracy is available.
- *Flexibility*: I/Os can be selected and configured in flexible way—in single, redundant mode and/or through via network and as local/remote
- Hot swap/standby: Possibility of changing/swapping standby I/O modules online.
- *Special features*: IS type, single or dual fault tolerance (type), and/or TMR type.
- *Certification*: International certification for safe module (e.g., Ex IS, if applicable).
- *Temperature*: (−)20 to 55°C

2. *CPU/control unit*: Remember that by selecting the CPU type you are basically selecting the PLC type of the manufacturer. After short listing a few PLCs based on functional requirement, the CPU features discussed below could be used to compare them. Data presented below are from standard reputed manufacturers and all data may not match any particular system. The standard value against each parameter/item is just *an example*. *All may not be applicable simultaneously.*
   - *LED*: LED indications of different colors for run, fault, power, battery, data exchange, etc.
   - *Clock frequency*: System dependent, e.g. between 48 MHz and 133 GHz.
   - *Redundancy support*: Normally available for CPU fall back.
   - *Memory*: RAM e.g. from 2 to 64 MB.
   - *Cycle time*: <1 ms (typical word processing time: 0.01−0.12μS, whereas floating point processing time is higher at ∼1 μS).
   - *Number of timers and counters*: 256−2048.
   - *Number of I/Os*: 1024−8192 bytes sometimes limited by number of modules in I/O bus; e.g. 96 modules. In case of redundancy this will be limited further.
   - *Supportive communication modules*: PROFIBUS DP (PA via coupler), FF bus HSE (H1 via linking device), Serial link like RS 232, RS 485, and RS 422, if applicable. Apart from these the manufacturer's own system/family dedicated bus for drive, MCC, etc. Fieldbuses discussed above may be supported as *master* or *master slave.* Number of channels for each of the aforesaid Fieldbuses or serial devices may be single and/or dual along with cable redundancy. This could be a factor while comparing PLCs.
   - *Open user communications, if any*: TCP/IP and ISO on TCP support is also a key factor.
   - *Number of application per controller/number of programs per application (as applicable)*: Typically 8/64.
   - *Number of OPC servers per controller/number of clients per OPC server (if applicable)*: Typically one or two with a maximum of four. Frequency of OPC server update can also be compared.
   - *Number of Ethernet channels (if applicable)*: Two in IEEE 802.3 interface, in twisted cable (STP) with RJ 45 connector for 10 Mbps communication minimum (only indicative).
   - *Network redundancy switching time*: Better than 1−2 sec.
   - *Certification*: International certification, as applicable.
   - *IP class*: IP 20 minimum.
   - *Power supply/power consumption*: Normally 24 VDC/depends on the manufacturer (dissipation value important for cooling arrangement).
   - *Battery back type/internal back period*: Lithium/> 100 h for a larger system.
   - *Environmental*: Temperature (−20) to 50°C (storage higher range), relative humidity < 95%/
3. *Memory management scheme*: Memory management is important for functions like user programs, maintaining system data, diagnostic buffer, clock timing, etc. It does not include bulk memory for a PLC-based automation system. The functional part of the basic memory management scheme (b Fig. based on one siemens system: Courtesy Siemens) is presented in Figure VII/2.0.4-1

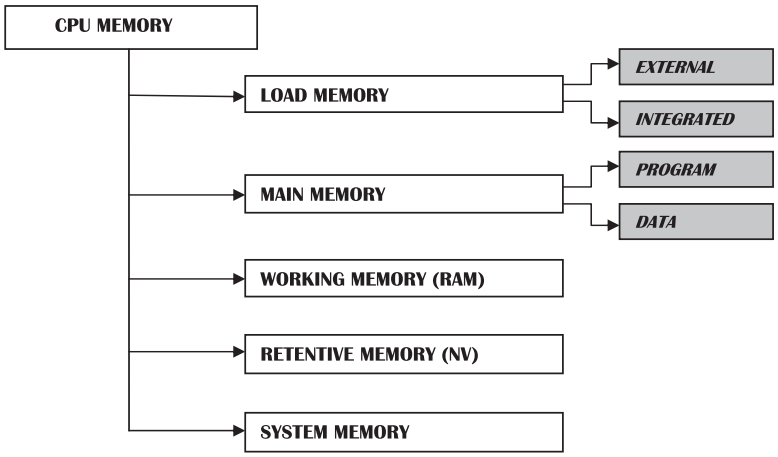


FIGURE VII/2.0.4-1 Basic memory divisions.

www.EngineeringBooksPDF.com

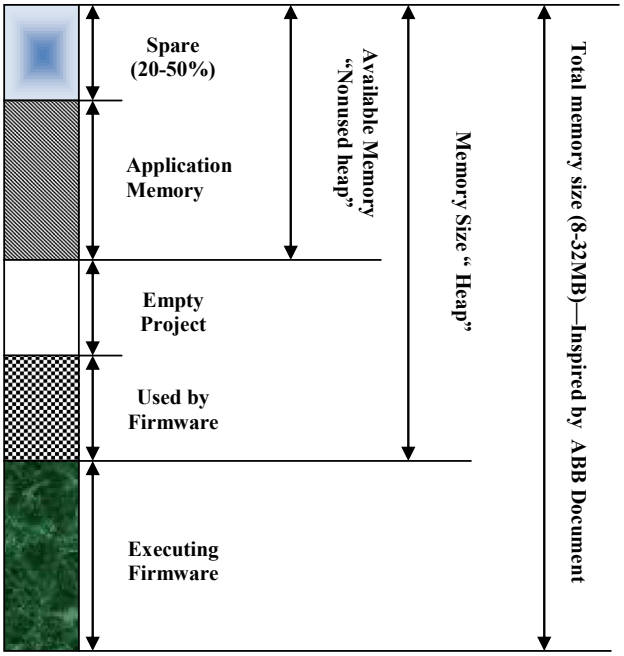


FIGURE VII/2.0.4-2 Physical memory divisions in terms of use.

and may vary with different PLCs. Storage space for the CPU for user program, data, and configuration including system memory diagnostic buffer, etc., can be divided as follows:

- *Load memory*: This nonvolatile memory is either a memory card (external: battery backed up RAM or flash memory) or integrated with CPU (internal: battery backed RAM). External memory could be up to 64 MB. When a project is loaded into the system its load memory is where it is loaded first. It stores all blocks with description and file format definition in a data block. Executive parts of block will be less than RAM size.
- *Main memory*: Main memory is integrated with CPU. It has two parts. One part is for program code or run relevant code, and process I/O images are stored in this part for code. The other part is for run time relevant data and data from the local data stack. By having separation in the main memory it is possible to access both parts simultaneously (e.g., S7-400 PLC). So main memory is used to store the process-related module, process image, local data, etc. Main memory has battery backed RAM, especially for the data part.
- *Working memory*: This is volatile RAM, used to store some user elements, by copying it from the load memory for better performance.
- *Retentive memory*: This is nonvolatile RAM used to have some limited quantity of work memory values. In case of power failure, the CPU is designed to have hold up time to store this data. It is used for markers, timer counters, data block bit memory, etc.
- *System memory*: System memory provides storage area for marker (M), timer (T) counter, and (Z) local data stack. The CPU also supports a time of day clock and diagnostic buffer. The entries are displayed in chronological order.

  CPU can understand whether the power ON (after power down) is buffered or unbuffered. In the former, the programmed section in the main memory goes to working memory. For unbuffered ON, executable parts are transferred from Load memory. CPU assigns specialized memory areas and has code blocks suitably addressed, e.g., input (I), output (Q), bit memory (M), local stack (L), and data block (DB). Memory size and performance is very important. (*Firmware is a basic program that PLC hardware can execute directly. It reads the program, written in higher level language, then executes it. It includes OS, a real-time clock, and communication*.)
- *Memory performance*: Physical memory size and less executing firmware gives the memory size. During start-up the amount of free memory in a controller is less because of the empty project space. The rest of the memory can be utilized by application programs. For example, a load-balancing memory diagram (Courtesy AC 800M

TABLE VII/2.0.4-2 Typical Timing for Various Functions

Function	T (μS)	Function	T (μS)	Function	T (μS)
Single loop	1100	Override loop	3600	Dint function	0.31
Cascade loop	1900	Boolean function	01.5	Real to dint	1.13
Fast forward loop	1600	String function	13.45	Dint to real	1.17
Mid-range loop	1500	Real function	1.79	Real to time function	10.1

The above data are from standard manufacturers and are presented to get an idea about timing.

www.EngineeringBooksPDF.com

systems of ABB) is shown in Figure VII/2.0.4-2. CPU load % = (total execution time/total time interval)*100. Depending on the applications and a few other factors, a suitable measure could be taken to keep this maximum 70% (typical 50%) This is important for the programs where communication is vital for the controller, such as in a large distributed system (see Table VII/2.0.4-2 for timing for various functions).

4. *Embedded system*: What is an embedded system? It is simply advanced dedicated computer to provide a fixed specific task. These embedded systems are found in cell phones and many other applications. PLC features discussed previously can be achieved with embedded systems. Now manufacturers have come out with these solutions, because system components residing within the control system make it possible to have greater flexibility and functionality (e.g., ABB 800xA). A few features of embedded systems for intelligent control applications are as follows:
   - Distributed intelligence and computing power means that control logic can be distributed at the place where it is needed most, and control logic can be distributed between several controllers exchanging measured and calculated values.
   - Time-critical real-time execution
   - A communication module protocol stack can be implemented in hardware and in firmware to run in the associated embedded CPU.
   - In a client server system software can be combined for operation flexibility.
   - Since the embedded system can withstand a harsher environment, it is better suited at the controller, which may have to face a harsh environment in the field.
   - In embedded systems the number of components is reduced. An embedded system can handle control logics and I/O scanning, so it is possible to modify online logic changes.
   - The I/O system gives maximum flexibility in an embedded system. It also offers preprocessing like I/O filtering and time stamping as well as diagnostic features.
   - System availability is very high and online replacement of modules is possible.
   - Development charges of the embedded system is high, but once developed, cost reduces drastically and system integration is smoother and easier.
5. *Communication systems and interface devices*: Maximum data transparencies across various levels of automation are a serious challenge to the data. The responsibility of communication is to ensure seamless transfer of data at the field level, controller level, operator levels, and management level as well as connecting long-distance clients with the network via the Internet.

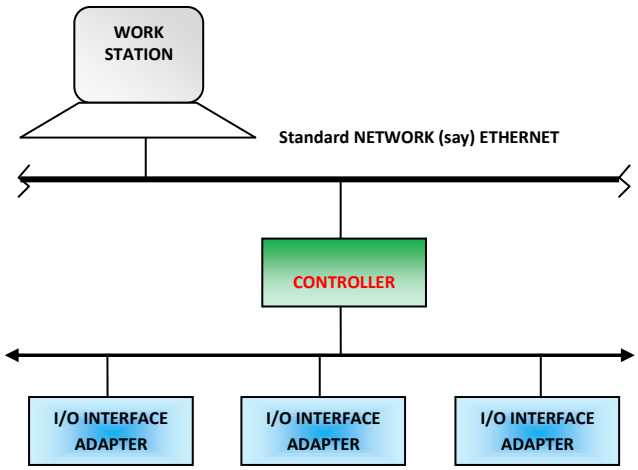


FIGURE VII/2.0.4-3 Remote I/O link with associated network.

Basic functions of a communication system are classified as follows:

- Adapt international standards to integrate other systems in the future.
- Combination of various communication options without affecting the system performance including safety security and diagnostics.
- Wireless communication wherever necessary, integrating routing functions for wide access.
- Integration of office applications wherever applicable, and integrating the system through the Internet for remote location operation.

There are several methods for system interface and associated communication, e.g., protocol support for the HART device MODBUS (RTU) and OPCs for various device support, etc.:

- *Own data highway bus*: All PLC manufacturers have their own system highway/module bus where various modules can be connected to communicate among them. Data highway plus (of Rockwell automation) a local network is an example of this.

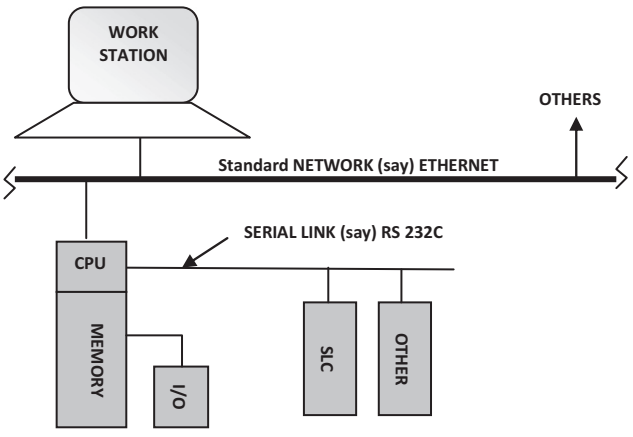


FIGURE VII/2.0.4-4 Serial link and network connection.

www.EngineeringBooksPDF.com

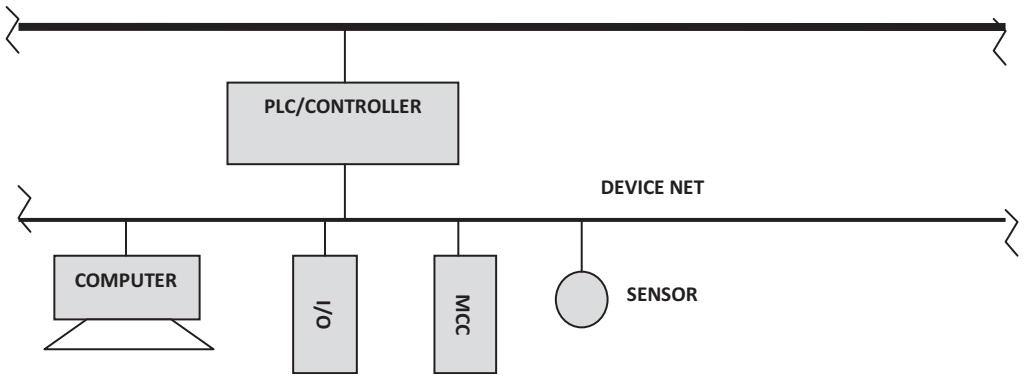


FIGURE VII/2.0.4-5 Device net connection.

Communication baud rate and the way of transmission may be unique (see Figure VII/2.0.3-2)

- *Remote I/O*: The power of the remote I/O hinges on the number of devices it can support via remote I/O (see Figure VII/2.0.3-2a). In its simplest form, remote I/O helps to cut wiring cost by connecting distant I/Os to the remote I/O card instead of using long-distance cabling. The remote in turn can be connected to the system via a serial link and/or these can be directly hooked up to the system bus, e.g., Mitsubishi FX_{2N}-32DP-IF is a module to connect to 256 I/O (with 240 VAC supply and 24 V service voltage) to PROFIBUS with electrical isolation. A remote I/O can form a network with the help of the associated controller, as shown in Figure VII/2.0.4-3. Typical speed of communication is 9.6−12,000 Kbps. The bit rate depends on the device and network used as well as the distance. These remote I/Os can be placed in normal chassis and an associated controller needs to support the remote I/O when used as link.
- *Serial link*: General configurable serial link should include RS 232, RS 422(A), RS 423, RS 485, etc., which may be used to transfer data to various devices such as a printer and other devices in ASCII or MODBUS/SNP protocol. Also these may be used for connecting various control devices like a single loop controller (e.g., a DM plant with mostly digital I/Os may have one SLC for degasser level control and the same SLC can be connected to a PLC via serial link). Some of the typical distance limits for these links are 15 m for RS 232 and 500 m for RS 485, etc. Shielded cable with a suitable pin (D pin) may be utilized to communicate at ∼9.6−19.2 Kbps. The number of these ports varies from system to system (see Figure VII/2.0.4-4).
- *Foundation Fieldbus*: As discussed earlier, many systems support full Foundation Fieldbus devices for PLC systems. While the H1 bus is a slow bus supporting field devices at 31.25 Kbps, the HSE bus is a high-speed bus that supports communication at 100 Mbps. C1860 module of ABB (800xA) is an example of this (see Figure VII/2.0.3-3a).
- *PROFIBUS DP*: PLC systems offer separate communication modules for PROFIBUS DP master and slave. Master interface card distance is dependent on baud rate. It could be as low as 9.6−12 Mbps. It allows comprehensive data processing as per the PROFIBUS DPV1 standard. The number of slave units supported varies from system to system and can be in the range of 64 to 128. Transmission is over bus network with PROFIBUS cable with a D connector. Message size varies between 244 and 32 bytes per slave (see Figure VII/2.0.3-3b).

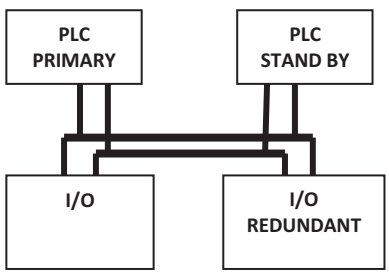


FIGURE VII/2.0.4-6 Redundant control net.

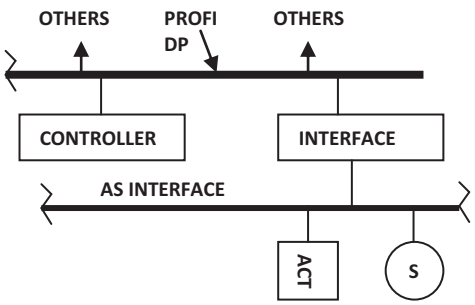


FIGURE VII/2.0.4-7 AS interface.

www.EngineeringBooksPDF.com

- *PROFINET*: There are CPUs with an integral PROFINET interface (e.g., Siemens S7-300/400). This is an equivalent of the industrial Ethernet with some features such as a Media Redundancy Protocol (MRP) to make a quick changeover (<200 ms) Like PROFIBUS it supports GSD files. Isochronous mode (synchronization of signal acquisition output by distributed output devices) of communication is helpful for closed control loops (see Figure VII/2.0.3-3b).
- *ETHERNET:* Ethernet interface with 10Base−T (10 Mbps) is common with all standard manufacturers. It supports TCP/IP protocol (Ethernet IP) and SRTP MODBUS TCP (e.g., GE: Module IC693CMM321). In certain cases a communication speed of 100 Mbps (100baseTx) is also possible. Cat 5 STP is a standard cable connection. In some systems like Rockwell PLC 5, an embedded Web server provides Web access to PLC Diagnostics due to the support of a Domain Name Server (DNS) and Simple Network Management Protocol (SNMP; see Figures VII/2.0.3-3 and VII/2.0.3-4).
- *Device Net*: This is a communication protocol used for an intelligent control device to share information. It is used to connect low-level devices to a controller with diagnostic facilities and less start-up time. Device Net also has master/slave interface modules. This interface module is used to read/write, for configuration downloads, and for device status monitoring. It has distance limitations: for speed it is 500 Kbps for 100 m, whereas for 500 m it reduces to a quarter of the maximum speed. The master can support nearly 32−64 slave nodes. Message size is in the rage 3 KB in master to 256 bytes in slave (see Figure VII/2.0.4-5).
- *Control Net*: (FIGUREVII/2.0.4-6): This open industrial protocol is used by a few PLCs, such as PLC 5 from Rockwell. It provides high-speed access to plant floor data, as it supports a number of controllers with their own I/O. Redundancy in the controller is possible with one controller as a primary. This is a deterministic system with a speed of 5 Mbps connected by coaxial cable (RG6; see Figure VII/2.0.4-6).
- *Actuator sensor (AS) interface*: (Figure VII/2.0.4-7): AS interface is a protocol used to connect field devices to the controllers. It defines the physical layer, and basic protocol, and it finds much use in PLC. A communication speed of ∼167 Kbps for a distance of ∼100 m is possible. Many manufacturers (e.g., Siemens SIMATIC-S and MitsubishiRX$_{2N}$-32ASI-M) utilize this interface to connect the field devices to any system bus via the PLC controller. (see Figure VII/2.0.4-7). In addition to these there is the **C**ontroller **A**rea **N**etwork, CANopen, from Mitsubishi.

6. *MMI*: PC-based MMI are quite common for PLCs. These can be used as client server as well. This can be one simple standard PC with 1.5 GHz and 1−3 GHz RAM, >30 GB HDD with Windows. This PC specification depends on the manufacturer of the PLC. In a normal configuration there can be a number of clients using the server in a network.

2.0.5 Software Considerations

Various PLC suppliers offer software packages to reduce programming and setup time (to a great extent) and to integrate the systems. These packages are also helpful for communication, for data exchange, and quick and direct data access. Programming is better done in a graphical environment in easy-to-use templates. Software should normally comply with IEC 61131-3 to meet the requirements of base level, conformity, and reusable definitions. PLC software development on Windows OS is quite common, e.g., WINDOW CE v 5.0 and WINCC for Siemens PLCs.

2.0.5.1 Main Component and Functional Features

The following are expected from software in a PLC (based on a standard PLC):

- System manager administrating all tools, creation of a multifunctional communication subsystem, online help, and project data storage on the CPU.
- Structured features of software programming
- Configuration and parameterization of hardware including limited configure in run and Internet linking. In some software during normal operation it is possible to tell which ports are operating based on the IEEE 802.1AB Link Layer Discovery Protocol (LLDP).
- Program editing is an interface of the user program, in the LD (may be higher languages like FORTAN and PASCAL), statement list, or Structured Control Language (SCL) as defined in IEC 61131-3 (for Programming Industrial automation system) for complex algorithms. Graphical representation of the control logic is useful.
- Setting up data transfer of the bus and open command interface.
- Integrated system diagnostics such as reporting error, summary, and detailed diagnostics.
- Standard compliance.
- Special functions like PID, etc.
- Creation of a program for fault tolerance and fail-safe mode as applicable.
- Tool calling interface.
- Same basic setup for every engineering work place.

1. STRUCTURED PROGRAMMING: Sometimes it is better to divide the complex and comprehensive

www.EngineeringBooksPDF.com

program in to smaller divisions which is self-content blocks. It is seen that these program blocks have definite correlations and appearing a number of times in the program. So any program can be implemented with this concept, and third party accessing the program for any purpose can understand the system clearly. It allows several programs to run concurrently. As is seen in *Siemens Step 7* programming, some of these Blocks are:

- *Organization block* : An interface between the OS and user program that is responsible for system start-up of the job, interrupt handling, fault handling, etc.
- *Function block*: This is an actual program, and each has one assigned data block or it needs to be supplied with current input values. Function block displays can be suppressed for privacy.
- *Data block*: It is the storage place for plant data.
- *System function blocks*: These are common functional blocks, and may be required repeatedly in the program, e.g., clock functions, counter working hours, etc.

2. *Program editor*: As the name implies, it can be used to edit programs in LD, statement list, and functional block diagram. There can be editors in the graphical type also. Sometimes it is easier to understand and edit in graphical form for sequencing structure, selection of processing steps, synchronizing manual and auto operation, etc. The graphic editor also is helpful for diagnostics (see standard IEC 61131-3). Some useful commands in SCL are template block and template commands like IF, THEN, ELSE, etc. Use of subroutines with GO TO commands are often useful.
3. *Control and network configuration*: It is a part of the system software to implement the control strategies, such as PID loop, etc. The control algorithms are parameterized with some programming component and structure. Complex algorithms need to be resolved with the help of standard library functions, control structures, and parameters. Also establishing communication is a job for the system software. Graphical representation of individual station links help to resolve the communication problem in a much easier way.
4. *Diagnostics*: It is also a prime function of system software and graphical representation of the topology display with status helps to identify and navigate from summary diagnostic display down to the component level diagnostics. Reporting of error is a function of the system software.
5. *Special tools and functions*: There are some special tools to meet the requirements like high availability, fault tolerance and powerful security, and fail-safe systems that may not necessarily deploy a redundant system. There are special tools for system integration and open system interface, e.g., tool calling interface.
6. *Engineering and program development*: Many system suppliers offer systems with computer software with little modification, while others have their own program development system that may be unique for the system. While selecting/evaluating a system, necessary emphasis may be put on the following features for the engineering and program development to get better performance of the system:
   - *User friendliness*: It must be user friendly to optimize the program development work.
   - *Uniformity in representation*: There should be a common software framework on which all the shared functions can be performed and they should have common online representation in the MMI so they can be felt uniformly both by operator as well as by the programmer.
   - *Intelligence in editor*: The programming systems having built-in intelligence help to use the drag and drop feature during program development. Intelligence in the programming system helps to split range the screen to simultaneously edit a number of programs as well as data exchange in the system.
   - *Data transparency*: One datum enters into the system only once, and this should be transparent to all the editors to avoid any future mistake and confusion. The system may have a centralized data management system in object-oriented language to ensure better transparency. Shared database must be consistent to the entire application, including MMIs. Any modification at one place needs to be updated at all relevant places simultaneously.
   - *System library*: There will a number of program bocks, sub blocks, face plate, etc. Used many times in the program, these need to be kept in a secure library. This helps to maintain consistency and quick response.
   - *Special tools and functions*: To ensure an open interface, safety, and security, some special tools may be built in the program development system.
   - *Program development device:* Laptop or a PC may be used with features like ergonomic design, robustness, and the capability of eliminating the electromagnetic interference (EMI) effect with a USB 2.0 Port and other connects.
7. *Totally integrated system software*: A totally Integrated system automation conforming to industrial standard IEC 61131-3 with internet access is shown in Figure VII/2.0.5-1 (e.g., ABB 800PEC).

2.1 PLC Types

In the previous clause, discussions started with basics of the PLC, and then slowly an integrated automation system

www.EngineeringBooksPDF.com

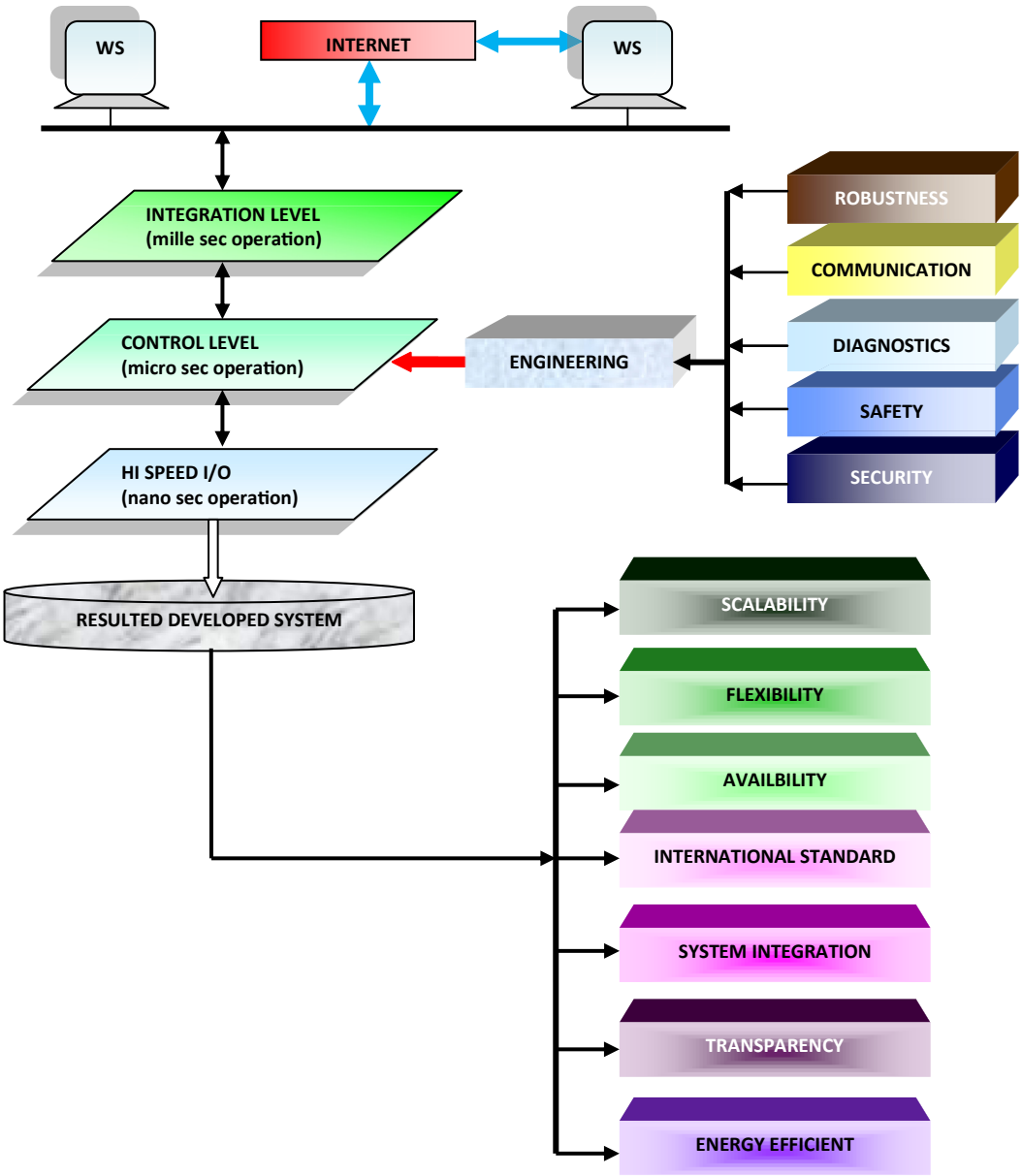


FIGURE VII/2.0.5-1 Totally integrated system (— a concept).

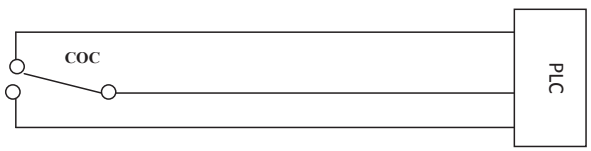


FIGURE VII/2.1.1-1 Change over contact (noncoincidence error).

(based on the PLC) was developed. Here short discussions are presented to illustrate how PLCs can be classified with special reference to selection criteria.

2.1.1 Redundancy Criteria

One of way PLCs can be classified is according to redundancy. Now the question is redundancy at which level. Redundancy can be at a controller/CPU level and/or at the I/O level. The two perspectives are completely different.

1. *I/O redundancy*: In case of redundancy at the I/O level, there will be two sets of inputs or outputs and may be distributed to two different chassis/modules. Now various issues related these will be discussed. This arrangement has an advantage; in case one module fails, I/Os will be available through another module.

www.EngineeringBooksPDF.com

Also, if one chassis is damaged (e.g., due to fire), another is available. However, there may be a little increase in cable cost. In case of a remote I/O, such distribution among two chassis will increase cost and complexity of connection. Another question is how the two I/Os should be handled if there is a mismatch between the two (e.g., if there is a snapped wire in or out of the two inputs). The answer is that the PLC needs to monitor the health of each channel and report in case of such an event. Still there may be difficulty if there is NO type of contact, because the same situation may happen when there is a snapped wire as well as if the contact is not made [i.e., changed from not on (NO) to no contact (NC)]. With an NC type power missing could be used to detect cable snap, the same situation will prevail when the cable is snapped or contact changeover has taken place. However, the situation is little better with changeover contacts (COCs; see Figure VII/2.1.1-1). Where the contact forms, the central terminal changes over to other two contacts to form NO or NC contact. In such cases all three terminals are connected to the system and the nonconcidence error is monitored (e.g., ISKAMATIC B of KWU control system). In cases where there are voting circuits, this needs to be suitably taken care of during system programming. A simple way to vote the two outputs to the actuators is to use a diode auctioneering circuit in the hardware. In Figure VII/2.0.3-2a and b redundant I/Os in one/two chassis are shown, respectively.

2. *CPU redundancy discussions:* There can be redundancy in the CPU/controller as shown in Figure VII/2.0.3-2b. Methods for bumpless transfer of control from one to another have been discussed at length in Slause 2.0.3.
3. *Communication redundancy discussions:* As shown in Figure VII/2.0.3-2a and b, the system buses may be redundant in nature to communicate data from various units over a redundant bus. Here communication over the bus is an important aspect, so there is no mismatch between the two. Also the physical bus may be routed through two different paths so if there is damage of one then the other can go on as it is. For two-bus systems the communication controllers are redundant, with suitable monitoring for uninterrupted communication.

2.1.2 I/O Connections

Based on the types of I/Os listed below, the PLC can be classified as

- Directly (local I/O; Figure VII/2.0.3-2a) or it can be an extension
- Remote I/O (connected by communication link; Figure VII/2.0.3-2a)
- Intelligent I/Os connected to the system over a system bus (Figure VII/2.0.3-2b)
- Intelligent I/Os connected via Fieldbus (Figure VII/2.0.3-3a and b)

2.1.3 System Integration

Starting from a small PLC, it is possible to develop a very large system catering to various controls, through system integration, based on functions demanded from the system, as discussed in the previous clause.

2.1.4 Features

The importance and criticality of availability, diagnostics, safety, and security of BMS/ATRS PLC is beyond question, when compared with the PLC in a raw water pump. It does not mean that the latter one is not important, just less critical. This is because if BMS/ATRS PLC is unavailable then the whole plant will trip. During selection importance is attached to these factors. Therefore it could be concluded that it has to be decided which factors are more important for the application, and thus various types of PLC subsystems with different distinguished features can be developed.

2.1.4.1 Hardware and Software Aspect

These are important to classify the PLC types based on hardware/software features. Hardware and software features discussed in Clauses 2.0.4 and 2.0.5 and are not necessarily applicable to all PLCs. As the application is huge it is hardly possible to specify these in detail in the book. Therefore generalized specifications have been presented, such as designer needs to select the features required for the particular application, so that the specification is neither over done nor under specified.

2.2 PLC (OLCS) in BMS: Preamble

The focus of BMS or furnace safeguard supervision system (FSSS) is to ensure safe operation of the furnace and boiler. Reliability and availability of the BMS is crucial to the control engineers in a power plant. FSSS/BMS is generally designed in accordance with the National Fire Protection Association (NFPA 8502) and other relevant standards. Generally BMS/FSSS can be subdivided in to the following sub groups:

- Boiler purge
- Igniter valve management
- Main fuel management
- Master fuel trip
- Draft controls (if in BMS)

Implosion/explosion are two important factors for designing BMS/FSSS. According to NFPA 8502, furnace explosion can be caused due to the ignition of accumulated combustible mixture within the confined space of a furnace

www.EngineeringBooksPDF.com

or associated boiler pass, duct, and fans that convey gases to stack. The degree of explosion is dependent on the proportion of air present at the time of ignition and relative quantity of accumulative combustibles. Major causes for such an explosion could be (NFPA 8502 Guideline) the following:

- Momentary loss of flame followed by delayed ignition
- Fuel leakage in idle furnace ignited by any source
- Loss of flame of a burner while others are working
- Complete flame out followed by attempt to light up

Similarly in line with NFPA 8502, implosion (is very important especially for large boilers) can be caused mainly by either of the following causes:

- Malfunction of equipment regulating boiler gas flow, resulting in furnace exposure to excessive induced draft fan head capability
- Rapid decay in furnace temperature and pressure due to MFT

Some *key factors* related o BMS/FSSS are given below:

Burner management	Safeguard and supervisory
• Burner oil and ignition process start/stop and sequence control of oil burner	• Purging system
• Pulverized coal combustion control start/stop and sequence control of coal burner	• Compliance with NFPA 8502(NFPA 85/ 86), etc.
• Pulverizer control for such preferential tripping of mills.	• Emergency tripping MFT
• Primary air fan control	• Fuel leak test (low pressure)
	• Control of indirect draft/forced draft fan wherever applicable

Generally the basic design aspects (detailed discussions in Chapter VIII) of FSSS/BMS need to take care of the following criteria:

1. Inhibit start-up in unsafe condition (e.g., permissive condition like no MFT)
2. Protection against unsafe condition (e.g., trip burner at low oil pressure)
3. Provide operator with full status message (e.g., status indications)
4. Initiating safe condition for operation and shut-down interlock (e.g., high/high or low/low furnace pressure or low/low feed flow (see number 9 below) for MFT
5. Reliable operation and avoid spurious trip by proper ON/OFF sequence
6. State-dependent interlocks
7. Link to set point control
8. Split of safety and control function (as stated above)
9. Also low/low drum level if a drum type boiler s used

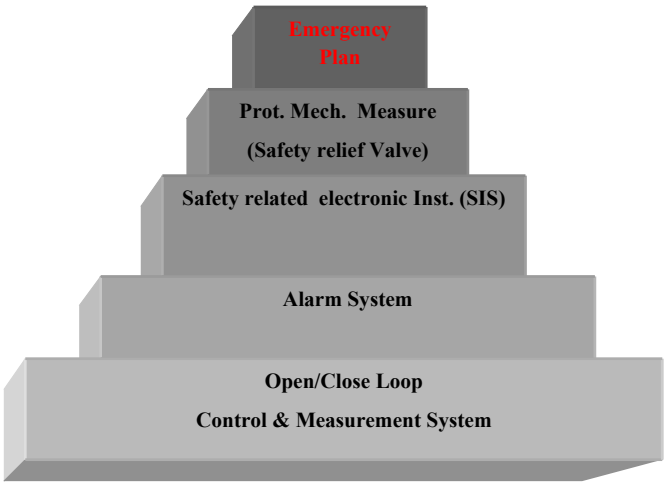
It is one of the duties of BMS/FSSS to determine when to move from one state to another and which valve/damper position is to be used in each condition. The condition-based safety and sequential-based logic requirement are specified needs to be implemented in the system.

2.2.1 Some Features of BMS/FSSS

There are certain features *generally* considered essential for BMS/FSSS; some of them are functional and some are related to fail-safe conditions:

1. All major and large systems need to be fail safe, i.e., any single fault in the sensor logic solver and the actuator would not lose its safety function. This is a similar requirement of the Safety Instrumentation System (SIS), which will be discussed later.
2. Major standards followed for BMS/FSSS in utility stations include but are not limited to the following:
   - NFPA 85 and NFPA 86
   - EN 50156-1
   - ISA S84
   - FM7605—IEC 61508
   - VDE 0160/VDE 0116
   - Also for petroleum use: APP 556 AND API 14C
3. BMS/FSSS systems have self-monitoring features, and all these faults are brought to the operator's notice at the right time so that suitable measures can be taken.
4. In many cases, especially in large utility stations, major logic such as master fuel relay (MFR) are implemented in TMR logic. Three independent channels have dedicated processors, I/O, etc. All safety-related inputs are fed to each of these channels separately. Sometimes each of these primary sensors (furnace pressure switch) can be triple redundant. Trip signals from the three channels are fed to fail-safe 2/3 redundant circuit to get the required output.
5. Functional criteria are included but are not limited to the following:
   - Any fuel firing can only be started after the purge sequence is complete, i.e., following any trip/shut down there will be a purge sequence before any start to make sure that there is no stagnant unburned fuel after the burner trip has occurred.
   - Any start-up can only be initiated after all required permissive conditions are fulfilled.
   - Continuous monitoring burner flame and trip in case of any undesired condition.
   - Continuous monitoring of boiler operation and trip MFR in case of any adverse situation.

www.EngineeringBooksPDF.com



At the low level open/close loop to maintain pressure. Next level is alarm for the same. Above is safety related instrumentation. Last level is for mechanical pressure relief valve. Even it fails some emergency plan to avoid accident. Here in case of failure of lower level, higher level is at its limit to avoid damage. Each level has different approach to reduce risk. Also device in each level shall not be used as safety application of higher level i.e. separate instrument to be used for alarm and lower level.

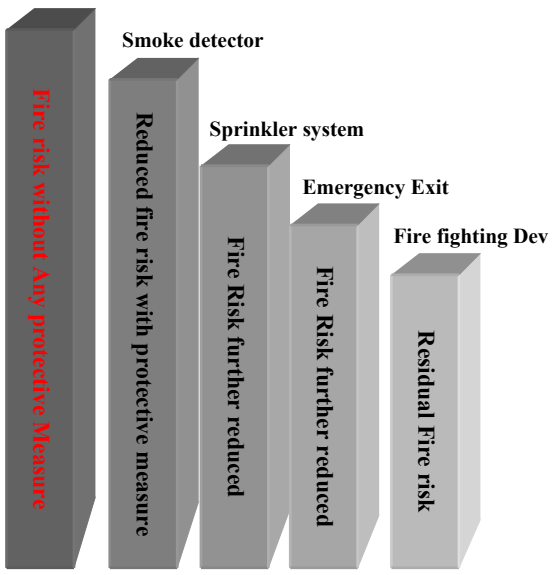
FIGURE VII/2.2.3-1 Risk-reducing plan.

- Reliable MFT but spurious tripping need to be avoided (if necessary defeating switches are used); also use of electromechanical MFT relay.
- Continuous monitoring of start-up, run, and shut-down logic sequence. Initiate alarm in case any fault is detected

6. Equipment status and process alarm feedback in a clearly written message without ambiguity.
7. First out feature, SOE features, etc., for selected inputs to help operating personnel identify the cause of fault as well as help system personnel identify fault up to the module level.
8. System design is modular in architecture.
9. It is desirable that the logic is kept in EEPROM to combat power failure situation.
10. Suitable redundant watchdog timer to detect system failure.
11. For dual firing smooth changeover of fuel at all operating condition is a pertinent feature.
12. Use of redundant flame scanners so that online cleaning and replacement of flame scanner is possible. This is a special feature that some PLCs offer.

2.2.2 Standards Related to BMS/FSSS

NFPA 85 is based and developed on the basis of all these six standards (8501−8506), so it is better to refer to



From the example it is clear that each protective measure reduces risk level (Drawn not to scale). So in order to protect personnel and environment it is necessary to determine the risks involved and to take necessary protective measure to avoid risk to the extent possible. A Safe Instrumentation System (SIS) is one possibility to cope up with such situation.

International Standard IEC 61508 is applied safety related systems applicable for ELECTRICAL, ELECTRONIC EQUIPMENT AND PROGRAMMABLE ELECTRONIC EQUIPMENT. IEC61508 is a generalized one & IEC 61511 is applicable for process industries.

FIGURE VII/2.2.3-2 Risk-avoidance diagram.

www.EngineeringBooksPDF.com

NFPA 85 which, in a generalized form can be applied to BMS/FSSS. However, it should be noted that NFPA 85/86 define "what" interlocks to be implemented and does not take care of "how" to implement them. So it is necessary to ensure that the system is safe (in the sense that failure is a part of the system). Now standards are being developed for the "how" part of the question. There are many situations where it is desirable to obtain FM certification on a PLC for BMS/FSSS (see FM 7605-1999). The basic purpose of the standard is to evaluate the system with respect to "….Performance requirement, making requirements, examination of manufacturing facilities, audit of quality assurance procedure and a follow up program." This standard calls for conformance to IEC 61508. There are requirements for SIL-certified BMS/FSSS in some cases. There is an ISA S84 BMS subcommittee that looks after the concept of a safety-instrumented burner management system. In the following clause risk and its avoidance are discussed to illustrate why a safety-instrumented system is necessary. IEC Standard 61508/61511(for process control) is not process specific. Therefore though this is discussed in

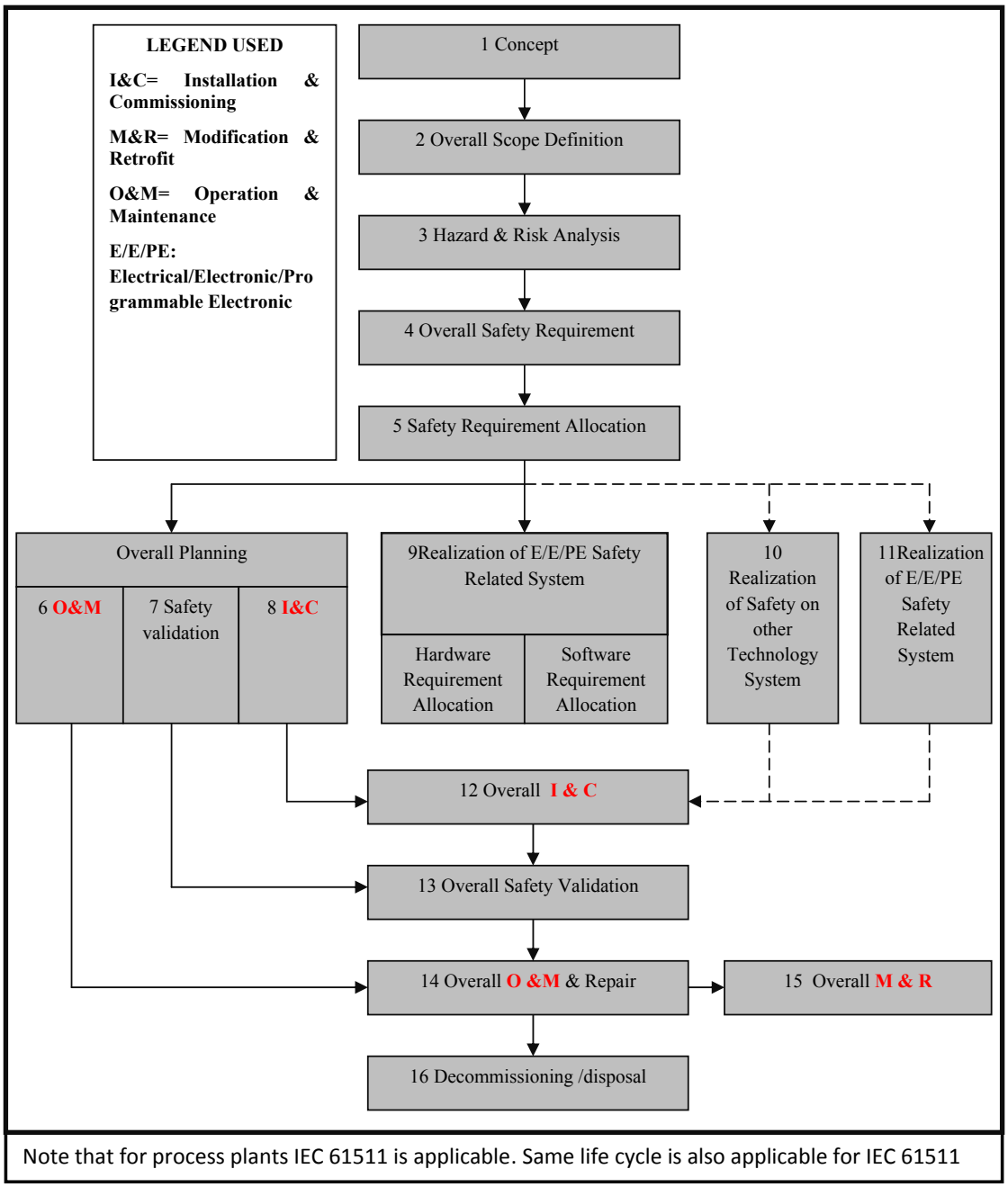


FIGURE VII/2.2.4-1 IEC 61508 life cycle model.

www.EngineeringBooksPDF.com

connection with BMS/FSSS but same can be extended for other critical systems also.

2.2.3 Risk

It may seem that the measure to reduce the risk is simple, but in reality it is extremely complex, because measures to reduce risk at various levels have totally different approaches. Figure VII/2.2.3-1 shows risk reduction in a simple pressurized system.

Figure VII/2.2.3-1 shows that by taking measures at various levels it may be possible to avoid accidents, but they cannot be eliminated totally; there always will be residual risk. It is clearer in Figure VII/2.2.3-2, which includes a fire-monitoring and fire-fighting system. Smoke detectors are installed for early fire/smoke detection, and sprinklers are used to sprinkle water in case of fire. A fire-fighting device (CO_2 extinguisher) is used to fight the fire and there may be emergency gate to escape. With all these can fire hazard be totally avoided? No, it only can be reduced, as shown in Figure VII/2.2.3-2.

What is risk? It can be defined as the probability of a hazardous event happening multiplied by the cost involved in it. It depends on the country/region, society, law, cost, and company policy**.** The same risk may have different repercussions for different companies. e.g., according to company policy one may accept tripping a plant under one situation than having a costly SIS with a higher SIL level. What is SIL? IEC 61508 and 61511 defined four Safety Integration Levels or SILs. The higher the SIL number (SIL1, 2, 3; SIL4 is not applicable with conventional devices) the higher is the risk reduction.

1. *Functional safety*: Functional safety according to IEC 61508 can be defined as "part of overall safety that depends on a system or equipment operating correctly in response to inputs," e.g., over temperature protection device to cut off motor before it gets over heated. Standards ISA S84.01/IEC 61511 define requirements of SISs and safety instrument functions (SIFs). SIS provides safety control functions and complements the basic process control system (BPCS). SIS is independent, and it provides a layer of protection to help the process against accidents. SIS includes sensors, logic solvers, actuators, etc.
2. *Functional safety and safety life cycle*: The performance-based standards (IEC 61508/61511) mandate that validation and verification of design should be done to check that it performs the intended functionality. This is done with a life cycle-based system, as shown in Figure VII/2.2.4-1. The safety life cycle gives the frame work of considerations at each stage from concept to final decommissioning. Some safety life cycles include risk analysis, consequence analysis layer of protection analysis, safety-integrated level determination, etc. One of the key factors is to assess and compare actual failure rate, which should be considered during the design stage. Major activities involved in functional safety management include:
   - Overall safety planning
   - Design assignment and audit
   - Tracking implementation in overall life cycle
   - Management of changes
3. *Risk analysis and quantification*: Performance-based SIS standard ISA84.01 and IEC 61508 require that risk analysis is done (e.g. by "HAZOP analysis,)" to determine risk ranking, which represents the act of evaluation of consequences. The basic objectives of risk analysis are listed below:
   - Determination of hazard and hazardous event for process and equipment
   - Sequence of events leading to the hazardous event
   - Determination of risk involved with the hazardous event
   - Requirement to reduce the risk
4. *Risk quantification*: Risk Matrix and risk graph are methods used to assess risk. The end user decides the risk analysis method and defines the risk associated with his operation. If inherent risk is less than tolerable risk, then no action is called for. If inherent risk is greater than the tolerable limit of the company, then SIF would be required to ensure the design achieves the required risk reduction so that the final design is within the tolerable limit.
5. *SIL determination*: In the next step SIL determination is performed. Hazardous event probability can be determined by the following:
   - Analysis of failure rate in comparable situation
   - Relevant database
   - Calculation based on accurate predictable method

   Basically it depends on the extent of damage, duration of stay of personnel in a dangerous situation, a version of danger, and the probability of such an occurrence.

   Determination of SIL level is a complex and elaborate method (see standard IEC 61508, part 5 and beyond the purview of the book). To make the system simpler, it may be argued that (for similarity, see Figure VII/2.2.3-2) SIL1 represents a requirement for one order of magnitude of risk reduction. SIL2 and SIL3 represent two and three orders of risk reduction, respectively. So after this discussions it can be said that in SIS BMS/FSSS one can determine:
   - How good or reliable hardware needs to be
   - How much redundancy is necessary and at what level
   - How often testing is necessary
   - Level of reliability of individual component

www.EngineeringBooksPDF.com

TABLE VII/2.2.6-1 NPFA and IEC 61511

IEC 61511 clause number	Requirements	Remarks
5.0	Management of functional safety activity	New to NFPA85
7.0	Demonstration safety life cycle	
8.0	Process hazard and risk analysis	
9.0 and 10.3.1	Determination of SIL for each SIS	
10.3.1	Requirement of proof test interval, in the meantime to repair	Not specific in NFPA 85
11.9	SIF probability of failure	Not defined in NFPA 85

6. *SIL verification and testing*: SIL verification requires the end user to use the reliability engineering concept to calculate probability failure demand (PFD; $$). This is to be performed on all SIL (1 and greater than 1). PFDs are dependent on these factors:
   - SIF architecture (sensor, logic solver, and actuator)
   - Estimated failure rate of each subsystem
   - Susceptibility of SIF to common failure
   - The diagnostic coverage of any periodic diagnostic test
   - Repair times for detected failure
   - Interval at which proof tests are under taken

   Functional testing is a mandatory requirement of SIS.

2.2.4 Fault Classifications

All faults are not the same, but they can be broadly be classified as

1. *Random*: This fault does not exist during delivery like short circuit faults and drift. These are mainly hardware faults. Fault probability can be calculated.

   Systematic: Does exist at the time of delivery like a software fault and incorrect rating of a measuring device. (Sometimes using two devices with different technologies may avoid systematic fault, e.g., two smart transmitters—one with a capacitance level probe and the other a DP type. Both are used to measure the level, but since they are different kinds, the probability is that the same systematic fault may not occur simultaneously.)
2. *Common cause*: This fault is due to EMI and temperature and environmental conditions. It has multiple effects. When used in a redundant configuration, systematic fault becomes a common cause fault.

2.2.5 NFPA 85 and IEC 61511

As stated earlier, NFPA takes care of which interlock is to be implemented, but it does not define how to do it so that all the functional requirements are met at the same time so there is no spurious trip. IEC 61511 developed leter supplements the requirements of NFPA 85, as given in Table VII/2.2.6-1.

2.2.6 SIL Rating Discussions

While determining the SIL level all fault types must be considered individually to get the SIL rating. Device manufacturers provide data with reference to systematic fault duly certified by an independent agency (e.g., TUV). This rating is *not* a part of the quantitative calculation of the owner. It gives guidance regarding the SIL rating against systematic fault. Discussions can be concluded by saying that the SIL number for the system is to be determined after calculation by the plant owner, and the owner is to select a system corresponding to that rating or a higher rating, i.e., if after HAZOP analysis and by calculation the SIL rating (based on the tolerance limit of the company) is SIL2, then one can choose SIL2 devices. On the other hand, if by calculation it is SIL3, then only SIL3 devices are to be used. Even if the cost of two SIL2 devices is less than one SIL3 device, SIL3 devices should still be chosen. Two SIL2 devices may reduce the random fault but not the systematic fault (e.g., software failure). i.e., two SIL2 devices are not equivalent to an SIL3 device. While selecting an SIL number, all of these aspects need to be considered. For further details, see relevant standards. In the following clauses, SIL for the logic solver is discussed.

When called for, SIL verification calculations need to be performed on sensor, logic solver, and actuator. General industrial processes related to BMS/FSSS are found in the ISA study that the majority of functions require an SIL1 rating; however, if there is at least one function, it requires an SIL2 rating, making the BMS/FSSS SIL2 rated. OSHA calls for functional test facility (removal of pressure from the fuel low pressure switch and to verify the desired action taken by the system). So SIS depends heavily on the functional test interval. NFPA allows relay-based systems and a few approved PLC systems. Even IEC 61508 allows the use of general-purpose PLC; however, general-purpose PLCs have certain limitations that are recognized in IEC 61508 and 61511. A safety PLC represents the industry's attempt to develop a microprocessor-based system to meet the requirements of IEC 61508 in hardware and software design. So a safe PLC is better choice to meet the schedule at a proper cost (otherwise it would be too high to meet the standard's requirements). There are many vendors with a certified PLC, but only a few can demonstrate certification for BMS/FSSS application. While selecting the PLC, it is necessary point to remember this. FM 7605-approved

www.EngineeringBooksPDF.com

BMSs inherently need to meet the requirements of IEC 61508. As fire devices grow in complexity and/or size (multiple burners with dual fuel), risk also grows and the requirements for safety aspects also grow. This also applies to sensors and actuators.

2.3 PLC (OLCS) in ATRS Turbine Protection and ATT

2.3.1 Preamble: A Confession

There are various separate control subsystems for turbines, and these are all interrelated (may have a common hydraulic circuit), so separate PLCs for ATRS, ATT, or turbine protection systems may not be practicable. For this reason most of the turbine system suppliers prefer a composite control system like an integrated DCS where functions like ATRS, ATT, and turbine protection systems are part of an open loop control system (OLCS), whereas other functions like electro hydraulic governor (EHG) control and seal steam pressure control are part of a closed loop control system (CLCS). A turbine stress evaluator is a computing device that directly interacts with ATRS and EHG. In this clause the basic requirements of OLCS/PLC functions for a turbine control system are discussed. Its worth noting that from criticallity point of view risk analysis, applications of IEC 61508/61511 are also applicable here. Although functionally all turbine control systems are similar, there are still large variations in implementation of these systems. It is not possible to address all systems, therefore, in the discussions below *one* globally reputed steam turbo generator (STG) manufacturer's system is the model to detail out functionality and implementation of these systems for detailed discussions, chapter IX may be referenced.

2.3.2 OLCS for ATRS

Basic coverage and interface of ATRS includes but is not limited to the following subsystems:

- HP oil and lube oil system and barring gear
- Condensate and evacuation system
- Turbine drain and warm-up and starting system
- Speed and load set point devices for EHG
- Turbine rolling and auto synchronization
- Seal steam system interface
- LP bypass interface

ATRS can be considered as a functional group in the turbine control system.

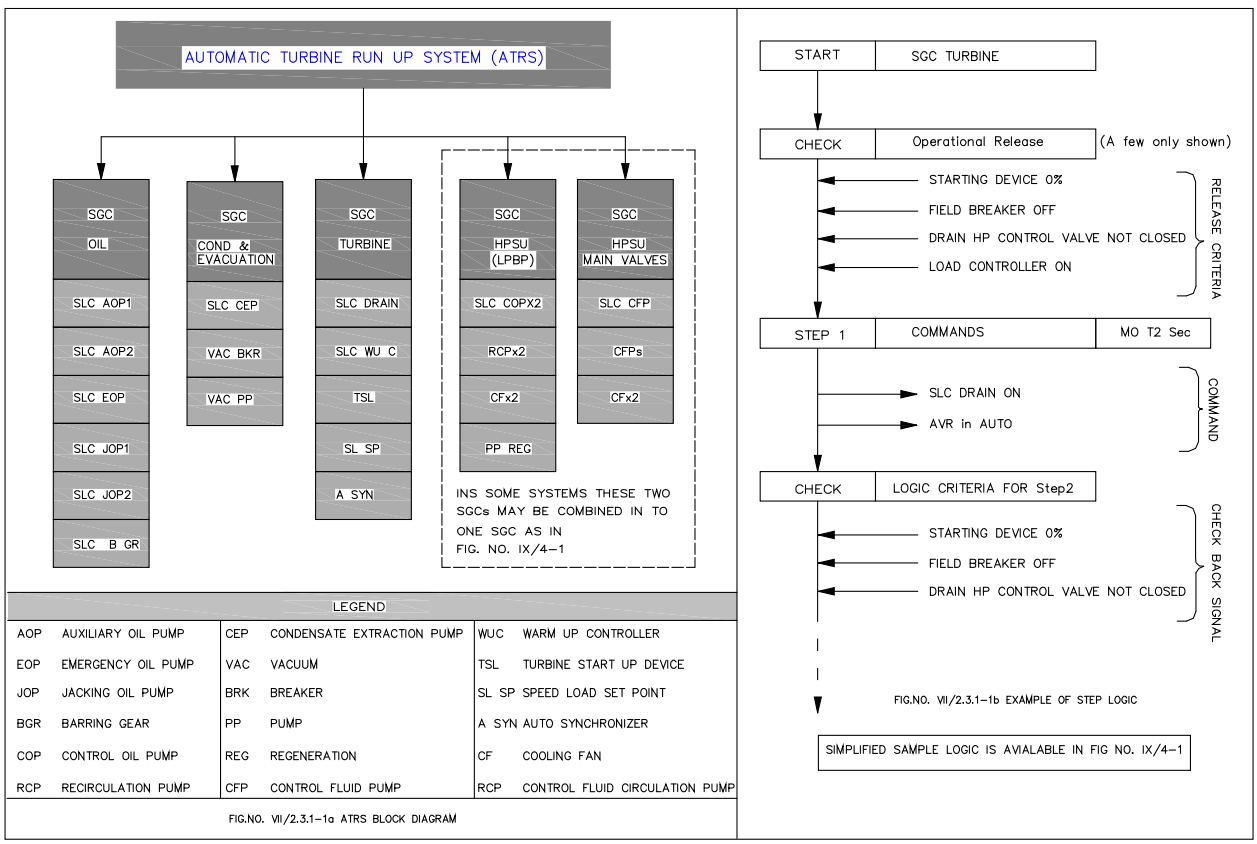


FIGURE VII/2.3.1-1 ATRS block diagram and step logic example.

www.EngineeringBooksPDF.com

1. ATRS functional group control (FGC) may be divided in to subgroup controls (SGCs), which execute commands to bring the associated sets of equipment to a defined status. Each of these SGCs can be divided in to subloop controls (SLCs) and drive interface (DI) units. Subloops may be conceived as a watchdog to bring associated equipment and/or parameters to a desired level. In subloops, normally there is no sequential control logic, whereas a DI can be a software module used to establish an interface between a remote-operated drive with plant commands (auto/manual) and provide feedback to the plant control system. DIs handle two-way communications with SGCs and SLCs. As shown in Figure 2.3.1-1a, a DI is not necessarily a dedicated special device (as described here), but could be implemented with the help of an intelligent I/O card with the required number of I/Os. ATRS consists of five (or maybe four when both control oil SGCs are combined) I/Os. In Figure 2.3.1-1, the HP oil systems for the LP bypass and main control valves are shown separately, but also could be common. In older units and units without an HP control oil system, ATRS may be devoid of an HPSU subgroup.
2. DIs are normally intelligent devices with dedicated algorithms to implement the associated drive function. There could be three drives/actuator types, based on functionality:
   - DI for unidirectional motors pertaining to various pumps, fans, etc. (e.g., AOP or DC EOP)
   - DI for bidirectional motor for various valve actuators, e.g., LO temp control
   - DI for solenoid valves, e.g., solenoid valve for barring gear gate valve control

   SGC and DI unit have various signals with different nomenclature so that in design documents these can be represented with suitable graphical symbols: P, protection signal; R, release signal; A/M, auto/manual command; c, check back signal; T, operators guidance mode. The symbol depends on the system supplier's convention.
3. Before a subgroup starts functioning, a number of preconditions, better known as "Operation Release," have to be fulfilled. Again while in sequence logic, a system issues a number of commands and checks back that these criteria are fulfilled. If the check backs are not available then it will not proceed to next step. However, certain steps can be bypassed by the operator (if not related to protection). See Figure VII/2.3.1-1b as an example of an SGC turbine, with only a few release and step criteria.
4. Timing and time monitoring is very important as can be seen ("MO" = monitoring time) with sequential steps in Figure VII/2.3.1-1b. After issuing a command, the watchdog has to monitor that within the specified time check back and/or criteria for the next step to appear as input to the system. This is called monitoring time, which can be defined as the time required to execute a command of any step and the time for criteria for the next step to appear. During the system design stage this is specified by the system supplier and it is set and/or adjusted during commissioning. Under healthy conditions within this time criteria the next step should appear if nothing is wrong in the system and the alarm is not initiated. This is applicable for all sequential logic systems. Even after all criteria are available, subsequent steps are normally operated only after a waiting time between the two steps to avoid any spurious actions. This waiting period— after the appearance of criteria until starting the next step is called the waiting time.
5. Theoretically, if all steps and criteria are available, in a healthy situation, the system can proceed in auto to the final stage. In reality this might not happen due to sensor failure or plant exigency, and some step(s) needs to be bypassed (not protection criteria). For this there are three modes of operations:
   - Auto mode
   - Operator's guidance mode
   - Step by step (semi-auto mode)

   In auto mode all steps proceed based on steps and criteria automatically in a sequential manner without manual intervention. In operator's guidance mode if some of the auto commands are blocked (i.e., not forthcoming), looking at the signal, the operator may bypass some steps (not protection) and issue a manual command so that the sequence can proceed. On the other hand, when there is a failure of transmitters, for example, so that check back/criteria are not appearing, then in step by step mode the operator manually simulates the criteria so that the step can proceed. However, in any modes of operation protection *cannot* be bypassed. Thus we see that in this system OLCS needs to operate in sequential mode withprotection iinterlocks.
6. For discussions on the functional aspect of ATRS, see Figure VII/2.3.1-1a:
   - *SGC oil*: It consists of a few SLCs, such as SLC AOP 1 and 2, and is responsible for operation of AOPs through a corresponding DI. Similarly there will be an SLC for an emergency oil pump (EOP; DC operated) and SLC jacking oil pumps. Take note that SLC ON does not mean that the corresponding pump is ON. It is the system that is made ready so that depending on the requirement the necessary devices can be started/stopped. For example, SLC EOP ON means that the EOP is to be kept ready so that in case of AOP failure the EOP drive can be started. There is also another SLC for the turning/barring gear gate valve.

www.EngineeringBooksPDF.com

- *SGC condensate and evacuation*: This SGC deals with condensate and evacuation systems like SLC CEPs, vacuum breakers, and vacuum pump and/or ejectors.
- *SGC turbine*: Handles warm-up controllers and drain SLCs (by opening the drain valves pertaining to various control valves) as well as checks the metal and steam temperature to admit steam based on metal temperature conditions. This is very important for turbine start-up. Apart from this, the SGC turbine interfaces with the governing system to decide speed and load set points (in conjunction with the turbine stress evaluator).
- *SGC HPSU*: It deals with control fluid pumps, cooling fans, etc., for HPSU for the main control valves and main valves as detailed in Chapter IX, Clause 4 (and Figure IX/4-1).

2.3.3 Turbine Protection System

The turbine protection system may be implemented in the redundant mode of a microprocessor-based control system. For utility stations with higher unit sizes, it is implemented in TMR mode at I/O as well as at the processor level. The GE turbine control system is an example of this. The turbine protection system is implemented in two of three voting logic with three independent tripping channels. Each of these channels has its own processor module, I/O, etc. in the two of three i.e. in two of three logic (may be implemented by independent relay output for each channel). Alternatively the system can also be implemented with two channels with hot back-up processors. So it depends on the purchaser's choice as well as the manufacturer's standard practice. In these cases there will be redundancy at the sensor level also. In addition to the electronic protection system, protection through hydraulic systems also is implemented. Turbine lock-out relay and redundant trip solenoids are commonly used for turbine protection as main output devices. Tripping devices have a DC supply for operation to take care of power supply failure. The health of the trip coils is continuously monitored and the operator is warned when necessary. Major electronic turbine protection signals are:

- Over speed
- Low vacuum
- High exhaust temperature
- High axial shift
- High/high vibration
- Low bearing oil pressure
- High/high bearing temperature
- High differential expansion
- Remote manual trip
- Generator protection
- High/low extraction pressure
- Low control oil pressure

  Tripping causes the opening of the drain path for the hydraulic fluid in trip oil header (auto stop emergency trip header). This causes the main stop and reheat stop valve to close very quickly (see Chapter IX, Clause 3). Normally the scan time for these protection device sensors is very short, e.g., 5 ms for over speed protection. Auto testing of the major tripping devices and self-diagnostics changed to preconfigured operating mode on detection of a protection device ON are some of the features of the OLCS for turbine protection systems.

2.3.4 Automatic Turbine Testing System

This is a feature present in OLCSs in most modern utility turbine control systems, but not common for all manufacturers. For detailed discussions on this, see Chapter IX, Clause 5.0. The ATT system allows online testing of turbine protective devices without hampering normal operation, and keeps the protective devices alive for turbine protection. Major devices in this category include:

- OP. and Cl. of HPSV (open: Close: high Pressure stop valve)
- OP. and Cl. of HPCV (HPcontrol Vlave)
- OP. and Cl. of IPSV (Intermedediate Pressure SV)
- OP. and Cl. of IPCV
- Over speed
- Low vacuum
- L.O. protection
- El. remote trip

The following features are included in the OLCS for ATT:

1. Individual testing of each of the protective systems separately.
2. For turbine protection, automatic, substitute functional protective devices are used.
3. Testing is possible *only* if the substitute device is healthy.
4. Each step in testing has a fixed execution time set by the manufacturer that needs to be monitored; if exceeded the alarm is issued.
5. Automatic resetting of the test program after a fault is detected.
6. Testing also includes the hydraulic circuit, and all alarms are to be initiated so that all portions are tested also.
7. During testing trip oil may be shielded, and instead control oil may be used so that actual tripping can take place.

Here the PLC/OLCS works as per fixed program to be executed as per the turbine testing schedule to simulate the fault situation as per manufacturer's recommendations.

www.EngineeringBooksPDF.com

2.4 PLC (OLCS) In Electrical System (SCADA): Introduction

Monitoring and control of electrical parameters pertaining to electrical facilities for the plant, including generators and transformers [unit/station/generator transformer forming part of the high-voltage (HV) system], may be a part of the main DCS or may be monitored by PLC integrated with the main DCS. Within the power plant all major HV and low-voltage (LV) system parameters are monitored in DCS. Normally all HV system parameters (e.g., MVA, MW, etc. of unit transformer parameters and station transformer), all generator and exciter parameters, all HV drives stataii, analog parameters (e.g., current, voltage. etc.), along with statuses of important LV drives, are taken into the DCS. In some cases, intelligent protection relays along with associated logic may form a part of the DCS/PLC also. Current/voltage transformers, transducers, contactors/relays, protection device/relays, circuit breakers, battery back-up (as needed), and communication channels along with associated control systems (PLC/DCS—OLCS) actually constitute this electrical control system. As far as instrumentation engineers are concerned, functionality of these is somewhat similar to process parameter monitoring and controls in PLC/DCS/DAS. The other important intelligent control in the electrical system is SCADA, which may be somewhat similar to PLC/DCS with some prominent differences. One of the major differences is its geographical spreading and control actions. PLC/RTU plays an important role in SCADA. Present generation SCADA involves networking and sometimes even networking via the Internet. SCADA systems are very susceptible to cyber attack, which makes the entire system very vulnerable.

2.4.1 What is SCADA? What are the Major Differences between the Two Systems?

SCADA is an acronym for **S**upervisory **C**ontrol and **D**ata **A**cquisition. Between the DCS and SCADA some differences are observed in architecture, operation, communication, safety, and security.

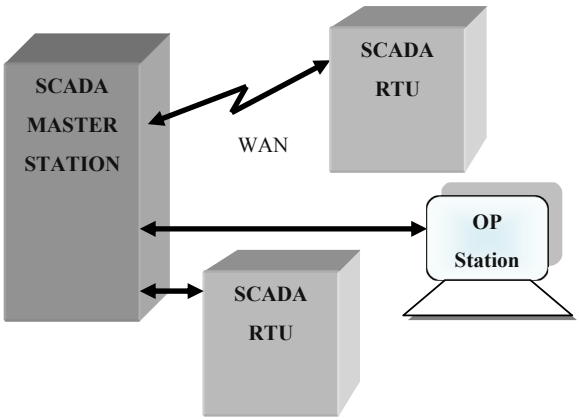
1. SCADA generally acts as a set point control supervision and coordinator and may not, truly speaking, be a real-time process/system control whereas DCS takes part in real-time process control. In SCADA *real-time control* is taken care of by the local controller (RTU or PLC).
2. While DCS is process driven and functionally responsible for the control aspects of the system, SCADA is event based and monitoring oriented.
3. Geographical spreading is a common feature in SCADA and mainly used in **WAN** (utilizing telecommunication channels), while DCS in general is restricted to local control via LAN.
4. In DCS, MMIs have direct access to I/Os. While in SCADA PLC/RTUs run preprogrammed processes, so in SCADA MMIs connected with the server disseminate these data in standard form acceptable to the operators, i.e., in SCADA data are presented after being processed in the server/host.
5. Newer generation SCADA networked in WAN is very vulnerable to cyber attacks. Hence in SCADA both safety and security are very important. Border router firewalls are some of the security measures of SCADA.
6. In SCADA special protocols are used. In SCADA IEC 60870 and DNP3 are major protocols.

2.4.2 Major Components of SCADA

The following system components are generally present in the SCADA system. However, there may be some variations according to the generation of SCADA.

1. *RTU/PLC—field interface device*: RTUs connected to the field devices, like sensors/transmitters, local switches, and actuators (e.g., circuit breaker), convert the electronic signals from sensors to digital data—a language used to transmit over the communication channel to the supervisory system. RTUs also interface to convert the data from the supervisory system to necessary electronic signals for the actuators. Because of band limitation, the automation of field devices are stored in local devices. Due to versatility, flexibility, and configurability, PLCs are also used as field device interfaces like RTUs. PLCs incorporate programmed intelligence in the form of logical procedures to be executed in the event of certain conditions. Communication modules connected with PLCs allow it to communicate with a remote device. In its origin SCADA was more connected with telemetry, whereas RTUs were used for basic information, and local relay logic carried out local control application. Here PLC may replace both functions. PLC also can be used with RTUs. In SCADA, from an overall control perspective, it is often necessary to influence the program within the PLC using a remote signal. This is called supervisory control of SCADA, where the control strategy may be affected by the remote supervisory system, over the communication channel. In switchyard SCADA, distributed PLCs/RTUs may be used to communicate with various intelligent protective relays.
2. *Master station or system server*: Either a single computer or a network of servers is used to provide MMI operator interface to SCADA. At this place(s) the information exchanged with RTUs/PLCs may be processed for presenting to the operator. The operator's MMI is connected to the server(s) utilizing LAN/WAN. Also this supervisory computer can acquire data, process it, and send the supervisory commands. Earlier host

www.EngineeringBooksPDF.com

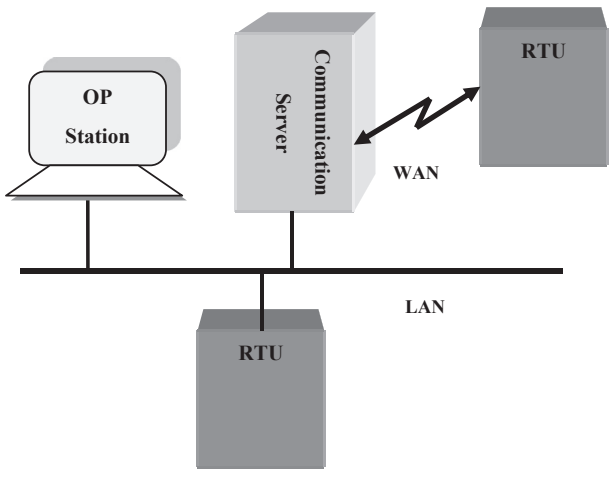


1st. Generation: Monolithic: These are main frame based system using LAN, WAN as shown. These are stand alone SCADA. The Protocols generally developed by RTU manufacturer are proprietary in nature. Redundancies in these systems are two identical systems in Primary and Back up system. No other system data traffics were mingled here.

FIGURE VII/2.4.3-1 First generation (monolithic) SCADA.

computers with proprietary OS and software were used. Current PCs and networking make it possible to use standard servers (independent of vendors) that can even connect office-based applications in the network. However, this makes the system more vulnerable and calls for more protection.

3. *MMI*: In most cases operator WSs are computer/PC terminals. In a client−server network WSs act as the client, which can request and send information to the server(s). Operators' interface software is quite important for SCADA. The MMI package for SCADA includes necessary software to provide trending, alarm handling and presentation, diagnostics, logistic information maintenance schedule, etc., by accessing the system database.
4. *Software component*: Software plays a very important role in SCADA, especially with the MMI package, which also contributes significantly to cost. For a better performing SCADA system the software needs to be well defined, designed, checked, and tested. Proprietary software dependent on hardware puts more emphasis on the process. In a multivendor environment, commercially off-the-shelf (COTS) types are used. This emphasizes variety of instrumentation and equipment. Therefore, software selection needs to be judicious. Various software components include but are not limited to the following:
   - *PLC/RTU software*: Local automation software for configuration and maintenance of control and monitoring application.
   - *Server(s) software*: Necessary OS, application software to exchange data with RTUs/PLCs, including Graphic user interface (GUI) for historian, trending and mimic functions, etc.
   - *MMI software*: Normally the same OS used in servers are used to form suitable networking. Also



2nd. Generation: Distributed: here the processing across multiple systems in LAN, each unit specific function. Communication processor is to communicate with RTUs. OP stations serve as MMI and some as Data base Server. Systems are connected using LAN protocols. WAN used to communicate with distant RTU. Obviously on account of distributions of functions the processing power is enhanced as well as more reliable and redundancy is easy to implement. LAN protocols were not open widely hence restricted to specific vendors.

FIGURE VII/2.4.3-2 Second generation (distributed) SCADA.

www.EngineeringBooksPDF.com

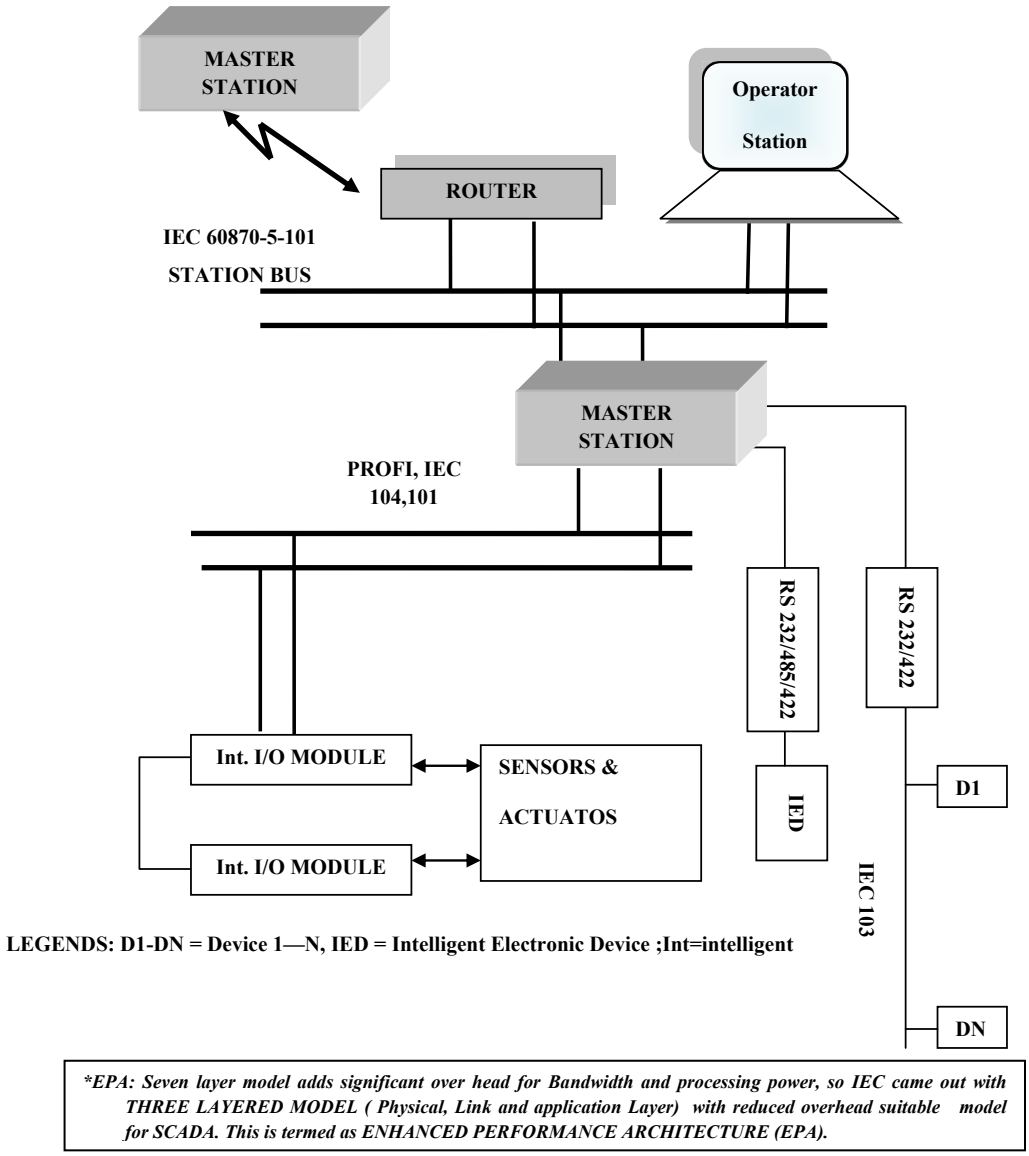


FIGURE VII/2.4.3-3 Third generation (networked) SCADA.

APPLICATION LAYER (ISO LAYER 7)		IEC870-5-101/102/103	EPA consists of three layered Structure: • Application Layer • Data link Layer • Physical Layer like RS232/485 IEC 69870-5- -1 Basic service requirement for physical & data link layer -2 Selection of Link Transmission Procedure -3 Rules for structuring application in Transmission frame -4 Information data element specification -5 Basic application function for telecontrol system
LINK INTERFACE		IEC870-5--5	
DATA LINK LAYER ISO LAYER 2	LLC		
	MAC		
PHYSICAL INTERFACE		IEC870-5--1	
PHYSICAL LAYER (ISO LAYER 1)			

FIGURE VII/2.4.4-1 EPA layered structure.

www.EngineeringBooksPDF.com

there will be application software to access the server in a network.

- *Communication software*: There should be suitable protocols when various systems are connected in a network. There should be suitable communication protocol drivers resident in the server as well as at the PLC/RTU. It is the responsibilities of the protocol drivers to prepare data for communication. Network management is another important aspect of communication software so that networks work without failure. Also there are suitable ways to monitor system communication. In case of any failure, quick recovery is essential.

2.4.3 SCADA History and Architecture

There three generations of SCADA: (1) First generation is monolithic, (2) second generation is distributed, and (3) third generation is networked. The typical configuration of first and second generations are presented in Figures VII/2.4.3-1and VII/2.4.3-2, respectively. Currently used third generation SCADA systems are shown in Figure VII/2.4.3-3. This networked SCADA utilizes an open protocol to make the system vendor independent and also could be distributed in WAN. It is possible to integrate third-party items and peripheral systems, such as printers and monitors, and hardware bases also may be open standard servers. The major advantage in this generation is utilizing WAN protocols like enhanced performance architecture (EPA)/TCP/IP communication between the systems. RTUs/PLCs are also the open type and they can communicate with masters utilizing the Ethernet (CSMA CD) as shown in Figure VII/2.4.3-3. From this architecture it is clear that various intelligent I/O modules are connected to the master station via the standard system bus. These I/Os could be replaced by PLCs as well. The master station also connects various intelligent electronic devices (IEDs) and other devices via RS links and with relevant standard protocols. The system may have more than one master and may be connected via router in a WAN. Operator station may be connected to the station bus based on protocol IEC 60870-5-101 for operator interface.

2.4.4 SCADA Protocol

In SCADA two sets of protocols exist. One is for RTU protocols consisting of statements for RTU initiation and/or response. The other protocol is for the master station initiation and response. Out of many protocols available in the market, IEC 60870-5 series and Distribution Network Protocol version 3 (DNP3) are the most popular. IEC is based on a three-layered EPA (see Figure VII/2.4.4-1) reference model for RTU with relays and other IEDs. (Protocol outlines and terms are only discussed; see standard book on SCADA and standards mentioned for further details).

1. *Standard IEC 60870*: As shown in Figure VII/2.4.4-1. IEC 60870-5 is very important for SCADA. Standard 101 provides structure directly applicable for RTU and IEDs. At the data link layer it specifies multidrop (unbalanced) or point to point (balanced), as discussed in Clause 1.0. Standard 101 defines the parameter support for multivendor devices. The following application functions can be utilized by standard 101:
   - Station initialization
   - Acquisition of events
   - Cyclic data transmission
   - Data acquisition by polling
   - General interrogation
   - Command transmission
   - Clock synchronization
   - Transmission of integrated total
   - File transfer
   - Parameter loading
   - Testing procedure

   IEC 60870-5-104 uses TCP/IP in place of EPA.
2. *Distribution Network Protocol (Version3; DNP3)*: DNP3 has specifically been developed for inter-device communication in SCADA like RTU−Master, RTU−IED, etc. Even though both have been developed from an EPA structure with some similarity, there are a number of differences (e.g. NP3 always use 16-bit addressing−source address and destination address, while IEC 60870 can use 8/16 bits and source address is not mandatory) making it incompatible. Also DNP3 depends on layers to confirm that data transmitted are successfully received by the recipient. IEC 60870-5 relies more on the security of the network. Because of pseudo transport layers, DNP3 really has four layers—application layer, pseudo transport layer, data link layer, physical layer—in place of a three-layer structure like EPA. Some features of DNP3 include:
   - *Open standard*: This Protocol can be used by vendors for RTU, IED, and master station/server.
   - *High data integrity*: Data link and application layer data are sent through a confirmed service.
   - *Flexible structure*: Application layer is object oriented with structure that allows a range of implementations retaining interoperability.
   - *Multiple applications*: This includes polled only, polled report by exception, unsolicited report by exception, and a mixture of above. It can use several physical layers in LAN and WAN.
   - *Minimized over head*: Can be used over an existing pair of wires.

www.EngineeringBooksPDF.com

Maximum data frame in DNP3 is 292 bytes and out of this 1 byte is used by the pseudo transport layer. DNP3 uses CRC check to avoid noise susceptibilities in communications. This is because DNP3 always tries to confirm that transmission is well received by the recipient. DNP3 supports various architectures, such as one to one (master master), multidrop, hierarchical, and data concentrator. In recent years to take advantage of Internet service, TCP/IP has been used to transport DNP3.

3. *MODBUS*: This is also almost an open standard used in SCADA communication.

2.4.5 SCADA Security

"Open-based standards have made it easier for the industry to integrate various diverse systems together, it has also increased the risks of less technical personnel gaining access and control of these industrial networks"(Courtesy: National Communication Systems Bulletin). Therefore integration is easier, but internet connections make them very vulnerable to cyber attacks. Major host attacks include but are not limited to the following:

- Use a denial of service (DoS)—shut down
- Delete system file (down time)
- Plant a Trojan and gain control
- Modify logging (data loss)
- From log key stroke for User ID and PW
- Log sensitive data loss and loss in competition
- Change data point to deceive operator
- SCADA server as launching point to defame

There two *major* fear points: authorized access by human or access by intention/accidental virus infection. There are several important steps to secure SCADA including:

- Patch host OS, application, and SCADA components (but may not be possible always)
- Control application communication between SCADA and other networks
- To regulate application communication within SCADA
- To regulate "who " and "what" to communicate in SCADA in the system
- Close monitoring of the system and reacting immediately to any virus or other type of attack

Several multiple detection mechanism may include:

- Stateful application-aware firewall
- Antivirus detection
- Application control
- Web filtering
- VPN (see Clause 2)
- Network anomaly and DoS prevention
- Database protection
- Wall application protection
- Updating antivirus and IPS signature database
- Known SCADA exploit already in antivirus and IPS database

Border router (main router in front of main firewall of the organization), proxy operating system, etc., are major systems deployed in industrial SCADAs. This is subject by itself, so only salient points have been covered in this limited volume of the book. For details, see a standard SCADA book.

2.5 PLC (OLCS) in Off Sites: Introduction

In power plant off-site controls, PLCs find a good number of applications. In most of the cases today, these PLCs are linked to the main plant DCS (if off-site controls are not integrated as one system with main plant control). What are off-site plants? Boiler turbine and generators (BTGs) are directly connected together for power generation, and there are various material supplies necessary such as fuel (oil-handling plant/coal-handling plant), water treatment plants (DM plant + pretreatment plant), treated cooling water, H_2 generation plants, etc., for the BTG to operate. Additionally there are plants/systems such as ash-handling plants, effluent treatment plants, fire detection and protection systems, etc., which are necessary so that power plants operate safely without pollution. All these plants/systems are as off-site or auxiliary plants for power plants. Major off-site plants include:

- Coal handling
- Ash handling
- Water treatment
- Fuel oil handling
- Fire detection and protection
- Equipment cooling water
- Circulating water (including Cooling Tower— as applicable)
- Hydrogen generation
- Effluent treatment

Also there may be control systems for ESP. Note that there will be a signal exchange from these plants to the main DCS to keep the operator always informed about the off sites so that the operator at the main control room is in a positions to initiate necessary action for safe and efficient operation of the plant. Apart from plant configuration and size, the owner's investment policy, plant utilization, etc., play an important role in deciding the type of PLC for off-site plants. A few generalized features normally found in off-site PLCs include but are not limited to the following (not sacrosanct, and may vary with Plants):

- PLC processors may be in hot standby mode to include a fall back feature.
- Redundancies in I/Os, with optical/galvanic isolations and expansion provisions, monitoring of power supply,

www.EngineeringBooksPDF.com

contact bouncing, etc., smaller PLCs may not have such features.
- Dual redundant communication channels to integrate various PLCs when necessary so that they form a LAN. This LAN is integrated with the main plant DCS for data exchange.
- Independent dual power supply scheme in each off-site PLC.
- There may be various modes of operations, such as "auto" semi-auto," and "operators guide mode" (see Clause 2.3). At any point it is possible to intervene manually; however, protection will always get priority. Semi-auto and operators guide mode are often seen in water-treatment and coal-handling plants.
- In case of power and other failures, fail-safe mode is chosen, and in case of sequence control, the last sequence prior to failure needs to be maintained.
- For off-site plants a minimum of one operator station and one programming station (may be special small-operator interface for stacker/reclaimer control cabin in place of WS/monitor) should be provided for the system. In case of multiple control locations, a suitable number of panels and operator interfaces need to be provided. There should be operator interface displays and logs. On demand/event-based/periodic/alarm logs are standard. Alarm, mimic display, and trend displays are standard depending on application and use. For example, mimic in CHP/AHP is quite important for operation. Similarly parameter trends in DM plant exchangers are very useful. In some cases large video screens are helpful for shared display.
- Like the main plant, local PB stations/de-interlock switch (as applicable) interface with the PLC.

2.5.1 Coal-Handling Plant Control Systems

In thermal power plants, the coal-handling plant is mostly the largest and costliest auxiliary plant. There are a number of subsystems in the plant including:

- Wagon tippler/track hopper control system
- Conveyor control including crushers
- Stacker/reclaimer
- Traveling trippers
- Dust extraction/suppression system

All of these systems are controlled by PLCs with remote I/Os. These PLC(s) normally have provisions for data exchange with the main DCS for status reporting and emergency operations from the unit control room. The major equipment in a coal-handling plant includes the following:

- Wagon tippler
- Stacker/reclaimer
- Paddle feeder
- Number of belt conveyors/feeders
- Traveling trippers
- Belt weigh scale
- Primary/secondary crushers
- Magnetic separator
- Dust suppression system

A number of independent controls or PLCs are deployed for subsystems such as for the stacker cum reclaimer, traveling tripper, wagon tippler, etc., so there may be a number of smaller PLCs and one main PLC. Also there may be a number of remote I/Os, e.g., at the MCC and for the main PLC of a CHP. These small PLCs and main PLC may be integrated together forming a LAN. This LAN is connected to a DCS through a soft link (may be through some RS link and protocol or via Fieldbus discussed earlier). In larger plants SCADA is also introduced so that the coal preparation system can form a part of the entire system. In CHP a few local panels are also deployed and may be connected with the PLCs. The majority of these are

- Paddle feeder (up to reclaimer) with dust suppression
- Belt weighing system
- Coal-sampling unit
- Electrical hoist
- Magnetic separators
- Sump pumps
- Mobile tripper over bunkers (if applicable)

Out of the above the belt-weighing system, coal-sampling system, and magnetic separator interface with the associated PLC control system. All the systems require dust extraction and a suppression system, which may have their own control with the interface to the subsystem PLC or may form a part of the subsystem PLC. Dust extraction/suppression for conveyors runs when the conveyor systems are running while for the bunkers it has to run around the clock.

1. *Local operation*: The coal-handling plant is controlled from the operator's station for the following systems under the main PLC. In some cases where there are independent PLCs, there will be a soft link for data exchange and control from the main PLC. Where there are systems with local panels, a suitable arrangement for control change over from each place is provided. The probable local operation centers are as follows:
   - Conveyors/feeders, crushers, vibrating roller screen, etc.
   - Paddle feeder (status)
   - Dust extraction and suppression system
   - Ventilation system (group/individual)
   - Vibration monitoring and temperature monitoring of HT drives, etc.
   - Magnetic separators

www.EngineeringBooksPDF.com

- Coal-sampling system
- Stacker/reclaimer (status)
- Belt-weighing system
- Traveling tripper, etc.

2. There may be a number of flow paths from which an operator can select for feeding coal. Therefore separate flow path selection is made possible through mode selection at the PLC with the help of a few subroutines. Whenever such a path is selected, the PLC selects the complete path so that the flow goes unhindered. Some of these paths are listed below:
   - Wagon tippler/track hopper to bunker
   - Wagon tippler/track hopper to crushed coal storage
   - Wagon tippler/track hopper to crushed coal storage and also to the coal bunker
   - Coal stock pile to bunker in normal and emergency

   In some large CHPs, SCADAs are also deployed and coal preparation systems, e.g., coal washery.

2.5.2 Ash-Handling Plant

Ash-handling systems consist of the following major systems:

- Bottom ash (BA) system
- Fly ash system (ESP/air heater)
- Ash water system
- Ash disposal system

The ash-handling system may be dry, semi-automatic wet, and wet system. Similarly the disposal system also may be wet and dry. Today dry pneumatic conveying is more popular. Because it retains the original characteristics of fly ash and its utilization, pneumatic conveying is used more often. For the purpose of control PLC systems are used extensively. Normally there is one main PLC with operator stations. The main control room for an ash-handling system may be located near the ash slurry pump house. There may be separate PLCs and local panels for a SILO system and one PLC for a water recovery system, as applicable. The local panels may have mimic displays or a conventional mimic panel (now replaced by WSs) with suitable interface to the PLC. These PLCs form a LAN so that the operator from the main ash-handling control room can oversee the entire system as well as when necessary take over the control.

Since an ash-handling plant is inter-related with boiler operations, this LAN is suitably connected to the main DCS for supervisory monitoring and control. Out of the various subsystems discussed, (dry) fly ash handling and disposal form the major part as far as I/Os are concerned. In each unit of mid- to large-sized units, the I/Os count could be 2000−2500 (when all switches, etc., are taken in to account) with sequence and logic per network ∼1000. The PLC should be integrated through the dual redundant wire/fiber optic communication channel with video control panel where at all times the sequence is displayed. In case any sequence fails, then the video control panel may be highlighted. Salient special features of these PLCs are

- Suitable menu(s) for set point and sequence control on MMIs
- Remote control of ash-dumping operation
- Event and analog parameter trending
- Manual/automatic sequence control and parameter set
- Integration with DCS

Time to empty each hopper, hopper-emptying sequence, etc., form the basis for automatic operation, or it could be done on the basis of level sensing for better boiler operation. In modern systems sequence optimization can be done with the help of adaptive controls or artificial intelligence through a learning process. There may be remote I/Os, because of distance and economy, connected to the main PLC for interfacing MCC and other systems.

2.5.3 Water Treatment Plant Including Effluent Treatment Plant

There are three different sections in water treatment plants (WTPs): pretreatment (PT) plant, post-treatment or DM plant, and waste treatment or effluent treatment (ET) plant. The ratio of analog to digital measurements are near (less than) unity, and since there is hardly any difference between DCS and PLC, selection of controls could go either way. However, due to the many sequential controls pertinent to each of the exchanger units in DM and effluent plants, the PLC is the preferred control system. In some cases a number of PLCs are utilized for total WTP plants.

Also some smaller units use PLCs with an SLC controller. WTPs encompass from the raw water pump house to the DM storage tank, and the location of the pretreatment plants are far from the DM plant control room where normally the main PLC and operator's station are placed. Sometimes it is better that pretreatment plants have a separate PLC with remote I/Os for raw water plants. Again the chlorination plant is almost an independent plant and may be controlled by a micro PLC.

Depending on plant size and configuration, the ET plant may be an elaborate system and involve many I/Os, so a separate PLC may be used for it. Finally, all of these PLCs may be integrated or linked so relevant data is available at the DM control room. Alternatively, this may be achieved by deploying remote I/Os and/or via Fieldbus to reduce cable cost. From the above discussion it is clear that it is necessary to have an integrated LAN with a soft link or Fieldbus connection to the main plant DCS.

In terms of automation there are different control systems deployed for PTs, DMs, and ETs. In pretreatment plants there are a number of pumps, and their automatic selections and associated logics are major issues. Also there are a few

www.EngineeringBooksPDF.com

measurements like flow measurement by Parshall flume, etc. For large power houses, there may be large number of pumps and valves, so these automatic selections are complicated and a dedicated PLC may be a better option.

In DM plants, on the other hand, there is sequential operation of solenoid-operated valves for backwash, regeneration, etc., for the exchanger units. Again these regenerations can be done in various modes, such as DP across exchanger, time-based, and/or conductivity-based systems. Naturally the PLC involved must take care of the same. Also in DM plants there are controls for chemical handling, e.g., brine tank automation. Like many other systems sequence control may be fully automatic, semi-automatic (manual initiation of operation, then all subsequent steps in auto mode), or manual. DM plants also involve a few modulating controls, e.g., degasser control and measurements of parameters involving analytical instruments such pH, conductivity, etc., so trending of parameters is important as well. In small DM plants a local dedicated sequencer is not uncommon. For these tasks it is preferred that a large DM plant has deploys separate PLC subsystems. This is a similar situation for an ET plant. Selection of IP rating for the PLC and local enclosure is quite important as the environment is very corrosive. In these plants local operations of a few drives are common, e.g., clariflocculator agitator, so local panels with operator interface and link to the LAN may have to be considered.

2.5.4 Fuel Oil-Handling System

This plant deals with unloading and storage of fuel oil. Since fuel oil is highly viscous, it needs to heated. Normally this is done with the help of steam. So control operation of pumps, heaters (to maintain desired temperature), and monitoring of various parameters like level, etc., are done with the help of a small PLC and local panel with an operator station. These PLCs are connected to the main DCS via a soft link.

2.5.5 Circulating Water and Equipment Cooling Water System

These two systems have different controlling philosophies. Also location wise they are in different places. The equipment cooling water (ECW) system is located in the main unit area whereas equipment for the circulating water (CW) is located outside of the main unit area. In both systems PLCs are deployed with a soft link to the main DCS.

1. *CW system*: The CW is directly related with operation of the condenser and with the turbine, so in many cases CW pumps along with associated valves form a part of the unit DCS that may be extended to control this part. However, in stations with a number of units, separate PLCs with full supervisory control at the unit control room can be deployed. In these cases the CW PLC complete with local operator stations are used to control the pumps and valves with an overridden control from the unit control room DCS, which may be connected to the PLC via a soft link or with the help of a Fieldbus. Normally an independent, local control panel/operator station with control is deployed for CW chlorination/treatment plants. Cooling tower water treatment automation may form a part of the CW PLC or it could be achieved by a micro PLC with a link to the CW system PLC.
2. *ECW system*: It uses DM quality water to cool equipment in the unit. This water is cooled by raw water by a water-to-water heat exchanger. Since this is in the unit itself, many times the control and operation of these pumps, valves, and associated logics are performed as a part of the main DCS. Sometimes (especially when the system is common to two units) separate, small PLCs and local control panels with operator's control and operating stations are provided. However, this will be connected to the main DCS of the plant for signal exchange.

2.5.6 Fire Detection and Protection System

PLCs here used almost everywhere in a fire system. Other than a PLC at the fire water pump house, other PLC/intelligent controls in the detection system are little different from conventional PLCs. Normally there is one operator station and one programming station for the PLC located at the fire water pump house for operation of these pumps and valves. Also alarms from these systems are made available to various other locations such as the fire station, Control room fire panel, etc. At present the fire alarm panel and detector panel are also basically intelligent PLC-based systems. The addressable detectors interface with these panels. However, these alarm detector and fire alarm panels have dedicated intelligent control systems that analyze analog-addressable detector signals internally and form an envelope of curves before really detecting a fire alarm. At the fire alarm panel LCDs are provided to show the address of the detector (i.e., location of the fire and/or manual call point). These fire alarm and detector panels may form a LAN with a PLC at the fire pump house PLC. In any case the fire alarm panel and fire Pump house normally have a soft link to be connected to the DCS for polling various data as and when necessary.

3. ANNUNCIATION AND SEQUENCE OF EVENT: PREAMBLE

Both annunciation and sequence of event (SOE) could be a part of the DCS as well as installed as an independent system. The alarm annunciator is initiated by a trouble/fault signal (contact) that brings the trouble at any part of the

www.EngineeringBooksPDF.com

plant to the notice of operating personnel. The SOE stores and records various events in sequence so that the event can be studied and analyzed in a more precise manner to detect the root cause of the problem. A story cannot be properly understood if the sequence of events is lost. Similarly, after any trip and/or any major fault it is most important to know the entire SOE: How did it happen and what are the consequences? The first event is not always the root cause of a catastrophe. A simple and coarse example would be that the turbine tripped, HP bypass did not come in time, and the boiler tripped. Even though the turbine trip occurred first, a plant with HP bypass needs it to come into operation in time. So for boiler tripping the HP bypass was the culprit. There are systems available where the SOE and annunciator (alarm system) are put together in one system, independent of the DCS, but suitably connected to DCS for management information system (MIS) and/or printing etc.

3.1 Alarm Annunciator

The annunciator consists of multiple, prewritten alarm display windows to draw the attention of the operator.

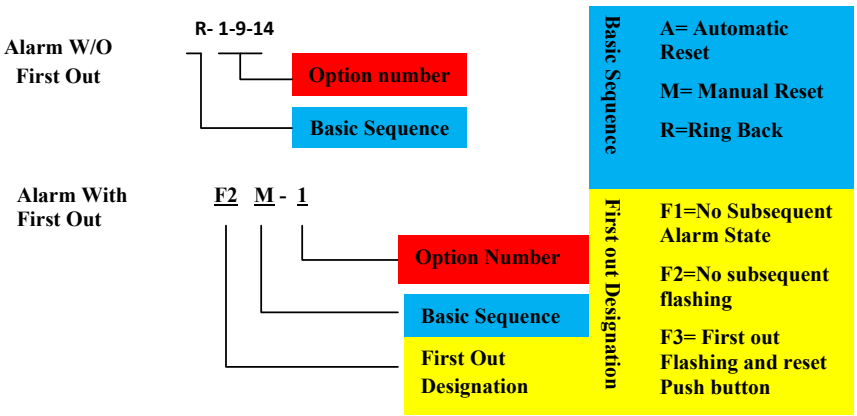


FIGURE VII/3.1.1-1 Alarm designation method.

TABLE VII/3.1-1 Alarm Option Numbers

No.	Key word	No.	Key word	No.	Key word
1	Silence push button	6	No audible	11	Common ring back visual
2	Silence interlock	7	Automatic alarm silence	12	Automatic momentary ring back
3	First out reset interlock	8	Common ring back audible	13	Dim lamp monitor
4	No lock in	9	Automatic ring back silence	14	Lamp test
5	No flashing	10	No ring back audible		

TABLE VII/3.1-2 Alarm Sequence A Automatic Reset (ISA 18.1)

Line	Process condition	Push button operation	Sequence state	Visual display	Audible device	Remarks
1	Normal		Normal	Off	Silent	
2	Abnormal		Alarm	Flashing	Audible	Lock in
3A	Abnormal	Acknowledge	Acknowledge	On	Silent	Maintained alarm
3B	Normal	Acknowledge	To line number 4			Momentary alarm
4	Normal		Normal	Off	Silent	Auto reset

www.EngineeringBooksPDF.com

These alarm points operate through a set of logic and trouble contacts. Annunciation systems also include a shared power supply, audible signal generator, horn, etc. There are various sequences of operation implemented with the help of a logic system. A number of alarms may be grouped. There may be first out alarms to identify first alarm occurrence in a group of multiple alarms. There are "acknowledge," "rest," and "system" (or lamp) test push buttons. The system/lamp test push buttons are used to test the alarm sequence (system test) or lamps (lamp test) in the annunciator. See ISA standard 18.1-1979 (R 2004) for annunciator sequences.

3.1.1 Annunciation Types

Alarm annunciation can be realized by a CRT/monitor alarm and an independent annunciator with or without a link to the DCS. In this clause, the discussions are restricted to independent annunciators, which can be realized in relay logic, solid-state logic (e.g., C MOS), and microprocessor-based logic with a serial link to the DCS. Alarm management system for DCS separetly later. Depending on the location of the logic system pertinent to the annunciator, it can be classified into two types: integral and remote.

1. Integral annunciators have a rack containing the logic card and power supply as well as display units. Display units are at the front panel door, whereas logic cards are inside the rack with terminal blocks at the rear of the rack (or at the two sides of the panel) for field and other terminations. In some integral annunciators associated push buttons are part of the rack. However, push buttons and hooters are kept at the control panel and are connected to the system by external wires.
2. Remote annunciators have separate cabinets to house the logic cards, whereas display units are separate and mounted in the main back up panel. Here also push buttons and hooters are externally connected to the system. These are slowly becoming extinct.
3. Semigraphic annunciator systems have been used since the 1960s. In this type of annunciation the alarm points appear as separate display points at various positions in the plant mimic and/or semigraphic panel. These may be individual integral annunciators or may be remote also. This type is normally used for process plants and used mostly in earlier days.

3.1.2 Alarm Designation Methods

According to ISA 18.1 these are designated as shown in Figure VII/3.1.1-1. Option numbers are listed in Table VII/3.1-1. A number of alarms may be grouped together, and as a result one alarm may generate a number of alarms in the group or in another group. To identify which had occurred first, "first out" alarms are used.

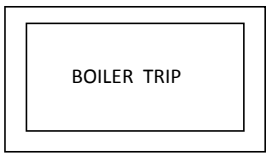


Fig VII/3.1.5-1 a Back lighted Ordinary display

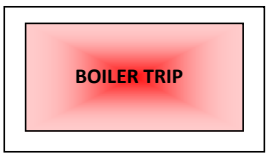


Fig VII/3.1.5-1 b Back lighted Translucent, Readable when alarm

FIGURE VII/3.1.5-1 Alarm window types.

3.1.3 Alarm Sequence

A typical alarm sequence is presented in TableVII/3.1-2. There could be quite a large number of alarm sequences, which are available in ISA 18.1 with a sequence diagram. To specify the annunciation alarm, the sequence needs to be known as discussed above.

3.1.3.1 Sequence Features

1. Acknowledge and reset PB
2. Alarm audible device
3. Lock in of momentary alarm until acknowledged
4. Audible device silence and flashing stops when acknowledged
5. Automatic reset of acknowledged alarm indications when process conditions return to normal
6. Operational test

3.1.4 Optional Items

1. *Annunciator*: This is initiated by the trouble NO/NC contact. However, it is better to include one built-in switch so on site this NO/NC contact can be altered, i.e., to change NO to NC (vice versa) at the alarm panel. Once this is specified, the supplier will include the necessary logic.
2. *System test*: Usually the lamp burned-out tests are performed out utilizing the lamp test push button. However, optionally it is possible to include the system test push button so that entire system including testing the flasher, logic card, and audible devices can be tested.
3. *Repeat auxiliary contacts*: In the system it is possible to include the necessary auxiliary contacts for various purposes including interlock, etc., for external use.
4. *Group alarms*: It is possible to initiate a single window alarm as a group alarm. Depending on initiating contact type NO/NC, these may be in parallel or in series. HT motor winding temperature high alarm may be an example of this type.
5. *First out*: Here alarms pertaining to a group (e.g., BFP) may be part of a cluster of alarms. One alarm may initiate several other alarms. To distinguish the first alarm (cause) first up is selected to detect the first alarm. When acknowledged, all other alarms will stop flashing

www.EngineeringBooksPDF.com

TABLE VII/3.1.6-1 Annunciation (conventional) Data Sheet

Feature	To be specified	Remarks
Type	Integral/remote/semigraphic	
Sequence	ISA designation and sequence table/diagram	
Logic type	Relay, solid-state, microprocessor based (indicate soft link and protocol if any)	To specify
Total display	Actual display, active spare, dummy if any there, quantity to be specified	
Power supply	Voltage, phase frequency, etc., interrogation voltage 24/48/110/220 V AC/DC standard	Also to specify back-up power if applicable
Window size	Dimension of window (height, width, and depth)	
Display area	Display width and height (R × C)	
Display type	Ordinary, or translucent type, color, etc.	
Cabinet details	IP class and cabinet-mounting style.	E.g., flush
Inscription details	Size and color of each character and channel/line	Number of lines
Logic cabinet specification	Tentative acceptable size, enclosure class, wiring standard, etc.	For remote type if any
Field contact type	NO/NC or site selectable	
Prefab cable	If any pre fab cable connection	
Contact discrimination and delay time	To specify first up discrimination time (1 ms possible), also how much delay (say 3 ms*) contact can be considered as authentic and not spurious	*If contact stays >3 ms it is nonspurious
Various control inputs	Number of push buttons with details of service	
Push button specification	Type and color for each service, number of contacts and type rating	
Horn	Type, power supply, etc.	
Isolation feature	Optical/galvanic isolation etc., as applicable	Optical Isolation up to 2.5 kV available
Special alarm	Ground fault, power supply monitoring alarm (type and details)	To specify
Type test	Associated type tests to be performed	
Ambient condition	To specify temperature, RH, etc.	
Alarm test feature	Lamp test/system test, etc.	
EMI	To specify required standard	EN 61000-6; 2/4
Spares	Spares quantity for logic cards etc., flasher, lamp, etc., as per project philosophy	

except the first one. First out alarm will be acknowledged only when the separate first out acknowledge push button is pressed after pressing the normal acknowledge push button.

3.1.5 Alarm Display Types

Annunciator display units are generally arranged in matrix form, i.e., a number of rows and a number of columns. There are various such R × C combinations available from the manufacturer. Also, individual window and alarm display sizes have wide variations. A typical size is 50 mm high by 75 mm wide. Designers have to choose suitable alarm displays depending on the control panel size and layout. The simplest display form is a transparent window with an inscription and back-lit translucent window. The inscription is readable from outside even when there is no alarm. When the alarm light glows the inscription can be read from

www.EngineeringBooksPDF.com

a long distance as shown in Figure VII/3.1.5-1 a. In Figure VII/3.1.5-1 b, the inscription can only be read when the lamp is glows. The lamps inside the windows could be LED or incandescent lamps (almost obsolete now). Depending on the importance the display, lens colors could be white, yellow, red, etc.

3.1.6 Annunciator Specification

In the Table VII/3.1.6-1 standard features to be specified for annunciation are presented with ISA 18.1 as a guideline.

3.2 SOE

Precise and continuous monitoring and recording of plant parameters is an absolute necessity. In modern times with highly sophisticated automatic control and protection, a single failure may result in a huge number of alarms, so operating personnel may be at a loss unless all such events are properly time tagged. OLCSs have scan times that are generally higher, so for precise analysis SOE recording is necessary to time tag such inputs in 1 ms so that the primary cause can be identified.

3.2.1 SOE Features (Separate)

Sequence of Event Recorder—SER normally have the following features:

1. A selected number of binary inputs in each of the subsystems such as
   - SG flue gas
   - SG fuel system
   - SG pressure parts

TABLE VII/3.2.3-1 SER Data Sheet

Feature	To be specified	Remarks
Type	Standalone/part of OLCS	
Packing	Standard 19″ rack	
Capacity	Store at least 100 recorded data of all SOE point change state and/or recording at least for 3minutes	~12,000—15,000 recording per unit
Cabinet details	IP class and mounting style in cabinet—flush, etc.	
Total display	Remote displays for back-lit lamp, LED, and/or monitor (CRT)	
Power supply	Voltage, phase frequency, etc., interrogation voltage 24/48/110/220 V AC/DC standard	Also to specify back-up power if applicable
System processing	In-built processor with necessary nonvolatile memory for setting as well as data	
Display character	~60 characters with time stamp	In milliseconds
Printer	Local printer if called for to specify printer types	
Character details	Size and color of each character	Also number of lines and characters per line
Field contact type	NO/NC or site selectable	
Software	Details regarding software and software development	
Contact delay time	To specify delay time after which contact SOE can be initiated	To avoid contact bounce (say 3 ms)
Isolation feature	Optical/galvanic isolation, etc., as applicable	Optical isolation up to 2.5 kV available
Interface	To specify link and protocol for DCS	E.g., RS 485 and MODBUS
Auxiliary relay	Group/any relay output	
EMI compliance	To specify required standard	EN 61000-6; 2/4
Time synchronization	Pulse/GPS signal, etc.	
Spares	Spares quantity for various modules	As per project

www.EngineeringBooksPDF.com

- TG run up system
- TG protection
- TG EHG system
- HP/LP bypass system
- CEP and condenser
- BFP Group
- Miscellaneous others
- Regular heater Group
- Generator
- Exciter
- Unit electrical system

All of the binary inputs related to the process trip and pre-trip conditions of the aforesaid subsystems are normally included in SER. Approximately 100–120 points in a regenerative reheat type power plant is a typical figure for a 200 MW plant. Exact quantity depends on plant control philosophy and needs to be decided in the planning stage.

2. In many cases SOE inputs are taken as a potential free contact for hardwired connections, to make SOE an independent system; however, it could be a part of the main OLCS also. For use of common resources, SOE inputs may be connected to the DCS via a link.
3. Like alarm systems, SOE contacts also have the necessary optical/galvanic isolations and digital filters to avoid contact bounce.
4. Normally SOE records at least a 100 point event for up to 3–5 minutes after the occurrence of any major disturbance, so the analysis is proper and sizing of the system is done accordingly. Approximately 12,000–15,000 event records are standard and available.
5. Standalone SER is available in high-density packing Euro racks.
6. SERs have interfacing facilities with plant DCSs, e.g., RS 485 MODBUS protocol.
7. SERs have separate self-diagnostic features and their own watchdog relays for outputs.
8. Standalone SERs are fully programmable and have dedicated programming units.

3.2.2 SER as a PART of the OLCS

When SER is a part of the OLCS it is then treated as a functional block in the program to collect a given number of channels in 16 or 32 bits for each channel. Whenever it is embedded in the subroutine the sampling rate is governed by subroutine execution time. SER can be configured for the pre- or post-triggered mode. Features stated in Clause 3.2.1, number 1 are also applicable here.

3.2.3 SER Specification

General specifications for standalone SER as listed in Table VII/3.2.3-1.

4. INTEGRATED DCS–DDC MIS: PREAMBLE

The title of this clause is enough to confuse the reader. DCS is enough to include the entire control system. Now the question is what is meant by DCS here? And why is it so? In this clause it is meant to indicate Distributed Control System—intended to mean a control system in which various functionalities are distributed to its basic subsystems/components to perform the entire function. There could be geographical distribution as well. This DCS may be conceived as DDC MIS. The term *DDC* (distributed digital control) means various control systems implemented diigitally and functionally distributed. These controls could be OLCSs and CLCSs. While the former one refers to a sequential control, interlock and protection system where direct feedback may not be mandatory, the latter stands for a feedback control system. MIS is a Management Information System wherefrom all the tags are monitored and supervised. In the title, word "integrated" before DCS means technological integration as well as functional integration. It should now be clear why "Integrated DCS–DDC MIS" has been chosen (from one of authors's project) as the title of this clause. Major basic features of the DDC MIS will be discussed here.

4.0.1 DCS Diagnostics Features

Fault detection and diagnostics are the keys to system stability and reliability. Whenever a fault occurs it must be reported to the operating and maintenance personnel. System diagnostics needs to quickly analyze the fault by exploring various data. Diagnostic functions of the system must be able to pinpoint the cause of system fault as far as possible, locate the fault (physical location), and finally evaluate and analyze the system response from these actions. Diagnostic software can monitor the faults at various levels such as:

- Network
- Network node
- Station/unit
- Module
- I/O channel

In many of these systems, there is a separate fault diagnostic system sometimes referred to as the control diagnostic system (e.g., Procontrol P14 of ABB). Most of the DCSs have intelligent I/O devices with self-diagnostic features. These diagnostic functions are active as long as they are connected to the systems and they are well communicated over buses to the other systems/system modules. It is possible to generate graphically the fault condition, location, etc., for operator's displays. Now with intelligent field devices in conjunction with Fieldbus systems, there has been a significant improvement in system

www.EngineeringBooksPDF.com

TABLE VII/4.0-1 Security Access Rights and Functions

User	Allowed functions	Functions not allowed
Operator	All Displays, control of drives/devices Changing of certain permitted set points and bias Report printing in various forms permitted by the system	Modification of controller parameter. Value pegging/forcing (*except* permitted ones— may be during sequence operations). Modification of logics/loop/database/MMI SW. Taking off scan, changing any assignment for log and displays
Unit charge engineer	All displays, control of drives/devices Changing of certain permitted set points and bias Report printing in various forms permitted by the system. Taking off scan, changing any assignment for log and displays	Value Pegging/forcing (*except* permitted ones— may be during sequence operations). Modification of logics/loop/database/MMI SW
Shift/station/O&M in charge/miscellaneous other users	All Displays, but no control of drives/devices Report printing in various forms permitted by the system	Control of drives and devices Modification of controller parameter Value Pegging/forcing (*except* permitted ones if at all any). Modification of logics/loop/database/MMI SW. Taking off scan, changing any assignment for log and displays
C&I maintenance In charge	All displays and print outs, control of drives/devices (normally during commissioning/plant modification) Changing of certain permitted set points and bias Value forcing and pegging Modification of logics/loop/database	Modification of MMI SW Control of drives and devices after expiry of temporary password given to handle control function during commissioning and modifications
System administrator	All Functions only in consultation with concerned personnel (may be joint access)	

TABLE VII/4.0-2 Security Access Category

Access	Functions	Remarks
Authentication	Password-protected user account to access the system for control and making change, e.g., an operator may access control and make a few changes in set point or trending data collection interval whereas an engineer may have the access to modify a part of logic/loop.	Many times systems keep the record of such changes and can be recalled later to identify who made the change and when. Most of the manufacturers have a minimum of three to four levels of access authentication.
User	Like e-mail and other systems, a unique ID could be assigned along with a password.	In an IT-enabled system, even users who are permitted access can also through the Internet.
Classification	User access level can be determined plant area wise and/or function basis.	

diagnostics, and maintenance personnel are greatly relieved to pinpoint the fault. Maintenance is slowly changing from reactive to preventive maintenance. The ability to self-diagnose device health and integrity and put forward the information are too valuable to ignore. Pressure transmitters now detect plugged impulse lines or sensor drifts and inform the operator if the measurement is not good. Control valve diagnostics and the ability to generate valve signatures for online diagnostics allow many valve problems to be easily isolated and remedied without much cost associated with replacement. With a Fieldbus system it is possible to identify failure, off specification, and check functions for the field devices. With the Fieldbus it is possible to diagnose function block resource block, , and transducer

www.EngineeringBooksPDF.com

block diagnostics, making it possible to spread the diagnostics at the device (sensor degradation, dynamic error band, etc., in addition to internal diagnostics and process diagnostics), loop, and operation levels (device and measurements identified by tag for fault detection identification). Another feature worth mentioning is that all of these events are time stamped at the source. Some systems like "PRM with advance diagnostic application of YEL" has a diagnostic navigator advanced mechanism for fault detection. Systems like the Invensys IA system offer modules with fault tolerance (see Clause 1) at all levels.

4.0.2 DCS Security

For security aspects of DCS, it is essential to restrict access at various levels. Such variations normally encountered in power plants are indicated in Table VII/4.0-1.

Security threat in an integrated DCS comes mainly from two sources: (1) human access at the plant location and (2) cyber access through the Internet (see Clause 2.4 & appendix IV). Many of the IT-enabled systems have protection and security for their servers and workstations against cyber attacks. Invensys workstations are examples of this. A "secured network is distinguished from unsecured ones by putting "s" after 'http' i.e. https." In many systems, protection and security are provided for field device maintenance also. Some general ways to classify this type of access to the systems is described in Table VII/4.0-2. Security divisions are discussed in Table VII/4.0-1

4.0.3 DCS Redundancy

Since DCS is the heart as well as brain of the plant, there will be redundancies at various levels. Depending on applicability, there could be redundancies at field, I/Os, redundant field I/O controller, I/O communication channel, controller, and main communication system and as such for the network. There could be redundancy at workstations also. Today workstations have global data tag access, so during failure of one workstation the operator can run the plant by accessing the same data from other workstations provided he has the security access for the data. Again in redundancies there are levels, such as 1:1 back-up or two of three redundancies. When two controllers are working in tandem, then there need to be a few considerations: output from one has to be inhibited and output of the active controller has to be tracked by the second one (back-up controller) so that in case of failure of the active one hot

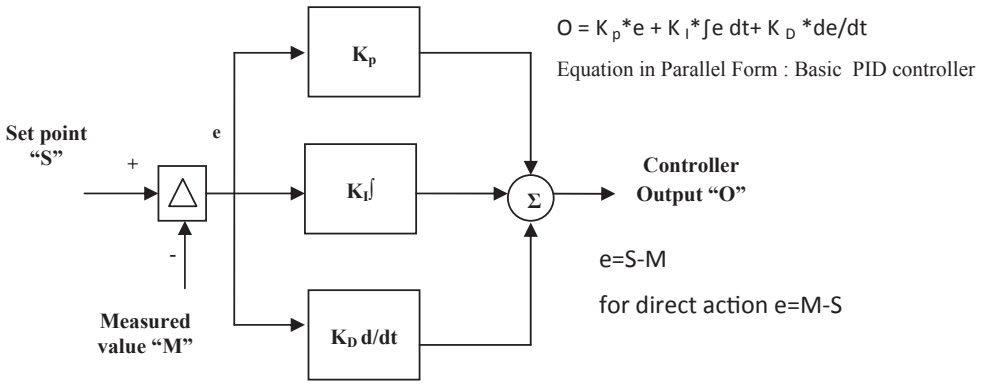


FIGURE VII/4.0-1 Parallel form: basic PID controller.

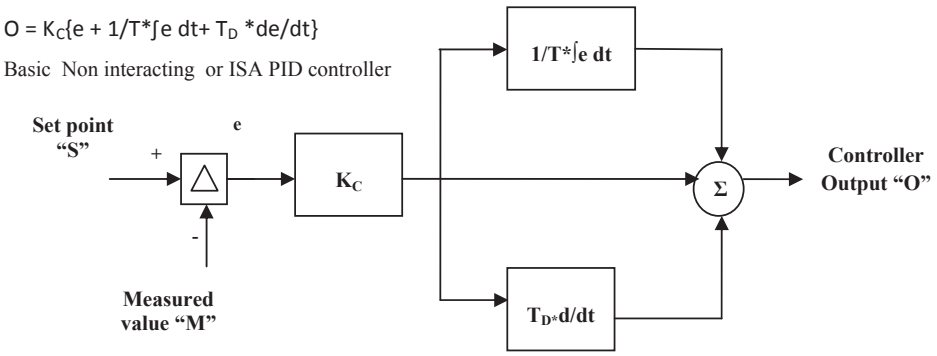


FIGURE VII/4.0-2 Basic PID controller noninteractive.

www.EngineeringBooksPDF.com

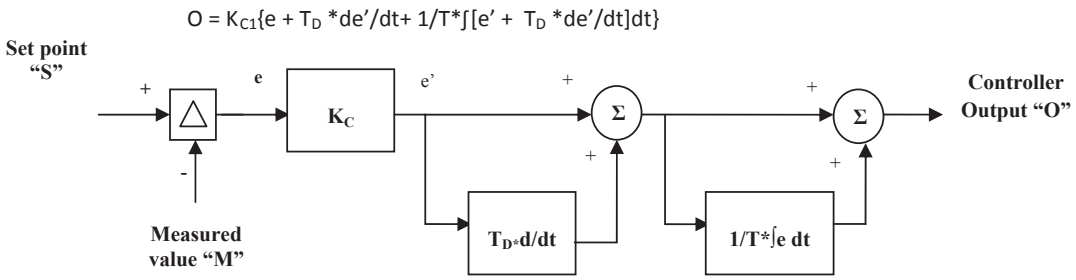


FIGURE VII/4.0-3 Basic PID controller interactive type.

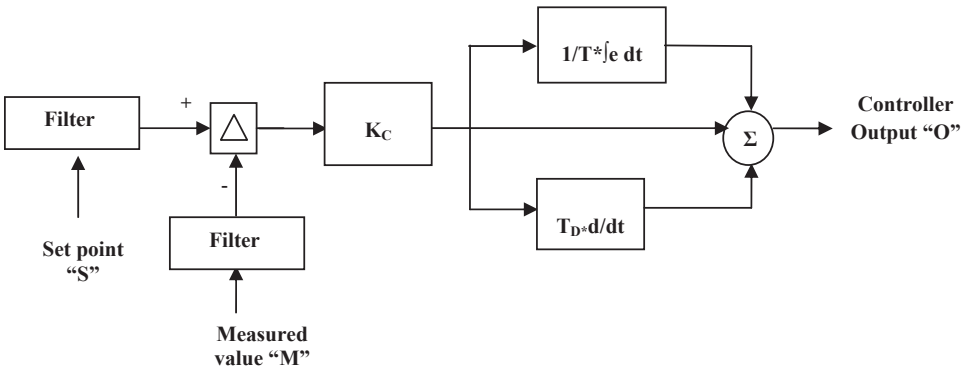


FIGURE VII/4.0-4 PID controller with filter at set point and measured variable.

standby has to fall back without any bump to the system. Also, in case of a hot standby system *either* some other processor has to check the health of the controllers or each of them must also check the health of the other so that failure can be detected for change over. The TMR system is a classic example of this. In case of a redundant system one advantage is that "on line up gradation" can be done easily, but one needs to be careful not to compromise system safety.

4.0.4 DCS Safety Aspects

Conventionally SISs earlier were separate from DCSs. Now these are integrated to develop a system that has the benefits of a DCS and the safety of an SIS is maintained (see Clause 2.2). YEL Pro safe RS is an example of this integration.

4.0.5 System Integration

A power plant is very interconnected as well as interactive, so an integrated system is a good solution for plant control. This is not only restricted to the main plant and may be necessary to integrate various off sites also. System integration ensures seamless data exchange between these units and off sites. Ethernet and OPC foundations have provided DCS suppliers access and exchange information among the various networks and helped the user to integrate the systems. Such integration provides improved operation and maintenance of the plant, better inventory, better MIS, remote access for manufacturer for troubleshooting, etc. Thanks to international standard IEC 61158-2, which made it possible to have some standardization of Fieldbuses, there is a way to integrate various systems (see Clause 1.0).

4.0.6 Control Algorithms

From this point onward (in this clause), we will concentrate on theoretical aspects of control systems and mainly feedback control systems. Any standard book on control system can be consulted for a refresher course on the basics.

1. *Basic PID algorithm*: A basic PID controller can be conceived as shown in Figure VII/4.0-1, where errors are generated at the input of the controller where it is subject to the mathematical treatment by the equation $O = Kp*e + K_I*\int e\,dt + K_D*de/dt$. As the error is fed parallel to the proportional, integral, and derivative operator, it is parallel form.

   In most cases the error is fed to the proportional controller then is fed to the other operators as shown in Figure VII/4.0-2, even if the value proportional to error is fed to the other operators.

   K_C is a proportionality constant and is dimensionless and expressed in percentage, whereas the T integral action time and TD are expressed in seconds as units of

www.EngineeringBooksPDF.com

time. There is another term, proportional band, which is defined as PB = $(1/K_C)$*100. As K_C increases PB decreases. For stability PBs are kept >100%. The proportional controller introduces error into the system, whereas integral action integrates the error, thus it provides zero error at steady state. For faster response derivatives actions are introduced into the system, but this is responsible for the generation of noise into the system.

There is another kind of basic PID control algorithm where the derivative is done on the proportional error prior to integrating it. This is also known as an interacting PID controller, as shown in Figure VII/4.0-3. Here integration is done not only on proportional error but also on the derivative of the proportional error. If the error for persists for a long time at the input, because of integral action, the output may grow to the highest possible value. This is called reset windup and is an important feature in the PID control system. In all modern controllers anti-reset windup features are provided to avoid uncalled for overshoot and disturbance to the system. It is necessary that the control system is tuned for proper response for a change in set point so that there is no output spike and bump due to derivative and proportional action. Also it has to cope with the rate of change of set point so that it is not too slow. Stability is another major goal of the control system. Because of delay, dead time, and high process gain there may be instability and/or oscillation in the system. Therefore tuning of the control system is essential. What is tuning of the controller? By tuning the controller the controller parameters like gain, integral time, dead time, etc., are set so that the controller can effectively match the process dynamics. Conventionally the "Ziegler–Nichols" method is popular for controller tuning.

To have better system response, set points and measured variables are applied through filters as shown in Figure VII/4.0-4. This kind of approach is helpful in preventing sudden spikes. Sometimes dead band timers are kept in the circuit to avoid spurious signals from affecting the control system

2. *Set point applications*: It is clear from the above discussions that each of the terms, such as P, I, and D, acts on error. So while applying the set point to the controller a suitable measure in the controller needs to be taken so there is no spike or bump at controller output due to sudden change in the set point. There are contradicting factors: if it is set to take care of the rate of change of set point then the system response will be slow, whereas if it is set to reject the disturbance then there will be overshoot. A softening effect along with suitable tuning is necessary.
3. *Various control types used in power plants*: Other than the PID control algorithm, there are other control types used in power plant controls. These include the following:
   - *Cascade controls*: This is a multiloop structure where the outer loop has the set point (acts as a master controller) and the output goes to the inner loop or slave loop as the set point to be compared with an intermediate parameter used as a process variable. Here disturbance in the second variable can be corrected at the slave controller without affecting the primary variable. Also the slave loop helps to reduce the process lag resulting in faster system response. In power plants steam temperature control is a typical example of this kind of loop.
   - *Feed forward controls*: Feedback controls have an inherent system lag (between changing of the manipulated variable and the effect of the change on the controlled variable). In a feed forward system, the major components of load are entered into a model to calculate the value of the manipulated variable required to maintain control at the set point. In combustion control at many places steam pressure is used as a main control variable, whereas steam flow/boiler load is used as a feed forward signal to make the loop responsive.
   - *Ratio control*: This is an elementary feed forward control system. The advantage of this loop is that here the control variable, air:fuel flow ratio, can be kept constant. It may not be in crude form but in a different fashion this type of control system is

MFA: Model based systems are developed based on good knowledge of process dynamics and operational environment. In practice this is not always possible! MFA combine adaptive theory with intelligent controls (viz. Fuzzy logic/ artificial neural network) in learning control mode.
Following are the basic features of MFA:

- ***No precise quantitative process knowledge***
- ***No Controller design for a specific process***
- ***No Manual tuning of controller***
- ***Stability criteria available to ensure closed control loop stability.***

The basic aim of these controllers is to produce an output to force the process variable to track the of the set point under variation in Set point, disturbances,& process dynamics. It does so through the process of learning and knowledge base

FIGURE VII/4.0-5 Note on model free adaptive.

www.EngineeringBooksPDF.com

deployed for fuel flow control (with fuel type the ratio may vary a little).

4. *Position and velocity algorithms*: The PID controller algorithm previously discussed produces the output to determine the position demand for the final control element. Thus this type of control algorithm is known as a position algorithm. The control algorithms, which determine the rate of change of the final control positions, are known as velocity algorithms. These are effective in digital implementation in the DCS. These are used for set point controllers for supervisory controls. In this system, the output effectively keeps the previous position so that it generates $\Delta O = O_n - O_{n\text{-}1}$. In DCS the previous position is stored in memory. After the velocity algorithm is calculated it is added to the previous position and is stored as a new "last position." For this the transfer is effectively bumpless. With velocity algorithms reset action on error is not effective, so it needs to be used as override action.
5. *Auto tuning and adaptive control system*: There are two processes involved in the tuning of the controller: one is to learn the process dynamics the other is to make the manipulated measured constant. Many DCS manufacturers use the auto-tuning method when the tuning parameters are continuously adjusted depending on the process dynamics. They use it to inject excitations at the loop to sense the process response. These excitations could be very small but are enough to analyze the control variable in response to the change. Such an excitation injection could be at the gain, set, and/or controller output depending on the manufacturer's design. The aim is to understand the process dynamic. Once it is effectively done, the necessary tuning parameters can be set until there is no further change in the system. In the majority of the advanced controllers these are done with the help of mathematical models with prediction. There are other methods such as Model Free Adaptive (MFA) control. MFA (see Figure VII.4.0-5) control does not require precise quantitative knowledge of the process, no special control for any process, etc. MFAs could be single loop and/or multiloop.

   There is another category of control system called a self-tuning controller. This is more popular with the single-loop controller. but it also could be part of DCS. There are three basic components of the self-tuning system:
   - *System identifier*: This algorithm is responsible for estimating the *parameters* for the process.
   - *Synthesizer*: Calculates the new *controller* parameter based on estimation of the algorithm result.
   - *Control block*: It is the main control algorithm whose parameters are evaluated by the synthesizer.
6. *Optimization*: Like any other system in power plant control, its aim is to maximize profit while maintaining the safety and production quality without degrading equipment life. In a power plant any economization is welcome as it saves energy, which is a scarce element. For optimization independent variables are identified. These are fed to a black box (the mathematical model). This model calculates the performance parameters based on various constraints like disturbances and intermediate variables. For further details see Clause 6.1.5.

4.0.7 Standard Library Functions

In any DCS there are a few standard functional algorithms available. In fact the control loops are functionally represented in terms of the algorithms. A list of such algorithms is presented in Table VII/4.0-3. The symbolic representation of some these functional blocks have been in the Control loops of this book. In this connection IEC standards IEC 61131-3 and IEC61804 are discussed Clause 4.1.5.

4.1 DCS Configuration (OLCS/CLCS Discussions): Introduction

In a power generation plant sequential controls/interlocks pertinent to an ATRS/BMS are as important as modulating controls like the governing control of a turbine, and/or combustion control in a boiler. Also for power plants all subsystems are *connected* and the process is *continuous* and *fast responsive*, so both systems need to be emphasized. In smaller plants a PLC/SCADA could be a solution, but in medium- to large-sized power plants, because of a powerful *function library*, DCS is preferred and chosen, Most DCSs support ISA S88 for interlock and have *embedded advanced control* and *safety* functions.

Various subsystems of a DCS in a power plant include: Closed loop control System—CLCS for modulating control; Open Loop Control System—OLCS for sequential control; and interlock and protection and Information System (IS) Management inormation System—MIS for monitoring, supervision, and interface functions, e.g., monitoring, performance calculation and operator's Interface.

Basic system components of the DCS are shown in Figure VII/4.1-1. Here it is seen that the two controllers have different patterns inside the box to highlight *notionally* that there will be two kinds of controls such as OLCS and CLCS and there will be different components for IS/MIS functions. However, in reality such a distinction between two control systems *may* not be done in the DCS. Had that been done then the OLCS could be replaced by the PLC (to curtail the cost). In DCSs such OLCSs/CLCSs are done very judiciously, as discussed in the following clauses.

www.EngineeringBooksPDF.com

TABLE VII/4.0-3 Standard Library Functions

Type	Algorithms	Explanations	Remarks
Computation	Summing	Sum of inputs	
	Difference	Difference. between Inputs	Error generator
	Median	Selection of mid value	Of inputs
	Average	Sum divided by number of input.	
	Multiplier	Multiplying two or more inputs	
	Divider	Divided an input with another	
	Scale and bias	Scaling input + bias value	$KX + C$
	Function generator	Output as function of I/P	Functions to be defined
	High/low selector	Selection of high or low of inputs	Maximum/minimum
	Dead time	Output after SP time	
	Comparator	Compare with SP or with other input for SP difference	DO or switchover
	Comparator + CO	Same as above with CO	CO = change over
	Lead/lag	Output increase or decrease allowed when compared	Between inputs
	Pulse generator	When input crosses limit a pulse/trend of pulses	
	Differentiator	Calculation of rate of change	Of input
	Integrator	Integration	Of input
	Square root	Square root extractor	
	Flow computer	Pressure and temperature compensation	$Q = \sqrt{(hP/T)}$
	Log function	Output as log of input	
	Exponential	Output as exponent of input	
	Limiter/clamp	Output limiter	
	Limit value monitor	Generate DO when input crosses the set limit	
	Tr. selection	Selection of transmitters on	
	1 of 2 selection	One out of two	Chapter 3
	2 out of 3/median	Selection of 2 of 3 inputs	Chapter 3
OLCS functions	AND/OR/NOT/ExOR	OLCS functions of input(s)	Boolean logic
	Switch	Types of switching functions	Latch, unlatch
	Timer	Delay of specified time	ON/OFF delay
	Counter	Counting of pulse, etc.	With DO
	Flip flop	Temporary memory RS/JK flip flop, etc.	
	Drive	Drive control with functions of various conditions and logics	Trip, permissive, etc.
	Subgroup function	Logical subgroup function	Owner's choice
	Pulser	Generate mono shot spike or pulse when input reached	
	Change over	Input change over	May be based on third AI/DI

www.EngineeringBooksPDF.com

TABLE VII/4.0-3 Standard Library Functions—cont'd

Type	Algorithms	Explanations	Remarks
CLCS functions	PID	PID functions with ratio, gap, anti-reset windup, etc.	
	Other PID functions	Feed forward/tracking/output limiting	
	Set point functions	Set point ramp, set point clamping	
	Auto manual	Switch over and tracking	
	Auto tuning	Auto/adaptive tuning	
	Others	To complete the list	

SP: Set point; Tr.: transmitter; DI/O: Discrete or Digital Input/Output; AI/O: Analog Input/Output.

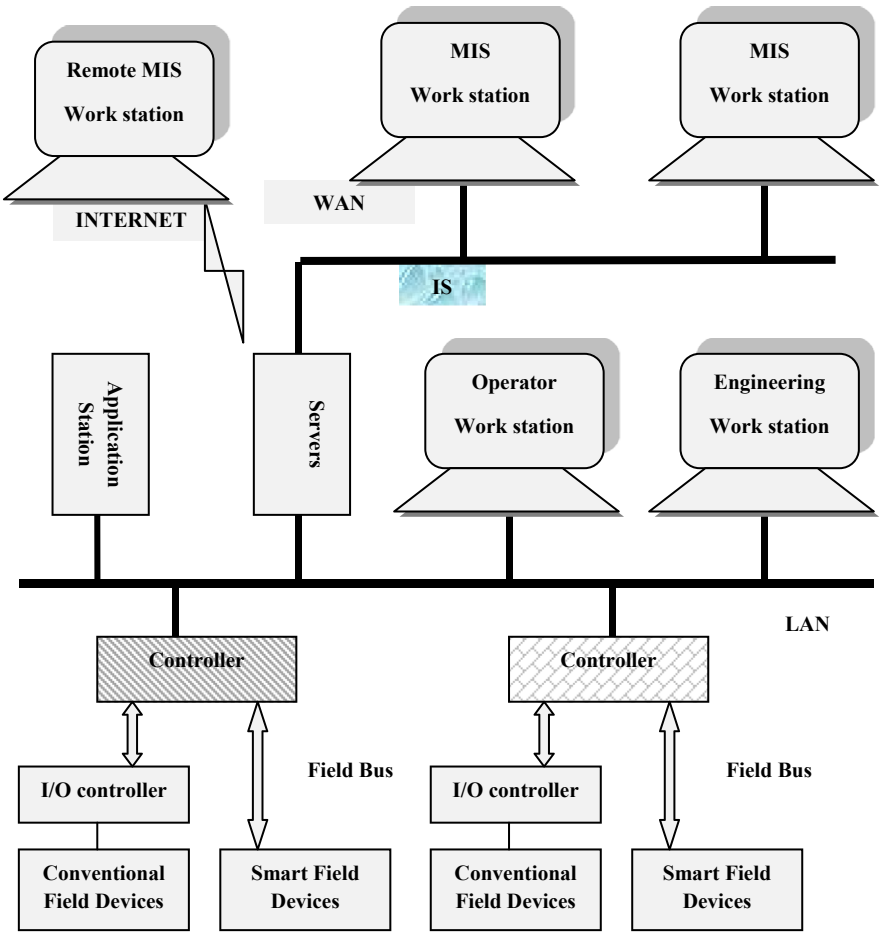


FIGURE VII/4.1-1 Basic DCS components.

4.1.1 Control System Grouping

The entire plant can be divided into the unit level, functional group level, subgroup level, and drive level. At the unit level automatic start-up or shut-down commands can be issued. Functional levels are where independent functions are performed, such as the feed water system (which is a functional group). Within the functional group there are subgroups such as the BFP subgroup comprising BFP and its auxiliaries and associated valves. The drive level is the last level where individual drives are addressed and controlled. If a particular functional group/subgroup is

www.EngineeringBooksPDF.com

considered, e.g., BFP "A" subgroup, then there will be both OLCS and CLCS functions associated with it. Start-up, shut down, and interlocks of BFP "A" will be OLCS functions, whereas the speed control of BFP A will be part of the CLCS function. Normally for each functional group/subgroup, in power plants as the modulating control loops are so inter-related, many times it is very difficult to distinguish between groups and subgroups for control functionality because of functional overlapping. Therefore a judicious decision regarding such a grouping is essential, and separate controllers complete with power supplies and I/Os are allocated to it independent so that if one functional group/subgroup fails, then another is not affected in terms of total control or its communication with IS. So the term controller would mean its associated I/O system, power supply, and communication system as well. Such groupings are mainly found in German and other European system design. Some of the functional grouping criteria are discussed below:

1. *Group considerations*: The grouping of drives depends on a number factors such as system configuration of DCS control, number of I/Os each controller can handle, communication speed of the system, the update rate both process data updates as well as update over the network, etc. As stated previously, many of the drive-related I/Os can be segregated and put in a drive control card, so that much of the I/O handling of individual controllers can be reduced. Also, since it is possible to manually control the individual drives, more equipment can be clubbed in the main controller (with drive control cards). This type of concept works when the manufacturer divides the systems in such group/subgroup and drive-level controls. On the other hand, there are systems that do not need such subdivisions. These systems have only I/O cards and a controller, and then some of the drive functions need to be done at the controller level. Also, fieldbus systems drastically reduce the controller's timing for I/O handling. Naturally the group division will be different. Although each of the two systems discussed has some benefits and drawbacks, neither is superior to other.

   Also some manufacturer use medium-sized multifunction controllers (with or without a back-up controller) to control a group of equipment (e.g. PROCONTROL P14 from ABB). Whereas some use a larger control processor with hot controller back-up to control a large amount of equipment (e.g., CP from Foxboro Invensys). Naturally I/O handling capability, power, and functionality of these two types of controllers are not the same. In the former case, many advanced functions are kept elsewhere. However, both types are workable and in service for many years and the choice is purely a manufacturer design philosophy. With so many options available, the system designer has to choose the better one as per his plant control strategy and philosophy. However, a designer's main consideration should be that failure of the controller cannot jeopardize complete loss of the control system (at worst condition, it can affect only a part). It will be clear from an example. The system is chosen in such a way that failure of one control system may affect one forced draft (FD), one induced draft (ID) fan, and/or three mill systems (out of say six mill systems) but not the entire system. It is a joint effort of the owner as well as the manufacturer to decide on the issue of controller assignment for various controls, which should be based on available devices required to control the plant.
2. *Hot back-up controllers*: With hot back-up controllers, in case one controller fails, another controller automatically falls back in a procedureless bumpless manner to the process with provisions for a manual switch from remote workstations.
3. *Inter-related controls*: There are many controls that are inter-related, e.g., a primary air (PA) fan is connected mainly with a mill, so while selecting a controller for the PA fan, associated mills could be considered. If necessary some of the signals may have to be repeated in two or more controllers; e.g., steam flow and air flow are the signals required at many places (at steam pressure control, steam temperature control, feedwater control, etc.) so these signals may be distributed in hardwired I/O cards or software at I/O bus levels to a number of controllers.
4. *Environmental conditions*: In power plants in the majority of cases electronics (except field devices) are placed in a controlled environment, yet there are cases, especially RTUs, where electronics/control system components may be placed in a harsh environment. While selecting the controls, due consideration must be given to the worst environmental conditions these controls will be subjected to.
5. *Process redundancy*: In a plant there may be three ID fans for redundancy, so the type of controller should be such that failure of one fan would not jeopardize the entire ID fan system. If drive control cards are used, then all the drives may have separate drive cards, which in a worst case can be controlled from the control room.
6. *Stream consideration*: In case equipment is required to be clubbed together in a controller, then due consideration needs to be given so that the failure of a single controller does not hamper the entire operation. Normally FD Fan A, air heater A, wind box A, etc., form a stream so while grouping considerations should be made so that in case one common controller fails, then another stream can be run. If cross running of equipment

www.EngineeringBooksPDF.com

is possible, then due consideration must be given to the interconnecting valves/damper. This will be clear from an example. If in a P&ID with the help of an interconnecting damper it is possible to run FD fan A with air heater B, in case air heater A fails, then while selecting the controller the interconnecting damper should be included in one or both (redundant) controllers.

4.1.2 OLCS Functions

OLCS functions should include sequential controls (ATRS), interlock and protection for various plant auxiliaries, valves, dampers, etc. For OLCSs a few features needing a designer's attention includes but are not limited to the following:

1. *OLCS hierarchy*: As discussed above, the OLCS system can be conceived to be arranged in a hierarchical structure including a unit level, group level (such as the boiler, turbine, feed water system, etc.), and subgroup level (such as the evacuation subgroup and drive level). Hierarchical structure may be helpful for sequential control implementation. However, some drive controls are implemented in I/O cards. It is purely a design philosophy of the manufacturer.
2. *Unit level start-up and shut down*: It is possible today to start-up/shut down a complete plant with a single key stroke. Such start-up or shut down is done at the unit level. While designing a control system of this kind, safety is given the highest priority at every stage so that the sequence may proceed properly.
3. *Group level control*: Such controls are quite common in systems like BMS, ATRS, ATT, etc., as discussed in Clauses 2.2 and 2.3. At this group level independent automatic startup and shutdown are possible. When at the unit level, all groups are started one by one from single start/stop command. For group starting or shut down, each group needs a separate command. All subgroups, subloops, and drive interfaces (as applicable) under each of these groups is started one by one under a single group command. It is interesting to note that these group commands can be either fully automatic and semi-automatic.
4. *Check back*: CLCS is a feedback control system. Sequential controls of an OLCS may have a check back (see Clause 4.1.7) that signals for the sequence to proceed. It is like the feedback in CLCS. After a command signal is issued, before proceeding, the system ensures that the previous command has been obeyed by all concerned within the allowed time gap. This is to ensure that there is no hindrance to the sequence. This is done by check back signals. If there is any constraint for the execution of the previous command, then the fault/constraint must be detected and removed (may be bypassed for noncritical check backs, even manually and/or by manual override). For example, to start a large fan it is necessary that its lubrication pump(s) runs to establish a flow of oil in the bearing. If a command is issued to start the pump, but the pump does not start or cannot send oil, then bearings will starve. Therefore check back signals (that the lube pump is running and oil pressure is okay) are essential for the sequence to proceed further. Now if there is no such check back for a large fan, then one can only imagine what would happen.
5. *Operation release and logic criteria*: Before issuing any command, safety and readiness of the concerned equipment and systems need to be checked. When a command is issued (even manually) it is the duty of the system to check whether all the conditions for the safety and readiness of the concerned equipment and systems are available before it can make the command effective. These criteria checked by the system at the start of the sequence for any subgroup/subloop/drive are normally referred to as operation release. For example, after a boiler shut down any fuel can be started only after purging is complete in the recent (allowed time gap) past. If the fuel is not started within a specified time after purge, another fresh purge cycle may have to be repeated before starting the first burner. Similarly at each stage, or for each interlock, such checks are done with the help of a check back and other status signals referred to as logic criteria, which need to be satisfied (or bypassed) to proceed to the next logical step.

Example to explain (Fig no. VII/2.3.1-1b Example Step Logic): Start up Command for Turbine sub group (e.g. KWU- Siemens) turbine will have the Operation Releases. Some of them are: Starting device 0%, Position set point turbine controller < 0%, Field breaker OFF. Generator breaker OFF.

Similarly in the same turbine start up example, For issuing command at one of the Subsequent step(3) shall have check backs as Logic Criteria before it can issue the command! Some of these criteria at that step would be Turbine speed > 15 rpm , Condenser pressure < 0.5Kg/cm2.,Any one CEP is ON------ this means that the only upon receipt of all operational released criteria available, start command shall be made effective. Similarly in subsequent step command shall be issued only after logic criteria are met. However in case of any safety condition/interlock (say), from Fire it will be made through as an emergent condition!

FIGURE VII/4.1.2-1 Step logic explanation.

www.EngineeringBooksPDF.com

Safety interlocks for a human/machine are executed at any stage and are given the highest priority (see Figure VII/4.1.2-1)

6. *Timing*: See Clause no 4 of Clause 2.3.2.
7. *Operational modes*: Normally three modes of operations are seen in this type of OLCS. These modes are automatic, semi-automatic (step by step), and manual (operator guidance). These are also discussed in no 5 of Clause 2.3.2.
8. *Monitoring and display*: To facilitate operation, it is customary to have these steps: operational release, step criteria, and check back status displays made available to the operator. There are provisions for alarms for abnormal situations. All modes, loss of timing, etc., are made available to the operator. Also it is important that access to these logic programs is restricted to the authorized persons. Certain "step/criteria bypasses" are allowed, but this is by operator only when faster action of operation is called for but *never at the cost of (human and equipment) overall safety, and only authorized persons are allowed to take such actions.* In addition to these, there are other sensor monitorings done including noncoincidence error, open/short circuit monitoring, etc.
9. *Coverage*: OLCS is not only applicable to main power plant sequence, interlock, and protection, it also includes all off sites as well. However, in these off sites a PLC may be used to integrate with the main DCS, but the criteria discussed for the OLCS could be used, depending on applicability. It is also applicable for the electrical control system.

4.1.3 CLCS Functions

These are modulating feedback controls deployed to achieve the desired parameter conditions. Combustion control, Feedwater control, governing control, etc., are all examples of CLCS. Some of the major features of CLCS are discussed below:

1. *CLCS control range*: CLCS is a control system that acts continuously both in position and time on control actuators (valves/dampers), mechanical equipment (hydraulic coupling), and electrical devices (VFD). Theoretically, modulating the control loop is done to control the parameter over the entire range. In reality, this control is applicable for steady-state conditions *mainly* between >50 (60%) and 100% maximum continuous rating (MCR) with variations in associated parameters within specified permissible limits. During transient stages, and at lower load, it may not be possible to achieve CLCS regulation as per the performance specification. (At steady state the loops are normally tested with STEP and RAMP functional signals).
2. *Control algorithms*: Power plant CLCS loops are interrelated and require complex control algorithms. However, some of the basic forms of control algorithm may be standard PID (Proportional + Integral + Derivative), PI, and P. See Clause 4.0.6 for ideas related to various control algorithms. Out of these the PI controller is used in most applications. Because of noise many engineers avoid the "D" action. PD control in *governing control stages* is common in many applications (e.g., KWU Siemens turbine). Since temperature is a slow-changing parameter and sensing is not fast, it is recommended to use PID controllers in temperature loops. Similarly I action in level controls may be chosen as a minimum. Cascade controls (super heater/reheater temperature control), adaptive gain control (any loop such as PA flow control), state variable controls (super heater temperature control), feed forward control (steam flow in combustion control, or difference between steam flow and feed water flow as feed forward signal in a three-element drum level control), ratio−bias control (fuel air ratio control), ON/OFF control (DM make-up water control), etc., are common. Mathematical model-based controls are also applied in CLCS.
3. *Control transfer and loop reaction*: In OLCS, since the devices and controls are discrete in nature, transfer from auto to manual and vice versa is not much of a problem. With modulating controls, since the control actuator can assume any position prior to transfer from Auto to Manual or Manual to Auto, it is a bigger problem. In both the cases, control system outputs have to be matching. If there is a mismatch in output there will be different inputs coming to the control actuator just before and after change over. As a result the control actuator may change posion abruptly. Because of this, there may be a big change in the measuring parameter, i.e., there will be a bump in the system. Therefore it is necessary that a CLCS has both auto and manual outputs that track each other so in case of transfer the changeover is bumpless and procedureless. It expected that the control loop reaction time is restricted within 400−500 ms or even faster for some loops.
4. *CLCS output*: Depending on the actuator used, the output of CLCS is fed to the control actuator through various converters. This is because in most of the cases the AO cannot directly interact with the actuator. So it is important that suitable measures are taken in the control actuator and/or in the converter so that in case of signal failure from the CLCS the actuators assume a safe position, as discussed in Chapter VI, Clause 4.0.
5. *CLCS operation*: The aim of all control systems is to achieve the maximum efficiency of the system/equipment under all conditions, provided the safety aspect is well taken care of and the permissible limit for the parameters are not exceeded. However, during

www.EngineeringBooksPDF.com

operation if the permissible limits of the parameters are exceeded then the CLCS needs to reorient itself so that control loop performs in such a way that it ensures safety and availability of the control loop. For example, when there is a ;load demand, the coordinate control loop will load both the boiler and the turbine in such a way to get the maximum load output with high efficiency. During this period, if there is large disturbance as a follow-up of a major upset or trip (of a major auxiliary), at this point all the loops will be disturbed due to interactions. Also parameters may swing in the range out of the permissible limit. At this point the concerned CLCS loop should first try to bring the parameters within the limits, and the main aim is to ensure safety and availability of the system instead of looking for higher efficiency or load demand.

6. *Logic control and time monitoring for CLCS*: There may be some interlock operation with some of the loops in the CLCS system. It is expected that these loops perform within the same control block utilizing logic functional block. For example, "if the following heater level is high then a higher heater will drain to condenser." Such interlocks are normally implemented in the same control loop and not on separate blocks. Like OLCS, the CLCS loop should be a time supervision facility so that if within a predefined monitoring time the output or feedback does not appear, then the operator should be alerted and the loop may trip to manual mode.
7. *Conditional output*: Under certain conditions it is necessary that the CLCS control loop needs to produce the preprogrammed output. These are mainly coming from coordinate control loops. These may be run back, directional blocking, etc. These will be clear from the following examples. From the load dispatch station (LDS) there may be a demand for a higher load from the unit. At this point if there is failure of one of the major auxiliaries (out of 2 × 60% FD fans one fan has failed), the boiler or unit loading will be decided by the capability of the running auxiliary. Firing, for example, will then run back to a maximum of 60% (or less) load demand. Also in a running plant in a similar situation of auxiliary failure, the CLCS loop will run back to preprogram position. Again under such a situation when any CLCS has reached maximum position (due to auxiliary failure or the full MCR is reached), then, even if there is a further demand to increase, the loop will not allow a further increase. But if there is lowering demand then it will be entertained. This will be a similar situation in for decreasing demand. So the loop is blocking the signal in one direction, hence, this is called directional blocking. Thus it is seen that run back comes mainly from major auxiliary failure or not running, whereas direction blocking comes from auxiliary/system limitations.
8. *Function library*: CLCS normally has a large functional library as indicated in TABLE VII/4.0-3. A supportive functional library may be considered as one of the criteria for evaluating a system. The majority of suppliers support functional blocks as per IEC 61131-3.

4.1.4 IS and MIS Functions

Apart from control functions, another important DCS function is the IS. Functions such as alarm/SOE monitoring and various displays and logs are examples of the IS. Various trend analysis, alarm SOE, and various logs help operating, technical, and management personnel to assess plant conditions both technically as well as commercially. So it could be argued that the IS is extremely valuable for running the plant as well as for plant performance analysis. When there is an IS system how is MIS used? It is like the plant overview display and detail display. Any one will appreciate that both of them have separate requirements. Operators prefer to view an overview display under normal conditions, and when required would use a detail display. As the information in a plant is enormous, various information presentations have separate value to various personnel. For example, the shift engineer may be interested to note the trend of the parameter over the shift to check the health of the equipment. Or he may be interested pre- and post-trip log to analyze the cause of the failure and how the plant was brought into the service. Again a person at the helm of the organization, located at a remote location, would like to have all major plant information at his fingertips. It all depends on how this information is presented. In ISs all normal information is presented in different forms, whereas in MISs this information/data are summarized before presentation in the format desired. MIS includes an overview, plant status, performance, and other calculations including commercial calculation. Therefore one can argue that MIS is a filtered IS, with filtering parameters set by the user subject to user's accessibility. Major components of these systems (IS/MIS) include:

1. *Operator interface*: Operator interface could be anything with which an operator interacts with the process presented before him. Operator interface includes but is not limited to call displays, alarm acknowledges, various parameter modifications (as permitted), call logs, group parameter assignments, calls for calculation results including those for performance calculation, etc.
2. *Calculations*: Various calculations and starting simple basic calculations like flow calculation, rate of change calculations to equipment efficiency calculation, and plant performance calculations.

www.EngineeringBooksPDF.com

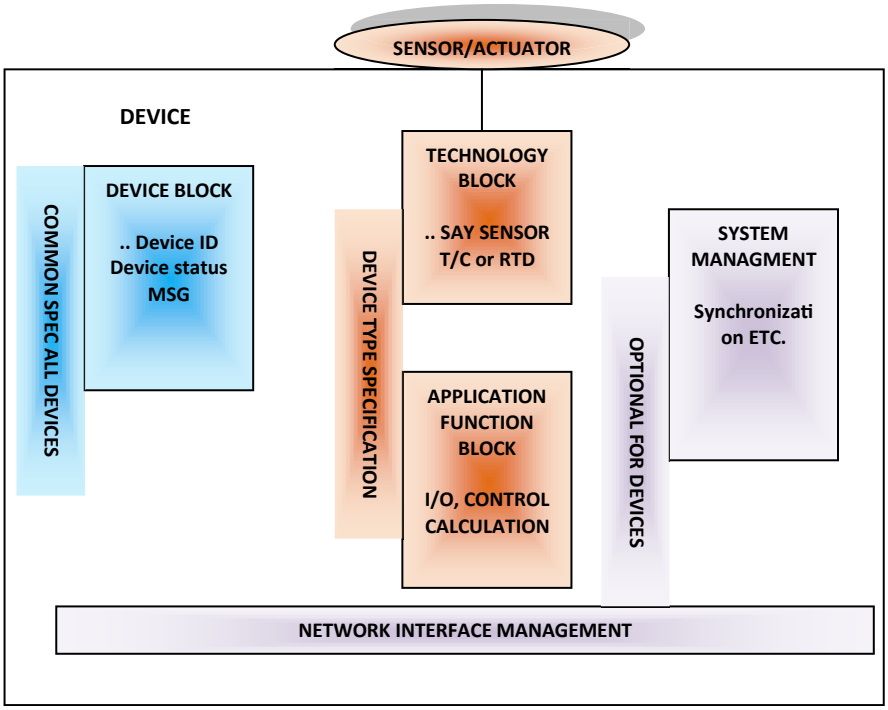


FIGURE VII/4.1-2 IEC 61804 typical device structure.

3. *Alarm analysis and alarm log*: Display of various alarms, return to normal alarms, first up alarms, alarm Logs, etc., with date and time stamping for future analysis.
4. *Logs*: Various kinds of logs on overview, on demand, periodic, historical, alarm, SOE, etc.
5. *SOE functions*: As predefined and/or following a trip−display and logging of various points assigned with SOE functions.
6. *Trending*: Trending of selected process parameters is part of the IS and provides useful tools for operating personnel for future analysis. Trending can be event based or manually selected.
7. *History function*: Keeping the parameter history and retrieval of these parameters as and when required are also a part of the IS function.
8. *Utility functions*: Some of the utility functions of the IS include the following:
   - Assignment of any point from the database for display and log group, their data collection interval (1, 2, 5, 10, 30, 60,120, and 300 sec, etc.), printing interval, header information, selection of these points for their maximum and minimum average value, etc.
   - Modification of group for display and log, i.e., inclusion and exclusion of tags from a group. However, each change in history can be available in the DCS and can be called at any time to check when and by whom such change was initiated.
   - Other utility functions are supported by the system such as MS office, MS projects, and other utility and office functions as supported by the system.

4.1.5 Graphics

All the functions discussed thus far need various kinds of graphics. IEC 61131 standard general control graphics is available. It is basically for the PLC, and it specifies Syntax, semantics, and display for the following languages:

- Functional block diagram (FBD)
- Ladder diagram (LD)
- Instruction list
- Sequence function chart
- Structures text

Out of these FBD, SFD, and LD have graphical representations. Programs are built from a number of different software elements written within the IEC-defined language (even C using basic blocks).

1. *Function blocks*: IEC 61131-3 defines ADD/SQRT/PID/COS/SIN, etc., function block called a Program Organization Unit (POU). It is possible to create a number of function blocks and use them multiple times in this program. These functional blocks can be used for both continuous and discrete functions. However, there are a few rules that define the use of these function blocks. The standard defines that an *independent*

www.EngineeringBooksPDF.com

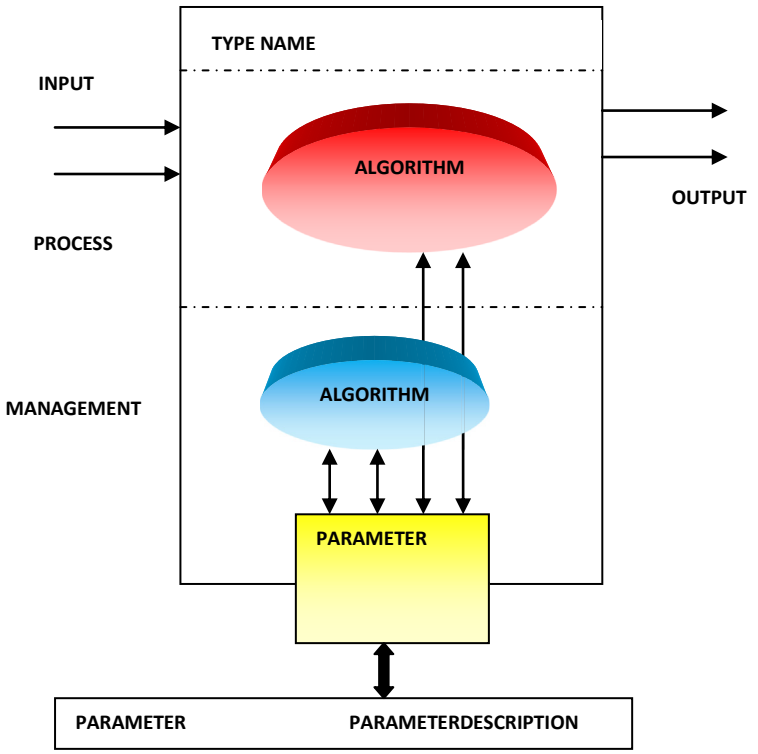


FIGURE VII/4.1-3 Typical IEC 61804 block overview.

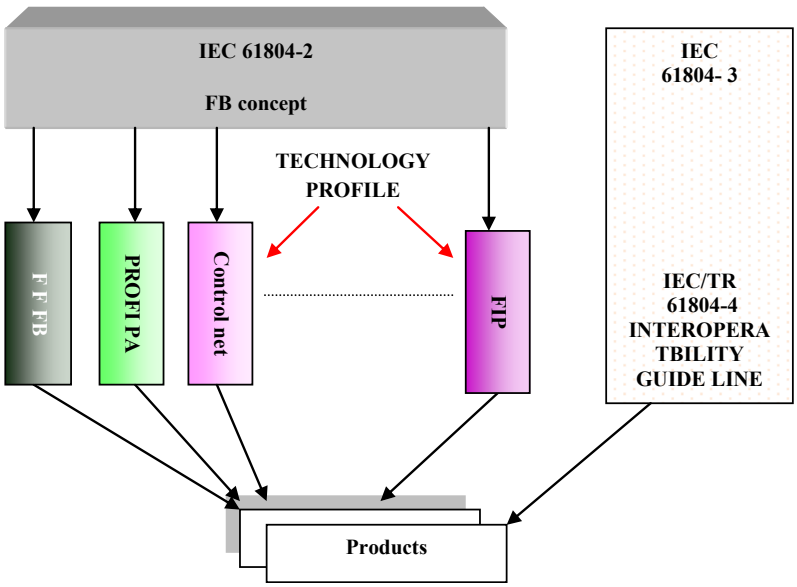


FIGURE VII/4.1-4 IEC 61804 conceptual FB mapped to specific communication.

function, which when executed would yield one or more results, can be represented as a function block, Some of the properties of function blocks as defined in the standard are elaborated below:

- Each of these function blocks must have an identifier (multiple identifiers can be created).
- Any value required for calculation is represented on the left-hand side.
- Function block I/Os have both values and status. Configuration values used in block diagrams and targets need not be shown as input connection but need to be defined as a contained parameter.

www.EngineeringBooksPDF.com

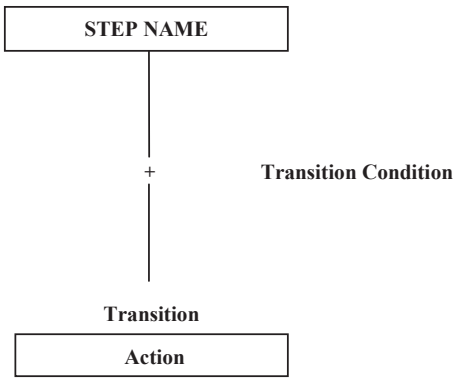


FIGURE VII/4.1-5 SFC structure.

- IEC 61804 is an international standard for the process industry. There are function blocks to define specific functionality of the device used in an automatic application. The device block defines the resource of the device, which contains information and function about the device. All devices in IEC 61804 are expected to have a similar logical device structure typically shown in Figure VII/4.1-2. A typical IEC 61804 (refer the standard for details) functional block structure is depicted in Figure VII/4.1-3.

Some of the mode parameters used in function blocks are interface direct, remote cascade input, contained variable, another function block cascade input variable, internal block algorithm, remote output in a contained variable, another block track input variable, etc. These are applicable to I/O as well as a source for set points as the case may be. Based on selected mode, the function block modes will be defined as follows:

- Out of service (not evaluated)
- Initialization manual mode
- Manual mode (set by operator not calculated)
- Remote cascade mode
- Remote output mode
- Local override (set to track tracked input parameter)
- Automatic mode (local set value to generate primary output)
- Cascade mode (set point supplied by another block)

Figure VII/4.1-4 shows how conceptual function block specifications in IEC 61804 have been implemented to a product utilizing various Fieldbus/network systems.

- All function blocks associated with control support a mode parameter. The values assigned to the permitted mode attribute are selected from the block designer.
- As listed below there are 10 fundamental function blocks as adapted in Fieldbus architecture. Also there are as many as 19 advanced function blocks. and the status of the output parameter is evaluated on the basis of "good," "uncertain," and "bad" in Fieldbus systems (Foundation Fieldbus).

Discrete input (DI)	Analog input (AI)	PID, PI, I	Manual loader (ML)	Bias/ gain (BG)
Discrete output (DO)	Analog output (AO)	P, PD	Continuous selector (CS)	Ratio station (RA)

TABLE VII/4.1-1 I/O Types

I/O type	Signal type	Signal value	Remarks
Analog input	High signal	0/4* to 20 mADC	*Life zero is used mostly
	High signal	1–5 V DC	
	Resistance at 0°C	Pt 100 Ω, Cu 53 Ω, and other	ISA Symbol L
	Thermocouple	B, J, K, R, S, and T	ISA symbol for T/C
	mV	Depends on device	Analyzer output, rarely directly, connected to DCS
Analog output	High signal	0–10,1–5 VDC,4–20mA	Voltage signal generally used within control room
Discrete input	Binary contact	24V DC,125/240 VAC (60/50 Hz)	Voltages are interrogation voltage
Discrete output	Binary contact	Same as above	Same as above
	Logic output	TTL, open collector	
Pulse input	Pulse	Depends on device	1–5 V DC common
Pulse output			

www.EngineeringBooksPDF.com

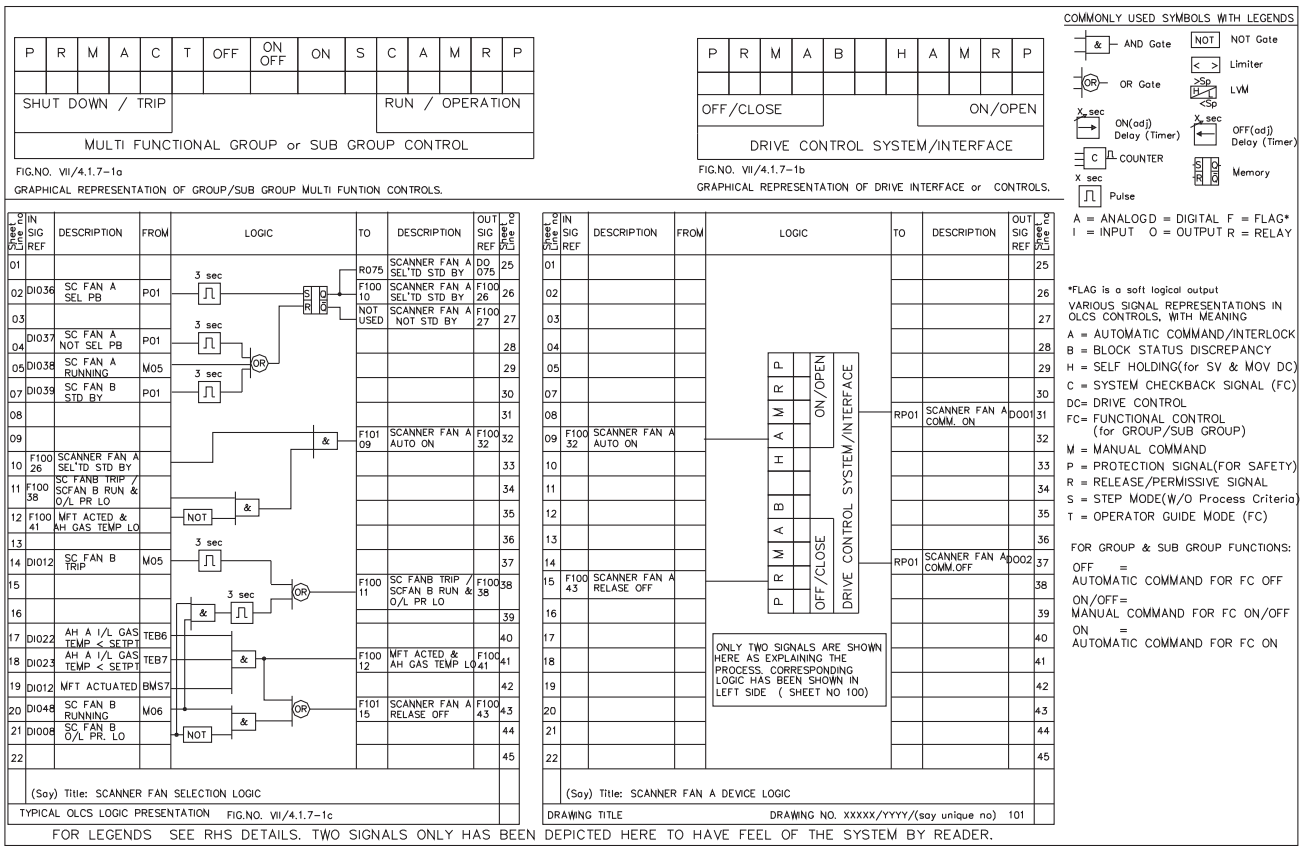


FIGURE VII/4.1.7-1 Plant auxiliary interlock diagram (example).

Figure VII/4.1-4 shows how conceptual functional block specifications in IEC 61804 have been implemented in to a product utilizing various Fieldbus/network systems.

2. *Sequential function chart*: IEC 61131-3 also defines SFC (see Figure VII/2.0.1-4c) for PLC. As shown in Figure VII/4.1-5 at any time a state of logic evaluation is defined by the following:
   - *Step*: This POU, with respect to input and output, follows defined rules.
   - *Transition*: It is the condition when control passes one or more steps preceding the transition to one or more successor steps along a defined direction. Corresponding to each transition there is a transition condition that needs to be true for transition triggering to occur.
   - *Action*: It is used to assign the result of an expression to a database item.
3. *Ladder diagram*: As shown in Figure VII/2.0.1-4a, IEC 61131-3 defines the ladder diagram with contacts (NO/NC), coils, and function block LIKE and OR.

In conclusion, it could be argued that IEC 61131-3 and IEC 61804-2 are the backbone to defining the graphical representation of control logics in modern control systems that utilize various Fieldbus systems for integration.

4.1.6 Input and Output Types

Whether it is CLCS/OLCS/SI/MIS of the DCS all functional subsystems require various types of hardware inputs and outputs. These are listed in Table VII/4.1-1, which shows *major* I/O types encountered in power plants.

4.1.7 OLCS Functions for Auxiliaries and Miscellaneous Systems

Looking at OLCS functions in main power plant (excluding off site) controls, there are clearly three distinct parts:

- *Boiler integral OLCS*: FSSS or BMS/SB control etc.
- *Turbine integral OLCS*: ATRS/ATT etc.
- *Other auxiliaries*: Controls of fans, pumps, and regenerative system equipment.

Since Boiler and Turbine OLCSs are well covered in this book (Clauses 2.2 and 2.3 and Chapter VIII and IX, respectively), here OLCS discussions will be restricted to major auxiliaries and systems in the main power plant.

www.EngineeringBooksPDF.com

For a short discussion on OLCS representation see Figure VII/4.1.7-1. As discussed in Clause 4.1.2, there could be hierarchical structure in some OLCSs. Figure VII/4.1.7-1a shows the graphical *representation* of a group or subgroup functional control that may be a subprogram (in software terms). There are two parts in this functional block, one for shut down/trip and one for run/operation. Similar kind of representations are used by many reputed manufactuer (e.g. Siemens KWU/ABB). Each of these sections have the following signals with different significance (for various signal definitions, see *ISA 77.22*):

P: Protection signal is used to avoid unsafe situations and taking corrective action (e.g., very low condenser level will initiate shutdown program for the CEP group).
R: Release signal is permissive (when condenser level is normal then only CEP can be initiated; see Clause 4.1.2, number 5).
A/M: Auto and manual command. In auto it could be a standby pump selection for example.
C: Check back signal already discussed above (see Clause 4.1.2, number 4). This is necessary for the sequence to proceed further.

ON or OFF are for auto group ON or OFF whereas ON/OFF is for the same purpose in manual mode. All of these have been described in the right-hand side of Figure VII/4.1.7-1. Drive control, step mode, and operator's guide mode have already been discussed in Clause 4.1.2, number 7, so it will not be discussed again. Note that here also are signals with P, R, etc., with the same meaning as discussed above. Here the reader's attention may be brought to signal point "B" (block status discrepancy), which comes when a command is issued but for some reason not obeyed and the operator takes corrective measures.

For MOVs and SVs the holding signal point H has been kept for normal operation. In Figure VII/4.1.7-1c two sets of logic sheets are shown. These are standard logic sheets used in our (Systems & Controls) various projects. On the left-hand sheet logics at higher levels are shown. The right side of the sheet shows how such a signal is used in a device or drive control logic. In this particular example, it shows how a standby fan is selected (F100-32 in LHS) and how it is applied to the drive control card (at A input on the right side). This drawing has been included to show how I/Os and flags (soft signal generated within the system as result of some logical operation and used elsewhere) are indicated, etc. The symbols used and presentation methods are *typically for example only*, and there could be other variations. It could be in the form of a ladder diagram or SFC also. With this in mind discussions on various OLCS for various auxiliaries will be discussed. The points listed below should be noted for HT drives.

- Normally bearing and winding (of an associated motor) temperature are monitored (see Figure III/9.2-6 for large fans but also applicable for pumps) and associated drives are tripped (one of the protection commands in *OR* mode for drive control) when it crosses a set point. Also for starting the drive it is ensured (one of the release commands in *AND* mode in drive control) that the temperature is within allowable limits.
- Many of the large drives have their bearing vibration /zero speed monitoring and/or other supervisory instruments—similar to TSI applicable for turbines of the turbine-driven BFP (TDBFP)], etc., monitored in a similar fashion as stated above (for temperature measurement).
- Large fans/pumps are started at no load (see Figure III/9.2.3.6-1) so that there are no high inrush currents (exception: starting up of standby BFP/CEP in a running plant condition). For this, inlet/outlet valve/dampers closed conditions are taken as a release signal. Similarly, drives with speed controls by scoop tube (e.g., ID fan/BFP) and minimum position of scoop tube are taken as release signals.
- Normally large drives have suitable oil pumps for supplying oil for bearing lubrication as well as supplying hydraulic fluid for other devices, e.g., scoop tube, aerofoil/blade pitch, etc. Naturally starting these oil pumps is one of the early preliminary conditions of starting the main drive.

The following points also need to be satisfied:

- Wherever there is a lubrication pump with a drive it needs to be started first (for HT drives this been discussed above already).
- After the lubrication oil (LO) pump has started, one needs to ensure that the oil pressure is okay for starting the main drive. If "LO pressure falls below a set value," or "LO pumps do run," the main drive will be tripped for protection.
- There are a few drives (whether HT drive, e.g., ID fan, or BFP. Or LT drive, or CEP or LO pumps of main drives) for which there are standby selections. Those with suitable logic (similar to that shown in Fig no VII/4.1.7-1c) will be applied to the A point of the drive control.

ID fan and FD fans in many cases are not covered in the FSSS, so OLCS discussions have been started with these, and then other major drives not covered in boiler and turbine controls will be discussed. There will be wide variations of these controls based on system designs and the number of auxiliaries. So here brief discussions only on salient points so that readers get an idea of how to deal with actual design. In this connection the reader needs to note that only *major process* interlocks (pertinent to fans/pump—not motor) have been listed below. Apart from

www.EngineeringBooksPDF.com

these there could be some electrical release or protection signals also (e.g., DC on or switchgear in the remote position, etc.)

1. ID fan (as applicable, e.g., if VFD is used then scoop tube condition is not applicable):
   - **a.** Release signal
     - **i.** Temperature and vibration monitoring criteria as discussed above.
     - **ii.** Lubrication pump criteria as discussed above.
     - **iii.** Requirement for no-load starting as discussed above (both inlet and outlet dampers).
     - **iv.** Scoop tube in minimum position.
     - **v.** Entire flue gas path is clear.
     - **vi.** No MFT.
   - **b.** Trip or protective signal
     - **i.** Temperature and vibration signals as discussed above.
     - **ii.** LO pressure criterion as discussed above.
     - **iii.** MFT due to loss of FD fans.
     - **iv.** If both FD (and ID) fans were running and one FD fan trips (selected), then the associated ID fan will trip.
     - **v.** Electrical protection (details not covered here).
   - **c.** Action upon trip (as applicable)
     - **i.** Bring scoop tube to minimum.
     - **ii.** All LO pumps in auto.
     - **iii.** Close inlet/outlet damper (if permitted, see below).
     - **iv.** Open inlet and outlet dampers for natural cooling, when both ID fans tripped due to loss of FD fans (*for this reason, ciii above says if permitted*). After a time gap manually close I/O dampers.
     - **v.** Trip the associated control loop to manual.
   - **d.** Standby selection
     - **i.** No MFT, upon tripping of any running fan, if other permissive conditions discussed above and electrical bus change over logic are satisfied then the standby ID fan can be brought into service. In case there are cross-connections of the air heater in the air flue gas path, it is necessary to check that the flue gas path is through before the standby fan is brought into service. It is worth noting that here the standby selection is not exactly like the immediate auto changeover of other fans (scanner air fan) or pump (BFP).
2. FD fan
   - **a.** Release signal
     - **i.** Temperature and vibration monitoring criteria as discussed above.
     - **ii.** Lubrication pump criteria as discussed above.
     - **iii.** Requirement for no- load starting as discussed above (outlet dampers).
     - **iv.** Blade pitch or final control element minimum position.
     - **v.** No MFT.
     - **vi.** At least one ID fan running (to ensure FD fan runs after ID fan is running ,i.e., the furnace is not pressurized).
     - **vii.** Both ID fans are running (for second FD fan to start when another FD fan is running to check; the furnace is not pressurized—as above).
   - **b.** Trip or protective signal
     - **i.** Temperature and vibration signals as discussed above.
     - **ii.** LO pressure criterion as discussed above.
     - **iii.** MFT due to loss of ID fans.
     - **iv.** Both ID (and FD) fans were running and one ID fan trips, the (one) FD fan will trip.
     - **v.** One ID fan and FD fans were running and the ID fan trips, the FD fan will trip.
     - **vi.** Electrical protection (details not covered here).
   - **c.** Action upon trip (as applicable)
     - **i.** Bring blade pitch or final control element position to a minimum.
     - **ii.** All LO pumps in auto.
     - **iii.** Close outlet damper (if permitted, see below).
     - **iv.** Open outlet dampers for natural cooling, when both FD fans tripped due to the loss of ID fans (*for this reason ciii above shows if permitted*). After a time gap manually close the I/O dampers.
     - **v.** Trip the associated control loop to manual.
3. BFP
   - **a.** Release signal
     - **i.** Temperature and vibration monitoring criteria as discussed above.
     - **ii.** Lubrication pump criteria as discussed above.
     - **iii.** Requirement for no-load starting as discussed above (close position of O/L valve and its integral bypass valve) for *initial pump* starting.
     - **iv.** Scoop tube (if applicable) to its minimum position (30%).
     - **v.** Suction valve is open and pump is properly ventilated.
     - **vi.** Recirculation valve control is open (at the time of BFP start).
     - **vii.** Recirculation valve control is in auto.
     - **viii.** Balance leak-off valve is open.
     - **ix.** Deaerator (feed tank) level normal (not low—for *booster pump, if it exists*).
     - **x.** Warm-up valve is open.
     - **xi.** BFP casing temperature is less than the feed tank temperature.
     - **xii.** No trip command exists.
   - **b.** Trip or protective signal
     - **i.** Temperature and vibration as condition discussed above.
     - **ii.** LO pressure very low.
     - **iii.** Working oil temperature very high.

www.EngineeringBooksPDF.com

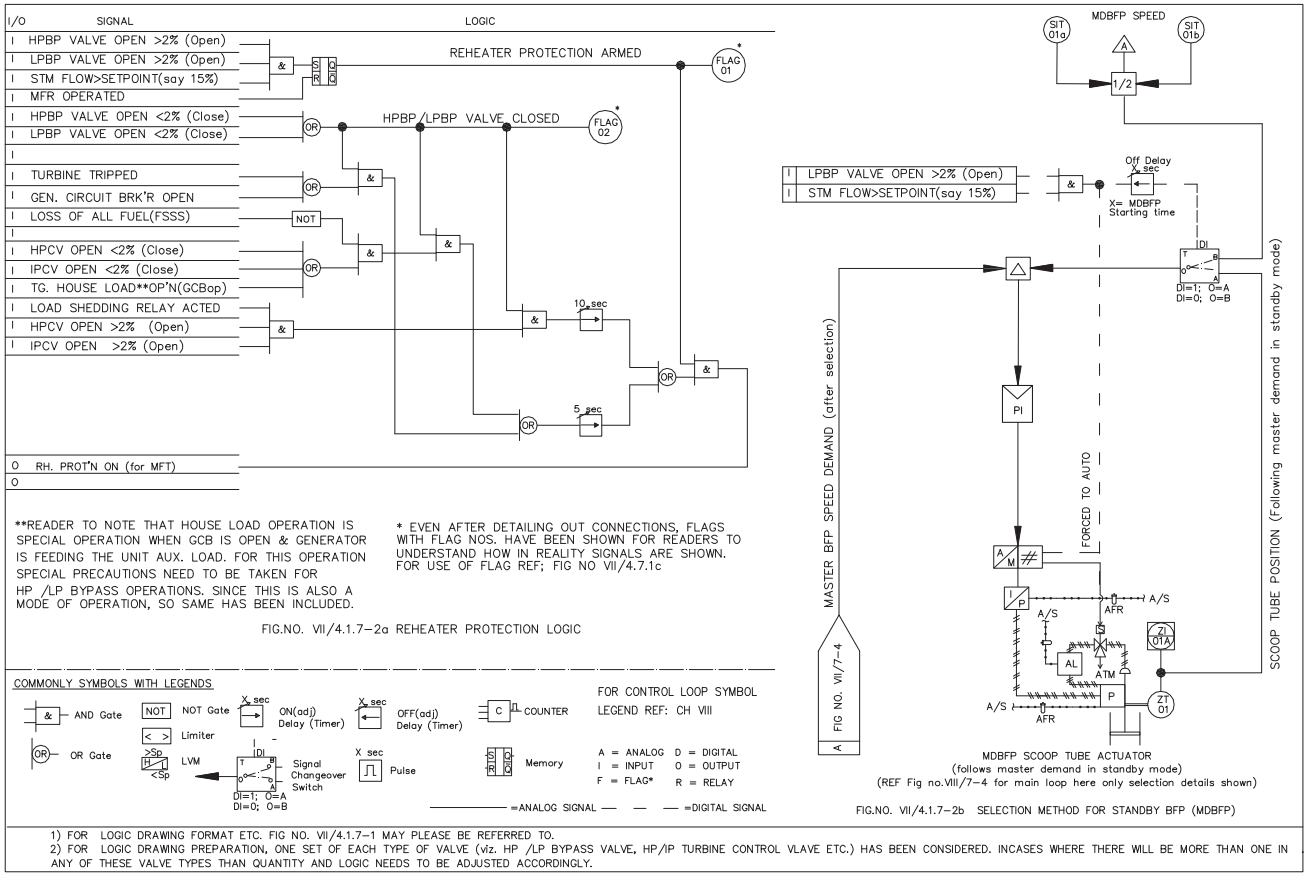


FIGURE VII/4.1.7-2 Miscellaneous OLCS functions.

iv. Working oil pressure low.
v. BFP discharge feed water temperature is high.
vi. Deaerator level very low (for *booster pump, if it exists).*
vii. Booster pump suction pressure low (*booster pump, if it exists*).
viii. Booster pump discharge pressure low (*booster pump, if it exists*).
ix. BFP over load (from low pressure and high flow; see Chapter VIII, Clause 7).
x. Balance leak-off valve not fully open.
xi. Suction valve not fully open.
xii. Electrical protection (details not covered here).

c. Additional trip conditions for Turbinne driven BFP–TDBFP
i. TD exhaust steam pressure high/high.
ii. TD exhaust steam temperature high/high.
iii. Live steam pressure high/high.
iv. Governor/control oil pressure low/low.
v. Axial shift high/high.
vi. Turbine over speed.
vii. Emergency trip from control center.

d. Action upon trip (as applicable)
i. Bring scoop tube (as applicable) position to minimum.
ii. All LO pumps in auto.
iii. Warm-up valve open.
iv. Recirculation valve open.
v. Discharge valve closes.
vi. Coasting down of turbine for TDBFP.

e. Standby selection: BFP standby pump selection is extremely important and needs to be done almost immediately so the boiler does not starve. This is more so for large units, especially for once-through boilers where the fuel:feed water ratio is extremely important for safety and operation. As a consequence, a few pertinent points to be noted are listed below:
i. Conditions for standby BFP selections are elaborated in points iv–vi in this clause. There could be two possibilities as discussed in point numbers ii and iii below.
ii. In cases where all the BFPs are motor-driven BFPs (MDBFPs), anyone can be selected as a standby provided the electrical bus selection is well taken care off (applicable for 3 × 50% BFPs). For standby selection "MDBFP" is

www.EngineeringBooksPDF.com

mentioned. Such selection details are shown in Figure VII/4.1.7-2b.

iii. In case of a combination of 2× TDBFP + 1× MDBFP (or so), MDBFP needs to be considered for the initial start-up and standby. Because of the starting time of the turbine, TDBFPs are not considered as standby. For standby selection the MDBFP is mentioned. Such selection details are in Figure VII/4.1.7-2b.

iv. To ensure that selected standby MDBFPs have all of the permissive conditions stated above duly fulfilled (including electrical conditions).

v. Selected standby MDBFP should have its discharge valve in open position.

vi. Standby MDBFP should follow the speed master demand so that whenever it is started it goes straight to the desired speed to meet the delivery demand.

4. CEP

a. Release signal

i. Temperature- and vibration-monitoring criteria as discussed above (if applicable).

ii. Lubrication pump criteria as discussed above (if applicable).

iii. Cooling water flow is normal.

iv. Requirement for no-load starting (if applicable) as discussed above (close position of O/L valve and integral bypass valve if any) for initial pump starting or any CEP that is running.

v. Suction valve is open and pump is properly ventilated.

vi. Recirculation valve control is open (at the time of CEP start).

vii. Recirculation valve control is in auto.

viii. Hotwell level is normal (not low).

ix. No trip command exists.

b. Trip or protection signal

i. Hotwell level low/low.

ii. Suction valve closed.

iii. Pump running and discharge pressure low.

iv. Electrical protection (details not covered here).

5. Reheater protection: Boiler will trip when any one or more of the conditions listed below occur. This is a

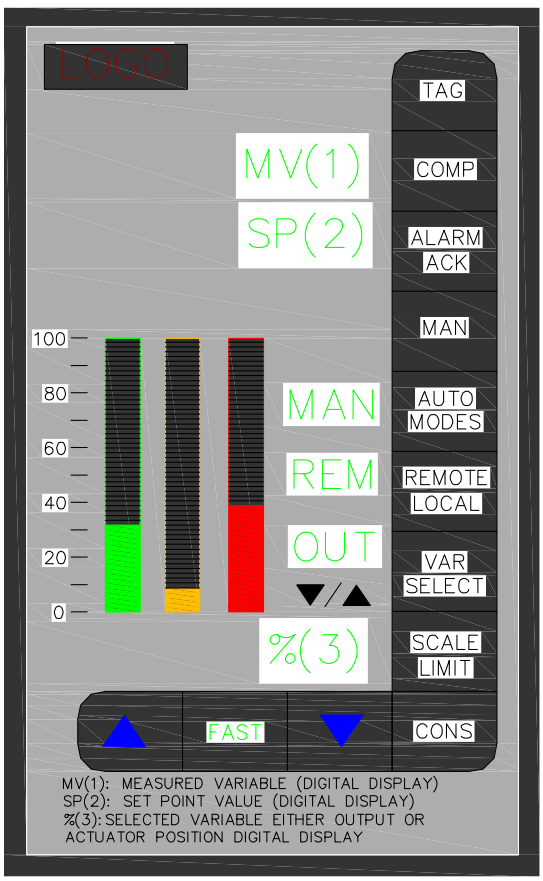


FIG.NO. VII/4.2.0–1a) SINGLE LOOP CONTROLLER FRONT FACE

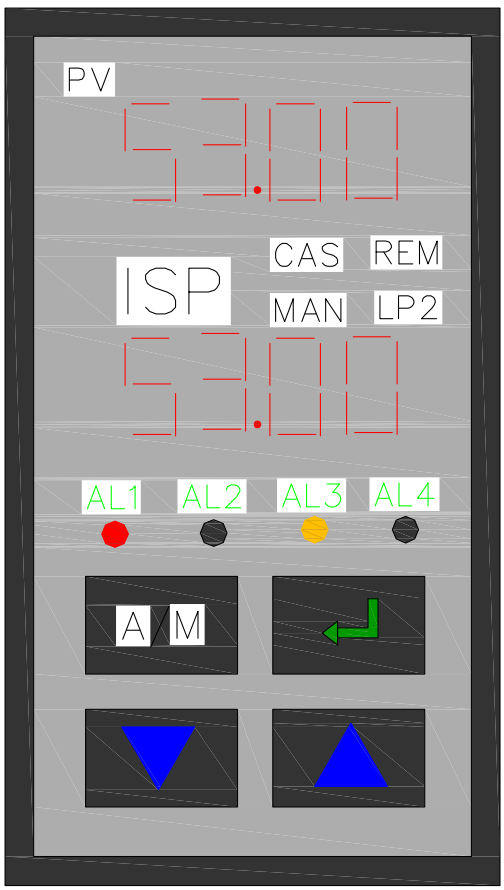


FIG.NO. VII/4.2.0–1b) MULTI LOOP CONTROLLER FRONT FACE

AL= ALARM A/M =A/M SEL'N CAS=CASCADE ISP/SP= SET POINT MAN=MANUAL REM=REMOTE

FIGURE VII/4.2.0-1 Controller front face.

www.EngineeringBooksPDF.com

part of the FSSS (see Chapter VIII) as one condition. How such the condition occurs has been elaborated here.

a. Turbine tripped or generator circuit breaker (GCB) open and HP *or* LP bypass opening <2%, i.e., closed. Then after a delay of 5 sec this signal will be generated.

b. Turbine working (HP and IP Control valve opening >2%) and load shedding relay actuated and HP *or* LP bypass opening <2%, i.e., closed. Then after a delay of 10 sec this signal will be generated.

c. If the turbine is not working (HP or IP control valve <2% opening, i.e., during start-up) *or* turbine in-house load (parallel operation with HP/LP bypass) and boiler are working (no contact loss of all fuel from FSSS) and HP *or* LP bypass opening <2%, i.e., closed. After a delay of 5 sec this signal will be generated (this may be during initial start of the unit with HP or LP bypass).

6. Arming of reheater protection: Once HP and LP bypass are open 2% and steam has increased beyond a set value, then reheater protection will come into effect. Logic for this is elaborated in Figure VII/4.1.7-2a.

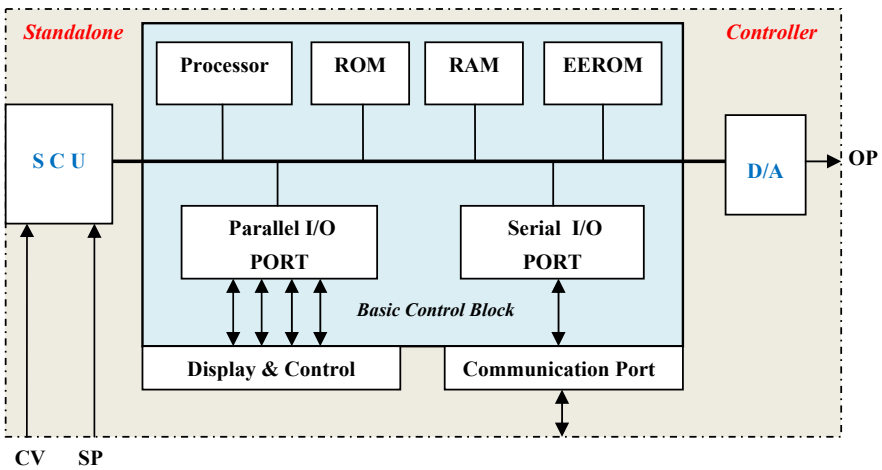
4.2 Standalone Controller Unit and its Integration with DCS

4.2.0 Preamble

The term standalone controller unit (SCU) basically refers to single-loop or multiloop controllers. These are digital microprocessor-based controllers packaged in one instrument generally sized as per DIN standard sizes like 72 × 144 mm (or better, 75 × 150 mm with bezel), 96 × 9 6mm, 48 × 48 mm, etc.

The typical front of these controllers is shown in Figure VII/4.2.0-1a and b. Some of these controllers are used in smaller units for main plants as well as off-site plants. In larger units they are applied in many off sites requiring a few modulating controls, e.g., degasser level control in a DM plant, fuel oil storage tank level control, or regenerative heater level control for smaller units. They are used mainly where controls are relatively independent or in those cases where there are less modulating loops, so that these can be integrated with the PLC to form a complete control system. Even though these are standalone controllers, they are mostly integrated with the main DCS or PLCs. Actually the reliability of the controller depends on the hardware selection, whereas the capability is a function of the software, which is the main factor for costing these devices. In view of the following reasons, microprocessor-based digital controllers have outperformed their analog counterparts.

- *High accuracy* of ~0.075% (dependent mainly on A/D or D/A conversion).
- *Flexibility* in configuration and topology and display modes.
- Additional *hardware* and wiring requirements are *minimum* (depending on algorithm and standard software module in the system library).
- Possibility of performing additional *arithmetic functions* such as totalizing, linearization, etc.
- Easy *communication* with external system with less hardware.
- *Integration* of the number of controllers and integrating with the PLC/DCS.



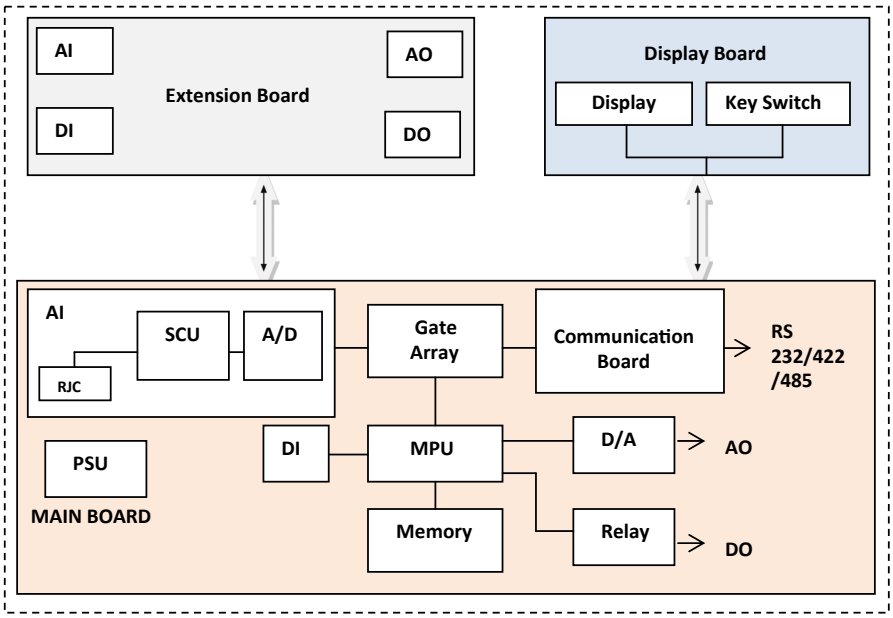
Legend: **SCU**= signal conditioning unit +A/D; **A/D**= analog to digital converter
D/A Digital to Analog Converter; **RAM** = Random Access Memory; **ROM**= Read Only Memory
EEROM Electrically Erasable ROM **SP**= Set point; **OP**= Output; **CV**= Control Variable

FIGURE VII/4.2.1-1 Basic block diagram for standalone controller.

www.EngineeringBooksPDF.com

*What is meant by universal input and how is it handled**? Universal input means that, at the same set controller input terminals, a variety of inputs, such as 4-20 mADC; different types of T/Cs ; and various kinds of RTDs and mV can be used. There are calls for programmable gain controllers that have the capability to linearize these inputs as applicable. Also reference junction compensation for T/Cs will be provided. For different classes of input signals for the same input channel there will be a number of terminals for each input. The advantage is that at a later date if the input type is changed it will not be difficult to connect it and run without any modification. Also it is seen that in many controllers the* DI/DOs can be swapped.

FIGURE VII/4.2.1-2 Universal input/output.



Legend: MPU, main processing unit; RJC, Ref. Junc. Compensation (T/C); PSU, power supply unit

FIGURE VII/4.2.1-3 Controller with extension board.

- *Configuration* is possible through hand-held calibrator or PC.

4.2.1 Standalone Controller Block Diagram

Typical architecture of a standalone controller is shown in Figure VII/4.2.1-1. The basic parts seen in this figure are the *basic control block* and s*upportive part*. The basic control block consists of a main processor, RAM, and ROM/EEPROM along with display electronics, communication port, etc. At the input side it is supported by an SCU comprising the programmable gain controller, signal conversion unit, multiplexer, and A/D converter, whereas on the output side there will be a D/A converter and relays (as applicable). As in basic microprocessor systems, temporary data are stored in RAM while the main program is stored in a long-life rechargeable battery-backed ROM of reasonable size or ROM EEPROM. EEROM, which is basically a programmable ROM where basic programs are put during commissioning or at the factory. Operating parameters are entered into the system by the operator. These are battery backed up (may be with monitoring facilities). These controllers have a built-in standard library for control sub blocks and arithmetic functions. During configuration, these functional blocks need to be linked by structuring data by a hand-held unit and/or by a PC.

Some controllers have side panels for adjustments of gain, proportional band, integral action time, etc. (e.g., SLPC controller from YEL). Some manufacturers offer optional portable memory modules to have redundancy in the system parameters (e.g., ABB MOD 30 series). Also the operating parameter range and set points can be set from the front panel. Supporting SCU provides the set

www.EngineeringBooksPDF.com

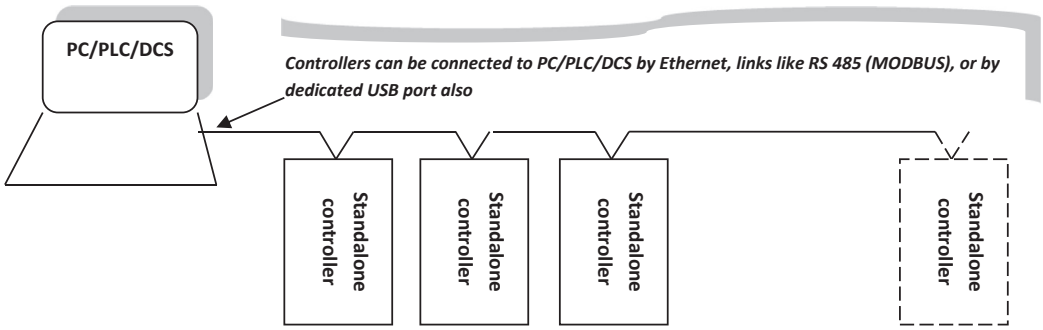


FIGURE VII/4.2.2-1 Controllers connected to PC/PLC/DCS to communicate.

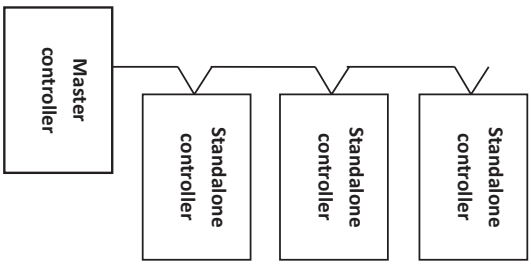


FIGURE VII/4.2.2-2 Controllers in coordinated mode.

features available from the standard manufacturer include but are not limited to the following:

• Auto tuning	• I/O linearization	• Math Functions
• Standard library for control blocks	• Discrete and continuous logic	• Independent PID and advanced control loops
• Auto/ manual/ ratio/bias	• Reduced number of instruments	• Communication over bus

point, control variable, etc., to be fed via programmable gain controller, multiplexer, and A/D converter. Most of these controllers support universal inputs (see Figure VII/4.2.1-2). Output support units have D/A converters for analog output and other processing circuits to provide retransmission output, relay contact, etc., as applicable. Digital display may be a bar graph or digital read-out type (or both, with an engineering unit) as shown in Figure VII/4.2.0-1a and b. For controller parameter and/or set point adjustment push buttons, keyboards are provided in the front with which a controller may communicate in parallel mode. There will be separate ports to communicate with external PCs, and other devices via a serial port. Serial communication may be performed with the help of an RS 232 in MODBUS Protocol, for example. Standalone controllers can support quite a large number of I/Os of different kinds and this is done with the help of an extension board as shown Figure VII/4.2.1-3.

Herein this controller is based on a standard multiloop controller. There are a few parts such as the Bezel display board, communication board, extension board, and Main Board all in one packaged instrument. The extension board may be at the side and terminals at the back. Some of the

4.2.2 Communication

Normally these controllers communicate over RS 232/485 using MODBUS or other standard protocols. In some cases these controllers communicate with other instruments or systems of the same family over their own system bus, e.g., ABB MOD 30 communicated with other instruments over an ICN bus to the DCS of the same family. Normally manufacturers support the necessary software for communication with a PC for configuration, etc.

In the Figures VII/4.2.2-1 and VII/4.2.2-2 connections of the controllers are shown for communication with PLCs, DCS, and PCs as well as with a master controller as necessary. This communication can be through the links using a standard protocol, and/or be Ethernet supported. There may be a dedicated USB port connection also for communication (e.g., YS series from YEL).

4.2.3 Typical Specification for Standalone Controller

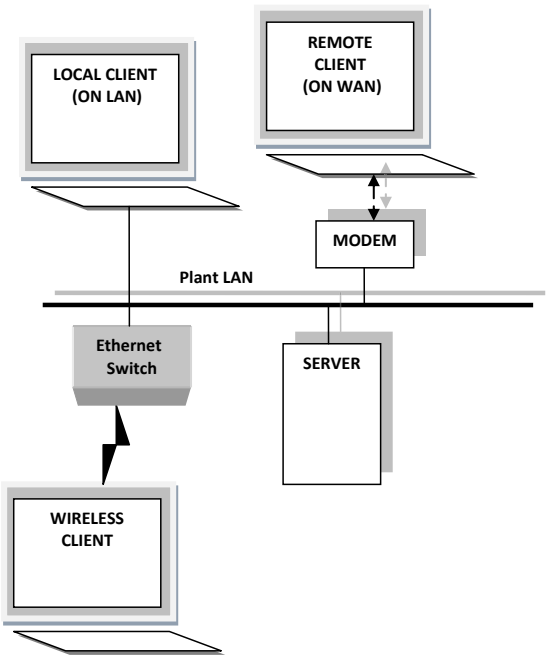
A standalone controller data sheet is included in Table VII/4.2.3-1.

www.EngineeringBooksPDF.com

TABLE VII/4.2.3-1 Standalone Controller Data Sheet

SL	Specifying point	Standard/available data	To be specified
1	Type	Single or multiloop or others	Detailed in Sl 3
2	Functions	Controller/PLC/totalizer, as stated below	To specify
3	Types of loop	Simple PI/PID/PD, etc., or cascade/remote/DDC, and/or totalizing, etc.	To be specified
4	Number and type of I/Os	"X" AI/"Y" AO/"Z" DI/"N" DO/other type if any	To specify the number and type of I/Os
5	Universal inputs	Number of universal inputs for AI	To specify
6	Transmitter power	Number of transmitters to be powered	To specify
7	Display type	Bar graph, digital back-lit LCD for curve generation, etc.	To be specified
8	Number of displays and functionality	Number and types of display and display selection; also LED/LCD/vacuum; fluorescent display and color	To be specified also
9	Control keys and functions	Number of control keys, e.g., A/M selection, increment/decrement control, set point, alarm acknowledge, mode selection, etc.	To be specified
10	Signal range	4-20mA/RTD/mV, etc., for each I/O	As applicable
11	Rating	3A, at 240 VAC DO contact	To specify
12	Sample rate	200 ms (an example)	To specify
13	Resolution	12/16 bit	
14	Set point limit	<(−)10%, >110%, etc.	
15	Diagnostic features	Number and type of diagnostic alarms (70)	To be specified
16	Process alarm	LL, L, H, HH, with set point	To be specified
17	Audio alarm	Beep, etc., to be specified	
18	Communication to external devices	To specify PLC/DCS/controller and type of data communication	Master slave/set point control to be specified
19	Communication	RS 232/485, etc., protocol such as MODBUS/Ethernet/other support	To be specified
20	Configuration	Any configuration tool, PC configuration support	To be specified
21	Instrument power supply	1 PH, 240VAC 50 Hz/110 VAC/60 Hz, etc.	To be specified
22	Instrument location	Field, control room	To be specified
23	IP rating	IP 65/IP22, etc.	To be specified
24	Certification	International certification, etc., as applicable (e.g., FM/CSA, etc.)	To mention standard reference
25	Accuracy	+0.1% or better/0.05%*	*Repeatability
26	Software support	To specify in case any third-party SW	
27	Environmental condition	(−)20 to 55°C 0−95% RH	
28	Stability and drift	8 h/days in %	
29	Optional feature	Optional back-up memory, etc.	
30	Special features	To be specified (termination desired)	
31	Size−bezel/cutout	To specify DIN or other standard	

www.EngineeringBooksPDF.com



This is a client server network. Here there are a number of clients, one is connected to LAN by wire and another is wireless. There is a third client, which is the remote client. This client could be at a remote place and may be connected to the network (say an Ethernet) with the help of a dial-up modem or via Virtual Private Network (VPN). This makes the network IT compliant. In this type of operator interface the network can be accessed by the remote-located operator for troubleshooting, etc., and this remote location could be manufacturer's workplace (for troubleshooting purposes only to guard the network's other data).

FIGURE VII/5.0-1 Client server network with remote client interface.

4.2.4 Support Functions

Standalone controllers provide support functions including:

• Multiloop functions	• Independent PID	• Cascade, feed forward cont
• Standard logic function	• Adaptive response	• Universal I/O support
• Linearization functions	• Dead time comp	• Multipoint indicator/ totalizer
• Small PLC functions	• Cont. Coordinator	• DI/DO swapping
• Number of standard soft control function modules	• Third-party support • Math unit	

5. MMI AND RECORDING: INTRODUCTION

What is man (/human) machine interface (MMI/HMI)? In the industrial design field, man (/human) machine interface is where people meet the technology. This is the place where man interacts with machines/processes for effective analysis, control, and operation of the system. Machines operate in a way unnatural to humans, so MMI *translates* these machine actions into a format *intelligible* to humans and *vice versa*. Starting from small switches, the display device forms part of the MMI. Now in the DCS, there are high-resolution windows in CRT/LCD/Plasma displays that present various mimic, trend, diagnostic, and alarm displays, with which humans can interact. MMIs are not only now restricted to the operator's interaction with the process, now thanks to WAN Internet, remote man machine access is also possible. Engineers can operate and troubleshoot the DCS from a remote location, as shown in Figure VII/5.0-1.

Web services help to integrate many manufacturers' application programs, to analyze the process precisely. Printers, recorder, etc., are devices that generate a printable form of these displays; these two devices go hand in hand. Therefore workstations and printers, in any intelligent control system, are the two most important peripherals for analysis, control, and operation of the plant.

5.0.1 Workstation

Workstations generally consist of a number of display devices such as CRTs, LCD/LED monitors, and some dedicated LCD/LED display panels (e.g., E300/200 from Mitsubishi Electric).Workstations also include standard/ custom-made keyboards, pointing devices such as a mouse and track ball, and touchscreen devices. Many places have multiple monitors/large-screen monitors supported by workstations. Some of the general features of workstation are included in the table below.

www.EngineeringBooksPDF.com

• Access to large numbers of tags (up to 3,00,000)	• User-friendly, easy navigation through display
• Intuitive graphic configuration with modifiable custom-made displays	• Predefined face plate/ templates
• Clear overview for management decision	• Sophisticated alarm handling and management
• Supervisory PCs and sophisticated engineering stations	• Object-oriented programming, and process optimization.
• Secured multitasking operation	• Trending both real time as well as historical data
• Third-party application and interface	• Multiplatform versatile setup and applications

1. *Workstation application*: Some of the workstation application are as follows:
   - *Overview display*: This gives a bird's eye view of the entire plant so that concerned personnel can get an overall idea of the plant. In this view current alarms are suitably displayed to draw the attention. Statuses of major drives and loops will be displayed suitably.
   - *Group display*: This display shows the operator a set of related parameters when arranged in a group defined by the user. Any alarm in the group should be displayed suitably.
   - *Alarm management*: All alarms are time tagged, and various colors can be assigned to them based on user-defined priority and return to normal message. There are several ways to present alarm management displays: current alarm list (with oldest pushed out of list as first in first out, etc.), alarm history, list of unacknowledged alarms, acknowledged alarms, user-defined priority alarm, trip alarm, plant area alarm, event alarm, etc. A user-defined alarm filter also can be used.
   - *Event messaging*: Event-based messaging can be sent to historians for data collection (i.e., high-frequency data collection), and/or to a printing medium for event-based logs, etc., with an event time tag, description, associated point tag, and node number.
   - *Mimic/process diagram*: Generally these diagrams present process information in a process flow pattern: process parameters, valve damper actuator status, alarms, etc., are presented in high-resolution graphic displays. These can be used to control, pan, zoom, or window any particular area, etc. Depending on the software package, these may be developed utilizing a standard CAD format and may be downloaded to the system at a later date.
   - *Trending*: Trending of parameters as selected by the user can provide the trend of real time as well as historical data. It is possible to create trend groups to see the trending parameters of these related points in a group, e.g., steam flow, feed water flow, and drum level could be predefined trends to see how drum level is affected with variations in two other parameters. Zooming, pan, and windowing of a particular area for details is possible. Trending can be for *X-Y* and *X-T* and could be in horizontal and vertical bar graphs. In historical trend average, maximum/minimum values as per user choice could be selected over a defined time. This mainly depends on the memory space allocated and sample rate.
   - *Face plate/logic diagram*: Controller faceplate display is very useful for control application. Similarly logic displays such a ladder diagram are helpful for logical/sequential operation.
   - *Point display*: Accesses any particular tag(s) to get its internal and external information. When the cursor is taken and clicked on any window or the window is touched, the point display provides the point tag, point value, status, and a great deal of other information through various navigational modes offered by the manufacturer as per the customer's choice.
   - *Point information*: This gives the complete database of the point including, point ID, node where it is connected, signal type, scan/alarm status, and point value.
   - *Point review*: This is a special type of display used to list what common characteristics as defined by the user, e.g., super heater stage temperature. It shows tag number, parameter name, process and signal range, limits (high/low), etc., for each of these parameters. It also shows signal quality (poor, bad, good, etc.) and time out.
   - *Multiplatform*: Multiplatform capability of the control system as well as the workstation to have common comfortable work environments for the operator to access a variety of applications using multiplatforms for an integrated system.
   - *Other miscellaneous applications*: Some other features of workstations include: multilingual displays, operator's pointing device interface, diagnostic message display, and multiwindow function (8−10 such windows in a single display is common today). User friendliness and built-in security functions for access are some of the important features.
2. *Workstation/operator console types*: The monitor is an important part of the workstation in the DCS/PLC. The CRT belongs to the emissive type of display monitor.

www.EngineeringBooksPDF.com

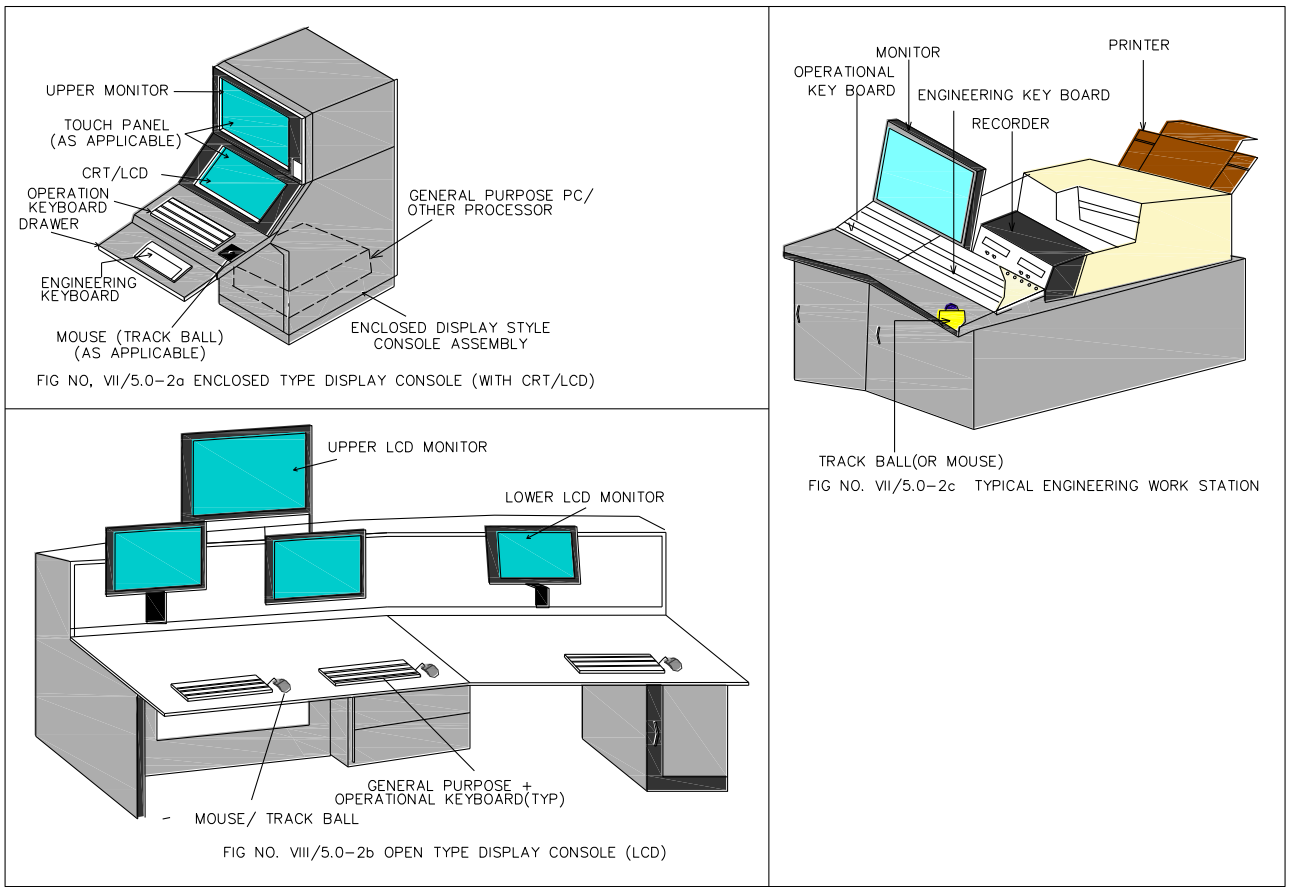


FIGURE VII/5.0-2 Workstation/console types.

Other discharge types of displays such LED, liquid crystal display (LCD), or plasma display units. The use of CRT types is declining. In computer applications LCD/LED displays are also quite popular. In view of smaller space requirements for LCD/LED types of displays, it is now possible to accommodate a number of these monitor stacked one after another on a desktop arrangement. However, in certain compact designs these may be placed one above other, with due consideration given to ergonomics. Generally speaking, there are two kinds of such designs in use one: the enclosed type display console design (Figure VII/5.0-2a) and the open type display console (Figure VII/5.0-2b). In open type console LCD/LED monitors. which are very slim, are used from an aesthetic point of view. For operational assistance, a touchscreen, mouse, and track balls are shown. Based on the system design each one or a combination of them can be used. In DCS applications, in addition to the normal keyboard, a dedicated operational keyboard/stylus, etc., are also common. Today all of these workstations are intelligent and have their own processing unit and hard disk drive (HDD). Normally small drawers, telephone jacks, etc., are attached to these consoles. Generally these have small doors to hold the power and other connections (if not wireless) from the back. PCs associated with these workstations can be kept inside the console.

3. *Engineering workstation features*: There are some difference between the engineering workstation and the operator's workstation. In the engineering workstation, mainly developmental work is done so that the software can be exported to the control system without disrupting the operation of the system. Some of the features in a standard engineering workstation include the following:
   - Simultaneous working on a control system, database, and graphics in a multiwindow environment.
   - Intuitive development system for generation of object-oriented graphics. For this there is usually an elaborate and advanced software support so that various control strategies, complex graphics, point recording, etc., can be developed and maintained in the system under all conditions. Software systems

www.EngineeringBooksPDF.com

TABLE VII/5.0.1-1 Comparison between CRT and TFT LCD

Comparing points	CRT	TFT LCD	Remarks
Visual search	Slow (WRT LCD)	Faster (~20%)	Text search on display
Eye fixation	Longer and more	Shorter and fewer	LCD ~10% less
Search error	More (~20%)	Less	
Geometrical distortion	Present, due to electron beam	Active pixels in flat matrix, no distortion	Electron beam is more tangential at the edges.
Flicker	Flicker prone (as electron scanning)	Flicker free—not an issue.	CRT display flickers needs refresh at 50/60 Hz rate
Glare	Prone to glare*	Glare free	*Due to glass CRT
Brightness	Nonuniform	Uniform*	*Nearly 2× CRT
Contrast	Better	Less (~equivalent available now)	At low light it is a useful parameter for comparison
Sharpness	Moderate to high	High	
Color purity	Excellent	Very good*	*Difference hardly noticeable/perceptible
Viewing area	Space-inefficient part area	Space-efficient full area	
Angle of view	Better	Less, up to 160° available	Some consider this as better privacy
Size vs equivalent display	For equivalent display larger size	For equivalent display smaller size	Due to space efficient
Dead pixel	NA	Irreparable	
Aesthetics	Bigger	Slim and stylish	
Space	More at back	Less	20% space saving with LCD
Weight	More	Less (2–3 kg)/15″	
Flexible position	Moderate	Highly flexible	
Electrical energy	60–80 W	20–25 W	For (typical) 15″ display
Heat emission	High	Minimum	Energy saving on AC
EMI	Affected	Not affected	LCDs available with speakers.
Response time	Better	12–16 ms	

www.EngineeringBooksPDF.com

may be very comprehensive but user friendly, so that the developer can easily work with a suitable menu-driven system. Major functions of this system include but are not limited to the following:
  - Control strategy builder
  - Graphic builder
  - I/O device configuration
  - Historian configuration
  - Trend grouping
  - Other application builder
  - General configuration tool
  - Security
- Engineering workstation software needs to have dual functionality so if necessary dynamic values could be accessed by an authorized person.
- Offline configuration and export to the system is an important feature. Also it may be possible to modify part and update the system to run it on a modified program without much difficulty.
- Open database integration.
- Embedded data System database.
- High security access to various functional aspects of the engineering station.
- Other miscellaneous engineering functions such as import/export, upload/download, hardware modification, help functions, etc.

4. *Choice between CRT and LCD monitor*: There are advantages and disadvantages to both. These need to be reviewed before choosing the right one for the application. Short comparisons between the two systems are presented in Table VII/5.0.1-1.
   - In CRTs high-voltage electromagnetic deflection and low-voltage electrostatic field focus maintain display quality in the P31/P1 screen of a CRT. There are *X-Y* linearity corrections for *X* and *Y* data input. This correction actually maintains the geometrical shape of the picture. Also the information supplied to the CRT must be refreshed continuously (60/50 Hz) so that flickering does not occur, and there is a potentiometer to control the brightness of the display. Therefore it is clear that the CRT needs a high-voltage as well as low-voltage supply and power consumption is appreciable. Since electromagnetic and electrostatic fields are in operation, these are very prone to alter performance due to an EMI effect. Also to accommodate electron scanning/deflection, some space on the backside is necessary.
   - In a thin film transistor (TFT) LCD, separate tiny transistors form each of the pixels on the display. Since the transistors are tiny, they require tiny charges, hence, redrawing a figure could be faster. This display is a direct one and resolution is not a problem. A typical 17" TFT display has nearly 1.3 million tiny TFTs, with a chance for one or two of them to malfunction on the display. When one (or two) transistor(s) fails there will not be any display of that pixel. This is called a dead pixel, and there is no guarantee against a dead pixel. This is critical for a TFT LCD. Manufacturers normally guarantee against failure of $>11-12$ dead pixels. In direct displays there is

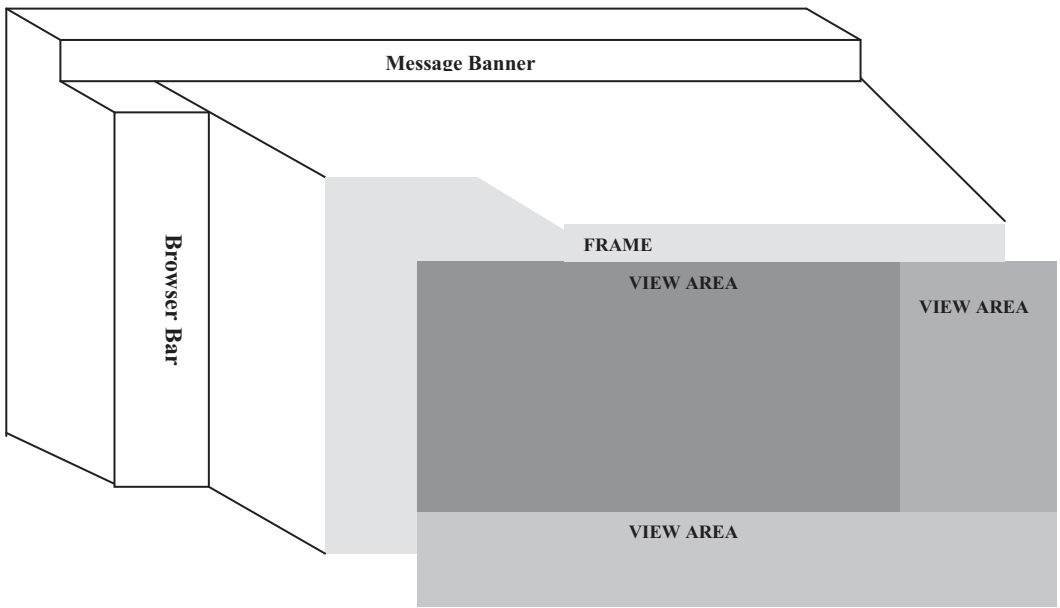


FIGURE VII/5.0-3 Operation and monitoring area for workstation display.

www.EngineeringBooksPDF.com

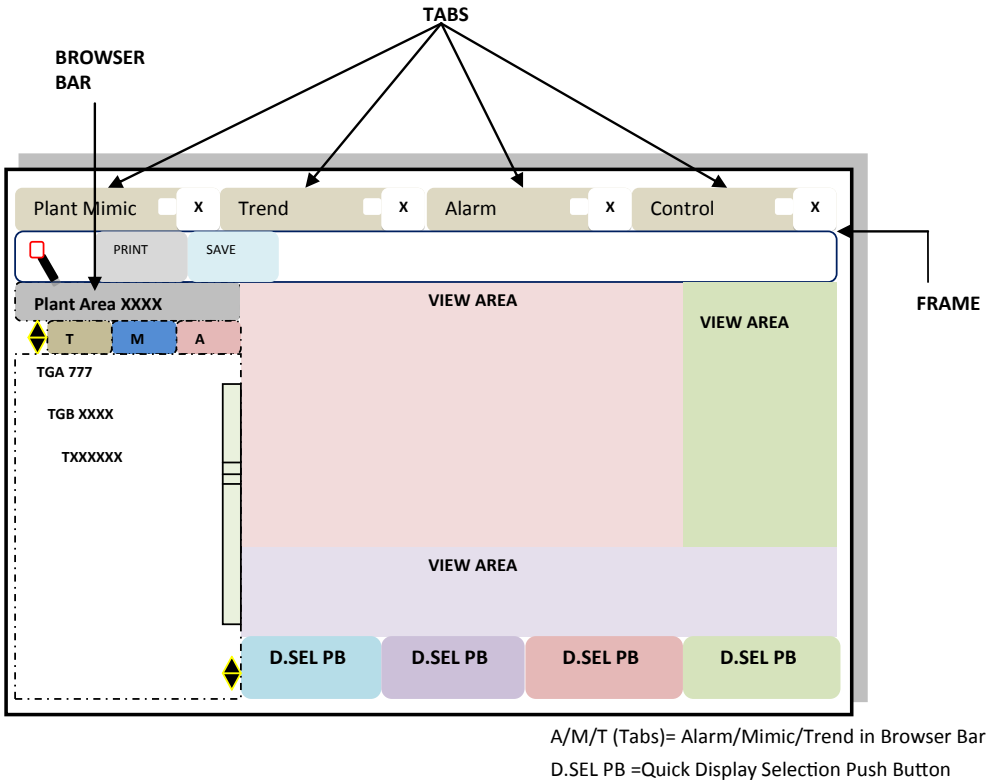


FIGURE VII/5.0-4 Browser bar and frame details.

no geometrical distortion and there is less power consumption. Although it has a smaller viewing angle, the effective display area is more than the corresponding CRT display area. Because of the technological difference, it is not affected by EMI.

5. *Display area in workstation monitor*: Typically any window-based workstation display has a few divisions for operation and monitoring. Such divisions are generally decided by the system supplier based on the system supplier's design. Typical such divisions (developed inspired by a YEL document) are shown in Figure VII/5.0-3. A few terms in this regard have been listed below.
   - *Message banner* : This is to indicate the type of the message with its details (see Figure VII/5.0-3). This may be "Over view" or "Alarm" display. It may also indicate the particular plant also, e.g., mimic "Display of Boiler Drum" to show that mimic of the boiler drum is in the display. These are generally placed at the top of the display. There may be another small dedicated display area to show the latest alarms of the area or of the plant (e.g., Centum VP keeps the system message banner on the top for alarms).
   - *Browser bar*: On the left side of the main viewing area there is a browser bar to call up various plant areas/various groups overview, trend, mimic, etc., as shown in Figure VII/5.0-4, so in the browser there may be several tabs. Based on the tab selected the required display area/group can be called. This can display a list of operations and monitoring in a hierarchical structure (e.g., in a tree-like fashion; (similar to standard Windows Explorer). In some cases additional tool boxes with required icons are also displayed for direct access.
   - *Frame*: In the frame there are a number of tabs for various functional purposes. It is possible to call up multiple tabs from the frame. The number of these tabs is dependent on the number of views allowed (as per display management philoophyof the manufacturer) in the display area (see Figure VII/5.0-4).
   - *View*: Based on system design, a number of different views—normal plant view, mimic view of an area, controller face plate (see Figure VII/5.0-5) of any of the control parameters in plant view, trend view of some parameters, and current alarms of the area—in one window is possible. In some designs at the bottom of the display there are dedicated buttons for quick display change

www.EngineeringBooksPDF.com

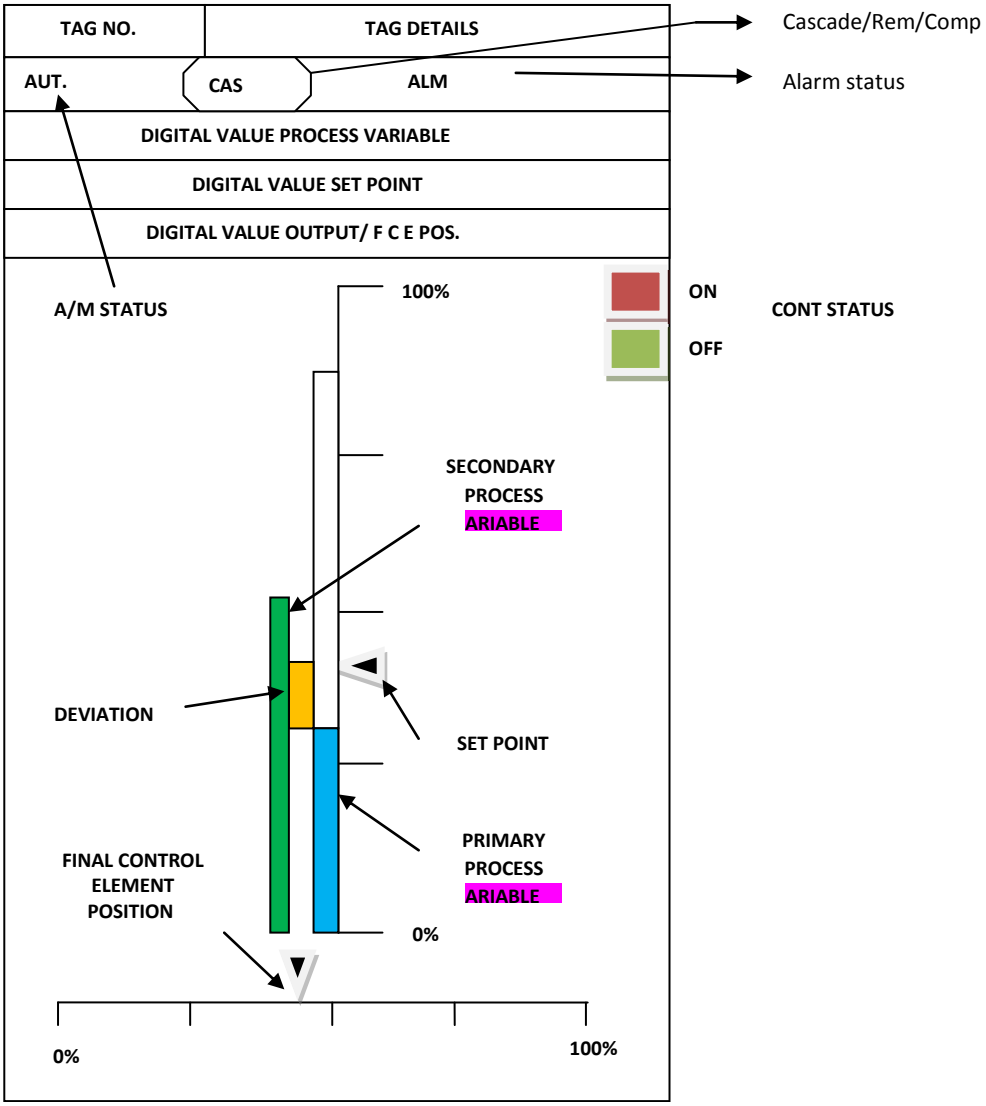


FIGURE VII/5.0-5 Controller face plate details.

over, and some systems dedicate one or two bottom lines for plant alarm/trip/SOE points (-e.g. WDPF).

6. *Various operation and monitoring functions*: Table VII/5.0.1-2 lists a number of workstation operations and monitoring function.
7. *Classification of workstation:* Based on hardware workstations can be classified as an *intelligent* workstation where the system has its own hard disk and associated software or as a *dummy* terminal without its own hard disk. Modern workstations are all intelligent. Again based on functions and use workstations can be broadly classified as seen in Table VII/5.0-3.
8. *Console/workstation hardware discussions*: Operator consoles may have a number of single or dual monitors of CRT or TFT LCD type. Some generalized characteristic parameters (standard Manufacturer) about monitors and associated accessories in a console are discussed below:
   - *Screen sizes*: 15/17/19/21" are available, but 19/21" is the most popular one.
   - *Power supply*: Normal 1 Phase 240/110 V 50/60 Hz. AC supply will do; however, the operating voltage inside the monitor may be as high as 15 kV in case for the CRT, for TFT such high voltage is not required.
   - *Refresh rate*: (CRT) 50/60 Hz.
   - *Channel/per line*: ~128", 75 lines in screen with up to a 96-character set.
   - *Aspect ratio*: 4: 3 or 16:9 for high-definition type.
   - *CPUs*: Normally reduced instruction set computer (RISC) processors have small, highly optimized

www.EngineeringBooksPDF.com

TABLE VII/5.0.1-2 Workstation Operation and Monitoring Functions

Common functions	Support functions	Maintenance function	Control window	Monitoring window
Browser bar	Remote operation	Status overview	Control loop	Mimics/graphics with attributes
Screen mode	Report	System alarm	Logic chart view	Face plate view
Window hierarchy	Security	Time setting	Sequence table	Tuning views
Plant hierarchy	Customization	Control system health status	Signal flow chart	Operator's guide mode
Print (print screen)	Historical viewing and reporting	Workstation health status	Face plate as shown in Figure VII/5.0-5	Alarm messaging
Shortcut key	Printer			Message
Circulation/ selection	Alarm filtering			
Related build up	Multimonitor			
	Field control			
	Open interface			
	Messaging			

TABLE VII/5.0-3 Workstation Classification

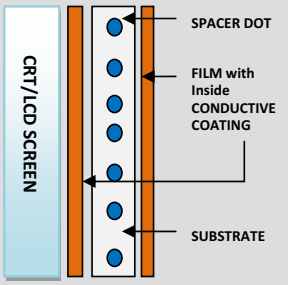
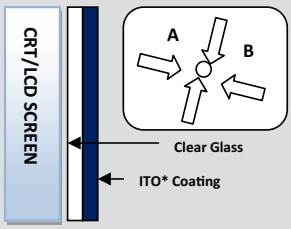
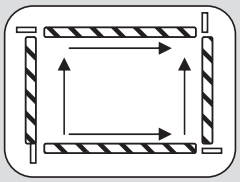
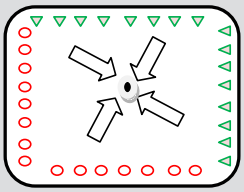
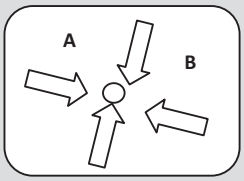
Workstation	Functionality
Operator WS	For monitoring control and operation of the plant
Engineering WS	Engineering and program development, e.g., control loop and logic program
Historian WS	It performs acquisition of plant data for storage retrieval, etc., for example, historical trend, alarm, and event history
Application WS	Third-party interface, historian, database management function, etc.
Gateway WS	Protocol translator, gateway (e.g., EPLCG from Honeywell) to enable networking with different systems such as OLE from Microsoft
Portable WS	Special functions such as portable vibration monitor; could be plugin/wireless

sets of instructions. The 64 bit processors are mainly used in larger systems.

- *Hard disk*: >>100 GB in Integrated Development Environment (IDE)—IBM PC)/Small Computer Systems Interface (SCSI) type. However, for both systems there is a minimum requirement of RAM that needs to be addressed; it is ~2 GB.
- *RAM size*: Selection is quite critical. The requirements come from how fast the graphics need to be updated as a new display and actual memory management system. Standard time to refresh most complex graphic is <1 S so RAM should be chosen accordingly by the supplier. Therefore the update rate needs to be specified. Also RAM for the video systems needs to be adequate.
- *Power requirements*: These are also important. As stated earlier, the power requirement and heat dissipation of a CRT is quite high compared with TFT LCD.
- *Other hardware requirements*: graphical board, Ethernet board, serial ports, USB ports, etc.
- *Keyboard*: Both standard as well as custom keyboards are used. In most cases (may not be for PC-based automation systems) membrane keyboards with hermetically sealed switches are used. Inside the keyboard there may be keys based on the Hall Effect and/or the Reed switch type.
- *Mouse*: Used to move the cursor on the computer screen by sensing the movement of the wheel below it and/or by optical sensing. The latter can adjust direction and speed of the cursor movement. Now a laser in place of the LED has been introduced in the mouse.
- Track ball: It has a stationary part that is larger than the mouse and has a ball in a socket, which allows

www.EngineeringBooksPDF.com

TABLE VII/5.0-4 Important Touchscreen Technologies

Resistive touchscreen	Consists of two film/polyester panels coated inside (facing each other) with electrically conductive materials. These two are kept separated by invisible spacer dots in the air substrate, for example. As shown these are kept ahead of the CRT/TFT LCD screen. Small current through the screen. When pressed by a finger or any other object then layers are pressed together and the panel behaves like a voltage divider causing the flowing current to differ. This difference is registered as a switch closure/touchscreen event and sent to the controller to locate the path.	
Capacitive touchscreen	Consists of clear glass panel coated with charge-storing coating indium tin oxide (ITO*), as shown. Touching the screen by conductive stylus, e.g., finger, as shown by circle in the figure. A: a small charge is developed, circuit at the corner measures the capacitance and the current which is proportional to the distance from the corners. Ratio of them gives the location. B: Location is calculated and sent to the PC.	
Acoustic detection touchscreen	In this method acoustic waves are sent across the glass surface. Since the glass surface is fixed for a given sound speed, the sound reflections will be sequential. When a stylus like a finger touches the glass, the sound is attenuated because of the absorption of energy by the finger. This is detected by a detector to calculate the location. Some use piezoelectric transducers situated around the screen. When a finger touches the screen small vibrations are created, which are sensed by these transducers. One example is the Tyco International touchscreen system.	
Infrared touchscreen	This method depends on the interruption of an infrared (IR) beam. IR LEDs and Opto-matrix comprising photodiodes are placed on opposite sides of the display as shown. These LED beams cross each other in vertical and horizontal patterns. When a stylus, including a finger, enters the grid to obstruct the beam, a number of photo detectors are obstructed, which sends signals to the electronic board mounted behind the bezel. *X, Y* coordinates are calculated hence the position is detected and signal sent to the processor.	
Optical imaging touchscreen (camera)	In this method a number of image sensors are placed at the corners. There is an IR light source in the field of the camera placed on the opposite corners. When a part of the screen is touched a shadow is detected by a pair of cameras to pinpoint the exact grid and report to the processor.	
Near-field imaging touchscreen	Sensor consists of glass coated with ITO. An excitation waveform to the conductive sensor is supplied and an electrostatic field is generated. When touched the electric field is changed, and this change is detected by electronics.	

www.EngineeringBooksPDF.com

TABLE VII/5.0-5 Comparison of Touchscreen Technologies

Technology	Resistive	Capacitive	Acoustic	Infrared	Optical	Near Field
Transmissivity	<78–82%	<90%	<92%	~100%	>92%	<85%
Touch	Anything	Conductive/ finger	Finger/pen	Finger/pen	Finger	Finger
Ambient light	Unaffected	Unaffected	Unaffected	Consult manufacturer	Consult manufacturer	Unaffected
Response time	10–15 ms	<15 ms	~10 ms	<20 ms		~15 ms
Dust/dirt rating	Unaffected	Moderate	Moderate	Moderate	Moderate, (resistant to moisture)	Unaffected
NEMA rating	4/12	4/12	12	4/12	12	4/12
Environment	0–50°C/ 95%	0–70°C/95%	0–50°C/ 95%	0–50°C/95%	0–70°C/95%	0–50°C/ 95%
Durability	3–5 years	<3 years	<5 years	<5 years	3–5 years	

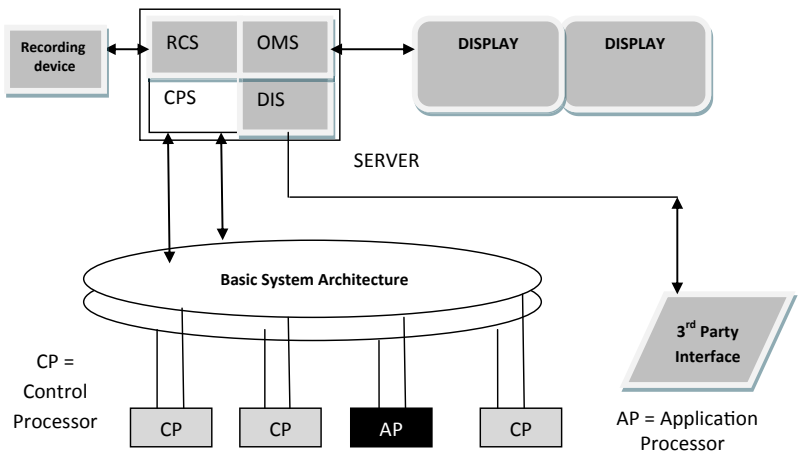


FIGURE VII/5.0-6 Typical WS software architecture.

the ball to move on two axes causing the movement of the cursor to be similar to that of an electronic mouse. This has much operational convenience for control and operation of the plant.

- Touchscreen: Less space, high accuracy, limited space requirement, time-critical application, and simple interface make touchscreens as a pointing device most popular. It is used with the CRT/TFT LCD screen, there is no additional space. It also has a direct interface, so this is in use in most of the applications (including those in mobile phones, video games, etc.). There are several technologies available to implement the design. These are discussed in Table VII/5.0-4.

It is important that engineers consider these factors: response time, resolution, transmissivity, stylus type, and reliability. Since image may be affected by any material in front of the image, transmissivity is important. Response time is important because the faster input is sensed, the better will be the design. Touchscreens need to have better mean time before failure (MTBF). Environmental factors are also important for durability. A small comparison among the touchscreen techniques is presented in Table VII/5.0-5.

9. *Console/workstation software aspects*: Most of the standard workstations available are based on Windows NT/Windows NT Embedded/Window 2000/Window 8/Window XP pro Embedded/UNIX/Linux, etc.,

www.EngineeringBooksPDF.com

which is the platform for running various system software to support operational functional services like operation and monitoring services (OMS), recording/reporting and calculating services (RCS), and data interface services (DIS). A standard manufacturer's MMI/WS software architecture based (courtesy: ABB) is shown in Figure VII/5.0-6. Control processing services (CPS) are not part of the workstation (shown for completeness only). Software systems can be categorized as the following:

- *Operating system*: As stated above.
- *System software*: This is the basic software for real-time data collection, process control message management, database management at basic level, and interface with other systems such as historians, application modules, etc.
- *Graphical User Interface (GUI)*: Graphical windows interface, for display management.
- *Application programming*: Data-based management, such as ACCESS, SQL, and third-party interface.
- *SOE*: Historian application, system maintenance support, etc.
- *Basic software*: Support for 10/100 Base T/F Ethernet, USB ports, Com Port including an RS 232/485 link, keyboard, and other pointing devices.
- *Software features*: These include but are not limited to:
  - Basic software support for 10/100 Base T/F Ethernet, USB ports, Com Port including an RS 232/485 link, keyboard, and other pointing devices.
  - Easy to use: user friendliness, intuitive menu/online help/multiwindow functioning/easy loading of applications/reliable run time applications.
  - Security feature for LOG in/out and also access control at various levels—multiple security.
  - Sharing and networking: Transfer of multiple interactive applications securely with LAN/WAN/remote node communication/sharing of data across workstations/support to transfer shop floor data for MIS presentation/support applications based on standard packages or software such as Excel, Access, C^{++}, VB, etc. Customized application software.
  - Openness to support OPC servers and other third-party software based on international standards.

Even though coordination efforts and testing times may be less when MMI software is procured from a DCS supplier, it is not mandatory. Below are a few points to consider for MMI software evaluation:

- System architecture
- Ease of implementation
- Scalability
- Integration facility
- System platform
- Operation speed
- Performance
- Provenness

TABLE VII/5.0-6 Display Features

Attribute	Quantity	Remarks
Process diagram	15,000–25,000	Depends on detailing and number of auxiliaries
Number of windows/displays	Minimum of 8	Multiple window supports
Dynamic field	Should not be any issue	
Dynamic field/diagram	As high as 200	Should be possible (analog + digital points)
Display update	<1 sec	
Number of colors per display	256	Typical value

TABLE VII/5.0-7 Display Hierarchy

Display type	Area	Process unit	Group	Detail
Operating data	Overview	Sub system	Group	Detail
Operator graphics	Graphic displays as defined			
Trend (as defined) Parameter can be max/min/avg, etc.	Area	Process unit	Group	
Hourly average			Group	
Sequence	Summary		Group summary	Detail
Alarm	Summary	Process unit summary	Group alarm	
Help	Help display as required			
Message	Message summary			

www.EngineeringBooksPDF.com

- Administration
- Multinetwork support
- Cost

10. *Typical display quantity*: Display features for a typical DCS deployed for medium to large size power plants are given in Table VII/5.0-6.

Process display as presented has a hierarchy in presentation for operational convenience. This is presented in Table VII/5.0-7. This hierarchy is user predefined. For example, for an operator in a boiler, draft system may be the "AREA" whereas air is a subsystem, or say FD fans may be the "PROOCESS UNIT" and in that there may be a "GROUP" of 8-16 Parameters (e.g. motor parameters) etc.

5.0.2 Large Video Screen

Giant video screens like those in sports stadiums are being utilized in the control room as an MMI for control and monitoring. This would not only help view the MMI—operator's screen in a larger scale but would also provide a way to see the CCTV signal, or any other camera signal also in shared video. Life video for communication is also a possibility here. These are generally TFT LCD (or LED or any other technology) displays with flicker-free uniform brightness display all over the screen with auto brightness adjustment facilities for the ambience. Normally these are placed in a control room environment with the ability to absorb ambient light so that the videos can be seen without having to darken the space (suitable light-adjustment facility). There could be two or three such large video screens (LVSs) in the control room. Some of the technical features are listed in the following table:

1	Diagonal size (mm)	2000-2100 (80-84″)
2	Type	LCD/LED or any other proven technology
3	Resolution	1024 × 1024 pixel
4	Control unit	Similar to operator's workstation
5	Video signal	MMI, compatible camera, or CCTV programmable
6	Switching unit	For selection of MMI, compatible camera and CCTV
7	Screen division	Multiple screen in selected areas with a provision to project any display on a particular screen/location following a predefined event
8	Interface and standard	PAL/NTSC/SECAM and others in VHS standard
9	Illumination level and viewing	Predefined or preprogrammed as per owner's choice/manufacturer's standard

5.0.3 Printers

Printers as operator interfaces are important when hard copies of plant data or trend is necessary. So, in almost all cases these printers are supplied with a DCS. Based on technology printers can be classified into two categories: impact printers and nonimpact printers. Also, based on printing speed and types, these can be categorized as serial and line printers. Dot matrix printers, inkjet printers, and laser printers are mainly used with DCS, Line printers are only used for large bulk printing, so these have limited use in the DCS.

1. *Dot matrix printer*: This is an impact serial printer. Here character dots hit the ribbon against the paper. Character fonts are stored in the memory. The characters are formed by a matrix of dots. The printing head consists of a number of columns of needle hammers and there are six such horizontal columns, which move across the paper. Based on the characters to be printed these dots are fired in sequence. The character quality depends on the number of dots in the character matrix, i.e., the more the number of dots the better is the quality. Typical printing speed of 900 CPS is common. When compared with an inkjet printer capital cost of these printers may be higher, but printing cost and quality is lower.
2. *Thermal matrix printer*: This is similar to a dot matrix printer meaning that the printing head also has 5 × 7 dots, and these dots are selectively heated to give character prints on special paper on which the head moves. In DCS applications in some cases these were in use, but they are not popular now.
3. *Inkjet printers*: These are the most common type of printer. Because of low initial cost, high-quality printing (per page printing cost may not be cheap), vivid color, and easy to use, these printers find huge application in the DCS. It works by propelling tiny droplets of liquid ink onto the plain paper. Based on this propulsion technique there can be three types of inkjet printers:
   - *Thermal*: This printer has a print cartridge with a series of tiny electrically heated chambers constructed by photolithography. The printer runs a pulse current through the heating elements, a steam of explosion occurs, and a bubble is formed and causes the ink droplet to propel to the paper.
   - *Piezoelectric*: Here in place of heating, a piezoelectric crystal is used. So when current pulse for printing is applied the crystal changes the size and shape forcing a droplet of ink to the paper. This is quite expensive.
   - *Continuous*: This type of printer is the most popular. A high-pressure pump directs liquid ink from a reservoir through a microscopic nozzle creating a continuous stream of ink. There is a piezoelectric crystal

www.EngineeringBooksPDF.com

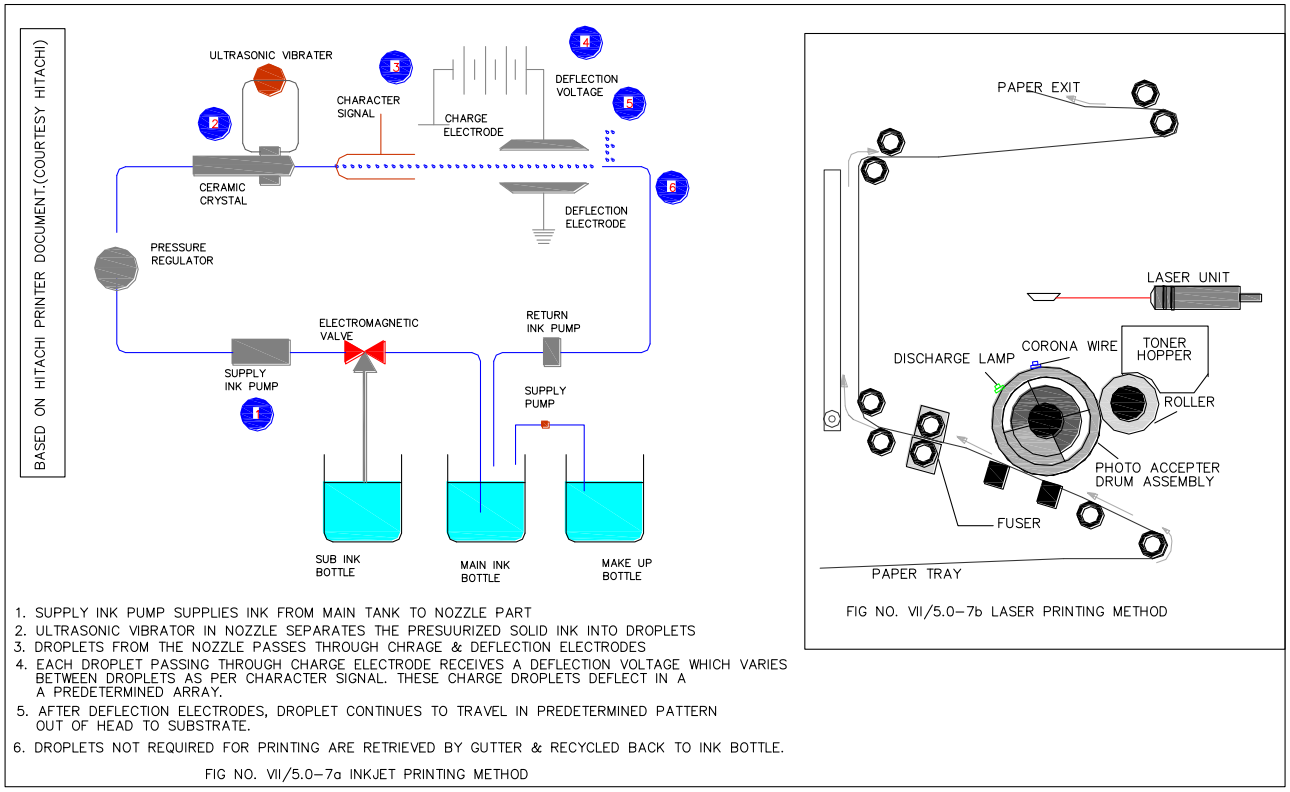


FIGURE VII/5.0-7 Inkjet and laser printing methods.

that causes the liquid stream to breathe droplets of ink. This piezoelectric crystal is subject to an electrostatic field formed by deflection plates in horizontal and vertical directions to shift and drop at the desired point on the paper. These deflection plates form the character by manipulating dot structure. The charge droplets are separated by guard droplets to avoid electrostatic repulsion between two charged droplets. To allow the jet mechanism work smoothly, a catch gutter is put in front of the last deflection plate (see Figure VII/5.0-7a). These printers use black and colored print cartridges.

4. *Laser jet printer*: Static electricity is the principle behind the laser jet printer, and it acts as a temporary glue. The major part is the revolving drum/cylinder type photoreceptor (see Figure VII/5.0-7b). Initially the photoreceptor is positively charged by a corona wire or charged roller. As the drum revolves, the printer sends a laser beam across the surface to discharge certain points. The printer then draws the letter and images as a pattern of electric charge—an electrostatic image. The laser is regulated based on image. After the pattern is set, the printer coats the drum with positively charged toner (a fine plastic powder that fuses at ~200°C to bond with paper). Since the toner is positively charged, it clings to the area of the drum discharged by the laser and not positively charged background. With the pattern affixed, the receptor drum rolls over a sheet of paper that is moving along a belt below. Before the paper rolls below the drum it is negatively charged by a corona wire or charged roller. This charge is stronger than the negative charge of the electrostatic image discussed, so that it pulls the power/toner back to the paper in an exact pattern. Laser printers can use black and/or colored toners/cartridges also. Since photocopying is done based on the same principle, most printers can be used as a photocopier. Speed of printing depends on many factors and varies with each model. Typical speed 200/100 (color) A4 pages per minute.
5. *Comments on various printers discussed*: Dot matrix and inkjet printers take incoming spooled data for printing, so the printing process is slow, and may stop printing when the printer is waiting for data. On the other hand, in these printers if the data required for printing is taken a little at a time and is buffered, then printing would be continuous. However, if it has to wait for such data there may be the possibility of misalignment. Generally in laser printers a raster image processor scans the entire page line by line and stores the bitmap of the page in raster memory, before staring the printing procedure. In laser and dot matrix printers A3 size printing is possible, but a longer banner may not be possible.

www.EngineeringBooksPDF.com

Various factors like, BandW/color, paper size for printing, and other facilities like copy, scan, fax, etc., influence the price of a laser printer. Depending on these factors, there are wide variations in price. In case of large-scale printing, laser printing cost may be economical even if initial cost of the printer is high. Also depending on the built-in processor/intelligence with the printer it can be hooked directly with the network, otherwise these may be hooked up with a server and/or any workstation/engineering station through a com port/USB port.

5.0.4 Recorders

It is possible to take the print out of the screen to get the print out of any trend, *X-Y* plot, etc. However, in many plants dedicated *microprocessor-based* recorders are used for selected parameters. Recorders are independent of the DCS and could be intelligent chart type and/or chartless type recorders. The advantage of utilizing microprocessor-based intelligent recorders is that these can be connected to the DCS through RS 232/RS 485 link with, e.g., MODBUS protocol. Also, it is possible to connect analog output of the DCS or directly from redundant output of the primary device to these recorders for hardwired connection. It is the choice of the designer/user. There are different kinds of recorders, such as strip chart pen (1/2/3/6 pens), multipoint (3/6/12/24 points), and circular chart (1/2/3/6 pen) and chartless recorder (None/6/12/24 inputs).

Number of pens/points: This represents input channels to the recorder. What is the difference between pen and point? In case of a pen recorder, there will be a separate pen (each with different colored ink), independent measuring channel, and signal-processing unit for each of the input channels. In the case of a multipoint recorder, there will be only one common pen, measuring channel, and signal-processing unit for all input channels. Several input channel parameters are recorded by multiplexing/scanning the inputs sequentially at a predefined rate. Also each channel can be distinguished from the other either by using different colored ink and/or using separate dot symbols (e.g., 1, 2, 3, etc., print corresponding to channel 1, 2, 3, respectively).

Chart types and speed: Recording charts could be strip charts, which are characterized by the uniform linear motion of the paper either horizontally or vertically with measurement lines that are either rectilinear or

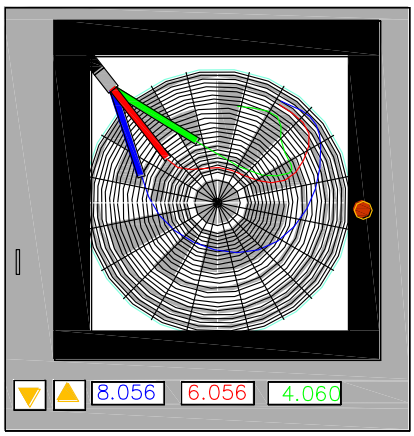


FIG NO. VII/5.0–8a CIRCULAR CHART RECORDER (front face)

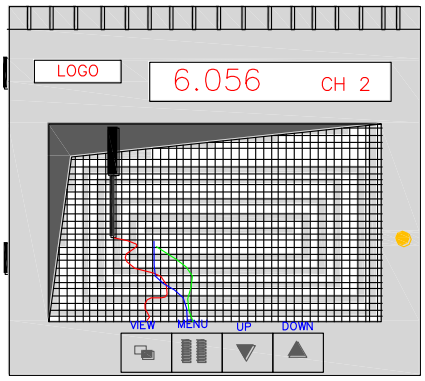


FIG NO. VII/5.0–8b STRIP CHART RECORDER (front face)

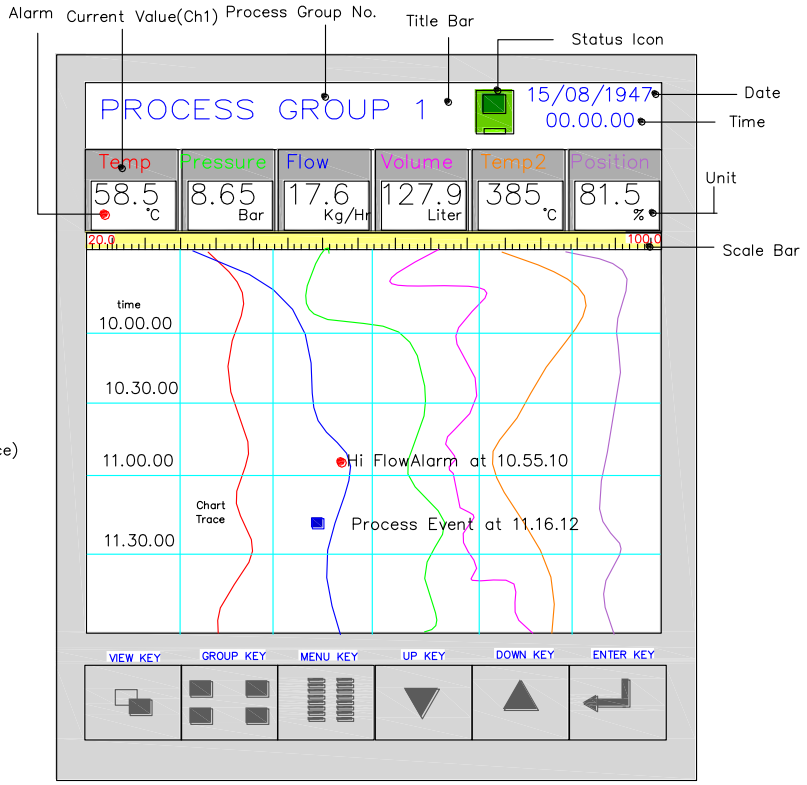


FIG NO. VII/5.0–7c CHARTLESS RECORDER (front face)

FIGURE VII/5.0-8 Various recorder types.

www.EngineeringBooksPDF.com

curvilinear recordings or a circular chart with uniform rotation per unit time, which is normally one revolution per day circular with 24 h divisions. With a chartless recorder there is no chart and the trends are shown in LCD displays like a workstation in a DCS. However, in *all* recorders the recording (chart) speeds are variable, and often the chart speed is made faster for better analysis of the trend of the parameter like boiler/turbine metal temperature during start-up.

Enclosure rating: Most recorders are available in IP 55/ NEMA 4 ratings.

Universal Inputs: Now almost all available recorders have a universal input, i.e., it can accept 4-20mA/types of T/Cs , mV, RTDs, etc. (see Clause 4.2).

Sizes: Almost all recorders are available in standard Din sizes such as 72 × 144, 144 × 144, 288 × 288, etc. The size of the recorder is dependent on the type of recorder and number of pen/points.

Indications: Most the recorders used are indicating a type, meaning that in addition to the recording on the chart, the input parameters are indicated either by scale and pointer or by back-lit LCD, LED, or bar graph.

Power supply: 1 Ph, 110/240 VAC, 50/60 Hz (VA rating: type dependent)

Noise rejection: Normally ∼120 dB at 50/60 Hz is standard.

Memory protection: Memory protection in E^2PROM is available. Also for a chartless recorder USB ports are available for downloading data as required.

Advanced Software functions: Advanced software functions such as math functions, e.g., totalizing, + - X/etc., are available in these recorders.

Alarm function: If needed functions for the number of inputs are available, but may not be popularly used, for recorders with a DCS.

RS link: These recorders offer an RS link for serial communications.

1. *Circular chart recorder*: As the name implies, the shape and movement of a chart is circular. In the chart the timescale is graduated along the circumference and parameter variation scale in radial manner. Some of the circular chart recorders have event timers driven by the recorder's real-time clock to start/stop the recording on a preset time. These are available in 1/2/3/4 pens. In some records, on each channel it is possible to have two to three event recordings. A typical circular chart recorder is shown in Figure VII/5.0-8a. It is also possible to perform some mathematical as well as logical problems in these recorders.
2. *Strip chart recorder*: In contrast to the circular chart, these recorders have the chart move in a linear motion, with timescale in a horizontal direction and the pen movement in a vertical direction. These are mainly used for 1/2/3 pen recordings with 72 × 144 size recorders, and in these instruments by opening the door an extended view can be observed without hampering the recoding. Pen movement in a horizontal direction, is shown in Figure VII/5.0-8b. This is done with a multipoint/pen recording 144 × 144 or above. The view is wider and strip chart recorders have displays in bar graph and/or in digital displays. In the front there may be switches to adjust speed and set alarms.
3. *Chartless recorders*: This type of recorder, as the name implies, does not have any chart, and the LCD display is very similar to a monitor display. These recorders have powerful functional capability with internal flash memories for recording and log and a battery back-up as well. These recorders are network compatible to hook up with the Ethernet network, as shown in Figure VII/5.0-9. High mathematical capability makes it versatile. Similar to a workstation monitor, it can be used for historical

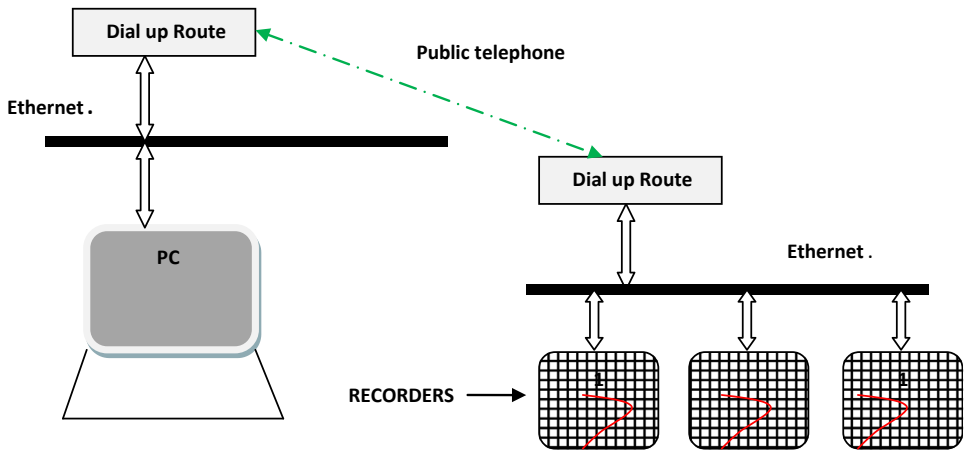


FIGURE VII/5.0-9 Chartless recorder Ethernet and Web connection.

www.EngineeringBooksPDF.com

TABLE 5.1-1 Display Quantities (Typical)

SL	Description	Quantity
1	Overview display	10 types
2	Control displays (group, sequence, loop, face plate)	400–700
3	Mimic/P&ID with dynamic attribute	250–450
4	*X-T* trend (in groups/mix)	5 × 20–25 (75–180 total)
5	*X-Y* plot user selectable/historic	70–150
6	Bar chart (horizontal/vertical) pie chart	75–130
7	Group display/individual displays	>100 (4–16 in each group)
8	Operator or start-up/shut-down guidance message	100–120 each
9	Status/system diagnostic message (manufacturer standard)	As required
10	Shared window types of display	10–15
11	Alarm display type and LVS alarm	As required by owner
12	Miscellaneous display types/ quantity	10/100

trends, etc., and its data can be retrieved by memory stick utilizing USB ports. Group display, menu, etc., push buttons are available in the front panels as shown in Figure VII/5.0-8c. Some of these have embedded Web servers

4. *X-Y recorder*: Notes the variation of one parameter with respect to the other (e.g., boiler load vs air flow). There are two kinds of such plotters available. In one the chart is stationary and two signals are connected to two axes, or if the chart is moving then one of the signals moves in the opposite direction while another signal goes along a direction 90°. These plotting signals can be either analog or digital.
5. *Miscellaneous recording systems*: There are other recording systems such a tape recording system, storage oscilloscope, etc. All of these devices are used to store the data for future analysis.

5.1 Display Types: Introduction

The role of various displays in operation and management of any plant cannot be overestimated. Major display types include: overview, mimic, group, point, alarm, trend, plant start-up and shut down, operators guide, loop and logic, controller face plate, *X-T*, *X-Y*, bar chart, etc. Each of them has separate significance. Typical quantities of displays in main power plants with medium/large units are enumerated in Table 5.1-1.

5.1.1 Overview Display

The overview display frame normally gives a bird's eye view of the entire plant/subsystem to the operator. The design of the overview display normally is engineered jointly by owner and manufacturer. Based on the owner's requirement for screen division (window) and content of each window, the manufacturer's engineer develops a system that is well supported by the system resources available. From overview displays it is possible to quickly go to various detailed displays/trending/control face plates, etc. For a subsystem, the overview display should be able to quickly switch to other subsystem displays (see Figure VII/5.1-1).

However, it is possible to quickly see the status of other subsystems, e.g., turbine/generator subsystem, with the help of a dedicated illuminated soft key (Figure VII/5.1-1, left). In the overview display, there could be various windows in a shared screen to display, mimic diagram, trend display, display controller face plates and alarm/SOE messages, to apprise the operator of the status of all important events as well as control parameter variations. In each of these windows desired parameters can be chosen. Normally date and times are shown at the top/bottom part, and it is also possible to take print out of any desired display. To keep the operator apprised of the situation of the subsystem, at the top or bottom there are three to four lines dedicated to show the latest alarm/SOE. In many displays such dedicated illuminated soft buttons are replaced by browser bars, as shown in Figure VII/5.1-2.

From this browser bar it is possible to view various loop/subloops, etc. The over view displays also can be selected with the help of browser bar. The browser bar enables the user to view the selected trend, mimic, etc., with the help of a selected flag. There can be tool box/ preselected tool boxes to perform various operator functions as well as to go to preselected display views. It is possible to perform history functions and search a tag from the tool box. Similar bars are found in many systems, including Centum VP from YEL.

5.1.2 Mimic/P&ID Display

Mimic display is extremely helpful for plant operation. It displays the graphical form of the process within the purview of a particular mimic diagram. All the drives have dynamic attributes. This means that, by using the cursor, touch, and or stylus associated drives can be operated and/or its status updated for viewing. In a typical mimic diagram shown in Figure VII/5.1-3a,

www.EngineeringBooksPDF.com

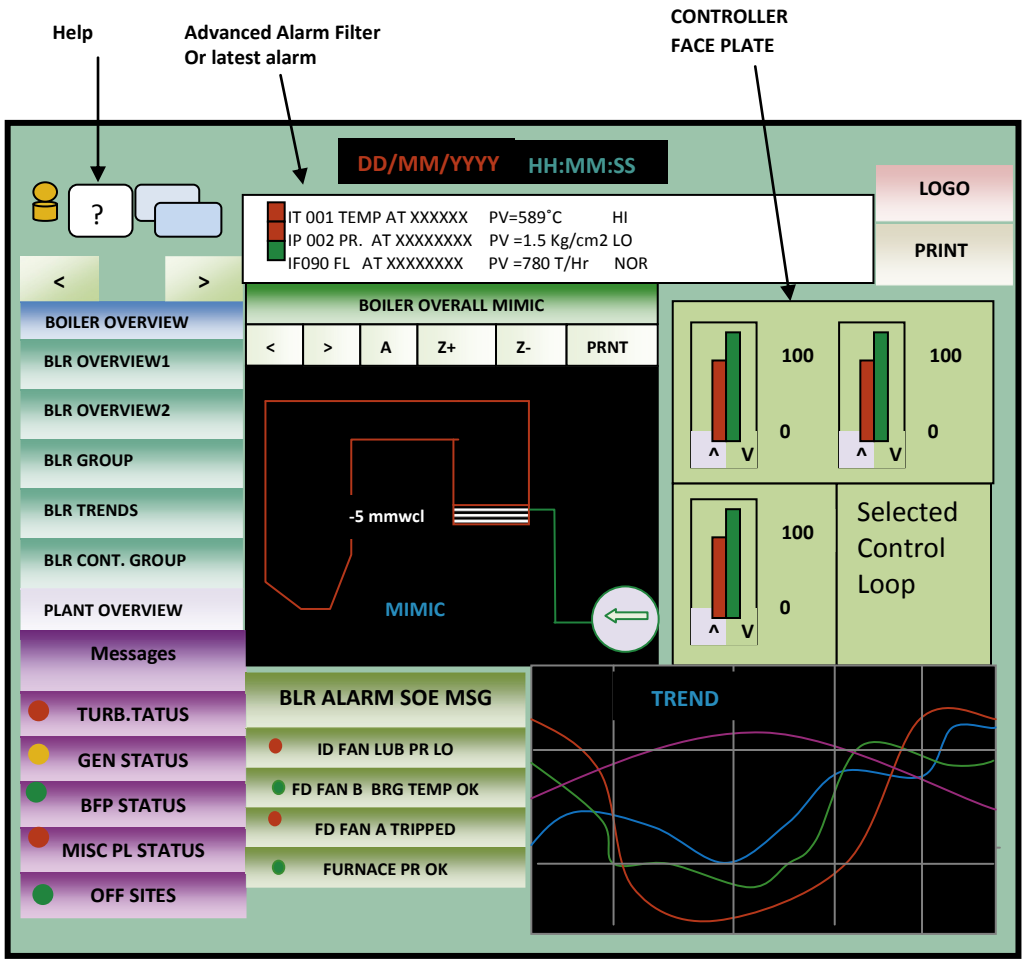


FIGURE VII/5.1-1 System overview display.

whenever the illuminated soft button associated with "Ammonia"/"Hydrazine" is touched, then the associated dosing control loop can be viewed. Similarly by touching the sample line status button it is possible to view the sampling point parameters. Also as shown in Figure VII/5.1-3a, whenever FIC 11/21 is touched it is possible to get the controller face plate display as a pop-up window for control purposes. This is an example of one of the possibilities available from the manufacturer for a plant. The basic design is engineered jointly by engineers from the owner and manufacturer. Normally it is possible to add a fixed number of the owner's predefined library symbols in addition to the standard library symbols available. With the help of multiple window operation it is possible to go to the trending of a few parameters in the mimic display. These mimic diagrams can be either an overview type or an individual type. As shown in Figure VII/5.1-3a, it is possible to highlight a particular loop mimic with different colors and/or show vessel level with shades. In most cases mimic displays have provisions for the alarm/SOE lamp displayed for the drives in the mimic and/or associated/related drives/processes.

5.1.3 Controller Face Plate Display

In this display, a number loops with associated drives are displayed along with related parameter values such as measured (process), set point, deviation, drive position, etc. These values can be depicted in a bar display as well as digital value. In the face plate the remote/local, A/M selection status is also shown. The display configurations could be eight loops at a time and/or a mix of a few loops along with the indication of a few related parameters, depending on the operator's choice as admitted by the manufacturer. As shown in Figure VII/5.1-3b, it is possible to display numbers (here four) of full control face plates along with numbers (here two) of indications and short controller face plates of related parameters. This combination depends on system capability, but a combination of such displays can be decided jointly. By window sharing it

www.EngineeringBooksPDF.com

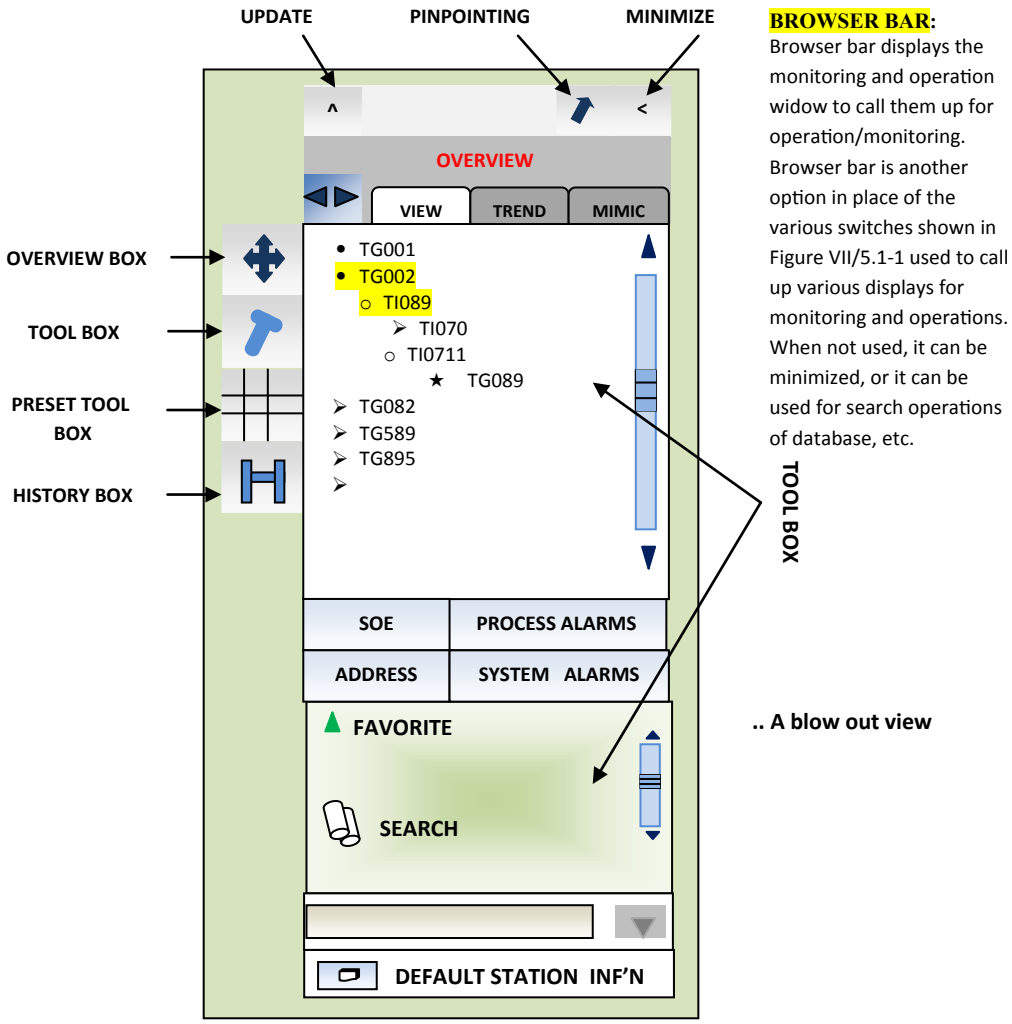


FIGURE VII/5.1-2 Browser bar details.

is possible to put forward an alarm/SOE status also and go other displays directly from these displays by browser bar and/or by a set of dedicated soft buttons (see Figures VII/5.1-1 and VII/5.1-2).

5.1.4 Trend Display

These are trends of an analog parameters with respect to time, so these are *X-T* displays. There are selectable time spans for these displays. While for current real-time parameters these could be selected from 10, 20, and 30 sec to 1, 2, 5, 10, 15, 20, 30, and 60 minutes or it could be 2, 6, 8, 24, 48, and 72 hours. Trend is possible to be extended to shift, daily, weekly, and monthly parameters. In the latter cases the parameter values chosen could be average, maximum, and minimum values selected by the operator. It is possible to get finer divisions in time span for selected parameters and for event-based trending, e.g., faster trending of furnace pressure following a disturbance in the system.

Based on available memory space, the sampling rate can be selected to get a better focus on a parameter under question. Depending on the sampling frequency and time span, historically the parameters can also be trended. A few parameters such as oil/coal/make-up water consumption, etc., it is possible to get a trend on accumulated value over a period on a shift, daily, weekly, or monthly basis. To help the operating personnel, it is possible to scale range as well as time trend display for detailed viewing. For a detail view it is possible to slide the view vertically as well as horizontally. These are shown in Figure VII/5.1-4a. Normally there are dedicated soft keys, which allow the operating personnel to view any particular parameter in the desired way by squeezing and stretching the parameter curve, and/or by zooming in/out. Pan and zoom for trend display is quite common. Normally there is a slider bar, which when put at a point it is possible to digitally read all the parameters at the point of slider (in timescale), located below (or above) the trend display. Although not shown, it

www.EngineeringBooksPDF.com

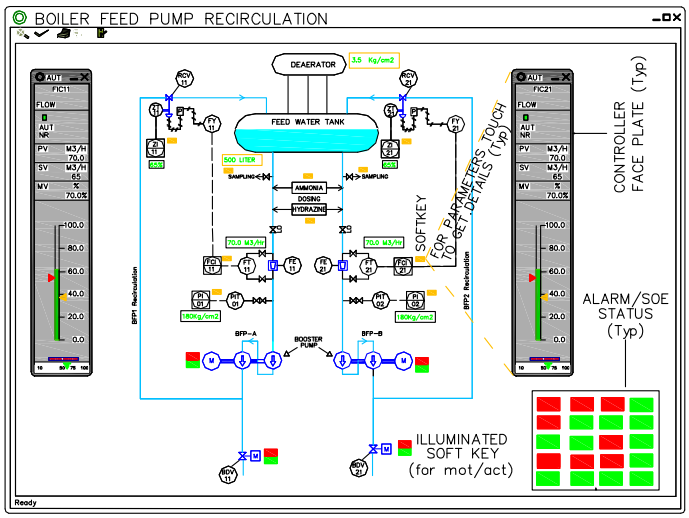


FIG NO. VII/5.1–3aPROCESS MIMIC DISPLAY

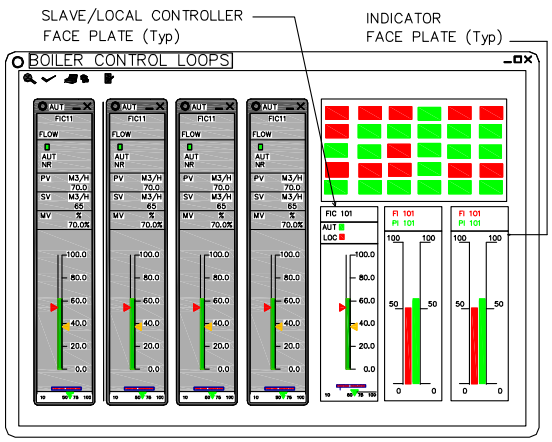


FIG NO. VII/5.1–3b CONTROLLER FACE PLATE DISPLAY

FIGURE VII/5.1-3 Mimic display and controller face plate display.

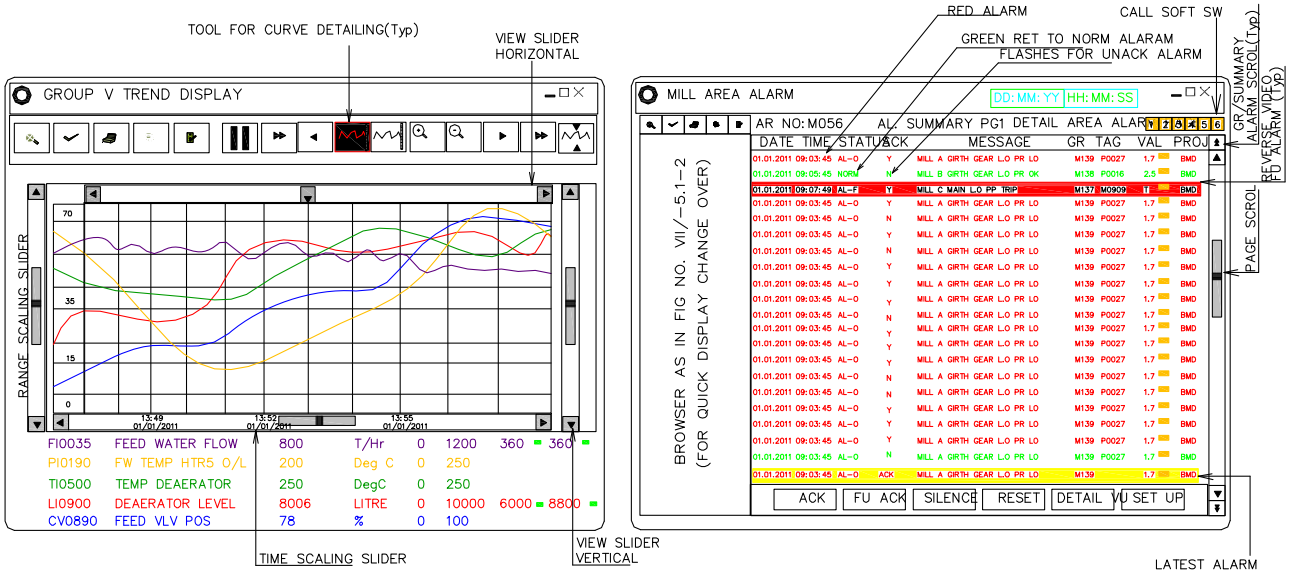


FIG NO VII/5.1–4a TREND DISPLAY (GR. TREND DISPLAY)

FIG NO VII/5.1–4b ALARM SUMMARY DISPLAY

FIGURE VII/5.1-4 Trend display and alarm display.

is possible to go other displays directly from these displays with the help of the browser bar and/or by a set of dedicated soft buttons (see Figures VII/5.1-1 and VII/5.1-2). Because of the presence of an object menu, it is possible to call any trend display easily and immediately by simply clicking the point from any display.

5.1.5 *Alarm Display*

A typical alarm summary display is depicted in Figure VII/5.1-4b. There may be a browser bar or dedicated soft switches to quickly switch to another display. Alarm displays and SOEs help operating personnel analyze the fault as well as become familiar with the health of the plant. The design of the alarm display generally comes from the plant control and operating philosophy of the owner, and there could be a variety of such displays. In Figure VII/5.1-4b, the alarm summary display shown includes mainly the information related to date, time, type of alarms (first up or ordinary or return to normal), actual alarm message, and tag of the device responsible. This also includes any grouping of

www.EngineeringBooksPDF.com

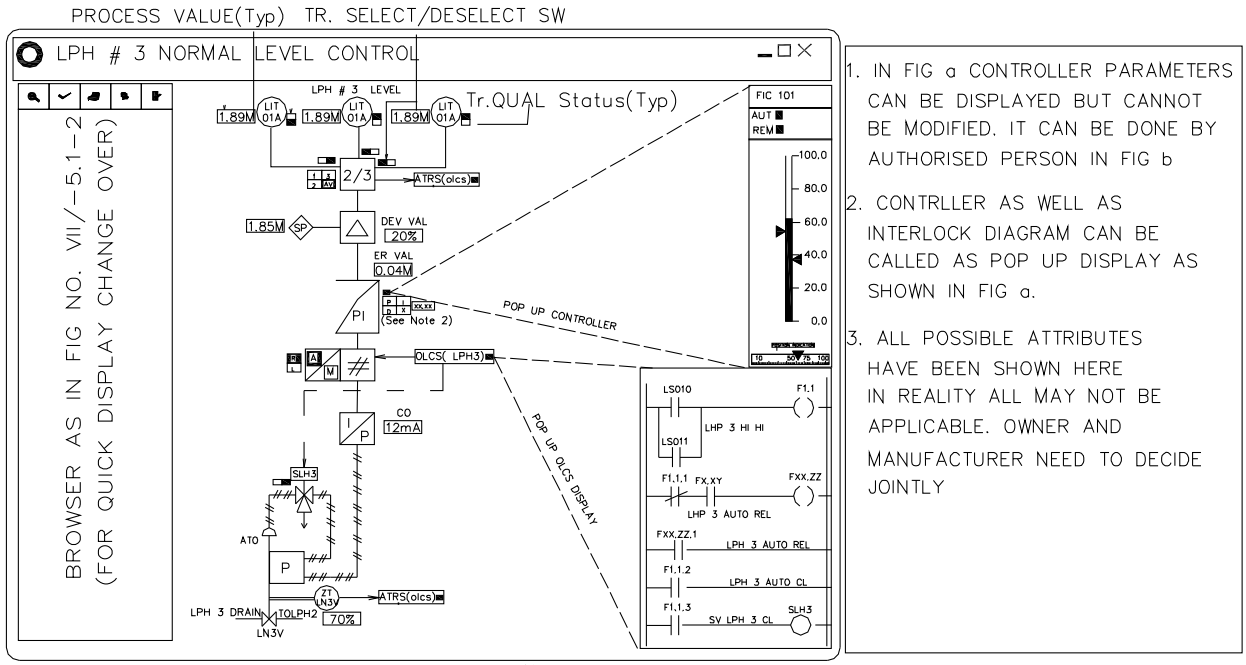


FIG NO. VII/5.1–5a CONTROL SYSTEM DISPLAY

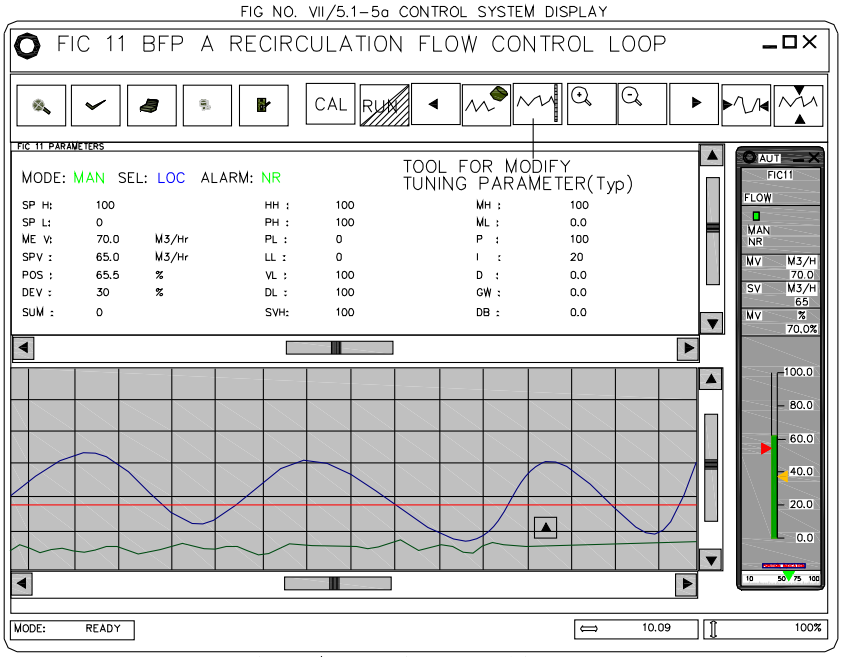


FIG NO. VII/5.1–5b CONTROLLER TUNING DISPLAY

FIGURE VII/5.1-5 Control system display and controller-tuning display.

these parameters (so that operator can go to the group display to watch the status of other points in the group) and area information. Normally alarm conditions are depicted by red or yellow colors, whereas return to normal is depicted by a green color display.

Ordinary and first alarms can be distinguished by color (yellow and red) or can be distinguished by reverse video as shown. The alarm may appear from the top or the bottom. Sometimes the latest one or two alarms are suitably distinguished. To distinguish between acknowledged and unacknowledged alarms flashing may be attributed to the alarm line (for better ergonomics, only " Y/N" may be flashing). Some displays show the set point and parameter value, but normally these can be displayed when a particular alarm value is clicked. When summary alarms are displayed, detail can be viewed as a pop-up window by clicking the detailed page associated with the alarm. Each of the alarms can be acknowledged/reset, etc., by selecting

www.EngineeringBooksPDF.com

the alarm and clicking the concerned button. Silence is shown separately to indicate that these could be a stop sound in case of a ring-back option, but it does not acknowledge the alarm. If there are too many alarms in a display, it is possible to scroll, and in case of a summary alarm, directly to other summary alarms. These summary alarms could be on an area/group basis also.

5.1.6 X-Y Plot

To establish the co-relation between the two variables. *X-Y* plots are done in the system. Normally 4—8 locus lines are displayed in one screen. There can be pre-assigned displays of 15—20 numbers in a DCS. Alphanumeric information is used for these variables as well as for their chosen scale. Pan and zoom functions are common. Also it is possible to superimpose an *X-T* plot of these variables on an *X-Y* plot. An *X-Y* plot using stored data is also quite common

5.1.7 Control System Display

Both CLCS and OLCS sequential diagrams can be displayed in DCS screens.

5.1.7.1 CLCS Display

Under this display control loop schematic/loop drawings with associated attributes are displayed as shown in Figure VII/5.1-5a. There may be a browser bar or dedicated soft switches to quickly switch to another display. also shown as a digital read out at the appropriate place. Valve position and controller outputs are also displayed. It is possible to look into the interlocks associated with the loop. Depending on the applicability status of various devices are also displayed, e.g., status of A/M, solenoid valve, etc. It is worth noting that even if controller-tuning parameters can be viewed, they cannot be modified (unless authorized) in this display for safety. As a pop-up window it is possible to get the controller face plate/OLCS ladder diagram, SFC, etc., by clicking the concerned display.

5.1.7.2 OLCS Displays

OLCS displays are associated with interlock and sequential operations. Sequence chain displays for each group and subgroup can be used not only to trace the control sequence but also to allow intervention (authorized person only) and/or change of mode of selection from auto to manual. In the entire chain a sub block can be viewed with the status of each device along with step number and waiting and monitoring time. On the display there may be a control plaque display enabling the user to know which step the operation is in and what the criteria and missing criteria are. A typical tablet and plaque is shown in Figure VII/5.1-6. In each step of the sequence control all criteria status may be displayed by a red or green light to signify availability. In operator's guide mode/in step-by-step mode, the operator can bypass the criteria (if system security and process protection permits). In a normal interlock any input can be forced (if system security and process protection permits).



FIGURE VII/5.1-6 OLCS display tabs and plaques.

As shown in Figure VII/5.1-5a, a complete loop and/or a combination of loops can be displayed with commonly used attributes. All of these are shown in one display to indicate the various possibilities of displays. The actual design needs to be firmed up jointly by the owner and the manufacturer. By using the loop A/M and local remote the loop can be selected in the desired mode. Each of the input and output values are shown and it is possible to select the transmitter in case multiple transmitters are used for the measurement. Set point deviation parameters are Auto/semi-auto and manual mode of selection as well as force input—bypass criteria can be done with the help of plaques depicted in Figure VII/5.1-6.

Normally OLCS displays views either in an SFC or ladder diagram as shown as a pop-up in Figure VII/5.1-5a. In many designs, various drives, whether the ON/OFF or modulating type, have separate displays. This can be a pop-up window in the control display or can be an independent display. It shows all the associated input and output pertinent to a drive (or could be a group of drives, such as

www.EngineeringBooksPDF.com

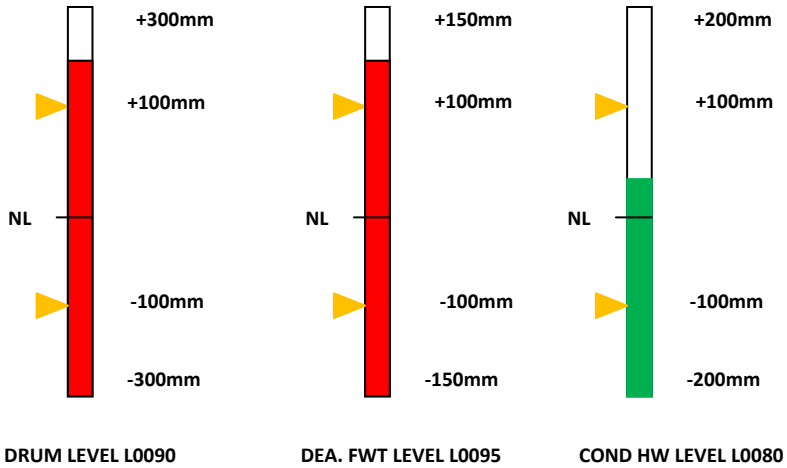


FIGURE VII/5.1-7 Example of a group display.

multiple LO pumps). There are many variations in displays, so owner and manufacturer need to freeze the design for the plant based on plant control philosophy and manufacturer's recommendation.

5.1.8 Controller-Tuning Display

It is possible to tune a particular controller from the DCS by the authorized personnel. A typical controller-tuning diagram is shown in Figure VII/5.1-5b, where there are a number of dedicated soft keys to assist controller-tuning function. This is normally done by taking the loop into manual and freezing output or offline. After the controller is properly tuned it can be put online. By changing the controller-tuning parameters, such as proportional band/integral action time, etc., the control loop response curve can be observed in the display as shown in Figure VII/5.1-5b. A controller face plate can be seen as a pop-up display. Even during operation the loop response can be observed. With the help of soft keys like "CAL"/"RUN," various mathematical algorithms can be built and the system can be run. Now systems are available to support embedded systems to provide powerful mathematical algorithms supported by various tools such as Active X controls from MATLAB (see Figure VII/5.1.8-1).

5.1.9 Other Miscellaneous Displays

Other kinds of displays are listed below:

1. *Group display*: This display includes the information point ID, value engineering unit, set point current value, and functional group. Presentation of this could be in various forms: a simple bar graph display, as shown in Figure VII/5.1-7. or a group display in the form of line message. Basically group messages are helpful when comparing related parameters to comparative behavior of various parameters at different operating conditions. Group operations can be from group displays. In Figure VII/5.1-3b a group of predefined controllers are depicted for performing the control tasks. Air flow is a parameter that is related with fuel flow/combustion control as well as steam temperature control. Again steam flow is related to both combustion control as well as feed flow control, so naturally these may be grouped at the controller face plate in a group

MATLAB (Matrix Laboratory) is a very useful tool for processing control system. This is a fourth generation programming tool for numerical computation and analysis. This allows implementation of algorithms and GUI. For programming it supports languages like C, C++, and FORTAN. Model-based system design (such as process model identification, stability assignment, process simulation, optimal/prediction control) and the embedded system are well supported by this tool. It has a predictive tool box and a fuzzy tool box to make the designer's work much easier.

FIGURE VII/5.1.8-2 Note on MATLAB.

www.EngineeringBooksPDF.com

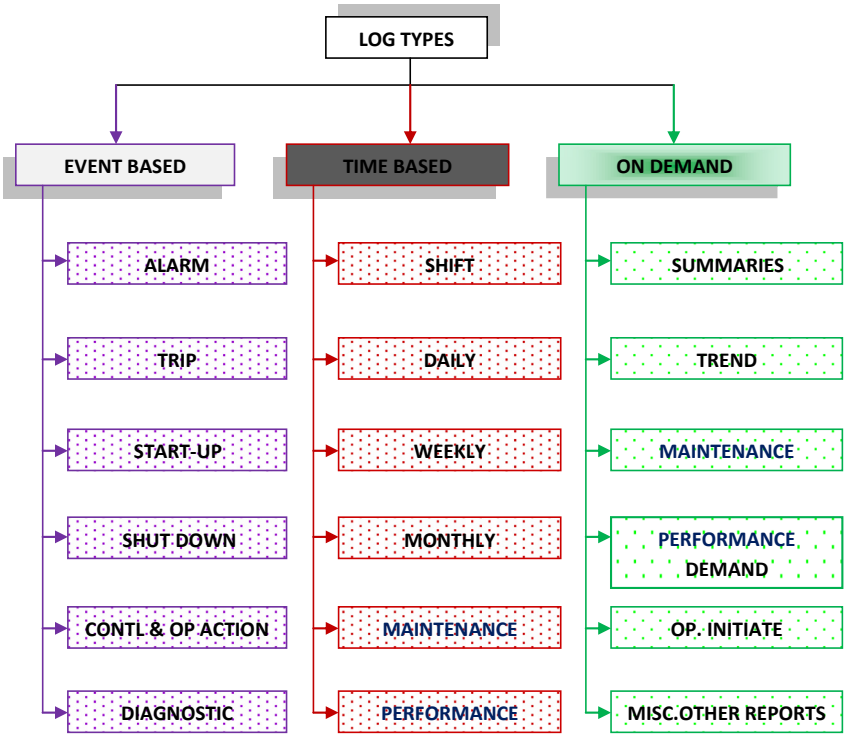


FIGURE VII/5.2-1 Log/report types.

display for control operation. Designers need to make such groupings according to plant operation.

2. *Point display*: It is possible to select a particular point from mimic, group, alarm, etc., displays to get a detailed point display. A point display contains all the database attributes for a particular point. In many cases even the terminal details of a particular point have been made available. This point display can be a calculated point as well. By clicking the calculated point the detailed calculation behind it could also be displayed.
3. *Bar graph display*: These can be horizontal as well as vertical, and there can be large numbers in one display as long as the view permits. Many related parameters of commercial importance are also presented in bar graphs and pie charts.
4. *LVS*: These are generally mounted at the top of the wall the operator is facing so the alarm display in a conventional annunciator overlaying the mimic would be in a better position. Special displays such as a CCTV view of the burner, drum level display from electronic water level indicator (e.g.,: Hydrastep) are also included. Large digital display of selected parameters are also put on the LVS so that from a long distance people can view it.

5.2 Log Types: Introduction

When display types are very important for plant operation, log types are equally important for keeping track of the plant operation and performance. The format, point assignment, and generation of each type of log/report varies from project to project and is finalized jointly by the owner's designer in consultation with the manufacturer.

Now most of the log sheets are compatible to the spread sheets (e.g. MS Office Excel). Although most of the log/report functions are automatic, manual time-tagged log/report generations are also possible from any display and or type of log. In automatic log generation it is possible for each log type to drop/inhibit any page/selectable group/point in any log for a selected period of time (or until further initiation). However, such inhibiting action can be initiated only by the authorized person. Inhibiting details (such as by whom and when that inhibition was canceled, etc.) may be recorded. In a larger network with a number of printers there may be pre-assigned selection (primary and secondary) for each log type. If necessary any particular log may be repeated at various printers. DCS logs/reports can be categorized into three types as shown in Figure VII/5.2-1.These include the following:

1. *Event based*: When the log/report is generated after an event occurs.
2. *Time based*: When the log/report is generated periodically after a time gap
3. *On demand*: Manually generated log/report, generated when necessary.

www.EngineeringBooksPDF.com

5.2.1 Event-Based Log/Report

These logs/reports are generated after an alarm or trip happens. SOE is also an event-based log/report. Normally dedicated printers are assigned to the alarm/trip and SOE. These logs/reports are generated during start-up and shut down of a unit/subsystem. Control-related log as a predefined operator action such as database modification (when authorized) is also an event-based log/report and is stored for future recall to see who did the change at what time and date.

5.2.1.1 Pre- and Post-Trip Log/Report

Some predefined parameters (owner's choice—changeable at site) of approximately 200−300 tags (for medium- and large-sized plants) with 50−150 readings for each of them are logged in a pre-trip and post-trip log. Naturally suitable memory space is created to collect these readings so that 50−150 prior readings at a predefined interval (normally onsite modifiable), just before the trip, can be reported in the pre-trip Log. This method is similar for the post-trip log. Trips of major system/equipment (four to five−system dependent) are assigned for such pre- and post-trips, e.g., boiler, turbine, generator, BFP, etc.

5.2.1.2 Start-Up and Shut-Down Log

During major equipment start-up such as for a boiler turbine, a number of parameters needs to be monitored. Such parameters are also logged immediately after initiation of start-up and control shut down of the equipment/systems. These log types are also similar to the pre- and post-trip logs discussed above. For a boiler and a turbine start-up/shut down metal temperature play a great role to indicate heat soaking, so the number of tags in these group log/repots will be greater and is decided by the owner as per recommendation of the main system manufacturer. DCS suppliers size the system to accommodate this, since heating surface and configuration vary greatly with boiler/turbine design and unit size.

5.2.1.3 Control/Operator (OP) Action Log

These are also event-based logs. Control actions such as manual intervention and forcing or bypassing a criterion will be logged with the time tag and person who tagged it. Similarly, whenever any database attribute, controller parameter, etc., is changed it is logged/reported with time and date stamping along with the record of the person who initiated the changes.

5.2.1.4 Diagnostic Log/Report

Any system fault diagnosed by the system is duly reported in diagnostic logs. Generally these logs/reports are not generated on just any printer; they are generated in printers specified for the system administrator. The exact format of such a log/report depends on the manufacturer, but general information such as device ID up to the card level, type of fault, date and time of such fault, any replacement suggestion, and time of fault rectification.

5.2.2 Maintenance Log/Report

Normally this is generated on demand. However, in certain cases the maintenance schedule is routinely produced on a time basis, such as after a certain interval (e.g., monthly). It gives the schedule of preventive maintenance and routine inspections for major equipment. Nearly 70−130 (depends on unit size and number of auxiliaries) pieces of equipment are included in medium-to large-sized plants. Information such as equipment tag, description, redundancy, loss due to down time, total running hours, current running hours prior to this schedule, and lubrication schedule are all logged. These log formats are designed as per owner's specifications.

5.2.3 Performance Log

This log contains the results of performance calculations. In most places these are treated as "On-demand Logs/Reports," but in many places such calculations are done routinely and log/reports are generated on a time basis. A daily performance log is not uncommon. In most of the cases such calculations are done by ASME/other international standards and the results are printed in a standard format.

5.2.4 Time-Based Log/Report

Shift daily logs/reports are time activated, which means they are generated at every time interval. However, these time-activated logs/reports can be stopped by authorized persons when they are not needed—if for some reason the unit is in long shut down then such logs can be deactivated. Normally hourly records of 200−350 points (may be subdivided into groups) are included in each of these logs/reports. The exact format for each of log depends on the manufacturer. Generally the information included in these logs/reports include date and time, source ID, description, value with unit, set point if any, and status including alarm/trip status, group ID, and any other relevant information. There can be monthly reports of a few selected parameters as defined by the user during the engineering stage.

5.2.5 On-Demand Log

Any screen display can normally be considered an on-demand log. Various summaries and trend logs are

www.EngineeringBooksPDF.com

examples of on-demand logs/reports. Normally 10–20 points in various groups (50–70) are included in the trend Log. These trendings could be of historical value also. Various summary displays can include functional group/subgroup summary, area summary, alarm/event summary, electrical drive summary, and cabinet wise I/O summary as part of the "process summary log/report." There can be a system summary log/report such as a scan summary, summary of constants, summary of substituted values, and fault diagnostic summary.

5.2.6 Log Generation

This is a utility program that normally all mid- to large-sized systems have. This makes it possible for the user to generate a set of logs/reports utilizing the database of the systems as well as some assigned constants, any offline manually entered value/parameter, etc. Each of the system suppliers has their own system rule to enter such parameters/constants manually for generation of a log/report group. Normally 8–16 such groups are permitted by various systems. The following facilities are normally included in these systems to help the owner generate logs/reports:

- Header Information date and time.
- Selection of point tag from the database (both point tag and/or calculated value in the system) for a particular log/report group/type. Selection of data collection intervals with various assigned collection frequency such as 1, 2, 5, 10, 15, 30, 60, and 120 minutes. If necessary, the intervals can be at a faster rate for each log/report group separately.
- For predefined point tags 80–120 can be arranged in different log/report groups, with a faster rate of collection frequency in the order of 1, 2, 5, 10, 15, and 30 sec, which are very helpful during start-up.
- Free choice of initiating the event for such data collection at the above defined rates, as well as use of calculated values for such logs/reports. Not only event oriented, these logs/reports can be time based and/or both time and event based (after event initiation for a particular period as defined by the user and permitted by the manufacturer). For time-based logs/reports such printing intervals are user selected.
- Freely assigned samples for each database and selection of average/maximum/minimum samples over a predefined period of time is possible.

Apart from the system suppliers' own automation software, now various other third-party software is available. These provide a development and runtime environment for process information management for HMI and SCADA applications, with advanced historian and optimization utility and powerful graphics. Normally these are part of an MIS server and support DCS protocols for MIS utilization, direct log collections with tight integration with advanced historians, and/or controls.

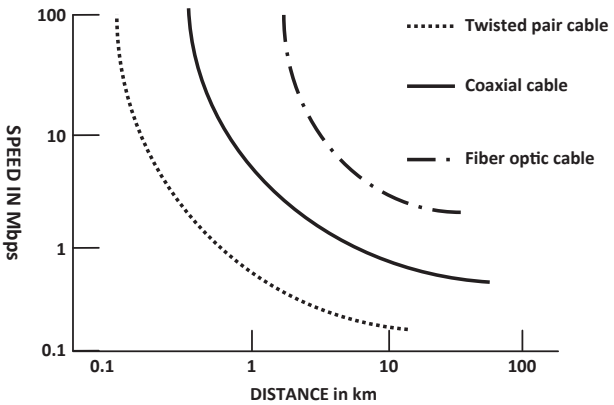


FIGURE VII/5.3.1-1 Speed versus distance capabilities.

5.3 Configuration and Communication: Introduction

DCS is initially built around the controller, I/O workstations, historians, and configurator, which have evolved a great deal. This evolution process is ongoing. The major reason for such changes is the ever-increasing "performance: price ratio." The evolution of communication technology and its supportive components in the area of DCS have changed the fundamental configuration of DCS to a great extent. LAN, WAN networking, and the Internet contributed much to DCS communication and configurations. Ethernet, TCP/IP and OPC (See Clause 1.0) made it easier to integrate third-party items into the DCS network. Fieldbus technologies such as Foundation Fieldbus, PROFI bus (see Clause1.0), etc., have brought about a large change in DCS communication and configurations. For power plants, other factors like ever-increasing fuel costs, the need to reduce loss and energy savings, and statutory regulation to reduce environmental impact further accelerated the process of system integration for smoother data exchange and communication to facilitate central monitoring as well as operation and maintenance from various remote places. These integrations also help in interfacing DCS with a company's Enterprise Resource Planning (ERP) projects.

As stated earlier, with the development of the Fieldbus much of the time-consuming data exchange and control have traveled to the field giving rise to further functional and geographical distribution and hybrid control systems. Before any further details about networking, a brief discussion on wire communication is undertaken below.

www.EngineeringBooksPDF.com

TABLE VII/5.3.1.1-1 Cat Cable (and Connector) Short Specification and Comparison

Specification	Cat 5 UTP	Cat 6 UTP	Cat 5 STP	Cat 7ScTP
Conductor size Φ in mm	0.5	0.56	AWG24×7	27AWG
Pair (×2)	4X2			
Insulation	PVC/PE/FRLS0H			
Data rate (MHz)	100	250	600	600
Length (m)	100	100	70	100
LAN	100Base Tx **5E** -1000Base T	1000BaseT		10GBase
Attenuation dB/100 m	22	32		
IEC standard	IEC61156-5			
Connector	RJ45			GG45
ISO classification	D	E	D	F

UTP, unscreen twisted pair; *STP/ScTP, screen twisted pair; FRLS0H, fire resistance low smoke 0 halogen

TABLE VII/5.3.1.1-2 Common Fieldbus Cable Short Specification and Comparison

Specification	PROFIBUS	Foundation Fieldbus
Conductor material)	Annealed copper solid/stranded	
Size (Φ mm)	0.64—22AWG	1.05 (AWG −1.6 (AWG14)
Pairs	4×2	2×2, 1×4
Insulation	Foamed PE/PE/PVC	
Type	Twisted pair	
Shield and copper drain wire	Aluminum foil + metal side copper drain wire(Φ 0.15mm)	
Standards	IEC 60332(flame) and 61158	
Outer jacket	PVC/thermoplastic	
Impedance Ω/km	∼110	100
Attenuation	∼40 dB/km	<3 dB/km (maximum 20 dB/km)

5.3.1 Communication Medium

Out of various kinds of cables used, twisted pair, coaxial, and fiber optic are the most popular. Twisted pair cables, depending on communication speed allowed, are separated into several categories (Cat 3, 5, 5e, 6, 7, etc.) and are commonly used in network systems. Figure VII/5.3.1-1 shows a variation of communication speed with distance for the various types of wires/cables discussed above. These curves are indicative only to gain an idea about variations among the different types of cables.

5.3.1.1 Twisted Pair Cable Category (Cat Cable)

Being moderately rugged in construction, easy to install and repair, moderately noise immune (when shielded), standardized, and low cost made this category of communication medium most popular. All Cat cables (mainly Cat 5, 6, and 7 cables), fall under the twisted pair cable category. Table VII/5.3.1.1-1 gives a short specification and comparison of these cables (Chapter XII, Clause 4.5.4 and the manufacturer's catalog for details).

Each of these Fieldbus cables has defined data transmission rates and distance limitations (see Clauses 1.6 and 1.8) for PROFIBUS and Foundation Fieldbus, respectively. For further details, see manufacturer's catalog/data sheet and Table VII/5.3.1.1-2.

5.3.1.2 Coaxial cable

Thin Coax is used in 10BASE2 Ethernet, meaning a maximum distance of 200 m. Normally AWG 14−18 solid copper with approximate resistance 100 Ω/km is used. These cables have an attenuation of 14 dB at 31.5 MHz/22 dB 100 MHz/100 m. Braided copper wire is used as a shield making the overall all diameter ∼6.75 mm 85% with shield. Black vinyl is used as outer the sheath. For connections, BNC connectors are used.

5.3.1.3 Fiber Optics

Single or multiple optical fibers are quite often used in computer networks as a communication medium. Fiber

www.EngineeringBooksPDF.com

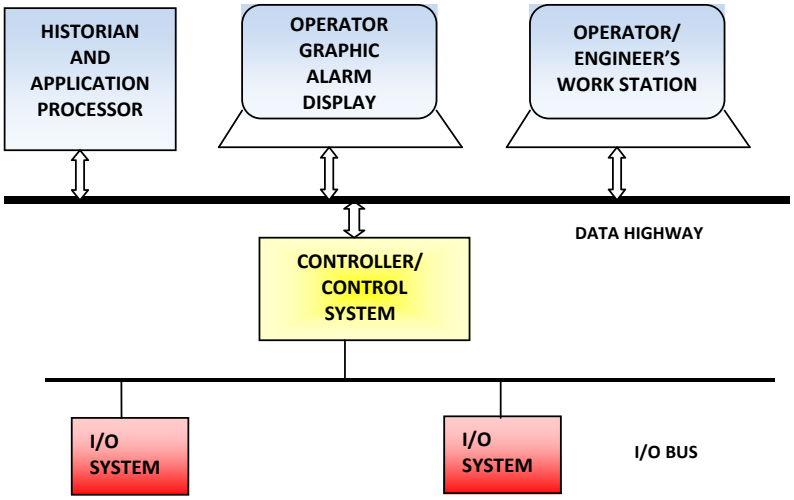


FIGURE VII/5.3.2-1 Basic functional structure of DCS.

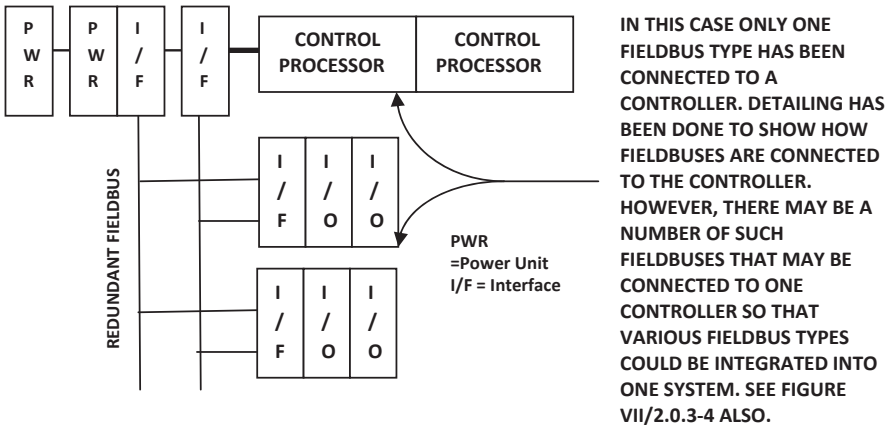


FIGURE VII/5.3.2-2 Redundant Fieldbus, I/O with redundant controller.

optics finds its applications both in industrial Ethernet and Fieldbus. Four or six fibers with a core diameter of 62.5 µm and with cladding 125 µm are quite popular. Normally 1000 MHz is the bandwidth with attenuation ∼1 dB/km. Snap-type connectors are mostly used. Connectors can be FC, LC, SC, ST, MTRJ, and V pin types. For further see Chapter XII, Clause 4.5.4 and the manufacturer's catalog/ data sheet.

5.3.2 Control Network Structure

In its basic form the control network for DCS consists of three basic layers, as shown in Figure VII/5.3.2-1. These layers are various I/Os, connected to the controller via I/O bus (to form the I/O system), controller/control system and Operator's control console, and application processors. The data from the controller are presented to the operator via the data highway. On the data highway there is one historian and application processor connected to carry out miscellaneous functions such as trending, performance calculations, etc. There could be redundancy at various levels (e.g., at the operator's workstation and I/O level) similar to that seen in Figure VII/2.0.3-2. As discussed earlier, there may be smart devices such as IEDs and transmitters connected to the system via Fieldbus, as shown in Figure VII/5.3.2-2.

Integration of various system buses into the systems is shown in Figure VII/5.3.2-3. In this case the industrial Ethernet created at the top is responsible for control, monitoring, and supervision since all MMIs are at that level. In the drawing a number of controllers have been shown, which could be OLCS/CLCS or an intermix,

www.EngineeringBooksPDF.com

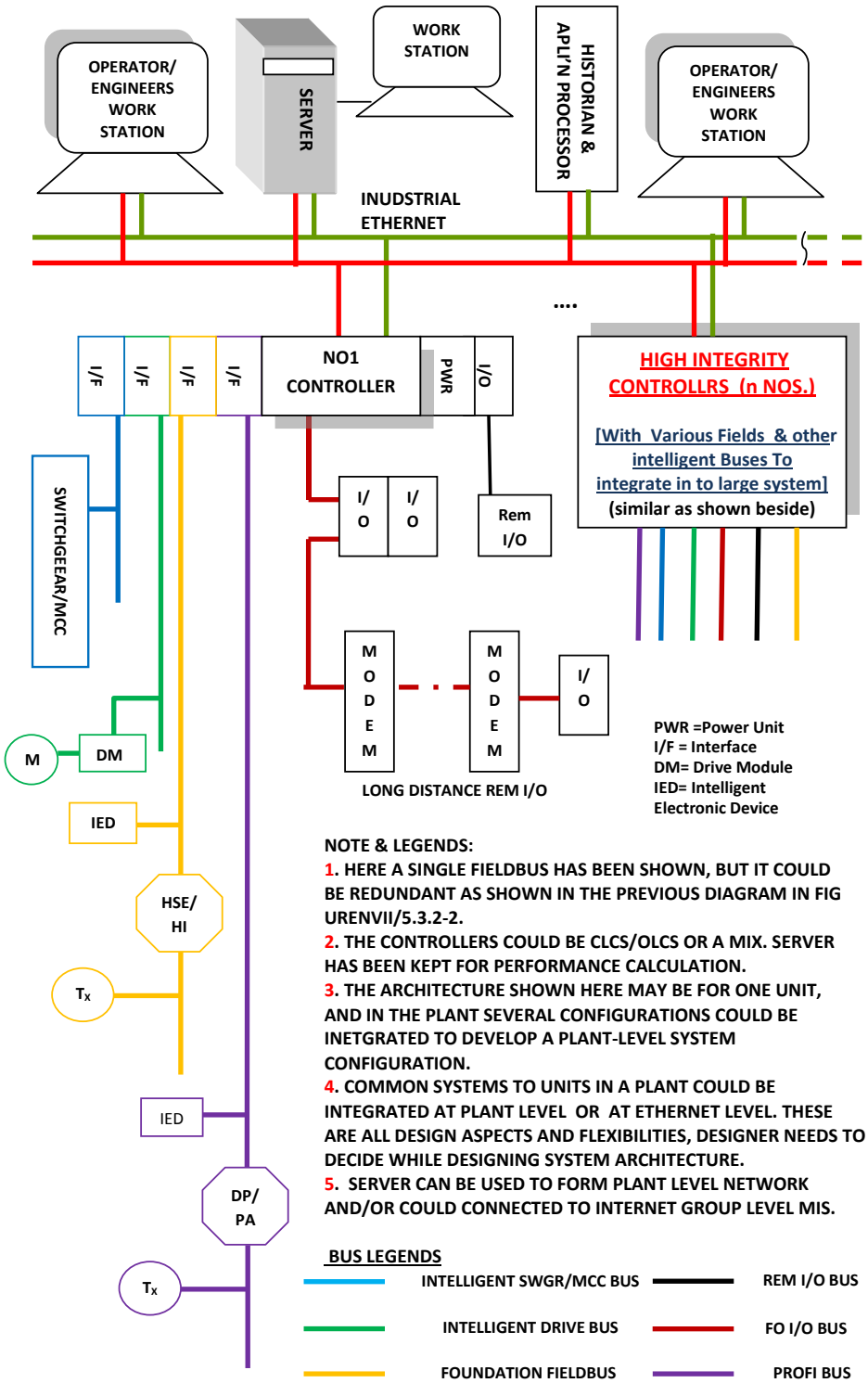


FIGURE VII/5.3.2-3 Integrated DCS.

depending on the manufacturer's system and owner's choice for the particular application. These controller divisions could be on a process or area basis also. The configuration in Figure VII/5.3.2-3 is for one unit, and similar units could be integrated to form a plant network with a common server and/or application processor. A system to form a plant level network is shown in Figure VII/5.3.2-4. Common offsite/systems to the units

www.EngineeringBooksPDF.com

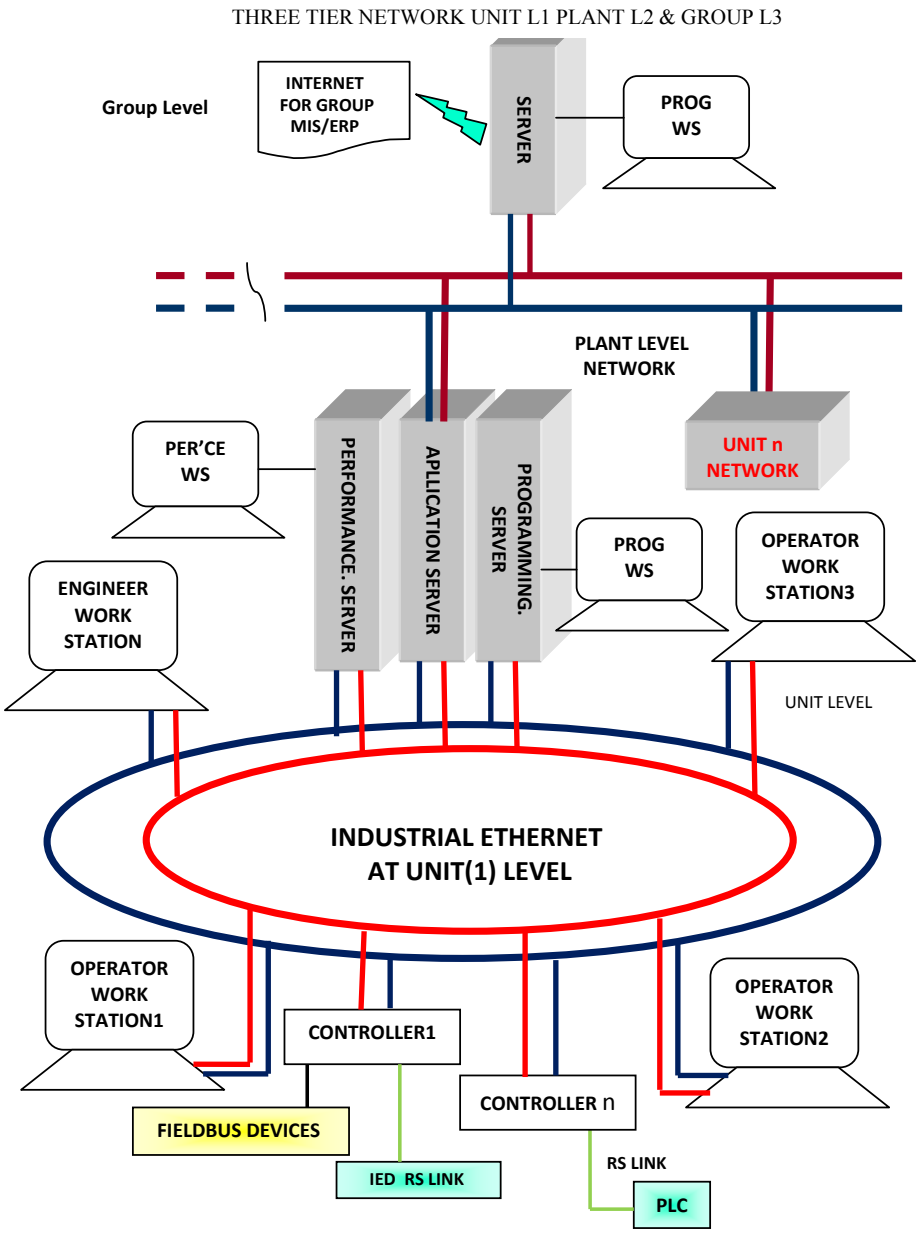


FIGURE VII/5.3.2-4 Plant-level network and interface to MIS.

may interface at that common level. For fewer units the industrial Ethernet may be extended to form a single network, and common systems may be interfaced via one controller of the Ethernet.

Figure VII/5.3.2-4 illustrates three-level structures of the DCS. The first level pertains to a unit with three operator stations and one engineering station and a performance server for one unit (say unit 1). The second level is plant level. At this level various units (*n* units) have been connected at a common network. Also common systems and offsite control systems interface at this level so they can be utilized by the operator of various units. Also at this level data exchange between the two units is possible (e.g., at the start-up time the unit may check the auxiliary steam header condition of the other unit and may open the interconnecting valve to take the supply from the other unit for starting). The third level is the group level wherefrom information exchange with the central office is possible or the load distribution program, etc., can be run. Also various MIS and ERP programs, run by the group, can interface at this level. Below is a list of the three layers of controls and monitoring.

www.EngineeringBooksPDF.com

- *MIS or group level layer*: Top layer where all MIS services, ERP interfaces, etc., are done through a remote network and/or Internet so that from a central place all managerial functions can be done, supervised, and/or advised. Also, units may get the load demand for LDS through this level.
- *SIS or plant level layer*: This is where production management at the plant level is carried out. Also here resource sharing between the units is possible.
- *Control and monitoring or Unit layer*: The bottom-most layer is for control and monitoring of individual units and/or local process monitoring and control.

5.3.3 System Configuration Aspects

There are many aspects considered when configuring or designing a system architecture for DCS. These components include the following:

- Physical configuration
- Control and monitoring strategy
- Safety and security
- Historian
- Integration
- Communication

Merely connecting various DCS components does not mean configuration. Actually configuration basically means generation of a huge database that enables the user to create and modify the control functions and downloading it to the controllers from the programming unit (the programming console or portable configurator plug into the system) via DCS. These configurations are not restricted to the controller alone; they can be an operator's interface, display types, or even field devices such as an IED, field transmitters, etc. So configuration is the strategy imparted to the system/unit so that it can operate in a desired way.

5.3.3.1 Physical Configuration

This involves connecting various nodes, devices, and cards by linking and structuring data. Many of these systems can auto sensing, making configurations easier, or the systems sometime suggest such linking to make the task easier.

5.3.3.2 Control Strategy

A piece of information is useless unless it is known what it is and how it would benefit the target. In DCS, provisions should be there to consistently reference and represent the information (tag). With the help of this tag and information structure it is possible to apply it to developing the control strategy. Normally this information is independent of the basic physical device. To calculate "how much HFO is consumed" one may call up F0011 CALHFO, which will give an output as the difference of say two inputs from FT 0011A and 0011B. This tag is the independent transmitter type and is only related to the tag.

Modern DCSs support multiple languages to include various function blocks, sequencing chart text ladder diagrams, signal flow charts, etc., in line with international standard for control programming IEC 61131. Most of the control strategies in modern DCSs support advanced and safety functions. The quality of the DCS varies greatly with the quantity, types, and variety of/function/algorithm library supported by the system (see Table VII/4.0-1). Built-in sub programs/subroutines and the function library make project engineers' work much easier and also enhances the power of the system in implementing advance control strategies. A power plant is a fast-acting, continuous process and power plant control loops are very interactive. So there is a complexity in control strategies for power plant control loops. Therefore systems with plenty of functional library will be very helpful. DCS systems should have online adjustment and up graded features also. Time-tagged data for alarm and event management are very important for power plant DCSs. As discussed earlier, all of these must be displayed with proper attributes such as SOE (alarm, acknowledged, unacknowledged, priority, alarm value set point, etc.) and operator ability to suppress and filter alarms is a general feature (see ISA S50 and IEC 61804 for Fieldbus). Alarm management, including creation and management of active alarms, pre- and post-trip alarm, priority alarm, and SOE are important monitoring strategies. Update alert and discrete alert are also important aspects. Whenever a system is upgraded the existing system information is necessary to update the operator to highlight the changes.

5.3.3.3 Safety and Security

Safety of the system comes from the ability to diagnose the problem, and in case of failure, to fall back in to a system when the system can run safely. *System diagnostics* play a major role. Diagnostics covers hardware, controls, communication, and software. Normally I/Os and controllers have self-diagnostic features. In certain cases there are fault LEDs at the module level, and in some cases separate diagnostics reporting HMI is used as shown in Figures VII/2.0.3-3and VII/2.0.3-4 (Clause 2.0.3, number 4 is also applicable here). In case of actual failure, the system has to fall back on the redundant system.

Redundancy and fault tolerant system: To tolerate failure and at the same time offer safety, redundancy is necessary. There is redundancy at the I/O, controller, and communication level. In case of controller redundancy, it is necessary to make sure that whenever such fall back action takes place there is no bump in the system. So naturally the redundant controllers have to follow each other. In communication

www.EngineeringBooksPDF.com

redundancy the system checks this type of failure by various means, e.g., the easiest one could be check sum. See Clause 2.0.3, number 2, for applicability. In case of redundancy, it is easier to upgrade the system online. However, precaution both in hardware as well as in software is necessary so that the system is not endangered from online upgrading.

System Security: For integrated SCADA security is extremely important. Identification of user, authentication, and area/system wise security are an extremely important aspect in a computer network. Security discussed in Table VII/2.0.3-1 is applicable here. Apart from that, each user must have a user account to work in the network with a suitable ID for use in a well-defined area/system scope. There can be a number of levels of access in a network. There is at least segregation of work and access among operators, shift charge engineers, control engineers, programmers, etc. Normally any modification done in the system is properly recorded with a user ID and time of change. (see Clause 4.0.2). Password protection is the most common way to restrict such access. Also there may be access restriction system wide, e.g., a water treatment operator can access the network to know the status of the main plant condition but cannot modify any data. For SCADA additional security against cyber crime as discussed in Clause 2.4.5 is important.

5.3.3.4 Historian

All DCS have the ability to collect and store plant data and event records. In modern systems this is an integral part of the system for generating various IS functions. All pre- and post-trip analysis and process failure analysis would be meaningless and/or impossible without historians. For generating trends and various IS/MIS operations the historian plays a vital role.

5.3.3.5 Integration

As already discussed and shown in Figures VII/5.3.2-2 through VII/5.3.2-4, there is a complete integration of various Fieldbus systems and other systems. System integration discussed in Clause 2.0.3, number 3, is also applicable here and Clause 5.3.2 discussed above also portrays the benefit of system integration. Drastic reduction of cable cost and decentralization of many functions in field instruments following IEC 1158-2 standard made Fieldbus integration with DCS smoother. The OPC-defined standard makes it possible to access information in the other control systems, making system integration even easier.

5.3.3.6 Communication

A communication network is like physiological functions in a body. Industrial IT-compatible instruments/devices make it possible for global access to the system (e.g., remote fault finding and repair). This aspect is very good and makes the life easier, but there is a greater security threat. Various functions of communication system can be summarized as follows:

- *Physical connection*: Hardware connection of various nodes.
- *Real-time data exchange*: Exchange of real information across the network.
- *Various modes of transfer*: Both asynchronous as well synchronous data transfer, and read write operation among various subsystems and components.
- *Message broadcast*: Hosted messages are broadcast over all subsystems.
- *Upload and download*: Various configurations when permitted can be downloaded to various nodes. Similarly, required data from the network could be uploaded for MIS.
- *Auto sensing and rearrangement*: Whenever a new controller is put in to the system and/or whenever a node is dropped, the communication system detects it and rearranges the network for communication.
- *Debugging and diagnostics*: It has the ability to debug the system and report. Diagnostic reports are communicated over the network.
- *Search function*: Communication systems make it possible to pinpoint a node, component, and control strategy over the network.
- *Online upgrade*: Online DCS upgradability without disturbing normal operation.
- Restarting strategy: Cold/warm/hot start strategies can be implemented.
- *Alarm and event*: Process, system, and device failure alarms and events are generated and communicated over communication systems to various parts of the network.
- *Security*: All access must be secured, otherwise communication system wills not allow any such access or communication.
- *Time*: To get a meaningful record it is necessary that all devices and nodes in the network are time synchronized.
- *Variety*: There are varieties of networks and associated communications.

It is clear that communication software has to work at its best to keep process data fresh and to be used by various clients. Modern digital networks can be conceived as shown in Figure VII/5.3.3-1. Here in this architecture there are basically three networks: field, control, and information network. While the field network is mainly concerned with field devices and local controller, the control network is the main control system doing all group control, performance calculation, and alarm and other

www.EngineeringBooksPDF.com

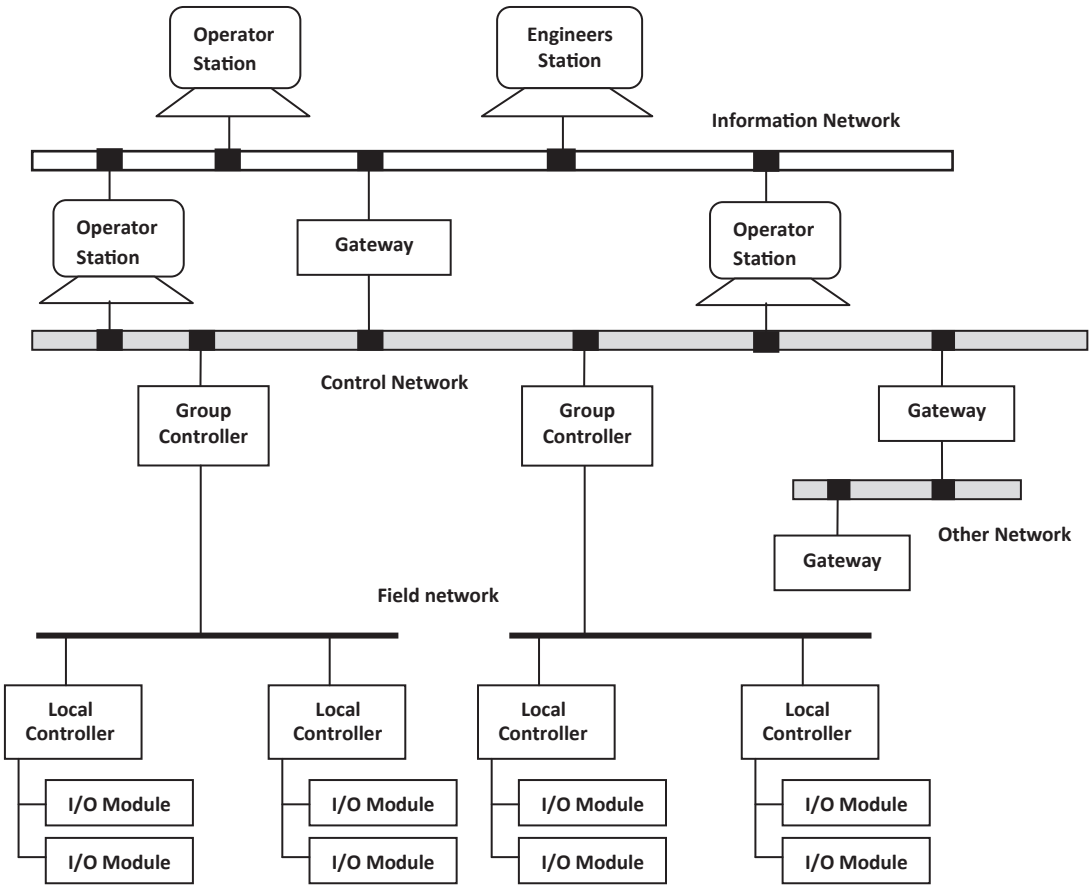


FIGURE VII/5.3.3-1 Hierarchical system architecture.

monitoring with operator interface. The third network is supervisory and information management. There are several network variations and possibilities as discussed such as Ethernet, Device Net, Control Net, PROFINET, FDDI, etc. Out of these, Gigabit Ethernet is the most popular. However, each of network has different protocols to manage each respective system. The aim of all these protocols is to ensure network quality services, which service depend mainly on the following:

- Predicting time delay of the network
- Improving throughput of the network
- Network utilization
- Networking efficiency
- Medium access control
- Message scheduling
- Minimize lost data, etc.

The timing component is a vital issue in network communication. In a network time delay can be conceived as a device delay and a network delay. A device delay has two parts, source device delay and destination device delay. At the source there two delays: preprocessing delay (T_{Preprop}) and waiting delay (T_{wait}). For destination delay there is only postprocessing delay (T_{Postprop}), while network delay includes total transmission delay (T_{Tx}) and propagation delay. If the transmission rate is 3×108 m/s, the propagation delay can be ignored.

$$\text{Total Delay}: \; T_{\text{Delay}} = T_{\text{Preprop}} + T_{\text{Wait}} + T_{\text{Tx}} + T_{\text{Postprop}}$$

See Table VII/5.3.3-1 for time delay significance.

In network communication these timing considerations are important. Controller performance is normally evaluated by integrated absolute error (IAE) or integral time multiplied by absolute error (ITAE), which depends highly on the sampling period when a common transmission medium is shared by various devices. Sampling period influences phase margin and bandwidth (BW), which is directly related to controller performance.

As discussed previously, because of interactions of network and control requirements, selection of the best sampling period is really difficult, so there must be a compromise so that both services can be optimized. This is because a smaller, better sampling period is the controller performance, whereas in a limited BW network,

www.EngineeringBooksPDF.com

TABLE VII/5.3.3-1 Time Delay Significance

Terms	What Is It?	Remarks
Preprocessing delay	Time needed at source to acquire data from external environment and encoding the same into data format of the network	This is dependent on HW and SW characteristics of the device and may vary in nature and may be noticeable
Waiting delay	Waiting time in queue at source/ sender's buffer	Depends on source node traffic and network traffic and may not be significant
Post-processing delay	Time needed at destination to decode network data in to physical data	
Transmission delay	It is time required for transmission. T_{Tx} = Message Size (N) XBit time + propagation delay (negligible)	Deterministic parameter; it depends on data rate, message size, and node-to-node distance

high-frequency communication may jeopardize network quality service. So there has to balance between the two (see *Network Design Consideration for Distributed Control Systems* by Feng Li Lian, James Moyen, and Dawn Tilbury).

6. MIS: INTRODUCTION

The target of all electric companies is to enhance production and work efficiency and reduce overall cost. MIS is an effort to meet this target. In this chapter a brief discussion about this was presented to study the various systems that can be integrated with the plant DCS. The shop floor automations/DCSs have been realized in seamless connection with upper management systems of the enterprise. For utility enterprises, systems controlling critical infrastructure for electricity generation, transmission, distribution, etc., can no longer be isolated. For substations, remote-located pump house (e.g., raw water pump house) network-based access reduces operational cost by enabling remote monitoring and maintenance. Audit report generation, data gathering, etc., can be achieved by this. All of these drastically reduce the cost. Now if these are also integrated with supply and material management and account management, there be high cost reduction and better control of the entire operation. Mid to large enterprises may have various data processing/ERP software projects such as SAP (which is beyond the scope of this book). In this clause DCS interfaces to these systems, i.e., seamless connections to the upper level management systems will be discussed. In most of the cases these systems were originally developed for a non-networking environment for threats from Internet-based systems. In DCS/SCADA safety is inbuilt for machine fail-safe operations. However, there may be a cyber attack, which may mislead and jeopardize the entire operation. There have been instances that complete safety has been overridden purely due to cyber attack, so security is of

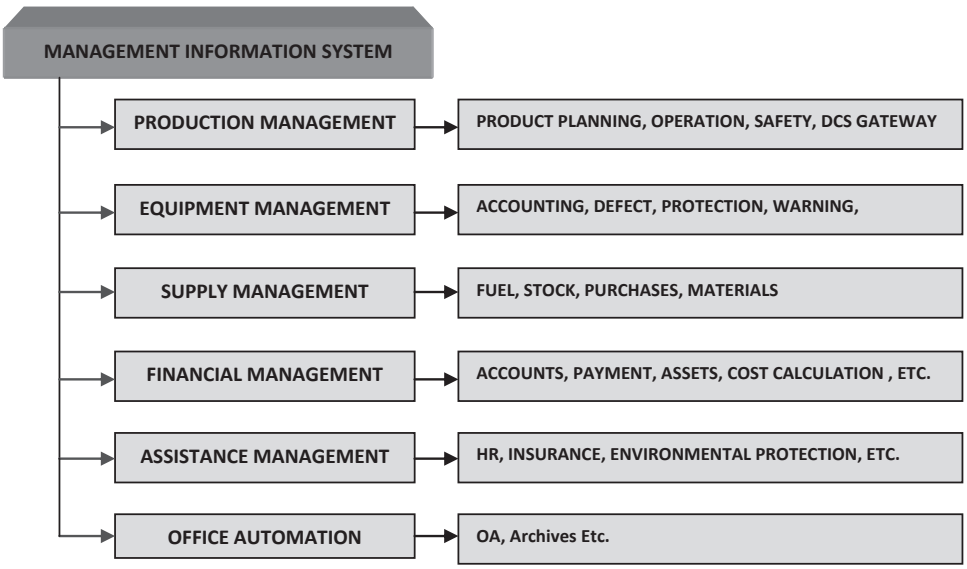


FIGURE VII/6.0-1 MIS profile.

www.EngineeringBooksPDF.com

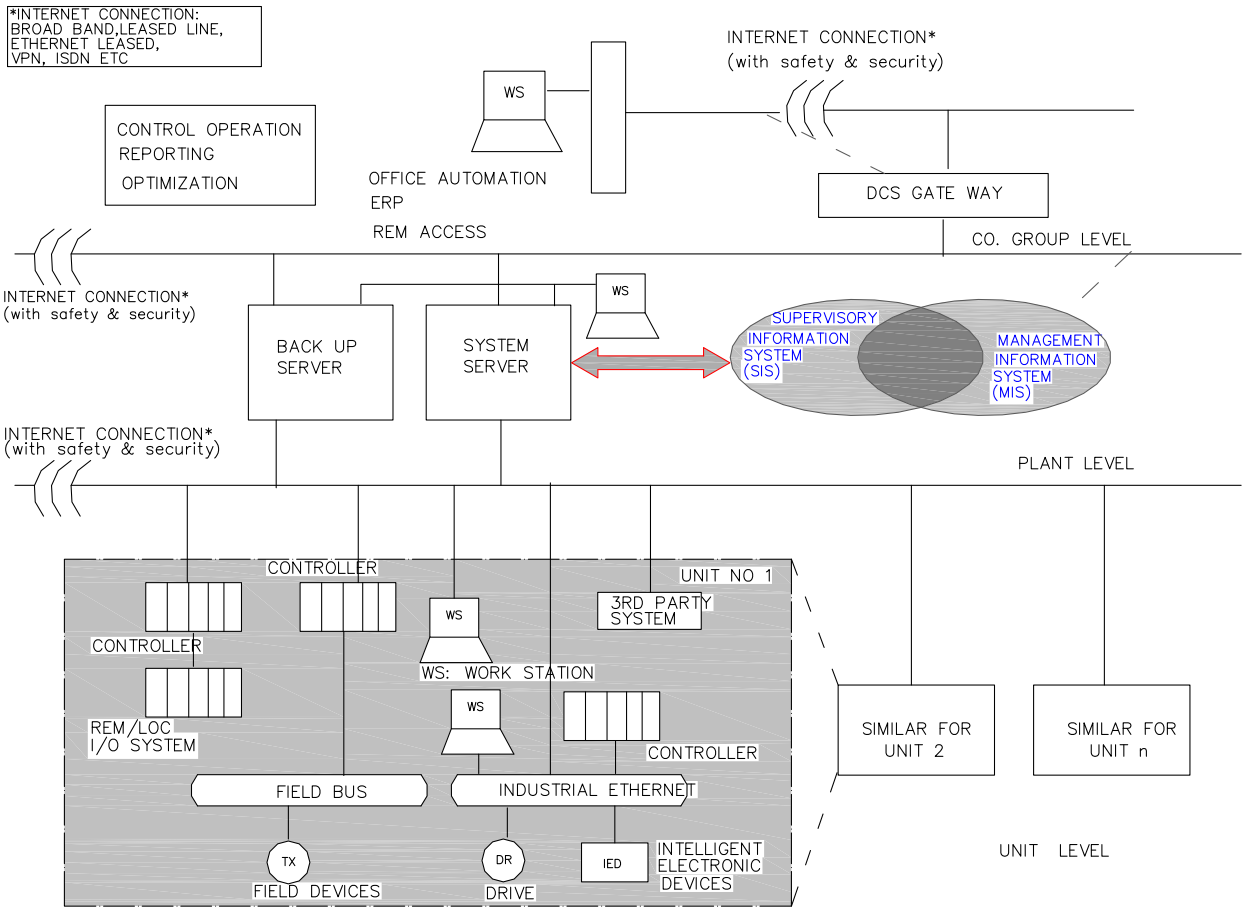


FIGURE VII/6.0-2 Position of MIS (with SIS).

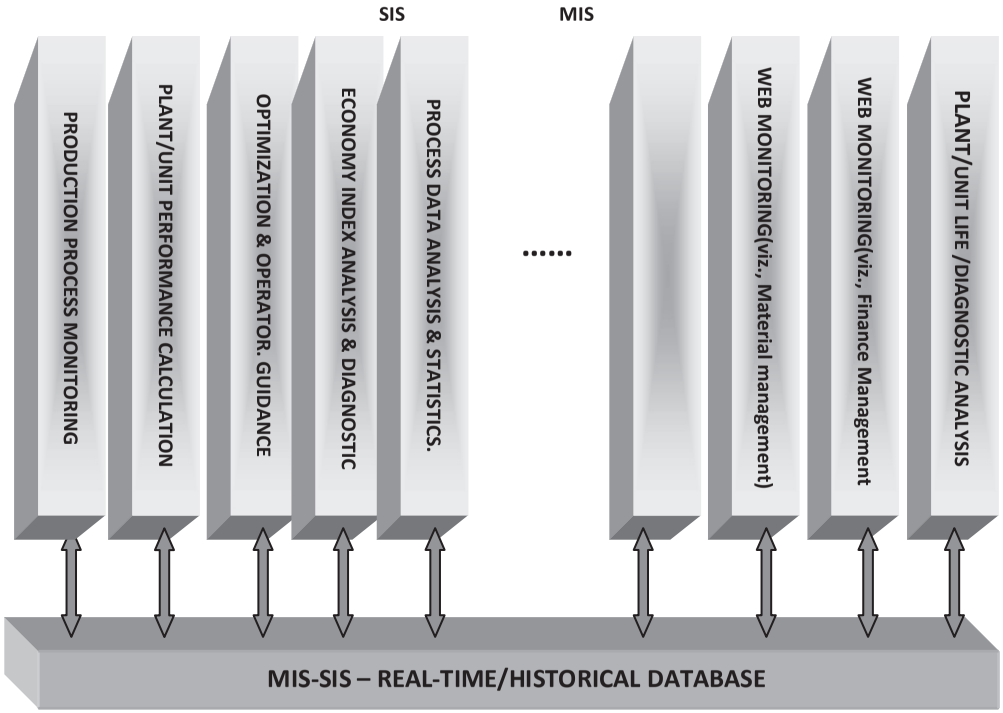


FIGURE VII/6.0-3 Main application functionality (MIS).

www.EngineeringBooksPDF.com

great concern (see Clause 2.4). Primary concerns for any network include the following:

- Assurance of integrity of the network
- Control system-specific security policy
- Securing remote access
- Validation and authentication for every device and user on the network

6.0.1 MIS Characteristics

MIS needs to be economic and based on a network platform of Internet technology with high reliability, safety, and security.

For electric enterprises MIS characteristics are listed below:

- Conformance to electric power industry standard
- Tailored to unified reporting system standards for electric power companies
- Easy-to-use and consistent user interface
- Automatic production control with seamless connection with DCS gateway
- Strict monitoring and control of environmental factors
- Real-time monitoring and control including log operation
- Automatic monitoring and control of material management including fuel supplies
- Effective maintenance management functionality
- Accurate cost calculation and financial management
- State-of-the-art technology and to support ERP and data processing systems
- Future-oriented platform for process control, especially for electric enterprises

Upper management programs interfacing with a DCS is shown in Figure VII/6.0-1.

6.0.2 MIS Position and Functionality

With respect to the complete network, it lies in between unit level and company group level as shown in Figure VII/6.0-2. The database at the server level constitutes Supervisory Information System (SIS), which is basically related to production monitoring and control. However, various upper management program data exchanges are done through MIS. Since SIS is a subsystem of the MIS database mainly for production monitoring and control, it can overlap, as shown in Figure VII/6.0-2.

Again unit and plant performance calculation as well as optimization are also done using these databases. This is also a part of SIS. Since performance calculations and optimization are important subsystems of DCS, they need a fair bit of discussions, so they are discussed: separately in Clause 6.1. Main application functions of MIS with SIS are shown Figure VII/6.0-3.

Some of the SIS and MIS functions (Technical) include:

- *Supervision functions*: At the unit/plant level perform various calculations and make online calculations and display the result and/or analysis data for operator assistance.
- *Plant performance calculation and optimization*: Unit performance calculations and optimizations fall under this category and are discussed in Clause 6.1. Here production people become aware of the result of detailed analysis as well as the operator's guide. Automatic change of the set point is also possible in case it is allowed.
- *Production management*: On a daily, weekly, or monthly basis the heat and material balance calculations are performed to see the periodic yield and utility consumption. Validated data are compared with the target to see and minimize the deviations.
- *Economy index analysis*: At any instant plant performances of boiler efficiency, turbine heat rate, etc., are calculated and thereby cost analysis can be done to pinpoint the deviation. From this deviation, remedial measures can be suggested to minimize the cost. Variable cost on a daily basis can be calculated from validated and reconciled plant data.
- *Equipment health monitoring and predictive maintenance*: Major equipment and auxiliary equipment data are monitored to detect early failure and predictive maintenance. Thermographic images, vibration analysis, and lubrication oil sample data are displayed. Condition-based maintenance coordinator modules assess the situation to suggest the status of acceptable/watch/marginal/unacceptable conditions of equipment with suggestions for maintenance.
- *Maintenance scheduling*: Based on a reliability study and the guide and schedule for maintenance from the library of data for the industry standard.
- *Environment monitoring*: In this module the various acquired data are validated and generate pre-alarm and alarm emission limits with respect to the environment. It is possible to generate the necessary reports for public authorities.
- *Material management*: It manages all logistics at various arrival conditions. It is possible to link the material management functions from here. In most cases mid- to large-size plant owners with a number of plants opt for ERP projects. Thus to support the same data exchange from the MIS through DCS gateway is possible.
- *Web monitoring*: MIS supports the exchange of data from the MIS so that Web monitoring of the plant from a central place is possible. Also it supports the remote station (one substation and remote pump house) from the central control room of the plant.

www.EngineeringBooksPDF.com

6.1 Performance Calculation and Optimization: Introduction

It is quite possible that the a power plant does not operate at the design condition; naturally there will be deviations from the design plant efficiency and heat rate. Major influencing factor for this include:

- Variation in fuel properties
- Variation in fuel calorific value
- Process parameter variation
- Ambient variations
- Leakage factor
- Boiler tube failure
- Equipment degradation
- Improper controller tuning/failure
- Other mechanical problems

Therefore the performance calculation of SG/TG at regular interval is essential and system optimization needs to be performed to get the best results. Other suitable actions like regular soot blowing leads to a savings of ~2.2%. Basic plant optimization consists of optimizations of major equipment and systems such as SG,TG, feed water heater, condenser, etc.

6.1.1 Calculations

In power plants there are various types of calculations:

- Class I calculation
- Class II calculation
- Other miscellaneous calculations

Class I calculations: These are mainly equipment-protecting calculations for detection and alarming:

- CRH Steam approach to saturation temperature
- SH spray O/L approach to saturation temperature
- Feed water heater temperature deviation from standard
- Drum saturation temperature rate of change
- Turbine rate of temperature rate of change
- Excess air deviation from standard
- Turbine steam−metal temperature difference

Class II calculations: These are performance calculations of equipment along with heat rate deviations, revenue calculations, tariff, etc.:

- Boiler efficiency
- Gross TG heat rate and deviation
- Gross unit heat rate and deviation
- Net unit heat rate
- Condenser performance
- Deaerator performance
- CEP/BFP performance
- Economizer performance
- Air heater performance
- ID/FD fan efficiency
- Unit availability
- HP turbine enthalpy drop efficiency
- Intermediate pressure turbine enthalpy drop efficiency
- LP turbine enthalpy drop efficiency (dry exhaust)
- Feed water heater terminal temperature difference performance
- Feed water heater performance drain cooler approach

In each of the above calculations deviation from standard is also calculated. Net unit heat rate *V*s load profile using last value is interpolated at different load values.

Other miscellaneous calculations: Apart from the Class I and II calculations discussed above, there are a few other calculations that include but are not limited to: analog point sum/difference, average/maximum/minimum, selection of one analog point out of two or three, digital point status, duration of time at which an analog point is beyond a threshold, running point average of digital points, rate of change, time projection, variable alarm limit calculation, specific calculation needed for long-term storage, and other calculations like the following:

- Running hours of rotating machine
- Number of start/stop devices
- Plant calculation
- SH/RH creep (stress)
- Number of hot/warm/cold starts of the TG
- Cumulative running hours of TG beyond threshold steam alarm
- Cumulative running hours of bearing beyond threshold alarm

6.1.2 Standards

These performance calculations in the DCS are carried out in accordance with certain international standards. Various test codes such as ASME PTC 4 for SG and ASME PTC 6 for TG are the most popular. The following codes are widely used as references as they are mostly used by the manufacturers at testing facilities:

6.1.2.1 Steam Turbines

- *DIN 1943*: Thermal acceptance tests for steam turbines
- *BN EN 60953*: Rules for steam turbine thermal acceptance tests
- *ASME PTC 6*: Steam turbine performance test code
- *IEC 953*: Rules for steam turbine thermal acceptance tests

6.1.2.2 Gas Turbines

- *DIN 4341*: Acceptance rules for gas turbines
- *BS 3135*: Specification for gas turbine acceptance test

www.EngineeringBooksPDF.com

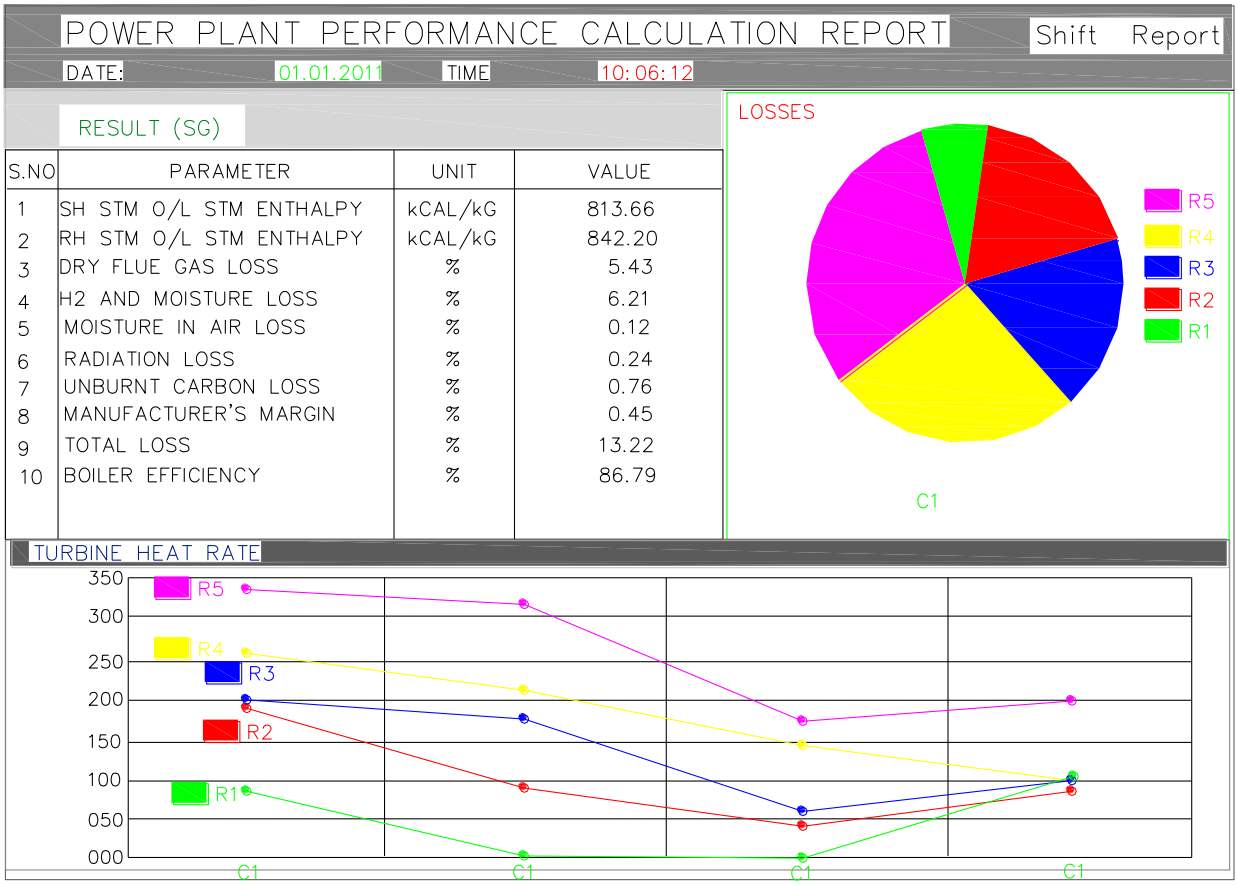


FIGURE VII/6.1-1 Performance calculation report (presentation) type I data with curve and chart. Inspired by document from: "Kalki Communication Technologies".

- *ASME PTC 22*: Gas turbine power plants—power test code
- *ISO 2314*: Gas turbines—acceptance tests
- *ISO 2314*: Acceptance tests for combined cycle power plants and amendments

6.1.2.3 Steam Boilers

- *ASME PTC 4.1*: Steam generating unit performance test code
- *ASME PTC 4.4*: Gas turbine heat-recovery steam generator performance test code
- *DIN 1942*: Acceptance test for SGs

6.1.2.4 Reciprocating Engines

- *IS:10000 Part IV-1980*: Method of tests for internal combustion engines
- Declaration of power, efficiency, fuel consumption, and lubricating oil consumption
- *IS:10000 Part VIII-1980*: Method of tests for Internal combustion engines
- Performance tests

6.1.3 Measuring Points

The measuring points (list also available in ASME PTC codes) and accuracy of measuring instruments are the same as mentioned in the latest versions of the applicable standard. Currently highly accurate instruments are easily available to cater to these requirements.

6.1.4 Data Presentation

Calculation results can be presented in the form of display and/or printouts. A typical printout is presented in Figures VII/6.1-1 and VII/6.1-2. In the report the synopsis of the calculation result of SG efficiency is presented with turbine heat rate with different losses. This presentation is based on "Kalki Communication Technologies" (communication

www.EngineeringBooksPDF.com

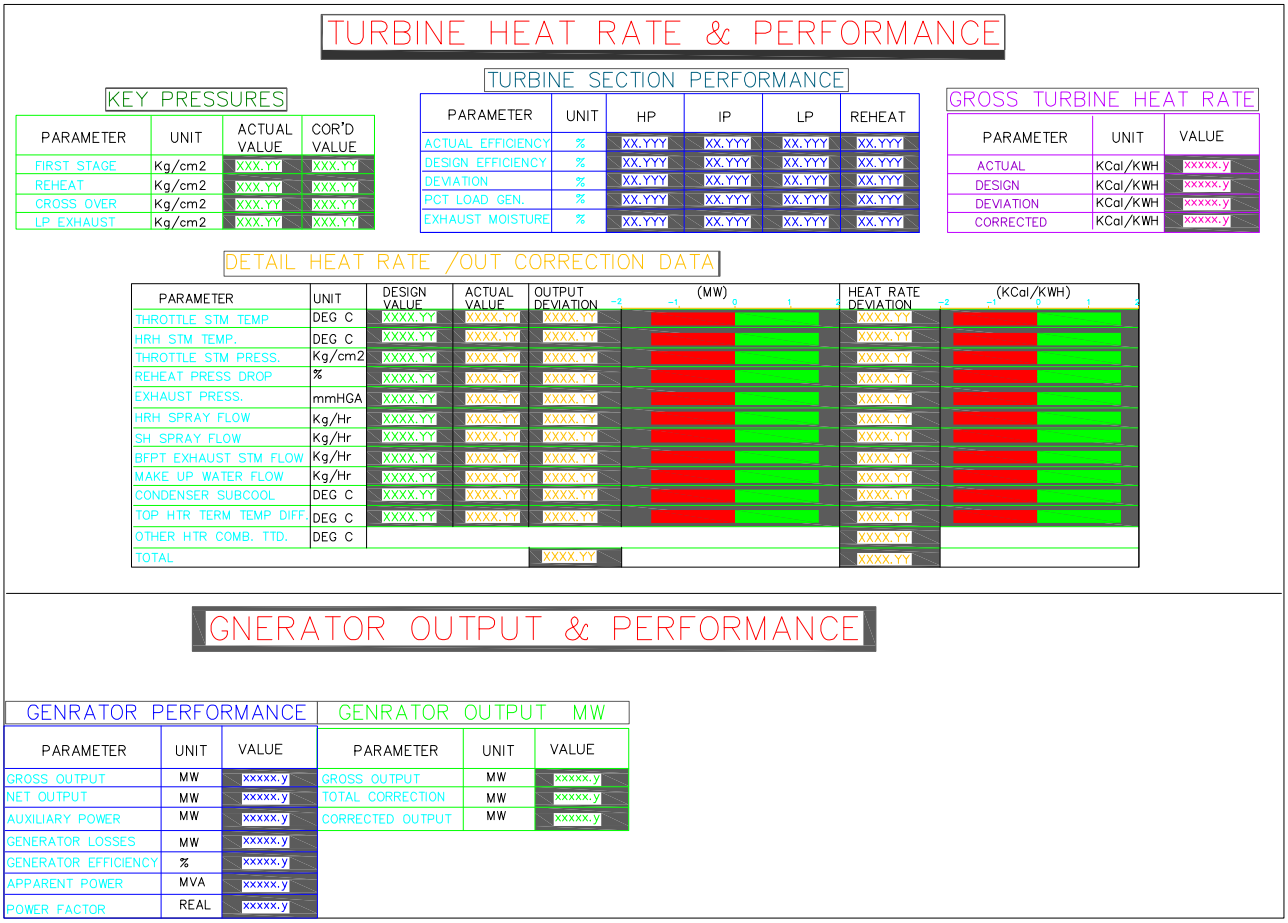


FIGURE VII/6.1-2 Performance calculation report (presentation) type II with data. Inspired by document from: "Kalki Communication Technologies"

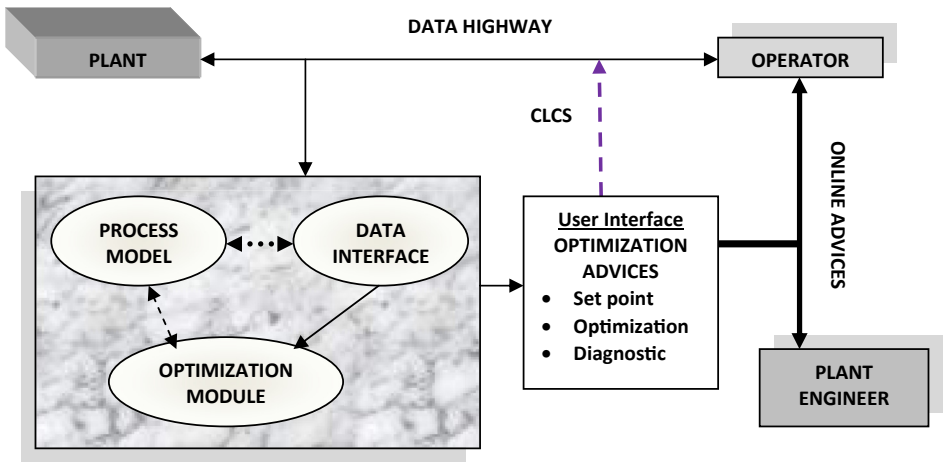


FIGURE VII/6.1.5-1 Typical optimization package interface.

www.EngineeringBooksPDF.com

and computing technology meant primarily for the energy sector). Different suppliers may have different formats but information content will be similar.

6.1.5 Optimization

Optimization packages may be a separate package that needs to be interfaced with DCS software or it may be supplied as part of the system. Technological development of DCS in conjunction with software development made it possible to enhance the optimization package. Artificial intelligence (see Clause 1.0) in the form of neural networks (NN) made it possible to frame a computer model to predict the best possible operations under given constraints. Most of these NNs work in a similar fashion in terms of their complexities, application, and interface with DCS. These performance packages are normally complete with performance analysis and diagnostic and optimization modules. Generic NOx Control Intelligent System (GNOCIS) is an example of this type of package. Several optimization packages are gaining popularity because of severe competition and pollution abatements. In the competitive market, when there is a rising trend for fuel price and many restrictions on pollution, operating personnel have no other choice but to find the ways and means to increase plant efficiency. There are several versions available commercially. In some cases the optimization package output is directly applied to the control system to automatically modify the set point, whereas in some cases these may be sent as guidance for the operator who will evaluate it in the perspective of overall gain.

Mill selection is a classic example: Mill selection may affect the performance as well as emission, so the pros and cons have to be evaluated before automatic selection and/or using guidance only. Operators can then base their decisions on actual conditions. Figure VII/6.1.5-1 shows that the plant data are acquired with the help of plant DCS and presented to the operator. The same data are fed to the optimization module after passing through a prediction model. An optimization package in conjunction with the process model advises plant-operating personnel on the best possible action and, if necessary, generates the best set point at that time under the plant-operating condition.

Basic scope of optimizations include but are not limited to the following:

- Optimization package belongs to overall plant production and automation process; even if it is a separate package it needs to be interfaced suitably.
- Building platform of unified process—real-time and historian database.
- To act as a bridge between production management and process control.
- Tapping potential of main and auxiliary equipment to realize optimization and reduce energy consumption.
- The tool for implementation of such optimization includes but is not limited to the following:
  - Information highway.
  - Huge database.
  - Production information portal—for process information development and application.
  - Power generation checklist—any instant cost of production.
  - Online economic analysis to analyze reason for increase in cost of production and find means to reduce the cost.
  - Use of NN.
  - Equipment health monitoring.

Actual implementation of the system is depicted in Figure VII/6.1.5-2. The operator receives the display from DCS as well as from the optimization package (as advice).

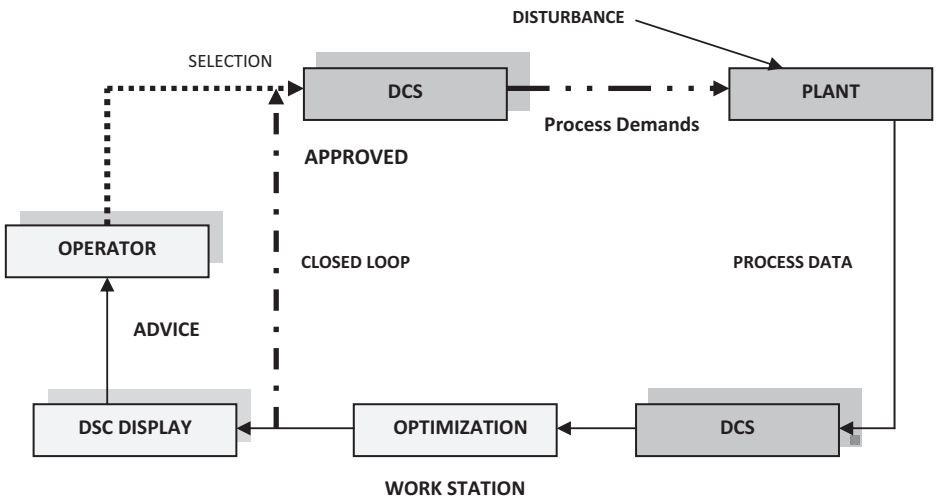


FIGURE VII/6.1.5-2 Optimization implementation.

www.EngineeringBooksPDF.com

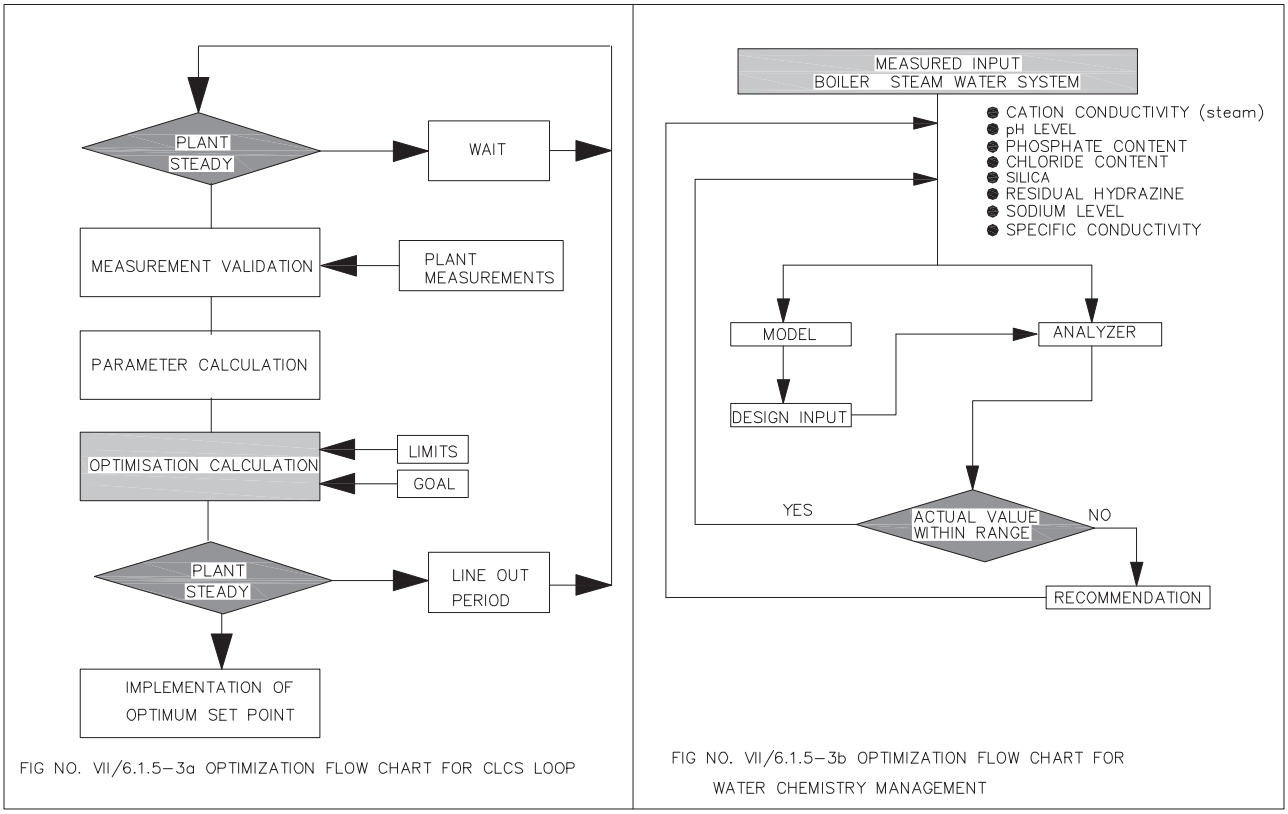


FIGURE VII/6.1.5-3 Optimization of flow charts.

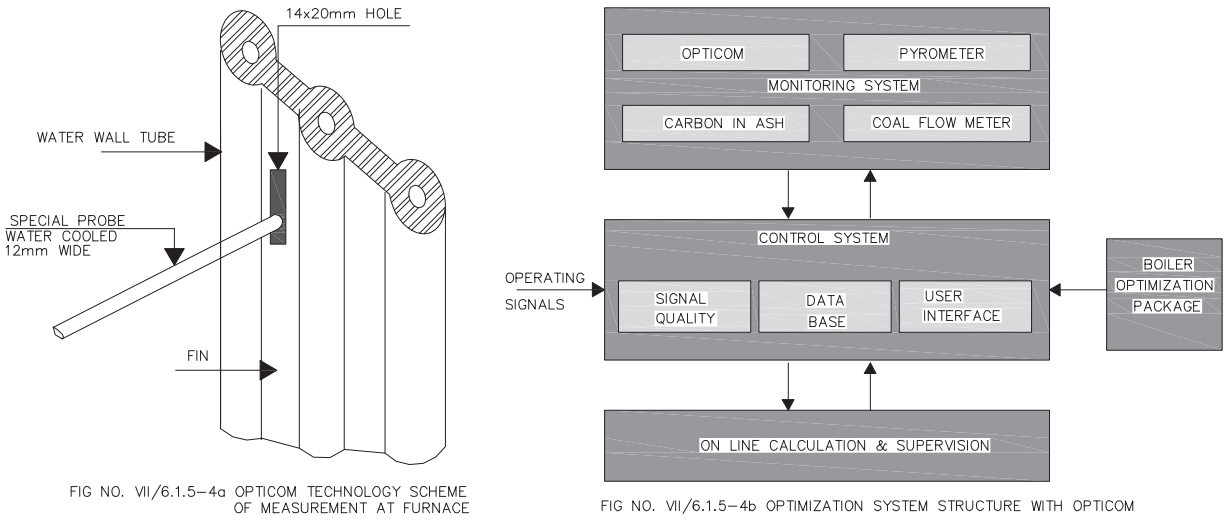


FIGURE VII/6.1.5-4 OPTICOM and boiler optimization. (Refer Short note on Opticom Figure: VII/6.1.5-6).

It is up to the operator to select judiciously. Also it is possible to automatically modify the closed-loop set point. A brief discussions on basic functionality of these optimization packages is presented in the following clause.

6.1.5.1 Functioning of Optimization Model

Implementation of these optimization and prediction modules can be thought of as per the following stages:

www.EngineeringBooksPDF.com

- *Initialization*: During this stage it gathers inputs from DCS and does the validation checks, before these can be transformed in to model variables such as excess O_2, total fuel flow, and boiler efficiency.
- *Transformed variables*: Are used to run the model in two modes:
- *Straight prediction mode*: Model is run to produce/calculate predicted O/P.
- *Optimization mode*: Goals and limits are fed and the model is run to achieve the desired goal under given limits optimally.

However, in both modes the adjustment biases are different. While prediction biases can be updated, optimization mode biases are constant for an overall impact on the entire system. So it is better to first go to the predicted mode to get the predicted output before correction, then model input, actual output, and predicted output are fed for gain bandwidth correction to update the models. A typical system flow diagram, with "limit" and "goal" settings, for various optimization packages, is depicted in Figure VII/6.1.5-3. Figure VII/6.1.5-3a shows the typical flow chart in connection with a CLCS loop while Figure VII/6.1.5-3b shows a flow chart for water chemistry management discussed later in this clause.

6.1.5.2 Boiler Optimization Package

Major workload for a boiler optimization package includes combustion control optimization to limit NO_X and CO emissions (see Figure VII/6.1.5-4). Under a rapid load-changing situation, there is a tendency for the emission levels to rise; NN models show appreciable improvement in this area with the help of real adaptive control to limit the emissions. For overall thermal efficiency, it is important to maintain SH and HRH temperature at the specified value. Now higher steam temperature not only degrades the boiler tube but also requires attemperation, which will reduce plant performance. NN-based models can optimize and balance burner tilt and attemperation via real-time adaptive control. As stated earlier, GNOCIS is an example of this optimization package/module.

As discussed previously, the main interface of the optimization package is to put forward a suitable display with all advices to clearly convey the recommended benefits and predictions. Operators based on plant-operating constraints set them to get the recommendation under a given sets of constraints. There are normally two sets of recommendations made available to the operator along with present plant conditions. In case of combustion optimization, the two recommendations could be (1) change current mill operation settings either automatically or individual manually if the recommendations are accepted by the operator or (2) optimum mills in service and associated emission benefits. Based on the predicted benefit the operator is to decide. A similar display is also be available to the plant engineers as shown in Figure VII/6.1.5-1. Similarly a closed loop can also be selected from an optimization workstation for set point controls. Energy saving by optimizing O_2 content in flue gas and flue gas

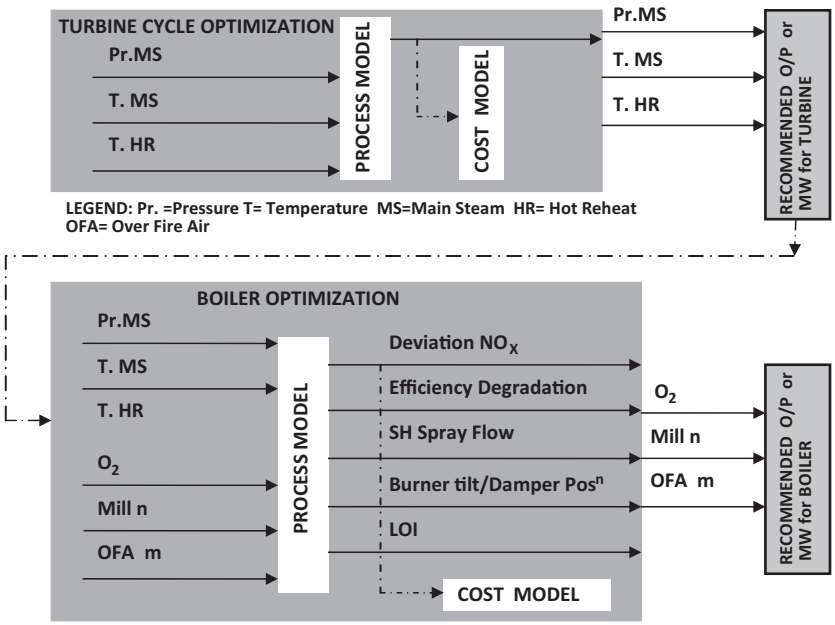


FIGURE VII/6.1.5-5 Turbine cycle optimization (coordination with SG).

www.EngineeringBooksPDF.com

temperature optimization would be extremely important for boiler optimization, as these reduces energy consumption greatly.

Another important boiler optimization package is the Intelligent Soot Blowing System (ISBS). It works on the basis of exhaust gas temperature and steam temperatures. Suitable models are developed to assess the soot formation in each of the heat transfer sections of a boiler. ISBS gathers these data from the DCS and processes them to compare with data from historians of the DCS to detect the buildup and allocate steam to remove the fly ash buildups. It is known that ash buildup will jeopardize the heat transfer at the tube so steam conditions become poor. ISBS is more effective than the traditional soot blowing operation/system based on time lapsed. It has been found that with ISBS there is improvement in boiler efficiency at $\sim 07-0.8\%$. It also guides the operator to section wise optimal soot blowing requirements, after assessment of fouling of the heat transfer section. Advantages of ISBS include the following:

- Determination of boiler cleaning action dynamically.
- Guide existing soot blowing system in real time to get best result
- It uses adaptive modeling and expert rules
- It calculates in real time heat transfer co efficient of each section.
- It initiates strategic soot blowing sequence to minimize heat rate.

6.1.5.3 Steam Turbine Cycle Optimization Package

The steam turbine cycle referred to here is for a utility station with a TG and other regenerative heaters in the heat cycle. Cogeneration/combined cycle plant optimizations have been dealt with separately. For turbine optimization, steam parameters are very important, and these highly depend on the boiler, so a similar package may be more helpful. Temperature, pressure of main steam and HRH are major influencing parameters for steam turbine cycle optimization. Normally steam temperatures are maintained at a fixed set point (as suggested by the boiler and turbine manufacturers) by boiler controls. In case of once through, boiler steam temperature controls are extremely important because they influence combustion control to a high degree. Main steam pressure can be controlled by a fixed throttle pressure set point, while the flow through the turbine is regulated as per the first stage pressure. In sliding pressure mode (within a band of load) the valve is in wide open condition and pressure is regulated as per load demand.

Obvious advantages of sliding pressure mode are reduced loss due to throttling and higher steam temperature, which at reduced load provides better thermal efficiency. All these parameters are highly dependent on boiler-operating conditions, so these parameters, which could be the outputs for the steam turbine cycle optimization package, may be set as targets for the boiler optimization package, as shown in Figure VII/6.1.5-5.

In this case the turbine cycle optimizer makes the target recommendations for main steam pressure (Pr.MS), main steam temperature (TMS), and hot reheat temperature (THR) as targets for the boiler optimizer. There will be full coordination and resources will be allocated to both the systems. On partial coordination a direct link between the two systems may be broken, but still there will be coordination between the systems. As stated earlier the two optimization packages will be similar but both will have different process models. In turbine cycle optimization, there may not be much CLCS optimization, but there will be more OLCS recommendations. The main aim of turbine optimizations with main steam pressure are

- Determining the break points for constant pressure and sliding pressure
- Determination of, for example, optimal mode of operation of the turbine at different loads
- Comparison of economy between constant pressure and sliding pressure operation

6.1.5.4 Total Plant Optimization

As discussed above various optimization packages for SGs and TGs can be combined in conjunction with several other software packages for optimization of other systems (e.g., ESPert from EPRI) and a total plant optimization can be achieved. It is worth noting that water chemistry management is another important model. A typical flow diagram is shown in Figure VII/6.1.5-3b. This module helps keep the internal corrosion in check by continuous real-time analyzer outputs with the adaptive model and recommends the operator's action for various dosing and other controls. So this always tries to sense the root cause and suggest action.

For total plant optimization a single package can be developed, but it may be too complex to really achieve the desired target. Alternatively there may be several

TABLE VII/6.1.5.5-1 Ambient Influence

Parameter	Compressor inlet	Turbine outlet
High temperature	Lower density hence less mass flow	
High pressure		Less GT power O/P
Humidity	Higher specific volume, less mass flow in GT	

www.EngineeringBooksPDF.com

OPTICOM Technology: A new approach is OPTICOM technology in which advanced monitoring and control of local combustion conditions are done for effective performance optimization. ****For power plant optimization the concept had been used by INRECO, AICIA, and ENDESA Spain. The discussions below and the Figure VII/6.1.5-4 are prepared in light of an Internet article "Boiler Efficiency and NOx Optimisation through Advanced Monitoring and control of Local Combustion Conditions"by Copado,Canadas,Gomez and Pereze).**** *The major advantage of this system is direct combustion characterization in any part of the boiler or furnace, allowing accurate assessment imbalance of air and fuel. It is capable of characterizing distribution of fuels with different properties within the furnace. Optimization with OPTICOM has reduced heat rate by nearly 1% coupled with reduction of NO_X by 30%. Major features of this system include:*

- ★ *Collection and analysis of gas samples and online local measurement of temperature gas concentration (O_2,CO, NO_x, SO_2)*
- ★ *Online calculation and supervision of unit energy efficiency*
- ★ *Advisory and optimization for boiler efficiency and NO_X reduction process*
- ★ *Measurement of type and stability of flames*

OPTICOM technology essentially consists of a system that allows measurements to be taken in any area interior to the furnace near burners. To meet the goal these measurements are made through small openings in the fins which are the tubes that make the water walls . In this way it is possible to take measurements at levels of each burner without significant changes in the structure. The probe is 10-12 mm wide and capable of withstanding temperatures of 1400-1500˚C. The sample collected is passed through a heated filter to drive out fly ash and then conditioned to send it to the PLC, which is used for measurement and feeding data to the control system (see Figure VII/6.1.5-4).

FIGURE VII/6.1.5-6 Short note on OPTICOM technology for optimization.

optimization packages arranged in a hierarchical manner so that top levels will receive inputs from suboptimization packages for coordination to achieve the desired goal. Some of these suboptimization packages could be one regenerative heater, BFPs, BFPTs, etc. The latter approach is better in the sense that each of the models to be developed will have a reduced scope so that it can achieve the goal in a better way. Also since each unit has less input, the chance of failure of the subsidiary optimizer due to input failure will be less, and even if it fails, the failure of one subsidiary optimizer will not jeopardize the entire system. Also each module testing is easier.

Each subsidiary optimization package can be characterized for the unit easily (viz. optimizing steam consumption in BFPTs and optimizing heat transfer areas for regenerative heaters by regulating heater levels energy consumption can be reduced for better overall plant performance). However, there are problems, e.g., several suboptimizers may give conflicting control settings and compromise may have to be weighed keeping in mind the overall objective. The overall objectives need to minimize total unit cost, which must be related with high level plant variables such as boiler efficiency, NO_X, etc.

6.1.5.5 Gas Turbine Performance and Optimization

With a gas turbine there are several factors including the ambient condition effect of the performance of the gas turbine. To get better performance aerodynamic design of compressors and turbines has been improved to minimize the conversion loss to attain higher efficiency. Another factor affecting GT efficiency is operation at the high pressure and high temperature condition at inlet. Sustained operation at high pressure and temperature seriously affects the durability of GT components. In modern GTs the process conditions are such that they almost reach their

www.EngineeringBooksPDF.com

mechanical and thermal stress limits. So naturally, modern cooling systems and selection of materials for the components are of immense importance. Ambient conditions such as air temperature and humidity affect the GT performance in two ways, at the compressor inlet as well as turbine outlet.

Aerodynamic design tries to minimize conversion loss and the GT gives optimum performance at a base load range, beyond the same flow balance between GT and compressor varies, and optimum performance is not achieved. Similarly, fuel heat value affects the performance. Ambient influence on GT performance is given in Table VII/6.1.5.5-1.

Now performance analysis helps to distinguish between "natural" cause and machine degradation. This can be done with the help of the engine performance model, combined with mechanical condition monitoring of the machine. Various factors need to be properly addressed to get the various correction factors necessary to calculate the GT performance. GT manufacturers specify these correction factors for variations in inlet temperature, inlet pressure drop, coolant injection, and load variations. Depending on applicability, there will be separate correction factors for heat rate and power output, corresponding to each of these parameters. Once the operating data are collected, performance analysis is performed by comparison with the model with the help of software. The performance analysis will be different for simple cycle and combined cycle. There are several performance analysis products available in the market, e.g., efficiency map and Bently performance map. Traditionally the controllers for GTs are tuned seasonally, but now there are software available by which such work need not be repeated.

BIBLIOGRAPHY

[1] ABB 800XA Engineering Over view:ABB Limited.
[2] ABB 800xA high integrity BMS Solutions:ABB Limited.
[3] ABB your Partner Functional Safety:ABB Limited.
[4] AC 500 OPC server:ABB Limited.
[5] AC 800M control Software: ABB Limited.
[6] AC500 -eCO: your PLC From ABB: ABB Limited.
[7] An Intelligent Conveyor Control System ForCoal Handling Plant of TPP: Makarand Joshi.
[8] An Open Filed bus comparison: MTL Document.
[9] Application Note: www.hachultra.com.
[10] Architecture for Secuure SCADA and DCS Network: juniper Networks: White Paper 2010.
[11] Ash Handling for Power Plant:KOPAR OY Finland: Document.
[12] Automated System for Water Treatment Plant: Industrial Control Systems: www.ics-me.com.
[13] Automation of Coal Handling Plant:A Dutta, A chowdhury, S.Karforma, S.Saha, S.Kundu, S.Neogi.
[14] Benefits of HART Protocol; SMAR.
[15] Boiler Eefficiency and NOx Optimization thru' advanced monitoring and control of local combustion conditions:A. COPADO, F. RODRÍGUEZ, L. CAÑADAS, V. CORTÉS, P. GÓMEZ, E. PÉREZ-SANTOS: International Paper on July 2008 OPORTO (Portugal).
[16] Burner Management System Solution:Emeson process management:Delta V SIS.
[17] Centrum VP Document:Yokogawa Electric limited.
[18] Centum CS Work Station:Yokogawa Electric Corporation.
[19] COAL-FIRED POWER PLANT HEAT RATE REDUCTIONS: Sargent Lundy USA: Jan 22'2009.
[20] Comander SR 100A: ABB Limited: Catalog.
[21] Communication Standards in Power Control:A.C West (Triangle microworks Inc.):ESAA 1999 Residential School in Power System Engineering.
[22] Compact HMI 800:ABB Limited:(V 4.1).
[23] Comparison between CAT 5,5e,6 and 7:Discount Cables USA.
[24] Comparison Of Single loop controller with Delta V multiloop controller:Emerson Process management:DELTA V white Paper Nov 2011.
[25] Computer Networks: Book:A.S. Tananbum and D.J. Witherall.
[26] Delta V Digital Automation System:Emerson Process Management.
[27] Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NOX) Emissions from Coal-fired boilers (500MW):DOE Assesment: March '2004.
[28] Design Concept of Foundation Filedbus Product:M. Yoshitsugu.
[29] Devicenet Automation:Lumberg Automation.
[30] Digitric 500: ABB Limited: Catalog.
[31] Dry System/modern controls upgrade Labadie AH: J.Shadduck W.Stillman:Union Electric Co.
[32] Effectively managing Power plant Information: Energy Tech magazine; September 2011.
[33] Ethernet.ph3:en.kiosk.net/contents/technologies.
[34] FAQ Sheet for S84/IEC 61511:www.primatech.com.
[35] Foundation Fieldbus:Samson Document.
[36] Foundation Fieldbus:www.instrumentation guide.com.
[37] Foundation Fieldbus Application Note: Fluke.
[38] Foundation System technology:Developer Training:Seminar Document.
[39] Fuzzy gain Scheduling PID. Control for power plant wide range operation:R.G. Ramirez, K.Y.Lee:International Confernce on intelligent system Application ISAP 2007.
[40] Hart Communications:Samson Document.
[41] Honeywell 620 Logic Controller: Honeywell: Catalog
[42] Human Machine Interface:Mitsubishi Electric:Catalog.
[43] Industrial Systems 800xA AC 800M Control and I/O: AB B Limited.
[44] Industrial System 800 xA Device Management:AB B Limited: System Document.
[45] Integrated Thermal Power and Desalination Plant Optimization:P.Pechtl, M.Dieleman, M.Posch, B. Davari, M. Erbes, S. Schneeberger:GE Energy Services, Optimization Software.
[46] Intelligence Based Hybrid Control for Power Plant:W.Wang H.X.Li and J.Zhang:IEEE Transaction on control Systems Technology vol. 10 no2.
[47] Intelligent Failure Tolerant Control:R.F. Stengel:IEEE Control Systems.
[48] Intelligent systems:www.intelligent-systems.com.ar.

www.EngineeringBooksPDF.com

[49] Internet Document:http://technology.ezinemark.com
[50] Introduction to HART: Emerson Process management.
[51] Introduction to Intelligent control System With High Degree of Autonomy:P.J. Antsaklis U of Nortre Dame and K.M.Passino Ohio State University.
[52] Introduction to MODBUS: Contemporary Controls: Internet document.
[53] IntroductionBeyond Single Loop PID Control:ISA Philadelphia ChapterDavid B. Leach:Industrial Process optimization March 2003.
[54] Lecture notes on internet protocol CSC343:Wake Forest University.
[55] Master Logic PLC: Honeywell: Catalog.
[56] ME 4012 Digital Turbine Control System D. Baran: Helmut Mauell GmbH.
[57] Memory and execution performance: ABB Limited.
[58] Mod30 1701RP controller: ABB Limited.
[59] MODBUS Protocol Ref. Guide:MODICON, Inc., Industrial Automation Systems.
[60] Model X500F SER: Ronan Engineering Company: Catalog.
[61] Network design Consideration for Distributed Control Syatems: F.L. Lian, J. Moyen, D.Tilbury.
[62] Network Modules: Mitsuishi Electric.
[63] New Generation Integrated Monitoring and Control System:S. Takahashi, S. Shimizu, T. Sekiai:Hitach.
[64] Omron PLC based power plant automatic control for pneumatic AH equipment:Source Net Author:admin:26th July 2010.
[65] Operation and monitoring Function Centtum CS: Yokogawa Electric Corporation:Sept 2008 Document.
[66] Ovation Operator Work station:Emeson Process managemen.
[67] Planer touch Screen Selection Guide:www.planartouch.com.
[68] Plant Performance Calculation Kalki Technologies India.
[69] PLC 5 Programmable Controllers:Rockwell Automation:Selection Guide 1785 and1771.
[70] PLC based controls for Ash handling plant:Diamon Power Inc. Document.
[71] Power plant Automation:ABB Limited: Write up.
[72] Preferred BMS Logic: Preferred Instruments USA.
[73] Preferred Utilities manufacturing corp−BMS Logic Discussions.
[74] Principles of LCD Display:Physics Group Project:May 2001.
[75] Process control and OptimizationVol. II:by B.g. Liptak*:*P. M. B. SILVA GIRÃO.
[76] Process control and Optimization Vol II by B.g. Liptak*:B. Kamali:Touch screen display.
[77] Process control and Optimization Vol II by B.g. Liptak*:G.B.Sing, B.G. Liptak:Work station Design.
[78] Process control and Optimization Vol II by B.g. Liptak*:T.L. Belvins M. Nixon:*DCS Modern control Graphics.
[79] Process control and Optimization Vol II by B.g. Liptak*:T.L. Blevins M. Nixon:DCS operator graphics.
[80] Process control and Optimization Vol II by B.g. Liptak*:R.R. Rhinehart, F.G Shinskey and H.L.Wade:Control Modes.
[81] Process control and Optimization Vol II by B.g. Liptak*:J.A.Moor, B.G.Liptak, T.L.Blevins and M.Nixon:DCS System Architecture.
[82] Procontrol P write up: ABB Limited.
[83] Profibus Cable: ABB Limited: Data Sheet 10/63−6.47.
[84] Profibus PA: Samson Document.
[85] Profibus Workshop: Siemens Limited: April 1999.
[86] S800L I/o modules:ABB Limited.
[87] Safety in Process Instrumentation with SIL rating:Siemens AG:2007.
[88] Safety Instrumented BMS: M. Scott and B.Adler Applied Engineering Solutions.
[89] Safety Technologies Incorporated in the Safety Control Station:E. Toshiyuki K Shigehito.
[90] SCADA applications in thermal power plants:M.N. Lakhoua.
[91] SCADA Security: Challenges and solution:Schneider Electric:Doc N: TBULM01012−32.
[92] Sceen Master 2000: ABB Limited: Catalog.
[93] Securing SCADA INFRASTRUCTURE: Fortinet CA USA: White Pape.
[94] Selecting and using RS 232,RS422and RS 485 Serial data standards: Maxim: december 2000.
[95] Sematic Controller Siemens AG: Catalog April 2000.
[96] Sematic Controller Software:Siemens AG: 2010.
[97] Sematic Modular controller:Siemens AG: 2010.
[98] Sequence of Event Recorder:Series 90/30/20 micro PLC: GE Document.
[99] Series 90-30 GE intelligent Platforms Control Solutions:www.ge-ip.com.
[100] Sematic PC based Automation:Siemens AG: 2010.
[101] SLPC (YS 1700 1310): YEL: Catalog.
[102] Smart Process Plant Optimization and performance software Emerson Process Management: Document.
[103] Software Funtional Design Specification:Honeywell: Project document.
[104] Stadard Tech. Specification For Main plant Package of Sub Critical Thermal power plant (500MW and above):Central Electricity Authority New Delhi:New Delhi September2008.
[105] Standard Design Criteria/Guideline for Balance of plant (2X500 MW TPP)Central Electricity Authority New Delhi:New Delhi 2010.
[106] Steam/its generation and use: Book: Babcock and Wilcox.
[107] Steam Turbine Optimization:A.D. Gavrilos ABB/ETSI.
[108] Supervisory Control and Data Acquisition (SCADA) Systems:National Communication System:Technical Information Bullentien 04-1 (2004).
[109] Supervisory Information System at Power Plant Level (SIS) and Its Development: Y.Dong:Thermal Pwer Research Institue PR China.
[110] System 9000TS SER: RTK instrument:Doument.
[111] Turbine ATRS NTPC: Korba Simulator.
[112] Turbine zSystems: EDC Singrauli India.
[113] Twisted Pair Cables:www.infocellar.com.
[114] What is OPC: OPC Foundation: OLE Wikipedia also.
[115] Write up on ATRS BHEL-KWU Document.
[116] Write up on ATRS: BHEL Hardwar.
[117] Intelligent Sootblower Scheduling for Improved boiler operation: X.Cheng, R.W. Kephart, J.J. William: Westing House Process Control Inc.

www.EngineeringBooksPDF.com

Chapter VIII

Boiler Control System

1. BASIC CONTROL REQUIREMENTS

1.0 Introduction

Modulating control in a power plant is extremely important. It is always advisable that the designer frame a basic control philosophy before developing a control loop. This chapter discusses control loops as they relate to boilers, dealing with the following issues:

- *Objective of the control loop:* Purpose, control parameters, other manipulating variables, and final control elements
- *Description of the loop* (and various subloops)
- *Operation:* When to trip to manual, including tripping the loop because of transmitter/sensor failure
- *Protection and interlock* (if any)
- *Special features* (if any)
- *Transmitter selection*

1.1 Transmitter Selection

Most of the control loops in power plants incorporate redundancies in transmitters, as discussed in Section 1.0 of Chapter III. They often trip to manual on account of transmitter failure in various ways. This basic philosophy of tripping to manual is discussed here and applies to all of the control loops discussed in this book (see Chapters IX, X, and XI also). As discussed in Section 1.0 of Chapter III, any transmitter failure trips an alarm on the operator's monitor.

1.1.1 Control Loop to Manual for One of Two Selection

If there are two transmitters, while operating in auto mode the control loop trips to manual in any one of the following events:

- If both transmitters fail (they may be out of range—for example, O/P < 4 mA or > 20 mA).
- Both transmitters are healthy (not out of range) but deviation between them is too high (this may be an installation problem).
- The operator has selected one transmitter for control (for some reason) and it fails. Now the operator may select the other transmitter and put the loop back on auto provided the second transmitter is healthy.
- When the average of two transmitters is selected and one transmitter fails (it may be out of range), the other can automatically be selected (without being tripped to manual—an exception) or the operator can select it manually depending on the control philosophy adopted.

1.1.2 Control Loop to Manual for Two of Three Selection

If there are three transmitters, while operating in auto the loop trips to manual in any one of the following events:

- If a median or average is selected and two transmitters fail (may be out of range), the operator can select the third transmitter and put the loop back to auto.
- If at least one transmitter is available, the operator can select the other transmitter and put the loop back to auto.
- If a single transmitter has been selected for control (for some reason) and it fails, the operator may select the average (or median) or one of the other two transmitters and put the loop back to auto provided the other transmitter is healthy.
- When the average/median of three transmitters is selected and one transmitter fails (it may be out of range), the average/median of the other two can automatically be selected, or the operator can select one of the two healthy transmitters manually depending on the control philosophy adopted. In this case automatic selection of the average is considered.

1.2 Utility Functions Associated with Control Loops

In control systems designed with state-of-the-art technology, a few utility functions can be implemented easily through system software. A few such conditions are discussed and have been followed (in Chapters VIII, IX, X, and XI) as a general philosophy (unless stated otherwise for any loop).

1.2.1 Trip to Manual

Whenever the auto enable (release to auto) signal is absent, the loop is forced to manual and cannot be switched to auto by the operator until the auto Enable signal is restored. The

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

auto enable signal missing alarm may be generated on a diagnostic or any other monitor

If a protection runback/forced open (or close) condition exists or appears in the A/M station, the operator cannot reverse the command. This is also true in the case of directional blocking because of run up or run down protection arising from the failure of the main auxiliary(ies). In certain control systems having three-tier password protection, it may be possible for the engineer to reverse a few of these commands, but in all such cases doing so is alarmed and the engineer's intervention is on record with time stamping.

Generally, all control loop output is monitored against time if the feedback of the control action does not reach the loop in a specified time (each case may be different) after the control command has been issued, or if there is a deviation between command and control actions. Either way, all actions are alarmed at the monitor. All set point reasonability is checked in the loop and in case of mismatch is alarmed at the monitor. If change over contact does not reach either end, an alarm is generated in the monitor as a noncoincidence error.

1.3 Position Signal

All of the control (modulating) valves must have a position transmitter for position indication at the distributed control systems (DCS) monitor. In some of the loops discussed in this book, no feedback from the final control element (FCE) position is provided to balance the loop (instead, the feedback is provided through the process parameter—a general convention) for better steady-state response.

The legend sheets are presented in Figure VIII/1.1; they are applicable to all control loop strategies depicted in Chapters IX, X, and XI.

2. STEAM PRESSURE CONTROL WITH LOAD INDEX

2.0 General

For any steam generation plant, steam pressure is the most vital parameter that indicates the state of balance between the supply of steam and the demand for it—that is, the supply of heat input or fuel and output as steam withdrawal from the system for various utilities like heating or

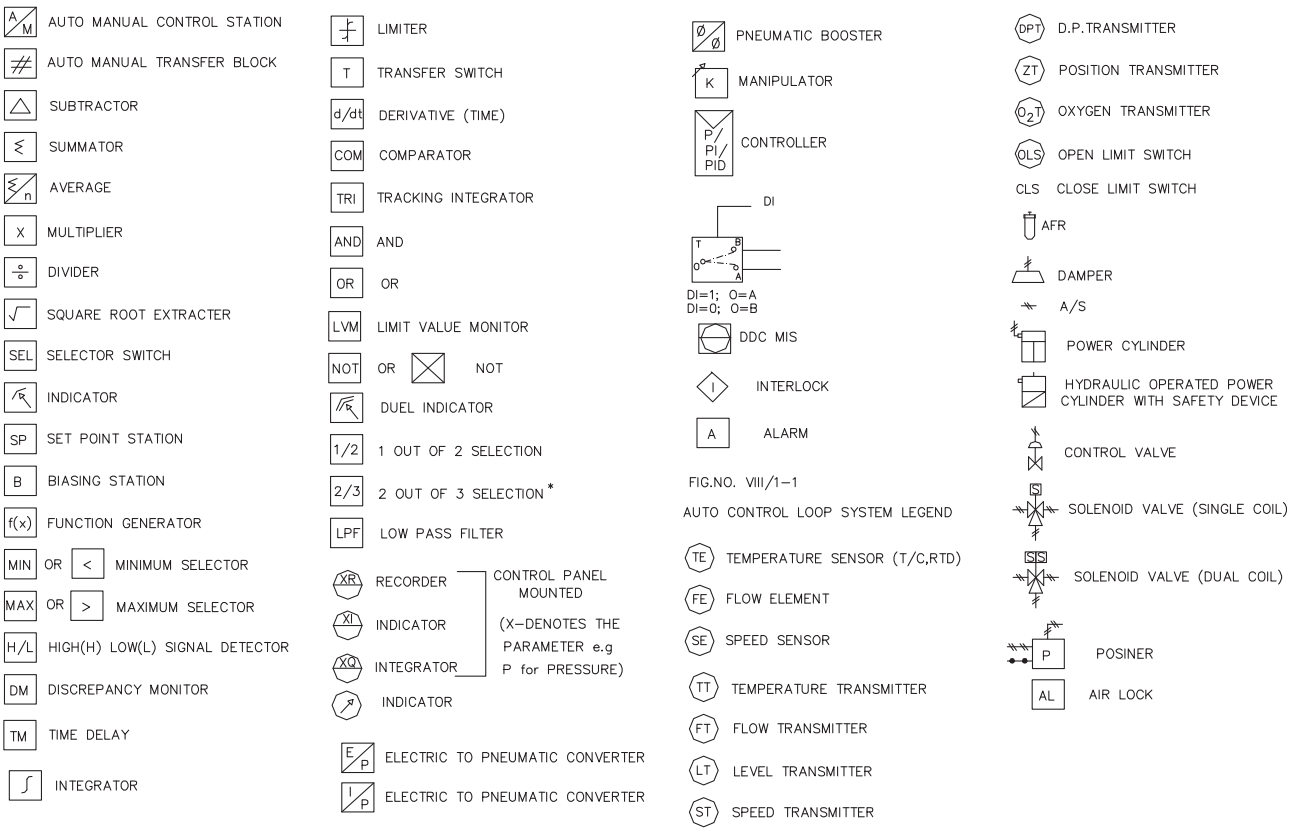


FIGURE VIII/1.1 Auto control loop system legend.

www.EngineeringBooksPDF.com

power-generating turbines. If supply exceeds demand, the pressure obviously increases, whereas if demand exceeds supply, the pressure decreases. The control loop strategies discussed in this chapter are for a subcritical thermal power station (i.e., with a drum-type boiler).

2.1 Objective

The steam pressure control with Load Index as a feed-forward signal is provided to maintain the main steam pressure vis-à-vis combustion control. For a thermal power plant, the throttle steam pressure is maintained at a fixed pressure or at a variable pressure as part of a sliding pressure control strategy.

2.2 Discussion

In the past, when low-pressure boilers were in use and there was little development of superheaters (SHs), the measuring point of steam pressure control was the drum itself. This is the common steam header, with multiple steam generators connected to it; steam pressure is the controlled parameter for each boiler, which has its individual bias setting to suit the prevailing site condition.

When there is an individual turbine for any boiler plant (e.g., a utility plant), the very point of measurement for control purposes is the throttle pressure or the turbine inlet pressure. The boiler control system in general takes care of the many fold aspects that cover the following required controls:

- Integration with the coordinated control system, combining turbine and generator for MW control
- Combustion, with fuel and air control using a lead−lag control strategy
- Burner management system
- Drum or startup separator (for once through the SG plant) level
- Superheater and reheater steam temperature
- Adequate display and data for the operator to continue in case of emergency and for system engineers to analyze any catastrophic situation

During certain periods of time in the past, the normal practice was to provide separate and independent control systems for subsystems such as boilers and turbine/generators with minimum or no coordination between them. Nowadays, the coordinated control system provides a complete solution, with the main and ultimate demand controller output issued simultaneously to each subsystem to ensure more responsive control loops for better results.

Coordinating the entire plant with all the subsystems in tandem requires an intimate knowledge of these systems and selecting the appropriate operating mode to make them work together. The main motivation behind this idea is to take care of the time lag and minimize the effect of interactions among the subsystems. The time lag normally refers to boilers that have enormous thermal mass and are therefore relatively slow to respond to. Turbines, on the other hand, are very compact and almost immediately respond to any changes called for by the control system or an operator action.

The coordinated control loop in the boiler follow mode receives a load demand signal, provided by the operator or by *load dispatch centre* (LDC) to control the position of the turbine governor or control valves. The throttle or system steam pressure changes, and the boiler controller accordingly takes corrective action to control the input of fuel and combustion air and feedwater (FW) to maintain system steam pressure at a predetermined fixed or variable level.

Alternatively, in turbine follow mode, load demand is issued to the boiler whereby fuel, air, and water inputs are respectively controlled. As the steam pressure varies because of changes in heat input, the turbine controller adjusts the position of the governor valve to set the system steam pressure at a preset value. The main intention behind turbine follow mode is to maintain throttle pressure at all times, but overall system performance is not regarded as very efficient. The reason is that this mode is not capable of making maximum use of the stored energy in the boiler in order to maintain a constant pressure. Detailed discussion is included in Section 1.1 of Chapter X.

However, boiler control vis-à-vis the total control system has been designed to cope with ever-increasing power demand with good frequency control over the entire range. In addition to overall systems requirements, there must be a provision for extracting maximum energy from the boiler, with well-defined set limits in which the boiler is assured of efficient and safe operation.

The basic concept of a coordinated control system is to issue load demand signals simultaneously to the boiler and turbine control systems as a feed-forward signal; it is used mainly for minor or trim corrections in response to detection of errors in throttle pressure, megawatt, and frequency adjustments. The most important application of the feed-forward signal is the use of control philosophy to reduce interaction and to increase the probability of the best dynamic response. Utilizing this signal is always advantageous as it senses the load changes very fast and enables corrective action before any significant errors crop up. Feedback controllers may be used as a final or further trim at the appropriate level to make amend for minor deviations and adverse effects in getting better steady-state response.

To be more specific, the throttle pressure is measured through redundant transmitters and compared with a fixed or variable set point which provides the throttle pressure error and is subsequently fed to a controller with integral action applied to the turbine control system beforehand. The throttle pressure error signal is utilized to readjust the load set point. On the other hand, the MW output delivered

www.EngineeringBooksPDF.com

by the turbine is measured and compared with the MW set value to provide megawatt error and is subsequently fed to a controller with integral action and is used along with the throttle pressure error signal before being applied to the boiler control system for the subsequent control of the air and fuel inputs to the boiler. The details are discussed in Chapter X.

2.3 Control Loop Description

As indicated earlier, the boiler steam pressure control system is the basic system for maintaining pressure, be it main steam throttle pressure or header pressure (multiple boilers in a single header configuration) by adjusting the fuel and air input to supply proper heat input as per the demand sensed by the change in steam pressure.

This control loop is actually a part of the boiler combustion control loop and a variety of such loops to match the requirements of the individual boiler have been developed over the years. The final choice of configuration depends on so many factors such as type of fuels, firing system, various subsystems (e.g., boiler, turbine) pattern of load demands, layout of various subsystems, and associated accessories.

Figure VIII/2.1 is a schematic representation of the control loop in a typical 250 MW plant having a drum-type boiler with a downshot opposed fired (fossil/coal) furnace (Babcock design) for occasional oil support. The control loop may vary with the manufacturer's special design but the basic idea remains the same.

A similar loop with little difference in philosophy is shown later in Figure VIII/4.4-1 Here the main steam pressure to be controlled is measured with sufficient (triple) redundancy. This measured signal after the necessary voting circuit is sent to the coordinated control system as discussed earlier.

The main steam pressure is compared with the set point, which may be fixed or variable depending on the power plant unit configuration and type of subsystems (e.g., boiler, turbine). The main steam pressure error signal is then fed to a controller, with output having built-in proportional, integral, and derivative action. Controller tuning is normally with an auto tuner, but the system engineers may tune it to suit the particular site condition.

The controller output signal is then suitably trimmed via a function algorithm whose input is the characterized signal from the FW temperature at the economizer inlet and feed-forward signal from the boiler load demand signal derived in the coordinated control system (Chapter X in Figure X/2.1). In this control strategy a derivative signal is the feed-forward signal from the coordinated control system. The feedwater temperature at the economizer inlet is also a part of the feed-forward signal generated in the boiler control subsystem. The significance of this signal is the enthalpy carried by the FW from the outside of the boiler into the boiler. When the temperature is lower, the heat input demand is higher and vice versa.

Another trimming signal is taken from the furnace draft; this is the pressure signal with sufficient redundancy before

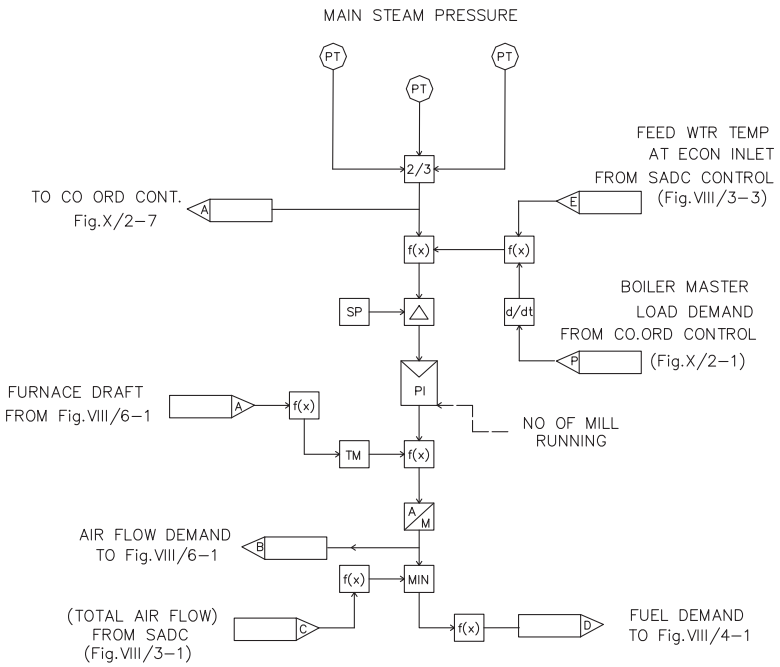


FIGURE VIII/2.1 Steam pressure control with load index.

www.EngineeringBooksPDF.com

voting. The loading of the boiler corrects itself in accordance with the furnace's present running condition—that is, whether further loading or unloading is required to maintain furnace pressure. As the furnace pressure is always fluctuating, this signal is fed through a time delay and filter circuit to avoid oscillation in the controller output.

The trimmed output signal is utilized by the air flow controller as load demand. The same signal is also used as fuel flow demand but not before passing through a minimum selector, with total air flow as other input ensuring that the fuel flow demand or actual flow can never be more than the air flow demand or actual flow.

The control philosophy for a tangential tilt (TT) burner, as is shown later in Figure VIII/4.4-1 (based on the CE boiler design philosophy) may be different as utilized in another 250 MW power plant with TT burners. Here the main steam pressure demand is compared with the pressure set point (with a fixed or sliding pressure option). The error created (by the difference between actual pressure and set point) is fed directly into a PI controller, and the output of the controller is the desired pressure demand signal. In order to make the loop more responsive, the load index signal is added as the output of the controller. Since the loop is tuned with the load index signal at the output, any change in demand affects the loop; at the same time the derivative signal, which always contributes noise, has been eliminated. As shown, there can be a number of parameters to be considered for the load index signal and these are

- Steam flow is when the same is measured (in higher MW plants this may not be measured because of permanent loss in the flow element)
- First-stage pressure of the turbine added with high-pressure bypass (HPBP) flow (if partial HPBP is allowed)
- Simple first-stage pressure if no partial operation of HPBP is envisaged.
- Generator load.

Section VIII/4.4 may be referred to for more details.

3. AIR FLOW CONTROL

3.0 General

Air flow control, a very vital part of the combustion control system, generates the demand and ensures adequate air flow, which is required for complete combustion of fuels as requisitioned by the combustion control system for keeping the steam pressure at its desired value.

3.1 Objective

Air flow control is provided to supply the total air flow at the exact quantity that satisfies the demand of the fuel firing rate, considering the *stoichiometric ratio* (the chemically correct or perfect ideal air—fuel ratio) and "excess air" to some extent to guarantee complete combustion. The control loop discussed here actually computes total required air flow vis-à-vis mill-wise air flow demand; when the relevant PA flow is subtracted from it, the balance is regarded as secondary air demand required for stoichiometric combustion.

3.2 Discussion

The importance of air flow control has long been known. Inadequate air flow makes combustion incomplete, leaving carbon monoxide, in exhaust flue gas, to pollute the environment, which is not allowed nowadays by regulatory agencies. The cost of fuel is also an important factor to prevent its misuse for lack of air flow affects efficiency as well. For this reason some amount of excess air is provided for the firing process to take place with as near to complete combustion as possible. On the other hand, too much excess air does not take part in the combustion process but carries over the extra heat simply as waste, causing a higher cost of equivalent fuel and lower efficiency.

3.3 Control Loop Description

Figures VIII/3.1, VIII/3.2, VIII/3.3, and VIII/3.4 are schematics of the control loops in a typical 250 MW drum-type boiler and coal-fired furnace with occasional oil support (Babcock design). The control loop may vary with the manufacturer's design and the type of fuel to some extent, but the basic idea remains the same.

3.3.1 Measurement of Various Parameters

3.3.1.1 Total Air Flow

The types of flow element used for measuring air flow are normally dictated by the boiler manufacturer. For a large plant, there are multiple forced draft (FD) fans whose suction or discharge points are selected for measurement and then summed to achieve total flow.

Sufficient redundancy is provided (shown as triple redundancy). This measured signal after the necessary voting circuit is density compensated with redundant temperature transmitters and then square-rooted to provide a linear signal. Pressure compensation is not required in this case. This signal is also utilized for fuel flow control and furnace draft control and binary signals for the burner management system' may also be derived from this signal, as shown in Figure VIII/3.1.

3.3.1.2 Measurement of Oxygen Percentage in Flue Gas

This measurement forms an important part of the air flow control philosophy as far as complete combustion and

www.EngineeringBooksPDF.com

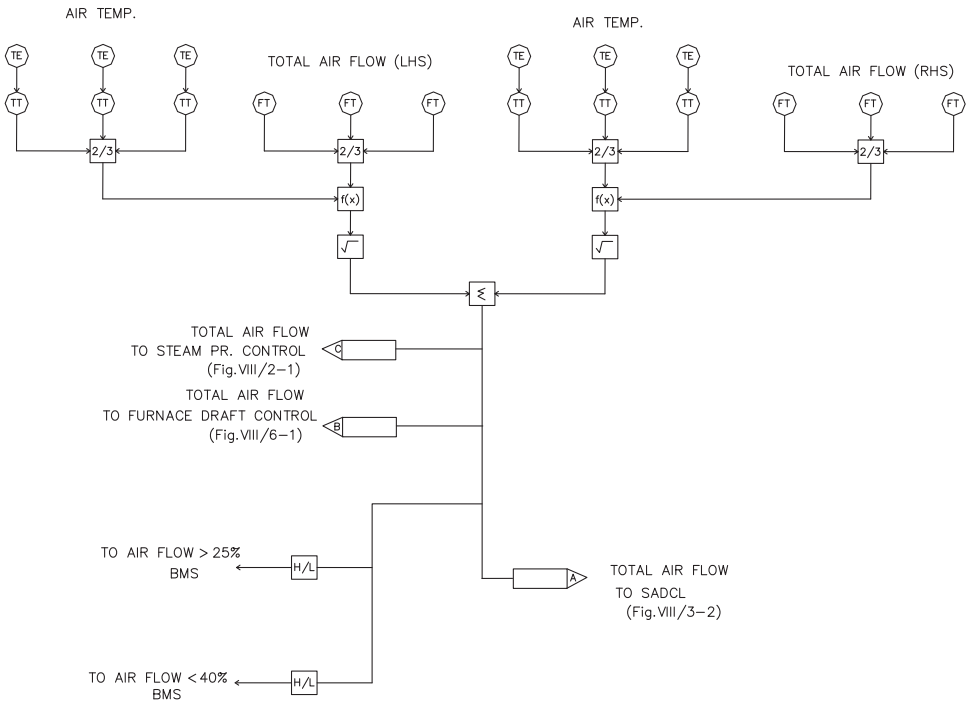


FIGURE VIII/3.1 Air flow control/SADC control 1.

excess air presence is concerned. Figure VIII/3.2 indicates a triple redundancy measurement and the corresponding voting circuit. The strategic tapping point of oxygen percentage measurement is also important and varies according to different school of thought. The probable points may be at economizer inlet, outlet or the air heater inlet where flue gas temperature varies and so the type of transmitters may also. Normally in situ or on line instruments are preferred over sampling-type measurement considering availability of output at a much faster rate.

3.3.1.3 Measurement of Feedwater Temperature at Economizer Inlet

This measurement, with sufficient redundant measurement and voting circuit, is used as a feed-forward signal as discussed earlier and utilized as a trimming factor for the steam flow signal. This steam flow signal (refer to Figure VIII/7,1 later) forms the boiler load index. As observed from time to time, there are specific values of oxygen percentage against each percentage of boiler load required for ideal combustion with excess air present. This relationship is provided as an algorithm where desired oxygen percentage is available for any load and forms the desired set point for a controller to maintain optimum oxygen percentage.

3.3.1.4 Measurement of Secondary Air Flow

Figure VIII/3.2 shows two secondary air dampers dedicated to each pulverizer mill that provide combustion air for the mill-wise coal flow. The air flow in each line is measured with redundancy and voting circuit and summated to achieve the total secondary air flow meant for supplying combustion air mill-wise. Density compensation may or may not be provided depending on the point of flow measurement vis-à-vis excursion of temperature.

The mill-wise secondary air flow is now corrected as per the oxygen trimming signal obtained from the dedicated controller output having a measured oxygen percentage value as its process/measured variable and the set value as described in Section 3.3.2 of this chapter. This combined secondary air flow duly trimmed with oxygen percentage in flue gas (see Figure VIII/3.1) has now become the process variable for the secondary air flow controller. The set value formation of this controller is dependent on the load that is on the steam pressure controller output after necessary adjustment.

3.3.2 System Controllers

3.3.2.1 Oxygen-Trimming Controller

Figure VIII/3.3 is schematic representation of the oxygen trimming in the control loop. The combustion process needs excess air as discussed earlier. Residual oxygen present in the flue gas is an index of the excess air. This excess percentage of oxygen toward optimum combustion is not a constant value but depends on the percentage of load. An approximate value is around 4% when the boiler load is less than 60%; at loads more than 60%, the presence of oxygen gradually becomes less and is ~1.5 to 2% up to

www.EngineeringBooksPDF.com

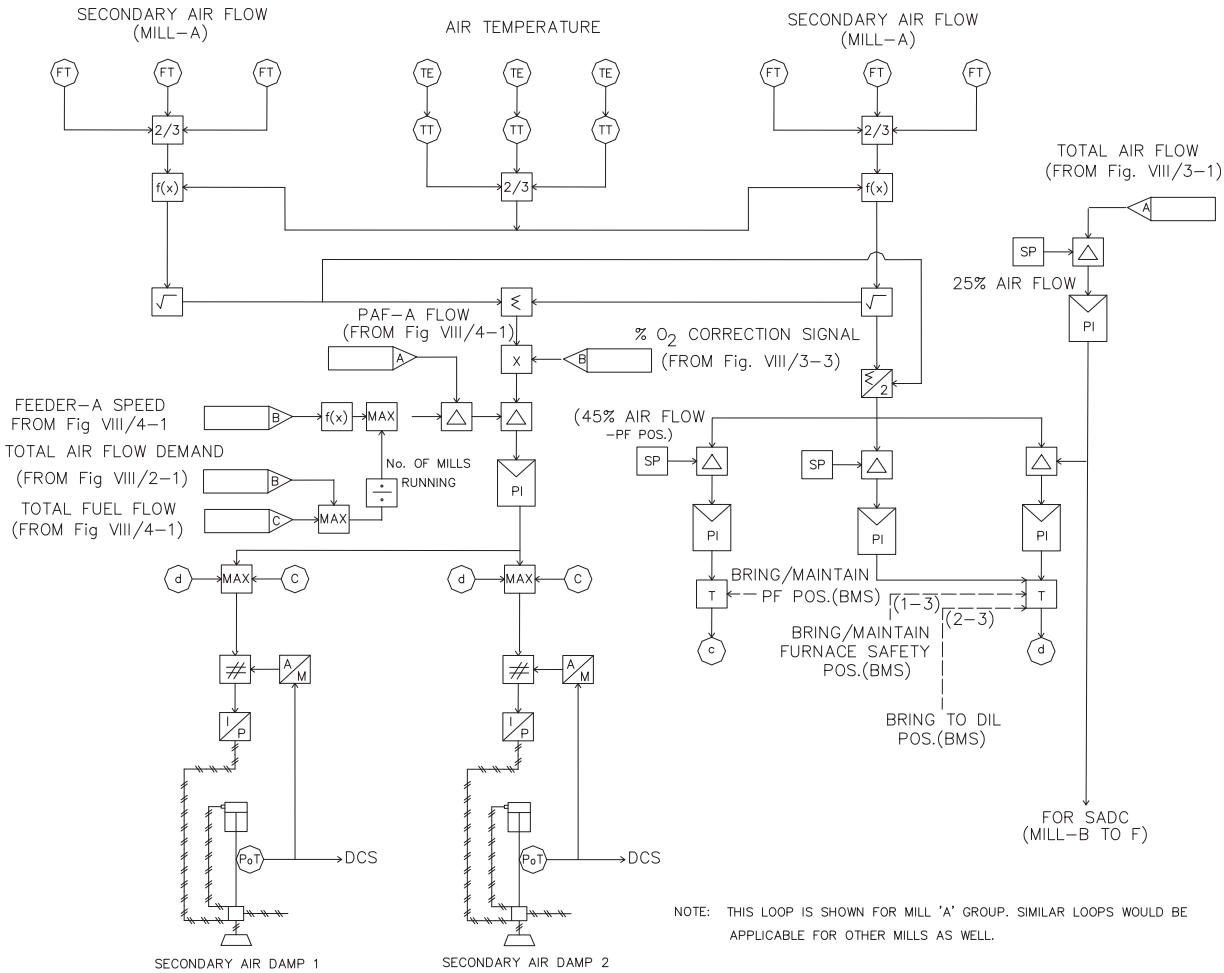


FIGURE VIII/3.2 Air flow control/SADC control 2.

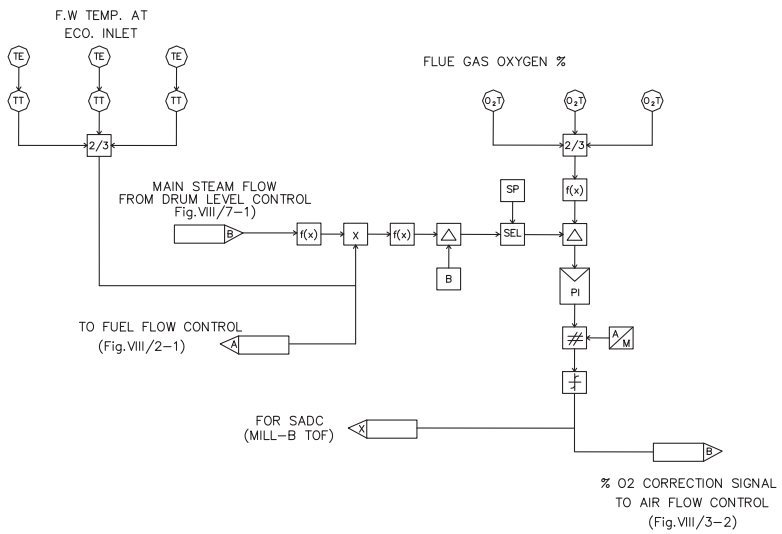


FIGURE VIII/3.3 Oxygen trimming in air flow control/SADC control.

www.EngineeringBooksPDF.com

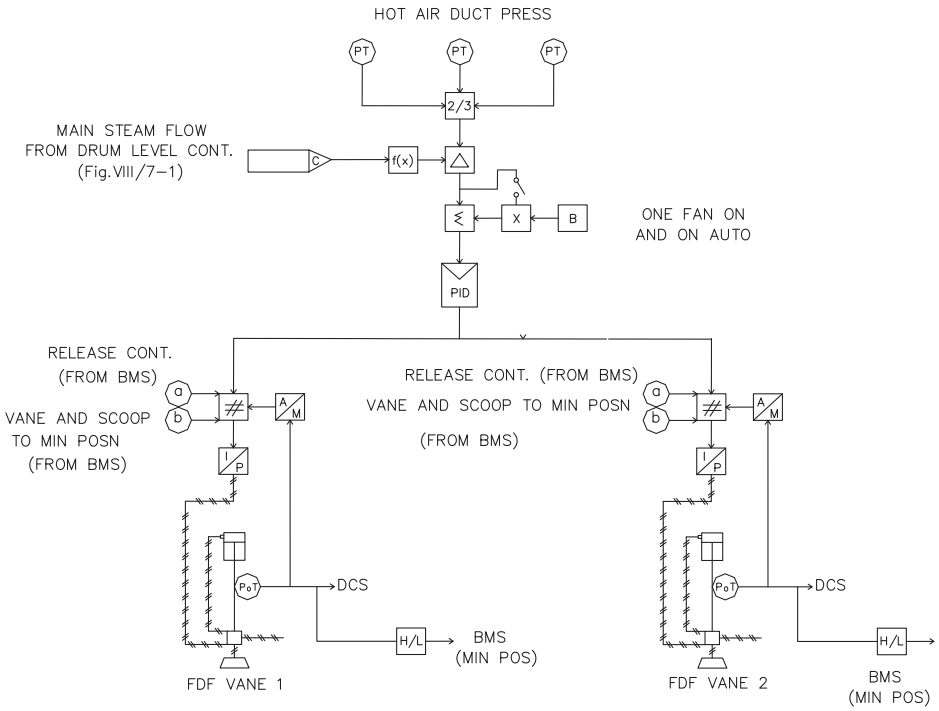


FIGURE VIII/3.4 Hot air duct pressure control (total air flow control).

~75 to 100%. See the graph depicting excess percentage of oxygen versus percentage of load in Figure VIII/3.4.

The main steam flow is taken as the boiler load with sufficient approximation (i.e., no leakage, no intermediate requirement, etc.) and corrected with the FW temperature at economizer inlet signal as the feed-forward signal (refer to Figure VIII/7.1). After correction, the boiler load is converted to percentage of oxygen in flue gas using the algorithm represented the graph in Figure VIII/3.3. A bias has been added in the control loop as finer-tuning or adjustment to suit site conditions is the desired set value of the percentage of oxygen that goes through a selector switch to provide the manual set point. The selector output is connected to the controller for delivering the output with the proportional-integral-derivative (PID) option. To prevent overcorrection, the controller output is passed through a high/low limiter with limit values that are hand set to correspond to a particular boiler and sent for air flow control. The same signal is used for supplying combustion air to all the mills' fuel controls.

3.3.2.2 Secondary Air Flow Controller

As discussed, there are two secondary air dampers provided in the air flow path to supply combustion air to each pulverizer mill, and provisions are made to control these dampers as per command issued by the relevant controller.

Both the air flow demand and the characterized feeder speed signal as generated, shown later in Figure VIII/4.1, are passed through a maximum selector option to ensure higher air flow in both increasing and decreasing load. The new air flow demand as derived is the total combustion air flow required for each mill and also comprises the PA flow as provided by separate PA fans. For this reason, the PA flow pertaining to each mill (refer to Figure VIII/4.1) is subtracted from the derived new air flow demand to generate the actual requirement of air flow as the set point of the secondary air flow controller, with a process/measured variable that is measured and corrected by the oxygen trimming signal as discussed earlier.

The controller (with PID option) output (refer to Figure VIII/3.2) then passes through a maximum selector option with other signals related to minimum air flow, pulverized fuel position, oil position, and so forth. These other signals are analog but triggered by the binary signals initiated by particular boiler operating conditions, which are described as follows:

- A dedicated controller is provided for maintaining the secondary air flow at 45% (typical value) when initiated by the burner management system related to pulverized fuel under operating conditions.
- A dedicated controller is provided for maintaining the secondary air flow at 10% (typical value) when requirement is initiated by the burner management system related to oil as fuel under operating conditions.
- A dedicated controller is provided for maintaining the secondary air flow at 25% (typical value) when by the burner management system related to furnace safety condition.

www.EngineeringBooksPDF.com

These are all typical values and may vary plant to plant. The ultimate strategy is to ensure air-rich conditions throughout operation of the boiler subsystem without fire hazards and with optimum efficient output. The final output signal from the maximum selector then drives the respective secondary air damper. Similar loops are envisaged for each pulverizer mill group according to the boiler load.

3.3.2.3 Hot Air Duct Pressure Controller

Forced draft (FD) fans are provided to supply the air required for complete combustion of all types of fuels being fired. Normally two FD fans are provided with about 60% (typical) load-bearing capacity.

There are several methods of final control that are deployed for controlling air requirements such as FD fans with vane controls, impeller controls, damper controls, and so forth. In this control loop philosophy, FD fan vanes are seen as final control elements and are modulated to control the hot air duct pressure.

FD fans suck air from the atmosphere, and then the air passes through air heaters to raise the outlet temperature before being used for combustion. This hot air duct pressure is maintained at its desired value so that the downward control elements such as secondary air flow dampers can be utilized for flow control at a desirable upstream pressure. As the pressure normally decreases at higher load, it becomes difficult for the downstream control elements to supply adequate air flow. Hence the control of hot air duct pressure is important for smooth control.

The air pressure in the hot air duct is measured with redundancy and voting circuit to form the process/measured variable. The steam flow signal as generated from Figure VIII/7.1, which can be found later in this chapter, for drum-level control is considered the load index and characterized to act as the desired pressure set value for this control. Necessary arrangements are made to take care of demand signal increases in case the fan is on and running in auto mode. In that case the only running fan takes more load, in its capacity, than the load shared by two fans.

3.3.3 Alternative Air Flow Control Concept

There are boilers, such as the TT burner type (CE DESIGN BASE), in which FD fans and PA fans may be independent—that is, cold PA systems may be used. Figure III/9.2-3 shows that secondary/combustion air from FD fans is heated at the air preheater (APH) and goes directly to the windbox of the furnace and then to the combustion chamber. Note that the steam coil air preheater (SCAPH) may come before the APH in some systems. There are a number of FCEs in the path. All of those located in the windbox are responsible for distribution of air at various elevations of the boiler.

FCEs associated with FD fans control the total quantity of combustion air/secondary air (CA/SA) for the furnace. As stated earlier, even though these loops control SA/CA controls, they do so after computing total air flow (i.e., including PA flow) so that under any conditions the stoichiometric ratio is maintained. Shown in Figure III/9.2-2(a) is a cross-section of any corner of the windbox of a typical TT boiler . Here it is clear that double-lettered elevations have auxiliary air dampers, and some of them have fuel air dampers, whereas all single-lettered elevations have fuel air dampers. Table VIII/3.3.3-1 lists FCEs.

3.3.3.1 Secondary Air Damper Control

Secondary air damper control (SADC) is a part of the furnace safeguard and supervisory (FSSS) system. The basic purpose of this control is to distribute the total quantity of SA among the various elevations so to ensure proper combustion. As stated earlier, these dampers can be categorized as

- *FA damper:* Regulates air surrounding a fuel compartment.
- *AA damper:* Regulates air adjustment to a fuel compartment.

The main philosophy of control is that auxiliary air dampers modulate the fixed differential pressure (DP) between the windbox and the furnace whereas fuel air dampers are modulated in proportion to the rate of fuel at that elevation. AA dampers (located at double-lettered elevations) in all elevations in a group are controlled in proportion to the windbox and the furnace DP.

The fuel dampers at the four corners of each elevation are group-controlled in proportion to the rate of fuel fired at those elevations. During purging and at lower load up to 30%, AA dampers are regulated to maintain windbox furnace DP at around 40 to 50 mmwcl. There is an exception: For double-lettered elevations that have oil burners, say AB, CD, EF, GH, when oil firing takes place at one of those elevations, the corresponding elevation damper opens at a fixed opening; otherwise, it acts as an AA. Normally all FAs at single-lettered elevations are closed and open after a small time delay (this is different for tube mills) after the associated feeder starts so as to ensure availability of SA in the corresponding elevation. These dampers modulate in proportional to the corresponding fuel flow.

3.3.3.2 Air Flow Control Loop

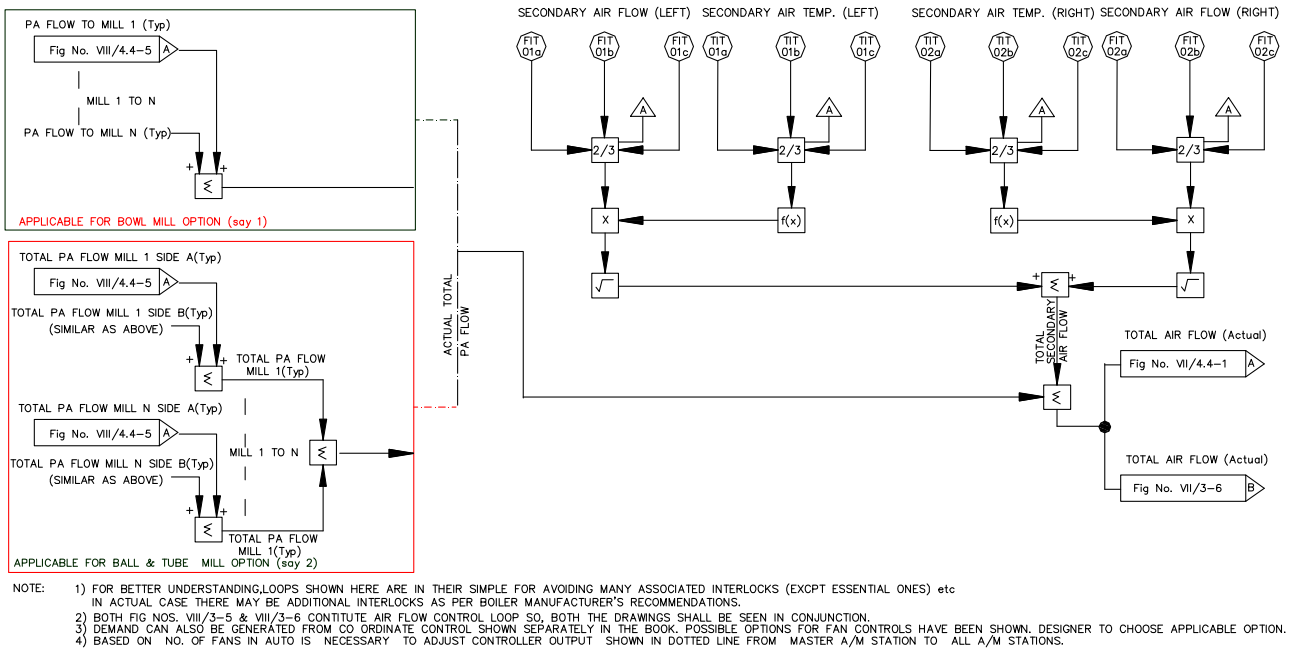
Figures VIII/3.5 and VIII/3.6 provide information about the air flow control loop.

3.3.3.2.1 Discussion An alternative is a cold PA system (i.e., it does suck air from SA/CA). Therefore, to compute total air flow, the PA fan flow needs to be added to the SA/CA flow.

www.EngineeringBooksPDF.com

TABLE VIII/3.3.3-1 FCEs for Combustion Air

Type	Location	Control	Remarks
Fan impeller	FD fan	Control total quantity of SA/CA for the boiler Main modulating control loop and part of combustion control	Normally pneumatic power cylinder to regulate flow by restriction
Fan inlet damper			
Speed control by VFD (associated with FD fan motor)			Electrical type—regulates flow by speed control of fan—more energy-efficient
Auxiliary air (AA) damper	Windbox at double-lettered elevations	Maintains furnace windbox DP to regulate and distribute SA/CA to the corresponding elevation during operation	Furnace windbox DP control loop in SADC system—part of FSSS
Fuel air (FA) damper	Windbox at single-lettered elevations (and in oil elevations, when oil firing is taking place; AA becomes FA)	Regulates damper opening in proportion to feeder speed or coal flow to corresponding elevation to regulate and distribute SA/CA to corresponding elevation during operation	Fuel air damper control loop (proportionate to coal flow) in SADC system—part of FSSS



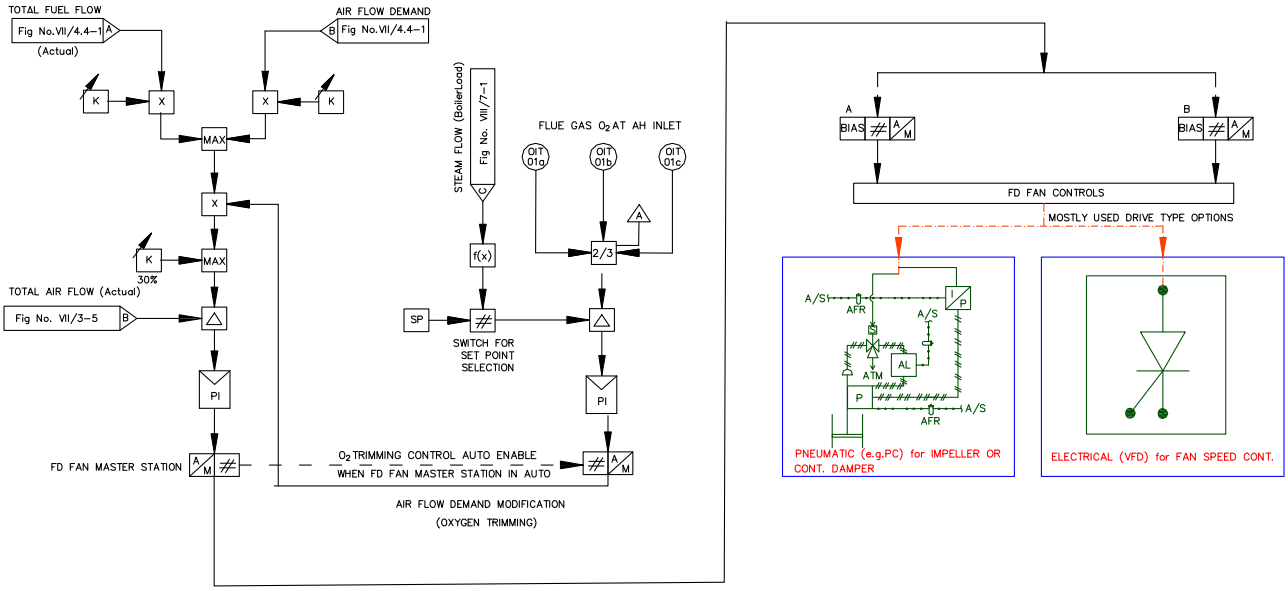
NOTE:
1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS (EXCPT ESSENTIAL ONES) etc IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER BOILER MANUFACTURER'S RECOMMENDATIONS.
2) BOTH FIG NOS. VIII/3–5 & VIII/3–6 CONTITUTE AIR FLOW CONTROL LOOP SO, BOTH THE DRAWINGS SHALL BE SEEN IN CONJUNCTION.
3) DEMAND CAN ALSO BE GENERATED FROM CO ORDINATE CONTROL SHOWN SEPARATELY IN THE BOOK. POSSIBLE OPTIONS FOR FAN CONTROLS HAVE BEEN SHOWN. DESIGNER TO CHOOSE APPLICABLE OPTION.
4) BASED ON NO. OF FANS IN AUTO IS NECESSARY TO ADJUST CONTROLLER OUTPUT SHOWN IN DOTTED LINE FROM MASTER A/M STATION TO ALL A/M STATIONS.

FIGURE VIII/3.5 Total air computation for secondary air flow control of TT boiler.

Normally (as shown in Figure III/9.2-3), there are two independent lines from FD fans to the windbox, and air flow is measured in these lines after air preheaters. airfoils, Pitot tube, or Piccolo tube flow elements may be deployed. DP transmitters in redundancy may be used as these are very vital parameters. Two of three redundancies have been shown; there can be one of two also. Since these are hot SA/CAs, temperature measurement for density compensation is essential. Here also the redundancy shown in Figure VIII/3.5 is recommended in case of redundancy for both parameters. Compensation is with two of three (one of two) output signals so that a better result is obtainable.

Since FD fan pressure is low and there is not much chance of variations, pressure compensation has been avoided. As shown in Figure VIII/3.5, both side computed

www.EngineeringBooksPDF.com



NOTE: 1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS (EXCPT ESSENTIAL ONES) etc IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER BOILER MANUFACTURER'S RECOMMENDATIONS.
2) BOTH FIG NOS. VIII/3–5 & VIII/3–6 CONTITUTE AIR FLOW CONTROL LOOP SO, BOTH THE DRAWINGS SHALL BE SEEN IN CONJUNCTION.
3) DEMAND CAN ALSO BE GENERATED FROM CO ORDINATE CONTROL SHOWN SEPARATELY IN THE BOOK. POSSIBLE OPTIONS FOR FAN CONTROLS HAVE BEEN SHOWN. DESIGNER TO CHOOSE APPLICABLE OPTION.
4) BASED ON NO. OF FANS IN AUTO IS NECESSARY TO ADJUST CONTROLLER OUTPUT SHOWN IN DOTTED LINE FROM MASTER A/M STATION TO ALL A/M STATIONS.

FIGURE VIII/3.6 Secondary air and oxygen-trimming control of TT boiler.

SA/CA flows are added to arrive at the total SA/CA Computation. As discussed in Section VIII/3.3.3.1, PA flows are also added. There may be two options here, as shown in Figure VIII/3.5, either bowl mills, where there is individual-mill PA flow computation, or ball-and-tube mills, where is the possibility of individual side-of-mill operation, which requires that for each mill each side PA flow needs to be computed and added to arrive at total air flow to the furnace.

For combustion it is necessary to have the exact quantity of total air flow corresponding to fuel to ensure that the combustion is optimum (correct stoichiometric ratio maintained) and complete. Since complete combustion may give rise to accumulation of CO, which is very dangerous for causing explosion, it is customary to have a little excess air (refer to Section VIII/3.2). For this reason lead-lag circuits are used. Here, as shown in Figure VIII/3.6, actual total fuel flow is passed through a MAX selector, where air demand is also fed. When fuel demand decreases, air flow demand cannot decrease unless actual fuel flow decreases (MAX circuit). Similarly, unless air demand increases, fuel flow cannot increase (see the MIN circuit shown in Figure VIII/4.4-1).

In order to obtain the exact stoichiometric ratio, as discussed in Section 3.2, air demand is modified /trimmed with excess O_2 in the flue gas. There are two school of thought on this. One is that this trimming should be done on the demand side (as shown in Figure VIII/3.6); the other is that it is better to do the same in the measurement circuit, as discussed in Section 3.3.2.1. Now, corresponding to the operating load of the boiler, there is a desired set value for O_2. So a set point is given as a function of load, as shown in Figure VIII/3.6. At lower load this may be a fixed value, so two set points have been shown though a selector switch The O_2 PI controller provides the trimming signal for demand modification. This modified demand signal is checked against the minimum value (30%) and allowed to enter an error generator.

The output of the error generator is fed to a PI controller to generate a demand signal for the FCE associated with the FD fans. These can have various options, as shown in Figure VIII/3.6 and given in Table VIII/3.3.3-1.

4. FUEL FLOW CONTROL

4.0 General

Like the air flow control system, the fuel flow control system is a vital part of the combustion control system. On receiving a boiler load demand signal from the steam pressure controller with other influences, the fuel flow control system generates the demand for fuel flow and at the same time ensures adequate fuel flow as requisitioned by the combustion control system considering the necessary air flow required for complete combustion of fuels for keeping the steam pressure at its desired value.

www.EngineeringBooksPDF.com

4.1 Objective

The fuel flow control supplies the fuels at the exact quantity to satisfy the demand of the fuel firing rate; it is closely coordinated with the air flow control system to ensure that the stoichiometric ratio is maintained with some excess air flow throughout the combustion process. It also ensures that the fuel flow decreases prior to air flow for a decreasing load demand and that the air flow increases prior to fuel flow for a increasing load demand so that an excess-air or air-rich condition always prevails to guarantee safe and complete combustion.

4.2 Discussion

As discussed in Section 3 of this chapter, for various reasons air flow control is always associated with fuel flow control. The increasing cost of fuels has always been the main consideration, given that fuel quantity is always affected by incomplete combustion or too much excess air. Nevertheless, the percentage of carbon monoxide present in the flue gas leaving the chimney to environment is also a serious matter of concern. Local or state pollution control boards are so empowered that they can even stop operation of any power plant if it suspects it of polluting the environment.

Whatever the mill type, the ultimate product, powdered or pulverized fuel (PF), is transported by temperature-controlled hot air called *hot primary air*. Separate fans, known as *PA fans*, perform this duty. For all mill types, the conveyance or transportation system for solid fuels is the same: blowing pressurized hot air from the PA fans through the mills up to the furnace. The number of PA fans depends on the manufacturer, plant design, and layout of the steam generator unit. There may be two or three centralized PA fans forming a common header from which primary air is supplied to each mill for transporting pulverized coal/PF to mills. Another design is an individual/dedicated fan for each mill. The control loop (Figure VIII/4.1) discussed here is has three centralized PA fans, but the control loop philosophy remains almost same, with some minor modifications.

The suction of PA fans may be directly from the atmosphere or from the common header at the discharge of the FD fans and sent to the common trisector/separate primary air heater (AH), which is popularly called the *cold PA system*. In the cold PA system, the PA discharge header is common; a major part of the PA fan discharge is sent to the PA heater to gain temperature/heat. The rest is made available as a cooling medium for controlling the PA temperature at a specific designed value with individual hot and cold air control dampers for each mill.

When the PA fan suction is connected to the common (hot PA) header at the discharge of the FD fans after bisector AH, it is termed a hot PA system. In a hot PA system, another common header is formed before the AH and forms a cold PA header. Mill-wise PA fans are provided to transport fuel at controlled temperatures through hot and cold air dampers.

In Babcock's design, to maintain uninterrupted and smooth PA flow control, the header pressure is controlled at a fixed value. PA fan suction dampers are of the modulating type in order to serve this purpose. Large fossil-fired power stations mainly use coal or lignite—that is, pulverized fuel (PF)—as the main fuel. Heavy fuel oil (HFO), low-sulfur, high-stock (LSHS), or light diesel oil (LDO) are also used as supporting fuels. (Poor-quality or water-soaked PF also prompts the operators to use oil support.) During startup, oil firing is needed. At the time of initial startup, LDOs are used to start firing. However, in many plants use of LDO has been supplanted by high energy arc (HEA) igniters, and even at startup HFOs and LSHS can be used.

When the furnace is designed for HFO or LSHS, which are highly viscous fuels, it is necessary to keep these oils at a higher-than-ambient temperature to bring down the viscosity to an acceptable level. For this purpose, steam tracing or electrical heating is required to line up the supply pipe to the furnace ring header or front/rear header and the return oil line also down to the pumps suction.

4.3 Control Loop Description

Figure VIII/4.1 may be referred for a control loop schematic representation (Babcock design). The control loop may vary with the manufacturers' special design and with the type of fuel to some extent, but the basic idea remains the same; however, related control loops are presented for TT-type boilers and for ball-and-tube mills.

4.3.1 Measurement of Various Parameters

4.3.1.1 Primary Air Flow

The actual and accurate measurement of PA flow is very important as it is utilized as the demand for coal/pulverized fuel flow in the control loop under consideration. Various flow elements are also used for measuring PA flow which are normally dictated by the boiler manufacturer as per its standard scope of supply. Here DP across PA fans is used to compute PA fan flow.

Sufficient redundancy is provided (triple redundancy here, but it depends on the plant size and the customer or it consultants). This measured signal after the necessary voting circuit is density-compensated and square-rooted to provide a linear signal. Temperature transmitters are also used with necessary redundancy and voting circuit for density compensation as pressure compensation is not required in this case. This signal is also used for air flow/secondary air damper control (refer to Figure VIII/3.2) and

www.EngineeringBooksPDF.com

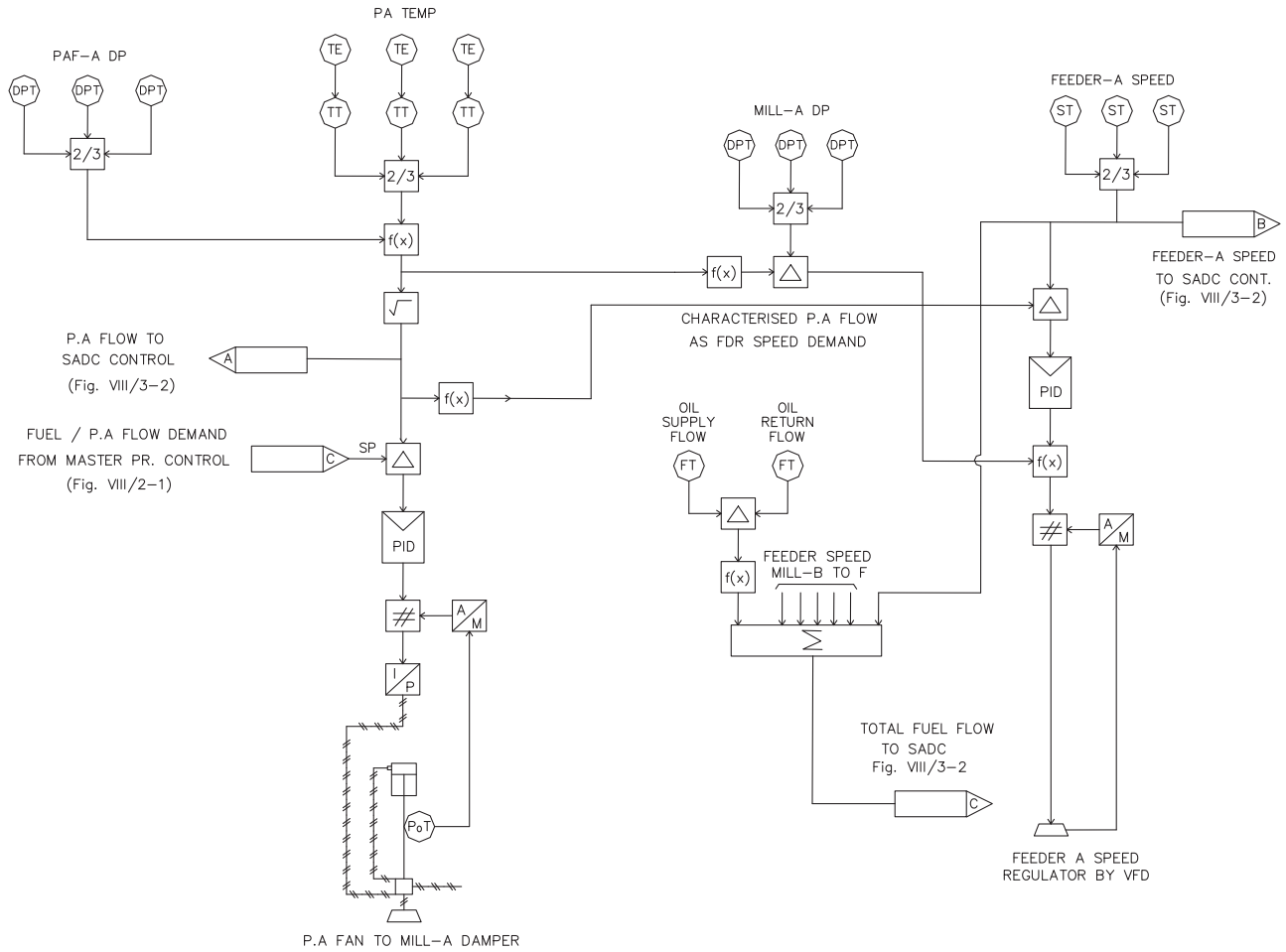


FIGURE VIII/4.1 Fuel flow control schematic.

for formation of the controller set point of the feeder speed controller.

4.3.1.2 Measurement of Feeder Speed

Feeder speed measurement is an essential part in the fuel flow control philosophy as the actual feeder speed is represented by the measured or process variables of the controller of this part of the control loop. The accurate measurement is very much desirable as this signal enables the boiler load control to ensure the much needed supply of fuel flow. The bed height remains almost constant (by some external arrangement) and hence the speed of the feeder is equivalent to the quantity of the materials on it. Sufficient redundancy is provided (triple redundancy here, but it depends on other factors). This measured signal after necessary the voting circuit is sent to the speed controller.

4.3.1.3 Measurement of Differential Pressure across the Mill

This parameter, with sufficient redundant measurement and voting circuit, is utilized as a feed-forward signal and as a trimming factor for the feeder speed demand signal (per Babcock design).

4.3.1.4 Measurement of Consumption of Oil

As discussed previously regarding the warming-up facility requirement of the oil line layout, some part of the oil is sent back. There are two flow elements of which one is placed in the oil supply line and the other is placed in the return oil line. The two flow elements' signals are subtracted to arrive at the actual oil consumption through the oil burners. As the operation may be required for a short time, there are no redundant transmitters in the control loop. However, if the quantity required is more, and considering the cost of fuel or other technical consideration, redundant transmitters may be employed with the necessary voting circuit.

4.3.1.5 Measurement of Primary Air Pressure

This parameter with sufficient redundant measurements and voting circuit is utilized as measured or process variable for the controller.

www.EngineeringBooksPDF.com

4.3.1.6 Generation of Secondary Air Flow Demand

All of the feeder speeds representing PF flows are summed to get the total solid fuels that are utilized for firing. In addition, the actual oil flow is added to the PF flow with proper adjustment toward calorific value to reach the actual heat input. This summed value is auctioned with air flow demand (refer to Figure VIII/3.2) in a maximum selector the output of which constitutes all the important signals for the secondary air flow demand. As there are individual sets of secondary air dampers (refer to Figure VIII/3.2) for each mill group, this same demand signal is utilized for all mills.

4.3.2 Various Controllers

4.3.2.1 Primary Air Flow Controller

The primary air flow controller takes care of the PA flow according to the PA flow demand from the master pressure controller (refer to Figure VIII/2.1) vis-à-vis boiler load demand. With this signal as the set value, the actual density-corrected PA flow acts as the measured or process variable. The PA dampers are provided for each mill group and are modulated as per the individual controller output (adaptive controller or PID tuning facility).

4.3.2.2 Feeder Speed Controller

The feeder speed control loop (see Figure VIII/4.1) is provided to vary the feeder speed through the variable frequency drive (VFD) or any other suitable drives to meet the modified fuel demand. The fuel demand or set point is derived from the characterized PA flow. The primary air is the transporting medium for the solid fuel, so the flow signals of these two measured values have a particular relation or function of proportionality for a particular type of fuel. This relationship is exploited in algorithm form where PA flow constitutes the input and equivalent feeder speed represents the output and finally the set point for the feeder speed controller. The actual feeder speed plays the role of a measured/process variable and the controller output (with the PID tuning facility) is further trimmed with a signal that may be termed a feed-forward signal.

Whenever the load increases, the air flow (both secondary and primary) increases first and fuel flow follows accordingly. If there is a delay between the two actions or a substantial difference, the DP across the mill becomes low compared to PA flow. The difference in values is obtained through a subtraction function and acts as the earlier mentioned trimming signal of the controller output. This enables the feeder speed to increase in advance to avoid a significant mismatch in complying with the actual fuel requirement. For decreasing load, the DP across the mill becomes high compared to PA flow and forces lowering of the feeder speed prior to decreasing the command coming directly from the controller.

4.3.2.3 Primary Air Header Pressure Controller

Primary air header pressure control is a very straightforward system (Figure VIII/4.2), and the pressure controller gets its set point at a fixed value depending on the size of the plant and the location of the transmitters. Generally some flexibility is given to the operators to select the fixed set point or a variable set point (in parity with load) selection via the selector switch as shown in Figure VIII/4.2. Some variations and options are available to the designer:

For ball-and-tube mills the maximum position of the damper of PA flow through the mill out of *both* sides of *all* mills (i.e., maximum coal flow condition) may be taken as the set point so that the PA fan regulates itself to cater to the maximum demand.

In a bowl mill mainly used in the TT boiler design, the highest feeder speed condition is taken as the set point. In some other cases a base set point added with boiler load (boiler load possible options are shown in Figure VIII/4.2) is used as set point.

The set point is compared with the actual PA header pressure to generate an error signal that is fed to a PID controller. The output of the controller regulates the working fan capacity by changing the fan speed in VFD or the inlet vane/suction damper. Speed control is more efficient for obvious reason of lower loss. Immediately after the controller, there is one A/M station called a *master A/M station*. This is kept so as to facilitate common manual operation. Final demand at the output of the A/M station (for both auto and common manual mode) is adjusted for gain depending on the number of PA fans in auto.

4.3.2.4 Coordination between Air Flow and Fuel Flow Controls

Although descriptions of all measurements and controllers are given in relevant sections of this chapter, included here is a summary of how the preceding two control loops are interrelated.

It is well known that combustion process in the furnace of steam generators requires oxygen, which comes from the air in the atmosphere. To avoid incomplete combustion and inefficient operation of the plant, the air flow rate needs a close watch on its measurement and control along with fuel flow. To summarize, the main philosophy of the air flow and fuel flow control loops can be described as follows:

Boiler load controller: This gets its set value from the main steam pressure at an appropriate point near the turbine inlet. The controller output gets properly trimmed by the feed-forward signal from the coordinated controller output. The trimmed signal (refer to Figure VIII/2.1) is then regarded as demand for the secondary air flow, provided this boiler load demand is more than the fuel flow (refer to Figure VIII/4.1), and sent to each mill group for SA controls. This signal

www.EngineeringBooksPDF.com

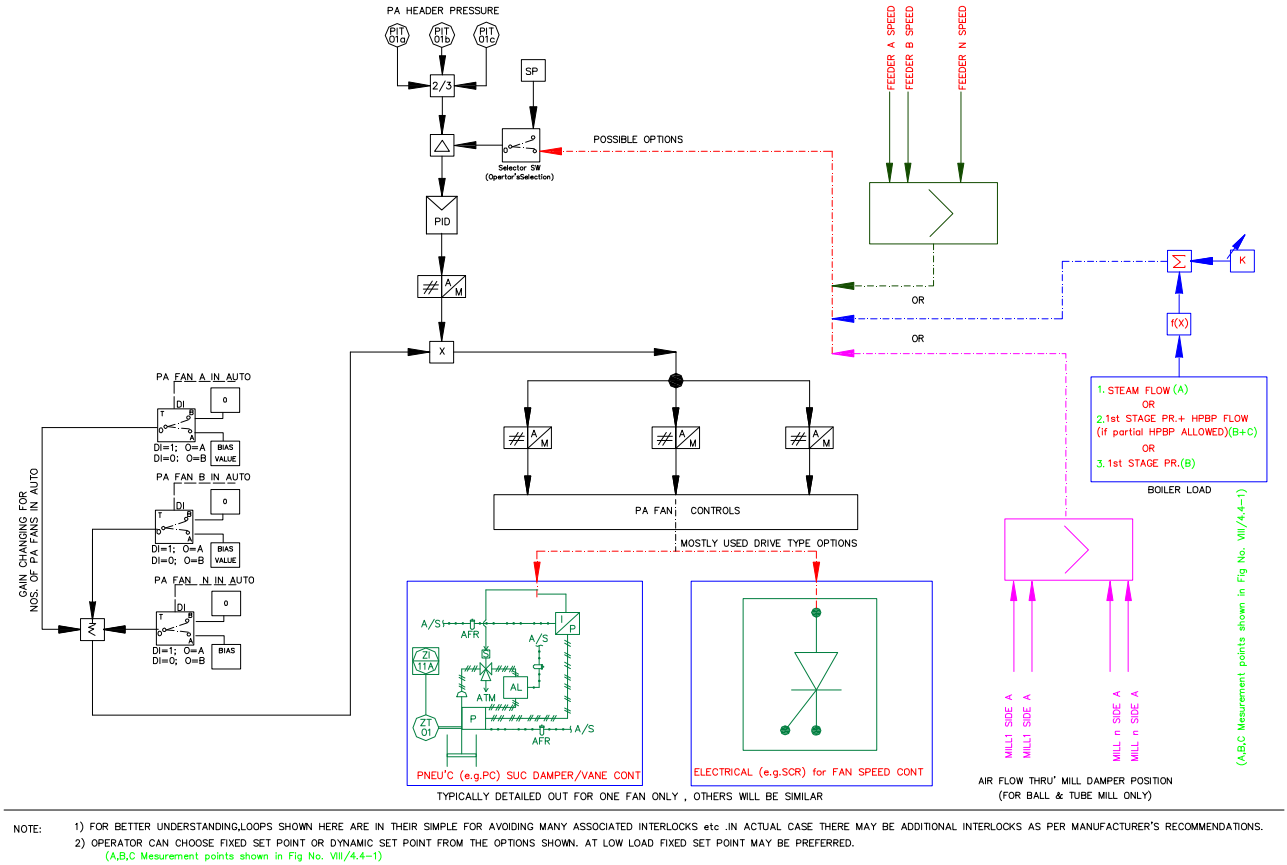


FIGURE VIII/4.2 PA header pressure (fuel flow control).

represents the total air flow, the PA flow is subtracted to get the mill-wise SA demand only, and the subsequent controller looks after that the SA dampers are acting accordingly.

Demand for PA flow: This, on the other hand, is generated from the trimmed boiler load (from the master pressure control) signal and allowed to proceed further if this *boiler load demand is less than the total air flow* signal. This signal is then treated as a mill-wise PA flow set point. After the PA flow controller takes care of the PA flow, the feeder speed controller gets its set point from the characterized PA flow and regulates the fuel flow through the speed changing device.

From the discussion of the generation of demand for air SA flow and fuel flow(via PA flow), it may be noticed that *whenever the boiler load increases, the SA flow increases first; the PA/fuel flow then increases.* When the boiler load decreases, the PA/fuel flow decreases first and then SA flow. This unique feature is called the *lead—lag relationship* between air and fuel flow. This particular idea is maintained throughout so as to prevent unsafe boiler operation and happens to be the essence of the control philosophy.

4.4 Fuel Flow Controls for Tangential Tilt Burner-Type Boilers

Although the basic objective and associated discussion, as detailed in Sections 4.2 and 4.3, are same, during implementation and control loop practices they vary with boiler design. The following subsections discuss boilers with TT burners with bowl or ball-and-tube mills.

4.4.1 TT Boiler Master Demand Control

MS steam pressure is considered the determining factor for a generation of fuel demand signals in conventional loops which does not consider the coordinate control loop. In plants where there is coordinate control the demand signal is generated after it is processed in the coordinate control system discussed separately in Chapter X. For direct control, the master pressure signal is generated with the help of turbine inlet pressure transmitters (Figure VIII/4.4-1).

4.4.1.1 Main Steam Pressure Control: Fuel Demand of a Tangential Tilt Boiler

With fixed pressure control, manually set pressure (fixed set point) is compared with the measured pressure signal

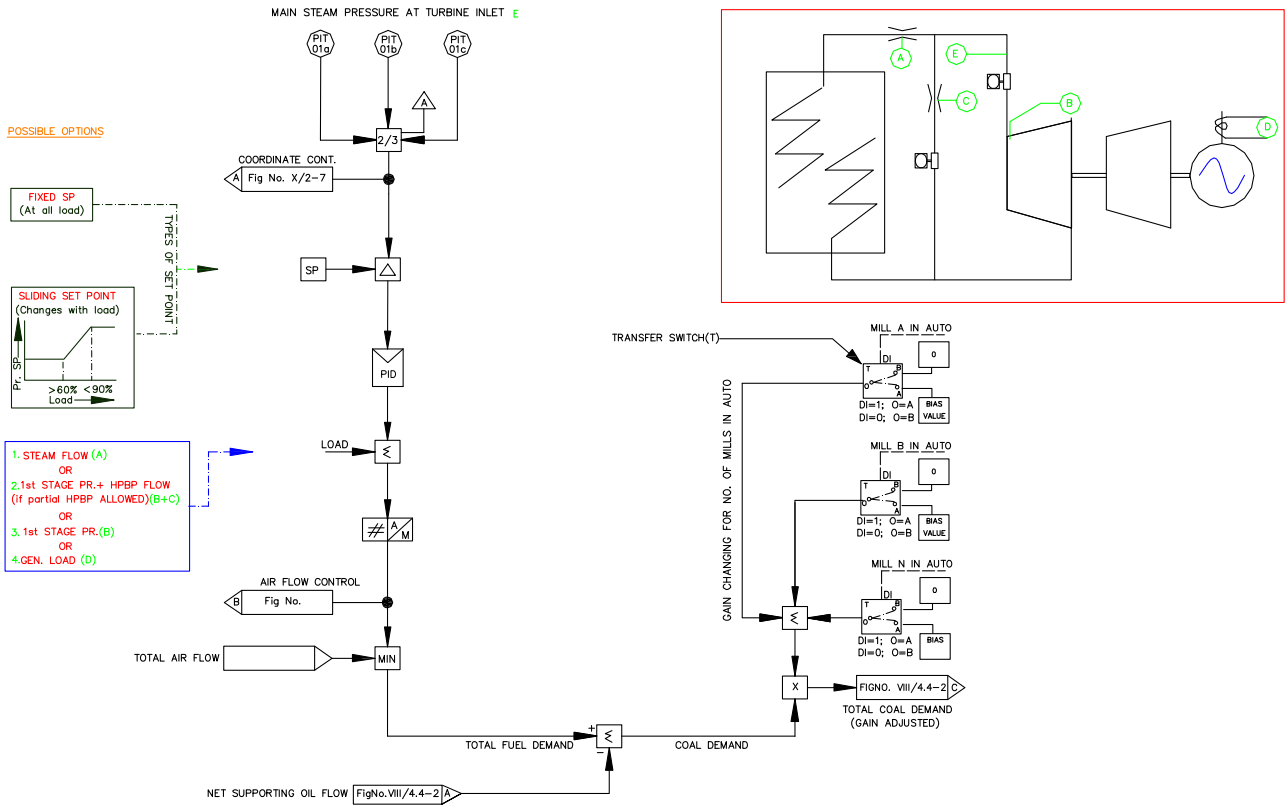
www.EngineeringBooksPDF.com

obtained from two out of three circuits (for redundancy) as shown in Figure VIII/4.4-1. For sliding pressure control, which is quite common in once-through (OT) boilers, a sliding set point is used in place of the fixed set point discussed earlier. Normally for the latter, the set point slides/changes with load, from >60% (below which the auto loop is in effect). In reality, this sliding is made effective mainly between 70% and 90%. Beyond this range, the set point is fixed. In the regime load >90%, pressure is kept fixed as a cushion to meet eventualities. During sliding pressure operation, governor valves are kept wide open so that turbine inlet pressure slides as per load (hence less loss due to drop against the control valve).

Supercritical/ultra-supercritical plants, which mostly have OT boilers, may go for sliding pressure operation, with the possibility of saving some energy. Thus both options have been shown in Figure VIII/4.4-1. The difference between the set point and the measured value creates the error signal fed to the PI controller to generate the fuel demand signal. Since inertia of the boiler is higher in comparison to system demand, system load is taken as feed-forward. Since derivative signals are basically the source of high-frequency noise, the loop shown is made to tune with boiler load as feed-forward is added with the demand from the master pressure controller to make the loop more responsive. A few options available to use as load index are listed here:

- Steam flow (in larger boilers steam flow may not be measured to avoid loss due to permanent pressure drop)
- First-stage pressure/wheel chamber pressure, which is proportional to turbine load can be considered. However, if partial bypass is allowed in the system, the first-stage pressure signal summed with the HP bypass flow is considered the boiler load
- In some cases, direct generator load is considered in place of first-stage pressure

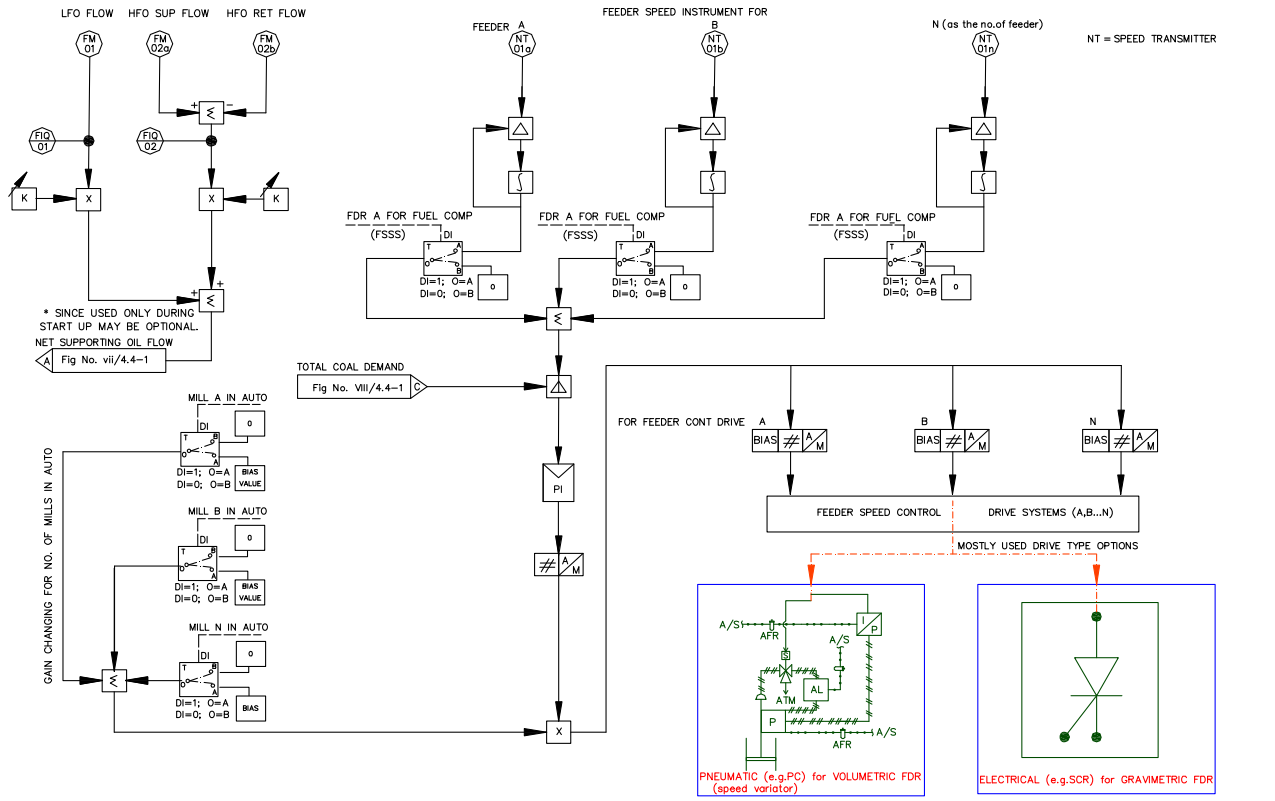
As discussed earlier, for actual fuel demand signal generation, it is necessary to cross-limit the fuel demand signal with actual air flow so that under all situations, an air-enriched condition prevails (i.e., in case of increasing load, the air increases before the fuel is allowed to increase and the fuel is reduced first before the air flow is allowed to decrease, in event of lowering the boiler load). This is ensured by the MIN selector and actual air flow. The fuel demand signal thus generated needs gain correction for the number of mills in operation. The location of each of the measurement points has been shown in Figure VIII/4.4-1.



1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS etc .IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER MANUFACTURER'S RECOMMENDATIONS.
2) FUEL DEMAND CAN ALSO BE GENERATED FROM CO ORDINATE CONTROL SHOWN SEPARATELY IN THE BOOK. POSSIBLE OPTIONS FOR M S PRESSURE SET POINT & LOAD HAVE BEEN SHOWN. DESIGNER TO CHOOSE BEST OPTION.
3) AS APPLICABLE, SLIDING PRESSURE IS POSSIBLE FOR 20–25% LOAD SPAN IN THE LOAD RANGE BETWEEN 60–90%. BELOW 60% NOT REALLY APPLICABLE AND CUSHION BEYOND 90% IS ESSENTIAL FOR EFFECTIVE OPERATION.

FIGURE VIII/4.4-1 Main steam pressure control: Fuel demand of a tangential tilt boiler.

www.EngineeringBooksPDF.com



NOTE: 1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS etc .IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER MANUFACTURER'S RECOMMENDATIONS.
2) THIS TYPE OF CONTROL LOOPS ARE APPLICABLE FOR MEDIUM SPEED BALL /BOWL PULVERIZERS. FOR SLOW SPEED BALL TUBE PULVERIZERS CONTROL LOOP IS DIFFERENT AND SHOWN IN FIG NO. VIII/4.4–3
3) FUEL DEMAND CAN ALSO BE GENERATED FROM CO ORDINATE CONTROL SHOWN SEPARATELY IN THE BOOK. POSSIBLE OPTIONS FOR FEEDER SPEED CONTROLS HAVE BEEN SHOWN. DESIGNER TO CHOOSE APPLICABLE OPTION.
4) IN ADDITION TO THE REQUIREMENT OF TOTAL FUEL COMPUTATION, NO. OF MILLS IN AUTO IS ALSO NECESSARY GAIN ADJUSTMENTS.CONNECTION SHOWN IN DOTTED LINE FROM A/M STATION IS APPLICABLE FOR ALL A/M STATIONS.

FIGURE VIII/4.4-2 Fuel flow control of a tangential tilt boiler (bowl mill).

Generally, the fuel oil flow in the boiler is controlled by the oil pressure control, discussed separately. Out of the total fuel flow there may be some contribution from oil flow also. Oil flow measurements are shown in Figure VIII/4.4-2. The difference between the supply line and return line flow of HFO gives the net HFO flow; this, along with the LDO flow (insignificant in reality) with the necessary calorific value correction, computes the total oil support of the fuel. This is subtracted from total fuel demand to compute the net coal demand in Figure VIII/4.4-1.

4.4.2 TT Boiler Fuel (Coal) Control Loop for Bowl Mill

In bowl mills which have very little holding capacity, coal flow is computed by feeder speed (Figure VIII/4.4-2). Feeder speed is measured with the help of speed transmitters to avoid spurious signals; the feeder speed signal is passed through a low-pass filter. A feeder speed signal is taken for the loop only when it is permitted by FSSS interlock, so that during the preparatory stage it is not taken for coal flow computation. Feeder speed signals are put in to a summation unit for total coal flow computation.

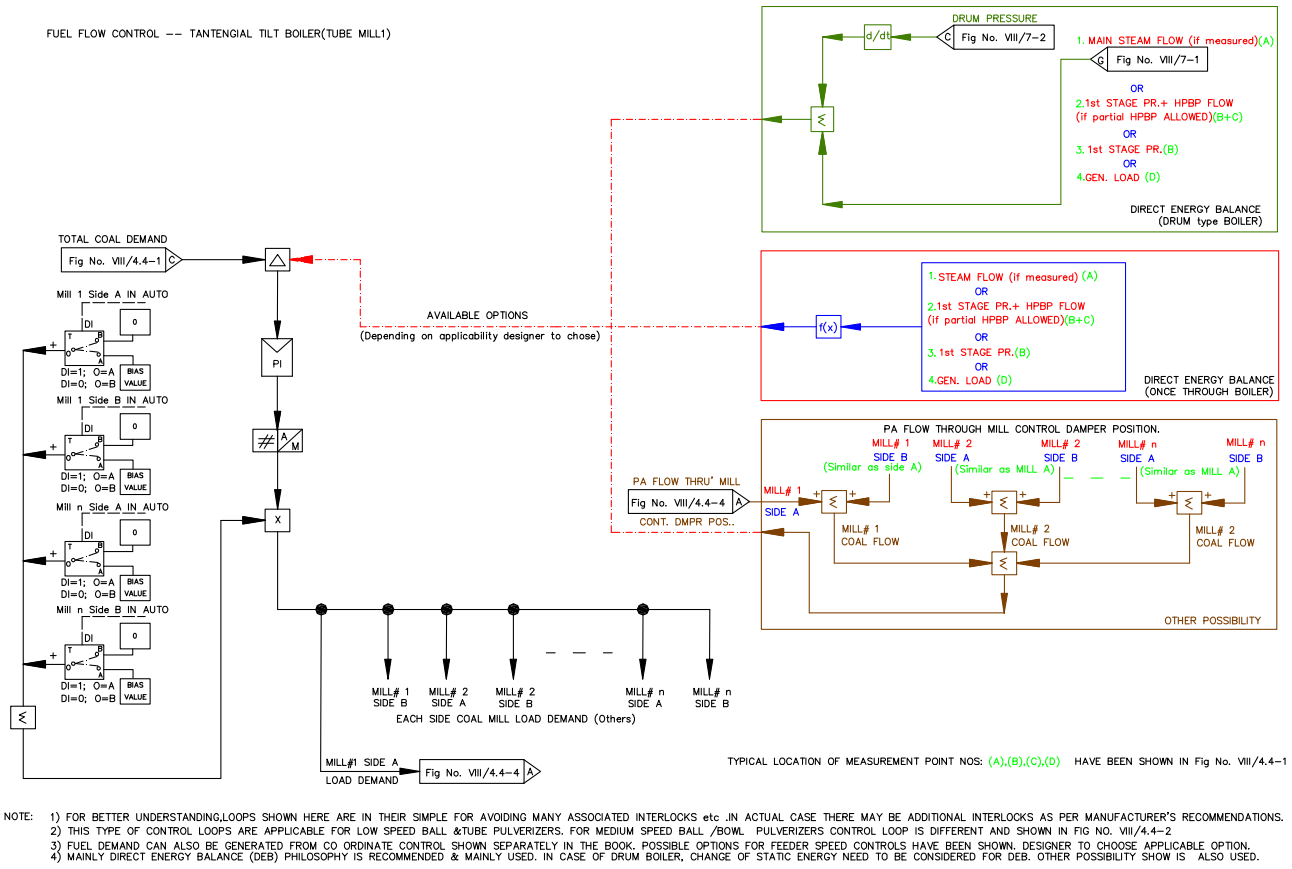
Total coal flow thus computed is compared with net coal demand (see Figure VIII/4.4-1) to generate the error signal for the PI controller. The output of the controller generates the total coal demand signal at that instant. Immediately after the controller there is one A/M station (feeder master A/M station) kept so as to facilitate common manual operation also. Final coal demand at the output of the A/M station (for both auto and common manual) is adjusted for gain depending on the number of feeders in auto, as shown in Figure VIII/4.4-2. Each of the feeder controls has its own A/M station to facilitate individual manual operation as well as to add bias.

The output of each of these A/M stations drives the feeder speed variator with help from the pneumatic power cylinder *or* it may drive the SCR controller for the gravimetric feeder. Both options are shown in Figure VIII/4.4-2.

4.4.3 TT Boiler Fuel (Coal) Control Loop for Ball-and-Tube Mill

Refer to Figures VIII/4.4-3 and VIII/4.4-4 for information about the TT boiler fuel control loop. To understand this type of loop, it is better to understand the operation and

www.EngineeringBooksPDF.com



NOTE: 1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS etc .IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER MANUFACTURER'S RECOMMENDATIONS.
2) THIS TYPE OF CONTROL LOOPS ARE APPLICABLE FOR LOW SPEED BALL &TUBE PULVERIZERS. FOR MEDIUM SPEED BALL /BOWL PULVERIZERS CONTROL LOOP IS DIFFERENT AND SHOWN IN FIG NO. VIII/4.4-2
3) FUEL DEMAND CAN ALSO BE GENERATED FROM CO ORDINATE CONTROL SHOWN SEPARATELY IN THE BOOK. POSSIBLE OPTIONS FOR FEEDER SPEED CONTROLS HAVE BEEN SHOWN. DESIGNER TO CHOOSE APPLICABLE OPTION.
4) MAINLY DIRECT ENERGY BALANCE (DEB) PHILOSOPHY IS RECOMMENDED & MAINLY USED. IN CASE OF DRUM BOILER, CHANGE OF STATIC ENERGY NEED TO BE CONSIDERED FOR DEB. OTHER POSSIBILITY SHOW IS ALSO USED.

FIGURE VIII/4.4-3 Fuel flow control of a tangential tilt boiler (tube mill).

flow diagram for this type of mill discussed in Section 5.2. In fact, discussion of this loop is more relevant in Section 5.2, but is taken up here so that the reader can have options for various kinds of fuel flow control loop. First, a short discussion on the principles of ball-and-tube mill operation is helpful.

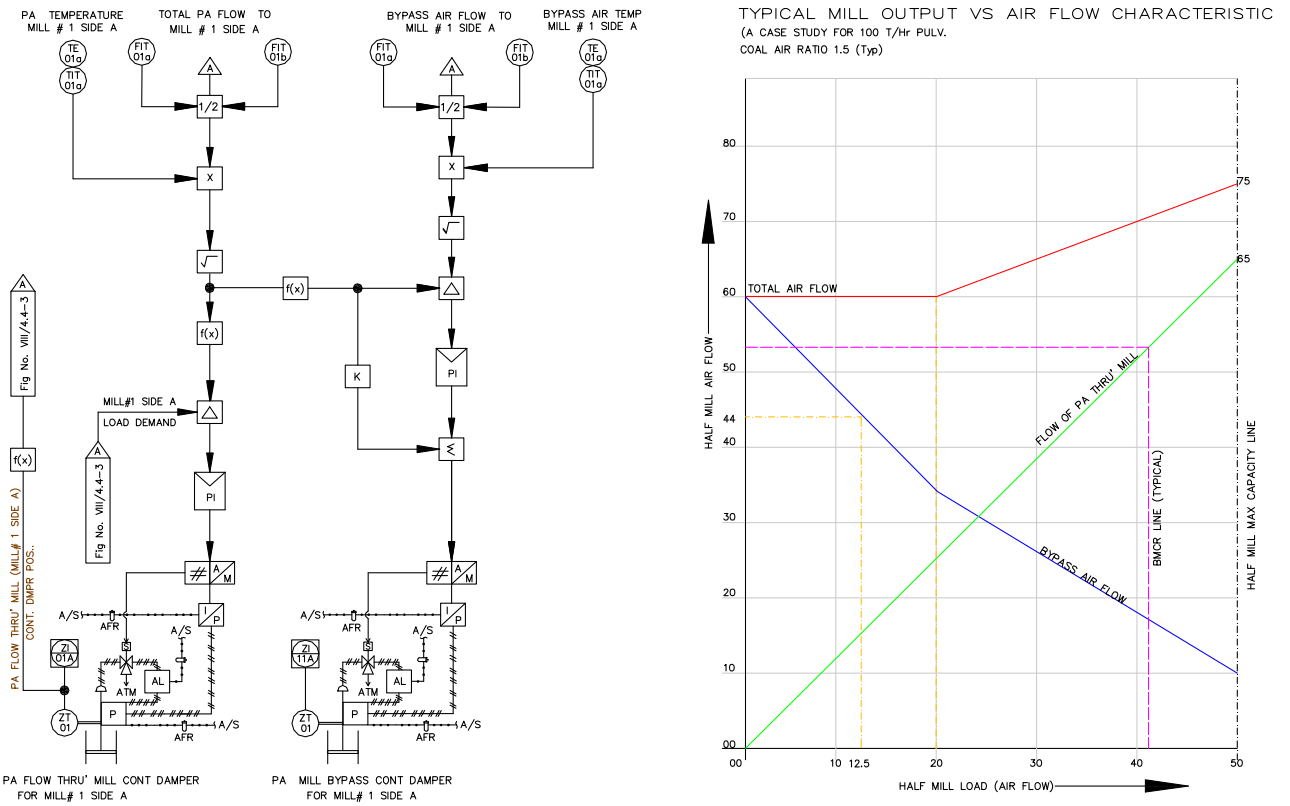
The ball-and-tube mill consists of two perfectly symmetrical grinding circuits. On each side the raw coal from the RC feeder discharge falls into a mixing box where it is predried by the hot bypass air (normally connected to the coal classifier pipe carrying coal rejects from classifier to mixing box). It then enters the mill through the trunnion tube, and the screw conveyor conveys the coal into the mill. The coal is then pulverized by the movement of balls inside the rotating body. Hot primary air is introduced into the mill through the central tube of the screw conveyor. It completes the coal drying and carries the pulverized coal out of the mill through the trunnion annulus around the central tube to the coal classifier counter to the raw coal feed direction.

The pulverized coal and primary air mixed with bypass air from the mixing box enter the classifier installed above the mills. The double-cone-type classifier is fitted with adjustable vanes to regulate the pulverized coal particle size. The large grains of coal fallback mix with the raw coal and are repulverized. The finely ground coal, suspended in the primary air, is transported from the classifier outlet to the burners, for injection into the furnace. The amount of PA through the mill in each side regulates the quantity of coal coming into the furnace from each side. There is a damper in the PA flow through line to regulate this flow. Its worth noting that for proper performance in this kind of mill, the coal:air ratio is very important—typically such a value can be 1.4 to 1.5.

For a 100 T/hr mill the diameter is typically around >4.5 m and the length is ~7.2 m. This large-volume slow-speed mill normally feeds two elevations in a TT boiler. Normally a level inside the mill is maintained by controlling the feeder speed. Theoretically it is possible to operate one side of the mill but in practice there may be a few problems and probable hazards associated with one-side operation for sustained periods. It is clear that in this mill, instead of feeder speed air flow through the mill and bypass air dampers are regulated to control coal flow discussed later.

Now the net total coal demand generated in Figure VIII/4.4-1 has to be balanced with actual coal flow. For other

www.EngineeringBooksPDF.com



1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS etc .IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER MANUFACTURER'S RECOMMENDATIONS.
2) IN BALL & TUBE PULVERIZER BOTH BYPASS AIR AS WELL AS AIR THROUGH MILL DAMPERS NEED TO BE CONTROLLED FOR MILL OUTPUT REGULATION.
3) CONTROL SYSTEM FOR ONE MILL ONE SIDE HAS BEEN SHOWN TYPICALLY HERE OTHERS WILL BE SIMILAR.

FIGURE VIII/4.4-4 Mill air flow for ball-and-tube mill.

mills where low coal levels are maintained, it is reasonable to compute coal flow from feeder speed, but in the case of a ball-and-tube mill having a desired coal level, it is not possible to go for such measurement. How to measure coal flow going to the boiler for these kinds of mills?

The answer to this question is very simple when one considers this conceptually. What does the coal do when it reaches a running boiler? In the boiler coal burns to release energy so that steam can be produced. Thus energy released by the boiler at an instant in time is proportional to steam flow. Also energy released by the boiler is proportional to total fuel flow (i.e., proportional to coal flow) since at a higher load of fossil fuel an nondual fuel boiler HFO actually acts as supporting fuel for flame stabilizing. Therefore, boiler load can be considered proportional to actual coal flow. The boiler load can be the following:

- Steam flow from the boiler
- Turbine wheel chamber pressure or the generator load (all are proportional to boiler load)

However, in systems with partial HP BP operation allowed, steam flow in the HPBP line needs to be summed with any of the preceding parameters for boiler load computation.

The parameters just listed are true so far as kinetic energy is concerned and true for OT boilers. But in drum-type boilers, the drum acts as a source of static energy, and for any change in energy release from the boiler, it also participates in releasing energy. Therefore, for drum-type boilers the rate of change in drum pressure needs to be summed with any of the parameters like steam flow from the boiler, turbine wheel chamber pressure or the generator load These are very distinctly shown in Figure VIII/4.4-3. In order to make fuel computation from energy-released signals more precise, energy supplied by the supporting fuel if any is subtracted from the total energy released.

As discussed earlier, in each side of the mill, as the PA flow through the mill is changed there is a change in coal flow out from that side of the mill. Therefore damper position in the PA flow through mill line on each side of the mill is functionally related to the coal flow. The sum totals of these signals can form a signal for total coal flow, as shown in Figures VIII/4.4-3 and VIII/4.4-4.

Total coal flow thus computed is compared with net coal demand to generate the error signal for the PI controller. Immediately after the controller there is one A/M station (the master A/M station) kept so as to also facilitate common manual operation. Final coal demand at

www.EngineeringBooksPDF.com

the output of the A/M station (for both auto and common manual mode) is adjusted for gain depending on the number of mill sides in auto. Thus load demand (in other words, position demand for damper in PA flow through the mill) on each side of each mill is generated as shown in Figure VIII/4.4-3. Each PA flow through the mill damper has its own A/M station to facilitate individual manual operation as well as to add bias. The output of each of these A/M station drives PA flow through the mill damper with the help of a pneumatic power cylinder to achieve the desired position.

4.4.4 Mill PA Flow for Ball-and-Tube Mill

Total PA flow and bypass PA flow to each side of each mill are measured. The total PA flow and bypass air flow to each mill have variations characterized according to mill load (each side). These are shown earlier in Figure VIII/4.4-4. Initially the bypass air flow on each side is kept higher to dry up the incoming coal. Bypass air flow also serves to take away the coal dust in the incoming coal and is mixed with PA flow through mill to drive the coal out to the boiler. Also during the initial period bypass air flow helps in gaining velocity. As the PA flow through the mill increases with mill load, bypass air flow decreases as velocity boosting and heating are achieved. Normally even at the highest load, bypass air flow may not be closed but kept open up to 10% so that coal dust in the mixing box is driven out and so that there is some drying effect in the incoming coal.

Total PA flow at each side of the mill is measured and characterized compared with the mill load signal in Figure VIII/4.4-3. The error this generates is fed to the PI controller PA flow through the mill damper position so that a regulated quantity of coal goes out to the boiler.

As stated earlier, bypass air flow maintains a particular characteristic with total air flow so the characterized total air flow signal is used as a set point for bypass air flow damper control. The set point compared with the actual bypass air flow drives one P+I controller to generate the demand for bypass air flow damper position. To make the loop more responsive function of total air flow after scaling is added to the controller output as a feed-forward signal.

5. COAL MILL CONTROL—MILL AIR FLOW FOR TT BOILER

5.0 General

There are two main modulating control systems associated with mills. These are mill air flow control and mill temperature control. Mill temperature control is covered in Section 5.1 of this chapter. Mill air flow controls in opposed-fired and front-fired boilers based on Babcock designs are mainly based on PA DP controls and are well covered in Section 4 of this chapter. In this section only mill a controls for TT boilers (bowl mills) are discussed. Mill air flow controls for tube mills are covered in Section 4.4.3 of this chapter and also detailed out in Section 5.2 of this chapter. Apart from these there may be a few more controls associated with tube mills these are covered in Section 5.2.

As shown in Figure III/9.2-4, PA flow P&ID, PA from PA fans header is divided into two parts: One goes via APH (and SCAPH as applicable) to form hot PA (HA); the other part bypasses APH (and SCAP as applicable) to form cold or tempering air (CA). Both air lines are further divided, one set (HA and CA) for each mill. Before entering the mill HA and CA are mixed. In each of these HA and CA going to individual mills, there are two regulating dampers. The regulating damper in hot PA is termed the hot air damper (HAD) and the regulating damper in cold PA is termed the cold air damper (CAD) (refer to Figure III/9.2-4); the same is the case for other mills also. As the mill load is increased by changing the feeder speed, naturally the PA flow through the mill has to be increased so that more coal is flown to the furnace; otherwise, there may be jamming.

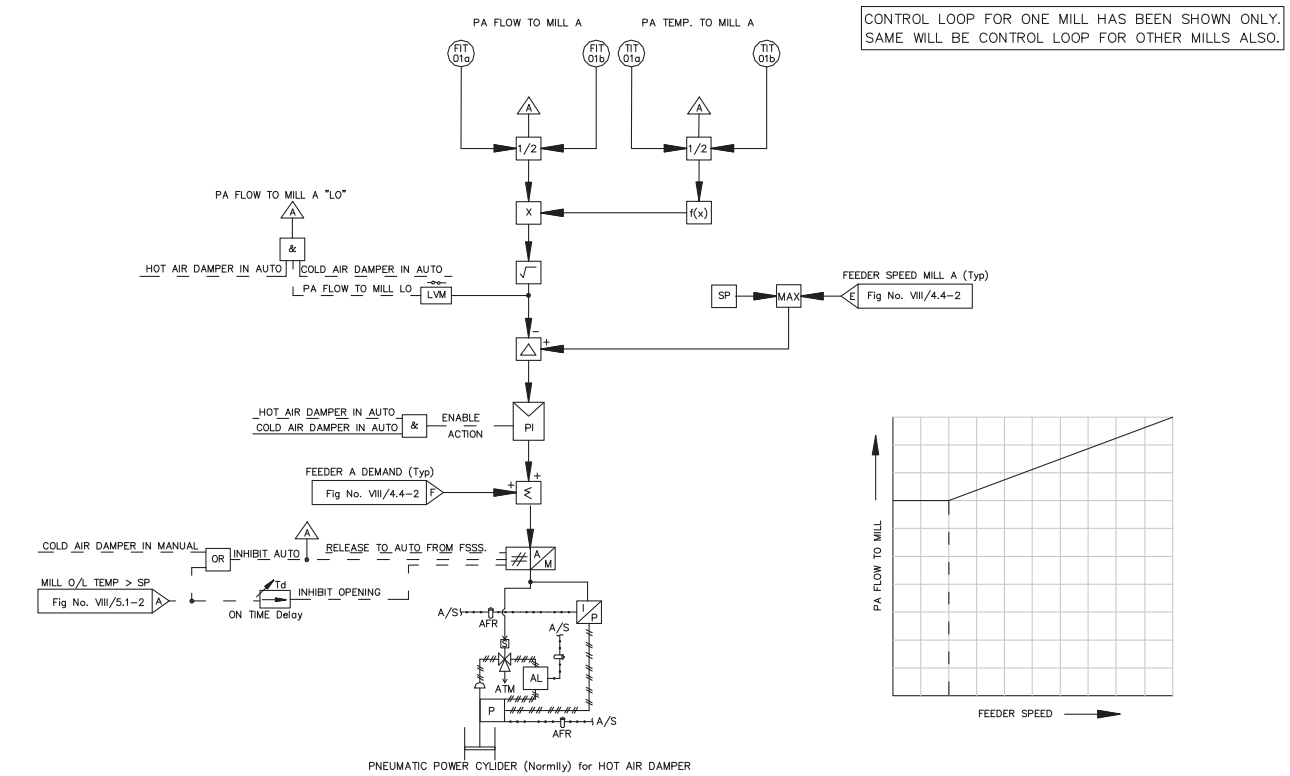
The mill outlet temperature is kept in a temperature band so that the coal is dried enough to be ignited instantaneously in the furnace; at the same time it is not so high so that there is a chance of fire. Exactly for these reasons both dampers are used. In older days of bowl mill cross-operation controls using HAD and CAD were used to regulate both air flow and mill temperature control. This cross-operation showed poor performance because of too much interference of the two loops. In modern days attempts have been made to make these two loops independent. It is very difficult to get a good temperature at the mill outlet during cold or rainy weather when the coal is wet. Also, HA quantity is much higher than CA quantity.

Now, if the loops were to be operated as per the old system, both dampers are increased to raise PA flow and the temperature immediately drops. In fact such cross-operation of the two dampers in tandem becomes a nightmare for operation and process control engineers, especially when the coal is wet. In modern-day philosophy, PA flow change due to load change is taken care of by HAD; if, because of this, the temperature increases, then only CAD is modulated to regulate mill outlet temperature. To be specific, PA flow to the mill is regulated by HAD and temperature is regulated by CAD independently with protection interlocks. Mill temperature control is discussed in Section 5.1 of this chapter so mill air flow is discussed here.

5.0.1 Objective

The objective is to ensure the required quantity of PA flow through the mill so that the exact quantity of coal demanded from the particular mill can be fulfilled under all load

www.EngineeringBooksPDF.com



NOTE: 1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS etc .IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER MANUFACTURER'S RECOMMENDATIONS.
2) THIS TYPE OF CONTROL LOOPS ARE APPLICABLE FOR MEDIUM SPEED BOWL MILL .
3) INTERNAL AUTO / MANUAL SIGNALS OF THE LOOP HAS NOT BEEN DETAILED OUT TO AVOID COMPLEXITY.
4)TO GIVE AN IDEA TO THE READER, OPEN LOOP CONTROLS HAVE BEEN SHOWN IN DASHED LINE TO DISTINGUISH IT FROM MODULATING CONTROLS. THIS IS HOW IT COULD BE REPRESENTED IN REALITY FOR BETTER UNDERSATNDING

FIGURE VIII/5.0-1 Mill air flow control for bowl mill TT boiler.

conditions and there is no mill jamming. It is very important to understand the philosophy behind the loop and the relative dispositions of these dampers and flow elements (refer to Figure III/9.2-4 PA flow PID). The entire quantity of PA demand for the mill is taken care of initially by hot PA so that the chances of a temperature drop are less. However during summer and dry seasons, there is the possibility that the temperature at the mill outlet may rise. If so, the cold air damper, discussed in the next section, opens more and there is an increase in cold air.

As a result, there is more PA flow than demand from the feeder speed and naturally the HAD opening is reduced. Here also there is cross-operation of both dampers, not in the loop but through process; hence, there is less chance of interference. However, as a precautionary measure, interlock is incorporated to see that, when CAD is in manual or the temperature is too high, the HAD loop goes to manual. In this way, chances of mill outlet temperature change can be eliminated.

5.0.2 Description

PA flow is measured after the mixing of HA and CA with the help of the Venturi/Pitot/Piccolo tube and redundant smart DP transmitters (Figure VIII/5.0-1). Since there is a possibility of temperature variation, suitable temperature compensation arrangements as shown are made to compute total PA flow to the mill.

There can be two options for set value: one manually adjusted set value and one derived proportional value from feeder speed. The maximum value between the two is considered for the set point so that in any case the PA flow is never less than that required for the corresponding the feeder speed. In fact, to clear out any mill jamming, the operator can set a value other than that required by the corresponding feeder speed. The error signal generated by the difference between the set value and the measured value is fed to the controller. At the output of the controller, feeder speed demand is added as a feed-forward signal so that in case of any load change the PA flow can act fast. Finally, the output of the controller and/or the A/M station goes to the FCE of HAD to be regulated.

5.0.3 Alarm and Interlock

5.0.3.1 Alarm

PA flow to mill A is generated with the help of LVM from the actual PA flow. Here, to avoid a spurious alarm, HAD

www.EngineeringBooksPDF.com

and CAD in auto mode have been taken in through an AND gate, so during startup and other operations such an alarm does not sound. Whenever CAD is in manual or the mill outlet temperature is high, an alarm is generated to draw operator attention, as in any of these conditions, so the loop can be operated manually.

5.0.3.2 Interlock

As a protection, when CAD is in manual *or* in case of high temperature at the mill outlet, the auto operation of the loop is inhibited. If even after operator action the high temperature persists over a period of time, the HAD is further opened a precautionary measure. The loop is released to auto only when it is permitted by FSSS/BMS. An error signal is fed to the controller or there is controller output only when both CAD and HAD are in auto so that there is no saturation of the controller.

5.0.4 Set Point

Normally, up to a certain percentage of feeder speed, the set point may be fixed; later it increases with feeder speed, as shown earlier in Figure VIII/5.0-1

5.1 Mill Temperature Control

5.1.0 General

Mill temperature control is an essential part of coal or pulverized fuel combustion for the following reasons:

- Coal, when coming out of the pulverizer, must be dry to avoid clogging up the coal pipe lines leading to the furnace chamber of the boiler house
- A significant amount of moisture may increase the dew point, so moisture removal is necessary to the extent possible by drying the coal at the mill outlet
- Coal types normally used in power plants require preheating to make them more easily combustible
- Appropriate coal drying calls for lower pulverizer startup costs

The total moisture content of the coal delivered to any power station is affected by weather and other seasonal changes and variation in coal quality from shipment to shipment. Considering this variability and also to handle serious problems like clogged coal pipelines, a fixed set point must be maintained at a higher value capable of providing a sufficient margin to handle spikes in surface moisture.

5.1.1 Objective

The mill temperature control is provided to supply fuels at an optimum temperature. *Optimum* means that it should be high enough to maintain flowability and low enough to avoid fire hazards. For this purpose, the transportation media that is primary air (PA) inlet temperature to mills is considered the heating agent with a sufficiently high temperature and quantity to raise the mill outlet temperature, which is the measured or process variable in this control loop strategy.

5.1.2 Discussion

The mill temperature control is actually a control strategy for maintaining the mill outlet temperature at a set value and for that purpose, preheated PA is introduced at the mill's inlet. The right quantity of PA is equally important to ensure a sufficient heat input rate to be exchanged through direct mixing with the solid but pulverized fuel. For obvious reasons, the amount of air is ultimately proportional to the mill load vis-à-vis the fuel or total air flow or main steam flow as per the control loop philosophy. Normally for each group, one set of hot and cold PA dampers is provided as the final control elements for the above purpose. The operation of this set of control dampers varies from plant to plant.

In earlier days, the hot PA and cold PA dampers were regulated in the same direction when there was a change in primary air flow demand (no separate damper for PA flow control vis-à-vis fuel flow control; even today no separate PA flow to the mill damper exists). Rather, they (hot PA and cold PA dampers) were supposed to move in the opposite direction to respond to the change in mill outlet temperature. Here, the PA flow control action for a load change takes place first as per the boiler load demand during the process transient condition, but the time it takes is excessive.

According to some schools of thought, the feeder speed controller output, after receiving the command for boiler fuel, is transmitted to the coal feeder speed-changing system and to the position controller of the hot PA damper. This arrangement envisages simultaneous control actions in speed change and repositioning of the hot air damper. The primary duty ascribed to this hot PA damper, according to this control strategy, is to maintain only the mill outlet temperature to a desired value and also to take care of the feeder speed demand as a feed-forward signal for damper position control.

The function of CA damper position controller, on the other hand, is to control the total primary air flow to a value required to maintain the flow velocity for safe and smooth transport of the pulverized fuel to the furnace for combustion. The demand signal for the cold PA damper may be generated directly from the boiler load demand after the lead–lag route, and the same signal also acts as a process trim on the feed-forward control applied by the hot damper controller. There may be some modification where hot air damper receives the feed-forward signal from the PA flow

www.EngineeringBooksPDF.com

controller as well and the CA damper controller receives the feed-forward signal from both the fuel and the temperature controller.

Unfortunately, the control action is not so effective due its sluggish response, wasting excessive time and resulting in undesirable disturbances in steam pressure whenever boiler load or fuel quantity changes are called for. The control loop considered in this section is for a typical 250 MW thermal power fossil-fired station with a Babcock design, where the quantity of PA flow to each mill is determined by a separate damper after the hot and cold PA flow paths are adjoined, that is, in the common line. The hot and cold PA dampers are dedicated to temperature control only. If there is no temperature change due to increasing or decreasing load, these dampers do not respond to the new flow requirement, but the PA fan inlet dampers come into picture to take care of the new load by maintaining the PA header pressure.

Hot-air and tempering-air mixing requirements vary as fuel moisture varies and as primary air bias varies. Mill outlet temperature control systems are nowadays so properly set up that their activity cannot even temporarily influence any impact in PA flow.

5.1.3 Control Loop Description

Figure VIII/5.1-1 is a schematic representation of how the control loop is implemented in a typical 250 MW plant having a drum-type boiler and coal-fired furnace with a Babcock design. Control loop philosophies are of various types, as discussed previously, and may vary with manufacturers' design and type of fuel to some extent. However, the basic idea remains the same. As there is a separate section dedicated to the control loop for ball-and-tube mills, this section covers the control loop for other type of mills.

5.1.3.1 Measurement of Mill Outlet Temperature

Sufficient redundancy is provided (shown as triple redundancy but depends on the customer or its consultants). This measured signal after the necessary voting circuit is transmitted to the controller as a process or measured variable. The measuring or tapping point is important so as to ensure a representative temperature and at the same time avoid a maximum abrasive position. The protective thermowell must be made of suitable material such as tungsten carbide, which is about eight times stronger than 316 SS to

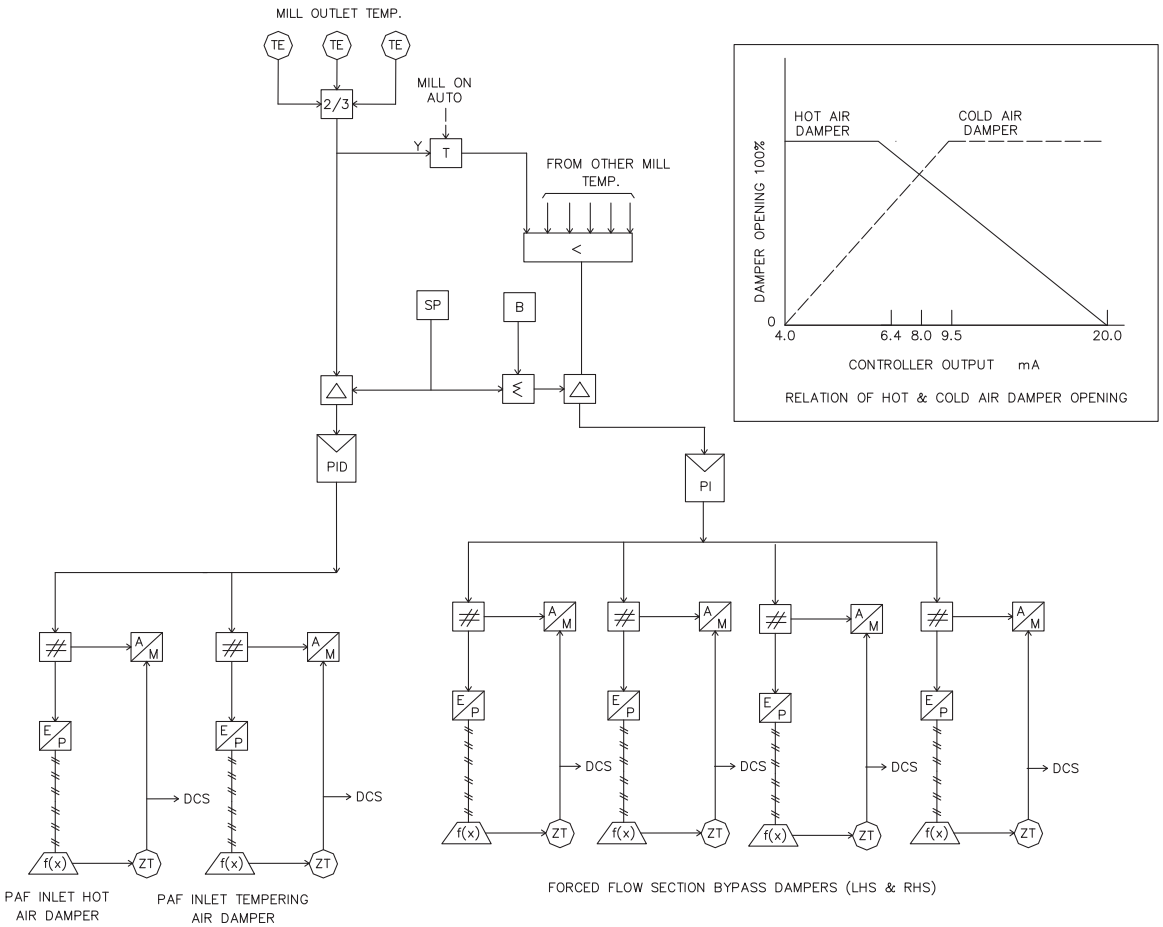


FIGURE VIII/5.1-1 Mill outlet temperature control.

www.EngineeringBooksPDF.com

withstand the fierce nature of the medium with a sufficient high velocity.

5.1.3.2 Mill Outlet Temperature Control

Among the many control strategies to choose from, the selected loop as described in this subsection is a part of the total PA system which takes care of temperature control only, without taking into consideration the other parameters and effects. As described elsewhere in this section, the mill-wise PA flow is separately maintained by dedicated PA dampers. Mill-wise HA and CA dampers are provided to maintain the mill outlet temperature and the total impact of all the mill-wise PA flow and mill outlet temperature controls on the actual total PA flow is taken care of by the PA inlet dampers by maintaining PA header pressure. This control loop strategy appears to be the most noninteractive between PA flow and temperature where both parameters are very important in creating the optimum transportation condition of pulverized fuel.

The controller is set with a fixed desirable value for the mill outlet temperature, and the simultaneous action of hot and cold PA dampers is used in this control loop to maintain the temperature. The normal operating zone envisions the full open condition of the hot PA damper, and any temperature change is taken care of by the cold PA damper. With the full open condition of the hot PA damper, the cold PA damper may be modulated from a full closed position up to an opening of almost 60% (typical value). At 60% any increase in mill outlet temperature causes the controller output to call for a further opening signal to the cold PA damper position and simultaneously for decreasing the signal to the hot PA damper position.

This operating zone of simultaneous positioning of the two dampers is very limited and if the temperature still increases, there is a certain point where the cold PA damper remains in the full open position and then, after any further increase in temperature, is taken care of by the hot PA damper. The situation is just the reverse when the temperature starts decreasing so that the hot PA damper position increases toward 60% (typical value) and the cold PA damper position decreases. After a certain time the hot PA damper is again at the full open condition while the cold PA damper is modulated.

In this control loop, there is the further need to maintain the mill outlet temperature if that goes beyond the capabilities of the hot and cold PA dampers in case the air temperature itself is low at the outlet of the PA heater because of low flue gas temperature, resulting in poor heat exchange. The sole cause for this event is the flue gas heat content, and some measures can be taken to prohibit it from falling across the heat exchangers instead of bypassing a part of heat exchangers in the superheater/reheater section of the boiler. This is accomplished by providing another common temperature controller. The measured or process variables are the same mill outlet temperatures, but through a minimum selector and for those mills whose controllers are running in auto mode only.

The set point is derived after putting a negative bias on the previously mentioned set point of the main mill outlet temperature control. This set point being lower, its controller output is not normally interfered with by the main control system. When the mill outlet temperature cannot be maintained even by fully closing the cold PA damper and fully opening the hot PA damper, the temperature comes down after some time. As soon as the temperature becomes lower than the bias value, the second controller takes charge and transmits the output command to the bypass dampers to take a proportionate bypass position so as to allow a part of flue gas to flow without taking part in the heat exchange system. The average flue gas temperature now being more than that without bypass, then assists in raising the mill outlet temperature with a higher PA temperature at the PA heater outlet.

5.1.4 Mill Outlet Temperature for a TT Boiler

The control loop for mill outlet temperature discussed here is mainly for TT boilers based on a CE design with bowl mill (refer to Figure VIII/5.1-2). A similar loop is valid for a ball-and-tube mill, which is discussed separately in the next section. In order to understand the loop in the figure, it is advisable to look at Figure VIII/5.0-1 and the associated PID figure (refer to Figure III/9.2-4).

5.1.4.1 Objective

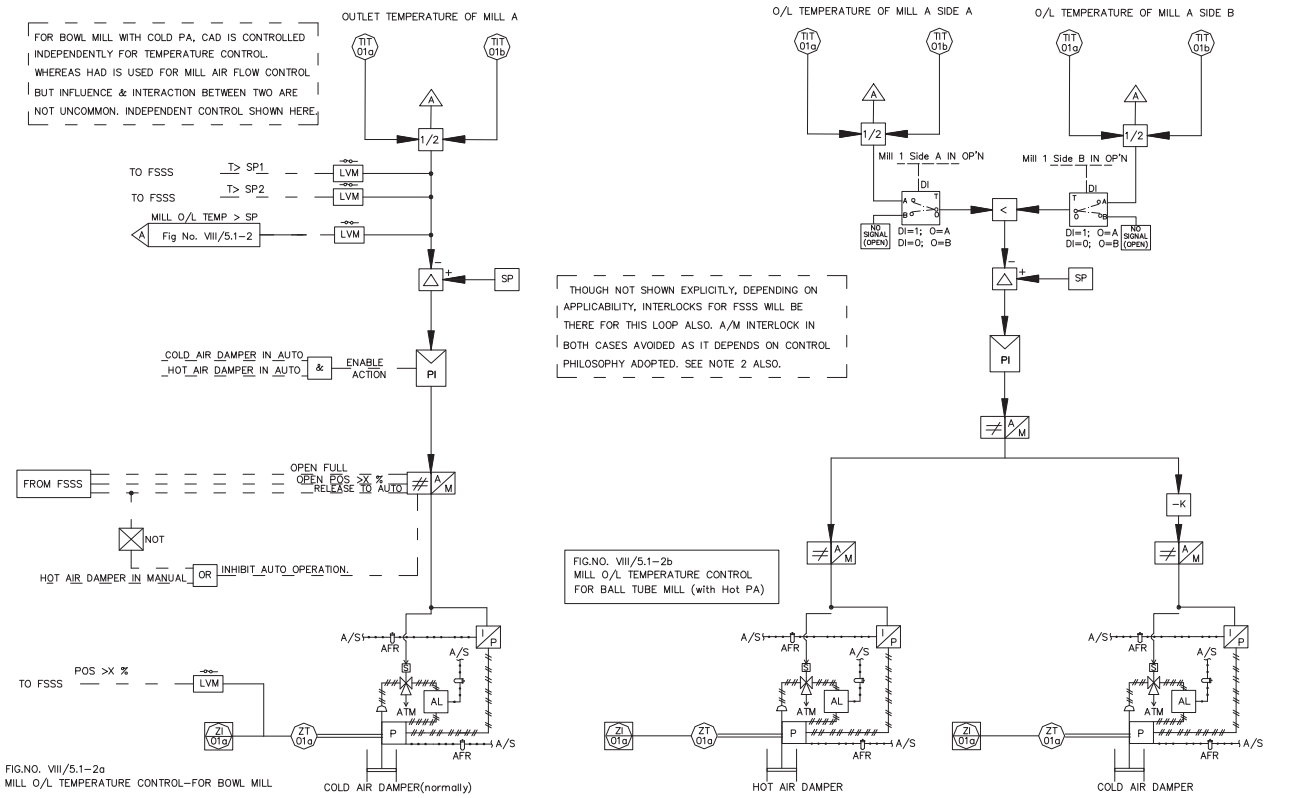
The outlet temperature of the coal mill is maintained at desired point so that the coal delivered from the mill is completely dry and achieves the desired temperature. Also, in case of high temperature at the mill outlet, cold air is blown in to reduce the risk of fire.

5.1.4.2 Discussion

Normally, the entire requirement of PA flow necessary for a particular load at the mill is initially attempted through HAD so as to ensure complete drying of the coal (especially during rainy seasons) and to raise the mill temperature at a desired point. However, there may be times during hot dry summers when the mill outlet temperature shoots up. This is also never a desired situation because of fire hazard. In fact, to combat this fire hazard, arrangements for mill-inerting systems with inert gases (e.g., N_2 and CO_2) need to be made (another purpose is to reduce air supply).

This is more important for ball-and-tube mills, especially when these are operated with one side only. Therefore, CAD comes into operation whenever there is need to bring down the mill temperature. Naturally when this

www.EngineeringBooksPDF.com



NOTE: 1) IN ACTUAL CASE THERE MAY BE MORE NUMBER OF INTERLOCKS FOR PROTECTION OF THE MILL, THESE ARE NOT SHOWN TO AVOID COMPLEXITY AND BETTER UNDERSTANDING (ALSO DIFFERS WITH MANUFACTURER,
2) CONTROL LOOP SHOWN HERE IS FOR ONE MILL ONLY , OTHERS WILL BE IDENTICAL. IN FIG VIII/5.1-2b HAD & CAD ARE SHOWN IN CROSS MODE BUT IN REALITY IT MAY BE DIFFERENT, e.g. MAY BE CAD WILL OPEN ONLY WHEN 'HAD' HAS TAKEN MIN VALUE STILL THE TEMPERATURE IS HIGH (MOSTLY HAD WILL BE USED TO CONTROL!). INTERLOCK ASSOCIATED WITH A/M STATIONS HAVE BEEN AVOIDED FOR SIMPLICITY. Typ FSSS INTERLOCK SHOWN IN ONE LOOP.
3)TO GIVE AN IDEA TO THE READER, OPEN LOOP SIGNALS HAVE BEEN SHOWN IN DASHED LINE TO DISTINGUISH IT FROM MODULATING CONTROLS. THIS IS HOW IT COULD BE REPRESENTED IN REALITY FOR BETTER UNDERSATNDING

FIGURE VIII/5.1-2 Mill outlet temperature control for bowl mill and tube mill.

damper operates (i.e., starts opening through process feedback), the hot air damper closes. Here also is a cross-operation of the two dampers but through process and not directly via the loop, so control loop disturbances are fewer than in the old days when cross-operations were implemented in the loop.

5.1.4.3 Description

Mill outlet temperatures measured by redundant temperature elements and transmitters are put in an error generator. (Temperature element specialties were discussed earlier and so not repeated here.) The output of the error generator drives a PID controller. In general, since temperature is a sluggish parameter it is always advisable to use PID controllers for better results. To prevent controller saturation, controllers are put into service only when both the loops are in auto. The output of the controller through I/P converters normally drives pneumatic actuators meant for CAD.

5.1.4.4 Interlock

As stated earlier, only when both HAD and CAD are in auto is the controller put into operation. Since FSSS operations depend on mill temperature conditions, with the help of the limit value monitor (LVM) necessary contacts statuses are shared with FSSS. The loop can be released to auto by an FSSS command. As a protection, both the full opening command and the >x% command for the mill CAD are issued from FSSS so sufficient cold air is circulated. If the auto release command from FSSS is missing or if HAD is in manual, it is necessary to inhibit auto operation so that the operator pay complete attention to the mill outlet temperature. That is the check back signal for FSSS from the loop for damper position.

5.2 Mill Control for a Ball-and-Tube Mill

5.2.1 General

The ball-and-tube mill is one of the many mill or pulverizer types used for trimming material size, such as grinding various types of fuels like coal or other minerals such as cement plant ingredients (Figure VIII/5.2-1).

A ball-and-tube mill basically includes a large, hollow cylindrical drum that rotates along its axis, supported by a trunnion on each end. Wear-resistant liners are provided inside the drum that contains a variety of ball sizes that fill

www.EngineeringBooksPDF.com

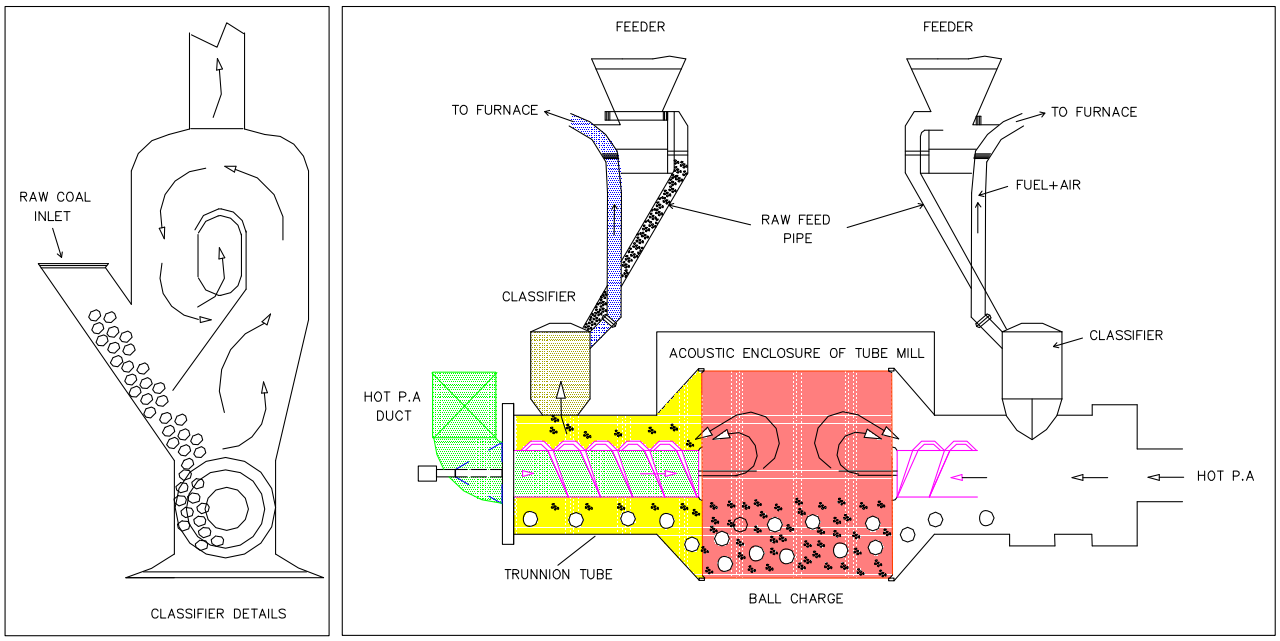


FIGURE VIII/5.2-1 Schematic of ball-and-tube internal arrangements.

approximately half of the drum. These balls are normally made of cast alloy steel or forged steel range from 25 to 150 mm, or more for higher-capacity mills. The drum is made to rotate at a slower speed by suitably reducing the high speed of standard electric drives. Speed reduction is achieved by a gear train consisting of a reduction gear box and a large spur gear.The slow speed is normally available at 13 to 35 rpm depending on the size of the drum—specifically, its diameter.

During rotation of the drum, all the balls move upward approximately 60 to 70% along the periphery and then cascade over each other with a tendency to move toward the center of the drum as a continuous process. As a result, a mass of balls and larger materials mix with each other at the bottom of the drum, which forces the material size to be reduced to small particles. The reasons behind this action may be attributed to the following:

- Force due to the impact of the falling heavy balls on the materials
- Force due to attrition of materials with each other and with liners
- Force due to crushing of the heavy balls rolling over each other with the materials between them and the same action by the liners and the balls

Primarily the larger sizes of raw feed (∼25 mm) are cracked on impact and finally reduced to powder from attrition and crushing force developed as the balls roll and slide inside the drum along with the charge materials. Very high coal fineness is achievable in the range of 70 to 90 microns at the outlet.

Raw feed and hot PA are supplied and also taken out from both sides of the mill. For this type of arrangement, half-mill operation for partial loads is possible and carried out in practice. However, one-side or half-mill operation may result in high temperature and accumulation of pulverized fuel in the unused classifier side, causing an explosion.

Primary air after adequate heating (the temperature is controlled by mixing cold air) is blown through the mill for drying the powdered materials or PF, which are then made fine and light enough to become airborne and are vented out of the pulverizing zone of the drum for use in further processes such as coal combustion. The hot air enters the mill through the hollow shaft of the screw feeder inside the pulverizing zone. Raw materials, as already discussed, are introduced from both ends of the drum through variable speed feeders so as to regulate the PF flow as per demand.

The outlets of PF and air mixtures are also taken out from both sides of the drum for distribution toward the combustion chamber. An external classifier is provided at both sides of the drum to allow only the fine particles outside. Because of the whirling action, larger particles experience more kinetic force and collide with the classifier wall only to lose the force to zero; this rejected material comes back downward, forced by gravity to the grinding zone with the raw feed. The new raw feed continuously enters through the ends of the drum to assume the already vacated place of the airborne particles that are leaving.

The classifier should be so designed as to ensure removal of fine feed particles from the grinding zone. Thus, the classifier should be designed to ensure removal of fine

www.EngineeringBooksPDF.com

feed particles from the grinding zone so that production of extreme fines are eliminated and mill current is kept within limit. The power consumption is more toward that unnecessary activity. The relatively large quantity of raw feed and semi-ground feed mixture in the grinding zone may actually be regarded as additional storage, and any unexpected and abrupt increase in demand can easily be met by it. However, it is to be noted that the electrical power consumed for a particular quantity of raw feed for this type of mill is very high, especially at the partial load.

There is a possibility of clogging at the feeding end of the pipe caused by moisture on the surface of the raw feed, which may in turn reduce the capacity of the mill. It is therefore very important to reduce the moisture content in the raw feed. However, the arrangement of recirculating the heated and dried oversized rejects helps in reducing moisture and thereby clogging at the feed inlet. The hot air with powdered fuel flows out of the mill through the annular portion of the screw conveyer or feeder and the trunnion tube, and thereby dries the raw feed while approaching the screw feeder.

During the starting period a portion of the hot PA is bypassed and sent through the raw feed to minimize the moisture in it; as the load increases, this bypass air is decreased and finally brought to zero above a particular load. However, according to another school of thought, the bypass damper is kept open to a minimum value of, say, 10% even up to 100% of the mill load so that even at a high load fine feed dusts are not unnecessarily fed to the mill to increase mill current. When the mill trips, a good quantity of the heat trapped in it is lost. Also, a good inerting arrangement to eliminate fire hazard may be necessary.

A trunnion seal is provided between the rotating drum and the related stationary components, such as the raw-feed piping system, so that the material can move to the rotating drum. The trunnion seal assists passage of raw feed toward the rotating drum, but it prevents the escape of material into the surroundings. It is always desirable to form the best possible seal between stationary and rotating components to thwart the tendency of the fine particles to escape because of the inadequate sealing arrangement. Replacing the trunnion seals is a cumbersome job that requires removing the inlet/outlet box from the foundation blocks under the trunnions; the downtime required is significant. However, a sealing arrangement is provided by supplying pressurized air through separate seal air fan(s) in an arrangement of common redundant fans or individual fans.

5.2.2 Advantages of Ball-and-Tube Mills

Ball-and-tube mills advantages include the following:

- High availability
- Large reserve capacity
- Low maintenance
- Relatively low air—PF ratio
- Suitability for hard and abrasive raw feed/fuels
- Comparatively fast response over the entire load range
- Availability of constant capacity and fineness
- Suitability for use with a wide range of coals
- Practically unaffected by the unwanted presence of foreign material

As just pointed out, maintenance requirements are lower and also easier to some extent; in the normal case, only new ball charging is essential at a regular interval so as to make up for the loss of metal in the balls in order to carry out the grinding process.

5.2.3 Disadvantages of Ball-and-Tube Mills

The following are some of the disadvantages of using these mills:

- Changing the lining is a lengthy process
- More floor space required
- Comparatively weighty machine with various gear and clutch arrangements
- Higher cost compared to a same capacity pulverizer
- Unsuitable for a plant with intermittent operation
- High required electrical power/starting torque
- Considerably high noise level
- Possibility of inerting arrangement requirement

The wear and tear on the lining of the mill drum is less, but once called for, the replacement procedure is cumbersome and takes considerable time. The floor space requirement for this type of mill is high compared to other type of mills as well. Because of the larger space requirement and the corresponding weight of ball-and-tube mills, the cost also high.

Ball-and-tube mills are not suitable for intermittent operation because of the significant amount of heat energy stored in both the raw feed, particularly coal, and the balls may lead to overheating and fire when the mill is kept idle. The huge combined mass of the mill and the two charges(raw feed and balls) requires continuous high power from the drive motor. The design or the arrangement itself stipulates a high starting torque electric motor. As per the operating principle and functional requirements of the mill, the noise level is significantly high and requires a noise-suppressing enclosure or an acoustic muffler.

5.2.4 Objectives of Control Strategies

There are a few control loops for safe and efficient running of mills. The important loops are shown along with a flow diagram in Figure VIII/5.2-2 and Figure VIII/5.2-2(a,b). Fuel flow and mill air flow control details for ball-and-tube mills are given in Section 4 and illustrated in Figures VIII/4.4-3 and VIII/4.4-4.

www.EngineeringBooksPDF.com

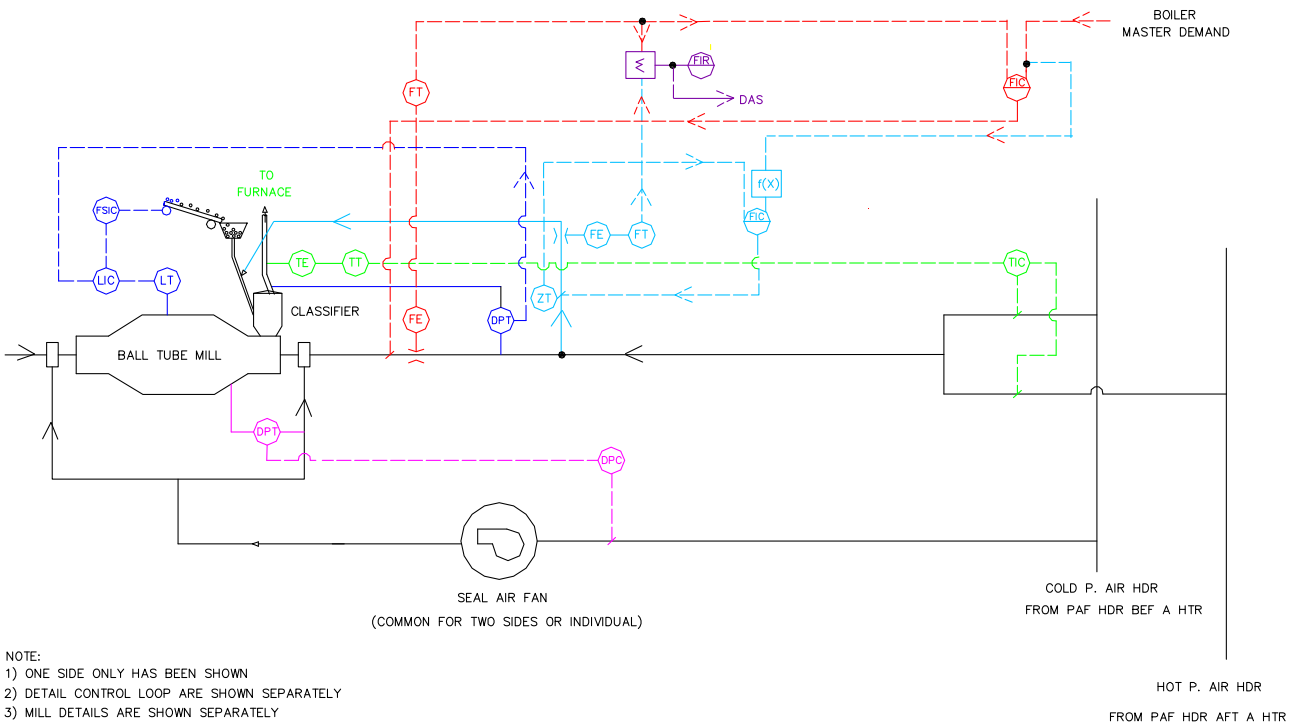


FIGURE VIII/5.2-2 Typical flow and control diagram of ball-and-tube mill with common PA fan system.

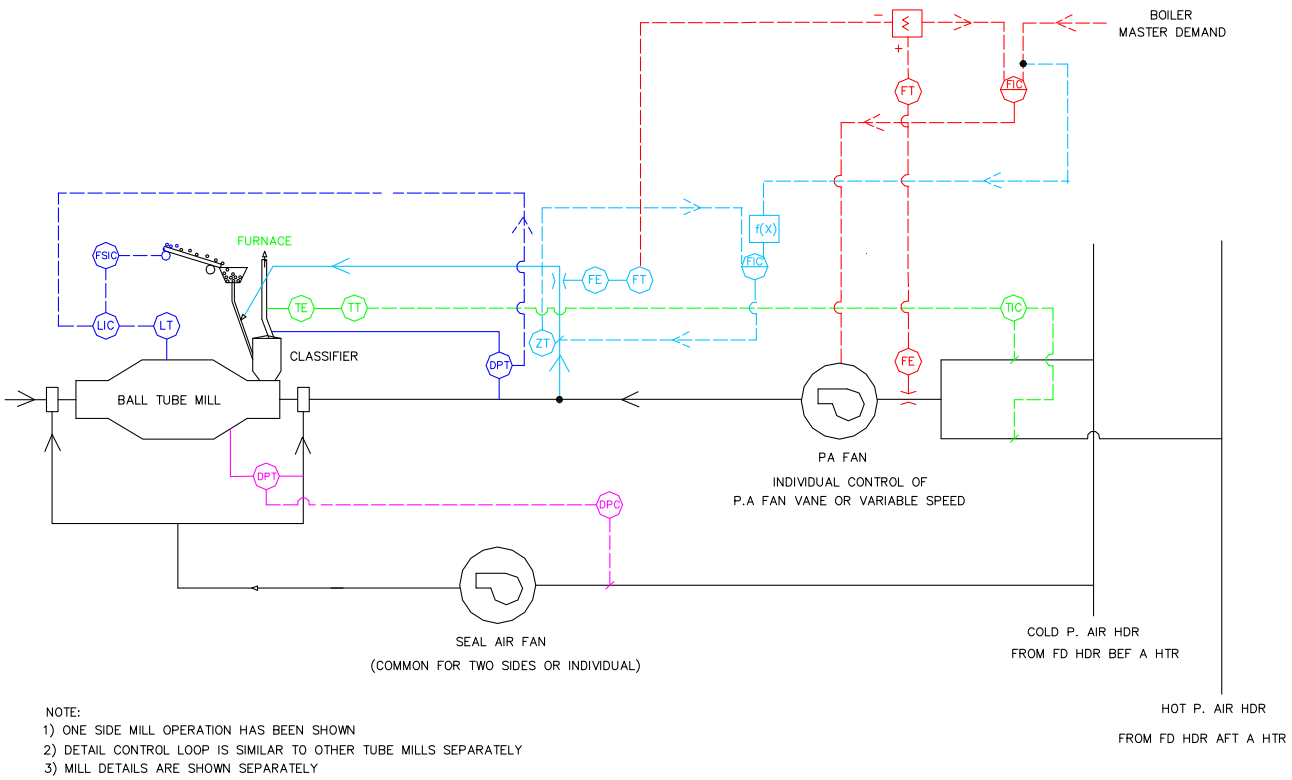
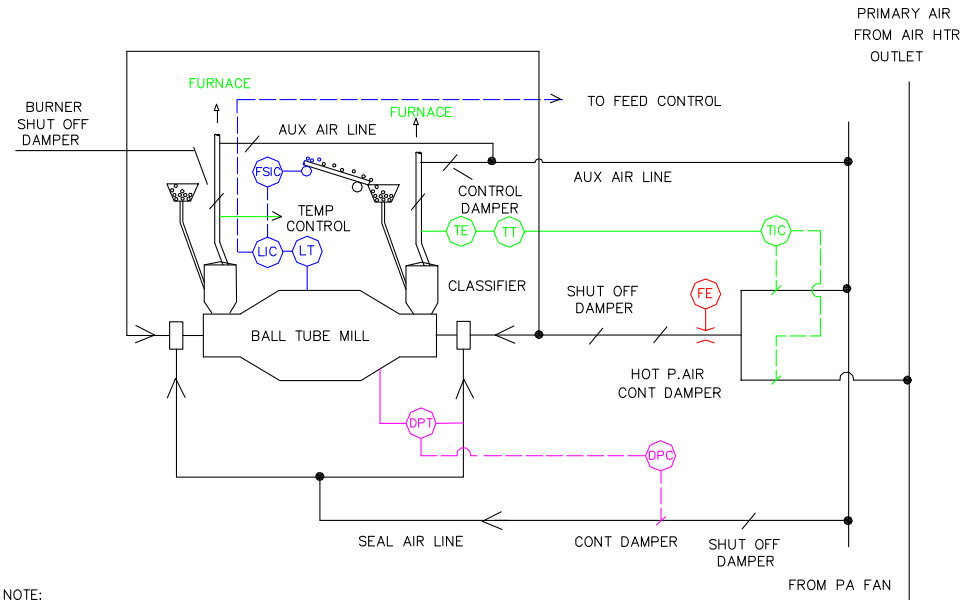


FIGURE VIII/5.2-2(a) Typical flow and control diagram of ball-and-tube mill with individual PA fan system.

www.EngineeringBooksPDF.com



NOTE:
1) MILL OPERATION HAS BEEN DISCUSSED IN SECTION 5.2.6.4 OF CHAPTER VIII
2) DETAIL CONTROL LOOP IS SIMILAR TO OTHER TUBE MILLS EXCEPTING COMMON PA FLOW AND SEPARATE AUX AIR CONNECTION
3) MILL DETAILS ARE SHOWN SEPARATELY

FIGURE VIII/5.2-2(b) Typical flow and control diagram of ball-and-tube mill with common PA flow control.

The first and most important one is the mill outlet temperature control and is provided to supply fuels at an optimum temperature. The philosophy and purposes are the same as for other type of mills. During startup, the moisture and temperature are controlled by diverting a portion of hot air in between the feed pipe and the classifier; the control of this part is in the temperature control of PA flow to mill.

In some plants, a PA inlet pressure control loop is provided to maintain the common PA header pressure before the primary air heater and takeoff point of the cold PA header. Here the PA fans may be totally independent of the FD fans or may be from the discharge of the FD fans and often called the *cold PA system*. Mixing hot PA (taken after the primary air heater) and cold PA is done for controlled temperature for each mill. Although not shown in the figures' drawings, the PA header pressure control loop assists smooth and bump less control of actual PA flow to mill accomplished by the PA to mill damper control. The PA pressure control may not be required when mill-wise PA fan suction is taken from the temperature controlled individual hot PA header. The cold and hot PA header is taken from the FD discharge before and after the common air heater respectively without requiring a separate PA heater.

The mill drum-level control loop is meant for maintaining the level of the charges in the side the drum. Figure VIII/5.2-3 may be referred for easy depiction of the control strategy. This control is achieved by sensing the load on the mill by measuring differential pressure across the mill or the characteristic sound produced by the mill at different feed levels. The set point is normally a fixed value and the controller output is used to regulate the speed of the solid fuel feeder so as to maintain appreciable fuel reserve through an assured level in varying load. On account of ambient sound, sonar transducers are used as corrective or confirmatory elements and not as prime element to measure the level.

Mill load or fuel flow control follows the demand from the boiler master demand control signal and, unlike vertical-type ball or bowl mill, is achieved by regulating the quantity of PA that is a transporting agent only. The control strategies may be of various types as indicated next:

- Control of individual PA dampers with common PA fans
- Control of individual PA fans through PA inlet vane/damper control
- Control of individual PA fans speed through VFD

The details are provided in Sections 5.2.6.4 and 4.4.3 of this chapter in conjunction with Figure VIII/4.4-3.

Differential seal air pressure control is achieved by sensing the DP across the mill air inlet and mill drum inside by the DP transmitter and by regulating the seal air damper position. Seal air-to-mill inlet pressure is varied to ensure some extra pressure to arrest dusty air escape from the mill. There is a dedicated control loop for the purpose which may be common for the two sides of a mill or may be

www.EngineeringBooksPDF.com

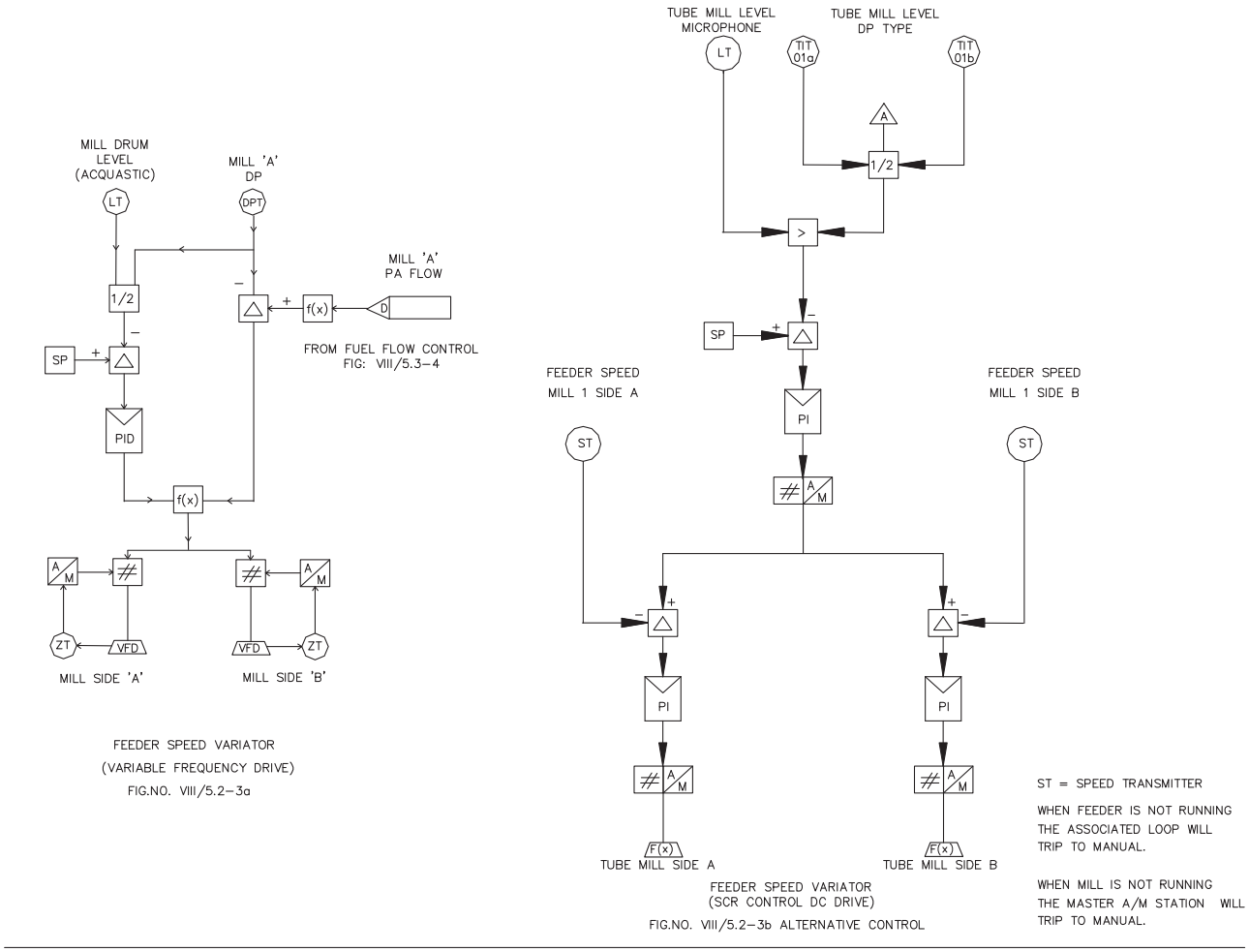


FIGURE VIII/5.2-3 Ball-and-tube mill level control.

individual for each feeder (twice the number of mills in general) as dictated by the milling system.

5.2.5 Discussion

5.2.5.1 Mill Outlet Temperature Control

The basic mill temperature control loop was discussed in Section 5.1 of this chapter. For ball-and-tube mills, there is another consideration for addressing the problem of moisture in the raw feed before it enters the mill. This untoward situation may be eliminated by increasing the raw feed temperature at mill inlet by the bypass damper, which is mainly operational during startup but may be continued up to a certain load and even up to full load depending on the design of the mill concerned. In fact, during startup, the amount of hot PA is less and may not be sufficient to prepare the feed in the right condition for proper grinding and flow. To fix this problem, a bypass line is taken out before the entrance of hot PA into the mill and introduced into the classifier (mixing chamber) between the raw material feeder and the mill inlet. This additional hot air preheats the feed to reduce the moisture content. Although this appears to be a part of mill temperature control, this initial control is accommodated in the mill load control that is a part of PA flow to the mill control as depicted in Figure VIII/5.2-4 or in Figure VIII/5.2-5.

5.2.5.2 Mill Drum-Level Control Loop

As mentioned earlier, the mill drum-level control loop is meant for maintaining the level of the charges in the side the drum. In this type of mill, the capacity of raw feed storage is very high and is maintained at an average constant value by means of level control of the charges irrespective of actual fuel flow. The advantage of the availability of a constant amount of materials at all loads is the reserve fuel, and it is highly favorable for process

www.EngineeringBooksPDF.com

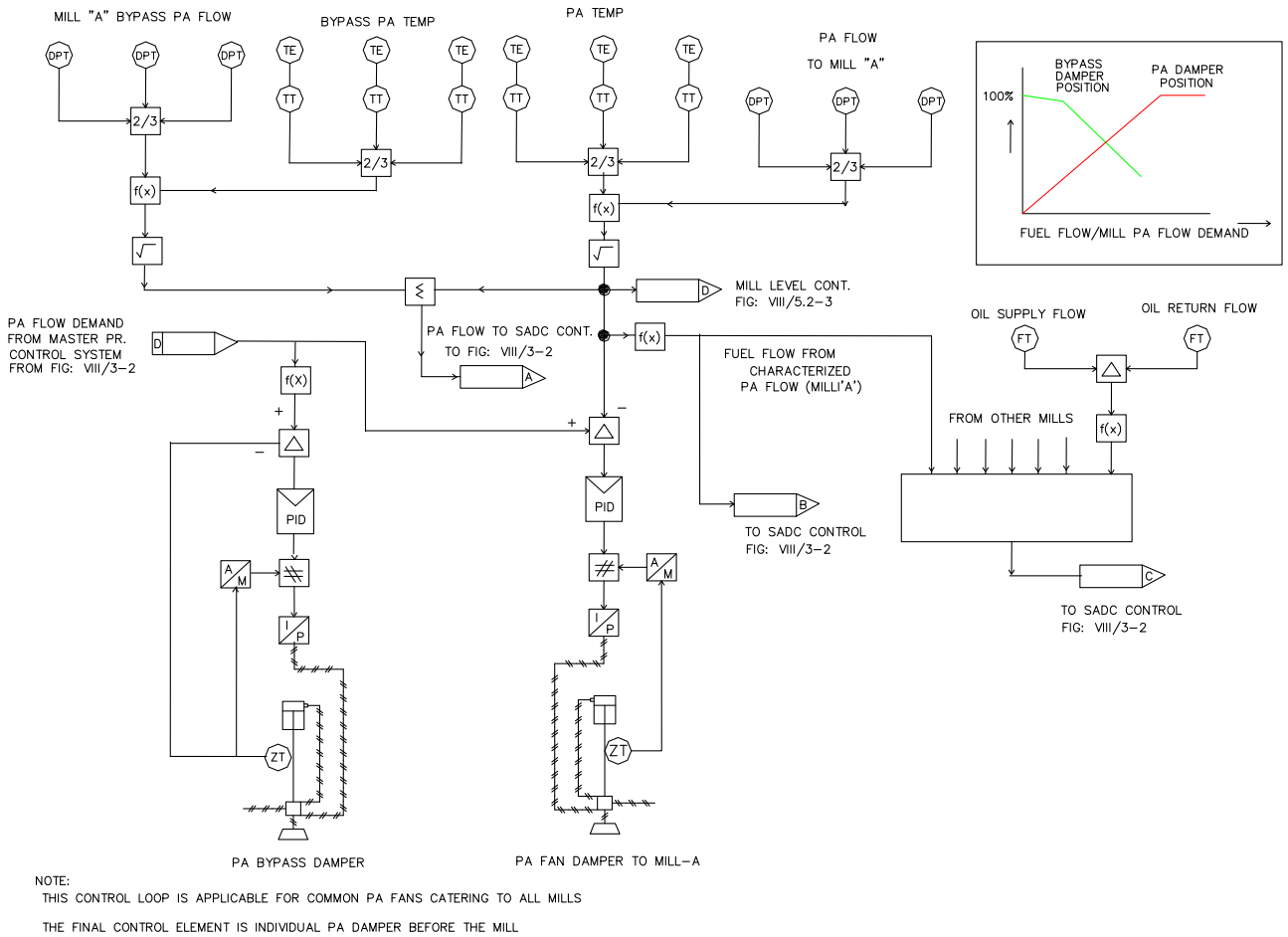


FIGURE VIII/5.2-4 Fuel flow control for ball-and-tube mill (by PA damper).

control, especially when there is a sudden load increase. The extra amount of load is fed by the reserve capacity before the feeder response takes place. The shortfall of materials in that case is detected by low level and the feeder then responds accordingly. However, there may be a feed-forward signal from the PA flow to increase the feeder speed. This control is achieved by sensing the load on the mill by measuring DP across the mill or the characteristic sound, which is also called the *electric eye*, produced by the mill at various levels.

5.2.5.3 Mill Drum-Level Sound Detector

It has been observed that the sound or noise level of a mill, as generated during the normal range of operation, changes in accordance with the magnitude of the mill loading. Elaborate experiments reveal that the character of sound, as well as its intensity, is different, even when a mill grinding a single material, under the operating condition of running wet or dry in open or closed system without any relation to whether producing a coarse or fine product or to an actual real time feed rate. For example, the sound intensity is going to be more as the drum charge level becomes lower; on the other hand, as the charge increases, the sound intensity is going to decrease and turn out to be practically indistinct, that is, less than the exact sense of hearing of a human operator.

Automatic control of ball-and-tube mills utilizes this property of sound as the controlling variable and has been proved a highly convenient, realistic, and dependable solution with an economical sanction. By installing a microphone suitable for the range of frequency generated and proficiently utilizing the energy output of the detector to control raw feed into the mill, and thereby maintaining the grinding efficiency at a its maximum level. The acoustic detection device is installed in a kind of parabolic reflector to permit the sensor to pick up the signal generated by only one mill at a time.

The raw and low-level electrical signal output of the acoustic detector is then amplified and modified in an electronic transmitter to make it suitable for use in the automatic control loop. The detection system as a whole is calibrated to measure the optimum sound level predicting

www.EngineeringBooksPDF.com

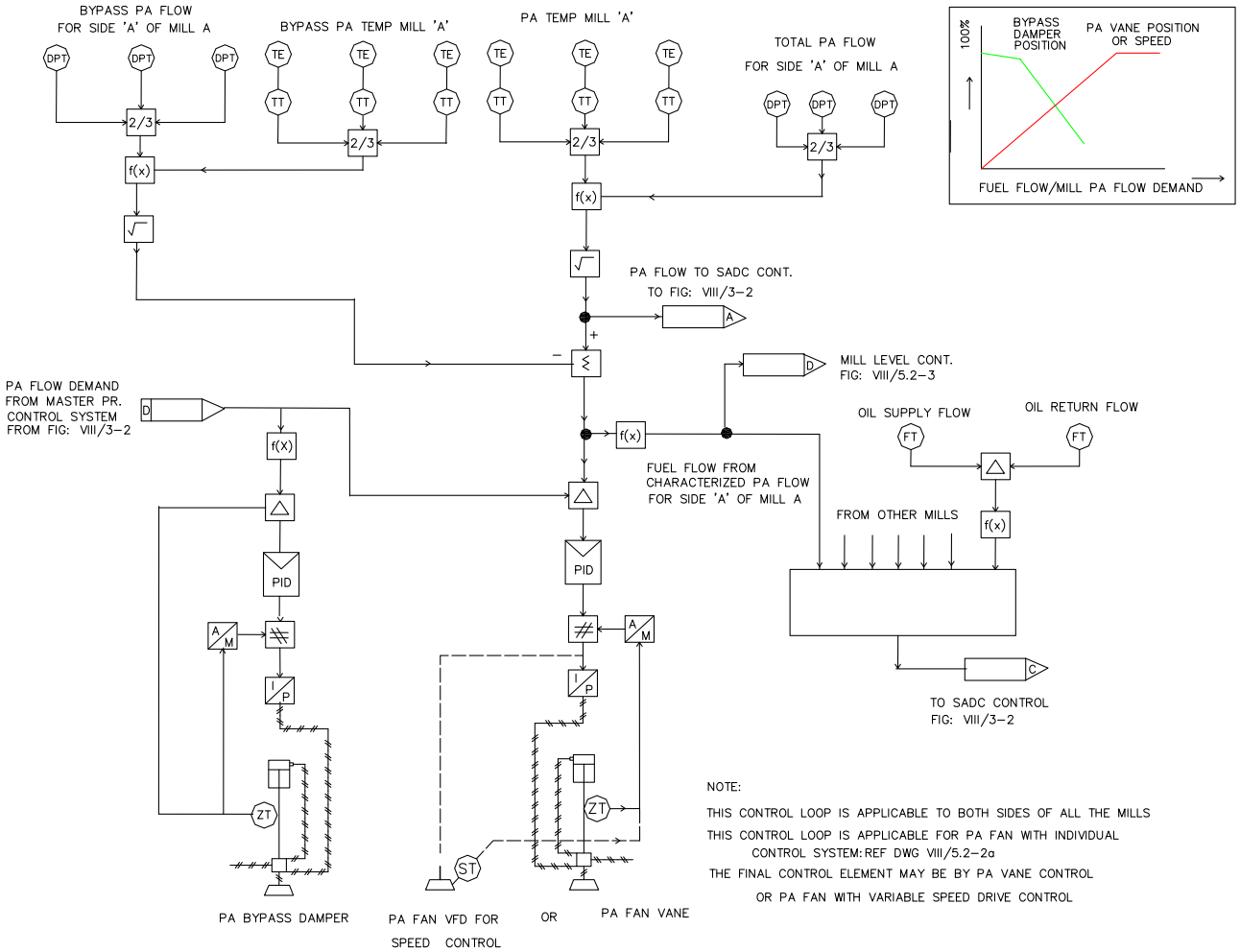


FIGURE VIII/5.2-5 Fuel flow control for ball-and-tube mill (by vane or speed control).

the mill charge level, and the control loop strategy is built to maintain that level at a constant value by adjusting the speed of the raw feeder to allow more or less material into the mill.

5.2.6 Control Loop Description

5.2.6.1 Mill Outlet Temperature Control

The control loop is similar to that discussed in Sections 5.1.3.1, 5.1.3.2 and 5.1.4. The relevant figure for reference is Figure VIII/5.1-1.

5.2.6.2 PA Inlet Pressure Control Loop

As already discussed, this control loop is provided to maintain the PA header pressure before the mixing of hot and cold PA duly controlled for temperature. Figure VIII/4-2 is also applicable for this type of mill when the PA is common to all the mills. The control loop is of course different for individual PA fan systems, as the above is applicable for the common PA system only. For control loop description, see Section 4.3.2.3 of this chapter. Common PA fans are provided with suction normally from the atmosphere or it may be from the FD discharge header. Header pressure control is performed through various types of final control elements.

As the fuel/load control is solely done by position adjustments to the PA damper near the mill, this control loop assists smooth and bumpless control of the fuel flow transported by the PA flow to the mill as the upstream PA header pressure control takes responsibility for providing an adequate quantity of air at any environmental condition without sacrificing the required downstream pressure,

5.2.6.3 Mill Drum-Level Control Loop

Figure VIII/5.3-3 later in the chapter depicts the simple control loop. Any of the mill DP transmitters or level (sound-detector) transmitters is selected and the selected signal is connected to the controller as the process or

www.EngineeringBooksPDF.com

measured variables against a fixed-level set point. Sufficient redundancy in measurement may vary according to the plant's operating philosophy. The controller output is utilized for adjustment of feeder speed with the help of a VFD or SCR control for the gravimetric feeder/feeder speed variator.

At the higher load the charge level inside the drum decreases and the feeder speed should increase accordingly to replenish the material. For a decreasing load, the reverse action takes place. To take care of the sudden load change, the deviation between characterized PA flow and DP across the mill is used to modify the controller output to achieve the desired mill charge level.

5.2.6.4 Fuel Flow Control Loop

Mill load or fuel flow control follows the fuel demand from the boiler master demand control signal and is achieved by regulating the quantity of PA that is transporting agent only. Figures VIII/5.2-4 and VIII/5.2-4 depict the functioning of the control loop, which is similar to that of other mill types. For other mills the fuel demand signal from the boiler master demand is first taken care of by the mill-wise PA flow control system if the demand is less than the prevailing air flow control system. The characterized PA flow is then construed as the feeder speed demand. The ball-and-tube mill control system, on the other hand, uses feeder speed control for maintaining mill level control only and so the fuel flow control is achieved through control of the feeder-wise PA flow to mill itself.

However, the feeder-wise PA flow as measured after redundant transmitters voting selection and density compensated through temperature correction is again determined to get equivalent fuel flow. The total fuel flow is then computed by summing all the fuel (PF) flow of the running feeders and the supporting fuel (oil or gas) if any are being utilized at that time with proper weightage, taking consideration of their thermal or calorific value. The higher selection of this total equivalent fuel flow signal and the air flow demand signal from the boiler master demand (Figure VIII/2.1) is then taken as actual air demand just as in other type of mills.

As already discussed in Section 5.2.1, there is another feeder-wise control system associated with fuel flow control known as a *bypass damper control*. This feeder-wise damper is provided for each mill end for preheating the raw feed, which is an essential requirement during startup. No process measurement signal is utilized in this subloop. The same fuel demand from the boiler master demand (Figure VIII/ 2-1) is taken as the set point for the position demand of the bypass damper after due characterization, as shown (refer to Figures VIII/5.2-4 and VIII/5.2-5) in the control strategy and the graphical representation of approximate positions of the two final control elements. The previously mentioned two-position demands operate in opposite directions. After being in a fully open position for a certain load, ensuring elimination of initial moisture, this bypass damper begins to close gradually as the load increases.

There are two main types of fuel flow controls achieved through the proportionate PA flow only: (1) common PA fans with individual PA dampers and (2) individual PA fans with vane or speed control. There is also one known as a *mill-wise PA flow control* that is common to both sides.

5.2.6.4.1 Common PA Fans with Individual PA Dampers Figure VIII/5.2-4 may be referred to for this type of control along with Figure VIII/5.2-2. Here the mill PA flow and bypass PA flows are combined to form the total mill-wise PA flow to the furnace. The boiler master demand acts as a set point here, where the mill-wise PA flow is the measured value as this air flow is only responsible for transporting the fuel to the furnace. The controller output is the demand signal for the individual PA damper. For bypass dampers, the boiler master demand generates the set point while the actual position of this damper acts as the measured value for the controller output, which is the demand signal for the bypass damper.

For any load change, the two flows readjust their positions to deliver the required PA flow. For higher load the bypass damper tends to close to allow less flow for preheating of raw feed and the PA damper to the mill opens more to take care of the load demand.

Some alternative systems for ball-and-tube mill controls are presented in Section 4.4.4. For these loops, Figure VIII/4.4-4 may be referred to.

5.2.6.4.2 Individual PA Fans with Vane or Speed Control Figure VIII/5.2-5 may be referred to for this type of control along with Figure VIII/5.2-2(a). Here bypass PA flows need to be subtracted from the total mill-wise PA flow for the fuel flow control, and the total mill-wise PA flow to the furnace is required for air flow control. The reason for this is that the final control element and the flow element are both located in the common primary air path to the individual mill. The boiler master demand acts as a set point here, where the PA flow to the mill is the measured value. The controller output is the demand signal for the individual PA vane or variable speed drive as the case may be.

For the rest of the control loops (i.e., for bypass dampers), the control strategy is the same as the one described previously.

5.2.6.4.3 Mill-Wise PA Flow Control Common to Both Sides This type of mill design vis-à-vis operation is somewhat different from other types, as discussed earlier. Figure VIII/5.2-2(b), which is mainly followed by

www.EngineeringBooksPDF.com

manufacturers, such as the Foster Wheeler Energy AG corporation, may be referred to for information. Here the boiler combustion control signal regulates the output of the mill by PA flow control dampers placed in the common line to both the ends or sides. The predrying of coal feed is done at the entry of each side before it enters the drum, unlike what is done by the bypass PA damper in many types of tube mills.

Another significant difference is the provision of an auxiliary air and purge air supply line taken from the cold PA for each side of the mill drum. The same is designed to the required minimum velocities of the PA/fuel mixture for maintaining proper flow inside the coal duct and to prevent fuel settling during startup or in extreme low-load operation. This feature extends the individual mill load range without encountering drifting or pulsating fuel flow to the burners. The other purpose is to purge the coal air line automatically when burners are taken out of service.

The feed level control in the drum, classifier outlet temperature control, and seal air DP control are very much similar to those in the other type of mills with the exception of the source of the seal air. Here the seal air supply is taken from the cold PA without any provision of a seal air fan.

6. FURNACE DRAFT CONTROL

6.0 General

The boiler control system consists of this very important control loop named furnace draft control. As discussed in previous chapters, the boiler has two distinct zones of functional operation. The first one is the firing zone; the other is, in general, the heat exchanger zone. The firing zone consists mainly of various types of burners suitable for a variety of fuel types and appropriate types of flame scanners for monitoring the health of the firing through these burners. The firing zone along with waterwalls (to insulate the heat contents from around the side and top walls) is normally described as the furnace.

The pressure of the top portion of such a furnace is generally maintained at below atmospheric pressure, that is, a −3mm to −5mm water column. This task is accomplished with the help of induced draft (ID) fans, which evacuate the products of combustion—the combination of different gases from the furnace. The term *furnace draft control* at such a typical pressure value implies so many things that it is quite surprising. The low but near to atmospheric value ensures that neither explosion or implosion takes place. It is known that an explosion in a furnace occurs when the rate of volume of flue gases or the products of combustion increase abruptly as a follow-up action of introducing huge quantities of fuels and air. The situation causes instantaneous volume boosting at a much higher temperature as a result of exothermic reaction. The furnace volume and the wall thickness being fixed and limited, the increased gas volume, if it goes beyond the design limit, may cause explosion.

Near-atmospheric pressure is not only safe against explosion but also prevents the possibility of implosion, which may arise because of a sudden collapse of flames, as discussed later in Section 6.2. The advantages are as follows:

- It is generally safe against explosion or implosion.
- Wall thickness is much less as the operating pressure is so chosen.
- Because of less than atmospheric pressure, there is also a lower risk to operating personnel; for example, when they are viewing the flame through the inspection hole.
- There is less possibility of leaking flame or hot flue gas, which means less heat loss and pollution.

The ID fans are normally supplied with inlet vanes for controlling the amount of volumetric flow handled by the fans. The control loop selected for discussion of furnace draft control in this section is a typical 250 MW thermal power plant that has ID fans with an additional mechanism, hydraulic coupling along with scoop-tube control for varying the speed of the fan vis-à-vis the added controllability of handling the gas flow. In fact, any one of these is sufficient to administer the control system as the final control element, but the present loop is quite interesting as to how things are taken care of by the two devices mainly for higher MW plants to achieve better and smoother controls.

6.1 Objective

The furnace pressure is maintained at a negative pressure and hence is popularly known as the *furnace draft*. The main objective of this control loop is to achieve the desired pressure at all loads by sucking the appropriate amount of flue gases—that is, the products of combustion along with excess air and unburnt fuels, if any, and other nonparticipating gases in the combustion process. The ID fans are provided to perform their duty with the necessary arrangement of having controllability, so they act as the final control elements of this important loop. These control accessories are made to open (or increase) and close (or decrease) to suck the required amount of flue gases so that the furnace draft is maintained.

6.2 Discussion

Furnace draft control is a comparatively simple loop compared to the other control loops in a thermal power plant, but the furnace itself is a huge voluminous part of the boiler, handling the burning of fuels, so the safety implications are important and significant. The applicable codes

www.EngineeringBooksPDF.com

and standards must be followed to avoid any untoward situations when dealing with the design aspects of the furnace-related equipment. The National Fire Protection Association (NFPA) provides guidelines that one must read and codes that must be followed. The most relevant code, such as NFPA 85: Boiler and Combustion Systems Hazards, concern protection measures to be taken against fire and furnace explosion and implosion.

The NFPA also stipulates some additional interlocks for incorporation in the furnace draft control loop so that the required operating safety margins are ensured. For example, the interlocking signal from high and low furnace pressures are to be utilized to block the final control elements from repositioning that may jeopardize furnace conditions. Another interlock example, as stipulated in the NFPA codes, is taken from the MFT logic signal actuated in dangerous conditions and emergency shutdown of the boiler. In such a sudden event, the flame in the furnace collapses violently when all types of fuels are completely and abruptly removed. This state of affairs invites implosion and also can be the reason for severe wear and tear of boiler parts. The interlock allows the controller output to maintain the final control elements to attain a predefined fixed position for a definite period of time and then to release the device back to normal operation. Normally the ID fan suction head is more than the negative pressure the furnace structure is designed to withstand in case of any eventuality.

One advantage of maintaining the furnace pressure at a constant value may be explained by the universal law of perfect gas:

$$PV = MRT$$

where

P = absolute pressure
V = volume of the system
M = mass of the substance in the volume considered
R = universal gas constant
T = absolute temperature of the system

Considering the system as a whole, it is apparent that the volume V is also a constant value where as the universal gas constant R is approximately constant which means $P = kMT$ (where k is a constant).

The equation depicts that the product of M and T can be made constant if the furnace pressure (or the draft) is kept constant. As the furnace temperature depends on the boiler load, or, in other words, the thermal energy balance (heat input and output), the mass inside the furnace is automatically kept adjusted by the ID fans, which suck the required amount of flue gas. At the time of MFT, when the fuel is immediately cut, the temperature of the furnace drops rapidly with a subsequent drop in pressure; instead of flue gas, only hot air is sucked by the ID fans. The drop in furnace pressure causes the ID fans to suck less gas as instructed by the furnace draft controller, and the mass M in the furnace improves such that the product MT again equals the constant furnace pressure P. The amount of hot air pushed by the FD fans under this condition may be different for various boiler manufacturers, but the ID fans finally take care of the mass availability in the furnace under any condition so far as implosion of the furnace is concerned.

The burner management system (BMS) also generates binary signals to enable the control system to run in automatic mode or the final control elements to attain minimum position as per the demand of the prevailing situation.

6.3 Control Loop Description

Figures VIII/6.1 and VIII/6.2 may be referred for a schematic representation of the control loop's implementation in a typical coal-fired furnace with occasional oil support. The control loop may to some extent vary with the manufacturer's special design and the type of fuel used, but the basic idea remains the same.

6.3.1 Measurement of Various Parameters

6.3.1.1 Furnace Pressure

The furnace pressure is measured by differential transmitter with sufficient redundancy and at the appropriate location to get an average and representative measurement. For a larger furnace, there may be sets of transmitters at opposite walls for a better result. Span selection of transmitters is very important; normally these should not be too wide or too narrow. Because of the very fluctuating nature of the furnace pressure and the dusty atmosphere resulting from fuel combustion, normally a special volume chamber is put in each transmitter for measurement purposes, as detailed in Figure XII/3.1-2(b). Because of the volume chamber, fluctuations are arrested at the same time the dust settles in the chamber and line choking can be avoided.

6.3.1.2 ID Fan Inlet Vane Position

These parameters, representing the position of the final control elements, are measured as a standard procedure and also used in the control strategy for ID fan speed control through hydraulic scoop-tube control (it may be through VFD as well.)

6.3.2 Other Controls

6.3.2.1 Furnace Draft

Furnace pressure is a very fast changing parameter; this signal may disturb the desired control action if connected to the controller directly. To circumvent this situation, a low-pass filter (LPF) algorithm is utilized to eliminate the

www.EngineeringBooksPDF.com

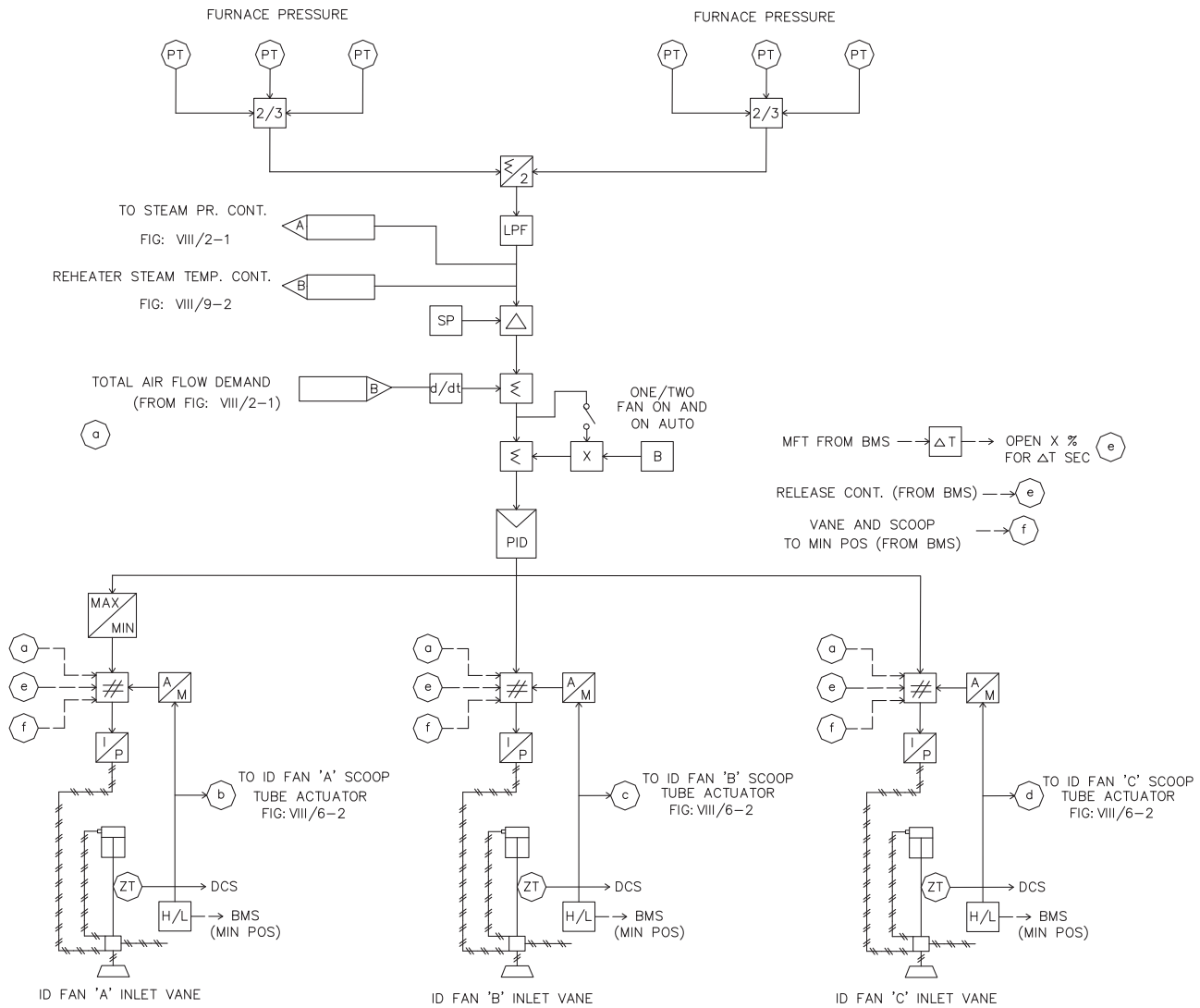


FIGURE VIII/6.1 Furnace draft control (inlet vane).

high-frequency components of the furnace pressure transmitter output and to allow only the signal with a comparatively low frequency. The output signal after treatment in the LPF is taken as the measured/process variable, whereas the set value to the controller is fixed, as discussed earlier. The total air flow acts as a feed-forward signal after passing through a derivative function and summed to the error signal between the measured and set values. In an alternative (ISA-recommended) loop, the FD fan impeller/vane control demand signal is taken as a feed-forward signal and added at the output of the controller for a similar purpose. Then the gain function is added to take care of the number of ID fans running on auto mode.

The final error signal acts as the input to the PID controller. The controller output has to pass through a maximum and minimum limit so that the inlet vanes do not reach the end positions, which may lead to furnace safety risk. Regarding fine-tuning of the furnace controller, one should avoid the use of a very fast integral. It is a fact that furnace pressure changes at a very fast rate but not instantaneously; therefore, the process being compressibly fluid, the capacitance effect, which incorporates the size of the furnace, the huge ductworks between the furnace and the fans as in the system, and so forth, needs to be considered.

The inlet vanes assume positions as per controller output to maintain the furnace draft only, but they have some other interlocked functions for taking care of the safety aspects. These are discussed as follows for a typical boiler, but may be different to some extent as per the manufacturer's recommendation. The safety features are

- Inlet vanes are forced to assume the open position of a certain preassigned value or as dictated by the control

www.EngineeringBooksPDF.com

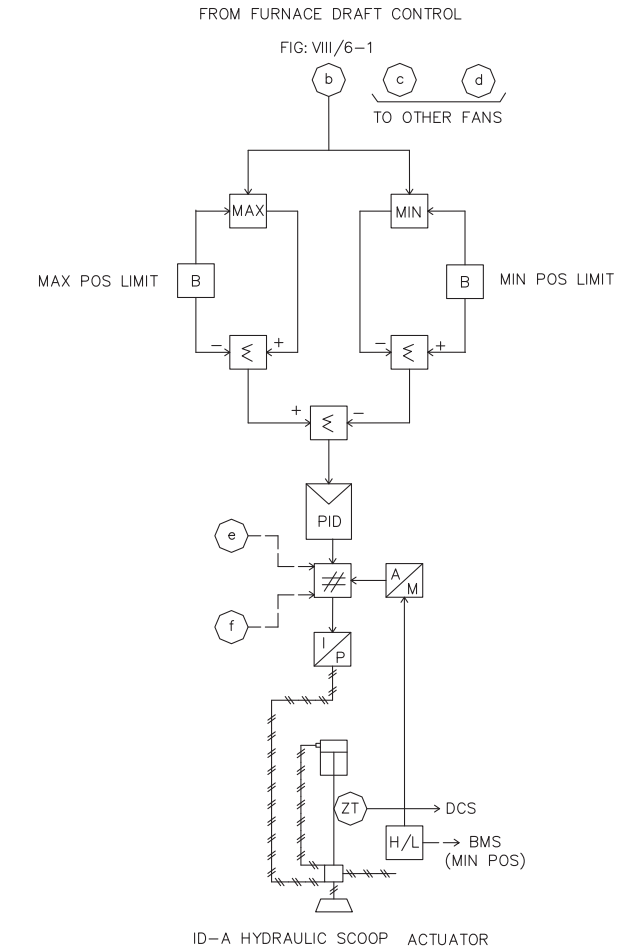


FIGURE VIII/6.2 Furnace draft control (scoop tube).

strategy for a certain period of time in case of MFT (other than FD or ID fans). This interlocking command enables the unburnt fuel if any to be evacuated to avert any explosive situation. For MFT due to both FD/ID tripping, vanes/dampers in the air and flue gas path open slowly to full value to create a natural draft to ensure that the furnace does not go beyond its design limits.

- BMS issues the command signal to release to automatic control upon checking for relevant conditions congenial to auto control operation.
- BMS also issues commands to assume the minimum position in certain process conditions to prevent implosion when the time period as described in the first bullet item is complete. On a very negative furnace pressure signal also, the BMS binary signal output may be used as an interlocked condition that closes the ID inlet vane, decreases ID fan speed, or blocks the increasing signal to prevent implosion.

There are other interlocked operation scenarios that recommend blocking of the closing signal of the ID fan inlet vanes from the binary signal set to actuate on a preset high furnace pressure. The opposite case is low furnace pressure, upon occurrence of which the binary signal blocks the opening signal of the ID fan inlet vanes. The settings for all these signals are ascertained by the boiler and fan supplier during plant design and dictated for safe operation of the plant.

The ID fans are equipped with another final control element called the *scoop-tube actuator*, which varies the speed of the ID fans, either increasing or decreasing the suction capability. The scoop-tube actuator, on receiving the modulating command, adjusts its position to allow more or less oil in a chamber to raise or lower the oil level. The oil chamber is a part of the hydraulic coupling connected to the electric motor (refer to Chapter VI, Section 3.4, Figure VI/3.4-1) and the ID fan itself, where the motor runs at a constant speed and the ID fan speed varies as per the oil level vis-à-vis the scoop-tube position. In this control loop part (see Figure VIII/6.2), scoop-tube actuators play a secondary role. Here the scoop-tube actuator is modulated so that the inlet vanes operate in certain maximum and minimum positions.

The vane position signal is an input of a maximum selector, which has another input set manually to represent the maximum limit position of the inlet vane There is one summator having its one input (with + sign) from the maximum selector output and anther input (with a minus sign) from the vane maximum limit position. As long as the vane is operated within the maximum limit, this limit signal is selected as the output and the summator receives both signals, which are of the same magnitude but of opposite signs, canceling each other out for a zero output. Similar is the case for the minimum position of the vane, the summator output is also zero when the vane is operated at a position more than the minimum as set manually. The two summator outputs again act as inputs to another summator whose output acts as an error signal to the scoop-tube controller and are also zero for the inlet vanes being operated within the set limits. In this case, the controller output is not changed and so the speed of the ID fans allows the inlet vane to operate freely as per the furnace draft excursion.

The case is different for situations when the vane exceeds the maximum or minimum limit positions. For example, when the inlet vane position is more than the maximum, the excursion is positive and the difference in signal forms the error signal (because the inlet vane position is more than the minimum, the magnitude of the minus signal of the downmost summator is zero) and the controller output is changed to attain the new position, enabling the vane position to be brought back within limits. In normal operation, there is no change in ID fan speed;

www.EngineeringBooksPDF.com

however, for adjustment and fine-tuning purposes, a bias facility is provided to adjust the optimum speed even at the entire range of operation. The similar interlocked operation is applicable as previously discussed for the inlet vane.

There can be other possibilities where the main furnace pressure control is controlled by varying speed and the vane may be kept wide open. The vane control may come into operation only when the demand signal for speed control is beyond a certain range. This philosophy is almost the reverse of what has been discussed. Because in this case most of the time vanes are kept wide open, pressure loss is less.

7. DRUM-LEVEL AND FEEDWATER CONTROLS

7.0 General

The boiler-drum control system is provided for the conventional drum-type boilers in subcritical power plants with a normally pulverized fuel-fired (coal/lignite) furnace. The boiler drum in this case acts as a reserve vessel that gets the feedwater as the supply at the inlet and saturated steam as the outlet.

There are number of control valves for drum-level control with various types of operating range and provisions for redundancy. To force the feedwater into the drum, there are a number of constant- or variable-speed FW pumps. If the feedwater level in the drum becomes too high, water particles can be carried over by the main steam going to the turbine and catastrophic damage might result. On the other hand, in case of a very low level of drum water, the drum itself becomes overheated, which may also result in a catastrophic situation..

In general, the drum-level control or the feedwater flow control has two modes of automatic operation: single- and three-element. The set point is the same for drum-level controls meant for both modes as set by the plant operator. For a single-element control system, the difference between the drum-level measured or process variables and the drum-level set point represents the error signal and is fed to the single-element controller to take care of the rate of water pumped into the drum by adjusting the position of the feedwater flow control valve. The term *three-element control* comes from the three process variables known also as elements: drum level, steam flow, and FW flow.

7.1 Objective

The objective of the drum-level control loop is very simple (FigureVIII/7.2). It is one of the most important control loops in the subcritical boiler category. The drum water level is maintained at a fixed value for the reasons stated previously, and it acts as a storage reservoir as well, irrespective of the boiler load.

7.2 Discussion

In a large-capacity thermal power plant, the normal range of operation is achieved by the three-element control strategy, which usually covers large boiler load variation from 30 to 100%. The drum level at a low boiler load is achieved by a single-element control system and is also a very simple loop, with a low-capacity control valve as the final control element.

There are generally two major control systems adopted for the three-element control strategy. One is to use full-capacity control valves ($2 \times 100\%$) as final control elements with one 30% capacity valve, or to use one 25 to 100% valve with one 0 to 100% bypass valve (say, VRT or drag valves as discussed in Chapter VI). The other control strategy uses the variable-speed boiler feed pumps (BFPs) through the hydraulic coupling between the BF pump and motor with the help of the scoop-tube actuator and/or the turbine-driven boiler feed pump (TDBFP).

It has been observed through long experience that the three-element control system is much more rugged and stable than single-element control. The advantage of using the three-element control strategy is that it can easily handle large and rapid load changes because it matches the mass balance between the main steam flow from the boiler and the FW flow to it.

The reason for using a single-element control is rather a compulsion because its accuracy is always under question at low range of flow measurements. As discussed earlier, the main two constituents are feedwater and main steam flow; measurements are based on empirical formula developed using a flow-measuring element, such as a flow nozzle (or an orifice plate for a smaller plant), where the DP produced across the flow element is proportional to the square of the flow rate. It is well known that at low boiler load vis-à-vis low (water and steam) flow rates, the relationships between differential pressures and flow rates are different from what is expected. In other words, three-element control at low loads introduces unreliability in the control action, so single-element control is used with low loads as a natural choice.

Normally the operator starts drum-level control in manual mode and continues up to the full range of single-element control, but because of the simple nature of this control strategy, the control system can be placed in automatic as soon as feed flow is established after any of the BFPs is started. As generally observed, the flow measurements are considered reliable with standard accuracy at an approximate reading of 20% or more. By keeping some cushion, when the flow figures are $\sim$25 to 30% of the

www.EngineeringBooksPDF.com

measuring range, drum-level control can be transferred to the much desired three-element control.

7.2.1 Drum-Level Computation

Drum level is measured by differential pressure transmitters installed in line with Figures XII/3.5-1(a,b). Note that for drum-level measurement a temperature-equalizing column has been used to ensure that in both limbs of DPTs temperatures are equal, meaning that the densities are equal. So far, the discussion has been about installation and making the two limbs' temperatures equal. Now level is measured by because there is an incumbent pressure P_1 at the top, which needs to be subtracted to get the level. So, finally, one is left with P_1 at the top and P_1 + pressure due to water head (P) on the other limb. Therefore DP = pressure due to water head, $P = h \times \rho \times g$.

For a particular place, g is always constant. So water head P varies with h (level) and density, which in turn depends on temperature. In the drum, incumbent pressure is due to saturated steam pressure, and for saturated steam for each pressure there is a particular temperature. Therefore, saturation pressure is chosen to compensate/correct the density effect. Temperature is a sluggish parameter, so pressure is chosen to compensate.

7.2.2 Shrinking and Swelling Phenomenon

Shrinking and swelling in the boiler drum are very common phenomena and must be borne in mind in determining the three-element drum-level control loop strategy for a subcritical boiler plant. Whenever there is a rapid excursion of load vis-à-vis steam extraction, there is bound to be a tremendous change in boiler drum pressure followed by drum level. For example, during a rapid increase in load/steam flow, a severe increase in level follows that is due to swelling caused by low drum pressure. The hot water close to the saturation point contains steam bubbles in the drum.

Shrinking and swelling are caused by a change in pressure in the drum that also changes water density. During a rapid increase in load, a severe rise in level takes place because of an increase in numbers and volume of the bubbles, which are the consequence of a drop in steam pressure as a result of load increase and also the increase in steam generation from the greater firing rate to match the load increase (i.e., the bubbles swell or expand). The double effect of lower pressure and higher temperature makes the situation worse. If the level in the drum becomes too high at this time, water carryover into the superheater or the turbine may be the worst consequence if the boiler is not made to trip from a very high water level.

Conversely, whenever there is a decrease in demand, the drum pressure increases and the firing rate changes, thus reducing or shrinking the volume of the bubbles (i.e., the bubbles get smaller). An abrupt and significant loss in load can result in high drum pressure, causing shrinkage severe enough to trip the boiler on a low level. A more severe catastrophic situation followed by boiler trip at high firing rates may create a condition similar to furnace implosion. If the implosion is severe enough, the boiler walls are likely to be damaged because of high vacuum in the furnace. However, these increases/decreases in level are apparent and are a transient phenomenon that is well taken care of by the control loop strategy.

It is true that a change in firing rate affects the drum level but not as severely as an abrupt change in the steam extraction rate, which is considered the most significant cause of steam bubble shrinking and swelling.

7.3 Control Loop Description

Figure VIII/7.1 and Figure VIII/7.2 may be referred to for a schematic representation of implementing the control loop in a typical 250 MWTPS having a drum-type boiler.

7.3.1 Measurement of Various Parameters

7.3.1.1 Drum Level

The level of the drum is measured with sufficient redundancy at both ends. This is necessary as there may be a difference in level because of the long length of the drum and the dynamic nature of the process requirement. The transmitters are not connected directly to the drum (because this would reduce the number of nozzles on the drum itself) but to the temperature-compensated constant head unit (refer to Figure XII/3.3-1), which is connected to the drum stand pipe to facilitate multiple tapping points. After necessary voting, the selected raw level signal is compensated for pressure, and the average value is taken for further action in the control loop.

7.3.1.2 Feedwater Flow

The feedwater flow to the boiler drum is measured with sufficient redundancy, and after necessary voting the selected raw level signal is compensated for temperature; the average value is then taken for further action in the control loop. The attemperation water flow with due compensation for pressure and for temperature is added to get the total feedwater flow depending on the relative locations of the flow-measuring device and spray line tapping.

7.3.1.3 Main Steam Flow

This flow measurement may be taken directly from the flow nozzle/transmitter combination or from the turbine first-stage pressure after suitable characterization through the first-stage pressure/steam flow relation algorithm. The measurement is done with sufficient redundancy and, after

www.EngineeringBooksPDF.com

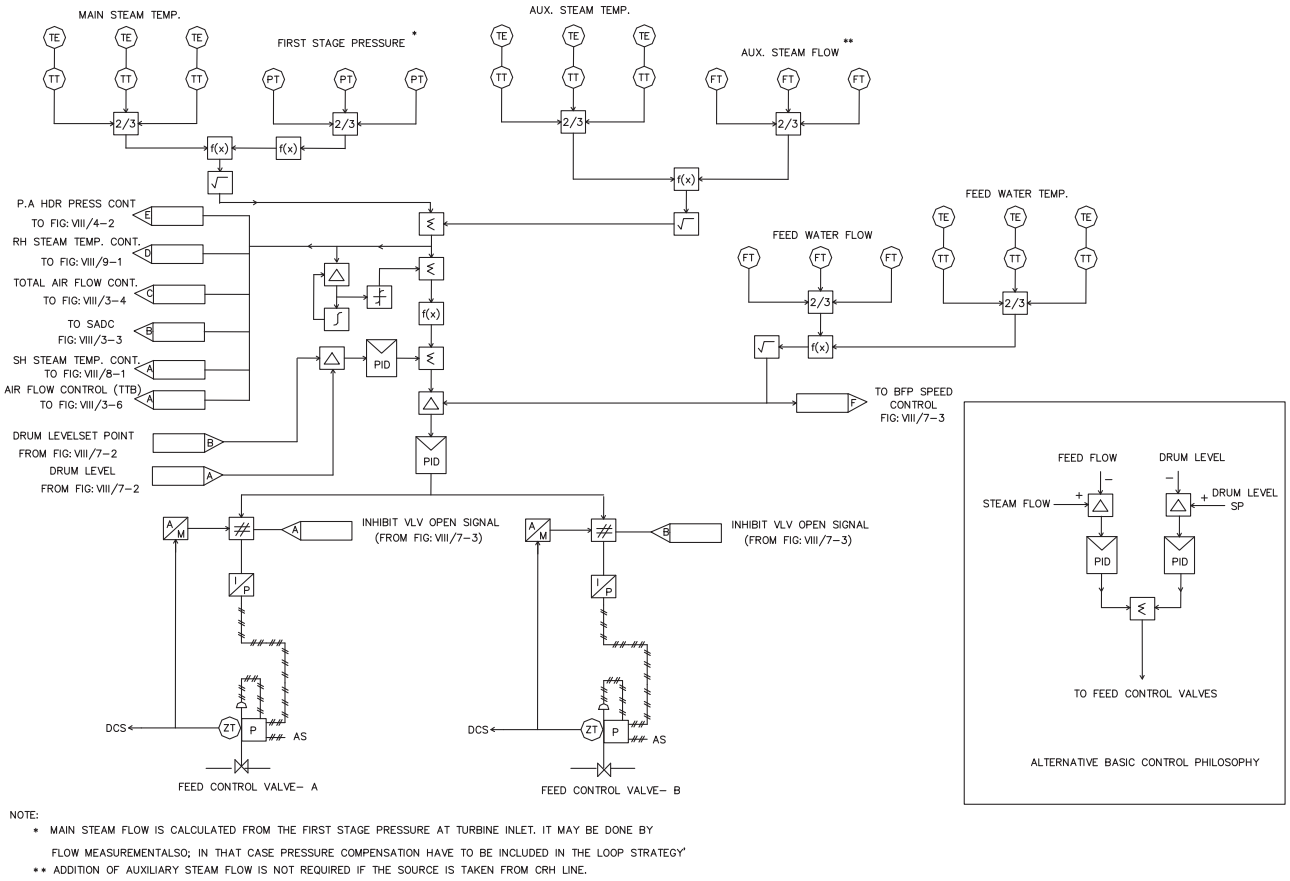


FIGURE VIII/7.1 Drum-level control schematic.

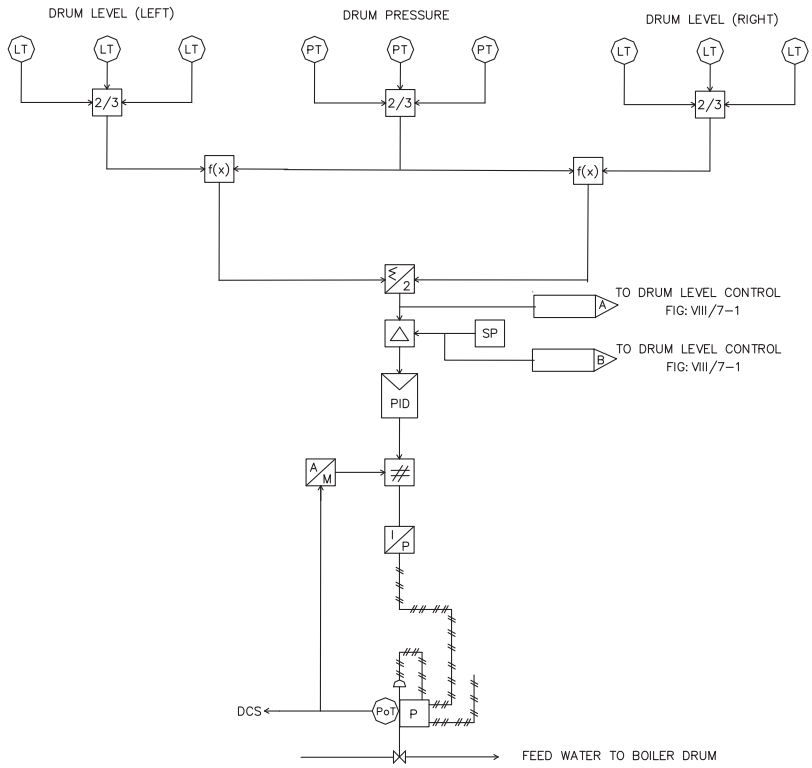


FIGURE VIII/7.2 Drum-level control (low load) schematic.

www.EngineeringBooksPDF.com

necessary voting, the selected raw level signal is compensated for temperature. The other steam flow signals such as HP bypass steam flow and auxiliary steam flow (if any), are also measured and suitably compensated for pressure and temperature and then added to get the total steam flow value for further action in the control loop.

7.3.2 Other Controls

7.3.2.1 Single-Element Control

As previously discussed, there are two stages of drum-level control: single-element and three-element. Although three-element control is accomplished in two ways (as discussed later), there is no such option available for single-element control. The finally selected drum-level signal acts as the process or measured variable and forms the error signal with the fixed drum-level set point. The controller is adjusted with the PID algorithm for optimum tuning. The low-load control valve acts as a final control element.

In general, tuning of the single-element controller necessitates adjustments with large proportional and very small integral gain settings.

7.3.2.2 Three-Element Controls

7.3.2.2.1 Three-Element Control with Flow Control Valve as Final Element Drum-level control normally uses the cascade control strategy, which consists of the formation of a master and a slave controller. The drum-level signal, being the prime element of this control loop, forms the error signal with the fixed set point and is connected to the controller designated as the master. Main steam flow is an indication of the rate at which water is being extracted from the drum. This measured or characterized (from first-stage pressure) main steam flow is taken as a feed-forward signal and added to the output of the master controller.

A special algorithm popularly known as the *anti-swelling and shrinkage circuit* is customarily provided to take care of the problem discussed in Section 7.2.1. The main steam flow, before being added to the drum-level (master) controller is routed through this algorithm, which corrects the steam flow signal for a quick change. The amount of correction can be varied as required by adjusting the gradient of the limiter function and the integration rate of the integral function algorithm. The correction becomes zero in due course when the steady-state condition is reached.

For an abrupt increase in steam flow, a negative correction applies to lessen the magnitude of actually measured or calculated steam flow so that less water is requested for the time being to keep the inflated drum water level (because of low drum steam pressure) from further increasing so as not to trip the boiler or the MFT from the very high drum water level. The reverse action is performed when there is a sudden load throw-off and the water supply is not decreased, as it should be in the normal case, so that the boiler/MFT tripping due to a very low drum water level can be avoided.

Another method of incorporating the anti-shrinkage and swelling function according to other schools of thought is to utilize the derivative signal of the drum pressure itself. For any quick change in load, the drum pressure ought to change as a result of energy imbalance. The rate of change with respect to time is the index of load change rate, and the signal thus derived is added to or subtracted from the steam plus drum-level controller output as per the tendency of the pressure increase or decrease.

In other words, the output of the master controller is added to the corrected steam flow, whatever the type of anti-shrinkage and swelling algorithm and finally becomes the demand or set point for the FW flow requirement. The difference between this set point and the measured feedwater flow now turns into the error signal for another controller, which may be termed the slave controller, for FW flow regulation. The output from this controller is then utilized to modulate for the position adjustment of the redundant feedwater flow control valves.

Tuning of the three-element control system has some special requirements. Here the feedwater flow (slave) controller must be tuned with much faster integral action than that of the drum-level (master) controller. This philosophy is in fact applicable to all types of cascade control strategy.

There can be another simple way to achieve the same goal. Here a demand is created by steam flow feed flow error (in the ideal case, steam flow and feed flow should match; only during changes is there error/difference between them). This demand is added to the demand from drum-level controller. For steam flow, feed flow and drum-level measurements with necessary corrections, as stated in the main description, are equally applicable here.

For the drum-level control loop, the strategy is otherwise simple without many manual interlocks or much control tracking. Though not specifically shown in the drawings, (Fig.VIII/7-1 & Fig.VIII/7-2), the control loops may be forced to run in manual mode if not all pump are running, the drum-level signal/feedwater flow valve control output goes out of range, and so forth, as may be deemed necessary by the appropriate authority.

7.3.2.2.2 Three-Element Control with Scoop-Tube Actuator for Control of DP across Valves When the three-element control for the drum level is accomplished by the flow control valves, another control loop controls the differential pressure across the feed control valves to enable them to operate smoothly. Controllability is also improved for a control valve when subjected to a DP with a predictable range. In some plants this DP is maintained at a

www.EngineeringBooksPDF.com

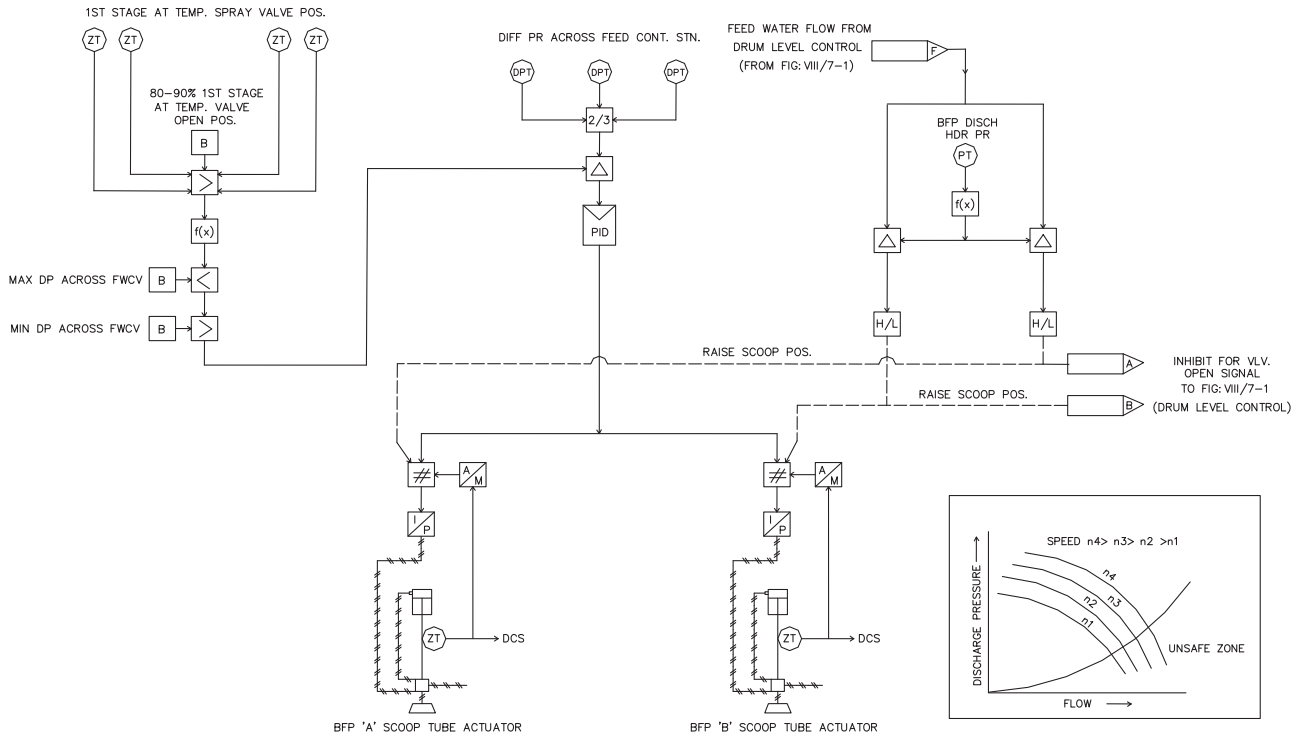


FIGURE VIII/7.3 BFP speed control (2 × 100% MDBFP).

fixed value by adjusting the BFP speed through hydraulic coupling vis-à-vis the scoop-tube actuator. Figure VIII/7.3 may be referred to for a schematic representation of implementing the control loop in a typical 250 MWTPS having drum-type boiler.

In this control loop strategy, the DP across the feed valves is measured with sufficient redundancy, and, after necessary voting, the selected raw DP signal is taken as a measured or process variable for further action in the control loop. The error signal is formed after receiving the desired or set value of DP, which is not a fixed value as in other types of power plants, as stated earlier. This particular power plant has a variable set point for the DP after due characterization of the selected (high) position transmitters of the first-stage attemperation spray valves. All of these position signals are passed through a high selection algorithm.

There is another fixed input of the high selector which ensures the minimum value of this selector output as the 80%–90% (adjustable) position of the attemperation spray water valves. After characterization as per the predictable relation of the flow control valve DP with respect to the spray valve position, the output is again passed through a high/low selector switch, which limits the derived set point not to go beyond the maximum and minimum DP values across the flow control valves. The error signal thus obtained drives the PID controller, whose output is used for position adjustment of the scoop-tube actuator for varying the speed of the BFPs.

The control loop strategy maintains the DP across the feed valves to such an extent that the upstream pressure of the flow control valve, which is incidentally the upstream pressure of all the spray control valves as well, slides to the minimum required value (for better efficiency), which is sufficient to push an adequate amount of spray water with the spray valves almost fully open. It is quite obvious that wider opening of a control valve demand less DP across it with the flow being same. With the downstream pressure of the spray valves being dictated by the boiler load, the upstream pressure is now the minimum pressure required for necessary flow of spray water.

This minimum pressure calls for the minimum discharge pressure of the BFP required at that point of operation, thus minimizing pumping loss. The flow control valve readjusts its opening to suit this DP to maintain the feedwater flow to keep the drum level at a constant value. This control strategy thus ensures minimum but adequate upstream spray water pressure to keep the spray control valves operating in a satisfactory manner without running the BFPs at an unnecessary high discharge pressure. For a single-loop control strategy, the scoop-tube actuator(s) would remain in a fixed position irrespective of whether the control mode is auto or manual.

www.EngineeringBooksPDF.com

With one BFP running, the standby BFP (for a 2 × 100% configuration) should have its scoop tube in auto follow-up mode so that if the running pump is tripped, the second pump should start forwarding feed to the boiler without much loss of time. The maximum allowable delay time in starting the second pump is dictated by the boiler-drum storage capacity and the permissible time limit required to come to a very low drum level from normal drum level. For a 3 × 50% BFP configuration, the standby BFP has its scoop-tube actuator in auto follow-up mode to track the maximum position of the two running BFPs' scoop-tube actuators.

For TDBFPs, there needs to be a motor-operated BFP mainly to act as a fallback. The hydraulic coupling scoop tube always tracks the TDBFPs so that in case of a trip of any TDBFP, a motorized BFP can immediately meet the flow requirement. Also, the discharge valve is kept open and the BFP motor must be rated in such a way for loaded start.

Interlocked operations of this particular loop are based on whether the BFP is running at a safe pressure against the flow delivered at a particular point in time. Here the characterized BFP discharge header pressure represents the limit of safe discharge flow at a particular pump speed. When the actual flow is more than the safe flow, a binary signal is generated in the high/low signal detector (high in this case) and forces the scoop-tube actuator to raise the speed of the BFP so that the operating point is shifted so that the safe flow is more than the actual flow at a higher discharge pressure. The interlocked signal is also generated at the same time to prevent the flow control valve from further opening and thus increasing the feed flow to an unsafe region of operation. For 3 × 50% BFP, individual pump suction flow is to be measured and compared to safe flow from the characteristic curve at corresponding discharge pressure.

7.3.2.2.3 Three-Element Drum-Level Control with Pump Speed Variation with Scoop Tube Actuator/ Steam Turbine-Driven BFP The designers/manufacturers and customers of modern power plants prefer the FW flow to be controlled by the variable-speed feed pump with a scoop tube for the hydraulically coupled BFP along with the drive motor and/or steam turbine−driven BFP. This arrangement requires a low-load feed control valve, which is operated in the boiler load range of 0−30% as a part of single-element control strategy, as discussed in Section 7.3.2.1. For a load greater than 30%, the usual control strategy—the drum-level controller with the addition of total steam flow, duly incorporating the anti-shrinkage and swelling algorithm—becomes the set point of the feedwater flow controller. Figure VIII/7.4 may be referred to for a very simplified schematic representation of the control loop of a typical 500 MW power plant having one motor-driven BFP and two turbine-driven BFPs with a 3 × 50% pump configuration.

Parallel to the low-capacity FW control valve (i.e., in the main FW line) another valve of the throttling-cum-isolation type is made (manually or automatically) to slowly open to increase the boiler load more than 30%, up to 100%. With this action, the low-capacity FW control valve closes gradually to 0% and the FW is then controlled by adjusting the speed of the pumps with the main line isolating valve fully open. The error between the feedwater flow set point and the feedwater flow measured/or process variable is connected to the FW flow controller but only after a manual or automatic changeover selection representing whether or not the boiler load has reached more than 30%.

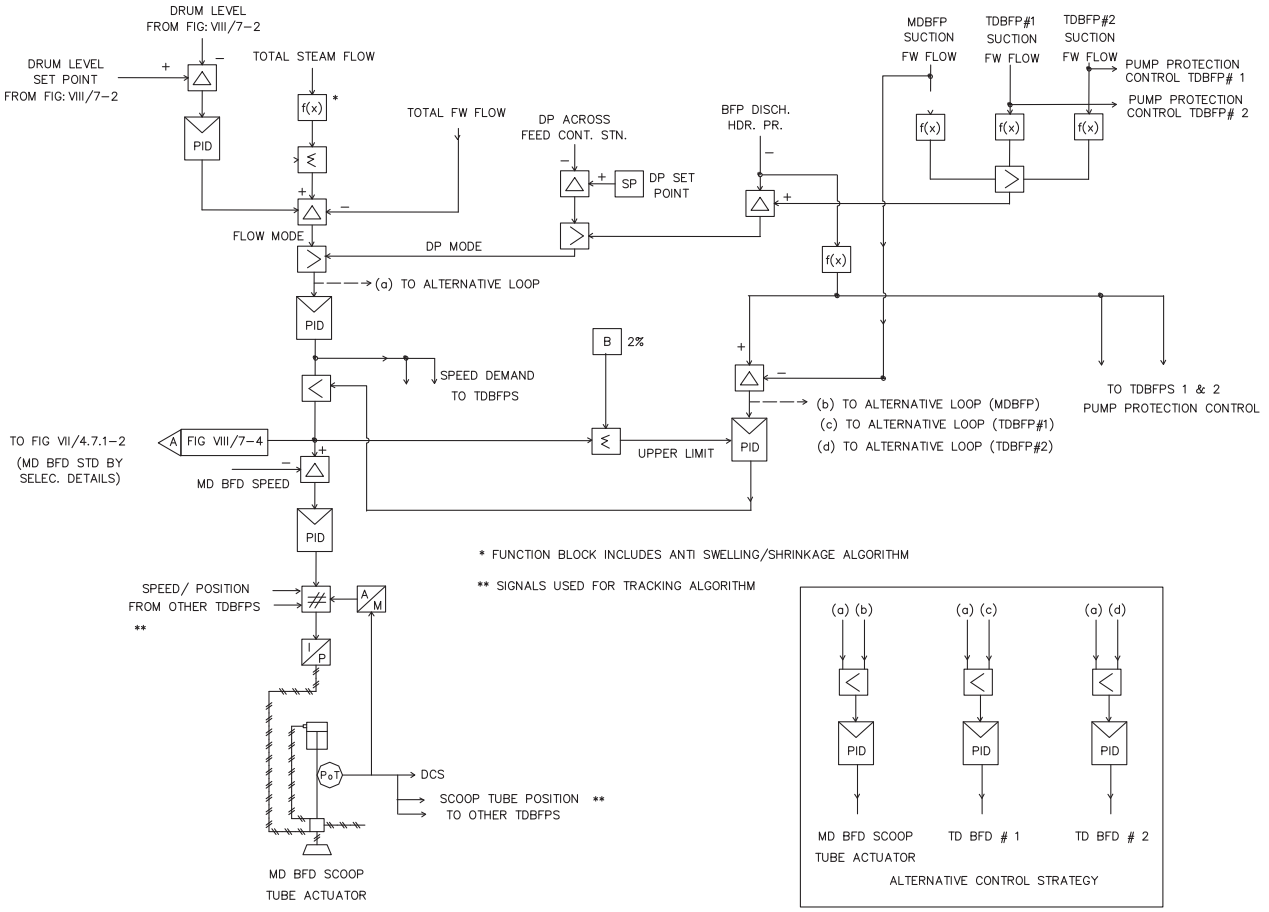
As depicted in Figure VIII/7.4, there generally are number of PID controllers, but tuning them is very important. As discussed earlier, the speed controller may have a very fast integral action rate whereas the FW water controller may have a slower one, with that of the drum-level controller even slower. However, all of the tuning activities depend on plant condition, quality and capability of the control systems, and of course the availability of equipment/accessories.

To avoid a three-stage controller situation, in some control strategies the drum-level controller is eliminated and the FW controller error signal is generated directly from drum-level measured/process variable (and the drum-level set value) plus the steam flow with a suitable anti-shrinkage and swelling algorithm; the FW flow signal is subtracted to get the error signal for the FW controller. When the boiler load is ∼30%, the main line valve is gradually opened and the low-load valve is gradually closed; this may be achieved automatically, but manual selection is often a better option from the point of view of loop stability.

The signal is derived from the DP error across the low-load feed valve or from the pump safe operation criteria as selected by the maximum selection function. The DP across the low-load feed valve is measured and the error with the DP set point forms one of the two inputs, which, if selected (through the maximum selector) does the same thing as the drum-level control system does with the feedwater flow control valve as the final control element—that is, the pump speed—is controlling the DP across the feed valve at a fixed value.

The other input is the pump safe operation signal. The measured flow signals (with sufficient redundancy and voting arrangement) of each pump are passed through a characterizer (flow versus discharge pressure), giving as their output the safe discharge pressure at any given flow, and are passed through another maximum selection function and compared with the actual discharge pressure at the BFP discharge header. This signal if selected via the maximum selector, tries to maintain the safe discharge

www.EngineeringBooksPDF.com



NOTE: 1) THOUGH NOT SHOWN SPECIFICALLY THE FOLLOWING FLOW SIGNAL ARE TOTAL FLOW IN ALL RESPECT.
i) TOTAL STAM FLOW INCORPORATES ANTI SWELLING / SHRINKAGE ALGORITHM AFTER SUMMATION OF ALL THE STEAM FLOW LIKE HPBP FLOW, AUX PRDS FLOW ETC.
ii) TOTAL FW FLOW INCORPORATES ALL ATTEMPERATION FLOW (SH.RH& AUX PRDS) ETC.
2) THE CONTROL STRATEGY ENVISAGES ONE MOTOR DRIVEN BFP AND TWO TURBINE DRIVEN BFPs HAVING 3x50% PUMP CAPACITY.
3) ALL MEASURING POINTS ARE WITH SUFFICIENT REDUNDANCY AND VOTING THOUGH NOT SHOWN SPECIFICALLY.

FIGURE VIII/7.4 Three-element drum-level control by pump speed variation.

header pressure of the BFPs by adjusting the speed of the running pumps. This part of the control loop is known as *DP mode*.

The DP-mode error signal is compared with flow-mode error signal in another maximum selector and acts as input to the flow controller related to the boiler load. Another flow controller is provided to take care of pump protection by bringing the individual suction flow to a safe value according to the common discharge pressure. The individual pump's protection-related flow controller is free to act with the upper limit derived by adding, say, a 2% signal value to the minimum selected signal of the two flow controllers discussed previously. Normally the common boiler load controller is selected as long as the discharge pressure is adequate enough to administer the required feedwater flow.

The minimum selector output of the flow controllers constitutes the speed demand of individual pumps and is compared with the pump speed to determine the operating speed of the pump. As already indicated, the MDBFP speed is varied by adjusting the scoop-tube position of the hydraulic coupling; TDBFP speed is made to vary by the electro-hydraulic governor control.

8. SUPERHEATER TEMPERATURE CONTROL

8.0 General

Superheated steam is steam with a temperature that is higher than the saturation temperature for a particular steam pressure. The saturated steam is described as superheated according to the degrees it has been heated to above the saturation temperature. Superheated steam is principally used in power generation plants as the driving force for turbines. Application of the Rankin cycle in thermal power plants is discussed in most text books on the thermodynamic properties of steam. Very brief discussions are also

www.EngineeringBooksPDF.com

presented in various sections of Chapters I and II. Superheated steam is more thermally efficient than saturated steam for driving the TG.

Because the extra heat causes transmission of more energy than saturated steam, it is utilized for additional power generation from the quantity of steam available. Although SH steam contains a large amount of heat energy, this energy is available from three sources: enthalpy of hot water, enthalpy from evaporation (latent heat) of water to steam, and enthalpy from the degree of superheat. The bulk of the energy is in the enthalpy of evaporation and then from hot water; less energy comes from the SH steam, which represents a comparatively smaller proportion of the total heat contents.

Using SH steam has some advantages that are very important—for example:

- It eliminates the problem of wet steam entering the turbine, which causes increased friction and produces the following harmful effects: water droplets vis-à-vis enhanced silica deposits and pitting of turbine metals.
- Erosion of turbine blades.
- Water carryover in saturated steam can cause steam formation and may give rise to overspeeding of the turbine, which is extremely dangerous.
- It permits higher steam velocities through the pipeline (up to 100 m/s), which automatically suggests that smaller pipelines can be used (provided that the pressure drop is not excessive).

Superheated steam does not cause condensation in the continuously running pipelines,

8.1 Objective

The objective of this control loop is to maintain of the steam at a constant temperature at boiler outlet, which also means an almost constant temperature at the turbine inlet (fixed or sliding pressure), with the provision of variation due to transmission loss. This control loop is also considered one of the most important control loops in the thermal power plant instrumentation system. The saturated steam from the boiler drum is superheated by adding heat from various superheaters. Before the final superheaters (left and right sides), water spray chambers in the DSHs spray the hot feedwater as directed by the temperature controller so that the steam temperature at the inlet of the final superheaters decreases sufficiently, while passing through them, to maintain a constant temperature at the outlet of the final superheaters vis-à-vis the boiler outlet.

8.2 Discussion

Superheated steam temperature control is a critical parameter for the efficient running of the steam generator vis-à-vis the turbogenerator (TG) unit. The temperature needs to be stable to reach the highest turbine efficiency. A stable temperature also reduces turbine metal fatigue, as discussed in Section 6 of Chapter IX.

The steam temperature is controlled by water of a comparatively colder temperature sprayed into the steam spray chamber. Maintaining a constant temperature is a bit problematic as the temperature measurement itself is a sluggish phenomenon. Adding to this problem is the time delay arising out of the process itself. The spray chamber is generally located before the final superheater, whose outlet temperature is measured and controlled. The changing process dynamics, including system gains, time constant, and delay, are also a cause of concern because it varies as the turbine load changes. Considering all this, it is apparent that SH steam temperature control has always been a critical issue in the efficient and most favorable operation of a power plant.

The control strategy, in normal practice, employs cascade-type controls, with controllers having PID algorithms at various levels to regulate the superheat temperature. State-of-the-art technology has created modern self-tuning controllers or controller algorithms, which enable the controller block to adjust the controller parameters (e.g., proportional band, integral time constant, and derivative action rate). However, some instrumentation manufacturers and researchers feel that self tuning controllers may not be capable of tackling the situation alone against the tendency of changing gains and time constants of the controlled system during disturbed conditions.

New adaptive control strategies are proposed for the improvement of SH-steam temperature control. The algorithm of these controllers are based on a cascade control system having PID functions but with self-tuning parameters programmed to adjust themselves following the recursive least squares (RLS) method. As claimed by the inventors, the smart adaptive system can cope with adverse disturbances much better than conventional control function algorithms can, with faster, more accurate response and greater effectiveness.

The RLS algorithm represents a type of adaptive filter. It is similar to other filter algorithms but in contrast to others, such as least mean squares (LMS), which eliminates the mean square error. RLS recursively and automatically finds the filter coefficients that minimize a weighted linear least squares optimization of input signals. Its input signals are considered deterministic stochastic (random) while those of LMS and similar algorithms they are considered stochastic. For further details related text books may be referred.

Another type of control algorithm popularly known as the *predictive adaptive controller* is also advantageous for maintaining the superheated-steam temperature of large

www.EngineeringBooksPDF.com

thermal power plants. Adaptive techniques combined with predictive elements enable the controller to continuously adjust the tuning of parameters by tracking plant dynamics variations.

An advanced and new predictive adaptive controller algorithm using function series approximation technique, called *dynamic modeling technology* (DMT), is, designed to take care of the system under control with long time delays and long time constants. The design is said to have the unique ability to build the models automatically while operating in a closed-loop configuration and to control the transient responses that occur during boiler load changes. The model (in other words, the mathematical representation) of the process response, which normally requires complex detailed knowledge, does not require building because DMT modeling method builds it using advanced mathematical functions. For details, refer to relevant textbooks.

Superheated-steam temperature control is a critical control loop, but a different approach had been used to address the problem with the help of a system popularly known as a *state variable control*. This is a unique set of variables that describe the state of a dynamical system at any point of time. In other words, the future behavior of a particular system can be predicted automatically to a close proximity if the data required by the state variable technique are provided.

To be more precise, the state variables themselves represent the state of any type of system. In a thermodynamic system, the state variable input data are pressure, temperature, heat contents, and related parameters such as enthalpy, entropy, and internal energy. This system is essentially a special method for building a system model employing the time-domain technique. Here the actual physical system that is the thermodynamic representation of the boiler and turbine is described by an ordinary differential equation of *n*th order. With the help of state variables, a set of first-order differential equations are calculated and grouped using a compact matrix notation depicted as a model and widely known as a *state variable model*. At any instant, the state equations receive the current inputs along with past states and bring the relation to the current state and output of the system so as to enable the control system to generate appropriate output.

8.3 Control Loop Description

All methods other than the self-tuned and optimized cascade PID controllers are explored so that a reduction in steam temperature fluctuations around the set point can be obtained. However, the control loop strategy for superheated-steam temperature control is discussed, incorporating the PID controllers for easy understanding of the control philosophy.

Figures VIII/8.1 and VIII/8.2 may be referred to for a schematic representation of implementing the control loop in a typical 250 MWTPS having a drum-type boiler, two-stage spray water attemperation systems, and reheated-steam temperature control via the gas-recycling damper and spray water attemperation.

8.3.1 Measurement of Various Parameters

The following measurements are made with sufficient redundancy (triple redundancy is shown here) and after necessary voting (two of three are shown here): the selected parameters are utilized in the control loop:

- First-stage attemperator outlet temperature (left and right sides)
- Platen SH outlet temperature (left and right sides)
- Second-stage attemperator outlet temperature (left and right sides)
- Final SH outlet temperature (left and right sides)
- Primary SH inlet pressure

8.3.2 Control Loop Description

The steam path in the system for which the control strategy is described incorporates the primary SH, the first-stage attemperator, the platen SH, the second-stage attemperator, and the final SH ad seriatim, irrespective of their physical location.

8.3.2.1 Boiler with Two-Stage Attemperation

8.3.2.1.1 Second-Stage Attemperator Outlet Temperature Control Loop The ultimate measured/process variable is the final SH outlet temperature, which is compared with the constant temperature set point (adjustable at low load) to form the error signal (refer to Figure VIII/8.2). This signal is connected to the master (or outer) controller with PID functional blocks (algorithms). A derivative functional block is normally provided in the controller for the temperature control loops to compensate for inherently sluggish sensor behavior.

The controller output now becomes the variable set point of the second-stage attemperator outlet temperature controller and forms the error signal along with the measured/process variable and connected to the controller. This PID controller, the slave or inner controller), generates the output for position adjustment of the second-stage attemperator spray water control valves. As already indicated, in the steam flow path the second-stage attemperator is located just before the final SH,. It provides the necessary injection of spray water flow while the main steam is flowing through it to adjust the attemperator outlet temperature at a value just necessary to maintain the final SH outlet temperature at a constant value after the necessary temperature gain in the final SH.

www.EngineeringBooksPDF.com

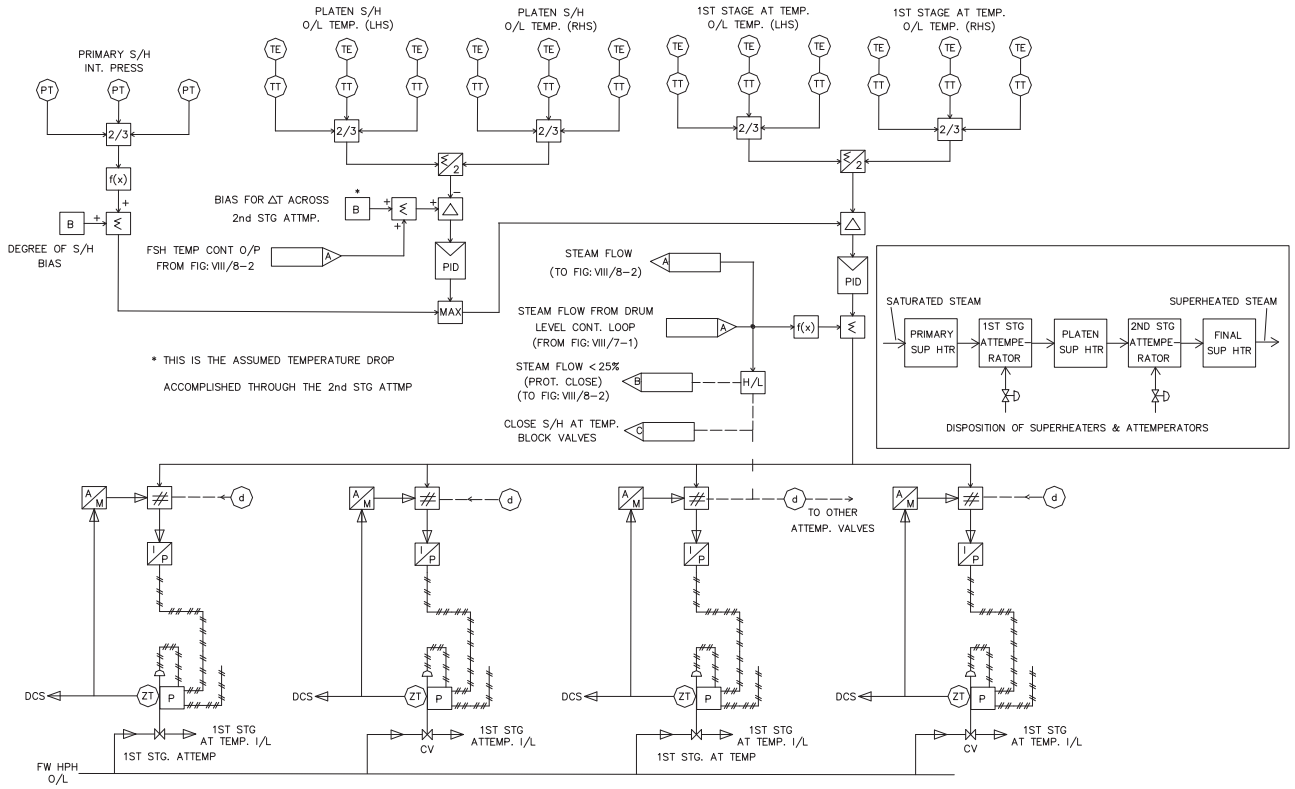


FIGURE VIII/8.1 Superheater steam temperature control.

Steam flow (or, in some plants, air flow) is added to the output of the controller as a feed-forward signal. The interlock from steam flow <25% is provided to block attemperation flow up to a 25% load.

8.3.2.1.2 First-Stage Attemperator Outlet Temperature Control Loop Now comes the first-stage attemperator outlet temperature control. Actually, the first- and second-stage attemperator outlet temperature control loops are interconnected in a cascade of control, justifying their interrelationship in the system. The first-stage attemperator outlet temperature control loop is also configured in master/slave mode with its master controller receiving its variable set point from the master controller of the second-stage attemperator outlet temperature control loops.

The first-stage attemperator, with its comparatively larger spray capacity, sets the temperature at the second-stage attemperator inlet, or, in other words, the platen SH outlet, such that the second-stage attemperator maintains, in the long run, the exact mean spray water flow and effectively controls the final main steam temperature at the required value. Both control loops are almost identical, the only difference being that the second-stage attemperator control loop master controller (or the outer controller) has a master (or outer) controller with a fixed set point whereas the first-stage attemperator control loop master controller has a controller with a variable set point that is only required to attain a value as dictated by the second-stage attemperator control loop master controller.

As a result, however, the second-stage attemperator control loop master controller output is actually the variable set point or the desired temperature at the second-stage attemperator outlet, it cannot at the same time be the set point for the first-stage attemperator control loop master (or outer) controller meant for the second-stage attemperator inlet (platen SH outlet). Therefore, the differential temperature as envisioned by the designers is added to the desired second-stage attemperator outlet temperature (as derived from the second-stage attemperator control loop master controller output) to obtain the anticipated variable set value of second-stage attemperator inlet temperature.

The measured and selected value of the platen SH outlet temperatures on the left and right sides are then averaged and become the process/measured variable for the second part of this cascade control loop. The error signal is formed by the above two signals and connected to the first-stage attemperator control loop master (or outer) controller output, which becomes the variable set point for the controller assigned to the first-stage attemperator outlet temperature control, but after a maximum selector.

Under certain operating conditions, the control system may demand a first-stage attemperator outlet temperature

www.EngineeringBooksPDF.com

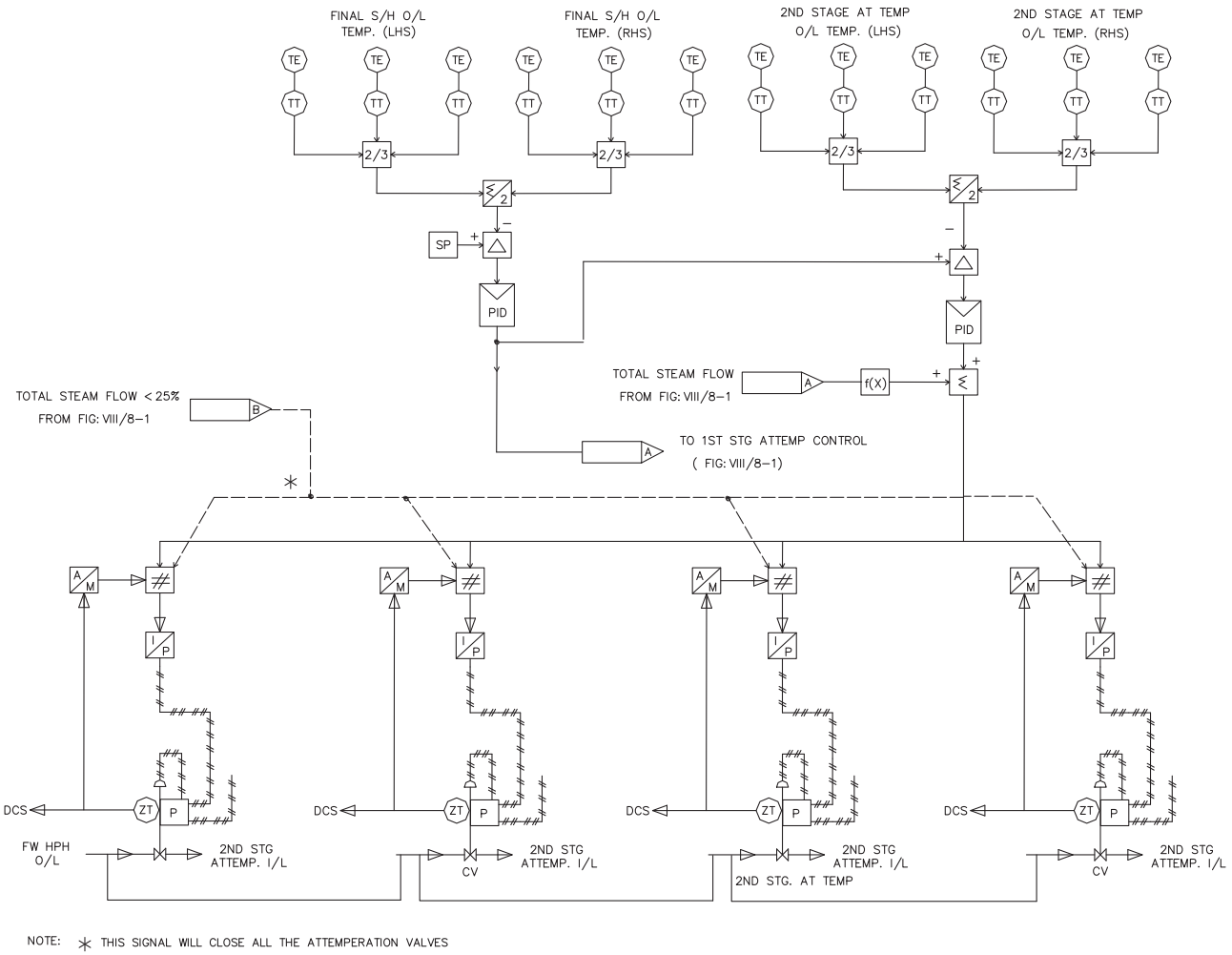


FIGURE VIII/8.2 Final superheater steam temperature control.

below the saturation temperature; this is taken care of through incorporation of an additional function so as to ultimately protect the platen SH. Because of the difficulty of accurately measuring saturation temperature and also to avoid the inherently sluggish response of temperature measurement, a signal proportional to the primary SH inlet pressure (or DP) is used, via a function generator, whose output is programmed to give the corresponding saturation temperature. To this signal is added (as a positive bias) an increment of around 20 to 35°C (which means a certain degree of superheat) depending on the operating pressure (the higher the pressure, the lower the permitted increment).The resulting summed signal (i.e., the saturation temperature plus a certain degree of superheat) is treated as the minimum permitted first-stage attemperator outlet temperature and becomes another input to the maximum selector to ensure that the steam temperature does not decrease near saturation (i.e., at first-stage attemperator outlet temperature) after the application of spray water.

This controller, with the variable set point previously discussed, acts as a slave controller for maintaining the first-stage attemperator outlet temperature, and its output is added to a feed-forward signal from the total steam flow as generated in the drum-level control loop (refer to Figure VIII/7.1) after due characterization. The output of the summator is now the position demand of the spray valves of the first-stage attemperator for maintaining its outlet temperature.

8.3.2.1.3 Safety Interlocks in the SH Temperature Control Loop The following safety interlocks are incorporated in this control loop to protect various components of the thermal circuit. They are described as follows in the following paragraphs.

To protect the superheater system from the effects of water droplets due to inefficient atomization of spray water at low loads, the spray water isolation valves as well as the block valves are interlocked to close automatically if steam

www.EngineeringBooksPDF.com

flow (or the equivalent boiler load) is equal to the 25% continuous maximum rating (CMR); they remain in the locked closed position as long as the steam flow is less than 25%.

Another interlocked operation takes place between the isolating valve and the spray valve auto manual station to prevent the release signal to auto mode of the spray water−modulating valves unless the isolating valve is fully open. This logic helps preventing the possibility of the modulating valves being open because of a position demand request from the control loop when availability of spray water is not ensured.

The spray water modulating valves are interlocked to the closed position through a bias close signal from "steam flow <25% CMR" when the isolating valve is fully closed; it also causes the controller output to trip to manual.

8.3.2.2 Boiler with Single Stage Attemperation for TT Burner-Type Boilers

The control loop just described takes care of a typical power plant of 500-MW capacity having a steam drum, a firing system with a burner tilting arrangement, provision for both a fixed and a sliding pressure control system, and so forth.

8.3.2.2.1 Discussion It is important to note that there are some differences in boiler design. In the case of TT burner-type boilers, the majority of the superheaters and reheaters are of the platen type, where heat absorption is mainly by radiation. Naturally, heat absorption by steam is less dependent on steam flow. This means in these cases that at lower load more and more spray flow is required. For this reason, during startup and low-load, set point is very critically chosen, as discussed in Section 8.3.2.2.3. For the same reason, when the load is high most of the heat is taken away by steam so that spray flow (mainly for SH steam) goes to a very minimum (even zero). The other types described in Section 8.3.2.1.2 have major superheaters and reheaters that are convection types. Of course, as the load increases, more and more heat is absorbed by steam, creating a tendency for the steam temperature rise, causing higher spray flow at higher loads.

Burner tilting (mainly used for reheater control) also has an impact on heat radiation in the superheater platen zone. Therefore, its effect is taken care of here. Now, the load index is the output of the boiler (in a drum-type boiler the derivative of drum pressure will also contribute energy output, so the *d/dt* of drum pressure to be added to the load index), and it must match fuel demand if not where the unbalanced energy will go this will try to disturb the steam temperature. Therefore, to make the sluggish temperature loop responsive, such effects are used in the control loop (see Section 8.3.2.2.3).

The measurement part covers the following measurements:

- DSH outlet temperature (left and right sides)
- Final SH outlet temperature (left and right sides)

Other signals may be available from other control systems, such as main steam flow, drum pressure, fuel demand, burner tilt position, and so forth.

The control loop is basically a cascade and has a control strategy similar to that of the second-stage attemperator outlet temperature control described earlier. The ultimate measured/process variable is the final SH outlet temperature, which is compared with the temperature set point to form the error signal (Figure VIII/8.3).

Here the set point is made variable and is programmed as a function of the unit steam flow signal for both constant and sliding pressure control, but with different characteristics. A manual set point is also provided, and the output of a minimum selector passes the set point for generating the error signal which is connected to the master (or outer) controllers with PID functional blocks (algorithms). A derivative functional block is usually provided for the temperature controllers to compensate for the sensors' inherently sluggish behavior.

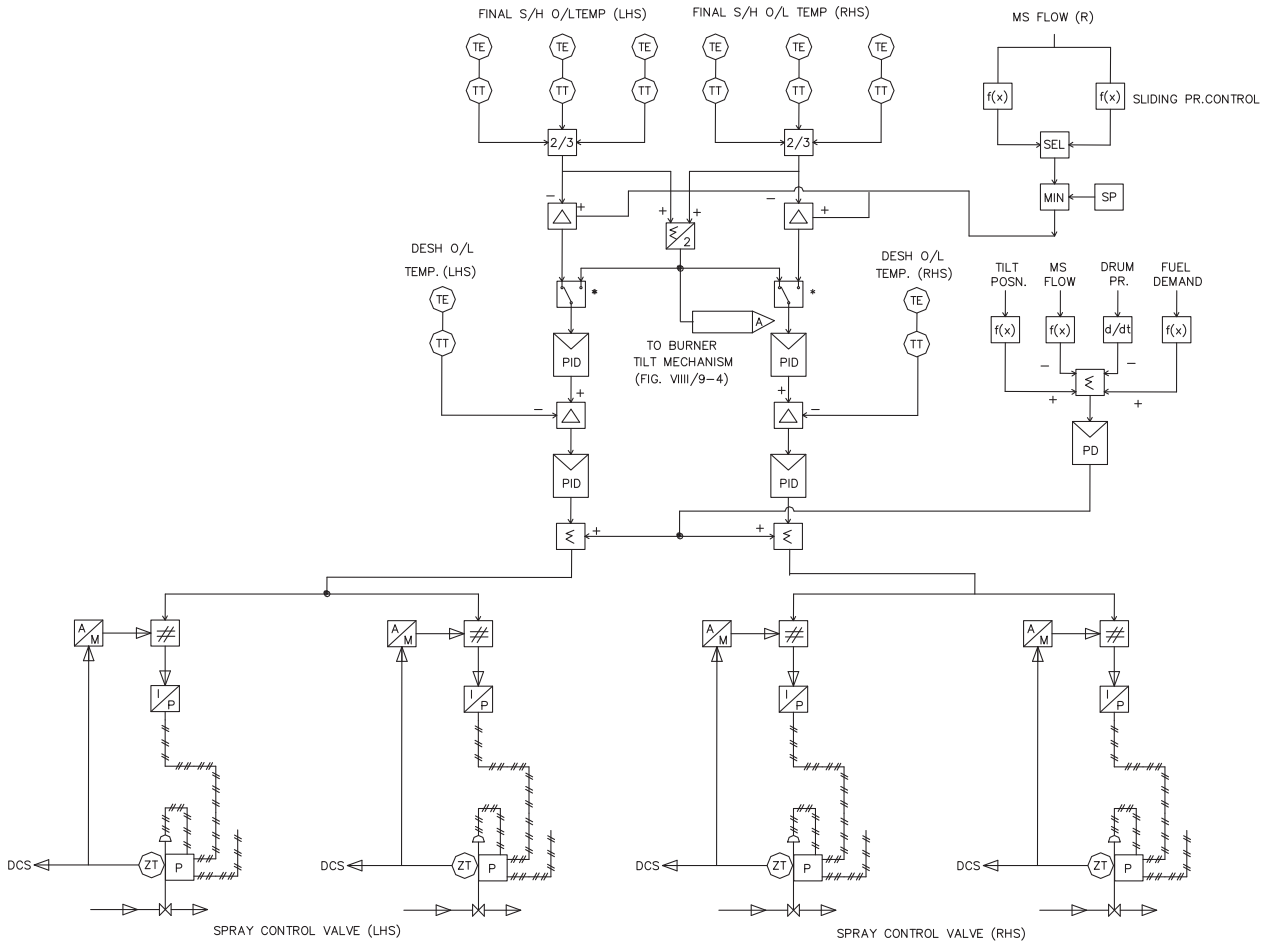
When the difference between the left- and right-side temperatures at the final SH steam outlet header are within the limit, their average temperature acts as the measured/process variable for both the "Master (or outer) controllers" of the left- and right-side temperature control loops. If a high difference between the two sides exists, the average signal is no longer considered as the measured/process variable and instead the individual final SH steam outlet temperature becomes the measured/process variable for respective temperature control loops.

The controller output now becomes the variable set point of the DSH or the attemperator outlet temperature controller and forms the error signal along with the measured/process variable and connected to the controller. The PID controller may be termed the slave (or inner) controller and generates the output for position adjustment of the DSH or attemperator spray water control valves. As it is needless to mention that the DSH or attemperator is located just before the final SH in the steam flow path, the attemperator provides the necessary injection of spray water flow while the main steam is flowing through it to adjust the attemperator outlet temperature at the value needed to maintain the final SH outlet temperature at a constant value after the necessary temperature gain in the final SH.

With reference to Section 8.3.2.2.1, some feed-forward signals are provided to make this control strategy more responsive:

- Burner tilt position
- Main steam flow

www.EngineeringBooksPDF.com



NOTE: * FUNCTION OF THE CHANGE OVER SWITCH IS TO PASS THE AVERAGE VALUE OF ERROR TO BOTH THE LEFT & RIGHT SIDE SPRAY CONTROLLER. IN CASE THE DEVIATION BETWEEN THE ERRORS IS MORE THAN A PRESET VALUE, IT LETS THE INDIVIDUAL ERROR TO INPUT THE CORRESPONDING CONTROLLER

FIGURE VIII/8.3 Superheater steam temperature control (500 MWTSP) with burner tilt.

- Drum pressure
- Fuel demand

Burner tilt position is taken as a feed-forward signal limits the anticipated temperature excursion by adjusting the flow of spray valves when the burner tilt operates to maintain the reheater temperature.

The same logic can be applied to the rate of change in fuel demand. For instance, when there is a possibility of increasing the fuel demand associated with overfiring, the spray valves are expected to open in advance to counter the initial temperature rise because of overfiring. The steam flow and drum pressure (derivative) signals are taken as the feed-forward signals as aftereffects of overfiring. The steam flow and/or drum pressure then rises and are used as the index to recognize the tendency for the temperature to drop. These signals are thus duly characterized to close the spray valves to counter the subsequent temperature drop.

All of the signals generate suitable output signals and are summed to make an input signal for a PD controller. This output is again added to the output of the slave (or inner) controller to become the position demand for the individual spray valves.

9. REHEAT TEMPERATURE CONTROL

9.0 General

As discussed earlier, the exhaust steam from the high-pressure turbine (HPT) is brought back to the boiler for making it again SH steam at a lower pressure but normally at the same temperature as the main steam temperature. Although application of the Rankin cycle in thermal power plants is discussed in most text books on the thermodynamic properties of steam, brief discussions are provided in various sections of Chapters I and II. It is apparent that SH steam is more thermally efficient than

www.EngineeringBooksPDF.com

saturated steam in driving turbogenerators. That is the reason that the exhaust steam from a HPT is reheated: the extra heat causes transmission of more energy and is used for additional power generation from the available quantity of steam.

9.1 Objective

The objective of this control loop is to maintain a constant temperature of the reheated steam at the boiler outlet, which also means an almost constant temperature at the IP turbine inlet that varies because of transmission loss. This control loop is also considered one of the most important in the thermal power plant instrumentation system. The exhaust steam from the HPT is superheated by adding heat through various heat exchangers popularly called *reheaters*. Before the reheaters (left and right side), there are arrangements for DSHs having water spray chambers in CRH lines. Hot feedwater is sprayed through this spray chamber as directed by the temperature controller so that steam temperature at the inlet of the reheaters decreases enough so that, while passing through the reheaters, a constant temperature is maintained at the reheater outlet vis-à-vis the boiler outlet. DSHs normally do not take part in the control action but are utilized as the last resort when all other final control elements reach their end positions.

9.2 Discussion

Similar to SH steam temperature control, reheated steam temperature control is a critical parameter for the efficient running of the steam generator vis-à-vis the turbogenerator unit. Steam temperature needs to be stable for the highest turbine efficiency. This also reduces the fatigue of the turbine metal, as discussed in Section 6 of Chapter IX.

Reheated steam with a low operating pressure is subjected to a variety of thermodynamic conditions from those of superheater steam. For the reheat system, problems may arise when injecting colder spray water which may have an unwarranted effect on overall efficiency. Control of reheated steam temperature thus normally avoids water spraying since long and uses a primary control system that takes care of this by either adjusting tilting burners through position control or by apportioning flue gas flow through the superheater and reheater banks or recirculating it into the furnace from a suitable takeoff point.

A spray water injection system is also provided but only as a last resort when the final control element reaches the extreme position and further influence is not achievable or the temperature has increased to a predefined value when emergency spray is necessary. The system so far avoids the requirement of spray water and confines its use for fine-tuning and emergencies only. In some control schemes, the system is used for controlling the furnace outlet temperature as well.

There are different schools of thought on adapting the reheated temperature control philosophy (other than spray water control) depending on the boiler manufacturer:

- Control through the gas-recycling damper (Babcock-type boiler)
- Control through the gas dampers(main line) or bypass dampers (Babcock-type boiler)
- Control through the burner tilting mechanism (CE-type boiler)

9.2.1 Control through Gas-Damper

For this control, a damper at the chimney inlet is provided in a common flue path at the ID fan discharge header. This arrangement ensures the generation of back-pressure with sufficient magnitude so as to force the flue gas from the discharge header to the furnace again through separate ducts between main flue line and the furnace hopper. This damper-controlled recycled gas flow alters furnace absorption and the mass flow of flue gas, which maintains the steam temperature within range at the reheater outlet. In this case the size of the ID fan is greater since it handles more flue gas.

There is another method of injecting flue gas into the furnace in which the takeoff point is much nearer the furnace. This means the flue gas has a much higher temperature but much lower pressure. To make this low-pressure flue gas admission to the furnace possible, recirculation fans are provided to generate pressure higher than the furnace pressure. The gas-recycling damper does the rest.

Some advantages of a flue gas recirculation system for reheat temperature control are the following:

- The total mass flow of the flue gas increases, enhancing heat transfer to each heater bank.
- Because of the admission of colder flue gas, the temperatures at various stages in the furnace/boiler decrease, although overall enthalpy and so heat transfer increases.
- As the colder flue gas is injected near the burner, the resultant low temperature helps to lower generation of SO_x and NO_x compared to a system without gas recirculation dampers.

The takeoff point for the gas recirculation system being at a low pressure zone, gas recirculation fans are necessary to ascertain the flue gas passage on its long way back to the furnace. By controlling gas recirculation flow, the steam temperature of both superheater and reheater may also be controlled. While providing gas recirculation dampers, it has to borne in mind that the reverse flow of very hot flue gas must be arrested to protect the fans in case of failure(stopping/tripping) of the fan itself.

www.EngineeringBooksPDF.com

9.2.2 Control through Main Path Gas Dampers or Bypass Gas Dampers

In this arrangement, the quantity of flue gas allowed to pass through the reheater is varied by the gas bypass dampers so that reheater temperature is maintained as required.

As discussed in Section 2.3.7 of Chapter II, only the part related to control is discussed here. The gas dampers do the apportioning of flue gas flow through both the superheater and reheater banks by adjusting their position. Some arrangement allows two separate and dedicated sets of dampers in the flue gas path of both the superheater and the reheater banks controlling individual flue gas flow. Dampers being located across the main path and controlling the total flue gas volume, the control system ensure that the dampers do not receive a closed signal at the same time which may lead to constriction of the flue gas path, resulting in overpressurization that may damage the boiler structure. To obviate this untoward situation, the control philosophy is such that only when one particular set of dampers is fully opened, the other set is allowed to throttle.

Emergency spray may be necessary here, as control through gas dampers is a slow response system for large units and a sudden rise in temperature following a rise in furnace heat input is expected to cope up with the load demand.

9.2.3 Control through Burner Tilt Mechanism

The steam temperature control system is genetically different in two types of furnaces: one with a tangentially fired tilting burner and the other with fixed burners. By this arrangement the burning zone is raised or lowered by the burner-tilting mechanism. The burners are corner-fired and focus tangentially on a common imaginary circle. When firing starts, a huge fireball forms with swirling action. As all the burners in a corner are gagged to a common set of actuators and all four corners get the same positioning signal, the fire ball moves vertically upward or downward, with the burner assemblies moving up or down.

Such repositioning of burners vis-à-vis the fireball changes the pattern of heat transfer to the superheater and reheater banks, thus controlling the steam temperature. The burners are so arranged to be tilted up or lowered down so the flame envelope in the furnace causes a good variation in the amount of radiation heat received by the reheater and superheater. In fact, the firing system in any type of furnace in a power plant boiler has reheater banks that affect the steam temperature of both superheater and reheater. It is very difficult to control both steam temperatures by a single control system, as corrective action for one steam heater bank may have adverse effect on the other bank. To circumvent this situation, separate control strategies are considered by the control engineers in association with the equipment designer.

9.3 Control Loop Description

9.3.1 Gas-Recycling Damper and Spray Water Attemperation

Figures VIII/9.1, VIII/9.2, and VIII/9.3 for can be referred for a schematic representation of implementing the control loop in a typical 250 MWTPS having a drum-type boiler with reheated steam temperature control through gas-recycling dampers and spray water attemperation in emergency cases.

9.3.1.1 Measurement of Various Parameters

The following measurements are necessary with sufficient redundancy and voting for reheat steam temperature control through gas-recycling dampers and 'spray water at temperation:

- Gas-recycling flow
- Reheat attemperator flow
- Reheater outlet steam temperature (left and right sides)
- DP across gas-recycling dampers
- Position of gas-recycling damper
- Position of reheat steam outlet valves (for temperature balancing)
- Measurement of other signals (e.g., main steam flow and furnace pressure) as in other control strategies

These loops are developed with the following considerations:

- Since there is one set of gas-recycling dampers, the average of both sides of the RH outlet temperature is utilized for control.
- The same average measured value has been taken to generate error but with a higher set value, and the (outer) controller output is considered a common spray flow demand in a cascade loop (inner controller) without taking into consideration individual side spray control and measurement of attemperation outlet temperature to avoid mismatch between the two interactive loops—namely spray control and gas recycling.
- The control strategy does not necessarily guarantee that on both sides have some heat absorption so as to have both side temperatures at RH O/L the same. However, by incorporating one valve in each side in the RH outlet such problems are overcome.

9.3.1.2 Control Loop Description

The final control elements in the system through which the control strategy is accomplished incorporate the following items:

- Gas-recycling damper
- Stack inlet damper
- Reheat attemperator valves
- Reheat steam outlet valves (for temperature balancing)

www.EngineeringBooksPDF.com

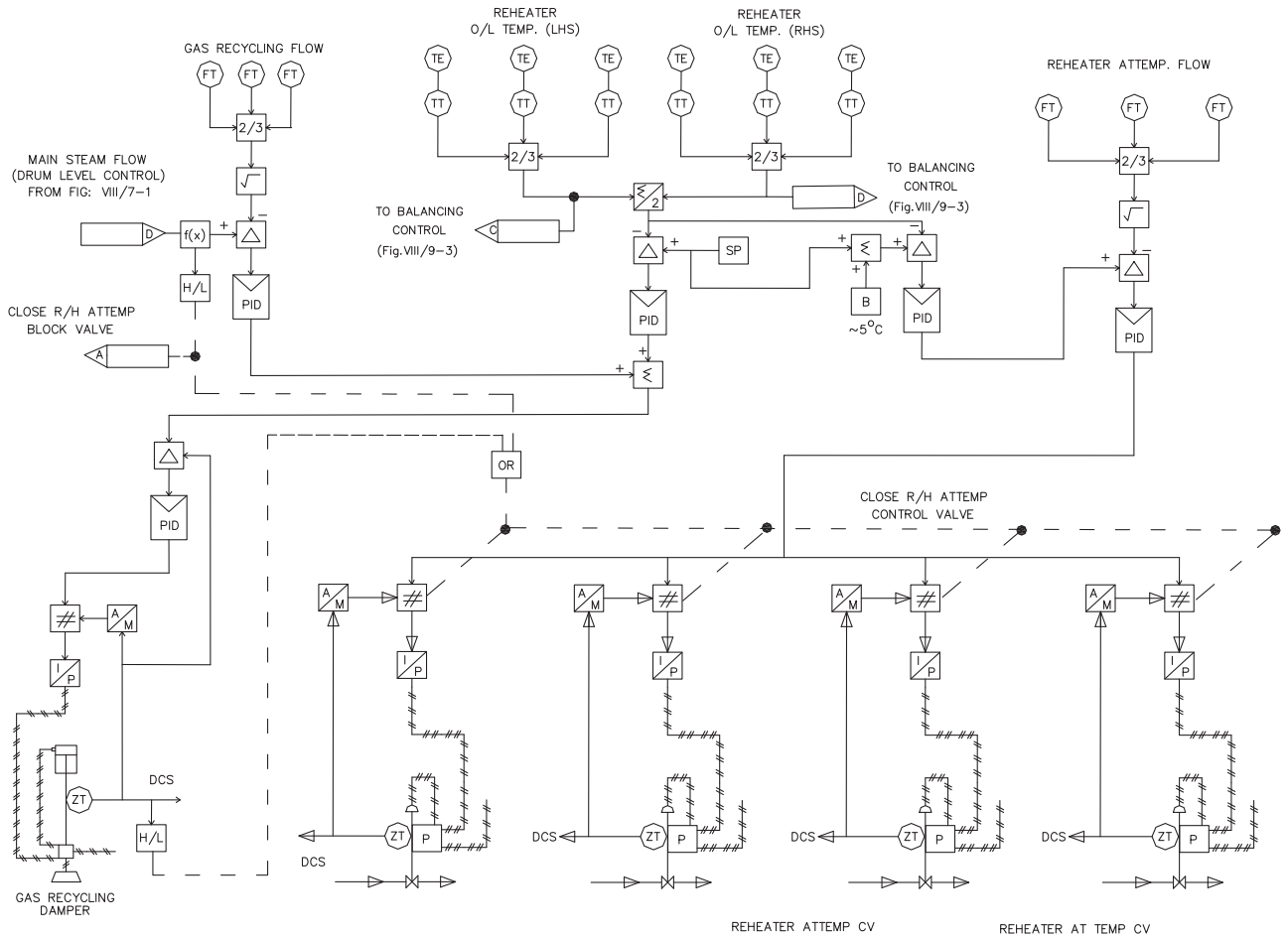


FIGURE VIII/9.1 Reheater steam temperature control by gas-recycling damper.

9.3.1.2.1 Function of Gas-Recycling Damper The steam temperature is measured at both outlet legs of the reheaters and averaged after selection and voting to form the ultimate measured/process variable for this control loop (refer to Figure VIII/9.1). The control strategy utilizes the recycled flue gas flow to the furnace hopper by throttling the single gas-recycling damper receiving the controlled input command from a temperature/flow cascade control action.

The PID (temperature) controller employed for this purpose has a set point adjuster for setting the desired value of the reheated steam temperature control system. The controller output is then summed with another PID (flow) controller output that signifies whether the requirement of gas-recycling flow is satisfied. The gas-recycling flow signal as measured forms the measured/process variable for this part of the control loop, and the set point is derived from the main steam flow (as load index) duly characterized to give out the corresponding expected recycled flue gas flow. The (temperature) controller output trims the flow controller output to derive the required desired position of the gas-recycling damper. This signal forms the set value of the position controller while the actual position of the damper is measured and connected to the position controller output, which is used to modulate the gas-recycling damper.

9.3.1.2.2 Function of Stack Inlet Damper This is a secondary part of reheater steam temperature control and helps the main control loop to function properly (see Figure VIII/9.2). Its sole function is to maintain the DP across the gas-recycling damper at a constant value. The stack inlet damper acts as the final control element in this control loop.

DP across the gas-recycling damper is measured and, after selection and voting, forms the measured/process variable (after passing through a maximum/minimum limit algorithm) for a separate controller whose set point adjustment at a fixed value made through a manual setter. The controller output is used as the positioning command

www.EngineeringBooksPDF.com

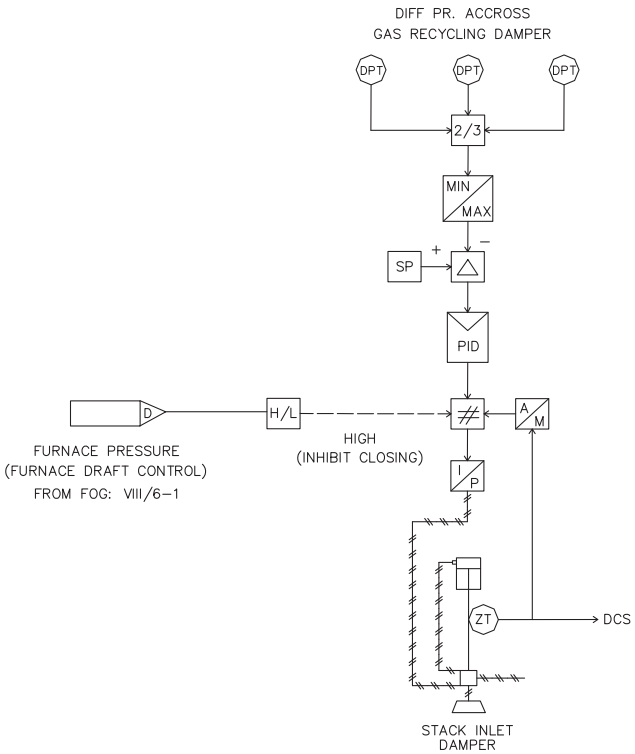


FIGURE VIII/9.2 Stack I/L damper control (RH steam temperature control by gas-recycling damper).

for the stack inlet damper, which modulates to maintain the DP across the gas-recycling damper. By this arrangement it is always ensured that a sufficient pressure head is available to force the flue gas from the ID fan discharge duct to the furnace chamber through the hoppers. The interlocked operation of this damper prevents its closing command when the furnace pressure is found to be high.

9.3.1.2.3 Function of Reheat Steam Outlet Valves for Temperature Balancing There are two butterfly-type valves located in the reheat steam line in each leg (refer to Figure VIII/9.3). The very purpose of this control loop is to maintain the steam temperature of both LHS and RHS pipe lines at the same value. This is done by slightly restricting the steam flow through the low temperature leg and vis-à-vis an increase the steam flow through the high temperature leg.

The steam temperatures (left and right sides) of both reheater outlet legs are measured and averaged to form the common set value of two the PID controllers whose measured/process variables are the individual reheater outlet steam temperatures. The output of these controllers is the position demands of the butterfly steam valves acting inversely so as to minimize the error (be it positive or negative). The purpose of the control strategy is not to maintain a fixed desired value but to lessen the temperature difference between the two legs.

Another purpose of this loop is to ensure a minimum steam side pressure loss. A separate PID controller is used whose fixed set value is the 100% position and whose measured/process variable is the maximum selected position transmitter signal of the two butterfly valves. The controller output is added to the main controller output to form the combined position demands of each valve. By this arrangement, the maximum-position-selected valve tries to reach 100% and the other valve position also increases by the amount, but the difference remains the same. This is accomplished by minimum integration rate action and high proportional band to allow a slow output signal until one valve reaches the 100% position without disturbing the temperature-balancing action.

As already discussed, spray water control systems maintain the reheat steam temperature in emergency cases if the gas-recycling damper alone fails to bring down the temperature. The normal control loop function is achieved by the gas-recycling damper, but if for any reason the temperature shoots up and if that condition persists the spray control valve comes into action to save the reheater from burnout.

The dedicated controller for this purpose has the same temperature set value but biased with ∼5 to 7°C to prevent the loop from interfering with the normal loop. The spray control valves remain closed unless the temperature rise crosses that biased amount. The controller gets its measured/process variable from the average reheated steam temperature and the output becomes the RH attemperator water flow demand or the set value for another controller, with the RH attemperator water flow measured signal directly becoming the measured/process variable. This controller output now becomes the position demand for the spray control valves.

There are also interlocked operations in which the RH attemperator spray valve opens; at that time the gas-recycling damper becomes automatically closed. The ID discharge damper is mechanically arranged with a limited stroke using a mechanical stop or setting the linkage so that the full stroke of the actuator provides partial movement of the damper.

9.3.2 Control Loop Description with Gas Dampers

9.3.2.1 Damper in Main Flue Gas Path

There are two arrangements for boilers with reheater temperature control by gas dampers (Figure VIII/9.4). For some boilers, gas dampers are provided in the common flue gas path and provided as the final control element for the reheater steam temperature which, when positioned, acts like a three-way proportioning valve and apportions the flue gas flow through both the superheater and the reheater banks. This means that the total flue gas flow is

www.EngineeringBooksPDF.com

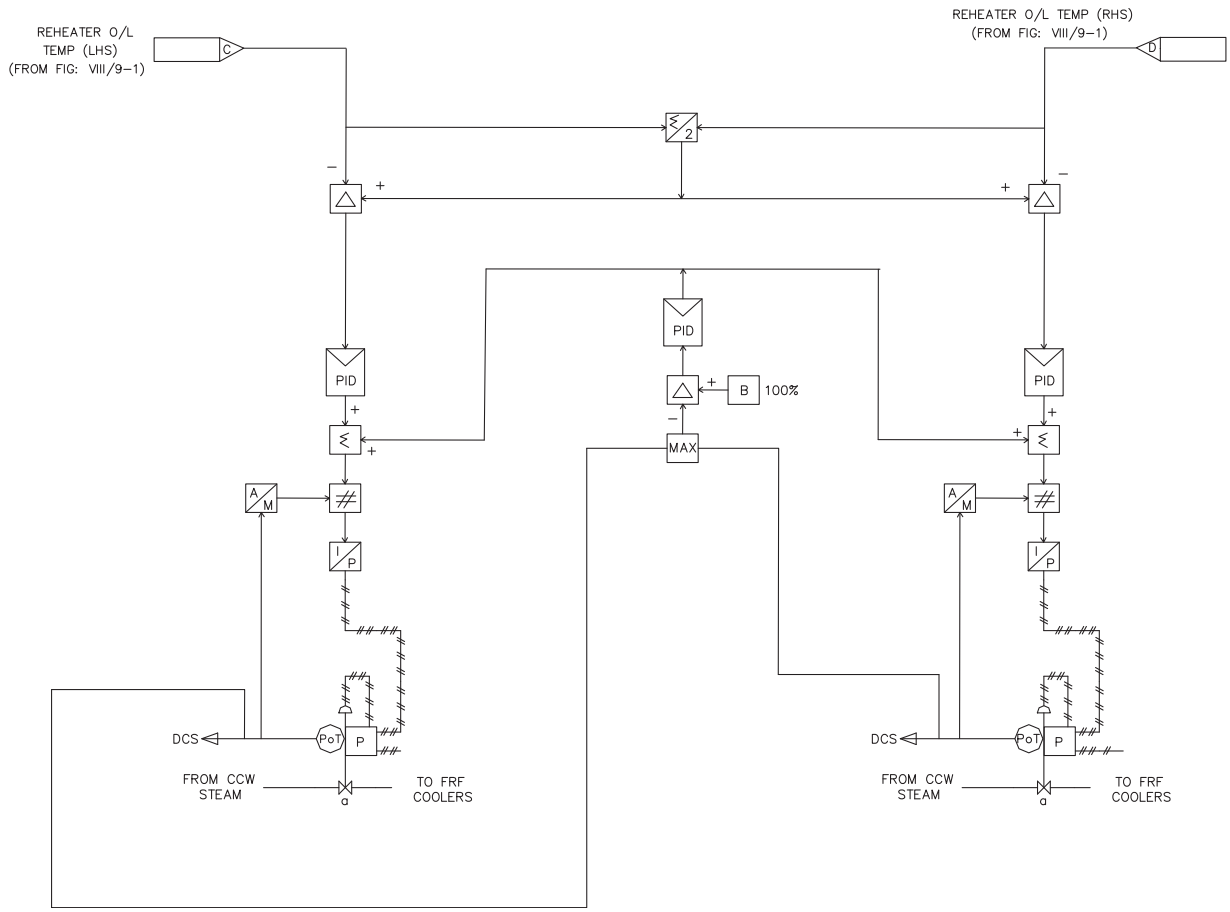


FIGURE VIII/9.3 Reheater outlet steam temperature control (by balancing control).

uninterrupted, with only the ratio of gas flow through them readjusted.

In some boilers, two separate and dedicated sets of dampers are provided in the flue gas path of both superheater and reheater banks controlling individual flue gas flow. As these dampers are located across the main path, they, unlike other types of gas dampers, control total flue gas volume, which means that interruption of gas flow may occur during auto operation of the control loops. Hence, the control loop should provide adequate measurement; in other words, proper care has to be taken so that both dampers do not receive a closed signal at the same time. In that situation, the flue gas path is constricted so badly that the overpressurization may damage the structure itself.

The control strategy adopted to obviate this untoward situation is such that one set of dampers is allowed to throttle only when the other set is fully opened. This interlocked operation also ensures that no gas dampers receive a fully closed signal at any time during the entire range of operation.

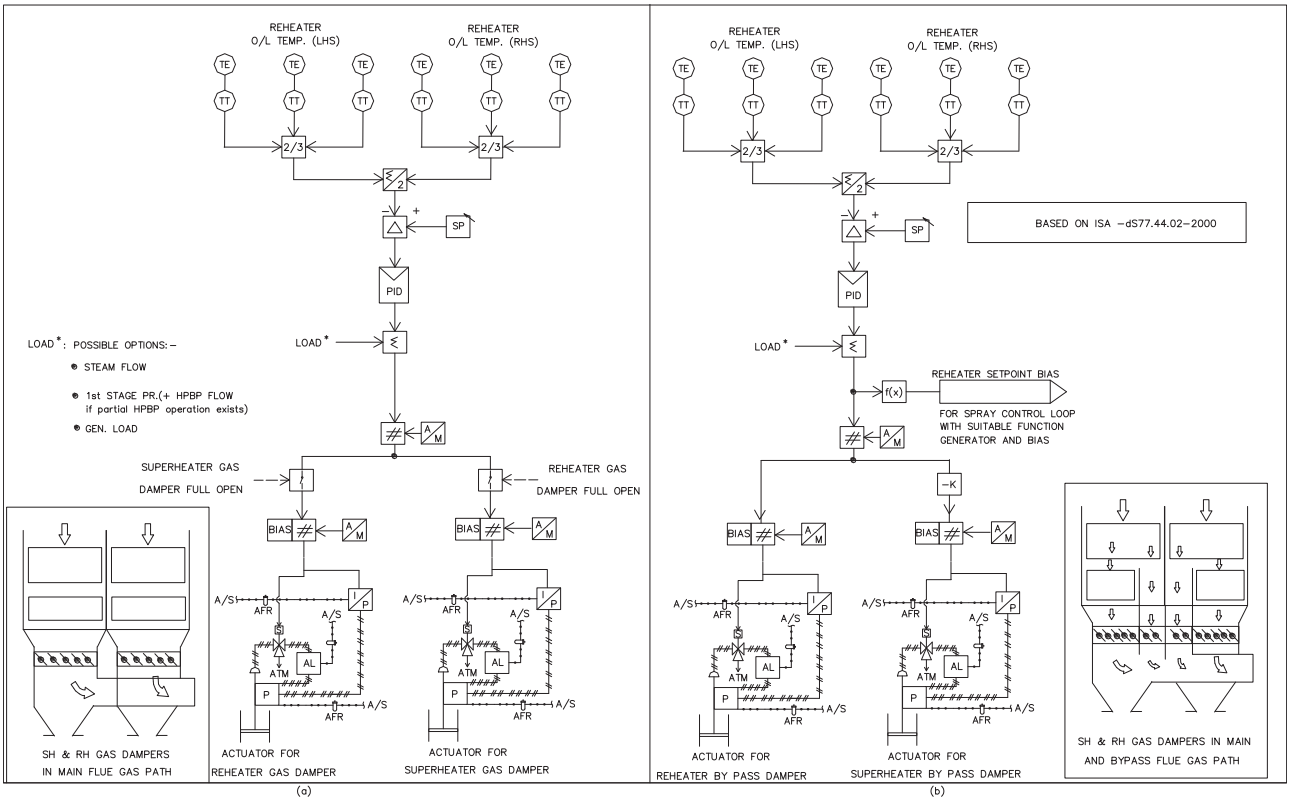
Intermittent operation of emergency spray valves may be necessary here as gas damper control is a slow response system for large units. Whenever there is a possibility of sudden overheating accompanied by a rise in temperature following a rise in furnace heat input to cope up with the considerably large load demand in a small span of time, the spray valves are expected to take care of the situation. The set point of the spray loop is also derived from the loop shown in Figure VIII/9.4(b).

As shown in FigureVIII/9.4(a), the measured variable (RH O/L temperature) is compared with the adjustable set point and the error thus created is sent to the PID controller. In order to make the loop more responsive, a load index is added at the output as a feed-forward signal. Because spray water is an emergency or a secondary control system for reheat temperature control, the spray valves are normally shut unless the temperature at the reheat outlet reaches a predetermined value higher than the normal set value.

9.3.2.2 With Bypass Gas Dampers

This control strategy is the same as that for main-line gas dampers but here bypass dampers in the SH and RH gas path are positioned in opposite directions, as shown in Figure VIII/9-4(b).

www.EngineeringBooksPDF.com



NOTE: 1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS etc .IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER MANUFACTURER'S RECOMMENDATIONS.
2) THIS TYPE OF CONTROL LOOPS ARE APPLICABLE FOR MAINLY FOR BOILERS WHERE CONVECTION TYPE HEAT TRANSFERS ARE PREDOMINANT..
3) INTERNAL AUTO / MANUAL SIGNALS OF THE LOOP HAS NOT BEEN DETAILED OUT TO AVOID COMPLEXITY.
4)TO GIVE AN IDEA TO THE READER, OPEN LOOP CONTROLS HAVE BEEN SHOWN IN DASHED LINE TO DISTINGUISH IT FROM MODULATING CONTROLS. THIS IS HOW IT COULD BE REPRESENTED IN REALITY FOR BETTER UNDERSATNDING

FIGURE VIII/9.4 Reheater (superheater) temperature control with gas bypass dampers.

During startup and at low load, the superheater bypass is wide open and the reheater by pass is at a minimum position. As the load increases, the operation is reversed. The aim of the loop also is to maintain the DP across the damper nearly constant by adjusting the loop parameters and relationships at all points of operation. The set point of the spray loop is also derived from the loop shown in Figure VIII/9-4b.

9.3.3 Control Loop Description with Burner-Tilting Arrangement

9.3.3.1 Measurement of Various Parameters

The following measurements are necessary, with sufficient redundancy and voting, for reheated steam temperature control with burner-tilting arrangement and spray water attemperation:

- Burner-tilt position
- Reheater outlet steam temperature (left and right sides)
- Reheater DSH outlet steam temperature (left and right sides)
- Measurement of other signals (e.g., main steam flow), which have been shown in other control strategy illustrations.

9.3.3.2 Burner-Tilting and Reheat Valves

The final control elements in the system through which the control strategy is accomplished incorporate the items such as a burner-tilting arrangement and reheat attemperator valves. In earlier times the burner-tilting arrangement was utilized to control reheat temperature only. Nowadays, it is being utilized to control any of the superheater or reheater outlet temperatures depending on the demands of the situation.

In larger units with boilers using TT burners, the area of platen superheaters is increased, so burner-tilt controls can be used for temperature control of either SH or RH based on demand. As discussed, in these cases the two loops (SH and RH temperature control) are interactive, so provisions are made for selection through maximum demand—because major heat transfer is not by convection.

The description of this control loop is for of a typical 500-MW capacity power plant having a steam drum, a burner-tilting firing system, provision for a sliding pressure control system, and so forth. Although this control loop needs a separate section, it is included in the section on reheat temperature control because many power plants of low and medium capacity still incorporate burner-tilting only for reheat temperature control with a feed-forward signal to the superheater temperature control system.

www.EngineeringBooksPDF.com

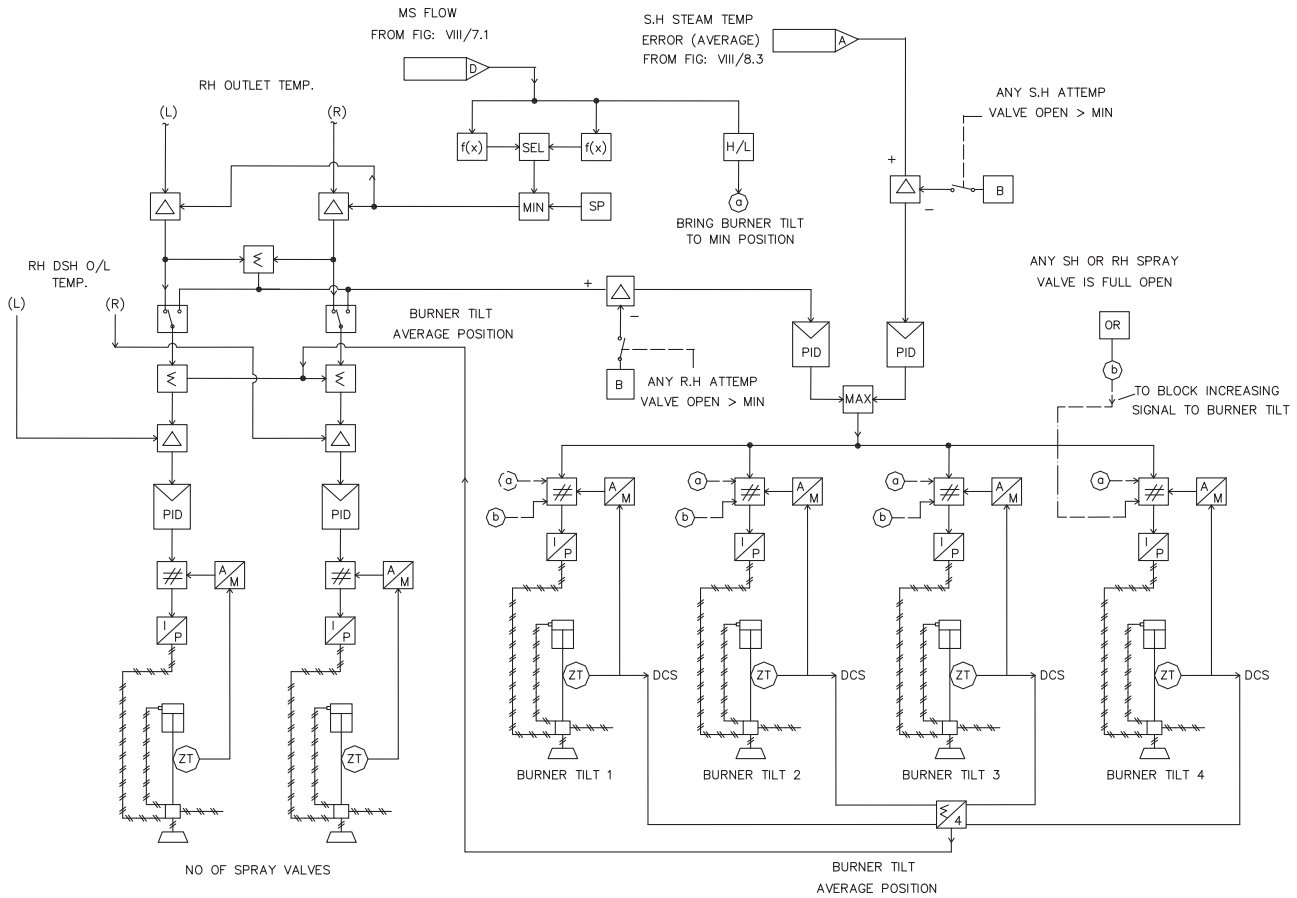


FIGURE VIII/9.5 Reheater (superheater) temperature control by burner tilt and spray water.

9.3.3.2.1 Function of Burner-Tilting Arrangement Here the average control error signals from both the superheater and the reheater controls loops are connected to individual controller outputs which are utilized in a maximum selector; the selected one, of the two the one related to lower temperature, turns out to be the position demand of the burner-tilting arrangement (Figure VIII/9.5).

Interlocking signals are provided as per the following logic: (1) when the steam flow vis-à-vis the boiler load is $\leq$25% MCR or is at MFT, the burner tilt maintains its base position (e.g., at the horizontal position only); and (2) in case any spray water valve fully opens, the burner tilt is prevented from raising its position any further, thus helping to avoid overheating of both the SH and RH elements.

9.3.3.2.2 Function of Reheat Spray Control Valves As mentioned, this description of the control loop is for a typical power plant of 500-MW capacity having a steam drum, a firing system with a burner-tilting arrangement, provision for sliding pressure control, and so forth.

The measurements cover the following:

- Reheater DSH outlet temperature (left and right sides)
- Final reheater outlet temperature (left and right sides)
- Burner-tilt position

Measurement of other signals may be available from other control systems such as main steam flow.

The **control loop** is basically a cascade type and has a control strategy similar to that of superheated temperature control, described in Section 8 of this chapter. The ultimate measured/process variable is the RH outlet temperature (left or right side), which is compared with the temperature set point to form the error signal. Here the set point is variable, programmed as a function of the unit steam flow signal for both constant and sliding pressure control but with differing characteristics. This error signal is connected to the master (or outer-loop) controllers with PID functional blocks (algorithms). A derivative functional block is usually provided for the temperature control loops to compensate for the sensors' inherently sluggish behavior.

www.EngineeringBooksPDF.com

When the difference between the left- and right-side temperatures at the final SH steam outlet header is within the limit, their averaged temperature acts as the measured/process variable for both the master (or outer-loop) controllers of the left- and right-side temperature control loops. If there is a large difference between the two sides, the averaged signal is no longer considered the measured/process variable; instead, the individual RH steam outlet temperature becomes the measured/process variable for their respective control loops.

The controller output now becomes the variable set point of the de-superheater or attemperator outlet temperature controller and, along with the measured/process variable, forms the error signal and is connected to the controller. The PID controller, which may be termed the slave (or inner) controller, generates the output for position adjustment of the de-superheater or attemperator spray water control valves. Needless to say, the de-superheater or attemperator is located (in the steam flow path) just before the RH; it provides the necessary injection of spray water while cold reheated steam is flowing through it to adjust the attemperator outlet temperature at a value just needed to maintain the RH outlet temperature at the set value after the necessary temperature gain in the reheater.

9.3.4 Common Features of Spray Water Valves in Reheater Control Loops

Certain common features of spray water valves are applicable irrespective of the primary arrangement of reheater temperature control, including the following:

- The spray water valves are generally provided at the inlet of the reheater to avoid any overheating, which may cause damage to the reheater elements. Another reason for keeping the attemperation at the inlet to avoid of water carryover.
- All the primary control systems are designed to avoid the requirement of spray water in normal operation and are confined to fine-tuning, secondary control system, and emergency purposes. However, a large TT burner boiler, as discussed here, may use this spray as a primary control as well. However, in such cases the requirement at high load is minimal, for reasons discussed in the previous section.

In some control schemes, the system is used for controlling the furnace outlet temperature as well. All of the final control elements used by the primary system are by nature sluggish, and any large step increase in boiler load may necessitate the action of spray water valves.

In addition to boiler-specific interlocked operation, the spray valves must be closed immediately in case of turbine tripping. The reason behind the interlock is that turbine tripping causes a collapse of reheater flow and in that case, per the recommendation of turbine water damage prevention (TWDP) act, cold spray water cannot enter the turbine in any way.

9.4 Other Reheat Steam Temperature Controls

This type of control is used for compartmented boilers with mill bias. These are three-element controls—reheat temperature, load demand, and total air flow with mill bias. Three-element controls are applicable mainly for rapid load changes, with variable steam and attemperation pressure. Here load demand is trimmed with reheat temperature control within the maximum allowable load demand. This load demand is compared with total air flow with mill bias. The controller decides the demand for excess air and mill bias. At lower loads, mill bias is increased first and then excess air bias, whereas at higher loads the reverse is true; the function generators are selected accordingly. Excess air is introduced into bottom idle compartments. Details are available from ISA.

10. MISCELLANEOUS BOILER CONTROLS, INCLUDING OVERFIRE AIR DAMPERS

10.0 General

There are many other control loops for boiler units that have not been described so far. These controls are listed here; however, the list is not all-inclusive because other control loops may be required for a particular make of boiler:

- Atomizing steam/air pressure control
- Air heater cold end or SCAPH temperature control
- Hot gas temperature control
- CBD tank level control
- SCAPH drain tank level control
- OFA damper control

10.0.1 Objectives

The objectives are as follows:

- Atomizing steam or air pressures are controlled at a fixed value for the purpose of HFO or LFO atomization for proper oil burning.
- The purpose of the air heater cold end or SCAPH temperature control loop is to maintain the average value of cold end temperatures of the air heater that is at air inlet and flue gas outlet at a fixed value above the dew point, which may vary in value from season to season and can be set in the controller accordingly.
- Hot gas temperature is controlled to minimize the flue gas temperature imbalances between the primary and

www.EngineeringBooksPDF.com

secondary air heater outlets. The average temperature of the two air heaters is maintained at a fixed value by positioning the gas dampers so as to readjust the distribution of flue gas in an effort to eliminate the difference between them.

- CBD tank level control is provided to maintain a fixed level in the tank to facilitate the transfer of drum water blown down as unacceptable quality for the steam-water cycle.
- SCAPH drain tank level control is provided to maintain a fixed level in the drain tank, where the heating steam is condensed at the outlet of SCAPH and collected to facilitate the transfer of water for further use.
- OFA control's objective is to minimize the NO_x level as per the directive of the local pollution control board.

The final control elements are the OFA dampers for the tangentially fired burners. By proper positioning of them, arranged at various elevations and locations, the desired level of NO_x can be maintained.

10.0.2 Discussion

10.0.2.1 Atomizing Steam/Air Pressure Control

This is a very important loop as far as firing with HFO or LFO in the furnace. Oil firing is normally done during startup and may be continued in up to 30% of the boiler load during the initial stage. This can be brought into service even in higher loads so as to provide oil support in disturbed conditions such as the rainy season or a shortage/interruption of the PF supply, etc.

For HFO, steam atomization is required, whereas for LFO both steam and air atomization is recommended and the choice of atomizing media depends on availability. The pressure of the atomizing media is always maintained at a fixed value but it may be more or less than the operating oil pressure depending on the type of burner being used.

10.0.2.2 Air Heater Cold End or SCAPH Temperature Control

This is provided for maintaining the average cold end temperature above the dew point so as to prevent condensation at the air heater surfaces and thereby prevent the resulting corrosion of the associated materials. The flue gas contains sulfur oxide (SO_x) and moisture, which condenses when the temperature goes down at the flue gas outlet of the air heaters (cold end). This may happen from both ends—that is, when the incoming air temperature itself is low because of the noncongenial ambient conditions from which the air is sucked and/or the flue gas temperature is not capable of raising the air temperature and as a result may decrease nearly to the dew point.

To avoid that situation this control loop is provided, along with a separate air preheater where the air from the FD fan discharge can be preheated through the steam coiled heat exchanger, which gets steam from an auxiliary steam source. Normally SCAPH is located in the bypass duct at the outlet of each FD fan. For a separate primary air heater system, SCAPH should also be provided in the bypass duct at the outlet of each PA fan. With this arrangement, the flow control valve provided at the SCAPH inlet of the steam line modulates as per command from the controller and maintains the requisite temperature: $\sim 10^{\circ}C$ more than the acid dew point for flue gases

It should be noted that SCAPH is not normally put into service under normal operating conditions for the entire range. It is required during startup and low load and under abnormal climatic conditions.

10.0.2.3 Hot Gas Temperature Control

As already described, this control minimizes the gas temperature imbalances between the primary and secondary air heater outlets. The sustained differences in these two temperatures results in stratification of flue gases at the ID fan inlet and jeopardizes unit efficiency as a whole. The controller output is the input of a function generator of each damper control loop. Limit values are provided to restrict damper movements between preset maximum and minimum values. The dampers are to be made 100% open manually during startup and those positions are sent to the ID fan as start permissive. In auto operation, the controller for any temperature imbalance tends to close the hotter-side damper while the colder-side damper remains in the open position.

The following two controls are provided to maintain a sufficient level only to facilitate the passage of incoming media as and when required: (1) CBD tank level control and (2) SCAPH drain tank level control.

10.0.2.4 Overfire Air Damper Control

In certain type of furnaces, OFA dampers are provided to control the NO_x ($NO_2 + NO$) level in the flue gas product of combustion. The NO_x level is also restrained through provision of a flue gas recirculation damper, but control action is available.

As discussed in Section 9.2.1.8 in Chapter III, the production of NO_x in a thermal power plant depends on many factors: time, temperature, turbulence (stochiometric ratio), etc., which is described as thermal NO_x when airborne nitrogen (N_2) and oxygen (O_2) react with each other during combustion. NO_x can be kept under control with the help of OFA dampers. The other source of NO_x may be from the organically bound nitrogen compound in the fuel itself. A detailed discussion of NO_x formation and control was presented in Section 10.3 of this chapter.

www.EngineeringBooksPDF.com

10.0.2.5 Control Loop Description

The OFA damper control strategies are discussed in Section 10.3 of this chapter.

10.1 Auxiliary Steam

10.1.1 General

Auxiliary steam in a power plant plays a significant role, especially during startup of the boiler and turbine. Many plants with small and medium-sized units may have separate auxiliary steam headers for the boiler and turbine. These are known as *boiler auxiliary steam* (BAS) *and turbine auxiliary steam* (TAS). Generally in larger units a common auxiliary steam header is formed to supply auxiliary steam to the boiler and turbine. The requirement for auxiliary steam is high during startup of the both boiler and turbine. The boiler is started with oil, so auxiliary steam is required for FO heating and FO atomization; SCAPH, which may be in service, also requires auxiliary steam.. Similarly during startup of the turbine, the auxiliary steam requirement is as high as for the deaerator pegging, starting ejector, and the like. In larger units generally the turbine is started after the boiler is somewhat stabilized with the help of the bypass system. Thus, when boiler is starting up, there is no need for auxiliary turbine steam.

On the other hand, when the turbine is starting up the auxiliary steam is mainly for the turbine, as the boiler has stabilized! In this way, the load from the common header is well distributed in time, which is why it is better for larger units (where the requirement of auxiliary steam is also high) to employ a common header in place of individual BAS and TAS. If smaller units are without a bypass system, the boiler and the turbine may have to be started simultaneously; in those cases separate BAS, TAS may be better!

Whenever there are a number of units in one plant (in the same geographical location) the auxiliary steam headers of each unit may be interconnected so that during initial startup of one unit, auxiliary steam may be supplied from the other unit. Also, if there is an auxiliary boiler, auxiliary steam from it must be connected with the auxiliary steam header. Such configurations are more feasible in common auxiliary steam headers.

Another aspect of the common auxiliary steam header is important. In larger units CRH pressure is high enough (>30 kg/cm^2) to create an auxiliary steam header from it, instead of from MS so as to minimize energy loss due to large pressure and temperature reductions! However till the time there is pressure in CRH line is high enough, source of auxiliary steam is MS, as shown in Figure III/5.2-4. Normally auxiliary steam headers are formed with P = 10 kg/cm^2 and T = 210°C for medium size plant and with P = 16 kg/cm^2 and T = 230°C for larger size plants. As discussed earlier that the requirement of auxiliary steam (whether BAS or TAS) vary greatly during startup and during normal operation.

BAS or TAS takes the supply from MS and at the time of startup the MS pressure may be lower, than when the unit is stabilized, and during this time larger auxiliary steam flow is necessary, so at lower pressure drop higher Flow through control valve is required. On the contrary when system is stabilized, control valve have high pressure drop to allow lower flow. Thus, it is necessary to use separate control valves with Higher and lower capacity as shown in Figures III/5.2-1 and VIII/10.1-2.

In this book both BAS and TAS are dealt with separately in this chapter and Chapter XI, respectively. However in this section, common auxiliary steam header aspect have also been discussed, and not repeated in Chapter XI.

10.1.2 Boiler Auxiliary Steam *Objective*

The purpose of the common auxiliary steam header is to obtain a header of constant pressure and constant temperature irrespective of changes in load in boiler and turbine, as it is supplying auxiliary steam to both boiler and turbine.

10.1.3 Common Auxiliary Steam Header Objective

The purpose of this control is to obtain a header of constant pressure and constant temperature irrespective of changes in the boiler load and the turbine as it is supplying auxiliary steam to both the boiler and the turbine.

10.1.3.1 Discussion

As is clear from the objective just presented, the header pressure as well as the temperature needs to be maintained at a constant value, so the control system basically consists of two separate loops—the pressure control loop and the temperature control loop—so that both parameters can be kept constant. The control system is basically a pressure-reducing de-superheating (PRDS) system. There are some variations in design. In one system there may be combined PRDS stations, and the same control valve that is responsible for pressure reduction has the DSH built into it, where water is controlled and sprayed using temperature control. In other systems, pressure-reducing control valves and de-superheating stations are separate. After pressure is reduced, there is a de-superheater in series through which the steam with reduced pressure is passed, and water spray is controlled to control the final temperature. One typical combined PRDS is shown in Figure VIII/10.1-3.

10.1.3.2 Control Loop Description

The control loops involved are pressure control and temperature control. In these loops air lock relay and solenoid valves are introduced to indicate that, in case of air supply

www.EngineeringBooksPDF.com

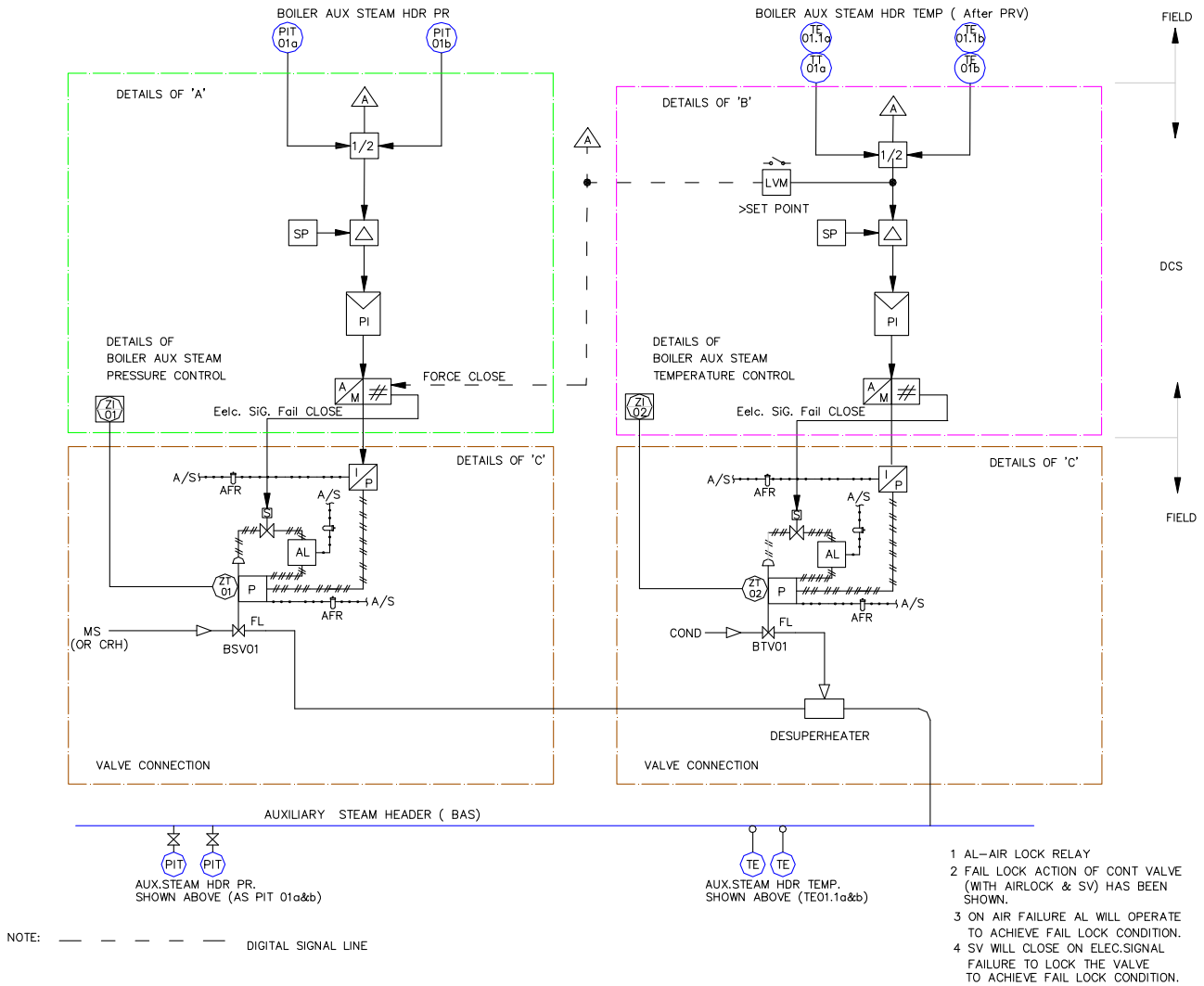


FIGURE VIII/10.1-1 Boiler auxiliary steam pressure and temperature control.

failure and electrical signal failure, the control valve may be locked in its previous position (i.e., to attain fail lock).

10.1.3.3 Boiler Auxiliary Steam Control Loops

This system consists of two separate loops (Figure VIII/10.1-1), as described in the following:

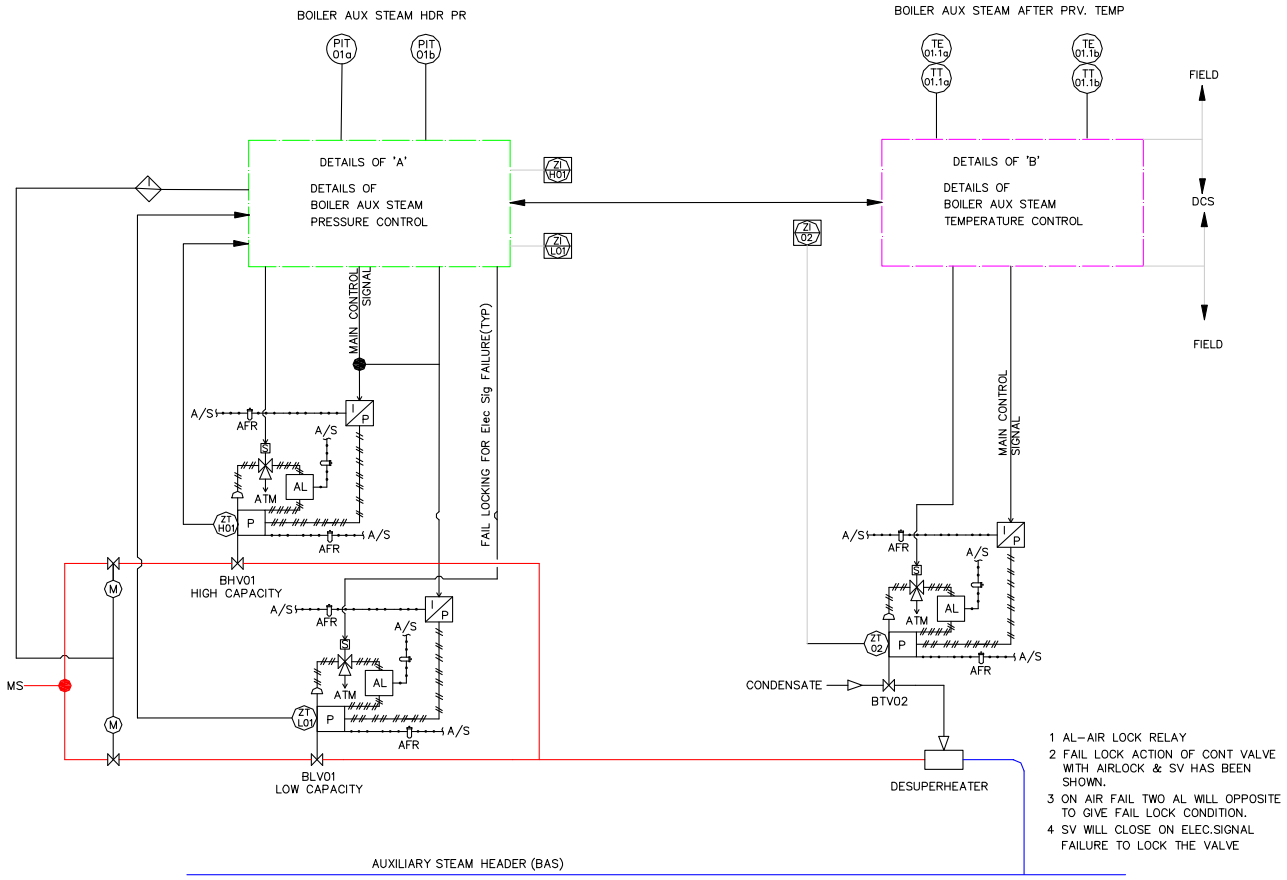
Boiler auxiliary steam pressure control: Here the auxiliary steam header pressure is measured in one of two modes and compared with a fixed set point. The deviation this creates is used to drive a PI controller. The output of the controller through the A/M station and I/P converter regulates the pressure-reducing valve to maintain constant pressure at the auxiliary steam header at all loads.

Boiler auxiliary steam temperature control: The steam temperature at the auxiliary steam header is at the outlet of the pressure-reducing valve (PRV) after the de-superheater is measured and compared with the fixed set point deviation thus created is fed to a PI controller (it may be PID also, as temperature is a slow-changing parameter; thus, PID may be more effective). The output of the controller regulates the condensate flow to the DSH to control the temperature at the auxiliary steam header. In Figure VIII/10.1-1, a separate de-superheater is shown, but it can be combined with a pressure-reducing station, as shown in Figure VIII/10.1-2.

10.1.3.4 Boiler Auxiliary Steam Controls

As discussed in Section 10.1, there may be a necessity for high-capacity and low-capacity PRVs. The basic pressure and temperature control loop description is the same as discussed in Section 10.1.5, so it is not repeated here.

www.EngineeringBooksPDF.com



NOTE:
1) POSITION TRANSMITTER DETAILS SHALL BE SAME AS SHOWN IN VIII/10.1–1
2) SINGLE TEMPERATURE CONTROL VALVE IF INSUFFICIENT, THEN THERE MAY BE IN HIGH/LOW CAPACITY LINES
3) POSITION FEED BACK SIGNAL FROM VALVES SENT TO CONTROL SYSTEM MAY BE USED FOR VALVE CHANGE OVER.

FIGURE VIII/10.1-2 High- and low-capacity BAS.

However, the loops may be operative in split range, when the load is high, then both low- and high-capacity valves must be operative. When the load is reduced, the high-capacity valve starts closing first. After that, the pressure must be maintained by regulating the low-capacity valve. These high- and low-capacity control valves can be put in service with the interlock of the upstream isolating motorized valve from the loop. Until the low-capacity valve is, say, 80% open, the upstream isolating valve of the high-capacity control valve may be kept closed so that there is no flow through it. Similarly, when the high-capacity control valve is around, say, 20% open, the associated isolating motorized valve may be closed and the low-capacity isolating valve may be opened.

Note that the high- and low-capacity pressure-reducing valves are kept in parallel. The de-superheater is placed in series after these pressure-reducing valves. Temperature control is the same as discussed in Section 10.1.5.2. It is worth noting that temperature control may be single and common to both high- and low-capacity PRVs. However if necessary this can be dual also one each temperature control associated with each of high- and low-capacity PRV. In a combined PRDS design, there are two such temperature control loops.

10.1.3.5 Common Auxiliary Steam Header Control for MS and CRH

This header is common for both BAS and TAS (Figure VIII/10.1-3) Here there may be three loops. One common pressure control loop and two temperature control loops—one each for MS and another for CRH. There are two sets of pressure-reducing valves. One set must reduces MS to auxiliary steam and another reduces CRH to auxiliary steam. However, based on selection, either of the two control valves must be in operation. This selection of control valves may be through interlock, as discussed in Section 10.1.9. Initially, when the CRH pressure is not developed, the source of auxiliary steam must be from MS. When the CRH steam pressure is established, then it is switched over to CRH as the source. Whenever CRH is

www.EngineeringBooksPDF.com

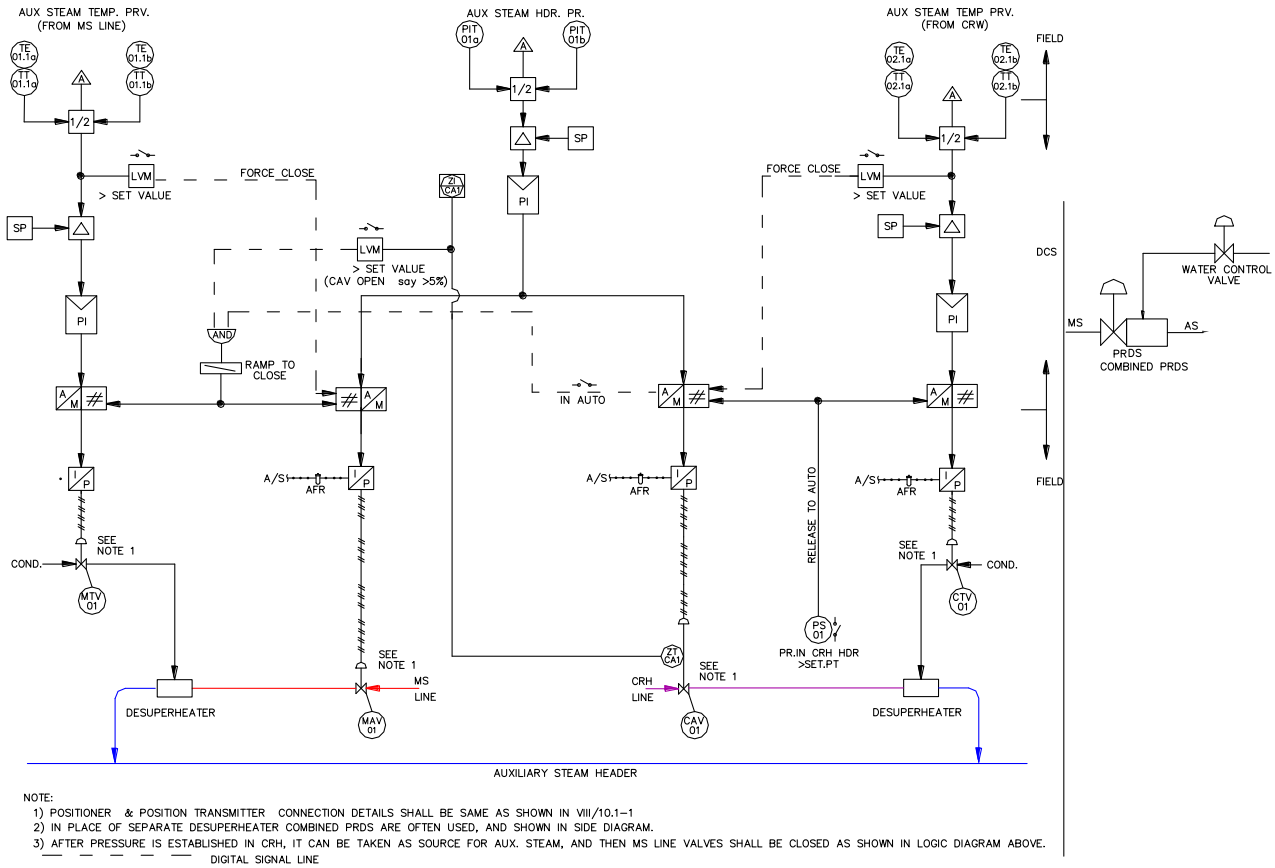


FIGURE 10.1-3 Auxiliary steam header from MS and CRH.

selected, the PRV in the MS line must be closed following a ramp circuit.

Common auxiliary steam pressure control: Here the steam header pressure is measured in one of two modes and compared with a fixed set point. The deviation this creates is used to drive a PI controller. The output of the controller, through two sets of A/M stations and I/P converters, can regulate the pressure-reducing valves in MS and CRH lines to maintain constant pressure at the common auxiliary steam header at all loads. However, only one of the two control valves is in service at any point of time. Whenever the CRH pressure is established, the PRV in the MS line must be closed in ramp. **Common auxiliary steam temperature control***:* Two sets of steam temperature control loops regulate the condensate flow to the DSH after the PRV in each for the line from MS and CRH. (These DSHs may be combined with the PRVs, which are also as shown in Figure VIII/10.1-3, for a combined PRDS.) The steam temperature at the auxiliary steam header is i.e. at the outlet of the pressure-reducing valve, after the de-superheater is measured and compared with the fixed set point deviation thus created, is fed to a PI controller (may be PID, as temperature is a slow-changing parameter; hence, PID may be more effective). The output of the controller regulates the condensate flow to the DSH to control the temperature at the auxiliary steam header. With suitable interlock, condensate flow to the nonactive de-superheater is prevented. (See Section 10.3.)

10.1.4 Control Loop Operation

This section discusses automatic and manual operation of the loop. Also refer to Figures VIII/10.1-1, VIII/10.1-2, and VIII/10.1-3 for further details.

- This loop, as per Section 1.1.2.1 of this chapter, may trip to manual in case of transmitter failure and /or selection. The operator needs to select the correct transmitter to continue with the loop.
- At any time, the loop is operable in the auto /manual position.
- There are additional signals for releasing control loops associated with the CRH PRV (control valves CTV and CAV in Figure VIII/10.1-3) and associated with the temperature control loop. These loops can be

www.EngineeringBooksPDF.com

released to auto only when pressure in the CRH line established. The control valve CTV in Figure VIII/10.1-3 also prevents condensate flow when the associated pressure is not in service.

10.1.5 Control Loop Interlock

The following interlocks may be specific to the loops:

- *BAS (Figures VIII/10.1-1 and VIII/10.1-2):* If the temperature at the outlet of the DSH after the PRV (i.e., at the auxiliary steam header) is higher than the set value, the PRVs (both high- and low-capacity ones) must be forced to close. Also, in case of signal failure, the associated solenoid valve must be closed from the DCS so as to attain fail lock of the associated valve.
- *Common header interlock:* The PRV must be closed in case the temperature is greater than a set value sensed by LVM associated PRV must be closed..
- Whenever PRV in CRH line (CAV) is in auto and open >5% (say), the PRV in MS line must be closed. Also, the associated temperature control valve must be closed from the same signal, as shown in Figure VIII/10.1-3.

10.1.6 Control Valve Considerations

As discussed earlier, there may be two sets of valves to cater to the requirements of startup and normal operation. For that reason, due consideration must be given to the sizing of these valves. Typical parameters for PRDS valves in auxiliary steam systems are discussed in the following.

Some extreme conditions (typical parameters) for PRVs and temperature control valves are listed in Table VIII/10.1.10-1. In these cases, high-pressure drop, high temperature, and high noise are very important in selecting the valves, especially for PRVs. For example, cage-guided low-decibel trims with multiple holes are used to minimize noise effects.

10.1.7 Use of Auxiliary Steam in the Boiler

Major uses of auxiliary steam in boiler sides are as follows:

- Fuel oil heating
- Fuel oil atomization
- Heating of air in SCAPH
- Soot blowing
- Steam tracing
- Flue gas sampling(if any)

TABLE VIII/10.1.6-1 Typical PRV and Temporary Control Valve Parameters

Parameter	PRV	Temperature Control Valve
Inlet pressure	175 (/145) bar	190 (/165) bar
Outlet pressure	16 (/10) bar	16 (/10) bar
Temperature	540°C	160°C

10.2 Soot-Blowing Steam Pressure and SCAPH Pressure Control

10.2.1 General

In a modern thermal power plant there are steam requirements at various pressures and temperatures depending on the consumer and the working parameters at the consumer ends. Soot-blowing (SB) steam and SCAPH pressure controls are the examples of two such requirements.

10.2.2 Soot-Blowing Steam Pressure Control

As discussed in Section 12.3 of this chapter, the soot-blowing steam pressure control plays a vital role in the cleaning of furnace and air heater heat transfer surfaces. In a steam-generating plant, steam is readily available as and when it is operating. Normally, a suitable tapping point from the auxiliary steam header (see Figure III/5.2-4), with process parameters of 10 to 16 kg/cm^2 pressure and 2100 to 2500°C temperature, almost matches the requirement of soot-blowing steam. However, the exact requirement may be achieved via separate PRVs.

10.2.2.1 Objective The objective of this control loop is to exactly maintain the soot-blowing (SB) steam pressure of the main SB header from which all the furnace waterwall and convection-zone soot blowers get their steam supply. As discussed in Section 12.3 of this chapter, it is quite obvious that the main steam temperature and the flue gas outlet temperatures are affected by the cleanliness of the surfaces where the heat transfer takes place. Soot blowing with the proper quality of steam at the proper sequence and frequency is the only way to improve overall efficiency and pollution control by reducing the unwanted accumulation of dirty substances.

10.2.2.2 Discussion Experience says that the SB steam quality must be ~10 to 15 kg/cm^2 pressure and 500 to 600°C superheat temperature in order to obtain sufficiently dry superheat steam to avoid moisture in the cleaning media. As the normal source of SB steam is the high-pressure steam already available, any reduction in pressure raises the temperature of the superheat. The source may be the main steam or the hot reheat, or even the auxiliary steam header. Normally the source is chosen so that temperature control does not become necessary.

www.EngineeringBooksPDF.com

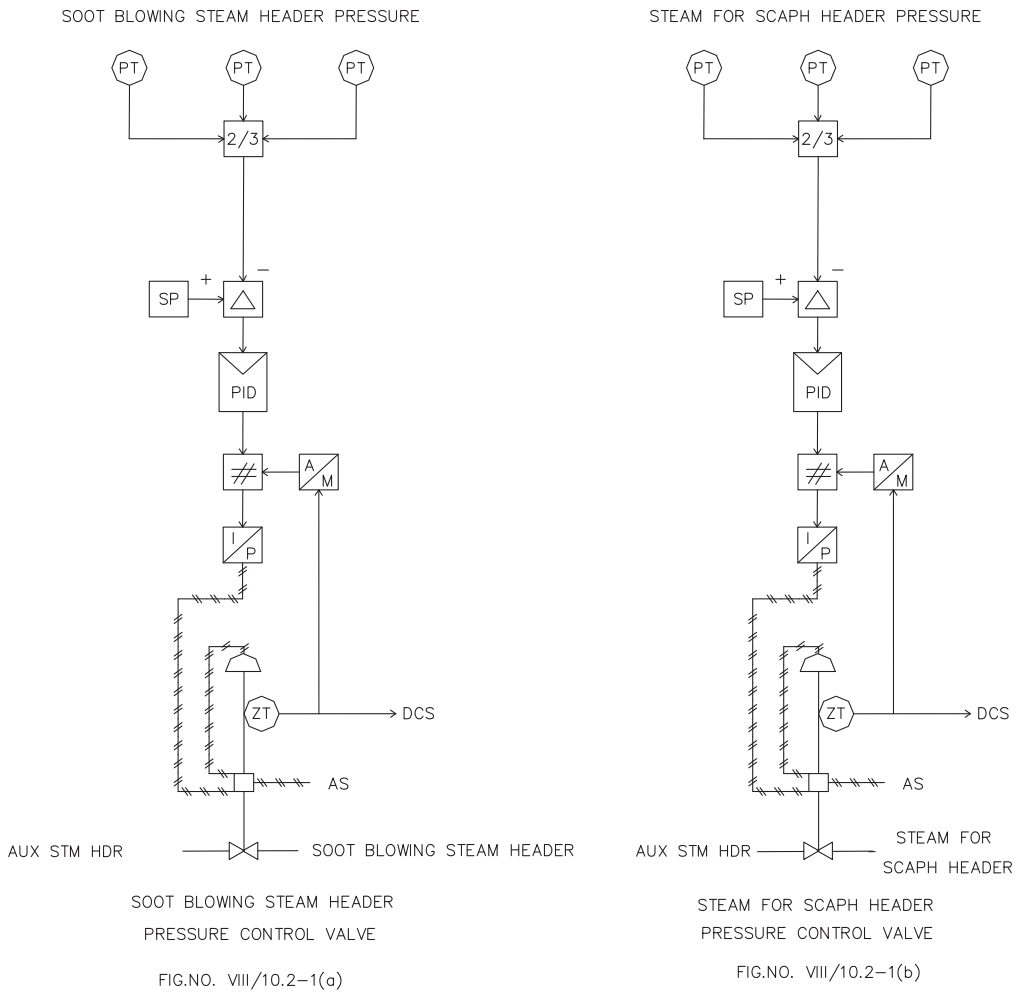


FIGURE VIII/10.2-1 Soot-blowing and SCAPH steam pressure control.

10.2.2.3 Control Loop Description The soot-blowing steam control loop in a typical 250 MW plant having a drum-type boiler and a coal-fired furnace with occasional oil support is shown in Figure VIII/10.2-1. The control loop is direct, single, and simple.

10.2.2.4 Measurement of Parameters The soot-blowing steam pressure is measured by the pressure transmitter with sufficient redundancy and at the appropriate location to get an average and representative measurement. There may be different steam pressure values for the main furnace and the air heater soot blower. In that case there may be two different pressure-reducing stations, or the number may be according to the individual plant's needs.

10.2.2.5 Control Loop The measured/process variable is compared with a fixed set value to form the error signal. The controller output is the position demand signal of a PRV with the capacity required by the maximum number of blowers in simultaneous operation. There may be individual soot blowers or an array of soot blowers that require different inlet pressures for their operation. In such situations, individual blowers or groups of blowers are provided with self-PRVs while catering to them from the main SB steam supply header.

10.2.3 SCAPH Steam Pressure Control

Section 10.3.3.1.1 of this chapter provides a brief discussion of the requirement of providing SCAPH to control SO_x, using process control loops as one of the ways to do so.

The control strategy adopted for avoiding deposits of condensed sulfuric acid (H_2SO_4) and sulfurous acid (H_2SO_3) vapors on exposed metal is ultimately to ensure that the temperature does not fall below certain values at specific points. The minimum temperature average of gas

www.EngineeringBooksPDF.com

and air is maintained so that acid condensation does not lead to corrosion.

As also indicated in Section 10.0.2 of this chapter, the SCAPH is located just before the air heater so that air temperature increases while entering the air heater. To implement this control, an external steam supply is required with separate control valve(s). The temperature/flow control valve(s) provides a steady and controlled steam pressure at the inlet so that the requisite and ultimate temperature control is achieved.

10.2.3.1 Objective The objective of this control loop is to exactly maintain the inlet steam pressure of the main SCAPH temperature control valve(s).

10.2.3.2 Discussion There may be more than one SCAPH for systems with separate heaters for secondary air and primary air. The requirement of steam supply pressure is normally the same and hence separate pressure control valves may not be required. As the only purpose is raising the air temperature, the steam pressure may be ~5 tob 7 kg/cm^2. The source is normally the auxiliary steam header

10.2.3.3 Control Loop Description Figure VIII/10.2-1 earlier shows a schematic representation of implementing the control loop in a typical 250 MW plant having a drum-type boiler and a coal-fired furnace with occasional oil support. The single control loop is a direct and simple.

10.2.3.4 Measurement of Parameters The SCAPH steam pressure is measured by a pressure transmitter with sufficient redundancy and at the appropriate location to get an average and representative measurement. There may be different steam pressure values for the two types of air heater (PA and SA). In that case there may be two pressure-reducing stations, or the number may be according to the individual plant's needs.

10.2.3.5 Control Loop The measured/process variable is compared with a fixed set value, normally 100°C more than the acid dew point of the flue gas to form the error signal. The controller output is the position demand signal of a pressure-reducing valve with the required capacity.

10.3 SO_x and NO_x Controls

10.3.1 General

A variety of oxides of sulfur and nitrogen, SO_x and NO_x, are generated as by-products of the combustion of different kinds of oil and coal in the furnace of a steam generation plant. The fuels and the atmospheric air contain these basic elements in various forms, and after combustion the elements are converted to their corresponding oxides in the presence of very high temperature and form the flue gas along with different oxides of carbon and other gases.

10.3.2 Objective

The main objective of these controls is to reduce the SO_x and NO_x levels. There are several methods of doing this in the thermal power plant. Some methods reduce the generation of these pollutant gases at their respective sources. Some, on the other hand, incorporate chemical processes for reducing these generated gases before they are discharged to the atmosphere. Such processes, however, do not reduce the gas generation at the source; instead, they convert them into harmless compounds that meet local pollution control board guidelines.

10.3.3 Discussion

The reference drawings for SO_x and NO_x controls are shown in Figures VIII/10.3-1 through VIII/10.3-5.

10.3.3.1 SO_x

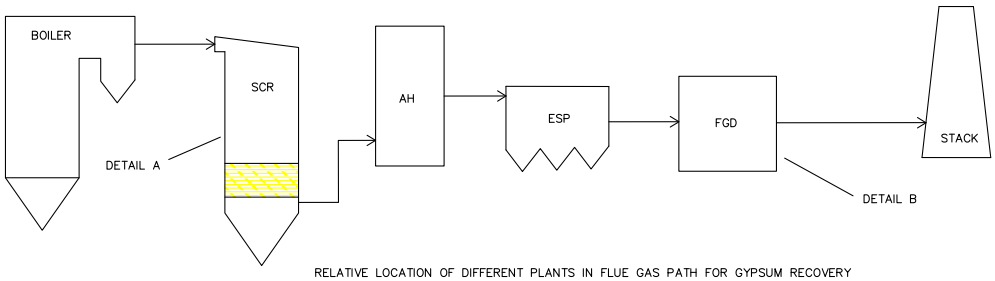
Sulfur dioxide (SO_2) and trioxide (SO_3) are produced during the combustion process as a by-products and are present in the flue gas. They combine with moisture contained in the flue gas at a lower temperature to form sulfuric acid (H_2SO_4) and sulfurous acid (H_2SO_3). When the temperature of the flue gas falls below the H_2SO_4 dew point, droplets of condensed H_2SO_4 are formed on the metal surface of air heaters and ducts exposed to the flue gas. Under these conditions, corrosion occurs because of the presence of a thin film of acidic electrolytes over the surface, giving rise to localized and uniform corrosion also known as *acid dew point corrosion*. It has been observed that long or extended shutdown of the unit may cause deposits of corrosion-aiding agents.

Too much excess air assists formation of the SO_x; in contrast, if the stoichiometric ratio is low, unburnt constituents also cause corrosion at waterwall surfaces. This is somewhat eliminated whenever the oxidizing atmosphere is maintained near waterwalls mainly used for delayed mixing, discussed later. Unlike NO_x, SO_x cannot be minimized at the source, but its condensation on the duct/air heater can be prevented by several methods.

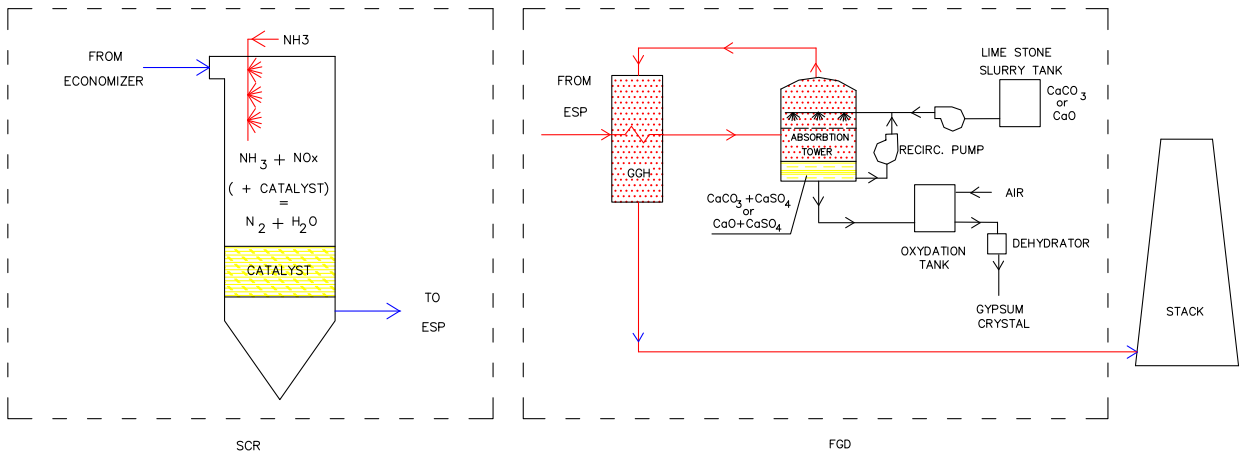
10.3.3.2 NO_X

NO_x is not itself a compound/radical, but represent a family of seven compounds/radicals. Out of these, NO_x NO_2 is considered an important pollutant that is regulated by the EPA. Environmental concerns about NO_x include ground-level ozone and acid rain formation, aquatic acidification, and deforestation. The EPA's National Air Quality Standards define air quality requirements along with necessary safety margins. Electric utility plants contribute around

www.EngineeringBooksPDF.com



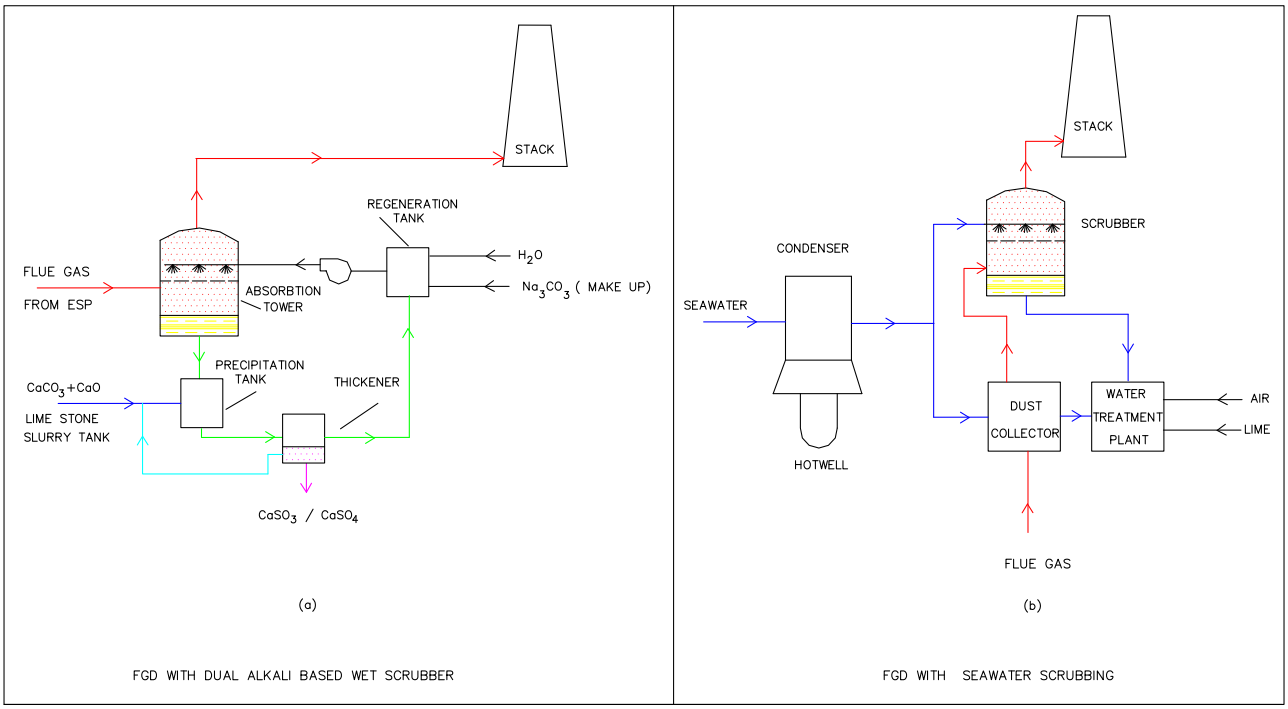
RELATIVE LOCATION OF DIFFERENT PLANTS IN FLUE GAS PATH FOR GYPSUM RECOVERY



DETAIL A DETAIL B

NOTE
- A TYPICAL SYSTEM OF SCR & FGD EACH IS SHOWN FOR REFERENCE ONLY
- SCR AND FGD PLANTS MAY BE OF SEVERAL TYPES. FOR DETAILS,CHAPTER VIII SECTION 10.3 MAY BE REFERRED.
- NH3 MAY BE ANHYDROUS OR AQUEOUS; IN PLACE OF NH3, AQUEOUS SOLN OF (NH2)2CO3 MAY OLSO SUSED

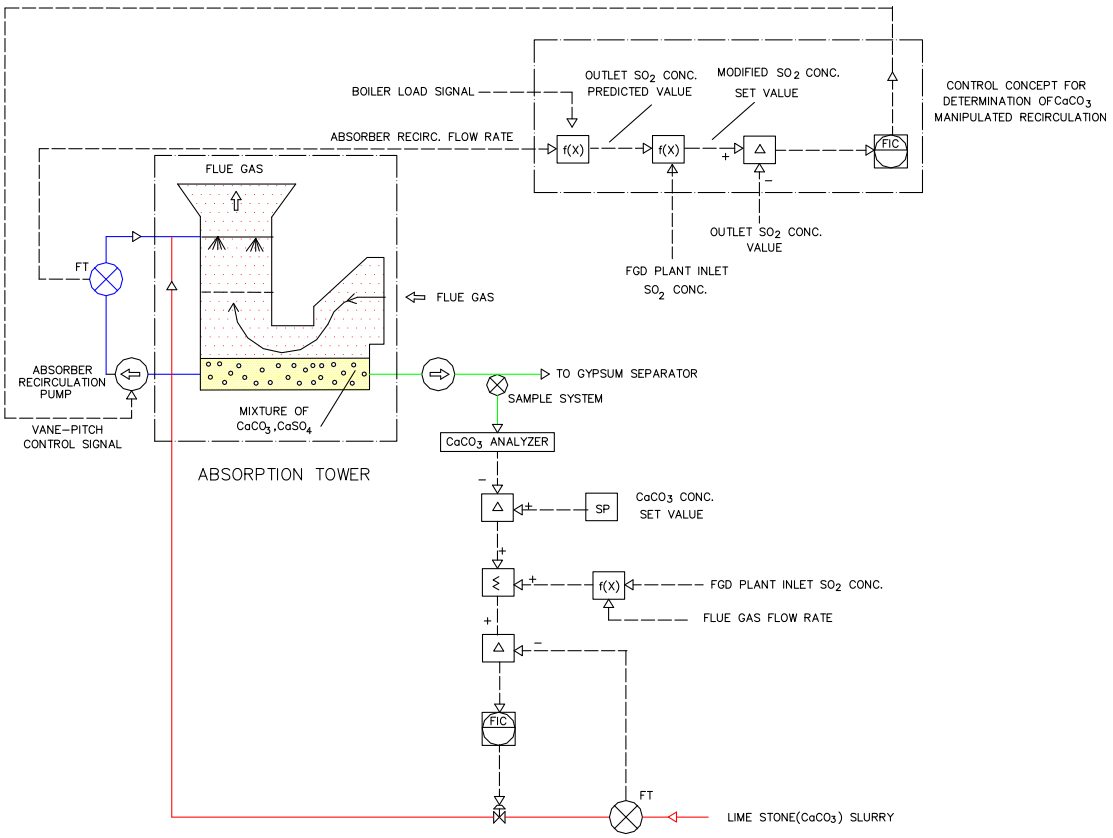
FIGURE VIII/10.3-1 Schematic of SCR and FGD plants.



NOTE FOR REACTIONS AND DESCRIPTION DETAILS,CHAPTER VIII SECTION 10.3 MAY BE REFERRED.

FIGURE VIII/10.3-2 Schematic of FGD with dual alkali-based wet scrubber and seawater scrubbing.

www.EngineeringBooksPDF.com



FIGUREVIII/10.3-3 Control loop schematic of SO_x control with limestone absorber and gypsum recovery.

22% of NO_x formation (the other major source is transportation at ~56%).

Nitrogen (N_2) is also available from the same sources; there is plenty in atmospheric air and from various kinds of fuel oils and coals, which are organic compounds that naturally contain N_2. It has been observed that during the combustion process only 5% of NO_2 is present whereas there is 95% NO in the total available NO_x.The NO_x produced from the source of atmospheric air is often called *thermal NO_x*. Various test results and equations indicate that thermal NO_x conversion is dependent on temperature, and concentrations of both N_2 and O_2 as well as the time in which the combustion takes place.. It is also observed that the same depends on the fuel-rich flame front (i.e., diffusion flame, where fuel and air are introduced separately and mixed through turbulence due to fuel burning), and on the fuel-lean flame front (premixed flame where fuel and air are mixed before being introduced to the furnace).

The other source of NO_x generation is "fuel NO_x," which is from the fuels only. Test results show that this generation is not so dependent on temperature but is related to the availability of oxygen (O_2). The O_2 reacts with the gaseous state of fuel-bound nitrogen compounds such as NCH and NH_3 to generate NO if the combustion atmosphere is air-rich only. On the other hand being unstable these nitrogen compounds, simply reduce to N2, a harmless gas under fuel-rich conditions. To summarize, the following design strategies are important:

- Lower thermal NO_x levels can be achieved using a low-excess-air operating strategy and a furnace designed for lower gas temperatures. Various furnace types use burners with low-turbulence-diffusion flames, OFA compartments, efficient waterwalls, and flue gas recirculation .
- Designs for lower-fuel NO_x levels control the flow of air released for mixing with the fuel in the initial burning zone or combustion chamber. The lowest NO_x level can be achieved if the coals used have the lowest fuel:nitrogen and fuel:oxygen:nitrogen ratios.

The generation of NO_x thus can be reduced to a significant level. The methods are listed in Table VIII/10.3.3.2-1 for ready reference. Those listed are typically adopted by manufacturers to meet local/national pollution control board and customer specification requirements.

Major approaches to reduce NO_x discharge to the atmosphere include either or both of the following: (1)

www.EngineeringBooksPDF.com

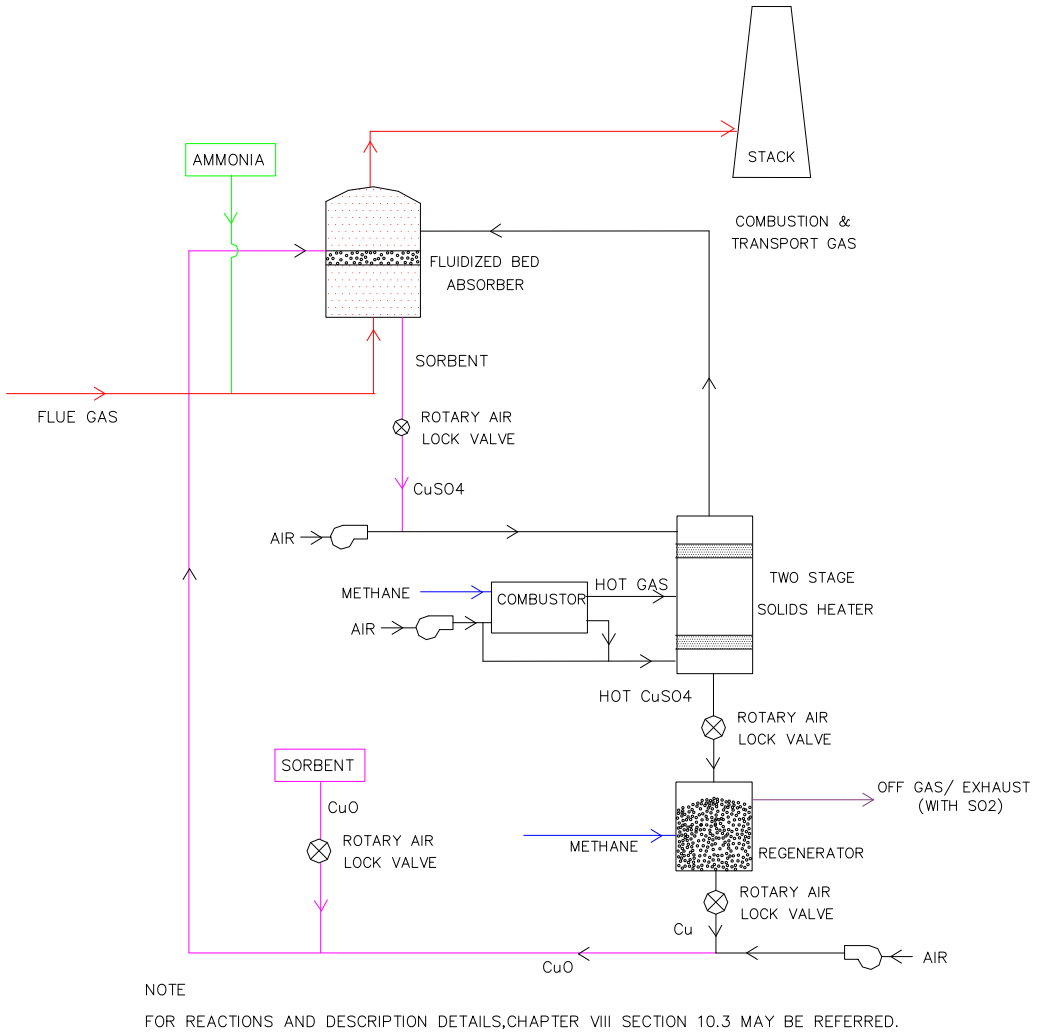


FIGURE VIII/10.3-4 Schematic of SO_x-NO_x control with fluidized bed copper oxide process.

reducing the production of NO_x or (2) mitigating the NO_x already produced

The first approach may be less costly than the post-production approach. Use of overfire air dampers in TT boilers is by far the most cost-effective way to control NO_x. Some of the major NO_x control methods are listed in Table VIII/10.3.3.2-2; they were derived from a 1999 EPA technical bulletin. Not listed are methods such as reducing air preheat, injecting oxidants, and using nonthermal plasma.

To combat NO_x pollution, three technologies are used:

1. *Primary technology* which is mostly concerned with air staging; that is, to reduce availability of O_2 (less than required as per stoichiometric ratio) in primary combustion zone and later balancing the same shortfall (balance air in downstream)
2. *Secondary technology* mainly concerned with fuel staging such as re burning, injection and chemical reaction such as SNCR (basically postproduction treatment)
3. *Posttreatment* such as SCR

Apart from these use of O_2 in place of air utilizing air separation plant is not uncommon. In IGCC these are discussed in appendix. In ultra-supercritical boilers also, in many system design N_2 is separated from air and oxygen is used so that there is remote chance of NO_x formation. The following paragraphs discuss equipment /methods that are utilized to curb formation of NO_x.

In a low-NO_x burner (LNB), NO_x formation is limited by regulating the temperature profile and stoichiometric ratio; see Figures VIII/10.3-5(a-c). The design features control the aerodynamic distribution and mixing pattern in the burner to delay complete mixing to the extent possible so that

www.EngineeringBooksPDF.com

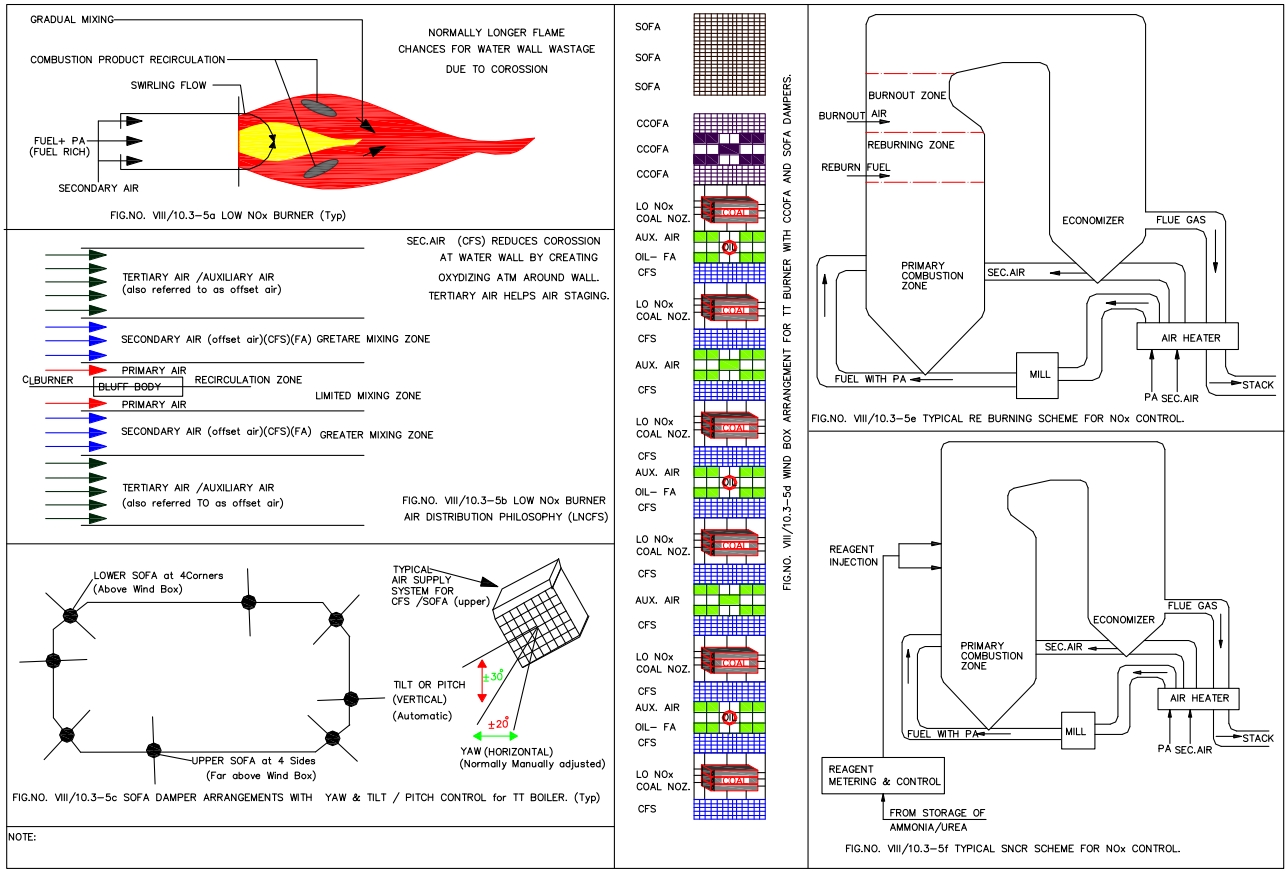


FIGURE VIII/10.3-5 Low NO_x burner OFA damper reburning and SNCR for NO_x control.

TABLE VIII/10.3.3.2-1 Methods for NO_x Reduction

Methods/Systems	NO_x Reduced	Approximate Reduction	Remarks
Flue gas recirculation	Thermal NO_x	75%	Offered by Babcock design
Overfire air damper	Thermal NO_x	75%	Offered by CE/Babcock design
Low NO_x burners	Thermal NO_x and fuel NO_x	25%	Can be fitted to any boiler
Staged burners	Thermal NO_x and fuel NO_x	70%	Can be fitted to any boiler
Air mixing and air flow control	Thermal NO_x and fuel NO_x	70%	Depends on boiler design

- There is reduced oxygen in the primary flame region to limit formation of both thermal and fuel NO_x.
- Flame temperature is lowered; hence, there is less thermal NO_x formation.
- Residence time is reduced because of distribution, causing less thermal NO_x formation.

Coal rank and volatile matter content have a direct impact on NO_x formation in LNBs. Lower-rank coals have a more volatile release, which inhibits NO_x formation near the burner because more nitrogen is released in the fuel-rich environment near the burner is converted into molecular nitrogen (N_2). In contrast, the LNB can cause economic losses because more unburnt carbon (UBC) is produced. UBC can have an impact on tube and electrostatic precipitator (EP) performance, as well as on the marketability of fly ash (ASTM C618 limits UBC to 6% in fly ash). However, this can be circumvented by using more fine coal and changing the air/fuel distribution. Coal with greater fineness promotes less NO_x formation in the LNB because less air is required to carry them as well as less chance of UBC.

www.EngineeringBooksPDF.com

TABLE VIII/10.3.3.2-2 Major NOx Control Methods

Basic Principle	Technology	Description	Advantages	Disadvantages	Impacts	Applicability
Reducing peak temperature	Low NO_x burner	Internal staged combustion	Low opportunity cost compatible with FGR	High capital cost	Long flame, fan capacity, turndown stability	All fuels
	BOOS/OFA	Staged combustion	No cap. cost for BOOS, low cost for OFA	Higher air flow for CO high capacity cost	Long flame, fan capacity, header pressure	All fuels, for BOOS multiple burners
	FGR	<30% flue gas recirculated with air, decreasing temperature	High NO_x reduction potential for low-nitrogen fuels	Moderately high capital and operating costs Affects heat transfer and system pressures	Fan capacity Furnace pressure Burner Pressure drop, turndown stability	All fuels Low-nitrogen fuels
	Air staging	Admits air in separated stages	Reduces peak combustion temperature	Extends combustion to a longer residence time at lower temperature	Adds ducts and dampers to control air furnace modification	All fuels
	Fuel staging	Admits fuel in separate stages	Reduces peak combustion temperature	Extends combustion to a longer residence time at lower temperature	Adds ducts and dampers to control air Furnace modification	All fuels
Chemical reduction of NO_x	Fuel reburning	Injects fuel to react with NO_x	Moderate cost Moderate NO_x reduction	Extends residence time	Furnace temperature profile	All fuels (pulverized solid)
	SNCR (add-on technology): urea; ammonia	Inject reagent to react with NO_x	Urea: Low capital cost; moderate NO_x removal Nontoxic chemical Ammonia: Low operating cost; moderate NO_x removal	Urea: Temperature dependent NO_x reduction less at lower loads Ammonia: Moderately high capital cost; storage, handling, injection system	Urea: Furnace geometry Temperature profile Ammonia: Furnace geometry Temperature profile	All fuels
	SCR (add-on technology)	Catalyst located in air flow, promotes reaction between ammonia and NO_x	High NO_x removal	Very high capital cost High operating cost Catalyst siting Increased pressure drop Possible water wash required	Space requirements Ammonia slip Hazardous waste disposal	All fuels
Removal of N_2	Oxygen instead of air	Use oxygen to oxidize fuel	Moderate to high cost Intense combustion	Eliminates prompt NO_x Furnace alteration	Equipment to handle oxygen	All fuels

Continued

www.EngineeringBooksPDF.com

TABLE VIII/10.3.3.2-2 Major NOx Control Methods—cont'd

Basic Principle	Technology	Description	Advantages	Disadvantages	Impacts	Applicability
Reducing peak temperature	Combustion optimization	Change efficiency of primary combustion	Minimal cost	Extends residence time	Furnace temperature profile	Gas Liquid fuels
	Water/steam injection	Reduces flame temperature	Moderate capital cost NO_x reduction similar to FGR	Efficiency penalty Fan power higher	Flame stability Efficiency penalty	All fuels as low-nitrogen fuels

Note: BOOS, burner out of service; FGR, flue gas recirculation; SCR, selective catalytic reactor; SNCR, selective noncatalytic reactor; LEA, less excess air

Because of the longer flame in an LNB, a deeper furnace may be called for to prevent the flame from damaging the waterwall. In addition, there is waterwall wastage (corrosion due to unburnt sulfur/chlorides, etc.; for such corrosion, prediction computational fluid dynamic (CFD) codes are available), especially in boilers with LNBs, and/or other means of external staging.

The problem is acute in cases of supercritical boilers (more specifically using relatively high-sulfur coal). For this reason, partly offset auxiliary air is used (to be discussed later). A low-NO_x concentric firing system (LNCFS) improves coal air mixing by forming an air circle outside the fire ball created by fuel PA, as shown in Figure II/2.3-2. An LNCFS is mainly for retrofit in TT furnaces. It produces a stable flame front with an inner fuel-rich core fire ball, which helps in converting bonded nitrogen to form N2 molecules. The air distribution philosophy behind the low NO_x burner is depicted in Figure VIII/10.3-5(b). As shown in Figure VIII/10.3-5(d), normally in a TT furnace there is a concentric firing system (CFS) between two adjacent Low-NO_x coal nozzles.

Through the CFS offset, auxiliary air is introduced. The angle of these nozzles—YAW (horizontal) and tilt/pick (vertical)—can be adjusted, as shown in Figure VIII/10.3-5(c). Tilt is usually automatically controlled according to RH (or SH) temperature control (i.e., it is gagged with the burner tilt mechanism) and YAW is adjusted manually. Offset air is directed toward the furnace to reduce fouling and produce an oxidizing environment to minimize waterwall wastage. LNCFS burners have nozzle attachments that allow coal to burn near the nozzle so as to minimize NO_x formation. Normally, the CCOFA is above the top coal nozzle; it is discussed next.

Overfire air: As indicated earlier, about 5 to 20% of total air required is diverted from primary combustion zone and injected through an air port downstream of combustion for complete combustion, for reducing UBC, and so forth. OFA in wall-fired boilers with LNB can help NO_x reduction by 10 to 25%. In TT furnace OFA is an integral part of the design. In a TT furnace with OFA, 20% up to more than 60% NO_x reduction is possible depending on the initial NO_x level but coupled with any increase in UBC and CO. However, the extent of this increase depends on OFA design and coal rank. There are two kinds of overfire air:

1. *Closed coupled overfire air (CCOFA) dampers:* In close proximity to the primary combustion zone, CCOFA is mainly responsible for reducing residence time in the fuel-rich primary combustion zone and increases residence time in the fuel-lean burning zone.
2. *Separate overfire air (SOFA) dampers:* Distinctly distant from the primary burning zone as well as from the burnt-out zone, SOFA provides additional residence time in the primary combustion zone and less residence time in the burnt-out zone.

The combination of CCOFA and SOFA helps reduce NO_x and, at the same time, helps reduce UCB.

Dispositions of these dampers for a TT furnace are shown in Figure VIII/10.3-5(c,d). Just above the top coal nozzle is one set of CCOFAs (like the CFS) and above that is another set. Between the two is a CCOFA port for tertiary air. Separated by some distance are the SOFA dampers. Some of the design features in a TT furnace are as follows:

- SOFA ports above the windbox
- Increased separation between auxiliary air and the fuel admission nozzle
- Reduction of control dampers for secondary air flow
- Reduction of secondary air flow while maintaining system pressure drop and injecting velocity for efficient mixing.
- Addition of separate tilt control of under-bottom end-air admission for CO control.

www.EngineeringBooksPDF.com

In a TT furnace especially in larger or supercritical boilers there are two sets of SOFAs. Lower SOFAs are essentially in the corners and tilt control is gagged with burner tilt control. Upper SOFAs are normally above the lower SOFAs and are mounted on side walls, as shown in Figure VIII/10.3-5(c). Normally, upper SOFA dampers are connected to the automatic control loops. They may be regulated to control NO_x. The desired NO_x set point is compared with the actual value; based on the error thus created, the controller issues the position demand for the associated damper.

Some loops may have MAX selection, between the set point and the output of the function generator (having the boiler load as input) so that there is dynamic set point to take care of changes in boiler load. However, the YAW of each of these is normally adjusted manually. Reburning is the process in which up to 25% of the total fuel heat input is provided by injecting secondary fuel (~90% of the air required by the stoichiometry of the secondary fuel) above the main combustion zone to produce the slightly fuel-rich reburnt zone; refer to Figure VIII/10.3-5(e). This results in hydrocarbon fragments coming into contact with incoming NO_x (from the upstream combustion zone) in a fuel-rich condition, to form hydrogen cyanide (HCN), isocyanic acid (HNCO), and the like. These are finally converted into N_2 molecules. Furnace dimension is very important here so as to achieve the desired goal, where sufficient residence time is essential. An increase in reburnt heat input and a matching decrease in main combustion heat input, decreases the stoichiometry in the reburnt zone, thus increasing NO_x-reduction efficiency.

SNCR is basically post-NO_x production control, where reagents like urea and ammonia are injected into the furnace above the combustion zone so that the NO_x formed can be converted to N_2 molecules as per the following reactions:

$$(NH_2)_2CO + NO + \frac{1}{2}O \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

This injection can be done at the furnace where the temperature is above 1150°C. Urea is injected as an aqueous solution whereas NH_3 can be anhydrous or an aqueous solution; see Figure VIII/10.3-5(f).

SCR is discussed later. As for *miscellaneous other systems and water/steam injection methods*, by injecting water or steam into the flame, its temperatures are reduced, thereby lowering thermal NO_x formation and overall NO_x levels. Water or steam injection can reduce NO_x up to 80% (when firing natural gas) and can result in lower reductions when firing oils. FGR, as discussed at length in Section 9.3.1, on reheater temperature control loop, can be another way to limit thermal NO_x. For coal-fired units, it is good for RH steam temperature controls, but may not be a foolproof and effective method for NO_x reduction. Control loop optimization also helps to reduce NO_x.

Control loop considerations: As discussed earlier, fuel:air ratio control by the staging of combustions is a major way to combat NO_x production. Reburning control is also a part of combustion control. In tangential-tilt burners, the tilt controls of CFS and CCOFA are part of reheat/superheat steam temperature control. As also discussed earlier, YAWs are usually manually adjusted. However, there may be a separate auto control loop for SOFA based on NO_x measurement so that, in case of excess NO_x production, more air may be admitted through this port to reduce NO_x production by complete combustion.

Eight-corner method: There is another method to curb NO_x generation, known as Babcock & Willcox (B&W) *eight-corner firing*.

10.3.4 Description of Control Loops

The generation of SO_x cannot be avoided during the combustion of fuels but can be minimized by proper fuel selection if the choice is available. However, once generated, SO_x's detrimental effect on duct/equipment is minimized by separate subplants—namely, the SCAPH with its associated control loops. Control loops are also provided for flue gas desulfurization (FGD) plants meant for eliminating postproduction SO_x by converting it to sulfites or sulfates.

10.3.4.1 SO_x Controls

10.3.4.1.1 SO_x Control through Main Plant Process Control Loops After various experiments, the relationship between the minimum metal temperature, gas temperature, and air temperature has been established, by which the corrosion of air heater—exposed metal can be controlled. Normally the average cold-end metal temperature of the main air heaters throughout the year is kept at a minimum of 10°C above the acid dew point for flue gases. The following methods are applied with the preceding controls.

The SCAPH located just before the air heater so that air temperature increases while entering the air heater. Here, the average of gas outlet and air inlet temperatures is taken as the measured variable and controlled against a calculated preset temperature value that does not allow the acid condensation, as discussed previously and in Section 10.0.2.

Some arrangement made near the air heaters so that a portion of the total air is bypassed and the heat exchange takes place toward the amount of air passes through the main line only. As the quantity through the air heater becomes less, the loss of temperature experienced by the flue gas is also less which prevents the metal temperature from further going down. The gas dampers at the inlet of the air

www.EngineeringBooksPDF.com

heater and the bypass line modulate according to the controller output, with the input just like that in the SCAPH control loop. The controller output is so adjusted that the bypass damper modulates only when the main-line damper is fully open. During operation, if the bypass damper goes to the maximum position, then only the main-line damper starts modulating. Interlock should be provided so that both dampers cannot operate simultaneously.

There is some other arrangement made near the air heaters so that a portion of the total hot air is diverted from the air heater outlet to the FD fan inlet so that air temperature increases while entering air heater. The recirculated hot air flow quantity depends on the controller output with the same control strategy and inputs as described previously. The amount of heat exchange that takes place is almost the same (except for the heat loss in the recirculation line and the additional heat required to raise the air temperature handled by the FD fan) as before, toward more air passing through the air heater but with a higher inlet temperature. The dampers in the recirculation line modulate as per the controller output to maintain the average temperature of the flue gas outlet and the air heater inlet temperature.

10.3.4.1.2 Control of SO_x through a Separate Chemical Process Plant There is a special type of chemical process plant dedicated to reducing SO_x levels; it is popularly called a *FGD plant*. Because SO_x (or, in particular, SO_2) is an acid gas, its removal requires an alkaline scrubbing reagent (scrubber) or sorbent to react and convert it into a nongaseous sulfur compound.

There are broad classifications for these compounds such as wet or dry and regenerable or nonregenerable, as follows:

- Wet (nonregenerable) FGD processes, including
  - Lime/limestone forced/natural oxidation
  - Lime/limestone inhibited oxidation
  - Lime and magnesium-lime
  - Seawater process
- Dry (nonregenerable) FGD processes, including
  - Lime spray (dry and semidry)
  - Duct Sorbent Injection
  - Furnace Sorbent Injection
- Gas phase oxidation/Ammonia Injection (both SO_x and NO_x)
  - Regenerable FGD processes, including
  - Sodium sulfite (wet)
  - Magnesium oxide (wet)
  - Sodium carbonate (wet)
  - Amine (wet)
  - Fluidized bed copper oxide process (both SO_x and NO_x; dry)
  - Activated carbon (dry)

The term *regenerable* means that the main scrubber is regenerated at the end of its reactions and reused. Only a small percentage is required to be injected into the system to compensate for the cyclical loss.

Scrubbing of sorbents, such as limestone or lime, is the most common method followed in FGD plants. It is a catalytic chemical process for removal of SO_2 produced during combustion, in which sulfur compounds combine with a calcium-containing sorbent—generally lime (CaO) or limestone ($CaCO_3$)—to form a slurry. The slurry after use can be treated as waste or a useful by-product.

Although there are several processes, as just indicated, three types of FGD plant are normally available for large thermal power plants using chemical reagents:

- Wet scrubber (after ESP)
- Spray dry scrubber (before ESP; (dry and semidry)
- Sorbent injector(furnace and duct)

Wet Scrubber. This type of SO_2 removal system is the most efficient (removing more than 95% of SO_2). Wet scrubbing is a gaseous and liquid phase reaction that transforms SO_2 into a liquid under saturated conditions. In general, wet scrubbing results in a liquid waste stream requiring wastewater treatment and produces a slurry as a by-product, which needs a disposal system. As broadly classified, there are three processes characterized by the use of absorbents, which dictates the scrubber design itself along with the generation of waste and by-product.

Other processes have been used but are no longer manufactured. These include sodium- or dual alkali-based systems, which were developed to avoid the consequential fouling encountered with lime/limestone wet scrubbing processes. These systems became unpopular because of their higher cost, unavailability, production of higher waste slurry, and so forth. Another reason for their unpopularity is the conception that the higher reactivity of sodium compounds negatively affects SO_x removal..

In a lime/limestone-based wet scrubber, flue gas is sprayed with an aqueous slurry of composed of CaO (a dry lime) and $Ca(OH)_2$ (a milk/slurry of lime) or composed of $CaCO_3$. SO_2 is removed during the series of chemical reactions between SO_2 and slurry to form calcium sulfate (gypsum) and sulfite. The reactions are as follows:

$$CaO + SO_2 + H_2O = CaSO_3 + H_2O \text{ (with dry lime)}$$
$$Ca(OH)_2 + SO_2 = CaSO_3 + H_2O \text{ (with lime slurry)}$$
$$CaCO_3 + SO_2 = CaSO_3 + CO_2 \text{ (with limestone slurry)}$$

In some plants, the cost of FGD installation is offset to some extent by converting the slurry into useful by-product as gypsum (the remaining sulfite in $CaSO_4$). This can be achieved with or without air added to the thickener or oxidation tank, which processes are, respectively, referred to as natural or forced oxidation. The latter produces a

www.EngineeringBooksPDF.com

higher gypsum quality that finds wider application, and the larger crystals make the dewatering process simpler. To achieve this, compressed air is blown in either in the scrubber process or in the following stage as a part of what is popularly known as *forced oxidation*. The reaction is

$$CaSO_3 + O_2 + H_2O \rightarrow CaSO_4, 2H_2O$$

The clean gas is then sent through gas-to-gas heater (GGH). The GGH raises the temperature of the flue gas at the chimney inlet as it decreases during processes taking place at the absorption tower. The incoming flue gas after the ESP heats the outgoing flue gas after the absorption tower, as shown earlier in Figure VIII/10.3-1.

The thermal performance of GGH is very significant, as the reheated gas outlet temperature must be kept above the minimum specified value to achieve adequate flue gas buoyancy and ensure plume dispersion. This is also required to achieve a sufficient chimney effect, which largely depends on the gas outlet temperature and, of course, on the stack height. Finally, the reheated flue gas is discharged through the high stack. The efficiency of this type of plant is 99%. Generally, the system includes gypsum dewatering for commercial purposes. The wastewater after proper neutralization is sent to an ash slurry sump or another suitable place.

The plants discussed here have other auxiliary systems and have a good amount of instrumentation; total control is accomplished generally by dedicated programmable logic controllers (PLCs). All the relevant to-and-fro data are connected to the main plant DCS via a link. In Japan, it is common practice to utilize $CaCO_3$ concentration analyzer to optimally control SO_2, as shown in Figure VIII/10.3-3. However, gypsum recovery works only when the ESP is located before the FGD.

As mentioned, there are other systems that are no longer in common use—sodium-based and dual alkali-based—which are mainly of academic interest. They are discussed briefly here. The sodium-based wet scrubber system uses sodium hydroxides (NAOH) or sodium carbonate (NA_2CO_3) as an absorbent and has a low liquid:gas ratio because of these compounds' high reactivity with respect to lime/limestone slurry absorbent. The reactions are

$$2NaOH + SO_2 = Na_2SO_3 + H_2O$$
$$Na_2CO_3 + SO_2 = Na_2SO_3 + CO_2$$

Further oxidation converts sodium sulfite (Na_2SO_3) into sodium sulfate (Na_2SO_4), both being highly soluble and so needing a special type of disposal. If Na_2SO_3 slurry is used in place of Na_2CO_3, the reaction is:

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3 \text{(sodium hydrogen sulfite solution)}$$

By heating this solution, the reaction reverses and Na_2SO_3 can be recovered rather than consumed. This process is known as Wellman-Lord and was once regarded as the most widely used wet and regenerative sorbent FGD treatment. It is similar to the dual alkali process, discussed later. Na_2SO_3 acts as the actual sorbent while $NaHSO_3$ acts as a sulfur-binding compound. However, the sulfur is not passed on to calcium, but when heated is released again as SO_2, which is extracted as a concentrated mixture with water (approximately 85% SO_2) for further processing into sulfuric acid. In the process of scrubbing, sodium sulfite or sulfate is also formed as a by-product. Because of some process loss in sodium content in the form of Na_2SO_4, a small percentage of continuous make-up through Na_2CO_3 (soda) or Na_2CO_3, $NaHCO_3$ (trona) is required to be added in the regeneration tank to balance this loss. The reactions are as follows:

- Inside the scrubber:

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$
$$2Na_2SO_3 + O_2 \rightarrow 2Na_2SO_4$$

- Inside the regenerator:

$$2NaHSO_3 \rightarrow Na_2SO_3 + SO_2 + H_2O$$

- In the makeup process:

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2$$
$$Na_2CO_3, NaHCO_3$$
$$NaHSO_3 + NaHCO_3 \rightarrow Na_2SO_3 + H_2O + CO_2$$

- Sulfuric acid formation reaction:

$$2SO_2 + O_2 + 2H_2O \rightarrow 2H_2SO_4$$

In some systems, magnesium hydroxide ($Mg(OH_2)$) is used as an absorbent; the reaction is

$$Mg(OH_2) + SO_2 = MgSO_3 + H_2O$$

The dual alkali-based wet scrubber system utilizes sodium-based reagents like sodium hydroxide (NaOH) or sodium carbonate/soda (Na_2CO_3) as the primary absorbent for SO_x treatment, in a process similar to Wellman-Lord. Initially, when Na_2CO_3 (soda) or NaOH reacts with SO_2 in the absorption tower, the following reaction takes place:

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2$$
$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

Na_2SO_3 further reacts with SO_2 to form $NaHSO_3$ and comes out of the absorption tower as a sulfur-binding compound. Calcium-based reagents are then applied to this slurry for regeneration of the basic reagents: NaOH or Na_2CO_3.

This method was intended to address the problems associated with lime-scrubbing systems, such as the low

www.EngineeringBooksPDF.com

solubility of lime and limestone in water and gypsum scaling. The solubility of sodium salts is much higher, which led to the concept of a scrubbing liquor with $NaHCO_3$ and Na_2SO_3 as the SO_x-binding compounds. The process is shown in Figure VIII/10.3-2(a). The following reactions occur at different places:

- Inside the absorption tower:

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$
$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

- Inside the precipitation tank:

$$2NaHSO_3 + CaO + H_2O \rightarrow Na2SO_3 + CaSO_3, 2H_2O$$
$$NaHSO_3 + CaO \rightarrow CaSO_3, 2H_2O + NaOH$$
$$CaSO_3, 2H_2O + O_2 \rightarrow CaSO_4, 2H_2O(\text{gypsum})$$

- Inside the regeneration tank:

$$NaHSO_3 + Na_2CO_3 \rightarrow Na_2SO_3 + NaHCO_3$$
$$NaHSO_3 + NaHCO_3 \rightarrow Na_2SO_3 + H_2O + CO_2$$

Because of some process loss in the sodium content in the form of $CaSO_3$ and $CaSO_4$, a small percentage of continuous make-up through Na_2CO_3 (soda) or Na_2CO_3, $NaHCO_3$ (trona) is required to be added in the regeneration tank.

Spray Dry Scrubber. The spray dry scrubber is of generally of two types: semidry and dry lime. These processes were developed as a competitive alternative to the classical wet scrubber technology. Spray dry scrubbers are the second most popular method, with an efficiency as good as that of wet scrubbers, if not better. The process technology can achieve SO_x removal efficiencies of up to 98%, as claimed by some manufacturers. In a FGD plant with spray dry scrubbers, unlike wet scrubbers, the Electro Static Precipitator(ESP)/dedusting equipment is located after this plant, which is a major layout requirement. This process makes use of a water-based sorbent containing lime (CaO) or milk of lime. The lime-based reagent is injected into a reactor vessel in the form of milk of lime (in a lime spray dryer or semidry process) or in the form of humidified powder (in a dry process).

The atomized form of the reagent, when it comes in contact with the hot flue gases, becomes dry; then the reaction takes place between hydrated lime and SO_x (mainly SO_2) in the flue gases. The solid reaction product is collected by downstream dedusting equipment (e.g., ESP for a thermal power plant or a baghouse filter for a sinter plant) and part of it is recirculated. Recirculation of this reaction product is through the lime slurry preparation tank to reduce the bulk consumption of lime and hence the running cost of the project. The $Ca(OH)_2$, when it reacts with SO_2, converts to a mixture of calcium sulfate (gypsum) and sulfite. One of the many advantages of this process is that the requirement of a water treatment plant is eliminated.

The in-duct sorbent injection method is also available as a comparatively less costly approach and can be located further upstream in the flue gas path. This system does not require any extra space or reactor vessel in the flue gas path and be can easily installed in older or existing plants that are not equipped with a proper desulfurization facility. This system is part of the sorbent injector process at a lower temperature.

Additional activation of the sorbent may be achieved by spraying water on the flue gas downstream of the sorbent injection point where the sorbent is actually fed. The part of CaO that failed to make contact or react now is converted to $Ca(OH)_2$, which is more reactive to SO_2, giving calcium sulfite part of that is further oxidized to calcium sulfate.

The normal sulfur removal efficiencies of this type of FGD is 80 to 85%, but higher efficiencies can be attained if arrangement is made for water spraying after the sorbent injection point into the flue gas path (which reactivates the free sorbents in the flue gas), by spent sorbent recycling, and by selection of the optimized location of the sorbent injection point with respect to the temperature.

Na_2CO_3 can also be used as a sorbent where Na_2SO_4 is the by-product, which is soluble and requires special handling. This, along with availability and the cost factor makes this compound less popular than other sorbents.

Sorbent Injector. The third method is known as a *sorbent injector* but is less popular and offers approximately 60 to 65% efficiency. In this process, dry sorbent such as limestone or $Ca(OH)_2$ is sprayed into the hot flue gases in the upper part of the furnace itself (in this case the process is termed a high-temperature sorbent injector), and, because of the reaction of sorbent and SO_2, gypsum is produced and later captured in a fabric-type filter or an ESP along with fly ash.

In this system, the gypsum cannot be used for commercial purposes as it is mixed with fly ash, reacted SO_x, and calcium compounds. The maximum temperature limit is around 1200°C, and $CaSO_4$ is not stable above ~1250°C in typical flue gases from a typical coal-fired SG plant. For direct sorbent injection, whether low or high temperature, the efficiencies depend upon approach temperature, sorbent fineness, injection point, and recirculation of used sorbent.

Seawater Scrubbing. Other than scrubbing by alkaline chemical reagents, seawater, being a natural alkaline, can be used as a sorbent that absorbs SO_x/SO_2 and causes further oxidation by adding oxygen to promote formation of SO_4^- ions and free H^+ ions. The H^+ ions then react with carbonates in the seawater to release CO_2 gas. The reactions are

$$SO_2 + H_2O + O_2 \rightarrow SO_4^- + H^+$$
$$HCO_3 + H^+ \rightarrow CO_2 + H_2O$$

www.EngineeringBooksPDF.com

This type of FGD system can be suitable for coastal regions; see Figure VIII/10.3-2(b). Seawater is already used for condenser cooling, and the outlet seawater, obviously, is preheated in the condenser while absorbing the heat from the turbine exhaust steam. A part of this seawater is used to scrub SO_x/SO_2 along with fly ash particles. In the water treatment plant, the pH of the scrubbing liquid at the outlet of the FGD unit needs to be adjusted before being sent back to the sea. Lime may be used for adjusting the pH of the discharge seawater.

10.3.4.2 NO_X Control

NO_x control is very important as a part of the denitrification measures taken with the products of combustion (flue gas).

10.3.4.2.1 NO_X Controls through Process Control Loops NO_x levels in a power plant can be reduced in many ways as per the considerations set by the system manufacturers. The two basic ideas behind the reduced production of NO_x are (1) the staging of air and/or fuel, which was discussed in Section 10.0.3.2.2; and (2) a separate chemical process plant

10.3.4.2.2 NO_X Controls through a Separate Chemical Process Plant There are several methods of denitrification of flue gas other than those applied at the source. This is important because generation of NO_x cannot be fully avoided by the protection at source. NO_x removal from flue gas through a separate chemical process plant is achieved by the following methods:

- Dry process, which is more popular and needs discussion
- Wet process, which is a complicated process requiring wastewater treatment; it is seldom used

The dry process may be of different types using catalytic and noncatalytic reduction:

- SCR by ammonia spraying NH_3 in the presence of a catalyst type that depends on the temperature of the flue gas.
- SNCR by ammonia or NH_3 spraying without a catalytic presence requiring a high temperature (800−1000°C).
- NSCR using the presence of multiple catalysts—namely, Pt with CH_4 or CO or H_2.
- Catalytic cracking using Pt as the catalyst.

Only SCR, being the most widely used plant, is discussed in this chapter. It is a means of converting NO_x in the presence of various catalytic agents into N_2 and H_2O. Generally, SCR is located between the economizer and the air heater, and ammonia is injected before entering a catalyst chamber. The approximate NO_x reduction possibility is 90% by this method.

Aqueous or anhydrous ammonia, aqueous urea (also used as a reductant in place of ammonia), and the like, are added to the flue gas stream to remove NO_x. Other possible reductants include cynuric acid and ammonium sulfate. Typical reactions are

$$2NO_2 + 4NH_3 + O_2 = 3N_2 + 6H_2O;$$
$$4NO + 4NH_3 + O_2 = 4N_2 + 6H_2O;$$
$$NO + NO_2 + 2NH_3 = 2N_2 + 3H_2O$$

Secondary reactions may be

$$2SO_2 + O_2 = 2SO_3;$$
$$2NH_3 + SO_3 + H_2O = (NH_4)2SO_4 \text{ or } NH_3 + SO_3 + H_2O = (NH_4)HSO_4$$
$$4NO + 2(NH_2)2CO + Oh = 4N_2 + 4H_2O + 2CO_2$$

When urea is used, CO_2 is also formed. The reaction for urea is

$$4NO + 2(NH_2)2CO + O_2 = 4N_2 + 4H_2O + 2CO_2$$

The ideal reaction has an optimal temperature range of 360 to 450°C, but can operate at a lower range of 230 to 450°C. In that case, however, a longer reaction time (residence time) has to be arranged. The minimum effective temperature depends on the various fuels, gas constituents, and catalyst type and geometry.

10.3.4.2.3 Catalysts Used for SCR Operation SCR catalysts are manufactured from various ceramic materials used as a support or carrier, such as titanium or aluminum oxides, whereas the active catalytic components are usually oxides of base metals, such as vanadium or tungsten, or zeolites. Even various precious metals such as platinum are used as catalysts, as mentioned previously (in NSCR or the catalytic cracking method) Each catalyst component has its own advantages and disadvantages.

Base metal catalysts, such as vanadium and tungsten, are not suitable for use at higher temperatures because they lack high thermal durability, but are popular because of their lower operating cost. Most industrial and utility boiler applications work well at the temperature ranges they offer. Zeolite oxides, on the other hand, are capable of operating at substantially higher temperatures. The continuous operating temperature of 630°C is quite common as opposed to the maximum short temperatures' withstanding capacity of up to 850°C.

The shape or geometry of the catalysts is also considered as an influential factor in SCR system design. The catalysts are available in various forms/shapes such as granule, grid, and honeycomb plate and each has its advantages and disadvantages. For example, honeycomb configurations are smaller than plate types and less expensive, but they have higher pressure drops and are

www.EngineeringBooksPDF.com

susceptible to plugging much more often and easily. Plate-type catalysts, on the other hand, offer lower DP loss across the chamber and are less susceptible to plugging and fouling than are the honeycomb types. They are also much larger and more expensive.

Instrumentation and controls' involvement here is not great, and they can be integrated with the main DCS. In order to keep excess NH_3 within limit (as it has harmful effects on human life), it needs to be monitored and controlled. The catalyst bed loss or the DP loss across the catalytic chamber also require close monitoring.

10.3.5 Combined SO_x–NO_x Removal

10.3.5.1 SO_x–NO_x Removal by the Fluidized Bed Copper Oxide Process

This process is an advanced technology that provides control of SO_x and NO_x at the same time in coal-fired power plants (Figure VIII/10.3-4). The copper oxide process offers a number of advantages over the conventional SO_x and NO_x controls discussed earlier. These advantages are as follows:

- The combined removal of SO_x and NO_x is accomplished in a single reactor vessel.
- The system is regenerative so far as copper oxide is concerned.
- The process by-product is a saleable form of sulfur for example sulfuric acid.

Currently this type of FGD is regarded as a potential type of NO_x control with the aim during the initial period of eliminating SO_x only because that was considered the most important pollutant. There are three basic compartments in this system: the absorber, the heater and the regenerator. In the absorber, the sorbent is fluidized by the flue gas injected from the bottom. The copper, as copper oxide, reacts with sulfur oxides to produce copper sulfate at about 400°C. The reactions are

$$2CuO + 2SO_2 + O_2 \rightarrow 2CuSO_4$$
$$CuO + SO_3 \rightarrow CuSO_4$$

NH_3 is injected into the flue gas or premixed before it enters the absorber. In the absorber it reacts with nitrogen oxides, with the copper sulfate acting as the catalyst. The reactions are

$$4NO + 4NH_3 + O_2 \rightarrow N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

These are exothermic reactions and when heat-generated can be utilized in the flue gas in the air preheater located next to this plant.

The process then needs CH_4, part of which is burnt in a combustor; the hot gas is sent to the two-stage heater vessel. Copper sulfate sorbent is heated typically at about 500°C. The hot copper sulfate is then allowed to enter a moving bed regenerator from the top of the reactor whereas the methane is introduced at the bottom. When the copper sulfate comes into contact with the methane at ~500°C, it is reduced to Cu releasing SO_2. There may be some Copper Oxide (CuO) contained in the sorbent entering the regenerator, and it reacts readily with SO_2 in the exiting offgas or exhaust gas to form $CuSO_3$. To summarize, inside the regenerator, the sorbent may consist of copper sulfate and a small amount of copper oxide and copper sulfite.

The reactions are as follows:

$$CuSO_4 + CH_4 \rightarrow Cu + SO_2 + CO_2 + H_2O$$
$$CuSO_3 + CH_4 \rightarrow Cu + SO_2 + CO_2 + H_2O$$
$$CuO + CH_4 \rightarrow Cu + CO_2 + H_2O$$

The concentrated SO_2 can be used to produce sulfuric acid, as in the Wellman-Lord process. The Cu sorbent is transported back to the fluidized bed using air, during this transport it is oxidized to CuO as per following reaction:

$$2Cu + O_2 \rightarrow CuO$$

The copper sulfite, if any, is also oxidized to the basic sorbent form:

$$2CuSO_3 + O_2 \rightarrow 2CuSO_4$$

The exhaust product gas, or offgas (i.e., SO_2) from the regenerator may also be utilized for recovery of sulfur in its elemental form in a separate place called the *section plant*. At this plant, the exhaust gas, containing some methane, is then converted as per this reaction:

$$2CH_4 + 3SO_2 \rightarrow S + 2H_2S + 2CO_2 + 2H_2O$$
$$CH_4 + 2SO_2 \rightarrow S + CO_2 + 2H_2O$$

H_2S gas is also converted to yield elemental sulfur by the following reaction:

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O$$

10.3.5.2 SO_x–NO_x Removal through Gas Phase Oxidation/Ammonia Injection

Gas phase oxidation/ammonia injection is a new technology used for both denitrification and desulfurization of flue gas. It involves a radiation chemistry process in which the physical effects of radiation are used to cause a desired reaction. In this process, an intense beam of electrons is fired into the flue gas along with a simultaneous injection of ammonia. This system is not popular because of the unavailability of high-quality accessories such as electron gun vis-à-vis accelerator, and the like, suitable for continuous operation in an industrial environment.

www.EngineeringBooksPDF.com

The electron beam is meant to encourage the oxidation of sulfur dioxide to sulfur compounds. The purpose of injecting ammonia is to make it react with the sulfur compounds to facilitate formation of ammonium sulfate. This by-product is known as a nitrogenous fertilizer after further processing to produce ammonium sulfate crystals through proper separation, drying, and screening before bagging or bulk loading.

The injection of ammonia is also useful for decreasing nitrogen oxides in the flue gas as described before.

10.4 Fuel Oil Pressure Control

10.4.0 General

Fuel oil is as a supporting fuel in any combination with the main pulverized fuel (PF). Fuel oil may be of any type such as heavy fuel oil (e.g., HFO, heavy petroleum stock (HPS), low-sulfur high-stock (LSHS)). As discussed in Section 4 of this chapter, fuel oil is normally used in steam-generating plants for startup, low-load operation up to certain loads, and of course coal flame stabilization at all loads if the situation demands. Fuel oils need to be heated before being burned. For example, the flash points are 66°C for HFO and HPS and 75°C for LSHS.

In some plants, firing of LDO, which does not need preheating for burning, is also used for cold startups of steam generator(s). The fuel oil is drawn from the HFO storage tank(s) by pressurizing pumps and pumped through the steam oil heaters. The oil duly pressurized and heated reaches close to the boiler front in a ring main. The extra oil not required by the firing control system is returned by way of recirculation to the storage tanks. The exact amount of oil required by the oil burners is taken off from the ring main. Oil pressure is maintained at the required set value of the header pressure in the ring main by a control valve provided in a separate recirculation line near the pressurizing pumps. Oil temperature is controlled by regulating steam flow to the fuel oil heaters.

The LDO firing system facilitates the starting of units when no auxiliary steam or auxiliary boiler is available from an external source. An LDO firing system must also be used for cold startup of steam generators and for flushing of HFO lines.

It may be noted that the basic scheme for an LDO system is the same as discussed for fuel oil systems, except that suction for the LDO-pressuring pumps is taken from the LDO tanks and there are no heating requirements.

10.4.1 Objective

There are two control loops and their objective is to maintain the fuel oil header pressure at the pump discharge and at the burner front ring main from which all of the burners get their oil supply. It is very important that these header pressures are maintained at a fairly constant value and that each burner gets more or less the same quantity of oil when the burner valves (open/close type) are fully open; see Figures II/2.3-1 and VIII/10.4-1(a,b).

10.4.2 Discussion

The very nature of fuel oil (HFO, HPS, or LSHS)—a highly viscous liquid—requires that the temperature always be kept at such a value that the necessary viscosity is available to maintain the mobility of the fluid. Another important requirement is recirculation of the oil line from the burner front to the oil tank itself so that the viscosity is maintained by with steam tracing or lagging with electrical heating. This line is popularly called the *long recirculation line* and covers the entire oil line while the unit is operating.

There is another recirculation line that enables the oil to recirculate back to the oil tank long before the burner front and after the fuel oil pumps and heaters. This line is popularly called the *short recirculation line* and covers a smaller part of the oil line while the unit is not operating that is set for a long shutdown. This valve may be kept at a 10%opening even when the unit is operating so as to ensure fuel oil mobility.

The pressure control valve is located in another recirculation line after the fuel oil pumps and heaters so as to maintain a fixed fuel oil pressure at the discharge header pressure. The pressure control valve should have the full capacity to pass total burner flow when no burner is operating. As the valve is located in the recirculation line near the fuel oil pump discharge, it has to send all the oil from the discharge side of pump back to the tank by fully opening in case oil firing is not required. The fuel oil pressure is ~15 to 25 kg/cm^2 depending on the type and size of the burners, maximum burner elevation, distance from the remotest burner, and so forth.

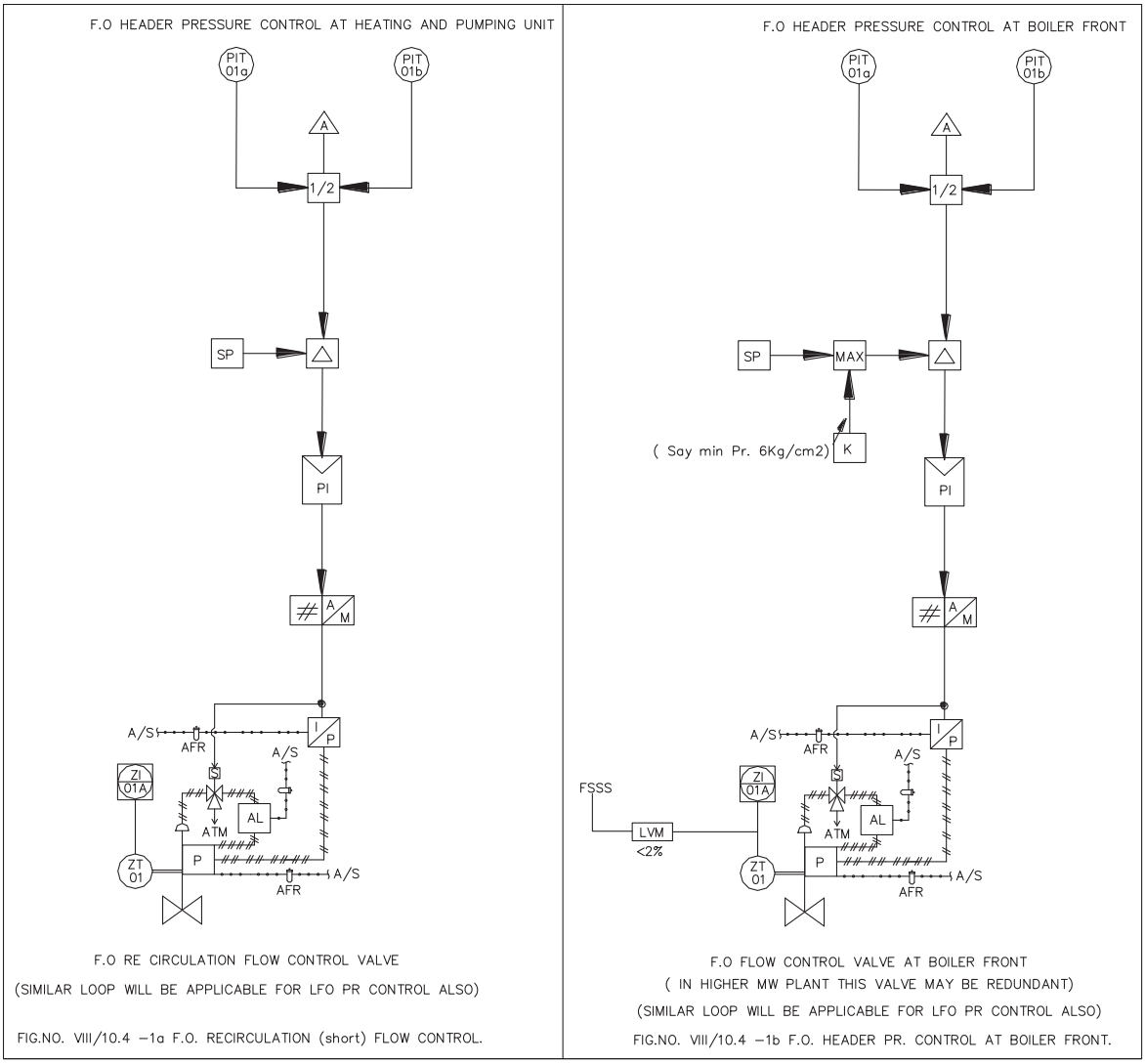
10.4.3 Control Loop Description

Figure VIII/10.4-1a may be referred to for a schematic representation of implementing the control loop in a typical 250 MW plant having a drum-type boiler and a coal-fired furnace with occasional oil support. The control loop is direct, single and simple.

10.4.4 Control Loop (HFO/LFO Recirculation Control)

The measured/process variable is compared with a fixed set value to form the error signal. The controller output is the position demand signal of a control valve in the recirculation line. When there is less demand, there is more recirculation and vice versa. The pressure transmitters are normally of the sealed diaphragm type to avoid chocking or wax formation/deposition inside the sensor. The impulse line up to the transmitter, however, is steam traced or electrically heated.

www.EngineeringBooksPDF.com



NOTE:

1) FOR BETTER UNDERSTANDING,LOOPS SHOWN HERE ARE IN THEIR SIMPLE FOR AVOIDING MANY ASSOCIATED INTERLOCKS etc. IN ACTUAL CASE THERE MAY BE ADDITIONAL INTERLOCKS AS PER MANUFACTURER'S RECOMMENDATIONS.

2) LOOPS ARE SHOWN FOR HFO ONLY, BUT SIMILAR WILL BE APPLICABLE FOR LDO ALSO. FIG NOS. III/11.2.2.2–1 & 2 MAY BE REFERRED TO ALSO.

FIGURE VIII/10.4-1 Boiler oil pressure control.

10.4.5 Control Loop HFO (/LFO) Flow Control at Boiler Front

The fuel oil pressure is measured by the pressure transmitter with sufficient redundancy and at the appropriate location near the front of the burner to get a representative number (refer to Figure VIII/10.4-1(b)). The measuring point is important because it ensures that the highest and remotest burner gets sufficient pressure to fulfill requirements. The type and installation of pressure transmitters were discussed earlier. The set point is sent through a max circuit to ensure that under all conditions a minimum pressure in the header at the boiler front is maintained. The error created by the set point and actual pressure is sent to the PI controller to regulate the valve(s) to fulfill the HFO flow demand. When the opening of the valve is less than 2% (i.e., closed), the signal is sent to the FSSS to close the trip valve for positive isolation. The loop description here and in Figure VIII/10.4-1(b) is given for HFO only but is similar for LDO.

11. HP–LP BYPASS SYSTEM

11.0 General

There are situations in large power plants in which the TG sets undergo extreme operating conditions like sudden

www.EngineeringBooksPDF.com

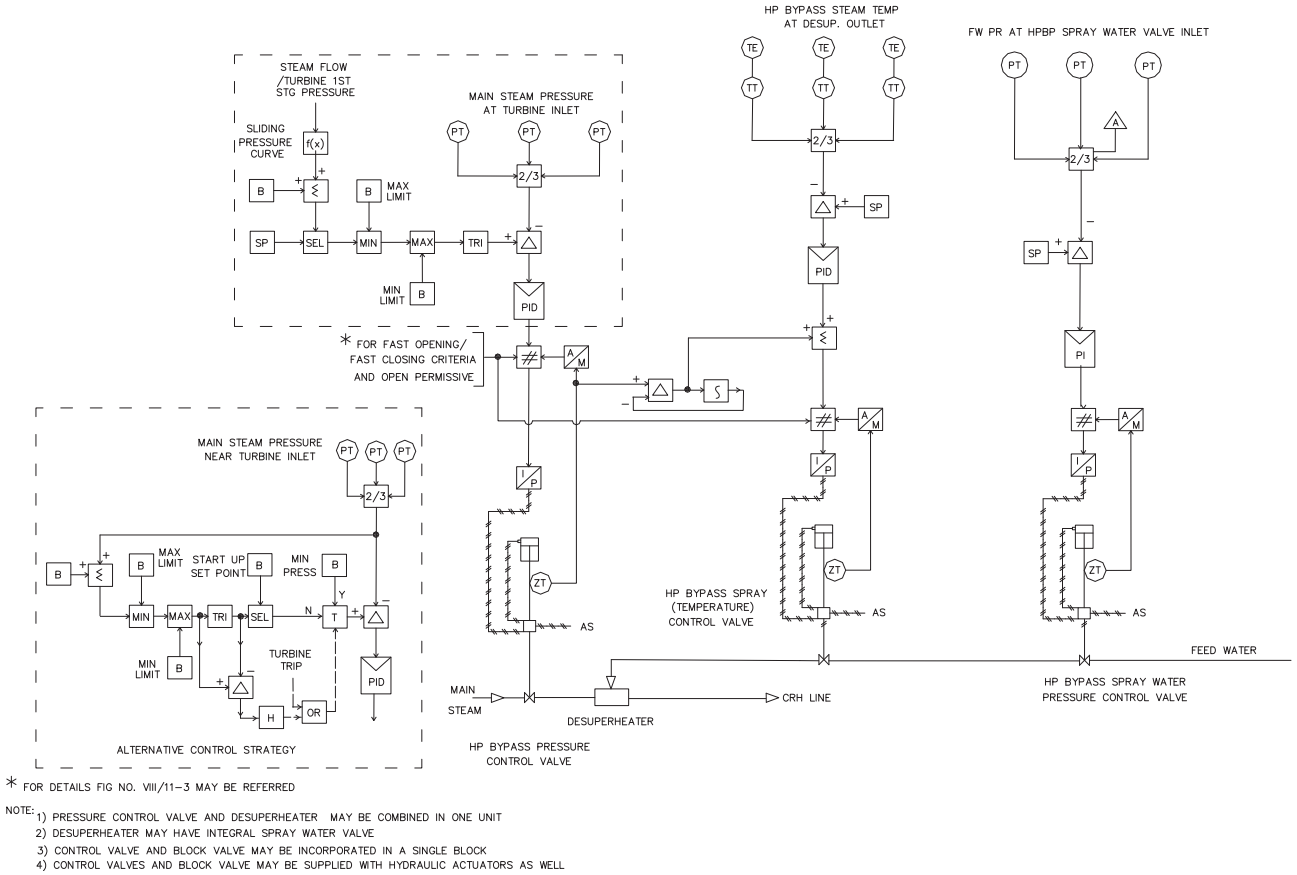


FIGURE VIII/11.1 HP bypass pressure and temperature control.

load throw-off, full-load trip-out, or even a planned shutdown for a short span of time. In all such conditions, the TG set is expected to run on house load/low load. In the case of turbine trip/shutdown/open generator circuit breaker, it is set to restart as quickly as possible so that revenue earning continues. For quite a while, the design trend for the TG set has been that the units must be compatible with the systems that enable them to run at house-load operation.

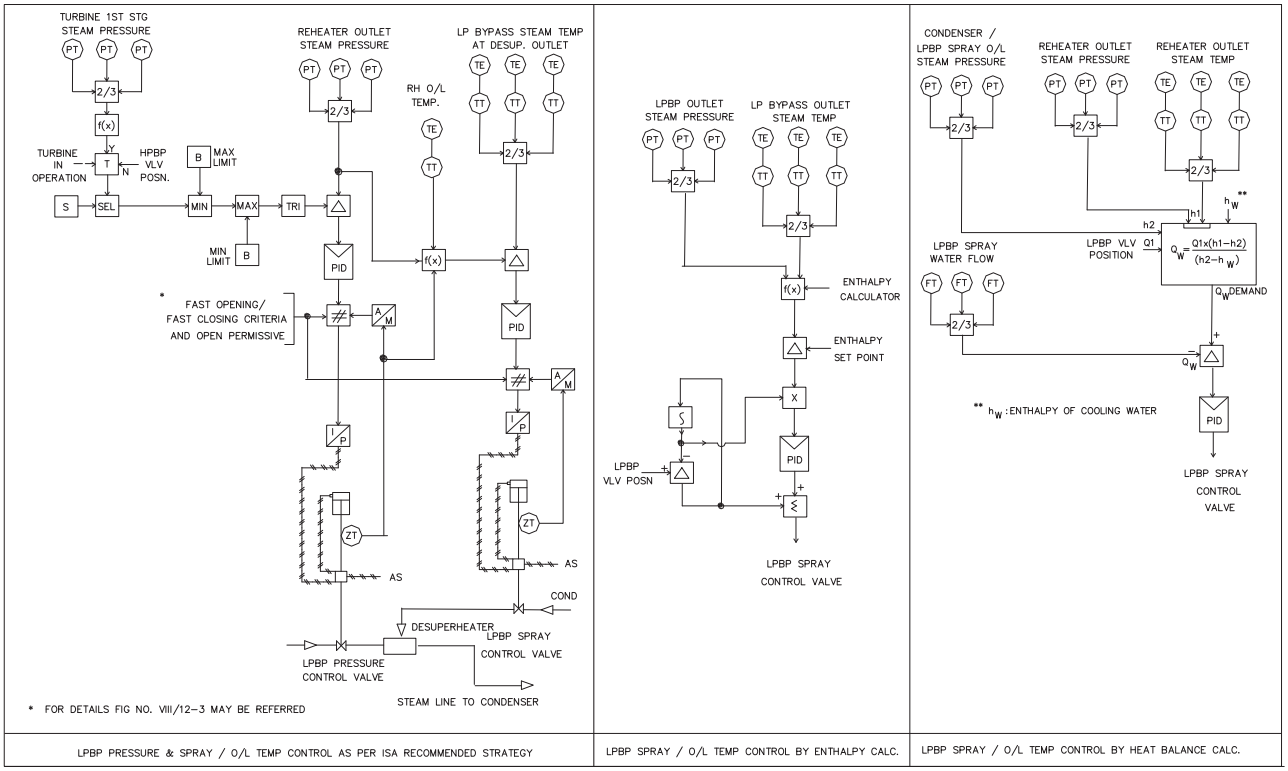
In house-load operation, the unit can supply its own auxiliaries' electrical load and need not depend on the external power supply from the grid supplied by the other connected units. When there is a blackout—that is, full-load tripping from the failure of the entire grid, the house-load operation facility keeps the boiler running and keeps the TG set ready for the earliest further loading. All of these facilities are obtainable if the unit is designed for and supplied with an HP–LP bypass system having sufficient steam-handling capacity, which may be 60% or even 100% depending on several influencing factors.

In many standard turbogenerator systems, HP–LP bypass is essential for startup and shutdown. In other words, TG cannot be started (e.g., heat soaking) without HP and LP bypass. In some system designs, parallel operation of the bypass is also allowed. (See Figures VIII/11.1 through VIII/11.4.)

The most important function of the steam turbine bypass system is to simulate the expansion and heat transfer process that normally takes place inside the operating steam turbine. In other words, the HP–LP bypass system provides an alternative route for the steam line from the boiler to the condenser so that steam generation is almost uninterrupted or artificially loaded when there is no operating load (startup), turbine trip, or a part load on the turbine. This system facilitates faster plant startups by raising steam parameters to suit the turbine requirements as needed by various types of startup. The most advantageous condition for the HP–LP bypass system is to implement a hot startup, which means minimum life expenditure of the turbine components and auxiliaries. The overall advantage is that availability of the boiler, turbine, and generator increases.

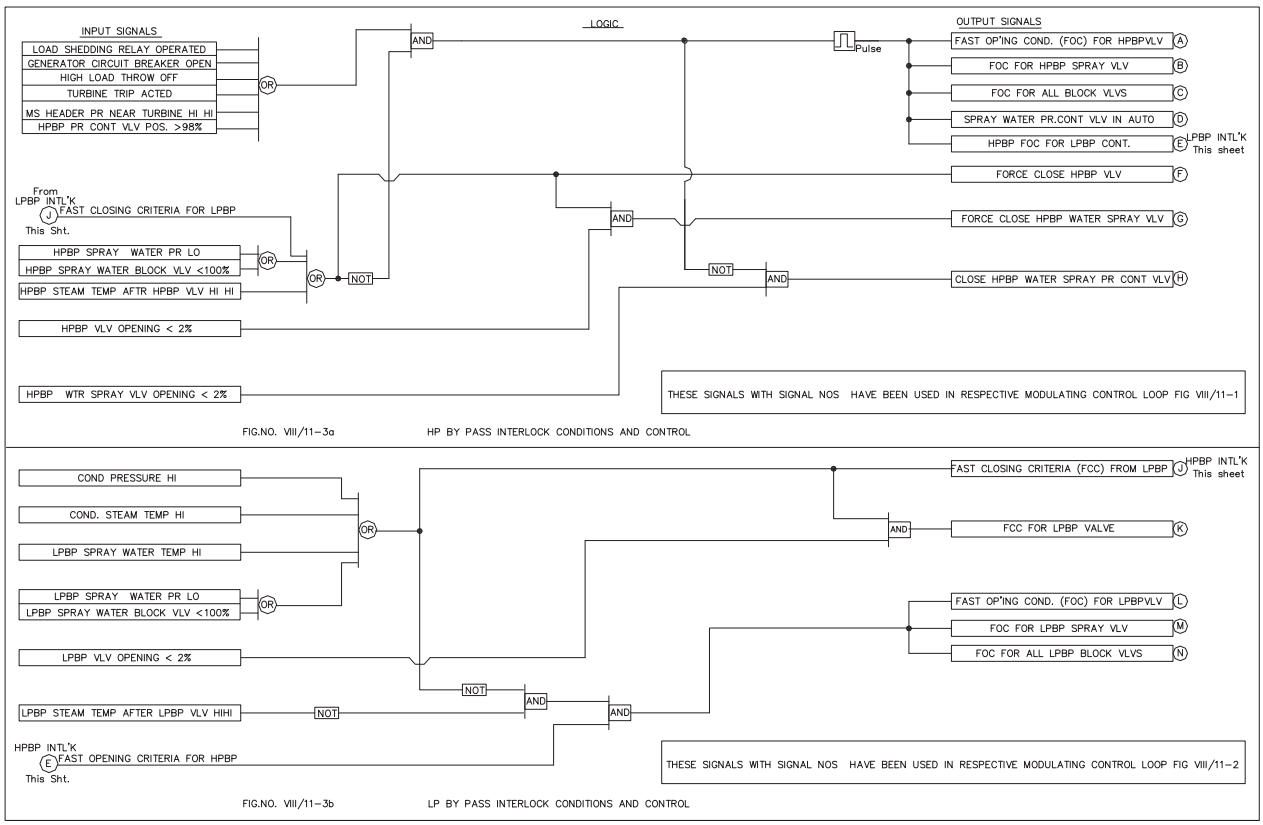
The turbine bypass system has manifold applications as it is suitable for handling almost all possible startup conditions such as cold startup, warm start, hot restart, and turbine shutdowns, and disturbed situations such as load

www.EngineeringBooksPDF.com



NOTE:
1) PRESSURE CONTROL VALVE AND DESUPERHEATER MAY BE COMBINED IN ONE UNIT
2) DESUPERHEATER MAY HAVE INTEGRAL SPRAY WATER VALVE
3) CONTROL VALVE AND BLOCK VALVE MAY INCORPORATED IN A SINGLE BLOCK
4) CONTROL VALVES AND BLOCK VALVE MAY BE SUPPLIED WITH HYDRAULIC ACTUATORS

FIGURE VIII/11.2 LP bypass control pressure and temperature control.



NOTE: 1. BASIC INTERLOCKS HAVE BEEN SHOWN ONLY. NO INTERLOCK FROM SIGNAL BAD CONDITION OR DUE TO REDUNDANCIES HAVE BEEN SHOWN FOR SIMPLICITY.

FIGURE VIII/11.3 HP–LP bypass interlock conditions and control.

www.EngineeringBooksPDF.com

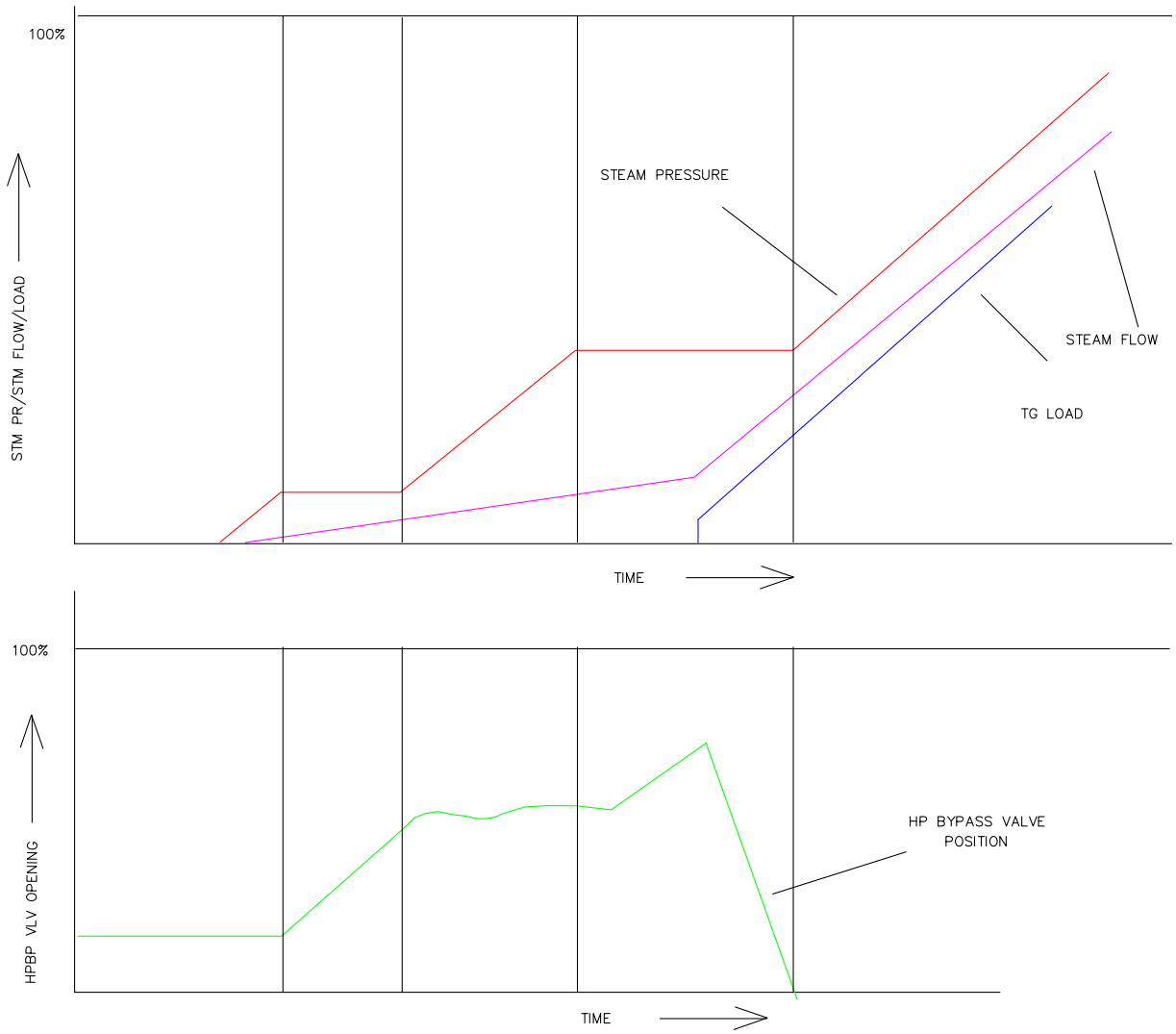


FIGURE VIII/11.4 Cold startup: Parameters for HPBP valve position.

rejection and unit trips. In any case, bypass operation always calls for loss of energy but this may be traded off by the time and money saved in achieving the emergency and/or long startup time of the boiler.

The HP bypass (HPBP) system during the situations mentioned connects the main steam to the cold reheat steam line at matching pressure and temperature conditions through the HPBP valve bypassing HPT.

The LP bypass (LPBP) connects the hot reheat line to the condenser through the LPBP valve, bypassing IPT and LPT with suitable steam conditioning. In the case of ultra-supercritical plants, there may be HP, IP, and LP bypasses because there may be two stages of reheating and IPTs. However, all of these systems operate in tandem. The system is designed to incorporate the controls of parameters like pressure, temperature, and flow of steam as they should have been at turbine entry and exhaust points during the turbine's prevailing running conditions before the HP–LP bypass came into action and then steered to the condition suitable for the purpose it is used at that moment. Normally, the HP–LP bypass system does not directly interface with the turbine control and supervisory system but is set to maintain all of the steam parameters by directly carrying out process measurements to tackle the situations it is deployed for. The overall benefits of an HP–LP bypass system are summarized as follows:

- Unit can be started even if there is a grid failure and consequent blackout
- Safety valve popup situations are fewer and may even be rare
- Demineralized water requirement is less during startup and tripout conditions

www.EngineeringBooksPDF.com

- Rate of pressure rise in the boiler under tripout conditions is less
- House-load operation is practicable.

For medium- and larger-capacity HP—LP bypass systems, steam flow measurement through the HP bypass system needs to be considered for calculating the total steam flow and the corresponding feedwater flow requirement to develop the control strategy for boiler control systems, especially where parallel operation is allowed.

This is especially required where steam flow to the turbine is measured by the characterized turbine first-stage pressure or if the flow sensor is installed after the bypass connection. The signal from the flow sensor at the HP bypass line or a characterized bypass valve position indication may be used to measure bypass steam flow. On the other hand, if the steam flow is measured before the HP bypass connection, separate measurement of HP bypass flow can be eliminated.

The bypass system itself, along with the control system, is normally designed so that fluctuations or oscillations of flow, pressure, and temperature are brought to a minimum value in order to avoid unintended effects on the performance of associated systems. The bypass system, especially the LPBP system design, must incorporate and ensure proper conditioning of LP bypass steam as it enters the condenser chamber. It is extremely important that steam conditioning be guaranteed to the level at which thermal or vibration damage to the sensitive heat transfer surfaces and structures in the condenser is totally eliminated. The European Boiler Codes allow omission of the conventional safety valves and operation of the system with HP bypass valves only. The American Boiler Codes require conventional safety valves even with the bypass valves.

11.1 Objective

The objective of the HP—LP bypass system control loops is to maintain steam pressure, temperature, and flow as demanded by the situation at suitable points.

11.1.1 High-Pressure Bypass System

The HP bypass system is designed to accomplish the following system requirement:

- Boiler main steam pressure control
- Temperature and flow control of steam to match CRH conditions in the cold reheat line to cool the boiler reheater elements
- Control of steam flow through the main steam line to cool the boiler final superheater in case of sliding pressure operation. For example, in the case of an OT boiler, steam temperature control is highly dependent on feedwater flow and firing rate. The effect of firing rate reduction can take more while the feed rate has to be maintained to cool the superheater; this results in more steam than required, so HP-BP system takes care of the extra steam.

11.1.2 Low-Pressure Bypass System

The LP bypass valve is mainly for the protection of the condenser. The system is designed to reduce the reheated steam to a condition acceptable to the condenser, and obviously calls for much a larger valve as the final control element because of the enormous increase in the specific volume of the steam as it is lowered to condenser pressure, which is necessarily subatmospheric.

The LP bypass system is designed to accomplish the following system requirements:

- Control of steam pressure after bypassing the HP turbine—in other words, the HRH steam pressure according to loading of the turbine.
- Control of the temperature and flow of steam through the cold reheat line to cool the boiler reheater elements. If the condenser pressure/temperature is high, the LP bypass dumping must be stopped and must be vented otherwise (followed by firing rate reduction!)

11.2 Discussion

Turbine bypass control valves have long been associated with demanding process conditions. In controlling high pressure/temperature steam, the valves need to open in a few seconds; however, on the other hand, they are supposed to have a high degree of closure, normally with a leakage rating of Class V or better. The bypass system being a critical service, all valves in it necessarily require a sophisticated valve design and fast as well powerful actuators that enable the valves, of any size, to have a full travel time of two seconds or less. Noise immunity is extremely important. For installations requiring stringent noise restriction, such as larger plants and supercritical plants, major suppliers recommend de-superheaters with a special design for better performance.

Some major differences, in type of actuator, between U.S. and European norms is that hydraulic power units are popularly used in Europe for the turbine bypass system's final control elements whereas in the United States pneumatic actuators are preferred because of their relatively low cost.

11.2.1 System Capacity

A number of possibilities and influencing factors determine the capacity of the bypass system. They are as follows:

- A bypass system capacity of only 15% maximum continuous rated (MCR) flow at valves wide open

www.EngineeringBooksPDF.com

enables the unit to match steam-to-turbine metal temperatures with a reduction in startup time by about 30 minutes.
- A bypass system capacity of 40% MCR flow at valves wide open that can cope with minor transient or disturbed conditions is considered sufficient. Larger capacity may be considered for handling more critical situations.
- A bypass system capacity of 100% MCR flow at valves wide open takes care of the situation in which the boiler is running at full load and any untoward situations such as turbine or generator trip do not cause the safety valves to blow.

Bypass systems with suitable capacity can bring down steam generation in the boiler in ten minutes or fewer to a house-load capacity of approximately 10 to 20% without creating excessive temperature gradients. In this case, some manufacturers recommend 60% HP–BP and 100% L–PBP systems.

The steam flow capacity of the bypass system is also influenced by a number of factors:

- Condenser capacity, internal arrangements, and materials
- Turbine rotor diameter
- Startup, shutdown, loading, and unloading procedures and requirements
- Safety considerations related to SH, RH, and condenser
- Reheat pressure for turbine start
- Number of warm starts and hot starts and requirements for house-load operation
- Cost

11.2.2 Various Bypass System Start Modes

The modes of operation discussed in the following subsections are possible, justifying the best use of bypass systems after considering proper size and design.

11.2.2.1 Cold Start

The HP–LP bypass system permits improved operation of the furnace, primary and secondary superheaters and reheaters, and main and reheater steam lines. The system as a whole improves the quality of the steam generated by the boiler before starting the turbine, in this way reducing startup times significantly. The turbine can be started from the turning gear and can reach the rated speed in 15 to 30 minutes, provided that temperatures at various points of the turbine rotor are proper and follow the turbine manufacturer's temperature gradients as per the thermal stress evaluator (TSE) guidelines. The bypass operation may take approximately 2.5 to 3.5 hours. The steam flow through the superheater and reheater guarantees that tube cooling is effective and facilitates a higher furnace firing rate for the boiler.

11.2.2.1.1 Role of the HPBP System during Cold Start The steps involved in a cold start follow.

1. Bypass valve is kept wide open or open up to an admissible minimum position to allow steam flow through the SH and RH banks as soon as the furnace starts firing. After generation of sufficient steam capable of exerting the minimum required pressure, the bypass valve begins to open as required by the controller to maintain steam pressure at a certain value. (See Figure VIII/11.4.)
2. Valve position—having reached the preassigned value sufficient to initiate pressure buildup through a ramp—commences with more production of steam through a more or less fixed opening of the valve. This step allows more steam in the pressure building but with a gradient within the limit permissible by the system.
3. Steam pressure reaches the value desirable for preparing the turbine startups and the bypass valve opens further to maintain the steam pressure at a constant value.
4. After a certain time period the turbine is ready to be synchronized with a small load and the bypass valve starts closing no sooner the turbine takes further loading.
5. Bypass valve is fully closed after a predetermined load is delivered by the TG set.

11.2.2.1.2 Role of the LPBP System during Cold Start During cold start, the LP bypass valve can be operated in two ways as indicated next:

- The valve remains closed to allow the reheat pressure to develop and then starts opening to control the RH steam pressure as per the set point generated.
- The valve acts similarly to the HPBP system to develop pressure in a controlled manner.

11.2.2.2 Warm Start

The benefits deriving from a cold start are also applicable to a warm start. The only difference is that the initial casing temperature of the HP turbine is usually above 100°C. However, the bypass systems enables an efficient startup operation by corelating the steam temperatures to the corresponding metal temperatures under all speed conditions.

11.2.2.3 Hot Start

Again many of the advantages of cold and warm start are applicable to this mode of operation as well. Sometimes the TG set trips out to save itself from minor disturbances. This tripping can be rectified in a comparatively short time and then unit becomes suitable for a hot restart. The bypass systems are designed to enable unit startup at the earliest

www.EngineeringBooksPDF.com

possible time through close watch and then by matching the steam temperature with the metal temperatures of the thick and heavy turbine parts. The incorporation of a hot start facility in the bypass systems enables the unit to shrug off unnecessary cooling and rewarming procedures.

11.2.2.4 Quick Start after Full Load (or Partial Load) Rejection

The duty of the bypass system calls for an immediate opening of the bypass control valves in the case of a partial- or full-load rejection. They open the bypass valves to the same position the turbine control valves were in before being closed because of unacceptable conditions.

Protective systems should be provided to trip the boiler when the HP bypass or LP bypass valves fail to open and when insufficient cooling steam flow passes through the superheater or reheater. Adequate safety systems for condenser protection, especially for the LP bypass system, should also be provided.

11.3 Control Loop Description

Figures VIII/11-1 and VIII/11-2, respectively, may be referred to for a schematic representation of implementing the control loop in a typical 250 MWTPS having drum-type boiler. The implementations shown are for normal-load operation, not for the startup, which is usually controlled manually.

11.3.1 Measurement of Various Parameters

The following subsections discuss parameters that are measured with sufficient redundancy and voting before they are used in the control loops.

11.3.1.1 Measurements for HP Bypass Control

The measurements done in the system that carry out HP bypass control are the following:

- Main steam header pressure near the turbine inlet
- HP bypass steam temperature downstream of the HP bypass valve for DSH spray water flow control to maintain the outlet steam temperature at the desired level
- DSH spray water pressure to lower the takeoff FW pressure to a pressure suitable for spraying over steam at the HRH/CRH pressure level

11.3.1.2 Measurements for LP Bypass Control

The measurements done in the system that carry out LP bypass control are the following:

- Turbine first-stage steam pressure
- Reheat outlet steam temperature
- Reheat outlet steam pressure
- LP bypass temperature at the DSH outlet
- Position signal for both LP bypass and temperature/spray control valves
- LP spray water pressure

11.3.2 Control Loop Strategy

The final control elements in the system that carry out the control strategy are the following:

- HP and LP bypass pressure control valves
- HP and LP bypass spray water (temperature) control valves
- HP bypass system spray water pressure control valve

11.3.2.1 HP Bypass Control

11.3.2.1.1 HPBP Pressure Control The control strategy is based on a single-element control concept. The selected signal of main steam pressure near the turbine outlet becomes the measured/process variable. For a fixed main steam pressure control system, the HPBP set point is also a fixed value that is normally higher than the master pressure control set point, with a slight margin ($\sim$5.0 kg/cm^2). For a variable set point for a sliding pressure-controlled system, the set point is derived from the load index (e.g., main steam flow or first-stage pressure) and then the bias for the margin is added.

After selection, the set point signal is passed through a maximum and a minimum selector. The steam pressure set point is thus limited within minimum and maximum values; it is then passed through a tracking integrator (TRI) to ensure a ramped and smooth output, and then becomes the final set point so as to prevent process upsets. The maximum value of the integrating gradient is limited; in fact, the operating gradient is a very low value so that the instantaneous set value becomes lower than the main steam pressure value in case of a sudden upset. For example, when there is a large load rejection, the steam pressure starts rising and if it becomes higher than the set point (with margin), the bypass valve opens as per the controller output command and tries to reduce it. The set value, for a variable pressure system, readjusts its value as per the new load and the bypass valve remains open up to a certain value until the steam pressure matches. The firing rate is then modified as per the load and the steam pressure is readjusted so as to gradually close the bypass valve to bring back the normal operating condition.

Another control loop strategy applicable to both fixed- and variable-pressure system is also shown in the preceding drawing Figures VIII/11-1 as an alternative. Here the main steam pressure itself is utilized as the set point after adding the bias for margin DP; it passes through the TRI to generate the final set point. The TRI plays a vital role, as described previously.

www.EngineeringBooksPDF.com

The TRI changes its output at a very slow rate. Whenever there is a large-load throw-off, the MS pressure shoots up at a very fast rate while the set point increases at a slower rate, causing the HPBP valve to open to arrest the high pressure excursion. When the load and heat input stabilizes, the bypass valve again closes. If there is a turbine trip, the bypass valve opens and the pressure control set point becomes the minimum value (e.g., the pressure required for hot startup). The rest of the HPBP control system is same as before.

11.3.2.1.1 HPBP Temperature Control (by Spray Water Valve) The control strategy is based on a very simple single-element control concept. The selected signal of steam temperature at the outlet of HP turbine bypass becomes the measured/process variable. The set point is a fixed value. The difference between the two signals forms the error signal of the control loop, and the controller (PID) output is supplemented with a feed-forward signal from the HPBP valve position to obtain an advanced sense of the process condition. If measured separately, the bypass steam flow itself may be used as a feed-forward signal for the temperature control system; otherwise, the suitably characterized bypass valve position and indexed by the steam pressure may be taken as the definitive signal of this steam flow. The combined signal is used to regulate the high-pressure DSH spray water control valve.

11.3.2.1.2 HPBP Spray Water Pressure Control It is desirable that the header pressure of the spray water be maintained at a desired value. For this there is a separate pressure control loop as shown in Figure VIII/11.1. Here the error generated by the set point and the measured variable (i.e., pressure at the spray water valve inlet) is fed to a controller that regulates the opening of the HPBP spray water pressure control valve.

There are two interlocked conditions other than the fast-opening and fast-closing criteria indicated in Section 11.3.2.3.1: (1) valve is not permitted to open when the HPBP spray water pressure is low and (2) valve is not permitted to open when the HPBP spray block valve is not fully open.

11.3.2.2 LP Bypass Control

11.3.2.2.1 LPBP Pressure Control The control strategy is based on a single-element control concept. The selected signal of reheater outlet steam pressure at turbine inlet (HRH) becomes the measured/process variable. The set point has a variable value obtained from the characterized turbine first-stage pressure. The relationship between the turbine first-stage pressure and the HP turbine exhaust, that is, cold reheat (CRH) steam pressure, is exploited with some consideration of the line pressure loss in the reheater circuit determines the HRH set value.

When the turbine trips and/or during startup there will not be any first-stage pressure to act as the set point. Thus, the HPBP valve position (in case of more than one HPBP pressure control valve average valve position) is taken as the set point through a selector circuit as shown in the loop.

The difference between the two signals forms the error signal of the control loop, and the controller (PID) output is used to regulate the high-pressure control valve.

11.3.2.2.2 LPBP Temperature Control (by Spray Water Valve) Efficient operation of any DSH calls for the injection of hot water, essentially at a temperature near the saturation temperature of the steam being cooled. This ensures that mainly the latent heat is extracted from the steam to evaporate the injected water. This design criterion assumes minimum suspension time for the water particles in the steam path so as to make certain that the injection water is completely evaporated. Complete evaporation must be attained before the first pipe bend to avoid the impinging of water particles on the inside walls of the pipes. DSH performance depends on the degree of atomization of the injected water and the mixing with steam. Proper and speedy evaporation depends on the proper location and direction of the spray water jet as well.

The control strategy for LP bypass temperature control is based on ISA-recommended simple single-element control; see Figure VIII/11.2(a). The selected signal of steam temperature at the outlet of the LP turbine bypass becomes the measured/process variable. The set point is calculated essentially from the steam mass flow and steam condition. Normally the steam mass flow online measurement is not taken in this large-diameter pipe but is calculated as a function of the bypass valve position duly characterized for the steam flow and the corresponding steam conditions. The difference between the two signals forms the error signal of the control loop, and the controller (PID) output regulates the high-pressure desuperheater spray water control valve lift position and determines the requisite quantity of injection water flow that provides the guideline for the LPBP downstream steam condition.

An alternative loop suggests that the measured variable should be the calculated unit enthalpy from the LPBP valve outlet temperature and pressure multiplied by the calculated steam mass flow; see Figure VIII/11-2(b). The set point is the manually adjustable enthalpy as desired. This loop has been developed to take into consideration that steam conditions after the LP-bypass DSH spray are very close to or at saturation, so the temperature after the DSH is not recommended as a control signal. The feed-forward signal is incorporated from change in LPBP valve position.

www.EngineeringBooksPDF.com

Another alternative loop that avoids LPBP temperature measurement incorporates the heat balance method to determine the requisite quantity of spray or cooling water to maintain the enthalpy vis-à-vis the temperature at the condenser outlet; see Figure VIII/11-2(c). The heat loss by the steam is equal to the heat gained by the water when mixed to form a saturated condition. Heat lost by steam is the product of steam quantity and difference between enthalpy at the LPBP inlet, and the condenser inlet heat gain by water is the product of water quantity and difference between enthalpy at the condenser inlet and the spray water. The enthalpy is taken from the steam table at process temperature and pressure. The desired water quantity is the ratio of total heat lost by steam and enthalpy difference from the water side, which becomes the set point. Water quantity is the measured variable, and the controller output regulates the spray water valve lift.

As already discussed, the LP bypass is basically provided for the protection of the condenser. Some condenser manufacturers stipulate the following guidelines in addition to the control philosophy discussed here for startup, intermittent, and continuous control to maintain LP bypass downstream steam temperature conditioning:

Enthalpy restriction Steam entering the condenser with enthalpy more than 670 to 680 Kcal/kg is restricted; in the case of sudden high flow steam dumps the enthalpy is recommended to be restricted to 660 Kcal/kg. In certain cases steam admission to the condenser with enthalpy more than 680 Kcal/kg is also considered where the specific conditions of operating the unit suggests that.

Pressure restriction: The maximum pressure of steam admission to the condenser is restricted to a limit value of 16 kg/cm^2 (g) mainly applicable for the dump condenser.

To accommodate these guidelines, temperature and pressure at suitable point are measured to calculate the enthalpy of the entering steam and considered a measured/process variable. An appropriate set value, as depicted earlier (Figure VIII/11-2(b).), is provided for generating the control error, and a controller output is added to the conditioned steam flow derived from the LP bypass pressure control valve position to form the demand for the LPBP spray control valve position.

There are certain interlocked conditions other than the fast-opening and fast-closing criteria indicated in Section 11.3.2.3.2. The valve is not permitted any of these conditions exist:

- DSH spray water pressure is insufficient
- Block valve is not fully open
- Condenser pressure is high
- Condenser temperature is high
- Condenser hot well level is high

11.3.2.3 HP–LP Bypass Interlocks

Refer to Figure VIII/11.3 for a description of implementing HP–LP bypass interlocks.

11.3.2.3.1 HP Bypass Interlock Refer to Figure VIII/11.3(a) for a description of HP bypass interlock.

Fast-opening criteria: Under these severe conditions, it is required that: the HPBP valve and the associated spray valve and block valves open fully for a period to allow the HP bypass to dump the steam. During this time the spray control pressure valve is on auto so that suitable pressure is maintained. Also, a suitable signal is sent to the LPBP system to open fast. Typically these conditions are shown as signal output; the initiating criteria listed here are shown as input signal. These criteria are applicable for all cases:

- Load shedding relay is operated
- Generator circuit breaker is open
- Turbine trip is activated
- High (system) load is dumped
- MS pressure at/near the turbine is very high
- HPBP valve is almost open (to ensure full open)

Force-/fast-closing criteria: The HPBP valve closes under any of the following conditions :

- Fast-closing criteria from the LPBP (discussed in Section 11.3.2.3.2)
- HPBP spray water pressure low (valve not permitted to open)
- HPBP spray block valve not fully open (valve not be permitted to open)
- Steam temperature after HPBP valve high-high
- HPBP spray control valve closes under all previously listed conditions, provided associated HPBP valve closed (<2% open)
- HPBP spray pressure control valve closes when HPBP spray control valve closed, provided no fast-opening criteria exist

11.3.2.3.2 LP Bypass Interlock Refer to Figure VIII/11.3(b) for a description of implementing the LP bypass interlock.

Fast-closing criteria: For condenser protection, it is necessary that under certain conditions which tend to increase temperature rise in condenser. The LPBP valve must be closed under the following conditions:

- Temperature at condenser high-high
- Condenser pressure high-high
- LPBP spray water temperature high-high
- LPBP spray water pressure low
- LPBP spray block valve not full open

www.EngineeringBooksPDF.com

LPBP spray valve must be closed under the conditions just stated, provided the associated LPBP valve is closed (<2% open).

Force-/fast-closing criteria: The HPBP valve must close under any of the following conditions:

- Fast-closing criteria as discussed for the LPBP valve
- HPBP spray water pressure low
- HPBP spray water pressure low (valve not be permitted to open)
- HPBP spray block valve not full open (valve not be permitted to open)
- Steam temperature after HPBP valve high-high

The HPBP spray control valve must close under all of these conditions provided the associated HPBP valve is closed (<2% open). Also, the HPBP spray pressure control valve must close when the HPBP spray control valve is closed, provided no fast-opening criteria exist.

Fast-opening criteria: Under these severe conditions it is required that the LPBP open under HPBP fast-opening conditions, provided no fast closing criteria exist or the LPBP steam temperature after the LPBP valve is high-high. These will cause all LPBP pressure and spray valves and associated block valves to open.

12.0 BOILER OLCS: INTRODUCTION TO INTERLOCK AND PROTECTION OF BOILER BMS, SADC, AND SB CONTROL

12.0.1 General

The closed-loop control always takes feedback from the process for which it is employed and readjusts the control output accordingly to obtain the desired process parameter. In other words when a more accurate or adaptive control is necessary, it is imperative that the output signal system back to the controller be measured as another input of the control system. This type of system is referred to as a closed-loop control (CLC). Normally, CLC is regarded as a regulatory part of total control systems and is accommodated in the auto control loops. An open-loop control (OLC); in contrast, does not utilize the same (feedback) and so is also called a *non-feedback control*.

As the OLC does not normally utilize the feedback signal in computing the output, it also does not take care to see that the desired condition has been achieved in the input. This means that the control system is insensitive to the output and does not monitor the processes status it is controlling. It can be said that the open-loop system normally does not compensate for disturbances in the system and, unlike CLC, cannot correct any errors that might be generated while issuing the output. However, in a sequential control system, the feedback signals are checked before proceeding to next step.

The OLC is most suited for the following applications:

- Simple processes where feedback is not critical or control in a moderated band is acceptable, and where the cost of the continuous control system can be reduced.
- Processes where control output mainly depends on proper assessment by the human operator and where automation may lead to wasted energy.
- Processes related to implementation of sequential or safety (protection)/interlocking logic systems where process measurement feedback signals are not required; for sequential logic, status feedback signals are required to proceed to the next step only.

In general OLC is the interlock and protection part of total control systems and is accommodated as a separate entity.

An interlock and protection system is designed to automate the required operator actions during an abnormal event or because of any change in the operating status of the plant (e.g., trip, startup, shutdown). All of the preceding (trip, startup, shutdown) conditions necessitate immediate and accurate handling/management either by the operator or by some other means. Experiments show that the human response to emergencies is not beyond question. There is every possibility of an erroneous operator action regarding a judicious decision or timely intervention. These untoward situations can be tackled well if actions are seen in a logic form and then implemented through state-of-the-art technology, thereby avoiding human, environmental, and equipment damage resulting in more capital cost, loss of production due to a long shutdown time, and/ultimately loss of revenue. For this reason, a separate interlock and protection system is justified.

The separation of interlock/protection processing from the regulatory control systems has always been at the center of discussion in control and instrumentation packages for thermal power plants. In a large power plant, the control systems are large and complex, developed with state-of-the-art technology using sophisticated software and hardware. Although several signals are required to be exchanged between the two systems—that is, between CLCS and OLCS—the same can be done through hardware or wet/soft signals without increasing the resultant security and reliability risks. The logic must differentiate between safety protection and interlock in plant requirements, based on the degree of possible hazard, including injury to personnel and damage to equipment and the environment. The degree of redundancy in logic processing is also determined by the previoiusly discussed criteria for selection of hardware (i.e sensors) and its implementation through software.

www.EngineeringBooksPDF.com

12.0.2 Boiler OLC

A boiler OLC mainly consists of different sequential or safety (protection)/interlocking logics. The boiler OLC covers the following categories:

- Equipment:
  - ID fans, FD fans, PA fans
  - Boiler water circulating pumps, BF pumps (if in boiler package)
  - Seal air fans, scanner air fans
  - Mill/pulverizer motors, feeder motors, lubricating-oil pumps (for all drive motors needing lubricating oil—that is, without grease lubrication (which is covered in BMS/FSSS or separate OLCs).
- On/off dampers and valves (motor- and/or solenoid-operated) for air, oil, steam lines, and the like. (Covered in BMS/FSSS.)
- Logic systems for boiler tripping, purging/firing, startup, shutdown, and so forth. (Covered in BMS/FSSS.)

12.0.2.1 OLC for Lubricating Oil Pumps

The main drives such as ID fans, FD fans, PA fans, boiler water circulating pumps, BF pumps, and the like. if equipped with forced lubricating oil and a control oil system (necessary to bring final control to minimum, and so forth, necessary for starting a big fan). oil pump startup/tripping or shutdown logic implementations are taken care of in the OLC.

12.0.2.1.1 LOPs Logics Normally two LOPs are supplied with the main drives. The starting logic ensures that the first pump (as selected by the operator) is started by the operator if a LOP suction head or pressure is available. The LOP continues to run to develop the lube oil pressure for the main drive. The second pump (as selected by the operator) cuts in automatically if the running LOP trips for any reason or the LO pressure goes down below the minimum value and continues to run as long as it goes over a preset value.

The LOPs normally trip because of overload, low suction head or pressure, electrical circuit trouble, and the like. They can be shut down manually if required by the operator.

12.0.2.2 OLC for Main Drives

All of the main drive motors, be they HT (e.g., 11/6.6 KV) or LT (e.g., LT A.C), related to boiler parts are taken care of in this part of the OLC. Typical drives include the following:

- ID fans (HT)
- FD fans (HT)
- PA fans (HT)
- Mill/pulverizer motors (HT)
- Feeder motors (LT)
- Seal air fans (LT)
- Scanner air fans (LT)
- BF pumps (HT)
- Boiler water circulating pumps, if any (HT)

There are in general two sets of interlock and protection requirements for any drive motor; One set is from the drive or process side and the other is from the motor side.

12.0.2.2.1 Drive Motor Logics The start permissive logics from the drive/process side are typically from

- Process pressure/temperature/flow/level within acceptable limits
- Inlet/outlet dampers/valves, hydraulic coupling scoop tube, and the like, open or closed as per the protection requirements from the process/equipment side (e.g., no-load starting)
- Running or tripping of any other system-related drives (e.g., to run standby pumps)
- drive bearing temperatures not high
- Adequate LO pressure
- Manual or automatic/sequential start (if any) command for selected drive

The start permissive logics from the HT motor side are typically from

- Winding temperatures within acceptable limits
- Motor bearing temperatures within acceptable limits

The tripping logics from the drive/process side are typically from the process pressure/temperature/flow/level, etc., that are beyond an acceptable limit.

Some inlet/outlet dampers/valves open or closed when starting commands are issued for the main drives and/or any other conditions; if those inlet/outlet dampers/valves fail to execute those commands, a trip signal is issued to that particular drive after some time delay.

- Preferential tripping in case of disturbed process conditions
- Drive bearing temperatures very high
- LO pressure very low and/or pump running/trip status
- Manual or automatic sequential trip command

The tripping logics for the HT drive from the process side are typically from (1) very high winding temperatures or (2) very high motor bearing temperatures.

12.0.2.3 On/Off Dampers and Valves

The on (open) interlock logics are typically from

- Process related interlock signals from pressure/temperature/flow/level are high/low/normal, etc.

www.EngineeringBooksPDF.com

- Running or tripping of any other system related drives
- Main drive on or open command as per the process requirements
- Manual or automatic/sequential on (open) command of selected drive.

The stop (close) interlock logics are typically from

- High/low/normal process-related interlock signals from pressure/temperature/flow level.
- Main drive stop or close command as per process requirements
- Manual or automatic/sequential off(close) command of selected drive

12.0.2.4 Logic Systems for Boiler Tripping, Purging, Starting, and Shutdown

This logic system is popularly known as *master fuel trip* (MFT) logic and is briefly discussed in Section 12.1 of this chapter. In many thermal power stations, MFT-related logics are developed in dual redundant or even triple redundant mode. The total inputs, outputs, and processing sections are redundant (dual or triple) to avoid any incorrect operation of processing units, faulty sensors, and the like..

12.0.3 OLC in SADC

The secondary air damper control (SADC) philosophy, as discussed in Section 12.2 of this chapter is different for two major types of boilers. In both types, the secondary air dampers are normally operated in modulating mode through CLC. In some phase of operation, however, they maintain some other set point or position as per the command of BMS/FSSS.

12.0.3.1 Boiler with Fixed Burners and Flue Gas Recirculation Damper

The secondary air dampers control loop strategy was discussed in Section 3 of this chapter. In this case OLCS in BMS issues three distinct output commands requiring SADC to modulate the dampers accordingly. The following modes of operation are recommended:

Furnace safety position mode: BMS issues this command in case of any emergency situation (e.g., boiler tripping) occurring during boiler operation. In this condition, the air flow is to be maintained at about 25% of the total air flow.

Oil position mode: BMS issues this command when the first set of oil burners are introduced after the purging operation is completed successfully. At this position, minimum air flow (10% of secondary air flow) in the corresponding oil burners only is maintained to ensure oil flame, which may be extinguished in the presence of more air flow.

PF position mode: BMS issues this command during the introduction of the first set of PF burners. At this point the air flow of the corresponding PF burner is maintained at about 45% of secondary air flow.

During normal operation, the main air flow signal from the auto control loop becomes dominant through the maximum selector.

12.0.3.2 Boiler with Tilting and Corner-Fired Burners and Overfire Air Damper

In this type of boiler the auxiliary air dampers are modulated to maintain the DP between the windbox (WB) and the furnace. Auxiliary air dampers are located in all two-lettered elevations (e.g., AA, AB, BC, CD) between coal burners. In some elevations provision for oil firing (say, AB, CD, CE.) is made. These dampers become fuel air dampers, maintaining a fixed position provided oil firing is taking place at that particular elevation(s).

The only OLC output from FSSS is issued for adjusting the SADC modulating signal when MFT trips. The set point for the DP between the WB and the furnace is typically 150 to 200 mm of water column.

12.0.4 OLCS in Soot Blower Control

The soot-blower control system can be basically divided into two parts. The CLCS takes care of the pressure control system whereas the OLCS selects the blowers and their duration of operation. As discussed in Section 12.3 of this chapter, there are many types of soot blowers and methods of operating them to suit the furnace, the fuels, the sensors, and so forth. In a nut shell, the operations discussed in the following subsections are possible for operating soot blowers individually or in a selected group as and when required.

12.0.4.1 Fixed Programmed Time-Based Operation

The open loop control (OLC) of the soot-blowing system in this strategy is simply through step-by-step operation of the blower(s) in a sequential manner. In automatic mode, the blowers operate one (or group) by one (or group) as logically recommended by the boiler manufacturer and may be modified by the system and plant engineers to suit site conditions. OLC takes care of the starting time of advancing, time span of blowing, retracting, and time gap between the end of one blowing and the start of the next one for each blower (or group)

12.0.4.2 Temperature-Based Operation

The routine operations, as discussed previously, may cause unwanted blowing of relatively cleaner tubes and may

www.EngineeringBooksPDF.com

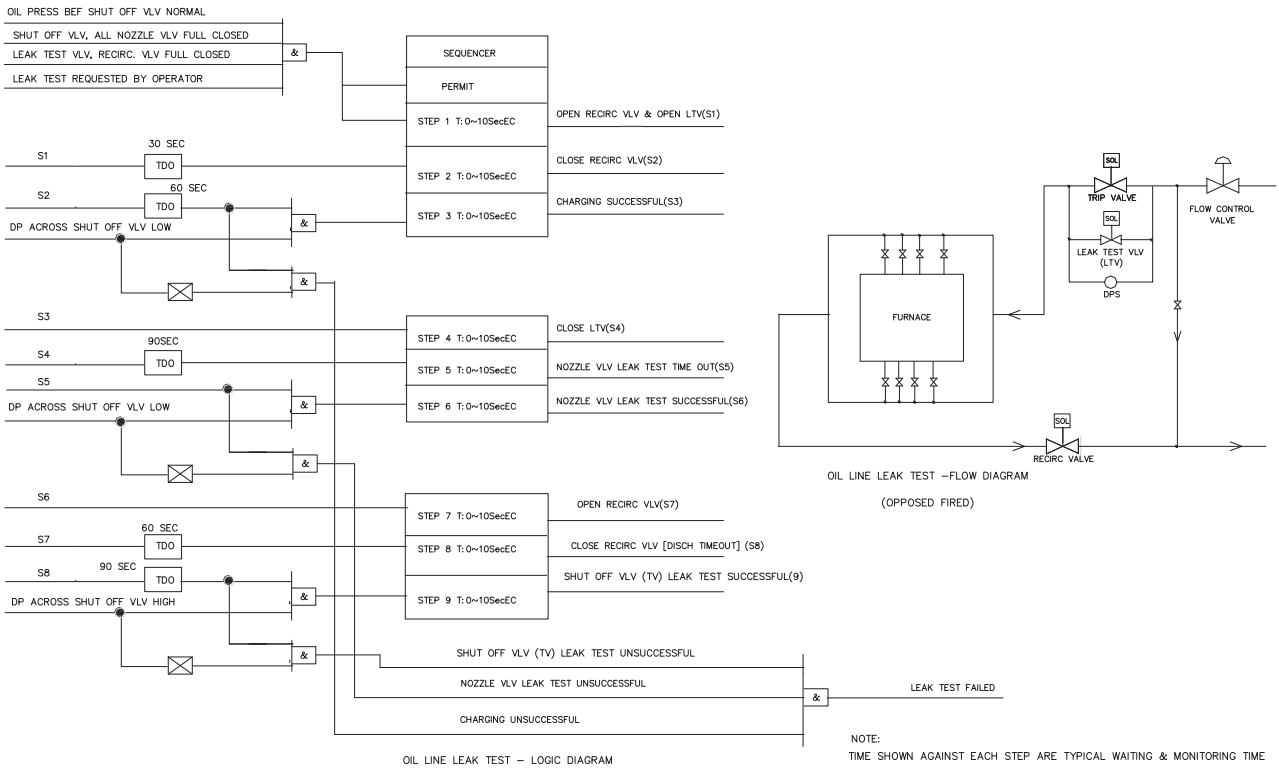


FIGURE VIII/12.1 Oil leak test: flow; logic diagram.

result in wear and tear and wastage of expensive soot-blowing medium. In contrast, the heavy-soot-deposited tubes may starve blowing at the right time and frequency. This advanced technology enables cleaning of selected soot blowers per the decision taken by the system logic with the help of water tube wall temperature sensors associated with each soot blower. Temperature sensors welded to the tubes sense the actual surface temperature near each soot blower. The measured water tube wall temperatures are compared with the corresponding temperature set point based on the saturation temperature of that point; if it becomes less (than the set point, the associated soot blower(s) is/are given the command to start blowing. This is a need-based operation to clean the soot-affected areas only.

Although effective for water tubes, this method is not suitable for areas where the fluid flowing through the pipes is steam or a steam-water mixture, neither of which has any further bearing on saturation temperature. For supercritical boilers, where a mixture of water and steam is passed through the tubes above the supercritical pressure of water, there is no way of calculating the desired value to determine the metal temperature, which can be taken as index of furnace dirtiness.

12.0.4.3 Heat Transfer/Heat Flux-Based Operation

The other soot-blowing strategy utilizes a more direct sensing system. The local heat transfer rate is measured by employing a heat flux meter to assess the degree of soot deposition so that the tube walls or air heater ducts can be selectively cleaned.

The sensing elements are located in every region of the tube walls surrounding the soot blowers to detect the rate of local heat transfer from the hot flue gas to the steam/water tubes in the furnace or in the air heater heat-exchanging elements (flue gas side). The heat flux meter output is utilized for operating the soot blower. Details are incorporated in Section 12.3.2.3 of this chapter. Other control actions may be taken via the differential temperature.

12.0.4.4 Leak Test of Oil Lines

Leak testing of nozzle valves and trip valves is performed by a separate leak test valve in many plants before plant startup The logic diagram is shown in Figure VIII/12.1.

12.1 Burner Management System

12.1.1 General

The very name *burner management system* (BMS) suggests efficient management of the burners and all associated drives and accessories required by the furnace firing system in almost all thermal power plants, whether medium or large, this system is an indispensable and very important

www.EngineeringBooksPDF.com

part of steam generation. It includes safe starting, safe operation, and graceful emergency shutdown vis-à-vis the steam generation package as a whole. Similar systems offered by other major boiler manufacturers are popularly known as a *furnace safeguard supervision system* (FSSS). Both names are quite familiar and acceptable the world over.

Whatever the brand name of the product, the ultimate purpose of the system, along with other normal functions, is to act like a watchdog to thwart any formation of explosive fuel—air mixture and avoid implosion in the furnace throughout the complete operating range. BMS/FSSS is basically a dedicated fire protective system along with logic implemented for startup, running and shutdown. It is globally accepted that the National Fire Protection Association (NFPA 8502/8503) guidelines are to be followed as a standard.

NFPA defines the burner management system as follows:

> *The control system dedicated to boiler furnace safety and operator assistance in the starting and stopping of fuel preparation and burning equipment and for preventing misoperation of and damage to fuel preparation and burning equipment.*

BMS/FSSS is required to perform logical or binary functions with quite a few inputs simultaneously and issue corresponding binary outputs paying due attention to the protective aspects—that is, to avoid firing hazards well in advance . There should be no confusion regarding the role of BMS/FSSS in the boiler operating system. It is a completely separate stand-alone system and is not related in any way to the boiler's normal automatic process controls such as steam pressure/temperature or boiler drum-level controls.

12.1.2 Process Functions Expected from BMS

The design basis of BMS/FSSS is to ensure, among others, the following:

- Satisfactory completion of the purge sequence before every startup of fuel firing to ensure that there are no unburnt fuels left over to cause a secondary firing!
- Satisfactory compliance with all start permissive conditions for startup of individual fuel-firing equipment.
- Flame (both oil and PF) monitoring when fuel-firing equipment is in service.
- Sequential operation, including control of drives and monitoring of status feedback during startup and shutdown (e.g., cutting in/taking out of elevations)
- Initiation of MFT through the master fuel relay (MFR) under adverse firing conditions beyond extreme limits, which can be hazardous to both equipment and personnel, to stop/close all sources of fuel not only at the burner end but also upstream (e.g., HOTV or mill trip).
- Sensing and alarm conditions for annunciators or monitors and indicators and sending them to the operator's unit control board (UCB) to facilitate smooth manual operation if necessary.
- Provision of all logic and safety interlocks, including tripping instructions compliant with NFPA 8502/8503 guidelines.
- Inclusion of the first-out feature to identify the root cause of any trip, whether related to the burner or the boiler as a whole.
- Provision of a complete BMS diagnostic or fault analysis system to immediately identify to the operator any system, subsystem or module failure.
- Start, stop, and trip of burners and igniters on an individual burner basis sequence and/or on a corner basis, as in a TT boiler.
- Boiler load—based operation of automatic cut-in and cut-off of burners/elevation. The operator may select the sequence of burner operation—for example, preferential tripping of mills in case of fixed wall burners.
- Provision of triple modular redundant (TMR) logic and/or a parallel and backup trip path by hardwired MFT or an electromagnetic relay independent of processors and I/O modules.

Using sophisticated microprocessors, BMS has long been implemented through OLCs or through programmable logic controllers (PLCs) for more reliability, flexibility, and availability (refer to Section 2.2 of Chapter VII).

12.1.3 Hardware and Software Functions Expected from BMS

The following criteria should be met in BMS:

- The system must be 100% foolproof, based on proven hardware and software.
- The system must be provided with an automatic self-monitoring facility.
- All modules must be of a failsafe design so that any single fault in any individual primary sensor, I/O channel, processor, and the like, should not jeopardize safety.

In addition, all faults should be annunciated to the operator immediately with a first-out facility. The BMS must meet all applicable relevant safety requirements, including those stipulated in latest editions of the DIN standard for electrical equipment for furnaces from Verband der Elektrotechnik (VDE 0116, Section 8.7; VDE 0160), NFPA 8502/8503, and so forth.

Another criterion is that the BMS hardware may be configured as triple-redundant fault-tolerant as per the

www.EngineeringBooksPDF.com

modern trend. Three independent sets of hardware (channel) comprising dedicated processors, I/O modules, communication interface, and the like, receive identical input signals. The complete logic part is implemented independently in each channel. The primary sensors for protection logic should also be triple-redundant.

12.1.4 BMS/FSSS Functional Configuration

The functional arrangement of the system can best be described if broken down into the following areas:

- Logical functions as the heart of the system
- Sensors, such as different process and position switches or manual commands
- Various drives, diaphragm/solenoid-operated valves and actuators
- Operator interface or the plaque/Keyboard, or the monitor in the control board

12.1.4.1 BMS/FSSS Logical and Functional Groups

The description of starting, tripping/shutdown, or other interlocking logic signals is mainly for FSSS. The basic philosophy is more or less same with, of course, major differences in some areas where the equipment itself is different. Some of these are

- Firing system:
  - BMS, which is built around fixed burners with front, opposed, and downshot burners
  - FSSS, which is built around burners with tilting and corner-fired systems
- Pulverizer system:
  - BMS, which is normally is based on ball mill—type pulverizers
  - FSSS, which is based on bowl-and-tube mills
- Fuel oil recirculation system:
  - BMS, which is meant for long recirculation systems only; the short recirculation valve is used for long shutdowns
  - FSSS, which takes care of both long and short recirculation systems; an orifice across the recirculation valve (normally closed) provides a constant return flow
- Primary air system
  - BMS, which is built around both common PA fans and header systems and individual PA fans
  - FSSS, which is built around individual PA fan systems normally common PA fans/headers

12.1.4.1.1 Leak Test Valves For some boilers, a leak test facility with valves is supplied for checking the passing through the HOTV and all downward pipe lines; and valves such as oil burner nozzle valves, including HORV. Leak test valves are installed across the main oil shutoff or trip valves. (See Figure VIII/12.1.)

The leak test procedure is described in a simplified way to provide some idea about the system. The following criteria must be met for starting the test:

1. Oil pressure before the shutoff valve is adequate
2. Shutoff valve is fully closed
3. All oil burner nozzle valves are fully closed
4. Leak test valve is fully closed
5. Oil recirculation valve is closed

After receiving all of the listed permissive signals, the test starts when the start command is issued by the operator. The oil pressure control system must be operating satisfactorily so as to maintain the required pressure of the oil header near the shutoff valve. Then the operator's start command initiates the following activities:

1. The oil recirculation valve opens.
2. The leak test valve opens.
3. The oil recirculation valve closes after approximately 20 to 30 seconds after the feedback from preceding two signals is affirmative, in order to flush the oil line before the actual testing is performed.
4. When the oil recirculation valve and the oil nozzle valves are closed, the leak test valve is fully open with the oil pressure control already in action. The oil line is charged gradually through the leak test valve, showing the differential pressure across the parallel combination of oil shutoff valve and leak test valve, which, initially high from the starting point, is on a decreasing trend. The charging time is set at approximately 60 seconds to ensure that the charging is complete some time before that. After the charging time expires, the pressure down the leak test valve is supposed to be the same as the upstream pressure and the DP should then be very low. In contrast, if the DP is still high, the charging failure condition is enacted and the leak test cannot continue.
5. If the DP is still very low in the fully charged condition. As soon as the DP low permissive confirmation is available, the leak test valve automatically closes and that status is maintained for approximately 90 seconds. After this time period, if the DP is still found to be low (meaning no leakage downstream in the oil line (the burner nozzle valves and the recirculation valve) it gives permission to the next step.
6. The oil recirculation valve automatically open as a measure of checking the leakage through the main oil shutoff valve.
7. The oil recirculation valve is kept open for 60 seconds to drain out all the oil in the pipe line and the DP should show high as the downstream pressure no longer exists. Then the oil recirculation valve is made to close fully.

www.EngineeringBooksPDF.com

8. Then the leak test valve is made fully closed. These conditions that is, oil recirculation valve and oil nozzle valves in full closed position, is maintained for approximately another 90 seconds. After the expiry of above time period, if the DP is becoming not high, then the main oil shutoff valve appears to be leaking and leak test failure condition is announced. However, if the DP high condition can persist up to 90 seconds, the "No leakage" condition is achieved and the system may be declared as passed the leak test.

12.1.4.1.2 Furnace Purge Logic Before every startup of the furnace vis-à-vis firing system of the boiler, it needs complete purging by blowing air through the furnace for a particular time period as recommended by the manufacturer. This may be termed *prefiring purge* and applied strictly to make sure that all the residual unburnt fuels that might have been accumulated are entirely eliminated. The air flow rate and the time period may vary but normally the fairly accurate value may be taken as 30% of the total air for about 5∼6 minutes. Some approximate amount of purged air, suggested to be close to 9 times the furnace volume.

It may not be out of the place to mention that purging is not only necessary for "prefiring purge," it is equally important to purge the furnace after every normal shutdown popularly termed *post- firing purge* to avoid possibility of explosion. Purging is also necessary for the oil burner valves at every time after closure of burners which is normally done by blowing an atomizing medium for a specified time period and also called *scavenging* and covered in the fuel oil related logics.

During purging, the windbox dampers or air registers are maintained in a particular position along with other permissive conditions so as to allow proper air velocities and travel through various routes consisting of radiant, convection and economizer zones. This complete purging system enables also the checking of proper operational functionalities of the air dampers, burner valves, flame monitoring systems, etc. in the way of ensuring permissive signals.

The furnace purge cycle normally needs the following conditions to be satisfied for an eligible purge start initiation:

- The AC and DC power supplies are available. (They are taken as a loss of AC/DC power for more than two seconds does not exist to avoid any spurious tripping.) This is mainly done in cases of FSSS meant for TT burners where equipment in elevation(logics) are normally run on AC supply and DC supplies are used for running of equipment for common or unit (e.g., HOTV have DC solenoid valve (may be double coiled) whereas elevation nozzle valves may have AC-operated solenoid valve.
- Drum level not high. It is taken as an absence (not) of drum level very high signal, which must exist for more than 10 seconds to avoid any spurious tripping.
- Drum level not low. It is taken as an absence (not) of drum level very low signal, which must exist for more than 10 seconds to avoid any spurious trippin).
- Any BFP is ON
- Any ID fan is ON
- Any FD fan is ON
- All associated air and flue gas dampers are open
- All PA fans are OFF
- All SA fans are OFF

When the air flow is adequate, such as greater than 30% and less than 40%:

- Auxiliary air/secondary air dampers are proven modulating at required position
- Windbox-to-furnace DP is proven satisfied (for TT boiler)
- Waterwall circulation is "adequate"
- Furnace pressure not high
- Furnace pressure not low
- All oil valves (trip and individual valves) are in closed position
- All pulverizers are OFF
- All hot air gates are proven "Closed"
- The flame scanners indicate "No Flame"

When all the preceding start permissive signals are available, the "Start Purge" command signal, if issued from the control board, the purging process is initiated and lasts for a specific period of time as set during commissioning (∼5 minutes). On expiration of the counting period, a successful furnace purge cycle is taken for granted and then the system becomes ready for the next step of operation.

12.1.4.1.3 Fuel Oil Firing Logic When the light diesel oil (LDO) is used in a plant, it does not require the recirculation of LDO before purging and temperature interlock is also not taken care of. For heavy fuel oil (HFO) both are necessary to maintain the proper temperature vis-à-vis viscosity. So the recirculation-related logics are applicable to HFO only. However, in some plant designs, the recirculation of LDO is also provided for better mobility and leak test facility.

The fuel oil trip valve (FOTV) and fuel oil recirculation valve (FORV) require manual opening after an MFT condition arises and before the purge cycle is initiated for full-fledged boiler operation. This arrangement fulfills the condition of recirculating the hot oil near the burner area to raise the oil's temperature as needed for firing.

www.EngineeringBooksPDF.com

12.1.4.1.4 Fuel Oil Recirculation Logic (for HFO Only) The sequence of oil recirculation is as follows:

1. FORV is opened first after MFT takes place and the boiler is about to restart
2. FOTV opens with all of the following start permissive signals:
   - FORV is fully open
   - All oil burner valves are fully closed
   - MFT signal exists
   - Open push button (PB) is pressed

After some period of recirculation, if the oil temperature and pressure are adequate, the FOTV and FORV must be closed for start of the purge cycle.

Before the purge activities start, leak tests are performed as designed and provided by the manufacturer in some steam generation plants, as discussed in Section 12.1.4.1.2 of this chapter.

- *FORV open logic:* The valve can be opened with the PB on the console if all oil burner valves are closed.
- *FORV close logic*: The valve closes automatically when any oil burner valve is not closed or can be closed by pressing the close PB.

12.1.4.1.5 Fuel Oil Trip Valve Logic The fuel oil trip valve can be reopened provided all of the following are in place:

- Purge complete
- No MFT
- All individual oil burner valves are closed
- Fuel oil header temperature (for HFO only) is higher than normal (~95°C)
- Fuel oil header pressure is higher than normal (15–25 kg/cm^2 depending on plant size)
- Atomizing steam pressure is adequate, which may be more or less than the fuel oil header pressure depending on the burner design
- No close/trip command is issued and the open PB is pressed

The FOTV trips automatically when any oil burner valve is not closed and if any of the following conditions occur:

- MFT signal is raised
- Fuel oil header pressure is very low for more than a specified time
- Fuel oil temperature is very low for more than a specified time
- Atomizing steam pressure is low for more than a specified time
- Electrical power is lost for more than two seconds

Other than in these conditions, the FOTV can be stopped manually by selecting the manual mode of operation and then pressing the stop button.

12.1.4.1.6 Fuel Oil Firing Logic (Elevation or Mill Group) Fuel oil firing can now be initiated elevation-wise or mill group-wise according to the burners and firing systems supplied by the manufacturer. The following interlocks are checked before going ahead with fuel oil firing:

- Fuel oil trip valve is fully open
- Air flow is adequate (typically more than 30% and less than 40%)
- Burner nozzle tilts are horizontal (typically for boilers with tilting burner nozzles; this interlock is not required for other types of boilers); second and third items are applicable for first-elevation starting only
- No MFT
- Command to start oil firing can be manual or automatic with automatic sequence logic (if provided)

The firing system is different for various manufacturers. As two distinct systems are available, it is best to discuss them separately.

B&W boiler firing systems are normally front-fired, opposed-fired, or downshot-fired having individual igniters and oil guns for every coal burner distributed in two or more elevations/layers depending on the capacity of the power plant vis-à-vis SG plant. Two such elevations for an opposed-fired system (may or may not be a downshot burner) are typical for up to a 250 MW plant, whereas four elevations for an opposed-fired system are typical for up to a 650 MW plant.

In CE boilers, the firing system is based on tangentially corner-fired nozzle burners spread over a number of elevations with in-between air supply compartments for fuel air, auxiliary air, and so forth. Oil burners are strategically located in some of the elevations between coal burners so that one oil burner may support two adjacent (top and bottom) coal burners. In this system burners operate in pairs and not on an individual or single-unit basis.

A simple logic flow is described to provide some idea about how it works first for TT boilers with FSSS and then for wall-fired boilers. If permission for oil firing is available with all safety features taken care of, the following steps are taken manually or sequentially:

1. The oil elevation can be started in the "pairs" or "elevation" firing mode. The firing mode selected is automatically determined by the status of the PF feeders. The pairs firing mode is automatically selected when all feeders are off for more than two seconds. The "elevation" firing mode is automatically selected when any feeder is proven or an auto start support ignition signal is given. Diagonally opposite corners—for example, 1 and 3—are placed in service as one pair. Corner 1 is placed in service initially and after some time Corner 3 is automatically placed in service. Then Corners 2 and 4 are placed in service as one

www.EngineeringBooksPDF.com

pair in the same manner as Corners 1 and 3 were placed in service.

2. The following start permissive signals are checked before proceeding:
   - No MFT
   - Auxiliary air dampers in the associated oil elevation are closed
   - Associated oil gun is engaged
   - Associated scavenge valve (meant for purging oil burners using atomizing media after every oil burner valve next to subsequent firing) is closed
   - Fuel oil isolation valve is open
   - Atomizing steam isolation valve is open
3. The following events take place sequentially for a corner-wise oil burner to fire:
   - Associated oil igniter (may be a HEA igniter or any other type that suits) advances to the firing position
   - Steam-atomizing solenoid-operated valve is open
   - Oil gun moves to the firing position
   - HFO solenoid-operated burner valve opens
   - HEA igniter delivers "spark" energy to establish an oil flame in the relevant corner

If, after some time period and with all commands complied with, the flame is established (as sensed by the strategically located associated oil flame scanner), the igniter spark command is stopped and retracted to the normal position. The concerned oil corner is taken as in service. A similar procedure is repeated for starting other oil corners and placing them in service. When a minimum of three out of four corners are operating, the oil elevation is taken to be in service. This signal allows proceeding to the next step: startup of PF firing.

Another simple logic flow is described to provide some idea of how it works for B&W boilers. First, all permissible signals for oil firing must be available with all safety features taken care of; then the following steps are taken manually or sequentially:

1. Firing is started with LDO first to warm up the boiler such that the heavy oil firing operation gets sufficient thermal energy to start with. LDO firing arrangements are not provided for all HFO/coal elevations and normally are provided strategically just to warm up before HFO firing can start. For a particular HFO/coal elevation any HFO burner can be selected manually or sequentially automatically and started. When selected and the start command is available, the steps of a burner firing are carried out. The following start permissible signals are checked before proceeding:
   - No MFT
   - HFO header pressure is normal and the fuel HOTV is open
   - Associated scavenge valve (meant for purging the oil burner using atomizing media after every oil burner valve closure next to subsequent firing)
   - FORV is open
   - Atomizing steam pressure is normal and the isolation valve is open
   - Instrument air pressure is normal
2. The following events take place sequentially for each oil burner firing:
   - Oil gun moves to the firing position
   - Steam atomizing solenoid operated valve is open
   - Associated oil igniter (which may be a HEA igniter or any other type that suits), advances to the firing position
   - HFO solenoid-operated burner valve opens simultaneously
   - HEA igniter delivers "spark" energy to establish an oil flame in that burner for a specific period of time
   - Oil igniter retracts from the firing position to the base position outside the furnace

If, after some time and with all commands are complied with, the flame is established (as sensed by the associated oil flame scanner that is provided for each oil burner). The oil burner is taken as in service or running. A similar procedure is repeated for starting other oil burners and placing them in service. When the minimum requisite burners out of all burners in that elevation are in service, the oil elevation as a whole is taken as in service. This signal enables the next step to take place: startup of PF firing.

The LDO firing procedure is similar. The recirculation valve may or may not be applicable, and the atomizing and scavenging media may be air. The igniter may or may not be the same one depending on the situation.

12.1.4.1.7 Pulverized Fuel-Firing Logic

Pulverizer Start Procedure. The pulverizers and feeders can now be in auto operation mode, and then they can be considered for startup after other permissive conditions are satisfied. Before the pulverizers and feeders, the PA fans are started. In fact, they can be started any time after successful furnace purging. Any start permissive condition signifying availability of sufficient ignition energy is required to start PF firing, which is different for individual pulverizers and feeder sets. In general, the following are the required conditions:

- Adjacent fuel oil elevation (upper or lower) is in service (for corner-fired burners of CE boilers); in addition, if the opposite elevation is in service, there is sufficient ignition energy for B&W boilers.
- Alternatively, the adjacent PF elevation (upper or lower or opposite) is proven, with the associated feeder speed running at greater than (for example) 50% and the boiler load is greater than around 30%.

www.EngineeringBooksPDF.com

Any pulverizer can be started after receiving all of the start permissive signals, as follows:

- Sufficient ignition energy for PF firing is available
- Air flow is adequate for (e.g., >30% and <40%). This signal is considered redundant after any feeder is proven to be on for more than 50 seconds
- Burner nozzle tilts are horizontal; signal is not required after any feeder is proven to be on for >50 seconds and is applicable to corner-fired boilers only
- No MFT
- PA pressure is adequate (Once the pulverizer is on, this signal is no longer required.)
- All pulverizer discharge valves are open
- Pulverizer outlet temperature is ~95°C
- Cold air gate is open
- Valve for the tramp iron hopper (meant for taking out mill rejections) is open
- Feeder inlet gate is open
- Pulverizer lube oil pressure is adequate for more than five minutes
- LO sump level is adequate
- LO temperature is more than sufficient (~30°C); once the pulverizer is on; this signal is no longer required
- No mill trip
- Pulverizer seal air header to mill under bowl DP is adequate (~200 mm wcl)
- Hot air gate is closed
- All other permissive signals related to the particular type of pulverizer are engaged

When the pulverizer is on, the following interlocked actions take place:

- The open command to the hot air gate is issued if the DP between the mill and the seal air to the mill is adequate.
- The signal to open the cold air damper to 100% is removed from the auto control system.

The pulverizer's temperature control now receives a signal to release the air and temperature control to auto mode. The pulverizer can now be considered in service and the next step can proceed manually or automatically by mode selection.

After receiving the start command, the pulverizer seal air valve opens first and the seal air header to pulverizer under bowl DP is established. After some time period, when the DP is more than 200 mm wcl (typical value), the pulverizer hot air gate can be opened and the feeder can be started. During this period, the following operations are locked temporarily:

- Pulverizer discharge valve cannot be closed
- Pulverizer seal air valve cannot be closed
- Associated auxiliary air dampers cannot be closed

Pulverizer-Tripping Interlocks. The pulverizer trips if any of the following conditions occur:

- After the time set for establishing the DP across the pulverizer expires, if the DP is not more than adequate (after starting), the pulverizer is tripped
- Pulverizer seal air header to pulverizer under bowl DP is very low (typically around 125 mm wcl) and remains so for more than a specified time
- Pulverizer start command is not on for more than a specified time
- Pulverizer is on and LO pressure is low for more than a specified time
- Ignition energy is lost before it becomes self-sustaining
- Any of the PDVs are not fully open
- Hot PA duct pressure is very low
- Both FD fans trip
- Both PA fans trip
- If both PA fans and both FD fans are running and any PA or FD fan trips, pulverizers start tripping from the top elevations with some time gap between tripping, until half of them are available
- MFT

The pulverizers can be stopped manually by selecting the manual mode of operation and then pressing the stop PB.

Feeder-Starting and Associated Interlocks (Other than Tube Mill). The feeder can be placed in service if the following conditions are encountered:

- Pulverizer ignition energy is available
- Associated pulverizer remains on
- Journal hydraulic pressure is satisfied
- No MFT
- Pulverizer outlet temperature is more than sufficient (~55°C)
- Feeder speed demand is at a minimum
- Hot air gate is open (feeder can be placed in service in manual mode without opening the hot air gate)

The feeder can now be started. If the feeder discharge chute is not plugged, after some time period the feeder start signal is taken as established and the feeder is considered in service if the PF flow signal (i.e., the coal-on-belt signal) is received.

When the feeder-running signal is established, the following actions take place provided that the corresponding pulverizer motor power is within limit and the DP across the pulverizer bowl is not high:

- Withdrawal of the demand signal signifying that the drive feeder speed is at a minimum
- All counting timers are reset, signifying readiness for the next operation

Once the feeder is on, the following events take place after some time period:

www.EngineeringBooksPDF.com

- Total coal flow totalizing circuit takes this feeder into account after some time period
- Feeder speed control is released to auto after some more time has passed.
- Feeder speed rises more than 50%, and then, if a sufficient number of coal flame scanners sense flame in the corresponding elevation, the combined signals in AND logic generate output after a comparatively long time period of ~3 minutes, signifying a signal pulverizer ignition permissive

The pulverizer ignition permissive confirms that the furnace flame has been established and sufficient pulverizer ignition energy is available. At this point, the initial pulverizer start permissive signal to support PF firing is no longer required, because the flame is self-sustaining, and it can be withdrawn. However, it is recommended that a minimum of two pulverizer/feeder sets be established at greater than 50% loading before the ignition support energy is withdrawn.

Normally after the established running of the first pulverizer/feeder set, the adjacent pulverizer/feeder set is brought into service. The pulverizer/feeder set connected to an elevation remote from the running elevation is brought into service only in an emergency situation. Whatever the situation, standard operating practice is to introduce the second set and load both feeders to greater than 50% before the ignition energy is removed.

Feeder-Tripping and Associated Interlocks. The feeder is tripped automatically under any of the following conditions:

- No coal on the belt
- The pulverizer motor power is low
- The discharge plugged
- MFT
- Associated pulverizer is off (may not be applicable for tube mills)
- Absence of ignition energy is removed in a specified time after the feeder is started
- Feeder is in manual mode and the stop PB is pressed

The feeders can be stopped manually by selecting the manual mode of operation and then pressing the stop PB.

Removing feeders from service requires a reverse procedure. The pulverizer ignition energy need to be reinstated when only two feeders are in service and operating at less than 50% loading. The fuel oil firing in the corresponding elevation is continued until the last pulverizer/feeder set is withdrawn.

The manual shutdown of the feeder causes the following sequential action to take place after some predetermined time period:

1. Hot air dampers are closed if the hot air gate is not already closed. This interlock makes possible minimizing the pulverizer fire.
2. Cold air dampers are opened to the 100% position.
3. Pulverizer temperature control's air and temperature control are transferred to manual mode.
4. Hot air gate is closed after some time period.
5. When the hot air gate is closed, the close command to the hot air dampers is removed if the pulverizer outlet temperature remains less than 95°C

12.1.4.1.8 Short Description of Master Fuel Trip Signals The BMS checks the health of the steam generation package as a whole and senses a boiler emergency trip signal or MFT and when it senses any of the following signals:

- Loss of all FD fans
- Loss of all ID fans
- Loss of all BFPs
- Very low deaerator level
- Loss of scanner cooling air
- Insufficient waterwall circulation
- Very high furnace pressure
- Very low furnace pressure
- Loss of all flames
- Loss of all fuels
- Loss of air flow
- Reheater protection operation
- Very high drum level
- Very low drum level
- Failure of power supply to BMS/FSSS cabinets
- Emergency PB is pressed
- High-high MS pressure (typically) for supercritical boilers

MFT Signal Description. The following are short descriptions of the tripping signals that cause emergency shutdown of the steam generation plant vis-à-vis immediate closure of all fuel inputs:

Loss of all FD fans: When both FD fans are running, tripping of one may cause a reduction in boiler load if the prevailing load was more than a single fan could handle. In the event of other fan tripping, the boiler should trip for the obvious reason that there is no air flow in the furnace, resulting in unburnt fuel accumulation.

Loss of all ID fans: When more than one ID fan is running, the tripping of one fan may cause a reduction in boiler load as per the prevailing load and single-fan capacity. In the event fans trip, the boiler should trip for the obvious reason that there is no suction of flue gas and residual air from the furnace, resulting in high pressure that may cause an explosion.

Insufficient waterwall circulation: This type of tripping signal is applicable mainly to a forced circulation water system in a boiler having separate BCWPs. As

www.EngineeringBooksPDF.com

the heat transfer design is not based on natural circulation, any insufficient water circulation through the waterwall for the problem in the BCWP system jeopardizes heat transfer and causes the waterwall itself to burn out because of loss of cooling media.

Furnace pressure very high: MFT takes place when the furnace pressure is very high in order to prevent an explosion in the furnace. The tripping value varies widely and depends mainly on the sheet thickness of the furnace wall and the furnace volume.

Furnace pressure very low: MFT takes place when the furnace pressure is very low in order to prevent implosion in the furnace. This tripping value also varies widely and depends mainly on the sheet thickness of the furnace wall and the furnace volume.

Loss of all flames: There are two types of tripping from loss of all fuel:

- All flame scanners show no flame in the boiler running condition
- Any particular feeder is in service and corresponding elevation flame failure takes place with no chance of oil support in associated or nearby oil burners. This condition is quite dangerous, indicating the presence of fuel without any flame, meaning that there is a chance of accumulation of unburnt fuel in the furnace.

Loss of all fuels: MFT takes place when all PF feeders are off, with FOTV off, or an inadequate number of oil burner valves are in service and, of course, after the MFT is reset after previous tripping and any type of fuel is introduced for firing (e.g., three out of four oil burners on in any elevation)

Loss of airflow: This tripping signal is applicable only during startup and up to a boiler load of 30%. Only this zone of operation experiences MFT if the total air flow is less than 30%. This arrangement ensures that the air-rich combustion condition covers the complete startup period. Once the boiler load increases beyond 30%, this trip signal is inhibited.

Reheater protection operated: This tripping signal is included to protect the reheater when boiler is working but there is no or low flow through the reheater. The conditions may be any of the following:

- Turbine trip/generator circuit breaker opens with the HP/LP bypass in the closed position for more than a specified time
- Load-shedding relay operates (heavy-load throw-off) with the turbine in working condition and with HP/LP bypass remaining in the closed position for more than a specified time
- HP or LP bypass system suddenly trips or closes while during house-load operation—that is, the turbine and the HP/LP BP systems are operating in parallel
- HP or LP bypass system suddenly trips or closes during the startup time—that is, when the turbine is bypassed and the boiler steam flow is channeled through the HP/LP bypass system

Drum level very high: This MFT signal is for boilers having a drum for intermediate storage. When the drum level is very high, there is a possibility of water particles being carried over to the turbine and impinging directly on the turbine blades, which may cause severe damage. The set point for the very high drum level depends on the boiler's steam-generating capacity as well as the capacity of the drum itself.

Drum level very low: This MFT signal is also vital for boilers having a drum for intermediate storage. When the drum level is very low, there is a possibility of water starvation in various portions of the boiler tubes and the drum itself, and may cause severe damage to the boiler's metal parts. The set point for a very low drum level also depends on the boiler's steam-generating capacity as well as the capacity of the drum itself. For OT (no drum) boilers, this water starvation is taken care of by low water flow with firing-started memory.

Power supply failure to BMS/FSSS cabinets: If power supply failure occurs in any of the input sides of the main power to the system cabinet or to the remote drives' end, the MFT operates so as to avoid a disastrous situation of lost controlling power.

Emergency PB operated: There is a provision for manual tripping in case of unforeseen events. Two special PBs are provided with connections in series or logically in AND mode. This arrangement ensures the intentional pressing of both PBs at once to avoid any accidental or incorrect action during normal plant operation.

Loss of BFPs or deaerator level very low: The significance of these signals is loss of feedwater which means the boiler is starving and burn out of tubes may take place.

Loss of scanner cooling air: Due to high temperature near the flame scanners, these fans are provided to cool them and loss of cooling air causes damage to the delicate lenses of the flame sensors and monitoring of flames may become inactive.

12.1.4.2 Sensors Used in BMS/FSSS Functional Configuration

Various sensors have been used in the BMS/FSSS as dictated by the system, such as a variety of process switches, position switches, flame scanners and associated electrical contacts, and manual commands.

Flame sensors are conditioned in a separate standalone cabinet popularly called a *scanner cabinet*. Sensors and scanners are of various types: ultraviolet, infrared, and even

www.EngineeringBooksPDF.com

visible light frequency range. Since flame radiations have a wider visible light range, nowadays visible light scanners are more popular. Analog low signals sent by the sensors are not capable of generating binary contacts or analog signals for display and hence are transmitted to the BMS/FSSS cabinet via the scanner cabinet, where they are processed, conditioned, and converted to generate binary signals. These detectors are capable of automatic/manual checking of the optical path and have self-diagnostic features. They are available in flameproof and NEMA 4× enclosures suitable for boiler applications.

12.1.4.3 Diaphragm/Solenoid-Operated Valves and Actuators of Various Drives

Several drives and actuators are connected to the BMS/FSSS for executing the commands processed by the system. The drives include high-voltage (HV) unidirectional motors for FD fans, ID fans, PA fans, pulverizers, and so forth. Bidirectional drives include motorized valves. Some actuators may be solenoid-operated valves, pneumatic diaphragms or hydraulic piston-operated valves. (Solenoid valves are normally double coiled for maintaining stay-put conditions in case of wire snapping.)

12.1.4.4 Operator's Interface or the Plaque/Keyboard and Control Board Monitor

This particular item is a combination of different facilities through which the operator can reach the remote drives or devices if manual interventions are required. All of the processes may be binary or analog, and actuator statuses are made available to the operator to enable him or her to make prompt and appropriate decisions in a time of need. The following facilities are normally available in the operator's interface:

- Indicators may be analog (e.g., flame scanners) or binary—for example, normal or abnormal process conditions caused by pressure, temperature, or other levels, switches, flame status in on/off form, actuator or bidirectional drives' open or close positions, unidirectional drive running/stopped/tripped conditions, and so forth.
- Command devices may be push buttons, selector switches, control switches, and the like, required for manual operation or intervention as may be needed.
- Separate plaques or consoles are provided for hardware interfaces; CRT monitor–based systems with touchscreens or separate keyboards are also quite common in modern plants.

12.1.5 BMS/FSSS Manual Operation/Automation

BMS/FSSS is provided normally for achieving basic safety interlocking features without intervening with the process control system. Through evolution it also includes the startup and normal operation/graceful shutdown of the SG plant. With the help of this system, the operator, through regular interaction and observation of device status, may issue commands from the remotely located plaque, console, or a special window in the monitor required for startup and normal shutdown of various devices and/or drives individually or in groups. The system is completely user-friendly and guides the operator toward proper actions in a desired sequence. The sequence is not allowed to proceed until each requisite permissive signal is available and the proper mode of operation is selected. Once startup is carried out successfully, the boiler is ready for the loading/unloading process and protected by the BMS/FSSS from any hazardous situation. This type of operation is described as manual and the operator is required to take action at every step.

Automatic mode is more sophisticated and higher level of operation that allows the operator to issue a single command that enables a group of devices/drives (subloop-organized according to process requirements) to start up or shut down in an appropriate sequential manner. Typically for boiler operation, complete automation is not required for load demand and pulverizer characteristics, which are brought into service one by one to suit the load requirement. Thus, the most straightforward way to divide all devices/drives is to make the pulverizer group-wise, which includes igniter, pulverizer, feeder, and so forth, with manual intervention if needed. For example, the sequence of a particular pulverizer subloop operation may be:

1. An ignition permissive signal is arranged
2. If the ignition permissive signal is available, the pulverizer motor starts
3. Hot air gate opens
4. Pulverizer outlet temperature control is released in auto mode
5. Feeder starts
6. Feeder speed control is released in auto mode
7. Windbox damper or air register controls are released in auto mode

12.1.6 Flame-Monitoring System

As indicated earlier, the flame-monitoring system is an entirely separate, standalone system used for monitoring each individual burner's flame condition.

For tangentially corner-fired boilers, once the burners of a particular elevation are operated at more than 30% of their capacity, a "rotating fireball" is produced. The resulting ignition energy in one elevation can support the initial ignition energy required for a fresh introduction of fuel in other elevations. Effectively, the furnace is then considered a single burner and the flame is detected on a statistical basis by multiple sensors. For a particular

www.EngineeringBooksPDF.com

elevation, a single flame detector that fails to indicate flame in its adjacent burner is ignored and not shut off because of a loss of flame condition. As indicated earlier, the statistical basis is counting all four corners' flame or no-flame status and then determining the health of that elevation's firing condition. For example, if three out of four flame detectors sense no flame, only that elevation is considered unsuitable for further firing operation and is taken out of service.

In tangentially corner-fired boilers, the change in firing characteristics from startup to fire ball is gradually achieved by increasing the elevation fuel admission to about 30% loading capacity relying on hands-on experience to provide a sufficient factor of safety.

For other types of firing systems such as front-fired, opposite-fired or downshot-fired boilers, the flame produced at all fuel-firing rates demonstrates individual burner characteristics—the same as demonstrated by tangentially corner-fired boilers at low firing rates up to 30% of individual capacity. This means that the type of flame produced does not have the energy to provide enough ignition permissive to burners at other locations. In such boilers, each PF burner requires separate ignition energy (from nearby oil burners' firing), and the logic should take this into account. BMS in many plants includes interlocks of auxiliaries like ID and FD fans and associated dampers.

12.1.7 Seal Air Fan Control

Redundant seal air fans (SA fans) supply sealing air to pulverizers and their associated dampers and valves. SA fan suction is normally taken from the PA cold air duct, and a differential pressure is available for sealing coal-laden dust from the pulverizers.

Any SA fan can be started automatically if this mode is selected, and any PA fan can be run manually. One SA fan is in standby mode. The relevant discharge damper then receives a command to open. The standby fan starts automatically if the main fan does not start within a few seconds or if the differential pressure is less than about 100 mm. The SA fans are removed from service automatically when both PA fans are off longer than a specified time. When the SA fan is off, its associated discharge damper is closed.

12.1.8 Scanner Air Fan Control

Redundant scanner air fans (ScA fans) are provided to supply cooling air to the scanner. ScA fans suction is normally taken from the FD fan discharge, and a DP is maintained. Any ScA fan can be started manually or automatically (if the differential pressure over the furnace is less than ~150 mm wcl). One ScA fan is on standby mode. The associated discharge damper receives a command to open and the other fan, if off, discharge damper receives a closed signal.

The standby fan starts automatically if the main fan does not start within a few seconds or if the DP over the furnace is less than about 150 mm wcl. When both FD fans are off, the ScA emergency damper opens and the cooling air is supplied through atmospheric air. When at least one FD fan is on, the scanner air emergency dampers are closed. Either ScA fan can be removed from service manually if the scanner duct-to-furnace differential pressure is greater than 150 mm wcl. If the loss of unit-critical power is for more than two seconds, both ScA fans are started and both outlet dampers are opened simultaneously. If the scanner duct to furnace DP remains at less than 150 mm wcl for more than 10 seconds, it is taken as "loss of scanner cooling air" for boiler tripping.

12.2 Secondary Air Damper Control

12.2.1 General

To accomplish efficient burning of any type of fuel, air supply is vital. The total air flow must take care of the stoichiometric ratio of the fuel being burnt, optimum excess air vis-à-vis oxygen percentage, and so forth. It is normally provided to the furnace in the form of primary and secondary air flow. The low-NO_x design requires a separate section of total air flow, which may be termed overfire air. There are specific reasons for the segregation of total air flow. For example, primary air not only contributes to initial combustion air but also transports pulverized fuel.

Secondary air flow provides additional air or oxygen to ensure complete combustion of any unburnt hydrocarbon. The purpose of OFA, as was discussed in Section 10.3 of this chapter, is to purposely delay the final part of the combustion process to minimize thermal NO_x levels. By design, the secondary air dampers are normally adjusted so that at the full open position an optimum swirl position is created that maintains the long flame and reduces the flame temperature.

For wall-fired boilers, secondary air (fuel air and tertiary air) combined enter the individual burner; fuel and tertiary air is proportioned in the burner and needs to be equal in all burners; however, it may change slightly according to plant conditions. This control strategy is shown earlier in Figure VIII/3.2.

12.2.2 Secondary Air Damper Control Objective

Secondary air has two parts: fuel air and tertiary or auxiliary air. Fuel air allows the higher hydrocarbon, or char, to burn; tertiary/auxiliary air delays the combustion process by design to reduce NO_x level. The control strategies for each type of boiler are specified according to the manufacturers.

www.EngineeringBooksPDF.com

12.2.3 Discussion

The basic purpose of this system is to distribute secondary air according to the firing of various burners to ensure complete fuel firing without producing much pollution

12.2.3.1 SADC for Wall-Fired Boilers (with Flue Gas Recirculation System)

For wall-fired boilers, secondary air (fuel air and tertiary air) combined enter the individual burner and of fuel air and tertiary air is proportioned in the burner. The basic idea is to keep that ratio equal in all burners, although it may vary slightly to suit plant conditions.

The control strategy is shown earlier in Figure VIII/3.2. Secondary air flow control by secondary air dampers was described in Section 3.3.2.2 of this chapter for a boiler with a flue gas recirculation system. As there is only primary and secondary air in the total air flow, the share for each is 30 to 35% for primary air and 65 to 70% for secondary air.

For each burner, individual secondary air flow is measured in each burner. This measured flow is used in the automatic control loop and is used to adjust the equal secondary air flow for all burners.

12.2.3.2 SADC for Tangentially Corner-Fired Boilers

Secondary air flow control by the secondary air dampers for tangentially corner-fired boilers is somewhat different. This system is applicable for combustion in tangentially fired furnaces and the auxiliary air portion of the secondary air flow is obtained by the separate auxiliary air dampers mainly for regulating the velocity and distribution of the air flow at the intermediate stage of combustion.

For this type of system, the individual secondary air flow is not measured as in other furnace types. Here the fuel air flow (provided for each coal nozzle), being a part of the total secondary air flow, is controlled by the load demand of the boiler through the individual demand for air flow from each pulverizer loading through feeder speed. As a fireball is just a swirling mass of huge flame produced by the burning of pulverized fuel (PF) and sufficient air flow to support it, the fuel air dampers act as final control elements and are placed in every fuel injection compartment to supply the initial combustion air. The fuel nozzles discharge angle determines the size and rotational velocity of the fireball; into this swirling mass of flame, enough fuel air, a portion of the total secondary air, is injected as required for stoichiometric conditions to enable continuation of the combustion process with delayed mixing.

The remainder of the secondary air (i.e., auxiliary air) is directed with enough velocity to form a layer between the fireball and the inside walls of the furnace. This layer acts as a cushion over the fireball while rotating in the same direction; it functions to resist the impingement of slag on the tubes that line the walls of the furnace, which makes soot blowing easier. While doing this, SADC control utilizes the windbox-to-furnace DP as the measured/process variable which is maintained at a constant value at the initial stage and after that at a variable set point up to a certain boiler load and ultimately a higher fixed value. This control is achieved by employing the final control elements in the form of auxiliary air dampers placed below and over each fuel injection compartment with an aim of providing equal air flow through each compartment, the DP between the WB to the furnace is maintained at desired preset values by regulating the auxiliary air dampers in all double-lettered elevations. In those with oil nozzles the dampers are kept at a fixed opening only when oil firing is taking place in that elevation(s).

12.2.3.3 Summary of Secondary Air Control System

The SADC system in a tangentially fired boiler with overfire damper can be summarized as follows:

- All secondary air is fed through windboxes.
- Windbox-to-furnace DP is maintained by separate set of secondary air dampers called *auxiliary air dampers.*
- A part of the secondary air, the fuel air, is controlled as per the requirement that the fuel flow (i.e., the fuel air flow) be proportional to the fuel flow in a particular fuel injection compartment. The result is total fuel air flow that is proportional to total fuel flow.

12.2.4 Control Loop Description

The control loops for the SADC system for boilers with flue gas recirculation systems was described in Section 3.3.2.2 of this chapter and so is not included here. The control loop for tangentially corner-fired boilers is discussed here.

12.2.4.1 Measurement of Parameters

Windbox-to-furnace DP is measured through suitable transmitters with sufficient redundancy and voting before actually use in the control loops.

12.2.4.2 Control Loop Strategy

The control strategy for the SADC system is based on a simple single-element control concept—Figure VIII/12.2-1(a). The selected windbox-to-furnace DP signal becomes the measured/process variable. The set point is normally a fixed value during the initial operation up to 30% of boiler load.

It begins to vary as the load increases through a function generator. Because the load is more than a preset value, the set value becomes the fixed initial value. The tracking

www.EngineeringBooksPDF.com

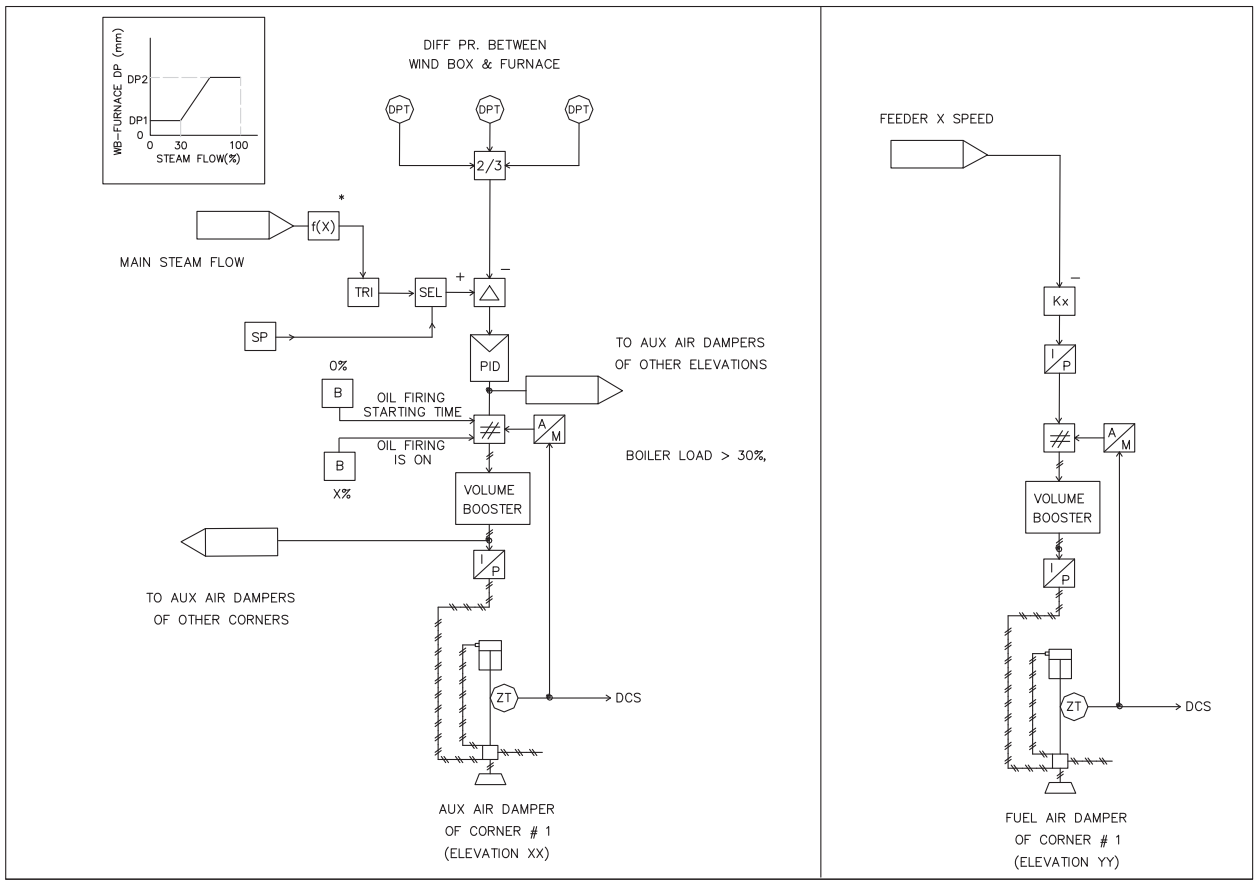


FIG.NO. VIII/12.2–1a FIG.NO. VIII/12.2–1b

NOTE:

- AT BOILER LOAD > 30%, AUX AIR DAMPER ELEVATION NOT HAVING OIL NOZZLES WOULD CLOSE FROM TOP WHEN ADJACENT PULVERIZERS ARE OFF AND ANY OTHER FEEDER IS ON
- AT BOILER LOAD > 30%, AUX AIR DAMPER ELEVATION HAVING OIL NOZZLES WOULD CLOSE FROM TOP WHEN ADJACENT PULVERIZERS ARE OFF AND OIL BACK UP TRIP OCCURRED
- AFTER MFT, ALL AUX AIR & FUEL AIR ERS WOULD BE IN MANUAL AND OPEN TO 100%
- FUEL AIR DAMPERS OF A PARTICULAR ELEVATION WOULD MODULATE AS PER CORRESPONDING FEEDER SPEED / FUEL FLOW AFTER THE FEEDER IS PROVEN 'ON'

FIGURE VIII/12.2-1 Secondary air damper control for TT boiler.

integrator limits the rate of set point change. However, the set point can be changed manually through selection. The controller output regulates all auxiliary air dampers adjacent to the coal elevation in tandem at load >30%. At load less than 30%, all of these dampers modulate to the same signal.

Some auxiliary air damper elevations incorporate oil nozzles and these dampers close during oil firing startup and at fixed opening when oil firing is proven on. Auxiliary air dampers not serving any adjacent coal/oil nozzles must be closed at boiler load >30%.

As shown in Figure VIII/12/2.1(b), fuel air dampers are modulated in proportion to the feeder speed/coal flow in the corresponding elevation.

12.3 Soot-Blowing System

12.3.1 General

In steam-generating plants wherein an ash-bearing fossil fuel such as coal, lignite, fuel oil, bagasse/refuse, or any other type of oil/by-product is burned, there is always the problem of soot formation during the combustion process, with the soot carried by the hot combustion products to the various heating elements in the furnace as well as in the air heaters. Deposition affects heat-transferring surfaces, such as waterwalls, superheaters, reheaters, and economizer steam pipes, covering both radiant and convection zones in the furnace chamber, as well as the air heaters (cold-end deposition).

www.EngineeringBooksPDF.com

Fly ash carried along with flue gas combines with moisture and other harmful by-products when it falls below the condensation temperature. Natural gas is a comparatively much better fuel so far as soot deposition is concerned because it is almost clean fuel with negligible ash content. Oil has a low ash content that is water washable. The actual problem of soot deposition lies with the PF-fired boilers. The ash content and coal quality vary widely from country to country and even in various regions of a particular country; hence, the form of soot varies accordingly.

When the soot is deposited on surfaces, it acts as an insulating medium and encumbers proper heat transfer from flue gas to water, steam or air as the case may be. The soot may be dry and powdery or hard slag depending on many factors such as the temperature, percentage of ash contents, percentage of sodium, and so forth. The most difficult type of soot deposit is caused by PF with a high ash content, a high percentage of sodium in the ash, and a low ash fusion temperature that means the possibility of more ash being stuck to the fluid tube outer surfaces and, in turn, high deposition.

The practical behavior of soot is like thermal insulation between the fluid inside the tubes of the furnace; the hot products of combustion thereby reduce the heat transfer—the more soot on the furnace walls, the less effective the heat gained by the operating fluid, resulting in a steady decrement in fluid temperature. In other words, the heat transfer from the hot flue gas to the fluid is very high and the temperature of the combustion products leaving the furnace is relatively low when the furnace is in a very clean condition as is normally the case in the initial stages of installation. However, in time, the heat-exchanging surfaces in the furnace become coated with layers of soot, the heat transfer from the hot flue gas to the fluid inside the tubes is significantly reduced, and, as a consequence, the temperature of the fluid decreases while the hot flue gas leaving the furnace significantly increases.

This phenomenon over a period of operation causes a significant change in the overall heat balance calculation and can threaten serious problems for the operator in balancing steam generation. The high flue gas outlet temperature has many associated problems as already discussed, such as low overall efficiency, high NO_x generation, more and so forth. There may be other problems, such as severe plugging of some sections, and adequate flue gas flow may not be available or erosion may result because of high local gas velocity.

12.3.2 Removal of Soot Deposits

Periodic removal of soot deposits is a very important for the efficiency of the unit. Because of the insulating nature of soot, overheating of the boiler tubes is natural as the temperature control loop tries to raise the temperature of the steam by allowing more energy input in order to maintain the final parameter.

To avoid this situation, a soot-blowing system selectively cleans soot deposits from all areas of such deposits. Therefore, it has become imperative for steam-generating plants to install a number of soot blowers at various locations in the furnace walls over the height of the combustion chamber, superheater, reheater, economizer, and so forth, to intermittently but regularly clean the furnace and heat-exchanging walls in the steam and water tube surfaces carrying various types of fluid. Each soot blower, whether selected manually or automatically, carries the spray assembly in an advance-and-retract mechanism to clean a region of the tube walls around it by blowing a steam jet at very high velocity.

The blowing medium for soot blowers may be anything such as steam, water, or compressed air. It is blown through the spray nozzle head passed through an opening in the furnace wall into the furnace chamber under pressure to hit directly against the surface area affected by the soot deposit. This type of advance and retract action is intermittent and used when necessary. Because of high-velocity impingement and thermal shock caused by the comparatively low-temperature medium, the blowing medium causes blowing away of loose deposits and high-impact loading on hard and slag-type deposits. This action causes the deposits to fall from the tube surfaces with relatively clean tube surfaces again being exposed for heat exchange to a higher rate.

12.3.3 Method of Removal of Soot Deposits

The location of soot deposition on the various surfaces is not uniform. Even the deposition on furnace walls is not uniform over the height or width of the furnace walls. Depending on the flue gas flow rate/velocity and travel path, some portions of the furnace experience more deposition while others may experience less. Prediction of such high deposition zones is very complicated for a particular time period of operation because the exact soot deposition profile may vary on the type of fuel and type of firing system in addition to what has already been described.

12.3.3.1 Fixed Programmed Time-Based Operation

It has become normal practice to adopt the open loop control strategy for the soot-blowing system through sequential operation of the blowers in a well-defined time frame. A few details were given in Section 12.0.3.1 of this chapter.

12.3.3.2 Temperature-Based Operation

The control strategy for soot blowing is based on certain assumptions and may not be entirely flawless. It may cause additional wear and tear and wastage of soot-blowing

www.EngineeringBooksPDF.com

medium, whereas tubes needing soot blowing may not get it in time.

Therefore, a system strategy has evolved that enables the timing of selected soot blower(s) as per the decision of the system logic. (See Section 12.0.3.1 of this chapter.) Thermocouples (a natural choice for high-temperature applications) welded to the tubes sense the actual surface temperature in the vicinity of each soot blower. The temperature set point is calculated from the saturation temperature of the water flowing through the water tubes as representative of a soot-laden furnace. The online waterwall tube temperatures, if less than a calculated set value, start the associated soot blower(s). All of the soot blowers thus respond to the need-based command to clean the soot-affected areas without disturbing the cleaner portions.

For obvious reasons, this method is not effective for pipes having steam or a steam-water mixture, neither of which has any bearing on saturation temperature. At the same time, it is evident that the local fluid saturation temperature for the water line varies with elevation. It is therefore not easy to determine an actual saturation temperature for obtaining the calculated preset temperature as an index of soot deposition in the furnace. For supercritical boilers, where a mixture of water and steam passes through the tubes above the supercritical pressure of water, there is no way of calculating the metal temperature, which can be taken as an index of furnace dirtiness. As already mentioned, the metal temperature varies significantly over the height of the waterwall depending on the local heat distribution and on the water-steam phase state of the mixture flowing through the tubes at that location—also next to impossible to determine.

Another method employs measurement of differential temperature of metal tubes and hot flue gas to initiate soot blowing at a higher differential temperature

12.3.3.3 Heat Transfer/Heat Flux-Based Operation

Another method of determining a soot-blowing strategy utilizes a more direct sensing system for selectively cleaning the furnace tube walls. The local heat transfer rate is measured by a heat flux meter (Figure VIII/12.3-1) to assess the soot deposition, instead of inferential measurement by the local wall temperature. In this scheme, the sensing elements are located in each region of the tube walls surrounding the soot blowers to detect the local heat transfer rate from the hot flue gas to the steam/water tubes in the furnace or heat-exchanging elements (flue gas side) of the air heaters.

The heat flux meter output signifying the local heat transfer rate is then compared with a manipulated signal that represents a corresponding lower heat transfer rate set point. The comparator generates an output whenever the sensed local heat transfer rate is less than the lower allowable set point. This lower manual set value of is obviously selected to represent the worst heat transfer rate expected for a tube wall covered with the maximum acceptable soot deposition. The comparator output provides an alarm/indication at the operator's console about this polluted tube/element condition for manual intervention; as an alternative action, the comparator output is used by the logic-processing unit for automatic activation of the corresponding soot blower.

Another comparator may be provided for comparing the heat flux meter output to a manipulated signal that represents a corresponding upper heat transfer rate set point for

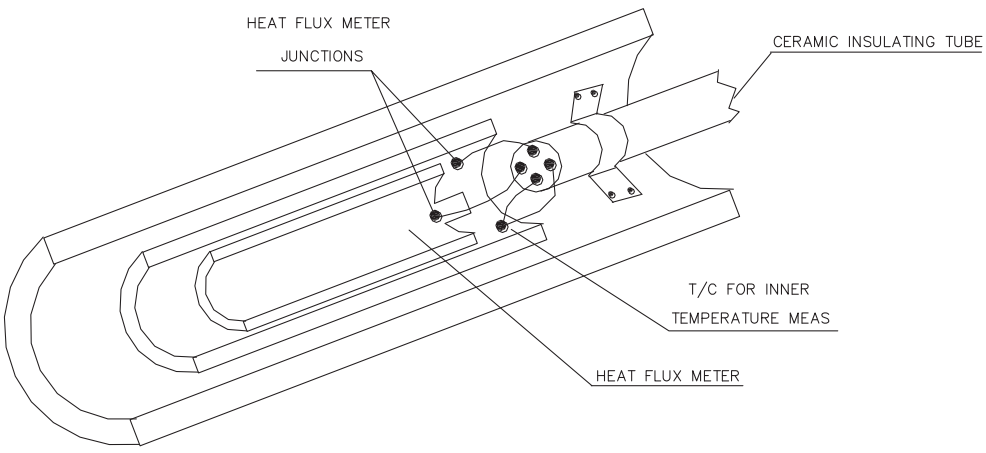


FIGURE VIII/12.3-1 Schematic diagram of heat flux meter.

www.EngineeringBooksPDF.com

generating an output whenever the heat flux meter output is greater than the upper manual set value. The upper set value now represents tube walls clean enough for a good heat transfer. When this comparator output is available, the alarm signal is withdrawn and a healthy signal may take its place. The corresponding soot blower may be retracted manually or automatically by the logic function.

Nowadays PC-based systems compute heat flux to optimize soot blowing. As stated earlier, excess soot blowing causes steam wastage, higher boiler maintenance, aggravated tube corrosion, less boiler efficiency, and higher stack opacity which may not be permissible. A dynamic model is available for ideal heat transfer and cleanliness. The heat transfer rate, based on a real-time parameter (temperature at various stages) is compared with the ideal value (model-based) to calculate the cleanliness factor. The other influencing factors are fuel type, fuel flow, windbox furnace DP, air parameters (e.g., flow, temperature, pressure), and so forth. The model works interactively with these factors to actually calculate the deviations. Then soot blowing is optimized in one of two modes:

- Steam-saving mode to avoid excessive soot blowing, assuming that there is a limit to soot-blowing frequency beyond which there is little improvement.
- Opacity mode, when uniform blowing is initiated in all sections to reduce opacity. This is achieved using artificial intelligence and neural networking.

12.3.3.3.1 Heat Flux Meter: Principle of Operation As mentioned, detectors of the local heat transfer rate are basically a heat flux meter mounted directly on the outer side (the combustion chamber side) of the tube walls (Figure VIII/12.3-1). The transducer is attached to the heat transfer surface by a clamp, ceramic cement, or any suitable bonding material. The transducer consists of a thermoelectrically metal body (not that of the main fluid tubes) that connects with the tube metal. Electrical connections are taken from the outer and inner face of the metal body to the processing unit situated outside in a room or ambient temperature environment. The heat flux meter creates a small temperature difference (because of thermal resistance of the metal body), which in turn generates an induced voltage or electromotive force (emf) across the transducer metal body whenever heat flows to or from the surface on which the transducer is placed.

The thermoelectric transducer generates a signal in microvolts, but the measuring unit is self-powered without any external excitation voltage. The thermal resistance introduced intentionally by the transducer produces the temperature difference vis-à-vis the potential difference across itself may be considered negligible for all practical purposes.

The DC microvolt signal generated by the transducer is then properly treated and conditioned so that the analog output (4−20 mA) and contact outputs are available for further application. The final output is proportional to the heat flux.

12.3.3.4 Types of Soot Blowers

12.3.3.4.1 Soot Blowers for Furnace Walls Generally, retractable blowers with short and single nozzles, called *wall blowers*, are used to remove the soot deposition from the combustion chamber area. During forward movement, the blower is inserted inside the furnace wall approximately 50 mm. The blower tip consists of a single nozzle with a high-energy jet capable of spraying the blowing medium at supersonic speed. After the forward movement is completed, the blowing starts with a time lag. It is also accompanied by rotation of the tip by 360 degrees to clean the deposition up to a radius of 1500 mm. Very difficult types of soot deposition in the form of slag require denser spacing with the effective cleaning radius becoming approximately 1000 mm. The frequency of operation depends on the rate of soot buildup.

12.3.3.4.2 Soot Blowers for Radiation/Convection Area The radiation and convection areas of the furnace have heat-exchanging sections, such as superheaters, reheaters, economizers, and so forth, which are quite distant from the furnace wall. Natural selection dictates long retractable blowers inside the gaps of the tubes for a better approach, and they are considered the most effective way to clear out the soot .

Generally available blowers of this type have a pair of nozzles located diametrically opposite each other. While in action, the blower moves in a forward direction accompanied by rotating motion. These simultaneous motions cause the blowing medium in the high-speed high-energy jet to form a spray that travels in a helical pattern to clean both tube surfaces and the spaces between adjacent tube assemblies. Some manufacturers recommend that the nozzles be at a slight angle in opposite directions from each other (with respect to the perpendicular axis) to make them more effective. However, the overall effective cleaning radius may vary 1200 to 3000 mm (approximately) for various reasons such as the flue gas temperature in a particular area selected for cleaning, the fuel ash characteristics, and the blowing media.

The forward and reverse motion of long retractable blowers may travel up to the middle of the furnace width, thus covering the total furnace width with the help of the opposite end blowers. The supporting arrangement of long blowers must take care of boiler expansion, which requires that the front portion be supported by the wall whereas the rear portion is supported by the boiler platform structure.

www.EngineeringBooksPDF.com

12.3.3.5 Soot-Blowing Media

In theory, three media are available for soot blowing. Water is normally not thought of as in the recommended list mainly because of the thermal shock it may inflict on the main fluid tubes, causing fatigue and in turn a shortened tube life. However, its use cannot be ruled out because it has some special uses in cases of deposition of a tenacious soot that forms slag. The other blowing media are high-pressure steam and air, which are equally effective. The selection normally depends on availability and reliability and, of course, cost.

Although the use of air as a blowing medium is considered as efficient, it requires installation of separate high-capacity compressors and associated pipe works. Another disadvantage is the loss of blowing medium if the compressor(s) fail, requiring redundant compressors that increase the cost. However, the most serious disadvantage of compressed air is its moisture content.

Steam as the medium requires installation of pressure-reducing valve(s) and pipe works because steam is not available before steam generation starts. The pressure-reducing station makes available at the valve outlet a dry quality of superheated steam as the pressure goes down while the steam temperature remains as before. The most significant advantage of steam blowing is that its kinetic energy out of the nozzle jet is almost 200% that of compressed air, which makes it a more effective medium for soot blowing.

12.3.3.6 Soot Blower Location and Operation

As already mentioned, the type of soot deposition depends on the percentage of fuel ash, the percentage of sodium in it, ash fusion temperature, etc. The location and type of blowers must also be decided on the basis of the severity of the problem. Normally the density of deposition is higher in the front and rear waterwalls of the furnace above the firing zone. A set or two are also provided below the firing zone. For the convection zone, sets of blowers are provided near and/or between the banks of platen SHs, reheaters, final SHs and before the banks of primary SH and the economizer.

The sequence and frequency of operation are normally suggested by the boiler manufacturer based on the binary sequence control system software. However, the initial operating strategy follows the loaded sequence; it may vary to suit plant conditions. Frequency is normally one complete cycle in each working shift, which may also depend on ash contents, deposition density in various zones, etc. A deposition study is conducted to determine whether some sets (grouped or single) of blowers require more frequent operation than others. PC-based software packages are available to optimize frequency of operation.

12.3.3.7 Soot Blowers for Air Heaters

Scale or fine-grain deposits are seen at the cold end of the air heaters when the flue gas temperature falls below the condensation temperature. At this point, the fly ash, moisture, and SO_x combine to form these deposits on the heating surface of the cold end that resist the heat transfer as an insulator.

By operating soot blowers of the correct type, the unwanted soot deposition can be cleared from the heating surface provided the deposits are not subjected to further moisture. There are many types of moisture ingress in the downside part of the flue gas path. They may be from economizer or the steam/water tube leakage, water-washing shutoff valve leakage, or the unprotected FD fan inlets from which rainwater may enter the system. Above all these causes, the main and most frequent source of moisture is leakage from the steam soot blower system. A suitable quality of steam can eliminate this problem.

AH soot blowers are generally installed at the cold end, where the depositions are observed. The gas-outlet side is the natural choice for avoiding entrance and mixing of fly ash, which is driven away into windboxes. Windboxes are installed either in the gas outlet duct work or as an integral part of the air heater.

12.3.3.7.1 Soot Blower Types for Air Heaters Soot blowers come in a variety of categories, generally as follows:

- Retractable-type, used for air heaters having large diameters of about 10 m or more.
- Stationary and multinozzle types, used for small package-type air heaters
- Types with nozzles mounted on a swinging arm, used for air heaters

12.3.3.7.2 Retractable Soot Blowers for Air Heaters As already indicated, retractable soot blowers are suitable for large-diameter air heaters. They are the same as used for the radiation and convection areas of the furnace (Section 12.3.3.2.2 of this chapter).

12.3.3.7.3 Swinging Soot Blowers for Air Heaters Swinging soot blowers are large and equipped with an electric power-driven source with a single- or double-nozzle arrangement. The nozzle assembly moves slowly over the face of the heat transfer surface. The nozzle arm simultaneously swings in an arc across the face of the heat transfer surface. The blowing cycle takes one pass across the heating face either from the periphery of the rotor to the central rotor post or in the reverse direction.

www.EngineeringBooksPDF.com

12.3.3.8 Air Heater Soot Blower Media

There are two widely accepted media available for air heaters soot blowing. One of the blowing media is obviously high pressure dry SH steam and the other one is high pressure ($\sim$12 kg/cm^2) or compressed air. Just like furnace portion soot blowing, both the media are equally applicable for the cleaning operation. The selection normally depends upon the availability and reliability along with of course the cost factor as discussed briefly in Section 12.3.3.3 of this chapter.

For air heater service, saturated steam itself, instead of its moisture content, is applied sporadically instead of the moisture contents in that quality of steam; but as per experience, dry SH steam is found to be the most effective medium of AH soot blowing than both compressed air and saturated steam. The temperature and pressure value of steam must be maintained around 70°C superheat and 15 kg/cm^2 for an efficient end result.

12.3.3.9 Washing Medium for Air Heater Deposits

Water as blowing medium is not at all recommended for AH soot blowing mainly because of the thermal shock. However, its use as a washing medium plays an important role in case the soot-blowing operation fails to remove tenacious soot. A water-washing cycle for the heating surface yields satisfactory result to prevent draft losses across the air heaters. The equipment normally used for this application is a standard one having stationary, multiple nozzles, medium-velocity jets for various types of air heaters. Water washing may be done during plant shutdown, with isolated air heater portion or full plant running.

12.3.3.10 Pressure and Temperature Controls of Soot-Blowing Media

It is extremely important that the blowing media must be supplied at the blowing nozzles with adequate pressure and temperature. Steam is the most effective medium for soot blowing and maintaining its pressure and temperature at constant values is very important so far as the dry SH steam supply is concerned.

The control loops details are discussed separately in Section 10.2 of this chapter.

BIBLIOGRAPHY

[1] Houtz AD. Cascade, feed forward and boiler level control. In: Controlguru: Practical process control e-textbook, Chapter 18 (Internet document). Kenai, AK: Automation Systems Group; 2006.

[2] Keller G, Baker B, Jones RJ. Innovative boiler master design improves system response. Power 2007;151(2). ??-??

[3] Leopold T. Boiler-Tuning Basics, Part II May 1, 2009.

[4] Foster Wheeler Energy Corp. "Pulverizereperation and Control," Doc. No 5076T.

[5] CCI Severe Service Applications in Fossil Power Plants. http://www.ccivalve.com/~/media/Files/C/CCI/pdf/959-TP-Severe-Service-Power-Applications-Handbook-low-res.pdf

[6] Siemens Energy & Automation. Procidia™ Control Solutions Boiler Control Overview. AD353−132, Rev 1 March 2006.

[7] Sulzar Valves a Product of CCI Turbine Turbine: Bypass Systems for Greater Plant Performances, product catalog.

[8] Croft A. Turbine Bypass Valves and their Application. Technical bulletin, WEIR Valves & Controls 2005.

[9] Vulcan Copes. Turbine Bypass Systems (SPX Flow Control). product catalog April 2008.

[10] Weir Power & Industrial product catalog for "Blakeborough Desuperheating Equipment & Systems," http://www.weirpowerindustrial.com/pdf/Blakeborough%20Desuperheaters.pdf

[11] Chaplin, R.A. *Thermal Power Plants, Vol.II, Fossil F*uel Fired Boiler Air and Gas Path. By Chaplin, R. A. http://www.eolss.net/Sample-Chapters/C08/E3-10-02-05.pdf

[12] Kashlwamkl M, Toshlkl M, Hisao H. U.S Patent no 4738226 April 19, 1988.

[13] CCI, USA. "CCI Severe Service Applications in Fossil Power Plants." http://www.ccivalve.com/~/media/Files/C/CCI/pdf/959-TP-Severe-Service-Power-Applications-Handbook-low-res.pdf

[14] Qingsheng L. Coal Pulverizer Design Upgrades to Meet the Demands of Low NO_x. Baltimore: Technical paper presented at: Electric Power; 2004, March 30-April 1.

[15] Gilman J. Special Section Flow/Level, Boiler Control Systems Engineering. 2nd Edition 2010.

[16] Leopold T. Boiler-Tuning Basics, Part I March 1, 2009.

[17] Kunkler, J.W. "Control of De-Superheating Process," Fisher Products Severe Service Group © 2006 Valve Manufacturers Association. Reprinted with permission. http://www.documentation.emersonprocess.com/groups/public/documents/articles_articlesreprints/ag365652.pdf

[18] Kashiwazaki, M. "Steam boiler with gas mixing apparatus," Patent no. US 4738226. Dtd. 19.04.1988

[19] Srivastava RK. Controlling SO_2 emissions: A review of technologies. EPA/600/R-00/093. National Risk Management Research Laboratory; November 2000.

[20] "Performance model of the fluidized bed copper oxide process for SO_2/NO_x control," Paper No. 93−79.01. Proceedings of the 86th Annual Meeting June 13-18, Denver, CO Air and Waste Management Association Pittsburgh, Pennsylvania June 1993. By H. Christopher Frey

[21] Institute of Clean Air Companies (USA). Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources December 4, 2006.

[22] Golder Associates. Control technology review. December 16, 2006 (Section 4 of 063-7567).

[23] Department of Energy (DOE). SNO_x™ Flue Gas Cleaning Demonstration Project June 2000. DOE/NETL-2000/1125.

[24] Zevenhoven, Kilpinen. Chapter 3, Sulphur. June 1, 2004.

[25] Operational Manual (500 MW Training Simulator) Volume II. Central Simulator Training Institute. NTPC Ltd - Korba (India) Dtd July 2006

www.EngineeringBooksPDF.com

[26] "Wind Box Arrangement" By BHEL, Power-Gen India, 2012 (BHEL's Role in Cleaner Environment)

[27] DCS integration for intelligent soot-blowing XCEL Energy, DCS Integration for Intelligent Sootblowing By Seth Whitworth, Sandeep Shah, P.E., and Huiying Zhuang.Published May 2006 Published By Clyde Bergemann, Inc.

[28] Boiler Soot-Blowing in Power Plants, By Hank Van Ormer Air Power USA. http://www.airbestpractices.com/sites/default/files/2009/CABP_February_09_single_LR.pdf

[29] Wynnyckyj JR, Rhodes E. U.S. Patent no 4607961 August 26, 1986.

[30] International Thermal Instrument Company "Heat Flux Measurements," product catalog. http://www.thermalinstrumentcompany.com/products/heatfluxtransducers/ht-50thermalfluxmeter

[31] Neural Network Intelligent-Sootblower Optimization Project, 05/12/2008 By the National Energy Technology Laboratory http://www.power-eng.com/articles/2008/05/neural-network-intelligent-sootblower-optimization-project.html

[32] Putting Combustion Optimization to Work. In: Spring Sr N, editor. Power Engineering; May 2009.

[33] Becker, B., Tonn, D. N., Speer, S. K. "B&W NO_x Reduction System and Equipment at Moss Landing Power station," Bill Becker,Don Tonn,Babcock & Wilcox Nancy Stephenson, Cormetech, Inc. Kenneth Speer, Jr. Duke Energy North America, Moss Landing, California, U.S.Presented to: (BR-1700) ICAC NOx Forum March 23-24, 2000 Washington D.C., U.S.A. B&W http://www.babcock.com/library/Documents/br-1700.pdf

[34] Cahill, J. "Reduction of NO_x through Combustion Optimization," Emerson Process Experts. http://www.emersonprocessxperts.com/2009/08/reducing_nox_th/#.VClyHmeSyt0

[35] "Ultra-low NO_x Integrated System for Coal Fired power plants," ALSTOM Power. By Galen H. Richards, Charles Q. Maney, and John L. Marion Power Plant Laboratories and Robert Lewis and Chris Smith,Performance Projects Businesses ALSTOM Power, Inc. http://seca.doe.gov/technologies/coalpower/ewr/nox/pubs/40754/ALSTOM-NOx-IJPGC-Apr11.pdf

[36] Seltzer, A. H., Fann, Z. "An optimized Supercritical Oxygen fired pulverized coal power plant for CO_2 Capture," By Andrew H Seltzer,Timothy Fout http://academic.research.microsoft.com/Paper/5449275.aspx Foster Wheeler

[37] Srivastav RK, Hall RE, Khan S, Culligan K, Lani BW. Nitrogen oxides emission control options for coal fired electric utility boilers. Journal of the Air and Waste Management Association 2005;55. Sept.

[38] Kokkinos A, Wasyluk D, Babcock Brower M, Wilcox Barna JJ. Reducing NO_x Emissions in Tangentially Fired Boiler: A new Approach. ASME International joint Power generation conference July 2000.

[39] India Power-Gen. Windbox arrangement: BHEL Role in Cleaner Environment. 2012.

[40] Tongmo Xu, S. L., Hui, S., Tan, H., Zhou, Q., Hu, H. "Comparison of NO_x emission Reduction with Exclusive SOFA and Combination of SOFA and CCOFA on Tangential-Fired boilers," Sen Li, Tongmo Xu, Houzing Tan,Qulan Zhou, Hongli Hu School of energy and power engineering PR China, Internet Document International Conference on Power Engineering-2007,October 23-27,2007 Hangzhou China.

www.EngineeringBooksPDF.com

Chapter IX

Turbo Generator Control System

1. INTRODUCTION

Modern thermal power plants are equipped with state-of-the-art technology instrumentation systems. Continuous advancement of science and technologies, especially in the field of electronics, with microprocessor-based hardware and befitting software has made great strides in the development of instrumentation systems, including both measurement and control. Turbo generator control systems are no exception in this regard. In the initial stage, the turbine is mainly controlled by a hydraulic system. As technological advancements were made, measurement systems became fully electronic and controlled by a mixture of electronic and hydraulic systems. Today the complete instrumentation package is supplied with an electronic system with hydraulic controls as a back-up.

Unlike the boiler package, normally the turbine package is equipped with modern hardware, software, and control strategies for their equipment and systems. Modern day turbine control systems include close loop control systems (CLCS) and open loop control systems (OLCS) including automatic turbine testing systems (ATT) and the automatic turbine run up system (ATRS).

The turbine control system, which includes both CLCS and OLCS, comprises five main subsystems or functional groups categorized according to their functional requirement, and takes care of the entire operation of the turbine and generator side. Those subsystems include the following:

1. Turbine high-pressure (HP) control fluid subsystem for the low-pressure bypass (LPBP) system
2. Turbine HP control fluid subsystem for main valves (Above two systems may be combined also)
3. Turbine control oil subsystem
4. Condenser evacuation and gland seal subsystem
5. Turbine control subsystem (warm up, start-up, loading, unloading, and shut down)

In some plants, the generator exciter subsystem is also included for better coordination.

The subsystem controls have their own group control and various other subgroups, each containing similar or redundant drives. There are sufficient displays at every step and an intelligent alarm annunciation system to enable immediate action for detection as well as rectification of disturbing element(s). During the occurrence of fault conditions, if contributed by a part of the control system hardware/software, the subsystem control takes over so that the remaining part of the main plant can continue uninterrupted operation.

1.1 Subsystems or Functional Subgroups

As indicated above, the subgroups are functionally divided to achieve better control over the entire turbine system. The main items particular subgroups control are discussed in the following clauses.

1.1.1 Turbine HP Control Fluid Subsystem

Whether combined or separate, subsystems have different standby liquid control systems (SLCs) and drives for LPBP and main valve systems to serve their assigned purposes, which are to supply HP power/control oil. This is done by using control oil pumps, recirculation pumps, cooling fans, pumps for regeneration circuits, etc.

1.1.2 Turbine Oil Subsystem

This subsystem takes care of the oil systems required for initial running of the turbine and shut-down procedure and includes SLCs and drives of auxiliary and emergency lube oil pumps, jacking oil pumps, turning gear gate valves, etc.

1.1.3 Condenser Evacuation and Gland Seal Subsystem

This subsystem includes SLCs for condensate extraction pumps and turbine drains as well (although it is a part of the turbine control subgroup) and drives for vacuum pumps, air extraction valves, instrument/service air solenoid valves, vacuum breaker solenoid valves, etc.

1.1.4 Turbine Control Subsystem (Start-Up, Loading, Unloading, and Shut Down)

The heart of the turbo generator control system is the turbine control subsystem (start-up, loading, unloading, and shut down) comprised of SLCs for drains, warm-up controller for generating the criteria for operation of drain

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

valves, soaking of turbine metals, and holding/speeding of the turbine rotor. Also included are the start-up device (TSL), speed and load set point devices of the turbine governing system, and the auto-synchronizer.

1.2 Testing Process by ATT

In addition to the above subsystems, there are standalone ATTs that enable online testing of all important drives or devices required for safe operation and emergency tripping of the turbo generator. In other words, all the protective equipment required for turbo generator safety is tested automatically with uninterrupted normal operation without jeopardizing the individual protection assignment bestowed on each device while running the test procedure.

The main function of the ATT system is to offer a fail-safe operation of the protective drives or devices by checking and analyzing their readiness throughout the turbine operation regime. The system ensures that the abovementioned duty is done by performing the tests cyclically in the automatic mode of operation and manually at the operator's discretion. The essence of this particular standalone facility is to test all the protective devices sequentially in a well-organized and systematic manner for verification of foolproof functioning of all the devices. The system is built to eliminate operator error, resulting from manual intervention, using the fully automatic test sequence. Individual tests for a particular device can be done by proper selection.

The standalone system for ATT includes the following items:

1. Turbine generator (TG) set over speed trip (mechanical)
2. Thrust-bearing trip (mechanical)
   Remote trip devices:
3. Hydraulic and electrical low vacuum trip
4. Opening and closing operation of control valves.
5. Opening and closing operation of emergency stop valves (ESVs).

Testing can be done for all of the listed items at any time, providing a protection device is substituted only after testing its good health.

Testing can also be done manually at the operator's discretion or cyclically through an automatic program. For testing the turbine over speed trip, high-pressure oil is introduced via a shaft hole producing a simulated condition of over speed and actuation of trip bolts at TG normal speed, causing the hydraulic circuit oil to drain. The resultant fall in pressure is detected by the tester and sends an alarm indicating successful testing operation. The oil pressure, although low, will not be allowed to close the main steam control valves (MSCVs) and ESVs as they will be supplied with high-pressure oil via the test valve. Detailed discussions are included in Clause 5.

2. ELECTRO HYDRAULIC GOVERNOR CONTROL SYSTEM

2.0 General Introduction

The turbine control subsystem or functional group as mentioned earlier is a very important part of automation of the TG set, which comprises the electro hydraulic governor (EHG) control system. This takes care of start-up, shut down, loading, and unloading of the TG set. With the advancement of technology, this control system has been transformed into an electro hydraulic system from a purely hydraulic system. However, the hydraulic governing system is not totally obsolete; it is used as a back-up as shown in Figures IX/2-1 and IX2-4.

The advantage of an electro hydraulic system is that it uses electronic hardware and software for the measurements, processing, or signal conditioning and implementation of critical and complicated control strategies, which could not have been possible by the pure hydraulic system. The added plus points of an electronic system are the tremendous speed of dynamic response, flexibility for further modification at any stage, and interchanges of signals with other subsystems or functional groups without additional hardware. The advantage of the hydraulic system is undoubtedly the fast and vast actuating force required by the increasing size of the final control elements. The EHG control system as a whole provides a very smooth, reliable, and speedy functioning as required by the modern, large-capacity thermal power plants.

The EHG operates hand in hand with the ATRS and turbine stress evaluator (TSE), details of which are described in Clause 6. The TSE guides the EHG control system to generate the speed and megawatt power set point within the safe operating margin, and ultimately the position demand of the turbine governor valves—the hydraulically operated final control elements, through which speed or power can be maintained as the situation demands. The TSE collects various temperature measurements related to turbine parts and valves to calculate the safe margin for speed and generator load considering allowable turbine metals stresses.

2.1 Task of the EHG

With the continuous development of TG control strategies, the following tasks are accomplished by the EHG:

1. Admission of steam and starting of turbine, raising speed gradually up to synchronizing speed, and then maintaining the rated frequency of the generated power load in accordance with the droop (load vs frequency) characteristics and associated provision for the proper adjustment of the same unit running on load

www.EngineeringBooksPDF.com

2. Addressing the problem of low transient frequency or speed excursion as well as permanent deviation taking place throughout the period of TG operation
3. Generator load control under the guidance of TSE
4. Pressure control when the boiler is not healthy but the turbine is (initial pressure control in turbine follow mode)
5. Graceful switchover from load control to frequency control in case of isolated grid condition
6. Smooth and reliable control in case of sudden disconnection of TG set from the grid

2.2 Duty Assigned to the Electronic Part of EHG

As discussed previously, the duty assigned to the electronic part of the EHG is twofold:

1. Collection of measurement data, processing or conditioning of raw data, arranging of those data for transportation to other subsystems or functional groups as and when required, and sending them as output to the front desk indication/recording/data acquisition system
2. Using the processed or conditioned data in various automatic control loops pertaining to EHG, which are TG set speed controller, generator power/load controller, steam pressure controller, and the valve position controller

2.3 EHG Control Philosophy

As stated above, there are three basic control loops: speed control, power/load control, and pressure control. Another control is the valve position control, which actually receives the selected output out of the three controllers as its input (see Figure IX/2-1).

There are various modes of operation for governing control systems and these vary by manufacturer. Modes from one of the reputed manufacturers of EHG control systems are elaborated in the Table IX/2.3-1.

2.3.1 Speed Control Loop

Figure IX/2-2 is a ready reference for the speed control loop. The speed set point may be manually adjusted or may be an automatic signal generated elsewhere by some suitable method (e.g., "synchronizer"). It is passed through a

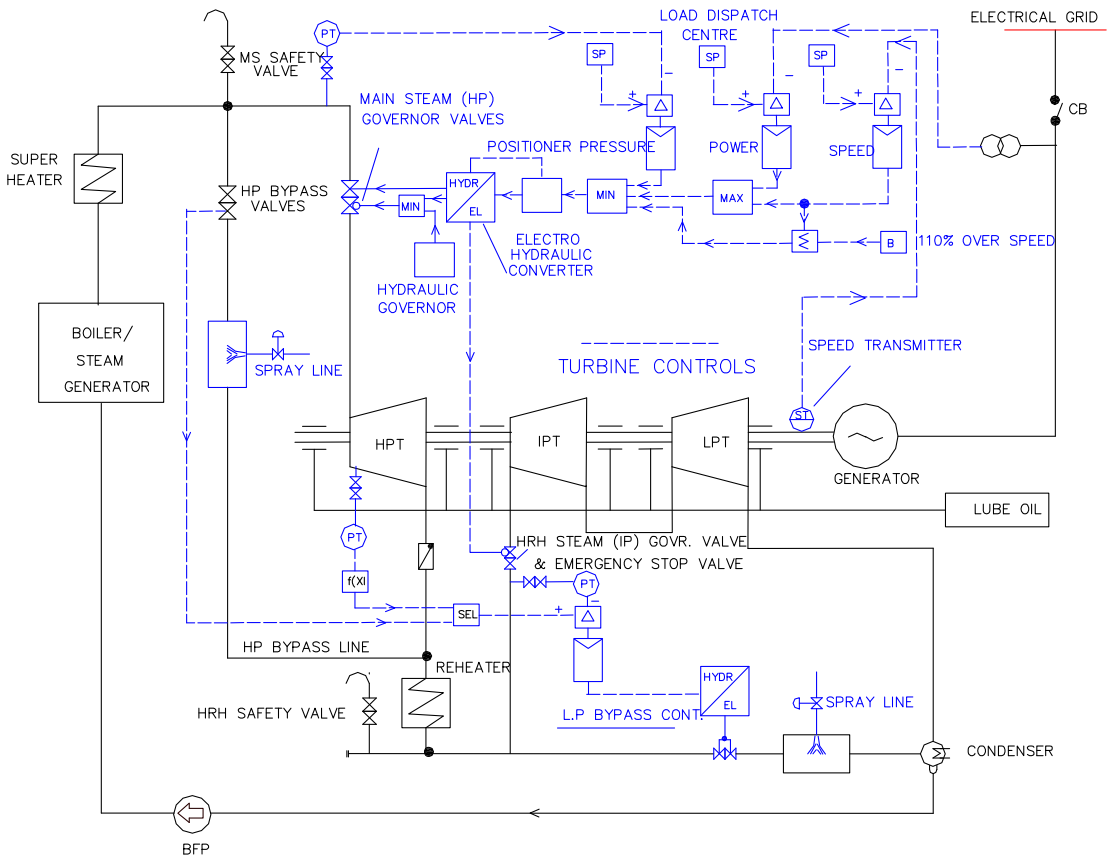


FIGURE IX/2-1 Simplified flow diagram of steam cycle with turbine controls.

www.EngineeringBooksPDF.com

TABLE IX/2.3-1 Operational Modes of EHG

SL	Operational Mode	Details
1	Start-up mode	EHG operates by switching ON the supply and setting speed/load set point to zero, with hydraulic governor control in the upper end (as hydraulic controller and EHG are selected via MIN selector switch). After turbine is put in barring gear the actual speed is sensed, and the speed controller is in service until synchronization.
2	Load control	After synchronization it is under load control either from load control center or various other means. The frequency change is selected by integral action of the load controller as per frequency droop* characteristic. Speed controller is in standby mode for load shedding.
3	Load shedding	It is the sudden separation of the generator from the grid. At this point the output of the load controller is immediately brought below that of speed controller. Because of the max selector as shown in Figure IX/2-1, the speed controller takes over the control and brings the speed to the reference set point. (See HP and LP bypass control also.)
4	Shut down	At normal shut down, the load controller is set to zero so that the speed controller can assume control and bring the system to safe condition.

**Frequency droop characteristic: the mismatch in power causes speed to change to bring the mismatch to zero, but there will changes in speed. The change in frequency due to the change in power is decided by regulation or droop. If 4% change in frequency/speed causes 100% change in power, then the droop characteristic is 4%, i.e., 0.04 per unit power. At 100% load frequency is 100%. If there is a drop in 50% power, then there will be increase in 2% frequency. Normally 4–5% is the standard droop value (see Figure IX/2-2). There is another parameter called dead band (governor control), which is very important in governing the system. There is a minimum value of speed that cannot be picked by the sensing mechanism, so it may remain uncorrected. This minimum value is called the governor insensitivity or dead band. The governing system action depends on speed sensing. With change of time for the same turbine due to wear and tear, this value may change. Normally dead band is expected to be 0.06% of the rated speed.*

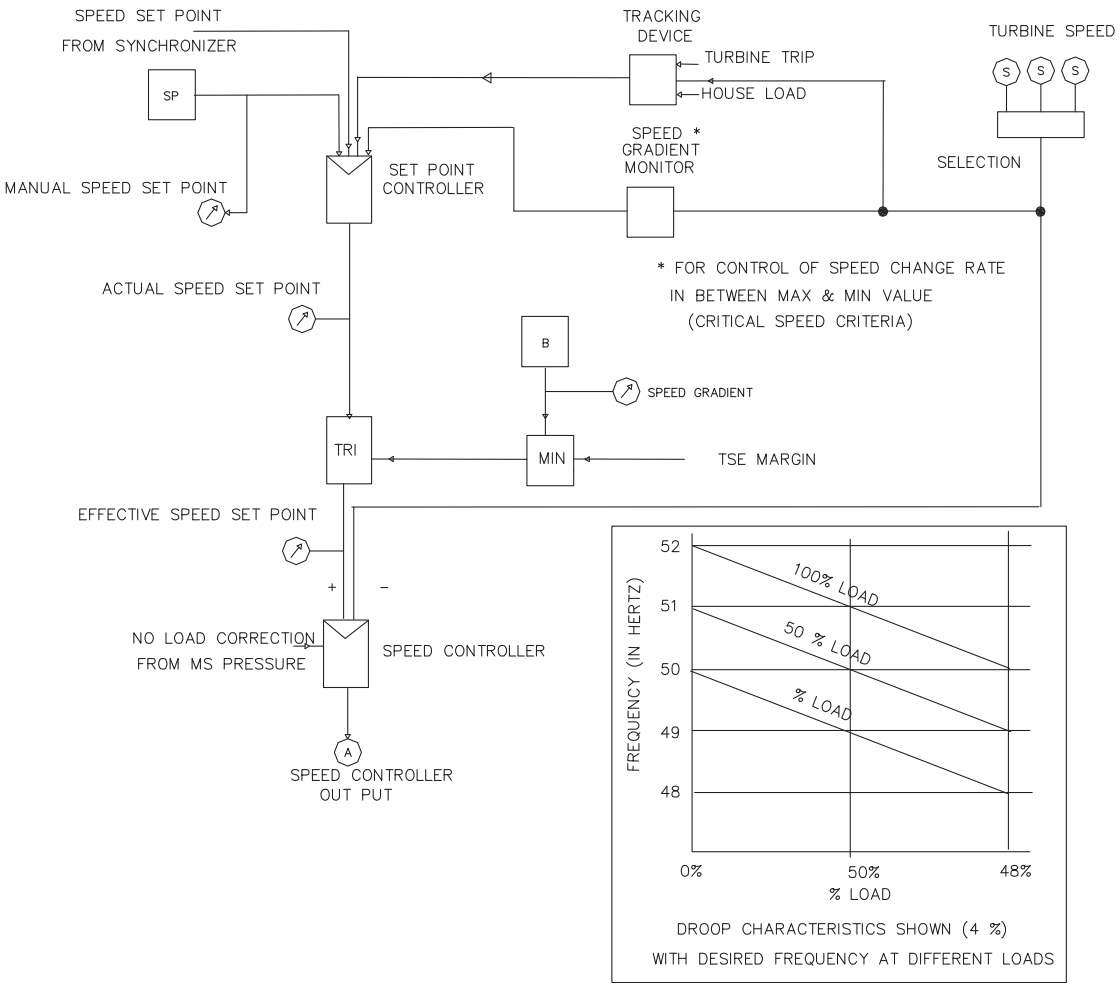


FIGURE IX/2-2 Turbine speed controller block diagram.

www.EngineeringBooksPDF.com

tracking integrator whose output rises with a gradient and is finally equal to the input. The speed gradient is manually set and passes through a minimum selector whose other input is from the TSE margin, which is actually modified at every instant depending on the condition of the turbine metal temperature.

This time-dependent speed set value at the time of start-up is therefore the optimum speed by which the turbine can speed up. The automatic speed setter takes the TG set from barring speed to first-hold speed (~20% rated speed) for the soaking process for a specified time and temperature margin. Then the speed setter raises the speed close to rated speed, and when the metal temperatures permit and generator voltage is matched through the automatic voltage regulator (AVR) with the grid voltage, the TG set is synchronized. The time-dependent, set value generator, however, also takes care of the time when the TG set passes through critical speed (~2800 rpm). At speeds more than 2850 rpm, if the "difference between speed reference value and time-dependent set value exceeds a specified limit" and any of conditions take place—like TSE is not available or during start-up or reference speed is <50 rpm than actual speed during transition period from electro hydraulic controls (EHC) to hydraulic controller—the integrating action for the time-delayed set point would be blocked.

This optimum speed set value is then taken as the input of the speed controller whose measured value is the selected speed transmitter signal of an appropriate voting circuit. The integrator is ON only when the TSE has a healthy signal. If the TSE goes wrong, the integrator is disabled and can be enabled again after switching the TSE OFF. Then the speed set point will change as per the manual setter of the speed ramp value.

A speed gradient monitor is introduced that takes input from the actual speed and calculates the real-time speed gradient and feedback to the set point generator. This does not allow the output to be less than the minimum set speed gradient. The speed gradient of the speed set point value passes between maximum and minimum speed gradient to avoid the critical speed criteria.

A tracking device also is introduced for follow-up action that takes input from the actual speed. When the turbine trips, the speed set point follows the actual speed (minus ~60 rpm) and when the load controller is in action, it follows the actual speed plus 10% load proportionate value (within a band of 60−120 rpm). During follow-up action, the reference set point cannot be raised if rate of change of speed is less than a preset limiting value. The speed controller action is P + D, that is, the output responds immediately with a derivative action after an error is sensed and then comes back to a value proportional to the error at a predetermined slope. At a steady-state condition, the speed controller output signal will always be proportional to the error value (that is, the difference between the set value and the measured variable). This arrangement is made because it is the best-suited one for the load sharing of various TG sets connected in a common grid. During the initial running of the TG set, the starting time constant of the TG set as a whole is the most important factor to consider. If the TG set control is taken over by the power/load controller, the speed controller will still be operating in parallel as a standby and will activate when required.

The speed controller, with the help of other inputs, is used to take command of the TG set at the following times:

1. Start-up of the TG set
2. Synchronizing the generator with the grid
3. Operation of TG set at a minimum load if required, for example, house load, huge load shedding, etc.
4. Operation of TG set throughout the 0−100% range of load if required and dictated by extraordinary situations
5. Taking charge of the valve lift control during over speeding when the value exceeds the limit
6. Graceful shut down of the TG set

For synchronizing the generator, the separate and standalone synchronizer provides the appropriate command to the speed controller input so that the TG set can attain the synchronizing speed at the proper time and with proper speed as required by the machine (generator).

The TG set may be needed to operate at the minimum load delivered by the generator. This may happen during large load shedding, house load operation, or low load running, which is also called the idling mode of operation. Particularly in the case of load shedding, the speed of the TG set will tend to rise immediately above the synchronizing speed, but the speed controller will automatically take over the control and corrected output will bring back the TG set speed very close to the synchronizing speed. The speed controller temporarily takes over control of the TG set whenever rapid and/or large change in speed is experienced.

2.3.2 Turbine Load Control Loop

Figure IX/2-3 shows how the turbine load is controlled manually. The load or generator power set point may be manually adjusted or may be an automatic signal-generated from the Load Dispatch Centre (LDC) or from Coordinated Control System (CCS). The selected signal is passed through a high/low selector so that the demand does not go beyond the operating capability of a particular individual TG set. The LDC/CCS signal can be turned ON or OFF by the operator. IF the LDC signal is unhealthy, this component would automatically be switched OFF. In that event the manual load set point would take over the control of the TG set. While the LDC/CCS signal is in command, manual load set point would act in standby mode continuously matching with the LDC/CCS signal through a tracking

www.EngineeringBooksPDF.com

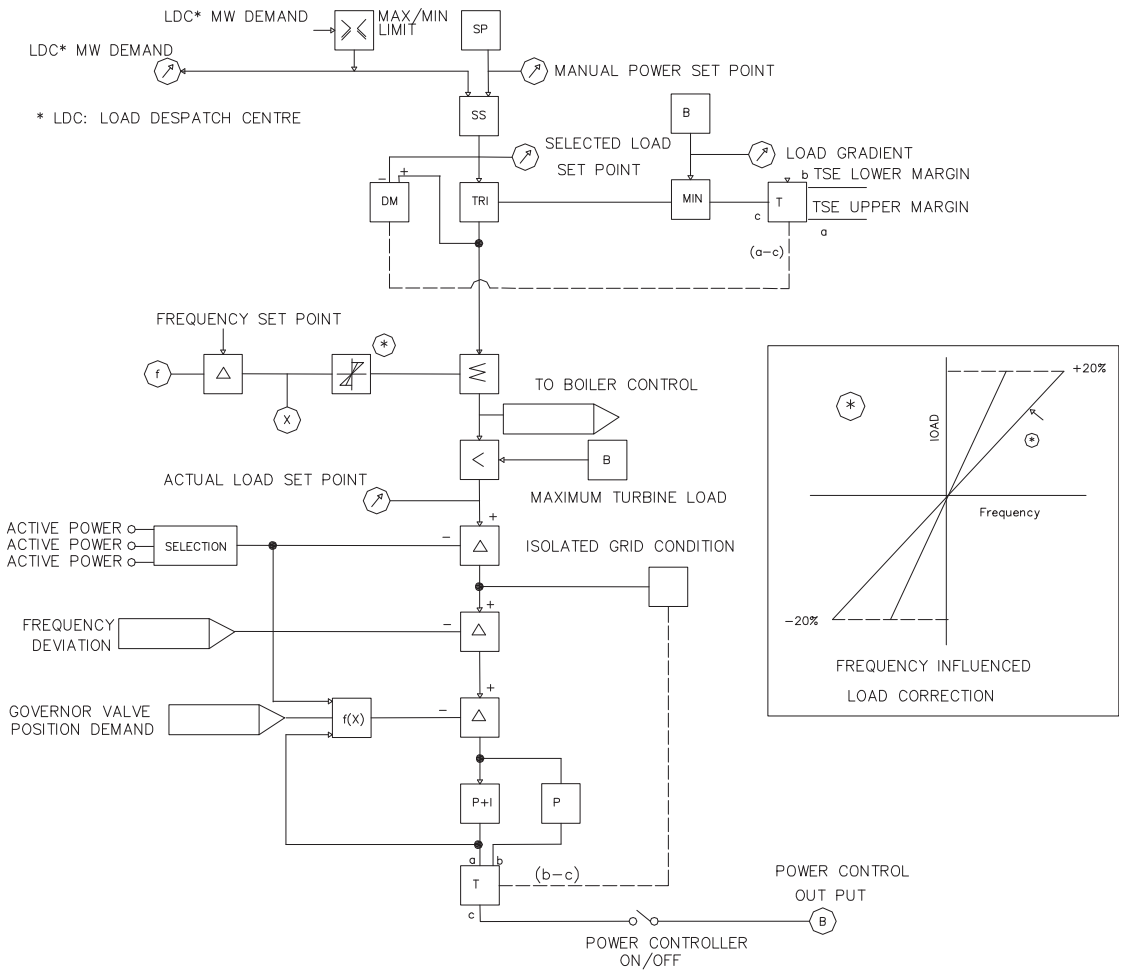


FIGURE IX/2-3 Turbine load controller block diagram.

circuit so that bumpless transfer is achieved. The selected output is then passed through a tracking integrator whose output rises with a gradient to finally equal the input. Just like the speed control loop, the load gradient can be manually set and passes through a minimum selector whose other input is from the TSE margin, which is actually modified at every instant depending on the condition of the turbine metal temperature.

Another component is added to this time-dependent integrated signal, which is actually a proportional fraction of the selected load set point. The total sum thus obtained is the P + I response, which behaves like a proportional output when the change is small and P + I when the change is significantly high. The proportional component of this load set value may be adjustable when the range is between 5 and 25%. It may be switched OFF when it is required to make the time-dependent load set value a purely ramp one. Here the integrator is only ON when the TSE has a healthy signal. If something goes wrong with the TSE, the integrator will be disabled and can be enabled again after switching the TSE OFF. If that happens, the load set point changes as per the manual setter of the load ramp value. The integrator would also be OFF when the load reference signal has been raised and the pressure controller goes/switches to limit pressure mode.

The final integrated set point signal continuously tracks the actual power/load until the main generator circuit breaker (GCB) is OFF, that is, before synchronization at the time the speed controller is in command and ensures bumpless and smooth transfer from speed controller to load controller during start-up after the GCB is ON.

With this time-dependent load set value another signal is now added which represents the frequency-related (droop-characterized) influence, which is actually a correction required on the load set value as per the frequency versus generator load/power delivered curve typical for each and individual generator. The total summation now is the optimum power/load demand, which takes care of the grid stability and the same signal is sent to the boiler control loop.

www.EngineeringBooksPDF.com

The frequency influence proportional component is typically adjusted between 2 and 8% in steps of 0−0.5%.The frequency influence component is liable to be automatically disconnected if any fault condition arises or it can be switched OFF through manual intervention. However, with introduction of free governor mode of operation, all units in a grid run under governor control without attaching any load restrictions, etc., to maintain grid frequency within a narrow band and droop characteristics are restricted within 3−5%. In the approved grid code (in some countries) it is mandatory for each generator to have the capability of 105% maximum continuous rating (MCR) capacity generation whenever the situation demands.

This power/load demand is allowed to be the set value for the controller if it's value is less than the maximum permissible load. In other words, the above set point cannot be more than the manual TG set capability.

To avoid any problems in operation during maximum permissible load setting during TG operation with the load controller in action, a rate adjuster of maximum load limiter settings is provided for conservative operation of the TG set without stressing the turbine thermally and mechanically. The maximum load limiter setting is sometimes made motor operated to take care of emergency shut down of the turbine.

The load/power controller gets its measured value from the selected active power transmitter signal of an appropriate voting circuit. The potential transformers (PTs) of the generator output voltage and current transformers of the generator output current are connected to the power transmitter measuring circuit.

The power/load controller action is P + I, that is, the output responds immediately with a proportional action for small changes integral for large changes and then comes back to a final value at a predetermined slope. At a steady-state condition, the load/power controller output signal will always be the value to maintain the zero error between the set value and the measured variable value allowing exact maintenance of the required power/load. The starting time constant of the TG set as a whole is the most important factor to consider during the initial running period of the TG set for proper speed controller tuning, whereas the transfer function of the generator and power grid is the most important criterion for proper load controller tuning. In case the TG set control is taken over by the power/load controller, the speed controller still operates in parallel as on standby through suitable tracking circuits and activates when required. A gradient monitoring device/software is provided that blocks the power/load controller output in case the real-time gradient exceeds the preset maximum load gradient. This is done to arrest the tendency of the controller failure in the direction of 100% load.

When the GCB is not ON or the GCB is ON and load shedding has taken place, the speed controller takes the charge and load controller output and tracks to speed signal in follow-up mode. If there is an isolated power grid condition when load control is in action, the controller will automatically switch over to a P action output only with ∼5% droop characteristics. The selected load controller output then constitutes an input signal rather than a set point of the valve lift controller through a series of selection procedures.

2.3.3 Turbine Pressure Control Loop

In this control loop configuration, both the measured variable and the set values are supplied by the boiler manufacturer. The controller output is set for P + I action and operates the main steam valve lift controller via the same series of selection criteria (see Figure IX/2-4).

The turbine inlet steam pressure control loop is mainly operated with any one of the three operational modes selected from the control desk by the operator, which include the following:

1. Initial pressure control
2. Limit pressure control
3. Sliding or variable pressure control

2.3.3.1 Initial Pressure Control

In this mode of control, the controller action is P + I and the actual main steam pressure at turbine inlet is the measured variable and main steam pressure set point is issued from the CCS (furnished by the boiler manufacturer). Here the power/load delivered by the TG set is dictated by the boiler up to a certain load level. In other words, this is called a "turbine follow" mode, where the turbine is following the boiler running with some limitation beyond which it cannot deliver the load.

2.3.3.2 Limit Pressure Control

This mode of operation is envisaged when a condition arises where there is pressure deviation between the actual main steam pressure at the turbine inlet and the main steam pressure set point exceeds a predetermined value of ∼10 kg/cm^2. With the help of this mode, the power/load controller takes care of the fast and small demands in load utilizing the boiler storage capacity. Here the boiler is healthy to deliver any power/load within its full capacity; this operational mode, though well thought of, is rare as the healthy boiler with an appropriate automatic pressure control system normally is able to maintain the main steam pressure within the desired low excursion.

2.3.3.3 Sliding or Variable Pressure Control

In this operational mode, the actual power/load signal, after necessary voting, is biased in such a way that the power/load controller output is modified to demand maximum

www.EngineeringBooksPDF.com

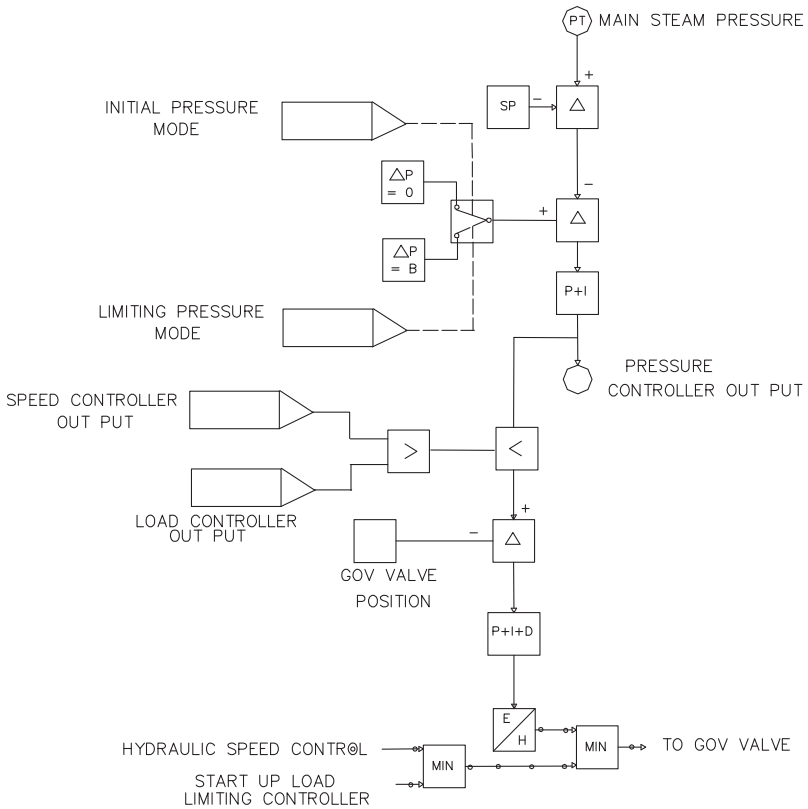


FIGURE IX/2-4 Pressure controller and selection of control valve position demand block diagram.

MSCV opening. When the MSCV is full open, the turbine has no control on the power/load delivered by the TG set; rather the boiler determines the full power/load. Here the throttling losses across the MSCV are reduced to zero thereby improving the overall efficiency, and the turbine control becomes less stringent as temperature variations occur less rapidly.

2.4 Selection of Controller Outputs

The response of the electronic turbine speed controller, turbine load controller, and turbine pressure controller is very fast compared with the hydraulically operated MSCV. An interface called a valve lift controller or position controller has been introduced in between the selection unit of the final control element of these three controllers to provide the necessary thrust required by the actuator of the MSCV.

All three controllers running simultaneously are on standby mode, except the one that is in command after the selection. The controllers on standby mode continuously track their output with the output of the controller in command to provide a bumpless and procedureless transfer during changeover of the controllers.

There is a maximum selector provided between the turbine speed controller and the turbine load controller. After the selection is done, the selected output is taken to a minimum selector along with the pressure controller output. The final selected output of the controllers is then brought to the electro hydraulic converter for further selection with other hydraulic signals.

2.5 Selection of Hydraulic Signals

The output from the electro hydraulic converter is the normal commanding signal, but a purely hydraulic speed controller is provided as a back-up. A separate hydraulic controller as a start-up device is also provided for initiating the opening signal for the main steam stop valve (MSSV). The above hydraulic signals of the hydraulic speed controller and start-up devices pass through a minimum selector and then again the minimum selected signal and the electro hydraulic converter signals are selected to operate the MSCV. The start-up device of the hydraulic controller output is kept high when MSSVs are opened. Hydraulic signals of the hydraulic speed controller output is also kept high so that hydraulic signals of the EHC take the command.

www.EngineeringBooksPDF.com

The electro hydraulic converter and hydraulic amplifier are connected to a set of follow-up piston valves to which trip oil is supplied through the restriction orifice and it flows in the secondary oil piping to control valves. The secondary oil pressure depends on the position of sleeves of the follow-up piston valves, which determines the amount of trip oil drainage.

2.6 Functional Description of Electro Hydraulic Converter

The electro hydraulic converter is not just a signal converter that has an electrical signal input and a hydraulic signal output. It is the interface between the selected controller's output and the MSCV actuator directly with suitable power-handling capacity as desired. See Figure IX/2-5 for the functional description.

The electro hydraulic converter constitutes items such as an electromagnetic plunger coil (item no. 1; getting signal from the selected controllers output), control sleeve (item no. 2; moving up and down as per control signal), pilot valve (item no. 3), spring (item no. 4), power piston (item no. 5), and position transmitter (item no. 12).

Figure IX/2-5 (left side) is applicable for comparatively smaller units up to ~210 MW. The plunger coil current value determines the vertical position of the control sleeve, which in turn dictates the drain cross-sectional area of control oil. The change in drain area determines the control oil pressure acting on the pilot valve, which will move upward or downward allowing power oil to enter one chamber of the power piston while the other chamber of the piston opens the drain passage. The power piston continues to move as long as the pilot valve stops the above action. The balanced condition is restored by the position feedback system (item no. 7), which pushes or pulls the pilot valve along with the spring in the opposite direction so that the pilot valve blocks both the entry and drain passage to the power piston that has already moved to its new position. In the steady-state condition, the force balance is achieved

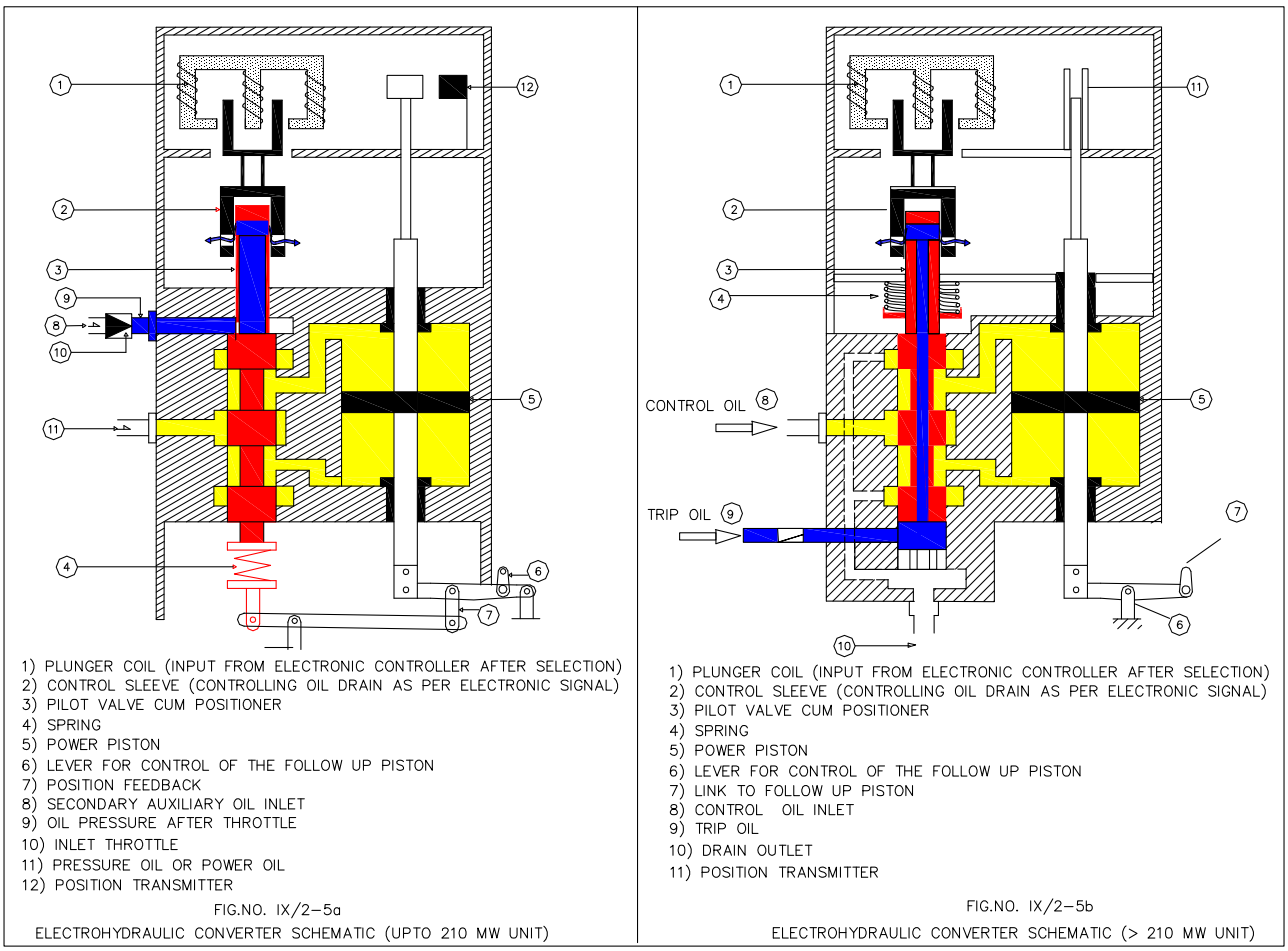


FIGURE IX/2-5 Schematic diagram of electro hydraulic converter.

www.EngineeringBooksPDF.com

through the force acting on the pilot valve (determined by the control oil pressure on the pilot valve multiplied by the actual effective area of the pilot valve) and the force offered by the compression spring.

The control oil pressure is a variable one depending upon two components, of which one is the output of the hydraulic speed controller entering the inlet (item no. 8). The other component is the drain cross-sectional area between the spool of the pilot valve and position of the control sleeve as allowed by the plunger coil energized with the selected electronic controller.

It is therefore evident that the electro hydraulic converter plays such an important role that it provides the interface between the hydraulic and EHC at the inlet stage of the device with a built-in minimum selector. The TG set automatic control has been developed with the idea that the leading control action is accomplished by the EHC and the back-up support is provided by the hydraulic speed controller.

Figure IX/2-5 (right side) is applicable for larger units >210 MW. Here the "trip oil" is used to move the pilot valve spool at the bottom in place of "secondary oil," which represents the hydraulic governor output. Just like the above system, the pilot valve spool is at the central position under steady-state condition. In the deflected position, the control oil is admitted above or below the power piston, the motion of which is transmitted via a lever and cam shaft to sleeves of follow-up pistons to change the secondary oil pressure.

Another significant modification is introduction of the electronic "admission controller" (PID), also referred to as position controller for proper positioning of the pilot valve spool. The EHC output serves as a set point, whereas the actual position of the power piston taken from two differential transformers acts as a measured variable and the controller output operates the plunger coil and regulates the oil drains of the HP/intermediate-pressure check valves (IPCVs). The current to the plunger coil is increased to close the HP/IPCVs. The reference signal thus works in a reverse manner.

Drain port opening of the follow-up piston depends on the pilot spool valve of the EHC output and determines the related secondary oil pressure. The drain port openings of follow-up pistons of hydraulic governors depend on auxiliary secondary oil pressure, upstream auxiliary follow-up pistons (due to action/position of speeder gear), and determine its related secondary oil pressure. The follow-up piston valves constitute a minimum value gate for the output of both governors. This means the governor with the lower reference set point is effectively in control. This is also called hydraulic minimum selection of governors (applicable for bigger systems and that of the electro hydraulic converter).

2.6.1 Starting of Control by EHC

First, the electronic controller output signal is kept low, which is a high current signal (as per design), to go to the electro hydraulic converter plunger coil. This enables the control sleeve to move upward and as per the strength of the signal it will rest at any intermediate position. Further lowering of the electro hydraulic converter at its minimum value means the maximum current to the plunger coil, and by this the control sleeve, achieves the top position and the drain cross-sectional area between control sleeve and the pilot valve becomes maximum. At this position the oil pressure sent by hydraulic speed controller is disturbed due to the wide drainage area. Now this hydraulic speed controller oil pressure is raised to a sufficiently high value so that EHC output, if it starts increasing or decreasing the current value, above the drain area will also decrease and opening of the MSCV will commence. The entire range of EHC output will then control the entire range of opening/closing of the MSCV.

2.6.2 Starting of Control by Hydraulic Controller

To achieve entire control by hydraulic controller, EHC output is kept at maximum value, which means no current to the plunger coil. The control sleeves slip to the lowest position allowing no drain passage, and the oil pressure from the hydraulic controller acting on the pilot valve becomes maximum. With EHC output at maximum value, the hydraulic controller output may be varied to control the entire range of opening/closing of the MSCV. In this mode of operation, with total closing of the control oil drain, the movement of the pilot valve with a power piston is the function of the hydraulic controller output oil pressure.

2.7 Operational Mode of the Electro Hydraulic Converter

2.7.1 Start-Up and Synchronization

As already described in Clause 2.5, the start-up device of hydraulic controller output is kept high when MSSVs are opened, and hydraulic signal of the hydraulic speed controller output is also kept high at that time. Note that the TG set has already started rolling by the turning gear at a lower speed and sensed by the speed sensor. From this point, the speed set point is raised manually by using the electronic speed controller. By increasing the speed of the TG set, as per TSE guidance, and minimum and maximum speed gradient to take care of the critical speed or kink speed criteria of the whole set, the TG set is raised to the rated speed before synchronizing with the external power

www.EngineeringBooksPDF.com

grid. The synchronization is done with the help of a separate synchronizing device dedicated for this purpose only.

2.7.2 On Load and House Load Operation

Just after synchronization of the TG set, the power/load controller takes the command of the TG set by increasing its output manually or automatically from the power grid controller or LDC. After the power/load controller is in total control, the speed controller output signal is made to match with the power/load controller output as a standby controller. This standby mode is continued from full load operation up to house/station load operation. When there is a sudden operation of a load-shedding relay, the loaded TG set is abruptly separated from the power grid. The power/load controller output is reduced to minimum as there is no demand from the grid and the speed controller subsequently takes charge of the TG set to provide house/station load through the minimum selector. During the house/station load operation of the TG set, the speed controller almost maintains the rated speed as it is meant for maintaining the rated speed at house/station load during the start-up of the TG set operation under load up to the beginning of full load operation.

2.7.3 Shut-Down Operation

In this mode of operation, the shut-down procedure of the TG set calls for a power/load controller output set to zero. From the minimum selector, the speed controller is in command and the power/load controller is switched OFF; in other words, it is disconnected from the grid. The speed set value then may be reduced by decreasing the house or station load gradually to zero. Finally, the speed of the TG set is gradually reduced to zero for initiating plant shut down.

3. TURBINE PROTECTION SYSTEM

3.0 General Introduction

There are various conditions that may take place any moment during the operation of a thermal power plant that demand an immediate and emergency shut down or "tripping" of the turbine. A few examples include low-bearing oil pressure causing serious malfunction and wear and tear of the turbine bearings; a very low/inadequate condenser vacuum may cause overheating of turbine blades located near the last row; excessive loss of metal or wearing of the thrust-bearing results in axial movement of the turbine causing misalignment of the rotating blades, which may cause catastrophic/excessive damage to the turbine internals; a loss of electrical load causing a dangerous over speed condition; or other critical conditions may occur necessitating emergency shut down or tripping of the turbine instantaneously to protect it from an extremely dangerous operating condition or serious damage.

Turbine tripping actually means total and immediate shut off (typical time is 0.3 sec for a large turbine) of all steam valves responsible for steam admission to the turbine internal components, and a failure or delay in executing that action in the event any of the catastrophic conditions may cause extensive damage to various components of the plant. Fixing this damage may either be expensive or need prolonged repair time or both meaning high cost. Thus, it is necessary that the protection system must be capable of responding at the fastest rate possible to every catastrophic condition.

Turbine protection, or to be more accurate, turbo generator protection, means that the turbine should always be given safe passage in the event of any untoward situation at any time during start-up or shut down and loading or unloading conditions. The actions include tripping and post-tripping measures and limited occurrence of associated systems' failure.

The protective devices are designed and selected in such a way that whenever the turbine protection system senses a dangerous condition, it automatically reacts to stop the danger condition within the fastest time possible.

The mechanical and electronic trip mechanisms are the last line of defense for protecting the steam turbine. The devices deployed for protection implementation must be absolutely reliable and foolproof so that the duty imposed on them can be carried out in time of need only eliminating any possibility of spurious operation. One way to check their readiness is by using the ATT as described in Clause 5. The operating description of the protective devices is also described in Clause 5 as they are related to the ATT. It is immensely important to avoid spurious tripping and that the measurement of the ATT values are accurate along with the system processing them. If there is emergency tripping, the redundancy with proper design and number must be considered. Figure IX/3-1 is an example of a turbo generator protection system.

Some protective devices are categorized as "passive protective devices." They receive signals from sensors of a "not so critical nature" and initiate prevention of further operation from start-up to graceful shut down. For example, if any of the start-permissive signals of a particular step goes wrong, the operation will not be allowed to proceed further. These are taken care of in the start-up/shut-down procedure logic.

The protective devices, which receive signals from sensors responsible for turbine tripping signals, are popularly called "active protective devices." In case of an abnormal situation the active protective device, excited from the tripping signals, may initiate either opening/closing or starting/stopping of some areas to arrest the

www.EngineeringBooksPDF.com

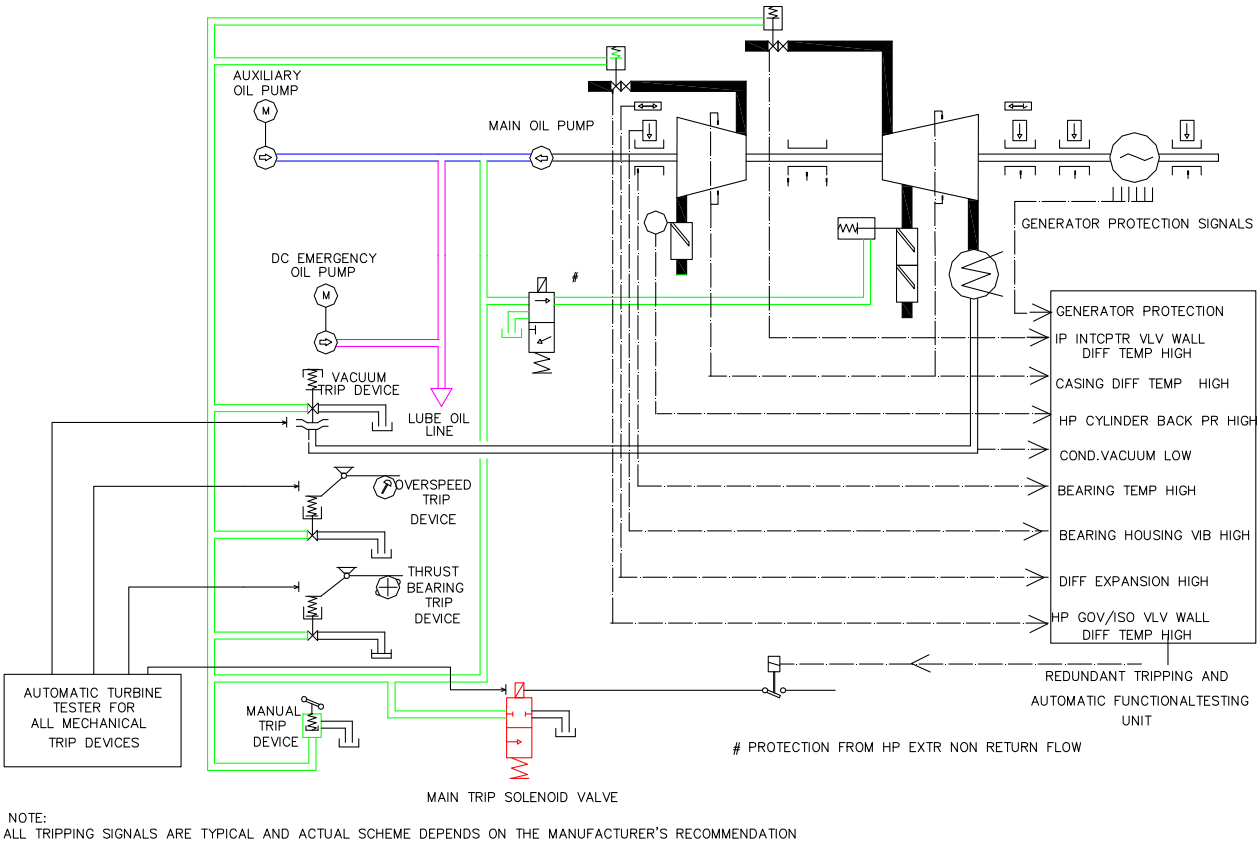


FIGURE IX/3-1 Schematic diagram of TG protection system.

unwanted deviation or may trip the whole turbo generator unit depending on the severity of the situation.

3.1 Turbine Tripping Input Signals

These following signals (typical only) will trip the whole turbo generator unit through active protective devices (see Figure IX/3-2):

1. TG set over speed (normally in duplicate for a hydraulic type; in case in case of electrical systems it is through a complex voting circuit, as discussed in Chapter V)
2. Thrust-bearing limit position (both hydraulic and electrical)
3. Very low condenser vacuum (both hydraulic and electrical)
4. Very low lube oil pressure
5. Trip command from ATRS (during shut-down operation)
6. Very low main oil tank level
7. Boiler tripped
8. High bearing temperature
9. High top and bottom casing temperature
10. High HP wall (mid and inner) differential temperature
11. High medium pressure wall (mid and inner) differential temperature
12. High ESV wall (mid and inner) differential temperature
13. Excessive differential expansion
14. Excessive bearing housing vibration
15. Very low steam temperature
16. Emergency hand tripping [both from remote (electrical) as well as from local hand trip lever (hydraulic)]
17. Generator protection operated as listed below.

Tripping of equipment is carried out mainly in three classes, A, B, and C, as per their severity in spreading and damaging. Of these three, Class C is only related to generator protection so it is not detailed in this clause.

A. *Class A protection*: Simultaneous tripping of the turbine and generator take places if any one of the following signals (typical) occurs:
- **a.** Generator reverse power relay operated
- **b.** Generator loss of excitation with under voltage
- **c.** Generator stator earth fault
- **d.** Generator rotor earth fault
- **e.** Generator over voltage
- **f.** Generator stator inter turn fault
- **g.** Generator differential

www.EngineeringBooksPDF.com

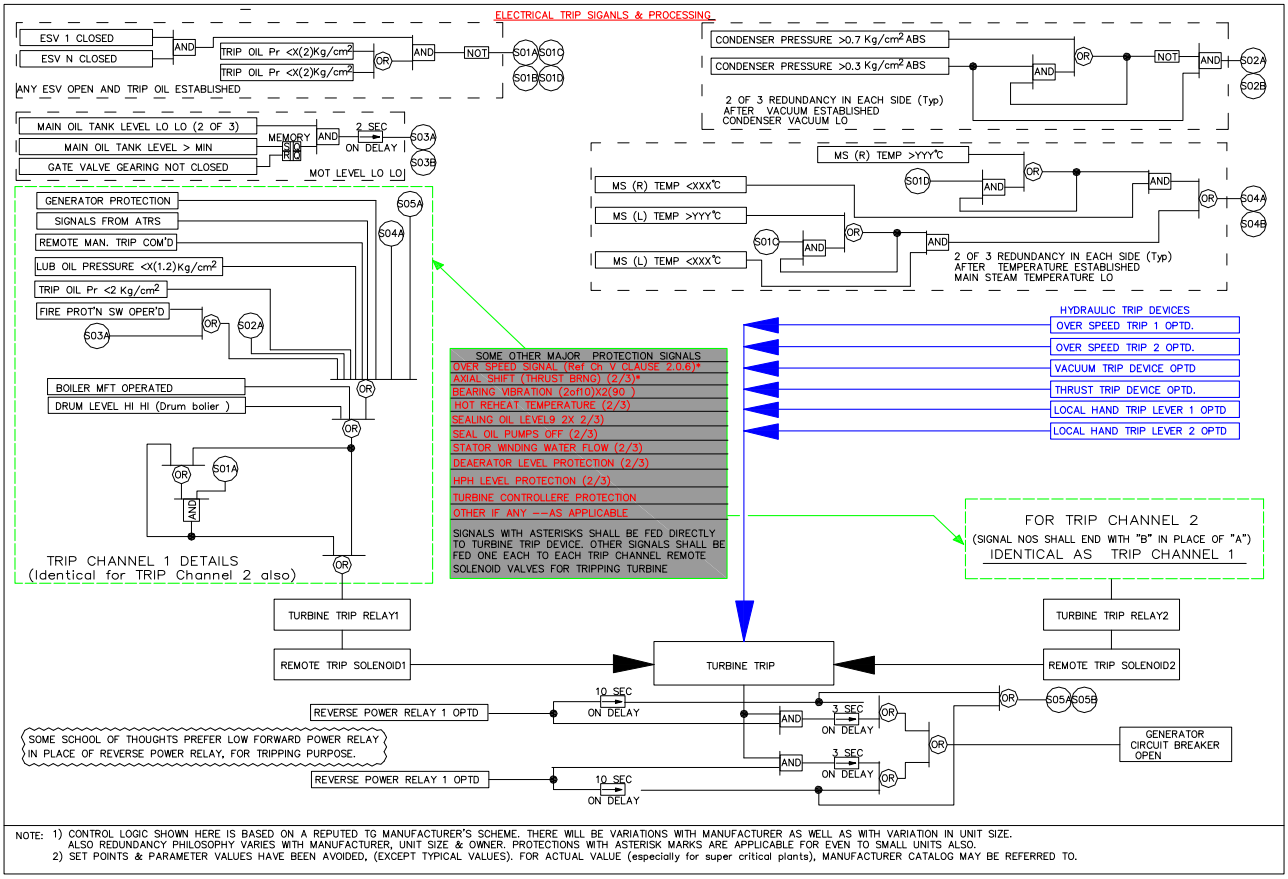


FIGURE IX/3-2 Typical steam turbine protection scheme.

h. Generator negative sequence
i. Generator distance back-up
j. Generator pole slipping
k. Generator and generator transformer overall differential
l. Generator transformer high-voltage (HV) side over current
m. Generator transformer restricted earth fault
n. Generator transformer standby earth fault
o. Generator transformer fire protection
p. Generator transformer Buchholz relay
q. Unit transformer differential
r. Unit transformer instantaneous and inverse definite minimum time over current
s. Unit transformer low-voltage (LV)-side earth fault
t. Unit transformer fire protection
u. Unit transformer Buchholz relay

B. *Class B protection*: Instantaneous tripping of turbine and generator; tripping (GCB opens) takes place after "low forward or reverse power relay operated" (with "'AND" logic) if any one of the following signals (typical) occur:

a. Generator loss of excitation
b. Generator rotor single earth fault second stage
c. Generator over fluxing
d. Generator stator earth fault in the range of 0–5%)
e. Generator stator winding distillate flow
f. Very high generator distillate conductivity
g. Very high generator transformer winding temperature
h. Very high generator transformer oil temperature
i. Unit transformer LV-side voltage operated earth fault
j. Very high unit transformer oil temperature
k. Very high unit transformer winding temperature

Out of the above tripping signals, the first three signals—TG set over speed, thrust-bearing limit position, and very low condenser vacuum—are normally received through mechanical/hydraulic active protective devices acting on the tripping circuit (hydraulic trip gear) in addition to parallel electronic/electrical tripping. Moreover, redundant over speed tripping sensors are taken through complex voting logic, as detailed in Chapter V, Clause 2.0, for extra precautionary measures. An electronic system measures pulses from a toothed wheel on the turbine shaft

www.EngineeringBooksPDF.com

and counts those pulses through a frequency to voltage converter.

Tripping signals 6−11 are all thermal or mechanical parameters measured through electrical transducers and are processed in an electrical protection circuit supplied with 220 V DC, which is still regarded as the most reliable source backed by a battery array. If any signals from these parameters is activated, the trip solenoid valve(s) is actuated, which in turn drain(s) the power oil responsible for keeping the main governing valves and stop valves open.

The tripping systems for TG set over speed, thrust-bearing limit position, very low condenser vacuum, and common electrical and emergency hand tripping are described in detail in Clause 5, which also includes the corresponding trip testing systems.

Modern electronic trip systems are strongly preferred by some manufacturers who adopt highly reliable voting circuits for higher "tripping speed" units. The spring-loaded trip bolt/plunger may behave in an unstable manner at higher trip speeds and requires separate hydraulic relay valves, which use hydraulic fluid in long piping runs. The direct mechanical system requires extra shaft overhangs, which may be detrimental to vibration at higher speeds. However, even now manufacturers still use hydraulic systems as the last resort in case of power loss/wire snapping.

The main advantages of the electronic system are high accuracy and repeatability, fastest response, high flexibility from adjustability, higher reliability through voting logic, and a testing facility with or without running the machine. It may be noted that many uncontrolled over speed events are the result of valves failing to close, even when the over speed trip device operates. Further, nearly all uncontrolled over speed failures are catastrophic, resulting in blade failures, shaft breakage, and retaining ring bursts. In case of turbine tripping the following typical actions are required to be performed:

1. Immediate closing of the ESVs and HP control valves (HPCVs)
2. Immediate closing of the reheat inlet valves
3. Immediate closing of the nonreturn valves in extraction lines

3.2 Generator Protection

There is also a Class C type of generator protection (and also a Class E type envisaged by some manufacturers) and "manual trip," which are meant for generator tripping only. Class C protection is mainly for the faults beyond the generator transformer and HV circuit breaker and includes fault of the grid and bus bar, GCB pole discrepancies, and manual tripping. Class E protection is related to GCB failure.

3.3 Unit Protection

This is the coordinated and integrated protection of individual boiler, turbine, and generator. The provision of HP/LP bypass has added flexibility in unit operation by decoupling the boiler and turbine in case of turbine tripping. The inter-relationships are indicated below:

1. Boiler trip due to its own protection and some other important tripping signals would cause tripping of both the turbine and generator; this is a Class U trip.
2. Turbine trip due to its own protection would cause tripping of the generator through low forward or reverse power relay but no command to trip the boiler.
3. Generator trip under Classes A and B would act as already indicated above.
4. Class C generator trip would not cause turbine or boiler tripping; turbine may become stabilized due to the "load shedding relay/governing system." Boiler may cut back one or more mills and would dump extra steam to condenser via the HP/LP bypass.

4. ATRS

Modern power plants are becoming larger in size, especially with super ultra supercritical plants, to cope with increasing power demands and at the same time reduction of costs. Any delay in starting time creates less revenue and will never be accepted by modern day operation practice code. To reduce starting time (with shut down as well) and eliminate human error, the ATRS was developed (see Figure IX/4-1).

The entire plant is grouped in relation to a particular functional requirement or subsystem. The main system identifies each subgroup with various subgroups consisting of drives or devices to respond in a timely manner according to the program logic (by hardware or software).

There may be some variations in features of this system with different manufacturers but the basic control philosophy and aim of the controls are the same. In view of this, an abridged discussion is presented here based on one of the most reputed and popular steam turbine manufacturers in Europe.

4.1 Subgroups Involved in Automatic Run Up

There is a number of subgroups connected to the automatic run up systems including:

1. Turbine HP control fluid subgroup for the LPBP system
2. Turbine HP control fluid subgroup for main valves (Above two systems also may be combined)
3. Turbine control oil subgroup

www.EngineeringBooksPDF.com

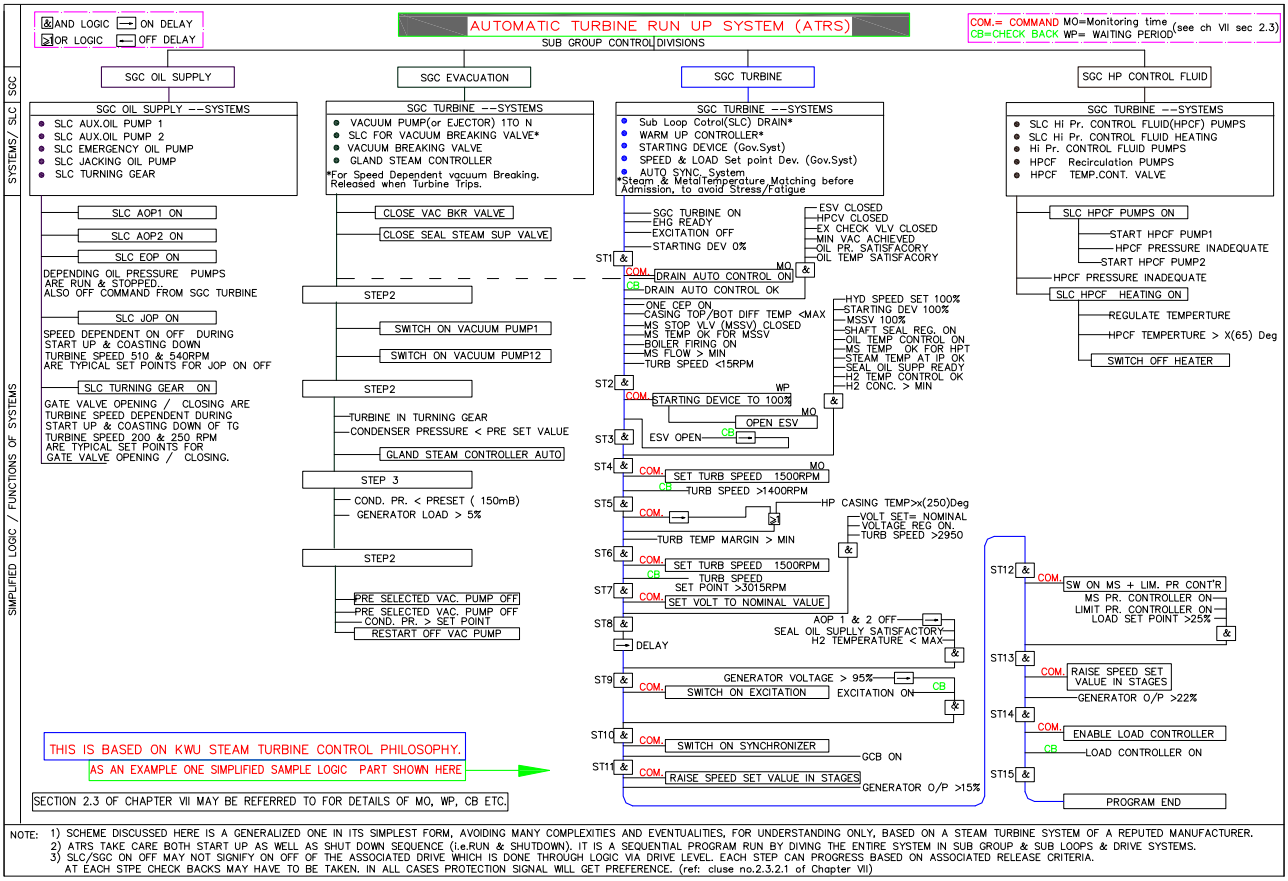


FIGURE IX/4-1 Typical ATRS scheme.

4. Condenser evacuation and gland seal subgroup
5. Turbine control subgroup (warm up, start-up, loading, unloading, and shut down)

In some plants, the generator exciter subgroup is also included for better coordination.

The basic function of ATRS is to reduce the starting time in the most optimum way. To accomplish the function, certain operations are performed in an overlapping way, for example, admission of main steam into the steam chest and a time period for warming up, maintaining the exact TG set speed for efficient soaking and speeding up of TG shaft running through critical speeds, and shortening of vibration run up.

4.2 TG system

As already described in several clauses in Chapters 2 and 3, the turbine of the modern large thermal power stations must include a high-pressure turbine (HPT) section fed with main steam from the boiler. HPT exhaust steam is called cold reheat (CRH) steam, because it gets reheated in the boiler and becomes hot reheat (HRH) steam. It is then re-admitted into the intermediate pressure turbine (IPT) section and its exhaust is directly sent to a low-pressure turbine (LPT) section before finally exhausting to the condenser. Although the steam sections are different, the rotor shaft is common to them all with a series of (moving) blades arranged to rotate inside an axial bore, which passes centrally through the turbine casing with (fixed) blades. The rotation of the rotor shaft is achieved by passage of steam from fixed blade to moving blades. The rotor of the generator, which is firmly fixed to the rotor, normally is cooled by hydrogen gas. A steam chest on both the right and left sides of the turbine includes ESVs and HPCVs for controlling the steam to be admitted to the HPT.

4.3 Warm-Up Process

The huge and thick metal mass of the steam chest as well as the TG set rotor shaft must be brought to operating temperature as quickly as possible before the main steam at high pressure and high temperature from the boiler can be admitted into the steam chest. As steam with very high pressure and temperature is to flow through the turbine to ultimately generate electrical power output, it is extremely important the thermal stresses are kept under normal value

www.EngineeringBooksPDF.com

during start-up and normal operation. The start-up procedure is more important as hot steam would stress the cold and thick turbine metals during initial entry of steam.

4.4 Start-Up and Thermal Stress

As steam with very high pressure and temperature passes through the turbine to receive power output, it is very important that the thermal stresses are kept under normal value during start-up and normal operation. The start-up procedure is very important as hot steam would stress the cold turbine metals during initial entry of steam, as detailed out in Clause 6.

After many years of close observation, it was found that a set of particular initial steam temperatures with optimally regulated flow rates passed through for a well-judged duration of time, which would enable the shortest period of time to start up the turbine and maintain thermal stress within the permissive limit. This procedure of steam admission, especially in the primary stage, is extremely necessary and important and is guided by the TSE by imposing upper and lower margin limits for the start-up operation. Any wrong step could lessen the life expectancy of the steam turbine and affect the start-up time of the plant.

The start-up procedure consists of cold start-up and hot start-up. Cold start-up is most important as the temperature difference is the maximum during the first admission of steam and must be handled carefully to avoid reduction in plant life expectancy.

As the name implies, the cold start-up of a TG set is applicable when the set is going to be started after a very long period of shut down with turbine case, chest, valves, and rotor literally cold with temperatures around the ambient condition. The temperature rise (heating ramps) must be controlled (by controlling steam flow rate and quantity by experiencing minimum thermal stresses on the turbine metal, especially of thick components like the steam turbine shafts). It is also important to avoid high differential expansion between rotor and stator case, which could cause contact between them because of their different thermal inertias. The most critical part of the plant as far as thermal stresses are concerned, is the turbine shaft in contact with the highest temperature steam, i.e., downstream the first stage of the turbine. The start-up control system must, therefore, be capable of keeping the controlled variables within the safe allowable limits. The "turbine control" subgroup contains a "sub loop control" of "warming up main steam lines" and takes care of controlled heating of the pipes, components, etc., up to the inlet of HPCVs. Subgroup "turbine control" then takes care of the rest of the controlled heating activities and the turbine load control afterward.

During the turbine start-up, the steam flow and the heat transfer coefficient are very low. Therefore, the rotor temperatures increase slowly and when, after a certain period of time, the HP valves are opened more rapidly, the rotor surface temperature travels nearer to both the HPT inlet and first (impulse) stage outlet and steam temperature. At the end of the transient period, all temperatures are equal, since there is no steady-state heat flow. After the heating ramp, the period is called heat soaking, which means the heating is continued for that period of time unless the desired temperature is achieved.

This is done to reduce the thermal stress peak by reducing the thermal shock before the very beginning of the steam turbine load pick-up. This can be obtained by allowing for a longer soak time for the turbine, i.e., once the turbine has reached full speed it is kept running without taking any load so that the steam flow can heat up the rotor a little bit more. The turbine start-up is therefore initiated earlier than normal start-up transient, and the turbine is kept idling for $\sim$1 hour.

The load pick-up phase is then started, and the rate of load change is steered to get a flat stress curve. After a desired load level is achieved, the rate of change is increased to the maximum allowable level. Here, two thermal stress peaks are observed and each of them contributes fatigue and thereby lifetime consumption. If the peak values are analyzed then, it can be seen that the first peak value may be slightly higher than the elastic limit, and thus correspond to a very low additional lifetime consumption. The second peak is higher than the first peak, however, still well below the previous standard start-up value. The start-up time is also reduced by considerable value from fuel savings.

When the heating is completed the turbine can be started under close supervision of the differential expansion measurements and when the unit can be synchronized (usually at a speeds of 3000 rpm, which is called the synchronizing speed). After the unit is synchronized, then the TG can be loaded according to the related load ramp (MW/min). The conventional system available requires that the steam chest be sufficiently warm before transferring control of steam flow from the MSSV bypass valves to the governor valves. If the steam chest metal temperature is less than the steam saturation temperature at existing pressure, then the transfer is delayed to allow the steam chest to heat up more. The improved method suggested that the start-up sequence can be squeezed by shortening the steam chest warm-up process through lowering the governor valves to maintain rolling speed and opening the MSSV bypass valves to the full stroke, thereby overlapping the MSSV and governor valve HPCV control mode to partially pressurize the steam chest and allow more steam to flow in.

www.EngineeringBooksPDF.com

4.5 Sequential Operation of the Subgroups for ATRS

4.5.1 Turbine Oil Supply

This system provides pumping, bearing lubricating/cooling, jacking/lifting oil, turning gear operation, and vapor extraction of the system and control fluid. After getting the ON command, the following sequence starts:

1. The AC auxiliary oil pumps (AOPs) and DC emergency oil pumps (EOPs) start at a per oil pressure setting and stop at a per pressure setting when the shaft-driven main oil pump (MOP) starts functioning.
2. The temperature control loop for the turbine-bearing lube oil is activated and run continuously as long as the turbine keeps running.
3. Jacking oil pump (JOP) inlet valve is opened during start-up and the JOP is started manually and then the SLC of all JOPs are turned ON. The valve closes and the JOP stops when the TG set attains a sufficient speed of >540 rpm (typically) to ensure adequate bearing lube oil. During turbine operation, the selected JOP(s) start (and valve opens) automatically if speed falls below 500 rpm (typically).
4. Hydraulic turbine mechanism for shaft-turning gear starts when its inlet valve opens. The preconditions required are hydrogen pressure, seal oil hydrogen DP is adequate, SLC is ON, and JOP is adequate at >130 bar (typically). During turbine operation, the turning gear starts (and valve opens) automatically if speed falls below 200 rpm (typically). The system will close automatically when the TG set begins to be driven by the steam, that is, the speed is typically >250 rpm (typically).

When the system gets the shut-down command, the following actions are taken. The selected JOP(s) start (and valve opens) when speed falls below 500 rpm. Turning-gear system inlet valve will be open so that the system is ON immediately when the turbine speed comes down to ~200 rpm during coasting down. It will stop operating automatically when the casing temperature settings permit it to do so. AOPs will again start and stop as per their pressure setting and shut-down command.

4.5.2 Condensing System

The "condensing system" covers the drives and/or devices required for extraction of air and noncondensing particles from the condenser-associated systems, a vacuum breaker valve, and gland sealing system for the turbine shaft. The air-extraction function can be achieved by vacuum pumps or steam air ejectors. Both vacuum pumps (normally two) usually run during start-up and emergency conditions and only one runs during normal operation of the TG set. For a system with air ejectors, there is one "starting air ejector" for the start-up purpose and running air ejectors for the normal operation.

Once the ON command is initiated, the sequence for systems with a vacuum pump and systems with air ejections starts like the following:

For systems a with vacuum pump:

1. Both vacuum pumps start and when the vacuum exceeds the preset value, one pump will be on the shut-down program as per selection with the other pump running. For a low vacuum condition, the second pump will start to maintain the vacuum and will stop again at the preset exceeded value of vacuum.
2. The associated cooling water supply valve opens whenever any vacuum pump starts.
3. The associated air-extraction valve opens whenever good running condition of the vacuum pump is established.
4. The vacuum breaker valve closes.
5. Warm-up system starts for the gland steam line in association with the steam supply valve drain valve.
6. If the warm-up condition is established and the vacuum has reached a preset value, the seal steam control valve will be released for gland steam start-up pressure control and the gland steam cooler exhauster will be switched on.

For systems with air ejectors:

1. To start the air ejector, the auxiliary steam supply isolation valve opens with the start-up pressure control valve crack open for the initial line warm up.
2. If warm-up condition is established, the start-up pressure control valve will be released to auto control.
3. The vacuum breaker valve closes.
4. When TG set load is established, the start-up isolation valve will be closed and the selected normal ejector isolation valve will open and the associated control valve will be released to auto control.

The rest of the sequence is the same as the vacuum pump system.

When the system gets a shut-down command, the following action is taken:

1. The vacuum breaker valve opens.
2. Gland seal leak off pressure control valve closes.
3. Main air ejector(s) stop or the vacuum pump stops and associated isolation valves close.

4.5.3 Turbine Control

The turbine control subgroup covers the functional requirements of the automatic run up systems and the

www.EngineeringBooksPDF.com

loading and run down systems of the TG set as well. The run up system includes the warm-up function of the remaining part of the TG set and then controlled speeding up through different stages up to the synchronizing speed. The complete operation of the turbine control system is achieved through the TSE and the EHG system along with speed, generator output/load controller, and pressure controller (for special purposes). Once the ON command is initiated, the sequence follows these steps:

1. First, open the ESV with a hydraulically operated starting device. The ESV is the first step to allow the admission of live steam into the turbine. The following start-permissive signals are verified for availability:
   a. Turbine is running (on turning/barring gear speed)
   b. Differential temperatures between top and bottom section of both HPT and IPT casings are below the preset permissible values.
   c. The condenser vacuum is well established above the preset value.
   d. Condensate transfer subgroup and turbine oil supply subgroups are established.
   e. MSSV must be closed.
   f. Steam parameters are suitable before MSSV.
   g. Steam generator with firing system in well-established condition.
   h. Turbine drains are operating as desired (discussed later).
2. The speed set point is increased to warm-up speed (or the first hold speed for heat soaking) provided the following permissive signals are available (a time delay is introduced to make the system get ready):
   a. Steam parameters are suitable before MSSV.
   b. Steam parameters before ESV are suitable for admission to turbine.
   c. Hydrogen (generator rotor coolant) temperature control is ready.
   d. Turbine seal steam pressure control system is in operation.
   e. Turbine oil temperature control system is in operation.
   f. Generator seal oil supply is made available.
   g. The starting device and speed changer are 100% positioned.

Upon availability of these start-permissive signals, the speed set point controller would raise, as guided by the TSE, the set point to "soaking up" speed for the speed controller, which will dictate the rate of steam flow by positioning the HPCV-required steam flow.

For a cold start, a certain amount of time delay is introduced after the TG set has reached its warm-up speed and then the speed set point controller will raise, as guided by the TSE, the set point to the rated speed when the turbine with all its associated accessories is adequately soaked with heat transmitted by the main steam.

As a next step, the generator's AVR is switched on when the TG MOP assumes the charge of total oil supply as the turbine is running at rated speed. The AVR is then set at its rated value and the generator is excited.

After receiving confirmatory signals from the above commands, the generator is synchronized by the auto synchronizer device and switched on with the help of the GCB to the external power grid. No sooner than the generator is synchronized, a certain minimum amount of power is delivered to the grid. The speed set value is then raised in stages and if generator output is more than a minimum value of $\sim$5%, the main steam pressure controller is switched on to the limit pressure control.

When the system gets the shut-down command, either manually or automatically, and when a protective tripping action is initiated and closing command of ESV has already been issued, it will take the following actions:

1. The TG set is unloaded by lowering the load set value 20$-$25% and then it automatically switches OFF.
2. The remaining unloading action is accomplished by reducing the speed set point of the speed controller.
3. The GCB is opened by energizing the tripping circuit with the help of reverse power protection logic.
4. For the next restart, the necessary plant conditions are ascertained as a last step of the shut-down program.

4.5.3.1 Turbine Warm Up and Drain Control

Turbine subgroup activates the warm-up controller to ensure a smooth and safe warm up of the ESVs and HPCV turbine as permitted by the TSE. The automatic drain control forms a separate sub loop control with all the drains hooked up and does not follow any sequence. According to the operational philosophy, the drain valves can open or close any time depending on the parameter operating status of the plant without any bearing with the load, speed, or time. Depending on the relative importance and significance of various drain valves, the criterion (mainly temperatures of relevant points) for opening/closing of each individual drain valve is defined and suitable logic built in to ensure safe operation. After the warm up of the ESV and CV of the HPT, the ATRS admits steam into the turbine to roll it.

After sufficient warming up with other permissive criteria, the ATRS takes the turbine from the barring speed to the first hold speed (nearly 20% of the rated speed) with the acceleration controlled by the TSE/turbine stress control system to prevent components from overstressing. The ATRS ensures a definite hold for soaking of turbine internally at this speed for a specified period if the HP metal temperature is less than 250°C, otherwise the hold period is determined by the time it takes for temperature margins of the TSE to be within permissible limits.

www.EngineeringBooksPDF.com

Once the desired thermal soaking of the components and process requirements is complete, the turbine control raises the speed of the set to rated value with the guidance of the TSE by controlled acceleration, except for the time when the rotor crosses the critical speed region.

After attaining a speed near synchronous speed (~2950 rpm) with sufficient available temperature, the TG set is synchronized with the grid. For the saturated steam turbine, drain automatic control is accomplished by sensing level in the drain loops.

4.5.4 Control Oil Supply

With the advent of using very high pressure oil as control oil for operating the hydraulic actuators of LP bypass valves, ESVs, HPCVs, etc., a separate independent subgroup control has been envisaged. The type of oil used is a nonflammable fluid or a fire retardant fluid (FRF). The fluid known as "phosphate ester" is the FRF currently used in a majority of applications. This fluid provides excellent hydraulic capabilities and good fire-resistant characteristics. However, some typical problems were encountered in using phosphate ester over time including:

1. High water levels from
   a. Moisture in the air breathed by the reservoir
   b. Condensation formation inside the reservoir caused by rapid fluid temperature changes
2. High acid levels in the fluid due to formation of phosphoric acids
3. Gel and varnish formation throughout the system; gels can ultimately change to a varnish
4. Low electrical resistivity of the fluid

Recently some alternative fluids were introduced as replacements for the existing FRF fluids. These fluids are approved as FRFs by the Factory Mutual (the certifying agency for insurance companies).

The replacement fluids do not create the harmful phosphoric acids like the existing fluids so they do not require the use of acid control filters. Replacement of the FRF fluids with these alternate fluids not only eliminates the problems and environmental hazards inherent with handling phosphate ester fluids, but it also eliminates the much larger problem of gel and varnish formation.

The replacement fluids lubricate better than the existing FRF fluids. If the fluid remains clean it helps prolong the life of most components in the hydraulic fluid system. The replacement fluids also have higher viscosity indices, which allow them to operate over a wider temperature range.

The basic components of the control oil supply subgroup include (2 × 100% or 3 × 50%) control oil FRF pumps, one circulating pump for fluid transferring to the filters, and temperature control systems with heaters and coolers for maintaining the requisite temperature. The FRF pumps are controlled by automatic start and stop (sub loop controller) logic to maintain the pressure and flow as required by the TG system.

The subgroup gets "start-up operation" unit coordinated command when LPBP operation is about to start after the condenser vacuum has attained more than the preset value and/or ESV is about to get the open command. The sequence follows this order after the ON command is initiated:

1. The selected FRF pump will start.
2. For 3 × 50% FRF pump selection, the second pump as selected will start as per the unit load demand of maintaining pressure and flow.
3. The FRF control oil temperature control is released for auto operation.
4. The circulating pump will cut in to ensure continuous filtration no sooner than the temperature has attained the preset operating value.

When the subgroup gets the shut-down command, the shutting down process starts after the LPBP operation has completed the shut-down operation. When the system gets the shut-down command, it takes the following action:

1. The circulating pump stops.
2. The temperature controller is OFF.
3. The FRF pumps begin to stop as per selection.

4.5.5 HP Control Fluid Supply

This subgroup controls the HP control fluid (HPCF) pumps, HPCF heating, HPCF recirculation pumps, and HPCF temperature control valve. Both CF pumps get switched ON through the SLC. The standby pump starts if the running pump fails to develop the required pressure. The required CF pressure enables SLC heating ON and starts the CF circulation pump, which feeds the regeneration circuit. Temperature control valve is put in auto mode to regulate the temperature. CF temperature in the tank is maintained at ~56°C by the CF heater ON/OFF control. The heater switches OFF automatically if CF temperature exceeds 65°C.

In the shut-down program, all the oil pumps are switched OFF and an SLC CF pump is also turned OFF. SLC heating is kept on to maintain the temperature required for the next start-up and can be manually switched OFF, if required.

5. ATT SYSTEM

5.0 Testing Process by ATT Systems

The ATT systems enables online testing of all the important drives (ESVs/HPCVs) or trip devices required for safe operation and emergency tripping of a TG. In other words,

www.EngineeringBooksPDF.com

all the protective equipment required for TG safety is tested automatically with uninterrupted normal operation without jeopardizing the individual protection assignment bestowed on each protective device while running test procedures. The mechanical or electronic turbine trip mechanisms are the ultimate line of defense for protecting the steam turbine and need to be available when required. However, testing is permitted only under specified conditions, such as healthiness of a substitute device, no trip conditions exist for turbine, etc.

For turbine tripping, i.e., to close the ESVs (also HP/IPCVs through secondary oil), the trip oil is drained, meaning substantial quick reduction of trip oil pressure, which is achieved through any of these protection devices. Normally ATT (if supported by the control system provided for the turbine—as not all manufacturers support ATT) extends in to the trip oil piping network, and with the help of test oil performs a similar function.

The main function of the ATT system is basically to ensure a fail-safe operation of the protective valves or devices by checking and analyzing their readiness throughout the turbine operation regime. The system ensures this duty by performing the tests periodically (see Figure IX/5-3C) in automatic mode of operation and manually at the operator's discretion. The essence of this particular standalone facility is to test all the protective devices sequentially in a well-organized and systematic manner for verification of foolproof functioning of all the devices. The system is built to eliminate operator error, resulting from manual intervention, by using the fully automatic test sequence. Individual tests for a particular device can be done by proper selection. Due to limited scope, control philosophy of only one reputed manufacturer (KWU) is discussed so that the reader becomes familiar with the basic idea of this type of control.

5.1 Scope of ATT

ATT covers the following items:

1. TG set over speed trip (mechanical)
2. Thrust-bearing trip (mechanical)
3. Low vacuum trip (mechanical)
4. Electrical remote trip
5 Opening and closing operation of control valves
6. Opening and closing operation of ESVs.

Testing can be done for all the above items manually at the operator's discretion or periodically through the automatic program (see Figure IX/5-1).

During the test program, the trip oil pressure is reduced by the ATT for testing of each tripping cause so that the tripped signal is available at proper strategic locations. The HPCVs and ESVs, until they are tested, would not be allowed to close during the testing of the protective devices as they would still continue to be supplied with high-pressure oil via trip test solenoid valve and ATT changeover valve by the ATT system itself so that normal operation of the turbo generator is continued (see Figure IX/5-2).

All simulated electronic trip components, however, could be tested (through the remote electrical trip solenoid)

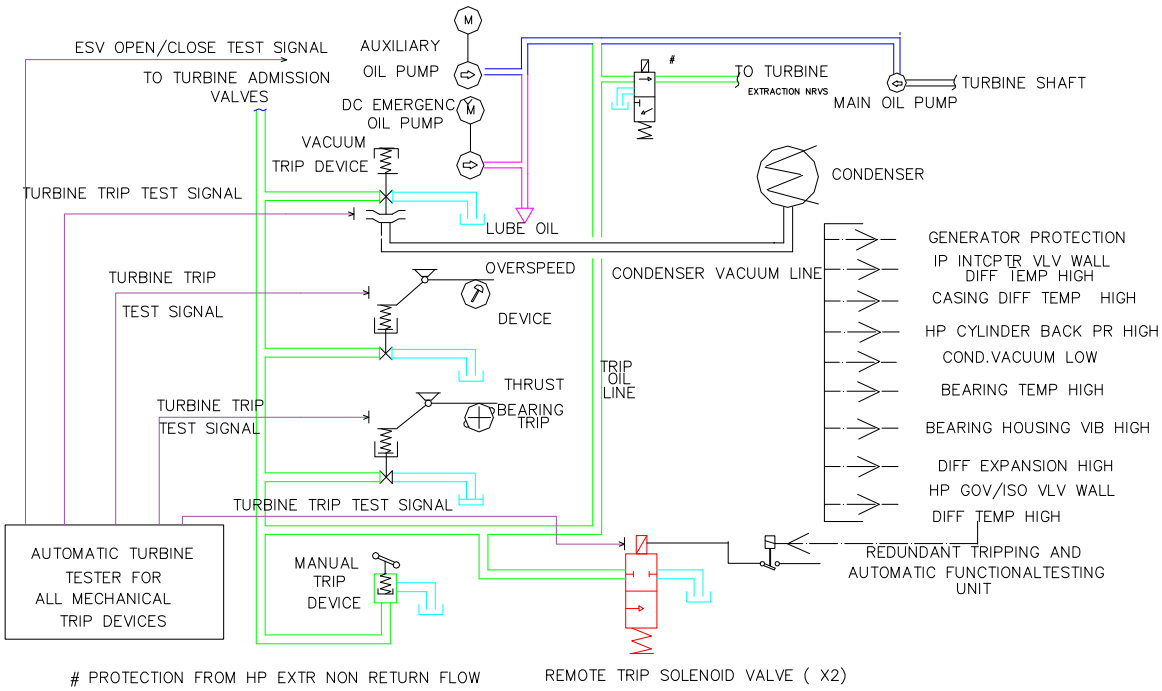


FIGURE IX/5-1 Schematic diagram of ATT system.

www.EngineeringBooksPDF.com

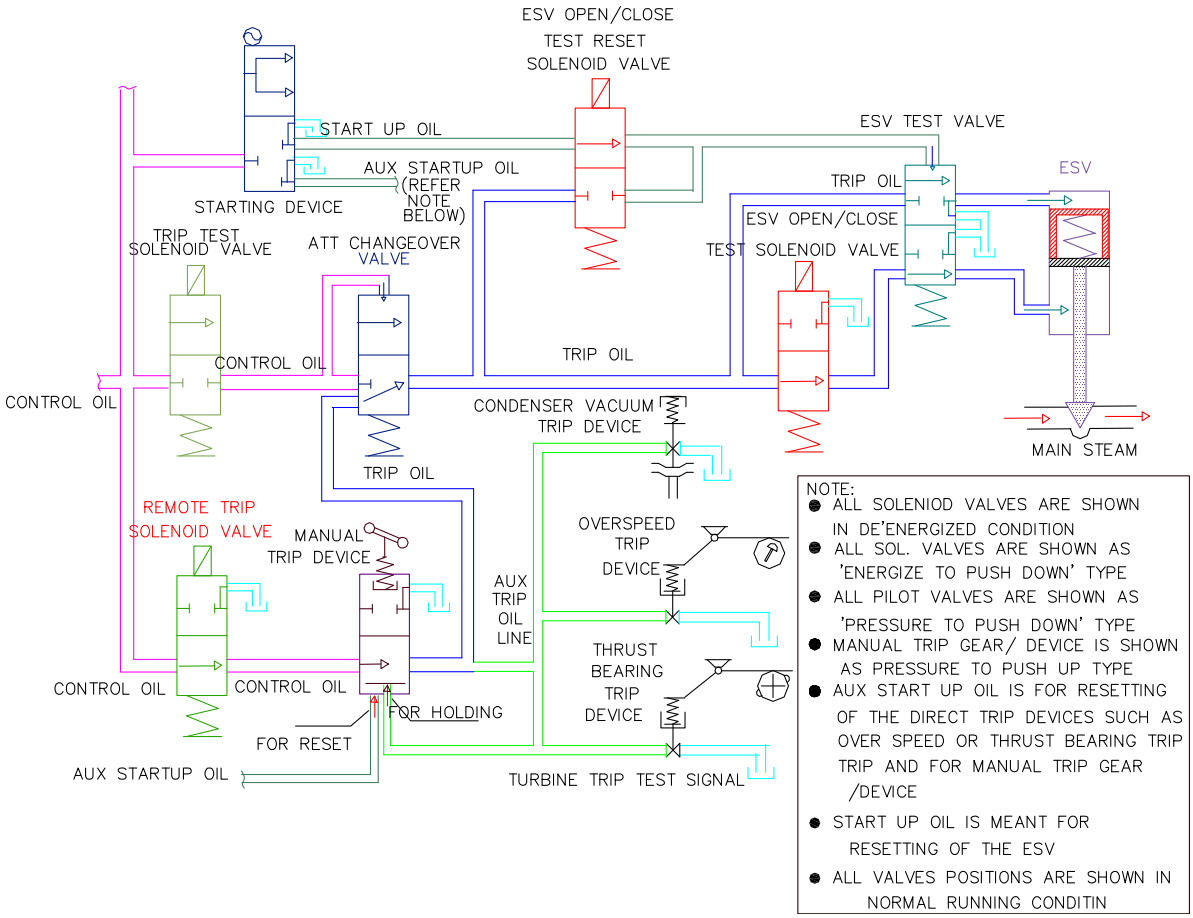


FIGURE IX/5-2 Schematic diagram of ATT oil circuit.

more frequently, for example, once a month if they have no direct effect on the steam turbine operation.

5.1.1 TG Set Over Speed Trip (Mechanical and Electrical) and Testing

It is customary that the steam turbines are fitted with an emergency over speed tripping system in addition to normal operating speed governors. Uncontrolled over speed failures due to the malfunctions or inappropriate control system of over speed protective devices are catastrophic, resulting in blade failures, shaft breakage and rotor winding retaining, ring bursts, etc.

5.1.1.1 Trip System

5.1.1.1.1 Direct Mechanical Type Over speed Trip The over speed measuring systems may be of any type, such as mechanical (fly wheel), hydraulic (positive displacement pump), or electromagnetic/electronic (Hall probe). In a thermal power plant, the hydraulic signal is used for the mechanical type of over speed tripping for faster response.

When the over speed trip mechanism is actuated (shaft speed exceeds the safe speed level, generally 10% more than the normal speed value), the TG set is tripped on an emergency shut-down basis by quickly draining the actuator/trip oil to close the ESVs. The system is absolutely independent of the TG set governor control system and forms one of the most important and last resorts for tripping criteria as electromagnetic/electronic type (as a part of the remote electrical trip) tripping is also included in addition to direct mechanical tripping.

The over speed trip system consists of two over speed sensing bolt/plungers normally mounted on the frontend-bearing pedestal of the TG shaft (location may vary as per the manufacturer's design), speed set point adjustment screw, pawl, etc. The over speed sensing bolt/plungers are eccentric, that is, they have their center of gravity slightly away from the center and covered along with mounting. When the TG speed increases beyond the safe value, the centrifugal force of the unbalanced bolt/plunger overcomes a spring force at a preset trip speed and moves outward to strike the respective pawl from the trip lever. When struck, the trip lever releases the spring-loaded

www.EngineeringBooksPDF.com

valve to drain the auxiliary trip oil and in turn drain the main trip oil, the pressure of which is no longer in a position to hold the ESVs. Different manufacturers use several methods such as some high-speed machines use a weighted disk and a dished washer to accomplish the tripping action.

5.1.1.1.2 Electrical Type Over Speed Trip For the electrical/electronic trip, speed is sensed by the Hall probe technique or proximity type sensing and the subsequent electronic and relay circuit generates a switching contact when speed reaches beyond the set point. There is a trip solenoid valve along with a trip relay that energizes along with other electrical trips that act in parallel and drain the trip oil to trip the TG set.

5.1.1.2 Trip Testing System of Over speed Trip

5.1.1.2.1 Direct Mechanical Type Over Speed Trip Testing Testing of proper functioning of a turbine over speed trip device, although centered on the over speed trip mechanism, should be treated as a complete system. For functioning rather than simulating the trip condition, high-pressure oil is introduced by a hydraulic test signal transmitter (HTT) via a shaft hole producing a similar but artificial condition of actual over speed for actuation of trip bolts at TG normal speed. This causes the hydraulic circuit, that is, the trip oil, to drain. The resultant fall in trip oil pressure would be detected by suitable pressure switches and the signal sent to the turbine trip tester, which in turn sends the alarm indicating successful testing operation. All associated alarms and indicators are also provided for proper observation in different operational and management areas. After testing resetting is done to move up the HTT spool and drain test oil.

5.1.1.2.2 Electrical Tripping Type Over Speed Trip Testing Some manufacturers provide an automatic online over speed test through the internal injection of a ramping frequency signal into the speed channels. This test verifies proper operation of the software, hardware, and hydraulic components of the trip circuit. Some manufacturers provide an automatic online over speed test by generating electrical relay contact at an over speed set point more than that of the mechanical trip set point and club it along with other electrical trips to act on the remote trip solenoid.

5.1.2 TG Set Low Vacuum Trip (Mechanical and Electrical) and Testing

This parameter is also very important as far as turbine protection is concerned, which is the reason why both direct mechanical and electrical tripping are provided along with the provision of testing its functional operation.

5.1.2.1 Trip System for Low Vacuum Trip

5.1.2.1.1 Direct Mechanical Type Low Vacuum Trip The function of this protection device is to trip the turbine in case the condenser vacuum becomes lower than a very low preset value. The basic device is a spring diaphragm-operated sensing element with the upper side of the diaphragm connected to the condenser vacuum line and to the primary oil pressure through a piston with an isolated chamber. The lower side is connected to the atmospheric pressure with the spring acting against the force applied by the primary oil pressure. When the vacuum falls, that is, pressure increases on the upper side, the net downward force experienced by the diaphragm is more than the upward force offered by the combination of spring tension and atmospheric pressure. The result is the downward movement of the spring diaphragm assembly causing the trip oil to drain and ultimately to trip the turbine. The protection need not be bypassed during start-up as the primary oil pressure builds up only when the TG set speed is more than the preset value.

5.1.2.1.2 Electrical Tripping Type of Low Vacuum Trip For the electrical tripping type, vacuum switches are used with sufficient redundancy and clubbed with other electrical tripping signals to operate the separate trip solenoid valves. The scheme/procedure of testing of this tripping system is similar to over speed tripping/testing except the sensing of low vacuum, which is from an electro/mechanical type switch for the electrical part.

5.1.2.1.3 Direct Mechanical Type Low Vacuum Trip Testing As the basic tripping device is a spring diaphragm with the upper side connected to the condenser vacuum line and the primary oil pressure, manipulation of any of the above parameters (depending on the manufacturer) to a higher value increases the downward force. The lower side is connected to the atmospheric pressure with the spring acting against the above combined and the forces do not change, and the net downward force on the diaphragm will cause the downward movement of the spring diaphragm assembly by the simulated turbine trip, which is more than the upward force offered by the combination of spring and atmospheric pressure. A separate solenoid-operated test valve is provided to perform this test.

During testing, first the hydraulic circuit is established, and with the help of the HTT (test solenoid valve) discussed above, the trip device is disconnected from the condenser vacuum line and simultaneously the upper port is connected to the atmosphere via resistances provided by a long spiral tube and restricting orifice, which causes the trip oil to drain. After testing the HTT is de-energized and the vacuum trip gets reset automatically.

www.EngineeringBooksPDF.com

5.1.2.1.4 Electrical Tripping Type Low Vacuum Trip Testing This procedure is similar to that of over speed trip testing.

5.1.3 Thrust-Bearing/Axial Shift High Trip (Mechanical and Electrical) and Testing

Thrust-bearing trip (mechanical) and testing is another important parameter for the turbine protection for which testing facility has always been provided in the ATT. Axial shift may be simply described as a rotor movement resulting from the wear and tear of the thrust pad. The difference in thrust created on the TG shaft by steam flowing through HP and combined IP/LP causes constant rubbing of the thrust pad in the thrust bearing by the high-speed TG shaft. The designed movement is kept at a minimum (typically 0.2−0.25 mm). The measuring/detection point is provided at a rotor anchor point where the thermal expansion of the rotor is zero so that the axial shift is not affected by thermal expansions of the casing/rotor.

5.1.3.1 Trip System of Thrust-Bearing/Axial Shift High Trip

5.1.3.1.1 Direct Mechanical Type Thrust-Bearing Trip Device This is a direct type of tripping provided for protection of the turbine against large amounts of wear and tear on the thrust-bearing pad and axial shift/movement. The physical arrangement is such that two pairs of cams are provided on the turbine shaft at an angle of 180° to each other. In each position of both pairs of cams, a pawl in provided between the cams. The pawl is positioned in between the cams, and it touches any of the cams whenever the TG set shaft moves horizontally toward a forward or backward direction.

If the pawl comes into contact with any cam, the latch of the thrust-bearing trip device is released and actuates the trip part just like the above tripping systems. Two pairs are provided diametrically apart to have redundancy in the protection system. The typical set value is between 0.6and 0.75 mm. depending on the manufacturer of the turbine.

5.1.3.1.2 Electrical Tripping Type Thrust-Bearing Trip Device Redundant position pick-ups are provided with the standard turbo supervisory instrument (TSI) package to monitor the axial movement of the disk mounted on the rotor near (normally within 25 mm) the thrust-bearing collar. Movement of the disk may be taken as the axial movement of this collar (neglecting the linear thermal expansion between the two). If there is excessive movement of the disk from thrust-bearing wear (if it is more than the value set for direct mechanical trip), relay contacts are generated in the TSI system and are utilized for energizing the remote trip solenoid to initiate the turbine trip.

5.1.3.2 Thrust-Bearing Trip System Testing

5.1.3.2.1 Direct Mechanical Type Thrust-Bearing Trip Testing The test scheme/procedure is similar to the over speed trip test. The thrust-bearing trip function is simulated by the solenoid-operated HTT, which simulates the movement of the pawl. When the ATT-generated test signal is sent to activate the solenoid of the test valve, pressurized test oil is allowed to pass through it to a spring-loaded power cylinder, the shaft of which pushes the pawl in the direction of what happens for actual tripping by a direct mechanical method. After testing, resetting is done when the HTT is de-energized, and auxiliary start-up oil resets the device back to normal position

5.1.3.2.2 Electrical Tripping Type Thrust- Bearing Trip Testing This procedure is similar to that of over speed trip testing.

5.1.4 Electrical Remote Trip Solenoid and Testing

All other trips, including generator tripping signals, are taken together as a part of the electrical remote trip and ATT. The remote electrical trip system includes the signals from electrical signals as well as mechanical process signals in the form of processed electrical contact or the process switch itself. These signals are already discussed in Clause 3. All of these signals are tested individually but through a common trip relay and a common remote trip solenoid valve when energized. The testing procedure is similar to that of earlier systems.

5.1.5 Testing of MSCVs (HP and IPCVs)

It is often desirable to test individual MSCVs or governor valves. To test them with minimum disturbance, the load must be reduced to a load that can be run by the other running governor valve(s) when a particular governor valve is closed. A valve test signal is generated in the ATT system for calculation of the valve position demand signals, which implements closures of the valve under test and appropriate proportionate increasing signal (from the EHC) for remaining valves to open further to maintain the load and stem flow as demanded by the load/speed controller during the test.

For a system with many control valves, normally one control valve is tested. The corrected, individual valve position demand signals are generated at the EHC depending on the load. The valve test procedure is then followed by gradual closure of the governor valve under test and at the same time opening of the others.

When a particular HPCV is closed, the associated ESV may be tested for closure so as not to disturb the load/speed control as dictated by the EHC. After the closing tests, as

www.EngineeringBooksPDF.com

considered by the ATT, the further corrected test-related position demand signals enable gradual opening of the previously closed HPCVs and proportional closing of the remaining HPCVs.

5.1.6 Testing of ESV for HP and IP

It is quite common for all types of valves to experience several constraints, such as deposits/build-up on the valve stem, different worn out components, poor stem condition, etc., which may pose problems with free and smooth operation of the valve if not total control. The ON/OFF valves are affected the most due to the above effects, as the control valves normally modulate continuously and are less affected.

These valve operations should be checked on a regular basis. The frequency may vary and some manufacturers suggest that valves be tested more frequently to assure they do not get stuck in a particular position due to prolonged process demand. It is also a stringent requirement that each and every valve must be able to attain full shut-off condition to avoid excessive over speed. If the valves are not fully shut off, and the other devices do not work properly, the turbine may still excessively speed up beyond normal value, because the steam source is still present and uncontained despite the trip mechanisms actuating properly. The desired testing method demands checking of full-stroke excursion of valves, that is, the capability to operate through its entire range from fully open to closed position.

ESV test valves are provided for each ESV so that individual testing operations can be accomplished. ESVs are supplied with trip oil through this test valve, which provides port openings for both trip oil and start-up oil. This start-up oil is utilized for resetting of ESVs after the turbine tripping takes place. Handwheels are provided with each test valve to test the ESV operation from the field as well. There are separate and individual solenoid-operated ESV open/close tests and reset valves, which are operated through ATT for testing ESV opening and closing operations. The details are stated in Clause 5.1.1, point 2b. Upon getting a signal from the ATT, it allows control oil to act as auxiliary starting oil, which pushes down the plunger of the ESV test valve. This action enables the control oil to enter the upper part of the ESV power cylinder while the control oil for the lower part is guided to the drain. Figure IX/5-2 depicts this operation. If the closing operation is tested on load condition, the TG set load must be brought down to a lower level such that sufficient steam can pass through the other valve to take care of the load. It is normal practice that a particular ESV may be tested for closing action after the associated HPCV is closed by the ATT command so as not to disturb the load/speed control as dictated by the EHC.

5.2 Scope of ATT

5.2.1 ATT Overview Based on KWU Steam Turbine Control Philosophy

Listed below is the ATT overview (see Figure IX/5-3):

1. *Salient features of an ATT*: These are essential to the ATT so normal operation of the turbine is not affected and they include the following:
   - **a.** Separate and individual testing of each protecting device and valves so that individual specialist functions/duty can be checked.
   - **b.** Provide functional substitute so that during testing normal operation and protection is never affected.
   - **c.** To ensure that substitute devices are healthy and oil circuit is established so that during testing normal operation and protection is never affected; for this reason before a main test the preliminary test and hydraulic circuit is checked
   - **d.** After each test the resetting procedure must be followed so the system goes back to its original condition for readiness.
   - **e.** During testing if the turbine trips or the test is not performed within a specified time, the test must be abandoned and solutions must be found.
2. *Test category and procedure*: There are two kinds.
   - **a.** One is protective devices such as mechanical over speed, thrust wear, low vacuum trips, and testing of remote solenoid valves. Each of them can be tested one at a time. The health of each substitute device must be tested and a hydraulic circuit must be established, i.e., control oil must be sent to the trip oil line during testing. During testing of the protective devices a substitute device is very important, for example, while testing the remote solenoid valve test trip, the solenoid through the changeover valve keeps the trip gear pressurized. Balance testing procedures were discussed above and are well depicted in Figure IX/5-3B (left side).
   - **b.** The other part of testing is the testing the control and stop valves (see Figure IX/5-2). Since this directly acts on main turbine load-controlling devices, some criteria must be considered such as the load must be greater than the preset value and EHG must be in operation so that normal load/pressure control of the turbine is not jeopardized due to ATT operation. Preset value stated above depends on MW rating of the TG and on turbine configuration, i.e., number and type of stop cum control valve, for example, a 500 MW turbine with a four set of such valves. ATT is carried out at a load <160 MW. In any case not more than one set of valves can be tested at a time. As stated earlier, with ATT initiation the positioner motor of

www.EngineeringBooksPDF.com

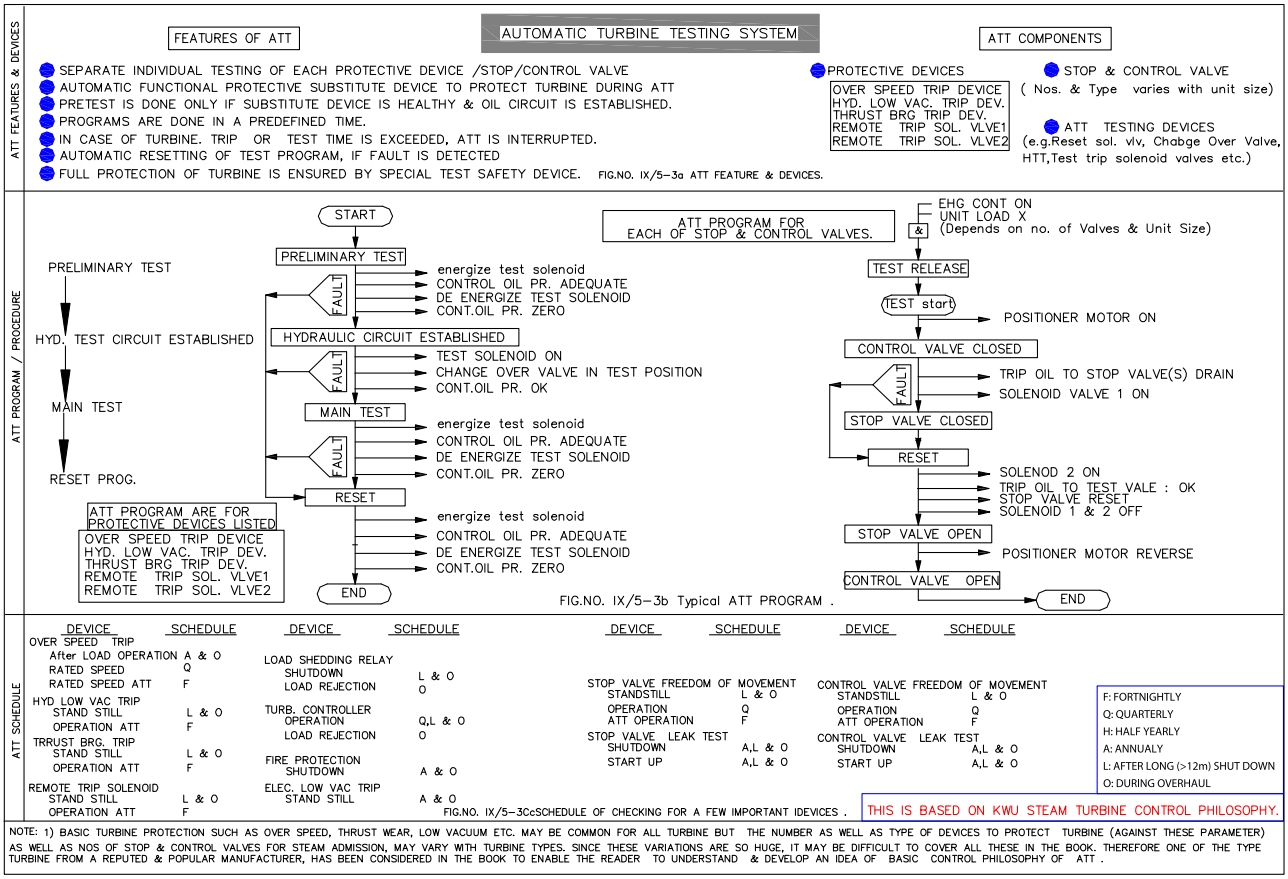


FIGURE IX/5-3 Overview of ATT system (typical for a particular turbine type).

the control valve moves to lower the oil pressure beneath the servomotor to close the control valve. When it is fully closed, ESV open/close test solenoid valve is energized to drain the trip oil (through the ESV test valve) beneath the disk of the stop valve servomotor piston; stop valve closes due to low oil pressure. After it is closed, the signal energizes another solenoid valve called the "test reset" valve, which allows trip oil to force the test valve spool to come down and supply oil to a place above and press the servomotor piston and the piston starts sitting on the disk. As soon as it sits on the disk, the pressure increases and is sensed by a pressure switch indicating preloading completion of the ESV servomotor. Both of these solenoids are de-energized; the ESV test valve afterward moves up to admit trip oil beneath the disk, and the space above the piston disk is drained. Naturally the stop valve goes up to open. After it is opened, the command goes to the control valve motor position to move in reverse direction to open the control valve. This is well depicted in Figure IX/5-3B (right side).

3. Details of the testing and checking schedules of other important devices are detailed in Figure IX/5-3C.

6. THERMAL STRESS EVALUATOR

Large-capacity thermal power plants are often required to start up and shut down the turbine a continuously increasing number of times. In consideration of the plant's long life (~25–30 years), the turbine metal stress conditions must be maintained for the plant to reach its life expectancy. During each start and stop, some metal stress is experienced by the turbine, which reduces power plant life expectancy in proportion to the amount of stress. Therein lies the necessity of the TSE, which evaluates and guides the TG set to run at minimum stress. The methods and equipment for monitoring turbine stresses are considered essential for all large-capacity turbines.

The TSE calculates and monitors the operational heat stresses of the turbine during every operational phase. The goal is to achieve continuous optimization between material stresses on the turbine and flexibility in reacting to operational changes. The TSE makes it possible to conduct both qualitative and quantitative evaluation of the thermal

www.EngineeringBooksPDF.com

stresses induced in the metal bodies during thermal shock. Detailed analysis of the TSE results in manufacturers developing materials with a high resistance to thermal shocks. There are a few methods by different manufacturers used to evaluate the thermal stresses at a given instant of thermal shock. The influence of the material anisotropy, that is, different properties at a given condition, on thermal stresses induced by thermal shocks is still unknown. However, simple expressions may be available using simulations to evaluate the thermal stresses when the material has anisotropies in physical properties, such as Young's modulus and a linear expansion coefficient.

6.1 General Causes of Turbine Stress

In rotating machines like a turbine operating in a high-temperature and high-pressure environment, repeated thermal shock causes damage and fracture. Such eventualities are big problems. There are many types of stress in metal bodies such as fatigue, creep, thermal stress, etc. Those type of stresses in turbine components are mainly caused by cyclic loading/unloading, steam temperature differences, and pressure and centrifugal forces(creep).The greater the applied stress value, the shorter is the material life. The damage is cumulative and materials do not recover even when rested from cyclic loading and unloading.

The TSE helps to calculate and predict nonsteady-state thermal stresses to which the steam turbine is exposed during different stages of operation, especially during start-up and shut down and as a result of changes in heat input to components during power operation are acquired and compared with the permitted limits. Such stresses mainly occur due to temperature difference between the exposed metal surface and the inner metal surface.

6.1.1 Fatigue

Material science is the progressive and localized structural damage that occurs when a material is subjected to repeated loading and unloading. The nominal maximum stress values are less than the ultimate tensile stress limit and may be below the yield stress limit of the material.

If the loads are above a certain threshold, microscopic cracks will begin to form at the surface. Eventually a crack will reach a critical size, and the structure will suddenly fracture. The shape of the structure also affects the fatigue life significantly. TSE determines the thermal stresses during operation and compares them with appropriate limits established on the basis of predictable operating conditions by means of appropriate low-cycle fatigue (typically less than 103 cycles) diagrams. TSE predicts various margins to limit rate of heating/cooling after evaluation of such fatigue and has now become a highly effective preventive maintenance feature for turbines.

6.1.1.1 Low-Cycle Fatigue

Low-cycle fatigue is the product of changes that take place in temperature and associated stresses whenever a dynamic change in TG operation is concerned such as start, shut down, loading, unloading, etc. The TG set has certain components with a thick cross-sectional area, for example, HPT and IPT casing, rotor, HPCV and ESV parts, etc., which are most affected by low-cycle fatigue.

6.1.2 Creep

Creep is a phenomenon detected by dislocations on grain boundaries of materials made of steel or related products caused by high temperature associated with high centrifugal forces, which ultimately result in permanent deformation on the affected turbine component. It is quite natural that the rotating components such as rotors, HPT and IPT blades, center bore, serrations, blade roots, etc., suffer most due to creep phenomenon.

6.1.3 Thermal Stress

Clause 3.5 of Chapter II discusses thermal stress; however, some brief discussion is incorporated here for quick recapitulation. Whenever there is a difference of temperature between the metal surface and inner metal, or mid-metal, thermal stress develops. It will be quite significant when metal thickness is appreciable.

During start-up and normal operation, steam with very high pressure and temperature passes through the turbine to become heated and deliver power output. The start-up procedure is more important as hot steam can cause cold turbine metal stress during initial entry of the steam. During normal operation, it is not as critical as the main steam temperature; a suitable temperature controller is always kept near a fixed temperature (after about 60% load) where thermal shocks are not expected. It is therefore extremely important that the thermal stresses are kept under normal value during start-up, whether it is a cold or the hot start-up.

6.2 TSE

6.2.1 Purpose

Modern power plants are equipped with a TSE for the purpose of safe operation guidance under all possible types of running conditions. A TSE is an instrument cum device that measures the turbine stresses in thick materials caused mainly from casing temperature and temperature differentials compared with the permitted limits.

The TSE generates the speed and load upper and lower margins, which are incorporated in the turbine start-up system, turbine automatic control systems, and are even used in the boiler control system while running on "coordinated control mode." The TSE guidance, popularly called

www.EngineeringBooksPDF.com

TSE influence, dictates the speed or load gradients along which the set value changes. In other words, the purpose of TSE influence is to limit the acceleration and load ramp gradients in optimum mode as regarding both degree of component fatigue and economical operation.

6.2.2 Measuring Temperature Points

Some typical and important measuring temperature points for a 250 MW plant are indicated below, but the actual number and measuring points may vary with the size of the plant and even with continued development of the device.

1. ESV inner and middle wall metal temperature
2. HPCV inner and middle wall metal temperature
3. HP casing inner and middle wall metal temperature
4. HP shaft surface and simulated middle wall metal temperature
5. IP shaft surface and simulated middle wall metal temperature

For items in 1−3, the mid or inner wall metal temperatures are measured at exact position by making grooves with the help of a honing process from the top through the wall of the subject material. But for items 4 and 5, since it is a rotating object, the mid-metal temperatures are computed from the corresponding surface temperature, which is located at a representative temperature point of surface of the shaft.

Other parameters are measured/calculated in TSE for computing the lower and upper margins, such as:

- Effective power and reactive power
- Steam before HPT and IPT pressure and temperature, also HPT mass steam flow
- HPT exhaust steam pressure and temperature
- HPT expansion section differential temperature

During start-up and shut down, the ESV and HPCV inner and middle wall metal temperature sensors (thermocouples) are utilized by the TSE to calculate necessary margins to the controllers for controlling the steam admission rate and quantity.

For the remaining TG set operations, that is, under normal loading/unloading operations, HP casing, inner and middle wall metal temperature and HP and IP shaft surface, and middle wall metal temperature sensors (thermocouples) are utilized by the TSE to calculate necessary margins to the corresponding controller for controlling the steam admission rate.

6.2.3 Principle of Operation

For each and every channel, the differential temperature between mid-metal and inner metal is calculated and then compared with the permissible highest and lowest temperature differences, which are dependent on the mid-wall temperature and are derived through the function generator. The results, that is, the subtracted values, are the upper and lower temperature margins and are available for warm up, loading, unloading, etc. The maximum selected upper and lower temperature margins are then the representative values for increasing or decreasing steam flow during start-up and then the rest of the on load operation. These values are indicated and also are utilized for further calculation. The upper load margin is added to and lower load margin is subtracted from the actual load, and the borders of the load range thus obtained are displayed as maximum and minimum permissible load, respectively.

7. LPBP SYSTEM

The LPBP system enables live steam to bypass the LPTs. These sophisticated systems as offered by different manufacturers have been working satisfactorily with much needed operational flexibility. The LPBP system was invented basically to cope with several transient modes of operation to ensure the protection of the plant components during various phases of turbine operation, which is a start-up and shut-down requirement in many plants.

With LPBP and high-pressure bypass (HPBP) systems functioning properly, the steam generator in fossil-fired utility boilers can operate on standalone mode as per its own system and process requirement bypassing the turbine mainly during start-up, shut down, and load shedding or any other type of huge load disturbance. It is therefore necessary that the LPBP systems must be adequately designed and sized to meet the requirements of different operating modes as decided by both owner and manufacturer.

The system helps not only in reducing time toward start-up and reloading of the TG set but also in enhancing the availability of the plant components and sizeable improvement on equipment life. The LPBP systems have been used in large, coal-fired thermal power plants as well as in combined-cycle power plants.

7.1 Purpose of LPBP System

Detailed discussions have already been incorporated in Chapter VIII, Clause 11.

7.2 Components of a Turbine LPBP System

As mentioned earlier, the main objective of the LPBP (and HPBP) system is pressure and temperature conditioning of steam with suitable pressure reducing cum control valve, compatible de-superheaters, and spray water control valve. As the process demands all the valves to reduce the pressure in any way, they must be suitable without generation of noise and vibration (associated with damage of valve trim due to wear and tear) beyond the limit values as

www.EngineeringBooksPDF.com

stipulated by controlling authorities. The LPBP system also controls the condenser protection by closing the associated valves in keeping with the system design demands. There are block valves in both steam and spray water lines to accomplish this job. The pressure control valve and de-superheater may be combined into one IP and LP turbine HRH bypass pressure control and de-superheating valve.

7.2.1 Isolation/Block Valves

The isolation/block valves upstream each of the LP bypass valves are provided to close the LPBP system for condenser protection as mentioned earlier. Isolation valves are installed according to regulatory body stipulation to ensure that leakage does not occur so that fluid can enter the condenser in LPBP closed condition. This function could be integrated in a composite control valve, provided the isolation valve's purpose is not compromised. The isolation valve therefore may be separate from the control valve or a combined valve having control function with a quick closing function and suitable leakage class as per the owner's specification/stipulation. This type of valve is normally hydraulically operated for achieving requisite very high actuating force and fast-closing criteria.

7.2.2 Pressure-Reducing and Control Valves

7.2.2.1 Sizing of Valves

Normally sizing of the LPBP system valves depends on the main system design as stipulated by the customer or consultant on their behalf as envisioned to take care of the individual plant requirements for a specific capacity. However, the range may go up 100% of the steam flow generated by the boiler as MCR. The pressure reducing/control valve and the de-superheater are available in combined configuration for less space requirement and other advantages like low noise and vibration design. Sizing of these valves actually depends on the quantity of steam flow to be bypassed to the condenser through the LPBP system, which in turn is dictated by a number of other variables such as condenser internals, start-up, loading, unloading, and shut-down practices and requirements for the unit, plant safety aspects, and of course the economic aspects.

There are a number of considerations and factors that determine the size of the bypass system. The combined HPBP and LPBP system may be selected to take care of the following operating conditions:

1. Fifteen percent of MCR flow when the system is to match the steam-to-turbine metal temperatures, which may save half an hour during start-up
2. Forty percent (or more) of MCR flow when the system is to match the difference between the supplied steam flow and the steam utilized for power generation and other uses during any disturbed or transient conditions
3. One hundred percent of MCR flow to keep the steam generation uninterrupted at full load in case of a turbine or generator trip without wasting energy and steam through operation of the safety valves

7.2.2.2 Noise and Vibration of Valves

The LPBP system valves are used to reduce pressure and hence are subject to generate a high noise level. The noise level as stipulated by different controlling authorities for the thermal power plant is 85 dBA from the source of noise. The standard method of abating noise is using acoustic insulation or providing back-pressure diffusers downstream the valve plug and near the outlet of the valve body. Some manufacturers' designs provide multiple zigzag channels in the specially invented outlet port of the valve that divide the fluid flow path into several discrete paths increasing the frequency of the generated noise. The adjacent piping and structures can easily absorb this higher frequency noise to such an extent that noise abatement is $\geq$10 dBA as compared to conventional noise-reduction methods.

Some manufacturers' designs incorporate special types of contoured profiles so that wave interference is produced. Due to this phenomenon a majority of the aerodynamic effects are canceled out resulting in reduction of noise and vibration. The injection of spray water for de-superheating within the body also causes noise attenuation in the combined pressure reduction and de-superheating system (PRDS) if applied for LPBP. Noise generated by the valve can thus be kept below 85 dBA throughout the entire operating range. A highly turbulent zone is created just near downstream the valve seat of the specially designed and contoured cage. For highly efficient mixing of steam and de-superheating spray water, the ideal place for in-body injection is this turbulent zone. The noise is automatically attenuated as water injection takes place inside the valve body, thereby ensuring that this turbulent zone is removed from the valve surface and the source of vibration is eliminated.

Excessive vibration in LPBP valves can damage pipe hangers, valve-trim materials, and shake accessories of different parts of the actuators causing high maintenance costs and unscheduled downtime leading to a loss of revenue.

7.2.3 De-superheaters

In modern thermal power plant application normally a direct water spray de-superheating system is used. This type of de-superheater represents the vast majority of de-superheating applications. In water spray de-superheaters, superheated steam is passed through a section of pipe fitted with one or more spray nozzles. These inject a fine spray of cooling water into the superheated steam, which causes the water to be converted into steam, reducing the

www.EngineeringBooksPDF.com

quantity of superheat by the temperature of the steam. The cooling water may be introduced into the superheated steam in a number of ways, consequently, there are a number of different types of water spray de-superheater. The design of water spray de-superheaters are affected by the following factors:

1. *Particle size*: The smaller the water particle size, the greater the ratio of surface area to mass, and the higher the rates of heat transfer. Since the water is directly injected into the moving superheated steam, the smaller the particle size, the shorter the distance required for heat exchange to take place. The water is broken into small particles using either a mechanical device (such as a variable or fixed orifice nozzle) or steam-atomizing nozzles.
2. *Turbulence*: As the flow within the pipeline becomes more turbulent, the individual entrained water particles reside longer in the de-superheater, allowing for greater heat transfer. In addition, turbulence encourages the mixing of the cooling water and the superheated steam. Increased turbulence results in a shorter distance required for complete de-superheating to occur. The phenomenon of turbulence can be attributed to these two things:
   a. *Pressure drop across the nozzle*: Subjecting the cooling water to a higher pressure drop will increase its velocity and induce greater turbulence.
   b. *Velocity*: By increasing the overall velocity of the water and steam mixture, the amount of turbulence is inherently increased. The increase in velocity is usually achieved by creating a restriction in the steam path, which further generates turbulence by vortex shedding. In addition to these high velocities, if poor piping design practices are used, the speed of the superheated steam could, in theory, approach Mach 1. At such speeds a number of problems occur (including the generation of shock waves). However, this would be far in excess of the velocities used in good piping design. Typical velocities of steam entering a de-superheater should be $\sim 50-60$ m/s.

In LPBP systems de-superheaters are very important where comparatively low-temperature water is sprayed over the hot steam to lower the mixture temperature as desired by the process. A thermally efficient design of de-superheater bodies can eliminate the stresses caused by various reasons such as thermal transients associated with cycling duty.

In any efficient type of de-superheater design, complete evaporation of the injected water is ensured to avoid water particles hitting the adjacent walls of the valve or downstream piping. A high degree of atomization of the injected water is responsible for accomplishing a superior class of mixing with the steam and resulting in quick evaporation enhancing de-superheater performance.

For an efficient de-superheater, proper location and direction of the spray water jet is extremely important so that complete evaporation is attained before the first pipe bend to stop any high-speed water particles impinging on the pipe walls causing erosion. The relative speed of steam flow to that of injection water flow determines the quality of spray water atomization. Full atomization is always followed by high water injection speed and injection of the de-superheating water into a one of turbulent, high-speed steam flow. Other factors, such as piping layout, selection of spray water valve, flow range, and selection and performance of the control system, influence the performance of the de-superheater as a whole.

A de-superheater may produce good atomization when there is multistage pressure reduction to ensure smooth downward pressure drops to eliminate any cavitation, flashing, trim erosion, noise, and vibration and ultimately to maintain exact temperature control at all steam flows as required by the plant operating condition. The ideal place for water injection into a high steam-flow turbulent zone for efficient de-superheating is downstream the valve body just after the plug/seat/trim assembly. Appropriate selection of material, properly designed arrangement of the injection nozzles, and shape and hole pattern of the cage around the injection zone may give the best results for fully atomized spray water before the steam leaves the valve body. The efficient implementation of the whole process results in the shortest evaporation length.

There are various types of de-superheaters: single-point radial injection spray, multiple-point radial injection spray, single nozzle axial injection, multiple nozzle axial injection, etc. In the following clauses commonly used de-superheaters will be discussed.

7.2.3.1 Ring Type De-Superheater

Ring type de-superheaters are also suitable for LPBP applications. Here, a separate de-superheating chamber is provided downstream the pressure-reduction area. In a ring type de-superheater, the shape of the steam-flow steam causes the creation of turbulence inside the chamber. The steam velocity is increased by a contraction of the flow path and then allowed suddenly to expand. The injection and mixing are arranged to take place in this turbulent region so that the shortest distance as desired for atomization is ensured for proper evaporation.

7.2.3.2 Steam-Assisted De-Superheaters

This type of de-superheater is also another type of atomization outside of the valve body. The design is based on a combination of high-speed water injection into a high-velocity Venturi steam flow. Cooling liquid is introduced

www.EngineeringBooksPDF.com

into the steam header through a stainless steel nozzle assembly, which uniquely divides one large jet of liquid into many small jets. Just prior to entrance into the main header, each jet is bombarded by a higher pressure steam jet, creating a fine mist, which enters the stream flow without the need of a thermal liner inside the main header. The de-superheater thus reduces the size of the liquid particles so that the droplets can be quickly and efficiently evaporated.

Downstream temperatures can be controlled to within a small value higher than that of saturation. The thermal sleeve around the liquid tube ensures uniform expansion with the steam tube, thereby minimizing thermal stresses due to unequal elongation of the liquid and atomizing steam tubes. The cooling liquid is introduced through a series of small orifices, which are drilled circumferentially into the nozzle. Small slots are milled 90° to the drilled holes. Atomizing steam passes through each of the slots and blasts each of the cooling liquid jets. Liquid pressure of only a few bars above the steam header pressure is necessary to inject the cooling medium. Hard face (stellite) in the nozzle head minimizes erosion wear and tear.

Some designs introduce a compound swirl-type nozzle, which provides high injection speed while the atomizing steam provides a velocity that is virtually independent of the main steam flow that may be taken from a different source altogether. The spray pattern is centered in the piping to produce even temperature distribution at all flow conditions. For this type of de-superheater, the distance required for atomization is the shortest of all downstream de-superheaters. This design provides significantly better atomization than the ring type and spring-loaded nozzle de-superheaters currently available in the industry.

7.2.3.3 Spring-Loaded Injection Nozzles

Spring-loaded nozzles are typically used for LP bypass applications by introducing cooling liquids directly into the hot fluid. Multiple nozzles, which can be opened or closed to vary the coolant flow and provide a higher turndown than single nozzle units and where the amount of coolant flow is dependent only on the ability to vary the pressure drop across the nozzle, are used. The atomizing principle of spring-loaded injection nozzles is based on high-speed injection. Due to the design of the spring-loaded nozzles, a sufficient injection pressure and injection speed exists at minimum load. The injection speed results not only in good atomization but also in a sufficient penetration of the spray water into the steam flow. The design contains an integral spring-loaded flow plug, which moves in response to a change in pressure differential between the coolant inlet pressure and the main header pressure. As the plug moves, nozzles are uncovered introducing coolant into the main header. The varying inlet coolant pressure is controlled by a separate water or coolant control valve. The coolant enters the unit and passes through the center of the spring spacer, spring, and plug. Unbalanced forces created by the coolant over line pressure differential cause the plug to move, exposing more or fewer flow nozzles. The coolant is atomized as it passes under pressure through the spray nozzles, which further assist in evaporation of the coolant.

In some designs, a spring-loaded nozzle incorporates a unique swirl pattern, which provides rotational energy to the spray water over the entire range of flow conditions. This ensures an even distribution, which produces good mixing of steam and spray water with extremely good rangeability.

7.2.4 Instrumentation and Control System

This system was discussed in Chapter VIII, Clause 11.

8. TURBINE CONTROLS: SEAL STEAM PRESSURE CONTROL SYSTEM

8.1 Seal Steam Pressure Control: Background

The turbine shaft has to exit its casings to couple up or connect with the unit that the turbines drive (generator, reduction gears, pumps, etc.). The seal steam system enables the turbine to be sealed where the shaft exits the casing—in effect keeping "air out and steam in." Sets of labyrinth packing are used along the turbine rotor where the rotor exits the turbine casing to maintain this pressure differential between inside and outside. The labyrinths create many little chambers causing pressure drops along the shaft. The number of labyrinth sets depends greatly on the possible steam pressure in that area. Labyrinth packing alone will not stop the flow of steam from the turbine high-pressure part or prevent air into the turbine connected to the vacuum.

The gland sealing steam system provides low-pressure steam to the turbine gland in the final sets of labyrinth packing. This assists the labyrinth packing in sealing the turbine to prevent the entrance of air from reducing or destroying the vacuum in the associated condenser. Excess pressure (excess gland seal) also has to be removed and put into the gland steam condenser. The large, turbine gland sealing systems are basically self-sealing, in the sense at a load >40% HP steam coming out from the HPT side could be enough to seal the same on the LPT side. Up to nearly 40% load low-pressure auxiliary steam is supplied to the sealing header to seal HPT, IPT, and LPT glands. During this period the flow line to the condenser is closed with the help of a control valve. Above this load point the steam coming out of the HPT will be more than enough to seal the LPT gland and more, and the excess is sent to the condenser. At around this load point the auxiliary steam supply control valve is closed and the HPT and IPT glands

www.EngineeringBooksPDF.com

(as applicable) leakage steam is routed through the leak control valve to other glands so that seal steam pressure can be maintained and excess steam will be sent to the gland steam cooler/condenser. During start-up, vacuum building is the first step. It is necessary that some steam is supplied to the turbine glands from auxiliary steam via the seal steam supply control valve. With load building up inside the turbine, HPT and IPT leakage from there will go to the gland steam supply header to increase the pressure, which will compel the supply valve to close. Normally the auxiliary steam header is maintained at a fixed pressure and temperature (at 10 kg/cm^2 or 16 kg/cm^2 and ~210°C). However, because this seal steam is required during start-up and low load the seal steam pressure and temperature requirement may be much lower than the auxiliary steam header pressure and temperature. Therefore it is necessary that there will be requirement of the PRDS, which must be considered (not shown).

8.2 Control System

Since this control loop is connected with the start-up of the turbine, it is often supplied as an integral part of the turbine instrumentation package by the turbine manufacturer. Also during start-up, trip, and/or large throw off there will be a great deal of disturbance inside the turbine pressure so the control system needs to be designed to cope with these eventualities and has to respond fast to avoid unnecessary leakage in the turbine. For this reason, the actuators for these valves are often the electro hydraulic type. Also, some special characteristics are incorporated in the loop at the proportional part to cater to varying conditions of seal steam under different operating situation/eventualities.

8.3 Control Loop

See Figure IX/8-1 for an example of seal steam pressure control.

8.3.1 Objective

Seal steam from the seal steam pressure header is used to seal turbine glands so that steam does not out come out of the turbine and air does not go into the turbine. In both the cases there will be loss of turbine efficiency. The main objective of this loop is to ensure constant pressure at the

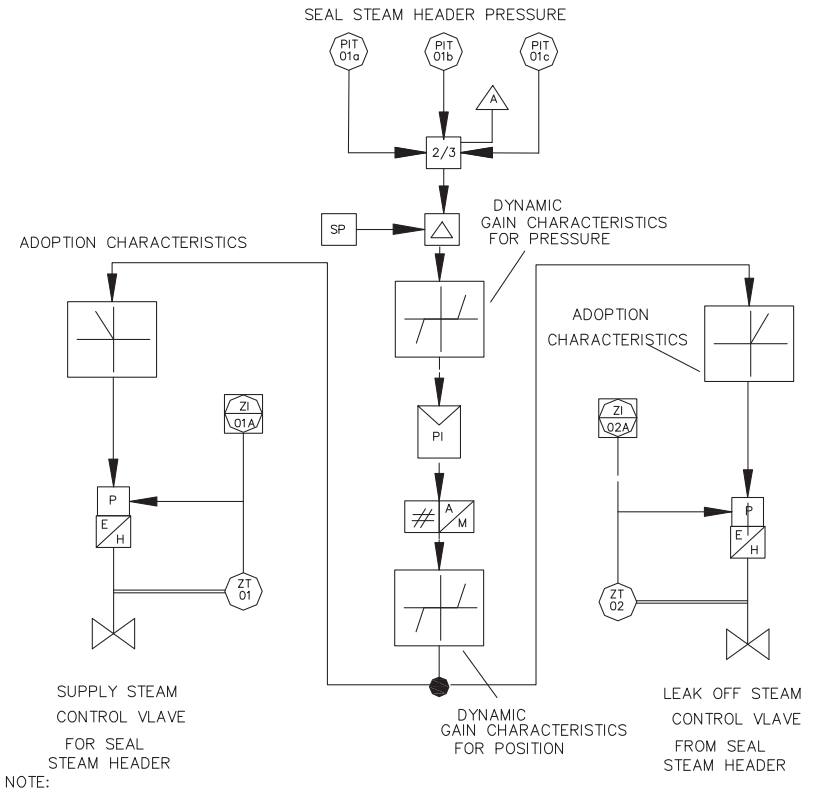


FIGURE IX/8-1 Seal steam pressure control.

www.EngineeringBooksPDF.com

seal steam header so that there is no leakage through any of the turbine glands.

8.3.2 Discussions

As discussed earlier, at lower load auxiliary steam supplies the required steam to the header used to seal the glands in HPT, IPT, and LPT. Pressure rather than flow to the seal steam header is controlled by regulating the supply steam control valve. As load increases (i.e., >40%) when the pressure inside the HPT and IPT increases, leakage from the these glands occurs. The supply steam from the auxiliary steam may not be necessary and it will self-sealing, i.e., this leakage steam from HPT and IPT glands is utilized to seal the LPT gland and excess steam is regulated via leakage control valve.

8.3.3 Control Loop Description

As discussed in the previous clause, there will be two control valves regulated to control the header pressure. The header pressure is measured by a number of pressured transmitters with due redundancies. It is important that redundancies are considered, but it depends on the manufacturer and owner. The measured value is compared with the set point, which could be set from a control room monitor and/or control plaque as applicable. The error thus created is fed into the controller. However, prior to sending the error signal to the controller it is passed through a dynamic gain characterizer. Apparently the loop is quite simple, but one has to bear in mind the eventualities.

During turbine trip, shut down, quick loading, and large load throw off, there will be a huge fluctuation in steam pressure inside the turbine and these would take place at a very fast pace. To cope with such situations, the error signal thus created is passed through the dynamic gain characterizer so that when there is an error signal more than the preset value, the gain will change to a greater value. Output of the controller is fed to a proportional controller via auto/manual (A/M) station. So, position can be controlled manually as well. Here also a dynamic gain characterizer is kept to meet the challenges discussed earlier.

Finally, the output is fed to the two control valves. As discussed earlier, the supply valve normally operates up to a preset (i.e.,40%) load, and after that it will close. Whereas the leakage control valve comes in to the operation load more than the preset value (i.e., 40%), and at lower load it remains closed. To utilize this characteristic to regulate two control valves from one output, each of them have been provided adoption-characteristic function generators to operate both valves in split range. Normally the final actuator of these valves are hydraulic, so the electronic signal from the loop is fed via an electro hydraulic converter with a suitable positioner. In most cases this control system forms a part of the integral instrumentation package of the turbine.

9. HYDROGEN SEAL OIL SYSTEM AND DIFFERENTIAL PRESSURE CONTROL

9.1 Hydrogen System

The brief description in Chapter II, Clause 4.1, incorporates the requirement and basic process of hydrogen and seal oil system. Hydrogen leaking because of a dangerous explosive mixture with atmospheric oxygen is prevented by oil sealing supplied with a slightly higher oil pressure. A CLCS is provided to maintain seal oil to hydrogen differential pressure (DP) control along with hydrogen and seal oil temperature control.

9.1.1 Moisture in Hydrogen Cooling System

In its delivered form, whether from an external or in-house source, hydrogen gas has a dew point of approximately −50°C. The hydrogen dew point for this type of requirement is normally maintained at <0°C. Problems may crop up when the generator is in shut-down condition and hydrogen moisture levels increase beyond this point. The water particles deposit and cause the retaining rings of the rotor windings to crack if there is moisture on the rings. There are generators cooled by hydrogen with dew points of −30°C or lower depending on the climatic condition of the site.

9.2 Seal Oil System

Hydrogen is hazardous if it leaks and mixes with air with the possibility of an explosion. The idea of preventing leakage of hydrogen along the rotor shaft developed into a sealing system consisting of oil with pressure slightly more than the hydrogen pressure. It receives make-up oil from the bearing lubricating oil system. The seal oil system defines the arrangement of arresting not only the escape of hydrogen from the generator casing but also the ingress of air into this casing near the rotor shaft projected outside of the casing at both ends.

Seal oil pressure at the seal housing is ∼ 0.25−0.4 kg/cm^2 higher than the generator coolant hydrogen gas pressure. The sealing arrangement is such that the seal oil flows in both directions, that is, the air side and the hydrogen side along the shaft. As the seal oil pressure is slightly more than hydrogen-side pressure, some oil flows toward the hydrogen (6−7 kg/cm^2) thus blocking the flow of hydrogen to atmosphere along the shaft. Conversely, most of the seal oil flows toward the atmospheric pressure zone through the bearing housing. On the air side, the air−oil mixture mixes with the bearing lubricating oil, while on the hydrogen side

www.EngineeringBooksPDF.com

some hydrogen gas mixes with the sealing oil. In some generator cooling systems, the bearing cooling oil and seal oil systems are different, whereas most of the manufacturers of generator cooling systems offer combined lubricating oil and hydrogen seal oil systems.

9.3 Description of Seal Oil Flow Diagram

The seal oil system supplies seal oil to the seal plates of the gas-tight TG set and all types of operation irrespective of normal or emergency conditions. A DP between the seal oil and hydrogen gas is maintained to prevent hydrogen leakage (see Figure IX/9-1).

This system normally takes its suction either from the governing or lubrication pump discharge with standby emergency supply from AC and DC seal oil pumps. Alternatively, the suction is from the oil reservoir and supplies oil to the seal plates with the help of separate seal oil pumps with sufficient redundancy. There is a recirculation line connected from seal oil pump discharge lines to the reservoir through a control valve, which modulates to maintain the DP between seal oil and hydrogen. The standby pump starts automatically when the pump discharge header pressure falls below a preset value through interlock with the pressure switch. There may be a flow switch instead that actuates the standby pump when the bypass flow falls below a preset limit. Many designers prefer the use of the flow-measuring device rather than DP sensors, because this flow-associated system can detect many types of malfunctions and anticipate the need for initiating standby pump operation before seal oil DP actually begins to drop.

In many thermal power plants the seal oil system is combined with the lubrication oil system of the turbine. The lubrication oil pump provides oil to the seal plates through a seal oil pressure-regulating valve. The back-up provisions made for the lubrication system are also available for the oil supply of the sealing system, making the system simplified without requiring a separate source of seal oil but necessitating a relatively high-pressure lubrication system. These systems typically operate with a pressure differential of $\sim 0.25-0.4\ kg/cm^2$. This is necessary to eliminate hydrogen contamination by air ingress in the seal oil, which is forced to flow along the shaft toward the hydrogen-filled generator.

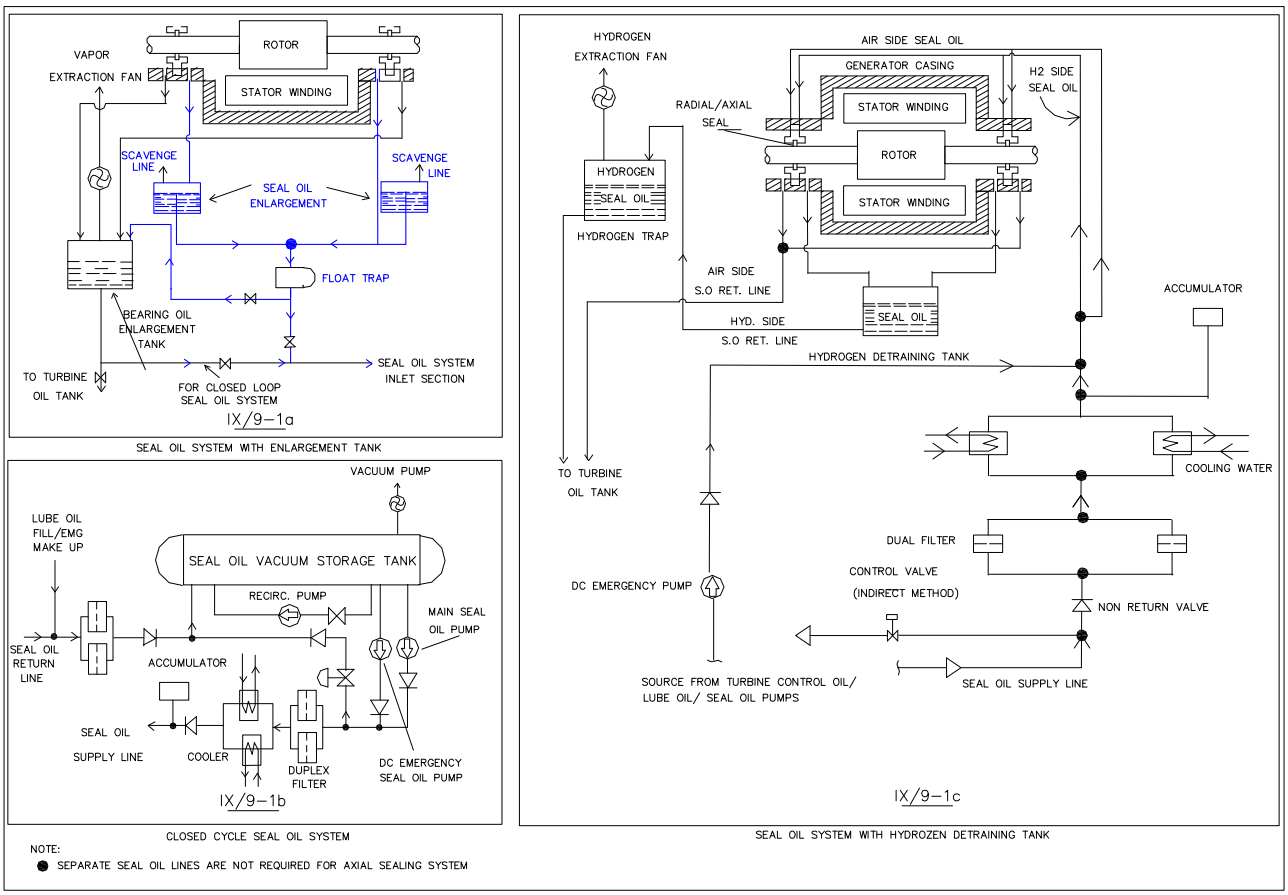


FIGURE IX/9-1 Seal oil flow diagram.

www.EngineeringBooksPDF.com

9.3.1 Requirement of Accumulator

To cope with abrupt change or failure, the standby pump cannot be brought up to full pressure immediately and for maintaining uninterrupted seal oil flow an accumulator may be provided, which supplies seal oil for a few minutes when there is a sudden drop in seal oil pressure below the normal operating value. The nonreturn or check valve in between the accumulator and the pump discharge header (after the recirculation line) would prevent seal oil to flow back but supply the seal plate. The pressure or flow-measuring devices are excellent in detecting maloperation when the seal oil supply decreases at a relatively slow pace. The nonreturn or check valve in between the accumulator and the pump discharge header prevents seal oil from flowing back and supplies the seal plate.

9.3.2 DP Control System

There are two types of control philosophies: indirect and direct. The indirect type has the control valve placed in the recirculation line, which modulates as per the output of the controller's measured variable—the DP between the seal oil and hydrogen against a fixed set point. The amount of excess oil necessary to maintain this DP returns to the reservoir (see Figure IX/9-2C and D).

The direct type envisages the control valve in the pump discharge line, which regulates the DP by directly allowing oil flow (see Figure III/11.1.2-7) as per the controller output. In some double-injection types, separate sets of seal oil pumps are provided for the hydrogen-side and air-side sealing systems and DP is controlled only for the hydrogen side; one control system each for exciter end and turbine end is also provided. Seal oil and hydrogen temperature controls are shown and incorporated in Figures IX/12-2 and IX/12-3, respectively.

9.3.3 Type of Pumps

There are three types of pumps available:

1. *Screw*: Generally used for the services where constant flow with high pressure is the requirement.
2. *Centrifugal*: Generally used where constant pressure is required for the system.
3. *Positive displacement gear type*: Recommended for constant flow services.

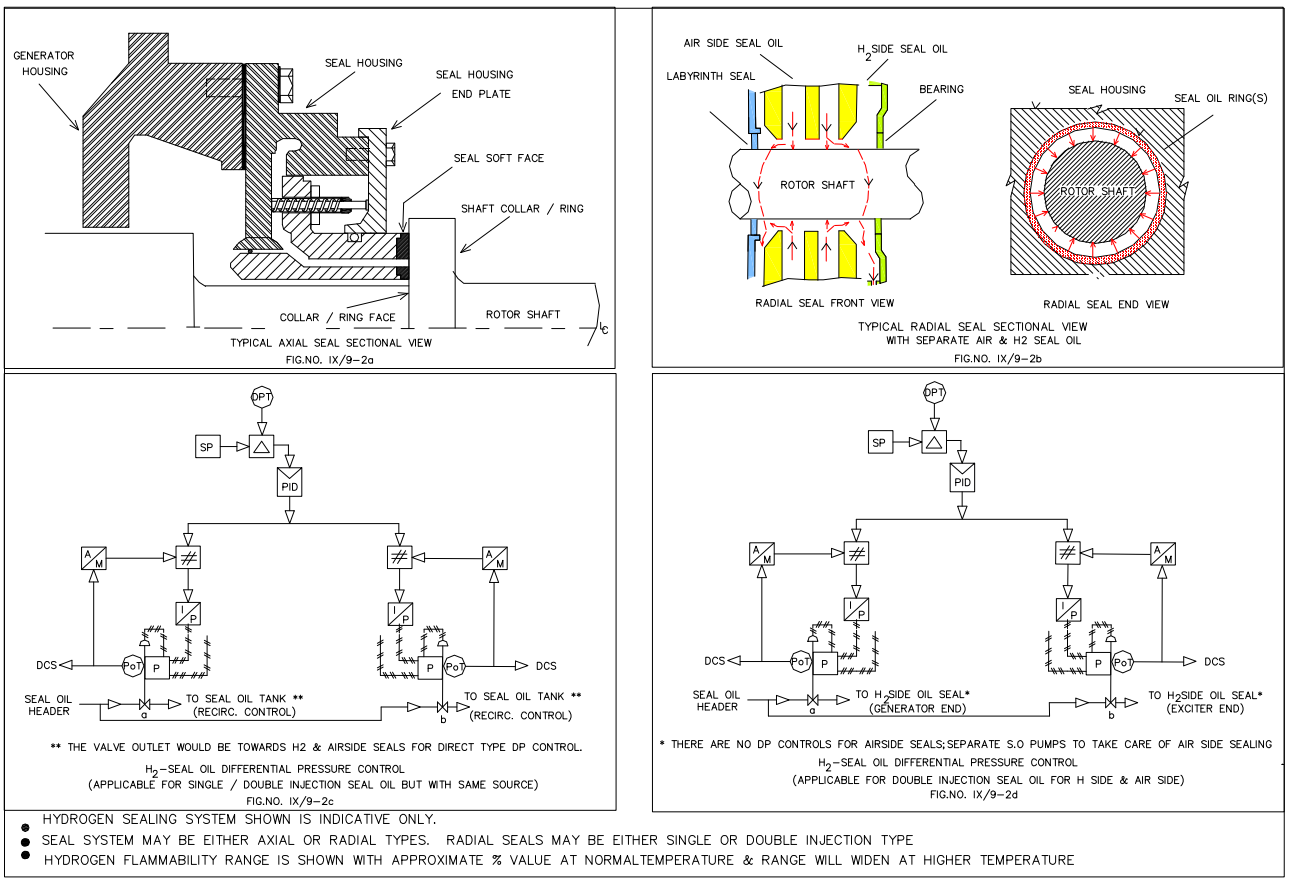


FIGURE IX/9-2 Basic type of (axial and radial) seals used in hydrogen and seal oil systems.

www.EngineeringBooksPDF.com

All of these pumps are supplied with an integral safety relief valve at the pump discharge side to return to the reservoir to avoid high-pressure build-up over and above the designed pressure. The pump discharge head is calculated on the basis of maximum generator hydrogen gas pressure plus the DP to be maintained between seal oil and gas, pressure drop of the system, and 10% spare capacity.

9.3.4 Requirement of Filter

Whatever the type of sealing arrangement, the effect of generator contamination is the same. Shaft-sealing system failure may take place when a particulate contaminant enters the seal oil system due to wear of the gland seals. This untoward situation lets hydrogen escape the generator and results in a forced outage with particulate contamination in the sealing process.

To circumvent particulate contamination, filtration of sealing oil is essential before it reaches the generator seals. Ensuring the proper mesh size of the filters prevents passage of particulate coarse enough to cause damage to associated materials. The international guideline as per ISO 4406 is generally followed to minimize erosion and maximize the component life of the seal oil system. Normally the above guideline is expressed as "cleanliness level" and for the generator seal oil system it is recommended to be maintained at an ISO 14/12 cleanliness level. ISO 14/12 has now become a standard recommended practice and it specifies using a 3−5 μg filter with a duplex construction and online changeover facility.

9.3.5 Requirement of Seal Oil Coolers

Note that function of seal oil is not only to arrest leakage of hydrogen gas from the generator but also to keep the seal metal at an acceptable temperature limit. During the sealing process, the seal oil takes the heat away from the sealing surface and experiences some rise in temperature that needs to be transferred to another cooling media to maintain the closed loop seal oil system. Redundant seal oil coolers are provided for that purpose and the cooling media is the water supplied from the clarified cooling water header.

9.3.6 Basic Types of Seals

Hydrogen seals are metal rings normally made of babbit, bronze, brass, or may be of carbon. They use very precise geometry to maintain proper sealing over the total range of operating conditions. The seal system may consist of a single seal or a separate seal for hydrogen- and air-side leakage prevention. The seals are categorized into two basic sealing systems, which are widely deployed:

1. Axial ring shaft seal or thrust collar type
2. Radial oil seal or journal (ring) type

For the axial ring shaft seal (Figure IX/9-2A) the seal ring floats on the shaft and does not rotate. The seal ring is held against the shaft ring face with the help of axial force exerted by the spring and partly by the seal oil pressure. The seal ring at the front of it is provided with a continuous soft metal face. The seal oil pressure forces itself to flow toward the seal face while the majority of the oil flows outward and the rest flows inward toward the rotor shaft. The pressurized oil is supplied at a particular pressure to both sealing sides to maintain required oil-film thickness formed in between the soft seal metal of axial thrust face and the rotating collar, which acts as lubricating oil and as a cooling agent for the heat generated from friction and to lessen the wear and tear caused by the same.

Radial oil seal (Figure IX/9-2B) or journal type seals are the most common type of seal. These seals are different, because they do not have any contact with the turbine shaft and thus require no soft metal seal face. The inner diameter of the seal is slightly larger than the outer diameter of the rotor shaft and is held tightly around the shaft with springs. The ring with the narrow clearance is placed between the sealing ring holder/bracket and the rotor shaft. High-pressure oil is injected from a set of holes/ports and grooves into a stationary seal ring surrounding the rotating shaft. High-pressure oil is thus spurted onto the shaft toward both sides of the seal. These seals are sometimes referred to as hydrogen gland seals. If only the ring is pressed without any clearance from free movement, the oil injection can be avoided. But in that case, friction between the ring and shaft develops and causes damage to both of them. The pressurized oil acts here as a cooling and sealing media, and lessens the DP across the seal (without seal oil the DP would have been the generator casing hydrogen pressure). The seal oil system may consist of both single or dual/multiple (for air and hydrogen side) pressurized oil lines. Figure IX/9-3 incorporates the views of single seals and two separate hydrogen-and air-side seals. Two sets of holed rings are for the hydrogen side and the air side with a vacuum ring located in between these two rings to extract the oil from the seal area. These rings can accommodate both axial and radial shaft movements. Radial seals are used for both separate and common seal oil pressure lines as depicted in Figure IX/9-3.

9.4 Hydrogen and Air Removal from Seal Oil

Other critical components of the seal oil system are included in the hydrogen and air removal systems, which supply clean and pure oil to the extent possible for sealing purposes. Examples are listed below:

1. *Degasification through spray nozzles*: Degasifying plants use a very common method of removing

www.EngineeringBooksPDF.com

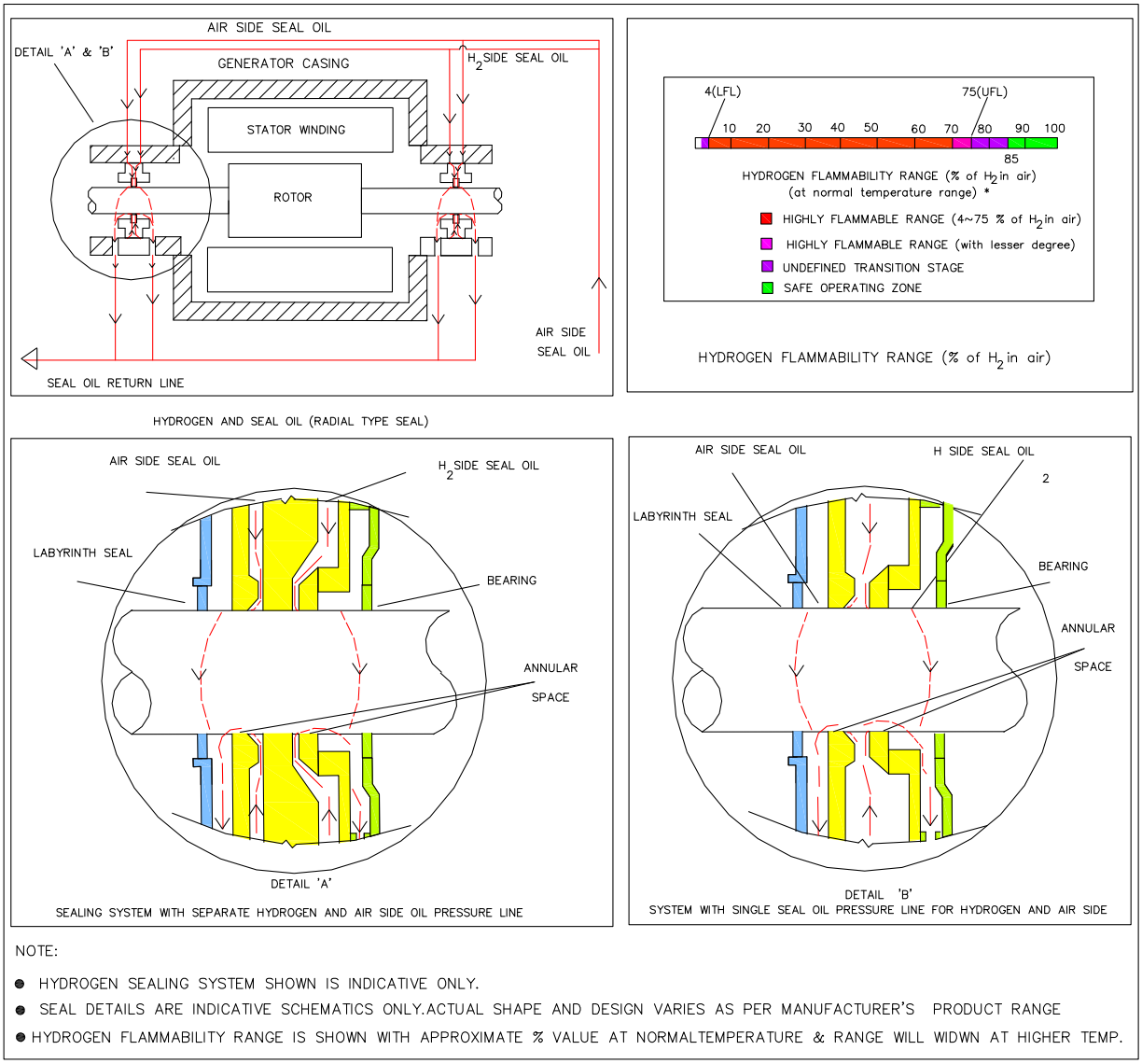


FIGURE IX/9-3 Different types of radial seals used in seal oil lines and hydrogen flammability range.

entrained hydrogen and other gases is through "vacuum-treat" of the seal oil before applying it to the seals. The same is done directly in the main seal oil supply tank when separately provided. The seal oil is extracted right from the sealing location into this tank, which is maintained under vacuum. The oil reaches the tank through a spray nozzle and is converted into a fine mist and supports the action of liberating dissolved gases from the oil, which are then are removed from the system. In this type of plant, an additional recirculating pump is also provided to recirculate oil back to the supply tank through a series of spray nozzles for continuous gas removal (Figure IX/9-1B).

2. *Removal through detraining tank*: A separate "detraining tank" is provided along with a "hydrogen trap" and "extraction fan" to accomplish removal of entrained hydrogen from the seal oil system. Due to the configuration of the seals and sealing arrangement, the majority of seal oil flows to the air-side drain of the seals and is led to the main/seal oil tank through bearing sumps, etc. A small portion of seal oil flows toward the hydrogen side and drains through to reach the detraining tank. The two sides of the tank are connected through pipelines of sufficient bore diameter to enable seal oil to drain and hydrogen to pressurize the tank. Two lines are used to keep the tank under pressure balance. The entrained hydrogen is almost separated from

www.EngineeringBooksPDF.com

the oil and the oil accumulated at the bottom of the tank is forced upward to the hydrogen trap by the generator hydrogen pressure,. The trap is equipped with an extraction fan, which removes any remaining entrained hydrogen by venting it to the atmosphere at a safe place. The oil in the hydrogen trap, however, returns to the turbine oil tank through gravity action (see Figure IX/9-1C).

3. *Removal through scavenging via enlargement tank*: It is possible that air is entrained in the source of the seal oil, which may be released from the seal oil that flows into the generator-side hydrogen area causing reduced hydrogen purity if not removed. The removal process is popularly known as "scavenging." The hydrogen-side seal oil drain is arranged to accumulate in the enlargement tank whose oil level is maintained though overflow pipe. The tank may be a single type with one vertical separator or one for each side. The two overflow pipes are connected via loop seals to a float trap. This arrangement assists entrained hydrogen and mainly air bubbles to release and gather at the top of the tank. A small amount of gas (air and hydrogen) is allowed to be vented from this seal oil enlargement tank where the entrained air is expected to be released from the seal oil to the atmosphere at a safe area. The seal drain enlargements are vented through the needle valves in the scavenging lines, and scavenging flow rates can be controlled according to the hydrogen purity reading. Because a small amount of gas (air and hydrogen) is continually vented to atmosphere through the scavenging system, the pressure inside the generator decreases and must be replenished into the system in the generator casing from a source of high-purity hydrogen (see Figure IX/9-1A).

The air-side seal oil is also taken to a vessel known as a bearing drain enlargement tank with maintained oil level with mainly air on the top where it is released to the atmosphere through a vapor extractor.

The hydrogen-side seal oil drain after the float trap is sent to the bearing drain enlargement tank for normal plant operation or sent to the seal oil recirculation line for standstill condition. For the common turbine oil tank, vapor extractors are provided to release the entrained air (mainly) to prevent air ingress in the generator casing through the generator-side seal oil as the only source.

In some closed loop seal oil systems, the hydrogen-side seal oil drain enlargement tank is also called a "H_2 detraining tank" without a scavenge connection line, whereas the air-side oil drain enlargement tank is called an "air detraining tank" with a vent connection to release entrained air and hydrogen. The major gas removal is done at the main seal oil tank as stated above.

9.5 Discussions on and Problems with Hydrogen and Seal Oil Systems

With aging and harsh process conditions, the geometry of various parts of the seal, such as rings, brackets, holding springs, etc., may change due to wear and tear or even by premature damage resulting in excessive leakage of seal oil. For example, dirty oil can also be responsible for wear of the seal rings due to abrasion. The application of the type of seal oil system depends on the type of shaft seal used in a particular generator. Axial and radial movement (although very small) and vibration of the generator rotor, drift in set value, or any other problem of the seal oil/ hydrogen DP control system may be the source of increased seal oil flow.

In some generator cooling systems, the bearing cooling oil and seal oil systems are different; in that case, the air—oil mixture of the air-side mixes with the bearing lubricating oil, while on the hydrogen side the sealing oil drains mixed with hydrogen gas return to the seal oil reservoir. The trouble with having individual seal oil systems is that somehow at some point the seal oil and bearing lube oil mix with each other causing problems. Most of the systems, however, provide combined lubricating oil and hydrogen seal oil systems to avoid this problem.

A great deal of care is taken to avoid mixing water with lubrication oil as it causes many problems. As per ASTM D95, the concerned regulatory authority, the limit value imposed on the presence of moisture in the lubricating oil is specified as 2000 ppm (0.2%) for a turbine/generator of a typical thermal power plant. Hydrogen dew point is affected with the amount of moisture present in the lubricating oil, so users prefer the moisture concentration maintained at a value well below 2000 ppm if not 1000 ppm. There is always a chance of the contaminated lubricating oil mixing with the seal oil where in turn it can mix with the hydrogen gas.

In service, the hydrogen gas dew point usually is required to be maintained between −30 and 0°C depending on the seal oil system clearances and operation, size of the generator, and on the hydrogen gas pressure (higher gas pressure calls for lower dew point). It is obvious that generators operating with high dew point are very prone to insulation failure in the windings.

The moisture content in hydrogen is important because hydrogen gas is hygroscopic at about −50°C dew point and looks like a dry sponge in the presence of oil with 1000 ppm water. Because of this, hydrogen may become physically "changed," for example, by an increase in stickiness or volume.

It is a well-known fact that one of the common sources of moisture contributing to the deterioration of hydrogen dew point is the presence of water in the hydrogen seal oil system. Experiment results indicate that <50 ppm of moisture in seal oil is obligatory to maintain hydrogen dew

www.EngineeringBooksPDF.com

points below −10°C (provided other sources are negligible). Seal oil moisture >50 ppm increases the hydrogen dew point, and ultimately increases the dew point above acceptable limits and at point of seal oil moisture presence exceeds ∼250 ppm of water.

Another important source of moisture in hydrogen gas is leakage from the cooling water provided by the hydrogen coolers. The dryers and desiccants used to remove moisture in the hydrogen gas path requires regular and proper maintenance.

It is therefore of the utmost importance that necessary actions are taken to limit the moisture level. The major source of water ingress in the TG set lubricating oil is the condensed water from inadequate performance of the steam sealing arrangement of the turbine. If the lube oil and seal oil use the same facility, this type of water contamination needs to controlled. It is a "must" situation to find the actual source of the seal oil moisture and attend to it to avoid destructive consequences. Routine analysis of moisture content in both lubricating oil and the hydrogen seal oil (whether common or separate) can prompt the concerned person to maintain them at required levels, for example, in the range of 10 ppm (0.001%) for hydrogen seal oil. If the moisture content of hydrogen seal oil rises above 250 ppm, it is possible that the dew point of the hydrogen would shoot up beyond acceptable limits.

Increased hydrogen gas dew point in the generator cooling system affects the overall reliability of the generator and must be taken care of with proper priority. The formation of water vapor or moisture contamination inside a generator reduces the life of various generator components.

The reason moisture in hydrogen gas must be maintained at acceptable levels is the stator winding short circuit and failure due to stress corrosion cracking of retainer rings used to hold the rotor winding in place. If the retaining rings are not in place, the winding is flung from the rotor due to the centrifugal force caused by the rotor speed (typically 3000−3600 rpm depending on the country). The apprehension is quite legitimate as the repairing time may take 3−4 weeks at a minimum, which means a unit outage entailing costly repairs and loss of revenue. The worst-case scenario is that failure of the retaining ring destroys the generator altogether.

The normal practice in a modern thermal power plant is to maintain an upper limit dew point at <0°C. Dew points higher than this might allow moisture in the hydrogen gas to condensate on the retaining rings when the unit is out of service.

In addition to dew point problem, water present in seal oil can be evaporated due to heat produced by the churning effect when it comes in contact with the high-speed turbine shaft. This water vapor, if it enters the generator shell, reduces the purity of the hydrogen gas. Additionally, the entrained air may also be released, if not properly taken care of, from the oil and mixed with the hydrogen, which further reduces hydrogen purity. Decreased hydrogen purity, as already discussed, results in increased windage loss with its consequent problems.

It is therefore very important that the concentration level of water and entrained air in the oil should be kept well below the limit. The seal oil reservoir, whether common with the turbine lube oil system or separate, needs suitable measures against water and air contamination. Strict stipulations by customers want the oil purifier to ensure 100% removal of free water and air, and up to 80% of the dissolved water and air present in the oil.

10. GENERATOR CONTROL SYSTEM

The generator control system normally consists of the following items:

1. Generator voltage control by AVR
2. De-excitation system of the rotor
3. Generator protection system
4. Instrumentation system

Main systems pertinent to the generator are discussed in Chapter II, Clause 4.2.

10.1 Generator Voltage Control by AVR

Power demand is increasing for large-capacity thermal power plants, and in view of modern lifestyle requirements, increasing population, etc., large-capacity thermal power plants are being installed at a faster rate. As a consequence to this increasing constant and huge power load, there is the possibility that stability of both power and voltage may deteriorate in the power system. Today, this is a burning issue that needs to be addressed.

10.2 Effect of Excitation Control on Power System Stability

The rotor field excitation is controlled by the AVR. This control system is very effective during steady-state operation; however, during abrupt load changes or disturbances there may be some negative influence on the corrective action taken toward damping of power swings. The reason for this is that the AVR always try to force field-current changes in the generator. The modern tendency is the introduction of an additional control loop to supplement the AVR action, which is supposed to suppress the untoward system swings, such as voltage oscillations. This supplementary control loop is popularly termed the power system stabilizer (PSS). It produces a correction signal at its output to compensate for the oscillations of all the electrical parameters.

www.EngineeringBooksPDF.com

The typical range of associated oscillations in frequencies without PSS might go up to ±3.0 Hz and cause problems in smooth transmission of power to the grid. The measured variables included in the PSS input lists include:

1. MW generation or active power
2. Generator current
3. Generator EMF
4. Speed/frequency (real-time and set values)

Whenever a number of generators is connected in parallel, disturbances may arise from sharing power in between the generators. This needs quick suppression and a steady power must be maintained to return the power stability. Power system stability in turn is associated with voltage stability and ensures a constant voltage restoration. This can be maintained even when there are changes in load by taking care of the most severe operating conditions. The improvement of power system stability, however, needs the improvement of all other associated systems, such as by increasing the system voltage, availability of adequate power transmission lines, availability of sufficient numbers of capacitors to improve power factors to decrease reactive power, installation of the static volt ampere (VAR) compensator (SVC) if not already installed, etc., and last but not the least an improved method of generator excitation control system. Introduction of an improved control approach by digital control hardware and software makes it possible to haul out the capability of the generator the capability of the generator to the maximum extent by improving the control algorithm.

10.3 AVR by Rotor Excitation Control

Excitation current needed for the generator is provided by the excitation system. The AVR is a vital component of that system along with the exciter or the power source, the measuring elements, the PSS, and the protection unit.

The excitation power source can be from the exciter, which is either a separate DC or AC generator. The exciter has its field winding (DC current) in the stator and armature winding in the rotor. In the case of an AC exciter generator, the three-phase AC is induced in the rotor winding, which is rectified using diode, thyristor, or transistor bridge installed in the rotor. However, for a brushless excitation system and with a pilot exciter, its armature in the stator and field is a permanent magnet. The main exciter, however, is the AC generator at the rotor. Different options and alternatives of excitation systems are depicted in Figure II/4.2-1.

Rotor excitation systems are, in general, broadly classified into three groups according to the power source used for excitation (IEEE, 2006):

1. *DC excitation systems*: Use DC generators to feed the field windings of the synchronous machine.
2. *AC excitation systems*: Use AC generators with the help of rotary or static rectifiers to feed the field winding of the generator.
3. *Static excitation systems*: Use transformers and rectifiers for conversion of AC to DC current for exciting the generator field winding.

Another general and broad classification of excitation system also exists, which categorizes by excitation power source. The two major classes are

1. *Separate excitation systems that are be static or brushless*: These systems are independent of disruptions and faults that occur in electric power systems, and can force excitation. Brushless systems are used for excitation of larger generators (power generation at ~600 MVA) and in flammable and explosive environments. Brushless systems consist of an AC generator, rotating diode bridge at the rotor, and field at the stator. When this system is equipped with a pilot exciter, it consists of another AC generator at the stator and realized with permanent magnet excitation at the rotor. Attempts to build a brushless system with a thyristor bridge were not successful because of problems with thyristor control reliability. The result of this problem is a significant disadvantage of these systems as well as the inability to provide generator de-excitation. Another disadvantage is slower response of the system, especially in case of low excitation (see Figure IX/10-1).
2. S*elf-excitation systems*: The advantages of this system are simplicity and low costs. The thyristor or transistor bridge is supplied from generator terminals via transformer. The main disadvantage is that excitation supply voltage, and thereby excitation current, depends directly on generator output voltage. Brushless self-excitation systems also exist, although they are not used much.

Initially the generator output voltage was controlled by a separate small generator or exciter machine coupled to the shaft of the generator. The field was installed on the stator with AVR controlling its input current. The exciter rotor acted as a DC generator and output of the exciter is then controlled by AVR to deliver excitation for the main generator DC field through slip rings.

The above system introduced lag in build-up of magnetic fields in both the exciter and the main generator. Therefore, the idea of a self-excitation/shunt excitation system was developed. In this system, the separate exciter machine was eliminated and the power source was utilized directly from the generator output terminal with suitable controlled output rectifiers for the DC field excitation circuit. The advantage of this excitation system is that it can change the output voltage instantaneously to deliver the required current as needed to control the main generated voltage. Although the lag in the main generator field

www.EngineeringBooksPDF.com

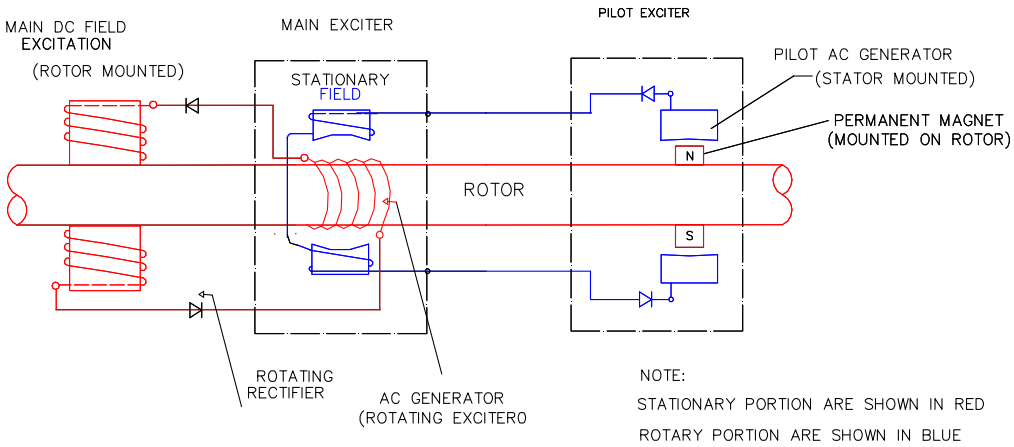


FIGURE IX/10-1 Schematic diagram of brushless excitation system.

winding still persists as dictated by its time constant, the availability of a higher voltage source to supply instant required field current reduces the lag.

In the self-excitation/shunt excitation system, generator output voltage is not available in the initial stage of starting up of the TG set. To take care of this situation, initially the excitation system was flashed by a brief application of DC from the station battery. This procedure helped to develop adequate field strength for generation of sufficient terminal voltage, which in turn could be fed back as a power source to start the normal excitation system. Some problems still exist in this system; as the machine starts at slow speeds, the excitation system needs to be on from the very beginning. This type of field-flashing excitation is suitable for axial flow turbines where the turbine is already at a fairly high speed.

An alternative scheme was necessary to avoid all of these problems, which meant provision of another source of power during the TG start-up time. The start-up excitation would continue until the TG set is ready to produce prerequisite power to feed the self-excitation system. At this point, the excitation power source is switched over to a system connected to the generator output terminal. The power source of start-up excitation may be from the station transformer or a diesel generator or a gas turbine, which is supposed to be available all the time.

The rectifiers available today are the thyristor-based bridge circuit with a digital voltage control system. Other important and necessary accessories include field circuit breakers, field discharge resistor, potential transformers, AC input circuit breakers, switch fuse unit, etc.

10.3.1 Brushless Excitation System for AVR

The AVR has slip rings, brushes, and commutators and is a bit of a cumbersome system; hence, the search was on for a brushless excitation system. Today brushless excitation systems are widely used to provide DC to develop the rotor magnetic field for the main generator. The brushless excitation system consists of a main exciter and a pilot exciter. Figure IX/10-1 is a representative idea for the arrangement and location of different accessories of the excitation system of a synchronous generator.

The pilot exciter includes a stationary armature winding in the form of an AC generator with rectifier and the DC magnetic field in the form of a permanent magnet and mounted on the same rotor shaft as the main generator of the TG set. The main exciter, on the other hand, includes a stationary DC magnetic field and an armature winding in the form of an AC generator with rectifier on the same rotor shaft as the main generator of the TG set.

Whenever the TG rotor shaft rotates, an electromotive force (emf) develops across the generator or armature terminals of the pilot exciter due to the effect of the rotation of the magnetic field of the permanent magnet. The AC voltage thus produced is converted to DC voltage from DC by the rectifiers. This rectified DC output is then fed to the stationary field winding of the main exciter. As soon as this current flows through the field, emf develops across the rotating generator terminals of the main exciter due to the effect of relative motion of the magnetic field and exciter generator winding. This AC voltage is again converted to DC voltage from DC by the rectifiers. This rectified DC output is then fed to the rotating field winding on the rotor shaft of the main generator.

As the main exciter generator, its associated rectifiers and the main generator's field winding are all mounted on the rotor, and the connection among them does not require any sliding contacts in the form of slip rings, brushes, etc. Thus function of a brushless excitation system is achieved. The use of the brushless arrangement improves the reliability/availability and efficiency by lessening the losses.

www.EngineeringBooksPDF.com

The maintenance problem is also reduced. Another kind of brushless excitation system is seen in Figure II/4.2-1b.

10.3.2 Use of Thyristors/Semiconductor in a Brushless Excitation System

Normally thyristors are used in the circuit of rotating rectifiers of the main exciter instead of semiconductor diodes because of the following:

1. Higher current handling capacity and their suitability for the rotating machine application.
2. Thyristors are less sensitive to vibration, accelerative force, and extreme weather namely temperature.
3. Output currents can be controlled smoothly over a wide range for both normal operation, that is, forcing mode of operation and de-excitation mode of operation, which is also known as counter-excitation

Many prefer power transistors to thyristors because of low (junction capacitance) *dV/dT* effect and better switching actions. Currently used are insulated gate-bipolar transistors (IGBTs) because of their input MOSFET advantage coupled with the bipolar advantage of bipolar junction transistors (BJTs). IGBT use in rectifiers as well as in AC drive control is very popular. Switching time of the IGBT may not be like MOSFET, but is faster than BJTs. ABB Unitrol is an example of excitation control by IGBT.

10.3.3 AVR Controller Output and Thyristors Gate Control in Brushless Excitation System

The digital or microprocessor-based control system takes the measured variable from the PT at the point of the generator output terminal and checks the error value by subtracting it to the set value as desired. The controller output is in the form of pulses of equal magnitude, but their timing of appearance at the thyristor gate, that is, the firing or triggering gates, varies as per the controller output. Power transistor digital control systems issue current pulses to control the input base circuit of power transistors, but for the IGBT it is a voltage-controlled device.

10.3.4 Effect of VAR Control on AVR/Rotor Field Current

On many occasions the rotor fails due to very high current flowing through it used to maintain generator terminal voltage. The highly mechanically stressed rotor insulation, when subject to excessive heat due to high rotor current, may fail at an earlier stage than the normal expected life. As the rotor repair work is time-consuming and costly, great effort is made to lower the rotor current to a value less than the limit but still at a safe and stable one. By using a suitable method and hardware to control reactive VAR, the generator output current may be reduced with remarkable improvement in the power factor, which in turn would require less generator emf to maintain the output terminal voltage compatible for connection to the grid.

10.4 De-excitation System of the Rotor

De-excitation is the withdrawal and suppression of excitation field current of the main generator when a major fault, namely a short circuit or excessive load current, takes place requiring immediate shut down of the power-generating plant. A conventional de-excitation system requires shorting of the main generator's magnetic field windings on the rotor so that the flux becomes zero and eventually the generator terminal voltage also becomes zero.

The brushless de-excitation system, on the other hand, arranges to send the current in the other direction for a short time by triggering the rotating rectifiers to be conductive only during the negative half-cycle of the main exciter generator or armature winding voltage waveform. As a result, during this part, the polarity of the generator field winding in the rotor becomes reversed. Due to this action the resultant current through the main generator field winding decreases to zero at a fast rate, allowing the generator stator winding-induced voltage to become zero. The time taken for de-excitation is faster than the system by shorting the rotor terminals.

Another procedure for de-excitation is the static de-excitation system, which is the fastest de-excitation system and works by subjecting the rotor field winding with a reverse polarity voltage across its terminals with the help of an external source and through slip rings, etc.

10.5 Generator Protection System

All signals for a possible cause of tripping the generator and turbine as a protection measure are already indicated in the Clause 3.1. This is a standalone system provided by the TG supplier as a part of their standard scope. The system includes necessary software and hardware with redundant measurements and multichannel measuring arrangements with adequate periodical testing facility.

10.6 Instrumentation System

10.6.1 Process Instrumentation

The following instruments(typical) are supplied with the TG set as a minimum:

1. *Hydrogen purity in percentage*: Three indicators, namely hydrogen in air, hydrogen in carbon dioxide, and carbon dioxide in nitrogen are provided.
   a. Hydrogen in air is meant for normal generator operation.

www.EngineeringBooksPDF.com

   b. Hydrogen in carbon dioxide indicator is useful when the generator is shut down and by slowly introducing carbon dioxide hydrogen is driven out from the generator casing (as an intermediate measure to scavenge generator casing) for the preparation of a long shut down.
   c. Carbon dioxide in nitrogen is meant for a long shut down when nitrogen is introduced to drive out carbon dioxide to completely fill the generator casing and is capped thereafter.
2. Hydrogen pressure and seal oil/hydrogen DP
3. Monitoring the seal oil system including vacuum treatment
4. Monitoring and control of the hydrogen cooling system
5. Monitoring and control of stator and rotor cooling system and primary/secondary water system

10.6.2 Instrumentation System for Stator and Rotor

The required electrical instrumentation package is also included as a part of the standard scope of the TG supplier. The following typical measurements are provided:

1. Active power generation in MW, power imported and/or exported through different feeders
2. Voltage in kV at the generator terminal, grid, and at any other points
3. Current in amperes through generator bus and any other feeders
4. Reactive power in mega VAR
5. Frequency in Hz

11. CONDENSER LEVEL AND DEAERATOR LEVEL CONTROL SYSTEM

Condenser level control and deaerator level controls are very interactive closed loop controls. The direct type of level control loop envisages the control valve after condensate extraction pump (CEP) discharge to modulate to control the condenser hotwell level, the deaerator level control to modulate its own dump valve to a reserve tank for a high-level band, and to modulate the make-up valve from the reserve tank to the condenser in case of a low-level band. In contrast, the indirect type of level control envisages the control valve after CEP discharge to modulate to control the deaerator level, the condenser level control to modulate its own dump valve to the reserve tank for a high-level band, and to modulate the make-up valve from the reserve tank to the condenser in case of a low-level band.

11.1 Condenser Hotwell Level Control

A typical direct control loop (250 MW TPS) for a condenser hotwell level in its simplest form is depicted in Figure IX/11-1. The main condensate control valve is placed in between the gland steam cooler and the drain cooler. The controller receives its measured variable input from the condenser hotwell level at a fixed set point. The controller output is connected to the abovementioned control valve, which opens more for a high level in the condenser hotwell and vice versa. In case this valve is fully open and the level still rises, then another control valve before the this valve connected to the reserve feed water (RFW) tank opens so that the level is maintained at the preset value. If these two valves are fully open and the condenser level is still high, then the control valve to the demineralized (DM) storage tank, whose connection is before gland steam condenser, would start opening to dump the condensate. For this loop, the corresponding deaerator level control loop is depicted in Figure IX/11-3.

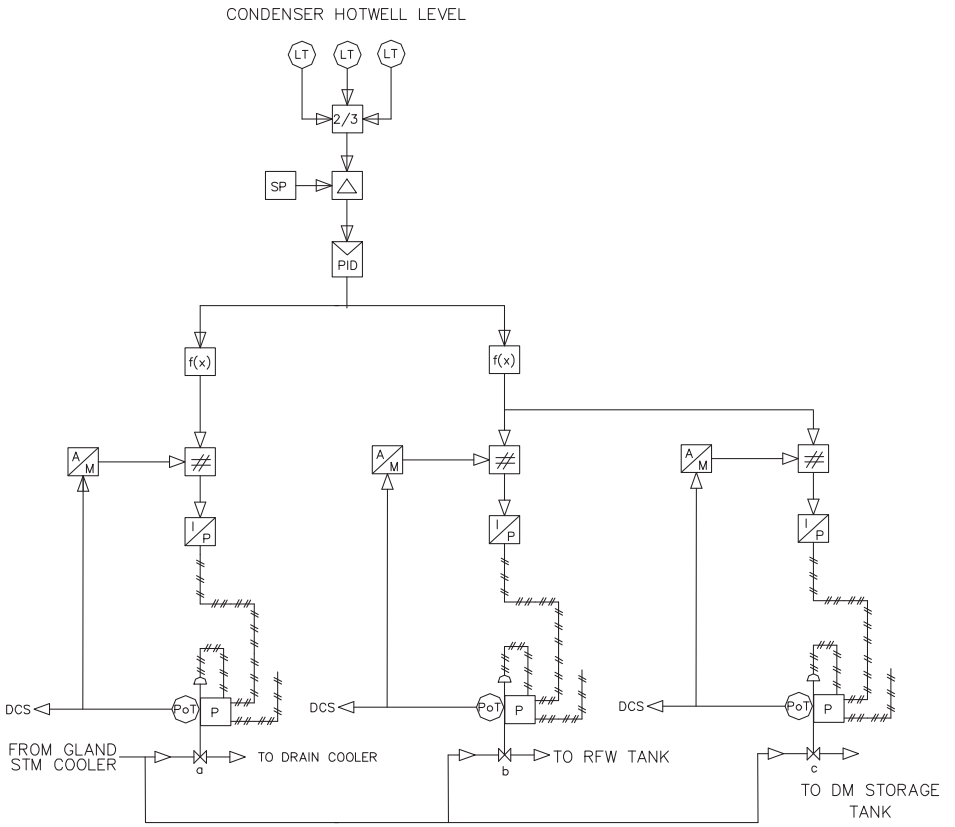
In some other control loop configuration, there is a condensate minimum recirculation valve that opens and allows the requisite flow to go back to the condenser hotwell in a low-load and start-up situation and maintain the condensate flow to maintain the level. The other configuration is the control valve in the main condensate line going to the deaerator via LPHs. As the load increases, the condenser level would tend to increase and cause the main condensate valve to open gradually and the CEP recirculation valve would close accordingly. After a certain time at a higher load the CEP recirculation valve would be closed and the hotwell level maintained by the main condensate valve.

For some large-capacity thermal power plants (500 MW), the philosophy of using a control loop for the condenser hotwell level is different. A typical control loop (500 MW TPS) for the condenser hotwell level in its simplest form is depicted in Figure IX/11-2.

Here there is a three-level domain with dead band in between each level. The normal level control in the condenser hotwell is controlled by the addition of make-up water by modulating the control valve in the make-up line from the DM plant to the condenser. The low-level control domain in the condenser is lower than the normal-level domain by a dead band and is controlled by a control valve located in the gravity make-up line to add condensate to the condenser. When this is still at a low level in the condenser and the valve is nearly full open, the condensate transfer pump across the gravity make-up valve automatically starts to take care of the situation by supplying required water via an emergency make-up line. In the level rising situation, the gravity make-up control valve would close first, and the condensate transfer pump would stop when the level reaches normal.

In the eventuality of a high-level domain higher than the normal level domain by a dead band, the high-level control in the condenser hotwell is controlled by a control valve placed in the condensate dump line and the excess condensate is dumped to the condensate storage tank.

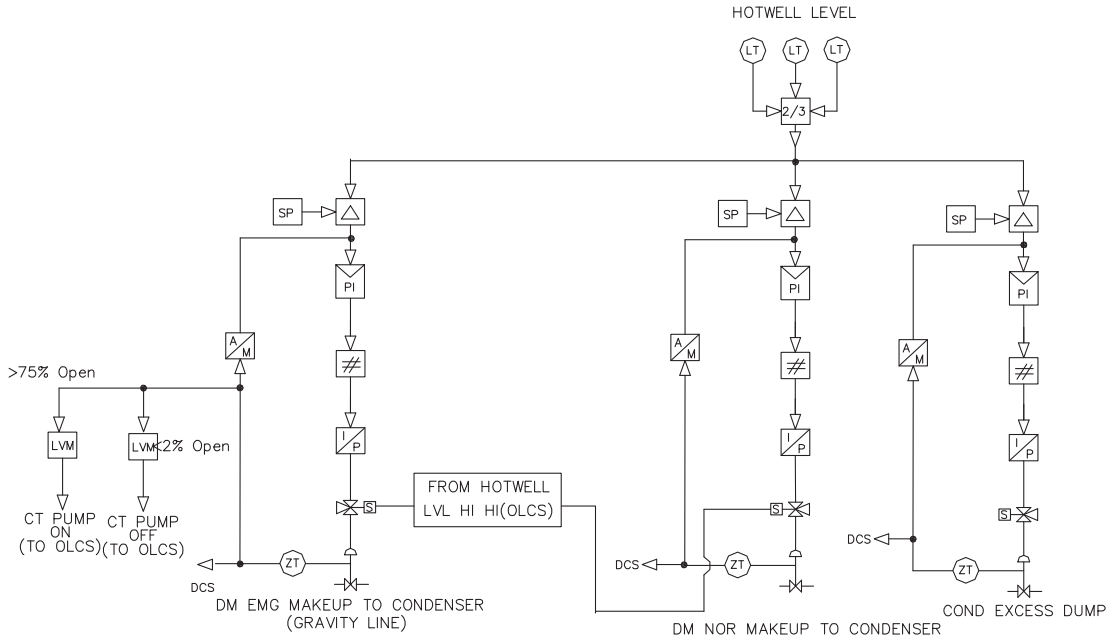
www.EngineeringBooksPDF.com



NOTE:

- ON AIR SUPPLY AND ELEC. SIGNAL FAILURE ALL THE VALVES WILL BE FAIL FIXED/DRIFT CLOSED.
- THE CORRESPONDING DEAERATOR LEVEL CONTROL LOOP SHALL BE FIG NO.IX/11–3

FIGURE IX/11-1 Condenser hotwell level control loop A.



NOTE:

- THECORRESPONDING DEAERATOR LEVEL CONTROL LOOP SHALL BE FIG.IX/11–4

FIGURE IX/11-2 Condenser hotwell level control loop B.

www.EngineeringBooksPDF.com

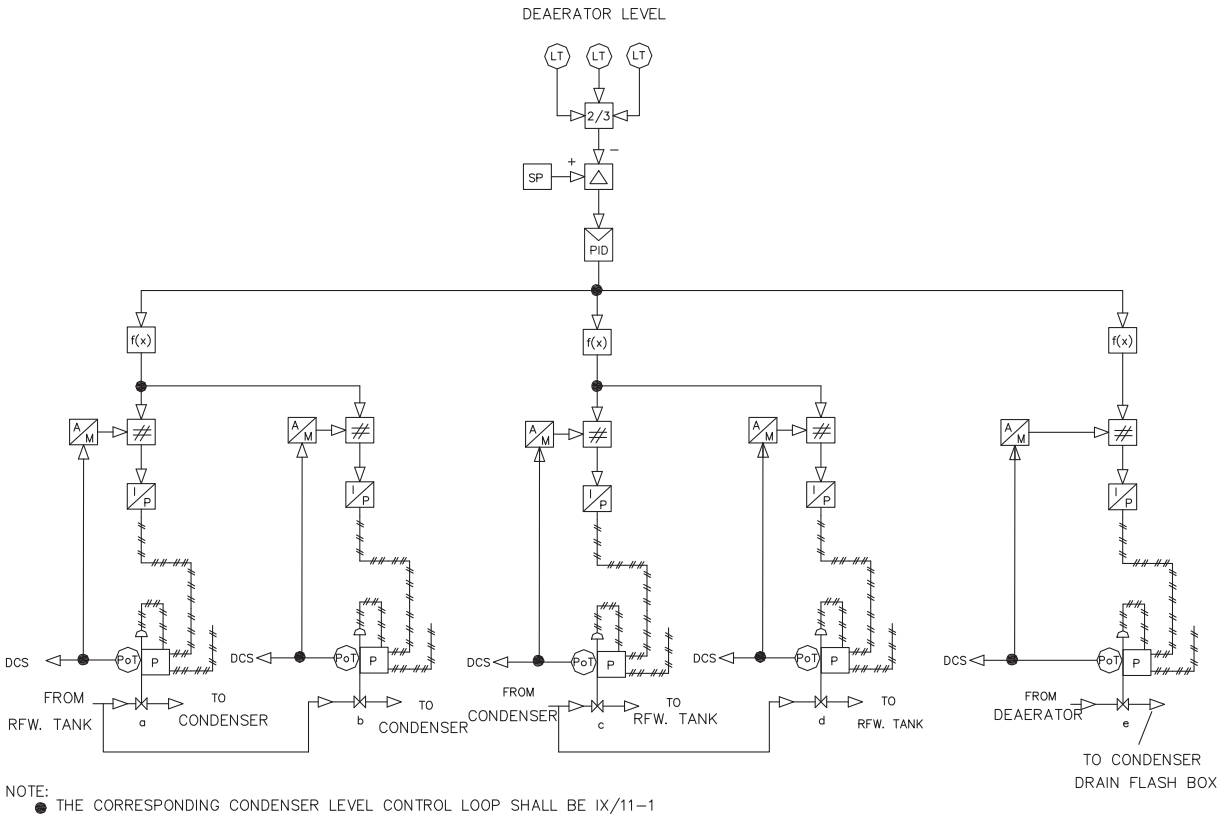


FIGURE IX/11-3 Deaerator level control loop A.

The corresponding deaerator control loop is depicted in Figure IX/11-4.

To ensure CEP protection, flow control valves are provided in the recirculation line from CEP discharge to condenser. The flow control valve in each pump recirculation line modulates as per the output of the controller, which has its measured input signal as the condensate flow. The set point is fixed, which actually means the minimum flow is to be maintained. This loop is normally activated during start-up and low-load application and detailed Chapter XI, Clause 3.

11.2 Deaerator Level Control

A typical direct control loop for deaerator level in its simplest form is depicted in Figure IX/11-3 and matches with the control strategy of the condenser level control depicted in Figure IX/11-1. In this control loop, there are two operating level domains where the separate control valves modulate to control the level of their respective assigned range. This may be achieved by a single control loop and split range control or by two sets of level transmitters and control loops.

For a high level in the deaerator, the control valve (condensate line to RFW tank) in the condensate line after the main condensate valve (as described in the condenser hotwell level control) modulates to maintain the deaerator level. In case of further high levels, the control valve in the line from deaerator to condenser drain flash box modulates to maintain the level after the (condensate line to RFW tank) control valve is fully open. When the level comes down from the high-level domain, this valve will remain closed. After some dead band (of level), if the level still decreases, then the control valve in the line from RFW tank to condenser modulates to allow more condensate to the condenser so that its level increases and the condenser level control valve opens more to force more water to deaerator.

The control loop philosophy for the 500 MW (or even 250 MW) TPS may be different from the above. A typical control loop for the deaerator level in its simplest form is depicted in Figure IX/11-4 and matches with the control strategy of the condenser level control depicted in Figure IX/11-2.

In this control loop philosophy, three element control systems are provided for a better response. The three elements are

1. Deaerator level
2. Total outflow from deaerator such as feed water flow plus total attemperation (SH + RH) flow

www.EngineeringBooksPDF.com

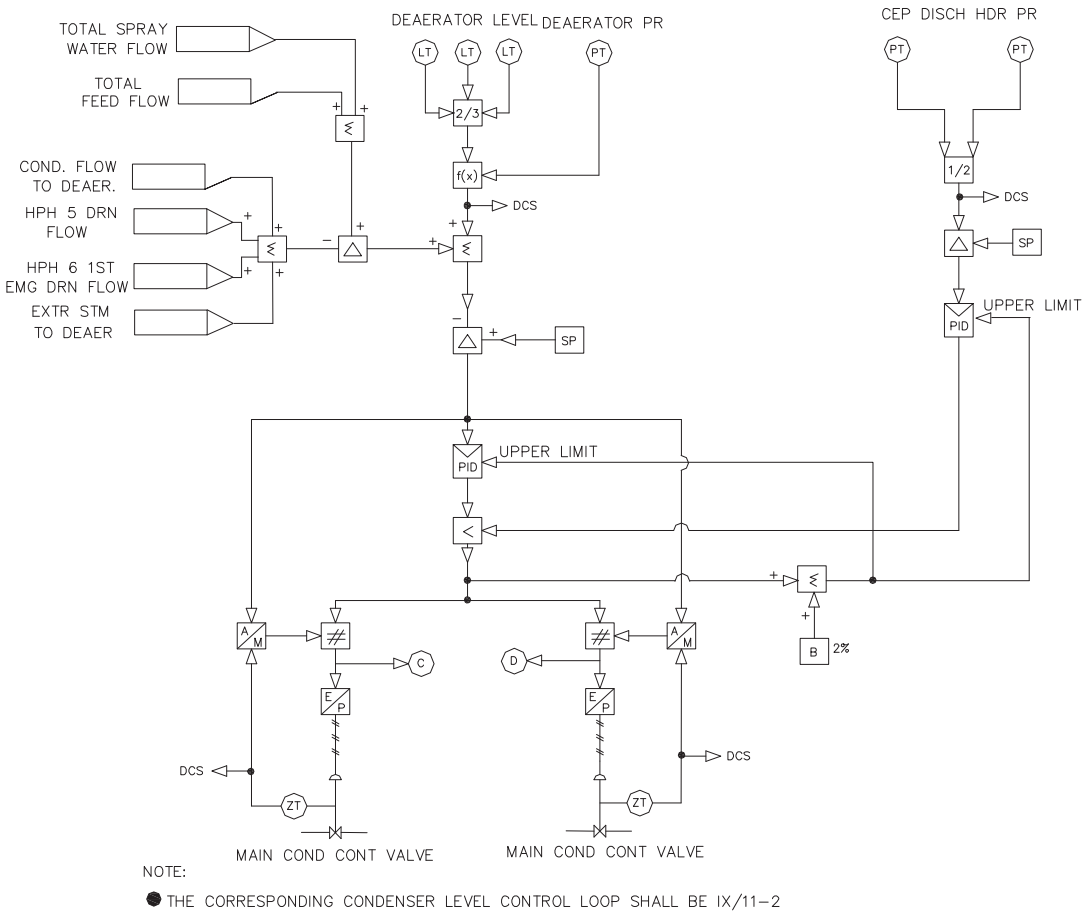


FIGURE IX/11-4 Deaerator level control loop B.

3. Total Inflow to the deaerator such as HPH 5 drain flow, first emergency drain from HPH 6, condensate flow to deaerator, extraction steam flow to deaerator

The controller gets the deaerator level as a measured variable with a fixed set point and the difference between total outflow and inflow as the feed forward signal so that the deaerator level is not disturbed much due to the excursion in demand. The controller output modulates the flow control valve(s) in the main condensate line. For the pump (CEP) safety from low discharge pressure, the controller output is taken through a minimum selector for maintaining minimum discharge pressure at the value above the CEP run out condition.

The interlocks are provided from the deaerator level, and in case the levels are very high as sensed by the level switches

1. The pegging steam supply (from low-temperature auxiliary steam line or CRH line) valves with their bypass valves will be closed.
2. The HPH 5 drain control valves will be closed.

12. VARIOUS TG OPTIONS AND MISCELLENIOUS TG CONTROLS

12.1 Steam Turbines

To cope with the stiff competition, thermal power plants, like other commodities, need to have suitable options and features that match the demands or requirements of the ever-changing market. In general steam turbines are applicable to both nuclear and thermal power plants. While being used in a combined cycle power plant (CCPP), steam turbines can be hooked up with the gas turbine in both multi-shaft and single-shaft configurations. In CCPP the scheme is related to the number and type of installed gas turbines. In the single-shaft configuration a gas turbine rotor shaft and a steam turbine rotor shaft are coupled together to drive the rotor of a single generator. For start-up and shut-down operations, this configuration obviously requires a switch gear to separate the steam turbine from the shaft train. Multi-shaft configurations use independent gas turbine generators and steam turbine generators.

www.EngineeringBooksPDF.com

12.1.1 Factors influencing Options in Turbine Selection

Options of TG sets in a modern thermal power plant depend on many factors including:

1. Size of the plant
2. Overall efficiency of the plant
3. Lifetime of the plant
4. Flexibility and reliability
5. Minimum start-up time
6. Capital and running cost of the plant
7. Optimized steam cycle path
8. Reduction in downtime/ease of maintenance
9. Minimum turbine manufacturing/delivery times
10. Different main steam conditions for suitable material selection
11. Ambient temperature and cooling system influence the size and design of the low-pressure end of the steam turbine.

To implement the above technological ideas and commercial aspects, turbine components along with the associated equipment connected to it are modified in design and/or with improved materials.

Different turbine stages, namely HPT, IPT, and LPT are accommodated in modules. In modern practice, there are, in general, three modules—HPT, IPT, and LPT—which are elaborately discussed in Chapter II, Clause 3.

12.1.2 Selection of Modules

In addition to the traditional concept of accommodating each stage of turbine in a single module, other configurations, that is, more than one turbine stage in one module, are also available for subcritical steam power plants ranging from 50 to 700 MW output capacity requiring main steam temperatures up to 600°C at main steam pressures of 177 bar. The modular concept has evolved and is expected to reduce the number of alternative components, ensuring short lead times, moderate prices, and proven reliability.

12.1.2.1 IPT and LPT in Single Modules

For power plants with lower power output up to 210 MW with/without high back pressures, IPTs and LPTs are often put together in one module with axial exhaust. HPT is a single module with combined control and stop valves. The turbine casing structure normally follows the proven barrel-type design without horizontal flanges at the outer casing to ensure a homogenous distribution of the forces. The improved design, as claimed by the manufacturer, provides the symmetrical expansion behavior of the turbine, and thus facilitates realization of small radial clearances between stationary and moving blades.

12.1.2.2 HPT and IPT in Single Modules

For medium-size power plants from 250 to 700 MW the selection is the other way around. In this option LPT is provided in one module whereas the other module comprises the combined HPT and IPT sections. Both modules are available with down, both sides, or a single side.

The combined HP/IP module is a double-shell design with horizontally split inner and outer casings including an admission section with stationary blade carriers. A thermal sleeve close to the center of the combined HP/IP turbine is provided for admission of the main steam. The reheat steam enters the IPT section of the same module again close to the center of the machine. Suitable shaft gland seal with an abradable coating to improve the sealing efficiency separates the two HPT and IPT expansion sections.

12.1.3 Selection of Single-Flow or Double-Flow Turbines

IPTs and LPTs can be either a single- or double-flow type, which is mainly dictated by the capacity of the turbine. For a single-flow turbine, steam enters from one end in the axial direction and exits from the opposite end. The selection of the entry side depends on the design of thrust calculation and balancing requirement and axial shift limitations. For a double-flow turbine, the steam admission is provided at the center of a particular turbine and exits from both sides of the turbine.

12.1.4 Selection of Multiple Identical Modules

Very large capacity power plants comprise more than one identical IPT or LPT module to take care of the huge steam volume flow at the later stage. The nuclear power stations normally operate on low pressure comparative to fossil-fired pressures; hence, they are provided with multiple identical IPTs or LPTs.

12.1.5 Selection of Governing System

There are multiple regulating valves for controlling the steam admission to the turbine at different loads and for receiving control signals from the EHC as already discussed in Clause 2. The final controller output distributed to these regulating valves are varied as per governing system philosophy. There are two types of governing systems: nozzle governing and throttle governing.

12.1.5.1 Nozzle Governing System

The nozzle governing system is the system where the regulating valves open one after another. In case of partial

www.EngineeringBooksPDF.com

load condition, a load for a main steam pressure may be controlled by varying the nozzle area at a constant pressure. This type of control is widely used in the United States and Japan. Here the internal efficiency of the turbine is much more than the throttle governing system as the pressure drops across the regulating valves are not applicable.

12.1.5.2 Throttle Governing System

In the throttle governing system, which is popular in Western Europe, all the regulating valves open or close simultaneously. Here the load is controlled by varying the inlet pressure to the nozzle envisaged for operating at a constant nozzle area. The internal efficiency is lower than the nozzle governing system.

12.1.6 Selection of Constant Pressure or Sliding Pressure Controls

The turbine, as it gets high pressure and temperature steam from the boiler or the steam generator, may be a constant pressure or a variable (sliding) pressure at the normal controllable load zone (60−100% load).

12.1.6.1 Constant Pressure Controls

For a constant pressure control system, the steam admission to the turbine is slowly increased to suit the turbine condition and load is increased up to a certain designed value by admitting steam with gradually higher pressure and temperature. Around this load, the steam condition at the turbine inlet is the same as in the full-unit load condition and is kept at constant values by the boiler and turbine controls. Any increase in load is accomplished by increasing the steam flow through the turbine governor valves.

12.1.6.2 Sliding Pressure Controls

In this type of control operation, the steam condition is gradually increased. The temperature is brought at the rated unit load value much earlier than the actual load reaches full load value, but the pressure is maintained by the steam generator at a value depending on the actual load. The relationship between the steam pressure and the unit load for any value of the unit load is predefined and the turbine governing system takes care of this by full or wide opening of the regulating valves after a particular specified load. Before that, the nozzle or throttle governing system controls the load as per requirement.

Modified sliding pressure operation, however, suggests that the throttle valves operate slightly closed at 90−95% load to utilize the reserve capacity of the valves and stored energy of the boiler can respond more quickly to rapid load change near full load. The throttling effect as temperature loss is nominal and cycling damage is disregarded.

12.1.7 Options Regarding Regulating Vales and ESVs

The steam admission to turbine is first through the ESVs with open/close function only. The actuator is hydraulic and suitably sized to meet the emergency closing feature. The regulating or governor valves are provided to maintain the steam flow/pressure to the turbine as desired by the EHC or hydraulic controller. These actuators are also hydraulic to meet fast-closing and huge power requirements for operating the valve for all situations.

Normally these two types of valves provide different services for all the turbine stages—HPT, IPT, or LPT—(if any) are combined in a single casing and arranged at right angles to each other. The connection with the turbine is made through flanges. Separate valves are also provided by some manufacturers.

In general the Venturi type valves have been used as turbine governing valves for quite a long time in large thermal power turbines to regulate the steam flow. The converging−diverging configurations of the valve passage restricts the total pressure loss at a low value, which is the main reason for their wide demand. However, to accommodate larger turbines there is a great demand for improved designs because of the complicated nature of the fluid, the basic mechanism causing valve vibration, and failure. The valve plug vibration is due to interactive force exerted by the fluid-induced excitation on the valve plug and hydraulic forces acting on the plug at its balanced position causing plug vibrations in the lateral and vertical directions. There are several improved designs available by changing the plug shape, etc. The flow patterns can be made much more symmetric, which reduces the intensity of steady forces and fluid plug interaction. For large power plants, there is not much choice in selection of these valves, but for smaller plants the other standard type valves can be used.

12.1.8 Options Regarding HPT/IPT and LPT Blading

Overall efficiency of steam turbine power plants depends on and is very much related to the turbine blading performance and efficiency. The construction of the blade path is normally designed from guidelines of the standard and proven flow elements such as airfoils, roots, grooves, shrouds, etc., with its own advantages and disadvantages. Other aspects regarding specific design boundary conditions such as aerodynamics, forces, materials, and temperatures are also considered for optimum blade design. However, the customer probably has no choice regarding the selection of blades but on the TG set has a choice of overall efficiency and performance only.

www.EngineeringBooksPDF.com

12.1.9 Options Regarding Type of Condensers

Condensers are a very important subsystem equipment/accessory. There are various types made to suit the turbine design, construction, connectivity, etc. Details have been discussed in Chapter II, Clause 3.4. There are so many options and types, and the selection depends on the considerations, such as minimum back pressure from maximum output, lower condensate sub cooling, enhanced condensate deaeration, minimum tube corrosion and erosion, minimum cooling water leakage, improved tube cleaning system, etc.

There may be an option for once-through cooling water supply from external and flowing water resources such as a river, sea water, etc., or in-house cooling tower arrangements.

12.1.10 Options Regarding Subcritical and Super Critical Steam Parameters

As modern technology and a suitable choice of super critical steam parameters with suitable design provides most efficient power plants with the lowest fuel cost and minimum emissions such as carbon dioxide, etc., there is a demand for super and ultra super critical steam parameters, especially when the capacity of the power plant is on the higher side.

The worldwide power demand, according to general forecasts, will be twice that of the present value. To cope with future demand, higher capacity, super critical thermal plants are the optimum and ultimate selection for fossil-fired steam-generating units with a view to reduced fuel consumption, reduced emissions, and maximum efficiency. The optimum (43–46% efficiency) critical steam parameters are observed at ~270–285 bars and 600°C for HPT inlet and ~60 bars and 610–620°C for IPT inlet. The super critical steam turbine setup is influenced by the capacity of the plant, number of reheat cycles, plant atmospheric conditions, etc. The range of electrical power output generally covers from 600 to 1200 MW. In this category, normally the IPT and LPTs are double-flow design and the number of IPT and LPT modules is more than one, depending on the capacity of electrical power output of the plant.

12.1.11 Options Regarding Fossil-Fired or Nuclear Thermal Power Plants

Considering the limited resources of fossil-type fuels, there developed (around 1970) very large capacity nuclear thermal power plants up to 1500 MW and 27 kV generator voltage using radioactive elements as fuels. These plants are generally characterized by low steam temperature turbines with four pole generators or 1500 rpm rotors with more than one IPT/LPT module of double-flow design, depending on the capacity of the plant.

12.2 TGs

Since cylindrical rotors for a high-speed generator were invented in 1901, its use as a TG set for steam turbine and gas turbine is now a part of the history. In 1912, Ludwig Roebel invented the continuously transposed stator bar, which made it possible to implement large-scale winding application. Around 1930, generators were designed with various pole options (i.e., 2, 4, and 6 poles) to match the speeds of the steam turbines. There was continuous development in stator winding insulation also, which started with some form of mica paper compounded by shellac varnish and later substituted by asphalt withstanding voltages up to 12 kV. The use of hydrogen as a generator coolant also was introduced around 1930. Today, TG sets ranging from 30 (and even less) to 1500 MW (or more) are available.

The main improvements for design upgrades to match the demands for higher capacity TGs are a more efficient cooling and insulation. As the future demand would always be for higher capacity units, the options would naturally be oriented around efficiency and stability with the availability of commercially viable technologies.

Around 1960, DM water was introduced first as a cooling media in the hollow conductor of stator winding and the insulation system was adapted to the use of mica tape with synthetic resin impregnation, which permitted even higher temperatures of ~150°C, and is still used today. By early 1960 the TG set unit ratings escalated to as high as 500 MW. By that time there was tremendous improvement in the field of power-handling capacity of semiconductors, and close to the end of 1960 it was possible to change the then conventional DC machine excitation system to the static excitation system and even with a system with an AC exciter machine with rotating diodes, which totally eliminated the cumbersome system using slip rings, commutators, and brushes.

The early gas turbine models developed well before 1980 had a 25–40 MW capacity (low-capacity models were also available). Options for both 50 and 60 Hz with the same generator with a gear box wheel and pinion arrangement for frequency variation were presented as a standard. The gas turbine technology in early 1980 emerged with the introduction of 100 MW units and the same type of generators could be used for both gas turbines and steam turbines. The first 300 MW gas turbine was introduced in 1996 as a response to the growing demands from the user with a comparatively simple and robust air-cooling technology from some manufacturers.

12.2.1 Options for Power Output Ranges

12.2.1.1 Low Range Up to 150 MW

Low-range generators of ~150 MW TG sets are normally designed for low cost. The models used for gas turbines can

www.EngineeringBooksPDF.com

easily be adapted for steam turbines. The maintenance of these types of generators claimed to be quite simple and requires only some recommended spare parts with a small storage space. All of these machines are made for easy transportation and mounting on site. Even the turbine manufacturers often can mount and couple the generators to the turbine themselves.

12.2.1.2 Medium Range Up to 500 MW

TG set generators with pressurized hydrogen as a coolant are filled up with a gauge pressure of ~5.0−6.0 kg/cm^2. These machines are designed for both single-shaft and combined-cycle applications. The main theory of operation of the gas-cooled design is the same as that used for the air-cooled design. Normally the hydrogen-cooled types are used for high-capacity machines requiring more heat-dissipation facilities. They have also been used for both gas turbine and steam turbine applications.

Air-cooled TG set generators are also available from some manufacturers where the technological improvement is mainly made in the cooling arrangement, such as rotor axial cooling and winding indirect cooling using a special type of stator with a provision for multi-chamber air flow. These generators are distinguished by their simple design, which facilitates ease of operation and maintenance. By adopting suitable measures toward improved electrical design and cooling technology with increased air pressure inside the generator, the air-cooled generators also are increasing their market share by claiming high efficiency and usage up to 21 kV as a maximum limit.

12.2.1.3 Higher Range Up to 1500 MW

These thermal power plants, both fossil fired and nuclear, are all necessarily equipped with a hydrogen-cooling system for the rotor by axial flow of hydrogen through all conductors of a slot. Stator cooling is performed with direct flow of DM water through stainless steel tubes embedded in the hollow conductors of stator winding bars. Apparently the stator water cooling system has no upper limit as far as size of the TG. In contrast, the limiting factor is associated with the rotor winding. At 50 Hz, the rotor diameter of 1.25 m is the limit of mechanical stress. The rotor shaft dynamics calls for cautious and careful calculation in case active length extension goes beyond 8 m. However, experiments are still performed regarding multi-zone rotor cooling concepts with the possibility of higher hydrogen pressure with associated fan pressure in an effort to overcome the freeloading consequences like effects of stray flux, etc.

12.2.2 Options for Cooling Media

As the stability, reliability, and performance of a generator depends greatly on the temperature rise of the stator and rotor windings, it is strongly believed that the cooling media should be air-cooled units instead of hydrogen-cooled units and substitution of hydrogen/water-cooling system by the hydrogen-cooling system only continues to budge the ratings upward. Some major benefits from an air-cooled TGs include elimination of the hydrogen generation/transportation/treatment system and seal oil system and less sealing, civil work, piping, maintenance, and better reliability. However, the maximum achievable capacity of air-cooled generators, proven by tests and experiments, is ~400 MW so far.

12.2.3 Options for Insulation

Regarding options for insulation, important criteria are sensitivity to inconsistency in manufacturing, environmental compliance. and availability of the components from an alternative source. The generator windings insulation normally used today is based on the synthetic resin mica tape as discussed earlier, and the search for a better insulation is ongoing. Polymer insulations, as the experiments and test results indicate, might become a suitable option. Such new technology products are improved tape with high thermal conductivity using fillers, and higher mica content by denser roving carrier. The target for improving the insulation system to a higher thermal class (namely class 180) is in the close proximity of being introduced. The higher value of electrical field stress is also an added parameter allowing better heat transfer and more conductor in the slot. It is of utmost importance that both stator and rotor winding designs can accommodate their elongation due to thermal expansion.

12.2.4 Options for Stator Bar

For any new TG development, a refined stator bar improves efficiency to a great extent. The eddy currents and the circulating currents in the stator bars are very important factors and can represent ~30% of the total losses in the stator bars. The modified stator bar, actually made in accordance with the design of a compact Roebel bar, comprising strands of minimum possible size reduces significant losses with practically no eddy currents; thus, the efficiency is enhanced. This design is beneficial for both directly and indirectly cooled stator bars.

12.2.5 Options for Superconducting Field Coil

In 1911 Heike Kamerlingh discovered that "superconductivity" of a conductor/certain materials is an exactly zero electrical resistance that takes place below a particular temperature called critical temperature. The electrical resistivity of a metallic conductor decreases as the temperature is lowered. However, in ordinary conductors, such as copper and silver, this decrease is limited by impurities and

www.EngineeringBooksPDF.com

other defects. Even near absolute zero, copper shows some resistance. In 1986, experiments revealed that for some ceramic materials the critical temperatures are −183.15°C. From a practical perspective, even −183.15°C appears to be easy to reach with readily available liquid nitrogen having boiling point at −196.15°C, resulting in more experiments and applications. For TGs, field winding is the potential area where application of superconductors is considered for small generators only.

12.2.6 Options for Excitation of Field Coil

As previously discussed in Clause 10, there are different categories regarding options for excitation of field coils as listed below:

1. External static excitation system through slip ring, brush, commutators, etc.
2. DC generator/battery system through slip ring, brush, commutators, etc.
3. Rotating diode or thyristor rectifier circuit through main exciter with/without pilot exciter eliminating slip rings, etc.

AVR controls the generator terminal voltage by varying the excitation current. In case of "external static excitation" employing thyristors, the system is directly supplied by the three-phase voltage generated by the generator itself. There may arise a situation when the generator voltage drops to a certain value below the limits given by its AC feeding. There are some systems that provide slightly oversized transformer inputting from the generator and supply the excitation system with a suitable voltage regulator. This keeps the control of the excitation current as required, even if the generator output voltages are at a low level. In some systems, there are adequately designed capacitor banks to maintain the said voltage, even if the main supply voltage experiences temporary heavy drops.

12.3 Miscellaneous TG Control Loops

12.3.1 TG Lubrication Oil Temperature control

1. *Objective*: As the name implies, the basic purpose of this control loop is to maintain the desired temperature of lubrication oil to ensure good flow ability and its proper action as coolant (see Figure IX/12-1).
2. *Discussions*: In some systems this control loop may be a part of the ATRS oil subgroup, because the oil goes to various turbine-bearing lubrication and other places, and is directly connected with start-up and shut down of the turbine. However, it could be a separate system in other turbines (especially for smaller units), so it is discussed separately.

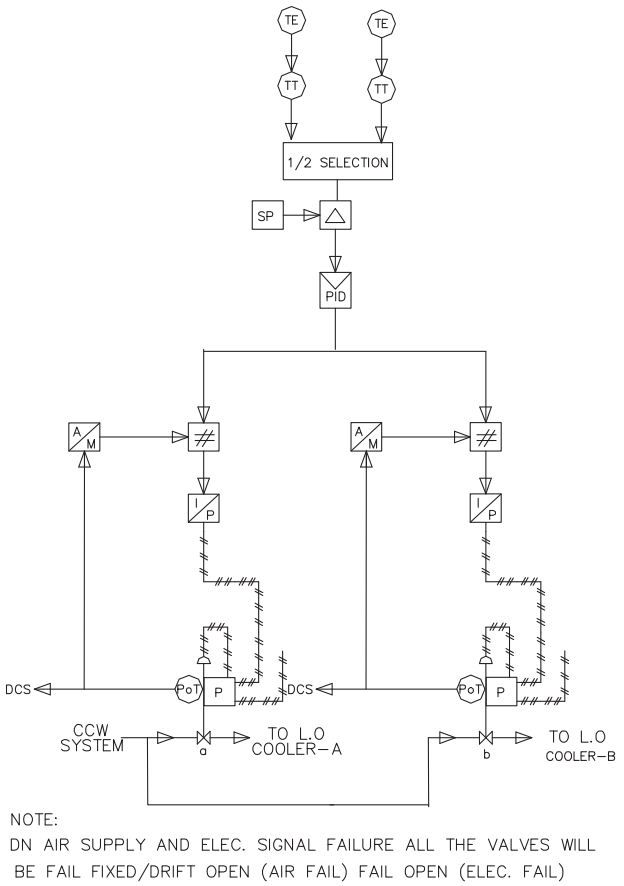


FIGURE IX/12-1 TG lube oil temperature control.

3. *Loop description*: Lubrication oil temperature is measured in the header after the cooler with the help of the redundant temperature elements (e.g., Pt RTD) with a temperature transmitter, since this is an important parameter. The measured value is compared with the set point from the monitor (or setter in the plaque as applicable). Set point and measured value is compared to create an error value. The error thus created is fed to one PID controller with an A/M station. The output via converter is fed to each of the control valves to regulate coolant flow to the redundant LO coolers.

12.3.2 Generator Seal Oil Temperature Control

1. *Objective*: As the name implies, the basic purpose of this control loop is to maintain the desired temperature of seal oil to ensure good flow ability and proper action sealing medium (see Figure IX/12-2).
2. *Discussions*: As discussed earlier, there is a possibility of moisture in seal oil, which may deteriorate the

www.EngineeringBooksPDF.com

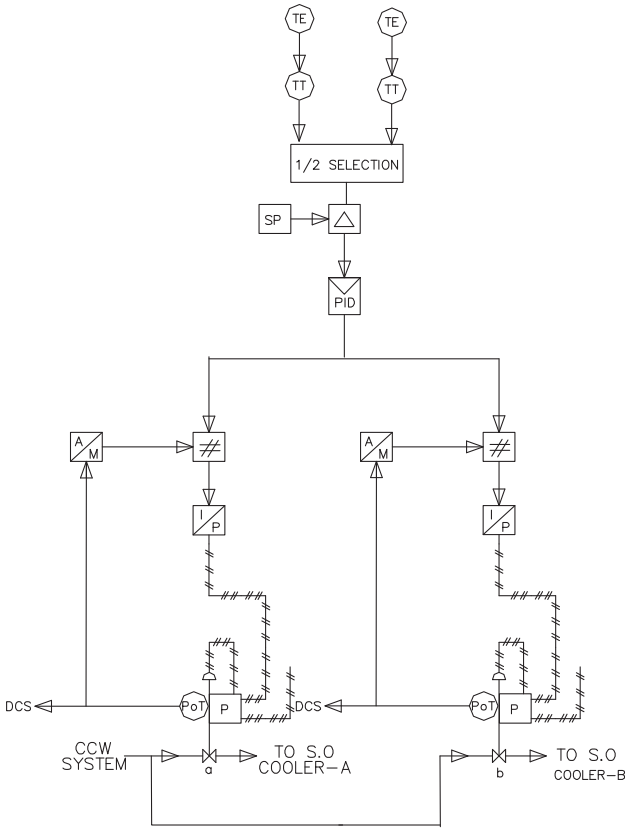


FIGURE IX/12-2 Generator seal oil temperature control.

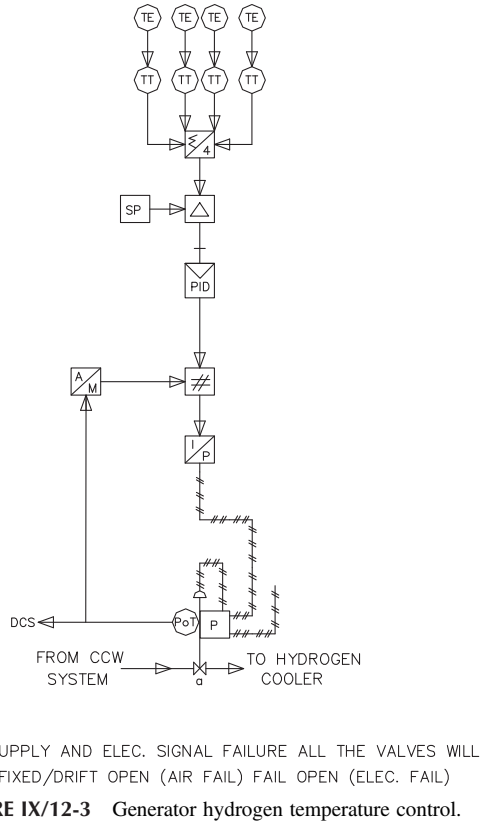


FIGURE IX/12-3 Generator hydrogen temperature control.

performance of the sealing application, so it is necessary to maintain the desired temperature to circumvent such a situation.

3. *Loop descriptions*: Similar to item 3 in Clause 12.3.1.

12.3.3 Generator Hydrogen Temperature Control

1. *Objective*: Basic purpose of this control loop is to maintain the desired temperature of hydrogen to ensure good cooling (see Figure IX/12-3).
2. *Loop description*: Hydrogen temperature is measured in the line going to both the ends with the help of the temperature elements (e.g., Pt RTD) with a temperature transmitter. Since this is an important parameter, redundancy in measurement is recommended so that the temperature on each side is considered and am average of all four is taken in the loop. The measured value is compared with the set point from monitor (or setter in the plaque as applicable). Set point and measured value is compared to create an error value. The error thus created is fed to one PID controller with an A/M station. The output via converter is fed to the control valve to regulate coolant flow to the hydrogen cooler.

12.3.4 Stator Coolant Flow Diagram and Temperature Control

1. *Objective*: Basic purpose of this control loop is to maintain the desired temperature of stator cooling water to ensure good cooling of the stator. The stator conductors are cooled by closed-circuit DM water. The stator holes through which water flows are quite narrow, and unimpeded flow through these holes is critical, because any overheating of the stator reduces generation and even leads to a catastrophic failure of the generator. Therefore suitable control is envisioned maintaining the temperature of stator water.
2. *Discussion*: Stator winding of the TG is cooled by circulating DM water through the hollow conductor of stator winding. DM water (known as stator cooling water, SCW) is fed to the feed header mounted inside the generator casing, toward the turbine side, from their Teflon lines are drawn to supply water to the conductors. This is done in a closed circuit. A pump (always with an auto standby pump) is used to drive the water through the filter, cooler, and the conductors and

www.EngineeringBooksPDF.com

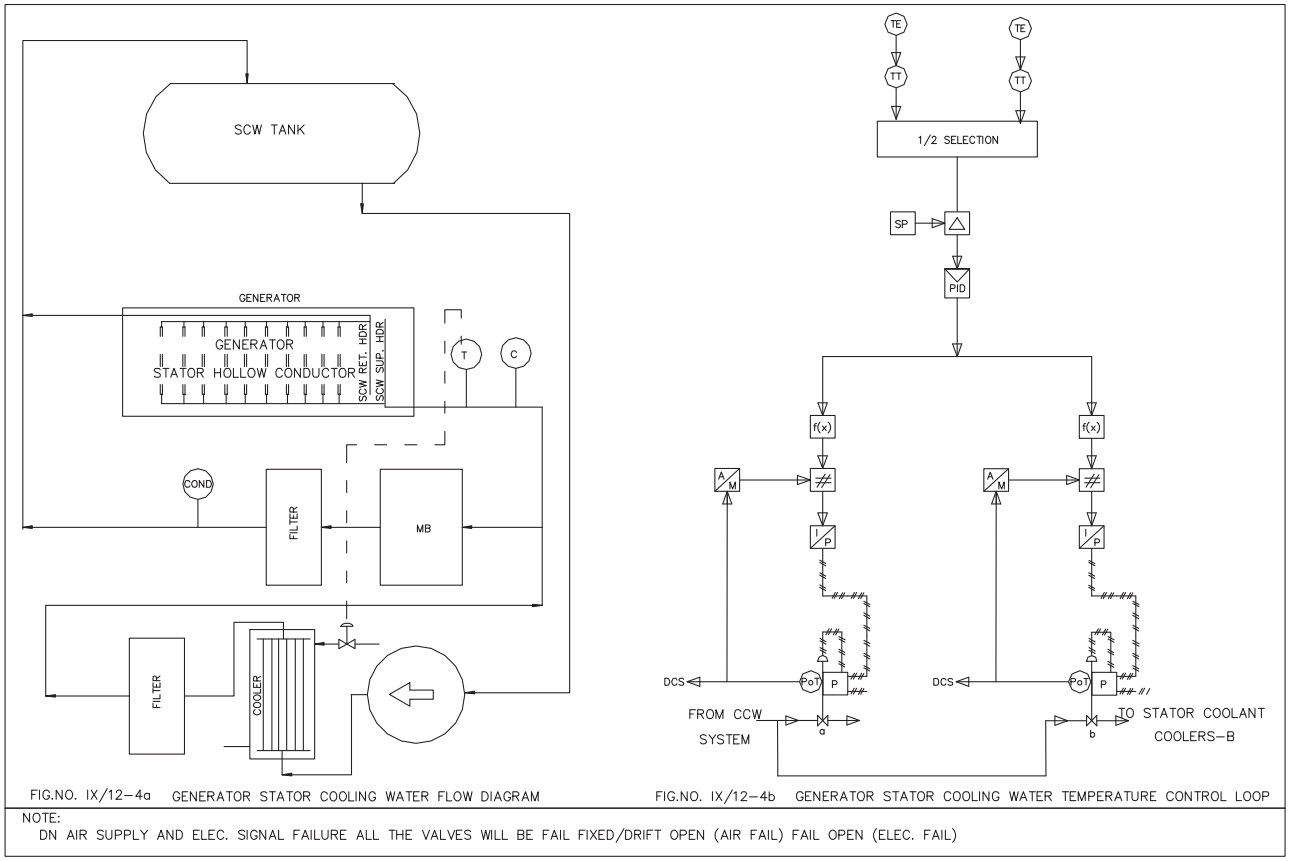


FIGURE IX/12-4 Generator stator cooling water system and temperature control.

returned back to a hermetically sealed expansion tank, which is kept in vacuum (200–250 mmHg) and mounted above the generator. The temperature of stator cooling water is controlled by regulating the coolant supply to the heat exchanger. The maintenance quality of stator water is very important. For this reason often it is supplied with standalone mixed bed units in a recirculation line. The conductivity measurement of stator water going to the generator is extremely important and is normally monitored. Also in some cases dissolved oxygen (DO) is often monitored. Since DM water passes through the stator conductors, which are quite narrow, any contamination or rise in temperature is very detrimental and often causes line blockage. A short flow diagram of typical stator cooling system is seen in Figure IX/12-4A.

3. *Loop description*: SCW temperature is measured in the feed header with the help of the temperature elements (e.g., Pt RTD) with a temperature transmitter. Since this is an important parameter, redundancy in measurement is recommended, so in the loop 1 of 2 redundancy is shown. The measured value is compared with the set point from the monitor (or setter in the plaque as applicable). Set point and measured value is compared to create an error value. The error thus created is fed to one PID controller with an auto/manual station. The output via converter is fed to each of the control valve(s) to regulate coolant flow to the redundant SCW cooler (s).

BIBLIOGRAPHY

[1] Instrumentation and Control Systems for Steam Turbine Generators: By Wolfgang Kindermann and Hans Georg Schwarz. Germany. Seminar document (1981).

[2] Instrumentation and Control for the Steam Turbine Generator Sets: By M/s KWU Germany. Seminar document (1981).

[3] Automatic Control of KWU Steam Turbine Generators: By Heribert Kurten Germany. Seminar document (1981).

[4] Electrohydraulical Controller (EHC) for Steam Turbines – Conventional Power Plants: By M/s KWU. Germany (Seminar Document - Write up). Doc no. V 793/8.1-8460/1/Pr/mt/engl 01.78.

[5] Electrohydraulic Steam Turbines Controller (EHC) (Iskamatic A): By M/s KWU. Germany (Seminar Document no. PSW 213/05.81 for Control Loop Strategies).

[6] Seal Oil System: Scavenging Type: BY M/s General Electric.

[7] Doc no. PI 30.23–2 (Excerpts from M/s Canteach CANDU). Electrical Equipment - Course PI30.2. Generator Auxiliary Systems. January 1990 (ITPO.01).

www.EngineeringBooksPDF.com

[8] Application Update for the Power Generation market: By M/s Pall Corporation. http://www.hydrafab.com/pdf/AU-Seal%20Oil.pdf.
[9] Product Catalog of M/s Westinghouse Type Seal ring and Seal Oil system.
[10] Basic A C Electrical Generators (American Society of Power Engineers). Obtained by O&M Consulting Services Inc. http://www.asope.org/pdfs/AC_Electrical_Generators_ASOPE.pdf.
[11] 11th Annual Conference and Exhibition on Electric Power.
[12] Fuji Electric Review: Vol. 12 No. 5: By M/s Tatomi Iwamitsu & Ryoichi Kuramochi. udc 621.313.322-81. http://www.fujielectric.com/company/tech_archives/pdf/12-05/FER-12-05-129-1966.pdf.
[13] United States Patent no 4,152,636 dt May 1, 1979 by Dale I. Gorden, Munhall, Pa.
[14] LPBP System – Product Bulletin from M/s Sulzer, USA.
[15] Turbine Bypass Systems (Vector Control Technology): By Nihon KOSO Co., LTD. Japan.
[16] Turbine Bypass Systems for greater plant performance-SULZAR valves a product of CCI.
[17] Overspeed turbine Trip: By Boyd Davis.
[18] Basic Electrical Theory: By Science and Reactor Fundamentals. Electrical CNSC Technical Training Group (Revision 1. March 2003).
[19] Product Bulletin of M/s Whitby Hydro Energy Services Corporation: Engineering and Construction Services on Generator & Exciter Basics. http://www.whitbyhydro.on.ca/pdf/5.2.C_GenBasics.pdf.
[20] Workshop on Mechanical Systems (Power Cycle) in thermal power station: By M/s BHEL India: dtd: July, 1982.
[21] Steam Turbines Hydraulic Systems Problems and Solutions: By M/s Barry Sibul and Company. Copywrite 2012. Barry Sibul Company, 3720 S. Ocean Blvd., Suite 108, Highland Beach, FL 33487 Phone: 888-433-0003 FAX: 877-789-4133 Email: barry@sibul.com Web: www.sibul.com.
[22] Bringing to Light Lube Oil Moisture in Hydrogen Cooled Generators: By James R. Mickalec, AEP Pro Serv Inc. A Noria Publication on Machinery Lubrication. http://www.machinerylubrication.com/Read/132/oil-hydrogen-cooled-generators.

www.EngineeringBooksPDF.com

Chapter X

Coordinated Control System

1. INTRODUCTION

In every thermal power plant, be it small, large, or very large, the fundamental objective is to supply thermal energy by the boiler as required by the turbine to convert the thermal energy to mechanical energy to match the electrical power delivered by the generator coupled with the turbine. There must be a balance among all these forms of power to ensure continuous supply of electricity. In a unit with a steam generator, a well-coordinated control system with a control strategy is absolutely important to ensure a largely fluctuating power demand with an optimum rate of load change resulting in a minimum amount of thermal stresses.

A modern power plant is a combination of several interacting control loops and subsystems. The control strategy for the main control loops must respond to a common control demand configuration, which determines individual set points and dictates the performance of the plant. The coordinated control system synchronizes the output of the boiler with the inherent slow response of the turbine and the faster response of the generator, to ensure optimum and stable performance for continuous load tracking of the load dispatch center (LDC) requirements (e.g., free governing mode of operation, FGMO) as well as the online load disturbances. Therefore the system must be configured in such a way that the main subsystems—the boiler, turbine, and generator—would appear to act as a single entity.

The combined process of a boiler, turbine, and condenser is complex and nonlinear. Ultimately the objective of the control system is to maintain the steam pressure (constant or variable) at the turbine inlet so the turbine can adjust the steam admission rate commensurate to the generator power output. With the help of the "state-of-the art" instrumentation and control system, all the major subsystems (i.e., boiler, turbine, and generator) are controlled in tandem in different modes of operation to manage the load-bearing capacity of the subsystems depending on the limitation of the subsystem's equipment/accessories.

1.1 The Basic Operating Modes in Coordinated Control System

Modern, large size thermal power plants connected to electrical grid can be described in three modes:

1. Coordinated control
2. Boiler follow
3. Turbine follow

Figure X/1-1 a–c depicts various modes as indicated above. Figure X/1-1 d and e depicts a coordination control system with direct energy balance (DEB) for drum type boilers. The same DEB coordination control system for supercritical plants with a once-through boiler is seen in Figure X/6-1.

1.1.1 Coordinated Control Mode

Coordinated control mode is the most desirable mode, and the unit is put in this mode of operation when both the boiler and turbine are capable of taking the full load in response to the load demands from the LDC without any contingency or limiting conditions. This mode ensures that any load demand will be processed suitably and the control output will be transmitted to both the boiler and turbine in a coordinated manner. This prevents mismatch between their actions so the demand is managed without posing any constraint to the operating condition. In addition to the coordinated control mode of operation, both boiler follow mode and turbine follow mode can be operated under the specific conditions of a particular plant. The coordinated control maintains a balance between the turbine and boiler control systems under steady-state conditions so the unit can generate the desired electrical load and share its frequency control by increasing or decreasing the boiler and turbine load demands. During transient operation, this system adjusts the correlation between the turbine and boiler demands by utilizing the system's stored energy.

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

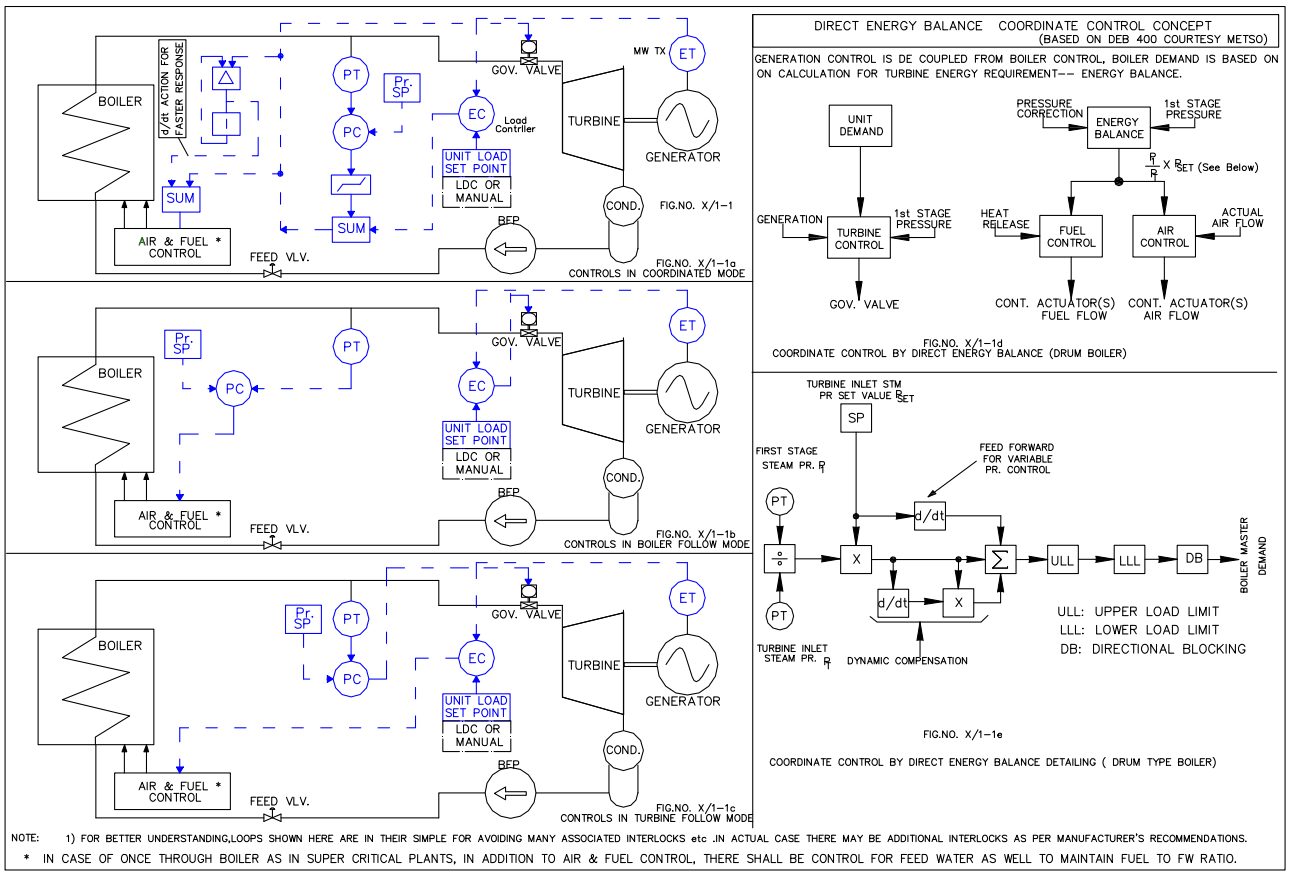


FIGURE X/1-1 Coordinated control fundamentals.

1.1.2 Boiler Follow Mode

In the boiler follow mode of operation, the turbine delivers the output as per its own control requirement, under the occurrence of a turbine load-limiting function, as per the unit load demand. The boiler follows the output delivered by the turbine by maintaining the main steam pressure at the turbine inlet at a fixed or variable value, depending on the requirement. In other words, the boiler follows the turbine by maintaining the steam pressure and the load is delivered by the turbine governor valve position and the steam pressure stays at the same value. This mode is automatically selected when a predefined turbine contingency occurs or by operator selection.

1.1.3 Turbine Follow Mode

In the turbine follow mode of operation, the boiler delivers the output as per its own control requirement, under the occurrence of a boiler load-limiting function, as per the unit load demand. The turbine follows the output delivered by the boiler by maintaining the main steam pressure at the turbine inlet at a fixed or variable value, depending on the requirement. This is done by providing the modified limit load demand to the turbine and boiler control. The turbine control receives an additional correction signal as required for maintaining the desired throttle pressure. This mode is automatically selected when a predefined boiler contingency occurs or by operator selection. There are three other auxiliary modes of operation that are applicable for temporary or short-term operation, but they are not really considered as a part of the coordinate control system.

1.2 Start-Up Control Mode

When the unit is starting from rest, the operating mode may be described as the start-up mode. In this mode, both of the basic operating modes (boiler follow mode and turbine follow mode) are possible because of the demand generated from the unit without referring to the LDC. There also may be an interlock, for example, whenever a generator breaker opens, the control is automatically transferred to the start-up mode.

1.3 Base Control Mode

When the boiler is operated at a fixed load and the turbine delivers the corresponding mechanical output, the mode is said to be operated in the base mode. In this mode the unit runs manually to set the fixed load.

www.EngineeringBooksPDF.com

1.4 Manual Control Mode

The control system of the plant goes automatically to manual mode if the boiler control station (if the feed water, fuel, or air control is put on manual) or turbine control station goes to manual or by operator's action.

2. COORDINATE CONTROL MODE

As previously discussed in Clause 1, the basic objective of the coordinate control mode of operation in a thermal power plant is to receive the unit demand and generate the output accordingly by the boiler and turbine acting in tandem. In this mode of operation, the boiler follow and turbine follow modes are not applicable. The boiler follow mode is possible in "master pressure control" mode in a system where a multiple number of boilers are connected to a common header. This will be discussed in a later clause.

2.1 Selection of Basic Modes

The selection of basic plant operating modes is generally at the operator's discretion unless there is some untoward situation that would command the unit to run on safe mode or manual mode. If the main "unit load controller" or the "coordinated load controller" operates on "auto mode," the operator can select any of the coordinated control, boiler follow, or turbine follow modes, depending on the existing conditions of the main subsystems. Whenever the main unit load controller operates on manual, all these modes would be deselected and trip to manual, then the manual demand may be routed to the boiler or turbine master controllers, as necessary.

2.1.1 Generation of Unit Load Demand

In the coordinated control mode, the unit load demand is generated from the LDC as the particular unit would be connected to the electrical grid (see Figure X/2-1). The LDC is a computer-controlled center that collects electrical data/parameters from the grid, such as voltage, frequency, individual feeder load, and generation of various generators connected to a particular grid. Depending on the health of each generating unit, demands of various feeders connected to it, and the software algorithm, LDC generates optimum demand pertinent to each unit connected to the system grid, which would then process the demand and pass on the relevant demand for proper execution by the boiler and turbine load control systems.

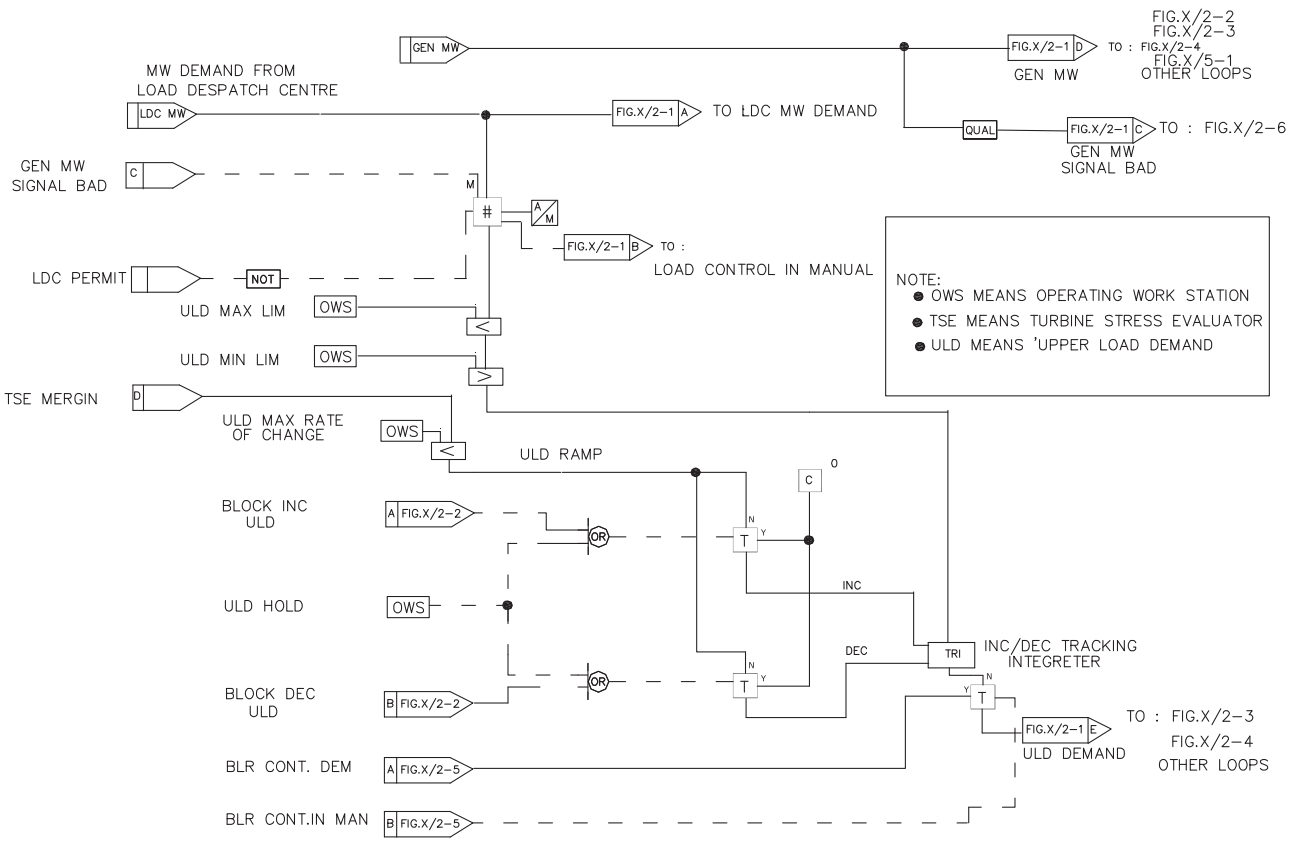


FIGURE X/2-1 Unit load demand control.

www.EngineeringBooksPDF.com

Over a communication network, the LDC conveys the load demand to the particular unit in the form of electrical pulses, which are then integrated to generate demand.

2.1.2 Auto Manual Selection of Unit Load Demand

The demand from the LDC is taken to the auto manual station (AMS) and the operator may transfer it to manual position if the LDC signal becomes unavailable, corrupted, or not executable. The output from the AMS then passes through high and low limiters, which determine the limit of maximum and minimum unit demand to be allowed as per the capacity of the unit or the load-bearing capability of the unit for a particular time or period of time.

2.1.3 Upper and Lower Limit Set of Unit Load Demand

These limiters are actually meant to provide manually set maximum and minimum unit load for normal coordinated control mode; if there are other modes of operation, the online generator MW load with ±10% (for example) may be used to set the limit values of unit load demand.

2.1.4 Upper and Lower Margin Set for Unit Load Demand Gradient

Any load demand varying within those two previously mentioned limits can only be made through a tracking integrator, which tracks the input and the output changes gradually in both directions at the rate (ramp rate) normally provided by the turbine "thermal stress evaluator" (TSE). This normally varies within an upper and lower rate margin set by the TSE. The TSE evaluates the online turbine load condition through the changing capability per unit time by sensing the turbine inner metal and mid metal temperatures at different strategic points, including governor valves, interceptor valves, etc. (see Chapter VI, Clause 9). However, there may be a minimum selection of ramp rate, which also receives a manual bias input value. This is set during commissioning time or any other subsequent time to match the plant behavior and condition or it may be an equipment limitation. Generally, the TSE dictates the unit load ramp rate under normal plant operating conditions. The minimum rate through manual bias plays a vital role during abnormal conditions for turbine protection and can be well maintained by the high-pressure/low-pressure bypass system or popping of safety valves provided at appropriate points.

2.1.5 Blocking of Increase and Decrease of Unit Load Demand

Once the selected ramp rate is available at the output of the minimum selector, there are certain restrictions that do not allow the unit load demand to change, even if permission is made by the minimum selector. When any one or more such restricting conditions take place, there are changeover arrangements that ignore the normal ramp rates and zero ramp rates are enforced through various switching algorithms. This ensures that the tracking integrator stops integrating its output further in a particular direction(s) based on the existing plant conditions used to activate the transfer switch. The restricting conditions are categorized as blocking of increase ramp, blocking of decrease ramp, and "hold" of ramp rates.

2.1.5.1 Blocking of Decrease of Unit Load Demand

Occurrence of any one or more of the following typical signals would activate the switching action of the ramp rate to zero so that any further decrease of unit load demand is blocked (see Figure X/2-2):

1. Very high mean steam pressure control deviation (in +ve direction) in coordinated control mode
2. Very high feed water flow control deviation (in +ve direction)
3. Very high fuel flow control deviation (in +ve direction)
4. Very high total air flow control deviation (in +ve direction)
5. Very high primary air pressure control deviation (in +ve direction)
6. Economizer outlet water temperature protection operated

Here "high" signals mean the parameter is higher than the desired or set value.

2.1.5.2 Blocking of Increase of Unit Load Demand

Occurrence of any one or more of the following typical signals would activate the switching action of the ramp rate to zero so that any further increase of unit load demand is blocked:

1. Very high mean steam pressure control deviation (in −ve direction) in coordinated control mode
2. Very high feed water flow control deviation (in −ve direction)
3. Very high fuel flow control deviation (in −ve direction)
4. Very high total air flow control deviation (in −ve direction)
5. Very high primary air pressure control deviation (in −ve direction)
6. High demand in turbine follow control mode

www.EngineeringBooksPDF.com

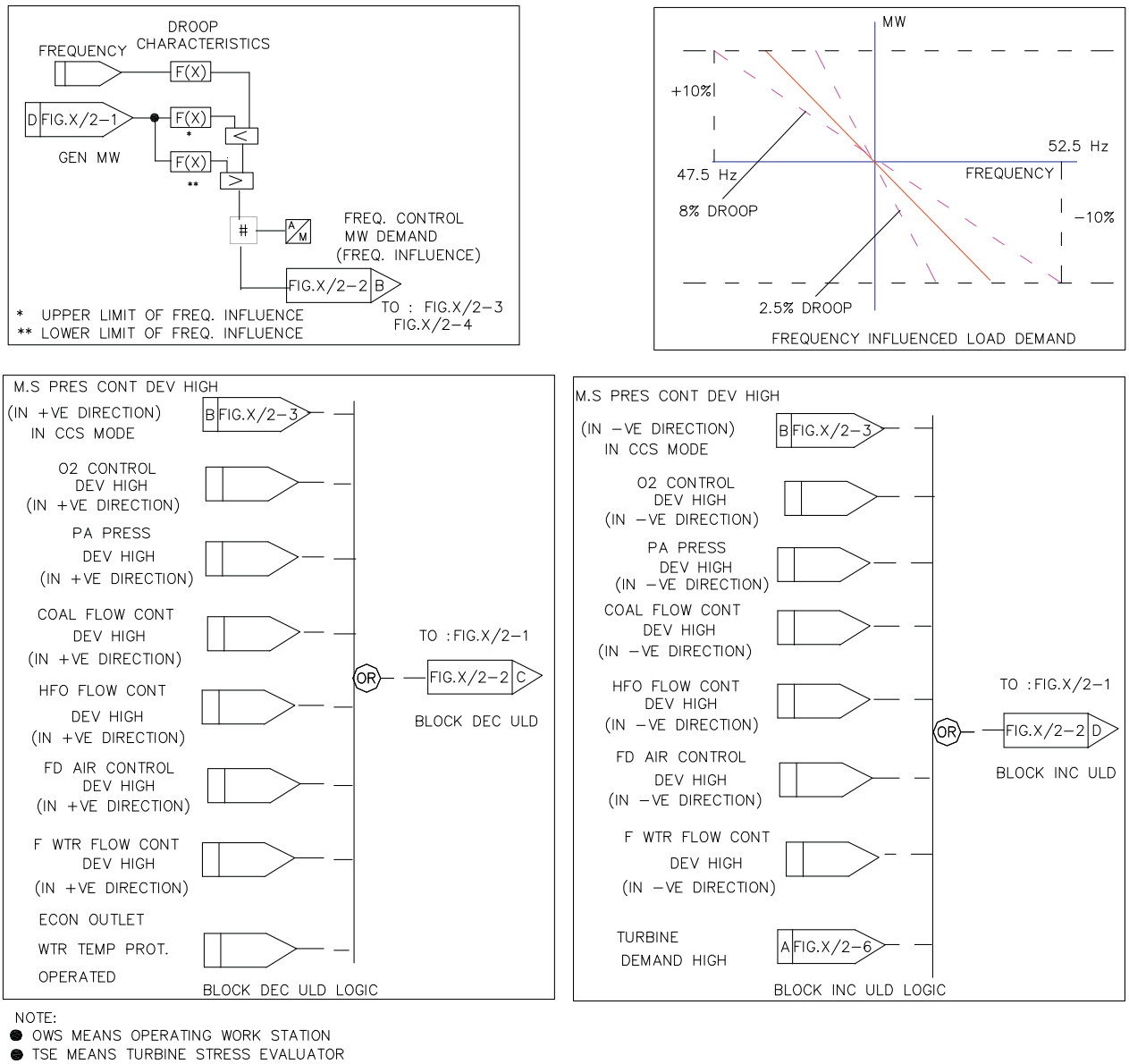


FIGURE X/2-2 Frequency-influenced MW demand and directional blocking.

2.1.5.3 Blocking of both Increase and Decrease (or Hold) of Unit Load Demand

Blocking this signal is normally issued by the operator from the workstation.

2.1.6 Generation of Ultimate Unit Load Demand, Boiler Master Demand. and Turbine Master Demand from Coordinated Control System

The tracking integrator output that maintains the restrictions described earlier constitutes the unit load demand signal. The frequency influence or the frequency-dependent component of MW demand is then added to the unit load demand to form the total unit load demand, that is, the set point for the controller of the coordinated control system. The generator MW signal acts as the measured/ process variable signal and is compared with this set value and the output signal from the comparator. This forms the ultimate error signal of the controller of the coordinated control system. The controller output thus generated is the basic demand for both the turbine and boiler. The controller output may either be auto or manual, depending on the operator's action and after incorporating some pressure correction or pressure-related load demand. This is discussed separately in subsequent clauses of this chapter. "Master boiler demand"

www.EngineeringBooksPDF.com

and "master turbine demand" signals are generated to manage the main steam pressure influence on the two main subsystems (see Figures X/2-3 and X/2-4).

2.1.6.1 Frequency-Influenced Load Demand for Coordinated Control System

The frequency influence signal is incorporated to take care of the droop characteristics (MW vs frequency) on the coordinated control system (see Figure X/2-2). The required dependence/relation of the load with the frequency according to the droop characteristics calculations is readily available by adding the supplementary load demand provided by the characterized droop unit. By measuring the speed through the frequency of the turbine generator set, the corresponding positive or negative MW corrections of the unit load demand signal is accomplished. However, there are maximum (approximately +10%) and minimum (approximately −10%) limits of this correction, which is also generated from the then MW generation value denoting the allowable load changing requirement due to frequency excursion. These maximum and minimum values can be set from the workstation to suit the grid behavior.

Droop is the percent change in frequency causing unit generation to change by 100% of its capability. The previous proportional component of total load demand can be changed by adjusting the droop characteristic between 2.5 and 8% in steps of 0.5%. This is done by the operator/engineer through the bias, which multiplies/scales the basic frequency-dependent load component. The frequency influence may be connected or disconnected manually from the workstation or automatically if the frequency signal is not good.

2.1.7 Generation of Pressure Set Point for Coordinated Control System

For the unit with a variable or sliding pressure control system, the main steam pressure at the turbine inlet has a definite relation with the unit electrical load (MW) generated (see Figure X/2-3). The function generator algorithm is provided to get a variable main steam pressure with relation to MW generated. The pressure value thus available at the output is passed through a high/limiter and then through a tracking integrator output, which acts as a main steam pressure set point—an input to the error generator whose

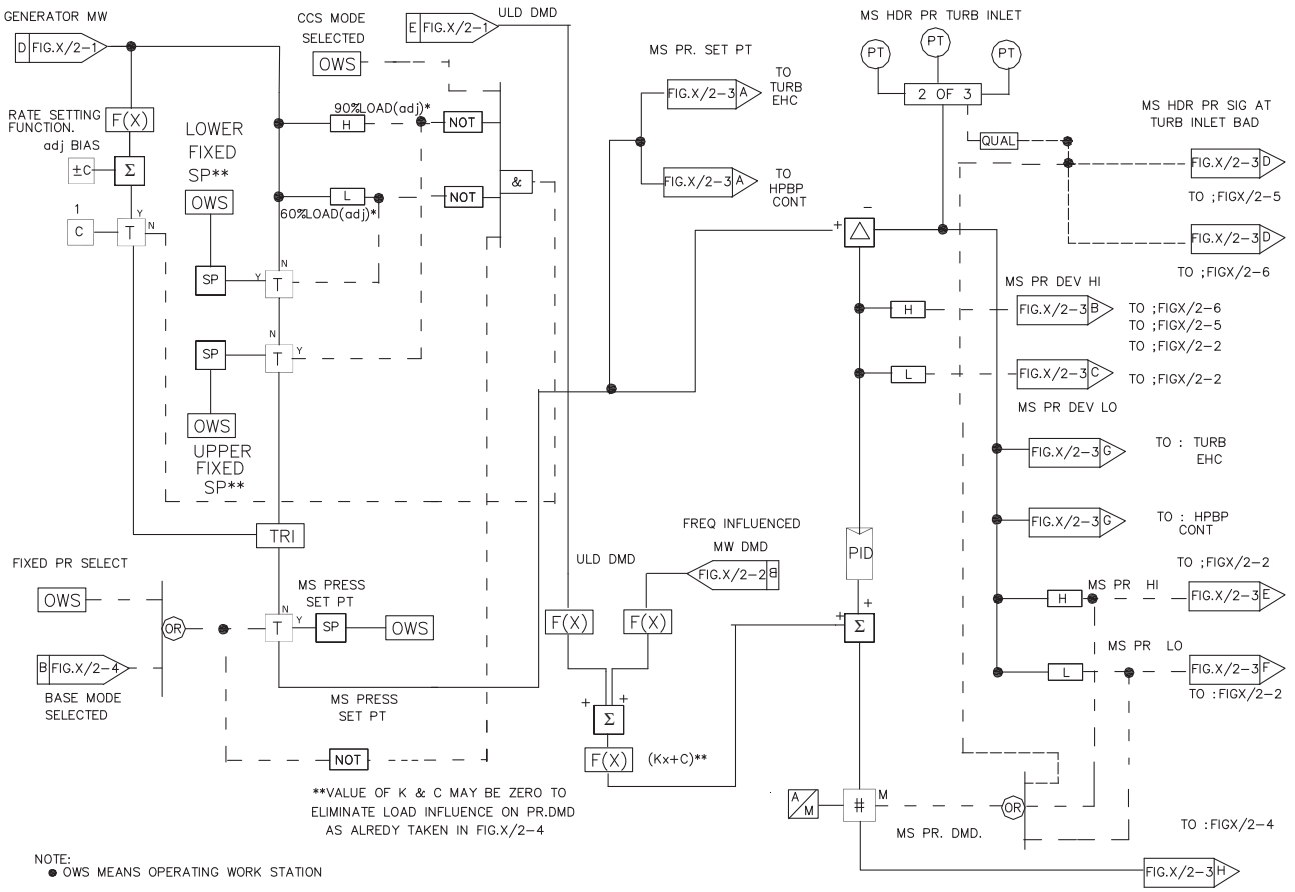


FIGURE X/2-3 Coordinated control: main steam pressure control.

www.EngineeringBooksPDF.com

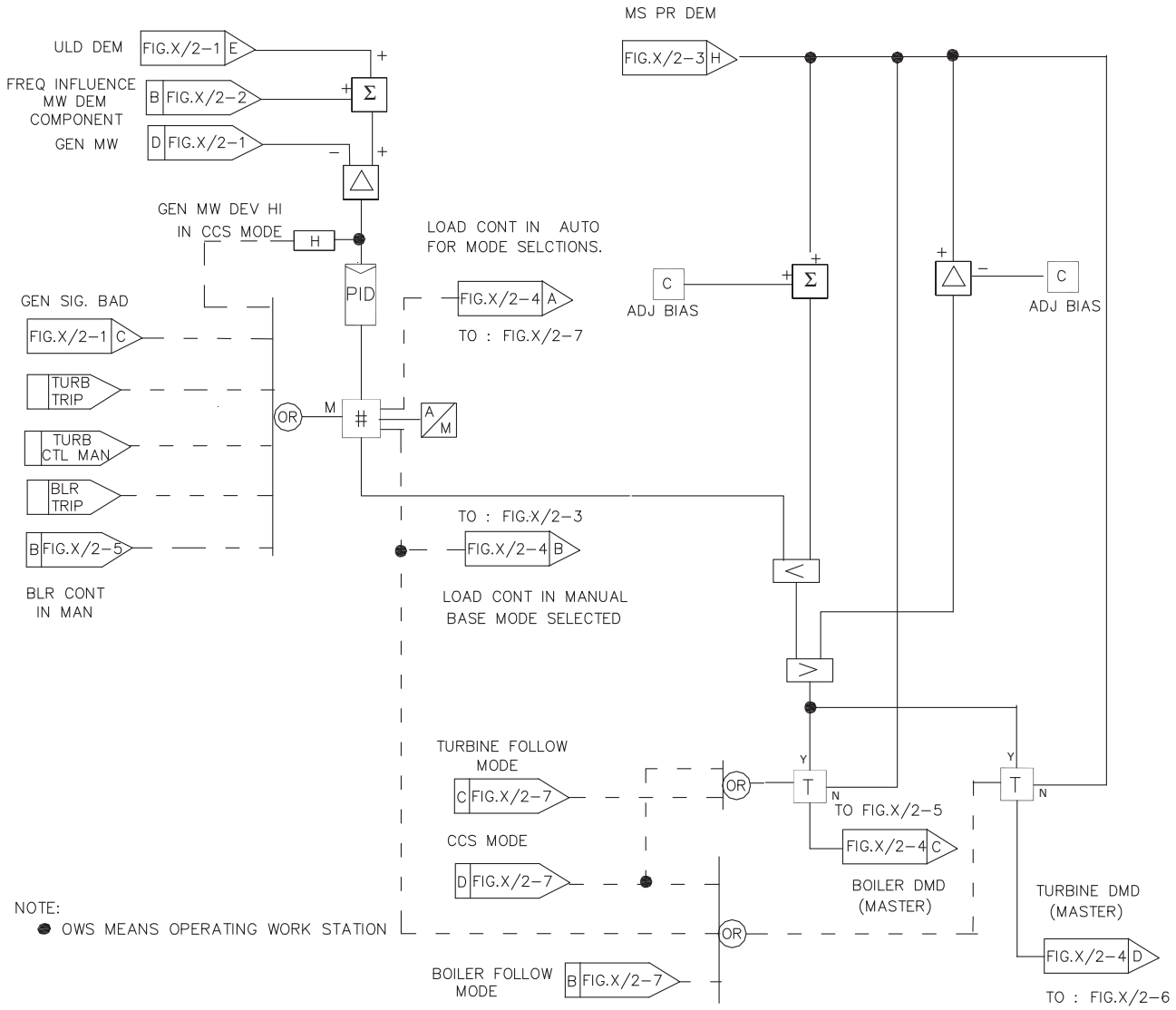


FIGURE X/2-4 Coordinated control : boiler and turban master demand.

other input is the actual main steam pressure. The main steam pressure set value and actual measured value are sent to the electro hydraulic controllers (EHC) and to the high-pressure bypass and turbine load control systems for any correction required by those dedicated control systems or turbine limit pressure control during any mismatch between boiler and turbine controllers.

2.1.8 Generation of Main Steam Pressure Demand for Coordinated Control System

The electrical load (MW)/unit load-dependent main steam pressure signal via the function generator and a tracking integrator as discussed previously make an input to the pressure controller at a variable set point (see Figure X/2-3). This controller is called "main steam pressure demand." The total unit load demand as discussed in Clause 2.1.6 and shown in Figure X/2-1 is, after passing through a function block and high/low limiter, added as the influence of load demand to the main steam pressure demand. The combined signal is the final demand signal for the main steam pressure control system, which would be routed to the boiler and turbine master controller.

Under certain conditions this main steam pressure control demand becomes predominant and acts on either the boiler master demand or turbine master demand (see Figure X/2-4). The total unit load demand is compared with the actual generator load (as measured/process variable) to form the error signal of the main load controller of the coordinated control system. The output of this controller, in manual or auto mode, is made to pass through the high and low selector. That is, if the load controller demand output

www.EngineeringBooksPDF.com

varies within the allowable plus or minus range (as set manually) of the main steam pressure controller demand, it would be selected as a boiler master demand and turbine master demand when the unit is run on coordinated control mode. This is done to enable the system to generate electrical power as per the load demand ignoring the small allowable pressure excursions managed by both the boiler and turbine controls. When the pressure departure goes beyond the set values, pressure demand takes charge of the control to avoid unwanted fluctuation of turbine inlet pressure. When this happens, neither the coordinated control mode nor turbine following mode is selected, and the main steam pressure control demand becomes the boiler master demand. Conversely, when neither the coordinated control mode nor the boiler following mode is selected and the main load controller of the coordinated control system controller is on auto, the main steam pressure control demand becomes the turbine master demand.

2.1.9 Generation of Boiler Load Demand

The boiler master demand, as generated in the coordinated control mode (Figure X/2-4) after the auto/manual station, is output through a tracking integrator and becomes the boiler load demand in normal running condition. In an emergency situation when the "run back" condition is enacted, the "run back target" value is considered the boiler load demand using a selector switch (Figure X/2-5).

The generation of boiler load demand becomes manual due to following reasons:

1. Very high main steam pressure control deviation (in both direction) in coordinated control mode
2. Main steam pressure signal is bad
3. Both forced draft fan (FDF) controls in manual
4. Both induced draft fan (IDF) controls in manual
5. Both primary air fan (PAF) controls in manual
6. Fuel control master in manual

2.1.10 Generation of Turbine Load Demand

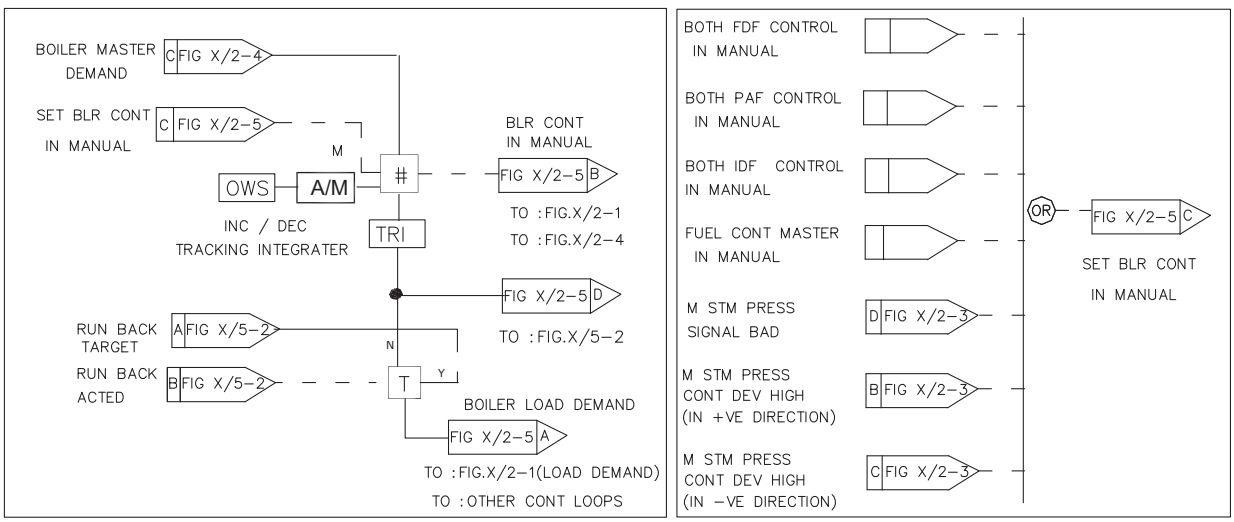
The turbine master demand as generated in the coordinated control mode (Figure X/2-4) is output through an auto/manual station and becomes the turbine load demand in normal running conditions (Figure X/2-6).

The generation of turbine load demand becomes manual due to following reasons:

1. High main steam pressure control deviation (in both direction) in coordinated control mode
2. Generator signal bad in coordinated control mode
3. Main steam pressure signal is bad in turbine follow mode
4. High main steam pressure control deviation (in both direction) in turbine follow mode
5. Turbine EHC control not in remote

2.1.11 Selection of Control Mode in Coordinated Control System

The three control modes can be selected one at a time. Any particular mode of operation can be selected, and when the operator opts for a particular mode, the "unit load control in auto" signal comes on (Figure X/2-7). Boiler follow mode is also possible in master pressure control mode in a system where multiple boilers are connected to a common header. This will be discussed in a later clause.



NOTE:
OWS MEANS OPERATING WORK STATION

FIGURE X/2-5 Generation of boiler load demand.

www.EngineeringBooksPDF.com

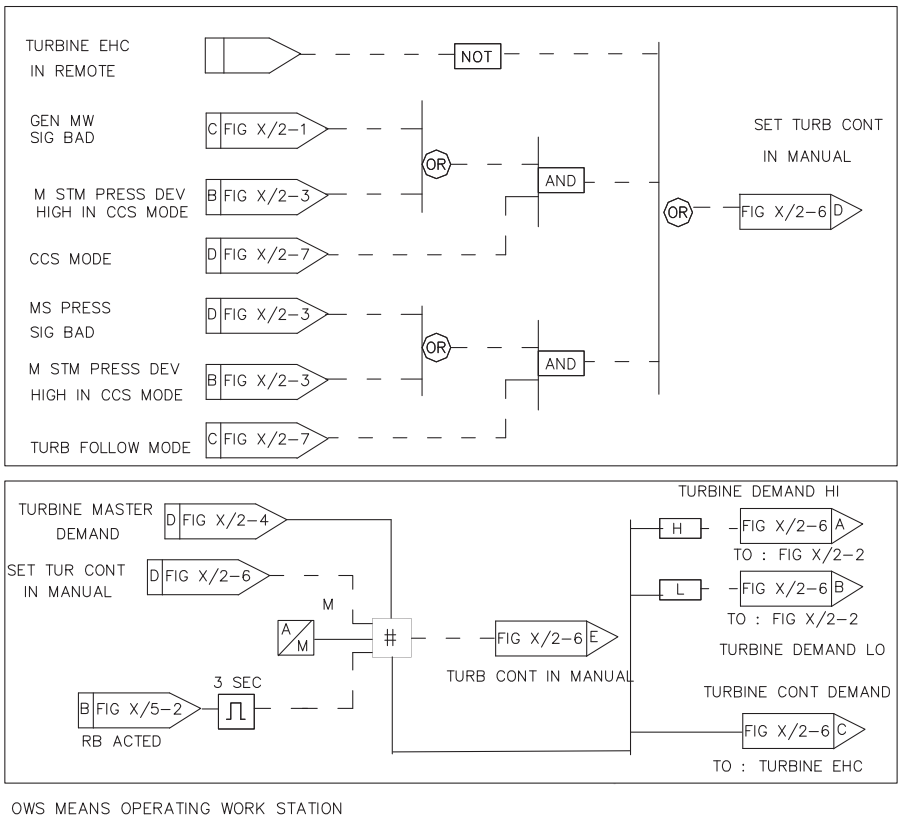


FIGURE X/2-6 Generation of turbine load demand.

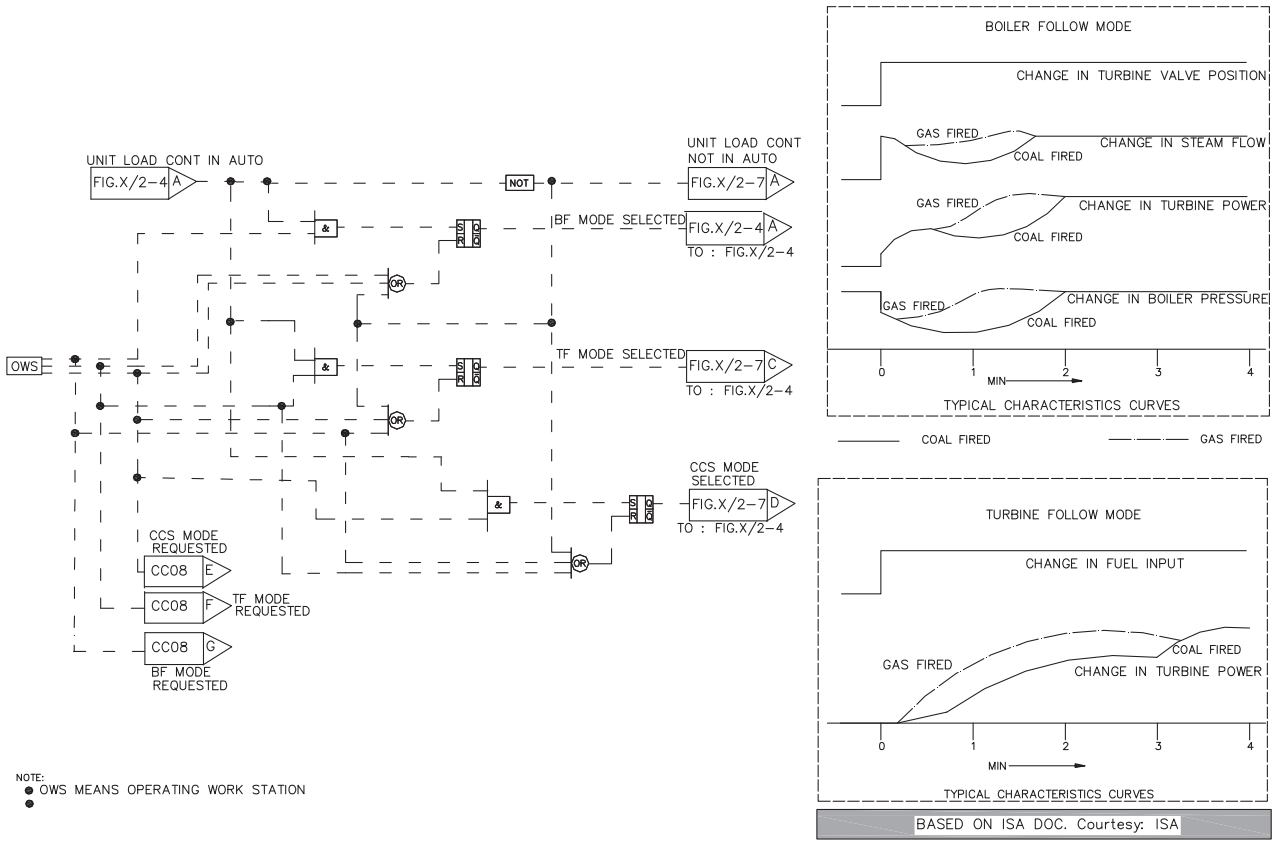


FIGURE X/2-7 Coordinated control: control mode selection.

www.EngineeringBooksPDF.com

3. TURBINE FOLLOW MODE

Turbine follow mode, as previously mentioned in Clause 1.1.3, is used when a boiler or steam generator is delivering the output as required by the unit load demand, coordinated control system, or as per its own capability in manual mode. In this mode of operation, the unit load demand signal may be issued directly to the boiler control system when there is no contingency or limiting criteria, but there may be some other problem that poses a limitation for the unit to run on coordinated control mode. This occurs because operation of the unit with the turbine follow mode is more stable than the boiler follow mode of operation, as per the study conducted by authorities to compare response characteristics under different modes of operation. During this mode of operation the steam supplied by the boiler has to be accepted by the turbine at the desired pressure by positioning the governor valves like the turbine is in auto mode and capable of producing full capacity output. This type of operation is normally performed when the unit is running on initial pressure control or during pressurizing of the system or limit pressure control.

3.1 Turbine Follow Mode: Steam Pressure Control Mode

In a turbine follow mode of operation (Figure X/2-7), the boiler output is at its maximum available capacity or as per the automatic load controller command. Here the turbine control system is forced to follow the boiler supplied load, whatever the value, and this mode of operation is applicable for the unit where difficulties are encountered in varying the boiler load. For any change in electrical load, the steam flow will change and the steam pressure is expected to change accordingly. As the boiler control system action is limited due to equipment limitation, the steam pressure is now controlled at the desired value by the turbine control system. Fluctuations in the steam flow are expected because frequency variation-related response in the turbine would now be canceled by the output of the pressure controller action.

If the boiler is supplying steam at a steady load, the function of steam pressure control in the turbine section is just to maintain the steam flow admission rate so that turbine's generator load matches the boiler load only. If there is any change in the thermal load supplied by the boiler, the pressure would change and the pressure controller action to maintain the pressure set value would change the turbine's generator load accordingly. This type of control philosophy is applicable for a once-through boiler where the boiler is dictating the steam flow delivery rate and the turbine adjusts its governing/control valve position to maintain the steam pressure at turbine end.

3.2 Turbine Follow Mode under Coordinated Control System

Turbine follow mode in a coordinated control system is normally meant when there are load-limiting criteria in the boiler, such as nonavailability of adequate fuel, air, or feed water support. This mode may be automatically entered by interlocked operation when such an emergency event occurs in a boiler, or it may be selected by the operator from the workstation.

As previously mentioned, in this mode of operation, the unit load demand or boiler load demand is directly commanded to deliver steam flow rate; at the same time the turbine follows the above load demand accordingly so that the generator output is maintained at a desired level. The coordinated control system would provide necessary command/correction to the turbine control system to maintain a constant throttle or variable pressure (Figure X/2-4).

4. BOILER FOLLOW MODE

Boiler follow mode, as previously mentioned in Clause 1.1.2, is used when only the turbine is controlling the load by positioning the governor valves. This mode ensures delivery of the required steam input to the turbine at the exact pressure (whether fixed or variable). The sole duty is accomplished by the steam generator plant through generation of suitable boiler master demand. This type of operation is possible when the unit is running under any of the following conditions:

1. When the turbine control system is in manual, the unit load demand may not be directly controlling the governor valve position, but at some value that may be fixed, for example, during the start-up/pressurizing operation of steam.
2. Due to some constraint the turbine may operate within some restriction or in manual mode due to limitations of its own equipment or accessories; namely, outage of any heaters, CW/ACW pumps
3. Turbine control is in auto mode delivering the load as per the unit load demand, which may be either in auto [LDC/automatic generation control (AGC)] or manual, and the boiler delivers the required steam at the required pressure without seeing the unit load demand.

4.1 Boiler Follow Mode: Master Steam Pressure Control Mode

This type of operation is applicable when a boiler maintains the steam pressure of a specified point only. The situation may occur when a number of steam generators/boilers with different capacities are supplying steam to a common main header. There may be a single turbine or many turbines

www.EngineeringBooksPDF.com

drawing steam from this header, according to the load demand decided by other systems. There may be steam extraction from the header or different turbine stages to meet the process requirements. Figure X/2-3 is a schematic representation of this system.

Whatever the consumer network, the steam pressure of the header is supposed to change in response to the varying load demand. Each boiler connected to this main header has its own steam pressure controller with the same pressure control set value used to maintain the main header steam pressure according to its own capacity. This is called parallel operation of boilers. In this arrangement, the demand is mainly generated by the turbine through the governing/control valve modulating in response to the electrical load demand. Here, a boiler is just meeting the demand by supplying steam at a desired pressure or, in other words, is "following" the turbine demand. As the control of main header steam pressure is the only criterion for this type of operating mode, it is called "boiler following turbine" or "boiler following—master pressure control."

There must be a time delay for the controller to take corrective action as per the demand; the once-through type boilers are unable to cope with this type of requirement. This mode of operation can, therefore, be implemented only for drum type boilers where some cushion is available for the energy stored in the drum.

4.2 Boiler Follow Mode under Coordinated Control System

This control mode of operation is selected by the operator from the workstation, as previously discussed in Clause 2.1. In this mode of operation, the main steam pressure plays a vital role in the boiler side control while the turbine controls the load. Figure X/2-7 is a schematic representation of this system.

Boiler follow mode is part of a coordinated control system used when a turbine load-limiting function exists. This mode is automatically entered when a turbine contingency such as valve position limit or operator action occurs. The boiler must have fuel, water, and air on automatic to regulate the pressure and the turbine controls the MWs within its own limitation. The load limit is restricted as set by adjustable bias over main steam pressure (controller output) demand.

In boiler follow mode, the output from the main load controller of the coordinated control system directly goes to the turbine control system as the turbine master demand by switching algorithms, whereas another switching provision at the same time enables the main steam pressure control demand to become the boiler master demand. During this mode of operation, the unit load demand is totally managed by the turbine governor valve position controls. By doing this, the main steam pressure at the governor valve inlet is liable to change. Unless the steam pressure is maintained at the desired value, the load control would become an impossible task. Hence, the steam pressure is controlled in the boiler by controlling the fuel inputs.

5. RUN BACK SYSTEM

A run back system in a coordinated control system operation means the unit load demand comes from the unit load. As such, the load level decreases as dictated by the type of emergency situation. If load is not already lower, then the new emergency load restriction is called a run back load. In some coordinated control systems, only the boiler demand is reduced to run back load and turbine control is forced to manual.

The run back demand is a variable load value dependent on the type of emergency condition. In this condition the load demand is gradually brought to a desired run back target set level as per the run back gradient, which is also dependent on the severity of the run back condition (see Figures X/5-1 and X/5-2).

The number of main drives, such as IDFs, FDFs, PAFs, and air preheaters (APHs), and number of mill boiler feed pumps (BFPs), condensate extraction pumps (CEPs), circulating water pumps (CWPs), etc., determine the magnitude of run back load. Here, the total number of drives (other than standby drives) is considered capable of delivering 100% load. For example, $3 \times 50\%$ BFPs means 100% equivalent load when any two BFPs are running (the other is a standby) and outage of two such pumps with only one pump running would mean the unit capacity would $\sim$50% or capacity of each pump. For $2 \times 50\%$ FDFs, there is 100% equivalent load and outage of one such fan would mean unit capacity would also be $\sim$50% or capacity of each fan.

IF any of these drives fail, the equivalent load value, as shown in Figure X/5-1, would be $<$100% load. If the plant was running at a higher load (as delivered by the generator), then the new run back condition load, which has now become the run back target for that particular type of drive failure (FDF/IDF/BFP, etc.), may be selected as the emergency boiler load demand. When the generator MW demand signal is more than the generating capacity of any type of drives indicated above, the run back condition/action is now recognized for each type of drive. The low selector enables the minimum signal of all of the above-mentioned run back targets to pass through as the input to the tracking integrator (TRI). The new load value would now be integrated gradually through the TRI with the gradient (rate of change) setter whose value also varies depending on the nature of the drive failure. As shown in Figure X/5-1, the run back rates are also set by providing suitable bias values applicable to each type of drive whenever an individual type of drives goes on run back

www.EngineeringBooksPDF.com

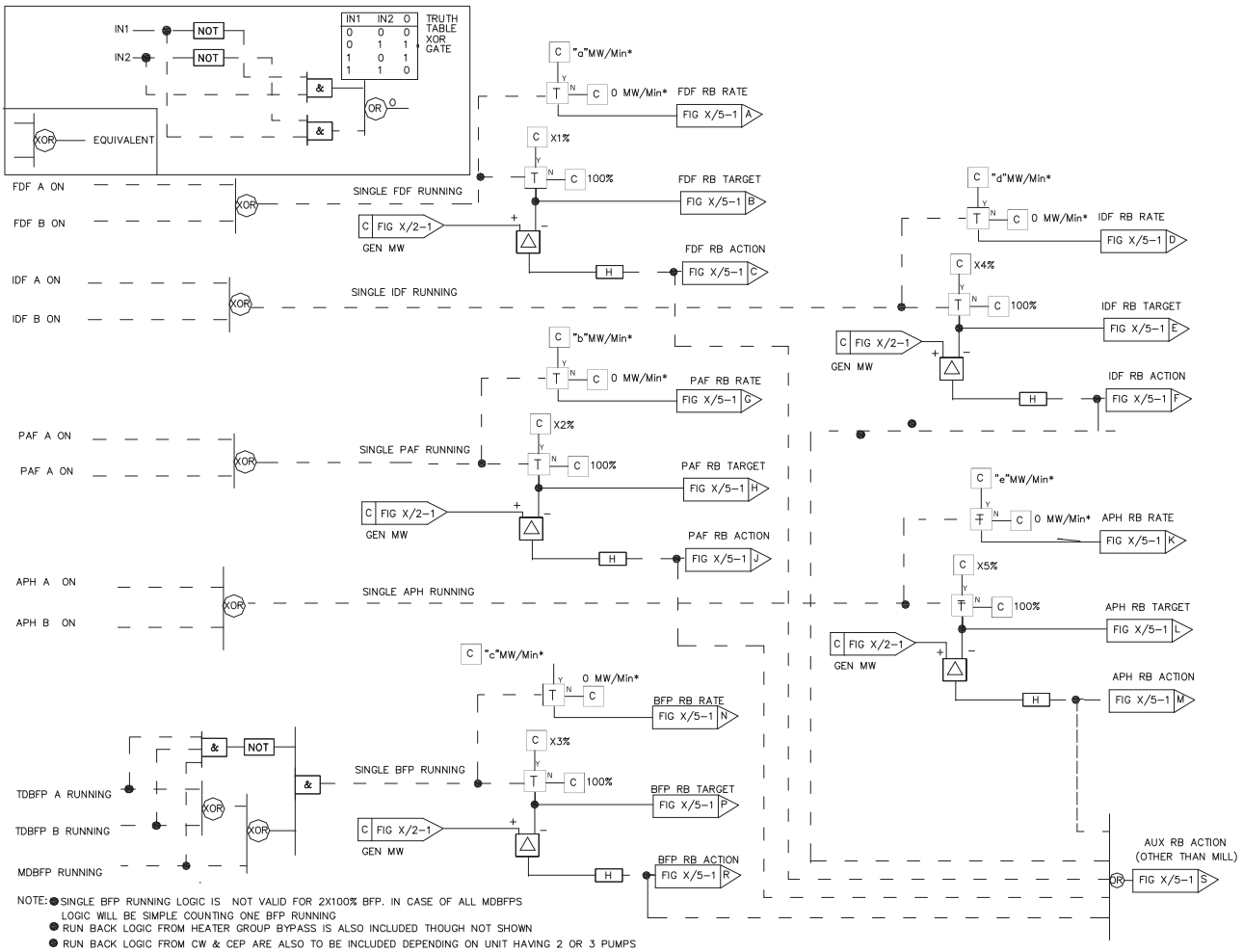


FIGURE X/5-1 Run back logic 1.

condition. All the run back rates are input for maximum selection, and the output determines how fast the lowest run back load demand would be achieved to dictate the boiler load or unit demand.

This gradient would gradually bring down the boiler/unit load to an optimum condition to avoid any major bump in the system. Run back logic for mill tripping is different from that of one FDF/APH, etc. Normally, in medium to large units a minimum of one mill is kept as standby. Figure X/5-2 assumes M number of mills to run for 100% load out of a total of N number of mills. If Q number of mills running corresponds to the assigned run back target ($\sim$60%) and the number of mills running at any instant becomes $\leq Q$, the run back system is generated. Other run back inputs are from burner management systems/furnace safeguard supervision systems and/or "fuel control deviation high" logic. With ball and tube mills, each side could be considered equivalent to one other mill type.

While the boiler/unit load demand is brought to run back (other than mill run back input) load, the mills are cut sequentially to tally with the new demand value. Failure of each type of drive determines the number of mills to be "ON" in run back condition, and the other mills are cut in a sequential manner. This sequence may be initiated from the top of the furnace up to the desired level, which is normally followed in TT boilers. As the design of wall-fired boilers includes many types of firing systems—opposite firing, front firing, down shot firing, etc.—this preferential mill tripping depends on the guidelines indicated by the manufacturer.

Mill cutting is necessary in a run back condition as the reduced number of mills would then deliver near full capacity output to maintain the new boiler load. This is done because a number of mills are not supposed to run at lower loads; this may jeopardize the stability of the mill. With this new scenario, the boiler control can run in automatic mode, but the turbine may be tripped to manual.

www.EngineeringBooksPDF.com

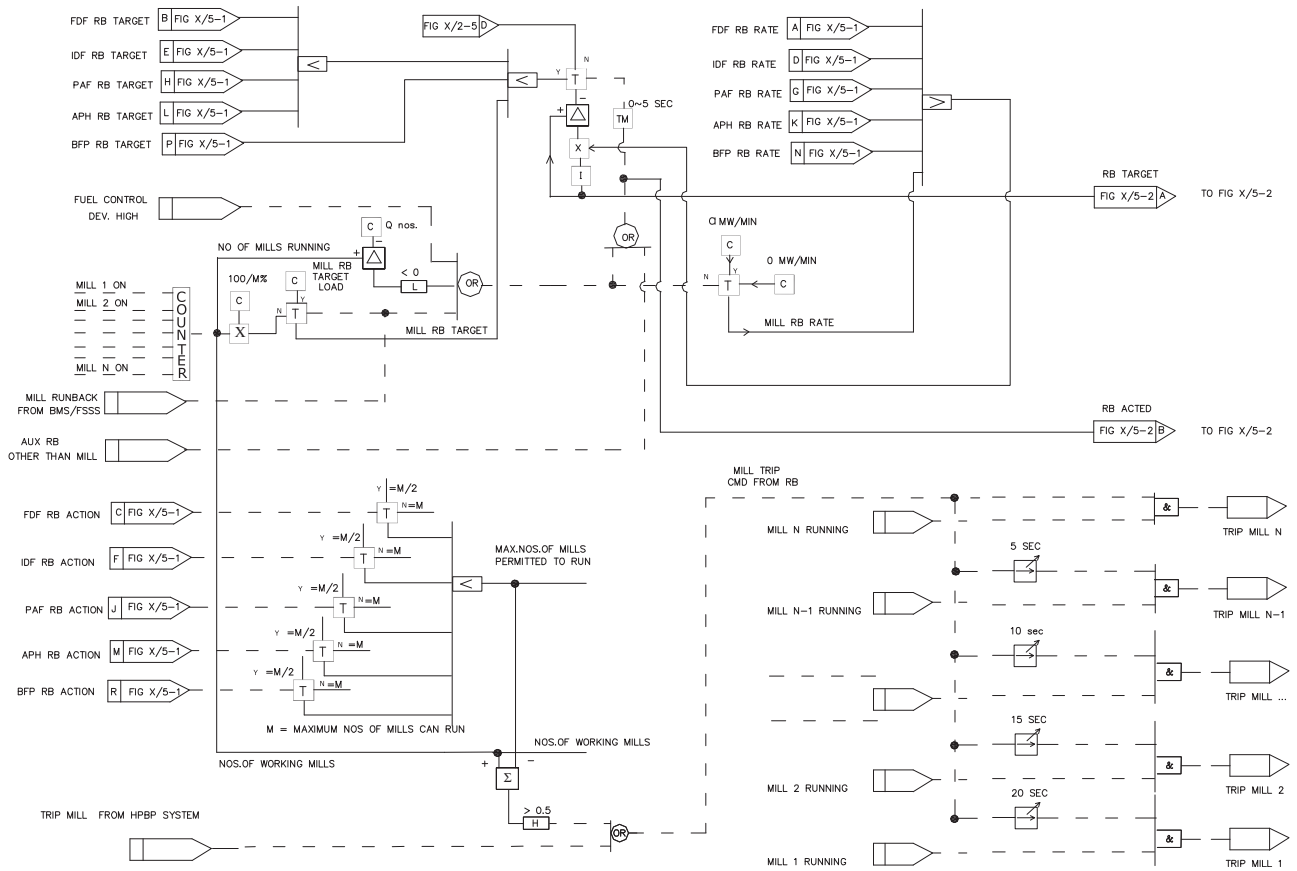


FIGURE X/5-2 Run back logic 2.

The command of such an operation lasts for a short time, and the operator can take the turbine control to auto mode if the situation demands.

6. DISCUSSIONS AND EXPLANATIONS

The first application of the coordinated control system was in the United States in the 1950s for a large once-through supercritical unit. The concept has gained significant acceptance and recognition throughout the world for achieving engineering excellence since its inception. In view of the FGMO, as discussed in Chapter IX, and trouble-free operation of large modern thermal (fossil-fired) power stations, today the coordinated control system plays a vital role.

Coordinated control implies a coordinated "as a single unit" operation of the boiler—with all its associated accessories related to fuel, air, and feed water—and a turbine with related accessories and generator—including heaters, condenser, CWPs, CEPs, etc.—to meet the prime objective of the plant, that is, to supply adequate steam flow at proper temperature and pressure for delivering electrical power generation according to demand. By this definition the unit load demand is utilized as a requirement for the boiler thermal inputs as well as electrical power generation through the turbine. The coordinated control system is generally used to get the boiler, the turbine, and the generator to work in tandem under all operating conditions such as steady fixed load, during changing of load through ramp with preprogrammed gradient in a normal application, and with different preprogrammed gradients under emergency conditions. The basic objective is to deliver maximum electric power, as per the demand initiated in-house or by an external LDC or AGC under all conditions such as at steady load or during changed demand at the optimum rate, considering the process limitation such as outage of vital drives or the capability of auxiliary equipment/systems. The constraints may be from any subsystem, such as the boiler, the turbine, and the generator, and the rate is programmed to be limited by the least responsive variable. The most common objectives for coordinated control systems are as follows:

1. Balancing of electrical demand and generation—the MWs generated are matched with the unit load demand at highest possible rate and in a linear trend.

www.EngineeringBooksPDF.com

2. Consequent to electrical balancing, boiler−turbine balance is controlled in all situations, even under emergency conditions.
3. Subsequent to electrical balancing, boiler inputs (fuel and air; feed water as well for once-through boilers) are safely and efficiently controlled to match energy input requirements. However, this part of the main three objectives is maintained in the boiler control system.
4. Safe and stable operation during limitations and emergencies, such as during run back and directional blocking.
5. Simple operator interface enables other modes of operation such as boiler follow mode, turbine follow mode, and base mode, i.e., manual control of unit demand when the boiler will be responsible for load change and the turbine and to follow and stabilize the throttle pressure.

Normally the load gradients are programmed to follow a linear path to reach the new target in spite of disturbances in the steam generator and/or turbine, main steam pressure excursion, the nonlinear characteristics of turbine governor/control valves, etc. The energy balance between the thermal energy input to the steam generator with the corresponding electrical energy output from the generator is achieved by issuing common demand to the boiler and turbine. This concept has been equally applicable for both drum and once-through units. The system must ensure that boiler and turbine controls are coordinated, even if the turbine is controlled independently, as per the recommended control philosophy, or as an outcome of emergency requirements.

The system uses a common unit demand for the boiler and turbine. When applied to the boiler it is first subjected to dynamic rate action to produce over firing on increasing load and under firing on decreasing load. This rate action is applied in proportion to the boiler load derived from the unit load, compensates for the inherent stored energy in the boiler, and is reflected in turbine throttle pressure. This enables the boiler to act as quickly as possible to compensate for the stored energy already used by the faster operation of the turbine control through turbine energy requirements corresponding to the unit load demand.

In DEB, another coordinated control strategy, the boiler control does not relate its coordinated action with the electrical generation; the boiler demand in this concept is calculated based only on the turbine energy requirements. Here (as per DEB 400, METSO) unit load demand acts on the governor valve to change the active power by varying steam flow, which changes the first stage pressure of the turbine. Thus, the ratio of first stage pressure P_1 and throttle pressure P_T. This P_1/P_T. is duly rationalized with throttle pressure set point P_S and after dynamically compensated to act as the energy demand signal for the boiler. The boiler is decoupled from electrical load change and connected to the system via energy balance utilizing direct coordination between boiler and turbine. This calculation is called the energy balance signal and represents the turbine requirements for steam under all conditions. It responds as fast as the turbine valves move, even during emergency conditions or when the manual operation of the turbine is performed. Here the boiler demand minimizes the use and effect of rate signal as the feedforward signal, which may provide more stable control on load changes.

This coordinated control system is a better operating philosophy applicable to all boilers with different types of fuels and turbine combinations, such as large central stations with single boiler tandem compound turbine−generators (fixed pressure and sliding pressure applications, multiple boilers connected on headers−co-generation and combined heat and power, simultaneous burning of multiple fuels, etc.).

6.1 Demand from LDC

In all developed countries a large portion of power is generated by nuclear plants and combined cycle plants (gas turbine and HRSG/steam turbine), and most run on base load. Consequently, thermal power plants with fossil firing systems are utilized to operate on a wider range of generating and load-sharing conditions, such as load peaking up, low load operations, load cycling, etc. Even in India, there is a larger proportion of nuclear plants compared with hydel power plants. The following list contains a very rough figure regarding the proportion of power generation in India:

1. Fossil-fuel fired thermal power plant: 75−80%
2. Hydel power plant: 15−20%
3. Nuclear power plant: 5−7%

This phenomenon caused a strong impetus to regulate all power plants from remote, centrally operated LDCs. To implement this, it is extremely important that the coordinated control system is responsive. The LDC is normally conceived as a global load center for the entire grid subdivided into regional grids. There are some conditions, e.g., a fluctuation in load, in which a particular region may not be controlled from an LDC. During those conditions, several units in that region can be operated from regional grids under AGC.

As previously discussed in Clause 1 and 2, the desired generation (MW) can also be set by the plant operators in addition to a signal from the LDC/AGC. Regardless, the response of the load generation controller should ensure a linear output at a maximum possible rate to avoid untoward bumps in the control systems. Although a competent boiler controller coordinates the combustion air and

www.EngineeringBooksPDF.com

corresponding fuel (and feed flow to maintain fuel to feed water ratio in once-through boilers) and the turbine control includes an intelligent governor control system for MW control, only a well-coordinated system can ensure complete harmonized operation of turbine and boiler. There are many problems associated with the turbine governors while control action is passed on directly by the LDC/AGC.

Significant disturbing phenomena include the nonlinear response and mechanical hysteresis affecting the governors to respond in a desirable way. These types of problematic elements need special provisions in the coordinated control system so that the response of the unit as a whole is commensurate with the load variation. If these types of anticipatory problems are not managed properly, the final action may be lacking in linear response and may consist of dead time and overshoot. These features may be incorporated in the coordinated control system and turbine control to receive the command and act accordingly when put in coordinated control mode and the turbine control is in remote auto mode.

6.2 Boiler Turbine Balance

In the conventional coordinated control system, the controller output from deviation of unit demand and MW generated is issued to both the boiler and turbine with the incorporation of signals appropriate to individual subsystems (for boiler and turbine). For fine-tuning this load signal is corrected by the throttle pressure deviation signal or limited by the throttle pressure controller ± bias values. In some coordinated control systems, the load demand for the boiler is not derived directly from the unit demand as described earlier, but through DEB.

6.2.1 Turbine Demand

For the turbine subsystem, the turbine load demand from the coordinated control system as generated is matched with the first stage pressure as a process feedback signal. The governor or turbine control valves are set to move at a much faster rate to comply with generation demand. In this configuration the system is able to achieve response at the maximum possible rate to follow the changes in MW demand. The same is accomplished by consuming the energy already stored in the pipelines and boiler steam superheaters to the greatest extent, thus fulfilling one of the main targets of the coordinated control system—intelligently managing the stored energy.

6.2.2 Boiler Demand

Here the boiler load demand is representing, under all conditions, the effective turbine valve opening through the turbine energy requirement from the boiler [see Figures X/1-1 d and e (by DEB) and X/6-1]. The effective turbine valve opening is simply the ratio of turbine first stage pressure

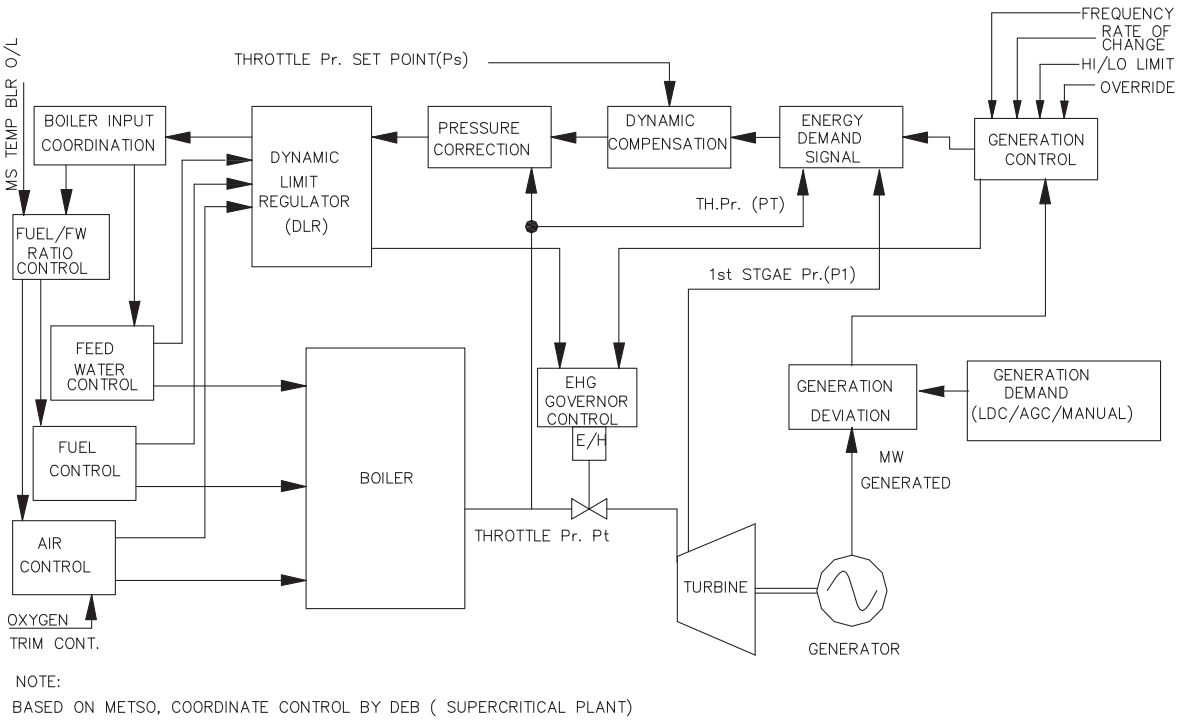


FIGURE X/6-1 Coordinated control—energy balance concept for supercritical boiler.

www.EngineeringBooksPDF.com

(P_1) to throttle pressure (P_T) and is well-accepted as the linear representation of the effective turbine valve opening. It appears it is independent of different disturbances caused during operation of the boiler subsystem, such as a change in fuel quality or limitation in production capacity in a particular mill, etc. This signal, multiplied by throttle pressure set value, constitutes a better load index, unlike steam flow or first stage pressure, which are commonly used as load signals and are apprehended to engender regenerative signal during boiler upsets. This signal acts similarly to a self-calibrating feedforward signal; hence it is recommended as a load index to the boiler control system. Because that signal is supposed to be the ideal feedforward signal from the user side, introduction of the same will initiate optimum firing rate by restraining the final demand through minimizing the intermediate over firing or under firing command that might be generated otherwise.

When load increases, the stored energy is withdrawn from the boiler and there is an equivalent drop in throttle pressure. The tendency of the simple boiler control systems is to overcompensate with continuous integral control action and may cause general instability. The desired controller action should have the self-tuning/calibrating capability as a measure of energy balance signal with a proper combination of proportional and rate action to deliver the correct amount of control output signal, thus the loss of stored energy in the boiler is compensated for at the quickest possible time. As the pressure approaches the set point as the steady-state condition is attained, the controller output signal automatically decreases to a level where energy input to the boiler equals generation output. Overshoot and instability can thus be avoided and the stored energy used to assist the immediate load change is restored to a new value appropriate with the new level. The derivative signal is appropriately scaled according to the preliminary demand (to avoid noise) before being added at the summator (Figure X/1-1e) to arrive at the final demand. The upper and lower load limiter and directional blocking functional blocks are included to arrest any rapid change in boiler demand.

As there is no electrical generation (MW) signal in this energy balance concept, controller output is assumed to provide for "boiler–turbine coordination under all circumstances." This statement is valid even if it is not possible for the turbine control to be operated under automatic control mode; in other words, it is forced to operate in an emergency condition or put in manual. The boiler demand signal is, as is apparent from the above description, always considered as the current energy requirements. The energy balance signal is an independent calculation, and the boiler control can now operate without the demand or feedback from the generation control.

6.3 The Concept of Heat Release

To establish energy balance between boiler and turbine, the demand signal with an integrating type controller should be replaced with proportional and derivative or rate action as the former controller may cause instability. It is also recommended that the regenerative type of feedforward signal, such as steam flow, may also cause instability due to overshooting at the time of each load change. This problem may be more acute for the coordinated control system with sliding pressure control mode.

According to this theory, the concept of "heat release" is utilized for calculation of an accurate measurement of fuel or energy input to the boiler and not by measurement of steam flowing out from the boiler. This philosophy is most useful when there is a change of load or a change in fuel quality causing a change in the heating value of the fuel being burned. It is most important that the calculation is accurate, otherwise the controller cannot maintain the desired air–fuel ratio control and ultimately may result in untoward disturbances in the other control strategies, such as drum level control and steam temperature control. If a high amount of accuracy is not achieved, the rate and magnitude of the load change must be restricted.

6.3.1 Measurement of Fuel Input

There are two conventional types of fuel measurement adopted in thermal power plants. They are utilized in the combustion controls and each of these measuring systems has its own limitations. The first type is the direct measurement of fuel, and the second one is indirect measurement of fuel based on calculations and associated functions related to other parameters.

Direct measurement of the fuel is a widely accepted and standard method, but it has practical limitations. The fuel flow can only be successfully measured in (natural) gas-fired steam generating plants. Measurement of solid fuels, such as pulverized coal, are extremely difficult to measure and are normally measured by "coal feeder speed" or air flow through the mill, which are also indirect methods.

The second traditional method of the fuel measurement is an empirical one using the measurement of boiler output, typically, steam flow or turbine first stage pressure. The primary limitation in using boiler output measurement as a measure of energy input is that the output is proportional to the input under steady-state conditions only. A more accurate relationship between energy input and output must also include changes in stored energy. The change in stored energy must be added to or subtracted from the boiler output to make it proportional to energy input under both steady-state and dynamic conditions.

www.EngineeringBooksPDF.com

6.3.2 Energy Balance System

The design of a drum type boiler uses the working medium (water and steam mixture) at saturation pressure and temperature and accumulates in the drum. Due to the load change, the drum pressure changes as do the temperature and enthalpy. The majority of the stored energy is in fluid form. Because drum pressure is essentially linear with fluid enthalpy, it can be considered as a good index of stored energy.

The actual level of stored energy cannot be treated as a part of the load change, since it has no bearing on the fuel input. However, the changes in stored energy are of great importance since they are the result of changes in the fuel firing rate and/or heating value of the fuel. The basic equation for boiler energy transfer is as follows:

$$\begin{aligned}\text{fuel input (kcal}/H) &= \text{boiler output (kcal}/H)\\ &\quad + \text{change in stored energy (kcal}/H)\\ &= KP_1 + K_1(dP_{DR}/dt),\end{aligned}$$

where P_1 = turbine first stage pressure or boiler steam flow

$$P_{DR} = \text{drum pressure.}$$

From the above equations the rate of change of drum pressure (d/dt $\mathbf{P_{DR}}$) is an indication of boiler input and output balance similar to throttle pressure excursion and thermal energy balance between boiler and turbine. In the steady-state condition, that is, when the drum pressure is not changing (the value of d/dt $\mathbf{P_{DR}}$ is zero), the fuel input to the boiler equals the boiler output and correspondingly right at that moment the energy level of the boiler and the turbine are perfectly balanced.

6.3.2.1 Limiting of Unit Load Demand according to Boiler Input Limitation

The coordinated control system should provide bumpless, trouble-free, safe, and economical boiler operation and not permit a significant imbalance between the boiler inputs by sensing several control errors. For example, it reduces the turbine requirements when a boiler input is limited, at the same time it reduces the boiler demand to match the limitation in the different types of boiler inputs. Positive action is to be taken to make certain that the system load does not exceed the productive ability of the least capable boiler input.

Basically this part of the coordinated control system looks at the differences between the desired and the actual measurement/calculated values of all of the important process parameters, such as fuel, air, and feed water control systems. If any of these process deviations exceeds their limit value, the rate of directional changes (increase or decrease) of the common unit load demand, that could have increased the deviation, is either blocked or held. In advanced control systems, when the deviation approaches its limit value, the rate of change of increase or decrease of the unit load demand is reduced as a precautionary measure. When any of these deviations reaches their limit value, these rate changes in the demand signal are blocked. If any of these deviations exceeds the limit value, the unit load demand signal is corrected at a rate proportional to the magnitude of the error until balance is re-established. However, if there is much difference between the unit load demand and the ultimate boiler load (reflected in high generator MW deviation), the turbine control is transferred to turbine follow operation to follow the boiler in its limited condition.

Run back system is a coordinated control mode operation. A run back load occurs when the unit load needs to decrease to a lower load level as dictated by an emergency situation if it is not already lower than the new emergency load. Run back demand is a variable load value dependent on the type of emergency condition. In this condition the load demand is brought gradually to a desired run back level as per the run back gradient, which is also dependent on the severity of the run back condition (see Figures X/2-1 and X/2-4).

The number of main drives, such as IDFs, FDFs, PAFs, AHs, BFPs, CEPs, and CWPs, determine the magnitude of the run back load. Here, the total number of drives is considered capable of delivering 100% load. For example, 3 × 50% BFPs mean 100% equivalent load with two running pumps with one on standby. Outage of one of these pumps would mean unit capacity would be ∼50%. For 2 × 50% FDFs, there is 100% equivalent load and outage of one such fan would mean unit capacity would also be ∼50%. In both cases the pump/fan capacity may be slightly more as per the cushioning provided in the unit.

The "upper load limit" of a plant unit is normally set 10% above 100% load. As depicted in Figure X/2-1, the unit load demand is the output through a minimum selector that has its inputs as "demand from the LDC/AGC" and the abovementioned upper load limit. Then upper load demand is corrected by the "frequency-influenced" load value and sent to the boiler and turbine as load demand after passing through upper and lower limits set by the master pressure controller, as shown in Figure X/2-4.

If any of the drives fails, the equivalent load value would be less than 100% load. If the plant was running at a higher load than the new run back condition load, the latter is now selected as the new boiler/unit load demand. When any drive failure-related signal is less than the generator output the "run back condition" is recognized. The new load value is now to be achieved gradually through a limiter with a varying gradient setter whose value is also dependent on the nature of the drive failure.

www.EngineeringBooksPDF.com

As shown in Figure X/2-5, the number of drive-related equivalent loads of each type of drive is compared with the upper load limit. For any significant deviation, the comparator would trigger a switching action and allow the preloaded run back gradient signal, unique to individual type of drives, to a selector where other such signals from different types of drives are also input. The selector has the capability to select the priority among all the types of drives connected to the run back system. This priority selected run back gradient signal is made through another switching action only when the run back condition takes place. This gradient enables the boiler load to be brought down gradually and smoothly in an optimum condition to avoid any major bump in the system.

As discussed previously, DEB can be applied to a supercritical plant with once-through boilers, based on METSO documents (see Figure X/6-1). Also, boiler control is decoupled from the main unit load deviation signal so that stored energy can be utilized quickly to meet the demand. Unit load deviation directly sends a signal to the generator control system, which also manages other influences such as frequency, high/low limit, rate of change, etc. Generator control directly affects electro hydraulic governor control to change first stage pressure (P_1). At the same time the energy demand signal is generated accounting for the P_1/P_T ratio duly normalized with throttle pressure set point P_S at the dynamic compensation circuit. This signal after pressure correction is fed to the boiler input coordination input.

In once-through boilers there is no isolation between steam and water circuit via storage vessel boiler drum. Naturally, any change in parameter of steam directly affects the BFP, i.e., feed flow. So, in once-through boilers in supercritical plants, the ratio of fuel flow to feed water is very important. Thus the boiler input coordinator sends a signal to feed water and to fuel circuit via ratio setter. For any combustion the fuel/air ratio needs to be maintained; therefore, via ratio setter, a signal is sent to the air and fuel controller to manipulate the inputs to the boiler. During transit, boiler-stored energy is utilized, so that unnecessary overshoot and undershoot could be avoided. There is another sub block, dynamic limit regulator, shown in Figure X/6-1, which is fed from boiler input control systems. These subsystems feed the status of the control systems, and their various auxiliaries, so that run back and directional blocking signals can be generated to limit the demand for the boiler. These are mainly used during failure of major auxiliaries, and/or when capacity level is reached.

BIBLIOGRAPHY

1. The Smart Grid begins with Efficient Generation; Energy Efficient Design of Auxiliary Systems in Fossil-Fuel Power Plants. A technology overview for design of drive power, electrical power and plant automation system: By M/s ABB, Inc. in collaboration with Rocky Mountain Institute, USA (ABB Energy Efficiency Handbook). http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/5e627b842a63d389c1257b2f002c7e77/$file/Energy%20Efficiency%20for%20Power%20Plant%20Auxiliaries-V2_0.pdf.
2. Modern Control and Actuating Systems on Steam Turbines by M/s VGB Power Tech 3/2005.
3. D-E-B/400 Coordinated Boiler/Turbine Control System (Drum Units) :By M/s Metso Automation. http://www.metso.com/automation/ep_prod.nsf/WebWID/WTB-041110-2256F-8E7F4?OpenDocument#.VBf0YZSSyt0.
4. Chapter IX, Controls for Once-Through Boilers (ISA Document): Excerpts from M/s F.Paul De Mello and other Authors. De Mello F.P Chapter IX (ISA ref book) http://www.isa.org/~powid/boiler_dynamics_controls_course/De%20Mello%20course%20notes/De%20Mello%20Chapter%209.pdf.
5. Boiler-Tuning Basics, Part II: By Tim Leopold, May 1, 2009. ABB Inc. Dtd.

www.EngineeringBooksPDF.com

Chapter XI

Balance of Plant Control System

1. BALANCE OF PLANT: INTRODUCTION

1.0 Introduction

The balance of plant (BOP) controls for a power plant are defined as the controls outside the main power plant control, such as controls pertinent to off sites like a coal-handling plant, ash-handling plant, etc. All these auxiliary and off site plants have been covered in Chapter II and Chapter VII, Main Clause 2.5. However various control systems of the main plant, which are not directly related to boiler–turbine control, have been grouped here as BOPs, so the BOP of main plants will be discussed in this chapter.

- *Boiler control system (Chapter VIII)*: Control systems directly related to boiler controls such as the furnace safeguard supervision system, secondary air damper control, combustion control, furnace pressure control, drum level (as applicable), steam temperature controls, high-pressure (HP) bypass, etc.
- *Turbo generator control system (Chapter IX)*: This includes control systems directly related to turbine controls, such as electro hydraulic governor controls, automatic turbine run-up system (ATRS), automatic turbine tester, thermal stress evaluator, low-pressure (LP) bypass system, H_2 seal oil controls, condenser level control, etc.
- *Coordinated control system (Chapter X)*: Coordination in control between various systems.
- *BOP control system*: The BOP control loop is mainly related to equipment from regenerative systems. In co-generation/combine cycle plants, all controls other than gas turbines may be called BOP controls, which are well covered in the various control systems discussed in this book.

The following control loops have been covered under BOP controls:

- Boiler feed pump (BFP) recirculation control
- Condensate extraction pump (CEP) recirculation control
- Gland steam condenser (GSC) control (min flow control–gland steam header pressure control covered in Chapter IX)
- Deaerator pressure control (deaerator level control covered in Chapter IX)
- HP and LP heater level controls (both normal and emergency)
- Turbine auxiliary steam system (TAS; ejector control)

There are a few common actions/monitoring such as auto/manual (A/M) change over, final control element position monitoring in distributed control systems (DCSs), etc., which are not discussed separately in each loop as these discussions were covered in previous chapters (e.g. Chapter VIII).

2. BFP RECIRCULATION CONTROL

2.0 General

When large pumps run they create a great deal of heat from the churning effect of the impellers. So when the pump runs it is necessary to cool the pump impellers. During higher load operation, fluid flowing through the pump acts as a coolant. When the pump just starts and/or when the pump is running at very low load, normal fluid flow quantity may not be sufficient to cool the impellers. Therefore a minimum quantity of fluid needs to flow through the pump, thus balance fluid is returned to the source. This is achieved by recirculation flow of the fluid through the pump. Recirculation is defined as returning the pump discharge flow to the point where the pump has suction so that a minimum flow requirement of the pump is ensured through the pump (even when there is low/no load demand to the system from the pump). For recirculation flow of a BFP (the pump has its suction from the deaerator), the pump entire/partial flow water from the BFP is returned to the deaerator during start-up and at low load. Generally, the BFP handles high flow at high differential pressure (DP); pump sizes are large so even for small units such recirculation flow is necessary. The loop discussed here is applicable for each pump, so only one loop is illustrated.

2.0.1 Objective

The purpose of the BFP recirculation control loop is to ensure minimum flow through the BFP at all times.

2.0.2 Discussion

The BFP recirculation line is taken from the pump discharge ahead of the discharge valve and returned through the recirculation valve to a deaerator where the BFP has suction (see Figure III/6.2-1 and III/6.2-2). There are

Copyright © 2015 Elsevier Ltd. All rights reserved.
www.EngineeringBooksPDF.com

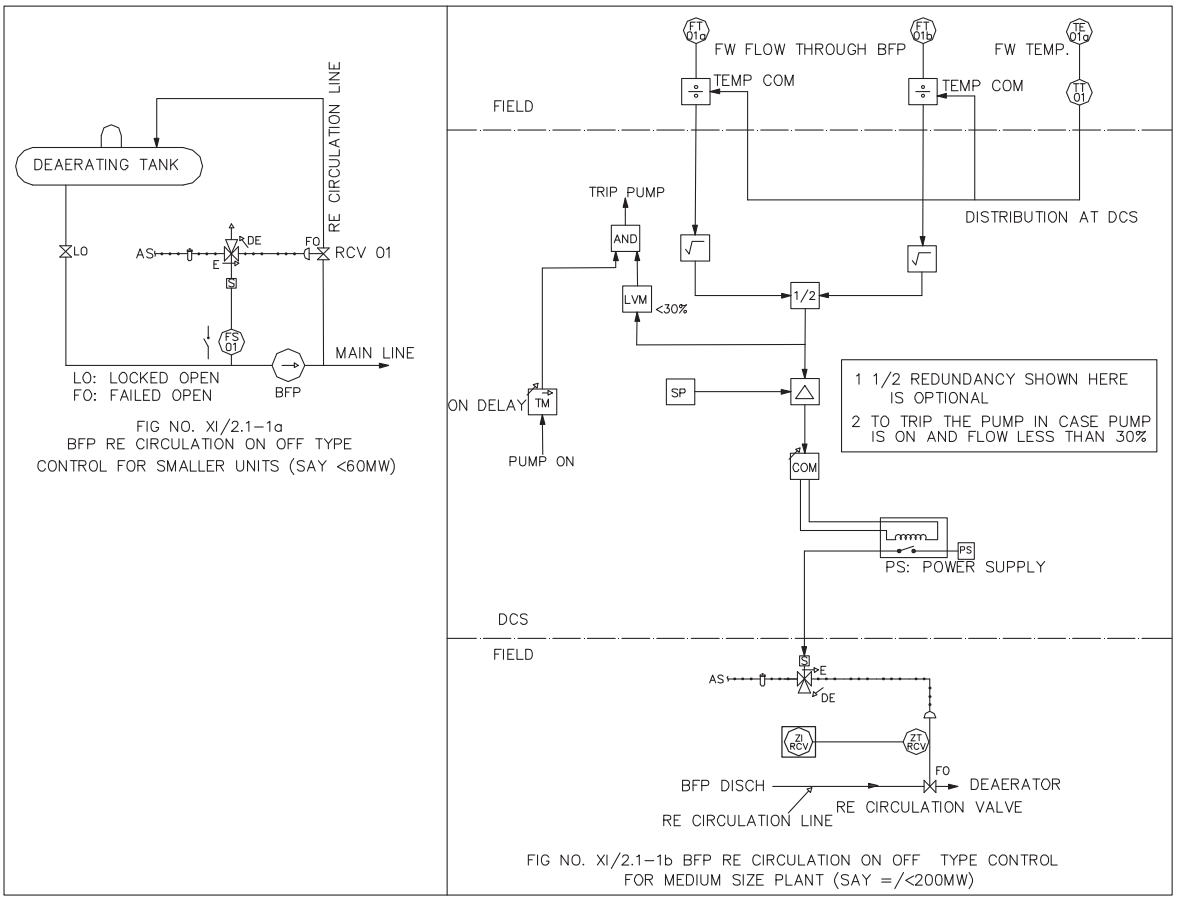


FIGURE XI/2.1-1 BFP recirculation control.

various BFP sizes, types, and unit sizes, as well as variations in controls. Generally, in power plants up to 200 MW (there are modulating types of controls for unit size <200 MW) an ON/OFF type of recirculation control is deployed. BFP recirculation control loops for unit sizes ≥500 MW are generally the modulating type. For smaller units a simple flow switch may be used to operate BFP recirculation control (see Figure XI/2.1-1a), whereas in 120 MW/200/210 MW units the suction flow of the BFP is measured and this signal is used to OPEN/CLOSE the BFP recirculation control valve (see Figure XI/2.1-1b). Since there will variations of temperature so, it is recommended to compensate the flow with feed water (FW) temperature at BFP suction.

2.1 Control Loop Description

The loop is applicable for each BFP (see Figures XI/2.1a and b and XI/2.1-2).

2.1.1 BFP Recirculation Control for Smaller Units

In this control loop a flow switch (i.e., target type) is put at the suction of the pump (see Figure XI/2.1a). This loop will be functional when BFP is running. The flow switch is set at a flow rate slightly higher than the minimum flow requirement of the pump (to sense falling flow). As long as the flow through the pump is greater than flow set point, the remote control valve (RCV) will be closed. During start-up or at low load, when flow through the BFP falls below the flow set point, a flow switch will operate [to have contact configuration: normally open (NO) contact is open and normally closed (NC) contact is closed meaning that if NO is connected then at low flow it will open the power to solenoid valve, on the contrary, if NC is connected then at low flow NC will bypass the solenoid and power will be connected to return path via resistance. both possibilities exist depending on circuit configuration. so, reader to take care of the same in the circuit. applicable in all such cases— also ref fig no Xi/2.1.1-1], to de-energize the solenoid valve. Consequently, air from the RCV will be vented, and the RCV will open. The contact configuration of the flow switch through selection of solenoid valve type is important. Normally the RCV is chosen as a fail-to-open type to ensure pump safety at all times (see Figure XI/2.1.1-1).

www.EngineeringBooksPDF.com

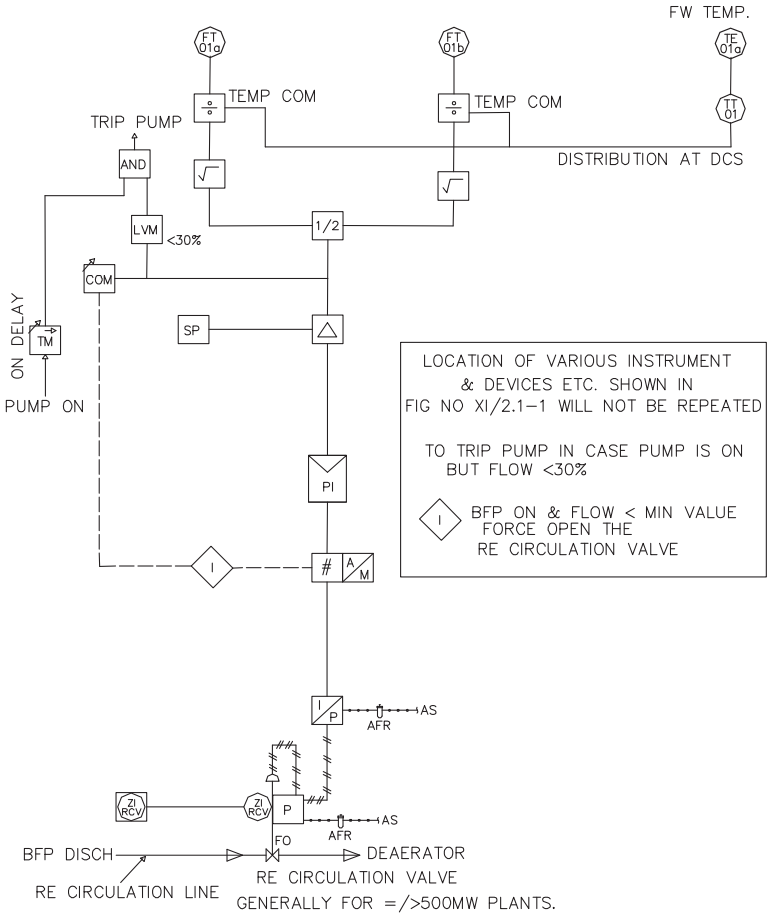


FIGURE XI/2.1-2 BFP recirculation modulating control (for higher MW).

2.1.2 BFP Recirculation Control for Medium Units

The basic control loop philosophy was discussed earlier (Figure XI/2.1a,b). The only difference is that here flow is computed at the DCS with the help of a flow transmitter, which is more accurate and stable. In this control loop a flow element and redundant transmitters are placed at the suction of the pump. To take care of the variation in density, a temperature compensation is made in flow computation in DCS (see Figure XI /2.1.2-1)

Why in FW flow computation is temperature compensation given?

This is done because, depending on the load, deaeration heating is done by auxiliary steam, cold reheat (CRH), and extraction steam, and in each case the heating temperature is different so the FW temperature is different. Also, when LP heaters come into service in combination, their FW temperature varies so temperature compensation is necessary.

This flow is compared with the set point and fed to a controller in ON/OFF mode as a comparator. As long as computed flow is less than the set point the output of the ON/OFF controller (COM) will be de-energized, and the solenoid valve will not get any power. As long as the solenoid valve is de-energized, air supply to the diaphragm of the RCV will be vented and it will open. When the flow set point is exceeded by the computed flow (with dead band) "COM" will generate output to close the NO contact and the solenoid valve will be energized to close the RCV. It can be configured in reverse, but as stated earlier, from a safety

How NO & NC for a switch is decided? Generally the contact configuration decided based on their condition at NO FLOW NO POWER CONDITION. Now any switch when bought from market, has no flow nor it is energized, so closed contact at this condition is NC and Contact at Open condition is NO contact. Same philosophy is for electrical switches, relays also.

FIGURE XI/2.1.1-1 NO or NC contact configuration.

www.EngineeringBooksPDF.com

Since Computed flow Q= √(hP/T) where h= DP head, P= static Pressure & T =Temperature.
When representing them in the loop Square rooting to be done after Pressure and / or Temperature compensation --- not immediately after DP transmitter O/P. This is control loop representation tip!! Water is incompressible, fluid so Pressure compensation is not applicable.

FIGURE XI/2.1.2-1 Flow computation.

standpoint it is recommended to use air to close the valve so that during air failure the BFP recirculation valve is open. With reference to Clause 1.2.1 of Chapter VIII, it may be noted that since there is no A/M station, if there is a transmitter failure alarm the operator needs to manually select the correct transmitter for proper control loop operation.

2.1.3 BFP Recirculation Control for Larger Units

For plant sizes ≥500MW, modulating type control loops are deployed for BFP recirculation loops (irrespective of BFP types such as motor or turbine driven; see Figure XI/2.1-2). The flow computation will be similar as discussed in Clause 2.1.2. This flow is compared with the set point and fed to a P+I controller. The controller output is fed through an A/M station to an I/P converter, which will supply the pneumatic control signal to the positioner of the Control Valve. The control valve will throttle according to the signal from the controller.

2.2 Control Loop Operation

The loop operation in small and medium sized units was discussed in Clause nos. 2.1.1 and 2.1.2 (Figure XI/2.1-2). As discussed in Chapter VIII, Clause 1.2.1, this control loop may be tripped to manual in case of transmitter failure and/or by selection. The operator needs to ensure the correct transmitter selection to continue with the loop.

2.3 Control Loop Interlock

To make the loop safe and avoid operator error in manual, an interlock can be incorporated to open the valve in case the BFP is ON and flow is less than the set value. Generally, it is set a little higher than the actual set point to avoid tripping the pump (see Figure XI/2.1-2). To save the pump, an interlock is incorporated so that when the pump is ON (time delay to avoid spurious tripping) and flow is less than the set value sensed by the limit value monitor (LVM; setting a little below recirculation set value), then the pump will be tripped (see Figures XI/2.1-1b and XI/2.1-2).

2.4 Control Valve Considerations

For medium size plants typical parameters for the RCV will be I/P pressure: 200−240 bar; O/P pressure: 8−10/12; bar temperature: ∼200°C with a drop in the range of ∼200−230 bar; and outlet temperature very near saturation temperature. Because of this there will be a high possibility of flashing and cavitation. As a result trim durability will be at stake due to high DP at low lift. Therefore it is recommended that for medium and large size plants drag, VRT, and multistep multistage RCVs may be deployed.

3. CEP RECIRCULATION CONTROL

3.0 General

Basic recirculation control, as discussed in main clause 2.0, is also applicable for CEP also. However, in smaller units the CEP recirculation may not be applicable because of the small pump size (because of low flow and lower DP), but for medium to large size units it is applicable. With CEP recirculation, the tapping for the recirculation line may be done after the GSC, to ensure minimum flow through the CEPs as well as through the GSC. This is also possible for 2 × 100 CEPs, and there may be a single CEP recirculation line as well as valve for two sets of CEPs. However, for the 3 × 50 CEP configuration this will not be suitable. There are variations in CEP recirculation loops and these are discussed in following clauses.

3.0.1 Objective

The purpose of the CEP recirculation control loop is to ensure minimum flow through the CEP at all times. In some cases (with 2 × 100 CEP configurations) the same control loop is deployed to ensure minimum flow through the GSC.

3.0.2 Discussion

The CEP recirculation line is taken from the pump discharge after the discharge valve and returned through the recirculation valve to the condenser hotwell (from where the CEP takes its suction) as shown in condensate P&ID (Figure III/7.2-1 and III/7.2-2). As stated earlier, for smaller units an auto control loop may not be necessary for CEP recirculation control. Generally, for larger units (≥500 MW) independent direct CEP recirculation control loops are deployed. For 2 × 100 CEPs a common control loop is used for both CEP and GSC minimum flow recirculation control (see Figure XI/3.1-2a) for medium size units. In these cases the RCV is placed after the GSC. A few variations in CEP recirculation control loops are found in medium sized units where the recirculation controls work with the condenser hotwell level control also. Here, the hotwell level signal is related with the control parameter for

www.EngineeringBooksPDF.com

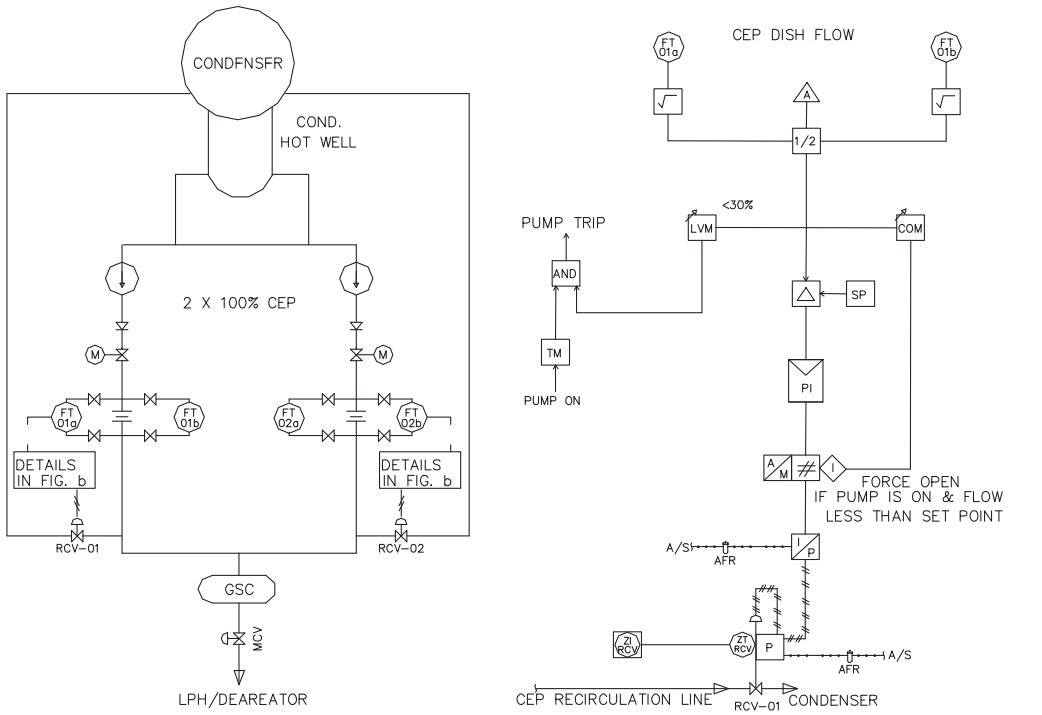


FIG.NO. XI/3.1–1a INDEPENDENT RECIRCULATION FOR 2X100% CEPs

FIG.NO. XI/3.1–1b INDEPENDENT CEP RECIRCULATION FLOW CONTROL FOR ONE PUMP OTHER (S) WILL BE IDENTICAL

FIGURE XI/3.1-1 Independent CEP recirculation control loop.

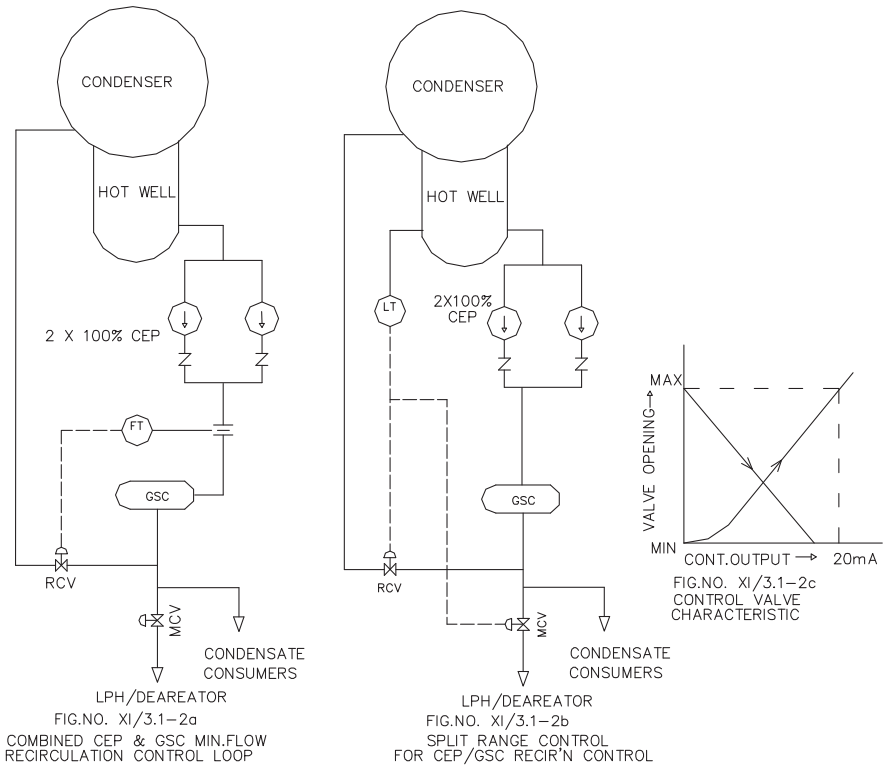


FIG.NO. XI/3.1–2a
COMBINED CEP & GSC MIN.FLOW RECIRCULATION CONTROL LOOP

FIG.NO. XI/3.1–2b
SPLIT RANGE CONTROL FOR CEP/GSC RECIR'N CONTROL

FIG.NO. XI/3.1–2c
CONTROL VALVE CHARACTERISTIC

FIGURE XI/3.1-2 Minimum recirculation flow control for CEP (2X100%) and GSC.

www.EngineeringBooksPDF.com

regulate CEP and GSC minimum recirculation controls (see Figure XI/3.1-2b). However, these loops are an indirect way of achieving the goal and have inherent limitations that are discussed in a later clause.

3.1 Control Loop Description

The control loop description given in this clause is related to the modulating part only. Associated interlocks for the loops are discussed separately in Clause 3.3 (see Figures XI/3.1-1 to XI/3.1-4).

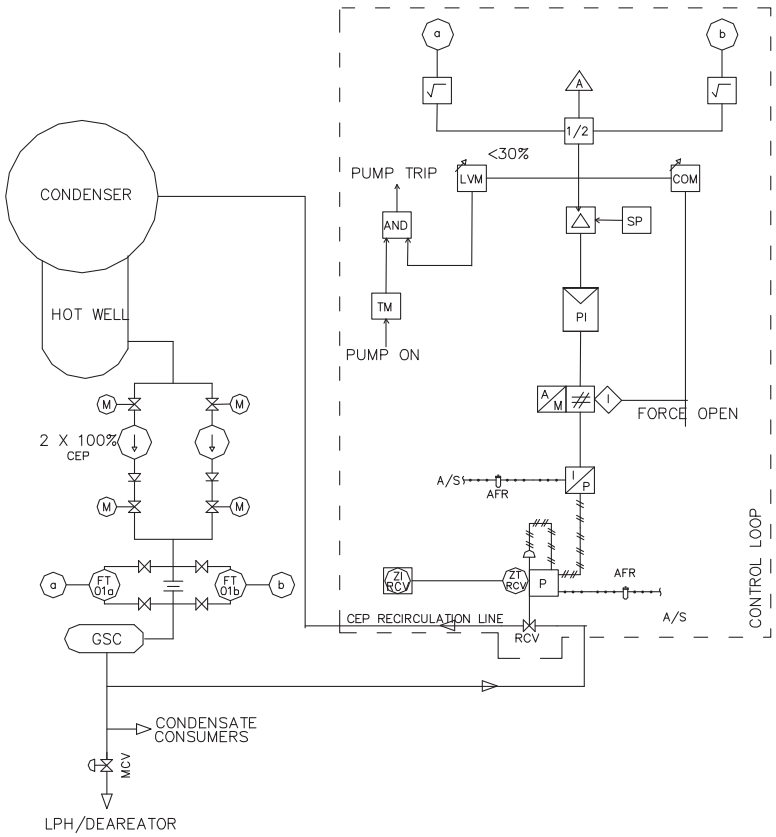
3.1.1 CEP Recirculation Controls Multiple CEPs (i.e., 3 × 50%)

In Figure XI/3.1-1a, two CEPs are shown with independent recirculation. Control loop details for both CEPs are identical, so only one will be discussed. Figure XI/3.1-1b illustrates individual CEP condensate flow, which is computed in DCS (for condensate flow computation, temperature compensation is not essential as flow is measured at CEP discharge where there may not be many variations in temperature because there is no heat exchanger in between and the temperature is almost the same as condenser) by measuring the flow by orifice (or flow nozzle) and flow transmitter in one of two modes. This flow is compared with the set point (for example, 30% flow capacity of each CEP) and the deviation thus created is fed to the P+I controller, which generates the position demand of the recirculation valve. The position demand is fed to the valve through the I/P converter and positioner. As long as the flow is less than the set point the recirculation valve will throttle to return the condensate to the surface condenser. When the set value is exceeded the valve will start closing.

3.1.2 CEP Recirculation Control Double (i.e., 2 × 100%) CEPs—Direct Control Option

Figure XI/3.1-3 shows that the control loop is almost the same as that discussed in Clause 3.1.1 with the exception that the flow measurement is not done for individual CEPs; one set of measurements is done for both CEPs as well as the GSC. Here it is noted that in this loop no outlet (including main system flow) for condensate is upstream the GSC, so the flow measurement just ahead of the GSC gives the net flow through the GSC (as well as through the CEP), which can be computed. Consumers (other than main system flow to low-pressure heaters, LPHs) of condensate, such as the de-superheating flow to auxiliary steam control system, LP bypass cooling, etc., may be taken from anywhere after the GSC. Because of the 2 × 100% CEP

FIGURE XI/3.1-3 Independent CEP recirculation control loop (2 × 100%).



www.EngineeringBooksPDF.com

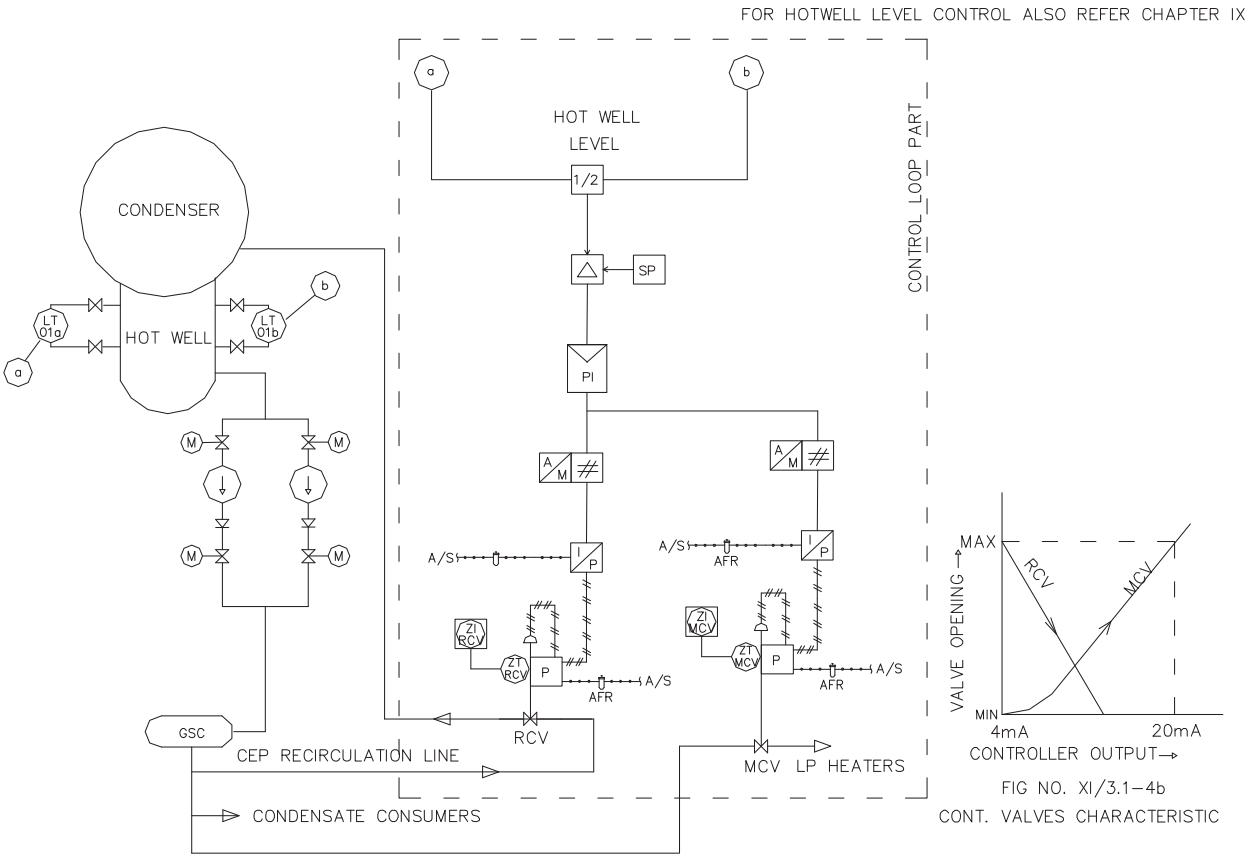


FIGURE XI/3.1-4 CEP and GSC recirculation control loop (indirect operation).

configuration, there is one advantage: one set of loops will suffice for CEPs and for the GSC.

3.1.3 CEP Recirculation Control for 2 × 100% CEPs—Indirect Control Option

Figure XI/3.1-4 shows that there are actually two loops in split range control mode, and two control valves, the RCV (works to return the condensate to the condenser) and the main condensate valve (MCV; which controls main condensate flow to LPHs, deaerators, etc.), operate in opposite way. When the MCV opens from 0 to 100% with a 4-20 mADC signal, the RCV closes from 100 to 0% (at which point the RCV is fully closed depends on which open position of the MCV maintains 30% flow so that minimum flow through the CEP and GSC is achieved) as shown in Figure XI/3.1-4b. In this loop the hotwell level is the controlling parameter, as the level increases (it may with load as more and more steam is condensed or more drain), i.e., set point is lower than the actual level. Deviation thus computed will be fed to the P+I controller, which will cause an increase in controller output and the MCV (fed by an I/P converter and positioner) will start opening. Since the RCV is in opposite mode, which was fully open at initial position, it will start closing; as flow through the CEP (hence GSC) increases, requirement of recirculation deceases and the RCV starts closing. So by modulating these two valves the hotwell level is controlled. During start-up and low load, and when condensate consumers (e.g., de-superheating condensate for auxiliary steam or LP bypass tempering water flow) will be drawing condensate, the level would also tend to fall (because of less steam condensation at low load) and the MCV may be closed and the RCV will be opened, which may be uncalled for—making the system less energy efficient. Also, in such an operation the main condensate flow will decrease due to closing of the MCV by control action, resulting in a decreasing deaerator level. This will cause make-up in the condenser and the condenser level will tend to rise and the MCV will open slowly. This is an indirect way of controlling the hotwell level, which is different from that discussed in Chapter IX, Clause 11.

3.2 Control Loop Operation

All these loops, as per Chapter VIII, Clause 1.2.1, may trip to manual in case of transmitter failure and/or selection. The operator needs to select the correct transmitter to

www.EngineeringBooksPDF.com

continue with the loop. In Figures XI/3.1-1 and XI/3.1-3 it is clear that the loop may be switched to manual by the operator; however, in such cases suitable measures, as discussed in Clause 3.3, will be taken to keep the pump from running dry. In Figure XI/3.1-4, it is seen that each of the two control valves can be switched to manual. However, the matter is trivial in this case, because if the loop is switched to manual there is no direct parameter to ensure minimum flow through the CEP and GSC. Instead, this can be done indirectly by looking into the hotwell level parameter. Also, the loop has inherent limitation, as discussed earlier. In addition to this there is the chance of operator error (in manual mode as there is no direct parameter for controlling the RCV) and the RCV may fail to open, and the situation may not be congenial. The way to circumvent this problem is to provide one common A/M station also after the controller to operate both the valves from there (thus any operator error can be avoided).

3.3 Control Loop Interlock

The following interlocks may be incorporated to save equipment (see Figures XI/3.1-1 and XI/3-3). To make the loops safe and avoid operator error, an interlock can be incorporated to open RCV in case the CEP is ON and flow is less than the set value (set a slightly higher than actual set value to take preventive action) if in manual. To trip the pump if flow is less than the set value (30%), after the pump is on for some time (adjustable), is a last resort.

3.4 Control Valve Considerations

The recirculation valve has to absorb full DP, i.e., pump discharge pressure at the inlet and condenser pressure at the outlet. Also the temperature is very near saturation, so for such a drop, there is the chance of cavitation and flashing. To prevent seat damage these valves should have good leakage. Some typical parameters are DP (=40−50 bar − 0.1 bar at condenser) approximately equal to 50 bar at 40°C. Because of high erosion due to cavity, materials like 17-4 PH and 440C steel should be used. Multistage design is a good solution.

4. GSC MINIMUM FLOW CONTROL

4.0 General

The basic purpose of this loop is to ensure minimum flow through the GSC so it is cooled. This loop as a separate entity is mainly applicable for medium and large size power plants where there are 3 × 50% CEPs (for 2 × 100% CEPs this may not be applicable). In this type of configuration, generally condensate consumers are placed after the GSC, and GSC flow measurement is done immediately before GSC so that it can manage those consumers in addition to normal condensate flow to LPHs.

4.0.1 Objective

The purpose of the GSC control loop is to ensure minimum flow through the GSC at all times.

4.1 Control Loop Description

4.1.1 GSC Control

Condensate flow through GSC is measured immediately before the GSC with the help of an orifice plate and flow transmitter (flow compensation may not be applicable really) similar to Figure XI/4.1-1. The flow is computed at the DCS. The computed flow is compared with the set point. Deviation thus created is fed to one P+I controller. The control loop is provided with an A/M station so that the valve can be regulated manually. The output of the A/M station is fed to the control valve through an I/P converter and positioner. Position of the control valve can be monitored at the DCS.

4.2 Control Loop Operation

This loop, as in Chapter VIII, Clause 1.2.1, may trip to manual if there is transmitter failure and/or selection. The operator needs to select the correct transmitter to continue with the loop.

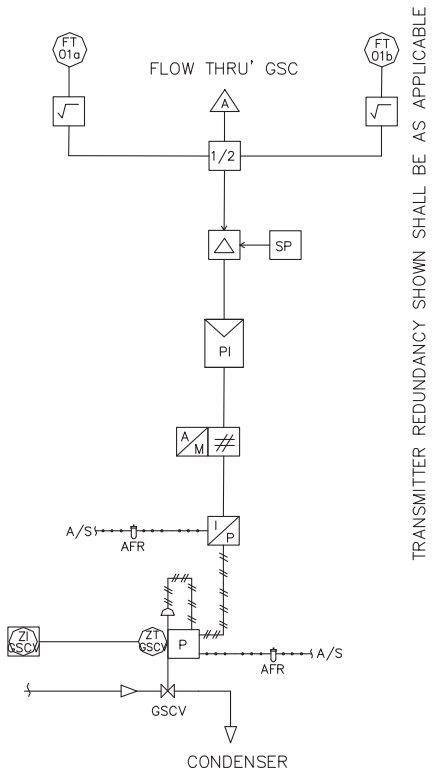


FIGURE XI/4.1-1 GSC minimum flow control.

www.EngineeringBooksPDF.com

4.3 Control Loop Interlock

There may not be any specific interlock for the loop.

4.4 Control Valve Considerations

These are similar to those discussed in Clause 3.4.

5. DEAERATOR (PRESSURE) CONTROL

5.0 General

Why deaerator pressure control? Any liquid at saturation temperature has zero solubility of gas. So to get rid of soluble gases, the condensate needs to be kept at its saturation temperature. Condensate contains dissolved O_2, CO_2, etc. Dissolved oxygen is the major cause of boiler corrosion and carbon dioxide makes the water acidic; therefore, it is necessary to eliminate them. This elimination is done chemically (as discussed in Chapter V) and physically (mechanical). In the deaerator these dissolved gases are eliminated by heating with the help of pegging steam from the auxiliary steam and CHR steam. Also at higher load when extraction steam is available, the heating steam is supplied from extraction steam of the turbine. The deaerator acts as an FW heater. The incoming condensate is sprayed in a fine mist (droplets) in an area surrounded by steam drawn from various sources like auxiliary steam, CRH, and extraction steam. In a droplet condition heat transfer area for water is larger when kept in intimate contact with the steam. This water is then passed over trays to form very thin sheets of water for gases to escape (vented out of the deaerator into the atmosphere). It is to be noted that various pressure values indicated below are arbitrary typical values only for mid- large size plants.

5.0.1 Objective

The purpose of the deaerator pressure control loop is to maintain required pressure (since pegging pressures are different at different conditions) in the deaerator, during start-up, and at low load. At normal or higher load, when extraction steam is available, the heating and deaeration are done as per extraction steam pressure, according to turbine load.

5.0.2 Discussion

Minimum pegging steam pressure is normally ~1.5 bar. As the boiler load increases, it is desired to have higher temperature FW, so, with a change in system load (until extraction pressure is available), the pegging steam pressure (when CRH is established, i.e., CRH pressure is sufficient) is also varied for energy efficiency. Initial (during cold start) pegging steam is supplied at 1.5 bar (may be at 0.8 bar for some smaller units) from auxiliary steam. At low load and/or during bypass operation, hot start-up, etc., the pegging steam may be supplied from CRH or auxiliary steam (if CRH is not available at suitable pressure) at ~3.5 bar.

With power plant load at approximately 55%, when extraction steam is available, the heating steam is supplied from extraction steam; pressure varies with load and is uncontrolled (pressure variation directly as per turbine load). The extraction steam (supplied to the deaerator) pressure typically goes up to 8 bar for typical medium to large size units. Another important aspect in designing the loop is rate of change of pressure in the deaerator. During sudden load throw off the pressure in the deaerator decays at a faster rate, which is not healthy for deaerator operation, so necessary measures are taken so that the high rate of change of pressure in the deaerator is arrested.

5.1 Control Loop Description

5.1.1 Deaerator Pressure Control (Simplified Version)

As discussed earlier, this loop consists of two distinct controls (see Figure XI/5.1-1). One is to control the auxiliary steam control valve (ASV 02) to keep the deaerator pressure at a fixed minimum value of 1.5 bar, pegging the deaerator at the set pressure during start-up conditions. Another loop comes into action when pressure in the CRH line is established, and the deaerator is maintained at 3.5 bar. When the CRH line is brought in to service the auxiliary steam valve in the first loop closes automatically (it has a lower set point) as well as by interlock.

1. *Control loop for auxiliary steam valve*: Set pressure is 1.5 bar compared with the actual pressure to generate the deviation. The deviation thus generated will drive the controller. Set point range is 0–8 bar so that the operator can set it to 3.5 bar during hot start-up.
2. *Control loop for CRH valve*: Set pressure is 3.5 bar compared with the actual pressure to generate the deviation. The deviation thus generated will drive the controller in the same way as discussed above. This loop can come in to operation only when the steam pressure in the CRH line is greater than the set value (sensed by a pressure switch), typically 8 bar.
3. *This loop has a serious disadvantage*: When a huge load is shaded by turbine then the pressure decay in the deaerator takes place very fast. When this happens, the loop has no protection for such fast decay and immediately goes to either 3.5 bar or 1.5 bar, depending on the condition of pressure at the CRH line at that time. This is not desirable as well as detrimental to deaerator; hence, the modified loop as shown in Figure XI/5.1-2, is

www.EngineeringBooksPDF.com

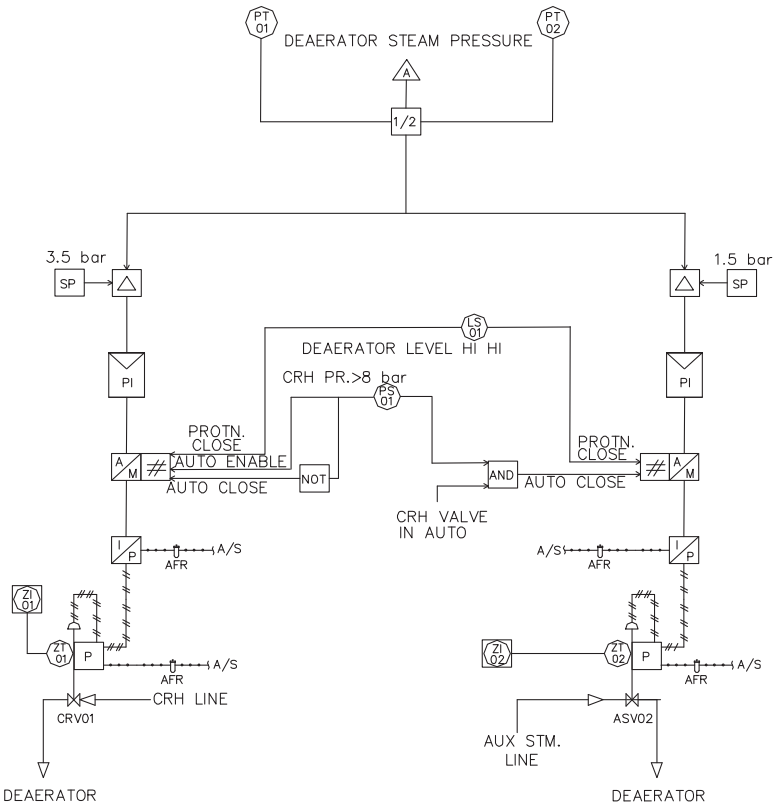


FIGURE XI/5.1-1 Deaerator pressure control loop (simplified).

considered where such faster depressurization as well as pressurization needs to be prevented.

5.1.2 Deaerator Pressure Control (Normally in Use)

The deaerator pressure control loop (shown in Figure XI/5.1-2) also has two distinct controls. One loop is to control the auxiliary steam control valve (ASV 02) to keep the deaerator pressure at a fixed minimum value. The second loop is activated when pressure in the CRH line is established. At this point the CRH valve is on auto and the deaerator is maintained at the desired set value. The same deviation station has been used, where two set points may be fed via suitable interlock. When the CRH is brought into service the auxiliary steam control valve is closed by interlock and automatic closure, as discussed in Clause 5.1.1, and will not be effective. The CRH valve will be brought into service after pressure in the CRH line attains the desired value.

1. *Set point establishment*: Normally the operator puts the set point to 1.5 bar during cold start-up, whereas during low load, hot start-up, or at the time of large load throw off, etc., the set point is 3.5 bar. The set point is generated based on the integrator circuit used. The gradient of integration is adjustable (for example, 0.5 bar/min). The measured value after integration (low-pass filter to filter out sudden changes) is one of the set points (mainly helpful at high load conditions), along with fixed set points through a max select circuit. During large load throw off, if the deaerator was running at higher pressure, the actual pressure decays very quickly. Because the integrator in the circuit generates the set point, such large changes will not be allowed; instead the same change will appear as a slow changed set point (as that time actual pressure prior to large load throw off was higher than the fixed set point). So slight decay from the original high pressure will appear as the set point, but the actual value is less, and the steam control valve will open to arrest the sudden decay. (This could be made clear from this hypothetical example: Near the full load of the turbine extraction pressure was 7.5 bar, and there was a sudden load throw off and pressure decays to 6.5 bar in 1 minute. Now, looking at the integrator circuit, the output of the integrator just prior to load throw of was 7.5, then in 1 minute actual pressure decays to 6.5 bar, but because the integrator has a decay rate of 0.5 bar/minute, the integrator output will appear as 7 bar in 1 minute, and because of the MAX selector this will be selected as the set point until the time this value is higher than the fixed set value. In this example, because the actual pressure is 5 bar, the

www.EngineeringBooksPDF.com

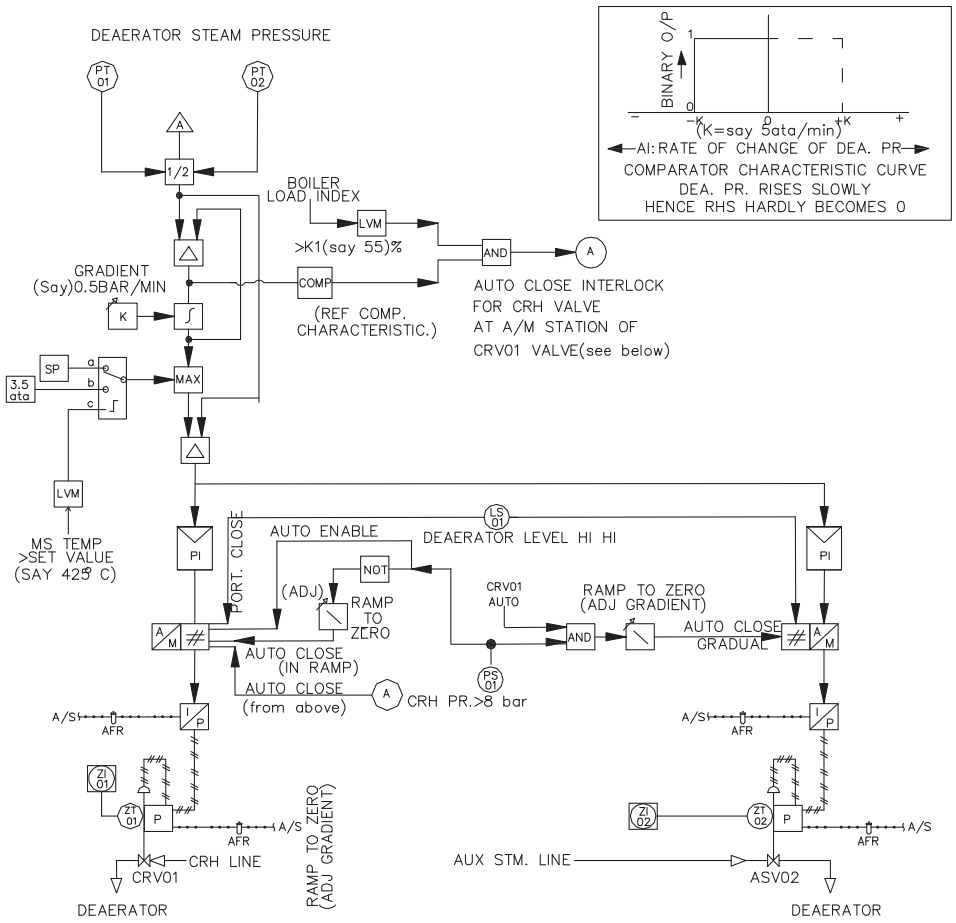


FIGURE XI/5.1-2 Deaerator pressure control loop (normally in use).

differential is that one of the valves will operate to arrest the decay rate.) Similarly, if someone wants to increase the set point the same will appear as a slow change in set point. There is an interlock operation in the set point generation circuit. If main steam temperature is >425°C then 3.5 bar will appear, otherwise the operator's selected set will be connected to the max selector. This is done so that during cold start-up the operator can set a 1.5 bar set point through the same circuit. In the loop, the same set point circuit has been utilized in both the loops through the interlock.

2. Based on the set point generated above, a deviation from actual value will be created. This deviation signal is fed to the respective controllers for the auxiliary steam valve as well as the control valve in the CRH line. Depending on the interlock discussed below, one of the two valves will be selected for maintaining the pressure in the deaerator. Another advantage of the loop is that the unselected valve, through the interlock, will be closed at a desired rate as shown by the ramp line (shown from last value to zero; the gradient of the ramp should be adjustable).

5.2 Control Loop Operation

In this clause auto and manual operation of the loop will be discussed (see Figures XI/5.1-1 and XI/5.2-2). This loop, as per Chapter VIII, Clause 1.2.1, may trip to manual if there is transmitter failure and/or selection. The operator needs to select the correct transmitter to continue with the loop. At any time the loop is operable in the A/M position. The control valve in the CRH line will be enabled only if pressure in the CRH line >8 bar, for example.

5.3 Control Loop Interlock

There may be some specific interlock for the loops. During auto close interlock, irrespective of the auto or manual operation selected, the valve will close. This closure is not instantaneous; the gradient of closing command is gradual from its last position to zero position (close position), which is adjustable in DCS.

1. Control valve in CRH will have auto close whenever pressure in the CRH line is *not* greater than the set value

www.EngineeringBooksPDF.com

2. Control valve in auxiliary steam line will auto close when pressure in the CRH line is more than the set value (for example, 8 bar) *and* the control valve in the CRH is on.
3. When the boiler maximum continuous rating (BMCR) is >55% (or any value when extraction steam is available for deaerator heating) *and* rate of change of the deaerator pressure is within the preset limit, the CRH valve (CRV 01) will be closed in auto through the A/M station. This is applicable for the loop in Figures XI/5.1-1 and XI/5.1-2 and to ensure that the CRH valve is closed when extraction steam is established (see below).
4. During protection close interlock, irrespective of the operation selected, the valve will close. This closure is instantaneous and immediate. Both the control valve in the CRH line and control valve in the auxiliary steam line will close in case of very high level in the deaerator.

5.4 Fixed Set Point Interlock

When there is a main steam temperature set value (i.e., >425°C), then a digital "1" signal will be generated to select the fixed set value (i.e., 3.5 bar) for the CRH. This is done through an interlock (see Figure XI/5.1-2). If the main steam temperature is less than the set value (i.e., >425°C) the fixed set value will be whatever the operator selects—cold start-up set value or higher set value for hot start-up or low load operation.

As long as extraction steam is available the CRH valve will remain closed. Without interlock valve closure may not be achievable if the rate of change of deaerator pressure is very slow. To ensure the CRH valve is closed when extraction steam is available, closing interlock with comparator has been incorporated. Also if there is a sudden load throw off/unit trip when the rate of change of pressure is high, then this interlock will be ineffective (to note the comparator characteristics) so that the CRH can be activated.

6. LP HEATER LEVEL CONTROL

6.0 General Discussion on Heater Drain

ASME TDP-1 2006 provides effective recommendations to prevent water induction damage in the turbine. TDP-1 offers guidance on how to identify systems that have potential for water ingress to the turbine. It also provides guidance for automatic disposal of water. Heater level control is very important as per these recommendations. If the heater level rises there may be water ingression to the turbine (of course this is also prevented by extraction line swing check valves and power-assisted nonreturn valves), through extraction lines. Also, if the heater level is not properly maintained then there will be improper heat transfer. Heater drain system design is more complex because of the two-phase flow phenomena.

Heater numbering system as used in the book is elaborated in Figure 6.0-1. Normally each FW heater will drain to the preceding heater with lower extraction steam supply, e.g., HPH 5 drains to the deaerator (Heater 4). LPH 1 (located at the condenser neck) may directly drain to the condenser through a loop seal or a control valve. The emergency (high level) drain flow path goes directly to the condenser from heater through a separate header and control valve. Emergency drain valves normally operate when the normal drain valves fail to maintain the heater level and/or normal draining equipment (downstream equipment in normal draining circuit) is not available (e.g., if tubes rupture in LPH 2 it is not available so, LPH 3 cannot normally drain in LPH 2). Improper design of the system would result in loss of plant efficiency. The two-phase flow at the downstream of control valve would result in high erosion, so material with higher thickness needs to be chosen. Normal and emergency drain flow does not necessarily match. Therefore normal drain control valves should be designed to cover from minimum load through full load of the plant, whereas the emergency drain flow control valve should be designed with minimum flow during start-up and full load plus emergency situation.

Normal convention to number the heaters and extraction lines from ONE (1) at the lowest pressure extraction at LPT and accordingly name that heater as LPH 1. The heater & extraction line numbering increase as we go along the Low pressure to High pressure (turbine) i.e. for a system with six regenerative heaters lowest pressure extraction (no 1) steam will send steam to LPH1 and highest pressure (e.g. CRH no 6) will send steam to HPH6.

FIGURE XI/6.0-1 Extraction and heater numbering system.

Physical Location of heaters plays some important role in heater draining system. LPH 1 has steam from Ex1 steam line having very marginal pressure difference WRT condenser so it is located at the neck of the condenser. Also pressure gradient between heaters are not much so it is better to have greatest elevation difference so that there will be proper drain flow.

FIGURE XI/6.0-2 Heater location and its importance.

www.EngineeringBooksPDF.com

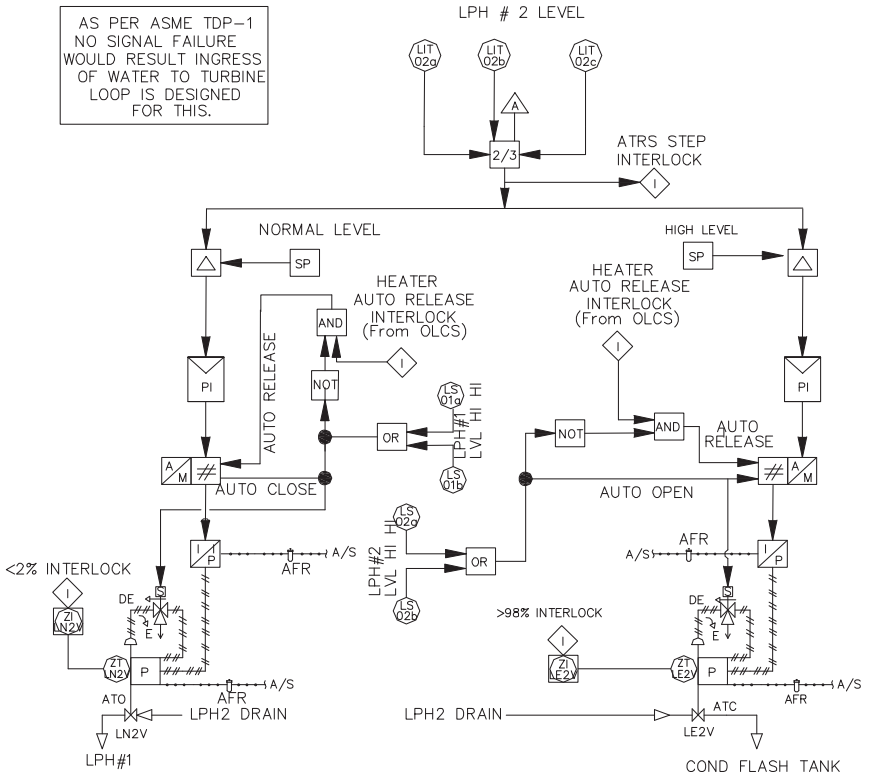


FIGURE XI/6.1-1 LPH 2 level control.

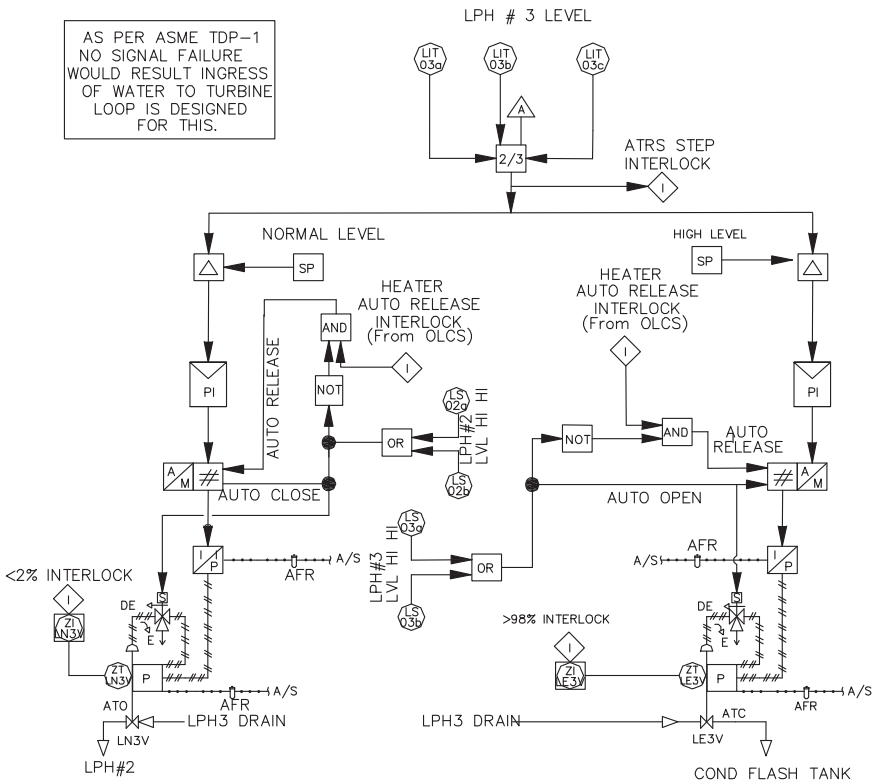


FIGURE XI/6.1-2 LPH 3 level control.

www.EngineeringBooksPDF.com

6.0.1 Objective

The purpose of LPH 2 (or LPH 3) level control loops is to maintain the LPH 2 (or LPH 3) level. Under normal conditions LPH 2 (or LPH 3) level is maintained by draining water from LPH 2 (or LPH 3) to LPH 1 (or LPH 2). However, in case of emergency level LPH 2 (or LPH 3) is drained to the condenser/drain flash tank to cope with the situation.

6.0.2 Discussion

It is clear from the previous discussion that these level controls are introduced to the system as per TWDPS requirements. According to ASME TDP-1 2006 "No single failure of equipment, device, signal, or loss of electrical power should result in water or cold steam entering the turbine." To meet these requirements several redundancies have been incorporated in the loop—e.g., redundancy in transmitters, closing of control valve to the following heater, and opening of emergency drain control valve of the same heater—directly through the solenoid valve (level switch) as well as through the DCS interlock.

6.1 Control Loop Description

Both LPH 2 and LPH 3 have two loops: one for normal level control and the other for high level control (emergency drain). Both loops in each heater have separate set points. Since both loops are almost identical, only one will be discussed at length. In level measurement three level transmitters (each covering an entire level range) have been considered in two of three modes. It is worth noting that with vertical heaters where the entire range may be too large, separate sets of level transmitters (in one of two modes) may be chosen for normal and high level control to have better control range. The actual level in the heater is also important for the turbine system to close the extraction (power-operated) check valve to prevent ingress of steam/water to the turbine. This voted signal is used in ATRS. Also when the turbine suddenly trips, extraction pressure falls and at that temperature water may convert to steam and tend to enter the turbine through the extraction line. Because of this, power-operated check valves may be closed during high heater level as well as during the turbine trip. In the loops the position signal of each of the drain valves (normal and emergency) is monitored. The signals for $<2\%$ open of normal drain (to recognize that the normal drain valve is closed) and $>98\%$ open for emergency drain (to recognize that the emergency drain valve is open) are also used for an interlock in the open loop control system (OLCS; see Figures XI/6.1-1 and XI/6.1-2).

6.1.1 LPH 2 (or LPH 3) Level Control

1. The measured value is compared with the normal set value of the heater. Deviation thus created is fed to the P+I controller. Output of the controller is used to throttle the normal level control valve to the preceding heater, i.e., drain control valve to LPH 1 (or to LPH 2 for LPH 3).
2. After opening the normal level control valve and the level in the heater cannot be maintained, and the level is high (for example, due to heater tube rupture), then when the high level set value is reached automatically, the other emergency level control loop activates. If the downstream heater in the heater drain circuit is not available then the emergency drain control loop also activates. Similarly, based on the high set value and the actual level, the emergency control valve will throttle to drain LPH 2 (or LPH 3) to the condenser via the LP flash tank.

6.2 Control Loop Operation

In this clause A/M operation of the loop will discussed. This loop, as per Chapter VIII, Clause 1.2.1, may trip to manual in case of transmitter failure and/or selection. The operator needs to select the correct transmitter to continue with the loop. At any time the loop is operable in the A/M position. LPH 2 (or LPH 3) normal drain valve loop can be released to auto if the level in LPH 1 (or LPH 2) is not greater than the hi hi value, and the overall interlock system is okay based on overall plant condition for interlock and protection of the plant from the OLCS. This is seen as "heater auto release interlock" in Figures XI/6.1-1 and XI/6.2-1. LPH 2 (or LPH 3) emergency drain valve loop can be released to auto if the level in LPH 2 (or LPH 3) is *not* greater than hi hi value, and the overall system interlock system is okay based on overall plant condition for interlock and protection of the plant from OLCS. If the LPH 2 (or LPH 3) level is greater than hi hi value, a direct open emergency drain valve command will be issued to bring the level down quickly.

6.3 Control Loop Interlock

There may be some specific interlock for the loops. LPH 2 (or LPH 3) interlocks are used for the following:

1. During a hi hi level in LPH 1 (or LPH 2) the normal drain control valve from LPH 2 (or LPH 3) will be closed via interlock via DCS and directly to the control valve (ATO type) with the help of the solenoid valve. This is done to circumvent the failure and/or cable snap from DCS so the system does not suffer.
2. Emergency drain valve (ATC type) of LPH 2 (or LPH 3) will be opened fully during a high level in LPH 2 (or LPH 3). The opening of the valve is done directly as well as via DCS as discussed previously.

www.EngineeringBooksPDF.com

6.4 Control Valve Consideration

As discussed earlier, there is a major problem in the heater drain control valve sizing due to the flashing liquid condition. Based on inlet and outlet valve pressure, control valves are sized and then selected one size larger to reduce velocity in the valve and lessen the chance of erosion. Again, when a larger valve size is selected and operated continuously at low opening the valve may poorly perform and have less integrity. Sometimes it is better to use a higher body size with reduced trim. A few tips on selection are listed here:

- *Trim size*: 70−80% opening to give full flow (is using an emergency drain, consider tube rupture).
- *Control valve*: must meet the minimum flow at slightly >15% opening.
- *Materials*: Hardened materials such as 400 series SS for valve trim to lessen erosion, for which 2−3mm erosion allowance should be considered; chrome Moly Steel is a good choice—ASTM A217 Gr C5/WC9 are also chosen for this services.
- *Control valve body*: Use erosion-resistant materials.

7. HP HEATER LEVEL CONTROL

7.0 General

The basic philosophy behind HP heater level control has been discussed in Clause 6.0. In ≥500 MW units, there may be two sets of heaters in parallel, for example, HPH 5A and HPH 5B and HPH 6A and HPH 6B in place of a single HPH 5 and HPH6.

7.0.1 Objective

The purpose of HPH 5 (or HPH 6) level control loops is to maintain level in the heater. Under normal conditions the HPH 5 (or HPH 6) level is maintained by draining HPH 5 (or HPH 6) to the deaerator (or HPH 5; cascade drain). However, during an emergency the level HPH 5 (or HPH 6) is drained to the condenser/HP drain flash tank to cope with the situation.

7.0.2 Discussion

To meet these requirements of ASME TDP-1 2006 several redundancies have been incorporated in the loop, as discussed in Clause 6.02.

7.1 Control Loop Description

HPH 5 and HPH 6 each have two loops: one for normal level control and one for high level control (emergency drain). Both loops in each heater have separate set points. Because both loops are almost identical, only one will be discussed at length. For level measurement three level transmitters (each covering entire level range) have been considered in two of three modes. With vertical heaters where the entire range may be too large, separate sets of level transmitters (in one of two modes) may be chosen for normal and high level controls for better control range. See Clause 6.1 for discussions on ATRS and valve position signal.

7.1.1 HPH 5 (or HPH 6) Level Control

1. The measured value is compared with the normal set value of the heater. Deviation thus created is fed to the P+I controller. Output of the controller is used to throttle the normal level drain control valve to the deaerator (or HPH 5).
2. When opening the normal level control valve and the level in the heater cannot be maintained, and the level is rising (heater tube rupture), and when the high level is reached, the other emergency level control loop is activated. Also, if the downstream heater is not available then the emergency control loop will activate.

Similarly, based on the high set value, the emergency control valve will throttle to drain HPH 5 (or HPH 6) to the condenser via HP Flash tank (also HPH 6 may drain to the deaerator in extreme case to condenser via flash tank; see Figures XI/7.1-1 and XI/7.1-2).

7.2 Control Loop Operation

In this clause A/M operation of the loop will be discussed. This loop, as per Chapter VIII, Clause 1.2.1, may trip to manual during transmitter failure and/or selection. The operator needs to select the correct transmitter for control. At any time the loop is operable in A/M position. HPH 5 normal drain valve loop can be released to auto if the level in the deaerator is not greater than the high value, and is released from the OLCS (i.e., overall system interlock system based on overall plant condition for interlock and protection of the plant). The HPH 5 emergency drain valve loop can be released to auto if the level in the HPH 5 is not greater than the hi hi value, and is released from the OLCS (i.e., overall system interlock system based on overall plant condition for interlock and protection). HPH 6 normal drain valve loop can be released to auto if the level in HPH 5 is not greater than hi hi value and is released from the OLCS (i.e., overall system interlock system based on overall plant condition for interlock and protection of the plant). HPH 6 emergency drain valve loop can be released to auto if the level in HPH 6 is not greater than the high value, and is released to from the OLCS (i.e., overall system interlock system based on overall plant condition for interlock and protection of the plant).

www.EngineeringBooksPDF.com

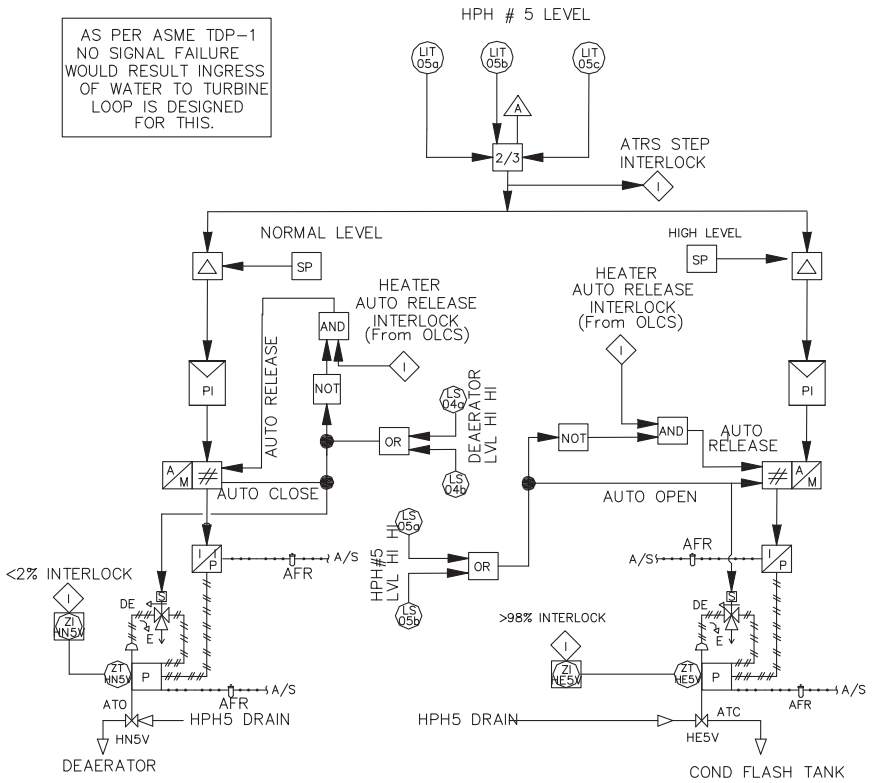


FIGURE XI/7.1-1 HPH 5 level control.

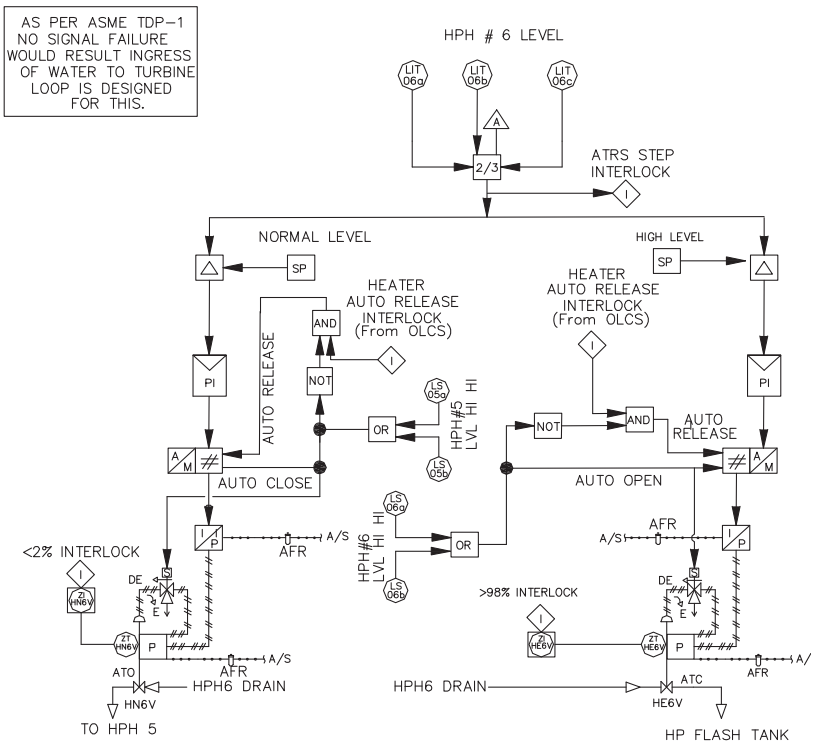


FIGURE XI/7.1-2 HPH 6 level control.

www.EngineeringBooksPDF.com

7.3 Control Loop Interlock

Listed below are some specific interlocks for the loops.

7.3.1 HPH 5 Interlocks

1. During high level in the deaerator (heater 4) the normal drain control valve from HPH 5 is closed via interlock by DCS and directly to the control valve (auto type) with the help of the solenoid valve. This is done to circumvent the situation of failure of and/or cable snap from DCS.
2. Emergency drain valve (ATC type) of HPH 5 is opened fully during a high level in the HPH 5. The opening of the valve is done directly as well as via DCS, as discussed previously.

7.3.2 HPH 6 Interlocks

1. During HI HI level in HPH 5 the normal drain control valve from HPH 6 is closed via interlock by DCS and directly to the control valve (ATO type) with the help of the solenoid valve. This is to circumvent the failure of and/or cable snap from DCS.
2. Emergency drain valve (ATC type) of HPH 6 is opened fully in case of a high level in HPH 6. The opening of the valve is done directly as well as via DCS, as discussed previously. Here in case of emergency drain show to condenser. In some cases ist high level drain could be to deaerator, then final emergency drain to condenser as shown in the drawing.

7.4 Control Valve Consideration

See Clause 6.4.

8. EJECTOR CONTROL AND TAS

8.0 General

Auxiliary steam in a power plant plays a vital role during start-up of the boiler and turbine. In many plants with smaller and medium sized units there may be separate auxiliary steam headers for the boiler and turbine. These are known as boiler auxiliary steam (BAS) and turbine auxiliary steam (TAS). Bigger plants may have a common auxiliary steam header. A general discussion on auxiliary steam controls is seen in Chapter III C main Clause 5 & Chapter VIII, Main Clause 10.1.

8.0.1 Ejector Control

The exhaust steam of turbine is condensed in the condenser maintained at vacuum, so that the steam pressure drop between the inlet and exhaust of the turbine is increased, resulting in more active power available at the turbine output to drive the generator. For water-cooled surface condensers, the vacuum is maintained by either a vacuum pump or a steam ejector. These ejectors use steam as the motive fluid to remove any noncondensable gases that may be present in the surface condenser. In the steam ejector, pressurized steam is passed through an ejecting nozzle and immediately after the nozzle steam is allowed to expand to create a vacuum. TAS is utilized for this purpose, and by reducing the TAS pressure with the help of one pressure-reducing valve (PRV) steam is supplied to the ejector. It is a simple pressure-reducing control (see Figure no. XI/8.6-1).

8.0.2 Objective

The purpose of TAS control is to obtain a header of desired constant pressure and constant temperature, irrespective of changes in load in turbine.

8.0.3 Discussion

See Chapter VIII, Clause 10.1.3 for further discussion.

8.1 Control Loop Description

The control loops involved are pressure control and temperature control. (In these loops both air lock relays and solenoid valves have been introduced to indicate the connection detail in a practical loop). During air supply failure and electrical signal failure control valves may be locked in their previous positions (i.e., they stay put; see Figures XI/8.1-1 and XI/8.1-2).

8.1.1 TAS Control

There are two control loops (see Figure XI/8.1-1):

1. *TAS pressure control*: TAS header pressure (downstream of PRV) is measured in one of two modes and compared with a desired set point. Deviation thus created is used to drive a P+I controller. The output of the controller through A/M station and I/P converter regulates the PRV to maintain constant pressure at the auxiliary steam header at all loads.
2. *TAS temperature control*: Steam temperature at the auxiliary steam header (i.e., downstream of de-superheater) is measured and compared with the fixed set point. Deviation thus created is fed to a P+I controller (may be P+I+D also, as temperature is a slow changing parameter P+I+D may be more effective). The output of the controller regulates the condensate flow to the de-superheater to control the temperature at the auxiliary steam header. There may be separate de-superheaters or a combined pressure-reducing and de-superheating system (PRDS) may be deployed.

8.1.2 High & Low Capacity TAS

As discussed in Chapter VIII, Clause, depending on load requirement, it may be necessary to have separate high and

www.EngineeringBooksPDF.com

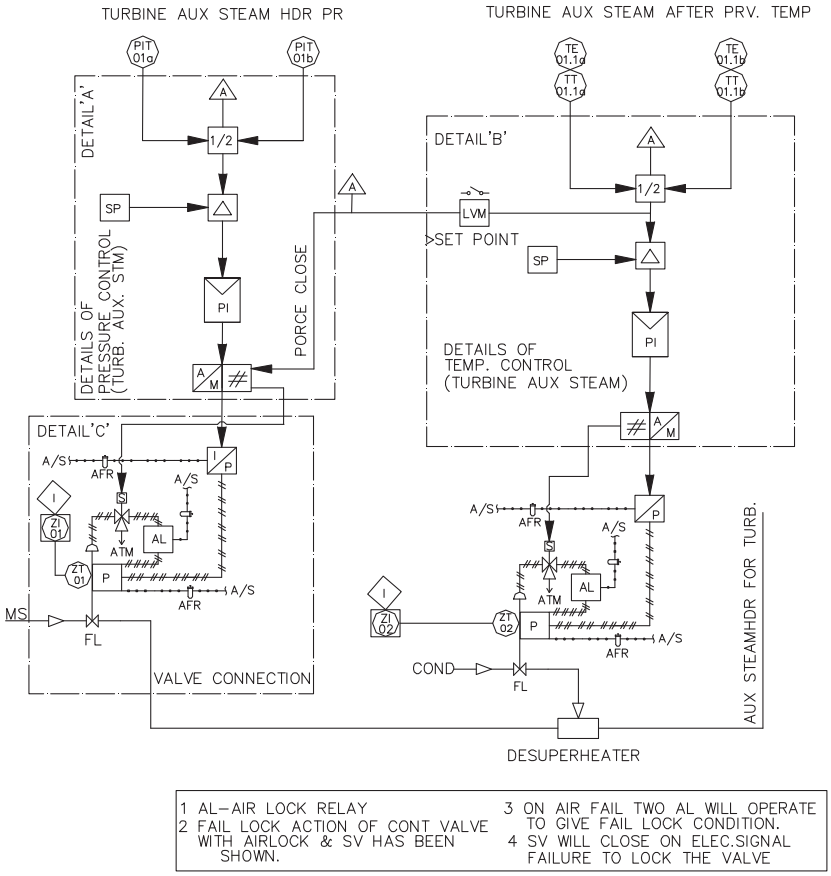


FIGURE XI/8.1-1 Turbine auxiliary steam pressure and temperature control.

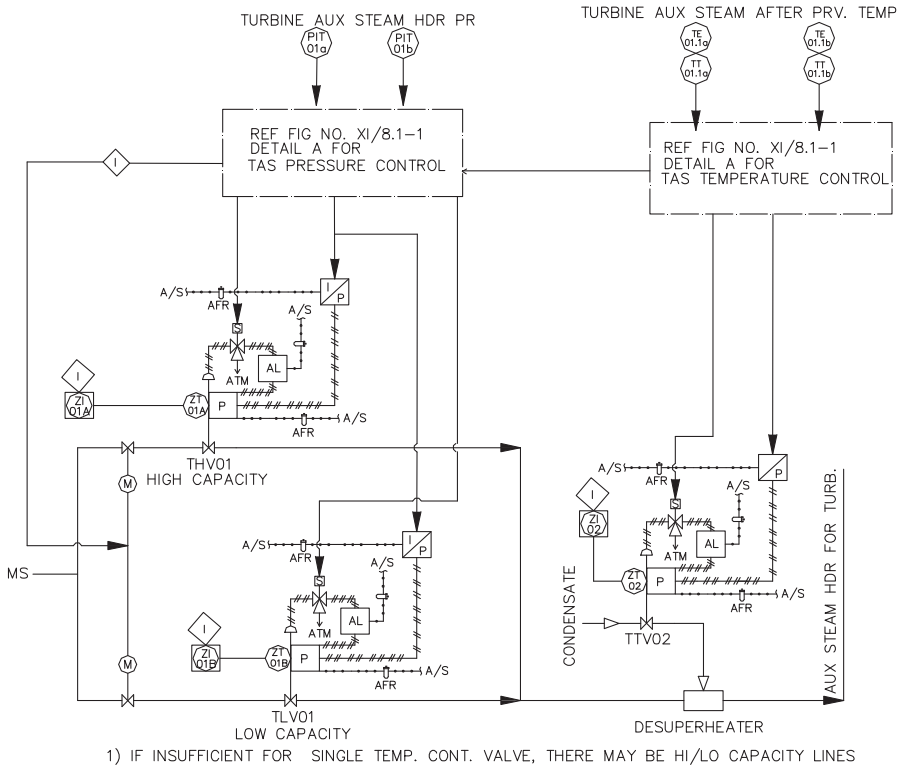


FIGURE XI/8.1-2 High and low capacity TAS.

www.EngineeringBooksPDF.com

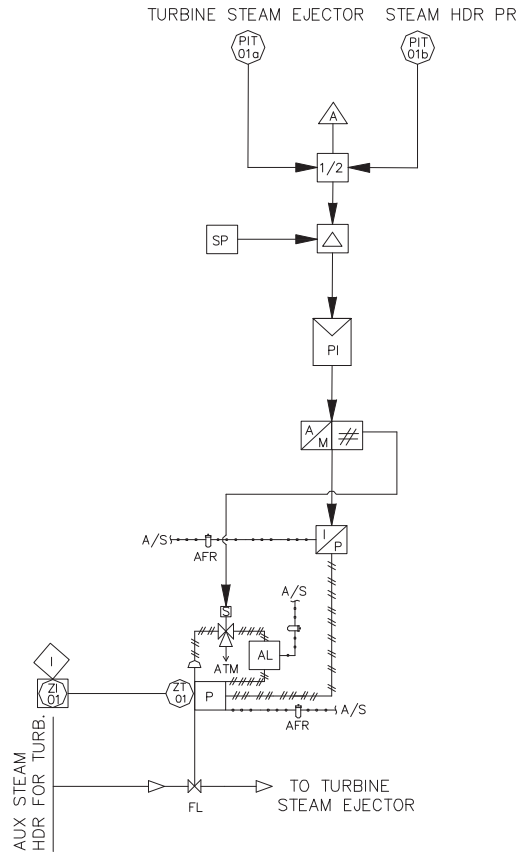


FIGURE XI/8.6-1 Turbine ejector steam pressure control.

low capacity PRDS systems. These loops may operate in split range as well. When the load is high and even with full opening of the low capacity valve, pressure cannot be maintained and the high capacity valve will start to open. During a transition period both low and high capacity valves may be operative, so in split range operation there may be some overlap. When load reduces the high capacity valve will start to close first, then the low capacity PRDS will start to operate (see Figure XI/8.1-2). For further detailed discussions, see Chapter VIII, Clause 10.1.6.

8.2 Control Loop Operation

In this clause A/M operation of the loop will be discussed. This loop (see Chapter VIII, Clause 1.2.1) may trip to manual during transmitter failure and/or selection. The operator needs to select the correct transmitter. The loop is operable in the A/M position.

8.3 Control Loop Interlock

There may be specific interlocks for the loops. If the temperature at the outlet of the de-superheater (after PRV; i.e., at auxiliary steam header) is greater than the set value then the PRV (both high and low capacity) will be forced closed. If there is signal failure, the associated solenoid valve will be closed from the DCS to attain fail lock condition of the associated valve (see Figures XI/8.1-1 and XI/8.1-2). If the temperature is greater than the set value sensed by LVM, the associated PRV will be closed.

8.4 Control Valve Consideration

As discussed earlier, there may be two sets of valves to cater to the plant requirements: during start-up and during normal operation. Therefore proper attention must be given to sizing these valves. Typical parameters for PRDS valves in auxiliary steam systems are as shown in tabular form:

Some extreme conditions (typical parameters) for PRVs and temperature control valves are as follows:

Parameters	PRV	Temperature control valve
Inlet pressure	175(/145) bar	190(/165) bar
Outlet pressure	16(10) bar	16(10) bar
Temperature	540°C	160°C

When high pressure drop, high temperature, and high noise occur, selecting values for these applications is very important, especially for PRVs. Cage-guided low dB trim with multiple holes are used to minimize noise effect.

8.5 Use of Auxiliary Steam in Turbine

Major uses of auxiliary steam on the turbine side are as follows:

- Deaerator pegging
- Steam ejector
- Gland steam Pressure control
- BFP drive (if BFP turbine is used)

8.6 Ejector Control

Auxiliary steam at 16 bar may not be directly fed to the ejector. Normally pressure is reduced before it is fed to the ejector as shown in Figure XI/8.6-1. The loop is similar to the pressure-reducing loop discussed in Clause 8.1.1.

BIBLIOGRAPHY

1. Cavitation in Control Valves: Samson AG: Technical information.
2. Control Valve hand Book :Emerson Process Management:4th Edition (Fisher).
3. Standard Design Criteria/ Guideline for Main Plant Package (2X500 MW TPP), 2010. Central Electricity Authority, New Delhi.
4. Drag valve (BFP Recirculation):Control component Inc.; Catalog Drag Valve for boiler Feedwater Control Application: Control component Inc.:Catalog.
5. Drag Valve for boiler Feedwater Control Application: Control component Inc.:Catalog.

www.EngineeringBooksPDF.com

Chapter XII

Installation Practices

1. INTRODUCTION

1.0 Preliminary Details & Source Point

Performance of a plant depends greatly on the performance of the control and instrumentation system (C&I system). A high-quality instrument may not perform well with the wrong kind of the mounting and installation, including cabling, etc. Different types of instruments have different types of installation requirements. Also, there are various standards followed in different parts of the world and each of these standards has certain requirements and practices. Also, each of these standards has some advantages and/or limitations.

These standards also have a unique way of specifying instruments and auxiliaries. Since ISA practices are very common in this book, efforts have been made to follow ISA guidelines and, consequently, many references have been made to ASME/ANSI standards. However, efforts have been made to generalize the discussions so that the basics and general guidelines are similar. Although in this book SI systems are followed, in some cases it was necessary to use only FPS systems as the standard associated with certain specifications is only defined in terms of FPS, e.g., ANSI flange ratings are only in pounds, or NPT/BS threads are only in inches. However, nearest equivalences have been shown in most of the figures, and the latest revision of the American National Standard for Metric Practice ANSI/IEEE Std. 268 is a good reference to use.

Field instrument installation practices have been divided mainly into two parts: mechanical and electrical. Instrument mounting, source connection details, installation of impulse pipe and other accessories, auxiliaries, and supporting details, etc., are discussed under mechanical installations. On the other hand, cable and cabling are detailed under electrical installation. In both systems basic (but currently in practice) specifications of major items are discussed in this chapter.

Before going into any further details on mechanical installation, some of the standard/common practices, also in line with ISA Guideline 1994, are enumerated below:

1. *Process tap*: When the pressure is $\leq$62.5 kg/cm^2 and the temperature is $\leq$426°C, 15 nominal bore (NB) pipe is used. If the pressure or temperature exceeds those limits, then 20 NB pipe is recommended. The material for process pipe, fittings, and root valves should be a material compatible with the process fluid.
2. *Impulse line*: For subcritical steam services the process design pressure is at saturation temperature. For other services the line is designed at process design pressure and temperature.
3. *Impulse line inside diameter (ID) and thickness*: To avoid plugging and sufficient mechanical strength, *minimum* ID >9.14 mm and thickness 1.25 mm are normally accepted. Only by calculation, for technical reasons, is deviation considered. The latest revision of ANSI B31.1 Clause 104 may be consulted for this tube thickness calculation.
4. *Commonly used tubing materials*:
   a. *SS tubing*: For noncorrosive tubing ASTM A213 GR TP 304 (for temperature up to 537°C) and ASTM A213 GRTP 316 (for temperatures up to 648°C) and ASTM A213 GR TP 316L (for temperatures up to 450°C). In larger plants, where pressure and temperature ratings are high, ASTM A213 Gr. TP 316 L and 316H are recommended.
   b. *Carbon steel*: For noncorrosive use ASTMA210 GR A1 (temperature up to 412°C).
   c. *Copper tube*: ASTM B88 or B75 or annealed soft temper (maximum temperature 205°C) mainly used for air and gas services.
5. *Valves and fittings*: Blow down valves shall be gradual opening type and shall be suitable for design Pressure & temperature. Fitting materials should be suitable for the application and compatible to the tubes and pipes. Any mercury or mercury compound, materials with lower melting points such as lead, arsenic, antimony, bismuth, cadmium, zinc, etc., are not to be used.
6. *Impulse line preparation*: Before laying the impulse line, it needs to be prepared as discussed in Clause 3.0, number 11.
7. *Slope of impulse line*: Normally 80 mm/m is standard. For liquid services, level, etc., the slope should be downward from the source point to the instrument, whereas for air and gas services it should be upward from the source point to the instrument. If it is not possible to obtain such a slope, the maximum available slope is to be used. Slope should never be less than 20 mm/m.

Copyright © 2015 Elsevier Ltd. All rights reserved.

www.EngineeringBooksPDF.com

8. *Line drain/vent*: High-point vent and low-point drain or a combination should be used to purge unwanted gas/liquid.
9. *Preferred relative position of source point and instrument*: These are preferred locations with distinct advantages, but are they are not mandatory:
   a. *Steam and water service*: Instrument preferably is below the tapping point to avoid any entrapped gas bubbles. This will also help to produce a lower temperature at the instrument end. Also this arrangement avoids an additional need for a high-pressure vent.
   b. *Vacuum service*: Instrument is located above the source point so that the line is self-draining, avoiding an error in measurement.
   c. *Air and gas services*: Instrument is located above the source point for self-draining of condensed moisture.
10. *Preferred location of tapping point on pipe and allied systems*: Theoretically, in a circular pipe cross-section tapping can be done at any position in the plane, but there are certain preferences in locating the tapping points based on the services as detailed in Figure XII/1.0-1.
    a. *For steam, air, and gas services*: Preferred tapping point location could be the top point, but it can be at any other position (upper half) with 45° on both sides of the vertical line as shown in Figure XII/1.0-1a–c to avoid any liquid ingress.
    b. *For liquid services*: Preferred tapping point locations are on either side of the horizontal line, but can be at any other position (lower half) with 45° on both sides of the horizontal line as shown in Figure XII/1.0-1d–f to avoid any entrapped gas. However, it should not be at the bottom or in any bottom positions beyond those discussed previously to avoid ingress of pipe dirt in the impulse line.
    c. *Temperature sensors (elements)*: Should be placed in flowing streams and not on stagnant fluid to get a representative reading; normally it should be directed to oppose the flow to create turbulence.
    d. *Purging connections*: In many cases (as applicable) these are used to prevent plugging, freezing, and corroding. These purge fluids must be compatible (no interaction with process fluid) with the process fluid. Care should be taken to see that purging does not introduce any error into the system. Quantity of gas/liquid purge is to be regulated. Purge fluids are normally independent of process fluids so that it is available even when the process fluid is not operating. Normally a purging system has a check and shut-off valve.

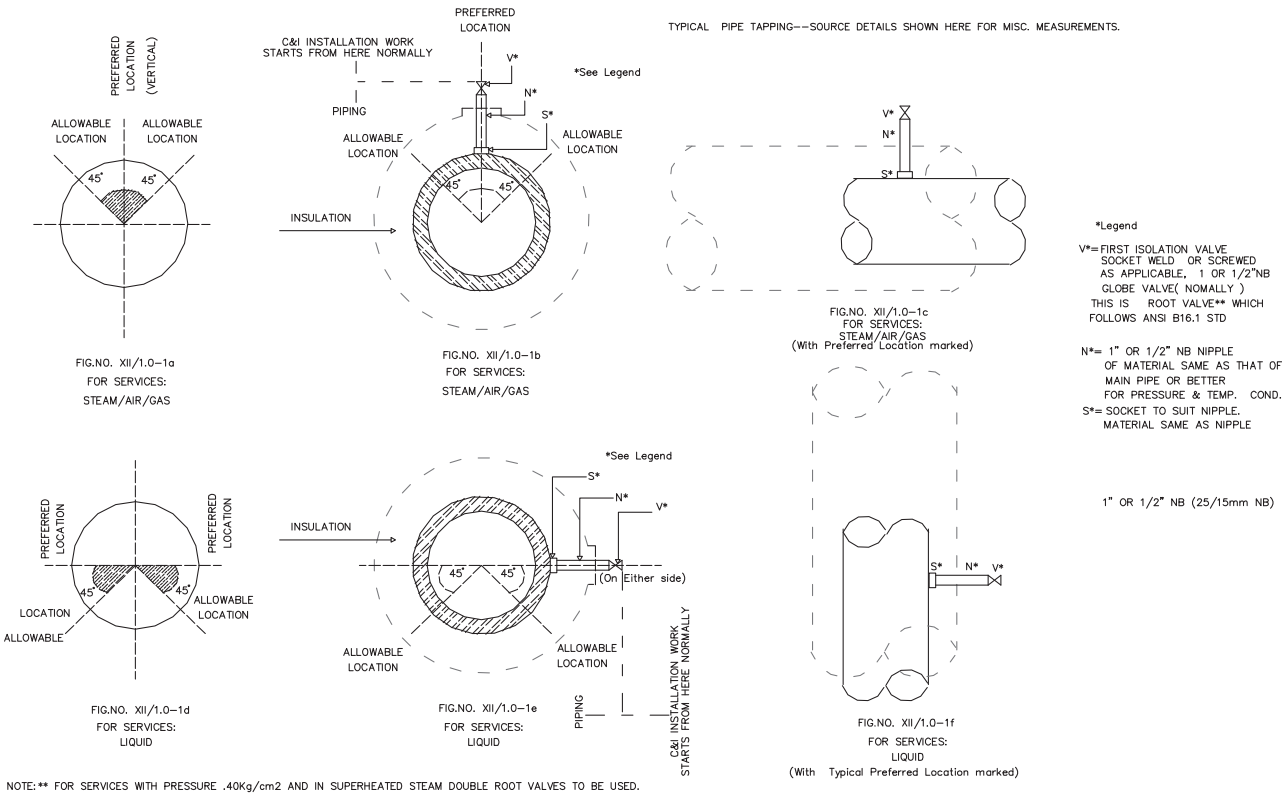


FIGURE XII/1.0-1 Tapping point location (source point).

www.EngineeringBooksPDF.com

11. *Source point*: Tapping socket, nipple, and root valve (first set of valve(s) at the tapping point) mainly constitute the source point of most instruments (exception: temperature tapping point when there is no nipple or root valve). Normally terminal point for a piping engineer (take off point for instrumentation) is a socket with plug for the temperature element and the root valve(s) for tapping points pertinent to other measurements. From there instrumentation installation work starts. Based on the application, root valve(s) could be a socket welded/flanged/threaded type. These will be discussed later, but it is important that these are well-defined so that there is no future coordination problem. If there is insulation, the pipe root valve(s) should be outside of the insulation (at least the operating handle should be accessible without opening the insulation). Normally in power plants any line where line pressure >40 kg/cm^2 (especially for steam service), two root valves are used. In lower pressure applications a single root valve would suffice. In flue gas service, which is in draft, no root valve is necessary (usually an improper root valve is a problem in those cases).
12. *Mounting location of instruments*: Mounting of instruments is done on the basis of the functional, operational, and maintenance facility. In power plants, to facilitate maintenance, a number of instruments (mainly transmitters and switches) in nearby locations are grouped together and kept in a separate enclosure referred to as a local instrument enclosure (LIE—closed type) or local instrument rack (LIR—open type). This helps in many ways: (1) as extra protection for the instruments; (2) instead of separate drain lines, as a common drain line from the enclosure or rack; or (3) as a convenience for maintenance personnel.

    Major points regarding location of instruments are as follows:
    - **a.** The field instruments are mounted in a location to minimize impulse pipe length.
    - **b.** All instruments should be easily accessible for calibration and maintenance from grates, a platform, and/or ladder. This is extremely important for instruments intended for safety/emergency. In a place where there is a chance of flooding instruments are to be located at least 1−1.2 m above ground.
    - **c.** Normally while routing the impulse piping/tubing, for height clearance, the following guidelines from ISA should be followed:
        - *Within structure*: 8 ft (2.44 m)
        - *Within yard area*: 10 ft (3.05 m)
        - *Over secondary road*: 14 ft (4.27 m)
        - *Over rail road and main building*: 22 ft (56.71 m)
    - **d.** If an instrument is to be located outside the handrail of the platform, then it must reach (300 mm) from the handrail horizontally and <1.5 m above the platform and not more than 0.5 m from a fixed ladder (e.g., instruments on a boiler platform).
    - **e.** Local instruments such as pressure temperature gauges, etc., need to be readable from the platform or walkway. Drum level gauge [differential pressure (DP)/optical) and drum pressure gauges at boiler operating platforms should be located in such a way that these are easily accessible and readable from a long distance. One interesting fact is that in spite of so many sofisticated instrumentation in plants, at many places these are not dispensed off !
    - **f.** Local controller/receiver instruments need to be located and readable in the vicinity of the control element.
    - **g.** The instrument rack/enclosure should not obstruct the walkway, so locating them should be done very carefully.
    - **h.** From a maintenance point of view, clearance is to be provided for removal of covers and cases/opening of doors of enclosures. Also there should be enough clearance (space) for lifting equipment.
13. *General power supplies and signal types*: Power supplies and signal types normally used are listed in Table XII/1.0-1a and b. Hydraulic supplies for various

TABLE XII/1.0-1a Supplies (Normal)

Electrical supplies	LER: 230/110VAC 1 PH 50/60 Hz
Instruments(field) supplies	24VDC
Field panel	230/110VAC 1 PH 50/60 Hz or 24VDC
Main ring pneumatic supplies	7 bar(g), maximum 10 bar(g)
Instrument air supplies (normal)	1.4 bar(g)

TABLE XII/1.0-1b Signal Types (Normal)

Analog input/ output	4-20mADC
Fieldbus/smart devices	PROFI/Foundation Fieldbus/Hart Protocol (ref ch VII)
Digital input	Potential free contact (Unless stated otherwise such as open collector, etc.)
Digital output	Relay output pot free/24VDC
Position	Proximity SWS with NAMUR interface.
Pneumatic signal	0.2−1.0 bar(g/3-15 psig)

www.EngineeringBooksPDF.com

actuators on the turbine or boiler side normally have self-contained hydraulic power units (HPU).

14. Instrument and tube/pipe support considerations:
    a. Local instruments such as pressure/temperature gauges can be supported by piping on main process pipe/equipment.
    b. Instruments are supported in LIE/LIR, and on any other support meant for support purposes only, but are not supported from process pipe to avoid heat and vibration from the process pipe. Separate 50 (2") NB Sch.40 galvanized pipe mounting with suitable support and stanchion is common. Pipe stands are to be securely anchored and grouted.
    c. Pipe stand directly embedded on concrete is not an acceptable practice.
    d. Weld area, drill, and threads on galvanized steel are prepared and sprayed with cold galvanizing coating.
    e. Instrument tube/impulse pipe are supported at regular intervals to maintain structural stability and to prevent strain on instruments, equipment, and piping.
    f. In all cases suitable measures need to be taken to accommodate thermal expansion due to variations in ambient temperature.
    g. All tubing/cable may be supported in steel trays.
15. *Environmental protection*: Some basic environmental protections are listed below:
    a. At all points the ambient temperature for electronics must be kept within the operating point, recommended by the manufacturer with some safety factor/margin.
    b. Normally hard type enclosures are acceptable for instruments, but if there are space constraints, a soft type may be chosen if it fits into the parameters.
    c. Normally process lines enter the enclosure of the instrument from the side or bottom, but never from the top, to minimize impulse tube length as well as for protection of electrical installation from leakage of the impulse tube. These are mainly for local gauge panel/racks. However, when there is a transmitter enclosure or steam and water analysis system (SWAS) sample conditioning panel, the impulse/sample lines normally enter the enclosure from the top, but in all these cases electrical points and mechanical instruments are kept separate. For this reason, a junction box in the transmitter enclosure is kept at the back side (away from instrument mounting) of the transmitter enclosure. In SWAS there are separate sections for sample conditioning and the SWAS analyzer panel.
    d. Normally LIEs are pipe/structure supportive or wall mounted type. If there is a bigger enclosure (transmitter enclosure), it could be self-supportive with proper grouting.
    e. Material for metallic enclosure should be corrosion resistant. IP 65/66 (NEMA 4/4X) Enclosure (Instruments) is normally chosen for outdoor installation in power plants.
    f. Space inside the enclosure should be sufficient for easy maintenance.
    g. To prevent freezing, insulation is provided for the instruments as well as associated accessories such as the valve manifold.
16. *Valve manifold*: This is a very important accessory for installation. Two-valve manifolds are used for pressure instruments. Three-valve manifolds are used for DP instruments. Five-valve manifolds are used also for DP measurements where there is a provision for a line drain. Detailed drawings of valve manifolds along with a flow diagram are shown in Figure XII/1.0-2. Valve manifolds used with instruments are generally the forged type and are usually mounted integral with the instruments, especially for DP instruments. The valves are normally tested 1.5 times the maximum process pressure they have to withstand. Block type design of the manifold is also used.

1.1 Source Point for Pressure Type Tapping

As shown in Figures XII/1.1-1 and XII/1.1-2, a socket/boss has to be welded to the pipe as a source point.

1. *Pressure/DP tapping on pipe*: Normally a socket of length and diameter 50 mm is butt welded to the pipe to accommodate the nipple (normal pipe of the same or better material). The nipple is placed at a small groove and welded with a socket. The optimum size for a 25/15 NB nipple is 250 mm. The thickness of the nipple depends on the application (mainly on the pressure rating), as detailed in Figure XII/1.1-1. The root valve is welded (or threaded for low-pressure application) to the nipple as shown in Figure XII/1.0-1b/c and c/f.
2. *Pressure/DP tapping on gas duct/furnace wall*: Since in gas services there are chances for dust, the upward pipe (normally 40 NB) of a suitable diameter and length (at 45° with the wall of the duct) or furnace is welded with the wall of the duct. The longer pipe is kept on a straight path for purging and poking, whereas at the side another pipe is welded at a 45° with the longer pipe for pressure and DP connection. As seen Figure XII/1.1-2, orientation is such that the dust is self-draining to prevent the impulse tube from getting plugged. The port for poking is kept closed by a cap with a gasket and chain to avoid leakage.

1.2 Source Point for Temperature Tapping

Here the boss/socket is similar to that of the pressure tapping. As per ASME PTC 19.3, the thermowell is to be

www.EngineeringBooksPDF.com

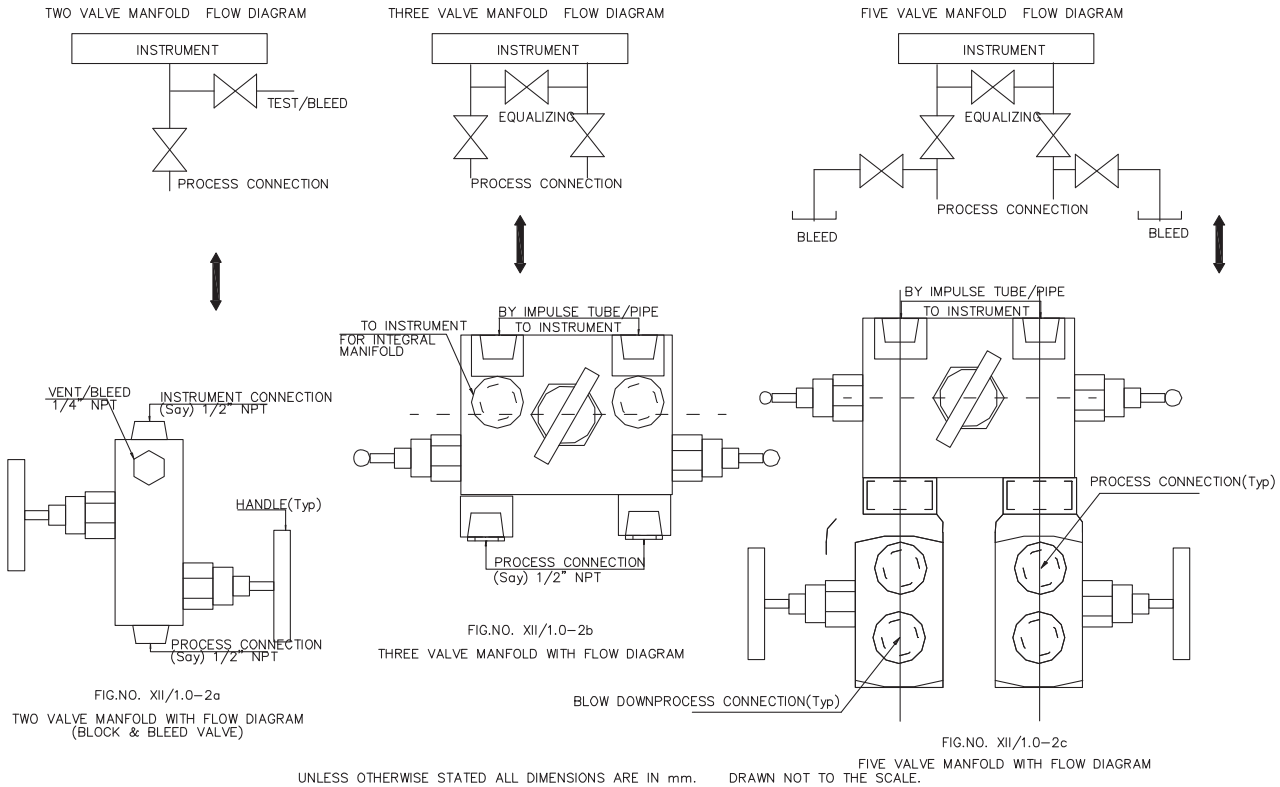


FIGURE XII/1.0-2 Source point—valve manifold.

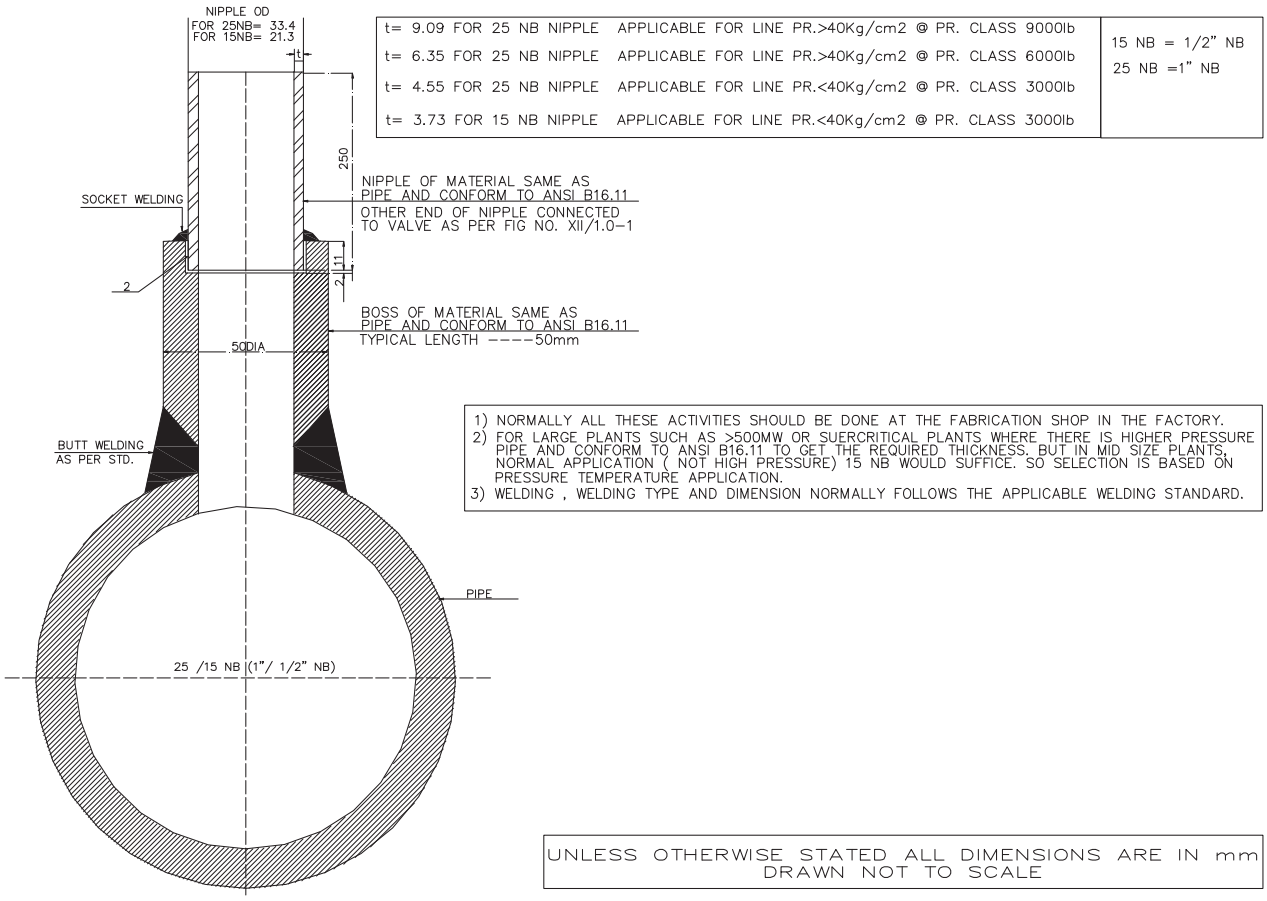


FIGURE XII/1.1-1 Source connection for pressure DP type instruments.

www.EngineeringBooksPDF.com

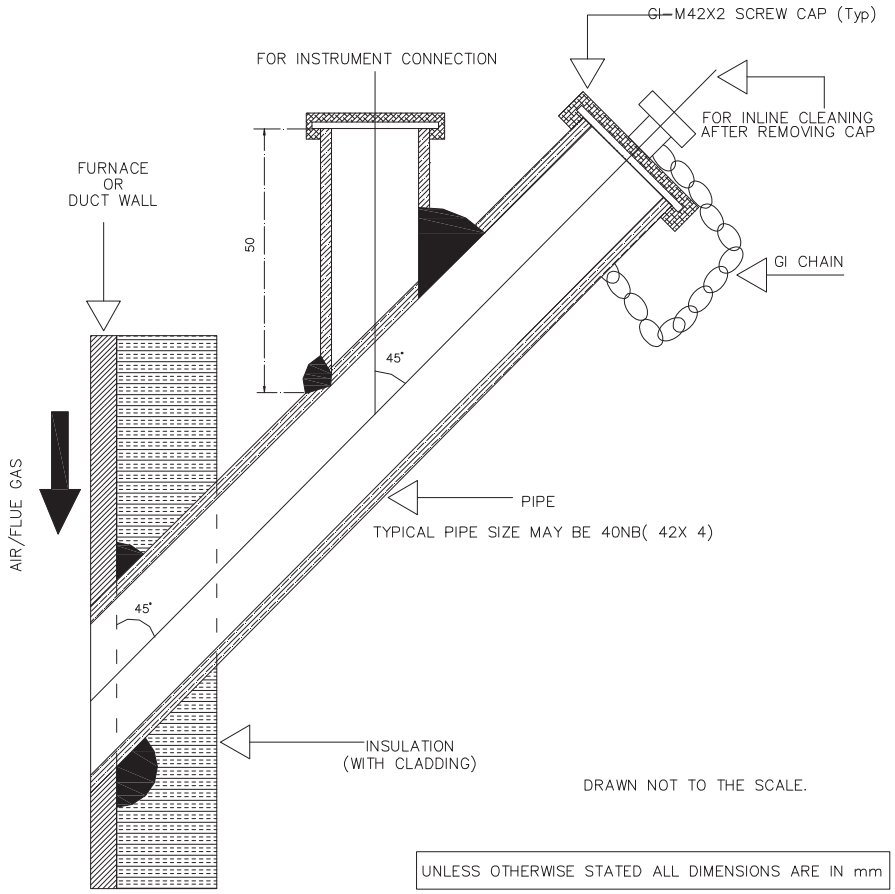


FIGURE XII/1.1-2 Source connection for pressure DP type instruments in gas duct.

immersed inside the pipe at least one-third of the pipe ID so that a representative temperature can be monitored. Again, there are some limitations regarding the length of the thermowell. If it is too small it is very difficult to fix or maintain and if it is too large it may break due to flowing fluid velocity, if not properly supported. For pipe, this is not a rule, but empirically thermowell length is 150 mm or half of the pipe ID (±13 mm), whichever is higher within the normal lower and upper limit of length (75 and 150 mm). For the gas duct it is more and the upper limit for the thermowell length may be as high as 1500 mm. Details regarding immersion length, insertion length, extension neck, etc., for the thermocouple has been discussed in Chapter IV, Clause 3.1, so it will not be repeated here. Unless otherwise stated, material for the boss is suitable for the application. In most cases the thermowell material is 316 SS or better, as per data sheet.

A few details about installing a thermowell are discussed below:

1. Inclined installations are mainly adapted for line size 75−100 mm NB pipe lines so that a suitable length for the thermowell can be chosen. The thermowell is mounted at an angle of 45° with a vertical so that the thermowell opposes the flow as shown in Figure XII/1.2-1 (flow vertically upward). If the pipe size is <75 mm NB, then an expander can be used to install in a vertical or inclined plane to get a suitable thermowell length. For very small pipe, such as pipe <50 mm NB, the installation shown in Figure XII/1.2-1b can be used. In this diagram a pipe junction is considered for installation of the thermowell. As shown, a suitable expander is used to accommodate the thermowell and a 150 mm thermowell is inserted. If suitable bends are available in the process pipeline, then it can be used when line sizes are between 75 and 100 mm NB, as shown in Figure XII/1.2-2.
2. A major effort has been put in these drawings to show mounting details for a thermowell on the pipes for power plants. There are two distinct cases: when process pressure >40 kg/cm^2 and when it is <40 kg/cm^2. In the first case, the thermowell is welded to the boss/socket in addition to tightening the thermowell with its external threads with the internal threads of the boss/socket. Naturally surface preparation in the boss

www.EngineeringBooksPDF.com

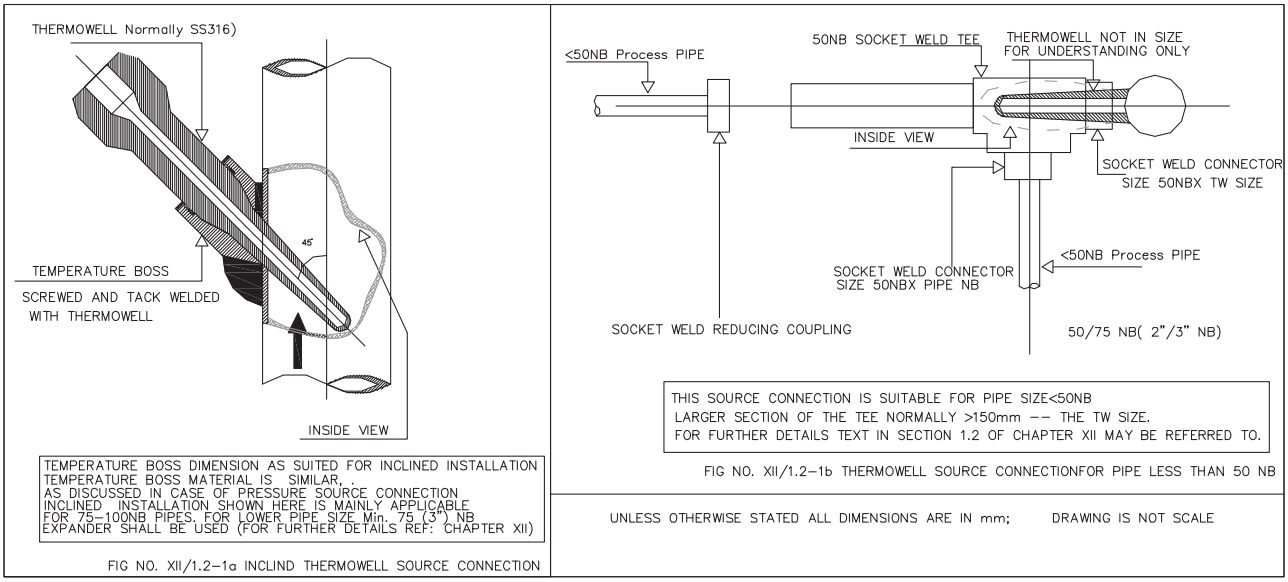


FIGURE XII/1.2-1 Source connection for temperature element (1).

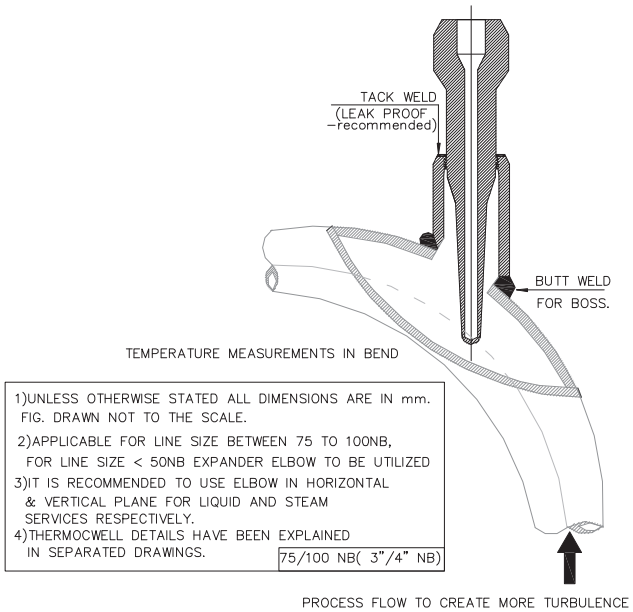


FIGURE XII/1.2-2 Source connection for temperature element (2).

is necessary to do the welding of the thermowell with the boss to make the system withstand high pressure. In these cases shop welding is done for the boss with the pipe as shown in Figure XII/1.2-3a. When the process pressure is <40 kg/cm^2, connection between the thermowell and boss could be only thread as discussed earlier and shown in Figure XII/1.2-3b. However, in addition to the thread connection tack welding makes the system leak proof (kills the chance of minute leakage through the thread). In most cases (exception: very low pressure services) the thermocouples are drawn from solid bar stock for better mechanical stability and strength. In power plants many of the pipelines where thermowells are mounted are insulated, so suitable extension length (ISA symbol L) as shown in these drawings should be considered. Internal bore of the thermowell normally follows ASME PTC19.3. Usually a 50 mm diameter boss is selected. The greatest diameter of the thermowell must match the internal bore of the boss, which is normally 40 mm, so that with external threads could be accommodated in the boss. Normally the lowest tip thickness of the thermowell is $\sim$4.5–4.8 mm.

3. Slip-on type flange connection of the thermowell is suitable for gas duct installations. One pipe (for example, 42.4 $\times$ 4mm) is welded with the wall of the duct. On the other end of the pipe is a flange to accommodate the flange of the thermowell. The length of this pipe should be long enough to go past the insulation to fit the thermowell. A typical 150 mm length of pipe outside the insulation accommodates/adjusts to various thermowell lengths with the help of a slip-on flange. Typically slip-on flanges as per ASME 19.3 are used (other matching types could also be used). Thermowell with a matching flange is inserted through the pipe to the gas duct (see Figure XII/1.2-4).

1.3 Source Connection for Flow Measurements

A variety of flow meters are used in power plants, but the majority of flow measurements are based on DP

www.EngineeringBooksPDF.com

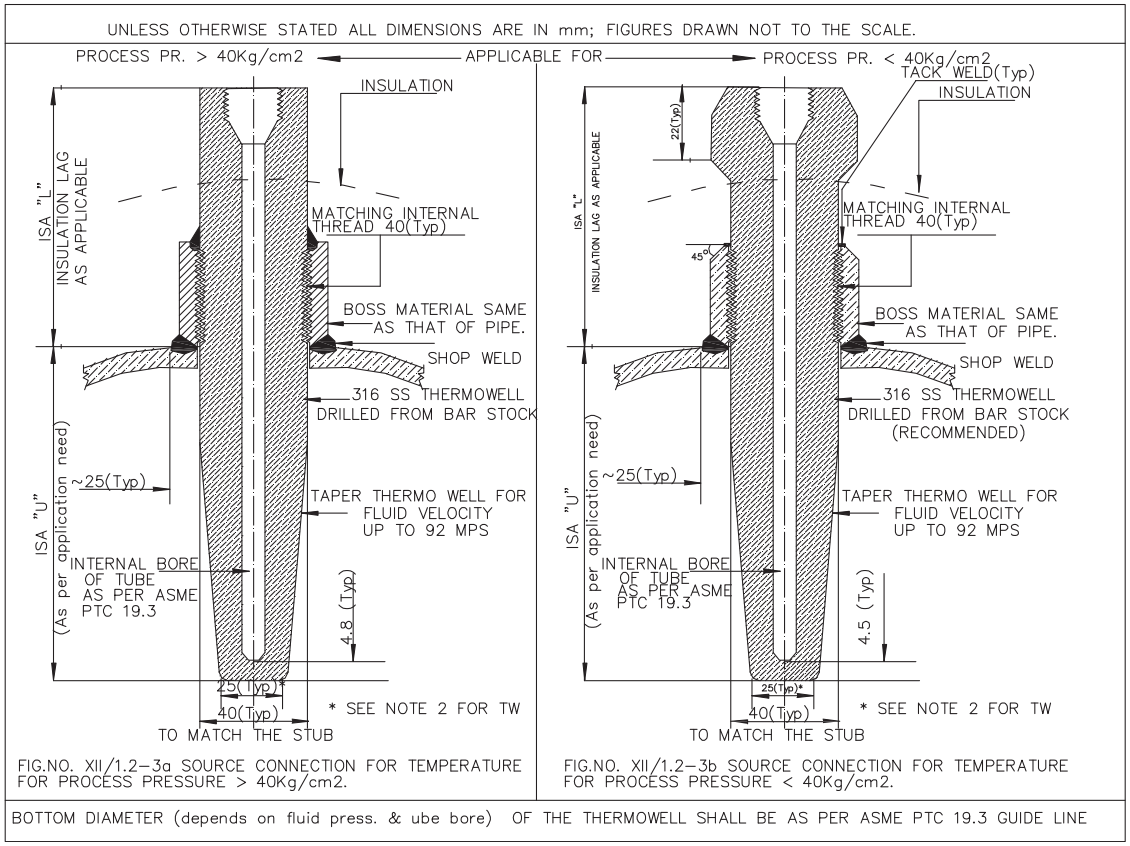


FIGURE XII/1.2-3 Source connection for temperature element (3).

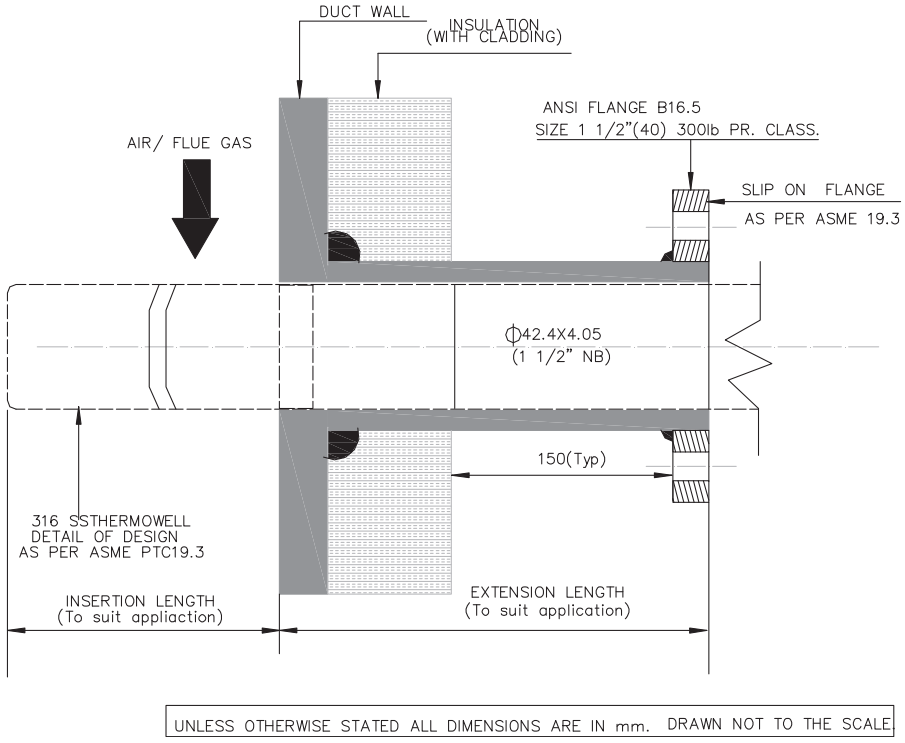


FIGURE XII/1.2-4 Source connection for temperature element in gas duct.

www.EngineeringBooksPDF.com

TABLE XII/1.3-1 Impulse Line Diameter (Minimum) and Length

Diameter for flow type	Line length (0–16 m)	Line Length (16–45 m)
Steam/water/dry air/gas	7–9 mm	10 mm
Wet air/gas	13 mm	13 mm
Oil (low/med viscosity)	13 mm	19 mm
Dirty fluid	25 mm	25 mm

measurements, so primarily we will discuss this type. In this method, impulse lines are used to measure the DP due to restrictions like the orifice plate, flow nozzle, and Venturi tube. A few problems associated with impulse lines are listed below:

- Damping of pressure signals/response
- Blockage
- Leakage at coupling
- Temperature (hence density) difference
- Condensate in line for gas flow measurement
- Gas bubble in impulse line for liquid flow measurement

1. *Issues related with the impulse line*:
   - **a.** *Impulse line length and diameter*: To have a better response, a narrow diameter of the impulse line is necessary. If it is too narrow there will be a blocking problem and capillary effect error, and the need to vent bubbles will become problematic. The recommended minimum diameter is 10 mm. With variation in length there is a variation in diameter. The length and diameter of the impulse lines as per ISO/CD 2186:2004 are given in Table XII/1.3-1.
   - **b.** Location of the DP instrument with respect to the primary sensor has a bearing on installation and was discussed in Clause 1.0, number 9.
   - **c.** *Location of tapping point and orientation*: Discussed in Clause 1.0, number 10.
   - **d.** *Routing and slope*. For proper functioning as well as accurate measurement it is recommended that there is a suitable length of the impulse line and suitable slope is maintained. Clause 1.0, numbers 7 and 12c may be referenced.
   - **e.** *Temperature effect*: Both ambient temperature and difference in temperature between the two limbs of the impulse line have a direct bearing on the accuracy of the measurement. During installation one limb of the impulse line should not be exposed to sunlight while the other is in the shade. Similarly both impulse lines should be close to one another so that both limbs are roughly at the same temperature (see Figure XII/1.3-1a). This is important because if there is variation in temperature between

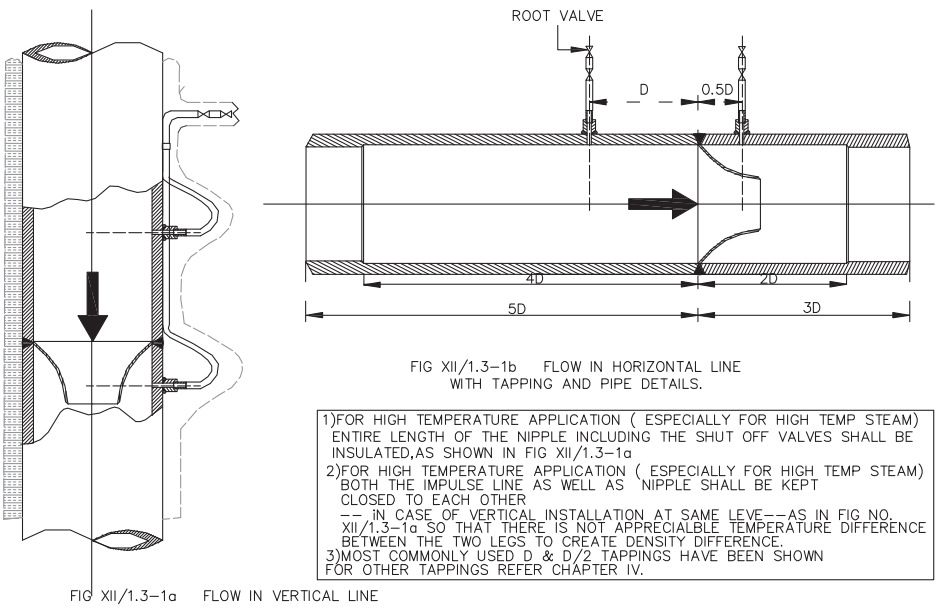


FIGURE XII/1.3-1 Source connection for flow elements (1).

www.EngineeringBooksPDF.com

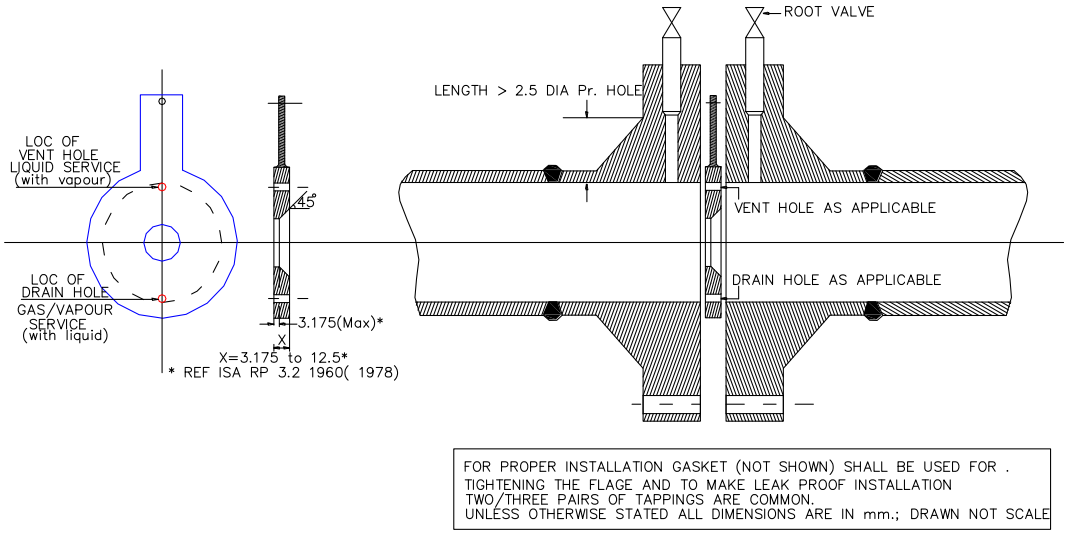


FIGURE XII/1.3-2 Source connection for flow elements (2).

the two sides of the impulse line then there will a variation in the density of the fluid in those limbs and it will affect the DP [DP = h*(ρ_1 − ρ_2)*g; so variation of ρ will affect the reading even for the same h].

f. *Fluid in impulse pipe*: For steam and condensate services the line is filled with water prior to the start of the measurement. In most of the cases condensate pots are used to ensure steam does not reach the instruments.

g. *Proper connections*: There needs to be suitable isolation of drain/vent valves and their connections for measurement accuracy. Also blocking and leakage at the coupling should be avoided.

2. *Flow nozzle*: Flow nozzle connections are seen in Figure XII/1.3-1a and b. Horizontal installation of the flow nozzle is preferred, but it can be used in a vertical downward installation for steam (wet). Normally Flow nozzle is welded with spool pieces. As shown in Figure XII/1.3-1a, to keep the temperature at two limbs the same they need to be run close to each other. In vertical installations the two limbs are first raised vertically before having a horizontal run. Horizontal installation is depicted in Figure XII/1.3-1b with D and D/2 tappings, which are very common for flow nozzles in a power plant application. As shown in Figure XII/1.3-1b, a straight length of spool piece is 8D. For further details see Chapter IV, Clause 4.1.

3. *Orifice plate*: Square-edge orifice plate with drain and vent hole is depicted in Figure XII/1.3-2. Orifice plates are mounted between the two flanges. There are a number of accessories, such as a carrier ring and an orifice plate. Corner tap, flange tap, and D and D/2 tappings are the various kinds of tappings available as detailed out in Chapter IV, Clause 4.1. Figure XII/1.3-2 shows an orifice plate with weld neck flange and flange tappings. In the drawing both drain and vent holes are shown, but should be used as applicable.

1.4 Source Point Connection for Level Measurement

Basically the tapping point types are similar to those for pressure measurements, only the sizes will be different (see Figure XII/1.4-1).

If there is tapping at the bottom of the tank, then the nozzle should be raised 150 mm above the bottom of the tank to avoid dirt. Also level instrument flange connections are depicted in Figure XII/1.4-1c.

2. PIPE VALVE FITTING MATERIAL SPECIFICATION AND RATING

2.0 Pipe Valve Fitting Specifications

In most cases all materials in power plants follow the latest editions of ANSI B31.1 and ANSI B16.11 for power piping, flanges, and fittings. There are also other international standards. In this clause various sizes, ratings, and material specifications of pipes, valves, and fittings will be discussed. All impulse lines (pipe/tube) need to be properly specified. Pipes are specified either by outside diameter (OD) × thickness or as an NB. Specifying pipe by NB is the most common way. Size, specified by NB, is actually the

www.EngineeringBooksPDF.com

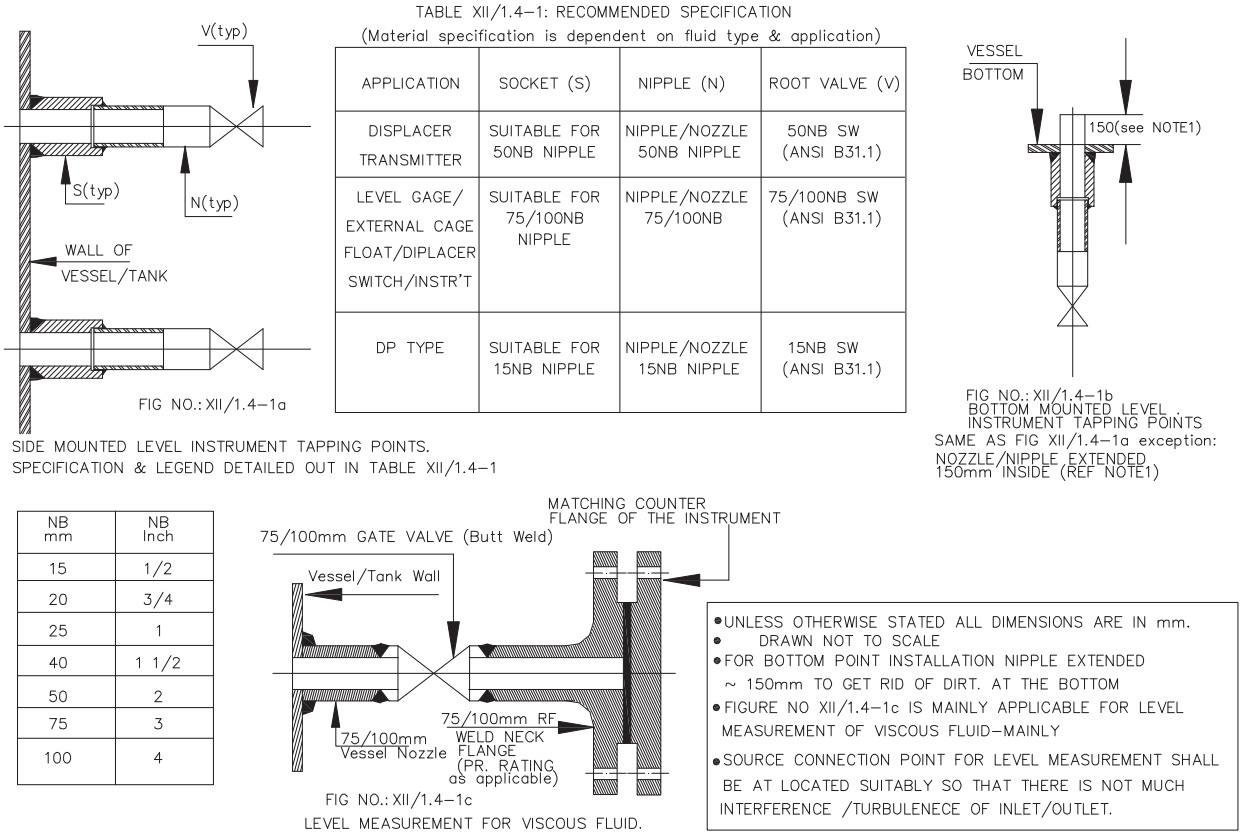


FIGURE XII/1.4-1 Source connection for level instruments (1).

diameter of an imaginary circle (may be anywhere between OD and ID). However, as long as the NB is spelled out, the OD of the pipe is specified (because corresponding to each NB there is a specific pipe OD). The advantage of this system is that for the same NB there can be pipes of varied thicknesses, so thickness of the pipe is specified by pipe schedule number, which also determines the pressure withstand capability of the pipe. Pipe dimensions are listed in Table XII/2.0-1. Tubes are specified by OD × thickness. Impulse lines could be impulse pipe or impulse tubes or a combination of the two. Commercially, on the field side, impulse pipes are quite common, and as in those cases CS and alloy steel pipes could be used. When instruments are placed in the LIE, it is *customary* (for manufacturing uniformity) to use a stainless steel impulse tube inside the enclosure. Bulkhead fittings are used to bring the impulse line into the enclosure. Listed below are a pipe valve fitting specifications:

1. *Pipe dimensions*: As discussed previously, there will be variations in dimensions of impulse pipe based on NB size and schedule. Important parameters, required for instrumentation, from ANSI B36.10 for selected sizes are presented in Table XII/2.0-1.

2. *Impulse line valve and fitting materials and ratings*: Various impulse lines and valve materials are enumerated below. All fittings are forged steel as per ANSI B16.11. The materials for forged tube fittings are ASTM A182 Gr. 316H and A182 Gr. 316L for high-pressure temperature applications as well as other applications, respectively. Bar stock tube fittings can be 316 SS. Valves are the forged type. All materials discussed are forged/bar stock types. There is a service list based on large power plants (for example, 650 MW) such as super critical plants where temperature and pressure ratings are higher. For mid to lower sized power plants parameters are less stringent and lower grade materials may be selected depending on actual conditions. The data given are approximate and are based on design pressure and temperature conditions:
   - **a.** *Service*: MS: Main Steam (MS) up to pressure-reducing valves (PRVs) in auxiliary steam (AS) and High Pressure Bypass HPBP lines:
     - **i.** *Impulse line*: ASTM A335 Gr. P91 Sch: XXS(1/2")
     - **ii.** *Valve body, flange, and fittings*: ASTM A182 Gr. F-91
     - **iii.** *Valve stem materials*: ASTM A182 Gr. F-6a

www.EngineeringBooksPDF.com

TABLE XII/2.0-1 Pipe Dimension (1inch = ~ 0.0254m)

Pipe NB (in.)	OD (in.)	Identification (Sch.)			Thickness (in.)
		Iron pipe Size	*Steel pipe Sch. No.*	*SS Sch. No.*	
1/4	0.405	—	—	10S	0.065
		STD	40	40S	0.088
		XS	80	80S	0.119
3/8	0.675	—	—	10S	0.065
		STD	40	40S	0.091
		XS	80	80S	0.126
1/2	0.84	—	—	5S	0.065
		—	—	10S	0.083
		STD	40	40S	0.109
		XS	80	80S	0.147
		—	160	—	0.187
		XXS	—	—	0.294
3/4	1.050	—	—	5S	0.065
		—	—	10S	0.083
		STD	40	40S	0.113
		XS	80	80S	0.154
		—	160	—	0.219
		XXS	—	—	0.308
1	1.315	—	—	5S	0.065
		—	—	10S	0.109
		STD	40	40S	0.133
		XS	80	80S	0.179
		—	160	—	0.250
		XXS	—	—	0.358
1 1/4	1.660	—	—	5S	0.065
		—	—	10S	0.109
		STD	40	40S	0.140
		XS	80	80S	0.191
			160	—	0.250
		XXS	—	—	0.382

www.EngineeringBooksPDF.com

iv. *Valve pressure class*: 3000 lb
v. *Fitting*: ASTM A182 Gr. 316H
vi. *Ratings of fitting/pipe*: 9000 lb

b. *Service*: Hot reheat (HRH): HRH up to PRVs in the Low pressure bypass LPBP line:
i. *Impulse line*: ASTM A335 Gr. P91 Sch: 160 (1/2")
ii. *Valve body, flange, and fittings*: ASTM A182 Gr. F-91
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 1500 lb
v. *Fitting*: ASTM A182 Gr. 316H
vi. *Ratings of fitting/pipe*: 3000 lb

c. *Service*: Downstream of AS PRV up to drain manifold:
i. *Impulse line*: ASTM A335 Gr. P91 Sch: 160 (1/2")
ii. *Valve body, flange, and fittings*: ASTM A182 Gr. F-91
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 1500 lb
v. *Fitting*: ASTM A182 Gr. 316L
vi. Ratings of fitting/pipe: 3000 lb

d. *Service*: BFP disch./superheater (SH) and reheater (RH) attemperation/spray lines:
i. *Impulse line*: ASTM A106Gr. C Sch: 160 (1/2")
ii. *Valve body, flange, and fittings*: ASTM A105
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 2500 lb (RH attemperation, line valve 1500 lb)
v. *Fitting*: ASTM A182 Gr. 316L
vi. *Ratings of fitting/pipe*: 6000 lb

e. *Service*: Cold reheat (CRH) up to tee off for HPBP/Ex 5 to high-pressure heater:
i. *Impulse line*: ASTM A335Gr. P22 Sch: 80 (1/2")
ii. *Valve body, flange, and fittings*: ASTM A182 Gr. F-22
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 900 lb
v. *Fitting*: ASTM A182 Gr. 316L
vi. Ratings of fitting/pipe: 3000lb

f. *Service*: CRH after tee off for HPBP:
i. *Impulse line*: ASTM A106Gr. C Sch: 80 (1/2")
ii. *Valve body, flange, and fittings*: ASTM A105
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 900 lb
v. *Fitting*: ASTM A182 Gr. 316L
vi. *Ratings of fitting/pipe*: 3000 lb

g. *Service*: Other lines in feed water/conditioning line:
i. *Impulse line*: ASTM A106Gr. B Sch: 80 (1/2")
ii. *Valve body, flange, and fittings*: ASTM A105
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 900 lb
v. *Fitting*: ASTM A182 Gr. 316L
vi. *Ratings of fitting/pipe*: 3000 lb

h. *Service*: Air flue gas line in furnace pass:
i. *Impulse line*: ASTM A335Gr. P22 Sch: 80 (3/4")
ii. *Valve body, flange, and fittings*: ASTM A 182 Gr.F22
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 900 lb
v. *Fitting*: ASTM A182 Gr. 316H
vi. *Valve pressure class*: 900 lb
vii. *Ratings of fitting/pipe*: 3000 lb

i. *Service*: Air flue gas line outside run:
i. *Impulse line*: ASTM A106Gr. C Sch: 80 (3/4")
ii. Valve body, flange, and fittings: ASTM A105
iii. *Valve stem materials*: ASTM A182 Gr. F-6a
iv. *Valve pressure class*: 900 lb
v. *Fitting*: ASTM A182 Gr. 316L
vi. *Ratings of fitting/pipe*: 3000 lb

3. *Air line*: There should be an instrument air supply line for each pneumatic instrument/valve/consumer, etc., provided through an air filter regulator (AFR). These connections are copper tube ASTM B88/B75. Minimum thickness for a copper tube is 1.6 mm and normally coated with PVC. For purging/cleaning purpose service air lines are used with various enclosures. Normally AFRs have a 5 μm filter and are suitable to withstand a pressure of 10 bar. These AFRs usually have 50 mm pressure gauges and bottom drain/blow down ports. For air lines the instrumentation installation point starts from the isolation 1/2" valve in the main air header or subheader, within 2−3 m from the instruments/pneumatic devices. All internal pneumatic distributions are done with instrumentation, e.g., for a control valve one air line point with an isolation valve may be provided and for an I/P converter, a valve positioner etc. copper tube for air lines may have to be arranged. Also interconnections by copper tubes from the positioner to the control valve are done with instrumentation. For such an air header/sub header distribution of 1/2" hot-dipped, galvanized mild steel pipe may be used. Fittings could be ASTM A 234Gr.WPB.

3. MECHANICAL INSTALLATION OF INSTRUMENTS

3.0 General

Right from the planning or design stage it is recommended to properly plan the complete installation of instrumentation systems for the entire plant for uniformity and interchangeability as well as lower inventory. As discussed earlier, there could be a number of packages under which the instruments are supplied and installed. Naturally, if not planned form the outset, there may not be any standardization of installation with many different kinds of fittings and accessories (hence more inventory). Therefore it is

www.EngineeringBooksPDF.com

better to attach instrumentation installation practices and specification as a part of the specification for all design packages to ensure uniformity. The impulse line is an important item in the mechanical installation of instruments. A few common points to decide before going any further with installation diagrams include:

1. *Tubes and pipes*: Both can be used for the same purpose. Generally tubes are preferred over pipes in small diameter applications, i.e., an impulse line. One major difference between a tube and pipe is that the tube is not threaded (as the wall thickness is too thin to hold thread) at the end to form a connection; instead tube fittings are used. The major advantages of tubes over pipes are as follows:
   - *Bending quality*: Good, stronger with a thin wall, which makes bending easier.
   - *Stronger*: Since there is no thread at the end it is stronger with no weak section.
   - *Less turbulence*: Smooth bends hence streamlined flow.
   - *Economy in space and weight*: Better bending, smaller OD, and less weight for fittings.
   - *Flexibility*: Less rigid, hence, immune to transmission of vibration between the connections when compared with pipe.
   - *Fewer fittings*: Because fewer fittings are necessary, no bend is necessary. Also all fittings act as a union.
   - *Less leakage*: When properly fitted there is no leakage. High-pressure tube may burst, but if fittings are properly fitted there is little change of leakage.
   - *Good look:* Because of good consistency, smoother contour, and less fittings, it looks better, especially when a number of tubes are placed parallel.
   - *Cleaner fabrication*: Because there is no thread, there is no chance of foreign material so there is no need for sealing.
   - *Easier assembly and disassembly*
   - *Less maintenance*

   However, as tubes are costlier when compared with pipe, from a cost consideration many designers may prefer impulse pipe. Regardless of the choice, it must be the same throughout the entire plant unless there is a particular reason behind any exception. As discussed in the previous clause, material selection is important for the impulse line. Keeping this in mind, the entire impulse pipe has been considered on the field side, up to the LIE. Inside the enclosure stainless steel tube is used for the book this has been chosen, so that it can cover almost all applications. This is not sacrosanct, it is only chosen to economize and cut down on variation when designing the LIE.
2. Another important aspect of the installation diagram is the demarcation between the scope division and the mechanical and instrumentation engineering section. This scope division is normally done in such a way that progress of installation work of one branch does not affect the other. The instrument devices are installed in place only after mechanical installation and testing activities (hydraulic testing of power and process piping, steam blowing, etc.) are finished. In fact matching connection details for all in line devices (for example, matching flanges), end-to-end dimensions, etc., are necessary before actual installation of the instrumentation devices in the pipe. Mechanical contractors use matching spool pipe to complete various mechanical activities, and later the actual instrumentation devices are installed. Good coordination between mechanical and instrument disciplines is extremely important; for example, when a Venturi is to be installed in an air duct precise dimension matching is absolutely necessary. This is the same for a steam flow nozzle in critical pipe, a piece of which (the spool piece) needs to be sent to the flow element manufacturer for positioning of the flow nozzle. Normally the instrumentation terminal point is the root valve, i.e., instrumentation work starts with suitable fittings (or welding at the root valve). Mechanical scope includes the stub, nipple (matching with application), and root valve. Root valve sizes vary say, 1 or 3/4", so, any necessary reducer (after the root valve) is part of the instrumentation. When there is no root valve, e.g., as in flue gas, the Y pipe welded to the flue gas duct/furnace wall is kept complete with the necessary screwed cap (may be fitted with chain) as shown in Figure XII/1.1-2. Inclined Y pipe is provided so that from the straight part a pocking rod can be inserted as necessary to remove clogging. With temperature element installations, the stub is left with a blanking plate so that mechanical activities can be completed (without actual thermowell, etc.) and then the thermowell is inserted to avoid damage from mechanical activity. All of this is based on standard practices normally followed in actual plants, and there could be some exceptions that need to be sorted out by the owner through proper coordination and mutual agreement between the engineers from each discipline.
3. Source connection details discussed in Clause 1.0 are very important and need to be prepared and circulated with all mechanical and other packages for implementation so that at the time of installation there is no mismatch. Normally 1/2" globe valves with socket weld connections are used as root valves. This is for guidance only, as other types (as per owner's choice) could also be used. However, consistency should be maintained throughout the plant.
4. Each owner adopts a specific standard, regarding the number of root valves, which needs to be followed during the design. As discussed earlier, normally double

www.EngineeringBooksPDF.com

root valves are recommended for process pressure >40 kg/cm^2 and in steam services (for their cases, Single root valve may be for pr.<40 kg/cm^2). Also where there is a drain of high-pressure lines where double root valves have been used, double drain valves need to be considered for line draining. This is done as a preventive action against leakage.

5. All impulse lines are duly coated with color as per the applicable prevalent standard, but such coatings must not be flammable or combustible. All impulse lines need free movement to take care of thermal expansion, etc. For preventing steam from reaching the instruments, pigtail/siphon, constant head unit (CHU) etc., are used. In some installations, in place of the CHU, a temperature equalization column is used. In some pressure installations especially for steam services, it is necessary to fill the line with water so that say, steam does not reach instruments. Drain valve of two valve manifold or bleed valve ((Clause 3.1.1 no 1d) is uilized for this purpose.
6. Bulkhead fittings shown in installation diagrams are the points through which impulse lines enter LIE. Bulkhead fittings are chosen for both end tube connections, but they can also be chosen as interfaces between a pipe and tube (to eliminate pipe to tube union), e.g., bulkhead male or bulkhead female in place of bulkhead union. All fittings and tubes inside the LIE are stainless steel so that these may be used for all applications. However, other suitable materials, as discussed in Clause 2.0, may also be selected. Since the valve manifold is normally inside the LIE, it is stainless steel (preferred). To avoid more fittings, transmitters with integral valve manifolds are recommended. Remember, these are only recommendations.
7. In the installation diagram discussed later, in all cases when Separate line drains have been used, instead of a five-valve manifold, a three-valve manifold will suffice (e.g. See figure XII/3.1-5 & figure XII/3.2-1).
8. In most cases, a main instrument air header or major subheader is provided at two or three places in the boiler , turbine area, off sites, and other places by in the mechanical design. From these headers, branch distribution lines may have to be drawn under the instrumentation scope of work. Normally a 2" GI pipe is used as a main subheader with 1" (or 1/2" branch line : refer point no 3 of clause 2.0 above also) GI pipe as branch lines. Normally, corresponding to each group of consumption points, there is one dedicated tapping point in the air line complete with a suitable isolation valve so that from there a pneumatic line can be drawn. In addition to these there may be purge lines for various measurements in the mill and flue gas systems. Also, there could be purge air lines for the LIE.
9. Purging process connections are used when there is a chance of the line getting plugged due to dust and/or freezing. Normally a fluid is used that does not interfere with the process medium. Air purging (as a part of cleaning the line) in the flue gas, mill, and fly ash system is quite common in a power plant. Care is to be taken to see that purging does not introduce error in measurement. If there is a freezing problem, the purging line should be properly traced. The purging connections mean cleaning is done by intermittent purging and is normally done with flexible pipes/hoses and quick connect fittings. But there are certain measurements, such as DP, across mill or level in fly ash bins, where continuous air purging is necessary as a part of the measurement. In such cases rotameters and DP regulators are used to purge the required quantity of fluid. Normally purge connections are kept near the process connection or near instruments for a long run of impulse line. Check valve and shut-off valves are used for purge connections.
10. Heat tracing may be required for impulse lines/instruments for highly viscous services (such as heavy fuel oil, HFO) or vapors, which can be frozen. Each of these applications needs to be studied to determine the type and degree of heat tracing necessary. The types of heat tracings can be categorized with associated conditions as follows:
    - Self-limiting electric heat tracing up to 120°C
    - Steam tracing <100°C
    - Constant resistance electric tracing for temperature-controlled application
11. Impulse lines are laid on a flat, smooth surface and are straightened by hand without pulling or heating to keep the ID unchanged. Only the required length should be uncoiled as repeated operations may cause a kink or damage. A bending tool or hacksaw/tube cutter with a sharp edge can be used to bend or cut the tube. All impulse line cuts are squared off with fine files. Minimum bending radius for the tube is 2 1/4 OD (for tube OD < 12.5 mm) and three times (for tube OD > 12.5 mm).
12. Impulse line joining and fitting installations are done as per ANSI B31.1.
13. Welding procedures and performance qualifications are normally done as per ANSI B31.1. Clause IX. Filler materials are also as per ANSI B31.1. Clause II.
14. For pipe threads, tape type sealants can be used in clean air, water (liquid), and steam services up to 230°C. Other sealants can be used as per manufacturer's recommendations. These are not applicable for tubes.
15. Normally the ANSI B31.1 standard is used for the hydrostatic and pneumatic testing procedure for impulse lines. All impulse lines, after the erection work is over, are tested for pressure withstand capability of 1.5 times the maximum pressure. During such tests the instruments are kept isolated with the help of an instrument shut-off valve. Similarly the air lines are tested by the pressure decay method as per ANSI B 31.1.

www.EngineeringBooksPDF.com

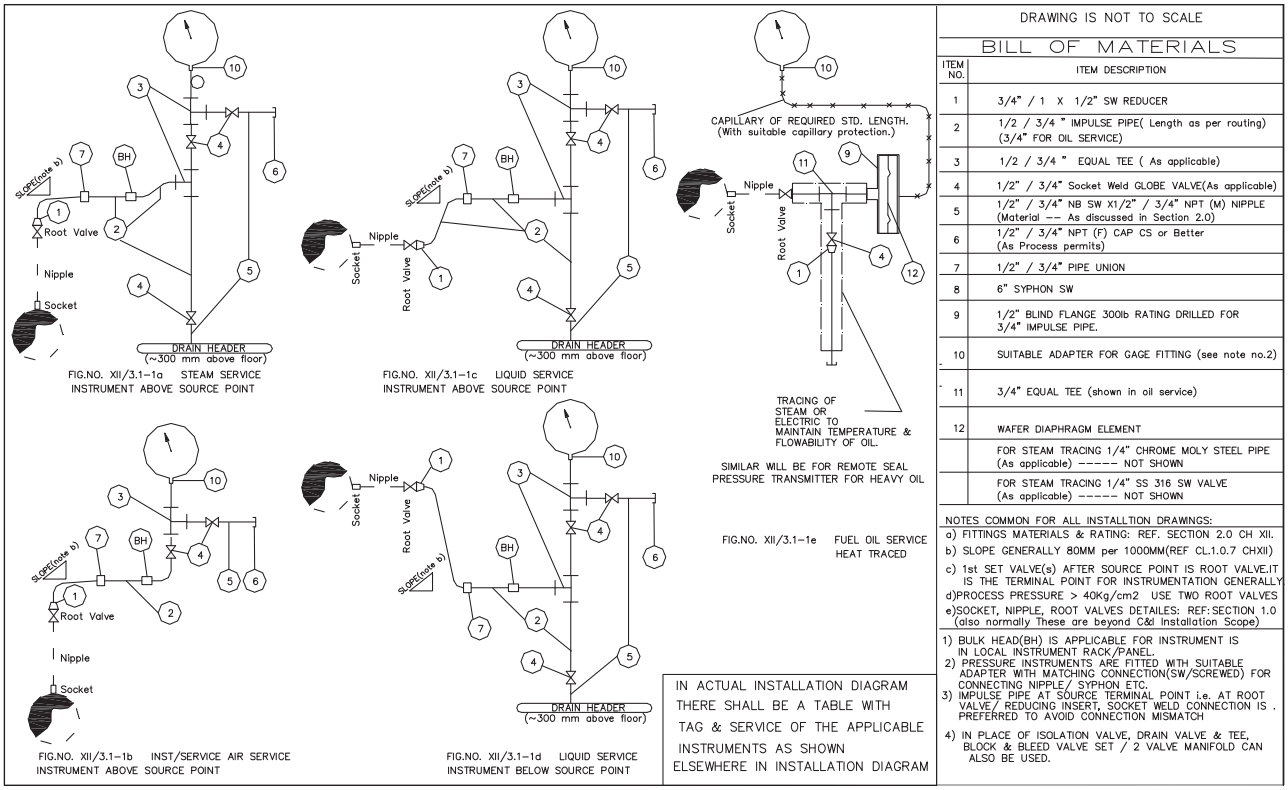


FIGURE XII/3.1-1 Local pressure instrument installation 1.

16. The salient point of each installation diagram is discussed below, as the diagrams are self-explanatory and do not need further discussion. Also, for the relevant bill of material, the drawings need to be consulted as these are not repeated here.

3.1 Pressure Instrument Installations

The pressure instrument installations are categorized as follows:

- Local pressure instrument, e.g., local gauges and switches
- Pressure instruments such as pressure switches and transmitters mounted in LIE/LIR
- DP instruments

3.1.1 Pressure Gauge Installation

1. *Steam service*: Instrument above the source point (see Figure XII/3.1-1a):
   a. This is for steam service, hence, the tapping is shown from the top of the pipe.
   b. Pipe union is used to make pipe fixings easier.
   c. Bulkhead fitting is shown for local gauge board installation possibility.
   d. Attention is drawn to the two valves connected to one TEE just ahead of the siphon. One valve is for isolation (to isolate the line from the gauge) and the other valve is for testing the gauge, draining from the gauge, etc. In place of these two valves a block and bleed valve in one block or a two-valve manifold can be used. A simple block and bleed valve is a better choice for all pressure gauges.
   e. There is a line drain connection shown with a valve. This is required when the gauge is first put into service (may be after a long period, or if the same is not in operation) so that the line can be drained to clear dirty water. When the pressure gauge is mounted in a local gauge board/panel, then the line draining can be done at a common header to avoid flooding the floor.
   f. Since the distance between the tapping and the instrument may not be long, an instrument is taken above the tapping point, therefore a pigtail or siphon is a must to ensure that the steam does not reach the instrument at any time.

2. *Air service:* Instrument above the source point (see Figure XII/3.1-1b):
   a. This is for air service, hence, the tapping is shown from the top of the pipe.
   b. Clause 3.1.1b–d are applicable here as well.

www.EngineeringBooksPDF.com

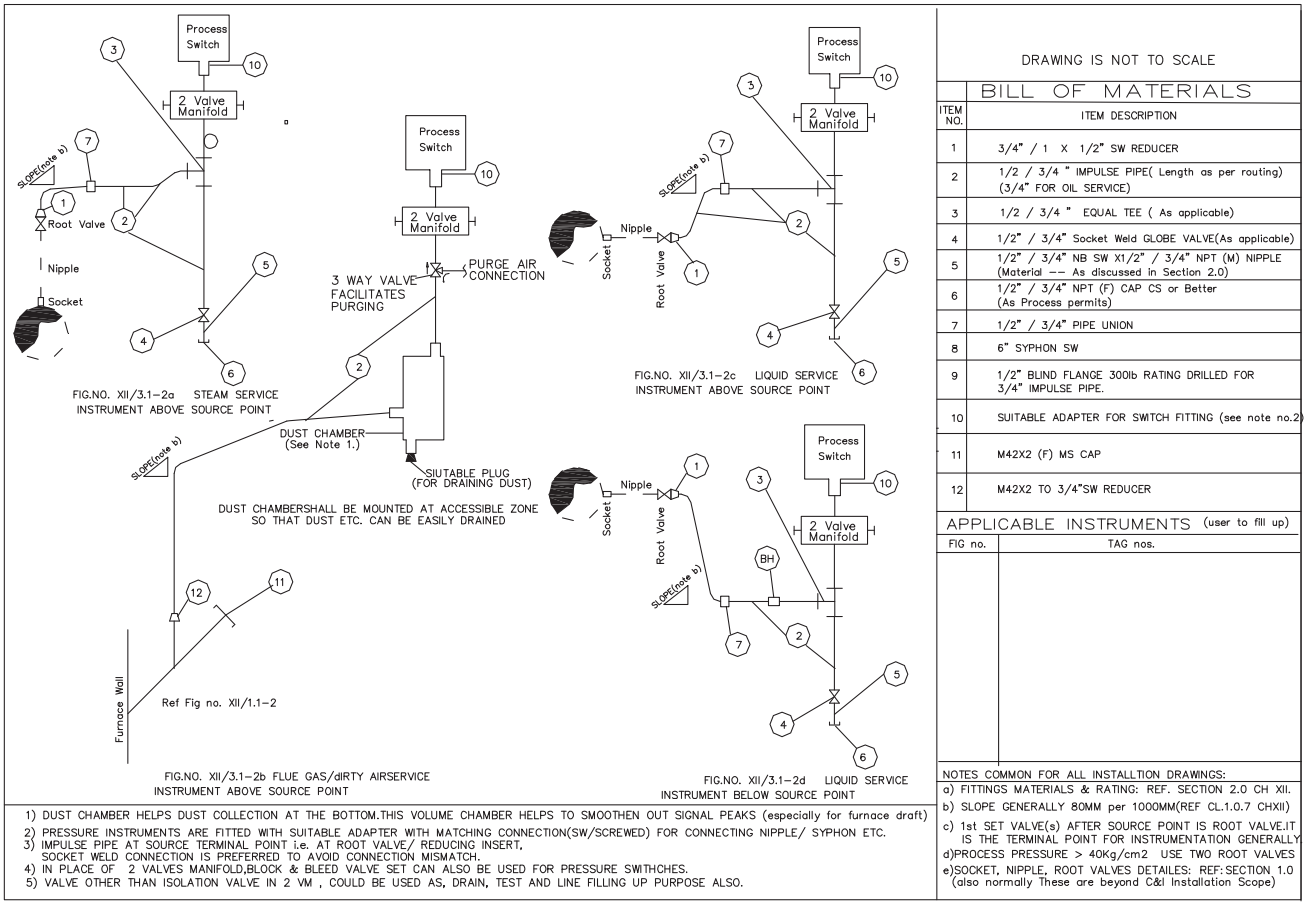


FIGURE XII/3.1-2 Local pressure instrument installation 2 (pressure switch).

3. *Liquid service*: Instrument above/below the source point (see Figure XII/3.1-1c and d):
   - **a.** This is for liquid service, hence, the tapping is shown from the side of the pipe.
   - **b.** Clause 3.1.1b–e are applicable here as well.
4. *Fuel Oil (FO) service*: Instrument has a diaphragm seal (see Figure XII/3.1-1e):
   - **a.** This is for liquid service, hence, the tapping is shown from the side of the pipe.
   - **b.** For heavy FO service for high viscosity, the entire line, including the line drain, needs to have heat tracing so that flow ability is maintained.
   - **c.** Diaphragm seal with capillary filled with inert liquid (e.g., silicone oil) has been used so that FO does not physically come in contact with the pressure gauge and the gauge is always responsive and not clogged with FO. This inert liquid actually transmits the FO pressure to the gauge.

3.1.2 Pressure Switch (Local) Installation

1. *Steam service*: Instrument above the source point (see Figure XII/3.1-2a). Similar as in Clause 3.1.1, number 1.
2. *Flue gas/dirty air services*: Instrument above the source point (see Figure XII/3.1-2b):
   - **a.** As indicated earlier, tapping is seen from the top part of the inclined Y pipe, so that through the straight part pocking action can be initiated as necessary. This end is normally kept closed with the help of the screwed cap as shown.
   - **b.** A dust chamber is seen, and this is helpful in two ways: first it helps to collect and secondly it acts as a volume chamber that (like a capacitor in an electrical circuit) helps to dampen the fluctuation in the measurement (i.e., acts as a low-pass filter). This is very helpful in arresting the fluctuations in the furnace pressure measurement, which naturally fluctuates. From time to time, dust collected at the chamber can be cleaned from the bottom.
   - **c.** A three-way valve with purge air connection has been kept to purge the line by operating the three-way valve and isolating the instrument. The dust can be returned to the system with the help of purge air.
3. *Liquid service*: Instrument above and below the source point (see Figure XII/3.1-2c and d):
   - **a.** Same for Clause 3.1.1, number 3a.
   - **b.** Clause 3.1.1 no 1b–e are applicable here as well.

www.EngineeringBooksPDF.com

3.1.3 Pressure Transmitter/Switch (In LIE/LIR) Installation 1

It is common in power plants that the transmitters/switches are grouped together and placed in the LIE/LIR. However, in many off site plants the transmitters are not grouped but are installed individually. In the installation diagram in Figure XII/3/1-3 transmitters/switches in LIE/LIR are seen. If they are not in the LIR/LIE, installation will be the same with the following probable changes:

- Bulkhead may not be applicable.
- Drain header may not be there; instead the drain line may be capped, but while draining care should be taken to ensure that the place is not flooded.
- Items 1 (SW tube connector) and 11(impulse tube) may not be applicable if impulse pipe is used.
- Equal TEE could be socket weld (SW) type when used with pipe.

1. *Steam service*: Instrument above and below the source point (see Figure XII/3.1-3a and b):

a. This is for steam service, hence, the tapping is shown from the top of the pipe.

b. Pipe union has been used so that pipe maintenance is easier.

c. Bulkhead fitting is shown for LIE/LIR mounting.

d. Attention is drawn to item 12 meant for pipe-to-tube interface, which is used for tube connection just prior to the LIE/LIR so that all tube fittings could be used inside the LIE/LIR including the bulkhead. However, this can also be avoided by having a male bulkhead/female bulkhead connector. In these diagrams a tube bulkhead union has been used.

e. All fittings inside LIE/LIR are stainless steel tube fittings; because of this, SW tube connectors have been used with the same SW valves (which can be used in pipes directly) in all cases to have less inventory.

f. Integral valve manifolds are shown for the transmitter (as transmitter connections are generally universal and a matching manifold is easily available), but it could be separate as shown for switches in Figure XII/3.1-3f. In that case, extra fittings will be necessary for mounting the manifold with instruments.

g. Connector to valve manifold could be a male tube connector also. The fittings for the switch need to

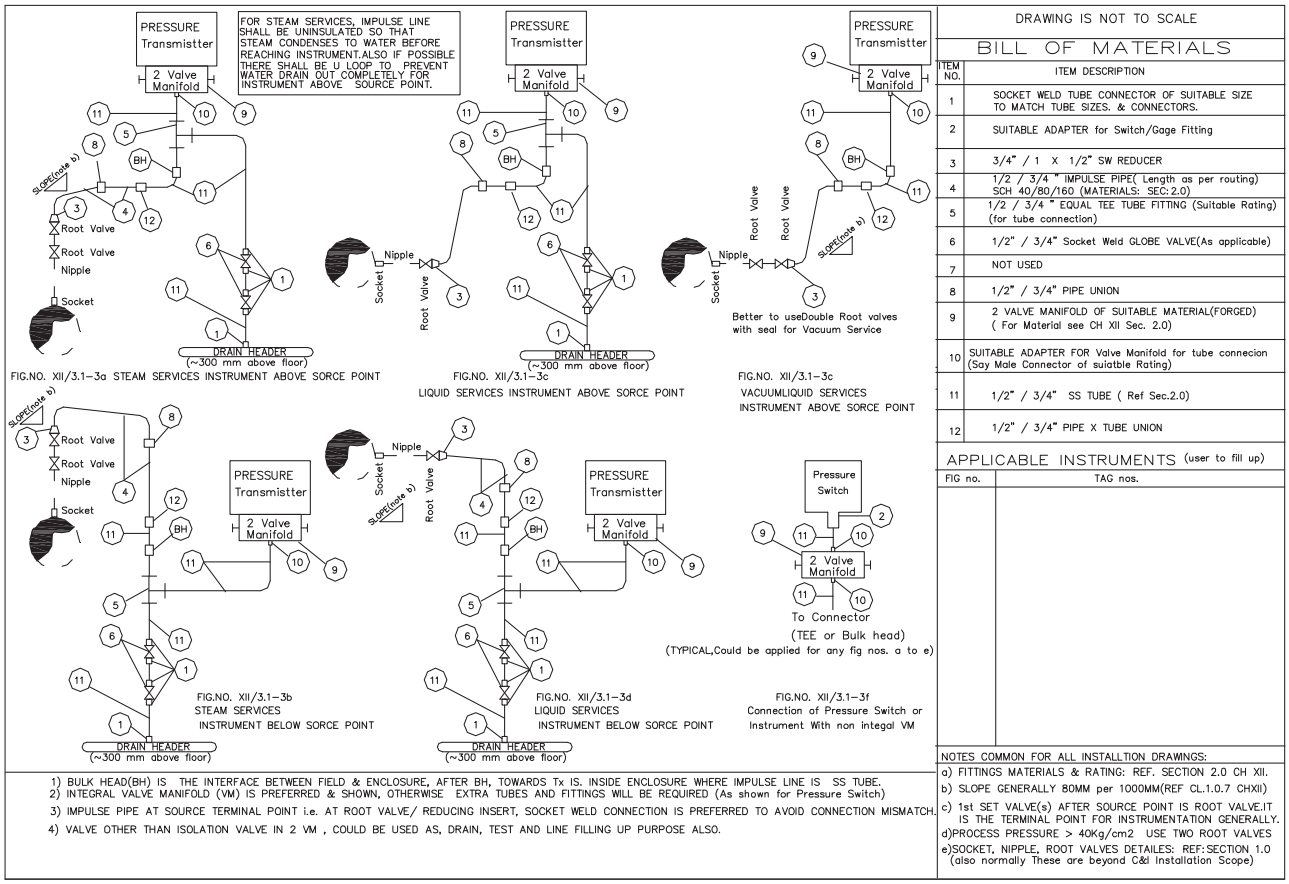


FIGURE XII/3.1-3 Pressure transmitters/switches installation 1 (in enclosure/rack).

www.EngineeringBooksPDF.com

match with the switch connection available (but this could be made to match while specifying the standard switch connection for the plant).

h. Drain header in an LIE/LIR is common, as shown in Figure XII/3.4-1.

i. With transmitters when the distance of the tapping point to the instruments is not very short a pigtail siphon could be avoided. However, if the transmitter is located above or near the source point, as a safety measure prior to transmitter connection, one U loop in the impulse tube could be made.

j. It is preferred that in both steam and liquid service transmitters are kept below the source point as in Figure XII/3.1-3b. (see Clause 1.0, number 9a).

2. *Liquid service*: Instrument above and below the source point (see Figure XII/3.1-3c and d):
   a. This is for liquid service, hence, the tapping is shown from the side of the pipe.
   b. Clause 3.1.3, number1b—h is applicable here as well.
   c. Same as Clause 3.1.3, number 1j.
3. *Vacuum service*: Instrument above the source point (see Figure XII/3.1-3e):
   a. This is for vacuum service, hence, the tapping is shown from the top of the pipe.
   b. As a safety measure against leakage double root valves could be used, as these valves must be highly leak proof (may be high-pressure quality).
   c. Clause 3.1.3, number 1b—h is applicable here as well.
   d. Same for Clause 3.1.3, number 1j.

3.1.4 Pressure Transmitter/Switch (in LIE/LIR) Installation 2

Here basic things are similar to those discussed in Clause 3.1.3. Below discussions on pressure measurement in clear air, flue gas, and dirty air are presented:

1. Pressure measurement in clean air (see Figure XII/3.1-4a)
   a. This is for air service, hence, the tapping is shown from the top of the pipe.
   b. Clause 3.1.3, number 1b—e and g and h is applicable here as well.
   c. Integral valve manifolds are shown for a transmitter (as transmitter connections are generally universal and a matching manifold is easily available), but it could be separate similar to corresponding switches as shown in Figure XII/3.1-4b. If this is the case, then extra fittings are necessary.

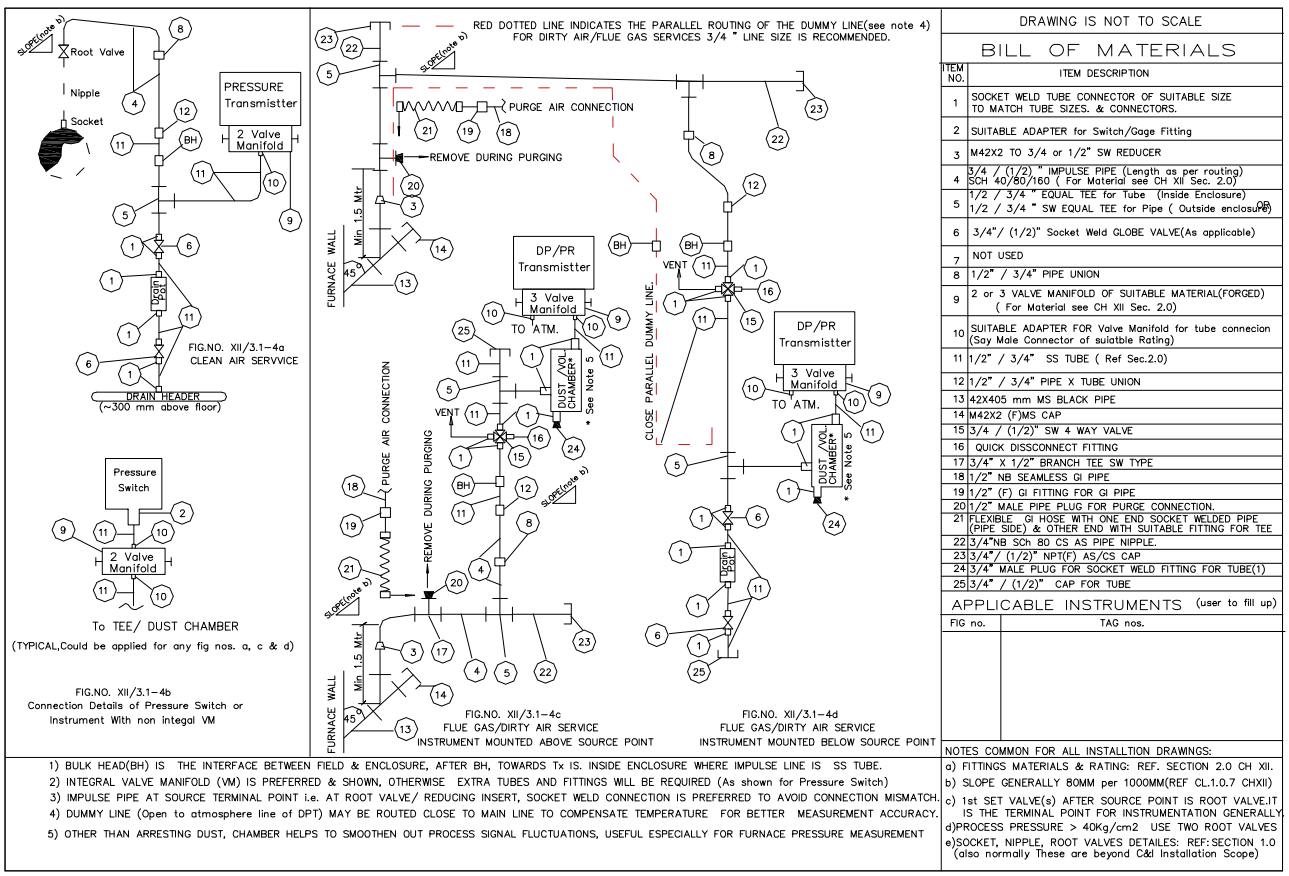


FIGURE XII/3.1-4 Pressure transmitters/switches installation 2 (in enclosure/rack).

www.EngineeringBooksPDF.com

d. Here the line drain is collected through a drain pot with one valve each upstream and downstream the drain pot, so that the water can be trapped at the drain pot for intermittent draining.

2. Pressure measurement in flue gas and dirty air (see Figure XII/3.1-4c and d)

a. This is for gas service, hence, the tapping is shown from the top of the pipe.

b. Clause 3.1.3, number 1b—e and h is applicable here as well.

c. Same as Clause 3.1.4, number 1c.

d. When the instrument is mounted below the tapping point (as in Figure XII/3.1-4d in some extreme case) the line drain is collected through a drain pot with one valve each upstream and downstream the drain pot, so that the dust, etc., collected can be drained intermittently.

e. As discussed earlier, by removing the cap (14) the line can be cleaned by a pocking rod.

f. To purge the line thoroughly the purge air connection, at the field side, quick connect fittings are kept at the first equal TEE division point (normally fitted with a plug). At the time of purging the plug is removed and the air connection is fitted.

g. Instrument tapping is taken after a straight length via another TEE, so that if necessary this length can also be cleaned by a pocking rod. This is kept closed by item 23 (cap).

h. Inside the LIE/LIR provisions have been kept with the help of a four-way valve for air purging.

i. As discussed in Clause 3.1.2, number 2b, a dust chamber is shown (mainly for flue gas measurement) to facilitate dust elimination and reduce measurement fluctuation.

j. Another interesting feature in this installation diagram is the dummy line (shown by a dotted line). In air and flue gas, pressure measurement is done by a differential pressure transmitter (DPT), keeping one port exposed to the atmosphere. If the impulse line is long, then naturally the length of gas column will also be long. Because of fluctuation in atmospheric temperature, the gas column pressure will also vary (even if the actual pressure to be measured does not vary) due to change in density. To compensate for the same, a dummy line connected to the unused port of the transmitter is routed along with the main line so that both limbs have the same length of gas column at the same temperature. Dummy line is shown for Figure XII/3.1-4d, but is applicable for XII/3.1-4c as well.

3.1.5 DPT/Switch (in LIE/LIR) Installation 3

These are mainly used for DP across a strainer/filter and/or DP in flue gas duct, etc.:

1. DP measurement for liquid services (see Figure XII/3.1-5a and b).

a. This is for liquid service for DP measurement, hence, two sets of tappings are seen from the side of the pipe.

b. Clause 3.1.3, number 1 b—e and g and h is applicable here as well.

c. Integral valve manifolds have been shown for a transmitter (as transmitter connections are generally universal and a matching manifold is easily available), but it could be separate similar to corresponding switches as shown in associated figures. Extra fittings may be necessary.

2. DP measurement for heavy oil services (see Figure XII/3.1c)

a. This is for liquid service for DP measurement, hence, two sets of tappings are seen from the side of the pipe.

b. For HFO service for high viscosity the entire line, including the line drain, needs a heat tracing so that flow ability is maintained.

c. Remote diaphragm seal with capillary filled with inert liquid (for example, silicone oil) is used so that FO does not come into physical contact with the pressure gauge and the gauge is always responsive and not clogged because of FO.

d. Both remote seals (may be wafer type) are placed against a flange in each line with the help of blind-matching flanges as shown.

e. Capillary length is long enough to meet the requirement of installation; if there is extra length is must be coiled, but should not kink at any place. Capillary may have necessary protection.

f. It is recommended that remote seals (such as wafer) are suitable for 3” RF flange. Matching flanges must be selected.

g. Even though line drains are seen! precautions need to be taken when draining the line with high-viscous slippery fluid (not to drain on the floor).

3.1.6 DPT/Switch (In LIE/LIR) Installation 4

These are mainly used for DP across the heat exchanger in a flue gas path:

1. DP measurement for flue gas/dirty air service (see Figure XII/3.1-6).

a. This is for gas service for DP measurement, hence, two sets of tappings are seen from the top/upper part of the duct.

www.EngineeringBooksPDF.com

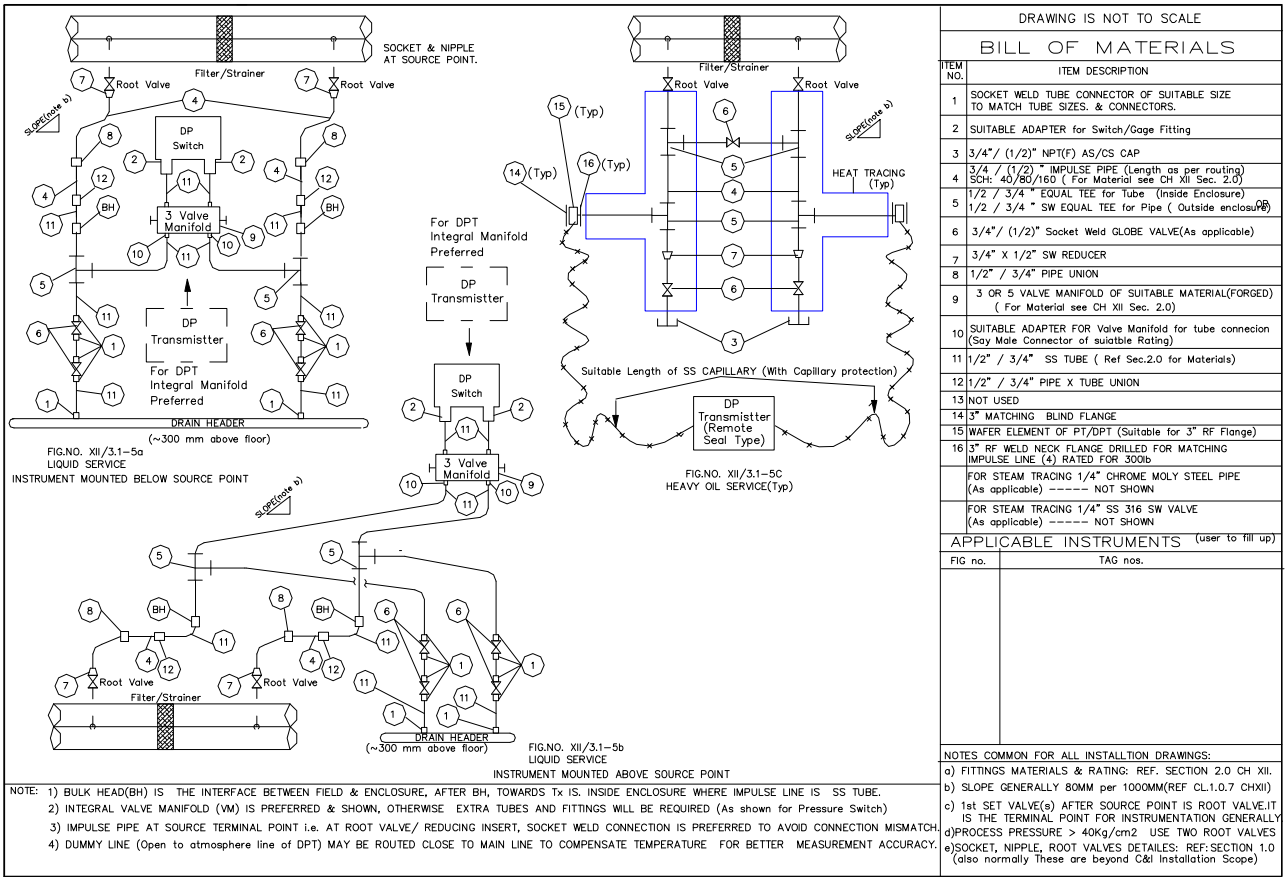


FIGURE XII/3.1-5 DPTs/switches installation 3 (in enclosure/rack).

b. Same as Clause 3.1.5, number 1c.
c. Clause 3.1.3, number 1b–e and g is applicable here as well.
d. Clause 3.1.4, number 2e–h is also applicable here.

3.2 Flow (DP Type) Instrument Installations

Flow measurements considered here under an installation diagram are all based on restriction type, i.e., with DPT. Other online flow measurements, such as magnetic flow meter, mass flow meter, etc., must ensure matching flanges at both ends so that meters can be installed (also see discussion in Clause 3.0, number 2). In the following sections, three types of flow elements are considered:

- Flow nozzle for steam and feed water flow measurement (Figure XII/3.2-1)
- Orifice plate for condensate flow measurement (Figure XII/3.2-2)
- Venturi for air flow measurement (Figure XII/3.2-3)

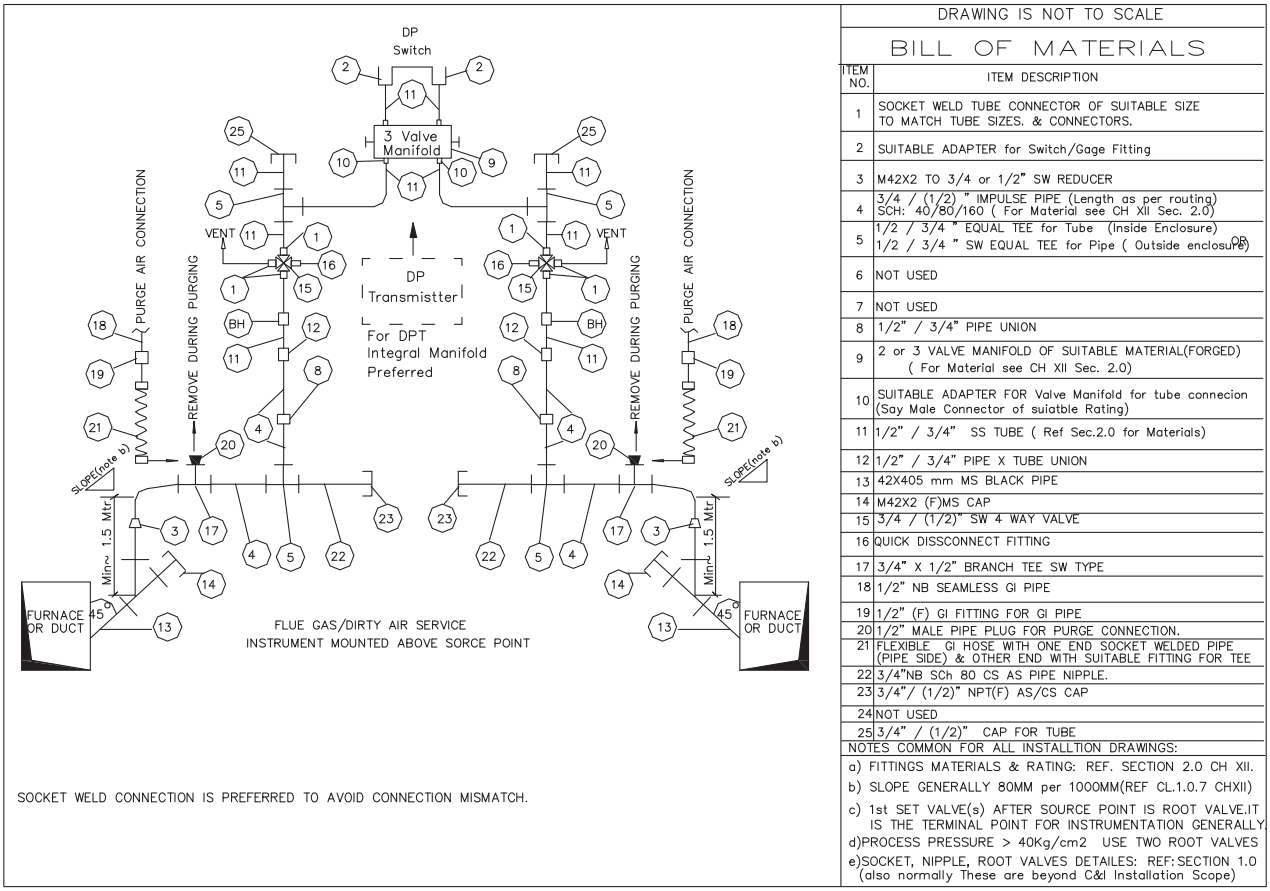
In all of these flow-measuring system installations, instruments above as well as below the source points are shown. Detailing has been done for flow elements in horizontal pipe. Even when the flow elements are not in horizontal pipe, installation details will be similar, so they are not repeated here. When the flow element is in vertical pipe for steam flow, lower tapping is brought up to the upper tapping point and then the two lines are brought close to each other and to the instrument. Similarly for liquid flow service upper tapping is brought up to the lower tapping point and then the two lines are brought close to each other and to the instrument.

3.2.1 Flow Metering Installation for Flow Nozzle

Steam and feed water service (see Figure XII/3.2-1a and b):

1. For steam service the tapping is seen from the top of the pipe, while for liquid services it is seen from the side, as shown separately.
2. Clause 3.1.3, number 1b–h and j is applicable here as well.

www.EngineeringBooksPDF.com



DRAWING IS NOT TO SCALE

BILL OF MATERIALS

ITEM NO.	ITEM DESCRIPTION
1	SOCKET WELD TUBE CONNECTOR OF SUITABLE SIZE TO MATCH TUBE SIZES. & CONNECTORS.
2	SUITABLE ADAPTER for Switch/Gage Fitting
3	M42X2 TO 3/4 or 1/2" SW REDUCER
4	3/4 / (1/2) " IMPULSE PIPE (Length as per routing) SCH: 40/80/160 (For Material see CH XII Sec. 2.0)
5	1/2 / 3/4 " EQUAL TEE for Tube (Inside Enclosure) 1/2 / 3/4 " SW EQUAL TEE for Pipe (Outside enclosure) DP
6	NOT USED
7	NOT USED
8	1/2" / 3/4" PIPE UNION
9	2 or 3 VALVE MANIFOLD OF SUITABLE MATERIAL(FORGED) (For Material see CH XII Sec. 2.0)
10	SUITABLE ADAPTER FOR Valve Manifold for tube connecion (Say Male Connector of suiatble Rating)
11	1/2" / 3/4" SS TUBE (Ref Sec.2.0 for Materials)
12	1/2" / 3/4" PIPE X TUBE UNION
13	42X405 mm MS BLACK PIPE
14	M42X2 (F)MS CAP
15	3/4 / (1/2)" SW 4 WAY VALVE
16	QUICK DISSCONNECT FITTING
17	3/4" X 1/2" BRANCH TEE SW TYPE
18	1/2" NB SEAMLESS GI PIPE
19	1/2" (F) GI FITTING FOR GI PIPE
20	1/2" MALE PIPE PLUG FOR PURGE CONNECTION.
21	FLEXIBLE GI HOSE WITH ONE END SOCKET WELDED PIPE (PIPE SIDE) & OTHER END WITH SUITABLE FITTING FOR TEE
22	3/4"NB SCh 80 CS AS PIPE NIPPLE.
23	3/4"/ (1/2)" NPT(F) AS/CS CAP
24	NOT USED
25	3/4" / (1/2)" CAP FOR TUBE

NOTES COMMON FOR ALL INSTALLTION DRAWINGS:

a) FITTINGS MATERIALS & RATING: REF. SECTION 2.0 CH XII.
b) SLOPE GENERALLY 80MM per 1000MM(REF CL.1.0.7 CHXII)
c) 1st SET VALVE(s) AFTER SOURCE POINT IS ROOT VALVE.IT IS THE TERMINAL POINT FOR INSTRUMENTATION GENERALLY.
d)PROCESS PRESSURE > 40Kg/cm2 USE TWO ROOT VALVES
e)SOCKET, NIPPLE, ROOT VALVES DETAILES: REF: SECTION 1.0 (also normally These are beyond C&I Installation Scope)

FIGURE XII/3.1-6 DPTs/switches installation 4 (in enclosure/rack).

3. Three-port condensate pot for steam application is essential when the instrument is located above the source point and is better to use even when the instrument is located below the source point.
4. In the majority of the cases D and D/2 tappings are used in these applications.
5. Because of high-pressure applications flow nozzles are used wherever flow elements are deployed.

3.2.2 Flow Metering Installation for Orifice Plate

Condensate service (see Figure XII/3.2-2a and b):

1. For condensate service the tapping is shown from the side.
2. Clause 3.1.3, number 1b—h and j is applicable here as well.
3. Weld neck flange orifice plate is shown here.
4. In the majority of the cases, flange tappings are used in these applications.
5. Since this normally is not a high-pressure application, a weld neck orifice would suffice.

3.2.3 Flow Metering Installation for Venturi

Air service (see Figure XII/3.2-3a and b):

1. For air service the tapping is shown from the top.
2. Clause 3.1.3, number 1b—h and j is applicable here as well.
3. Root valves may not be necessary so they are not shown in the drawing.
4. When the instrument is mounted below tapping point (as in Figure XII/3.2-3b), the line drain is collected through a drain pot that has one valve each upstream and downstream the drain pot, so that the dust collected can be drained intermittently.
5. Provisions have been made inside the LIE/LIR for purging of the line with air with the help of a four-way valve.
6. Venturi forms a part of the duct.

3.3 Level Instrument Installations

Various kinds of level instrument installations have been discussed. These instruments include DP instruments with

www.EngineeringBooksPDF.com

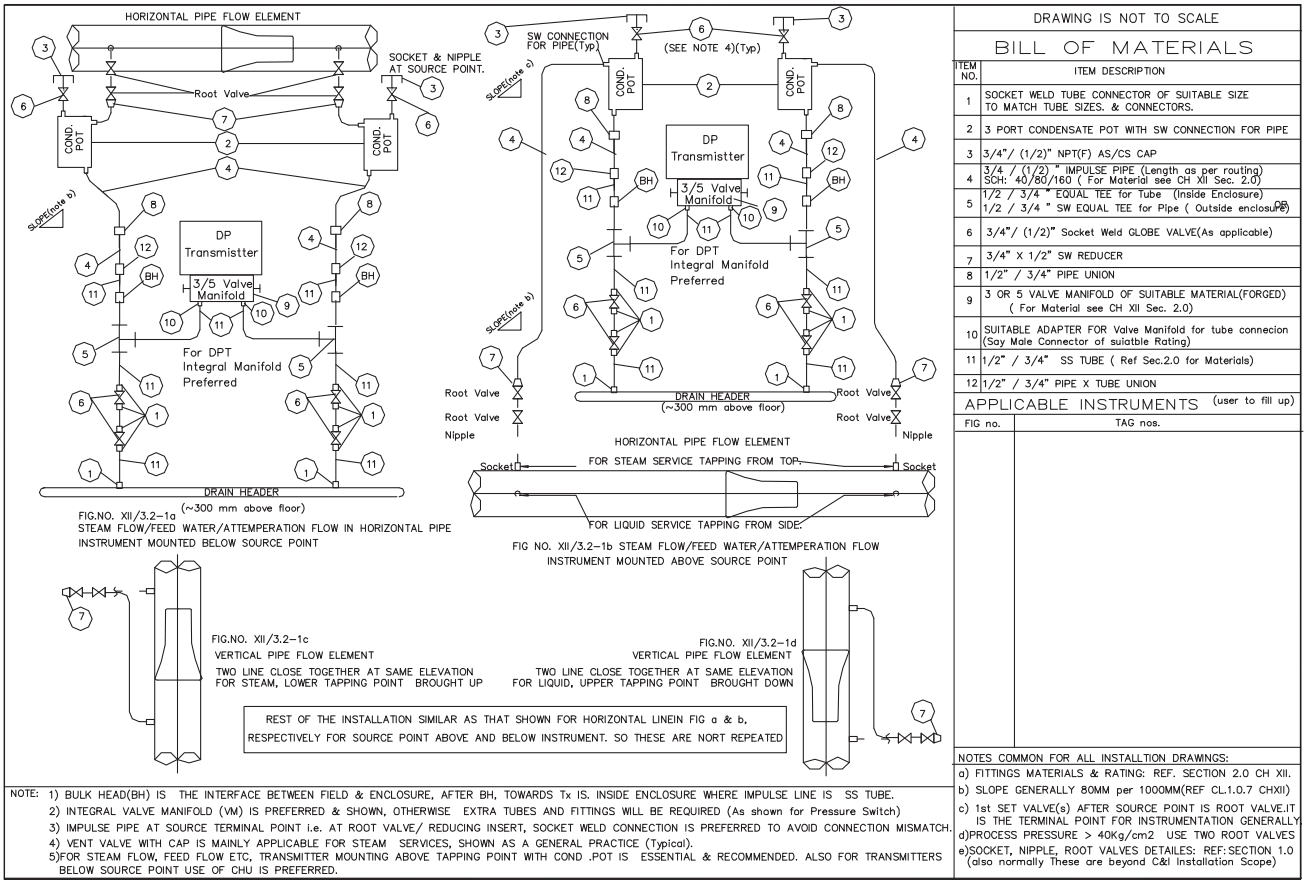


FIGURE XII/3.2-1 Flow transmitters installation1 for flow nozzle (in enclosure/rack).

and/or without suitable seal, local level gauges (gauge glass), and float/displacer types of instruments, etc. The following level instrument installations have been considered:

- Closed/pressurized vessel level measurement with DPT (Figure XII/3.3-1)
- Open/nonpressurized vessel level measurement with displacer/float instruments and level gauges (gauge glass; Figure XII/3.3-2)
- Open/nonpressurized vessel level measurement with DPT with/without instrument seal (Figure XII/3.3-3)

3.3.1 Level Instrument Installation for Closed/Pressurized Vessel

Drum level (for drum type boiler) and deaerator level measurements are examples of level measurements. The vessel is pressurized with steam at the top of the vessel with pressure "P". There are two tappings: one tapping (T_1) at the top, above the maximum possible water level, and another tapping (T_2) from the lower side well below the allowable low level. If these two tappings are connected by an impulse line to the two sides of the DPT, the side connected to T_1 will have pressure $= P$ whereas the other tapping will have pressure $= P + h\rho g$, where $h =$ level in the vessel, $\rho =$ density of the medium, and $g =$ acceleration due to gravity.

Therefore the difference in pressure is proportional to h in case ρg does not vary. Now g at a place is constant and if there is no variation in ρ, then the level can be measured by the DP method. If there is a chance of variation in ρ, as in the drum level, necessary compensations are provided (see Chapter VIII). Another point worth noting is that $T_2 - T_1 = h\rho g$, and so far this is okay. The connection from steam part is not directly fed to the transmitter; instead it is passed through the CHU, so that there is no possibility of steam reaching the transmitter and on one side the CHU is maintained and the other side varies with the level. Normally these transmitters are located below the tapping point. Naturally tapping from top T_1 will have more head than T_2, and as the level rises the difference will be narrower, hence, in a normal case the DPT out will be less. But in reality it is found that the O/P is proportional to the level.

www.EngineeringBooksPDF.com

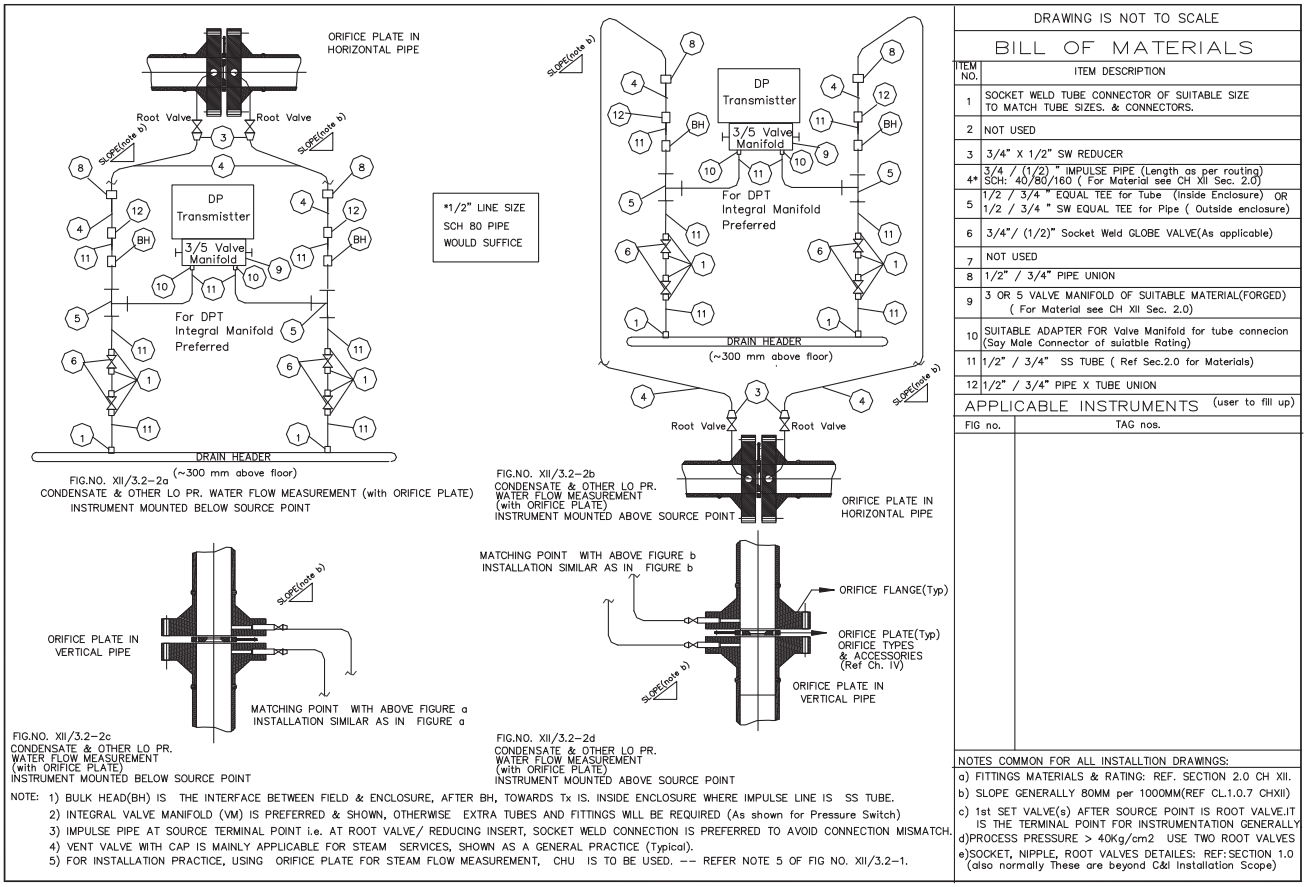


FIGURE XII/3.2-2 Flow transmitters installation 2 for orifice plate (in enclosure/rack).

This is normally done by full span suppression detailed in Chapter IV and/or standard books on instrumentation. As stated earlier, the CHU has to maintain constant head, but if more steam in the space above the point of CHU (where T_1 is connected) condenses then it will try to increase the level. This is not possible because CHU is connected to the vessel and will downward tilt toward the vessel so that spillover liquid goes back to the vessel to maintain constant head.

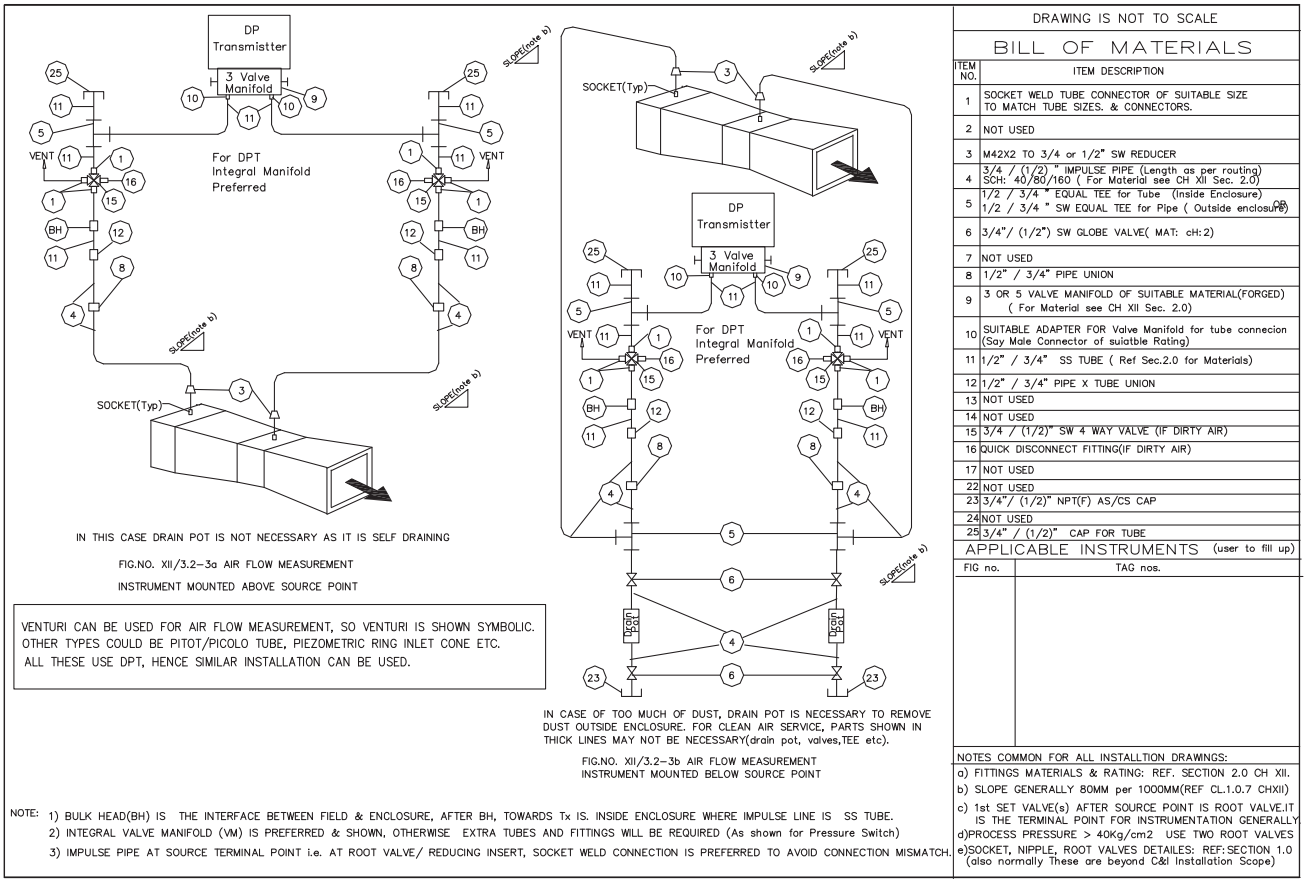
If the two legs of the DPT are not close to each other and are exposed, there could be a difference in density ρ in the two limbs and an inaccuracy in the reading. For drum level measurement instead of condensate pot, a temperature-equalizing column (as shown in Figure XII/3.3-1c) may be used. Here the central limb with a cup at the top acts as the CHU. The top connection is at the steam space. When steam comes inside the temperature-equalizing column, it condenses. If more steam condenses then the cup will spill and would try to increase the level outside. Since this part is connected to the water part of the vessel, it will ultimately go to the main vessel due to the downward slope toward the vessel. Since the water limb in the constant head (i.e., central limb) and the water in the main part are at the same temperature, both limbs are at the same temperature. Most of the large drum type boilers use a temperature-equalizing column.

1. Clause 3.1.3, number 1b—h and j is applicable here as well.
2. Three-port condensate pot is used as the CHU.
3. It is recommended that level instruments are located below the tapping point; however, if the instruments are located above the source point, then the elevation rise in both the limbs should be as shown in Figure XII/3.3-1b to avoid inaccuracy in level reading.

3.3.2 Open/Nonpressurized Vessel Level Measurement with Displacer/Float Instruments and Level Gauges (Gauge Glass)

For instrument details on gauge glass and displacer/float type instruments see Chapter IV. Since the vessel is an open type, single tapping would suffice, but two tappings are taken for mechanical stability of installation. The lower limb connection of the external chamber is always chosen

www.EngineeringBooksPDF.com



DRAWING IS NOT TO SCALE

BILL OF MATERIALS

ITEM NO.	ITEM DESCRIPTION
1	SOCKET WELD TUBE CONNECTOR OF SUITABLE SIZE TO MATCH TUBE SIZES. & CONNECTORS.
2	NOT USED
3	M42X2 TO 3/4 or 1/2" SW REDUCER
4	3/4 / (1/2) " IMPULSE PIPE (Length as per routing) SCH: 40/80/160 (For Material see CH XII Sec. 2.0)
5	1/2 / 3/4 " EQUAL TEE for Tube (Inside Enclosure) OR 1/2 / 3/4 " SW EQUAL TEE for Pipe (Outside enclosure)
6	3/4"/ (1/2") SW GLOBE VALVE(MAT: cH:2)
7	NOT USED
8	1/2" / 3/4" PIPE UNION
9	3 OR 5 VALVE MANIFOLD OF SUITABLE MATERIAL(FORGED) (For Material see CH XII Sec. 2.0)
10	SUITABLE ADAPTER FOR Valve Manifold for tube connecion (Say Male Connector of suiatble Rating)
11	1/2" / 3/4" SS TUBE (Ref Sec.2.0 for Materials)
12	1/2" / 3/4" PIPE X TUBE UNION
13	NOT USED
14	NOT USED
15	3/4 / (1/2)" SW 4 WAY VALVE (IF DIRTY AIR)
16	QUICK DISCONNECT FITTING(IF DIRTY AIR)
17	NOT USED
22	NOT USED
23	3/4"/ (1/2)" NPT(F) AS/CS CAP
24	NOT USED
25	3/4" / (1/2)" CAP FOR TUBE

APPLICABLE INSTRUMENTS (user to fill up)

FIG no.	TAG nos.

NOTES COMMON FOR ALL INSTALLTION DRAWINGS:
a) FITTINGS MATERIALS & RATING: REF. SECTION 2.0 CH XII.
b) SLOPE GENERALLY 80MM per 1000MM(REF CL.1.0.7 CHXII)
c) 1st SET VALVE(s) AFTER SOURCE POINT IS ROOT VALVE.IT IS THE TERMINAL POINT FOR INSTRUMENTATION GENERALLY.
d)PROCESS PRESSURE > 40Kg/cm2 USE TWO ROOT VALVES
e)SOCKET, NIPPLE, ROOT VALVES DETAILES: REF: SECTION 1.0 (also normally These are beyond C&I Installation Scope)

FIGURE XII/3.2-3 Flow transmitters (inside enclosure) installation 3 for air (Venturi).

at a point lower than the required set point to ensure the level in the external chamber is the same in the vessel. Center-to-center distance of tappings is chosen in such a way that the level set point falls within the same time the instrument installation is stable. However, center to center tapping distance is of great importance for side-mounted level switches (*2b— see later).

A few common points worth noting are as follows:

- External chambers for level switches/transmitters allow easier maintenance of the instruments, and an isolation valve allows the entire system to be isolated from the process.
- Normally the vent and drain connections shown help entrapped bubbles to escape as well as drain the line whenever required, especially when the instrument has not been in use for a long time. For level transmitters the connections are flanged as shown in Figure XII/3.3-2c.
- Figure XII/3.3-2 is self-explanatory, so only a few pertinent points are presented below:

1. See Figure XII/3.3-2a for a top-mounted level switch:
   - **a.** External chamber level and that in the vessel are the same within the range.
   - **b.** Single or multiple floats can be inserted to get switching actions at varied levels. However, all such set points should be within the length of the external chamber, i.e., the length of the external chamber should cover the entire range of set points.
   - **c.** In place of a float type instrument, displacer type instruments can also be used for the switching actions.
2. See Figure XII/3.3-2b for a side-mounted level switch:
   - **a.** Basic installation is similar as above, only these types of installations are applicable for single set point float type instruments.
   - **b.** *In these installations the tapping points are chosen so that the set point lies at the middle of the center to center distance of the tappings.
3. See Figure XII/3.3-2c for a top-mounted level transmitter:
   - **a.** Tappings for the external chambers are chosen to cover the entire range of levels for the vessel.
   - **b.** For the transmitter, only one external chamber has a single displacer instrument mounted from the top.

www.EngineeringBooksPDF.com

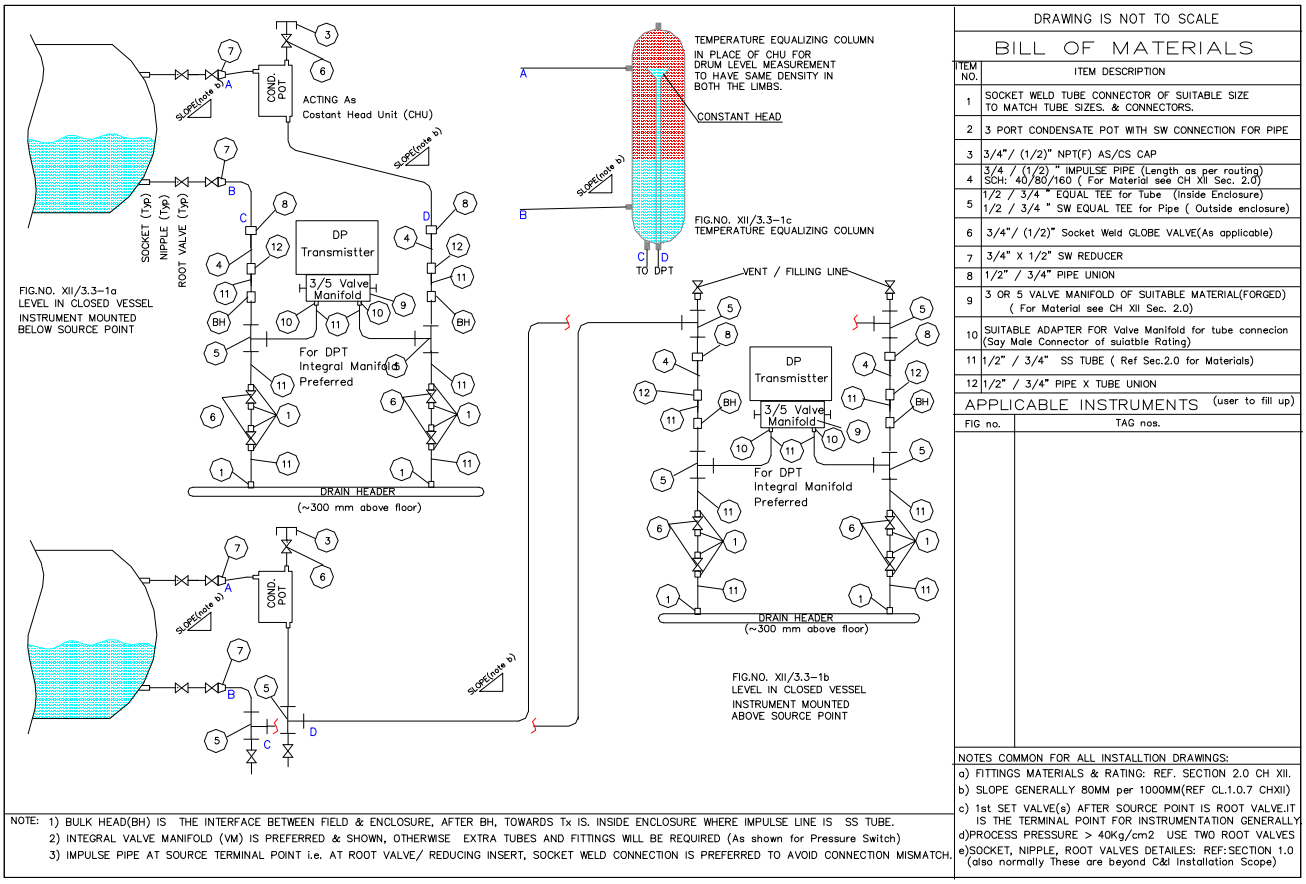


FIGURE XII/3.3-1 Level 1 installation 1—measurement in closed chamber (noncorrosive/nonviscous).

4. See Figure XII/3.3-2d and e for a level gauge glass:
   - **a.** Normally gauge glasses are supplied with the gauge valve check valve as shown in Figure XII/3.2-2d and e.
   - **b.** In many cases these gauge glasses are supplied and erected as a part of the vessel.
   - **c.** Vent and drain valves are provided to allow vent and drain for the gauge.
   - **d.** The drawing shows single gauge glass for the vessel and the range must cover the highest and lowest level for the vessel.
5. See Figure XII/3.3-2f for multiple level gauge glasses:
   - **a.** When the height of the vessel is too long (vertical feed water heaters) multiple gauge glasses are used with suitable overlap.
   - **b.** Clause 3.3.2, number 4 a–c.

3.3.3 Open/Nonpressurized Vessel Level Measurement with DPT with/without Instrument Seal

Since this is a nonpressurized tank (it also may have a roof) the level can be easily measured by a pressure transmitter (or by a DPT with one leg open to atmosphere) depending on the desired span of measurement. In a noncorrosive, nonviscous liquid ordinary pressure/DPT can be used and in a corrosive (for example, strong acid cat ion tank for a demineralization plant, although in such cases level measurements by other types of instruments such as capacitance are used more often) or viscous fluid such as HFO, etc., pressure/DPTs are used with suitable seals.

1. *Transmitters without seal*: As discussed earlier the transmitter could be a normal pressure or DPT and installation details are the same as discussed in Clause 3.1.5, number 1 and as shown in Figure XII/3.3-3a and b (if a DPT is used, one end must be kept open to the atmosphere).
2. *Transmitter with seal*: In these types of measurements the tanks are provided with suitable nozzles fitted with necessary root valve of sizes from 3/4 to 1". To have better response and accuracy, transmitter seals with minimum 3" diameters are chosen, so after the root valve, a suitable expander complete with a 3" or 4" flange (RF type preferable) with the required rating (300 lb) is used.
   - **a.** For a remote wafer seal the wafer is placed between the expander flange and another matching blind flange with the required pressure rating. Pressure sensed by the remote seal is sent to the transmitter via capillary filled with inert fluid. Capillary length is decided based on the requirement. All capillaries

www.EngineeringBooksPDF.com

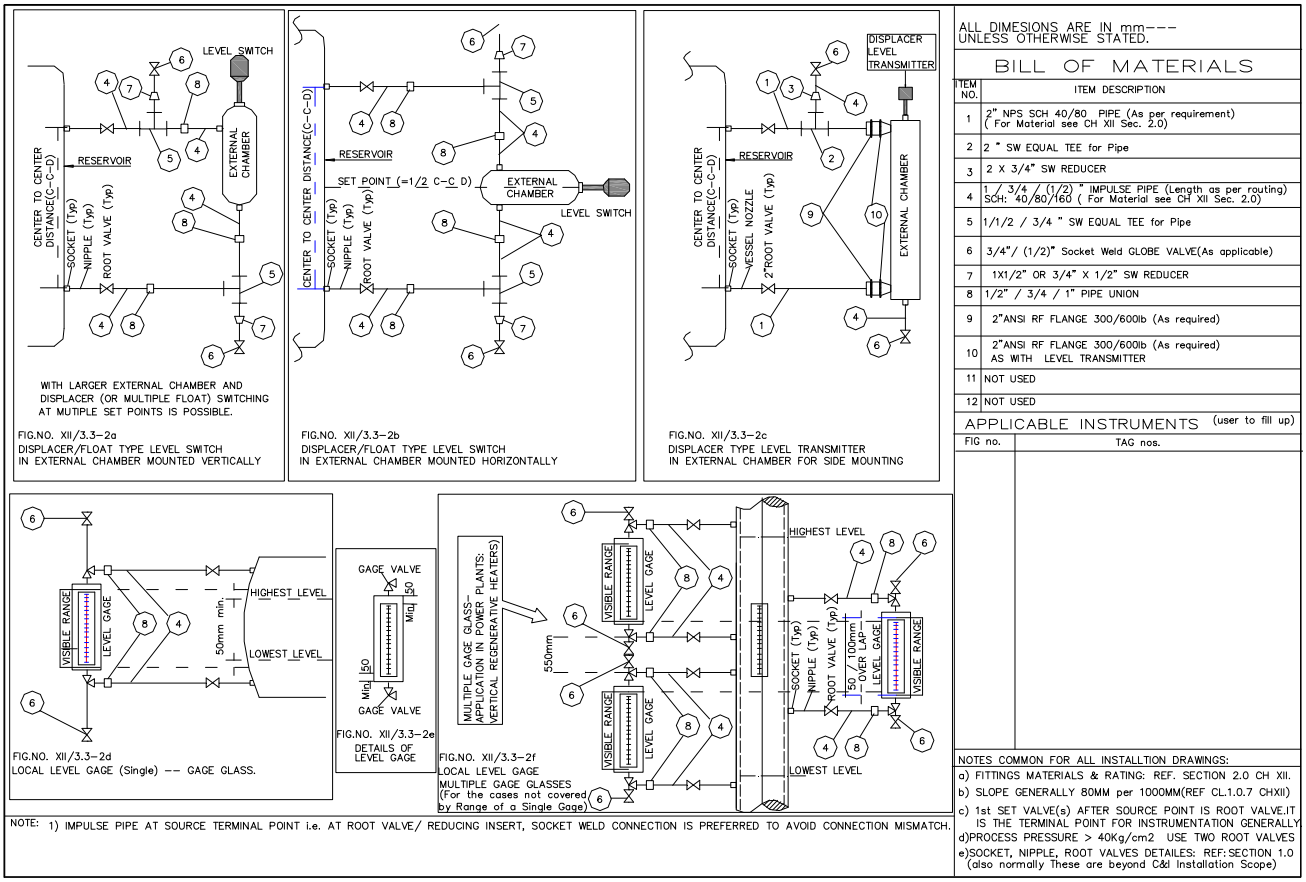


FIGURE XII/3.3-2 Level instrument installation 2 (level gauge/switches/displacer transmitter).

must have suitable mechanical protection. A transmitter may be located at a remote location as shown in Figure XII/3.3-3c.

b. Other types of seals could be a flush type or extended type seal, and in both cases instruments come with seals and flanges that directly fit into the flange of the expander as shown in Figure XII/3.3-3e and f (for flush type or extended type seal, respectively).

3.4 Transmitter Mounting and Transmitter Enclosure

There are a number of ways the transmitter can be mounted. Sometimes these are mounted on a stanchion or a local pipe stand. In power stations normally the transmitters are grouped and put in a local open transmitter rack or enclosure depending on whether the area is a closed space or an open area. Transmitters in a turbine hall may be placed in an open rack, as the rack is inside the turbine building (not open space), whereas transmitters in boiler platforms or boiler areas are basically in an open space so these should be placed in an enclosure. However, open racks with canopies are also seen in many boiler installations. It is recommended to have the transmitter enclosure in an open space for safety reasons. In the subsequent Clauses, a brief discussion regarding transmitter mounting and transmitter enclosures is presented. The discussions presented are recommendations only. From a techno-economic point of view, there could be other solutions as well.

3.4.1 Transmitter Mounting

Almost all transmitters come with a mounting bracket. In the present discussions a mounting bracket for 2" pipe is considered and shown in Figure XII/3.4-1a and b. The transmitters are fixed with the mounting bracket, which in turn is clamped with 2" pipe. These transmitters can be fixed on horizontal as well as vertical pipes, depending on the convenience of installation. When a single transmitter is mounted on a pipe, it may be convenient and easy to mount on a vertical pipe, whereas it may be convenient to mount the same in a horizontal pipe if there is a transmitter enclosure and/or transmitter rack. Based on the density of

www.EngineeringBooksPDF.com

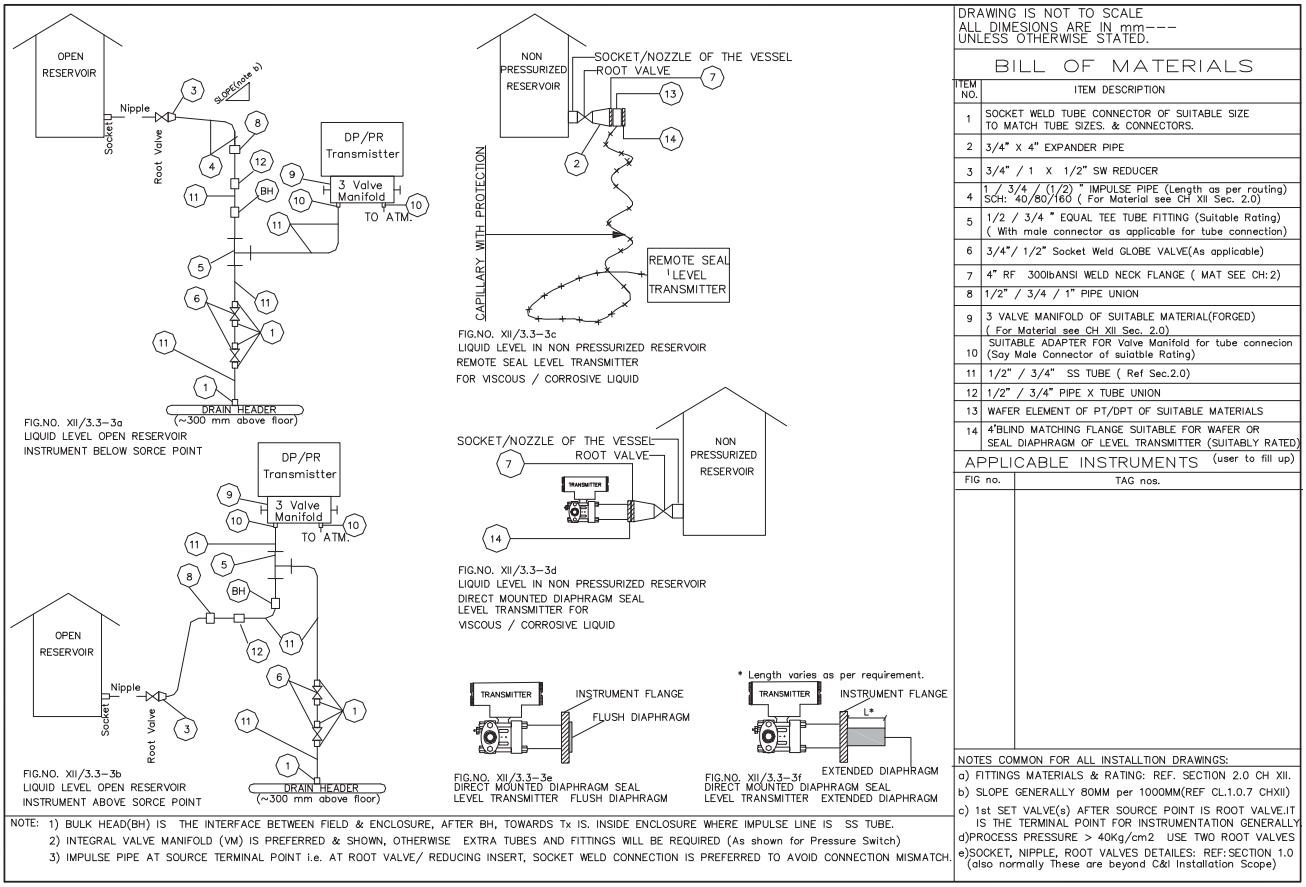


FIGURE XII/3.3-3 Level instrument installation 3 (open tank and transmitter with seal).

transmitters in one row of a transmitter enclosure and design of the same process, entry could be from the side and from the front as well. For many transmitters mounting in any plane is not permissible by manufacturer (even though most of the current smart transmitters do not have this problem). Figure XII/3.4-1a and b shows these two types of pipe entries (and mounting on horizontal and vertical pipes). It is preferred to have the transmitter mounted in such a way that the local display/indicator of the transmitter is faced toward the front, so that reading of the transmitter can be done standing in front of the transmitter rack/enclosure.

3.4.2 Transmitter Enclosure/Rack

As stated earlier the rack could be an open and/or closed type depending on the owner's design. Discussions here have been restricted to the structural part of the system. These open and closed type enclosures are often referred to as LIR and LIE respectively. In both cases a suitable junction box for cable grouping is placed where Fieldbus or protocols are not used so that a number of transmitters can be connected by a set of two wires. However, if the transmitters are connected by a Fieldbus, the number of cables would be less and a small terminal box may suffice.

1. Normally these are all free standing constructed with a minimum 3" angle or channel frame. If there is an open type rack, a canopy is necessary to protect the instruments from water/rain as well as from any falling objects in the plant. Normally the canopies are extended both on the front and back side. These are made with a 2.5−3.5 mm thick sheet.
2. For an open type rack there are at least four vertical members that may be welded on a 3 mm or 6 mm thick horizontal plate at the four ends with reinforcing steel members as typically shown in detail in Figure XII/3.4-1 as detail A for grouting.
3. A closed type transmitter enclosure, like any standard panel, should be mounted with the help of a 75 mm or 100 mm channel by grouting (similar to what is shown in Figure XII/3.4-1 as detail A) or the channel may be welded to the metallic insert at the place. The enclosure is placed on the channel discussed above. In case of transmitter enclosure properly designed antivibration mounting or pads also may be used.

www.EngineeringBooksPDF.com

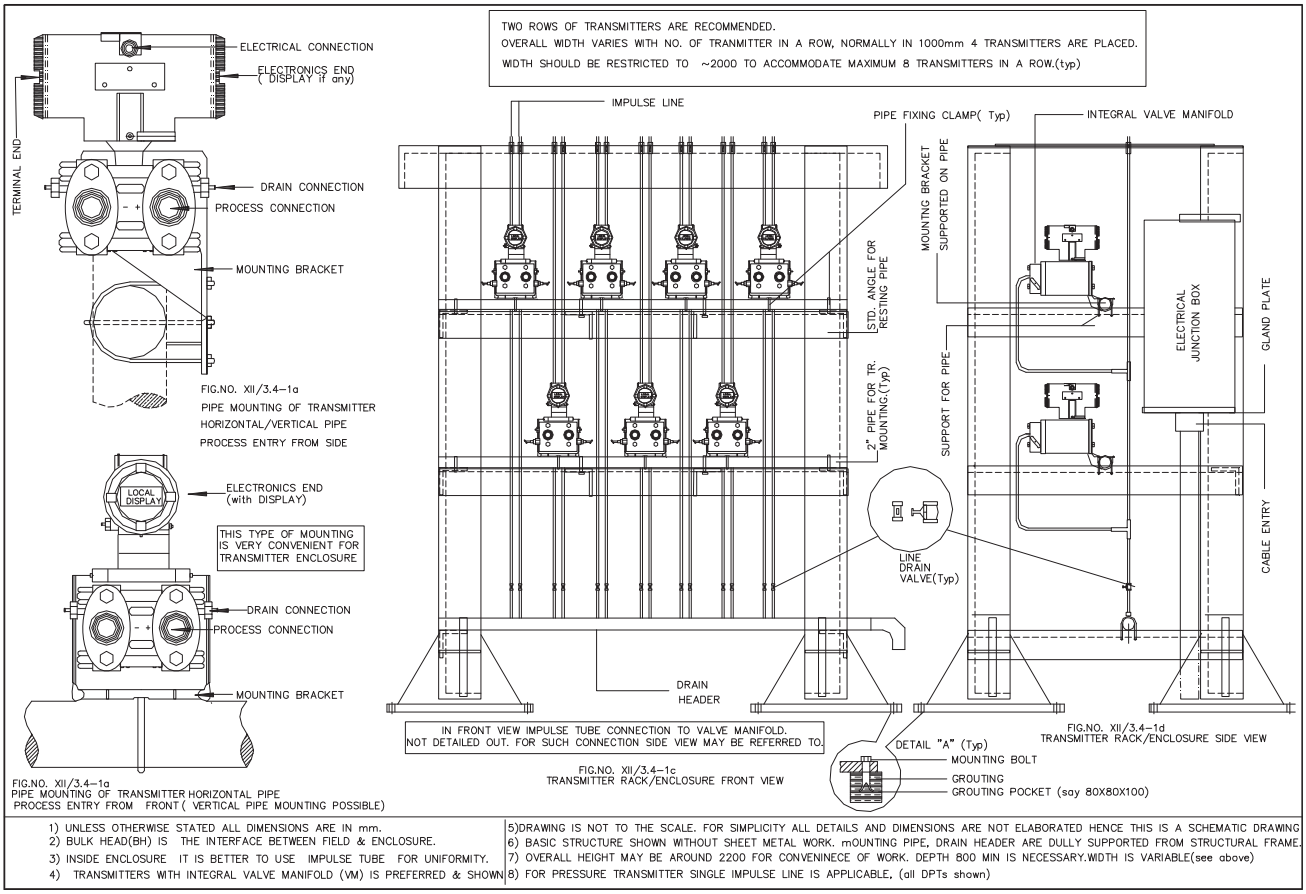


FIGURE XII/3.4-1 Transmitter mounting and transmitter enclosure schematic.

4. Closed type transmitter enclosures have sheet metal work with a cold rolled cold annealed (CRCA) sheet thickness of 1.6−2.0 mm. There may be a door at the front to see the meter reading. Also, there will be a door at the back side for maintenance purposes as well as for accessing the junction box.
5. Layout inside the LIR/LIE is done (as shown in Figure XII/3.4-1c and d) in such a way that blow down lines and impulse lines are easily accessible from the front. An integral valve manifold may add more space inside the LIR/LIE.
6. There should be a common drain line to which all line drains from the transmitters are connected. In many installations it is necessary to have provisions for purge air.
7. Transmitters are mounted on 2" pipe, which in turn is supported on an angle/channel with the help of suitable clamps as detailed in Figure XII/3.4-1d.
8. A suitable junction box of required terminals is generally mounted at the back side of the LIR/LIE. Normally these junction boxes have an IP 55 protection rating. Cable from the junction box may be taken out with the help of suitable pipe through the cable gland at the gland plate at the bottom of the junction box as detailed in Figure XII/3.4-1d, in case the LIE cable gland is at the bottom of the LIE. As discussed earlier, the cable requirements will be less in transmitters used in smart mode, i.e., a number of transmitters connected via a single cable. In the junction box there also may be provision for power connections.

4. ELECRICAL INSTALLATION OF INSTRUMENTS

4.0 General

Proper functioning of the distributed control system (DCS) and instrumentation depends on a number of factors such as a seamless system integration, selection of proper control strategy, and reliability of system components as well as proper installation of the electrical system, including proper cable connections, grounding, etc. Electrical installation of DCS and instrumentation mainly consists of the following issues in this clause:

www.EngineeringBooksPDF.com

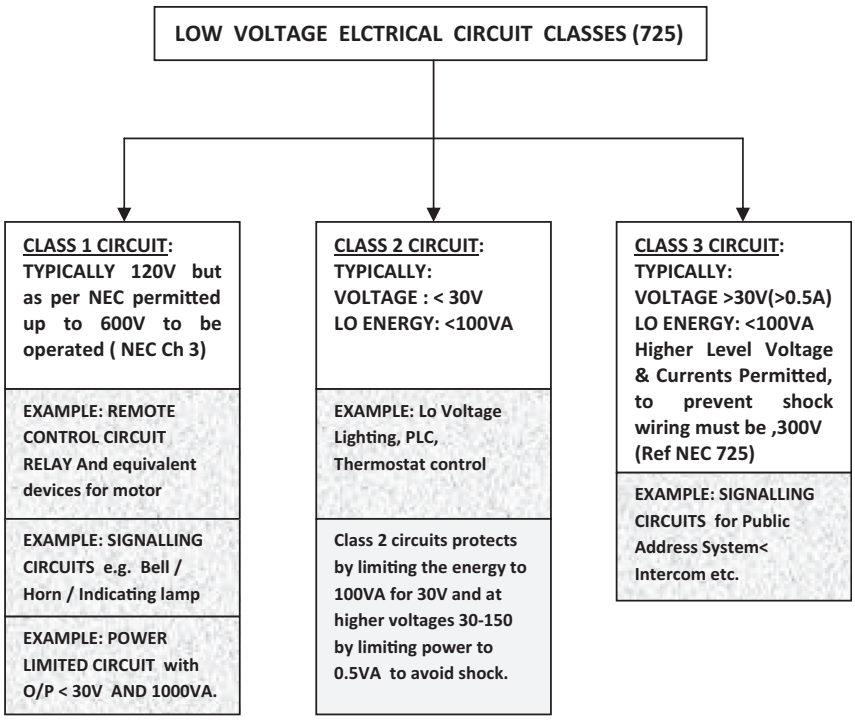


FIGURE XII/4.0.1-1 Electrical circuit classification in line with NEC (LV).

- Electrical grounding
- Cable tray and conduits
- Marshaling rack
- Cabling
- Junction boxes
- Selection of cable and specs

In power plants equipment has different voltage levels. During electrical installation suitable care must be taken so that there is no interference. There is high voltage (HV) used at the switch yard and switchgears (for larges motors) at 11 kV, 6 kV, or 3.3 k0V; medium voltage (MV) like 415 V is used for the motor control center; and a there is low voltage (LV) measured at 240 V, 110/120 V, and 24VDC. Even though control and instrumentation as well as SCADA are involved in monitoring and control of HV and MV systems, instrumentation cables are generally installed separately from other cables. Instrumentation and control is more concerned with 24VDC, but there may be power supply systems from other LV systems that are 240VAC or 120VAC. Best practices are essential for instrumentation and control cabling to maintain the health and complete integrity of the system as per standards such as NEC/NFPA 70 and IEEE 518,422. Before reaching these standards, it is important to understand the classification of circuits as per 725 of NEC, which encompasses remote-control, signal, and power-limiting devices.

4.0.1 Circuit Classifications

Short discussions have been presented on Article 725 of NEC: Class 1, Class 2, and Class 3 Remote-Control, Signaling, and Power-Limited Circuits. Because of a limited load and power source there are some changes from the general rule. Class 1, Class 2, and Class 3 remote-control, signaling, and power-limited circuits are dealt with in Article 725. Remote-control, signaling, and power-limited circuits are quite different from power and lighting, and as per NEC their intermixing is restricted. Circuits can be classified as shown in Figure XII/4.0.1-1, which is self-explanatory. Because of a low energy level, Class 2 circuits are protected from fire initiation as well as from shock. Class 3 circuits are also protected against fire initiation, but because of higher voltage they are not fully protected from shock. NEC defines these circuits based on their power supplies, which limit the total energy to a defined maximum value not to exceed even short circuits that occur on the load side of the power supply. Out of the three classes, Class 1 is associated with instrumentation mainly for specified functions, and it has a stricter limitation on power by the NEC. If the power limitation is exceeded, then stricter standards are applicable. Some of these limitations on Class 1 circuits include**:**

- Class 1 power-limited circuits can be AC/DC, but must be supplied from a source that limits the power to 1000 VA at 30 V, as discussed previously.

www.EngineeringBooksPDF.com

- Remote-control or signaling circuit voltage <600 V—no limit on power supply.
- Two or more Class 1 circuits can be in the same cable and enclosure raceway, but only when equipment power is functionally associated with a Class1 circuit.
- Conductor must have insulation >600 V.
- Conductor size is more than AWG 18.

Class 2 and 3 conditions: NEC does not require Class 2 and 3 circuits in a raceway, but if they are use, then installation guidelines recommend that they

- Are limited to 30 m (100 ft).
- Should have no more two 90° bend
- Have pull force maximum for Cat 5 and optical fiber as 25 and 100 lb, respectively.

Power supplies for Class 2 and 3 are from listed transformer/power supplies for respective classes, a dry cell of <30 V (for Class 2), and listed IT equipment.

As per NEC for Class 2 and 3, the following points are noted for cables and wiring:

- Equipment must be marked to indicate Class 2 and/or 3.
- Conductor and supply side of the Class 2 and 3 power source must comply with the power supply requirements.
- When it is necessary to install Class 2 and 3 circuits inside a raceway or cable with power or Class 1 circuit then it may be necessary to reclassify the circuits as Class 2 and 3 and go for a Class 1 circuit to use conductors with insulation grade 600 V (minimum).
- For a Class 3 use a conductor with insulation of 300 V, it may be less for a Class 2.
- Conductors of AWG 18, 20, and 22 are quite common for Class 2 and Class 3 circuits.
- It is possible to run Class 2 and 3 circuits in a raceway separate from Class 1.
- Class 2 and 3 with power conductors in boxes or enclosure if and only if the power conductor is introduced solely to connect to the equipment connected to Class 2 and 3 circuits.
- It is possible to mix conductors of Class 2 (or Class 3) with other conductors of Class 2 (or Class 3).
- Separation from power and lighting circuits is necessary for Class 2 and 3 circuits. Class 2 and 3 circuits are not permitted in the same enclosure/raceway with power and light circuits or Class 1 nonpower limited circuits. Exceptions include: separated by barriers, installed in a separate raceway, or other separation is provided (at least 50 mm separation).

Circuit classification for instrumentation applications: common circuits used in instrumentations are listed below with probable circuit classification in line with NEC and associated factors:

- 4-20mADC signal derived from ~24VDC power supplies, typically has a fuse rating of 0.1−0.25 A. Depending on listed power supplies and circuit card (without listed power supplies these may be Class 1), these may be classified as Class 2 or Class 3 circuits.
- 0−10 V or 0−1 V normally falls under Class 2 and the provided listed power source is used, otherwise these may be Class 1.
- Discrete signal 24VDC with fuse rated <0.25 A is the same as that discussed previously.
- Thermocouples, bimetallic junctions, etc., are rated as Class 2.
- Digital signals under 25 V, RS 422, RS 232, etc., derived mainly from IT equipment are generally Class 2 unless some equipment is not listed.
- 120VAC and 24VDC used for operated relays, solenoid valve, etc., could be Class 2 or Class 3 provided they have listed power supplies, otherwise a Class 1 circuit is applicable. Generally, 120VAC falls within Class1. A 120VAC discrete signal derived from a branch circuit with fuse <1 A falls within Class 1.

240VAC remote control and signaling circuits can also be classified as per explained above.

4.0.2 Signal Noise and Interferences

Compared with older instrumentation systems, modern instrumentation systems based on digital signals are very sensitive to any noise and signal distortion due to noise − for high frequency (hf) switching. Therefore it is necessary to use modern wiring techniques and better quality cables to achieve a better solution. Noise-coupling methods (based on the IEEE Guide for Instrumentation and Control Equipment Grounding in Generating Stations Standard 1050) are included in the following:

- Conductive (common impedance)
- Capacitive (electric field)
- Inductive (magnetic field)
- Radiative (electromagnetic)

1. *Conductive (common impedance) coupling*: When a common junction/wiring is shared by two circuits, such as a common return path, then noise or interference occurs. This could be intentional for grounding or could be from undesired leakage between the two circuits. The resulting ground potential can couple in to the signal path as shown in Figure XII/4.0.2-1a. Current in one circuit may appear as noise in the other circuit, and this noise voltage depends on the value of the common impedance. These may manifest in the plant from different ground potentials at various locations in the plant. Many times it may be futile to short out this potential. These may occur even if the receiving instrument has high common mode rejection (CMR) and when the shield is not correctly terminated or terminated at two points giving rise to a ground loop. In the grounded type of thermocouple this is quite prevalent.

www.EngineeringBooksPDF.com

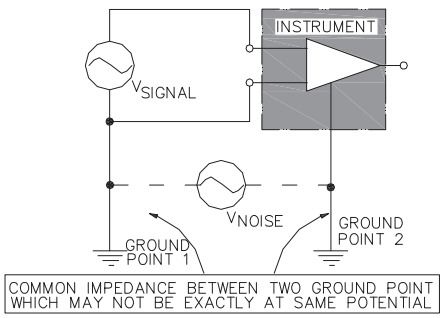


FIG.NO. XII/4.0.2–1a COMMON IMPEDANCE INTERFERENCE

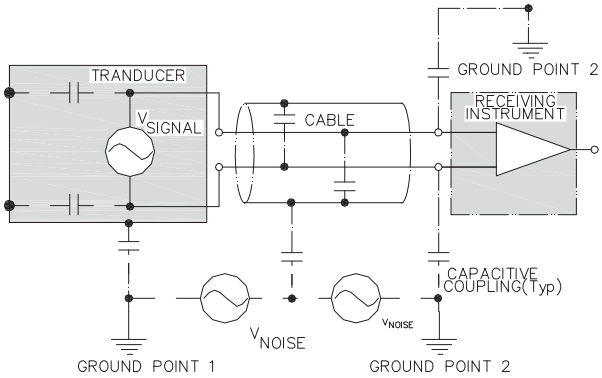


FIG.NO. XII/4.0.2–1b CAPACITANCE COUPLING FOR INTERFERENCE

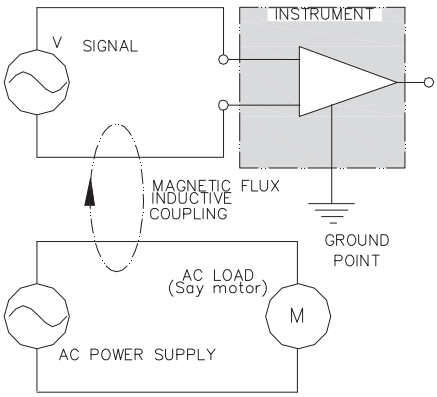


FIG.NO. XII/4.0.2–1c INDUCTIVE COUPLING INTERFERENCE

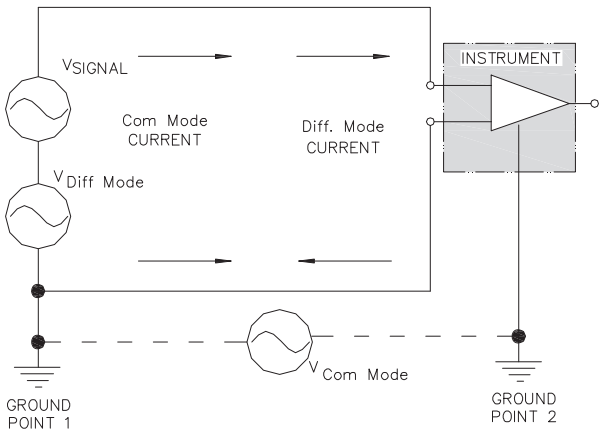


FIG.NO. XII/4.0.2–1d COMMON & DIFFERENTIAL MODE INTERFERENCE

ILLUSTRATIONS GIVEN ABOVE ARE IN LINE WITH IEEE Std 1050– 1989

FIGURE XII/4.0.2-1 Various noise interferences.

2. *Capacitive coupling*: In all portions, such as between the insulated conductors, there is capacitance. Any voltage change regardless of location will try to push a current through the various possible capacitances for coupling in the circuits, as shown in Figure XII/4.0.2-1b ($I = C\,dV/dT$). The length of two parallel wirings will increase the noise due to capacitance coupling (especially during hf switching). High-impedance circuits are more susceptible to it.
3. *Inductive coupling*: There could be many closed loops with mutual inductance, which is proportional to an area enclosed by the closed loop, as shown in Figure XII/4.0.2-1c. There is a transformer effect, which is equally applicable for a DC circuit whenever their current is interrupted or it changes periodically ($E = M\,dI/dT$). This coupling increases the function of the length of the coupled conductors and decreases function to the distance between them. (Noise source: dI/dT noise medium: mutual inductance coupled noise: voltage.)
4. *Radiative (electromagnetic) coupling*: The circuit/loop route within the electromagnetic radiation profile of interfering source. Normally the voltage from these field couples is common mode voltage. This coupling is proportional to the loop area and frequency. Even though these frequencies may be much higher than the control circuits, they still cause harmonic interferences.
5. *Interference modes*: Common, differential, and cross are a few modes of signal interferences. The first two modes are inter-related and their characteristics have been detailed in Table XII/4.0.2-1 and Figure XII/4.0.2-1d:
   - *Cross-talk*: This is another means of interference. When AC signals or pulsating DC signals are transmitted over multipaired cable then there is a tendency for the signals to be superimposed on the signals carried by the other pair of cables. This occurs because of the effects of both inductive and capacitive coupling and is proportional

www.EngineeringBooksPDF.com

TABLE XII/4.0.2-1 Interference Modes

Characters	Common mode	Differential mode
Introduction	Introduced into the signal channel from outside with at least one terminal that is not a legitimate part of the circuit. Chassis is always a terminal unless isolated.	Introduced in to the channel through the same path as the legitimate circuit. Other than the main signal path, no current path exists.
Cause	Caused due to potential difference between ground points and/or electromagnetic pick up or other electrical coupling.	May be due to conversion of common mode current to differential mode noise.
Effects	It indirectly acts on receiver and signal error, which be considered as common mode interference to differential mode noise. In a two-wire system, each wire usually has the same magnitude but opposite in phase.	Normally has frequency characteristic different from the desired signal. In a two-wire system, each wire usually has the same magnitude but opposite in phase.

See Figure XII/4.0.2-1d.

to the frequency of signals. The impedance change will cause proportional effects on capacitive coupling and is inversely proportional to inductive coupling. To minimize the cross-talk effect the predominant coupling has to be assessed and to changed accordingly. The use of a suitable RC filter, Zenner's filter, or varistors can be used to minimize interference.

6. *Cable considerations*: In the following list, the type of cables and their dressings and terminations are explained. Some tips for various signal types are detailed in Table XII/4.0.2-2.
7. *Considerations to effectively eliminate electrical noise*: In line with standard IEEE 518, the following methods may be adopted to effectively eliminate electrical noise:
   - To maintain physical separation between electrical noise source and sensitive equipment and between electrical noise-bearing wires and sensitive signal wire
   - Proper shielding practice
   - Proper grounding practice
   - Use of appropriate filter
   - Twisted pair wiring should be used in critical signal circuits and in noise-producing circuits to minimize magnetic interference
8. *Shielding*: Generalized term used as a barrier between an emitter and a susceptor. Shield effectiveness (SE) is measured in decibels (dB) and 20−80 dB is normal effective shielding. Only short discussions are presented here, and for more details refer to the latest edition of IEEE 1050. Most of the electronic devices are housed in steel cabinets, which provide some degree of shield, but their SE depends on a number of factors such as seam, cable penetration, apertures, etc., as any opening in the enclosure provides highly effective coupling. Similarly when electronic systems are packaged in nonconductive material (such as ABS), their cases should be treated with conductive materials to provide shielding. Cable shield, as previously discussed, is very important for diminishing noise effect on the signal. Only overall or individual pair shields should be used since the capacitance per unit length greatly increases when both are used. For digital signals in some cases an overall shield will suffice. Common shields used for cables are copper braid and

TABLE XII/4.0.2-2 Signals and Cable Types—a Guideline

Points	Analog/pulse/digital (low)signals	Discrete (high) signal
Signal types	4-20mADC, thermocouple, RTD, strain gauge, digital/network communication signal, pulses.	Process switches, limit switches, relay contacts, etc., with higher interrogation voltages.
Conductor	Twisted pair/triad	Twisted pair
Screening	Individually shielded pair/triads. Screen coverage 100%.	Overall shield—100% coverage is preferred.
Grounding	At field drain wire/screen to be cut and taped grounding at the marshaling end in control (equipment) rooms. The screen wire/drain wires should be properly terminated at the specified ground terminal board. The drain wire/screen of one loop must not be shorted at the marshaling rack/junction box.	

www.EngineeringBooksPDF.com

aluminized Mylar tape with (copper) drain wire. Metallic duct/conduits also act as a shield. A double grounding arrangement of aluminum/copper tape gives a very poor performance. It is advisable to ground the shield conductor(s) at one point only for single point grounding and the shield envelope should have an insulated jacket to prevent multiple grounds. Some shielding tips in line with the IEEE 518 Standard may be followed:

The shield should never be left floating as it enhances electrostatic coupling.

- Digital logic signals normally have shields grounded at the power supply end.
- Low-level signal sources requiring a differential amplifier should have shield grounding as per the manufacturer's recommendation.
- Multipair conductors used with thermocouple should have individual insulated shields, so that each shield may be maintained at the particular thermocouple ground potential.

9. *Other noise-minimizing techniques*: There are a few other means and methods to minimize noise, such as using the isolation transformer/neutralizing transformer/differential amplifier, etc.
10. *Classification of wiring as per noise susceptibility level (NSL)*: According to noise susceptibility, IEEE 518 classified wiring into four classes:

Level 1: High susceptibility: analog signal <50 V and digital signal <16 V mainly include these but are not be limited to the following:

- Fieldbus (foundation)
- 4-20mA or 4-20mA along with transmitter protocol(HART)
- RTD/thermocouple
- Millivolt/pulses
- All signals associated with digital hardware
- Discrete I/O such as process switches, valve limit switch relays, solenoid, and indicating lights
- Wiring connected with sensitive analog hardwire such strain gauge
- Phone lines

Level 2: Medium susceptibility: analog signal >50 V and switching circuits:

- Common returns to medium susceptible equipment
- Analog tachometer signal
- Discrete I/O DC or AC signals like those from process switches, limit switch relays, solenoid, and lights

Level 3: Low susceptibility: Switching signal >50V, analog signal > 50V, with current <20 A and AC feeder <20 A

- Fused control bus 50−250VDC
- Indicating lamp >50 V
- Thyristor field exciter, etc., electrical systems

Level 4: AC and DC buses of 0−1000 V with current 20−800 A

- Thyristor AC power input and DC output
- Other electrical systems (not discussed here)

As per IEEE 518 standard, level conditions may exist that require specific cables, and regrouping is not allowed. For class codes and other details, refer to the latest edition of IEEE 518. Tray spacing among these signals will be discussed in Clause 4.2.

4.1 Grounding/Earthing

"Grounding" and "earthing" are synonymous because both terms are used in various standards. From a safety and reliability point of view, the importance of proper grounding (or earthing) can never be overestimated. Improper grounding causes disastrous results in safety as well as plant operations because of distortions.

4.1.1 Grounding Philosophy

As discussed earlier, grounding has two objectives: to ensure safety and to minimize the effect of undesirable electrical coupling in the control circuit. Accordingly, the main points of the grounding philosophy are as follows (see IEEE Standard 1050-989):

1. To maintain a safe voltage across the entire plant and to minimize HV transients .and lighting surges. To minimize the shock effect, which may appear on noncurrent carrying equipment. As a result cabinet voltage may appear due to insulation failure and provide a low-impedance path for leakage, a path for static charge development. etc.
2. To minimize the effect of electrical noise in an industrial environment.
3. To minimize any disturbing effect within the control equipment and any propagation effect that may result in excessive ground current and fault current that may occur.
4. To minimize noise interference in the instrumentation system by providing a common reference point.

4.1.2 Grounding/Earthing Types

In an instrumentation system there could be three types of grounding (See figure XII/4.12-1 depicted later): dirty, mainly for 120, 240, and 480VAC power grounds; structural, such as a cabinet ground; or protective, any structure grounded to make it safe from lightning, etc.

On the other hand, DC grounds of 24VDC used in PLC/DCS with one common reference point are referred to as clean or reference grounding. Intrinsic safe circuits are also

www.EngineeringBooksPDF.com

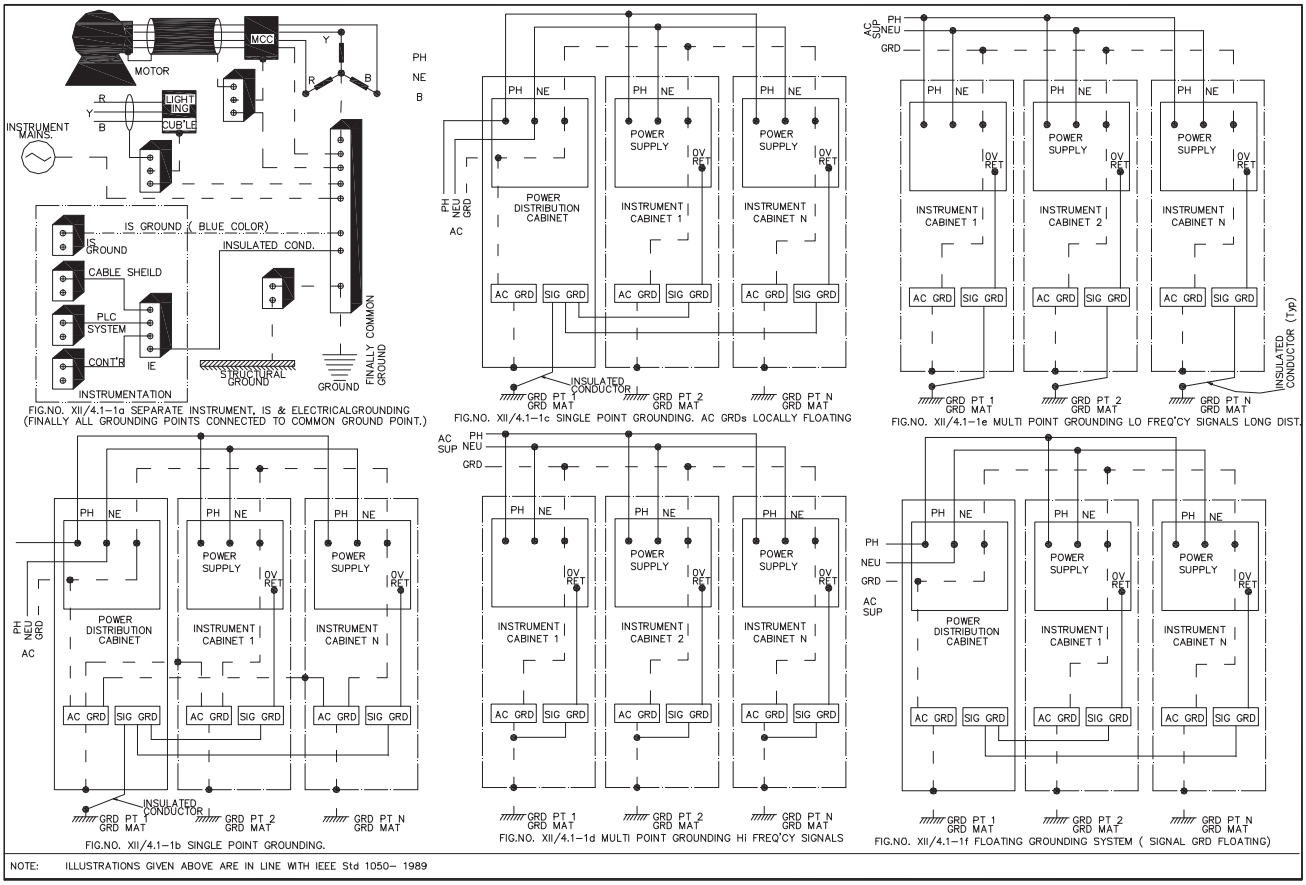


FIGURE XII/4.1-1 Various grounding systems.

grounded and this is called IS grounding. Normally IS grounds are treated separately and are done with blue cable (see Figure XII/4.1-1). In Figure XII/4.1-1, clean grounds are shown with a continuous ground line whereas a dirty ground is shown by dotted line and for IS ground blue color is written against it. There are three approaches to grounding: single point, multipoint, and floating (see IEEE Standard 1050).

1. *Single point grounding*: The circulation of ground current is eliminated and is quite effective for signal frequency at <300 kHz. However, this may not be effective at high frequency. At ground cable length more than 0.15 times signal wave length, cable is no longer a low impedance. In both variations shown in Figure XII/4.1-1b and c, the signal is ground at one point, and with cabinets, as in Figure XII/4.1-1c, electrical grounds are locally floating .
2. *Multiple grounding*: As shown in Figure XII/4.1-1d and e, there are two variations: one due to a high-frequency signal (for example, >300 kHz) and one with a long ground cable (for example, say 200 m; in line with IEEE Standard 1050). These types of circuit constructions are easy to build, but difficult to maintain, and they may give rise to multiple ground loops. However, instead of a direct ground if bypass capacitance is used at one shield end (say at the source end), it is possible that the cable shield appears ground at high frequency (because of capacitance) whereas at low-frequency capacitance carries hardly any current and would appear as a single point ground.
3. *Floating ground*: As shown in Figure XII/4.1-1f, it is used to isolate circuit or equipment from a common ground plane. It is implemented by interconnecting the systems yet isolating them from a common ground plane. The system is good, but may have a serious problem when there is static charge accumulation, which may be destructive and noise producing.

4.1.3 Electrical Earthing in Instrumentation

As discussed earlier, protective earthing of power supplies and cabinet earthing are electrical earthing done to prevent hazardous potential from developing between adjacent equipment grounds to protect personnel and equipment from an electrical power fault. This process includes the following:

www.EngineeringBooksPDF.com

- To make sure that all enclosures have suitable provision for an AC ground bus for termination of equipment ground cable.
- To connect only one multistranded ground cable between equipment and ground.
- All individual chassis in an enclosure must have an intentional ground connection.
- Armor of all field instrument cables needs to be terminated at the cable glands through which earthing connections are made to the cabinet earth bus.
- If the junction box is metallic then it needs to connect the earth stud bolt to the nearest steel structure. Otherwise the earth stud bolt will be located at the metal gland plate, which has direct metallic contact with the junction box.
- Each bus bar (25/40 × 6 mm) inside the cabinet is connected to a grounding dispatcher by cable (usually 35 mm^2 copper cable, green/yellow striped). This earth dispatcher connects all bus bars to the grounding loop.

4.1.4 Instrumentation Earthing

As per IEEE standard 1050-989, "The purpose of a signal ground is to reference all control signals within a system to a single point supposed to be at earth potential." In any enclosure there should be no more than one reference point. As a general principle of instrumentation earthing all individual or overall shield/screen cables should be isolated from electrical earthing and terminated at a different bus bar, which may have a final earthing at a suitable place in the building and may be common with electrical earthing. This instrument earth is called reference earth, the reference point in an instrumentation loop. Proper earthing hierarchy is helpful in eliminating unwanted signals. Often it has been found that most of the field noise problem is associated with poor grounding. The signal is properly guarded only when a shield is connected to true zero potential.

There are two possibilities for the input signal: grounded and floated. In the former case the correct point of grounding of the shield would be the place where the signal is grounded. If the source ground and output ground differ in potential then there will be a CMR problem. For a grounded signal, the signal ground should be where the transducer is located. Using a differential amplifier for a grounded source gives a better result. As a rule of thumb, the shield should be grounded at the signal source point and the receiving end may be left floating.

Floated signal may be necessary for safety and performance. The proper pathway from input circuit to the output ground is provided by the shield and ground resistance at the input. In practice it is extremely difficult to achieve this. Below are listed different types of grounding:

1. *Field transmitter grounding*: The majority of transmitter manufacturers use 4-20mADC output with/without HART. Even transmitters with Fieldbus recommend local grounding of their product through the "Grounding Terminal" provided by them. This is because modern electronics are vulnerable to surge current. Often these boards are provided with integral surge protection, so it becomes essential to make a path for surge current from the surge protection circuit. Normally there are two ground points in the transmitter, internal and external (mainly protective grounding). These are internally connected via a filter. For a non-isolated system grounding of the transmitter with a pipe structure will be sufficient. Otherwise a proven local ground with a minimum 12AWG ground wire GI locally has to be provided.
2. *Signal cable shield grounding*: Various suggested methods for cable shield grounding are discussed below and should be read in conjunction with the corresponding figures.
   - **a.** Transducer cable has an individual shield (drain wire) of single pair (/2C) cable that should be terminated at earth or ground terminal blocks inside the transducer/instrument enclosure (see Figure XII/4.1-2a).
   - **b.** Individual screen of single pair (/2C) cable from instrument to junction box cable in the junction box should be terminated at a terminal block inside the junction box.
   - **c.** Individual screen cable multipair (/M Core) from the junction box should also be terminated to the terminal block matching the individual shield of the single pair (/2c) cable discussed in b above. But the overall shield from the multipair cable from the junction should be terminated to the terminal block or bus bar (no matching criterion) for final grounding through a marshaling/system cabinet (see Figure XII/4.1-2a).
   - **d.** All individual shield/overall shields from multipair (/M Core) cable should be terminated into a respective instrument earth bus at the marshaling/system cabinet (see Figure XII/4.1-2a).
   - **e.** Individual shield from the digital single pair cable for digital signal going to the junction box should be terminated to the terminal block and shorted and then connected to the bus bar. Also the overall shield from multipair (/M Core) cable going inside the junction should be terminated to the bus bar.
   - **f.** Instrument bus bar is to be connected to the ground dispatcher by 25 mm^2 green/yellow striped copper cable.
   - **g.** From the Field instrument all the way up to the marshaling/system cabinet shield drain wire should be treated and terminated similar to the signal wire.
   - **h.** Exposed part of the drain wire within the junction box and marshaling/system cabinet should be inside an insertion jacket to avoid short circuiting of various loops.
   - **i.** All spare pair triads should always be terminated at both ends, with grounding at the marshaling/system cabinet.

www.EngineeringBooksPDF.com

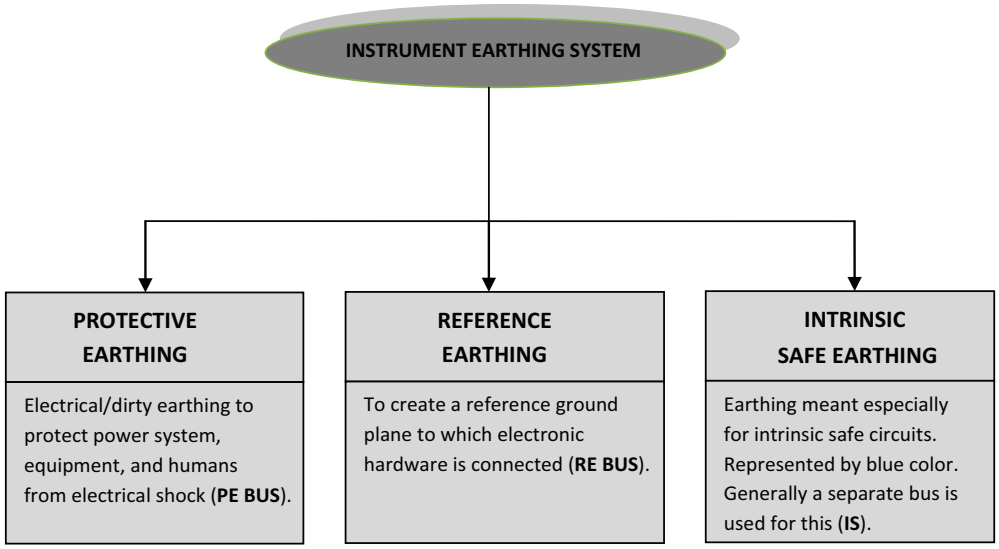


FIGURE XII/4.1.2-1 Instrument earthing types.

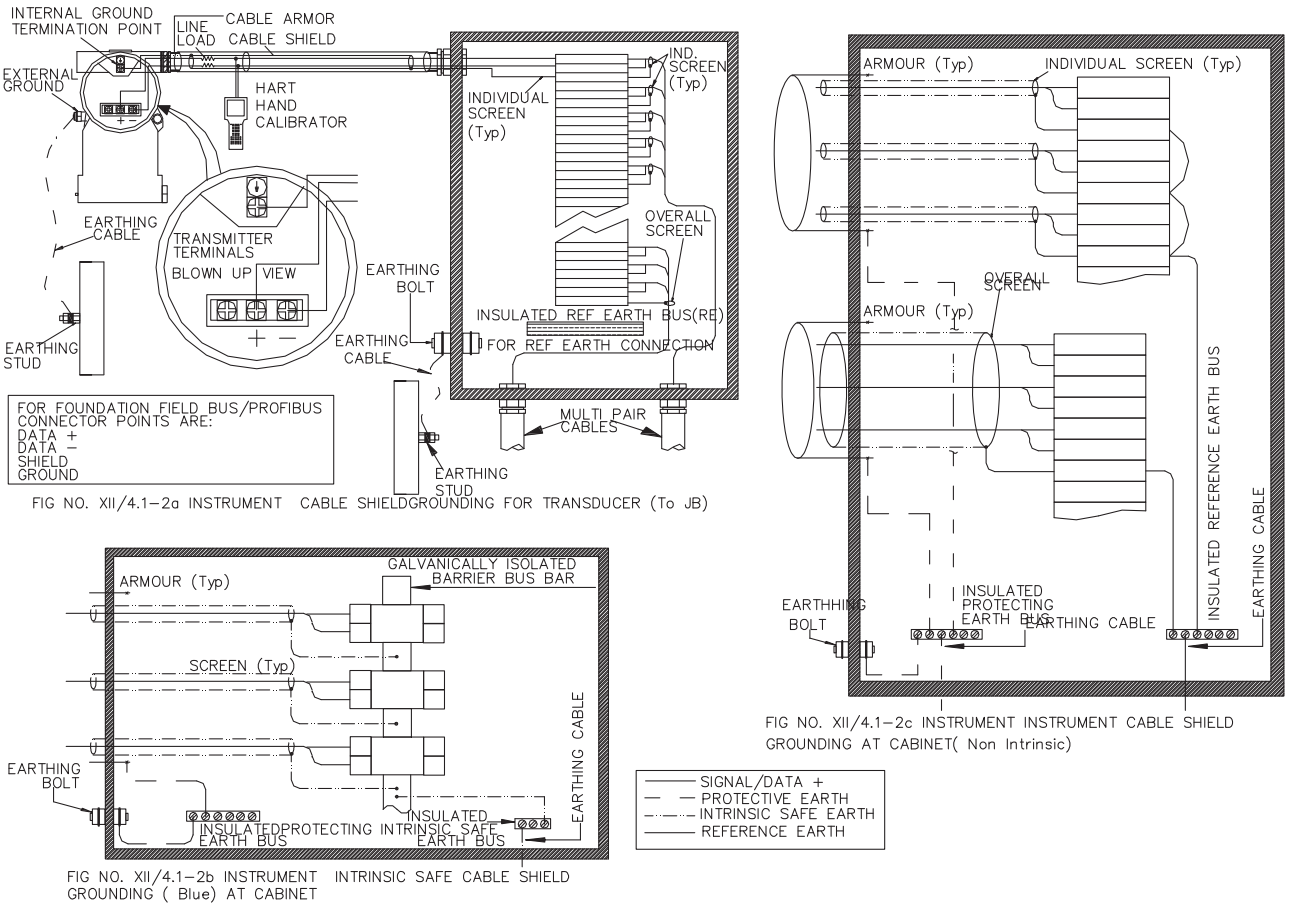


FIGURE XII/4.1-2 Instrument cable shield grounding methods.

www.EngineeringBooksPDF.com

j. In the central control room or control equipment room the marshaling/system cabinet must be equipped with both AC and DC or reference bus bars. The DC bus bar should be isolated from the cabinet structure. All shield DC common wires are connected here—as stated earlier it is important to ensure that these are grounded at one point. All DC/shield bus in all cabinets must be consolidated as the master DC ground bus of that building. Then this may be connected to the overall plant grid. See Figure XII/4.1-2c for this connection.

k. Some of the methods of connecting the control common reference point with ground systems include:
- Directly to a building column or electrically conducting mass determined to be at true earth
- To the termination point of equipment ground reference
- To the ground reference itself

l. Grounding of the centralized system is similar to what that shown in Figure XII/4.1-1b. Generally, there is one power supply system (common source) with power distribution done through the miniature circuit breakers. Each cabinet has separate equipment signal grounds. The cabinets should act as concentrators for both signal and equipment grounds. Normally centralized systems have a frequency <300 kHz.

m. Grounding of the distributed system is done when individual control systems are separated from each other. This is not uncommon for a large network in power plants with complete integration of the subsystems. Some of the design conditions in line with IEEE 1050-1989 may be as follows:
- An effort may be made to have a common power supply source (a common power transformer).
- Each of the cabinet/clusters has a local protective ground.
- Signal between the systems should be properly coupled (transformer/DC/optical) with CMR ground voltage under fault.
- One of the system cabinets may be considered as a master in which both ground types of points are collected. Remote station signal ground may be left floating.

n. Instrument grounding connections, especially with a thermocouple, are illustrated in in Figure XII/4.1-3b and c. For the thermocouple, the negative leg is connected to the earth. For a floated type grounding is done at the computer end via screen and not locally as in a grounded system.

o. Intrinsic safety circuit grounding principles are not much different from what has been discussed above. Normally blue cables are used for these. See Figure XII/4.1-2b for this connection. Overall screens of these cables in cabinets are connected to the insulated IS bus bars, whereas for individual screens the connection goes to the IS bus bar via a galvanic isolation circuit. Normally resistance between grounding dispatcher and IS bars is restricted to 0.5 Ω. In power plants there is not much application of the intrinsic safety circuits, but they are used in the oil sector.

p. A few other steps to a better result include:
- Unused conductors and shield should be terminated at both ends and in some cases it will be useful to ground the spare wiring at the marshaling/system cabinet.
- Power supply leads should be kept closely spaced for canceling the coupling due to a magnetic field.
- Care should be taken as per manufacturer's recommendations for circuits with MOSFET, which are susceptible to static charges possible cabling scheme for a typical modern Fossil fuel power station has been depicted in figure XII/4.1-4. Also typical Control & Instrumentation Interface cabling has been presented in Figure XII/4.2-1. These have been included for reader to get an idea of overall cabling, which a designer initially needs to prepare at time of design.).

4.2 Instruments, Cables, and Wiring Practices

A broad classification of various kinds of cables used in instrumentation is presented below. Wiring practices based on ISA, IEEE, and PIP also will be discussed in this clause (see Figure XII/4.2-1).

4.2.1 Typical Cable Type: Cable Types and Uses Presented in Line with PIP Standard

1. Instrument cable classification (see Table XII/4.2-1)
2. Wire and cable requirements for instrument circuits (see Table XII/4.2-2)
   - **a.** Type A circuits should be separated from all other types of instrument circuits by a conduit, tray dividers, or separate trays.
   - **b.** Conductor sizes given are minimum wire sizes, and the actual size is as per load and voltage drop. Use of parallel wire to meet the requirements is not allowed.
   - **c.** Higher DC levels require owner's approval.
   - **d.** Instrument tray cable (ITC; Figure XII/4.2.1-1 at a later part of the chapter) can only be used in power-limiting circuits, with <150 V and <5 A.
   - **e.** Vibration signals should be run in galvanized steel flexible conduit and armor from probe to transducer.
   - **f.** Maximum separation between redundant highways is obtained within the operating plant, and use of a single tray for redundant highways is not acceptable.

www.EngineeringBooksPDF.com

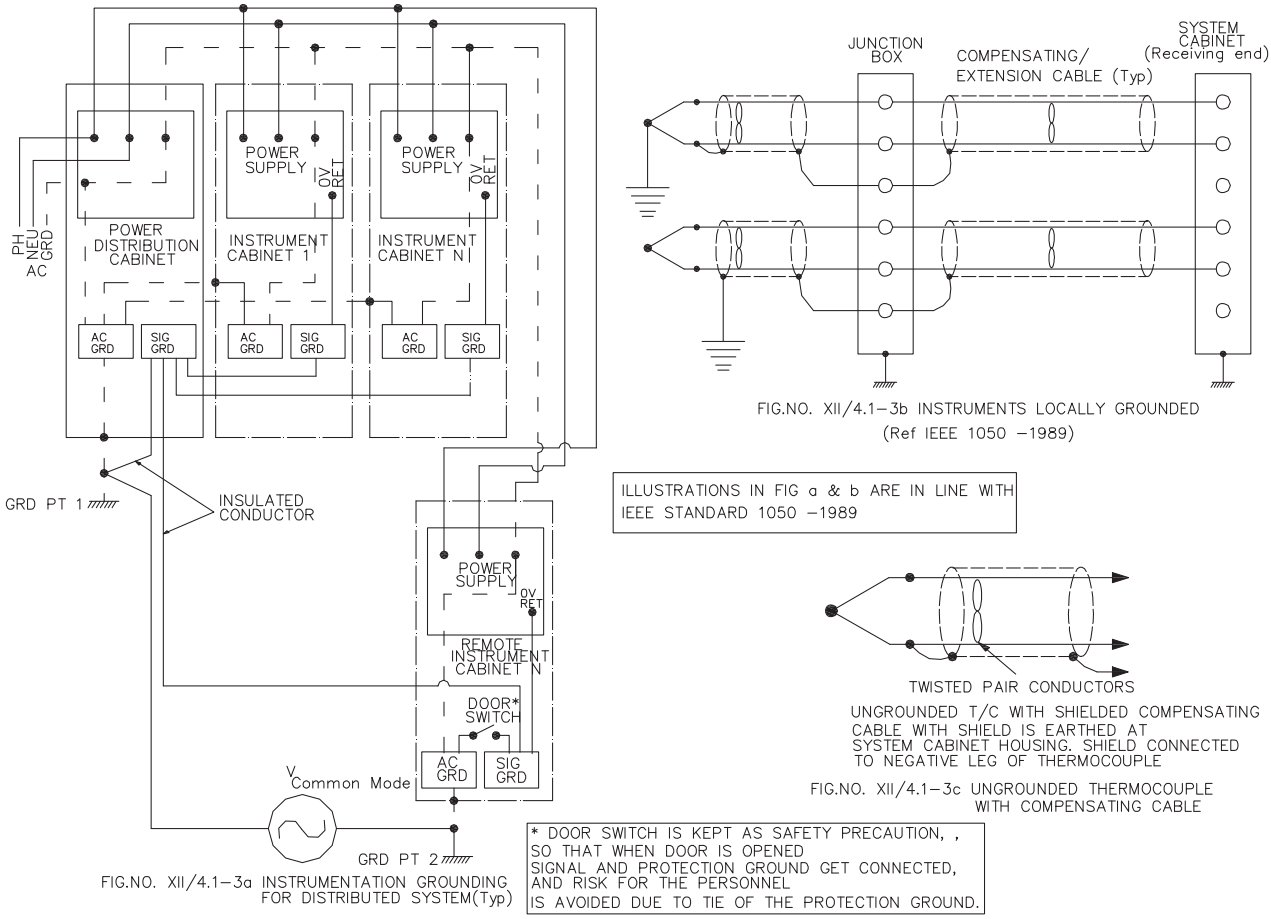


FIGURE XII/4.1-3 Instruments and systems grounding.

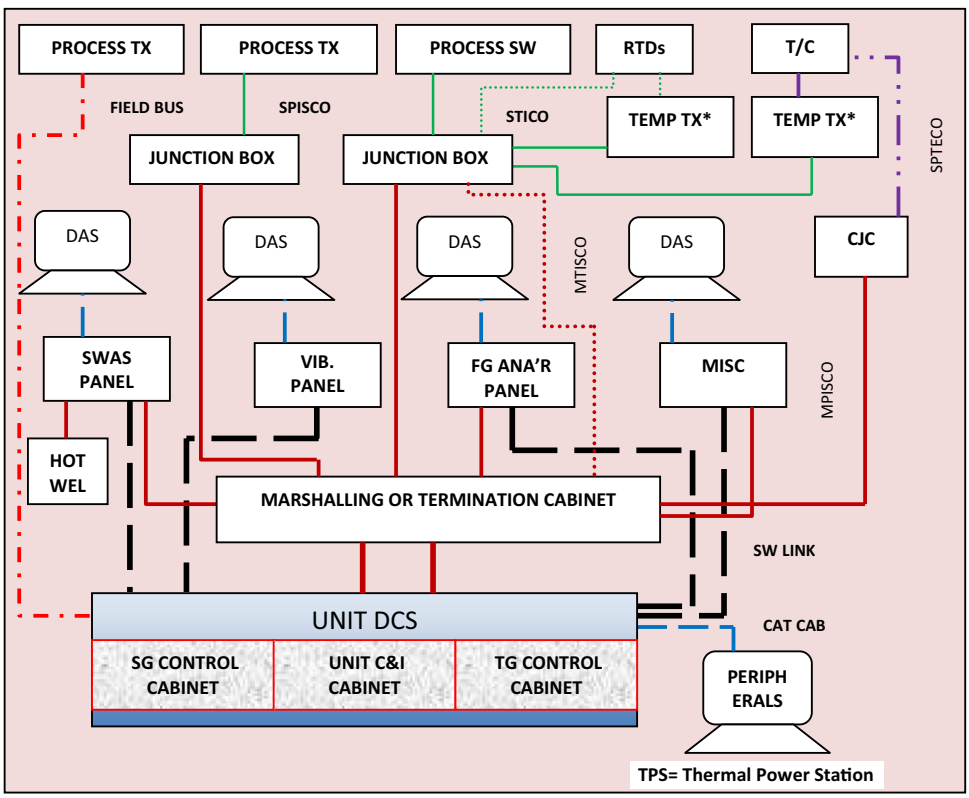


FIGURE XII/4.1-4 C&I cabling diagram in TPS (typical).

www.EngineeringBooksPDF.com

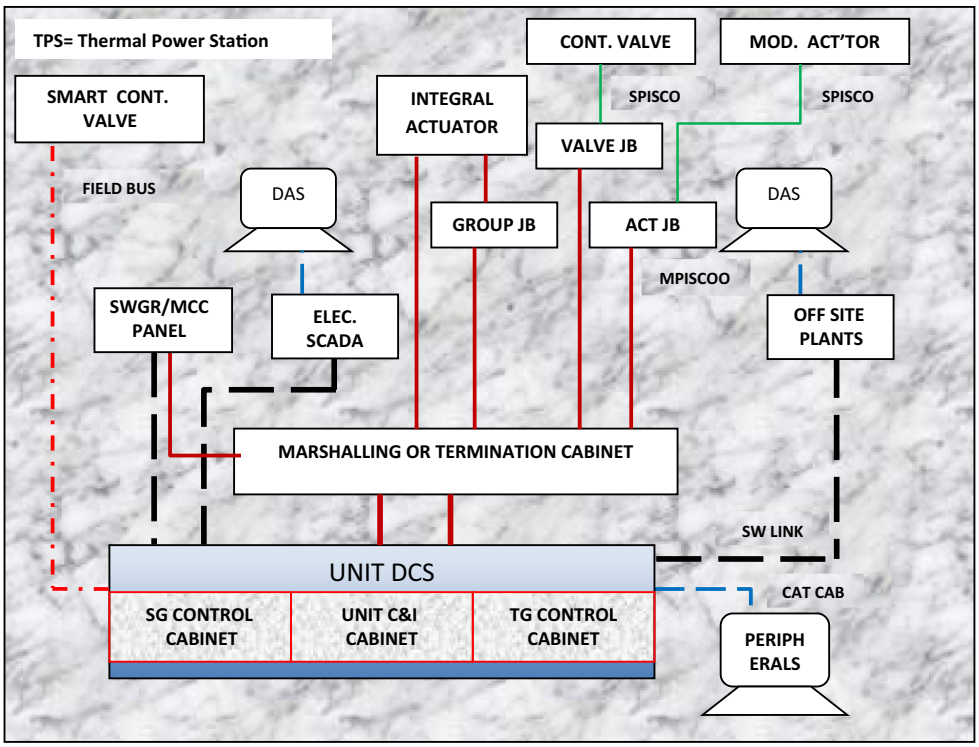


FIGURE XII/4.2-1 C&I interface cabling in TPS (typical).

TABLE XII/4.2-1 Instrument Cable Classification and Specification

Cable\name	Abbreviation	Minimum specification
Single pair instrument signal cable with overall shield	SPISCO	Pair of two copper conductor 16AWG, overall shield
Single pair thermocouple extension cable with overall shield	SPTECO	Each pair of two solid alloy T/C extension wires with color code as per ISA MC 96.1 with overall shield
Single triad instrument signal cable with overall shield	STISCO	Three copper conductor of minimum 16AWG with overall shield
Multipair instrument signal cable with overall shield	MPISCO	Multipair (for example, 12/24 pair) with overall shield; each pair of two copper conductors with a minimum 20AWG.
Multipair thermocouple extension cable individually shield	MPTECI	Multipair (for example, 12/24 pair); each pair of two solid alloy T/C extension wires with color code as per ISA MC 96.1 with overall shield minimum conductor size 20AWG
Multipair instrument signal cable individually shielded pair with overall shield	MPISCI	Multipair (for example, 12/24 pair) with overall shield; each pair of two copper conductors with a minimum size 20AWG with individual shield insulated from other pair shields
Multi-triad instrument signal cable with overall shield	MTISCO	Multi-triad (for example, 12/24 pair) with overall shield; each triad copper conductor of with a minimum size 20AWG
Multi-triad instrument signal cable individually shielded triads with overall shield	MTISCI	Same as above with individual shield insulated from other shields

www.EngineeringBooksPDF.com

TABLE XII/4.2-2 Wire and Cable Requirements for Instrument Circuits

NEC class circuits (Notes 1 and 2)			
Instrument class	**Circuit example**	**Conduit wiring**	**Tray cable**
1200VAC or less	Switches, solenoid, relays	600 V PVC insulated (THWN) 14AWG (min)	600V TC insulated
NEC Article 727 circuits, conduits and cable tray installations (Notes1 and 9)			
Instrument circuit class and type	**Circuit example**	**Single pair or triads**	**Multipair or triad cable**
24VDC or less	4-20mADC, RTDs, weigh cell, solenoids, alarms, switches, relays, secondary motor control, digital process transmitter	300 V shielded twisted pair or triads Cable types: SPISCO,S TISCO (Notes 2, 4, and 8)	300V ITC PVC insulated pairs or triad overall shield Cable types: MPISCO, MTISCO (Notes 2, 3, and 8)
Frequency or pulse train digital communication (Note 5)	Speed, vibration, turbine meter	300 V shielded twisted pair or triads Cable types: SPISCO, STISCO (Notes 2 and 8)	300 V insulated individually shielded pairs or Triads—300 V insulated Cable types: MPISCO, MTISCO (Notes 2, 4, and 8)
Thermocouple measurement (Note 7)	Thermocouple	300 V ITC 16AWG individually shield twisted pair Cable types: SPTECO (Notes 2 and 8)	300 V ITC, 20AWG individually shield twisted pairs, overall shield Cable types: MPTECO (overall shield) (Notes 2 and 8)
Data highway and other high speed circuits			
Data highway (Notes 6 and 8)	EIA-422A data highway/high speed communication	Follow cable and system manufacture's recommendations	Follow cable and system manufacturer's recommendations

Notes based on PIP PCCEL001.

g. Type B2 and B4 can be routed in the same conduit and trays.
h. Difference between manufacturer's recommended cables and these cables needs to be resolved with the owner.
i. Physical barriers are also required to separate intrinsically safe wiring from other wiring.

4.2.2 Cabling and Wiring Practices

Generally the installation of wiring and LV instrumentation cables needs to comply with international standards such as NEC. Some of these requirements are as listed below:

1. The routing of cables to the control room should preferably be through overhead cable trays and routing of cable trays through areas with fire hazards should be avoided.
2. Cables that are laid directly under a raised floor need proper approval from NEC Article 354 (non-metallic conduit with conductor or cables inside a non-metallic smooth wall conduit). AC power wiring (120VAC or higher) routed in a raised floor should utilize a conduit, metal enclosed raceway, or cable trays with adequate separation from the signal cable.
3. For the safety instrumentation system, ISA S84.01 needs to be followed, and if the electronic equipment room (normally process control room alone is not classified) is classified as an IT room then NEC Article 645 is to be followed.

ITC: A type of cable introduced after 1996, covered in NEC art 727. Earlier in case of low power Instruments, 600 V grade cables were used to meet the waveform and power limit of NEC. These were disadvantageous because of cost and size (diameter). ITCs are rated for 300 V insulation, with conductor size ranging from 22 (current limit <3 A not 5 A) to 12AWG. Conductors are copper and/thermocouple.

FIGURE XII/4.2.1-1 Note on ITC.

www.EngineeringBooksPDF.com

4. Splitting multiple conductor cables among multiple devices/boxes in the field is not permitted.
5. Instruments/electronics located in the field in a large open area or cable run >500 m should have a lightning protective device in line with NEC Article 280.
6. Devices may be protected by a metal oxide varistor or diode to protect the IT from EMF (AC/DC. respectively)
7. All the pairs/triads must have a suitable tag plat at both the ends. Cables should have suitable markings and defined color codes.

4.3 Segregation/Separation Requirements

As discussed in Clause 4.0.2, number 10, there will be different Noise Susceptibility Level NSLs and accordingly there will be separation between different NSL wirings as recommended in IEEE 518 and PIP Standard.

4.3.1 Class Codes

According to IEEE standard 518, level conditions may exist that require specific cable and regrouping is not allowed. So according to the same standard, there are class codes, and these are defined below:

A: Analog input/output
B: Pulse input
C: Contact/interrupt input
D: Decimal switch inputs
E: Output data lines
F: Display/contact output
G: Logic input buffer
S: Special handling of special levels requiring special spacing (see Standard)
U: HV potential unfused >600VDC

4.3.2 Tray and Conduit Spacing

The spacing between trays and conduits presented below in tabular form is based on summary of standards IEEE 518-1982 and PIP PCCEL001. The Following points need to be considered while referring to Tables XII/4.3-1—XII/4.3-3:

1. All distances are in inches. For the top and bottom tray it is the distance between the top of one tray to the bottom of the other tray. While for side trays the distance is between the sides of adjacent trays. For conduits, the distance is the outside surface of the conduits.
2. When unlike signal levels cross they should cross at 90° (a grounded metal barrier should be placed at the crossover of two levels).
3. Trays of all levels are based on metal trays solidly grounded with good ground continuity.
4. Trays containing Level 1 and 2 wiring should have solid bottom and proper tray cover to provide complete

TABLE XII/4.3-1 Tray Spacing (in Inches)—NSL IEEE 518

Level	1	2	3	3S[a]	4	4S[a]
1	0[b]	1[c]	6	6	26	26
2	1[c]	0[b]	6	6	18	26
3	6	6	0[b]	0[b]	6[d]	12
3S[a]	6	6	0[b]	0[b]	8	18
4	26	18	6[d]	8	0[b]	0[b]
4S[a]	26	26	12	18	0[b]	0[b]

[a]*S as defined in Clause 4.2.1.*
[b]*For zero distance (see Clause 4.3.2, number 8).*
[c]*If separate tray impractical, a common tray with grounded steel barrier can be used for two signal levels.*
[d]*Within junction/pull boxes, unlike levels, trays should be separated by ground barriers.*

TABLE XII/4.3-2 Conduit Spacing (in Inches)—NSL IEEE 518

Level	1	2	3	3S[a]	4	4S[a]
1	0[b]	1	3	3	12	12
2	1	0[b]	3	3	9	12
3	3	3	0[b]	0[b]	0[b]	6
3S[a]	3	3	0[b]	0[b]	6	9
4	12	9	0[b]	6	0[b]	0[b]
4S[a]	12	12	6	9	0[b]	0[b]

[a]*S as defined in Clause 4.2.1.*
[b]*For zero distance (see Clause 4.3.2, number 8).*

TABLE XII/4.3-3 Tray—Conduit Spacing (in Inches) NSL IEEE 518

Level	1	2	3	3S[a]	4	4S[a]
1	0[b]	1	4	4	18	18
2	1	0[b]	4	4	12	18
3	4	4	0[b]	0[b]	0[b]	8
3S[a]	4	4	0[b]	0[b]	6	12
4	18	12	0[b]	6	0[b]	0[b]
4S[a]	18	18	8	12	0[b]	0[b]

[a]*S as defined in Clause 4.2.1.*
[b]*For zero distance (see Clause 4.3.2, number 8).*

www.EngineeringBooksPDF.com

shielding. Covers connected to side rails must be positive and continuous to avoid high-reluctance air gap.
5. Tray and conduit of Level 1 and 2, as defined in Clause 4.0.2, number 10, should not be run parallel to any high-power enclosure. In cases where recommended spacing cannot be maintained, parallel runs >5 ft should be avoided.
6. Level 3 and 4 cables can be run in the same tray with a suitable barrier between them.
7. All these are not applicable for non-metallic conduits.
8. It is important to note that zero separation distance between signals of the same level does not mean different signals of the same level can be used in the same cable. Even if the signals are in the same NSL, cables should be separate for separate signal types.

Now in practice in power plants it is often required that the same tray/raceway is used for different types of cables including power (HT) cables, as it is not feasible to run separate instrumentation cable at every place in the plant. In this regard IEEE Standard 422 meant for cabling in power-generating stations may be referenced. In vertically stacked trays various cables may be taken with minimum separation as given below. In IEEE Standard 422 the instrumentation cables considered are the shielded type.

Unit HT (11/6.6/3.3 kV) power cable tray: ~36" (914 mm)
Medium voltage (415 V) cable tray: ~24" (610 mm)
Control supply cable tray: ~12" (305 mm)

In most cases the bottom-most one or two trays are left for instrumentation cabling. This is subject to owner's approval.

4.4 Cable Installation and Termination

In this clause a brief discussion on installation and terminations is provided.

4.4.1 Cable Installation Points

The cables from redundant devices and redundant cables should be routed in different paths as per recommendation of the IEEE 422 Standard. Also, cables of one unit need to be segregated from those of the other unit. Cable routing should be done so that in case of fire at least half of the critical drives of the unit and inter-unit auxiliaries are safe (not affected due to a single fire). Other points to be considered include:

1. Cables should be laid strictly in line with the prepared cable schedule.
2. All cables must have identification tags at both terminating ends, both sides of walls or floor crossing, at regular intervals in the tray or trench, etc.
3. All trays and subtrays must be numbered at regular intervals.
4. No jointing of cables for <250 m
5. Buried cables should be protected by concrete slabs with route markings at 20 m gaps and at the bends
6. Road-crossing cables need to pass through high-density polyethylene (HDPE) buried in PCC and suitable clearance is to be maintained with other LV and MV electrical cables as per owner's approval (not <1 ft).
7. All cables should be neatly dressed and clamped/tied in the trays. Fiber optic cables should be inside and could be placed inside cable trays whenever feasible.
8. Whenever fiber optic cables are to be buried it must be inside 2" GI/rodent-proof HDPE and put in a trench ~ 1.5 m in depth covered with brick and sand. Canal-crossing fiber optic cables in 2" GI/rodent-proof HDPE should be put inside HUME pipes.
9. During installation cable manufacturer's recommendation on cable-pulling tension and cable bends must be followed to avoid damaging the cable.

4.4.2 Termination

A few points on terminations are enumerated below:

1. A few accessories need to be used for safe cabling such as a surge suppresser, opto isolator, and fiber optic card cage as well as a set of terminating kits like a crimping tool or a Max Termi (a special type of termination used for better contacts—used mainly in German systems) tool.
2. Termination of twisted pair cables apparently is easy, but some experience is necessary to do the job. Cutting a proper length of cable for termination is very important to have adequate margin for connecting connectors, leaving excess cable at the termination point. For cable termination in cabinets (draw out type) sufficient cable should be coiled and kept inside.
3. For cables like UTP, the amount of cable to be kept exposed for RJ45 connectors is typically 1". Over twisting should be avoided. After installation initial termination testing is a part of the installer's job.
4. Fiber optic cables in networking is becoming increasingly important. The installer should be well trained regarding fundamentals of fiber optic cable installation, and in this case workmanship is extremely important for the performance of the network.

4.5 Brief Specification of a Number of Basic Items

In this clause a short specification of a number of basic items is presented.

www.EngineeringBooksPDF.com

TABLE XII/4.5.4-1 Instrument Copper Cable (DS)

Sl	Specifying point	Standard/available data	Remarks
1	Voltage grade (V)	225/300/600	Depending on application
2	Standards	ASTM D 2843/2863, BSBS5308, IEEE 383, IEC 60227/60228/60754, IS 1554/8784/10810, SS 4241475, VDE/0207 part 4 and 5/0815, etc.	
3	Temperature rating	70/85°C for HR cable	
4	Various tolerance	As per owner's approval	
5	Conductor: (electrolytic)	A high conductive annealed bare copper stranded (7 × 0.3 mm) conductor with cross section: 0.5mm^2; other sizes as per application	Other sizes as per application, e.g., 1.0/1.5 mm^2
6	Insulation	PVC of thickness 0.25–0.35mm	
7	Inner sheath	PVC	
8	Armor	Galvanized steel wire	As applicable
9	Outer sheath	Extruded PVC with FRLS property >1.8 mm thick with resistance to water and fungus, termite and rodent proof	
10	Pairs	1, 2, 4, 8, 12, 24, and 48	As required
11	Twisting	50 mm maximum lay	
12	Shielding	Individual/overall (see Table XII/4.2-2)	As per application and owners' approval.
13	Shield type	Polyester tape/aluminum Mylar tape (28 μm) with tinned copper drain wire (7 × 20AWG, 0.51 mm^2) with metallic side of the tape	Normally 50% overlap
14	Fillers	Non-hygroscopic, flame retardant	As applicable
15	FRLS properties (see relevant standard as mentioned above)	Oxygen index 29%	As applicable
		Temperature index: >250°C	
		Acid generation: <20%	
		Smoke density: <60%	
16	Electrical parameter	Mutual capacitance per km: bet cond. at 1 kHz: 100–120 nF Pair to pair: 115 nF Unbalanced capacitance at 1 kHz: 1 nF	Rough values as per manufacturer's value
		Insulation resistance: >100 MΩ	
		Conductor resistance/km: 36 Ω	
		Ch. impedance: <320 Ω at 1 kHz	
		Cross-talk at 1 kHz: 60 dB	
		Attenuation: 1.2 dB/km maximum	
17	Accessories	As required such as marker, jointer, etc.	
18	Color code of pairs	VDE Standard may be followed	
19	Markings	FRLS, pair number, circles, etc., as per standard.	
20	Tolerance	As per relevant standard	Owner's approval

www.EngineeringBooksPDF.com

TABLE XII/4.5.4-2 Instrument Fiber Optic Cable (DS)

Sl	Specifying point	Standard/available data	Remarks
1	Type and construction	Multimode, tight buffered color-coded fiber/dielectric and interlock armor; each fiber is protected in a mini cable and Aramid yarn/plastic is applied either inside the mini cable or within the inner jacket	
2	Application	Indoor outdoor LAN, Aerial, self-supporting, or direct buried cable	
3	Standards	IEC60092/60331/60332/60754/60793/60794	
4	Number of fiber	4/6/8/12/…36 as per application	Owner choice
5	Core and cladding diameter	62.5 and 125 μm	
6	Primary coating	0.274 μm	
7	Filler and rip cord	Strengthening material filler with option rip cord	
8	Inner sheath	Elastomer jacket	
9	Outer sheath	Halogen-free, low-smoke flame retardant (PVC/LSZH)	
10	Wavelength	850/1300 nm (typical)	
11	Attenuation	3.5/1.5 dB/km for optical wavelength of 850/1300 nm, respectively	
12	Testing/color coding	IEC 60793	
13	Mechanical properties	Tensile strength, impact, etc., as per IEC 60794-1	
14	Bending Radius	10 OD/20 OD during service and installation, respectively	Manufacturer's recommended
15	Testing	IEC 60793-1	
16	Temperature	70°C	
17	Connectors and accessories	Patch and splice mount/wall mount as applicable, connectors etc.	

TABLE XII/4.5.4-3 LAN Cable (DS)

Sl	Specifying point	Standard/available data	Remarks
1	Type	CAT (UTP/FTP/SFTP)	
2	Standard	EIA/TIA 568B IEC11801/ 60332/60754/61034 ISO 11801	
3	Conductor diameter (mm)	0.5 (0.64 mm^2 × 7 wire)	
4	Insulation	Solid PE thickness 0.2 mm	
5	Sheathing	PVC/LSOH/LSFROH	
6	Impedance	Typical characteristic impedance: 120 Ω	
7	Temperature	70°C maximum	
8	Screen	For FTP/SFTP Al foil over all with tinned copper drain wire; SFTP will have copper braid wire	
	Flame propagation/smoke/halogen acid test, etc.	As per IEC listed above	
	Attenuation typical	1000 base T at 1 MHz—2 dB/100 m for CAT 5 cable whereas same for CAT 6 cable will be at 4MHz—3.8 dB/100 m	

www.EngineeringBooksPDF.com

What is thermocouple wire? **Wire used in a thermocouple (T/C) from point of sensing to the point of cold junction/where the signal is measured. Different T/Cs use a different mixture of metals.**

What is Limit of error? What is the difference between standard and special limit**? Limit of error generally refers to the accuracy of wire. Special limit has the same features as the standard limit, with added features with better accuracy. The accuracy of measurements vary with the thermocouple types.**

What is the difference between thermocouple grade/compensating cable and extension wire? **Thermocouple wires are used to make the sensing point of the thermocouple. Extension wire is used to extend the a thermocouple signal to the reading instrument. The extension wire has lower ambient temperature limit. Thermocouple cable may be used to replace extension, wire but extensionwire cannot be used as a sensing wire. Compensating and extension wire are generally represented by putting "C" and "X" after the thermocouple type, respectively. For example, SC represents compensating cable for type S T/C and SX represents extension wire for S type T/C. Both have different materials of construction as indicated in the table. Naturally for thermocouples with noble metals extension wire are less costly. Thus economy is also a factor when deciding to have two types of cables for these types of cables.**

What is the maximum length of thermocouple Wire? **As a rule of thumb, the thermocouple wire with thickness 20AWG or higher can be used for a length of <100 ft. There are really many factors to consider when limiting distances. Two main factors may be loop resistance and noise interference. Since different T/Cs have different materials loop resistance depend on the same as well as the AWG of the conductor. Normally it is recommended to keep the total loop resistance below 100 ohms. For noise reduction, shield/wire braids may be used to pick up.**

FIGURE XII/4.5.4.4 Notes on thermocouple and T/C wires.

4.5.1 Conduits

Conduits are normally used for cables between a filed instrument to a local junction box and/or when there are less cables. Basic requirements are as follows:

1. *Type*: Rigid or flexible
2. *Materials*: Hot-dipped, galvanized mild steel/stainless steel inner part coated with enamel lacquer/zinc chromate
3. *Sizes (mm)*: 12/16/20/32/40
4. *Duty*: Heavy
5. *Other properties*: Flame retardant
6. *Fitting*: Suitable fittings to get IP rating

4.5.2 Junction Box

1. *No of ways*: 12/24/36/48/72/96
2. *Spare termination*: 20%
3. *Material*: Stainless steel, thick fiberglass reinforced polyester
4. *Grounding stud*: To be provided
5. *Type*: Screw fitted for door
6. *Terminal block*: Rail-mounted terminal block suitable for the cable type used
7. *Protection class*: IP 55/ NEMA 4
8. *External color*: Owner's choice, internal color normally brilliant white
9. *Gland plate*: Minimum 4 mm thick detachable gland plate for punches for cable glands

4.5.3 Cable Glands

Cable glands provide environmental protection by sealing the outer sheath, earth continuity, and sealing against other ingress. They also help to hold the cable level against the pulling force.

1. *Type*: Single/double compression; normal or hazardous application
2. *Materials*: Brass, nickel-plated brass, stainless steel, aluminum
3. *Accessories*: Gland reducer, lock nut, serrated washer, etc.
4. *Size*: Depends on cable size
5. *Selection*: Done based on type and material of armor

4.5.4 Instrumentation Cable

Instrumentation cables can be various types and categories, so it is very difficult to cover them all. So a generalized specification is briefly covered here. The cable type covered is mainly twisted pair cables. There are many international

www.EngineeringBooksPDF.com

standards on cables, and each of them has an equivalence with the other, but they are not exactly the same. IEC standards are found to be more acceptable.

1. Instrument copper cable, see Table XII/4.5.4-1 for a copper cable data sheet.
2. Instrument fiber optic cable; see Table XII/4.5.4-2 for a fiber optic cable data sheet.
3. There could be a variety of LAN cables used in automation and computer networking: examples include CAT 5e type UTP/FTP/SFTP with PVC/LSOH sheath. Similar cables include CAT 6 and CAT 7. These depend on network types deployed as discussed in Table VII/1.2.5-1. Actually there will be a difference in performance between CAT 5/6/7 cables and WRT. Different network and frequency standard manufacturer's specification may be consulted for details. See Table XII/4.5.4-3 for a LAN cable data sheet.
4. There are different kinds of thermocouples, but mainly ISA types K, R, and S are mainly used in power plants. In some cases type J thermocouples are used (such as a mill application). There are two kinds of cables used for thermocouples: compensating cables and extension cables terms used in different standards but none are really thermocouple grade. These are used for costly thermocouple materials such as ISA type R and S in power plants (refer to ISA Standard for types; see Figure XII/4.5.4.4 and Tables XII/4.5.4-4 and XII/4.5.4-5).

4.5.5 Types of Cable Terminations

There are a number of cable termination types and as listed below:

1. Plain screwed type with lug.
2. Plug–in connectors may be used with junction boxes, instruments, and valve damper drives.
3. Cage clamp type may be found in marshaling racks, system cabinets, and CJC boxes.
4. Prefab cable can be used with an annunciator, console to system cabinet, etc.
5. Manufacturer's standards are followed for a PA system, wire wrap, and Maxi Termi type as found in turbine generator cabinets.
6. With cable connectors Such RJ 45 for CAT cables (indicated separately for computer connections).
7. Opto cable connectors.

TABLE XII/4.5.4-4 Compensating and Extension Wire Details with Error Limit Color Code

Property	ISA Type J	ISA Type K	ISA Type R	ISA Type S
Temperature range	0–760°C	0–1260°C	0–1600°C	
Error limit (standard)	±2.2°C (±0.75%)	±2.2°C (±0.75%)	1.5°C for 0–600°C; 0.0025 XT for 600–1600°C ±0.057 mV	
Error limit (sp)	±1.1°C (±0.4%)	±1.1°C (±0.4%)		
T/C material +ve	Iron[a]	Chromel (Ni Cr)	Pt 13% Rh	Pt 10% Rh
T/C material –tive	Constantan (Cu/Ni)	Alumel (NiAl[d])	Pt	Pt
Compensating cable +ve	Iron[a]	Fe[a]/Cu[b]	Cu (IEC)[a/b]	Cu(IEC)[a/b]
Compensating cable –ve	Constantan (Cu/Ni)	CuNi	Cu Ni(IEC)[a/b]	Cu Ni(IEC) [a/b]
Extension cable +ve	Iron[a]	Chromel (Ni Cr)	Cu (ANSI)	Cu (ANSI)
Extension. cable +ve	Constantan (Cu/Ni)	Alumel (NiAl[c])	Cu Ni (ANSI)	Cu Ni (ANSI)
In. ANSI color ±	White/red	Yellow/red	Black/red	
In. IEC Color ±	Black/white	Green/white	Orange/white[d]	
Jac. Color ANSI	Black	Yellow	Green	
Jac. Color IEC	Black	Green	Orange	

[a]*As per IEC, KCA/RCA/SCA respectively.*
[b]*As per IEC, KCB/RCB/SCB respectively.*
[c]*As per IEC, magnetic.*
[d]*Not well defined.*

www.EngineeringBooksPDF.com

TABLE XII/4.5.4-5 Compensating Cable/Extension Wire (DS)

Sl	Specifying point	Standard/available data	Remarks
1	Voltage grade (V)	300	
2	Standards	ANSI MC96.1 DIN 45722/ IEC 584 IEEE 383, 70,000 BTU/UL 1581 NEC Article 725 PLTC NEC Article 510: Class 1, Division 2 UL Listed Subject 13	As Applicable
3	Temperature range	0−100/200°C (surrounding temperature)	
4	Conductor	20AWG solid alloy/ 0.5 mm^2	
5	Insulation	Color-coded PVC (see Table XII/4.5.4-1 for color codes)	
6	Insulation thickness	0.38 mm — Jacket thickness as per number of pairs	
7	Color sheath	Color-coded PVC (see Table XII/4.5.4-1 for color codes)	
8	Armor	Galvanized steel wire	As applicable
9	Outer Sheath	Extruded PVC with FRLS property > 1.8 mm thick with resistance to water and fungus, termite and rodent proof	
10	Pairs	1, 2, 4, 8, and 12	As applicable
11	Twisting	50 mm maximum lay	
12	Shielding	Individual/overall (see Table XII/4.2-2)	As per application and owners' approval.
13	Shield type	Polyester tape, aluminum Mylar tape (28 μm) with tinned copper drain wire (7 × 20AWG, 0.51 mm^2) on the metallic side of the tape	Normally 50% overlap
14	FRLS properties (See relevant standard mentioned above)	Oxygen index: 29%	As applicable
		Temp index: >250°C	
		Acid generation: <20%	
		Smoke density: <60%	
15	Electrical Parameter	Mutual capacitance per km: bet cond. at 1 kHz: 200 nF (typical)	Manufacturer's data sheet may be consulted for exact details as it varies with each type of cable
		Insulation resistance: >100 MΩ	
		Cross-talk at 1 kHz: 60 dB	
16	Markings	FRLS, pair number, circles, etc., as per standard	
17	Tolerance	As per relevant standard	Owner's approval

BIBLIOGRAPHY

[1] 2 Valve Manifold, Instrument:www.swagelok.com:Product Catalog.
[2] 3 Valve Manifold, Instrument:www.swagelok.com:Product Catalog.
[3] 5 Valve Manifold, Instrument:www.swagelok.com:Product Catalog.
[4] 5 Valve Manifold, Instrument:Sabre Valve:Product Catalog.
[5] Fitting, Tubing and Nipples (HP)1/30/2014Autoclave Engineers: Product Catalog.
[6] Impulse Lines for Differential-Pressure Flow meters - Best Practice Guide :M.J. Reader Harris & J.M. McNaught:NEL Glasgow UK Sept'2005.
[7] Installation Guidelines for C&I :Laying of Impulse pipe :BHEL India Write up.
[8] Instrument Installation:Telisman Energy Inc. : General Specification.
[9] Instrumentation Tubing and Their Conncetions: Instrumentationtubing.blogspot.in/2012.

www.EngineeringBooksPDF.com

[10] Instruments Installation Details :Copper Cameron Valves USA: Product buletin.
[11] Local Instrument Enclosures and Rack:Pyrotech:Technical Catalog.
[12] Misc. Fittings and accessories:Hex Valves (Richard Industries Valve group):Technical Product Bulletin.
[13] Polaris Engineering standard: Polaris Engineering:Internet Document.
[14] Standard Design Criteria/ Guideline for Main Plant Pacakge (2X500 MW TPP):Central Electricity Authority:New Delhi 2010.
[15] Valve Manifold :Baxcell Instrument Valves & Fittings Pvt.Ltd.
[16] Venturi tube, Flow tubes and Flow Nozzles:W.H.Howe, L.D.Dinapoli and J.B.Arant: Instrument Engineers' Handbook– B.G.Liptak –Book CRS press/Taylor & Francis 2006.
[17] Best Practices For Process Instrumentation Cabling:S.M. Al Abeedjah:Intech. March 2008.
[18] Best Practices for terminating Fiber Optic Cabling :D.Munch & T.Reinert Ideal industries Inc.:Electrical Construction and maintenance Apr'2004.
[19] Best Practices for terminating Fiber Optic Cabling :D.Payerle and S.Lindhart, IDEAL Industries, Inc.:Electrical Construction and maintenance Sept'2005.
[20] Considerations for Instrument Grounding:K.Y. Lung Agilent Technologies Tiwan:Application note.
[21] Electrical Connection HART version :ABB 2600 T Transmitter :ABB Catalog.
[22] Extension and Compensating Cable : ABB Limited : Product Catalog.
[23] Grounding and Shielding :R. Morrison President INSTRUM: CALEX.
[24] Grounding and wiring of Protection and Control Equipment:ABB Limited: Technical Document Feb'2002.
[25] Instrumentation Tray Cables:Wire Wisdom:Internet Document Feb 1997.
[26] Power Separation Guidelines:Data Network Resource: http://www.rhyshaden.com/pwrsep.htm (Internet Document).
[27] Process Industry Practices Process Control:PIP PCCEL001: Dec-99.
[28] Proper Grounding of Instrumentations and control Systems in Hazardous Locations:J Zullo MTL Americas:Explosion Protection and Hazardous Locations Conference 2009 – IDC Technologies.
[29] Thermocouple cables PVC insulation for fossil power plant:Nexans Cables:Prodcut Catalog.
[30] XLPE Instrument Cables:Caledonian Cables UK: Product catalog.

www.EngineeringBooksPDF.com

Appendix I

Process and Mechanical Standard Table

STANDARD PREFIXES

TABLE AP1/A Conversion Tables of Units

Coded prefix p	Meaning of prefixed unit	Multiply by	Coded prefix	Meaning of prefixed unit	Multiply by
da	deka	10	d	deci	10^{-1}
h	hecto	100	c	centi	10^{-2}
k	kilo	1000	m	milli	10^{-3}
M	mega	10^{6}	μ	micro	10^{-6}
G	giga	10^{9}	n	nano	10^{-9}
T	tera	10^{12}	p	pico	10^{-12}
P	peta	10^{15}	f	femto	10^{-15}
E	exa	10^{18}	a	atto	10^{-18}
Z	zeta	10^{21}	z	zepto	10^{-21}
Y	yotta	10^{24}	y	yocto	10^{-24}

STANDARD UNITS

TABLE AP1/B.1 Standard Units for Temperature

Celsius	C	K − 273.15	(F − 32) × 5/9	(R − 491.67) × 5/9
Rankine	R	K × 9/5	F + 459.67	C × 9/5 + 491.67
Fahrenheit	F	R − 459.67	C × 9/5 +32	K × 9/5 − 459.67
Kelvin	K	C + 273.15	R × 5/9	(F + 459.67) × 5/9

TABLE AP1/B.2 Standard Units for Pressure

Bar	bar	10^5 N/m^2	Atmospheres	atm	1.01325 × 10^5 N/m^2
Pascal	Pa	1 N/m^2	Inches of mercury	inHg	3.387 kPa
Pounds per square inch	psi	1 lb/in^2	Millimeters of mercury	mmHg	0.1333 kPa
Pounds per square foot	psf	1 lb/ft^2	Torr	torr	1.333224 Pa
Kilo psi	ksi	1000.0 psi			

www.EngineeringBooksPDF.com

TABLE AP1/B.3 Standard Units for Volume

Liter	L	1/1000.0 m^3	Barrel (petroleum)	barrel	158.9873 L
Gallon	gal	3.785412 L	Fluid ounce	oz_fl	29.57353 ml
Pint (U.S. liquid)	pint	1/8. gal	Tablespoon	tbl	1/32. pint
Quart (U.S. liquid)	qt	2 pint	Teaspoon	tsp	1/3. tbl
Pint (U.S. dry)	dpint	0.5506105 L	Cup	cup	16. tbl
Quart (U.S. dry)	dqt	2 dpint			

TABLE AP1/B.4 Standard Units for Mass

Gram	g	0.001 kg	Short Ton	ton	2000 lbm
Pound mass	lbm	0.45359237 kg	Long Ton	ton_l	2240 lbm
Tonne	T	1000 kg	Ounce	oz	28.34952 g
Tonne	T	2205 lb	Grain	gr	64.79891 mg
Troy pound	lbt	0.3732417 kg	Hundredweight	cwt	112 lbs/4 quarter
Carat (metric)	carat	0.2 g	Pennyweight	dwt	1.55174 g

TABLE AP1/B.5 Standard Units for Distance

Foot	ft	0.3048 m	Astronomical unit	AU / au	1.49598×10^{11} m
Inch	In	1.0/12.0 ft	Angstrom	Ang	10^{-10} m
Mile	mile	5280.0 ft	Angstrom	\\AA	1 Ang
League	league	3 mile	furlong	furlong	220 yd
milli-inch	mil	0.001 in	fathom	fathom	6 ft
Parsec	pc	3.085678×10^6 m	Rod	rd	16.5 ft
Meter	m	1.094 yd	Meter	m	10^6 μm
Meter	m	3.281ft	Nautical mile/h	knot	6080 ft/sec 1.853km/sec
Meter	m	39.37 in			

TABLE AP1/B.6 Standard Units for Area

Square mile	640 acres	259 hectares	Square meter	1.196 sq yds	10.76 sq. ft
Acre	4840 sq. yds	0.405 hectares	Square kilometer	100 hectares	0.3861 sq. mile
Square yds	9 sq. ft	0.836 sq. m	Hectares (ha)	10^4 sq. m	2.471 acres

www.EngineeringBooksPDF.com

TABLE AP1/B.7 Standard Units for Force/Weight

Newton	N	1 kg m/s^2	Poundal	poundal	1 lbm ft/sec^2
Dyne	dyn	10^{-5} N	Kilopound	kip	1000 lbf
Pound force	lb	lbm G	Kilogram force	kgf	kg G
Pound force	lbf	lbm G			

TABLE AP1/B.8 Standard Units for Energy

Joule	J	1 N m	British Thermal Unit	Btu	107.6 m.kg
British Thermal Unit	BTU/Btu	1055.056 J	British Thermal Unit	Btu	0.2520 kcal
Calorie	cal	4.1868 J	Erg	erg	10^{-7} J
Calorie	Cal	4.1868 kJ	Ton of TNT	TNT	4.184×10^9 J
British Thermal Unit	Btu	778 ft-lb	Electron volt	eV	1.602177×10^{-12}erg

TABLE AP1/B.9 Standard Units for Power

Watt	W	1 J/s	Horse power	hp	550 ft lb/s
Kilowatt	kW	738ft-lb/sec	Horse power	hp	746 W
Kilowatt	kW	102 m.kg/sec	Horse power	hp	76 m.kg/sec

TABLE AP1/B.10 Standard Units for Density

Density	Cu.ft/lb	0.0624 Cu.m/kg	Concentration	lb/Cu.ft	16.02 kg/Cu.m
Density	Cu.m/kg	16.02 Cu.ft/lb			

TABLE AP1/B.11 Standard Units for Electromagnetism

Coulomb	Co	1 Amp.sec	Oersted	Oe	79.57747 Amp turn/m
Faraday	faraday	96485.31 Co	Webber	Wb	V s
Farad	farad	Co/V	Tesla	Tesla	Wb/m^2
Stokes	stokes	10^{-4} m^2/sec	Henry	H	Wb/A

TABLE AP1/B.12 Standard Units for Viscosity

Dynamic	pascal.sec	10 Poise (P)	Kinematic	m^2/sec	10^4 Stokes (St)
Dynamic	pascal.sec	10dyne.sec/cm^2	Kinematic	1cm^2/sec	1cSt

www.EngineeringBooksPDF.com

FLANGE DIMENSIONS

They are determined by pipe size and pressure class required for the application. Most of these dimensions have been standardized and published as ASME, MSS, API, or other standardization organization specifications. ASME/ANSI B16.5 provides dimensions and tolerances for flanges in pipe sizes from 1/2" through 24"and in classes ranging from 150 through 2500.

TABLE AP1/C.1 Flange Dimensions: Class 150

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1/4	3-3/8	4	1/2	2-1/4
1/2	3-1/2	4	1/2	2-3/8
3/4	3-7/8	4	1/2	2-3/4
1	4-1/4	4	1/2	3-1/8
1 1/4	4-5/8	4	1/2	3-1/2
1-1/2	5	4	1/2	3-7/8
2	6	4	5/8	4-3/4
2-1/2	7	4	5/8	5-1/2
3	7-1/2	4	5/8	6
3-1/2	8-1/2	8	5/8	7
4	9	8	5/8	7-1/2
5	10	8	3/4	8-1/2
6	11	8	3/4	9-1/2
8	13-1/2	8	3/4	11-3/4
10	16	12	7/8	14-1/4
12	19	12	7/8	17
14	21	12	1	18-3/4
16	23-1/2	16	1	21-1/4
18	25	16	1-1/8	22-3/4
20	27-1/2	20	1-1/8	25
24	32	20	1-1/4	29-1/2

TABLE AP1/C.2 Flange Dimensions: Class 300

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1/4	3-3/8	4	1/2	2-1/4
1/2	3-3/4	4	1/2	2-5/8
3/4	4-5/8	4	5/8	3-1/4
1	4-7/8	4	5/8	3-1/2

www.EngineeringBooksPDF.com

TABLE AP1/C.2 Flange Dimensions: Class 300—cont'd

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1-1/4	5-1/4	4	5/8	3-7/8
1-1/2	6-1/8	4	3/4	4-1/2
2	6-1/2	8	5/8	5
2-1/2	7-1/2	8	3/4	5-7/8
3	8-1/4	8	3/4	6-5/8
3-1/2	9	8	3/4	7-1/4
4	10	8	3/4	7-7/8
5	11	8	3/4	9-1/4
6	12-1/2	12	3/4	10-5/8
8	15	12	7/8	13
10	17-1/2	16	1	15-1/4
12	20-1/2	16	1-1/8	17-3/4
14	23	20	1-1/8	20-1/4
16	25-1/2	20	1-1/4	22-1/2
18	28	24	1-1/4	24-3/4
20	30-1/2	24	1-1/4	27
24	36	24	1-1/2	32

TABLE AP1/C.3 Flange Dimensions: Class 400

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1/4	3-3/8	4	1/2	2-1/4
1/2	3-3/4	4	1/2	2-5/8
3/4	4-5/8	4	5/8	3-1/4
1	4-7/8	4	5/8	3-1/2
1-1/4	5-1/4	4	5/8	3-7/8
1-1/2	6-1/8	4	3/4	4-1/2
2	6-1/2	8	5/8	5
2-1/2	7-1/2	8	3/4	5-7/8
3	8-1/4	8	3/4	6-5/8
3-1/2	9	8	7/8	7-1/4
4	10	8	7/8	7-7/8

Continued

www.EngineeringBooksPDF.com

TABLE AP1/C.3 Flange Dimensions: Class 400—cont'd

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
5	11	8	7/8	9-1/4
6	12-1/2	12	7/8	10-5/8
8	15	12	1	13
10	17-1/2	16	1-1/8	15-1/4
12	20-1/2	16	1-1/4	17-3/4
14	23	20	1-1/4	20-1/4
16	25-1/2	20	1-3/8	22-1/2
18	28	24	1-3/8	24-3/4
20	30-1/2	24	1-1/2	27
24	36	24	1-3/4	32

TABLE AP1/C.4 Flange Dimensions: Class 600

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1/4	3-3/8	4	1/2	2-1/4
1/2	3-3/4	4	1/2	2-5/8
3/4	4-5/8	4	5/8	3-1/4
1	4-7/8	4	5/8	3-1/2
1-1/4	5-1/4	4	5/8	3-7/8
1-1/2	6-1/8	4	3/4	4-1/2
2	6-1/2	8	5/8	5
2-1/2	7-1/2	8	3/4	5-7/8
3	8-1/4	8	3/4	6-5/8
3-1/2	9	8	7/8	7-1/4
4	10-3/4	8	7/8	8-1/2
5	13	8	1	10-1/2
6	14	12	1	11-1/2
8	16-1/2	12	1-1/8	13-3/4
10	20	16	1-1/4	17
12	22	20	1-1/4	19-1/4
14	23-3/4	20	1-3/8	20-3/4
16	27	20	1-1/2	23-3/4
18	29-1/4	20	1-5/8	25-3/4
20	32	24	1-5/8	28-1/2
24	37	24	1-7/8	33

www.EngineeringBooksPDF.com

TABLE AP1/C.5 Flange Dimensions: Class 900

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1/2	4-3/4	4	3/4	3-1/4
3/4	5-1/8	4	3/4	3-1/2
1	5-7/8	4	7/8	4
1-1/4	6-1/4	4	7/8	4-3/8
1-1/2	7	4	1	4-7/8
2	8-1/2	8	7/8	6-1/2
2-1/2	9-5/8	8	1	7-1/2
3	9-1/2	8	7/8	7-1/2
4	11-1/2	8	1-1/8	9-1/4
5	13-3/4	8	1-1/4	11
6	15	12	1-1/8	12-1/2
8	18-1/2	12	1-3/8	15-1/2
10	21-1/2	16	1-3/8	18-1/2
12	24	20	1-3/8	21
14	25-1/4	20	1-1/2	22
16	27-3/4	20	1-5/8	24-1/2
18	31	20	1-7/8	27
20	33-3/4	20	2	29-1/2
24	41	20	2-1/2	35-1/2

TABLE AP1/C.6 Flange Dimensions: Class 1500

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1/2	4-3/4	4	3/4	3-1/4
3/4	5-1/8	4	3/4	3-1/2
1	5-7/8	4	7/8	4
1-1/4	6-1/4	4	7/8	4-3/8
1-1/2	7	4	1	4-7/8
2	8-1/2	8	7/8	6-1/2
2-1/2	9-5/8	8	1	7-1/2
3	10-1/2	8	1-1/8	8
4	12-1/4	8	1-1/4	9-1/2
5	14-3/4	8	1-1/2	11-1/2
6	15-1/2	12	1-3/8	12-1/2
8	19	12	1-5/8	15-1/2

Continued

www.EngineeringBooksPDF.com

TABLE AP1/C.6 Flange Dimensions: Class 1500—cont'd

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
10	23	12	1-7/8	19
12	26-1/2	16	2	22-1/2
14	29-1/2	16	2-1/4	25
16	32-1/2	16	2-1/2	27-3/4
18	36	16	2-3/4	30-1/2
20	38-3/4	16	3	32-3/4
24	46	16	3-1/2	39

TABLE AP1/C.7 Flange Dimensions: Class 2500

Nominal pipe size (NPS; inches)	Diameter of flange (inches)	Number of bolts	Diameter of bolts (inches)	Bolt circle (inches)
1/2	5-1/4	4	3/4	3-1/2
3/4	5-1/2	4	3/4	3-3/4
1	6-1/4	4	7/8	4-1/4
1-1/4	7-1/4	4	1	5-1/8
1-1/2	8	4	1-1/8	5-3/4
2	9-1/4	8	1	6-3/4
2-1/2	10-1/2	8	1-1/8	7-3/4
3	12	8	1-1/4	9
4	14	8	1-1/2	10-3/4
5	16-1/2	8	1-3/4	12-3/4
6	19	8	2	14-1/2
8	21-3/4	12	2	17-1/4
10	26-1/2	12	2-1/2	21-1/4
12	30	12	2-3/4	24-3/8

VISCOSITY

Dynamic viscosity of liquid water at different temperatures up to the normal boiling point is listed below.

TABLE AP1/D.1 Dynamic Viscosity of Liquid Water

Temperature in °C	10	20	30	40	50	60	70	80	90	100
Viscosity in mPa.sec	1.308	1.002	0.7978	0.6531	0.5471	0.4668	0.4044	0.3550	0.3150	0.2822

www.EngineeringBooksPDF.com

Dynamic viscosities of some gases at 1kg/cm^2 are listed below:

TABLE AP1/D.2 Dynamic Viscosity of Gas

	Air	Hydrogen	Helium	Argon	Xenon	Carbon dioxide	Methane	Ethane
Temperature in °C	0/27	0/27	27	27	0/27	27	27	27
Viscosity in μPa.sec	17.4/18.6	8.4/9	20	22.9	21.2/23.2	15	11.2	9.5

TABLE AP1/D.3 Dynamic Viscosity of Differential Liquids

Acetone	0.306	Mercury	1.526
Benzene	0.604	Methanol	0.544
Castor oil	985	Nitrobenzene	1.863
Corn syrup	1380.6	Nitrogen(liquid) at −196°C	0.158
Ethanol	1.074	Propanol	1.945
Ethylene glycol	16.1	Olive oil	81
Glycerol (at 20°C)	1200	Pitch	2.3×10^{11}
HFO	2022	Sulfuric acid	24.2

Viscosity (in cP) of liquids (at 25°C unless otherwise specified); 1cP (centi poise) = 1 mPa.s.
HFO, heavy fuel oil.

TABLE AP1/D.4 Dynamic Viscosity of Other Liquids

Blood (37°C)	$(3-4) \times 10^{-3}$	Molten chocolate	45–130
Honey	2–10	Ketchup	50–100
Molasses	5–10	Lard	≈100
Molten glass	10–1000	peanut butter	≈250
Chocolate syrup	10–25		

Viscosity (in Pa.s) of various fluids (at 25°C unless otherwise specified).

DYNAMIC VISCOSITY

Definition: If a fluid with a viscosity of 1 Pa.s is placed between two plates, and one plate is pushed sideways with a shear force of 1 Pa, it moves a distance equal to the thickness of the layer between the plates in 1 s.

Symbol: Greek letter mu (μ); http://en.wikipedia.org/wiki/Viscosity - cite_note-3used by mechanical and chemical engineers; Greek letter eta (η); used by chemists, physicists.

SI unit: pascal (Pa), Pascal second (Pa.s) or Newton.second/sq. meter (N·s/m^2) or kg/(m·s).

www.EngineeringBooksPDF.com

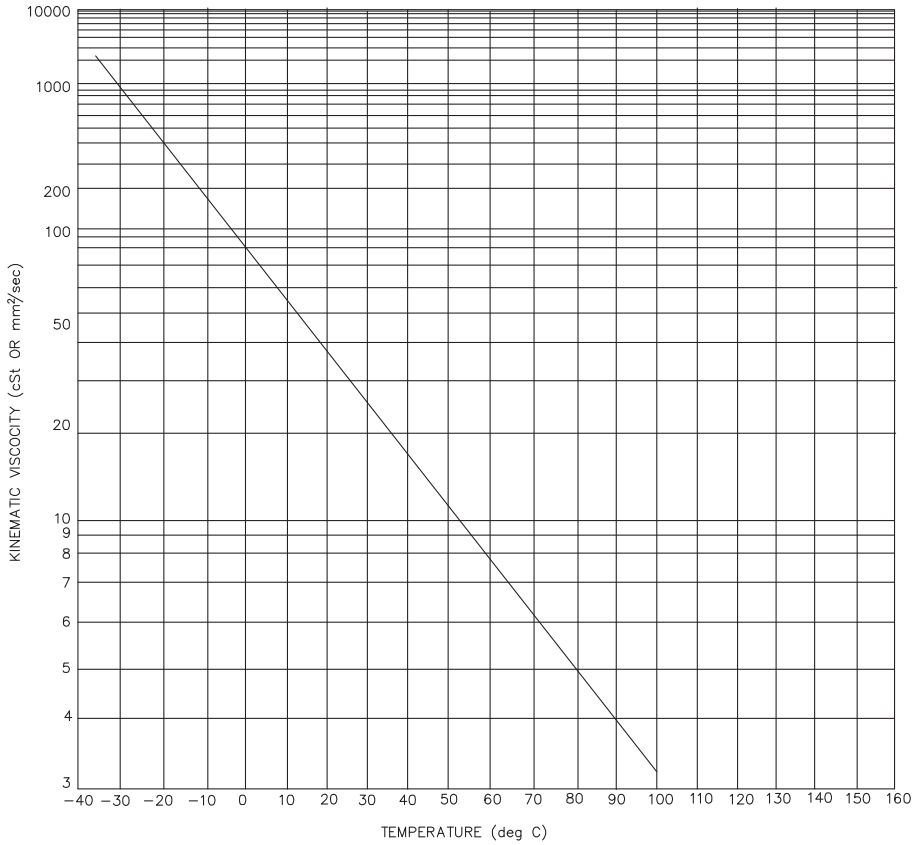


FIGURE A/1-1 Typical kinematic viscosity−temperature graph of a liquid.

Cgs unit: poise (P; named after Jean Louis Marie Poiseuille) or centi poise (cP).
Relations: 1 Pa.s = 10 P = 1000 cP.

KINEMATIC VISCOSITY

Definition: It is the ratio of viscosity and density or μ/ρ.
Symbol: Greek letter nu (ν).
SI unit: m^2/s (no special name). The SI unit of ρ is kg/m^3.
Cgs unit: Stokes (St; named after George Gabriel Stokes) or centistokes (cSt).
Relations: 1 m^2/s = 10,000 St = 10^6 cSt or 1 mm^2/s = 1 cSt. Water at 20°C has a kinematic viscosity of about 1 cSt.

Sometimes the ratio of the inertial force (resistant to change or motion) to viscous (heavy and gluey) force is required for calculation purposes, for example, Reynold's number ($Re = \mu.L/\nu$).

Effect of Temperature on Viscosity

The temperature and viscosity of liquids are inversely proportional. To be more specific, when temperature increases, viscosity decreases. For liquid services, kinematic viscosity of liquid is defined at a set temperature (for example, 40°C for oil as per the ISO standard). The curve is linear with viscosity values in the logarithmic scale (vertical axis) and temperature values in linear scale (horizontal axis). Each viscosity−temperature characteristic line is plotted according to their viscosity index, which is actually the gradient of the line. The greater the value of the viscosity index, the smaller the change in viscosity for a given change in temperature and vice versa. A sample characteristic curve is shown in Figure A/1-1.

www.EngineeringBooksPDF.com

TABLE AP1/E Combustion Equations and Heat Release

Combustible	Molecular Weight	Reaction	Heat Release in Btu/lb
Carbon	12	$C + O_2 => CO_2$	14,100
Hydrogen	2	$2H_2 + O_2 => 2H_2O$	61,000
Methane	16	$CH_4 + 2O_2 => CO_2 + 2H_2O$	23,900
Ethane	30	$2C_2H_6 + 7O_2 => 4CO_2 + 6H_2O$	22,300
Propane	44	$C_3H_8 + 5O_2 => 3CO_2 + 4H_2O$	21,500
Butane	58	$2C_4H_{10} + 13O_2 => 8CO_2 + 10H_2O$	21,300
Pentane	72	$C_5H_{12} + 8O_2 => 5CO_2 + 6H_2O$	22,000
Sulfur	32	$S + O_2 => SO_2$	4000
Hydrogen Sulfide	34	$2H_2S + 3O_2 => 2SO_2 + 2H_2O$	7100

The viscosity of gases, on the other hand, increases as temperature increases and is approximately proportional to the square root of the temperature. The viscosity—temperature characteristic line is plotted with both parameters in linear scale, and the graph indicates a hyperbolic curve.

BIBLIOGRAPHY

[1] ASME/ANSI B16.5 for flange details.
[2] Viscosity of Hydraulic Oil: By Martin Cuthbert MEng (Hons), Webtec Products Ltd.U.K.
[3] Documents on Reynold's Number : By National Aeronautics and Space Administration, Glen Research Centre.

www.EngineeringBooksPDF.com

Appendix II

Electrical Data and Tables

TABLE AP2/1 Stranded Annealed Copper Conductor Size with Electrical resistance

Size (AWG)	Diameter of each strand	Cross-sectional area (in mm^2; 7 strands)	Resistance in ohm/km at 20°C (as per EN 50288-7[a])	Resistance in ohm/km at 20°C (as per UL 13[b])
24	0.579	0.205	—	91.1
22	0.729	0.327	—	57.6
—	0.9	0.5	36.8	—
20	0.919	0.517	—	35.8
—	1.11	0.75	25	—
18	1.16	0.82	—	22.8
—	1.29	1.0	18.5	—
16	1.46	1.3	—	14.2
—	1.59	1.5	12.3	—
14	1.85	2.1	—	8.94
—	2.01	2.5	7.56	—
12	2.32	3.3	—	5.63
—	2.58	4.0	4.7	—

[a] *European standard.*
[b] *Underwriters Laboratory Inc. (United States).*

MULTIPAIR INSTRUMENTATION CABLES: SIZE, RESISTANCE, AND OTHER PHYSICAL DATA

TABLE AP2/2 Multicore Stranded Annealed Copper Conductor Size with Physical Data and Current Rating (Conforming IStrun -1 694)

Nominal area (in mm)	Number/ nominal diameter of each strand	Core diameter (in mm)	Nominal insulation thickness (in mm)	Nominal sheath thickness (in mm)			Overall diameter (in mm)			Rated current (in Amp)
				2 core	3 core	4 core	2 core	3 core	4 core	
0.5	16/0.2	2.2	0.6	0.9	0.9	0.9	6.3	6.7	7.3	4
0.75	24/0.2	2.45	0.6	0.9	0.9	0.9	6.8	7.2	8.0	7
1.0	32/0.2	2.6	0.6	0.9	0.9	0.9	7.1	7.5	8.3	12

Continued

www.EngineeringBooksPDF.com

TABLE AP2/2 Multicore Stranded Annealed Copper Conductor Size with Physical Data and Current Rating (Conforming IStrun -1 694)—cont'd

Nominal area (in mm)	Number/ nominal diameter of each strand	Core diameter (in mm)	Nominal insulation thickness (in mm)	Nominal sheath thickness (in mm)			Overall diameter (in mm)			Rated current (in Amp)
1.5	30/0.25	2.9	0.6	0.9	0.9	1.0	7.6	8.2	9.3	15
2.5	50/0.25	3.6	0.7	1.0	1.0	1.0	9.0	9.6	10.6	20
4.0	56/0.3	4.3	0.8	1.0	1.0	1.0	10.4	11.4	12.6	27

Collective Screened Pair Cables as Recommended by EN 50288-7

All dimensions are approximate.

TABLE AP2/3.1 Seven Strands of 0.30 mm Diameter of Each: Conductor with 0.5 mm^2 Cross Section

Number of pairs	Weight (kg/km)	Diameter over bedding (mm)	O/D (mm)	Conductor resistance (ohms/km)
1	175.00	5.2	9.5	36.00
2	250.00	7.6	12.0	36.00
4	315.00	8.8	13.5	36.00
8	440.00	11.3	16.0	36.00
12	565.00	13.5	18.0	36.00
24	1,000.00	18.3	24.0	36.00

TABLE AP2/3.2 Seven Strands of 0.37 mm Diameter of Each: Conductor with 0.75 mm^2Cross Section

Number of pairs	Weight (kg/km)	Diameter over bedding (mm)	O/D (mm)	Conductor resistance (ohms/km)
1	195.00	5.6	10.0	24.50
2	250.00	7.6	12.0	36.00
4	370.00	10.9	14.5	24.50
8	535.00	12.8	17.5	24.50
12	670.00	15.1	20.0	24.50
24	1,230.00	20.8	27.0	24.50

TABLE AP2/3.3 Seven Strands of 0.44 mm Diameter of Each: Conductor with 1.3 mm^2 Cross Section

Number of pairs	Weight (kg/km)	Diameter over bedding (mm)	O/D (mm)	Conductor resistance (ohms/km)
1	240.00	6.8	11.0	14.20
2	385.00	10.4	15.0	14.20
4	480.00	12.0	16.5	14.20

Continued

www.EngineeringBooksPDF.com

TABLE AP2/3.3 Seven Strands of 0.44 mm Diameter of Each: Conductor with 1.3 mm^2 Cross Section—cont'd

Number of pairs	Weight (kg/km)	Diameter over bedding (mm)	O/D (mm)	Conductor resistance (ohms/km)
8	720.00	15.7	20.5	14.20
12	1,095.00	18.9	24.5	14.20
24	1,780.00	25.9	32.0	14.20

Individual and Collective Screened Pair Cables as Recommended by EN 50288-7

TABLE AP2.3.4 Seven Strands of 0.3 mm Diameter of Each: Conductor with 0.5 mm^2 Cross Section

Number of pairs	Weight (kg/km)	Diameter over bedding (mm)	O/D (mm)	Conductor resistance (ohms/km)
2	310.00	8.7	13.5	36.00
4	375.00	10.2	15.0	36.00
8	540.00	13.1	18.0	36.00
12	685.00	15.7	20.5	36.00
24	1,255.00	21.5	27.5	36.00

TABLE AP2.3.5 Seven Strands of 0.37 mm Diameter of Each: Conductor with 0.75 mm^2 Cross Section

Number of pairs	Weight (kg/km)	Diameter over bedding (mm)	O/D (mm)	Conductor resistance (ohms/km)
2	345.00	9.7	14.5	24.50
4	430.00	11.2	16.0	24.50
8	620.00	14.4	19.0	24.50
12	930.00	17.4	23.0	24.50
24	1,495.00	24.0	30.0	24.50

TABLE AP2.3.6 Seven Strands of 0.44 mm Diameter of Each: Conductor with 1.3 mm^2 Cross Section

Number of pairs	Weight (kg/km)	Diameter over bedding (mm)	O/D (mm)	Conductor resistance (ohms/km)
2	435.00	11.4	16.0	14.20
4	550.00	13.4	18.0	14.20
8	970.00	17.6	23.0	14.20
12	1,250.00	21.1	27.0	14.20
24	2,265.00	29.2	36.5	14.20

www.EngineeringBooksPDF.com

TABLE AP2/4 Temperature versus Resistance Table (PRT 100)

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
0	100	41	115.93	82	131.66	123	147.19
1	100.39	42	116.31	83	132.04	124	147.57
2	100.78	43	116.7	84	132.42	125	147.94
3	101.17	44	117.08	85	132.8	126	148.32
4	101.56	45	117.47	86	133.18	127	148.7
5	101.95	46	117.85	87	133.56	128	149.07
6	102.34	47	118.24	88	133.94	129	149.45
7	102.73	48	118.62	89	134.32	130	149.82
8	103.12	49	119.01	90	134.7	131	150.2
9	103.51	50	119.4	91	135.08	132	150.57
10	103.9	51	119.78	92	135.46	133	150.95
11	104.29	52	120.16	93	135.84	134	151.33
12	104.68	53	120.55	94	136.22	135	151.7
13	105.07	54	120.93	95	136.6	136	152.08
14	105.46	55	121.32	96	136.98	137	152.45
15	105.85	56	121.7	97	137.36	138	152.83
16	106.24	57	122.09	98	137.74	139	153.2
17	106.63	58	122.47	99	138.12	140	153.58
18	107.02	59	122.86	100	138.5	141	153.95
19	107.4	60	123.24	101	138.88	142	154.32
20	107.79	61	123.62	102	139.26	143	154.7
21	108.18	62	124.01	103	139.64	144	155.07
22	108.57	63	124.39	104	140.02	145	155.45
23	108.96	64	124.77	105	140.39	146	155.82
24	109.35	65	125.16	106	140.77	147	156.19
25	109.73	66	125.54	107	141.15	148	156.57
26	110.12	67	125.92	108	141.53	149	156.94
27	110.51	68	126.31	109	141.91	150	157.31
28	110.9	69	126.69	110	142.29	151	157.69
29	111.28	70	127.07	111	142.66	152	158.06
30	111.67	71	127.45	112	143.04	153	158.43
31	112.06	72	127.84	113	143.42	154	158.81
32	112.45	73	128.22	114	143.8	155	159.18
33	112.83	74	128.6	115	144.17	156	159.55
34	113.22	75	128.98	116	144.55	157	159.93
35	113.61	76	129.37	117	144.93	158	160.3

www.EngineeringBooksPDF.com

TABLE AP2/4 Temperature versus Resistance Table (PRT 100)—cont'd

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
36	113.99	77	129.75	118	145.31	159	160.67
37	114.38	78	130.13	119	145.68	160	161.04
38	114.77	79	130.51	120	146.06	161	161.42
39	115.15	80	130.89	121	146.44	162	161.79
40	115.54	81	131.27	122	146.81	163	162.16

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
164	162.53	205	177.68	246	192.63
165	162.9	206	178.05	247	192.99
166	163.27	207	178.41	248	193.35
167	163.65	208	178.78	249	193.71
168	164.02	209	179.14	250	194.07
169	164.39	210	179.51	251	194.44
170	164.76	211	179.88	252	194.8
171	165.13	212	180.25	253	195.16
172	165.5	213	180.61	254	195.52
173	165.87	214	180.97	255	195.88
174	166.24	215	181.34	256	196.24
175	166.61	216	181.71	257	196.6
176	166.98	217	182.07	258	196.96
177	167.35	218	182.44	259	197.33
178	167.72	219	182.8	260	197.69
179	168.09	220	183.17	261	198.05
180	168.46	221	183.53	262	198.41
181	168.83	222	183.9	263	198.77
182	169.2	223	184.26	264	199.13
183	169.57	224	184.63	265	199.49
184	169.94	225	184.99	266	199.85
185	170.31	226	185.36	267	200.21
186	170.68	227	185.72	268	200.57
187	171.05	228	186.09	269	200.93
188	171.42	229	186.45	270	201.29
189	171.79	230	186.82	271	201.65
190	172.16	231	187.18	272	202.01
191	172.53	232	187.54	273	202.36
192	172.9	233	187.91	274	202.72
193	173.26	234	188.27	275	203.08

Continued

www.EngineeringBooksPDF.com

—cont'd

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
194	173.63	235	188.63	276	203.44
195	174	236	189	277	203.8
196	174.37	237	189.36	278	204.16
197	174.74	238	189.72	279	204.52
198	175.1	239	190.09	280	204.88
199	175.47	240	190.45	281	205.23
200	175.84	241	190.81	282	205.59
201	176.21	242	191.18	283	205.95
202	176.57	243	191.54	284	206.31
203	176.94	244	191.9	285	206.67
204	177.31	245	192.26	286	207.02

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
287	207.38	328	221.94	369	236.31
288	207.74	329	222.29	370	236.65
289	208.1	330	222.65	371	237
290	208.45	331	223	372	237.35
291	208.81	332	223.35	373	237.7
292	209.17	333	223.7	374	238.04
293	209.52	334	224.06	375	238.39
294	209.88	335	224.41	376	238.74
295	210.24	336	224.76	377	239.09
296	210.59	337	225.11	378	239.43
297	210.95	338	225.46	379	239.78
298	211.31	339	225.81	380	240.13
299	211.66	340	226.17	381	240.47
300	212.02	341	226.52	382	240.82
301	212.37	342	226.87	383	241.17
302	212.73	343	227.22	384	241.51
303	213.09	344	227.57	385	241.86
304	213.44	345	227.92	386	242.2
305	213.8	346	228.27	387	242.54
306	214.15	347	228.62	388	242.89
307	214.51	348	228.97	389	243.24
308	214.86	349	229.32	390	243.59
309	215.22	350	229.67	391	243.93
310	215.57	351	230.02	392	244.28

www.EngineeringBooksPDF.com

—cont'd

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
311	215.93	352	230.37	393	244.62
312	216.28	353	230.72	394	244.97
313	216.64	354	231.07	395	245.31
314	216.99	355	231.42	396	245.66
315	217.35	356	231.77	397	246
316	217.7	357	232.12	398	246.35
317	218.05	358	232.47	399	246.69
318	218.41	359	232.82	400	247.04
319	218.76	360	233.17	401	247.38
320	219.12	361	233.52	402	247.73
321	219.47	362	233.87	403	248.07
322	219.82	363	234.22	404	248.41
323	220.18	364	234.56	405	248.76
324	220.53	365	234.91	406	249.1
325	220.88	366	235.26	407	249.45
326	221.24	367	235.61	408	249.79
327	221.59	368	235.96	409	250.13

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
410	250.48	451	264.45	Negative temperature	
411	250.82	452	264.79	(–)	
412	251.16	453	265.13	200	18.49
413	251.5	454	265.47	199	18.93
414	251.85	455	265.8	198	19.36
415	252.19	456	266.14	197	19.79
416	252.53	457	266.48	196	20.22
417	252.88	458	266.82	195	20.65
418	253.22	459	267.15	194	21.08
419	253.56	460	267.49	193	21.51
420	253.9	461	267.83	192	21.94
421	254.24	462	268.17	191	22.37
422	254.59	463	268.5	190	22.8
423	254.93	464	268.84	189	23.23
424	255.27	465	269.18	188	23.66
425	255.61	466	269.51	187	24.09
426	255.95	467	269.85	186	24.52
427	256.29	468	270.19	185	24.94

Continued

www.EngineeringBooksPDF.com

—cont'd

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
428	256.64	469	270.52	184	25.37
429	256.98	470	270.86	183	25.8
430	257.32	471	271.2	182	26.23
431	257.66	472	271.53	181	26.65
432	258	473	271.87	180	27.08
433	258.34	474	272.2	179	27.5
434	258.68	475	272.54	178	27.93
435	259.02	476	272.88	177	28.35
436	259.36	477	273.21	176	28.78
437	259.7	478	273.55	175	29.2
438	260.04	479	273.88	174	29.63
439	260.38			173	30.05
440	260.72			172	30.47
441	261.06			171	30.9
442	261.4			170	31.32
443	261.74			169	31.74
444	262.08			168	32.16
445	262.42			167	32.59
446	262.76			166	33.01
447	263.1			165	33.43
448	263.43			164	33.85
449	263.77			163	34.27
450	264.11			162	34.69

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
Negative temperature		Negative temperature		Negative temperature		Negative temperature	
(–)		(–)		(–)		(–)	
167	32.59	128	48.82	89	64.7	50	80.31
166	33.01	127	49.23	88	65.11	49	80.7
165	33.43	126	49.64	87	65.51	48	81.1
164	33.85	125	50.06	86	65.91	47	81.5
163	34.27	124	50.47	85	66.31	46	81.89
162	34.69	123	50.88	84	66.72	45	82.29
161	35.11	122	51.29	83	67.12	44	82.69
160	35.53	121	51.7	82	67.52	43	83.08
159	35.95	120	52.11	81	67.92	42	83.48
158	36.37	119	52.52	80	68.33	41	83.88

www.EngineeringBooksPDF.com

—cont'd

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
Negative temperature		Negative temperature		Negative temperature		Negative temperature	
157	36.79	118	52.92	79	68.73	40	84.27
156	37.21	117	53.33	78	69.13	39	84.67
155	37.63	116	53.74	77	69.53	38	85.06
154	38.04	115	54.15	76	69.93	37	85.46
153	38.46	114	54.56	75	70.33	36	85.85
152	38.88	113	54.97	74	70.73	35	86.25
151	39.3	112	55.38	73	71.13	34	86.64
150	39.71	111	55.78	72	71.53	33	87.04
149	40.13	110	56.19	71	71.93	32	87.43
148	40.55	109	56.6	70	72.33	31	87.83
147	40.96	108	57	69	72.73	30	88.22
146	41.38	107	57.41	68	73.13	29	88.62
145	41.79	106	57.82	67	73.53	28	89.01
144	42.21	105	58.22	66	73.93	27	89.4
143	42.63	104	58.63	65	74.33	26	89.8
142	43.04	103	59.04	64	74.73	25	90.19
141	43.45	102	59.44	63	75.13	24	90.59
140	43.87	101	59.85	62	75.53	23	90.98
139	44.28	100	60.25	61	75.93	22	91.37
138	44.7	99	60.66	60	76.33	21	91.77
137	45.11	98	61.06	59	76.73	20	92.16
136	45.52	97	61.47	58	77.13	19	92.55
135	45.94	96	61.87	57	77.52	18	92.95
134	46.35	95	62.28	56	77.92	17	93.34
133	46.76	94	62.68	55	78.32	16	93.73
132	47.18	93	63.09	54	78.72	15	94.12
131	47.59	92	63.49	53	79.11	14	94.52
130	48	91	63.9	52	79.51	13	94.91
129	48.41	90	64.3	51	79.91	12	95.3
						11	95.69
						10	96.09
						9	96.48
						8	96.87
PRT 100 is the most commonly used resistance temperature						7	97.26
Detector (RTD) and hence the chart is reproduced						6	97.65

Continued

www.EngineeringBooksPDF.com

—cont'd

Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm	Deg °C	Ohm
Negative temperature		Negative temperature		Negative temperature		Negative temperature	
						5	98.04
Thermocouple elements used are of various types and for that reason are not included in this appendix due to space						4	98.44
						3	98.83
Constraint						2	99.22
						1	99.61
						0	100

BIBLIOGRAPHY

[1] IS:1554(PT-I)-1988 – Indian Standard
[2] BS: PAS 5308–1 :2009 (Part-1)- British Standard
[3] BS: PAS 5308–2 :2009 (Part-2)- British Standard
[4] BS EN 50288–7: 2005
[5] RTD Temperature vs. Resistance Table as per DIN 43 760

www.EngineeringBooksPDF.com

Appendix III

ISA Standard, Materials, Human Engineering, and Control Room

ISA standards and other material data, human engineering, and control room concepts have been outlined here for ready reference for the reader.

1.0 ISA STANDARDS

Presented below is a list of important and relevant ISA standards and technical papers.

TABLE APIII/1.0-1 List of Important ISA Standards

Publication Number		
Main Ref.	Sub Ref.	Title
1-55617-531-0		Standards Library for Measurements and Controls (ISA)
12.00.01	– 01.01, 02.01	Electrical Apparatus for Use in Hazardous Locations
12.10		Area Classification in Hazardous (Classified) Dust Location
12.16.01	– 16.01, 22.01, 23.01, 25.01, 26.01	Electrical Apparatus for Use in Hazardous Locations (ISA)
18.1		Annunciator Sequence and Specifications (ISA)
20		Process, Measurements, Instruments, Primary Elements, Valves (ISA)
26		Dynamic Response Testing of Process Control Instrumentation
37.1		Electrical Transducer Nomenclature and Terminology (ISA)
37.3		Strain Gage Pressure Transducers (ISA)
37.6		Potentiometric Pressure Transducers (ISA)

Continued

TABLE APIII/1.0-1 List of Important ISA Standards—cont'd

Publication Number		
Main Ref.	Sub Ref.	Title
37.8		Specifications and Test of Strain Gauge Force Transducers (ISA)
37.10		Piezoelectric Pressure and Sound Pressure Transducers (ISA)
37.12		Potentiometric Displacement Transducer
5.1		Instrumentation Symbol and Identifications (ISA)
5.2		Binary Logic Diagram for Process Operations (ISA)
5.3		Graphic Symbol for Distributed controls/Shared Display System (ISA)
5.4		Instrumentation Loop Diagrams (ISA)
5.5		Graphic Symbols for Process Display (ISA)
50.02.2 TR 50.02-9	–.–. 2,3,4,5,6	Fieldbus Standard for Use in Industrial Control Systems (ISA)
51.1		Process Instrumentation Terminology
71.01	–.01,02,03,04	Environmental Conditions Process Measurements, Control Systems (ISA)
75.01.01		Flow Equations for Sizing CVs (ISA)
75.02		CV Capacity Test Procedure (ISA)
75.03		Integral Flanged Globe Style CV bodies (ISA)

Continued

www.EngineeringBooksPDF.com

TABLE APIII/1.0-1 List of Important ISA Standards—cont'd

Publication Number		
Main Ref.	Sub Ref.	Title
75.04		Dimension for Flangeless CV (ISA)
75.05		CV Terminology (ISA)
75.11		Inherent Flow Characteristics, Rangeability of CV (ISA)
75.12		Socket Weld, Screw End Globe Style CV (ISA)
75.13		Method of Evaluating Performance of Positioner (ISA)
75.14	–.14,15	Dimensions of Butt Weld End Globe Style CV (ISA)
75.16		Dimensions of Flanged Globe Style CV (ISA)
75.17		CV Aerodynamic Noise Production
75.19		Hydrostatic Testing Of CV
75.22		Dimension of Flanged Globe Style Angle CV (ISA)
77.13.01		FFPP Steam Turbine Bypass
77.20		FFPP Simulator Functional requirements (ISA)
77.41		FFPP Boiler Combustion controls (ISA)
77.42.01		FFPP Feed Water Control Systems (ISA)
77.43		FFPP Unit/Plant Development (ISA)
77.44		FFPP Steam Temperature Control Systems (ISA)
77.70		FFPP Instrument Piping Installations (ISA)
82.02.01, 82.03		Safety Standard for Electrical and Electronic Equipment (ISA)
82.02.02, 82.02.04		Safety Standard for Electrical Equipment (ISA)
92.02.01-1 92.02.02		Carbon Monoxide Detection Instruments (ISA)
RA8425		Standards Library for Automation and Control
REWIC01		Programmable Logic Controllers in Safety-Related System
REWIC02		Achieving Safety in Distributed Systems (ISA)
RP2.1		Manometer Tables (ISA)
RP42.1		Nomenclature for Instruments Tube Fittings (ISA)
RP60.3		Human Engineering for CC (ISA)
RP60.4		Documentation for CC
RP60.6		Name Plate, Labels, Tags for CC
RP60.8		Electrical Guide for CC
RP60.9		Pipe Guide for CC
TR77.60.04		FFPP Human Machine interface

CC, control centers; CV, control valve; FFP, fossil fuel power plant.

2.0 MATERIAL COMPOSITIONS

Presented below is a list of important and relevant materials with the associated composition normally used in power plants

2.1 Carbon and Ceramics

TABLE AP III/2.0-1 Carbon and Ceramics Composition Details

Material type	Materials	Description
Carbon	Karbate (carbon)	Impervious carbon
	Karbate (graphite)	Impervious graphite
Ceramics	Pfaudler glass lining	Glass-lined metallic equipment (steel)
	Plate glass lining	Polished plate glass, flat or bent
	Pyrex	Glass type

www.EngineeringBooksPDF.com

2.2 Plastics and Rubber

TABLE AP III/2.0-2 Plastics and Rubber Composition Details

Material type	Materials	Description
Plastic	Koroseal	Plasticized polyvinyl chloride
	Polythene	Polyethylene
	Teflon	Polymerized tetrafluoroethylene
	Tygon	Synthetic compound
Rubber	Ace hard rubber	Vulcanized rubber
	Butyl	Solid copolymer of isobutylene and isoprene
	Neoprene	Polymer of chloroprene
	Nitrile Rubber or NBR	Synthetic rubber copolymer of acrylonitrile and butadiene

2.3 Metals

All elements are indicated in their chemical formula and amount in percentage if not in traces. The composition given here is a broad spectrum. For actual composition, relevant standards such as ASTM and DIN should be referenced.

TABLE AP III/2.0-3 Commonly Used Metal Alloy Composition Details

Brass	Cu 60–65, Zn 35–40, Pb 0.5–3
Brass red	Cu 85, Zn 15
Bronze (comm)	Cu 90, Zn 10
Bronze phosphor	Cu 88, Zn 4, Sn 4, Pb 4
Bronze phosphor 10%	Cu 89.5–90, Sn, P 10–10.5
Hastelloy A	Ni 17–21, Mo 17–21, Fe
Hastelloy B	Ni 24–32, Mo 3–7, Fe 0.02–0.12, C
Hastelloy C	Ni 14–19, Mo 4–8, Fe 0.04–0.15, C 12–16, Cr 3–5.5, W
Hastelloy D	Ni 8–11, Si 2–5, Cu 1, Al
Monel	Ni 67,Cu 30, Fe 0.15, C
Nickel	Ni 99.4, Mn 0.2, Cu 0.15, Fe 0.05, Si

Continued

TABLE AP III/2.0-3 Commonly Used Metal Alloy Composition Details—cont'd

Nickel-silver A/B	A: Cu 65, Ni 18, Zn 17 B: Cu 55, Ni 18, Zn 27
Platinum	Pt 99.99
Silver	Ag 99.9
Stainless steel (SS) 301	Fe 16–18, Cr 6–8, Ni 0.08–0.15, C
SS302	Fe 17–19, Cr 8–10, Ni 0.08–0.15, C
SS303	Fe 17–19, Cr 8–10, Ni 0.15 (max), C 0.07 (min), P, S, Se 0.6
SS304	Fe1 8–20, Cr 8–11, Ni 0.08(max), C 2 (max), Mn
SS310	Fe 24–26, Cr 19–22, Ni 0.25 (max), C
SS316	Fe 16–18, Cr 10–14, Ni 0.1 (max), C 1.75–2.75, Mo
SS317	Fe 16–18, Cr 10–14, Ni 0.1 (max), C 1.75–2.75, Mo
SS321	Fe 17–19, Cr 8–11, Ni, Ti 5 × C
SS347	Fe 17–19,Cr 9–12, Ni ,Cb, 10 × C (min)
SS403	Fe 11.5–13, Cr 0.15 (max), C
SS410	Fe 11.5–13.5, Cr 0.15 (max), C
SS416	Fe 12–14,Cr 0.15 (max), C 0.07 (min), P, S, Se 0.6 (max), Mo
SS430	Fe 14–18, Cr 0.12 (max), C
SS446	Fe 23–27,Cr 0.35 (max), C 0.25 (max), N
Steel	Normal carbon steel C < 0.2, Mn 1.5 (max), Si 0.1–0.2%, Cr 0.4, S 0.06–0.3, P 0.04
Tantalum	>99.9 Ta
Worthite	Fe 20,Cr 24, Ni 0.07 (max), C 3.25, Si, 3, Mo 1.75, Cu 0.5, Mn

2.4 Service Temperature Limit of a Number of Commonly Used Materials

TABLE AP III/2.0-4 Temperature Limits for Commonly Used Materials

ASTM Designation/trade name	Description	Temperature range (°C)
EPDM	Ethylene propylene terpolymer	−40 to 135

Continued

www.EngineeringBooksPDF.com

TABLE AP III/2.0-4 Temperature Limits for Commonly Used Materials—cont'd

ASTM Designation/trade name	Description	Temperature range (°C)
NBR	Nitrile	−54 to 82
NR	Natural rubber	−29 to 93
PTFE	Polytetrafluoroethylene Polytetrafluoroethylene (glass/carbon filled)	−73 to 204 −73 to 232
Flexible graphite, Grafoil		−185 to 540

2.5 Designation of Commonly Used High Nickel Alloys

TABLE AP III/2.0-5 Casting Designation of Commonly Used Alloys

Casting designation	Wrought trade name	Generic designation
CF3		304L
CF8		304
CF3M		316L
CF8M		316
CG8M		317
CW2M	New Hastelloy C	Alloy C276
CXW2M	Hastelloy C22	Alloy C22
CW6MC	Inconel 625	Alloy 625
CY40	Inconel 600	Alloy 600
CZ100	Nickel 200	Alloy 200
LCB		LCB
LCC		LCC
N7M	Hastelloy B2	Alloy B2
WCB		WCB
WCC		WCC

3.0 ERGONOMIC CONTROL ROOM DESIGN CONCEPTS

In this part human engineering based on ISA RP 60.3 and ergonomic design of control rooms based on ISO 11064 (various parts) are briefly discussed. In Figure APIII/1 reachability of humans along with control room design basics are depicted to get an idea about control room design. Today's superior ergonomic design makes it possible to have a number of large screens at the back (behind the workstation console) with the ability to have live video as well as screens in the front, in addition to process control graphics, etc. For a better control room environment, remote graphics are used to make the control room computer free. In modern control rooms, operators can control local temperature, lighting, etc. Also these large screen units and workstation consoles are motorized so that height as well as distance between them can be adjusted for better viewing. Modern control room concepts (based on ABB EOW—Technical Specification) are shown in Figure AP III/2. In some control systems even dedicated iPads are used as control devices (e.g., 800x of ABB).

3.1 Human Body Dimensional Details

The data given below are based on ISA RP60.3. Only major relevant data are presented, and are based on normal humans (male). Unless otherwise stated, data are in meters.

TABLE AP III/2.0-6 Human Body Dimensional Details (Human Engineering)

Human position	Dimensional element	5th percentile	95th percentile
While standing on the floor	Vertical reach (hand up)	1.9	2.2
	Eye to floor	1.5	1.7
	Side arm reach from center of body on either side of body.	0.7	0.8
	Forward arm reach (in front)	0.7	0.8
	Chest circumference	0.87	1.1
	Elbow to floor	1.0	1.2
(In body)	Head height	-	0.255
	Chin to eye		0.125
	Arm swing (aft)		40°
While sitting on chair placed on the floor	Sitting height to floor	1.3	1.4
	Eye distance from floor (standard chair)	1.2	1.3

Continued

www.EngineeringBooksPDF.com

TABLE AP III/2.0-6 Human Body Dimensional Details (Human Engineering)—cont'd

Human position	Dimensional element	5th percentile	95th percentile
	Standard chair height from floor	0.45	0.45
	Vertical reach	1.1	1.3
	(Top of) head to seat (sitting level)	0.84	0.95
	Eye level to seat level	0.7	0.83
	Thigh clearance (above seat)	0.12	.162
	Forearm length	0.34	0.405
	Seat length	0.37	0.54

3.2 Ergonomic Considerations for Control Room Concepts

In the past basic human factors were a functional grouping of instruments for operational facilities. However, in the modern control room there are so many ergonomic factors to be considered that the design is foolproof and helpful to the operators. The human factor, the machine (hardware and software), the work environment, and the control (operation and management) need to be in harmony and integrated during all phases of the design process. In line with ISO 11064, the basic steps for such a design are depicted in Figure APIII/1c. In the following clause other factors are discussed.

3.2.1 Layout

- The control room layout must take into account both 5th and 95th percentile data.
- Layout should be done after task analysis and both link and hierarchical task analysis.

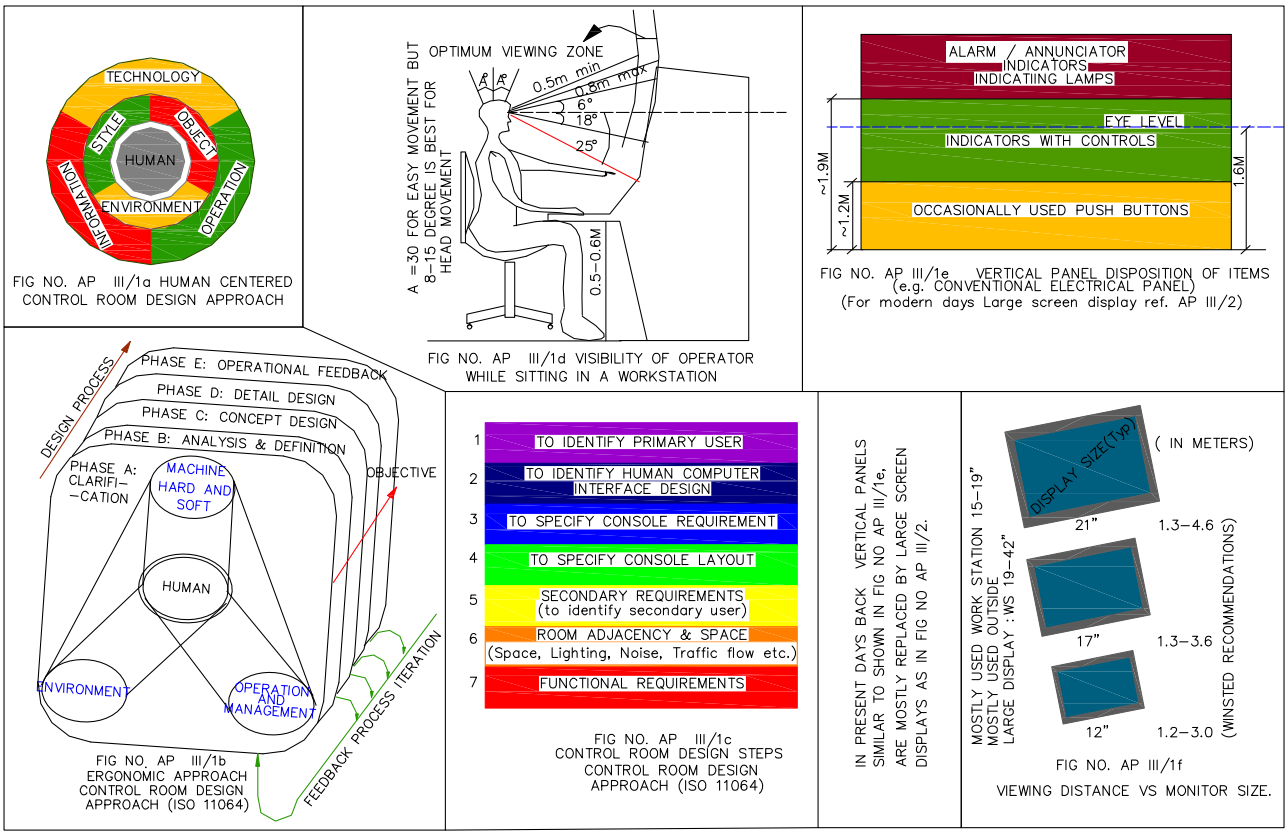


FIGURE APIII/1 Control room concept.

www.EngineeringBooksPDF.com

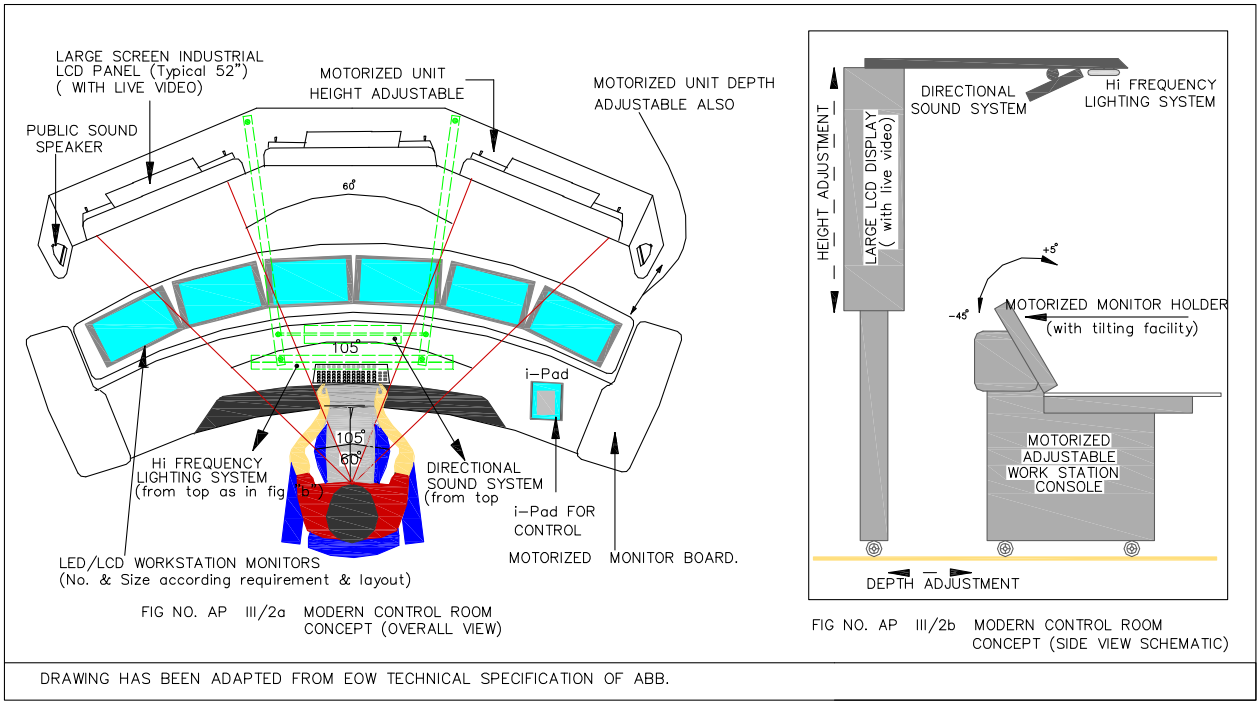


FIGURE APIII/2 Modern control room concepts.

- Emergency exit must be considered for 99th percentile.
- Adequate space and suitable use of space needs to be designed taking into consideration traffic flow, etc. and flow from general circulation areas should be discouraged.
- Line of site and communication means are very important factors in the layout of the control room.
- Allocation of responsibility and the requirements of supervision during high as well as low staffing periods is essential.
- While creating the layout the designer must consider a 300–700 mm distance between intimate zones (other's).

3.2.2 Temperature and Air Flow

Temperature varies little from place to place but a comfortable range is 24 ± 2°C (some places may demand lower than this, for example, 18–20°C) and air flow should be 0.11–0.15 m/sec with suitable make up. The current trend is for the operator to have his own comfort control.

3.2.3 Lighting

Suitable lighting is extremely important to avoid maladies like headaches and eye aches. The displays should be glare free, and there should be no reflecting surfaces, including veiling reflection on the VDUs. All illumination should be flicker free. Normally 500–800 lux is recommended. The current trend is to use a high-frequency illumination system as shown in Figure AP III/2.

3.2.4 Sound Level and Alarm

Sound level in the control room should never be >85 dB. Noise level should never cause a hindrance to the operators' attention to warnings and decision making. It has been found that blinking of lights and pulsating sound draws attention. During emergencies this will be a hindrance, making it very difficult for the operator to take action. In modern plants hundreds of alarms may occur when a unit trips, but many of them may be repetitive, so there should be some grouping and group acknowledgment of the alarms if possible. Alarm management is very important for this reason in modern units.

3.2.5 HCI Features and Alarm Management

Since these two aspects have been detailed in Chapter VII, Clause 5, they are not discussed here.

3.2.6 Coding

Coding by color, symbol, sound, shape, inverse video, etc., is quite common. However, these codes should follow international standard and should be consistent throughout the plant.

www.EngineeringBooksPDF.com

3.2.7 Text and Labels

These must also follow international standards and be consistent throughout the plant (for further reference, see ISA RP 60.4 & 60.6).

BIBLIOGRAPHY

[1] Standard Design Criteria/ Guideline for Main Plant Package (2X500 MW TPP):Central Electricity Authority:New Delhi; 2010.

[2] Process control and Optimization Vol II by B.G. Liptak: B.G.Liptak:Composition of Metallic and Other Materials CRS press/ Taylor & Francis 2006.

[3] Process control and Optimization Vol II by B.G. Liptak: B.G.Liptak:M.C.Togneri & B.G.Liptak: Human Engineering CRS press/Taylor & Francis 2006.

[4] EOW -x2 A superior complete workstation for System 800xA: ABB Limited :Technical Specification.

[5] Ergonomics – Control Room Design:AngloAmerical AA Standard.

[6] Control Room Design for Efficient Plant Operation. T.Naito, N.Takano, E Inamura & A.Hadji. Yokogawa Techncal Report; 2011.

[7] Planning and Design of a Control Room:The Winsted Corporation USA: Tech. Write Up.

[8] Control Room Design. http://www.hse.gov.uk/comah/sragtech/techmeascontrol.htm.

[9] System 800xA Extended Operator Workplace EOW-x : ABB Limited.

www.EngineeringBooksPDF.com

Appendix IV

Network Control and Communication

1.0 NETWORK CONTROL AND COMMUNICATIONS

A brief discussion is presented below related to computer networks meant to supplement the discussions presented in Chapter VII. The following subtopics are covered:

- Use of fiber optics in the network
- Electromagnetic spectrum mainly used in computer networks
- Firewall protection of network (network security)
- Fault Tolerant Ethernet (FTE; network availability)

2.0 FIBER OPTIC AND ASSOCIATED NETWORKS

Since there is no electromagnetic interference, fiber optic networks are becoming increasingly popular. Basic fiber optic cross sections are shown in Figure APIV/1a, and a typical fiber optic network is presented in Figure APIV/1b. Normally there are two taps: in one tap there is a light source such as an LED acting as a transmitting end and other tap is a receiving tap with a photo diode. There will be another interface that basically acts as a converter to convert the light signal to a full-strength electrical one (i.e. boosting the weak signal). At times, in place of an active repeater, passive star connections are used. As a primary light source both an LED and semiconductor laser can be used.

2.1 LED versus Semiconductor Laser

A comparative table between an LED and a semiconductor laser two is presented in Table APIV/2.0-1.

2.2 Optical Fiber in a Gigabit Ethernet

Gigabit Ethernet supports both copper and fiber cabling. A gigabit Ethernet with fiber cable has a light source that has to be turned on and off in 1 ns. This is impossible for an LED so a semiconductor laser is used. Gigabit Ethernet cabling is presented in Table APIV/2.0-2.

3.0 ELECTROMAGNETIC SPECTRUM

Any computer commuter network depends on electrical or optical signal transmission to carry out communication within or outside the network. Therefore the electromagnetic spectrum plays a vital role in computer network communication. Figure APIV/1c illustrates a wide variation of wavelength vis-á-vis frequency. Out of the entire spectrum, electromagnetic waves with frequency in the range of 10^4 to 10^{16} are more important for computer network communication. Networks with communication in the frequency range of 10^4 to 10^8 twisted pair cables UTP/STP also can be used. Coaxial cables in the range of 10^5 to 10^9 can be used, whereas optical fibers are used in the frequency range of 10^{12} to 10^{14}. However, for wireless communication duly modulated data can be sent over the medium via radio communication.

4.0 LARGE INTEGRATED COMPUTER NETWORK

Robust connectivity technology, economy, and business competition are forcing industries to integrate various kinds of networks together. Integration also helps provide a quick and rational flow of information. As a byproduct there can be problems associated with unauthorized access and protective measures must be put in place. With a control system the danger was discussed in Chapter VII, Clause I. A typical large network comprising Control System LAN with a remote control system, a corporate LAN, a business LAN, and Internet are depicted in Figure APIV/1d. Networks also need a back-up control system in case there is a major problem at a remote place. In large networks and in the public domain, security vulnerability is a problem. This vulnerability is addressed by connecting the servers/network to a set of subsystem "firewalls." A firewall only allows data that can be accessed from the outside (as permitted in the network design). An external client sends a request to the system through the firewall. If the request meets the set rule only then will it be serviced by the related server, otherwise the request will be denied. Any request

www.EngineeringBooksPDF.com

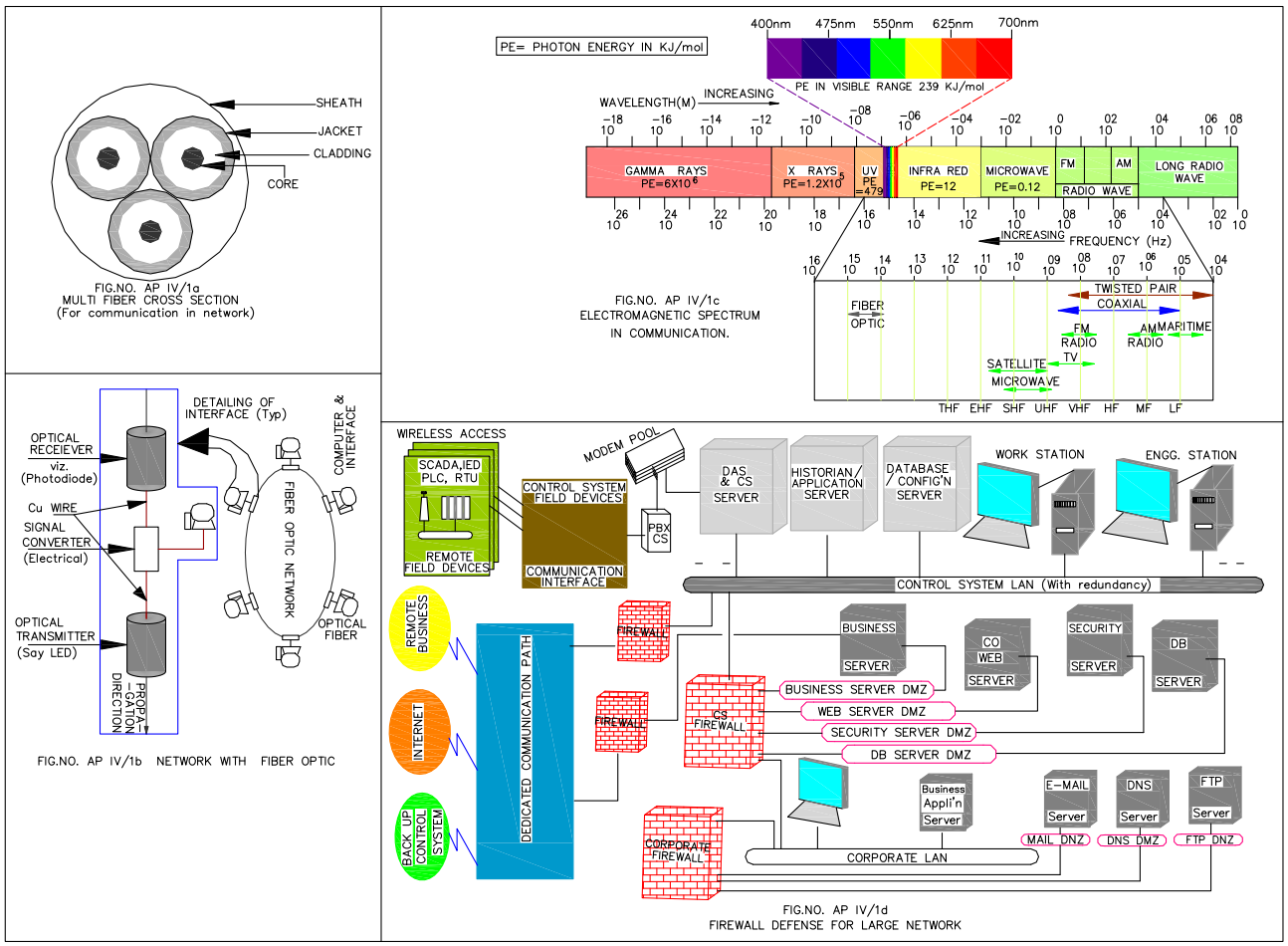


FIGURE APIV/1 Communication and networking.

TABLE APIV/2.0-1 LED versus Semiconductor Laser

Item	LED	Semiconductor laser
Data	Low data rate	High data rate
Fiber type	Multimode	Single or multimode
Distance	Short	Long
Cost	Low	Expensive
Lifetime	Longer life	Shorter life
Temperature stability	Not much	Substantially sensitive

TABLE APIV/2.0-2 Gigabit Ethernet Cable Types

Name	Cable	Segment (m)	Advantage
1000Base-SX	Fiber optics	550	Multimode (50 and 62.5 μm)
1000Base-LX	Fiber optics	5000	Multimode (50 and 62.5 m) or single (10 μm)
1000Base-CX	2P—STP	25	Shielded twisted pair
1000Base-T	4P—UTP	100	Standard Cat 5 UTP

www.EngineeringBooksPDF.com

from the public domain must be verified by two firewalls, e.g., if any request for a control system is permitted, then that request is sent to the control network. Also any control system and business server data exchange (from the same network system) will be done through the firewall. These are a few precautionary measures to restrict access to the control/business server/corporate network. Since there will be huge data flow in a large network, separate servers are dedicated for such security and authentication services. However, it must be kept in mind that that for control systems there should be a separate security system provided by the vendor as a lone firewall, which is mainly developed for IT/Internet application. This was discussed in Chapter VII.

5.0 FIREWALLS

Firewalls protect computer networks from unauthorized access. They may be hardware (HW), software (SW), or a combination of both. Apart from the broadband router, a network firewall is a proxy server acting intermediately between internal and external networks by receiving and selectively blocking data at the boundary. It also helps to hide the LAN addresses from outside access (to avoid Address Resolution Protocol—ARP poisoning; see Figure APIV/2).

5.1 Types of Firewalls

Firewalls can be classified in the following ways.

5.1.1 HW and SW Firewall Classification

Table APIV/5.0-l lists the advantages and disadvantages of HW versus SW firewalls.

5.1.2 Other Classifications of Firewall

Firewalls can also be classified as follows, but the description of these will be meaningful only after the functionality of a firewall is discussed:

5.1.2.1 Packet-Filtering Firewall

A packet-filtering firewall is classified as listed below:

- *Stateless packet-filtering firewall*: Also known as static IP filtering. It is a very inexpensive, high-throughput firewall. Included with router configuration software

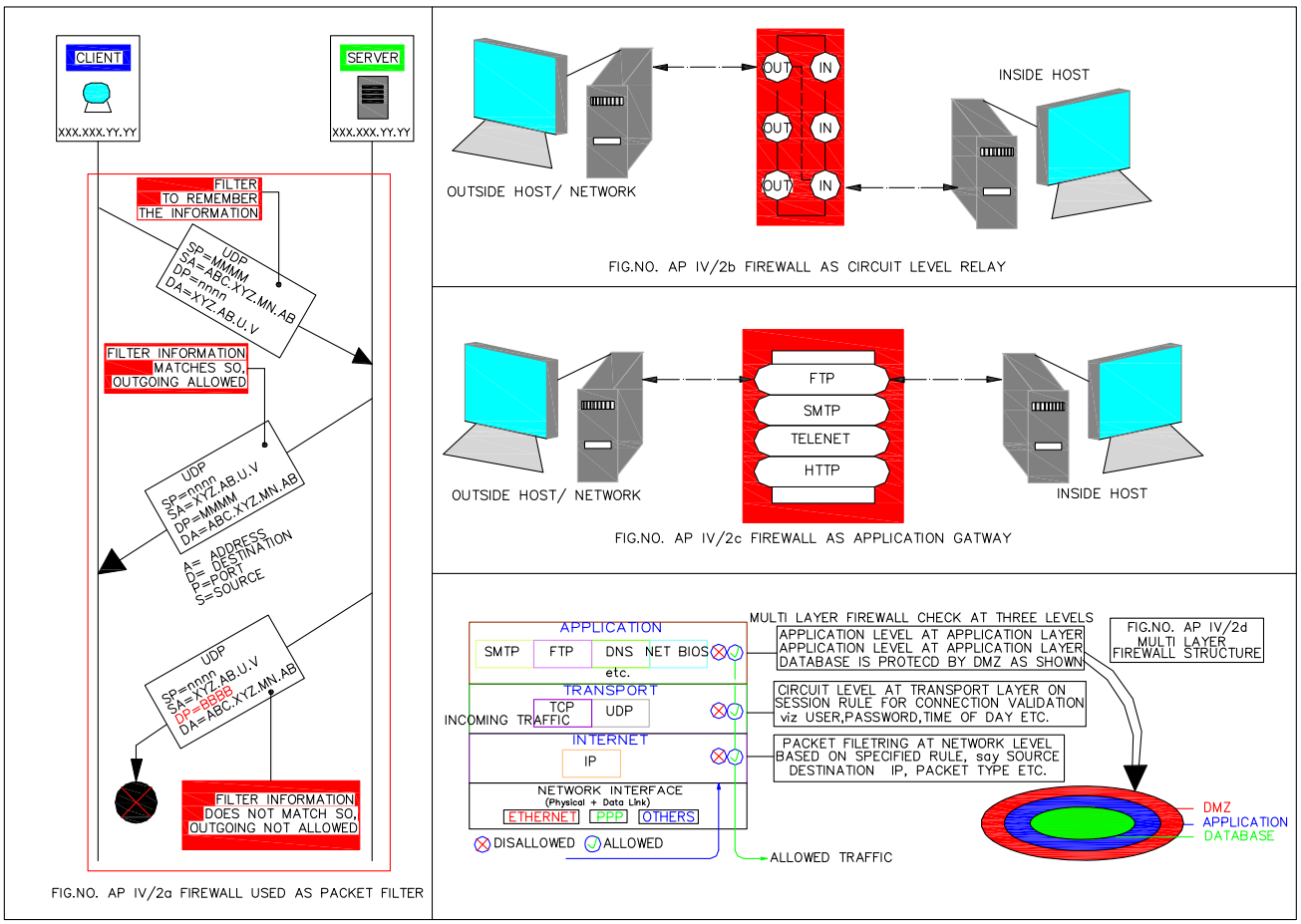


FIGURE APIV/2 Firewall functional details.

www.EngineeringBooksPDF.com

TABLE APIV/5.0-1 HW versus SW Firewall

Comparison	HW Firewall	SW Firewall
Advantages	No operating system, so immune to viruses generally Very fast, so better performance Single duty, so very effective	Less expensive, some free software available Can be implemented in an existing network Low administrative cost
Disadvantages	On single failure system, may collapse Proprietary, prior knowledge may be necessary • High cost for maintenance as well as for installation	Vulnerable to malicious attack Operating system dependent, so possibility of getting affected by virus Requires additional host resources like CPU/memory, etc. Low performances

or with most open source operating systems. These are highly vulnerable.

- *IP packet-filtering firewall*: Every packet is handled on an individual basis. Previously forwarded packets belonging to a connection have no bearing on the filter's decision to forward or drop the packet.
- *Stateful packet-filter firewall*: It is a pure packet-filtering environment.

5.1.2.2 Application Gateway/Proxies Firewall

A proxy acts as an intelligent intermediary between hosts on the internal network and hosts on the external network. These are rather expensive but quite secure.

5.2 Firewall Functionality

A true firewall is HW and SW that intercepts the data between external (Internet) and internal networks (private computer /network). Based on functionality, a firewall can be divided into the following categories (see Table APIV/5-2) with the functionality of each of them.

5.3 Demilitarized Zone

A demilitarized zone (DMZ) isolates the host, which is accessible from outside the internal server. As shown clearly in Figure APIV/1d, the business server has access from the outside and has a DMZ in the CS firewall. Basically, the DMZ is the outward facing level of the application. It is a subnetwork that resides between the known/trusted internal network and external network, providing services to the outside without allowing direct access. Some system components of the DMZ include:

- Public facing server
- Public facing File Transfer Protocol (FTP) server
- E-mail gateway
- Public facing Domain Name Server (DNS)
- Traffic management and security server
- Streaming video

5.4 General Discussion on Firewalls

Firewall policy is extremely important. No firewall can protect a network against inadequate or mismanaged firewall policies, so planning and implementation is extremely important. Any weakness in the policy and failure to implement the policy will result in failure of the firewall. If an IP Virtual Private Network (VPN) is used, then the placement of VPN with respect to the firewall needs to be considered. Some of the policy decisions may be based on the following:

- Internal and external access and their extent
- Remote user access
- Virus protection and avoidance
- Encryption requirement if any
- Program usage

The discussion presented here is very brief and meant to throw some light on the issue. There are many good papers available for the interested reader.

6.0 FAULT TOLERANT ETHERNET—AN APPROACH

Modern plant control systems are highly distributed and communication between the nodes becomes extremely critical. So for satisfactory operation of the system it is essential that these critical components are redundant and fault tolerant (as discussed in Clause 1.0 in Chapter VII). Fault tolerance of a network varies with system architecture design (see Figure APIV/3 for a typical Fault tolerant Ethernet). While in some cases it is better to continue operation, in some it is better to go for a safe state and not continue operation. Critical controls such as BMS and EHG systems in any situation have to run so that equipment and/or human safety is ensured. Cost is also another factor when designing such a system. Redundancy normally is achieved by duplicating the components; apparently it is not that difficult, but in reality unless there is some diversity built in the redundancy becomes meaningless. If two communication channels are used and routed in the same path,

www.EngineeringBooksPDF.com

TABLE APIV/5-2 Firewall Types According to Functionality

Type name	Feature
Packet filter (see Figure APIV/2a and d)	★ This is the first line of defense (see Figure APIV/2a). ★ Internet and other digital network data travel in packet of limited sizes. It consists of THE DATA, ACK, REQUEST, or COMMAND; PROTOCOL INFORMATION; SOURCE; AND DESTINATION IP ADDRESS, PORT ERROR CHECKING CODE, etc. ★ Filtering consists of examining incoming and outgoing packets compared with a set of rules for allowing and disallowing the transmission or acceptance. ★ It is rather fast because it does not check any data in the packet except the IP header. It works in the network layer (Internet) of the OSI model. ★ It is fast but not foolproof. IP address can be spoofed.
Circuit relay/gateway (see Figure APIV/2b and d)	• It is one step above the packet filter and commonly known as "Stateful packet inspection" to check the validation of the connection between the two ends (in addition to packet filtering operation) based on the following: ○ Source destination IP address/port number ○ Time of the day ○ Protocol • User and password • It operates on the transport layer. Stateful inspection makes the decision about connection based on the data stated above.
Application gateway (application proxies) (see Figure APIV/2c and d)	❖ It acts as proxy for the application at application layer of OSI ❖ This firewall authorizes each packet for each protocol differently. ❖ Following specific rules it may allow some commands to a server but not others or limit access to certain types based on the authenticated user. ❖ Set up is quite complex, every client program needs to be set up. Also each protocol must have a proxy in it. ❖ True proxy is much safer.
NAT/PAT	▶ Firewalls using Network Address Translation (NAT) or Port Address Translation (PAT) completely hide the network using NAT/PAT ▶ In NAT there will be a single IP address used for the entire network ▶ It has disadvantage that it cannot properly pass protocols containing the IP address in the data portion.

redundancy may not be effective due to accidental breakage of the communication cable. Also there is the probability of similar failure due to external causes. Another problem associated with such duplication is when and how to change over. Before further discussions about FTE, a brief history of various developments is outlined below.

IEEE 802.1D Spanning Tree Protocol (STP) is aimed at media redundancy. It supports various kinds of Ethernet mesh rings or a combination thereof, avoids looping problems in Ethernet connections, and uses Bridges to connect Ethernet LANs, which does the forwarding and filtering operation. The basic idea for an STP is to get rid of the looping associated with ordinary bridge operation and to choose tree topology. The shortest bridge is chosen as the root.

Another standard, IEEE 802.1w Rapid Spanning Tree Protocol (RSTP), has been created for faster recovery time (1 sec) from topology changes. RSTP provides faster recovery by monitoring link status of each port and then generating topology change after a link status change. Based on the standard Ethernet device, manufacturers are developing proprietary protocols to minimize recovery time. To get a better idea about these standards, consult the relevant standards and/or related standard write ups available on the Internet.

Another aspect to look into is the failure of electronics, so switches are also duplicated in many cases. A complete redundant network including redundant devices, port, switches, etc., would give the safest solution. However, in such cases, apart from cost, the recovery time is in the range of 10–30 sec for complete recovery, which depends on the complexity of the network. FTE developed by Honeywell could be a good solution. In the following clauses Fault Tolerant Network based on Honeywell PKS is discussed.

6.1 What is FTE?

The FTE connects a group of nodes typically associated with communication paths between them, so the network can tolerate all single faults and many multiple faults. FTE can

www.EngineeringBooksPDF.com

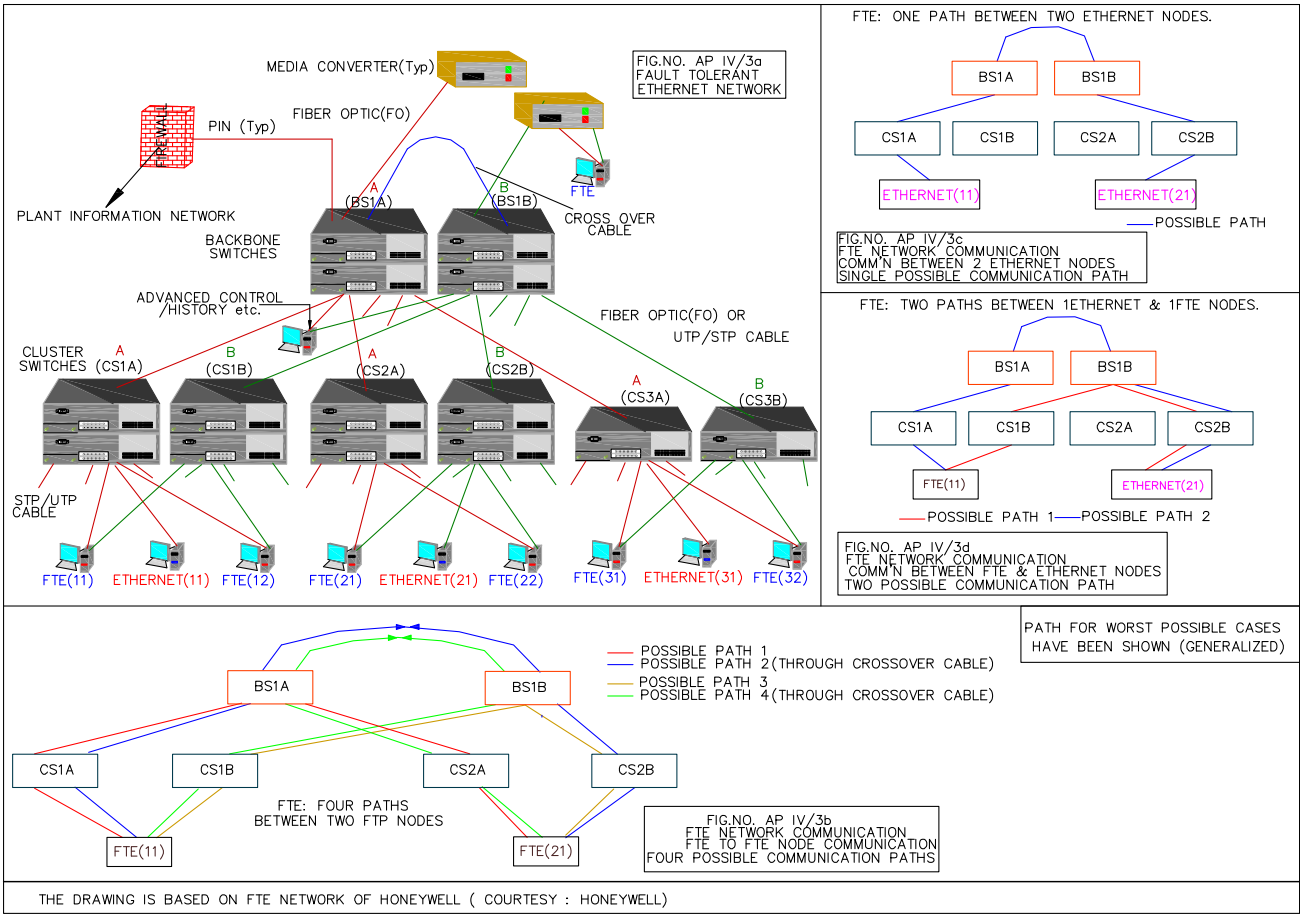


FIGURE APIV/3 FTE network. *Based on document from Honeywell.*

rapidly detect faults and, in case of communication failure, the switchover time is around 1sec. FTE uses commercial off-the-shelf equipment but with increased system availability.

6.2 Some Benefits of Fault Tolerant Ethernet

- *Rapid response*: In conventional Ethernet, there are two separate networks with each node (server) connected to both networks. The switchover time, in case of communication failure, is ~30 sec. FTE employs single network and does not require a server, so changeover time is less.
- *Possible communication path*: FTE provides more communication path possibilities than the Dual Ethernet Networks, as is clear from the Table APIV/6.0-1.
- *Full redundancy in single network*: Conventional Ethernet network with redundancy usually has two independent Ethernets, and naturally there will be a difference in performance and configuration between the two. Whereas in an FTE single Ethernet there is no such problem and at the same time it provides multipath capabilities in its unique topology.

6.3 FTE Topology

Two parallel trees of switches and cabling "A" and "B" are linked at the top to form one Fault Tolerant Network. Each FTE node has two ports that connect to a switch in each tree. In contrast, Ethernet nodes can connect to either if the switches are A or B. There may be one or more levels of switches and there can be multiple pairs of switches in each level. In Figure APIV/3a these have been designated as "cluster" and "backbone" switches. In the Honeywell FTE Node there are FTE software and Network interface controllers—one for each tree—and these networks are expandable. There can be 511 FTE nodes forming a community, within which it can talk as long as there is a possible path. Similarly a 511 non-FTE Ethernet can also be accommodated. As shown in Figure APIV/3a, a firewall or router can be connected between an FTE and other networks.

6.4 Major Components of the FTE

- *Cable*: Copper STP/CAT 5 for connections mainly in cluster switches used normally up to 100 m. Fiber

www.EngineeringBooksPDF.com

TABLE APIV/6.0-1 Comparison between Dual Ethernet and FTE

Connectivity	Supporting DWG reference	DUAL Ethernet	FTE
Number of networks	APIV/3a	2	1
DCN to DCN	APIV/3b[a]	2	4
DCN to SCN	APIV/3d[a]	1	2
SCN to SCN in same tree	Similar to APIV/3c	1	1
SCN to SCN in different trees	APIV/3c[a]	0	1

DCN, dual connected nodes; SCN, single connected nodes.
[a]*Each possible path(s) shown by shaded lines in the drawing.*

optics (62.5/125) are used for connections up to 2 km and mainly used in backbone switches.

- *Media converter*: Used for flexibility in networking for converting between Cu cable and fiber optic cable.
- *FTE software*: Proprietary in nature meant for multiple communication paths between nodes and faster switching.
- *Switches*: 10/1000 Mbps ports with run-time diagnostics and remote diagnostics available in Cu/fiber optic models.
- *Network interface controllers*: Two single-port or one dual-port card.

BIBLIOGRAPHY

[1] Computer Networks:Book: by A.S. Tananbum & D.J. Witherall.

[2] Standard Design Criteria/ Guideline for Main Plant Pacakge (2X500 MW TPP). New Delhi: Central Electricity Authority; 2010.

[3] Firewall Presentation: http://www.cs.northwestern.edu/%7Eychen/classes/mitp-458/firewalls.ppt:Internet Document.

[4] Firewall Architecture: Nextstep Broadband: White Paper.

[5] Internet Firewall FAQ: P.D. Robertson, M.Curtin& M.J. Ranum:Internet Document.

[6] Firewalls – Overview and best Practices:Decipher Information Systems:White Paper.

[7] Kuipers, D., Fabro, M., (Eds.), Control Systems Cyber Security: Defense in Depth Strategies. Idaho National Laboratory; May 2006. doument.

[8] NETWORK ARCHITECTURE STANDARD: California Technology Agency: 19-Sept'2012.

[9] Fault tolerant Ethernet (FTE) Specification and Technical Data: Honeywell Industry Solution; Aug'2002.

[10] Rapid Spanning Tree in Industrial Network :M.Galea Ruggedcom Inc.: Internet Document.

[11] The ABCs of Spanning Tree Protocol: Contemporary Controls; Feb'2006.

[12] Ethernet Fault Tolerance and Redundancy. Emerson Process Management; Mar'2007.

www.EngineeringBooksPDF.com

Appendix V

Super/Ultra Super Critical Power Plants

Depending on the operating condition, steam power plants can be divided into subcritical, supercritical, and ultra supercritical categories. The criticality is based on the critical pressure point for steam, i.e., 221 MPa and 374°C. Power plants operating at steam pressure below critical pressure are subcritical power plants, and plants operating with a steam pressure >221 MPa and steam temperature >374° are supercritical power plants. The supercritical stage is a thermodynamic expression describing the state of the substance; here it is water and steam, where there is no distinction between the liquid [water and gaseous (steam)] phases. In the subcritical stage latent heat is necessary to convert water to steam; at the supercritical state this is not necessary. In ultra supercritical plants the steam is operated at higher pressure and temperature (for example, 300 bar and 630°C). Now the question is why go supercritical and ultra supercritical? The answer to this question is clear from the information related in Table AP5/1.

This table shows a clear increase in efficiency from subcritical to supercritical, and finally to ultra supercritical. Also, there is a substantial reduction of CO_2 (as well as SO_2) starting from subcritical to ultra supercritical. The efficiency mainly increases with temperature and not from pressure when a plant switches from supercritical to ultra supercritical. However, there is an increase in per kW capital expenditure and auxiliary power consumption of the unit as it goes from a subcritical and finally to a ultra supercritical plant. A cycle efficiency increase from 30 to 50% results in a 30% CO_2 reduction. Water treatment, requirement of condensate polishing unit (CPU), etc., are critical in these types of plants. Another major task in supercritical and ultra supercritical technology implementation is the material selection for critical parts. However, initially discussions will be about the most critical item, i.e., supercritical steam generation.

The following points are significant to understanding of supercritical technology:

- When water is heated above critical pressure at a constant value, temperature is never constant.
- In the whole system two phases never exist. There is no distinction between water and steam; hence, density of the two phases is the same.
- The actual location of transition from liquid to steam is different under different conditions, hence, sliding pressure is possible.
- For effective heat transfer, under different load and pressure, a boiler is capable of optimizing liquid and gas amounts.

1.0 POWER PLANTS WITH SUPERCRITCAL AND ULTRA CRITICAL STEAM GENERATORS

These types of steam generating (SG) plants operate on pressure and temperature more than the critical point (that is. 220.6 bar and 374°C), which results in no boiling of water and it directly transforms to steam. Because of this, the boiler is not applicable for supercritical (SC) and ultra supercritical (USC) SG units. The subcritical SG units

TABLE AP5/1 Comparison among Typical Subcritical/SC and USC Plants

Plant types/parameter	Subcritical	SC	USC
Steam pressure (MPa)	16.5	29.0	36.5
Steam temperature (°C)	538/540	580	700
Auxiliary consumption (%)	4–6	5–7	6–8
Efficiency (%)	<40	42–45	>48
CO_2 (g/KWh)	855	780	710
SO_2 (g/KWh)	2.4	2.2	2.0

Based on POWER ASIA 2004 Supercritical and Ultra Super critical Plant.

www.EngineeringBooksPDF.com

normally operate at 150–170 bar pressure and are called boilers, while the SC SG units operate at a pressure ranging from 230 to 265 bar with a temperature ~600°C. The USC SG units operate at pressures around 300 bar and 620–640°C or more for better efficiency.

1.1 Historical Developments of SC and USC Thermal Power Plants

For a chart of historical developments of SC and USC thermal power plants, see Table AP5/2. Thermal power plants operate on the Rankine cycle and their efficiency depends on the operating pressure. Higher operating pressure and temperature means higher efficiency; hence, the modern trend is to install power plants in the super and ultra critical range. Higher efficiency means lower coal consumption per MWh and subsequently lower emission of pollutants such as CO2; these advantages force designers to an ever-increasing operating point, which may even go up to 385 bars and 750°C. The approximate efficiency values are envisaged to go beyond 50% and even may touch the magic value of 52% by the year 2020 (see Table AP5/3).

The main constraint is the quest for materials with a resistance to all degenerating factors like corrosion, stress, stress corrosion, high-temperature creep, oxidation, cyclic and thermal fatigue, etc. Austenitic steels or Ni-based super alloys cope with modern demands.

However, there were initial problems regarding the operation of SC and USC power plants before that were addressed appropriately and emerged as the state-of-the- art technology, such as:

- Complicated start-up process
- Lower operational flexibility
- Unstable availability and reliability
- Higher maintenance costs
- Turbine-governing valve erosion
- Thermal stress in turbine casing and governing valve body
- Erosion due to impingement of solid particle on turbine blade

TABLE AP5/2 Historical Developments toward the SC and USC Thermal Power Plants

Year	Steam pressure (bar)	Steam temperature (°C)	Efficiency	Reheat cycle
1957	310	612	35%	Single
1960	322	612	35–40%	Single
1965–1975	242	566	35–40%	Double
2000	265	600C	43%	Single/double
Currently	320	620	45%	Single/double

All data indicated above are approximate.

TABLE AP5/3 Comparative Features of Subcritical and Super/Ultra Critical Units

	Power plant with subcritical SG plant	Power plant with SC or USC plant
Efficiency	35% (maximum)	45% +
Installation cost	Less than SC or USC plant	Slightly higher than subcritical plant
Operating cost	Same as SC or USC plant	Same as subcritical SG plant
Fuel cost	More than SC or USC plant /per MW generation	Less than subcritical SG plant/per MW generation
CO_2 emission	High/per MW generation	Low/per MW generation
Additional equipment	Boiler drum(for drum type boiler) Boiler recirculating pump, separator, storage vessel, 100% CPU (for OT SG Plant)	Boiler recirculating pump, separator, storage vessel, 100% CPU (for OT SG plant)
Load change ramp	3–4%/min	7–8%/min

All the data indicated above are approximate.

www.EngineeringBooksPDF.com

The turbine is also more prone to water induction along with the main steam system due to the once-through (OT) process than drum type plants. The OT configuration also demands a very high quality of feed water as there is no drum in which the blow down can be made or chemicals can be injected to maintain the feed water quality. The CPU with a 100% full flow capacity along with oxygenated treatment is extremely necessary for SC/USC plants.

It is well established that higher steam temperatures mean greater efficiency, but it also results in higher bleed steam temperatures being used for the regenerative feed water heaters. This phenomenon reduces the efficiency for the regenerative feed heater area and eats up some portion of the overall efficiency gain. The idea of replacing a single-reheat by a double-reheat cycle is twofold. It helps to extract more work done by the turbine and lowers the degree of superheat of the bleed steam thus arresting the probable efficiency loss. Another important advantage of the double-reheat cycle is the substantial reduction of steam temperature and pressure at the low-pressure (LP) turbine inlet as the maximum allowable temperature is limited by the rotor and cross-over hood materials. For example, a plant with a single-reheat cycle can go up to 60−70 bar reheat pressure whereas with the double-reheat cycle can go up to 95−100 bar for first reheat pressure and 25−35 bar for the second reheat pressure, which means lower LP turbine (LPT) inlet pressure accordingly. The double-reheater system clearly offers lower generating costs and less corrosion at the last stage. The implementation of this, however, depends on the cost and complexity of the additional equipment, piping, etc.

There are other options available. For example, double LPT and double condensers provide more volume-handling capability so more work gets done. Possible configurations with both double reheaters and LPTs are seen in Figure APDX/V-6b. There are two ways the circulating (cooling) water can be fed to the condenser: by using a parallel path, i.e., the same quantity of cooling water fed to the two condensers, and by using a series path, i.e., circulating water (CW) is first fed to one condenser then the outlet of the same is fed to the other. In the former the drop in temperature will be the same in both the condensers, but in the latter, the temperature will drop more in the first condenser than the second one. For the same mass flow of water it is found (see Figure APDX/V-6c) that the average condenser pressure will be better in the series path. The higher the condenser pressure drop, the higher is the efficiency; hence, the series circuit is the preferred method.

Another very important aspect of an SC/USC power plant is the selection of final feed water temperature, which normally varies from 315 to 330°C, depending on a single- or double-reheat cycle.

2.0 SUPER AND ULTRA CRITICAL STEAM GENERATORS

2.1 The Temperature versus Entropy Relationship of SC/USC SG Plants

Figure APDX/V-6a shows the typical behavior path, which is conspicuously different from that of a subcritical boiler. Here the path does not follow the saturation line in normal operating range except in start-up, shut down, and abnormal situations like abrupt load shedding/run back.

2.2 Constant and Variable Pressure Operation

It is necessary for SC/USC plants to operate with an OT boiler configuration and operate either with a constant pressure or with variable pressure, depending on the load. At the initial stages of OT, SG plants for SC units were and still are operated in many regions/countries to maintain constant throttle pressure. Unit load demand in that case constitutes the demand set value for both the feed water flow and the firing rate. The ratio of firing rate to feed water flow is utilized for the steam temperature control strategy. During normal operation the fluid within the furnace is always maintained at SC pressure to avoid subcritical two-phase flow, which leads to high temperature and subsequently to tube failures.

In contrast, SG plants with a Benson design enable the unit to run in a variable pressure mode operation. In this design, two-phase flow is allowed to take place up to the critical point at a predefined load permitted by the design criteria. After this point (Benson point) the process turns entirely to a single-phase flow condition attaining up to full load as per demand. In the pre-critical point operation, a minimum recirculation flow is maintained by the boiler circulation pump (BCP) along with a (or pair of) vertical steam separator(s) and storage vessel.

At the Benson point or the load at which the steam separator(s) and storage vessel run too dry to permit initial firing, the BCP is shut off and the boiler feed pump (BFP) is controlled so the feed water flow will meet the demanded furnace enthalpy pick-up function (from the economizer outlet to the primary superheater inlet) in an OT operation. By this method, the relative proportion of steam generator surface serving as an evaporator and as a superheater is controlled as a function of load and is stabilized. Final steam temperature control range meets a set point from ∼50 to 100% load. Reheat steam temperature control range meets a set point from ∼60 to 100% load.

The constant pressure type SG plants are generally supplied with vertically arranged tubes and are very popular in the United States. The tube layout inside the furnace

www.EngineeringBooksPDF.com

is relatively simple and, hence, significantly less costly and easier to fabricate, assemble, and construct.

The variable pressure type, on the other hand, is generally designed with spiral tubes wrapped around the furnace and is used more extensively in Europe. The spiral tube design demands more complicated and costly fabrication and construction than vertically arranged tubes. This type of SG plant is are more advantageous than the constant pressure type as it is very efficient even at lower loads and, with the combination of a circulation pump, the plant can also be cycled "in on and off" mode as required in a very expeditious way thus enabling the unit to match the grid demand more effectively and more quickly.

2.3 Control and Monitoring of Parameters in SG Plant

SG plants have no energy reserves. The complete plant may be conceived as a bunch of heated tubes with high-pressure water and steam at the outlet. This simple configuration reveals that the output is a function of feed water flow and the amount of heat imparted to the tubes. The heat content per unit mass or enthalpy of outlet steam depends only on the ratio of heat supplied to feed water flow. When the pressure is constant at a particular load, the temperature of outlet steam becomes dependent only on the enthalpy of steam from the heat input to feed flow ratio. This means if feed flow is increased without increasing the heat input, the temperature of outlet steam would decrease and vice versa. In an SC/USC power plant, the output pressure and flow are maintained by the feed water pump and the main steam temperature is maintained by the heat input to feed flow ratio, in other words, the heat supplied to the system. The de-superheating spray water system is mainly used for emergency or for a transient requirement. Reheat temperature control philosophy is the same as a conventional boiler in that it is through redistribution of heat or by emergency spray valves.

In the absence of reserve energy, the OT SG plant needs a high degree of continuous monitoring and the control system, very quickly and accurately, enables the feed water flow and firing rate to deliver the steam to the turbine as required by the generator according to the unit or grid demand. The distributed control system (DCS) plays a more vital role in these types of plants than the drum type boilers. To avoid any delays originating from the inertia factors in the process, predominantly in the pulverized fuel circuit, the judicious location of transducers and the speed of control action of the temperature measuring system are extremely important.

The SG plant load demand signal, as generated from the DCS according to coordinated control mode selection, is passed on to the dedicated control system of feed water flow/pressure, heat input from fuel, and air flow to act as their strategic set values as a function of the load signal for rearranging the final control element position. Some typical automatic control loop strategies are depicted in Figures APDX/V1–6.

In some control strategies, the set values of the feed water flow are determined directly from the measurement of the steam conditions at different locations in the steam cycles. This is assumed to eliminate uncertainty related to any untoward disturbances in the process, as it is expected that the measurement of steam conditions affirms exactly how much water it needs independently from other systems.

2.4 Water Circulation and Start-Up Procedure

The start-up procedure of this type of boiler is a little different from subcritical boilers. As stated earlier, there is no boiler drum in this type of boiler like in the once through (OT) type. However, there are separator vessels and separator storage tanks (SSTs), which are important during start-up. The relative position of these vessels and tanks in a flow diagram is depicted in Figure APDX/V-7, and they play an important role during start-up. Also significant is the quality of feed water required for its operation. It is better to have a clear idea about the various modes of operation for these types of boilers. There are basically five modes of operations:

- Filling up the boiler
- Cleaning up the boiler
- Wet mode operation of the boiler (up to 30% load)
- Dry mode operation of the boiler (>30% load)

2.4.1 Filling Up

When the water system of the boiler is empty (economizer to separator) then is it filled with feed flow at around 10% turbine maximum continuous rating (TMCR). When the level reaches the filling set point, the drain valve DRV (Figure APDX/V-7) is opened slowly and kept open for a certain time to check that the level is maintained. Then feed flow is increased, up to 30%. The water level is maintained by regulating the drain valve for a certain time. If this is successful then it is considered that filling up is over. For simplicity, the number of drain valves is kept to one, but in reality there may be more.

2.4.2 Boiler Clean Up

As discussed earlier, the feed water quality is extremely important for OT SC boilers. When at the deaerator outlet and separator outlet feed water quality is not the right quality, then it is necessary to flush water from the system into the flash tank. During this time ~10% of the TMCR value of feed water is sent; it flows through the economizer

www.EngineeringBooksPDF.com

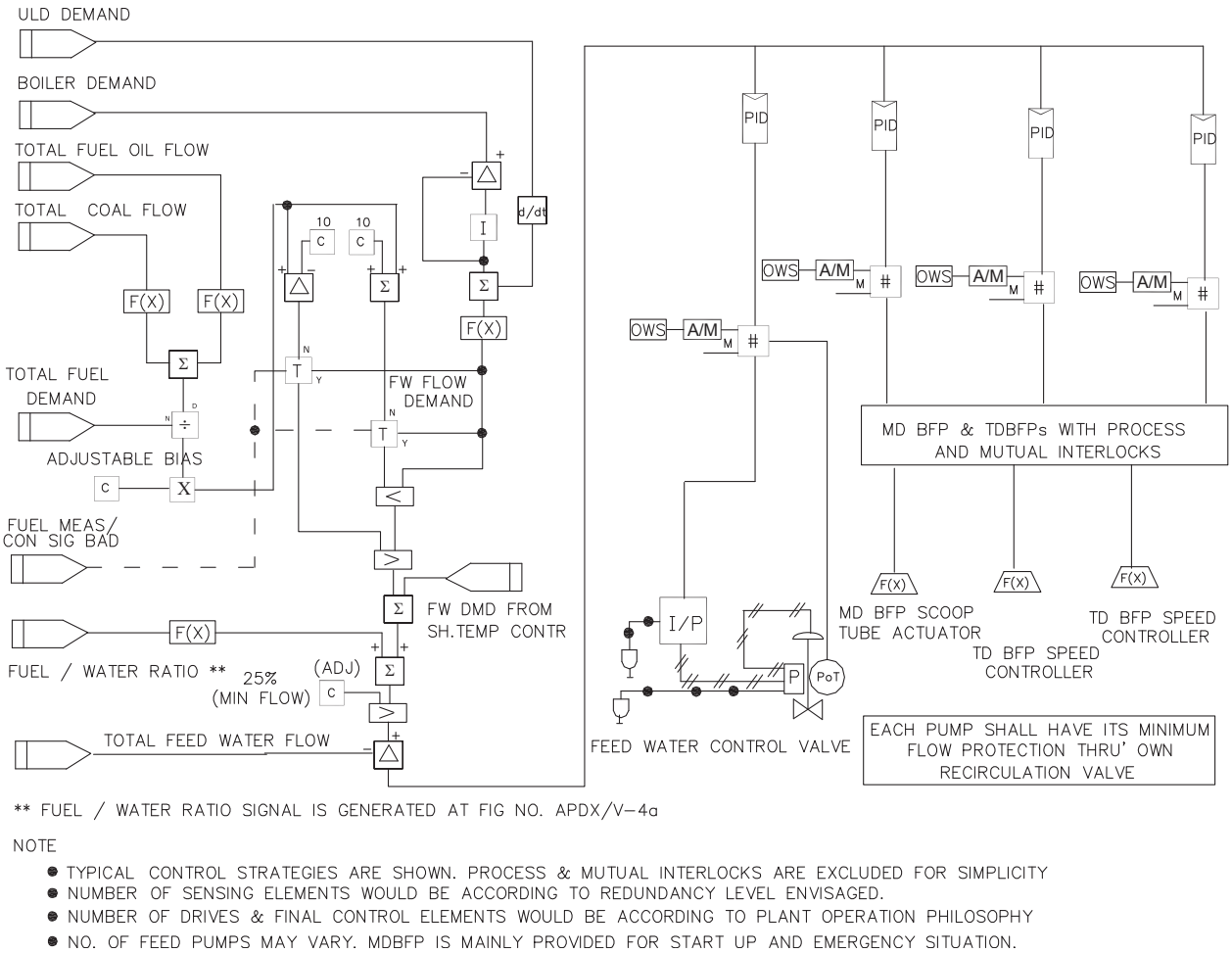


FIGURE APDX/V-1 Boiler load/feed water control.

and evaporator and is discharged to the flash tank via the drain valve DRV (Figure APDX/V-7) and then finally to the condenser. From the condenser it flows through the CPU to remove any impurities. The process continues until the quality (discussed later) is achieved.

2.4.3 Wet Mode Operation

This mode of operation is done during initial boiler light up until 30% MCR value (see Figure APDX/V7). During this operation the Benson point is reached. During this time the economizer minimum flow is ensured by the BCP, which is started during light up following start of the BFP and clean-up operation. There is one control valve in the discharge of the BCP, the water circulation valve (WCV), which is responsible for maintaining the required flow through the economizer. This valve also helps to maintain the level in the separator storage tank. The opening demand of the WCV is mainly determined by the economizer water flow, but it is done in such a way to help maintain the level of the separator storage tank. As shown in Figure APDX/V-7 (simplified for understanding; the actual system may be a little different but the basic philosophy is similar), there are certain level values in the SST level as determined by the SG manufacturer. Here levels A1 and A5 (Figure APDX/V-5 b) are designated as very low and very high levels, respectively, for the master fuel trip (MFT; only during the start-up period as in the dry mode of operation there will be no level since the MFT is not applicable), whereas A2 and A4 are low and high level, respectively. Normally during initial start-up the level is maintained between A2 and A3. Set point for flow through economizer can be derived from the following:

- Manual set value
- Minimum set value is derived from feed flow. Here, (−) KX has been chosen because as feed flow increases there will be less CW flow to meet the minimum flow requirement through the economizer. This and the above set points can be selected by the operator.
- From the level in the separator storage tank level, as the level increases, there should be more circulation flow to maintain the level in the storage tank.

www.EngineeringBooksPDF.com

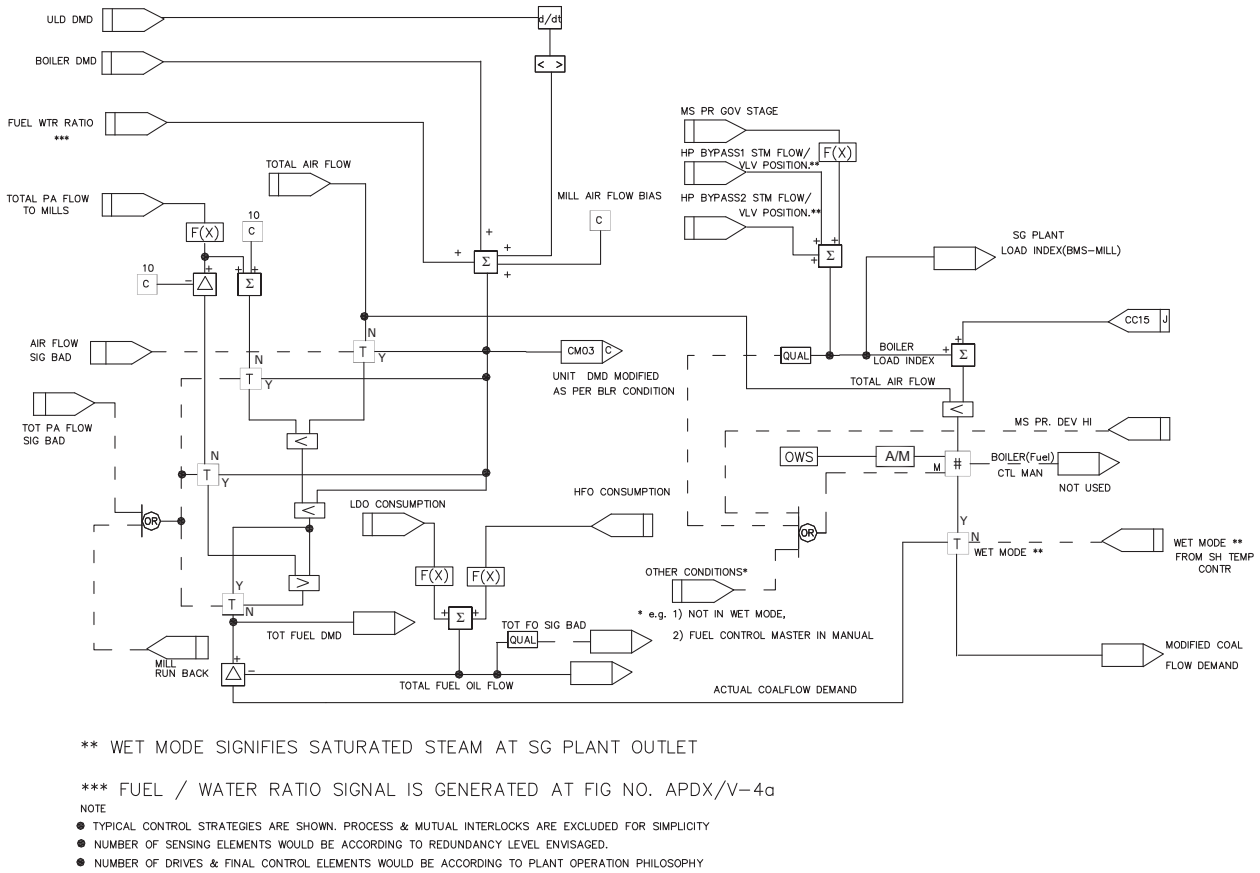


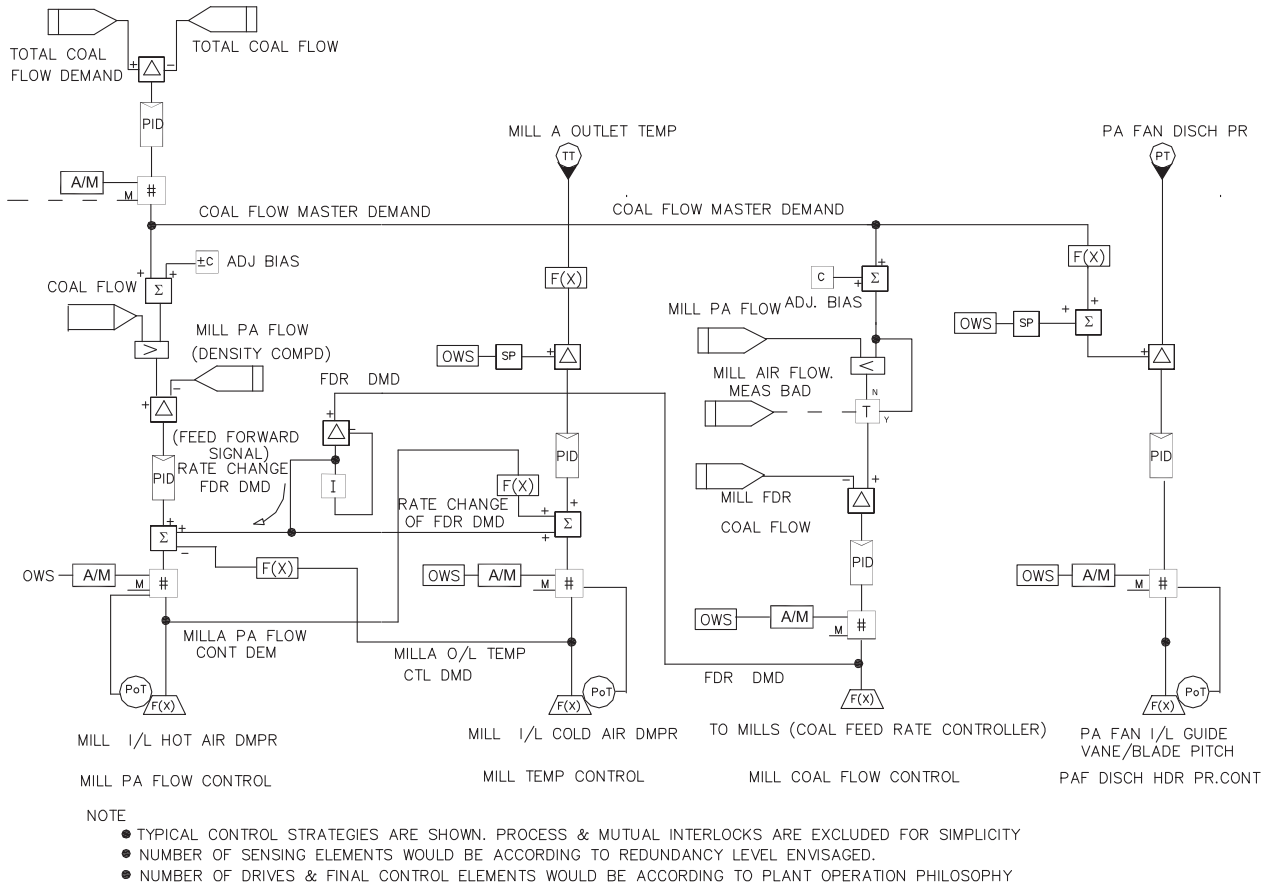
FIGURE APDX/V-2 SG plant load/fuel control.

These set values are fed to the system through the "MAX" selector so that minimum flow through the economizer is ensured via CW flow. Two function generators (f1 and f2) are illustrated in Figure APDXV-5. Function generator (f1) characteristics are blue. Between A2 and A3 the flow set point is proportional to the level value to circulate more water for steaming to maintain the level. After A3 up to A4 it is also linear but with lower slope, because near A3 DRV comes in to operation to maintain the level. At A4 (f1) it reaches maximum. When A5 is reached, the set point is zero to indicate that the valve is closed following MFT during start-up. Function generator (f1) is shown after A2 as BCP should start after the level is above the low level; hence, the WCV cannot open prior to that. For generating the circulation set point from the storage tank level, the actual level is measured and duly compensated for by operating the temperature and pressure to get a corrected level signal computation. Actual circulation flow is measured and compared with the set points discussed. The error thus generated will be fed to the PI controller to regulate the WCV. When the water level in the SST is on the higher side, the DRV is operated via the function generator (f2) to send some water from the storage tank to the flash tank. This valve DRV is important for other operations as discussed in clauses 2.4.1 and 2.4.2. The characteristics are shown in Figure APDX/V-5b by f2. There are different philosophies for circulation based on manufacturer's recommendations, for example, NTPC Sipat uses the separator level control parameter to regulate the feed water flow control valve (BFP speed), whereas minimum feed water through the economizer is controlled by the WCV.

2.4.4 *Dry Mode of Operation*

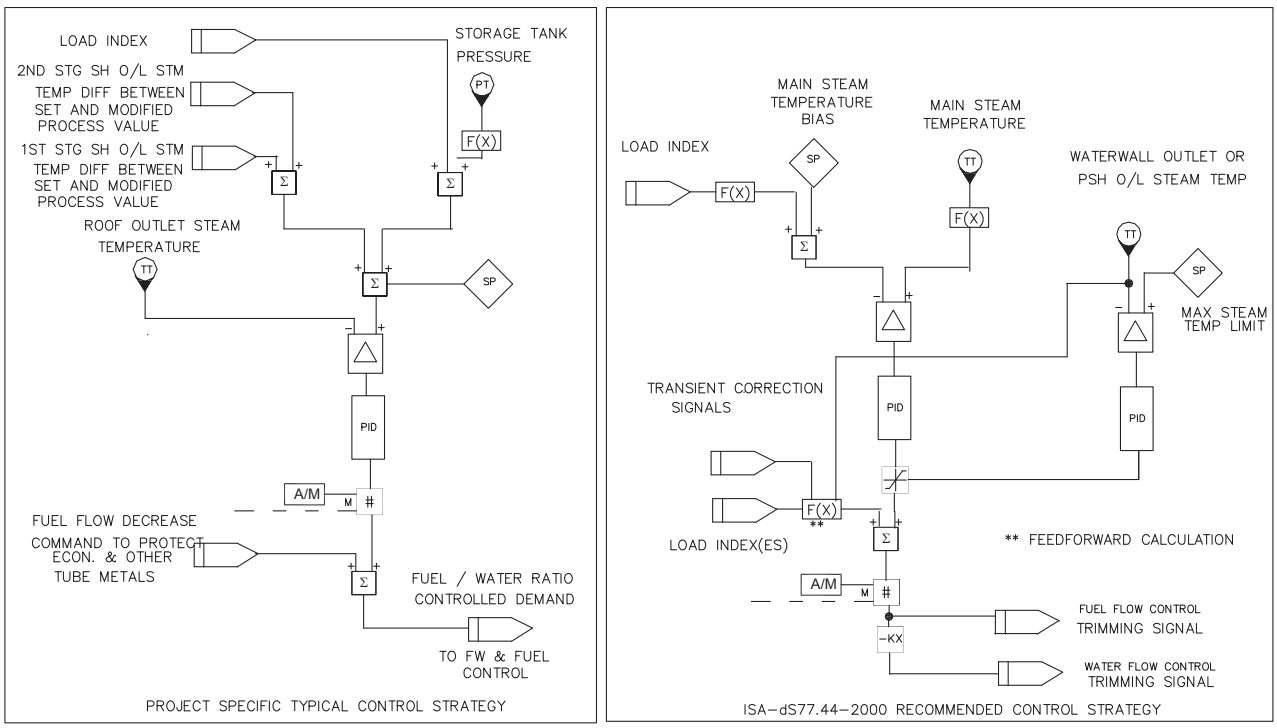
At 30% TMCR the separator should be completely dry with no level, and at this point (referred to as Benson point) the boiler changes from wet mode to dry mode. The BCP is shut and the boiler runs in OT mode. Economizer water flow is controlled by feed pump speed and the feed control valve (FCV; bypass valve full open). The boiler start-up system is isolated and platen and final superheating spray comes on. During transition from FCV (30%) to bypass or 100% FCV there may be fluctuation of pressure, which when stabilized, the FCV (100%) opens. In dry mode the steam temperature control loop and feed water control loop are interactive. These are discussed in the following clauses.

www.EngineeringBooksPDF.com



NOTE
- TYPICAL CONTROL STRATEGIES ARE SHOWN. PROCESS & MUTUAL INTERLOCKS ARE EXCLUDED FOR SIMPLICITY
- NUMBER OF SENSING ELEMENTS WOULD BE ACCORDING TO REDUNDANCY LEVEL ENVISAGED.
- NUMBER OF DRIVES & FINAL CONTROL ELEMENTS WOULD BE ACCORDING TO PLANT OPERATION PHILOSOPHY

FIGURE APDX/V-3 PA flow-press/mill temperature/fuel flow control.



NOTE
- TYPICAL CONTROL STRATEGIES ARE SHOWN. PROCESS & MUTUAL INTERLOCKS ARE EXCLUDED FOR SIMPLICITY; WRITE UP IN APPENDIX V MAY BE REFERRED
- NUMBER OF SENSING ELEMENTS WOULD BE ACCORDING TO REDUNDANCY LEVEL ENVISAGED.
- NUMBER OF DRIVES & FINAL CONTROL ELEMENTS WOULD BE ACCORDING TO PLANT OPERATION PHILOSOPHY

FIGURE APDX/V-4a Fuel/water ratio control.

www.EngineeringBooksPDF.com

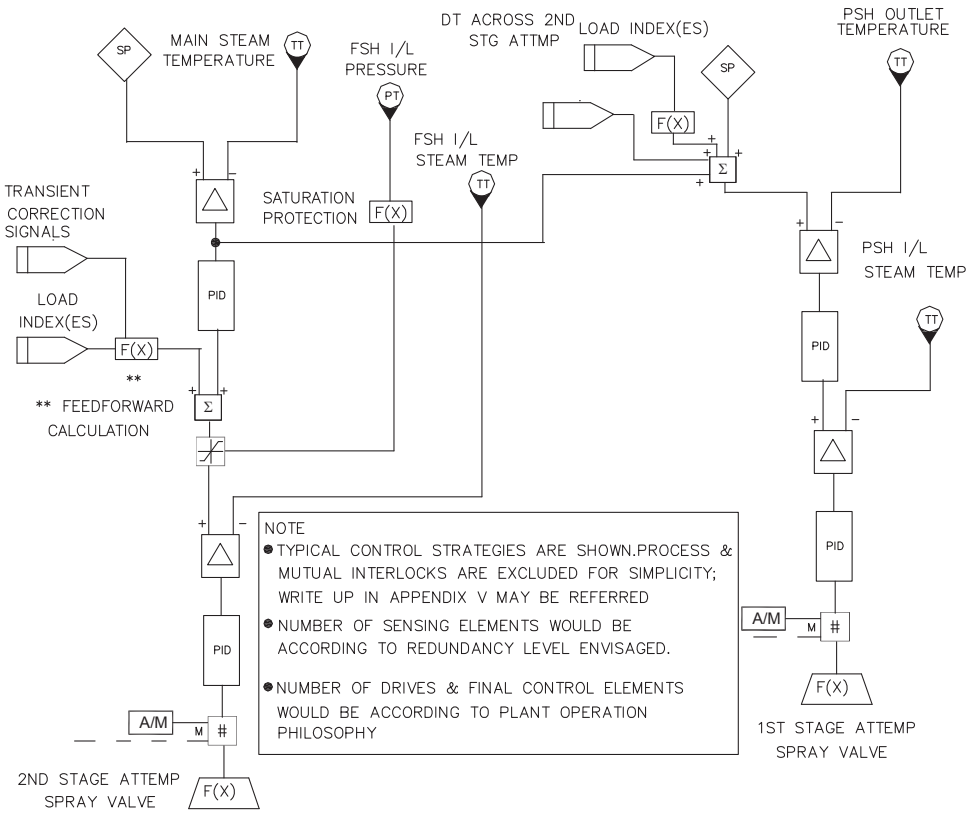


FIGURE APDX/V-4b Main steam temperature control (attemperation flow control).

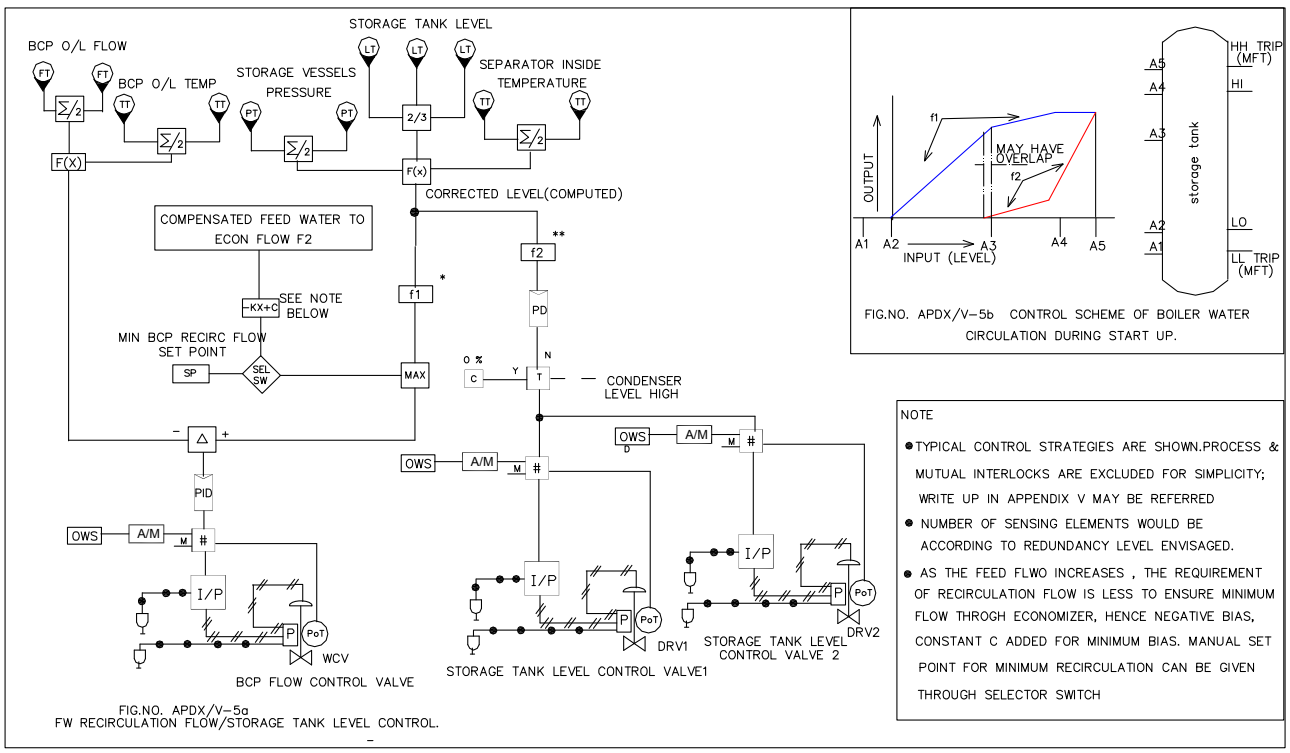


FIGURE APDX/V-5 Feed water recirculation and steam SST level control.

www.EngineeringBooksPDF.com

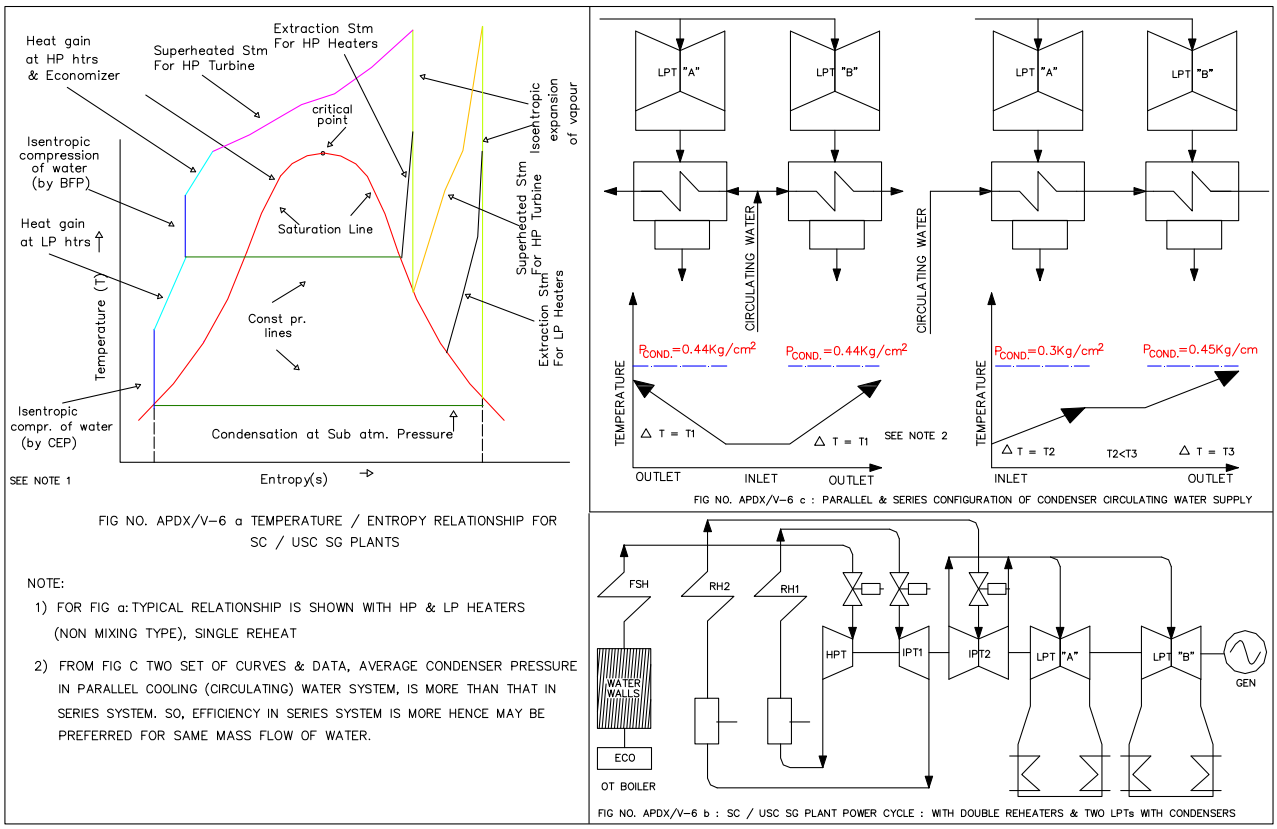


FIGURE APDX/V-6 Process cycle and components for SC and USC plants.

2.5 Chemistry of OT SC Boiler

Like any other boiler, in an SC boiler the water needs to be treated and there is a different dosing system to control the chemistry of water and steam. Various treatments such as oxygenated treatment and all volatile treatment (AVT; as discussed in Chapter V, Clause 4.0) are also applicable for SC OT boilers. For OT SC boilers, because of the absence of a drum, the quality requirements are stringent. Some of these requirements, as per the Electric Power Research Institute (EPRI), are listed in Table AP5/4. For feed water both treatment and associated commissioning values detailed using AVT-O and AVT-R symbols.

For SC plants and subcritical plants with a CPU, oxygenated treatments are performed for long-term protection of the pretreatment system by creating a hematite layer. Also, CPU operating time is due to low condensate ammonia and iron transfer. Normally this is done after the start-up period is over. For oxygenated treatment good quality make-up water and condensate feed water is necessary, so a CPU is essential. As shown in Figure V/4.0.1-3, normally high-purity oxygenated water is dosed at the CPU outlet and at the deaerator outlet. O_2, hydrogen peroxide, or air can be used as an oxidant with an O_2 level at ~30–15 ppb for OT boilers (30–50 ppb for drum type boilers). Based on dissolved oxygen and flow of condensate/feed water the dosing is regulated with the help of the flow control valve. Cat conductivity and pH monitoring is extremely important. As shown in Figure V/4.0.1-2, there is a relationship between pH and conductivity and it is crucial for OT SC boilers.

2.5.1 Control and Monitoring of Parameters in a Turbine Generating Plant

The turbine and generator control part in a turbine generating plant is similar to that of conventional power plants. They mainly differ in the mechanical and metallurgical aspect, for example, the double-reheat casing (as discussed above), two nos. double flow LP casings, blade shaping and provision of diffusers, etc. The exhaust diffuser at the LPT outlet stage provides for the necessary recovery of the exhaust steam pressure, which enables the outlet pressure of the last stage blading to become lower than the condenser pressure.

2.5.2 Control Loop Strategies

2.5.2.1 Steam Temperature Control

Due to the very configuration of an OT SG plant, final steam temperature is affected by the ratio of firing rate to

www.EngineeringBooksPDF.com

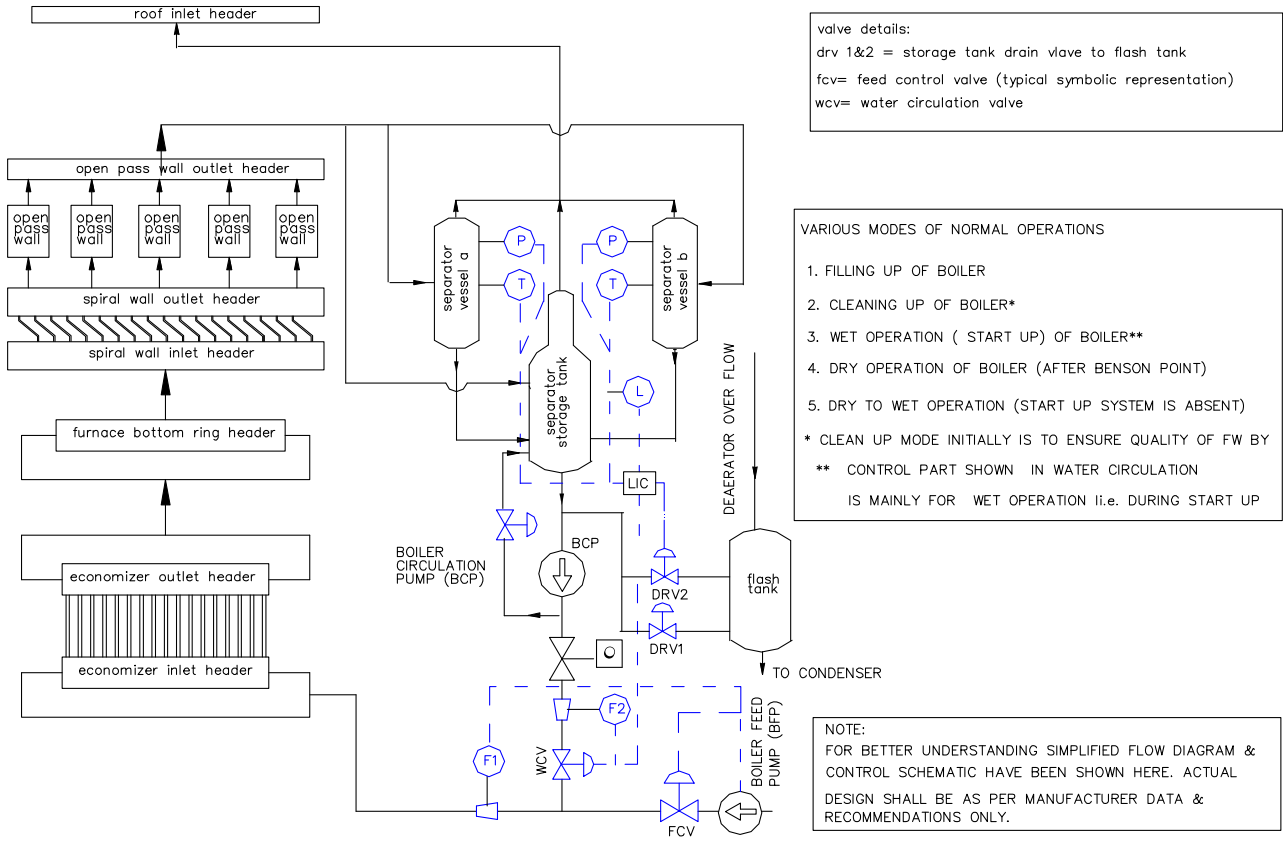


FIGURE APDX/V-7 Boiler water circulation (also start-up control scheme).

TABLE AP5/4 Target Value of Feed Water, Main Steam, and Reheat Steam Based on EPRI Recommendation

FW/MS/RH	Parameter	Unit	Target value	Remarks
FW	Ammonia	ppm	0.02–0.07	
FW	Iron	ppb	≤2	(AVT-O/AVT-R: <2*)
FW	Dissolved oxygen at Econ I/L	ppb	30–150	(AVT O: <10*; AVT-R: <5*)
FW	pH		8.8–8.5	(AVT-O/AVT-R: <9.2–9.6*)
FW	CAT Conductivity	μS/cm	≤0.15	(AVT-O/AVT-R: <0.2*)
MS and RH	CAT Conductivity	μS/cm	≤0.15 (<0.45*)	Action needed if it is 0.3
MS and RH	Silica	ppb	≤10(<40*)	Action needed if it is 20
MS and RH	Sodium	ppb	≤2(<12*)	Action needed if it is 4
MS and RH	Chlorides	ppb	≤2(<12*)	Action needed if it is 4
MS and RH	Sulfate	ppb	≤2(<12*)	Action needed if it is 4
MS and RH	TOC	ppb	≤100(<100*)	Action needed if it is >100

MS, main steam; RH, reheat; FW, feed water.
**Parameters in parentheses are the guideline of parameters during start-up and commissioning.*

www.EngineeringBooksPDF.com

feed water flow. At wet mode and/or at lower load it is necessary that fuel and feed water ratio is maintained at a point so that there is no chance of over fire. In feed water control strategy, minimum feed flow at all conditions is always ensured.

The control strategy changes either the firing rate or feed water flow or both to control the steam temperature. In a typical OT SG plant, unlike a subcritical boiler, the boiler master demand (BMD) signal is sent simultaneously to the fuel demand and the feed water demand. The boiler demand is fed to both the fuel flow and feed water flow control system in parallel as the BMD is commensurate with the MW output, which is the final product of the fuel inputs and feed water flow. In certain boilers feed water flow and/or fuel flow change is allowed to take part as per the BMD as long as the BMD is within the specified range of the desired feed water/fuel ratio added with approximately $\pm 10\%$ swing.

A separate temperature controller loop (Figure APDX / V-4a) is provided as a ratio controller whose output is then constituted as the trimming signal for any of the fuel flow and feed water flow control (with a scaling factor) or both depending on the plant configuration, manufacturer's/designer's recommendation, process variable response pattern, process constraints, etc.

Analysis of the individual effect of this ratio control on fuel flow control for final steam temperature control illustrates an adjustment between the control of temperature and the control of load. On the other hand, the individual effect of this ratio control on feed water flow control for final steam temperature control depicts an adjustment between control of temperature and steam outlet pressure. This type of control may eventually try to over fire or under fire the firing rate in response to load changes. The immediate response may create an erroneous steady-state fuel demand causing departure of temperature and pressure from their respective set points. It may be advantageous to utilize the ratio factor for both the fuel and water demand in an opposite direction to establish overall system stability as its effect on one process would offset the other.

However, note that due to the process safety requirement, which ensures minimum feed water flow through economizer/furnace tubes, the firing rate and feed water flow rate are released for adjustment to control steam temperature when after load means more than safe water flow.

Although it is useful to utilize the fuel/water ratio in steam temperature control, the inherent time delay in the water circuit makes it somewhat slow in response even if the fuel flow trimming signal is much faster than its water flow signal trimming counterpart.

To circumvent the time delay problem, attemperation through spray water valves at different stages is provided additionally to control main steam temperature. The philosophy behind provision of both systems is that spray attemperation would take immediate action to control initial temperature departures while the correction through the proper fuel/water ratio would be achieved from a steady-state component of the steam temperature control loop.

The traditional way to control steam temperature through multiple stages of spray attemperation is similar for subcritical boilers. The steam temperature control is equipped to take care of the faster transients to avoid the time delay (depending on the SG plant loads) of the water at the entry of the economizer and attaining the desired superheater temperature at the SG plant outlet. Without the transient correction approach, the tube metals can experience severe damage due to the miscalculation in actual spray water from the water flow requirement demanded to combat the transit time delay.

2.5.2.2 Fuel/Water Ratio Control

It was discussed above that for an OT SG plant it is extremely important to utilize this derived parameter. How it is derived, however, depends on the manufacturer's recommendation. This ratio determines all the final values of the main steam at the SG plant outlet.

Due to OT configuration, all feed water entering the SG plant becomes steam and therefore the throttle pressure is directly related to feed water flow, which is controlled by the BFPs. Since all the feed water is sent to the SG plant as per the unit master from the BMD, it must be evaporated through heat input by adjusting the firing rate control system. Superheater spray flow is taken out from total feed water flow. Any change in superheat spray flow would not influence a permanent adjustment in outlet main steam temperature since it does not change the ratio of firing rate to feed water flow.

The control strategies of main steam temperature control with the help of the fuel/water ratio and spray attemperation are depicted in Figure APDX/V-4a.

2.5.3 Short Description of the Control Strategies

2.5.3.1 Fuel/Water Ratio Control

Fuel/water ratio control is derived from the output of a temperature controller. Some manufacturers recommend an operator set point summed up with differential temperatures of both the two stages superheater temperature controllers' input, load index (as the feed forward signal) and characterized value of storage tank pressure (to take care of the saturation problem), whereas the "roof outlet temperature" is the measured or process variable. Corrections toward protection of the economizer and waterwall tubes are taken

www.EngineeringBooksPDF.com

care of by adding them to the controller output. The final output is then suitably processed to form a trimming signal for either of the fuel and water flow control systems or both.

ISA-dS77.44-2000 recommends the main steam temperature as the measured or process variable against the operator set point summed up with the load index (as the feed forward signal). The controller output is passed through a limiter to take care of the overheating of the waterwall tubes or platen superheater (PSH) tubes. The transient corrections from load index/indices and other signals are then added to the abovementioned signal output from the limiter to avoid under or overheating. The final output is then suitably processed to form a trimming signal for the fuel and water flow control system.

In other designs, mainly that of a TT furnace, differential temperature across the primary de-super heater is controlled by feed flow and the differential temperature for the final de-superheater is adjusted with the difference between the rate of change of main steam flow and that of the fuel rate flow (e.g., as seen in the Sipat Project of NTPC, India).

2.5.3.2 Main Steam Temperature Control (Attemperation Flow Control)

This is normally accomplished by the traditional control strategies but with some added features to take care of the OT configuration. Generally, two-stage attemperation systems are provided with independent or coupled systems. The first-stage attemperator controls the steam outlet temperature of the primary or PSH). The second-stage attemperator is used to control the final superheater steam outlet temperature. Both control systems operate in cascade mode as provided for subcritical boilers.

To take care of the transient conditions, feed forward signals are normally added to the primary controller to improve the control performance and are usually applied only on the final outlet temperature control strategy. The actual provision of feed forward signal sources and their characterization, however, depends on many factors. They should be applied as a minimum but not be limited to be sourced from the load index/indices, heat distribution signals like gas damper position or fuel nozzle tilt positions, fuel flow, airflow, etc.

The individual spray attemperator demand is distributed between both stages of attemperation. The individual spray demands are developed from the spray distribution and coordination control strategy as determined from the boiler manufacturer's recommendations and specifications. Both valves participate during transient boiler operation to minimize temperature excursions. The first spray demand protects the primary superheater from going into saturation at the inlet and from high temperature at the outlet. The control system must coordinate the first spray demand and the second spray demand to minimize correction from the final steam temperature controller.

2.5.3.3 Feed Water Recirculation Flow Control

Figure APDX/V-5 shows a typical control strategy in its simplest form. This control strategy is developed to ensure minimum feed water flow through the economizer, waterwall tubes, and the steam separator with the help of the BCP and associated valve for various functions, which include:-

1. To protect the economizer and waterwall during the low load
2. To minimize the BFP discharge flow and achieve heat recovery during start-up

The SST level is controlled for the BCP protection (to ensure NPSH) by regulating the recirculation flow valve position. Here the PI(D) controller gets the SST level as the variable set point and the recirculation flow (density compensated) as the process or measured variable. When the valve is positioned at full closed status or recirculation flow is less than a predetermined minimum value, a negative deviation of $\sim 5-10\%$ is imposed on the controller through a switching action to ensure sustained full closed signal to the valve.

The other interlocks, although not shown in the abovementioned control strategy, are normally provided as follows:-

1. To avoid sudden decrease in SST level:
   a. During starting of the BCP, the upper limit of valve opening command is set at 20% for a limited duration.
   b. During low load operation, the rate change of the valve position command is curbed if the SST level changes (mainly decreasing) too fast.
2. To avoid overflow, the valve receives a 100% opening command when the recirculation flow is more than a predetermined high value.
3. An increase bias may be added to the set point after BCP starts to raise expeditiously the economizer inlet temperature. By this action more hot water from the economizer outlet mixes with the economizer inlet, thus raising the temperature after mixing. The bias may be an adjustable fixed value or economizer inlet temperature with proper function generator.

2.5.3.4 Steam SST Level Control

Figure APDX/V-5 shows a typical control strategy in its simplest form. During water filling, start-up, and clean-up operations, the level of this tank is maintained by draining the water to the flash tank. The drain valve opening is proportional (through the rate adjuster) to level,

www.EngineeringBooksPDF.com

for example, the valve fully opens at 4000 mm and fully closes at 3000 mm. At normal load there would not be any water at the storage tank and the valve would remain fully closed. The interlocks included here include:

1. At a very high alarm level, high rate of change is automatically selected to arrest overflow.
2. Gain compensation of the drain valve opening signal may be incorporated to take care of the change in specific volume of water passing through the drain valve.
3. When level is decreasing at a high rate, a negative bias is added to the level signal to arrest the fast decreasing rate of level. For a fast opening signal, the rate change is restricted toward the opening path.
4. The drain valve would receive closing signal at a high condenser level.

BIBLIOGRAPHY

[1] PF-Fired Supercritical Boilers. Operational Issues and Coal Quality Impacts. Technical Notes 20 : By M/s B.J.P. Buhre, R. Gupta, S. Richardson, A. Sharma, C. Spero, T. Wall. Dtd; March 2002.

[2] Latest Development in Supercritical Steam Technology. Powergen Asia 2008; Kualalampur-Malaysia. Dtd; October 21-23, 2008. By Miro R. Susta (IMTE AG, Power Consulting Engineers. Switzerland).

[3] Ultra Super Critical Pressure Coal Fired Boiler -State of the Art Technology Applications - : By Yoshio Shimogori (Babcock-Hitachi K.K)

[4] Tube Vertical. Variable Pressure Furnace for Supercritical Steam Boiler. Las Vegas Nevada, U.S.A. Dtd: POWER-GEN International; 2001. December 11-13, 2001 : By M/s D.K. McDonald (The Babcock & Wilcox Company, USA) & S. S. Kim, U.S. Department of Energy, National Energy Technology Laboratory, USA).

[5] FWPG Benson VT Boiler- Process and Operational Description (Product Bulletin TP_PC_04_02.DOC) : By M/s Foster Wheeler Power Group, Inc.

[6] Design Factors and Water Chemistry Practices - Supercritical Power Cycles. By M/s Frank Gabrielli, Alstom – Windsor, USA & Horst Schwevers. Alstom –, Germany, (PREPRINT-ICPWS XV, Berlin) Dtd; September 8-11, 2008.

[7] Steam Generator for Advanced Ultra-Supercritical Power Plants 700 to 760C; (Technical Paper BR-1852;ASME 2011 Power Conference). By P.S. Weitzel, Babcock & Wilcox Power Generation Group, Inc Dtd; July 12-14, 2011.

[8] Design Features of Advanced Ultrasupercritical Plants. Part III. By Paul S. Weitzel, Babcock & Wilcox Power Generation Group, Inc. Dtd; July 30, 2012.

[9] Controlling Chemistry During Start Up and Commissioning of Once –Through Supercritical Boilers. K.Kirschenheiter, M.chuk, C.Layman, K. Sinha–Bechtel Corporation; December 2008.

[10] ISA Recommended Control Loop: ISA-ds77.44.02–2000

www.EngineeringBooksPDF.com

Appendix VI

Integrated Gasifier and Combined Cycle Plant (Pollution Control)

1.0 INTRODUCTION

Integrated gasification combined cycle (IGCC) technology will have high demand in the near future when it comes to catering to large energy needs. It offers a clean efficient option for the production of electricity from coal and other low-cost fuels. Like the circulating fluidized bed combustion boiler (CFBC; see Figure APVI/4), in this technology a variety of fuels such as coal, biomass petroleum coke/resid (residual after distillation), and waste can be used as fuel. In IGCC technology the gas turbine combine cycle enables high IGCC efficiencies, while the gasification block cleanly converts coal to fuel for the gas turbine. Apart from the core gasification technology and the power block there are a variety of auxiliary technologies to complement the core technology in its applications. This enables synthesized gas (syn. gas) conversion into a variety of liquid fuels, gases, and chemicals. The major important environmental benefits of IGCC include the following:

- Gasification allows both gas turbine generator (GTG) and steam turbine generator (STG) to produce energy.
- IGCC efficiency can be up to ~45% higher than super critical power plants.
- Pollutants like S, Hg, N_2, etc., are removed prior to combustion [unlike in pulverized coal (PC) boilers].
- Because of the inherent clean technology, it is more environmentally friendly than other technology.

1.1 What is Gasification?

Gasification is a thermo chemical process (not combustion) at elevated temperature and pressure in reducing (dearth of oxygen) atmosphere used to completely convert feedstock mixed with steam into a clean syn. gas (no toxic product) and other byproducts. Major items needed for this process are fuel and oxidant to produce syn. gas, which is finally cleaned. The basic block diagram of a typical IGCC is presented in Figure APVI/1a. From a pollution standpoint, the natural gas combined cycle plants provide better results when compared with various other types of technologies, but IGCC has better results when compared with PC/super critical/ultra super critical plants (see Table APVI/1.0-1).

As mentioned, IGCC is very environmentally friendly. In the subsequent clauses, the basic process along with advanced control systems deployed for this type of plant will be discussed. Keep in mind that IGCC is basically an integration of various systems and not a single process, so naturally the various systems will have different needs.

2.0 BASIC PROCESS

The gasification unit is the main part of the IGCC system. High-purity oxygen at high pressure of ~70 kg/cm^2 reacts with fuel at a temperature of nearly 1200°C to produce syn. gas. This syn. gas is cooled and cleaned and used as fuel in a gas turbine system in the combined cycle process. Also, there are a number of byproducts available such as sulfur/sulfuric acid, as part of the integrated process. This clean syn. gas also provides an energy source for various other applications, e.g., H_2 for fuel cells. As seen in Figure APVI/1a, the basic building blocks consist of a gasification unit, a clean-up unit, a combined cycle power block, and other utility/byproduct units and oxidant supply system including an air separation unit (ASU). The ASU, which separates oxygen from air cryogenically, plays an important role by supplying oxygen for the gasifier and nitrogen in an increasing mass flow in the power block (combined cycle plant). Various supporting units consist of the following:

1. *Coal storage and feed preparation*: This consists of a coal-handling plant, which provides the means for receiving, unloading, storing, reclaiming, and conveying coal for a storage facility. Mainly solid material handling equipment is normally used in PC power plants. For gasification preparation of fuel is necessary. In a gasifier

www.EngineeringBooksPDF.com

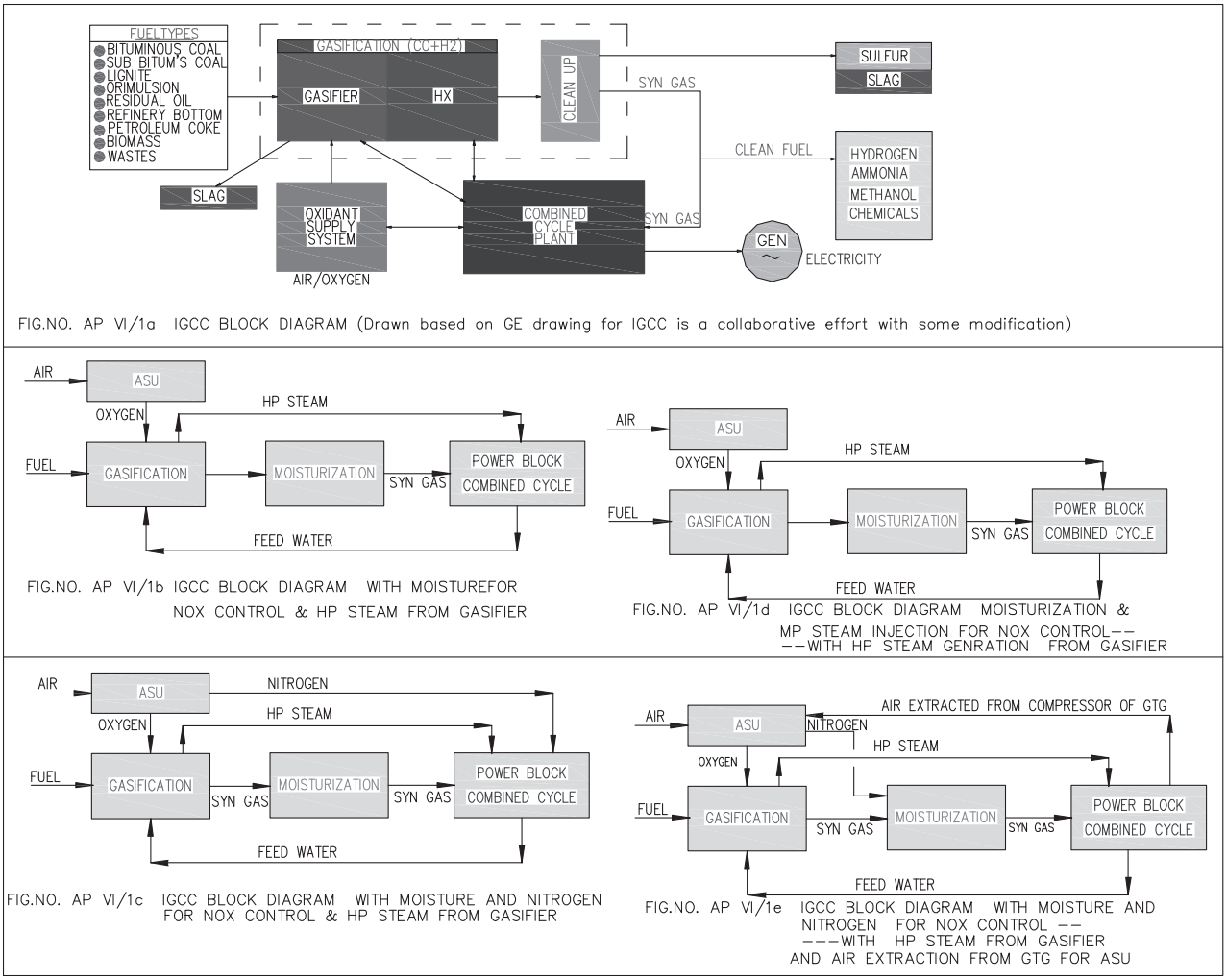


FIGURE APVI/1 IGCC block diagram and variations in types.

TABLE APVI/1.0-1 Comparison of Pollutants between IGCC and Super Critical/Ultra Super Critical Boilers

Criteria	Ultra/super critical PC (coal)	IGCC (coal)
NO_X (kg/GJ)	0.05	0.03
SO_X (kg/GJ)	0.03	0.15
CO (kg/GJ)	0.02	<0.005
CO_2 (kg/GJ)	100	96
PM (kg/GJ)	0.01	<0.005
Mercury (%)	30–90	>90

the coal is pumped in slurry form or can be sent in dry form via a lock hopper system.

a. Coal slurry is prepared by wet grinding of wet coal in a rod type mill. The coal needs to be ground to a specified particle size and distributed to maintain proper slurry solid concentration (60–65% by weight). Prepared slurry is stored in an agitated tank. Normally recycled water is used here. The disadvantage is that the requirement of water may absorb some heat.

b. The Shell and Siemens design uses a dry coal feed system, with the help of a locked hopper, which consists of one top and one bottom valve (one opening at a time). During operation the top valve (with the bottom valve closed) is opened to receive the coal fines. After the top valve is closed, the hopper is pressurized by N_2 from the ASU, at a pressure a little above the gasifier pressure, and then the bottom valve opens (with the top valve closed) for discharging to the gasifier. After this operation the bottom valve is closed and the hopper depressurized before the top valve is opened again.

2. *ASU*: The gasification process requires an oxidant such as air/oxygen. To minimize the size of the gasifier,

www.EngineeringBooksPDF.com

high-purity, pressurized oxygen is used most often. However, it accounts for nearly 15% of the total gasification plant cost and utilizes most of the power. ASUs working on cryogenic distillation are utilized in most cases to obtain 95% oxygen purity. In cryogenic distillation, air is liquefied at a very low temperature (−185°C). Atmospheric air is compressed in multiple stages with inter cooling and again cooling by chilled water. Then the air enters the "cold box" with a distillation column of many stages with an argon column for better purification. Oxygen and nitrogen, after removing other constituents, are warmed by a heat exchanger. Oxygen is stored for continuous gasifier operation. Nitrogen is compressed and may be used in a GTG or as a byproduct.

3. *Syn. gas cooling*: The raw syn. gas leaving the gasifier is >1500°C. Thus gas can be cooled by direct quenching or heat recovery can be done utilizing a radiant, convective heat exchanger. Typically there may be three stages of heat recovery.
   a. Raw syn. gas is first cooled in a high-temperature, radiant heat exchanger to produce high-pressure (HP) steam at approximately > 575° C for the power block. Hot syn. gas flows through the central waterwalls and HP steam is generated in the tube (>110 kg/cm^2).
   b. In the next stage it is cooled by a convection type heat exchanger, which produces medium pressure steam. It is then water scrubbed to remove fine soluble particles, such as ammonia, chloride, etc.
   c. In last stage it is cooled to ∼35° C to get low-pressure steam in the low-temperature gas cooler (LTGC).
4. *Syn. gas clean up*: To meet emission regulations and to protect downstream equipment, it is necessary to clean up and condition the gas to get rid of fly ash and other fine particles, sulfur, ammonia, and chloride traces of heavy metals such as Hg and CO_2. Depending on the application the cleaning process may vary as well as adjusting the H_2 to CO ratio requirements for the downstream system. Typical subsystems may include:
   a. *Scrubber, filter, and cyclone*: As discussed above raw syn. gas is quenched and scrubbed with water in a trayed column to remove fine char and ash particulates in the slurry-fed gasifier. For the dry gasifier, cyclones and candle filters are removed and recycled back into the system, and finally water quenched and scrubbed. With water scrubbing fine particles, ammonia, chlorides, traces of H_2S, and other contaminants are removed. Spent water is sent for sour treatment whereby decantation fine particles are further removed.
   b. *Water gas shift (WGS)*: Most of the sulfur in coal is converted to H_2S, but depending on gasification temperature, ∼3−10% sulfur is converted to COS. Approximately 99% of COS is first converted to H_2S by syn. gas through the catalytic hydrolysis reactor. For a higher H_2 to CO ratio, syn. gas is passed through a sulfur-tolerant shift catalyst to convert CO to CO_2 and water into H_2. In some cases steam injection is done for this ratio adjustment.
   c. *Acid gas removal (AGR)*: This is used for removal of H_2S and CO_2 followed by sulfur recovery for sulfuric acid plants. Removal of H_2S and CO_2 can be done by a physical process that is needed when syn. gas with <1 ppmv sulfur. This is not only very costly but it requires more power. However, for power generation where up to 30 ppmv sulfur is acceptable, chemical solvent processes such as methyl diethanolamine (MDEA) and sulfinol are used. This process operates slightly above atmospheric temperature (unlike the cryogenic physical process), so power requirement is less.
   d. *Activated carbon (not shown) filter to capture Hg*: Cooled syn. gas from LTGC is passed through a sulfide-activated carbon bed to recover ∼90% of Hg and other heavy metal contaminants. Since there is sulfur in activated carbon, it is normally placed ahead of AGR to eliminate the possibility of sulfur slippage.
5. *Power block—combined cycle (see Chapter III, Clause 10)*: Clean syn. gas is utilized in GTG for power generation. The exhaust gas from the GTG is used in heat recovery steam generators (HRSGs) for generation of steam that is finally used to run STGs for generation of power. A combined cycle plant is supported by a number of utility processing facilities such as steam condensation collection facilities (Figure APVI/2), distribution, pumping, and treatment units. Gasification unit heat is recovered through heat exchanger where feed water comes from the combined cycle and is heated to get HP steam. This steam later is superheated in the HRSG (shown in Figure APVI/2) to be utilized in STG for power generation (see Figure APVI/1a).
6. *Other uses for syn. gas*: Along with producing power, syn. gas can be converted into a variety of liquid fuels, gases, and chemicals with the help of various conversion methods such as Fischer−Tropsch synthesis.
7. *Gasification process*: Coal gasification is quite a complex process, but for instrumentation, such detailing may not be necessary and can be conceived as a few reactions given in Table APVI/2.0-1. In the gasification process a mixture of gas is produced known as syn. gas comprising mainly CO and H_2 along with other constituents such as CO_2, sulfur compound COS, H_2S, etc., as per the details given in Table APVI/2.0-2, when coal, steam, and oxygen are input in the system. The data show that a wide range of syn. gas composition is obtainable with variance in gasification types, feedstock, and operation parameters. In

www.EngineeringBooksPDF.com

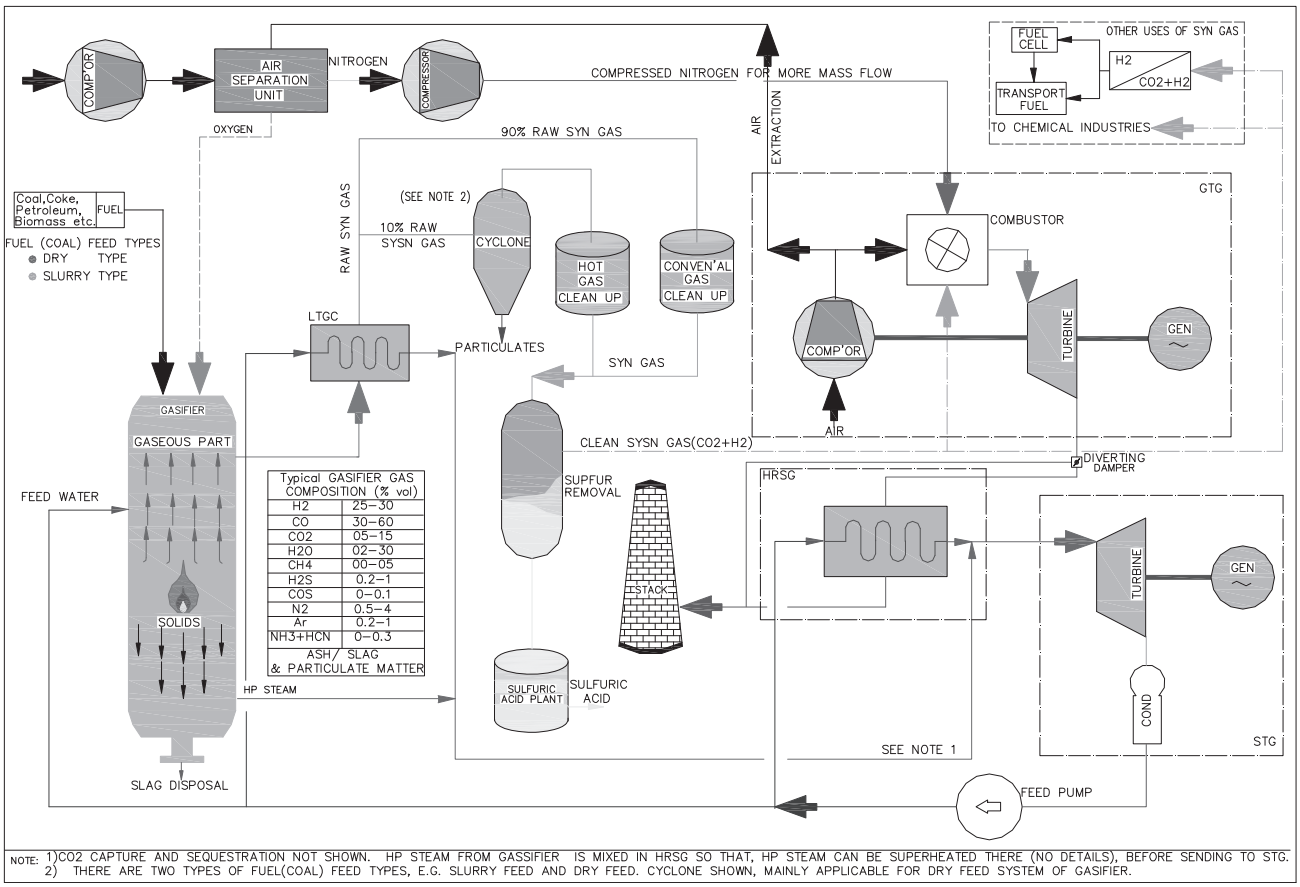


FIGURE APVI/2 Schematic for integrated gasification combined cycle with allied systems.

TABLE APVI/2.0-1 Gasification Process

Reaction type	Reaction
Gasification with O_2	$2C + O_2 \leftrightarrow 2CO$
Combustion with O_2	$C + O_2 \leftrightarrow CO_2$
Gasification with CO_2	$C + CO_2 \leftrightarrow 2CO$
Gasification with steam	$C + H_2O \leftrightarrow CO + H_2$
Gasification with H_2	$C + 2H_2 \leftrightarrow CH_4$
WGS Water Gas shift	$CO + H_2O \leftrightarrow H_2 + CO_2$
Methanation	$CO + 3H_2 \leftrightarrow CH_4 + H_2O$

gasification most of the fuel's sulfur is converted to H_2S and to a lesser degree COS. Nitrogen in the fuel is converted mostly to NH_3 and a small amount of HCN and chlorine is converted to HCl. Gasification reactions are reversible, and the reactions and their conversions are subjected to thermodynamic equilibrium and reaction kinetics. Thermodynamic modeling is a very useful tool in calculating the amount of steam and oxygen required, finding the composition of syn. gas produced, and optimizing the process efficiency. It has been found that to produce syn. gas with low methane content a high temperature with excess amount of steam (stoichiometric requirement) can be used. At a very high temperature, syn. gas production needs more oxygen, which would again lower system efficiency (because of the power for ASU). A few alternatives for gasification via system integrations

TABLE APVI/2.0-2 Composition of Typical Gasifier Gas (in % vol)

H_2	CO	CO_2	H_2O	CH_4	H_2S	COS	N_2	Ar	NH_3 + HCN	Ash/slag/ particulate matter
25–30	30–60	5–15	2–30	0–5	0.2–1	0–0.1	0.5–4	0.2–1	0–0.3	

www.EngineeringBooksPDF.com

are depicted in Figures APVI/1b–APVI/1e. The design uses moisturization for NO_X control as shown in Figure APVI/1b. These systems also use radiant and convective heat exchangers/syn. gas cooler along with an economizer in the feed water line for heat recovery. The HP steam from the cooler is superheated by HRSG in the power block to be utilized in the STG. In Figure APVI/1c nitrogen from the ASU has been utilized in GTG to boost the output with lower water consumption, but at the cost of using auxiliary power. Here the design uses moisturization for NO_X control. Figure APVI/1d is similar but there are ways to control NO_X by moisturization followed by medium pressure steam injection. In Figure APVI/1e moisturization of syn. gas and N_2 control NO_X.

8. *Design considerations*: A few points related to system design are listed below so the various subsystems could be integrated properly as integration plays a major role in IGCC.

   a. *ASU air extraction and GTG integration*: Syn. gas has a very low caloric value. This can add significant mass flow to the GTG when compared with the performance firing natural gas, with which most GTGs are optimized. Therefore when syn. gas is fired there is extra capacity in the compressor, so extra mass flow will boost output to the limit firing temperature, the GT expander flow, and expander blade materials. Similarly it is economical to use all the N_2 available from the ASU. N_2 is a function of coal feedstock, gasifier performance, etc. Adding N_2 and moisture to the maximum limit is called power augmentation, and this results in significant air extraction from the compressor for the ASU.

   b. As noted before, moisture, N2, and CO_2 can be considered as diluents for NO_X

   c. Proper design integration involves a trade-off between overall plant efficiency, capital cost, operability, availability, and proper selection of equipment, especially

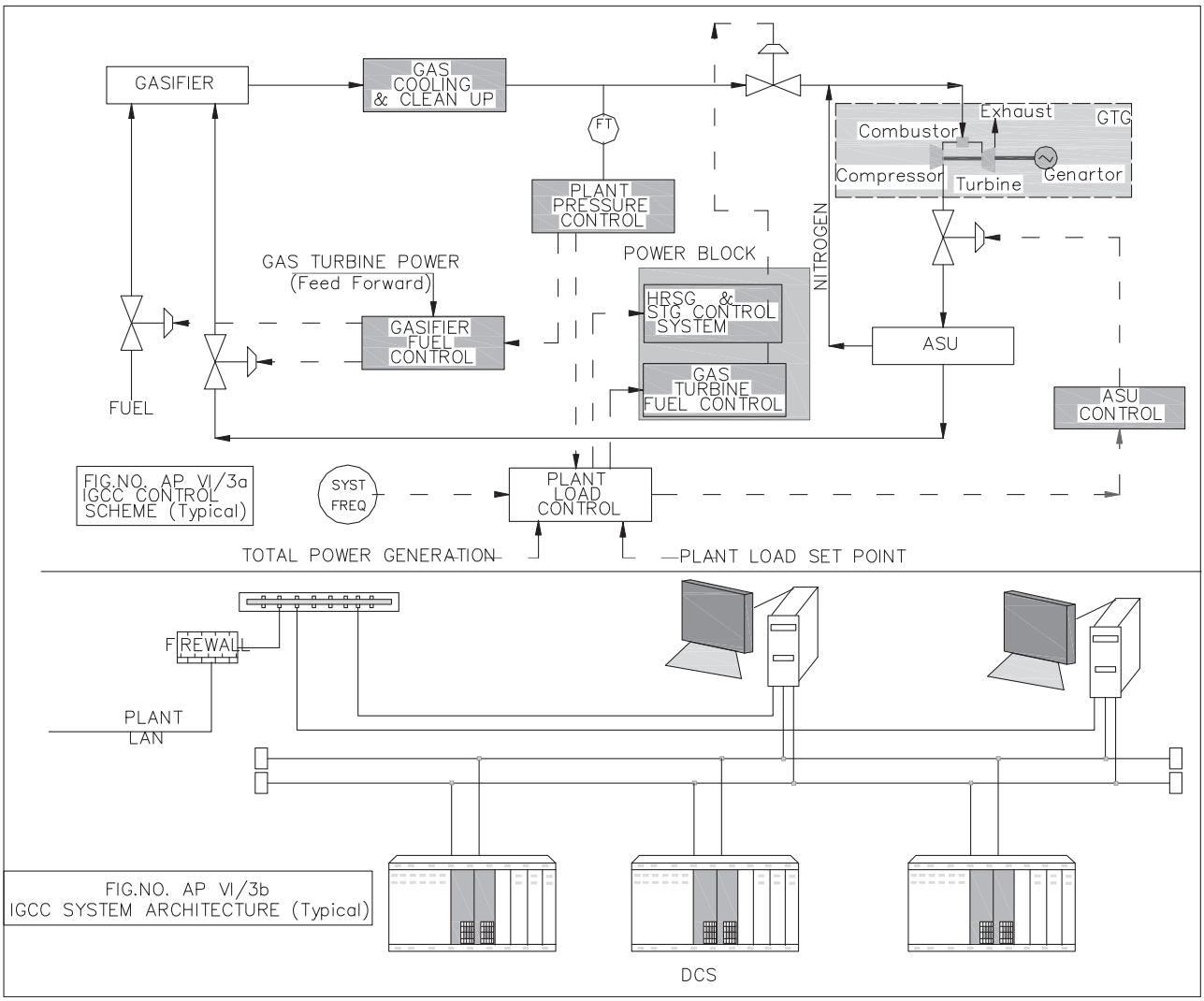


FIGURE APVI/3 IGCC control scheme and system architecture.

www.EngineeringBooksPDF.com

**CFBC:*
"When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream—the bed is called "fluidized."
With further increase in air velocity, there is bubble formation, vigorous turbulence, rapid mixing, and formation of dense defined bed surface. The bed of solid particles exhibits the properties of a boiling liquid and assumes the appearance of a fluid—"bubbling fluidized bed."
At higher velocities, bubbles disappear and particles are blown out of the bed. Therefore, some particles have to be recirculated to maintain a stable system—"circulating fluidized bed." The fluidized bed combustion (FBC) takes place at ~ 840 to 95°C. Since this temperature is below the ash fusion temperature, melting of ash and associated problems are avoided.
A CFBC is a good choice if the following conditions are met:

- *Capacity of boiler is large to medium.*
- *Sulfur emission and NO_X control is important.*
- *The boiler is required to fire low-grade fuel or fuel with highly fluctuating fuel quality.*

Major performance features of the circulating bed system are as follows:

a) It has a high processing capacity because of the high gas velocity through the system.
b) The temperature of ~87 °C is reasonably constant throughout the process because of the high turbulence and circulation of solids. The low combustion temperature also results in minimal NO_X formation.
c) Sulfur present in the fuel is retained in the circulating solids in the form of calcium sulfate and removed in solid form. The use of limestone or dolomite sorbents allows a higher sulfur retention rate, and limestone requirements have been demonstrated to be substantially less than with bubbling bed combustor.
d) The combustion air is supplied at 1.5–2 psig rather than 3–5 psig as required by bubbling bed combustors.
e) It has high combustion efficiency.
f) It has a better turndown ratio than bubbling bed systems.
g) Erosion of the heat transfer surface in the combustion chamber is reduced, since the surface is parallel to the flow. In a bubbling bed system, the surface generally is perpendicular to the flow. "

FIGURE APVI/4 Note on CFBC.

the GTG on which the entire integration hinges. Considerations regarding this are presented below:

i. *Design Points*:
- Feedstock and its flexibility. This in turn determines the performance of the gasifier and composition of the syn. gas.
- Ambient condition and site elevation necessary for GTG.
- GTG design and operating domain.
- Emission limit, standards, and waste water discharge guideline as applicable.

ii. *Integration considerations*:
- Gas turbine air extraction to the ASU
- NO_X control strategy
- Gas turbine power augmentation
- Heat recovery integration
- Steam generation conditions
- CO production

3.0 CONTROL SYSTEM

As IGCC is an integrated system, it is necessary that a coordinated control approach is deployed using the control strategy shown in Figure APVI/3a. In the control strategy load set point as well as total power generation could also be fed into the system so that a coordinated control system can integrate various generation units to initiate the actual requirement for the power block of a particular subsystem. The control demand sends signal simultaneously to both GTG fuel control, i.e., syn. gas flow, as well as to the ASU so that oxygen flow to the gasifier is regulated immediately. When there is a change in demand to the GTG syn. gas flow there will be change in pressure of the syn. gas header pressure. Through controllers this regulates the fuel and oxygen flow to the gasifier so that syn. gas demand is met and the syn. gas header pressure is restored. This is also sent to the coordinate controller as feedback to balance the new demand. Gas turbine demand is given as feed forward signal to make the system more responsive. Like the coordination control loop in PC boilers, a frequency signal is introduced.

Figure APVI/3b shows typical system architecture for IGCC. Here a number of controllers are hosted on workstation(s) that has an OPC server. Other workstations are kept for data collection and implementation. There are a number of controllers to regulate operation of the various subsystems such as a gasifier, cooler, and a conditioning unit. The IGCC control network could be

www.EngineeringBooksPDF.com

connected to other plant LANs via a firewall to limit access to the system. For details on functionality of firewalls in a network, refer to Appendix IV.

BIBLIOGRAPHY

[1] GE Gas turbine Performance Characteristics : GE Power Systems :GER 3567H(10/0)

[2] An Introduction to CO2 Separation and Capture Technologies. H.Herzog MIT Energy laboratory; Aug'1999.

[3] Advanced Process Control At an Integrated Gasification Combined Cycle Plant; 2007. M.Abela (Isab Energy Service), N Bonavita, R.Martini (ABB PS&SS SpA).

[4] Integrated Gasification Combined Cycle GE IGCC Technology. J.Tobin, S.K.Bae GE Power Systems:APEC Clean Fossil Energy Seminar; Dec'2003.

[5] IGCC—The Challenges of Integration. R. F. Geosits and Lee A. Schmoe—Bechtel Corporation:GT2005; Jun'2005.

[6] IGCC experience and further developments to meet CCS Market Needs. J.Krag Siemens AG Energy Sector Fossil Power Generation division; Sept'2009.

[7] The Tampa Electric Integrated Gasification Combined Cycle Project:US Department of Energy and Tampa Electric Company:A Joint report (Internet Document).

www.EngineeringBooksPDF.com

Appendix VII

A Few Operational Features of the Unit

1.0 INTRODUCTION

Basic measurements and control aspects pertinent to thermal power plants have been covered in the main body of this book. In addition to those, there a few other operational features with which instrumentation and control engineering are either directly or indirectly related. Here a brief discussion on the same is presented. In Chapters VII–IX and XI various controls pertinent to boiler turbine regenerative systems and BOP systems (both closed loop and open loop control systems) have been discussed at length. With this knowledge, a short discussion is presented in this appendix on the following topics:

- Unit protection system
- House load operation
- Bus transfer system (BTS).

Out of these three systems, the first two directly impact the control systems as previously discussed in the main body of this book, whereas a BTS indirectly effects the control systems. For abbreviation definitions, refer to Figures APVII/1 and APVII/3.

2.0 UNIT PROTECTION SYSTEM

As the name suggests, the discussion in this clause is about the protection of the unit, but it does not mean that in all cases entire units (i.e., all subsystems of the units) will be tripped. Since the degree of damage and/or abnormal situations varies, so does the type of protection. Common protections are offered against the following:

- Personal damage
- Equipment/system damage
- Safety operation mode for boiler turbine and generator, by limiting certain actions and even tripping equipment and/or a system

It is quite clear that there are abnormal situation classifications as there are different classes of trips. Internationally these classes are termed as Class A, Class B, and so forth. The most popular classes of trips for mechanical systems are shown in Figure APVII/1a.

2.1 Classification of Trips

Trips are mainly classified as Class U, Class A, Class B, Class C, Class D (also Class E—electrical system not included), etc. These classes are discussed in the following clauses.

2.1.1 Class U Trip

This stands for tripping of the unit or tripping of the boiler, turbine, and generator modules including regenerative cycle equipment (see Figure APVII/2). [This may not be applicable for cogeneration plants with a combination of boilers and turbo generator(s); TGs]. Major electrical fault (Class A electrical fault), very high condenser pressure, or damage of turbine bearing may fall under this category. In utility units without high-pressure (HP)/low-pressure (LP) bypass ,when the TG trips the boiler has to trip because there is no flow path left. The situation is totally different if the unit has an HP/LP bypass system. In this case people may question the need for tripping the boiler even if the (TG) trips. The question is valid, because in those cases there is no Class U tripping in true sense, it may be called Class A tripping. In reality this may not be true, because HP/LP bypass can be run for a certain amount of time, when there is the probability of getting back the unit within certain time, to avoid a long starting time (inertia) of the boiler. Faults are not easily repairable and it is questionable whether the HP/LP bypass should be run and waste energy. The repair time is long for major electrical faults or damage to the turbine bearing, etc. Also if the condenser pressure is high, HP bypass cannot be run. It has been found that many units' boilers are directly or indirectly tripped from high condenser pressure conditions.

All of these causes effectively call for an entire unit tripping. There are two schools of thought. One idea is that the boiler should be tripped directly, instead of attempting to start the HP/LP bypass. This gives rise to Class U tripping. The other idea is that the boiler is not directly tripped;

www.EngineeringBooksPDF.com

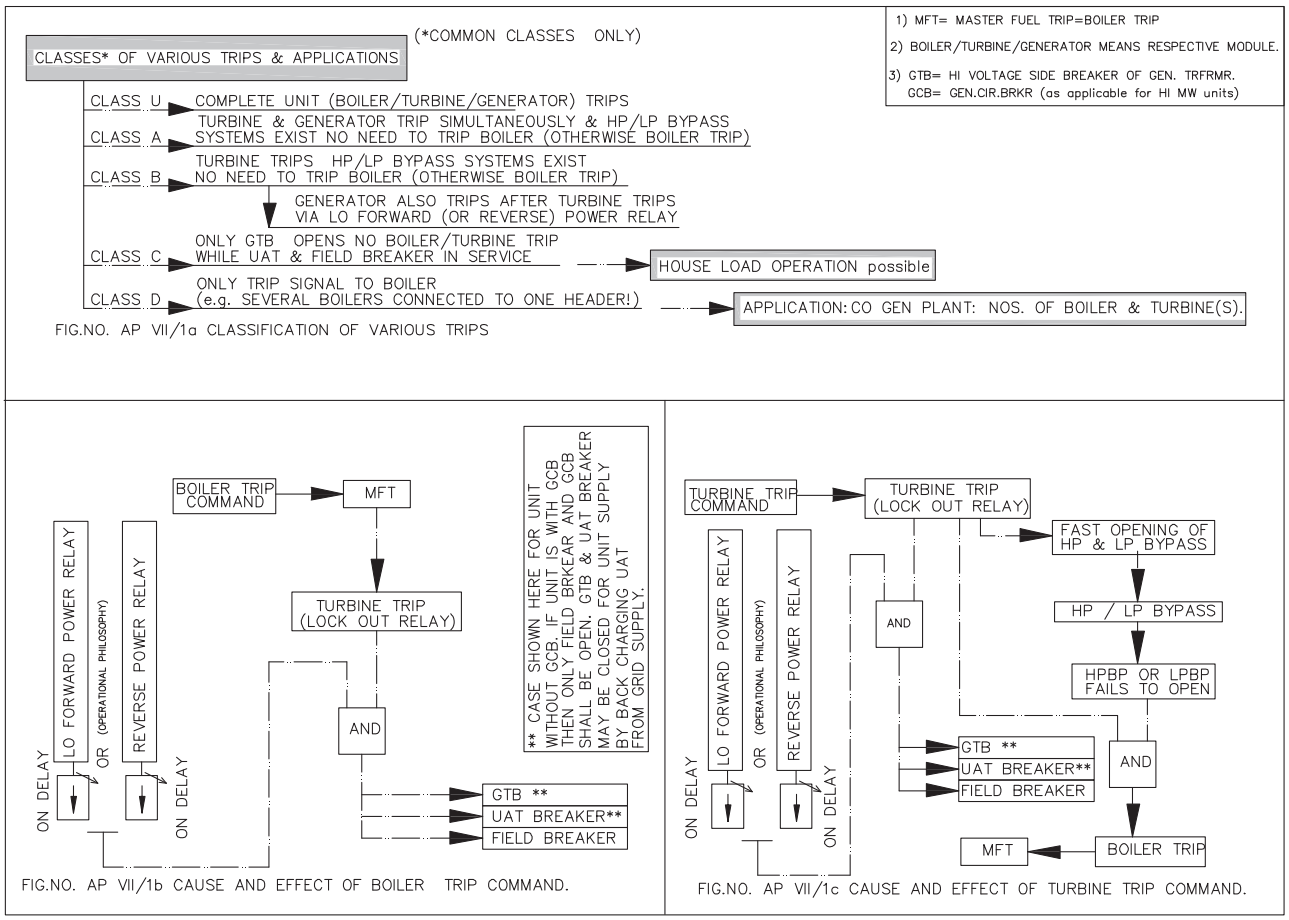


FIGURE APVII/1 Classification cause and effect of various trips, Scheme 1.

instead it may be tripped indirectly and/or manually. In the latter case Class U tripping has no significance.

2.1.2 Class A Tripping

In this situation both the turbine and generator trip. This is mainly caused by electrical trips (see Chapter IX, Clause 3.1). In utility units without HP/LP bypass the boiler will have to be tripped (same as Class U). In units with HP/LP bypass, the boiler may not be tripped; instead HP/LP bypass operates by fast-opening criteria. If either the HP or LP bypass fails to open, for reheater protection (see Figure VII/4.1.7-2a) the boiler will trip.

2.1.3 Class B Tripping

It is similar to Class A tripping; the only difference is that the generator will trip after the turbine trips from low forward power or reverse power relay with a time delay (see Chapter IX, Clause 3.1). What is the significance of this? The generator is run until the motive power is not totally exhausted so that when the generator trips, due to the remaining steam inside the turbine, it does not cause over speeding of turbine. Time delay varies from machine to machine, and use of low forward power or reverse power relay varies with manufacturers. Some believe that generators should be tripped when motive power is lost, just before setting the motor action of the generator. On the other hand, some manufacturers believe that a very short period of motoring action of the generator is necessary to ensure that there is no motive power left to eliminate any possibility of over speed (e.g., Siemens KWU machines).

2.1.4 Class C Tripping

In this type of tripping the generator connection to the grid may be cut off by tripping the generator transformer high-voltage (HV) circuit breaker (GTB), without tripping the breaker for the unit auxiliary transformer (UAT) and generator field breaker, so that it can supply power to the unit board—house load operation.

2.1.5 Class D Tripping

This is tripping of the boiler, and is more significant for cogeneration plants.

www.EngineeringBooksPDF.com

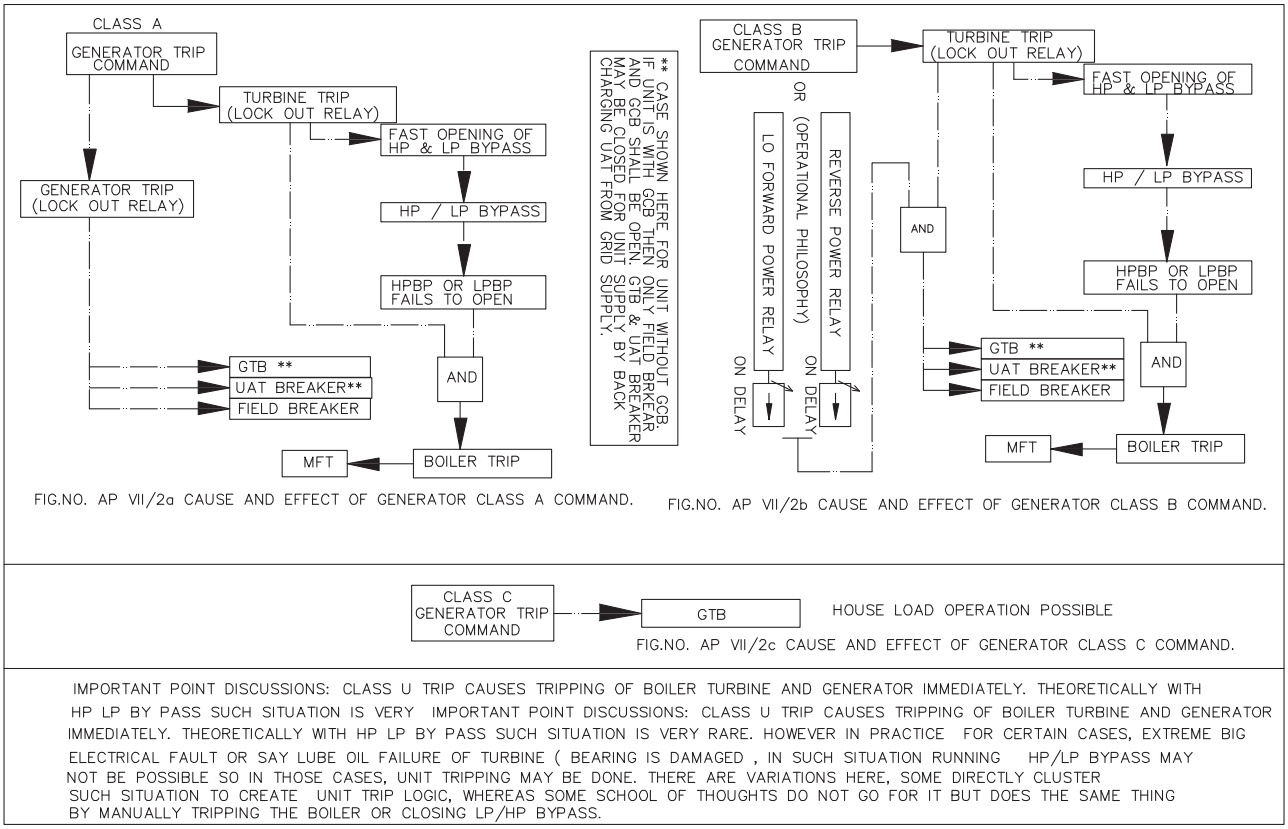


FIG.NO. AP VII/2a CAUSE AND EFFECT OF GENERATOR CLASS A COMMAND.

FIG.NO. AP VII/2b CAUSE AND EFFECT OF GENERATOR CLASS B COMMAND.

FIG.NO. AP VII/2c CAUSE AND EFFECT OF GENERATOR CLASS C COMMAND.

FIGURE APVII/2 Classification cause and effect of various trips, Scheme 2.

2.2 Cause and Effect of Various Types of Tripping

In this clause various causes and actions for boiler turbine and generator tripping are presented. Causes for boiler turbine tripping have been discussed at length in Chapters VIII and IX, respectively, and reheater protection was detailed in Figure VII/4.1.7-2a; hence, these are not repeated here. Only generator tripping causes will be discussed below:

2.2.1 Cause and Effect of Boiler Trip

Various boiler trip commands are discussed in Chapter VIII and detailed in Figure VII/4.1.7-2a (for reheat protection). Some commands trip the master fuel relay to trip the master fuel trip to cut all sources of fuel (i.e., cutting off all energy) to the boiler (see Figure APVII/2b & APVII/3c to understand the meaning of ** in Figure APVII/2b). Since there is no steam supply, the turbine needs to be tripped via the turbine lock-out relay (tripping solenoid), and consequently, the same generator needs to be tripped. However, the generator is not tripped immediately but tripped after it is ensured that motive power is lost as detailed in Clause 2.1.3. As a result GTB and the UAT breaker and field breaker will be opened. In larger units, where there is a generator circuit breaker (GCB), the GCB is opened along with the field breaker and the UAT breaker and the GTB can remain closed to supply power from the unit board by back-charging the UAT. This possibility is discussed to a greater extent in Clause 4.0.

2.2.2 Cause and Effect of Turbine Trip

Various turbine trip commands are discussed in Chapter IX, such as the trip turbine lock-out relay (trip solenoid valve) to trip the turbine immediately. Units with an HP/LP bypass will issue a fast-opening command. Tripping of the generator from the turbine trip will be similar to what was discussed in the previous clause. However, if either HP or LP bypass fails to open, then for reheater protection (as detailed in Figure VII/4.1.7-2a) the boiler will trip (see Figure APVII/1c).

2.2.3 Cause and Effect of Generator Trip

There are classifications of generator tripping: Class A, B, and C. Of these Class C trips are mainly concerned with faults beyond the generator transformer HV side. In this trip house load operation is possible as long as the generator

www.EngineeringBooksPDF.com

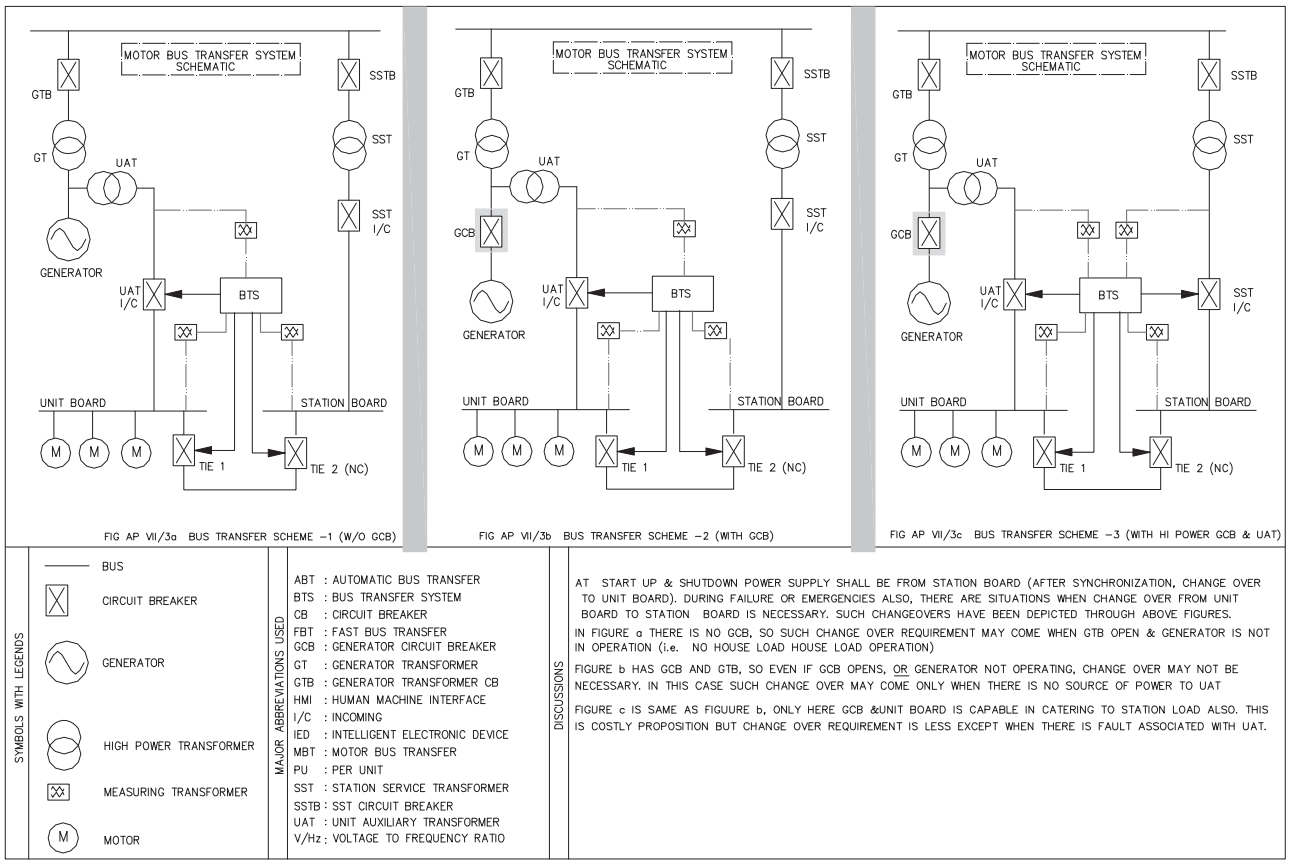


FIGURE APVII/3 Bus transfer, Scheme 1.

system is healthy. Two major Class C tripping causes include: "manual tripping of GTB when system fails to take power" or "bus bar failure." Major tripping causes for Class A and B tripping were listed in Chapter IX, Clause 3.1 (also see Figure APVII/2a–c).

As shown in Figure APVII/2a, a Class A trip will immediately trip the turbine and generator. Tripping of the boiler depends on the presence of HP/LP bypass. In case the system does not have an HP/LP bypass the boiler will trip, otherwise there will be fast opening of the HP/LP bypass. However, if either the HP or LP Bypass fails to open (and turbine lock-out relay operated) then the boiler has to be tripped for reheater protection (see Figure VII/4.1.7-2a). Class B and C tripping of the generator are similar to what has been previously discussed.

3.0 HOUSE LOAD OPERATION

A unit will be in house load operation when it is disconnected from the grid and feeding the power for its own auxiliaries. Class C tripping of a generator is a good example of this. If an external fault beyond GT occurs, grid frequency is beyond the permissible operating limit, or Class C tripping has taken place, then house load operation is possible.

3.1 Electrical Side Changes

As per the discussions on unit protection, a fault beyond GT causes generator tripping via Class A tripping. So if the unit is to be run in house load operation then the wipe-out condition needs to be initiated. This is done so that external faults, such as back-up over current protection, would cause the GTB to open and the generator will not trip. Again, if the unit is to be isolated from the grid, when grid frequency is beyond permissible value, then from a separate bus bar PT (Potential Transformer) is to be used to check grid frequency variation and the same signal should be used for tripping of the GTB. On the other hand, generator PT should be used to check frequency variation, even during house load operation.

3.2 Boiler Effect

When the GTB opens naturally there will be a sudden surge in the boiler from 100% to HP bypass flow. Upon closing the turbine valve and quick opening of the HP bypass (as

www.EngineeringBooksPDF.com

well as LP bypass) there will be a surge and safety pop-up may occur. Experienced manual handling may better save the situation at times. While reducing the boiler load, care should be taken to see that main steam temperature does not go below the permissible value (for example, 490°C).

3.3 HP Bypass

Quick-opening command is used for HP bypass, and after it is open operation with bias in the HP bypass pressure set point may be removed for better operation of the system.

3.4 Run Back for Coordinate Control

Boiler run back command may be issued to reduce the fuel to the desired point. During this operation run back rate and run back target may have to be adjusted for house load operation.

3.5 LP Bypass Control

When the control valve in the turbine attains position for house load condition, the first stage pressure will be reduced. This means a reduced set point for LP bypass pressure control. At this point reheater pressure will tend to rise, so LP bypass will open to maintain the reheater pressure.

3.6 Turbine Control

On the turbine side, getting the GTB to open, the two governor controls will select speed as a controlling parameter, i.e., speed will assume control in the electro hydraulic governors (EHG). Also in house load the work done is less in the turbine , hence, cold reheat pressure and HP exhaust temperature will tend to rise. The trimming device has to operate to increase flow through the HP turbine to reduce HP exhaust temperature.

3.7 Protection

For house load operation, the following must be available:

- Turbine in EHG mode of control not on hydraulic control mode.
- All turbine protections are ON and working.
- Functioning of load shedding relay.
- Functioning of trimming device to regulate flow through high-pressure turbine.
- TSE is available.
- Coordinate control system is operational.
- AVR in auto.
- All major auxiliaries are available.

4.0 BUS TRANSFER SYSTEM (BTS)

Bus transfer is the practice of transferring electrical load from one bus to an alternative source of power and other industrial plants during emergency or control transfer. The bus transfer has to happen at a high speed in a secure manner so there is no adverse, economic, or other effect on the plant operation. Often the connected loads are induction motors of various ratings naturally technical analysis for probable adverse effect has to be assessed beforehand. This clause starts with a brief discussion about how various loads are connected to various boards/bus systems in thermal power plants and what bus transfer really means.

4.1 Bus Configuration

Normally thermal power plants have least two sources of power for auxiliaries associated with the generating unit.

4.1.1 Two-Breaker (Main Tie) System

A typical unit with a generator and connected loads is shown in Figure APVII/3a. The generator is normally connected to the grid via a high-power, step-up transformer called Generator Transformer GT and a GTB. In Figure APVII/3a there are two sources of power to the feed unit board motor loads: one is from the generating unit (from a point upstream the GT) itself via a UAT and the other is from a station service transformer (SST). Normally unit auxiliary loads, such as a boiler feed pump, Induced draft/ Forced draft fans, Mills, etc., are connected at the unit board and are supplied via UAT and the UAT I/C is closed and the tie (1) is open. Start-up and shut-down power, when the main the generator is off line, is provided from an alternative source grid, via SST through the tie (Tie 1 and Tie 2 are closed and UAT I/C is open).

When the unit is synchronized with the grid, the unit board is transferred to the UAT. This is called station to unit transfer. During unit tripping conditions, e.g., a generator trip, a turbine trip, etc., along with UAT/GT trip situations (on differential, winding temperature, etc.; partly discussed above), it is required that the unit board is transferred from UAT to SST. This transfer is called unit to station transfer. Such transfers can be manual or automatic. During start-up and controlled shut down manual transfer may be possible; however, with the automatic bus transfer system (ABTS) a minimum dead time is preferred (during which the motor is de-energized) for the motor. In this method of transfer there are two ties, Tie 1 and Tie 2. Tie 2 is chosen as normally closed (NC) so that in the event of breaker failure logic if both UAT I/C and Tie 1 fail to open then dangerous back-feeding to the generator (permanent paralleling) is avoided.

Many (large) units have GCBs in addition to GTBs, as is seen in Figure APVII/3b. This system has one important advantage: there is less chance of bus transfer, because if the unit trips (GCB open) the GT can back-charge UAT to keep the unit board alive without BTS. However, under

www.EngineeringBooksPDF.com

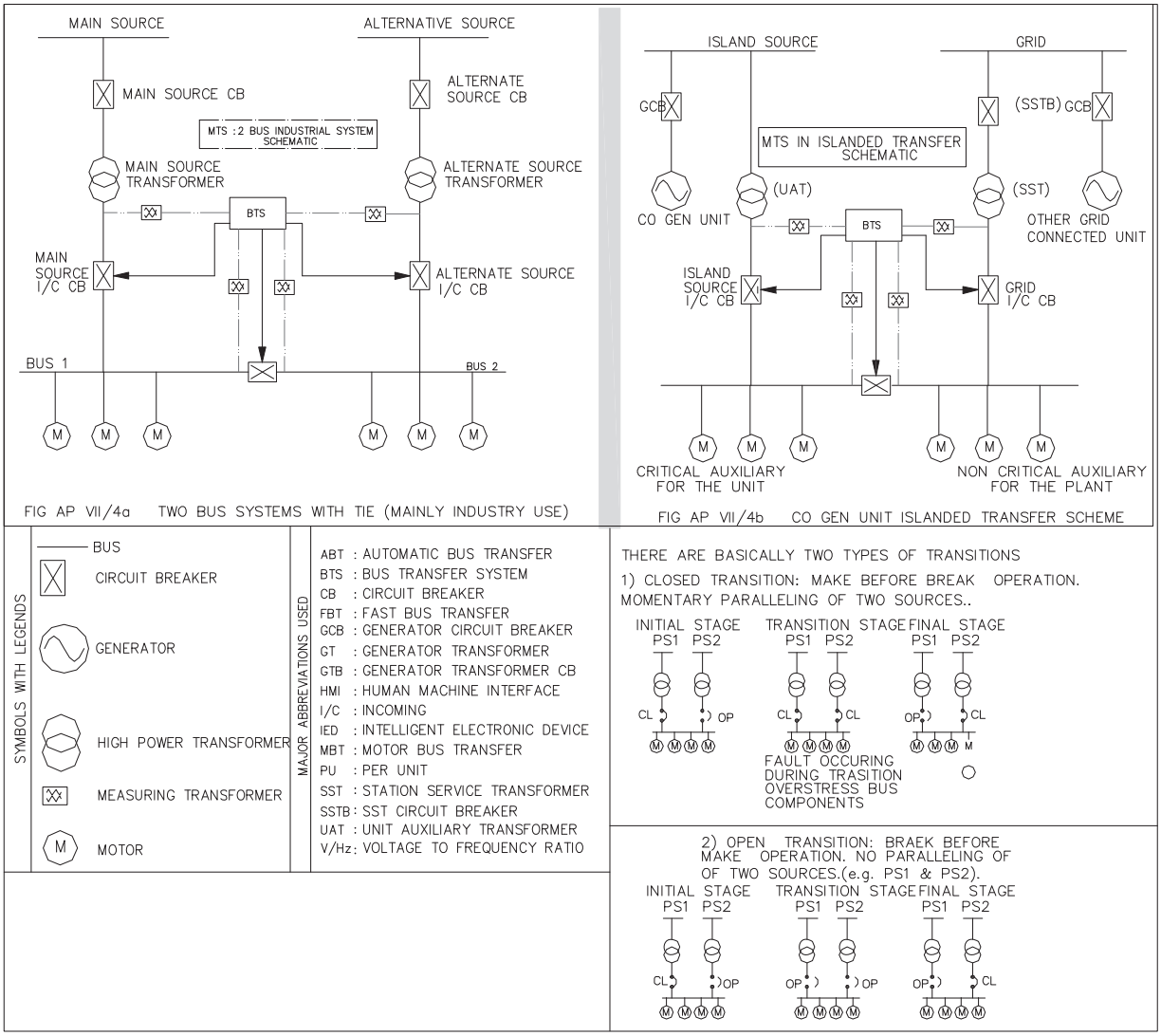


FIGURE APVII/4 Bus transfer, Scheme 2.

conditions such as GT/UAT trip, an automatic transfer is still required to ensure supply to the motor board. However, in both cases discussed so far, house load operation is possible (with some electrical side changes discussed in Clause 3.1). Figures APVII/3b and c are the same; the only difference is that in Figure APVII/3b UAT is sized to cater to the load of unit + station board load. This has additional capital cost, but the ABTS system can be a three-breaker (or main tie main) scheme, which is normally used in industrial system.. This kind of scheme has been seen in one 250 MW unit.

4.1.2 Three-Breaker Scheme (Main Tie Main)

This scheme, as shown in Figure APVII/4a, is more popular in industrial plants, but with a UAT it is highly rated; a similar scheme also might be used in thermal power plants. Here there are two sources, a main source and alternative source, each capable of catering to both motor buses. These two buses are connected via a tie. If the tie is the NC type, then the entire motor bus comprised of Bus 1 and Bus 2 is supplied by either of the two sources. On the other hand, for the normally open type tie, Bus 1 is fed by the main source and Bus 2 is fed by an alternative source. If one source fails, the source supplies power to that failed motor bus via closure of the tie.

4.1.3 Cogeneration Plant Islanding Operation

In Figure APVII/4b a typical configuration is shown for a process cum power plant (e.g., alumina plant) with a cogeneration unit. Critical plant loads are normally

www.EngineeringBooksPDF.com

supplied via a cogeneration unit in an islanded operation to avoid fluctuations in an unstable grid. Noncritical loads are supplied from the grid. Grid supply acts as a back-up for critical loads so that failure from the islanded supply will be supplied from the grid via the tie.

4.2 Considerations for Bus Transfer

The following parameters need attention during bus transfer:

- Coasting down duration of bus voltage during open circuit
- Electrical/mechanical stress on the connected motors with load
- Bus transfer system blocking during a short circuit.

When an induction motor is disconnected from the supply then self-generated voltage, known as residual voltage, appears across the terminal. When a bus is disconnected, the motor in the bus starts decelerating and the residual voltage decays due to decaying trapped air gap flux in the motor. Also the frequency of residual voltage continuously drops. Decay time is governed by the open circuit time constant of the rotor. The larger the size of the motor the longer is the time for voltage to decay. Also, the higher the load on the motor the faster is the frequency decay.

This has a direct impact on how fast the phase angle will change. So low inertia load will result in change of the phase angle as frequency decay will be faster creating a slip in the frequency between motor bus and new source. (Note: fans in thermal power plants have higher inertia.) Another important factor is the V/Hz ratio. According to IEEE/ANSI Standard C50.41-2000, for fast motor BTS, resultant V/Hz at the instant of transfer is <1.33 per unit. With increase in phase angle (assuming voltage at motor bus and source are the same) V/Hz will increase. Also as the voltage difference between two sources increases the V/Hz increases. It is clear that the following transient effects need due consideration:

- Magnitude of residual voltage between the motor and the bus
- Phase angle between motor bus residual voltage and alternative source
- Resultant V/Hz across the motor at the time of transfer.

The term "across the motor" is used because each motor will have a different residual voltage and a different impact, so the aggregate is normally considered. The worst-case scenario is when at the time of transfer there is little voltage decay the motors are in phase opposition. At this point the impact will create havoc, i.e., twice the normal voltage will be applied creating 9−15 times inrush current to the motor. Force will be proportional to the inrush current so the extent of damage is very easily conceivable.

4.3 Various Methods for Bus Transfer

There are two methods of bus transfer:

1. *Close transition*: Make before break or momentary paralleling of sources.
2. *Open transition*: Break before make without paralleling of sources.

Both methods are clearly shown in Figure APVII/4 (Discussions).

4.3.1 Closed Transition

A new source is connected to the motor bus when an old source trips to transfer the bus without interruption. However, it is necessary to evaluate voltage difference frequency as well as phase angle before making this transition. This has the clear advantage that the process is not interrupted and it is simple to implement with a synchronizing check relay. The major problem is that if there is a fault during transition bus components are overstressed and cannot be used when the main source loss is due to a fault.

4.3.2 Open Transition

In this method, unlike the previous method, an alternate source breaker closes only after the original/other breaker is open, leaving the motor bus without a source for a moment, as shown in Figure APVII/4 (Discussions). There are mainly three types of open transition:

1. *Fast transfer*: This is used to minimize dead time of the motor bus. The alternative source breaker is closed in the fast transfer method when the phase angle of the motor bus and the new source is within or moves in to the phase-angle limit within the fast transfer enable time. One cycle phase-angle response is necessary, along with a check back to ensure that the bus voltage level is within upper and lower limits before closing the breaker. Major advantages of these systems include: high-speed transfer, transient torque is less due to quick transfer, minimum interruption of process, no parallel operation, and no breaker fault effect.
2. *In-phase transfer*: Takes place when the phase angle of the residual voltage of the motor bus is in phase with the new source. For this, calculation of df/dt may be necessary. This can be done by a phase-angle relay capable of predicting the in-phase condition in advance of the new source breaker closing time, similar to a synchronizer. This is faster than the residual voltage method of transfer. This method minimizes V/Hz ratio. The new source breaker will be closed by predicting movement through zero phase coincidence between the motor bus and the new source during

www.EngineeringBooksPDF.com

transfer. It is an excellent back-up for fast transfer. However, this may pose serious problems when the bus transfer is initiated at a time the main source has a fault. Load shedding may be required for in-phase transfer; however, it is safe enough when the fast transfer is blocked.

3. *Residual voltage transfer*: Auxiliary loads are transferred in this method when motor bus residual voltage reaches a value that could cause damage to the motors. Typically this is ~25–30% rated voltage or when the motor bus falls to 0.33 pu (no matter what the phase angle; it could be much less than the 1.33 required by standard). This is a simpler, risk-free transfer method, and is usually too slow to cause plant interruptions.

4.3.3 Timing Diagram

A typical timing diagram for an open type transfer is shown in Figure APVII/5a. Before enabling any transfer the old source breaker must be opened. There are two methods for this: simultaneous and sequential.

4.4 New Transfer Technology

Today, with the introduction of intelligent electronic devices (IEDs; see Chapter VII) that can communicate with other IEDs, systems are simplified and more effective. In the past, a large amount of wiring and huge spaces were necessary to implement systems with relay logics. Now IEDs can be connected via the PLC, which in turn can be directly connected to the plant distributed control system for decentralized control and central monitoring.

4.5 Electrical Power Distribution

An electrical single line with a typical electrical power distribution scheme is presented in Figure APVII/6. In this scheme how power is drawn from the transmission system and distributed within the power plant is illustrated. From an overall economic point of view, in some large units there are various voltage-level bus systems, e.g., 11, 6.6, ad 3.3 kV, and low-voltage (LV) systems of 0.415 kV. These voltage levels are just some of the examples and the level is adjusted according to the country. In mid-size plants

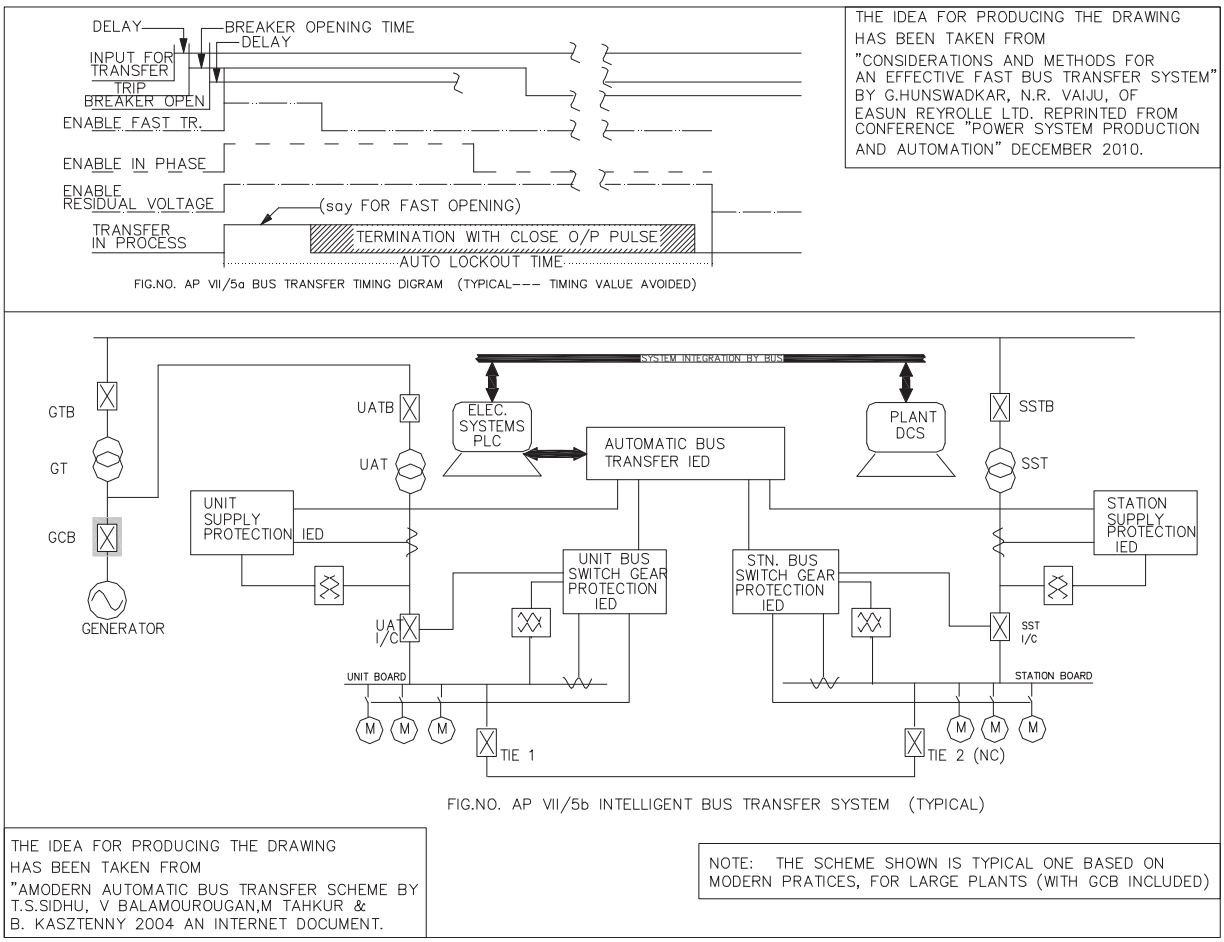


FIGURE APVII/5 Bus transfer, technical details.

www.EngineeringBooksPDF.com

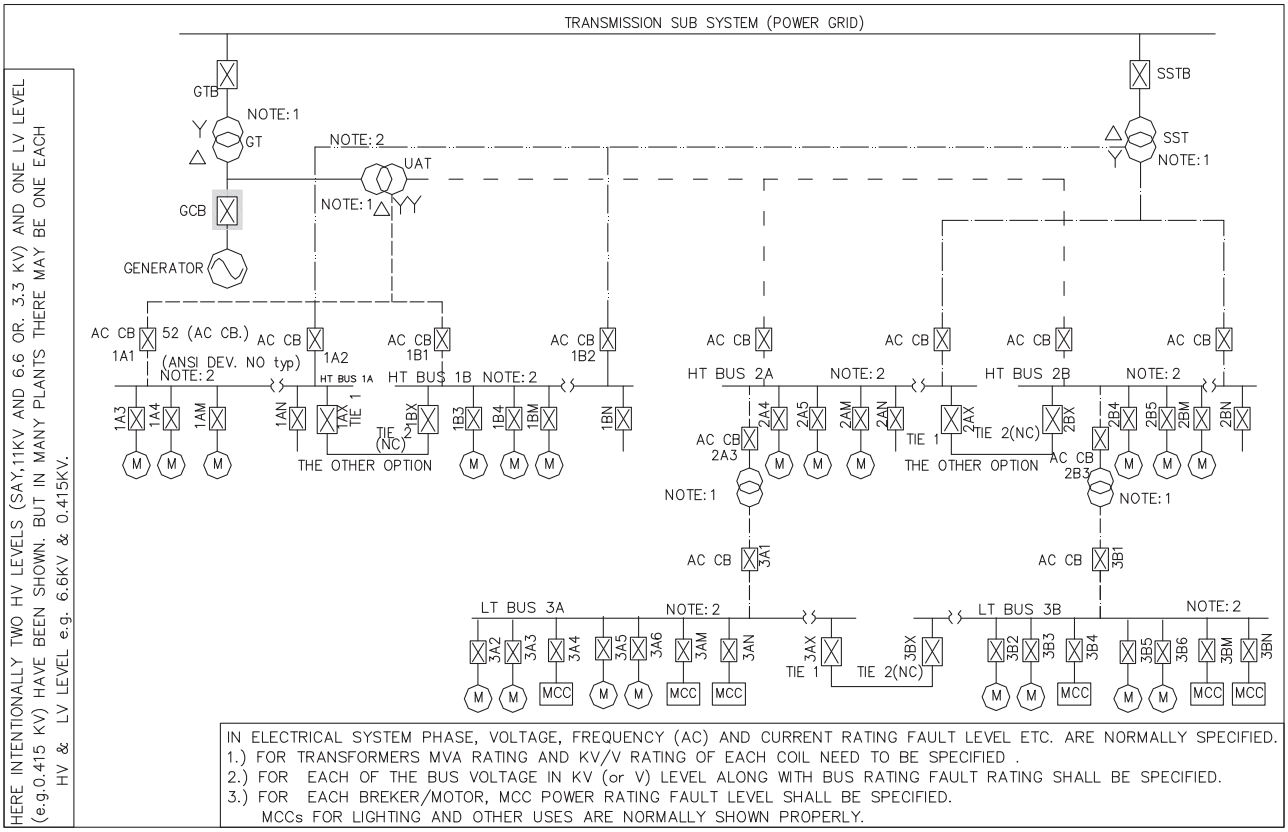


FIGURE APVII/6 Electrical power distribution, single line.

normally one HV and one LV (i.e., 6.6 and 0.415 kV) bus system is kept. Normally the loads are distributed over two sets of boards.

There could be several change-over options, as seen in Figure APVII/6. From the HV bus LV buses are created with the help of a step-down transformer. This scheme is presented so the reader has an idea of power distribution in thermal power plants and how to study the key single-line diagram. It is important for the reader to go through the notes in Figure APVII/6 to get an idea of how electrical equipment is specified and how tag numbers typically are allocated. In this scheme separate GCBs are shown, but in many mid-size units these may be missing. The utility of separate GCBs was discussed previously, so it will not be repeated here.

BIBLIOGRAPHY

[1] Workshop on Mechanical systems (power cycle) in Thermal Power Station BHEL New Delhi

[2] A modern Automatic Bus transfer scheme by T.S. Sandhu, V. Balamourougan, M. Thakur& B.Kasztenny (Internet document.)

[3] Considerations and Methods for an effective Bus Transfer System by G. Hunswadkar, N.R.Viju. Easun Reyrolle Ltd. Reprinted in from conference. Power System Production and Automation; December 2010. New Delhi.

[4] Fast transfer Systems. A SystemSolution Apprach by A. Raje, A. Raje & A chowdhary Member IEEE; July 2008.

www.EngineeringBooksPDF.com

Index

Note: Page numbers followed by "f" and "t" indicate figures and tables respectively.

A

Absolute vibration, 103
  casing vibration, 324
  shaft vibration measurement, 307, 308f
Accelerometer, 310, 317f, 318t
Accessories, 239, 427–439
  AFR, 427–429
  air lock relay, 429
  E(I)/P converter, 430
  hand wheel, 430–431
  limit switches, 431
  position indicator, 435
  position transmitter, 435
  positioner, 431–435
  solenoid valve, 435–436
  torque switches, 436
  volume booster, 436–439
Accumulator, 728
Acid dew point corrosion, 650
Acid gas removal (AGR), 393–394
Activated carbon filter (ACF), 122, 125–126, 394–395
Active protective devices, 705
Actuator sensor interface, 492
Actuators, 387–405, 419–427
  electric actuators, 425–427
  electro hydraulic actuator, 425
  intelligent actuator, 427
  ISA guidelines, 421
  piston cylinders, 421–422
  pneumatic actuator selection, 421
  safe failure, 422–424
  sizing, 419–421
Address Resolution Protocol (ARP), 448
Admission controller, 704
Aerofoil, 259
Air and flue gas system, 193–201, 195f–196f. *See also* Cogeneration (Co Gen); Condensate system; Extraction steam system; Feed water system (FW system); Main steam system (MS system)
  controls, 205–206
  equipment, 201–203
  mill air flow, 199f
  miscellaneous points, 206
  objective and function, 193–194
  parameter, 203–205
  redundancy in measurement, 206
Air and gas services, 788
Air bubbler type level transmitters, 286
Air detraining tank, 731
Air filter regulator (AFR), 799
Air flow control, 26, 34, 39, 589, 590f. *See also* Fuel flow control
  control loop description, 589–595
  excess air, 589
  FCEs for combustion air, 594t
Air flue gas path equipment, 47–51
  air heaters, 48–49
  dust collector units, 49–51
  FO systems, 57–58
  mills/pulverizers, 54–57
  stoichiometric air fuel ratio and excess air, 51
  tangential tilt burners, 58–59
Air heater (AH), 47–49, 596
  soot blowers for, 692
  washing medium for, 692–693
Air line, 799
Air lock relay, 429
Air preheater (APH), 593, 759
Air pressure control, 643
Air purging, 801
Air separation unit (ASU), 392, 889–894
Air service, 802, 808
Air-cooled
  dump condenser, 31
  TG set generators, 743
Air-side seal oil, 731
Airfoil control damper, 414–415
Alarm, 605–606
  annunciator, 512–513
    alarm designation methods, 513
    alarm display types, 514–515
    alarm sequence, 513
    optional items, 513–514
    specification, 515
  display, 558–560, 558f
All volatile treatment (AVT), 98, 349–350
American Society of Mechanical Engineers (ASME), 265
Amortisseur windings, 21–22
Amperometric DO analysis, 363
Amphoteric resin, 127
Anions, 122
  exchanger resins, 128–129
  regeneration, 130–131
Annunciation, 511–512. *See also* Intelligent control system; Sequence of event (SOE)
  alarm annunciator, 512–513
  data sheet, 514t
  types, 513
Apron feeders, 136–137
Area, standard units for, 838t
ASCII Encode, 461t
Ash handling, 138–146
  ash disposal system, 145–146
  ash water system, 144–145
  fly ash-handling system, 143–144
  influencing factors, 140
  mode of ash disposal, 140–143
Ash-handling plant (AHP), 39, 138, 510
Atomization, 224
Atomizing steam, 225f, 643
Attemperation flow control, 300
Auto manual station (A/MS), 752
Auto/manual (A/M), 726, 781
Automatic bus transfer system (ABTS), 901
Automatic generation control (AGC), 758
Automatic turbine run up system (ATRS), 476, 501, 501f, 695, 708, 709f, 767
  automatic turbine testing system, 503
  OLCS for, 501–503
  start-up stress, 710
  subgroups, 708–709, 711–713
  TG system, 709
  thermal stress, 710
  turbine protection system, 503
  warm-up process, 709–710
Automatic turbine testing (ATT), 81, 480, 695, 714f
  on KWU steam turbine control philosophy, 718–719
  oil circuit, 715f
  scope, 714–718
  testing process by, 696, 713–714
Automatic voltage regulator (AVR), 22–23, 699, 733–735
  controller output, 735
Auxiliary cooling water system (ACW system), 117, 120, 482–483
Auxiliary load, 46
Auxiliary oil pump (AOP), 79, 213, 711
Auxiliary steam control valve (ASV), 776–777

www.EngineeringBooksPDF.com

Auxiliary steam system (AS system), 9, 165–169, 644–648, 797–799. *See also* Cogeneration (Co Gen); Condensate system; Extraction steam system; Feed water system (FW system); Main steam system (MS system)
  boiler and turbine, 166f
  controls, 170
  equipment, 169–170
  header, 167f–169f
  objective and function, 165–166
  parameters and monitoring, 170
  redundancy in measurement, 170
Avogadro's Law, 3
Axial fans, 46–47
  control devices, 46–47
Axial ring shaft seal, 729
Axial shift, 304–305

B

Back-pressure turbine, 28–29
Balance chamber, 111
Balance of plant (BOP), 767
  BFP recirculation control, 767–770
  CEP recirculation control, 770–774
  control system, 767
  deaerator pressure control, 775–778
  ejector control, 783
  GSC minimum flow control, 774–775
  HPH level control, 781–783
  LPH level control, 778–781
  TAS control, 783
Ball valves, 406–408
Ball-and-tube mill, 601–604, 609–618, 610f, 614f
Ball-tube mills, 55
Bar graph display, 562
Barring gear, 80
Base control mode, 750
Bearing block vibration, 304
Bearing vibration measurement, 304
Bellows sensor, 238–239
Belt sway switch, 138
Benson point, 880
Bicolor level gauges, 290–291
Bimetallic elements, 252
Bimetallic gauges, 255
Bipolar junction transistor (BJT), 735
Bit collision, 452f
Black starting, 19–20. *See also* Gas turbine (GT)
  automatic voltage regulator, 22–23
  electric drive, 23
  hydraulic drive, 23
  LCI, 21–22
  self-contained black start, 20
  VFD, 21–22
Blade pitch control, 416
Bleed steam. *See* Extraction steam system
Block vibration (BV), 304
Blow down system, 43, 298, 380–382
Blowdown valve, 11, 74
BMS/FSSS system, 495
  fault classifications, 500
  features, 496–497
  IEC 61508 life cycle model, 498f
  NFPA 85 and IEC 61511, 500, 500t
  risk, 499–500
  SIL rating discussions, 500–501
  standards, 497–499
Boiler auxiliary steam (BAS), 151, 644, 783
Boiler circulating water (BCW), 44, 72
Boiler circulating water pump (BCWP), 40
Boiler circulation pump (BCP), 877
Boiler control system, 642–664, 767
  air flow control, 589–595
  auto control loop system legend, 586f
  boiler controls, 642–664
  boiler OLCS, 673–693
  boiler-drum control system, 622–628
  coal mill control–mill air flow, 604–618
  control requirements, 585–586
  fuel flow control, 595–604
  furnace draft control, 618–622
  FW controls, 622–628
  overfire air dampers, 642–664
  reheat temperature control, 634–642
  steam pressure control, 586–589
  superheater temperature control, 628–634
Boiler drum
  boiler accessories, 67–68
  boiler water circulation, 72–73
  drum internals, 68–69
  economizers, 71
  reheaters, 69–71
  superheaters, 69–71
Boiler feed pump (BFP), 9, 41, 67, 109–112, 622, 759, 767, 877. *See also* Condensate extraction pumps (CEP)
  associated measurements, 112
  with equidirectional impellers, 111
  opposite directional impellers, 111–112
  recirculation control, 767–770, 768f
  selection criteria, 110–111
Boiler master demand signal, 753–754, 885
Boiler maximum continuous rating (BMCR), 778
Boiler tube failure and metal temperature, 60–61. *See also* Air flue gas path equipment
  major reasons for, 61–64
  measurement, 64–66
Boiler-drum control system, 622
  control loop description, 623–628
  drum-level computation, 623
  objective, 622
  shrinking and swelling, 623
Boiler(s), 8–9, 39
  circulation system, 226–228
  clean up, 298
  demand, 763–764
  energy transfer, 765
  feedwater system, 40
  firing, 8
  follow mode, 750, 758–759
  following turbine, 759
  forced circulation, 8–9
  fuel and air/draft system, 39
  furnace position, 8
  heat source, 8
  load controller, 598–599
  load demand, 756
  optimization package, 580–581
  parallel operation, 759
  steam system, 40
  trip cause and effect, 445–447
  tube contents, 8
  turbine balance, 763–764
  water circulation, 72, 307f
    forced water circulation, 72–73
    natural water circulation, 72
    once-through boiler, 73
Bottom ash hopper (BAH), 141
Bottom ash systems (BA systems), 138, 140–143
Bourdon tube-operated sensor, 237
Bowl mill, 601
Bowl-type mill. *See* Vertical roller mill
Boyle's law, 2
Brayton cycle, 13–14
Brushless de-excitation system, 735
Brushless excitation system, 734–735, 734f
  AVR controller output, 735
  thyristors gate control, 735
  thyristors/semiconductor in, 735
Burner management system (BMS), 200–201, 476, 619, 676
  BMS/FSSS
    functional configuration, 678–685
    manual operation/automation, 685
  flame-monitoring system, 685–686
  hardware/software functions, 677
  process functions, 677
Burner tilt mechanism, 636
Burner-tilting arrangement function, 641
Burners, 57
Bus transfer system (BTS), 444, 455
Butterfly valves, 406–408
Bypass damper control, 617
Bypass gas dampers, 636
Bypass valve (BPV), 29

C

Cable(s), 824–828, 826t
  glands, 832
  installation points, 829
  termination points, 829
Cantilever pumps. *See* Vertical centrifugal pump
Capacitance type level transmitters, 286
Capacitive coupling, 817
Capacitive type sensors, 236
Carbon, 147
Carbon steel (CS), 63, 787
Carnot theorem, 5
Carrier ring type orifice plates, 264, 265f
Carrier Sense Multiple Access/Collision Detect (CSMA/CD), 453
Cascade drain, 781
Casing expansion (CS), 102, 305–307

www.EngineeringBooksPDF.com

Casing vibration, 321
Cation exchanger resins, 127–128
Cation-anion-cation stacked bed exchanger, 98
Cations, 122
Caustic corrosion, 61
Cavitation, 391–392
Centrifugal pump, 728
Ceramics, 147
Charge amplifier, 317f
Charles law, 2
Check valves. *See* Nonreturn valve
Chemical dosing system, 40, 43
Chemiluminescence type analysis system, 332–333
Chloride analyzer, 371–373, 373f, 373t–374t
Choked flow, 392
Circuit/noncoincidence (COC), 444
Circulating fluidized bed combustion boiler (CFBC boiler), 387
Circulating water pump (CWP), 41, 94, 759
Circulating water system (CW system), 39, 117, 482–483, 511, 877
  auxiliary and associated subsystems, 122
  closed-cycle type water system, 119–120
  instrumentation requirements, 121–122
  makeup and treatment system, 120–121
  once-through circulating water system, 118–119
Clarified cooling water system (CCW system), 117, 120
Class A tripping, 898
Class B tripping, 898
Class C tripping, 898
Class C tripping, 898
Class U trip, 444
Clausius statement, 4
Clean grounding, 820–821
Client server network, 540f
Closed cooling water systems, 120
Closed coupled overfire air dampers (CCOFA dampers), 656
Closed loop control system (CLCS), 186, 501, 521–536, 695
  display, 560
  functions, 526–527
  input and output types, 531
Closed transition method, 459
Closed type. *See* Local instrument enclosure (LIE)
Closed-cycle type water system, 119–120
  mechanical induced-draft type cooling tower, 119–120
  NDCT, 120
Closed-loop control (CLC), 673
Closed-type regenerative feedwater heaters, 116–117
Closed/pressurized vessel, 809–810
Closely coupled over fire Air (CCOFA), 196–197
CO analyzer, 344–346, 346t–347t
CO_2 analyzer, 347
Coal crushing, 134–136
Coal hammer crusher, 135
Coal jaw crusher, 135
Coal mill control–mill air flow, 604
  alarm, 605–606
  interlock, 605–606
  mill control, 609–618
  mill temperature control, 606–609
Coal storage and feed preparation, 392
Coal-handling plant (CHP), 39, 132
  accessories, 136–137
  coal crushing, 134–136
  coal stacker and reclaimer, 136
  conveyor safety switches, 138
  dust control and ventilation systems, 136
  influencing factors, 132–133
  instrumentation and control, 137–138
  unloading, 133–134
Coal-handling plant control systems, 509–510
Coaxial cable, 565
Cocked case, 305–307
Cogeneration (Co Gen), 206, 209–211, 212f. *See also* Auxiliary steam system (AS system); Heater drain and vent system
  combined cycle plants, 207–208
  GT control system, 211
  GT thermodynamics, 208f, 210f
  objective and function, 208
  parameter, 211–212
  plant islanding operation, 458
  redundancy in GTs, 212
  single-shaft CC configuration, 212–213
Cold air damper (CAD), 604
Cold PA system, 596, 613
Cold reheat (CRH), 67–68, 671, 709, 799
  steam, 9, 151
Cold rolled cold annealed (CRCA), 815
Cold start, 669
Cold start-up, 710
Colorimetric type hydrazine analyzer, 366
Combined cycle plant, 14
Combined cycle power plant (CCPP), 739
Combustible analyzer, 335
Combustion
  air, 53
  equations, 837t
Combustion air/secondary air (CA/SA), 593
Combustion engineering (CE), 58
Combustion turbine. *See* Internal combustion engine
Comité for Eurpéenne de Normalisation (CEN), 326–327
Common file format (CFF), 472
Common impedance. *See* Conductive coupling
Common mode rejection (CMR), 817
Communication
  medium, 565–566
  module, 320
  stack, 471
Compel Data, 471
Compensating cable, 833, 833t–834t
Component object model (COM), 472–473
Compressor turbine. *See* Gas generator
Computational fluid dynamic (CFD), 654–656
Concentric firing system (CFS), 656
Condensate extraction pump (CEP), 41, 79, 112, 349, 736, 759, 767
  with associated measurements, 112
  recirculation control, 770, 771f
    control loop description, 772–773
    control loop operation, 773–774
    and GSC, 773f
    recirculation line, 770–772
  selection criteria, 112
Condensate polishing unit, 39, 96, 349, 354–355. *See also* Miscellaneous turbine auxiliaries
  capacity, 99
  ion exchangers, 98–99
  presence of corrosive materials, 97–98
  quality, 99
  requirements, 96–97
Condensate surge tank, 35
Condensate system, 180–185, 181f. *See also* Extraction steam system; Reheat steam system
  condensate level control modes, 184f
  controls, 187–188
  equipment, 185
  miscellaneous points, 188
  parameter, 185–187
  redundancy in measurement, 188
Condenser(s), 40–41, 742
  CEP, 41
  condensing system, 711
  condensing zone, 117
  CT, 41
  CWP, 41
  evacuation, 83, 695
  function, 82–83
  heat exchangers, 41
  hotwell level control, 736–738, 737f
  level control system, 736–739
  steam ejectors and vacuum breaker, 41
  systems, 82–86
  vacuum, 83
Conductive coupling, 817
Conductivity
  analysis system, 355–356
  type level
    gauge, 292
    transmitters, 285
Conduit(s), 832
  spacing, 828–829
Constant
  pressure, 3
  temperature, 3
  volume process, 3
Constant head unit (CHU), 801
Continuous blowdown valve, 11, 74
Continuous maximum rating (CMR), 632–633
Control
  dampers, 414–415
  intelligence, 474–475

www.EngineeringBooksPDF.com

Control (*Continued*)
mode, 756, 757f
network structure, 566–569
oil, 80–81
pressure, 704
supply, 713
parameters, 34
system, 725
display, 559f, 560–561
grouping, 523–525
Control and instrumentation system (C&I system), 787, 825f–826f
Control loop, 588–589, 607–608, 641, 725–726, 768–770
BFP, 768–770
interlock, 770
operation, 770
CEP, 772–773
interlock, 774
operation, 773–774
deaerator control, 775–777
interlock, 777–778
operation, 777
furnace draft control, 619–622
GSC, 774
interlock, 774f
operation, 774
HPH, 781
interlock, 783
operation, 781
interlock, 648
LPH, 780
interlock, 780
operation, 780
reheat temperature control, 636–642
superheater temperature control, 630–634
Control Net, 492
Control processing services (CPS), 550
Control system security (CSS), 475t–476t
attack types, 475t–476t
types of threats, 476
Control valve, 387–388, 389t–390t, 405–414, 648
BFP, 770
bonnet, 413
CEP, 774
characteristics, 393–397
end connection for, 403
face-to-face dimension, 404–405
flow application, 395t
level application, 395t
LPH, 781
noise, 401–403
packing, 413–414
pressure application, 396t
sizing, 388–393
Controller face plate display, 556–557
Controller-tuning display, 561
Conversion tables of units, 33t
Conveyor safety switches, 138
Cooling media, 743
Cooling tower (CT), 41
Coordinated control system (CCS), 699–700, 749, 767
base control mode, 750
boiler follow mode, 758–759
boiler turbine balance, 763–764
coordinated control mode, 749, 751–756, 754f
DEB, 749, 762
demand from LDC, 762–763
energy balance, 763f
heat release, 764–766
manual control mode, 751
operating modes in, 749–750
run back system, 759–761, 760f–761f
single unit operation, 761–762
start-up control mode, 750
turbine follow mode, 758
Copper tube, 787
Coriolis flow meters, 272–274, 273f
Coriolis principles, 272–274, 273f
Corner firing, 52–53
Corrosion, 49, 348–349, 349f
fatigue, 64
Counter-excitation, 735
Counterflow cation exchanger regeneration methods, 130
Creep, 86–87, 720
creep-rupture, 63
Critical point, 7
Critical temperature, 743–744
Cross-axis sensitivity, 310
Cross-talk, 818–819
Curtis turbine, 76
Cycles of concentration (COC), 120

D

Dall tube, 258, 266–267
Damper windings, 21–22
Data acquisition systems (DASs), 477
de Laval turbine, 75
De-excitation system, 735
DEHA, 350
De-superheaters, 722–724
De-superheating control valve, 30
Deaeration area, 114
Deaerator pressure control, 775, 776f
control loop, 775–777
interlock, 777–778
operation, 777
fixed set point interlock, 778
Deaerators, 43–44, 113–117
level control system, 738–739, 738f
reason for deaeration, 113
working principles, 113–114
Decarbonators, 131
Decarburization, 61
Decibels (dB), 819–820
Degassers, 131
Demilitarized zone (DMZ), 232
Demineralized water (DM water), 120, 122–132
DM plant, 482–483, 736
inlet water quality requirement, 124
necessity for, 122–124
system operation, 124–131
Density, standard units for, 839t
Deposition, 348–349, 349f
Desuperheating zone enclosure, 117
Device description, 471
Device Net, 492
Diaphragm
sealed piston, 238–239
sensor, 238
type flow switch, 278–279, 282t
valves, 408–409
Diesel generating set (DG set), 20
Differential expansion (DE), 102, 297
Differential pressure (DP), 125, 229, 593, 767, 789
control, 728
Differential pressure transmitter (DPT), 36, 230, 806–807
Differential producer, 257
Differential temperature (dT), 88
Dilution air, 19
Direct control option, 772–773
Direct current excitation system, 107
Direct energy balance (DEB), 749
Direct level gauges, 289–292. *See also* Indirect type level gauges
bicolor level gauges, 290–291
displacer type gauge, 292
float
and magnet type gauge, 292
pulley type gauge, 291
and rotary shaft type gauge, 291
type gauge, 291
sight level gauge glass, 289–290
Direct mechanical type
low vacuum trip, 716
over speed trip, 715–716
thrust-bearing/axial shift high trip, 717
Dirty air service, 803
Discharge coefficient, 260, 261t, 265t
Displacer
type gauge, 292
type level
switch, 287
transmitters, 284
Display(s), 555, 556f. *See also* Intelligent control system; Logs
alarm, 558–560, 558f
browser bar details, 557f
control system, 559f, 560–561
controller face plate, 556–557
controller-tuning, 561
mimic/P&ID, 555–556, 558f
miscellaneous, 561–562
module, 320
quantities, 555t
trend, 557–558, 558f
X-Y plot, 560
Dissimilar metal welds, 63
Dissolved oxygen, 775
Dissolved salts, 98
Distance, standard units for, 838t
Distributed component object model (DCOM), 472–473
Distributed control system (DCS), 30, 137, 149, 299, 516, 781, 815–816, 878.

www.EngineeringBooksPDF.com

See also Intelligent control system; Management information system (MIS); Programmable logic control (PLC)
communication medium, 565–566
components, 523f
configuration, 521–536, 569–572
and communication, 564
control
algorithms, 519–521
network structure, 566–569
diagnostics, 516–518
functional structure, 566f
integration, 519, 567f
PID controller, 518f–519f
redundancy, 518–519
safety aspects, 519
security, 518
access category, 517t
access rights and functions, 517t
standalone controller unit, 536–540
standard library functions, 521, 522t–523t
Distribution Network Protocol version 3 (DNP3), 507–508
DO analyzer, 362–364, 364t–365t
Domain name server (DNS), 256
Domain name system, 448
Doppler frequency shift method, 271–272
Dosing control system, 298, 382–384
Double-flow turbines selection, 740
Downcomers, 72
Downshot firing, 52
DP type instrument installations. *See* Flow instrument installations
Draft system, 39
Drain control, 712–713
Drain neutralization system, 131
Drain valve, 11, 74
Drive interface (DI), 502
Droop, 754
Drum level
computation, 623
control, 593, 613
Drum-type boilers, 72
Dry
fog dust suppression system, 136
vacuum pump, 85, 94
Dry-type bottom ash system, 142–143
Dry-type fly ash handling system, 143–144
Dryness fraction of steam, 5
Dummy line, 806
Dump condenser, 31
Dust
collector units, 49–51
control and ventilation systems, 136
extraction system, 136
measuring instrument, 341t–342t
Dynamic modeling technology, 630

E

E(I)/P converter, 430
Earthing, 820–824
Eccentricity, 101, 300
Economizers, 71
Eddy current
proximity probes, 312–313, 313t
sensing principle, 311
Effluent treatment plant (ET plant), 510
Eight-corner method, 657
Ejector control, 783
Elastic deformation pressure elements, 35–36, 229
Elecrical installation of instruments, 815–816, 829–833
cables, 824–828
installation points, 829
termination points, 829
circuit classifications, 816–817
compensating cable/extension wire, 834t
copper cable, 830t
grounding/earthing, 820–824
instruments, 824–828
LAN cable, 831t
segregation requirements, 828–829
separation requirements, 828–829
signal interferences, 817–820
signal noise, 817–820
wiring practices, 824–828
Electrical
actuators, 425–427
data and tables, 65t
earthing, 821–822
eye, 614–615
low vacuum trip, 716–717
power distribution, 460–461
remote trip solenoid and testing, 717
over speed trip, 716
thrust-bearing/axial shift high trip, 717
Electro hydraulic actuator, 425
Electro hydraulic governor (EHG), 80, 501, 696, 703f, 901
control philosophy, 697–702
controller outputs selection, 702
duty assigning, 697
functional description, 703–704
hydraulic signals selection, 702–703
operational mode of, 704–705
task of, 696–697
Electro-hydraulic control system (EHC system), 80–81, 699, 754–755
Electromagnetic
safety valve, 74
spectrum, 230
Electromagnetic coupling. *See* Radiative coupling
Electromagnetic interference (EMI), 312
Electromagnetic safety valve, 11
Electromagnetism, standard units for, 839t
Electromotive force (EMF), 36, 104, 734
Electronic device description, 466
Electronic Industries Alliance, 448–450
Electronic over speed detection system (EODS), 303–304
Electrostatic precipitator (ESP), 47, 50–51, 138, 654–656
Emergency oil pump (EOP), 213, 711
Emergency reclaim hopper, 136
Emergency stop valve (ESV), 696
testing, 718
Energy, 2–3
balance signal, 762
balance system, 765–766
standard units for, 839t
Enlargement tank, 107
Enthalpy, 3
restriction, 672
Entrained hydrogen, 730–731
Entropy, 5–7
Environment, 443
protection, 790
EP. *See* Electrostatic precipitator (ESP)
Equidirectional impellers, 111
Equipment cooling water system (ECW system), 511
Ergonomic control room design, 149–151
Ethernet, 451–455, 454t, 492
Evacuation systems, 82–86
function, 82–83
methods, 83–86
Excess air, 51
Excitation
current, 104
system, 41
Exciter, 41–42, 104
Executable program, 472–473
Expansion measurement, 102
Expert system, 474
Extension wire, 833t–834t
Extraction, 81–82
Extraction steam system, 162–164, 163f. *See also* Feed water system (FW system); Heater drain system
controls, 165
equipment, 164
parameter monitoring, 164–165
Extractive multi-analysis system, 336–337

F

Fan jet. *See* Turbofan
Fans, 45–47
Fast Fourier transform (FFT), 299
Fatigue, 63, 720
Fault tolerance, 473–474
Fault Tolerant Ethernet (FTE), 232–240
Feed control valve, 880
Feed water system (FW system), 9, 150, 170, 172f–173f, 298, 587, 767–768. *See also* Main steam system (MS system)
controls, 179
controls, 622–628
equipment, 177
feed control station design, 176f
miscellaneous points, 180
motor-operated BFP, 174f
objective and function, 171–177
parameter, 177–179, 178t
recirculation flow control, 300
redundancy in measurement, 179–180
turbine-operated BFPs, 175f
Feeder speed controller, 598

www.EngineeringBooksPDF.com

Feeder speed controller (*Continued*)
flow, 623
heater, 115
system, 39–40, 42–43
Fiber optics, 565–566
and networks, 229
Field
coil excitation, 744
flushing system, 104, 108
transmitter grounding, 822
winding, 103–104
Field device tool, 466
Fieldbus Data Link Layer (FDL), 463
Fieldbus requirements, 461–462
File Transfer Protocol (FTP), 249
Filter requirement, 729
Final control element (FCE), 387, 401, 414–419, 586
control valve sizing, 388–393
dampers, 414–419
materials of construction and associated tables, 398–399
nominal pipe size and pressure rating, 405
seat leakage classification, 397
valves and actuators, 387–405
Final superheater (FSH), 67
Fire detection and protection system, 511
Fire retardant fluid (FRF), 713
Fire tubes, 8
Fireside corrosion fatigue, 62
Firewalls, 231–232, 231t, 475
functionality, 232
HW *vs.* SW, 231t
Firing systems, 8, 52. *See also* Steam generator (SG)
combustion air, 53
corner firing, 52–53
fixed-type firing, 52
mills/pulverizers, 54–57
start-up procedure, 53–54
First law of thermodynamics, 3. *See also* Second law of thermodynamics; Zeroeth law of thermodynamics
adiabatic work, 3
internal energy, 3
First-stage attemperator outlet temperature control loop, 631–632
Five-valve manifolds, 790
Fixed programmed time-based operation, 675, 689
Fixed-type firing, 52
Flame-monitoring system, 685–686
Flange dimensions, 1–4
Flashing liquid, 393
Float
floating ground, 821
and magnet type gauge, 292
pulley type gauge, 291
and rotary shaft type gauge, 291
signal, 822–824
type gauge, 291
Flow elements, 231–232, 259–270
Flow gauges, 36, 280–283
Flow instrument installations, 807–808
Flow measurement, 36, 231–232, 256, 258t. *See also* Level measurements
flow switch, 277–280
flow transmitters and meters, 270–277
level excursion method, 268–270
units of measurement, 256–259
Flow meters. *See* Flow transmitters
Flow nozzle, 258, 261–262, 796
flow metering installation, 807–808
Flow switch, 231, 277–280
diaphragm type flow switch, 278–279
flapper or paddle type, 277
piston type flow switch, 279
shuttle type flow switch, 279
thermal mass flow type, 279–280
vane type flow switch, 277–278
with velocity-based actuation, 280
Flow transmitters, 232, 270–277
Coriolis flow meters, 272–274
magnetic flow meters, 270–271
mass flow meters, 274–275
swirl flow meters, 274
ultrasonic type, 271–272
vortex flow meter, 274
Flue gas, 59
recirculation damper, 675
service, 803
Flue gas denitrification plant, 51
Flue gas desulfurization (FGD), 47
plant, 51
Fly ash-handling system, 143–144
FO trip valve, 58
Force collector, 236–237
Force/weight, standard units for, 839t
Forced circulation system, 8–9, 67
Forced draft (FD), 20, 39, 316, 589, 593
Forced draft fan (FDF), 756
Forced draught fan (FD fan), 45
Forced oxidation, 658–659
Forced water circulation, 72–73
Foundation Fieldbus, 467–472
Frame GTs. *See* Heavy duty industrial GTs
Free governing mode of operation (FGMO), 749
Free mineral acidity (FMA), 130
Frequency modulation (FM), 235–236
Frequency Shift Keying standard (FSK standard), 456
Frequency-influenced load demand, 754
Front firing, 52
Fuel and air/draft system, 39, 42
Fuel burners, 39
Fuel flow control, 595, 597f. *See also* Air flow control
loop, 617–618
loop description, 596–599
system, 26
for TT burner-type boilers, 599–604
Fuel input measurement, 764
Fuel NO_X, 24
Fuel Oil (FO), 803
firing logic, 679
pressure control, 663–664
systems, 57–58
Fuel oil recirculation valve, 679
Fuel oil trip valve, 679
Fuel oil-handling system, 511
Fuel/water ratio control, 299–300
Functional group control (FGC), 502
Functional subgroups, 695–696
Furnace
draft, 619–622, 621f
position, 8
pressure, 618–619
control, 34–35
purge logic, 679
Furnace draft control, 618
control loop description, 619–622
furnace pressure, 618
near-atmospheric pressure, 618
Furnace safeguard supervision system (FSSS), 495, 593, 676
Fuzzy logic system, 474–475

G

Gallons per minute (GPM), 256
Gamma ray type switch, 287
Gas analysis, 297, 330t, 331f–333f
Gas analyzers
gas components limit and range, 327t
mercury in stack gas analyzer data sheet, 342t–343t
oxy-fuel, 326f
for power plants, 325–340, 329t
Gas chromatograph (GC), 335–336
Gas generator, 17
Gas phase oxidation/ammonia injection, 662–663
Gas recirculation, 59–60
Gas tempering, 59–60
Gas turbine (GT), 13, 206, 300, 303t
closed loop cycle, 15
combustor with transition section, 19
with compressed air energy storage facility, 24
compressor section with diffuser, 18–19
control systems, 25–26, 211
double shaft, 17
effects of atmospheric condition, 26
emissions, 24–25
external combustion engine, 25
fuels, 25
influencing factors, 27
inlet sections, 18
open loop cycles
heat exchangers/regenerator, 15
intercooling and reheating, 15–16
single shaft, 16
thermodynamics, 208f, 210f
turbine firing temperature, 17
turbine pressure ratio, 17
turbine section, 19
Gas turbine generator (GTG), 387
Gas-damper, 635, 638–640
Gas-recycling damper, 636–638
Gas-to-gas heater, 659
Gasification, 387–388, 390t
Gate valve, 409

www.EngineeringBooksPDF.com

Gauge glass, 810–812
General station description (GSD), 465
Generator, 41–42, 103
  excitation, 107–109
  field excitation, 108–109
  hydrogen
    cooling, 105–106
    system, 220–221
    temperature control, 745
  inerting system, 41–42
  protection system, 735
  rotor, 103–104
  seal oil
    system, 106–107, 219–220, 220f
    temperature control, 744–745
  stator, 104
    and rotor cooling, 105
  trip cause and effect, 899
  working principles, 104–105
Generator circuit breaker (GCB), 700, 899
Generator control system, 732
  AVR, 733–735
  excitation control effect, 732–733
  generator protection system, 735
  generator voltage control, 732
  instrumentation system, 735–736
  rotor de-excitation system, 735
Gigabit Ethernet, 454–455
Gland
  exhaust fan, 92–93
  packing, 92–93
  seal subsystem, 695
  sealing systems, 40, 81–82
    system, 724–725
  steam condenser, 92–93
Gland steam condenser (GSC), 767
  minimum flow control, 774–775, 774f
Gland steam coolers (GSC), 9
Gland steam heater, 79
Globe control valves, 409–414
Gross calorific value (GCV), 132
Grounding, 820–824
Group display, 561–562, 561f
Guided wave radar, 286
Guided wave radar level instruments (GWR level instruments), 293–295

H

H_2 (purity) gas analyzer, 347, 347t–348t
H_2 detraining tank, 731
Hall probe, 302–303
Hammer-type mill. *See* Impact mill
Hand wheel, 430–431
Hardgrove Grindability Index (HGI), 132
Hardness ions, 122
Hardware functions, 677
Heat
  engine, 4
  exchangers, 41
    convection type, 70
    radiation type, 70–71
  flux meter, 690f, 691
  flux-based operation, 690–691
  release, 764–766, 847t
  soaking, 88–89, 710
  source, 8
  tracing, 801
  transfer-based operation, 690–691
  trap, 48
Heat recovery steam generator (HRSG), 13–14, 206, 210–211, 329, 354, 354t
Heater drain system, 188–191, 778–780. *See also* Feed water system (FW system); Main steam system (MS system)
  controls, 193
  equipment, 192
  HPH drain system, 190f
  LPH drain system, 191f
  objective and function, 188
  parameter, 192–193
Heaters, 9, 113–117
  tube rupture, 780–781
Heavy duty industrial GTs, 14
Heavy fuel oil (HFO), 39, 51, 596, 679, 801
Heavy petroleum stock (HPS), 663
Heavy spot, 101
High concentration slurry disposal system, 139
High energy arc (HEA), 54, 165, 596
High temperature (HT), 307
  creep, 62–63
  graphitization, 63
  oxidation, 62
High-pressure (HP), 695, 767, 897
  cylinder, 78–79
High-pressure bypass (HPBP), 589, 721
High-pressure heater (HPH), 9, 79, 781–783
High-pressure turbine (HPT), 11–12, 305–307, 634–635, 709
High-voltage (HV), 685, 707, 816
Highway-addressable remote transmission (HART), 229–230, 456–459
Hogging, 86
Holding, 86
Hot air damper (HAD), 604
Hot air duct pressure controller, 593
Hot gas temperature control, 643
Hot primary air, 596
Hot reheat (HRH), 12, 709, 797–799
  steam, 67–68
Hot reheat temperature, 581
Hot start, 669–670
House load operation, 448–450, 705
HP bypass (HPBP), 667–668
HP control fluid, 713
HP drain flash tanks, 188–191
HP–LP bypass system, 664–673, 666f
Human body dimensional details, 149
Hydrastep, 37
Hydraulic signals selection, 702–703
Hydrazine analyzer. *See* Residual hydrazine analysis system
Hydrogen
  cooling system, 41, 105–106, 726
    moisture in, 106
  dew point, 731
  embrittlement, 61, 349
  gland seals, 729
  purity, 735–736
  and seal oil system, 41
  system, 106
Hydrogen cyanide (HCN), 657
Hydrogen seal oil system, 726–729, 727f
  air removal, 729–731
  hydrogen removal, 729–731
  hydrogen system, 726
  problems with, 731–732

I

Igniters, 57
Ignition supports, 57
Immersion length, 249
Impact mill, 55
Impact probes. *See* Multi-hole pressure probes
Impulse line, 787, 799–802
  length and diameter, 795, 795t
Impulse turbine, 75
Impulse-reaction turbine, 76–78
In situ (modified) multi-analysis system, 337
In situ multichannel analysis system, 337
In-duct sorbent injection method, 660
Indirect control option, 773
Indirect draft, 316
Indirect type level gauges, 292–293
  conductivity type level gauge, 292
  pressure type level gauge, 293
Induced draft (ID), 20, 618
Induced draft fan (IDF), 756
Induced draught fan (ID fan), 45
Induced flue gas recirculation, 60
Induced-draft cooling tower, 119–120
Inductance, 237
Inductive coupling, 818
Inference engine, 474
Information system (IS), 521
  functions, 527–528
  grounding, 820–821
Initial priming, 94
Inlet damper control, 46–47
Inlet guide vanes (IGVs), 18–19
Inlet shoulder, 266–267
Inlet vane control, 46–47
Inputs/outputs (I/Os), 137
Inside diameter (ID), 787
Installation practices
  field instrument, 787
  instruments
    elecrical installation, 815–833
    mechanical installation, 799–815
  ISA guideline, 787–790
  pipe valve fitting material, 796–799
  signal types, 789t
  supplies, 789t
  tapping point location, 788f
  tube/pipe support considerations, 790
Instrumentation
  cable, 832–833
  earthing, 822–824, 823f

www.EngineeringBooksPDF.com

Instrumentation (*Continued*)
system, 735–736
Instruments, 35–37, 824–828
elecrical installation, 815–833
mechanical installation, 799–815
Insulated gate bipolar transistor (IGBT), 418, 735
Insulation, 743
Integrated gasification combined cycle technology (IGCC technology), 387, 388f
control scheme and system architecture, 391f
control system, 388–393
gasification, 387–388
Intelligent actuator, 427
Intelligent control system, 443
control intelligence, 474–475
fault tolerance, 473–474
Fieldbus requirements, 461–462
firewall, 475
Foundation Fieldbus, 467–472, 468f
HART Protocol, 456–459
MODBUS Protocol, 459–461
network basics, 445–456
OPC server, 472–473
PROFIBUS Application, 462–466
PROFINET, 466–467, 467t
security, 476
signals and signal processing, 443–445
World FIP, 472, 472t
Intelligent electronic devices (IEDs), 904
Intelligent system, 443
Interference modes, 818–819, 819t
Interlock, 606
Intermediate pressure turbine (IPT), 9, 709
Intermediate-pressure check valve (IPCV), 704
Intermediate-pressure cylinder (IP cylinder), 78–79
Intermittent blowdown valve, 11, 74
Internal combustion engine, 13
Internal energy, 3
International Organization for Standardization (ISO), 261, 445–447
International Union of Pure and Applied Chemistry (IUPAC), 256
Internet Control Message Protocol (ICMP), 448
Internet Group Management Protocol (IGMP), 448
Internet layer, 448
Internet Protocol (IP), 448
Ion exchangers, 98–99, 127
Ion-exchanger units, 126–131
ISA practices, 787
guideline, 787–790
ISA standards, 147–151
Isobaric process, 3
Isolation/block valves, 722
ISO–OSI model, 468–469
reference protocol model, 445–447, 446f

J

Jacking oil, 81
Jacking oil pump (JOP), 81, 711
Jet engines, 14
Junction box (JB), 470, 832

K

Katharometer, 334–335
Kelvin Planck statement, 4
Key phasor (KP), 304, 306f
Krell's bar orifice plate, 266
KWU steam turbine control philosophy, 718–719

L

Labyrinth glands, 82
Large integrated computer network, 231, 244f
Large video screen, 551, 561–562
Latent heat, 5
Law of conservation of energy, 3
Lead cation resin, 98
Leak test valves, 224, 678
Leak-off steam, 82
Level excursion method, 268–270
Level gauge, 36–37, 232, 288–293
direct level gauges, 289–292
indirect type level gauges, 292–293
Level instrument installations, 808–813
Level measurement, 232, 283
level gauge, 288–293
level switch, 286–288
level transmitters, 283–286
magnetostrictive and guided wave radar level instruments, 293–295
Level switches, 232, 286–288
displacer type, 287
gamma ray type switch, 287
magnetic and mechanical float type, 287
RF admittance type, 288
rotating paddle type, 288
vibration or tuning fork type, 287
Level transmitters, 35, 232, 283
air bubbler type level transmitters, 286
capacitance or RF type, 286
conductivity type level transmitters, 285
displacer type level transmitters, 284
magnetostriction and guided wave radar, 286
pressure or DP type, 283–284
ultrasonic type level transmitters, 285
Light diesel oil (LDO), 58, 165, 596, 679
Light emitting diode (LED), 235
semiconductor laser *vs*., 229, 230t
Limit pressure control, 701
Limit switches, 431
Limit value monitor (LVM), 609, 770
Linear variable differential transformer (LVDT), 299
Link Active Scheduler, 468, 471
Link layer. *See* Network interface layer
Liquid crystal display (LCD), 235, 541–542
Liquid services, 788, 803
Liquid-ring vacuum pump, 85, 94
Load commutated inverter, 21–22
Load dispatch center (LDC), 699–700, 749
Load dispatch controls (LDCs), 587
Load/power controller, 701
Local Area Network (LAN), 445
cable, 831t
Local instrument enclosure (LIE), 789–790
pressure transmitter/switch installation 1, 804–805
Local instrument rack (LIR), 789
pressure transmitter/switch installation 1, 804–805
Logical link control (LLC), 446
Logs, 562. *See also* Display(s)
generation, 564
log/report types, 562f
maintenance log/report, 563
on-demand log, 563–564
performance, 563
time-based log/report, 563
Long recirculation line, 663
Low vacuum trip, 716
trip system for, 716–717
Low voltage (LV), 707, 816
Low-cycle fatigue, 87, 720
Low-NO_x burner (LNB), 653–654, 654f
Low-NO_x concentric firing system (LNCFS), 656
Low-pass filter, 619–620
Low-pressure (LP), 767, 897
cylinder, 78–79
turbine, 877
Low-pressure bypass (LPBP), 667–668, 695, 721–724
Low-pressure heater (LPH), 9, 79, 772–773, 778–781
Low-pressure turbine (LPT), 9, 709
Low-sulfur high-stock (LSHS), 596, 663
Low-temperature gas cooler, 393
Lubricating oil (LO), 79–80
temperature control, 744

M

Machine health/condition monitoring system, 318–321
Machine vibration analysis system, 321
Magnetic flow meters, 270–271
Magnetomotive force (MMF), 109
Magnetostriction, 286
Magnetostrictive instruments, 293–295
Main bearing, 91
Main condensate valve, 773
Main oil pump (MOP), 79, 213, 711
Main path gas dampers, 636
Main steam
flow, 623–625
pressure
control, 599–601, 600f
demand, 755–756
Main steam control valve (MSCV), 696
testing, 717–718
Main steam stop valve (MSSV), 10, 73, 702
Main steam system (MS system), 150–151, 152f
controls, 155–156
equipment, 154

www.EngineeringBooksPDF.com

miscellaneous points, 156
parameters, 154–155, 155t
process and piping, 151–154
redundancy in measurement, 156
Main steam temperature, 581
Maintenance log/report, 563
Man machine interface (MMI), 481, 540. *See also* Intelligent control system
Chartless recorder Ethernet, 554f
client server network, 540f
CRT *vs*. TFT LCD, 543t
LVS, 551
printers, 551–553
recorders, 553–555, 553f
Web connection, 554f
workstation, 540–551, 542f, 547t
Management information system (MIS), 511–512, 572–574, 572f. *See also* Distributed control system (DCS)
characteristics, 574
functions, 527–528
hierarchical system architecture, 571f
OPTICOM and boiler optimization, 579f
performance calculation and optimization, 575–583, 576f, 578f
plant-level network and interface, 568f
position and functionality, 573f, 574
time delay significance, 572t
Manual control mode, 751
Mass, standard units for, 838t
Mass flow meters, 274–275
Master
A/M station, 598
pressure control, 34
steam pressure control mode, 758–759
Master fuel relay (MFR), 677
Master fuel trip (MFT), 298, 675
Material compositions, 147
Material science, 720
Maximum continuous rating (MCR), 232, 668–669, 700–701
Mechanical
dust collector units, 49
induced-draft type cooling tower, 119–120
installation of instruments, 799–815
vibration-type fatigue, 63–64
Mechanical flow meter, 259, 275
nutating disk meter, 277
oval gear meter, 276–277
piston meter, 276
turbine flow meter, 277
variable area meter, 275–276
Media access control (MAC), 446
Medium voltage (MV), 816
Metals, 148
Methyl diethanolamine, 393–394
Mill cutting, 760–761
Mill drum-level
control loop, 613–615
sound detector, 615–616
Mill outlet temperature, 607–608, 607f
for TT boiler, 608–609
Mill selection, 578
Mill temperature control, 606–609
Mill-wise secondary air flow, 590
Mills/pulverizers, 39, 44, 54–57
Mimic/P&ID display, 555–556, 558f
Ministry of Environment and Forests, 119, 139
Miscellaneous boiler equipment. *See also* Steam generator (SG)
blowdown valves, 74
drain valve, 74
electromagnetic safety valve, 74
MSSV, 73
nonreturn valve, 73
safety valves, 73
spring-loaded safety valve, 74
startup vent valve, 73
steam separator, 74
steam trap, 74
swing check valve, 74–75
Miscellaneous turbine auxiliaries, 91–100
circulating water pumps, 94
gland
exhaust fan, 92–93
packing, 92–93
steam condenser, 92–93
online condenser tube-cleaning system, 95–96
priming system for water box, 94
turbine bearings, 91–92
vacuum breaker valve, 94–95
vacuum trip device and solenoid, 99–100
Mixed bed exchanger, 98, 129
Mixed bed regeneration, 131
MODBUS Protocol, 459–461
Modern plant control systems, 236
Monitoring module, 320
Motor control center (MCC), 425–426
Multi-hole pressure probes, 259
Multiple grounding, 821
Multiple identical modules selection, 740
Multiple nozzles, 724
ejectors, 84–85

N

National Fire Protection Association (NFPA), 618–619, 677
Natural circulation. *See* Forced circulation
Natural gas, 688
Natural oxidation, 658–659
Natural water circulation, 72
Natural-draft cooling tower, 120
Near-atmospheric pressure, 618
Negative temperature coefficient, 249
Net Positive Suction Head (NPSH), 110–111
Network
control and communications, 229–232
interface layer, 448
network-connecting devices, 448
networking capability, 321
Transmission Technologies, 450–456
Nickel alloys, 148–149
Nitrogen, 652
Noise susceptibility level (NSL), 820
Noise-minimizing techniques, 820
Nominal bore (NB), 787
Non-feedback control, 673
Nonflammable fluid. *See* Fire retardant fluid (FRF)
Nonreturn valve (NRV), 10, 73, 163–164, 778
Normal temperature and pressure (NTP), 239
Normally closed (NC), 901, 768
Normally open (NO), 768
Nozzle governing system, 740–741
Nutating disk meter, 277

O

Object linking and embedding (OLE), 472–473
Oil transfer system, 58
Oil-handling plant, 39
OLE for process control server (OPC server), 472–473
On load operation, 705
On-demand log, 563–564
On/Off
dampers and valves, 674–675
differential, 239
valves, 718
Once-through (OT), 599–600
boilers, 155
circulating water system, 118–119
oil vacuum pump, 85, 94
process, 877
Online condenser tube-cleaning system, 95–96
Opacity instrument, 341t
Open loop control, 673, 675
boiler OLCS, 673–693
Open loop control system (OLCS), 186, 501–503, 521–536, 695, 780
for auxiliaries and miscellaneous systems, 531–536
displays, 560–561
functions, 525–526
graphics, 528–531
input and output types, 531
miscellaneous OLCS functions, 534f
Open System Interconnection (OSI), 445–447
Open transition method, 459
Open type. *See* Local instrument rack (LIR)
Open-type regenerative feedwater heaters, 116
Open/nonpressurized vessel level measurement
displacer/float instruments, 810–812
DPT with/without instrument seal, 812–813
Operating system (OS), 472
Opposed firing, 52
Opposite directional impellers, 111–112
Optical fiber in Gigabit Ethernet, 229–230, 230t
Optical pressure measurement, 237
Orifice plate, 258, 262–266, 796, 808
Oscillatory motion, 299f
Outlet damper control, 46–47
Outside diameter (OD), 796–799

www.EngineeringBooksPDF.com

Oval gear meter, 276–277
Over fire air (OFA), 196–197
Over speed trip system, 715
  trip system, 715–716
  trip testing system, 716
Overfire air, 656
  damper control, 643
Oxides of nitrogen (NO_x), 17
  analyzer, 338, 339t
  control, 384–385, 650–657, 653f, 655t–656t
Oxygen analyzer, 343–344
  ammonia analyzer data sheet, 342t
  paramagnetic, 334f, 345t–346t
  zirconia, 344, 344f, 345t
Oxygen-trimming controller, 590–592, 591f
Oxygenated treatment (OT), 349–350

P

Packet-filtering firewall, 232
Parameters, 32
  measurements, 33
    efficient running/control of plant, 34–35
    plant safety, 34
Parshall flume, 36, 268–269
Parson's reaction turbine, 78
Particulate matter (PM), 24
Particulate matter, 98
Pass out turbine, 29
Passivation of DM water, 120
Peak value, 298
Pegging pressure, 775
Perfect gas, 2
Perfect intercooling, 16
Performance log, 563
pH analyzer, 357–361
Phase, 101–102
  angle. *See* Phase
  measurement, 304
Phosphate analyzers, 367–369, 370t
Phosphate ester. *See* Fire retardant fluid (FRF)
Physical medium, 453
Piccolo tube, 259
Piezoelectric sensor, 315
Piezoelectricity, 237
Piezoresistive strain gauge, 236
Pipes, 800
  dimensions, 797, 798t
  valve fitting material, 796–799
Piping and instrumentation diagram (P&ID), 1, 147–149
  air and flue gas system, 193–206
  cogeneration, 206–213
  condensate system, 180–188
  control oil, 216f
  equipment, 148
  extraction steam system, 162–165
  FW steam, 170–180
  heater drain and vent system, 188–193
  instrumentation symbols, 147
  MS system, 151, 152f
  piping representation, 147–148
  power and process plant steam circuit, 153f
  process parameter, 148
  redundancies for transmitters, 149–151
  reheat steam system, 156
  SG-related, 222–228
  AS system, 165–170
  TG-related, 213–222
Piston cylinders, 421–422
Piston meter, 276
Piston type flow switch, 279, 282t
Pitot tube, 258, 267
Plain water dust suppression system, 136
Plastics, 147–148
Plate heat exchangers, 119
Platinum resistance thermometer (PRT), 37
Pneumatic positioner, 431–433
Point display, 562
Point-to-Point Protocol (PPP), 448
Pollution control, 384
Pollution-related analysis, 298
Pop-up valve. *See* Safety valve
Position
  controller, 702
  indicator, 435
  signal, 586
  transmitter, 435
Positioner, 431–435
Positive displacement gear type pump, 728
Positive temperature coefficient, 249
Potential transformer, 701
Potentiometric pressure measurement, 237
Power, standard units for, 839t
Power plant, 1, 749
Power plant off-site controls, 508
  ash-handling plant, 510
  circulating water system, 511
  coal-handling plant control systems, 509–510
  ECW system, 511
  fire detection and protection system, 511
  fuel oil-handling system, 511
  WTPs, 510–511
Power system stabilizer (PSS), 732
Predictive adaptive controller, 629–630
Pressure
  elements, 35–36
  gauge, 239–240, 241t
  level gauge, 293
  pressure-based measurements, 257–259
  pressure-compounded impulse turbine, 75–76
  pressure-reducing and control valves, 722
  restriction, 672
  set point, 754–755
  spring type temperature gauges, 229
  standard units for, 33t
  switch, 237–239, 240t
  tapping, 790
  transmitter, 232–235
    data sheet, 238t
    force collector types, 236–237
    point measurement for, 233t–235t
  velocity-compounded turbine, 76
Pressure instrument installations, 802
  DPT/switch installations, 806–807, 807f–808f
  pressure gauge installation, 802–803
  pressure switch installation, 803, 803f
  pressure transmitter/switch installations, 804–806, 804f
Pressure measurements, 229. , , See also Temperature measurement
  pressure gauge, 239–240
  pressure switch, 237–239
  pressure transmitter, 232–237
Pressure sand filters, 125
Pressure-reducing and de-superheating station (PRDS), 29, 148–149, 414, 644, 722, 783
  objective, 29
  system description, 30
Pressure-reducing valve (PRV), 13, 645, 783, 797–799
Pressure–volume diagram, 7
Pretreatment plant, 510
Primary /platen superheater (PSH), 67
Primary air (PA), 39, 53, 56–57, 193, 316, 606
  flow, 596–597
    controller, 598
  header pressure controller, 598
Primary air fan, 45, 596, 756
Primary coal crusher, 135
Primary technology, 653
Priming air ejector, 86, 94
Priming system, 94
Printers, 551–553
Probe node, 471
Probe response, 471
Process boiler, 28. *See also* Recovery boilers
  back-pressure turbine, 28–29
  pass out turbine, 29
Process instrumentation, 735–736
Process tap, 787
PROFIBUS Application, 462–466
PROFINET, 466–467, 467t, 492
Programmable logic control (PLC), 137, 443–444, 476, 659, 677. *See also* Distributed control system (DCS); Intelligent control system
  in ATRS turbine protection and ATT, 501–503
  basics, 477–480
  in BMS, 495–501
  configurations, 482–487, 482f
  CPU Tasks, 478t
  in electrical system, 504–508
  with Fieldbus systems, 484f
  hardware considerations, 487–492
  I/O connections, 495
  I/P output signals, 477f
  integrated plant control system, 485f
  integrated system, 494f
  memory divisions, 488f–489f
  networking, 483f
  in off sites, 508–511
  operating principles, 478f
  redundancy criteria, 494–495

www.EngineeringBooksPDF.com

salient features, 481
software considerations, 492–493
Proportional-integral-derivative (PID), 592
Pull chord switch, 138
Pulverized coal boilers (PC boilers), 387
Pulverized fuel (PF), 56, 596, 663, 687
Pulverized fuel-firing logic, 681–683
Pumps, 728–729
Purging, 679
connections, 788
process connections, 801
Push button (PB), 679

R

Radial oil seal, 729
Radial vibration, 321, 324
measurement, 304
Radial/centrifugal fans, 47
Radiative coupling, 818
Rankine cycle, 8
Rankine engine efficiency, 9
Rapid Spanning Tree Protocol, 236
Rateau turbine, 75–76
Raw water, 122
Reburning, 657
Recapitulation
Carnot cycle application, 5
Carnot theorem, 5
entropy of phases, 6–7
reversible cycle, 4–5
steam properties, 5–6
temperature–entropy diagram, 6–9
Recirculating water system. *See* Closed-cycle type water system
Recirculation control
BFP, 767–770
CEP, 770–774
Recommended Standard, 448–450
Recorders, 553–555, 553f
Recovery boilers, 27–28
Recuperative air heaters, 48
Recursive least squares, 629
Redundant instrument selection method, 150f
Reference earth, 822
Reference grounding, 820–821
Regenerative air heaters, 48–49
Regenerative cycle, 9, 81
steam separator, 11
steam trap, 11
valves and operations, 10–11
Regenerative feed heaters, 113, 115–117
closed-type, 116–117
comparison, 116–117
feed heating, 9, 81
open-type, 116
Regenerative heater, 81
Reheat cycle in utility boiler, 11–13
Reheat spray control valve function, 641–642
Reheat steam system
CRH steam system, 156–159, 157f
HRH steam system, 159–162, 160f
Reheat temperature control, 634–635. *See also* Air flue gas path equipment
burner tilt mechanism, 636
control loop description, 636–642
with gas dampers, 59
gas recirculation damper, 59–60
gas-damper, 635
main path gas dampers, 636
spray water injection system, 635
tangential tilting burner assembly, 59
three-element controls, 642
Reheater (RH), 47, 69–71, 149, 635, 799
Reinforced concrete cement (RCC), 134
Relative vibration of shaft, 102–103
Relay module, 320
Relief valve. *See* Electromagnetic safety valve
Reluctance, 237
Remote control valve, 768
Remote pressure transmitters, 229–230
Remote temperature transmitters, 230
Remote terminal unit (RTU), 444
RTU Encode, 461t
Reserve feed water (RFW), 736
Residual hydrazine analysis system, 365–367, 366f, 367t
Resins regeneration, 99
Resistance temperature detector (RTD), 37, 149, 230, 240–247, 307
Reverse osmosis (RO), 98
Reynolds number (Re), 274
Ring granulator, 135–136
Ring type de-superheater, 723
Ring-roll and ball-race mill, 55
Ringing, 285
Riser, 72
Root mean square (RMS), 298
Rotameters. *See* Flow gauges
Rotary piston. *See* Piston meter
Rotating paddle type level switch, 288
Rotating-type excitation system, 107
Rotor, 103–104
cooling, 105
excitation control, 733–735
field excitation, 732
Rotor de-excitation system, 735
Rotor eccentricity, 307–308
Rubber, 147–148
Run back
condition, 765
demand, 759, 765
load, 759
system, 759–761, 760f–761f, 765
Run-of-mine, 132

S

Safety valves, 11, 73
Salient pole rotors, 104
Sample conditioning system, 298, 374. *See also* Special instruments
components, 376–379
primary, 374
primary sample conditioning P&ID, 375–376
secondary, 375
secondary sample conditioning P&ID, 376
SWAS rack/panels, 379–380
Saturated steam, 628–629
Saunders' valves. *See* Diaphragm valves
SC/USC plants
constant and variable pressure operation, 297
steam generators, 297
Scanner air fan, 45, 57, 686
Scanner cabinet, 684
Scavenging, 107, 679, 731
Scheduled communication, 471
Scoop tube, 47
actuator, 621
Screw pump, 728
Scroll fan. *See* Squirrel cage
Seal air fan, 45, 57, 686
Seal oil
coolers, 729
system, 106–107, 726–727
Seal steam pressure control, 724–725, 725f
Seals, 729
Seat leakage classification, 397
Seawater applications, filters for, 126
Seawater scrubbing, 660–661
Second law of thermodynamics, 4. *See also* First law of thermodynamics; Zeroeth law of thermodynamics
Clausius statement, 4
Kelvin Planck statement, 4
Second-stage attemperator outlet temperature control loop, 630–631
Secondary air, 53
Secondary air damper control (SADC), 593, 675, 686
control loop description, 687–688
for tangentially corner-fired boilers, 687
for wall-fired boilers, 686–687
Secondary air flow, 598
controller, 592–593
Secondary air/combustion air, 193
Secondary coal crusher, 135
Segregation requirements, 828–829
Seismic probe
acceleration, 315–316
velocity, 313–314, 314f, 316t
Selective catalytic reduction, 24–25, 47
Self-contained black start, 20
Self-excitation system, 733
Self-pressure regulating valve (PRV), 79
Semi-closed cycle, 13
Semi-positive displacement meters. *See* Piston meter
Semiconductor, 735
Semiwet bottom ash system
SCC, 141–142
SFC, 140–141
Sensible heat, 5
Separate over fire air (SOFA), 196–197
dampers, 656
Sequence of event (SOE), 511–512, 515. *See also* Annunciation; Intelligent control system
features, 515–516
SER, 515t, 516

www.EngineeringBooksPDF.com

Sequence of event (SOE) (*Continued*)
specification, 516
Serial Line Internet Protocol, 448
SG HFO system, 222–224
Shaft-sealing system failure, 729
Shield effectiveness, 819–820
Short recirculation line, 663
Short recirculation valve, 58
Short-term overheating, 62
Shrinking, 623
Shut-down
operation, 705
program, 713
Shuttle type flow switch, 279, 281t
Side stream filters, 121
Sight flow glass, 231, 283
Sight level gauge glass, 289–290
Signal cable shield grounding, 822–824
Signal conditioning system, 299
Signals and signal processing, 443–445
Silica analyzers, 367–368, 369t
Simple cation bed exchanger, 99
Simple Mail Transfer Protocol (SMTP), 447
Single point grounding, 821
Single-element control, 625
Single-flow turbine selection, 740
Single-nozzle ejectors, 84
Sliding pressure control, 701–702
Smart noncontact position transmitter, 435
Smart/electro pneumatic positioner, 433–435
Socket weld (SW), 804
Sodium analyzer, 369–370, 371f, 372t
Software functions, 677
Solenoid, 99–100
valve, 435–436
Soot-blower control system, 675–676
Soot-blowing (SB), 648
media, 691–692
steam pressure control, 648–649
system, 39, 44, 688–693
Sorbent injector, 660
Sound pressure level (SPL), 401
Source point, 789. *See also* Installation practices
for flow elements, 795f
for flow measurements, 793–796
for level measurement, 796, 797f
for pressure type tapping, 790
for temperature element, 793f
for temperature tapping, 790–793
valve manifold, 791f
So_x–NO_x removal, 662–663
Spanning Tree Protocol, 236
Special instruments, 297–298
blow down
control, 380–382
system, 298
CO and CO_2 analyzers, 344–347
conductivity analysis system, 355–356
DO analyzer, 362–364, 364t–365t
dosing control, 298, 382–384
gas analysis, 297
gas analyzers, 325–373
H_2 (purity) gas analyzer, 347
miscellaneous special analysis systems, 367–373
oxygen analyzer, 343–344
pH analyzer, 357–361
pollution control, 384
pollution-related analysis, 298
residual hydrazine analysis system, 365–367
sample conditioning, 298
steam analysis, 297
steam and water analysis system, 348–355
turbovisory instruments, 297–325
vibration measurements, 297–325
water analysis, 297
Specific heat, 2
Speed
controller, 699
measurement, 102
speed/load control systems, 26
switch, 138
Speed control, 417–419
hydraulic coupling, 417–418
loop, 697–699
VFD for, 418–419
Spindle-operated ejector, 85
dry vacuum pump, 85
liquid-ring vacuum pump, 85
once-through oil vacuum pump, 85
Spray dry scrubber, 660
Spray water
attemperation, 636–638
injection system, 635
valves, 642
Spray-type deaerator, 115
Spring-loaded
injection nozzles, 724
safety valve, 11, 74
Squirrel cage, 47
Stainless Steel tubing, 787
Stack inlet damper function, 637–638
Standalone controller unit, 536–538
communication, 538
data sheet, 539t
standalone controller block diagram, 537–538
support functions, 540
universal input/output, 537f
Standard electronic position transmitter, 435
Standard temperature and pressure (STP), 239
Standby liquid control system, 695
Starting air ejector, 86, 711
Startup
control mode, 750
procedure, 86
and synchronization, 704–705
thermocouples, 64
vent valve, 10–11, 73
Startup and thermal stress, 86–91
damage mechanisms, 86–87
startup procedure, 86
stress, temperature, and startups relationship, 87–91
State variable control, 630
Static-type excitation system, 108
Station service transformer, 901
Stator, 104
bar, 743
coolant flow, 745–746
cooling, 105
Stator cooling water system, 41, 221–222, 222f, 745–746, 746f
Steam
analysis, 297
conditioning control valves, 414
ejectors, 41, 783
jet air ejectors, 83–84
multiple-nozzle ejectors, 84–85
single-nozzle ejectors, 84
pressure control, 586–589, 588f
mode, 758
properties, 5–6
separator, 11, 74
service, 802–803
Station service transformer level control, 302–309
system, 40, 43
table, 5
temperature control, 298–299
trap, 11, 74
and water service, 788
Steam and water analysis system (SWAS), 298, 348–355, 355t, 408, 790
Steam coil air preheater (SCAPH), 49, 166, 593
Steam generator (SG), 8, 42, 73
air flue gas path equipment, 47–51
boiler circulating water system, 44
boiler drum, 67–73
deaerator, 43–44
fans, 45–47
mills and pulverizers, 44
plants, 875–876
control and monitoring of parameters, 297
dry mode of operation, 298
fuel/water ratio control, 299
load/fuel control, 299f
OT SC boiler chemistry, 298–325
SC/USC, 297
water circulation and start-up procedure, 297
pumps and heating units, 45
soot-blowing system, 44
subsystems, 42–43
Steam turbine, 300, 739
condensers, 742
constant pressure controls, 741
cycle optimization package, 581
double-flow turbines selection, 740
fossil-fired power plants, 742
governing system, 740–741
HPT/IPT and LPT blading, 741
modules selection, 740
multiple identical modules selection, 740
nuclear thermal power plants, 742
single-flow turbines selection, 740
sliding pressure controls, 741
subcritical critical steam parameters, 742

www.EngineeringBooksPDF.com

super critical steam parameters, 742
turbine selection, 740
vales regulation and ESVs, 741
Steam turbo generators (STGs), 300
Steam-assisted de-superheaters, 723–724
Stoichiometric air fuel ratio, 51
Stoichiometric ratio, 589
Storage and transfer system, 58
Stress corrosion cracking, 61
Stress rupture, 62
DMW, 63
high temperature creep, 62–63
short-term overheating, 62
Strong acid cation (SAC), 124
exchanger resins, 127–128
Strong base anion (SBA), 124
exchanger resins, 128–129
Strouhal number (S), 274
Subcooling zone, 117
Subcritical critical steam parameters, 742
Subloop controls, 502
Submerged flight conveyor, 140–141
Suction heater, 58
Sulfur dioxide (SO_2), 650
analyzer, 340t
Sulfur oxide (SO_x), 643, 653f, 657–661
Sulfur trioxide (SO_3), 650
Super critical power plants (SC power plants), 297–298, 875
historical developments, 297
steam generators, 297
Super critical steam
generators, 68
parameters, 742
Superconducting field coil, 743–744
Supercritical systems (SC systems), 42
Superheated steam, 5
Superheater (SH), 47, 69–71, 149, 587, 799
fireside ash corrosion, 61–62
temperature control, 628–629, 631f
control loop description, 630–634
Recursive least squares, 629
Supervisory Control and Data Acquisition (SCADA), 504
components, 504–507
EPA layered structure, 506f
first generation, 505f
history and architecture, 507
protocol, 507–508
second generation, 505f
security, 508
third generation, 506f
Suspended matter, 98
Swelling, 623
Swing check valve, 74–75
Swirl flow meters, 274
Switched Ethernet, 453–454
Switches, 229
Synthesized gas (Syn. gas), 387
clean up, 393
cooling, 392
System, 443
capacity, 668–669
controllers, 590–593
properties, 3
System management (SM), 470

T

Tangential firing. *See* Corner firing
Tangential tilt (TT), 589
burners, 52–53, 58–59
TCP/IP reference model, 447–448
Temperature, 2, 103
control, 26, 745–746
element, 240–251
RTDs, 240–247
THCs, 247–248
thermistors, 248–249
gauges, 229, 254–255
bimetallic gauges, 255
data sheet, 256t
mercury in glass, 254–255
mercury or alcohol in steel, 255
measurement, 37, 240, 241t–244t
connection types, 249–251
immersion length, 249
temperature transmitter, 251–252
sensors, 788
standard units for, 33t
switches, 252–253, 255t
temperature-based operation, 675–676, 689–690
temperature-equalizing column, 810
transmitter, 231, 251–252, 253t–254t
Temperature–entropy diagram, 6
boilers classifications, 8–9
pressure–volume diagram, 7
of steam, 7–9
steam generators, 8
"Test reset" valve, 718–719
Thermal conductivity gas detection system, 334–335
Thermal fatigue, 64
Thermal mass flow type, 279–280
Thermal shock, 64
Thermal stress, 720
Thermal stress evaluator (TSE), 669, 719–721, 752
Thermistors, 37, 248–249
Thermocouple (THC), 37, 230, 247–248
cold junction compensation, 248
connection to instruments, 248
junction types and response time, 251f
properties and color codes, 250t
temperature ranges, 249t
voltage–temperature relationship, 247–248
Thermocouples (T/Cs), 149
Thermodynamic system, 1
Thermosiphoning, 72
Three-breaker scheme, 457–458
Three-element controls, 625–628, 628f, 642
Three-phase, 104
Three-valve manifolds, 790
Throttle governing system, 741
Thrust bearing, 91–92
Thrust position, 101, 304–305
Thrust-bearing trip function, 717
Thrust-bearing/axial shift high trip, 717
Thyristors, 735
gate control, 735
Time distribution, 471
Time division multiplexer (TDM), 443–444
Time-based log/report, 563
Timing diagram, 459–461
Token Bus, 455
Token Passing, 455
Token Ring, 456
Torque switches, 436
Total dissolved solids (TDS), 97, 121
Total organic compound (TOC), 98
Total plant optimization, 581–582
Touchscreen technologies, 548t–549t
Track hopper unloading system, 134
Tracking integrator, 670, 759–760
Transaction methodology, 460
Transition section, 19
Transmission control protocol (TCP), 448
Transmission fluid, 229
Transmitter
enclosure, 814–815, 815f
mounting, 813–814, 815f
redundancy considerations, 149
without seal, 812
with seal, 812–813
selection, 585
Transport layer, 448
Tray spacing, 828–829
Tray-type deaerator, 114–115
Trend display, 557–558, 558f
Triple modular redundancy (TMR), 302–303, 485–487, 677
Trips, 443–445
TT burner-type boilers, 599–604
Tubes, 800
inside corrosion, 61
outside corrosion, 61–62
tubing materials, 787
Tubular-type air heaters, 48
Tuning fork type level switch. *See* Vibration level switch
Turbine, 40
bearings, 91–92
main bearing, 91
thrust bearing, 91–92
condenser and evacuation systems, 82–86
demand, 763
evacuation system, 219
extraction and gland-sealing system, 81–82
firing temperature, 17
flow meter, 277
follow mode, 701, 750, 758
gear/barring gear, 40
gland sealing systems, 40
governor and isolation valves, 40
HP/LP bypass system, 40
inlet temperature, 17
jacking oil system, 214–215
LO system, 213–214, 214f
load control loop, 699–701, 700f
load demand, 756, 757f
master demand, 753–754
miscellaneous turbine auxiliaries, 91–100

www.EngineeringBooksPDF.com

Turbine (*Continued*)
oil subsystem, 695
oil supply, 711
oil system, 40
oil systems, 79–81
control oil, 80–81
jacking oil, 81
LO, 79–80
pressure control loop, 701–702
pressure ratio, 17
protection system, 503, 705, 706f
active protective devices, 705
generator protection, 708
turbine tripping input signals, 706–708
unit protection, 708
seal steam system, 217, 218f
start-up, 710
startup and thermal stress, 86–91
supervisory instrumentation, 100–103
eccentricity, 101
expansion measurement, 102
phase, 101–102
speed measurement, 102
temperature, 103
thrust position, 101
turbine-governing valve position, 103
vibration measurement, 102–103
trip cause and effect, 899
tripping, 714
input signals, 706–708
turbine oil systems, 79–81
turbine supervisory instrumentation, 100–103
types, 75–78
warm up, 712–713
Turbine auxiliary steam, 151, 644, 783
Turbine control system, 325, 710–713, 724–726
oil system, 215–217
subsystem, 695–696
Turbine generator control system (TG control system), 695–696
ATRS, 708–713
ATT system, 713–719
condenser level control system, 736–739
control loops, 744–746
cooling media, 743
critical temperature, 743–744
cylindrical rotors for, 742
deaerator level control system, 738–739
differential pressure control, 726–732
EHG, 696–705
field coil excitation, 744
generator control system, 732–736
hydrogen seal oil system, 726–732
insulation, 743
LPBP system, 721–724
operational modes, 698t
power output ranges, 742–743
stator bar, 743
steam cycle with, 697f
steam turbines, 739–742
subsystem, 695–696
superconducting field coil, 743–744
testing process by ATT, 696
TSE, 719–721
turbine controls, 724–726
Turbine maximum continuous rating (TMCR), 298
Turbine stress evaluator (TSE), 696
Turbine water damage prevention (TWDP), 642
Turbine-driven boiler feed pump (TDBFP), 622
Turbine-governing valve position, 103
Turbo generator (TG), 897, 79–80, 297, 629, 709
Turbo generator control system, 767
Turbo supervisory instrument (TSI), 717
Turbofan, 14
Turbojets, 14
Turboshaft engine, 17
Turbovisory instruments, 297
application notes, 324–325
BFPT TSI specification, 323
casing expansion, 323
frequency range, 309
GT, 300, 303t, 304f
measurement issues, 302–309
measuring sensor/transducer types, 309–310
speed measuring system, 305f
steam and gas instruments, 321–322
steam turbine, 300, 300f, 301t–302t
STG TSI specification, 322–323
system configuration, 325
valve position, 323–324
Turbulence, 723
Turning gear. *See* Barring gear
Twisted pair cable category, 565
Two-breaker (main tie) system, 456–459
Two-valve manifolds, 790

U

Ultra supercritical power plants (USC power plants), 297–298, 875
historical developments, 297
steam generators, 297
Ultrasonic type measurement, 271–272
Doppler, transit time, and, 271
Doppler frequency shift method, 271–272
level excursion type, 272
level transmitters, 285
Unburnt carbon, 654–656
Unit control board, 677
Unit load demand, 751–754, 751f
auto manual selection, 752
blocking of increase and decrease, 752–753
limiting, 765–766
upper and lower limit, 752
Unit protection system, 443
Universal gas constant, 3
Unloading, 133–134
Unscheduled communication, 471
User Datagram Protocol, 448

V

V cone flow device, 259, 267–268, 269f
Vacuum, 83
breaker, 41
valve, 94–95
condenser, 30
service, 788
trip device, 99–100
Vacuum pumps. *See* Steam ejectors
Valves, 387–405
lift controller, 702
manifold, 790
position, 309
Vane/damper control, 415–416
Variable area
meter, 275–276
type, 283
Variable frequency drive (VFD), 21–22, 47, 598
Variable inlet vane, 415–416
Variable orifice type, 283
Variable pressure control, 701–702
Variable-pitch control, 46–47
Velocity probe, 313–315
Velocity-compounded impulse turbine, 76
Vena Contracta, 260
Vent system, 188
Venturi meter, 257–258, 260–261, 808
Verband der Elektrotechnik (VDE), 677
Vertical centrifugal pump, 112
Vertical roller mill, 55
Vibration level switch, 287
Vibration measurement, 102–103, 297–299, 298f
absolute vibration, 103
application note, 316–318
building blocks for, 299
casing vibration, 311
condition monitoring, 299–300
frequency range, 309
influencing factors, 310
interpretation, 310
machine health/condition monitoring system, 318–321
machine vibration analysis system, 321
measuring sensor/transducer types, 309–310
monitoring system, 319f
proximity probes, 311–313
relative vibration of shaft, 102–103
seismic probe, 313–316
sources of, 311t
Vibration transducer, 299
Virtual field device, 471
Virtual Private Network, 235, 481
Viscosity, 2
dynamic, 2
index, 846
kinematic, 2
standard units for, 839t
Volatile organic compounds, 24
Volt ampere, 733
control, 735
Volume
booster, 436–439

www.EngineeringBooksPDF.com

standard units for, 36t
Von Karman Vortex Street principle, 274
Vortex flow meter, 274

W

Wagon tippler unloading system, 134
Wall firing. *See* Front firing
Warm start, 669
Warm-up process, 709–710
Washing medium, 692–693
Water
  analysis, 297
  induction, 778
  tubes, 8
  water-cooled dump condenser, 31
Water circulation valve, 298
Water gas shift, 393
Water treatment plants, 510–511
Waterside corrosion. *See* Tube inside corrosion
Waterwalls, 8
  fireside corrosion, 62
Weak acid cation (WAC), 124
  exchanger resins, 128
Weak base anion (WBA), 124
  exchanger resins, 129
Wellman-Lord process, 659
Wet bottom ash system, 140
Wet mode operation, 298
Wet steam, 5
Wet-type fly ash handling system, 144
Wide Area Network (WAN), 445
Wind box (WB), 57, 675
Wireless Local Area Network (WLAN), 445
Wiring practices, 824–828
Work, 2
Workstation, 540–551, 542f, 547t
  browser bar and frame, 545f
  controller face plate details, 546f
  display features, 550t
  operation and monitoring area, 544f, 547t
  Touchscreen technologies, 548t–549t
  WS software architecture, 549f
World FIP, 472, 472t

X

X-Y vibration, 324
X-Y Plot, 553

Z

Zeroeth law of thermodynamics, 2. *See also* First law of thermodynamics; Second law of thermodynamics
  energy, 2
  perfect gas, 2
  specific heat, 2
  work, 2
Zirconia oxygen detection system, 334

www.EngineeringBooksPDF.com