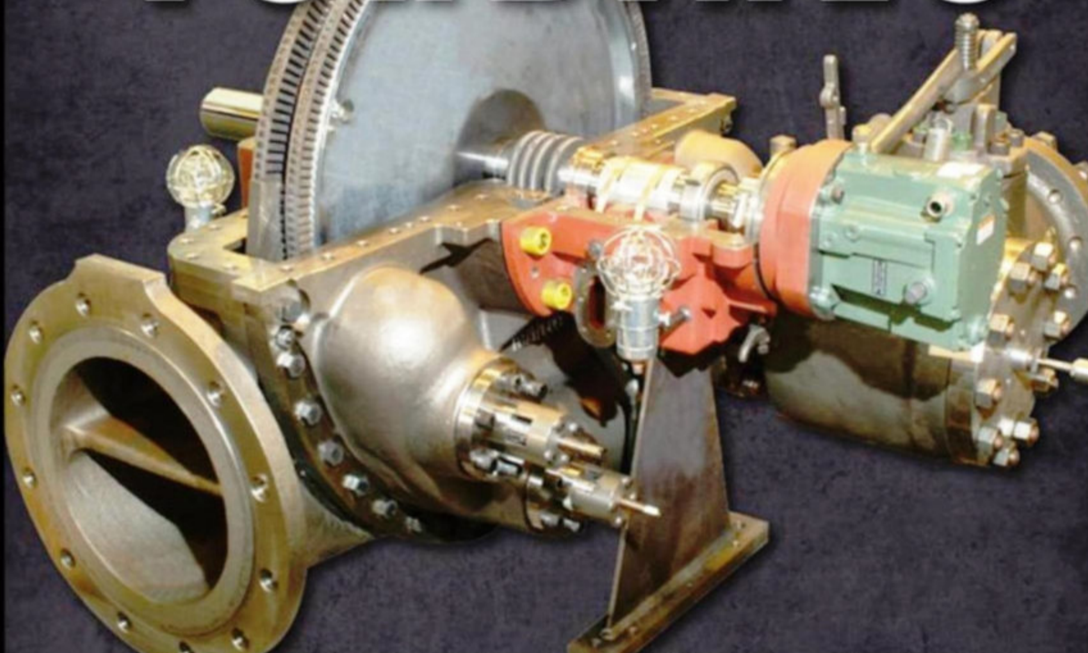
OPERATOR'S GUIDE TO

GENERAL PURPOSE STEAM TURBINES



ROBERT X. PEREZ and DAVID W. LAWHON

Scrivener Publishing

WILEY

Operator's Guide to General Purpose Steam Turbines

Scrivener Publishing
100 Cummings Center, Suite 541J
Beverly, MA 01915-6106

Publishers at Scrivener
Martin Scrivener (martin@scrivenerpublishing.com)
Phillip Carmical (pcarmical@scrivenerpublishing.com)

Operator's Guide to General Purpose Steam Turbines

An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting

Robert X. Perez and David W. Lawhon

Scrivener Publishing

WILEY

Co-published by John Wiley & Sons, Inc. Hoboken, New Jersey, and Scrivener Publishing LLC, Salem, Massachusetts.
Published simultaneously in Canada.

Cover design by Kris Hackerott

Library of Congress Cataloging-in-Publication Data:

ISBN 978-1-119-29421-4

Printed in the United States of America

10 9 8 7 6 5 4 3 2 1

We dedicate this book to our families for their constant support and encouragement.

Contents

Preface

"We are what we repeatedly do.
Excellence, then, is not an act, but a habit."

—Aristotle

If you operate steam turbines in your plant you are probably asking: Why do I need a whole book devoted to steam turbine operations? The short answer is because we all want our steam turbines to operate reliably and safely during their lifetimes and to avoid nasty surprises, such as massive failures, unexpected outages or injuries. Owners of steam turbines should continuously strive to protect life, limb and property and minimize the life cycle costs through the use of proven operating practices like those contained in this book. The best practices presented in this book can be used as a basis for your plant's steam turbine reliability program and operating procedures.

The life cycle cost (LCC) of a machine is the total of the purchase, installation, repair, and operating costs incurred throughout its lifetime. As an operator the only way to affect a steam turbine LCC is by minimizing maintenance cost. This is accomplished by employing proven start-up procedures that will minimize undue stresses and erosion and by monitoring them in order to detect minor issues before they lead to costly repairs. General purpose (GP) steam turbine drivers present operators with special challenges because they tend to have a minimum of automation and instrumentation which makes their reliability dependent on the skill and knowledge of their caretakers. In other words, their reliability is dependent on the quality of human implemented procedures and human-based monitoring methods.

When installed and operated properly, GP steam turbines are reliable and tend to be forgotten, "out of sight, out of mind". But these sleeping giants can create major headaches if ignored. Three real steam turbine undesirable consequences that immediately come to mind are:

- *Injury and secondary damage due to an overspeed failure.* An overspeed failure on a large steam or gas turbine is one of the most frightening of industrial accidents. A huge amount of thermal, chemical, and mechanical energy is contained within a large steam turbine when it is in service. If the rotational speed of the steam turbine ever exceeds its safe operating limits, the main shaft and impeller wheels can be pulled apart by centrifugal force, releasing a tremendous amount of energy. In the worst case, the disintegrating parts can break through the turbine housing and fling hot, fast-moving shards of metal in all directions. The results of such a failure are always very costly due to the peripheral equipment damage and can sometimes be fatal to personnel in the area.

- *The high cost of an extensive overhaul due to an undetected component failure.* The cost of a major steam turbine repair can run ten or more times that of a garden variety centrifugal pump repair. If an early failure is not detected, it will usually result in a more costly failure. For example, a simple packing leak can result in oil contamination, which can lead to a bearing failure, which can lead to major rotor damage. Repair cost can rapidly escalate if the chain of failure events is not stopped early, i.e., in the primary stage.
- *Costly production losses due an extended outage if the driven pump or compressor train is unspared.* The value of lost production can quickly exceed repair costs. Extending the mean time between repairs though the implementation of best practices will in turn reduce production downtime and dramatically increase overall profits.

A major goal of this book is to provide readers with detailed operating procedure aimed at reducing these risks to minimal levels. Start-ups are complicated by the fact that operators must deal with numerous scenarios, such as:

1. Overspeed trip testing
2. Starting up a proven steam turbine driver after an outage
3. Shutting down a steam turbine driving a centrifugal pump or centrifugal compressor
4. Commissioning a newly installed steam turbine
5. Starting up after a major steam turbine repair

It is not enough to simply have a set of procedures in the control room for reference. To be effective, operating procedures must be clearly written down, taught, and practiced—until they become habit. Operators must be fully committed to following the prescribed steam turbine operating procedure every time and carefully monitoring them in the field in order to detect signs of early failures before serious damage is done. To support this commitment this book will:

- Provide operators with a broad exposure to the principles of steam turbine design and operations
- Explain common failure modes and how they can be prevented or mitigated and

- Provide proven operating procedures that can protect your steam turbines from costly and dangerous failures.

The authors hope the reader will find the contents of this book to be useful and applicable in their present assignment. We also hope the ideas and suggestions provided here compel you to commit yourself to operational excellence.

Robert X. Perez and David W. Lawhon

Acknowledgements

The authors thank the following individuals who helped in various aspects of the book development:

- Ron Reeves for providing steam turbine reliability data
- Julien LeBleu for providing steam turbine inspection guidelines
- Danny Lawhon for providing an operator's perspective on turbine procedures
- Elaine Perez and Carolyn Dulak for proofreading and editing the manuscript
- Tom Brown and David Pribish with Elliott Group, Jeanne Lasley with Woodward Inc., and Jason Putnam with Inpro/Seal LLC for expediting the approval of photos and drawings

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

1

Introduction to Steam Turbines

1.1 Why Do We Use Steam Turbines?

Steam turbine drivers are prime movers that convert the thermal energy present in steam into mechanical energy through the rotation of a shaft. Industrial steam turbines fit into one of two general categories: generator drives and mechanical drives. Generator drives include all turbines driving either synchronous or induction generators for power generation. In this book, we will cover primarily steam turbines used in the petrochemical industry as mechanical drives for centrifugal pumps and centrifugal compressors. In mechanical drives, the rotational energy is transmitted to a process machine that in turn

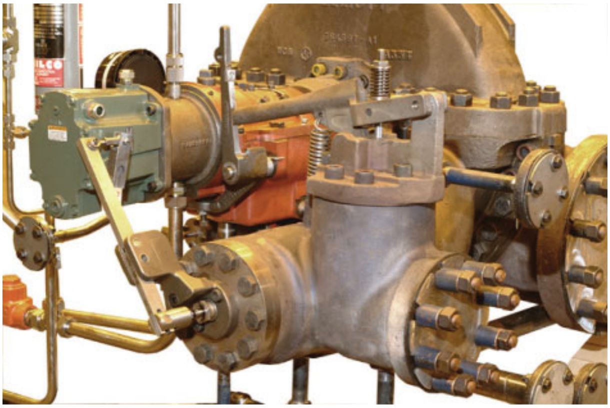


Figure 1.1 General purpose steam turbine. (Courtesy of Elliott Group)

converts it into fluid energy required to provide flow for a given process.

Heat energy → Steam energy → Rotational energy → Fluid energy

1.2 How Steam Turbines Work

Steam turbines are relatively simple machines that use high-velocity steam jets to drive a bladed wheel that is attached to a rotating shaft. Figure 1.2 depicts an impulse-type steam turbine in its most basic form: A steam nozzle and a bucketed, rotating wheel.

In this design, high-pressure steam is accelerated to a high velocity in the stationary nozzle and then directed onto a set of blades or buckets attached to a wheel. As the steam jet impacts the buckets, it is deflected and then leaves the scene. The change in

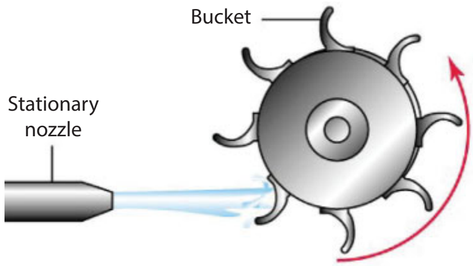


Figure 1.2 Basic impulse steam turbine.

momentum involved in the steam's deflection generates a force that turns the wheel in the direction opposite of the incoming steam jet. If the wheel is affixed to a shaft and supported by a set of bearings, rotational power can be transmitted via the output shaft.

To produce useful work in a safe and reliable manner, an impulse-type steam turbine, at a minimum, must contain:

1. A bladed wheel that is attached to a shaft.
2. A set of stationary steam nozzles capable of accelerating high-pressure steam to create high velocity jets. (See the steam nozzle in Figure 1.3.)
3. A pressure-containing casing.
4. Seals that can control steam leakage from traveling down the shaft. (See carbon packing end seals in Figure 1.3.)
5. A governor system capable of controlling rotating speed within design specifications. (Speed governor in Figure 1.3.)

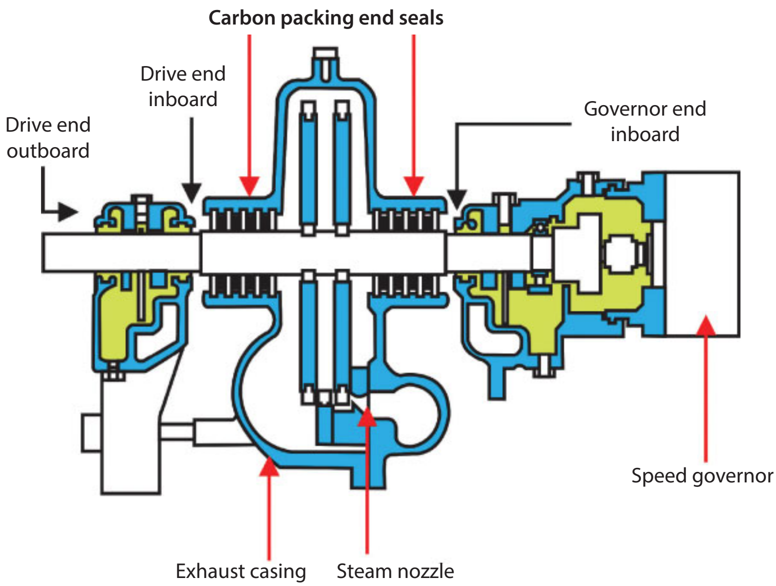


Figure 1.3 Cross section of an impulse steam turbine.

Governor systems fall into two main categories: hydraulic and electronic.

6. A coupling that can transmit power from the steam turbine to an adjacent centrifugal machine.

Steam turbines can be rated anywhere from a few horsepower to around a million horsepower. They can be configured to drive generators to produce electricity, or mechanical machines such as fans, compressors, and pumps. Steam turbines can be designed to operate with a vertical or horizontal rotor, but are most often applied with horizontal rotors.

1.2.1 Steam Generation

Steam is either generated in a boiler or in a heat recovery steam generator by transferring the heat from combustion gases into water. When water absorbs enough heat, it changes phase from liquid to steam. In some boilers, a super-heater further increases the energy content of the steam. Under pressure, the steam then flows from the boiler or steam generator and into the distribution system.

1.2.2 Waste Heat Utilization

Waste heat conversion is the process of capturing heat discarded by an existing industrial process and using that heat to generate low-pressure steam. Energy-intensive industrial processes—such as those occurring at refineries, steel mills, glass furnaces, and cement kilns—all release hot exhaust thermal energy in the form of hot liquid streams that can be captured using waste heat boilers (see Figure 1.4).

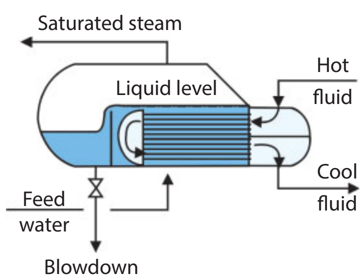


Figure 1.4 Waste heat boiler.

Figure 1.5 Steam drum.

The steam from waste heat boilers can be utilized for heating purposes or to power steam turbines.

Steam systems all tend to have the following elements:

- Boiler—A process subsystem that uses a fired fuel or waste heat to turn condensate into high-pressure steam. Steam is typically collected in a steam drum (see Figure 1.5)
- Steam Turbine—A rotating machine that converts high-pressure steam energy into shaft power
- Process Waste Heat Recovery or Condenser—A part of the process that recovers sufficient lower pressure steam heat to condense all the steam back to condensate

- Boiler Feedwater Pump—A liquid pump that raises condensate pressure back to boil pressure so that it can be returned to the steam boiler

1.2.3 The Rankine Cycle

The Rankine cycle is the thermodynamic basis for most industrial steam turbine systems. It consists of a heat source (boiler) that converts water to high-pressure steam. In the steam cycle, water is first pumped up to elevated pressure and sent to a boiler. Once in the boiler, liquid water is then heated to the boiling temperature corresponding to the system pressure until it boils, i.e., transforms from a liquid into water vapor. In most cases, the steam is superheated, meaning it is heated to a temperature above that required for boiling. The pressurized steam is: (a) transmitted via piping to a multistage turbine, where it is (b) expanded to lower pressure and then (c) exhausted either to a condenser at vacuum conditions or into an intermediate temperature steam distribution system. Intermediate pressure steam is often used for other process applications at a nearby site. The condensate from the condenser or from the industrial steam utilization system is returned to the feedwater pump for continuation of the cycle.

Primary components of a boiler/steam turbine system are shown in Figure 1.6.

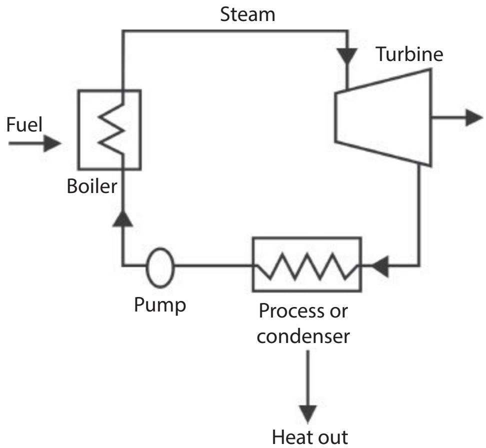


Figure 1.6 Components of a boiler/steam turbine system.

1.3 Properties of Steam

Water can exist in three forms, ice, liquid and gas. If heat energy is added to water, its temperature will rise until it reaches the point where it can no longer exist as a liquid. We call this temperature the "saturation" point, where with any further addition of heat energy, some of the water will boil off as gaseous water, called steam. This evaporation effect requires relatively large amounts of energy per pound of water to convert the state of water into its gaseous state. As heat continues to be added to saturated water, the water and the steam remain at the same temperature, as long as liquid water is present in the boiler.

The temperature at which water boils, also called boiling point or saturation temperature, increases as the pressure in the vapor space above the water

Figure 1.7 Tea kettle producing steam.

increases. As the water vapor pressure increases above the atmospheric pressure, its saturation temperature rises above 212 °F. The table below titled, "Properties of Saturated Steam" illustrates how the saturated steam temperature increases with increasing steam pressure.

If heat is added after the steam has left the boiler, without an increase in steam pressure, superheated steam is produced. The temperature of superheated steam, expressed as degrees above saturation corresponding to the pressure, is referred to as the degrees of superheat. Adding superheat to steam is a good way to prevent steam from condensing as it makes its way from a boiler to a steam turbine.

In general, we can say that the higher the steam pressure and its corresponding temperature the more energy it contains to perform useful work. In order to get a feel for typical saturated steam pressure and temperature, we will provide a few realistic examples. Refer to the "Properties of Saturated Steam" (Table 1.1) as you consider the following examples:

Example #1:

Let's assume we have a boiler operating at 265 psia or 250.3 psig (psia = psig + 14.7). If water in a boiler

Table 1.1 Properties of saturated steam.

Absolute pressure (psia)	Gauge pressure (psig)	Steam temp. (°F)	With 10 degrees superheat
165	150.30	365.99	375.99
175	160.30	370.75	380.75
195	180.30	379.67	389.67
215	200.30	387.89	397.89
240	225.30	397.37	407.37
265	**250.30**	**406.11**	**416.11**
300	285.30	417.33	427.33
400	385.30	444.59	454.59
450	435.30	456.28	466.28
500	485.30	467.01	477.01
600	**585.30**	**486.21**	**496.21**
900	885.30	531.98	541.98
1200	1185.30	567.22	577.22
1500	1485.30	596.23	606.23
1700	1685.30	613.15	623.15
2000	1985.30	635.82	645.82

is at saturated, steady-state conditions, we can expect the steam exiting the boiler to be at 406.11 °F. If we are able to add 10 degrees of superheat, we would have a steam temperature of 406.11 + 10 = 416.11 degrees.

Example #2:

Let's assume we have a boiler operating at 600 psia or 585.3 psig. If water in a boiler is at saturated, steady-state conditions, we can expect the steam exiting the boiler to be at 486.21 °F. If we are able to add 10 degrees of superheat, we would have a steam temperature of 486.21 + 10 = 496.21 degrees.

Question:

What steam temperature should you expect on a system operating at 1200 psia with 10 degrees of superheat?

Answer:

By inspection, you should expect to see a steam temperature of 577.22 °F.

Note: Appendix D contains additional steam property data.

1.3.1 Turbine Design Configurations

The potential steam-related energy available for a steam turbine is directly proportional to the differential pressure between the supply and the exhaust steam. The greater the pressure differential and the greater the superheat, the more work the steam turbine can perform. There are three categories of steam turbines aimed at extracting horsepower for various steam configurations. They are condensing, back pressure, and extraction types (refer to Figures 1.8 and 1.9): Condensing turbines use a surface condenser to convert steam from its gaseous state into its liquid state at a pressure below atmospheric pressure. Back pressure steam turbines are designed to exhaust into steam systems that operate above atmospheric pressure. Extraction type steam turbines have the ability to "extract" a percentage of the total inlet steam flow at some intermediate pressure as required by the plant.

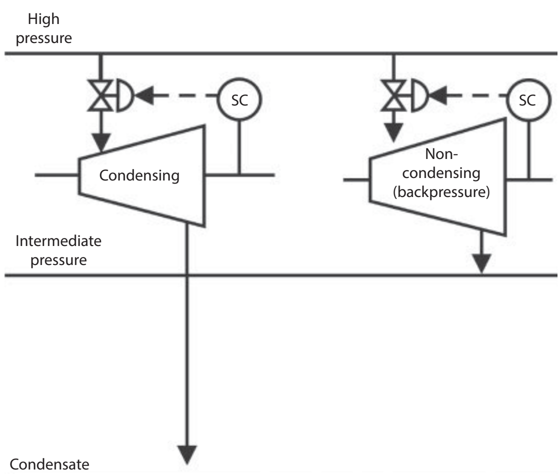


Figure 1.8 Condensing steam turbine (on the left) and non-condensing steam turbine (on the right). Notice that the non-condensing steam turbine exhausts into an intermediate pressure steam header.

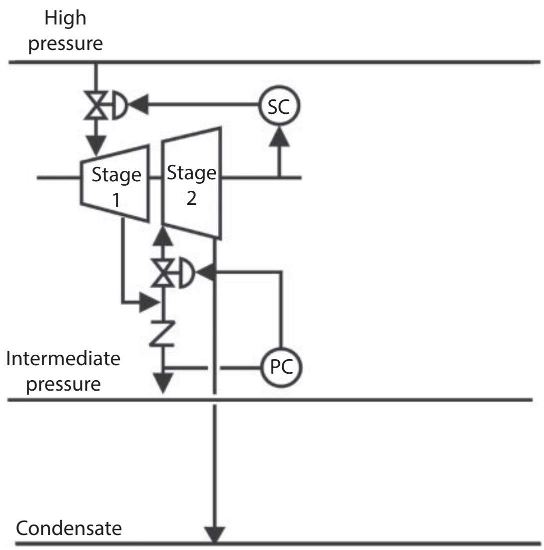


Figure 1.9 Extraction type steam turbine.

1.4 Steam and Water Requirements

1.4.1 Steam Conditions for Steam Turbines

The turbine's supply steam should be either superheated or at least very dry to prevent the erosion of the turbine blades. The internal nozzles, diaphragms, and casing can also be affected by erosion due to poor steam quality.

1.4.2 Water Conditions for Steam Turbines

It is important for boiler feed water to be monitored to insure its quality. When the quality is out of specifications, it can create not only problems for the boiler but for all of the steam users downstream. The turbine of course is one of the users of produced steam. Improper water quality can cause erosion and deposition on piping and turbine blades. Carryover of improperly treated water can coat turbine blades, potentially affecting produced power and causing rotor vibration.

1.4.3 Advantages of Steam Turbine Drives

Steam turbines found throughout petrochemical facilities are frequently used in critical process applications for the following reasons:

- Steam turbines can operate independently of the plant's electrical system. This is a vital requirement for processes that cannot tolerate upsets or trips due to electrical outages. Here are two applications where

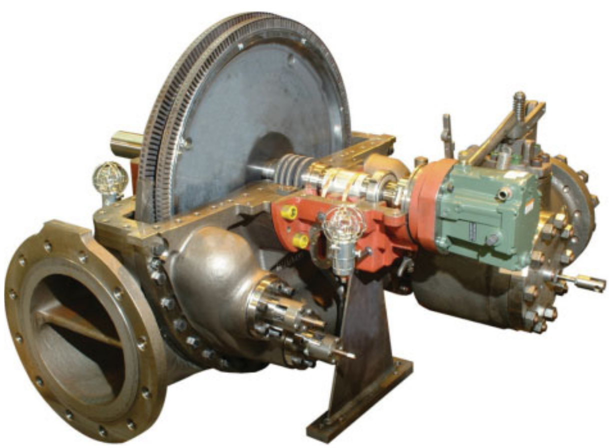


Figure 1.10 General purpose steam turbine. (Courtesy of Elliott Group)

maintaining a constant flow is critical: 1) Sustaining process flow to a heater that may "coke-up" heater tubes if flow is lost or 2) Maintaining compressor recycle flow across a catalyst bed to prevent poisoning of the catalyst.

- Steam turbines can provide variable speed capability. Variable speed capabilities are useful whenever variable flow or pressures are required to deal with changing conditions. Variable speed capabilities can be useful during start-up conditions when process flows, pressure, or fluid properties are different from design conditions.
- Steam turbines can be employed to optimize the plant-wide steam usage. In some production sites, steam is generated by the process and is needed at different pressure levels throughout the plant. Instead of wasting energy by using pressure-reducing valves to balance out the flow of steam at different pressures, steam turbines can be used to drop pressures while converting the steam power into useful horsepower as a mechanical driver. In some cases, the steam can be used to drive a generator and the electricity can be used to drive electric motors elsewhere in the plant.
- Steam turbines will not stall or trip on overload. Whenever process conditions

lead to a high driver load, the steam turbine will slow down, but will not trip. This capability allows stream turbines to better handle upset conditions.

- Other steam turbine advantages include:
  - They offer high horsepower ratings in a small package
  - They are non-sparking and explosion proof
  - They can be designed for remote starting

1.4.4 Speed Control

Governing of a steam turbine is the procedure of monitoring and controlling the flow rate of steam into the turbine with the objective of maintaining a constant speed of rotation. The flow rate of steam is monitored and controlled by a throttling valve between the boiler and the turbine. Depending upon the particular method adopted for control of steam flow rate, different types of governing methods are being practiced.

The control of a turbine with a governor is a critical function, as turbines need to be run up slowly to prevent damage. If this fails, then the turbine may continue accelerating until it breaks apart, often catastrophically. Turbines are expensive to produce, requiring precision manufacturing methods and special quality materials.

Steam turbine controls consist of two linked control systems, the governor and the valve operator. The governor is a specialized closed loop controller that maintains an adjustable set point speed or load on the turbine. The valve operator accepts the governor's output demand and closes a position loop for steam admission valve as commanded by the governor. Control valves are employed to regulate the flow of steam to the turbine for starting, increasing or decreasing power, and maintaining speed control with the turbine governor system. Several different valve arrangements are utilized.

Note: Steam control valves need to be cycled routinely to minimize the potential for the valves to stick. When the valves stick open or closed, the turbine is put into jeopardy as a result of losing the ability to control the turbine (i.e., increase or reduce load).

1.4.5 Turbine Overspeed Protection

Potentially, the most destructive event in the life of a steam turbine is an overspeed event, which occurs where the steam turbine and its driven equipment accelerate to an uncontrolled, unsafe speed due to a failure in the control system or the failure of a coupling. Inevitably, overspeed events can result in catastrophic machine damage, and can on rare occasion injure those who have the misfortune of being nearby during an overspeed occurrence.

Overspeed events, while infrequent, continue to occur on both small and larger steam turbines regardless of the vintage, technology level, application, or type of control system (digital, analog, hydro-mechanical, mechanical) utilized by the steam turbine. A steam turbine may employ a mechanical overspeed protection system, electronic overspeed protection system, or combination of systems to maximize protection.

Note: Regardless of the type of overspeed and trip protection systems provided, the system needs to be regularly tested by simulation and by actual testing of the complete system.

During normal shutdowns, always slow the steam turbine down and trip it off-line using the trip mechanism. This ensures the trip system is working and that the stop valve will actuate.

Questions

1. Industrial steam turbines fit into what two general drive categories?
2. The ______________________________ cycle is the thermodynamic basis for most industrial steam turbine systems.
3. One key advantage of steam turbines is they can operate independently of the plant's _______________ system.

4. A ____________ ____________ (two words) steam turbine is designed to exhaust into steam systems that operate above atmospheric pressure.
5. Potentially, the most destructive event in the life of a steam turbine is an ____________ event.

Answers

1. Industrial steam turbines fit into what two general drive categories?

   Generator drives and mechanical drives
2. The ____Rankine____ cycle is the thermodynamic basis for most industrial steam turbine systems.
3. One key advantage of steam turbines is they can operate independently of the plant's ____electrical____ system.
4. A ____back____ ____pressure____ (two words) steam turbine is designed to exhaust into steam systems that operate above atmospheric pressure.
5. Potentially, the most destructive event in the life of a steam turbine is an ____overspeed____ event.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

2

General Purpose Back Pressure Steam Turbine

The majority of the steam turbines used in the manufacturing plants, refineries and chemical plants are defined as general purpose back pressure steam turbines or simply back pressure turbines. The back pressure designation comes from the fact that the turbine exhaust operates at a pressure above atmospheric pressure. The typical exhaust in back pressure turbines ranges from 10 psig up to 200 psig. By definition, general purpose steam turbines will have inlet steam conditions that will most likely not exceed 700 psig and 750 F and have an upper speed limit of less than 6000 rpm.

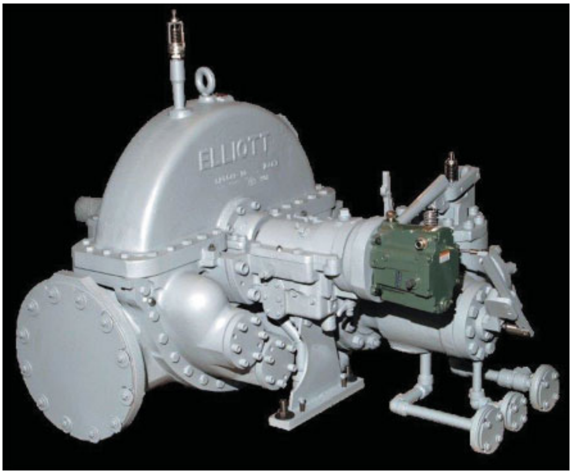


Figure 2.1 General purpose back pressure steam turbine. (Courtesy of Elliott Group)

2.1 Single-Stage Back Pressure Steam Turbine

The American Petroleum Institute (API) defines a single-stage steam turbine as one in which the conversion of the kinetic energy to mechanical work occurs with a single expansion of the steam in the turbine from inlet steam pressure to exhaust steam pressure. A single-stage turbine may have one or more rows of rotating blades that absorb the velocity energy of the steam resulting from the single expansion of the steam. This process is graphically represented in Figure 2.7 under the impulse turbine pressure and velocity profile.

2.1.1 Steam Flow Path

One of the first points of discussion for a steam turbine will be the flow path of the steam through the turbine. We will review the flow of steam and identify major components along the steam path. The figures below show cutaway views of the inlet section of a typical back pressure turbine. The steam flow enters the turbine through the inlet screen then flows through the trip valve. The trip valve will be discussed in more detail in later chapters.

Once the steam flows past the trip valve it will enter the governor valve or throttle valve. After passing the governor valve it will arrive at the nozzle ring or nozzle block. These items can be identified in the steam turbine cross section below. The governor

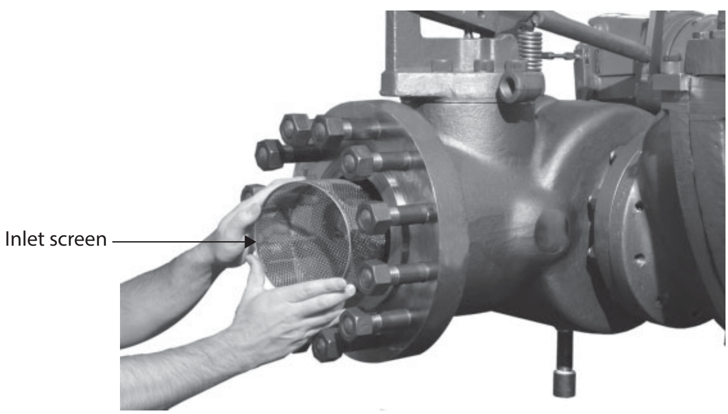


Figure 2.2 Inlet screen to steam turbine upstream of the trip valve. (Courtesy of Elliott Group)

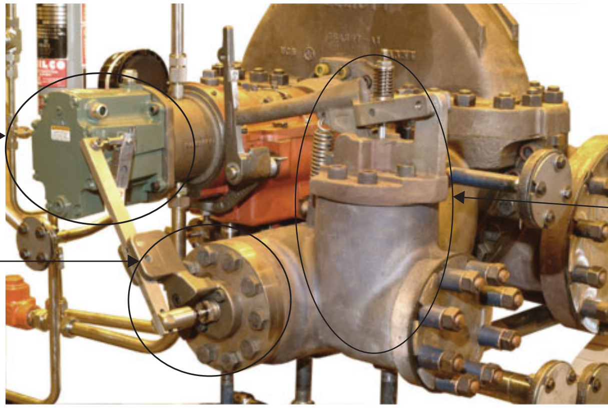


Figure 2.3 View of the trip valve and governor valve. (Courtesy of Elliott Group)

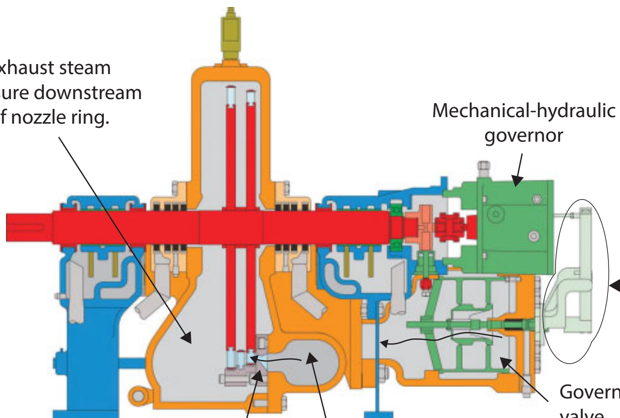


Figure 2.4 Single-stage steam turbine cross section. (Courtesy of Elliott Group) Arrows indicate steam flow.

valve can be seen in the lower right side of the turbine and nozzle ring on the bottom of the turbine casing. The nozzle ring is not a complete ring but a partial segment located in the lower half of the steam chest.

Figure 2.5 View of nozzle ring which is typically bolted to the inside of the steam turbine upstream of the rotating blades. (Courtesy of Elliott Group)

Figure 2.6 Complete nozzle ring. (Courtesy of Elliott Group)

One important point to understand about the nozzle ring is that it converts the high-pressure steam to a much higher velocity and lower pressure downstream. This action is similar to putting your finger over the end of a water hose and increasing the water velocity, which is similar to how the nozzle ring functions in an impulse steam turbine.

There are two basic types of turbine stages: 1) Impulse and 2) Reaction. Figure 2.7 below illustrates the change in steam pressure and velocity as it moves through the stationary nozzle ring and rotating blades for each type. Notice the rotor pictures at the top of the figures, which illustrate the basic design difference between the impulse and reaction staging.

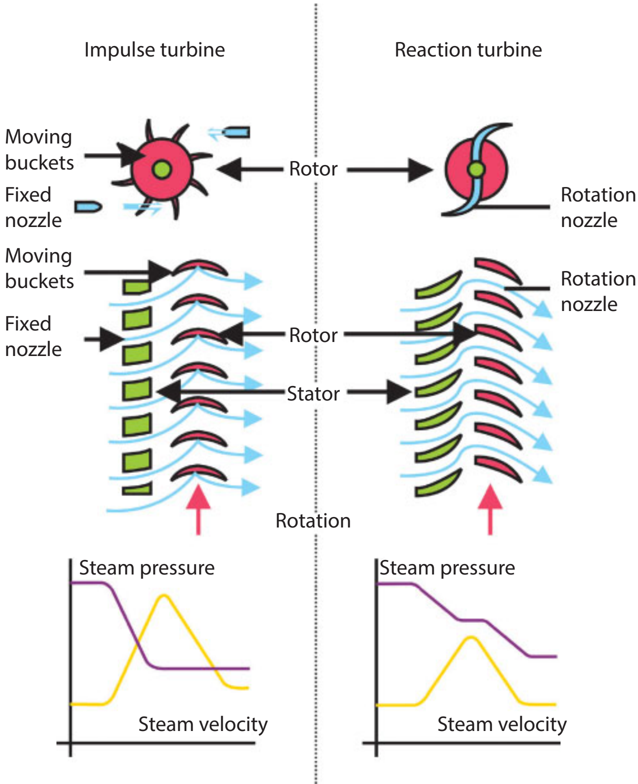


Figure 2.7 Comparison of impulse-type and reaction-type steam turbines.

In an impulse stage, the steam will expand only in the stationary nozzle ring, creating a very high-velocity steam jet that leaves the nozzle ring, contacts the rotating blades, and provides the energy required to power the rotating shaft. A pressure drop occurs only in the stationary nozzle, as can be seen in Figure 2.7. Notice that the steam turbine pressure is constant downstream of the nozzle ring and the velocity decreases as the steam passes each set of rotating blades. Impulse stages consist of three types:

1. Pressure impulse or Rateau stage, which consists of stationary expansion nozzle and one row of rotating blades.
2. A velocity-compounded impulse or Curtis stage, which consists of stationary expansion nozzle and two rows of rotating blades. This type of stage is very common in the manufacturing plants.
3. A velocity-compounded impulse reentry stage, which consists of stationary expansion nozzle, one row of rotating blades and one or more reversing chambers. The pressure drop across a Rateau stage is relatively low in comparison to the pressure drop across a Curtis stage.

In a reaction stage, the steam will expand in both the stationary nozzle ring and the rotating blades. The steam exits the stationary nozzle as a high-velocity steam jet and contacts the rotating blades. In addition, the steam will also expand in the steam path between the rotating blades transferring energy to these blades. As can be seen in Figure 2.7, the steam turbine pressure is changing throughout the steam path and the velocity is increased in the stationary blading but not as much as is seen in the impulse turbine.

The Curtis Wheel or Curtis Stage mentioned above consists of a stationary nozzle ring, two rotating blades and one row of reversing fixed blades. In our experience, this is the most common type of back pressure single-stage turbine design used in manufacturing plants. It has a long history of being very rugged and reliable for its power rating. The pressure drop and velocity diagram are shown in Figure 2.8 below. It should be clear that the entire pressure drop is taken across the nozzle ring and only the velocity changes throughout the steam path, as was described in the impulse turbine discussion above.

In general when we refer to turbines we will be referring to the Curtis stage unless we specifically state otherwise.

After the steam leaves the stationary nozzle ring it will make contact with the first rotating row of blades (Figure 2.9). These blades are typically attached to a solid metal disk by a special machined groove in the outer edge of the disk, as can be seen in the Figure 2.9.

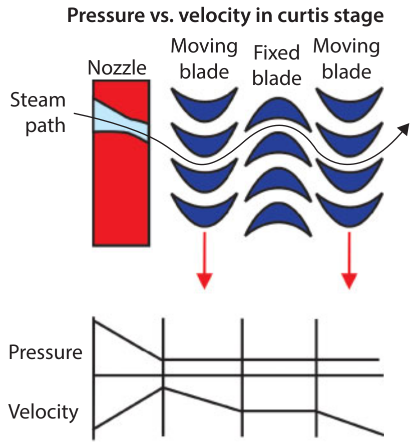


Figure 2.8 The purpose the non-moving blades or fixed blades serve is to redirect steam from the first set of moving blades on to the second set of moving blades.

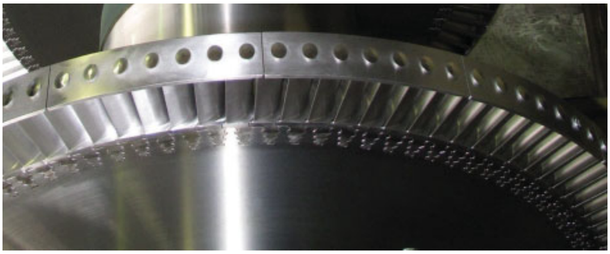


Figure 2.9 Rotating blades attached to a solid disk.

Notice the blade and special connection grooves seen in the disk. The solid metal disk is normally attached to the shaft by a key and or an interference fit, also called shrink fit.

Once the steam leaves the first row of rotating blades it flows into the stationary set of blades which will redirect the steam flow to the final row of rotating blades, as can be seen in Curtis stage in Figure 2.8.

After the steam leaves the row of rotating blades the steam will exit the turbine through the exhaust flange on the steam turbine, as shown in Figure 2.10.

The final steam path items to discuss are manually operated hand valves. Hand valves are mounted in the steam chest, as shown in Figure 2.11 below. The main function of the hand valve is to allow more or less steam into the nozzle ring to optimize turbine efficiency as required during load changes or off design operations. These valves should be either fully opened or fully closed, but should not be used to throttle the steam flow into the nozzle ring.

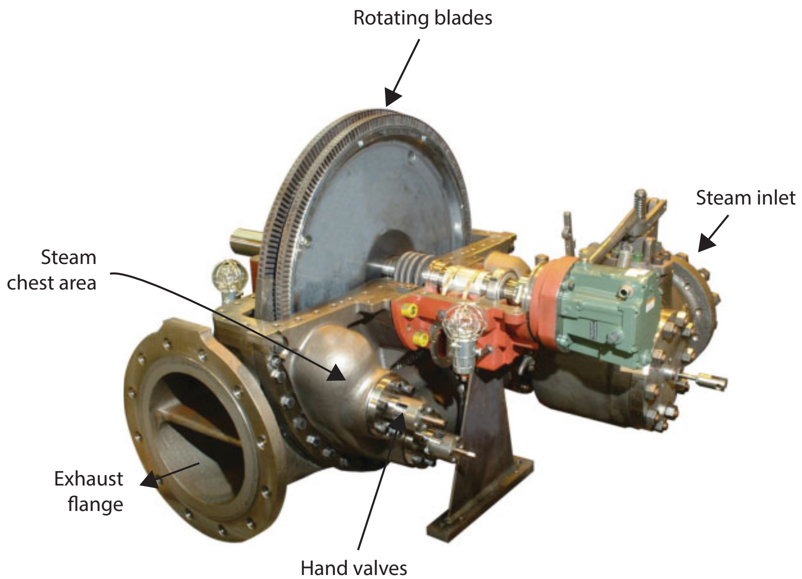


Figure 2.10 Notice the large exhaust flange exit on the lower left portion of this photo. (Courtesy of Elliott Group)

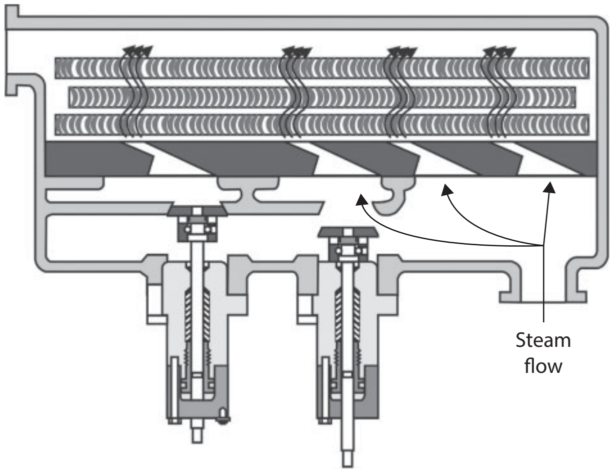


Figure 2.11 Hand valves allow users to control the amount of steam flow supplied to the stationary and rotating blades.

2.2 Mechanical Components in General Purpose Back Pressure Steam Turbines

2.2.1 Radial and Thrust Bearings

Within each general purpose back pressure steam turbine there are two radial bearings and one thrust bearing. The two radial bearings support the steam turbine shaft near each end of the turbine. These bearings are usually plain sleeve (journal) type bearings (also known as hydrodynamic bearings); they use an oil film to support the shaft and prevent the shaft from contacting the bearing surface directly. Bearing design has improved over the years and now there are many different types of hydrodynamic bearings that have different characteristics that can be used for various applications. Today most small general purpose back pressure turbines are supplied with sleeve-type bearings.

It is important to understand how a hydrodynamic or sleeve bearing works. It does so by developing an oil wedge that gets trapped between the bearing and the rotating shaft. The oil wedge generates sufficient pressure to raise the shaft up off the bearing surface and push the shaft in the direction of the rotation. You can think of this phenomenon as if the shaft is dragging the lube oil into the bearing. Since the distance between the shaft and bearing surface is very small and there is too much oil to go through this small opening, the oil builds up pressure, pushing the shaft off the bearing surface by a wedge of oil between the shafts and bearing surface. Figure 2.12 below shows the location of this oil wedge and the shaft movement inside the bearing.

The mechanics of the bearing operation are very important because it provides the background on why the oil must be free of small solid particles. The gap developed by this oil wedge between the bottom of the shaft and the surface of the sleeve bearing is on the order of 0.001″ to 0.003″, the oil film thickness depends on rotor load, oil viscosity, rpm, bearing length and bearing diameter. Therefore, one of the most important monitoring tasks is to keep the oil clean. If anything larger than 0.001″ were to get into the oil it would not be able to pass through this oil

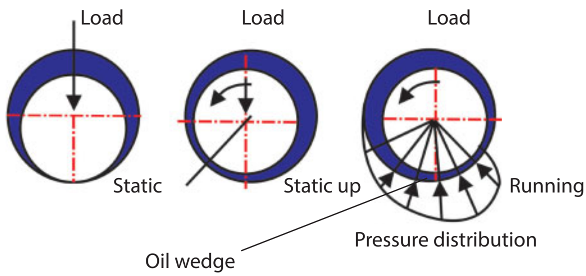


Figure 2.12 A hydrodynamic or sleeve bearing works by developing an oil wedge that gets trapped between the bearing and the rotating shaft. The oil wedge generates sufficient pressure to raise the shaft up off the bearing surface.

film or gap, causing damage to the bearing surface or shaft.

Thrust bearings are installed to transmit axial forces on the shaft to the steam turbine casing. In addition to handling the thrust load, they locate the rotor axially within the turbine casing. Thrust control is typically accomplished using anti-friction bearings (or ball bearings). These bearings can be of several designs, single row, multirows or angular contact, as can be seen in Figure 2.13; but the basic function of the thrust bearing is always the same: preventing the shaft from moving axially and locating the rotor within the casing.

2.2.2 Bearing Lubrication

A common form of lubrication used on back pressure turbines is oil ring lubrication. An oil ring

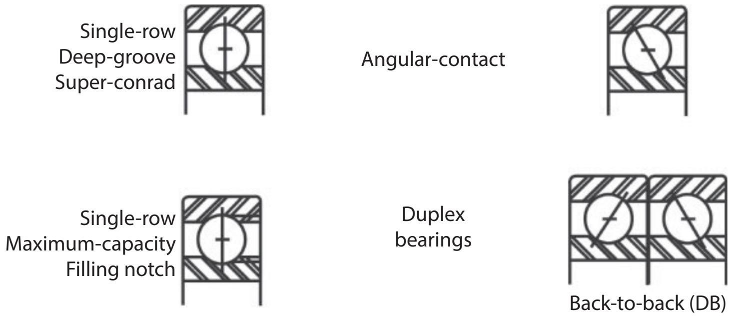


Figure 2.13 Typical ball bearing designs.

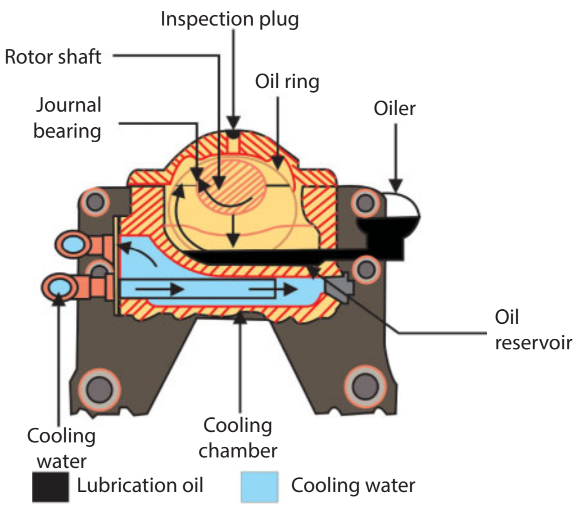


Figure 2.14 Oil ring lubrication showing rings contacting oil sump. Also notice the constant level oiler connected to the oil sump or reservoir.

lubrication system is a simple device, consisting of a large metal ring, typically bronze or brass, placed around the shaft at the bearing. See Figures 2.14 and 2.15, which shows an oil ring lubrication system. Notice the bronze rings on top of the shaft at the bearing area; these are the oil rings.

As the shaft rotates, the oil rings rotate with the shaft and are in contact with the lube oil sump in the bearing housing (see Figures 2.15 and 2.16). As the oil rings rotate, they lift oil from the sump as the oil adheres to the rings. The oil will then be removed at the top of the bearing by contacting the shaft with

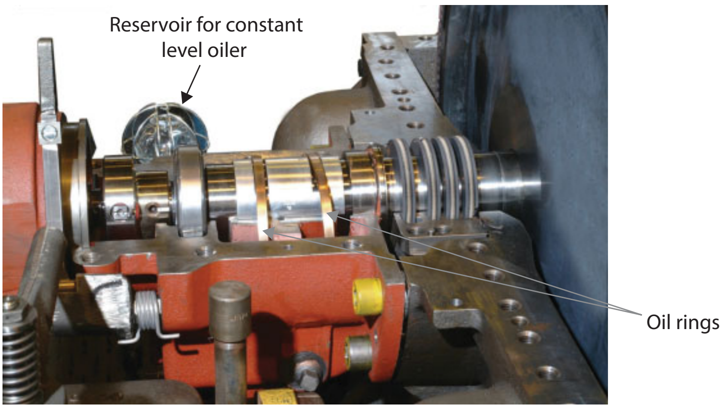


Figure 2.15 Location of lube oil rings on top of bearing; bronze or brass material typically. (Courtesy of Elliott Group)

Figure 2.16 Oil rings used for oil ring lubrication.

the inside diameter of the ring. The oil ring is an effective and very simple lubrication method with only one moving part, the ring. The device is crude, but its function is automatic, effective and reliable. However, it should be noted that this method can only be used in bearings with lower speed, light loads and smaller shaft diameters. This lubrication system is proven and has withstood the test of time for smaller back pressure steam turbines.

Another device, which is typically seen as part of oil sump lubrication, is the constant level oiler sometimes called "Trico Oiler". This oiler works by maintaining a constant level in the sump for the lubrication rings or bearings to contact. The constant level oiler has a small oil reservoir which is transparent, so the oil level can be easily seen. The oil will drain from the reservoir to make up any oil level drop inside the bearing housing. This is one of the most common types of oil systems in smaller sump lubricated systems. The typical constant level oiler can be seen in Figure 2.17 below.

Oil ring lubrication is limited to low speeds and smaller shaft diameters in order for these rings to provide necessary lubrication to the bearings. In order to know what lube oil method is best for the specific application we can use the DN calculation method. The DN method uses the shaft diameter "D" of the turbine multiplied by the shaft speed "N" to arrive at a number which is used to evaluate if the lubrication system needs to be forced or ring lubrication.

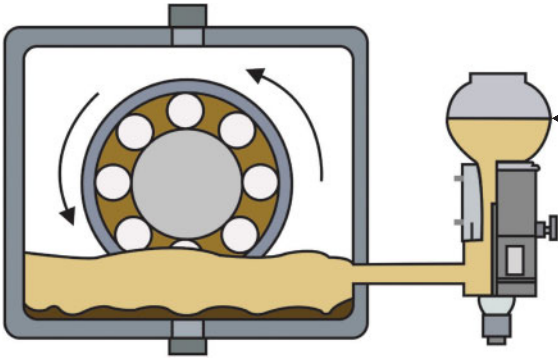


Figure 2.17 View of constant level oiler with ball bearings contacting oil in sump.

As a rule of thumb, it is recommended that oil ring usage be limited to applications with DN values less than 6,000. If we wanted to know the limit for oil ring lubrication and had a 2″ shaft diameter, we would need to limit the shaft speed to approximately 3,000 rpm since (2″ × 3000 rpm = 6,000). Different manufacturers have different limits and rules which they adhere to but this is a good rule of thumb and a little conservative. As stated previously, oil ring lubrication is only used in specific applications for light bearing loads, slower speeds and small shafts. However, for turbines which are larger, higher speed and require more load capacity of the bearings, forced lubrication systems are normally specified.

2.2.3 Force Lubrication Systems

A force lubrication system has a shaft driven oil pump or electric motor driven oil pump which draws oil

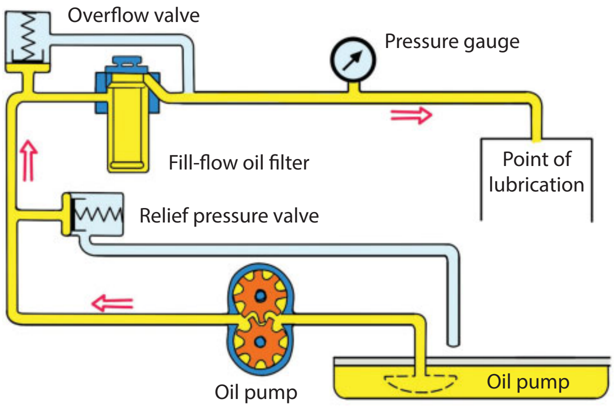


Figure 2.18 Basic forced lubrication system. Pump, bearings and oil reservoir.

from an oil sump or reservoir and distributes the oil to the bearings under pressure. The use of the pump or added pressure gives the system its name "forced lubrication system". Forced lubrication systems vary in complexity from the very rudimentary with a pump and an oil sump (Figure 2.18) to much more complex (Figure 2.19) with various relief valves, by-pass valves, filters, coolers, instrumentation, sump heaters, which can be seen in various degrees in steam turbine applications.

2.2.4 Lubrication

The basic function of lubrication is to minimize friction and to remove heat and wear particles from the bearings and shaft. If these primary functions are not provided by the lubrication systems then bearing life will be diminished. Therefore, monitoring the lubrication

Figure 2.19 Complex forced lubrication system with pumps, reservoir in blue, coolers, extraction fans on top of reservoir.

system is one of the most important tasks the operator must perform to assure long-term reliability.

The two major causes of lubrication degradation are water contamination and solid particulates in the oil. For steam turbine applications water contamination will be the most prevalent, especially if it goes unnoticed for long periods of time.

Water contamination in turbine lube oil is always a major concern. The cause of water contamination of lube oil can be due to failed steam seals, high humidity, water washing of equipment, or proximity to other steam turbines and boilers. The water content in oil is visible to the naked eye above approximately 400 parts per million (ppm) concentration. Water contamination of oil in concentration levels as low as

200 ppm can be damaging. Poor bulk lubricant storage and transfer methods often lead to high levels of both water and particulate contamination. As water content in the lubricating oil increases, its useful life will be reduced. If you can see the water separation in the oil with the naked eye then you already have a problem.

In addition to the water contamination of the oil, we also need to be concerned about particulate contamination. Particulate is a familiar type of contamination and is common where there are high levels of solid airborne particles such as pulp paper industry, chemical residue, refineries, dust, or metal in or around steel mills. The naked eye can only see particles in the 80 microns range (0.00314″) or larger. If these particles are found in the oil they will work into the gap between the bearing and shaft, causing damage to the bearings or scarring the shaft. Therefore clean oil is very important for long-term reliability of the turbine.

2.2.5 Bearing Housing Seals

Anytime a shaft passes through a housing, we need to have a seal to protect the internal components from outside commination and also prevent the oil from leaking out of the bearing housing. For bearing housings seals there are several options to choose from with various levels of protection and cost.

2.2.6 Lip Seals

Lip seals have been used for many years within the machinery industry. The basic design of the lip seal can be seen in Figure 2.20 below. The lip seal, which can be made of rubber, plastic or leather, will contact the rotating shaft to provide the seal or contact area between the shaft and the bearing housing. The lip seal is normally loaded by a metal garter spring connected around the out area of the lip seal. This spring provides the force to push the lip seal onto the shaft and makes the seal. In most cases, the lip seal will wear gradually as time passes and, as the shaft surface speed increases, the expected wear rate will increase accordingly. This type of seal is inexpensive and will typically last several months before needing to be replaced.

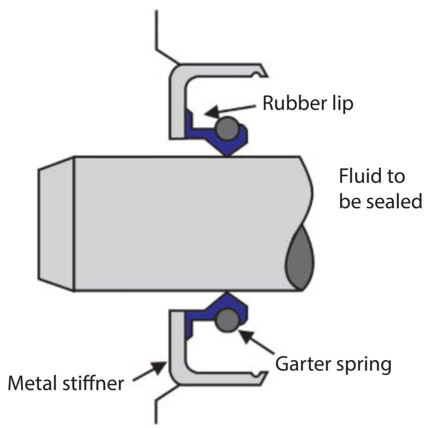


Figure 2.20 Side view of lip seal with garter spring.

2.2.7 Labyrinth seals

Labyrinth seals provide a very small clearance between the shaft and labyrinth teeth if the labyrinth is mounted in the housing (see Figure 2.21). They can also be mounted on the shaft to provide an additional barrier to prevent the oil from leaking down the shaft (see Figure 2.22). A labyrinth seal consists of a number of teeth (knife-edges) that can be either stationary or rotating. Stationary labyrinth teeth are

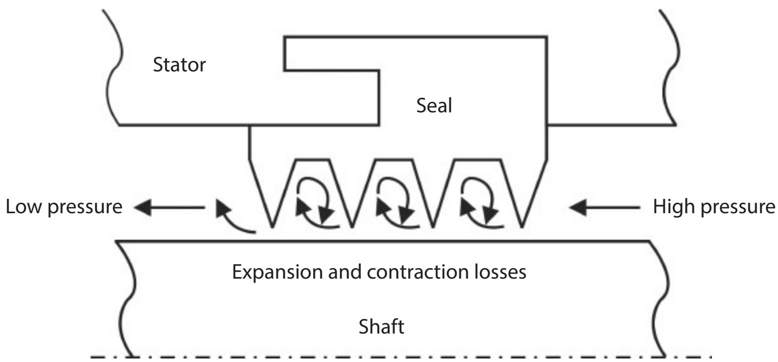


Figure 2.21 Shaft is rotating and labyrinth teeth are stationary in the bearing housing.

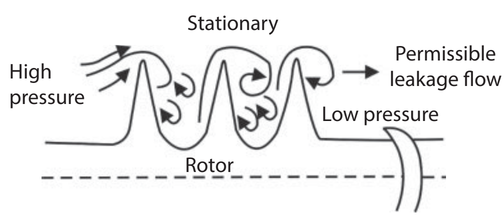


Figure 2.22 Labyrinth teeth mounted on the shaft provide an additional barrier to oil seal leakage due to centrifugal force.

fitted to the bearing housing with very close clearance between the teeth edges and shaft. The sealing action is the result of flow resistance caused by the repeated expansion and contraction along the length of labyrinth seal. It is this contraction at the teeth and then sudden expansion between the teeth that minimize the leakage due to repeated losses along the length of the entire labyrinth seal See Figure 2.24.

There are many advantages to the labyrinth type seals; they are relatively inexpensive and virtually maintenance free since there are no contacting parts. The main area of concern is damage to the teeth since they are usually made of a very soft material in order to prevent damage to the shaft if there is contact. If the labyrinth teeth edges are damaged, the close clearance needed to provide the expansion and contraction losses along the labyrinth seal will be inadequate. This will increase the leakage along the labyrinth seal allowing a direct leak path or contaminants to enter the bearing housing.

In recent years there has been a new generation of seals which have proven to be a very effective seal preventing oil contamination and oil leakage. They are typically called bearing Isolators or protectors (Figure 2.23). They do cost more relative to other types of bearing housing seals but are clearly the most effective seals that can be used. In our experience, if you have an issue and need to seal the bearing housing you will eventually be driven to one of

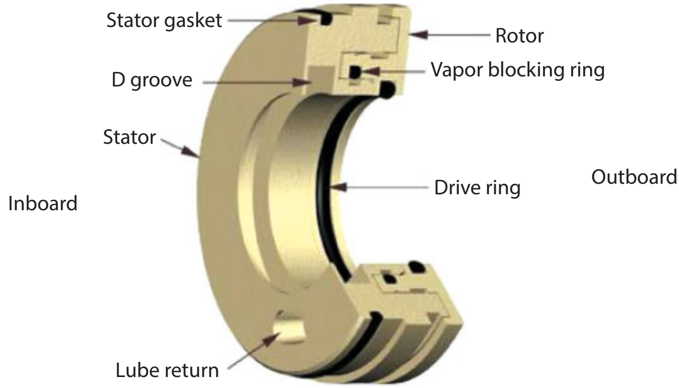


Figure 2.23 Bearing Isolators provide the most effective oil seals for bearing housings. (Courtesy of Inpro/Seal LLC)

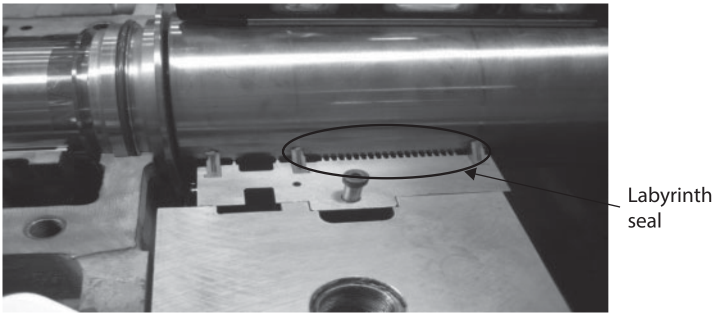


Figure 2.24 Labyrinth seal mounted on the housing sealing on the shaft. (Courtesy of Elliott Group)

these types of seals. You should expect them to cost more so they must be evaluated for each application.

2.2.8 Steam Packing Rings and Seals

The main function of shaft seals or packing in the steam turbine is to prevent excessive steam leakage into the atmosphere and impinging on the bearing housing. The location of the steam seals or packing can be seen in Figures 2.25 and 2.26. The seals are

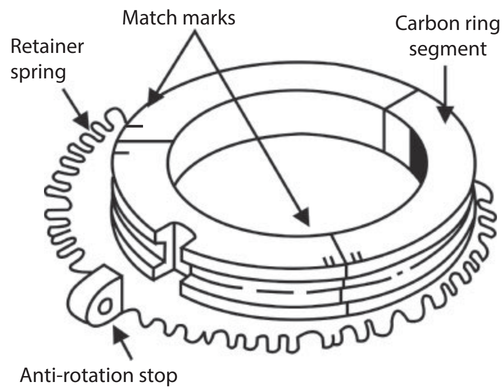


Figure 2.25 Three segmented carbon rings with garter or retainer spring and anti-rotation pin.

typically made from carbon and are configured in multiple segments. These segments are held together by a garter spring (see Figure 2.25). Each ring segment incorporates an anti-rotation pin to prevent the carbon seal from spinning with the shaft. The carbon ring packing has a very close clearance fitting against the turbine shaft and side of the seal housing or the separation wall. (Note: The top half of the packing box in the mechanic's hands can be seen in Figure 2.26.) The carbon ring seals have some self-aligning capability due to the segmented design and they have a very low friction coefficient which tends to prevent heat generation.

The carbon ring seals work by reducing the area available for the steam to pass around or under each seal (carbon ring). Once the steam passes the carbon seal it will expand. The process of flow restrictions at the carbon seals and then expansion between the

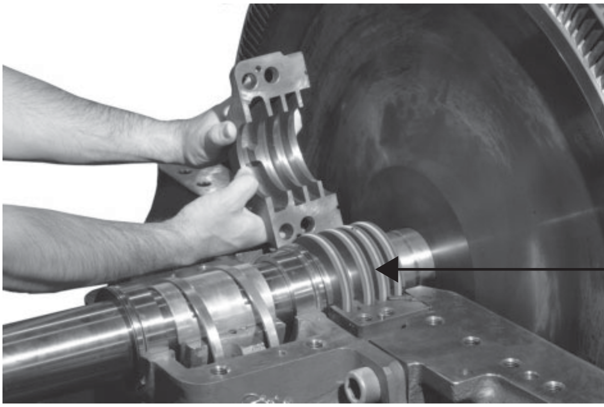


Figure 2.26 Steam steals or Packing. Notice the carbon seals and housing. (Courtesy of Elliott Group)

carbon seals will reduce the steam pressure and leakage to the atmosphere.

Most steam turbines have a series of carbon packing rings that the steam must traverse in order to leak out to the atmosphere. Notice in Figure 2.27 that there is a special gland leak off that assists in dropping the steam pressure as the steam leaks to the atmosphere. Gland leak offs are not always present but when they are they add another barrier to prevent the steam from leaking out and impinging on the bearing housing. If the leaking steam is allowed to impinge on the bearing housing, it can cause condensate to form in the bearing housing and degrade the oil and eventually damage the bearings.

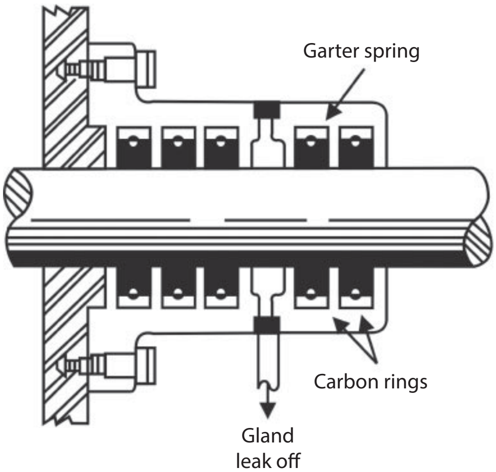


Figure 2.27 Carbon packing gland.

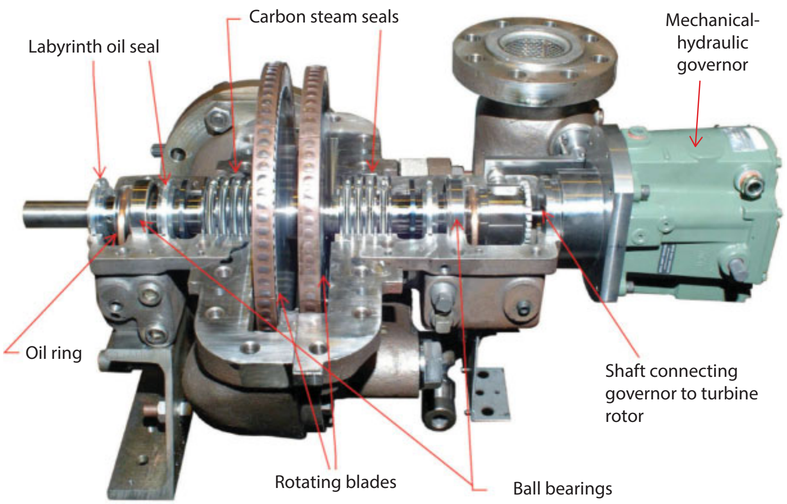


Figure 2.28 Overview of the general purpose steam turbine. Notice the location of the ball bearings, carbon seals, oil rings, rotating and stationary blades, shaft connection to governor, and oil housing seals. (Courtesy of Elliott Group)

Questions

1. List the major components in the steam path from the inlet flange to the exhaust flange for a Curtis Stage.
    a. ______________________________
    b. Trip valve
    c. ______________________________
    d. ______________________________
    e. ______________________________
    f. Reversing blades
    g. ______________________________
    h. ______________________________

2. What is the main function of the hand valves?
    a. ______________________________

3. What three things do we know about an application when we see oil ring lubrication?
    a. ______________________________
    b. ______________________________
    c. ______________________________

4. What is the main difference between oil sump lubrication and a forced lubricated system?
    a. ______________________________

5. Why do labyrinth seals reduce the leakage from a high-pressure to a low-pressure environment?
    a. ______________________________

Answers

1. List the major components in the steam path from the inlet flange to the exhaust flange for a Curtis Stage.

    a. Inlet screen

    b. Trip valve

    c. Governor valve

    d. Nozzle ring

    e. 1st row of rotating blades

    f. Reversing blades

    g. 2nd row of rotating blades

    h. Exhaust flange

2. What is the main function of the hand valves?

    a. Allow more or less steam into the nozzle ring.

3. What three things do we know about an application when we see oil ring lubrication?

    a. Light bearing loading

    b. Shaft has slow speed

    c. Shaft diameter is small

4. What is the main difference between oil sump lubrication and a forced lubricated system?

    a. lube oil pump

5. Why do labyrinth seals reduce the leakage from a high-pressure to a low-pressure environment?

    a. resistance to flow is due to repeated contraction and expansion along the length of the labyrinth seal.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

3

Routine Steam Turbine Inspections

The following inspections should be made while making your normal operational rounds. The basic idea behind these recommendations is to regularly look at, listen to, and feel steam turbines in order to detect abnormal conditions while they are still manageable. These simple inspection methods can help locate basic machinery problems early and allow you to avoid serious problems down the road. Employing these simple guidelines will help you to determine when a piece of condition-monitoring equipment is needed to quantify the magnitude of the problem and get help. With practice, these methods should become second nature.

Figure 3.1 Look, listen, and feel.

1. **LOOK** at the turbine as you walk up.
   - Is it shaking?
   - Smoking? Any signs of smoke, which may be an indication of an oil leak, should be acted on immediately due to the fire potential it represents.
   - Are there any indications of fluid leakage?
   - Are there vibrating parts on the turbine that have come loose? (Check coolers, piping, baseplate, bearing caps, etc.)
   - Is excessive steam leaking out of the glands that seal the shaft to the casing? (Note: Normally, there should be <u>no</u> visible leakage exiting the turbine seal glands. Any significant gland leak has the potential of injecting steam into the bearing housings and contaminating the oil.)

- Is there water in the oil? (Check level, is it rising, since water is heavier than oil.)
- Is the governor hunting? (This wears out valve packing and linkage.)
- Are the steam traps near the turbine working (see Figure 3.2)?
- Is the auxiliary pump running? Why?
- Is the oil pressure correct?
- Is the oil cool enough, based on your experience with this steam turbine? Is the cooler working?
- Look at the vibration readings for the turbine; are they steady and low? Is the oil level correct in the sump? Is the oil

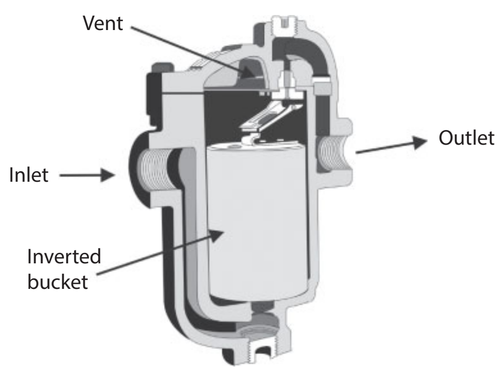


Figure 3.2 Condensate or free water in a steam turbine's inlet will lead to the rapid erosion of the steam path components, which is why steam traps are always installed in steam turbine inlet piping. A steam trap is used to remove condensate and non-condensable gases from steam piping, with a negligible consumption or loss of live steam.

level correct in the bearing housings? Is the oil level rising or falling?

- Are the ring oilers turning or hung up?
- Is there steam leaking out of the stem of the control valve?
- If installed, is the bearing housing air purge turned on to prevent steam from contaminating the oil?
- Are there coupling pieces on the pedestal under the coupling guard?
- Is the trip mechanism resting on its knife edge?
- Is the ΔP on the oil filter gauge high or constantly reading "0"?
- Look at piping support springs to insure that blocks were not left in after maintenance, especially if a hydrostatic, i.e., "hydro", test was performed on the piping system during any construction work.
- Look at the coupling area and see if there are shims from the spacer or dust if an elastomeric type of coupling is used.
- Are all of the anchor bolts in place? Are they tight?
- Is the governor linkage free of restrictions and are the connections tight?
- Is trip system knife edge and trip arm free of all obstructions? Is the spring connected?

- Are the hydraulic oil levels in governor visible and correct.

2. **LISTEN** to the turbine.
    - Is it noisy? Steam leaking?
    - Does it sound different today than yesterday?
    - Is the noise constant or changing? Is the governor steady or hunting?
3. **FEEL** — Touch the turbine bearing housings with your fingertips.
    - Are they excessively hot?
    - Is the temperature different than it was yesterday? How and why is it different than yesterday?
    - Is it shaking more than yesterday? Is it too much?
    - Is the oil pressure relief valve bypassing oil? Touch the inlet to the valve and the outlet from the valve. Under normal conditions, the outlet line should be noticeably cooler that the inlet line. If the relief valve is leaking, the outlet line will feel warm.
    - If it is bypassing oil, try to determine if this is normal or not.
    - Check oil cooler to ensure it is removing heat from the oil.

Questions

1. What are the three senses you can utilize during a machinery walk-though inspection?
2. List three things to feel for during a steam turbine inspection.
3. What would excessive smoke around a steam turbine be an indication of?
4. The one secret to detecting problems early is to know what ____________ is.

Answers

1. What are the three senses you can utilize during a machinery walk-though inspection?
    - Sight
    - Hearing
    - Touch
2. List three things to feel for during a steam turbine inspection.
    - Are they excessively hot?
    - Is it different than it was yesterday? How and why is it different than yesterday?
    - Is it shaking more than yesterday? Is it too much?

- Is the oil pressure relief valve bypassing oil? If so why?
- Check oil cooler to insure it is removing heat from the oil.

3. What could excessive smoke around a steam turbine be an indication of?
    - Any sign of smoke could be an indication of an oil leak and should be investigated immediately.
4. The one secret to detecting problems early is to know what __normal__ is.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

4

Steam Turbine Speed Controls and Safety Systems

4.1 Introduction

In this chapter, we will cover the various types of steam turbine speed control systems, overspeed protection, and overpressure protection typically encountered on general purpose steam turbines. The purpose of this section is not to make the reader an expert, but to make him or her aware of these systems, how they function and why they are important. For those involved in the actual maintenance and repair of general purpose steam turbines and their sub-systems, we recommend further study into these topics.

4.2 Speed Controls

A speed governor is a device that controls the steam turbine speed to a preset value, typically the rated speed. The speed control governor receives an input signal from the turbine shaft, compares it to the set-point and then produces an output proportional to the difference between the actual and set-point speed. This difference will then be used to signal the governor valve to change the position of the steam supply valve. The governor senses the turbine shaft speed in several different ways, which we will discuss in more detail in the next section.

We can think of the governor speed control as being similar to the cruise control used on automobiles. Consider this example: A car is traveling on a flat road with the cruise control set to 50 miles per hour (mph). The cruise control will maintain the speed at 50 mph until the terrain changes. Now let's assume that the terrain changes from a flat road to a steep incline or hill. At that point, the cruise control will sense the car's speed decreasing and respond by opening a valve to send more gasoline to the engine to bring the speed back to its set point. When the car is past the peak of the hill and is going downhill, the cruise control will sense the speed increasing and close the valve, reducing the gasoline going to the engine and bringing the speed back to the original set-point of 50 mph.

Instead of the cruise control we use on an automobile, we have a governor and governor valve on the steam turbine. They both do the same job of controlling the speed—one is for an automobile and the other is for a steam turbine. Now let's review the same scenario with the steam turbine. If the turbine is at a constant speed the governor valve or inlet steam valve will not move. It will continue to allow the same amount of steam into the turbine until something changes, such as the required load or the steam supply pressure. However, assume that the driven unit, pump or compressor, begins to deliver more product as the result of a fully opened discharge valve. The increase in load to the turbine will drag down or reduce the turbine speed due to the increasing load. In response to the load change, the governor will sense the speed decreasing and open the governor valve to allow more steam flow into the turbine. The increase steam flow will give the turbine more power and allow it to return to its speed set point.

Now assume that the driven unit load is suddenly reduced due to closing the discharge valve on the pump or compressor. This will reduce the load requirement on the turbine and the speed will start increasing. As the turbine speed increases the governor will sense this and start reducing the steam allowed into the turbine by closing the governor valve. This will then reduce the speed of the turbine back to its speed set point.

These examples illustrate that the governor control is a self-correcting device which will continually provide speed control to compensate for the change in driven equipment demand or load. Speed sensing, speed comparison to the set point, and finally speed correction are the basic functions of all speed control governors. Based on the criticality of the applications there are several types of governors today that can provide speed control with different levels of complexity. The following governor types will be reviewed and described below in more detail.

1. Mechanical governors
2. Mechanical – hydraulic governor
3. Electronic governor

Mechanical Governors are a purely mechanical means of controlling turbines, employing fly weight or fly ball systems as shown below (see Figure 4.1). In a mechanical speed control system the fly weights are connected to the turbine shaft

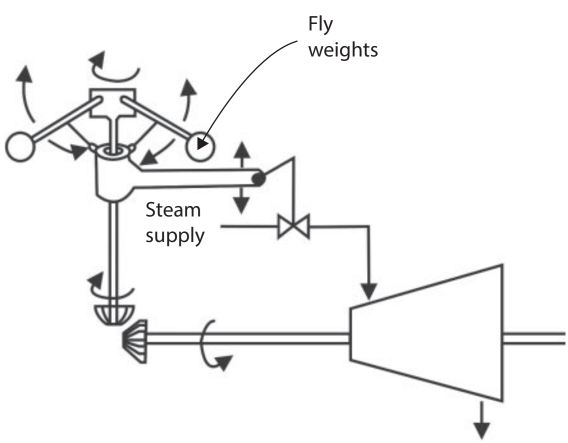


Figure 4.1 Basic mechanical governor.

by a gear which acts as the speed input to the fly weights. As the fly weights are spun faster, they are forced out due to centrifugal force. These weights are also connected to a collar with linkage connected to a lever that moves the steam inlet valve further open or closed depending on the movement of the fly weights. This is the basic mechanical governor system. These types of governors are limited in their application due to the amount of force that can be generated to open and close the steam inlet valve. Mechanical governors are the oldest types of governors. We think it would be a rare occurrence to see a pure mechanical governor in use today.

Mechanical-Hydraulic (MH) governors are the most common type of speed governors seen on general purpose steam turbines within the process industry. They are self-contained governors that use hydraulic fluid, typically automatic transmission fluid (ATF). Internally, MH governors contain a drive shaft driven fly weight or ballhead assembly to sense the turbine speed and a shaft-driven oil pump to create the necessary hydraulic oil pressure to control the governor servo piston and ultimately drive the changes in the governor valve (see Figure 4.2). MH governors employ a servo piston or power piston to increase the amount of output force that is transmitted to the steam governing valve.

Inside the governor enclosure is a small gear pump, which is connected to the end of the turbine shaft.

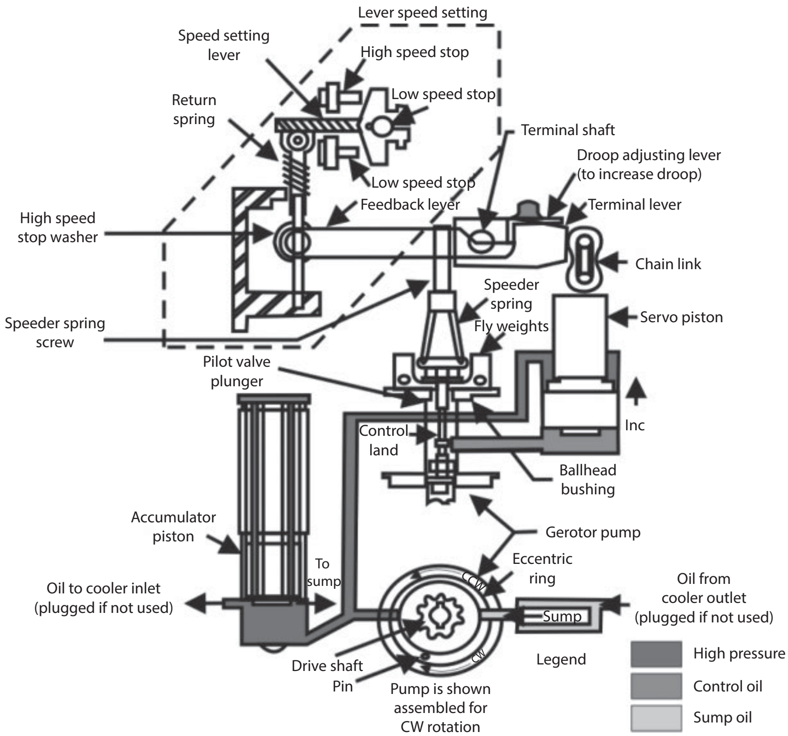


Figure 4.2 Mechanical-Hydraulic governor details.

As the speed of the turbine increases the fly weight or ballhead will sense the increased speed by the increased oil pressure being developed by the gear pump. This increased hydraulic oil pressure will move the pilot valve up, allowing more hydraulic oil to be recirculated back to the oil sump, bypassing the servo piston. This motion will close the governor valve, reducing the volume of steam entering the turbine and lower the turbine speed. When the turbine speed is too slow the gear pump will produce lower hydraulic oil pressure, which will move the pilot valve and allow more oil into the servo piston driving open the governor valve. This will allow more steam into the turbine and increase the speed.

Notice that the fly weight in this type of governor works the same way as it does in the mechanical governor. However, there is one major difference in the mechanical-hydraulic governor: The fly weights in a MH governor control a pilot valve that directs the ATF either to the servo piston or to the oil sump. The oil going to the servo piston will push the servo piston up to increase speed by allowing more steam into the turbine. If the speed is too high the ATF will be sent back to the sump again by the pilot valve which is controlled by the fly weights and allow the oil to return to the sump, lowering the amount of steam into the turbine.

The actual output from the MH governor enclosure is transmitted through a serrated shaft that extends outside of the governor housing. The serrated shaft will rotate up to 40 degrees to control the position of the governor valve via mechanical linkages to the steam valve. This serrated shaft connections and linkages to the governor valve can be seen in the figure 4.3 as well as the picture of the Woodward governor (Figures 4.3 and 4.4). All the basic MH governor component details can be seen in Figure 4.2 below.

Electronic Governors perform the same function as the mechanical-hydraulic governors except they do not use fly weights to sense the speed. Electronic

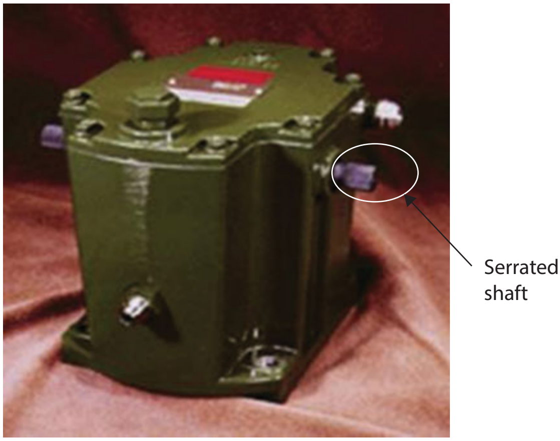


Figure 4.3 Woodward mechanical-hydraulic governor. One of the most common types of turbine governors (TG) used to control general purpose steam turbines. (Courtesy of Woodward Inc.)

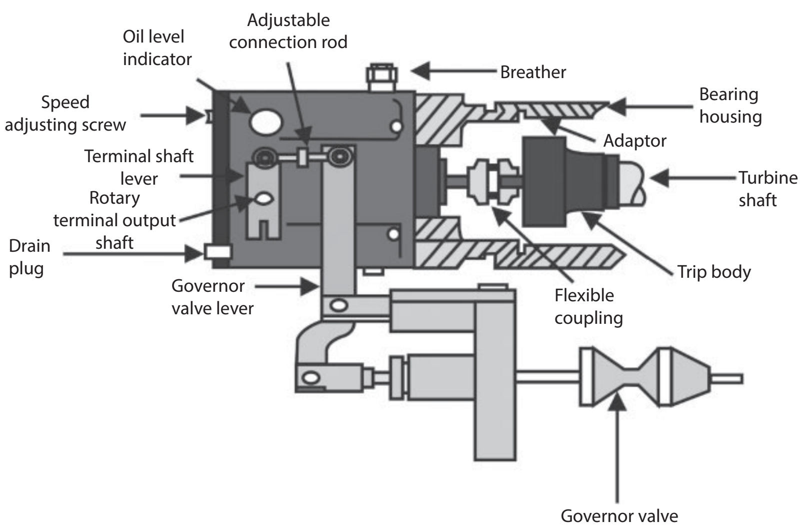


Figure 4.4 The overall governor system and its linkage from the mechanical-hydraulic governor. It should be noted that the governor controls only the governor valve or throttle valve. This is the only valve that controls the steam going into the turbine.

governors use a magnetic speed tachometer or speed pick-up to measure the shaft speed, as can be seen in Figure 4.5. Each time a gear tooth passes by the magnetic speed pick-up, an electrical pulse is produced that is proportional to the turbine rotor speed. Once the speed signal is in the electronic format, it can be used as feedback to control the speed of the turbine or any other process parameter of interest. This same speed signal can be used in conjunction with the pump or compressor performance map or curve to know exactly where the driven equipment is operating on its performance curve. All this available process train information can then be used to monitor overall efficiency and provide input into the overall facility control system.

The electronic governor control system has many benefits for overall control of a steam turbine, the driven machine and the overall process

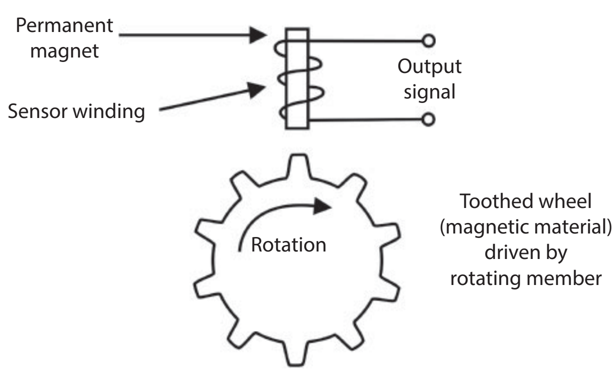


Figure 4.5 Magnetic speed sensor used in electronic governors. Each pass of the gear tooth produces a pulse in the sensor winding.

control system, but it is also the most expensive of the three being discussed. In most applications the cost of an electronic governor on smaller less critical general purpose back pressure turbines is not justified.

Figure 4.5 shows the typical configuration used to sense the turbine speed: A gear tooth is attached to the turbine shaft and a magnetic speed sensor that senses the teeth as they pass by.

4.3 Governor Classes

Steam turbine governors will control the speed of the turbine by regulating the amount of steam allowed into the turbine. However, these speed changes do not happen instantaneously when the speed drifts away from its set point. There are many factors, such as severity of the load upset, rotor rotational inertia and system hysteresis that can determine how long the speed correction will take. Another factor that plays a significant part in speed variation of a governor is the class of governor being used. Speed governor classes are rated in accordance to the National Electrical Manufactures Association (NEMA) publication number SM 23. This publication lists the "Class of Governing System" being used in four district classes: A, B, C or D. Each rating specifies what percentage of speed regulation is required, maximum speed variation and maximum speed rise as a percentage of maximum continuous

Table 4.1 The table lists governor specifications as percentages of maximum continuous speed. The maximum continuous speed is defined as the highest speed at which the turbine, as built and tested, is capable of continuous operation, at any of the specified steam conditions.

Class of governing system	Maximum speed regulation percent	Maximum speed variation percent	Maximum speed rise percent
A	10	0.75	13
B	6	0.50	7
C	4	0.25	7
D	0.5	0.25	7

speed. (See Table 4.1 for details for the various governor classes.)

Definitions for the terms used in Table 4.1:

Maximum Speed Regulation (Droop) – Speed regulation, expressed as a percentage of rated speed, is the change in sustained speed when the power output of the turbine is gradually changed from the rated power output to zero power output under steady-state conditions. This is also referred to as Droop. This is basically a measure of the allowable change in speed as load changes.

Maximum Speed Variation – Speed variation, expressed as a percentage of rated speed, is the total magnitude of speed change or fluctuations from the speed setting under steady-state conditions. This is a measure of how much the speed is allowed to deviate from the speed set point during normal or steady-state conditions.

Maximum Speed Rise – The speed rise, expressed as a percentage of rated speed, is the maximum momentary increase in speed that is obtained when the turbine is developing rated power output at rated speed and the load is suddenly and completely reduced to zero. This is extremely important for overspeed trip settings.

Additional definitions we will need for this section are:

The trip speed (in revolutions per minute): The speed at which the independent emergency overspeed device operates to shut down the turbine. The trip speed setting will vary with the class of governor. This is the speed at which the trip valve should actuate and prevent steam from entering the turbine. See Table 4.2 for trip speed settings.

The turbine "maximum continuous speed" (in revolutions per minute): The speed at least equal to 105 percent of the highest speed required by any of the specified operating conditions. It is the highest speed for continuous operation which will satisfy the process conditions on the driven equipment, pump or compressor.

Table 4.2 Trip settings as a percentage of maximum continuous speed.

Trip Speed Settings	
Class of governing system	**Trip speed setting as percentage of maximum continuous speed**
A	115%
B	110%
C	110%
D	110%

To better understand why Table 4.2 and governor classes are important, let's work through a couple of examples to illustrate the allowable speed variations for different governor classes.

Example – Speed Variation with a Class D Governor:

Assume we have a turbine with a rated speed of 3000 rpm, which is our set point and that is driving a centrifugal pump. The governor is Class D type and has a speed variation of 0.25%, as per Table 4.1. What is the maximum and minimum rpm the governor will allow during steady- state conditions, assuming no sudden changes in load?

> 3000 rpm × 0.25% = 7.5 rpm above or below set point. Therefore our speed range or variation is 3007.5 to 2992.5 rpm.

Repeat same example but change the governor class to A:

> 3000 rpm × 0.75% = 22.5 rpm above or below set point. Therefore our speed range is allowed to vary from 3022.5 to 2977.5 rpm.

Now that we understand how much speed can vary during steady-state conditions, based on governor class, we need to understand how fast the governor will respond to changes in load. There is a special name given to the speed regulation as the steam turbine load changes, and it is speed Droop or simply Droop.

Example: Speed Regulation or Droop with Class D Governor

Assume we are starting up a turbine that is driving a centrifugal pump with a Class D governor. The pump is blocked in and has no process load on it initially. The turbine is brought up to rated speed of 3000 rpm. As no product is being pumped the turbine is initially unloaded. Then, we gradually open the suction and discharge valves on the pump until they are fully opened. This will change the load on the steam turbinefrom no load to full load. Assume that under these conditions the fully loaded speed is 2990 rpm. The percentage change in speed, when we fully load the steam turbine, is referred to as Droop. The calculation would be as follows:

> % Droop = [(no load speed) – (full load speed)/speed at rated power output] × 100

in this case:

% Droop = [(3000 rpm – 2990 rpm)/3000 rpm] × 100
% Droop = 0.33 % - This is within the Class D governor range since it is below 0.50%.

Repeat example above using a Class A governor;

Rated speed is 3000 rpm at no load; speed at full load is 2750 rpm.

% Droop = [(3000 rpm – 2750 rpm)/3000 rpm] × 100
% Droop = 8.3 % - This is within the Class A governor range since it is below 10% on speed regulation.

Notice how much speed change there would be between the Class D and Class A governors. If the driven equipment speed change needs to be held closer to full load speed, then the Class D governor would need to be supplied since it has the least amount of allowable Droop or speed regulation.

If there is too much Droop, the governor will respond too slowly to load changes and if there is too little droop it might cause instability in the governor by reacting to the governor's continuous changes. Too little droop can make the control system unstable. The change in speed of the turbine in relation to load changes on the driven pump or compressor needs to be balanced to optimize the controllability and reliability of the system.

The maximum speed rise is defined by a scenario where the turbine is operating at its rated power output and the load is suddenly reduced to zero. This is the maximum speed rise that the governor will allow before it can regain control of the speed after a sudden loss of load. The governor is designed to regain control of the turbine speed if the load is suddenly lost, but there are many variables that all have to be maintained within certain limits to prevent the turbine speed reaching trip speed.

The trip speed settings are different for each governor class. For Class A governors the trip speed is equal to 1.15 × Maximum Continuous Speed and for a Class D governor the trip speed is equal to 1.10 × Maximum Continuous Speed.

Example: <u>Trip Speed Setting Class A Governor</u>

Assume we have a Class A governor with a Maximum Continuous Speed of 3500 rpm and the rated speed is 3000 rpm.

$$\text{Trip Speed} = 1.15 \times \text{Maximum Continuous Speed}$$
$$\text{Trip Speed} = 1.15 \times 3500 = 4025 \text{ rpm}$$

Repeat example above for Class D: <u>Trip Speed setting Class D Governor</u>

$$\text{Trip Speed} = 1.10 \times \text{Maximum Continuous Speed}$$
$$\text{Trip Speed} = 1.10 \times 3500 \text{ rpm} = 3850 \text{ rpm}$$

The difference in trip speed setting from a Class A and Class D governor in this example will be 175 rpm (4025 rpm – 3850 rpm = 175 rpm).

Now we will work a couple of examples to illustrate the speed rise for different governor classes.

Example: Speed Rise with Class D Governor

Assume we have a Class D governor; the rated speed is 3000 rpm at the rated power and maximum continuous speed is 3500 rpm. What is the maximum speed the turbine will reach before the governor takes control?

$$\text{Maximum speed rise \%} = [(\text{Max. Speed no load}) - (\text{rated speed at load}) \times 100]/(\text{rated speed})$$

If we rearrange this equation as follows:

$$\text{Max. speed rpm} = [(\%\ \text{speed rise from Table 4.1}) \times \text{rated speed}] + \text{rated speed}$$

$$\text{Max. speed rpm} = [(7\%) \times 3000] + 3000 = 3210\ \text{rpm}$$

This is the maximum speed (3210 rpm) the turbine should reach before the governor takes control and returns the turbine to its set point.

$$\text{Trip speed for class D governor} = 1.10\ (\text{Table 4.2}) \times 3500\ \text{rpm} = 3850\ \text{rpm}$$

This is the overspeed trip setting point (3850 rpm) for a Class D governor.

For a Class D governor, a 3000 rpm rated turbine would rise 210 rpm to a maximum speed of 3210 rpm due to a sudden loss of load. This is designed to be below the trip speed of the governor, which is calculated to be 3850 rpm.

<u>Repeat example with Class A governor</u>:

$$\text{Maximum speed rise \%} = [(\text{Max. Speed no load}) - (\text{rated speed at load}) \times 100]/(\text{rated speed})$$

If we rearrange this equation as follows:

$$\text{Max. speed rpm} = [(\text{\% speed rise from table}) \times \text{rated speed}] + \text{rated speed}$$

$$\text{Max. speed rpm} = [(13\%) \times 3000] + 3000 = 3390 \text{ rpm}$$

This is the maximum speed (3390 rpm) the turbine should reach before the governor takes control and returns the turbine to its set point speed.

$$\text{Trip speed for Class A governor} = 1.15 \text{ (table 4.2)} \times 3500 \text{ rpm} = 4025 \text{ rpm}$$

This is the overspeed trip set point (4025 rpm) for the Class A governor.

For a Class A governor, a 3000 rpm rated turbine would rise 390 rpm to a maximum speed of 3390 rpm if there were to a sudden loss of load. This is almost 200 rpm more than a Class D governor. It must be noted that the maximum speed rise values are only achievable for a well-defined set of operating conditions and system parameters. In addition to the governor speed rise limits there is always a safety system incorporated into the design that is independent of the governor system and is called the "overspeed trip system".

4.4 Overspeed Trip System

One of the most critical safety devices on any steam turbine is the overspeed trip system, which is a safety system that is completely independent from the governor-controlled system. The overspeed trip system's only function is to close the inlet steam valve when the turbine speed reaches the trip speed set point. This inlet trip valve is either fully opened or it is closed. It does not control the steam; it only allows steam into the governor valve or prevents steam from entering the governor valve.

The trip system is designed to prevent the turbine speed from exceeding the design limits of the rotating material within the turbine, mainly the turbine blades, disks and prevent loss of the interference fit between the disks and the shaft. Even though the

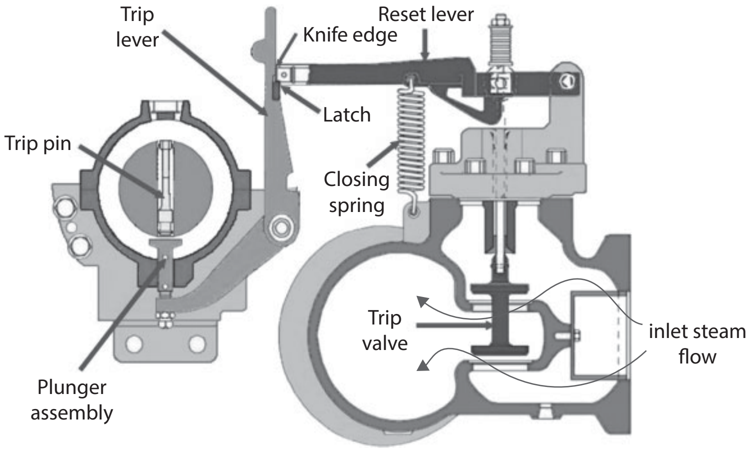


Figure 4.6 Double-seated trip valve. (Courtesy Elliott Group)

turbine governor is designed to stop the turbine from reaching the trip speed, these controls are for a specific set of variables which may not always be known or set correctly. Therefore, for safety reasons, we are required to have a system in place that will trip the turbine inlet steam valve whenever the overspeed trip speed setting is reached.

Figure 4.6 shows the steam flow to the trip valve (double-seated valve) before being allowed into the governor valve area. Now follow the trip valve to the top of the valve stem to the spring on top which is connected to the lever arm or trip lever. Where the two arms meet is called the knife-edge. The arm is supporting the knife-edge hand trip lever. Now follow the hand trip lever down to the bottom of the turbine to the trip pin assembly.

One of the key components of a mechanical overspeed system is the overspeed trip pin assembly. This is basically a spring-loaded pin or weight mounted on the turbine shaft, usually between the end of the turbine shaft and governor. As the turbine speed increases, the spring loaded weight or pin (see Figure 4.7 below) will respond to the increased speed by allowing the weight of the pin to move against the opposing spring force. The centrifugal force of the weight will overcome the opposing spring force at a specific speed (trip speed) and at that point the weight or pin will move outside of the trip body contacting the plunger assembly, causing the knife-edge to separate and allow the spring-loaded trip valve to close, stopping all steam flow into the turbine. The centrifugal force of the pin weight is designed to overcome the

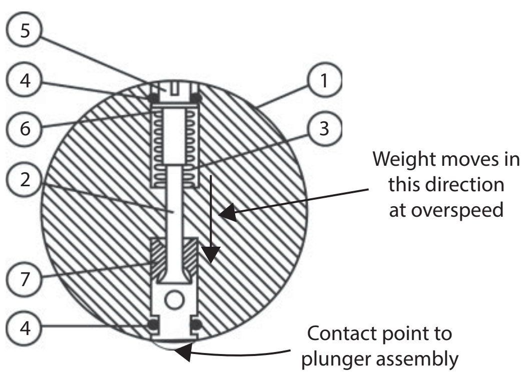


Figure 4.7 Spring-loaded pin or weight. 1. Body, 2. Pin, 3. Spring, 4. Lock U-Staple, 5. Adjustable nut, 6. Washer, 7. Auxiliary weight.

spring stiffness at the correct overspeed trip setting. In order to set the balance between the centrifugal force of the weight and the opposing spring force there is an adjustment nut that can be used to change the actual trip speeds. As can be seen by a close inspection of Figure 4.7, the adjustment nut can be used to increase or decrease the opposing spring force of the centrifugal weight which will change the overspeed trip setting.

Figure 4.8 shows an overview of a typical mechanical/hydraulic governor arrangement. The hydraulic governor (light green box) is connected to the governor valve via a linkage from governor to governor control valve. In the foreground is the trip & throttle valve. Here, the trip & throttle valve is in the tripped condition.

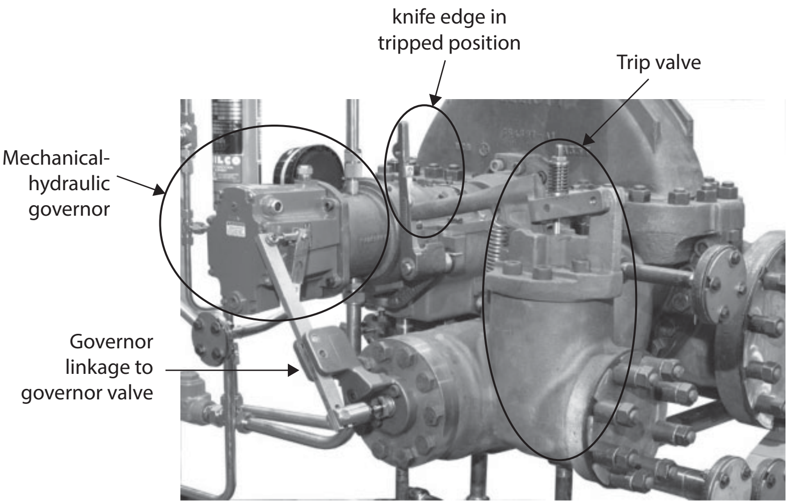


Figure 4.8 Typical mechanical-hydraulic governor arrangement. Notice linkage connection between governor valve and governor. (Courtesy of Elliott Group)

4.5 Overpressure Protection

The steam turbine casing is not always designed for full inlet steam pressure. Therefore, many steam turbine manufacturers install a small valve on top of the turbine casing called a Sentinel Warning Valve, which is specifically designed to warn users of casing overpressure conditions in the field. The valve can be seen in Figure 4.9. It is the silver valve installed on the top of the turbine casing.

This sentinel valve's main function is to provide an early warning sound or visible steam release to warn the operator that the pressure inside the turbine casing is too high and that corrective action must be taken quickly. Remember that the sentinel valve is too small to provide enough pressure relief to reduce the casing pressure to safe conditions if the exhaust

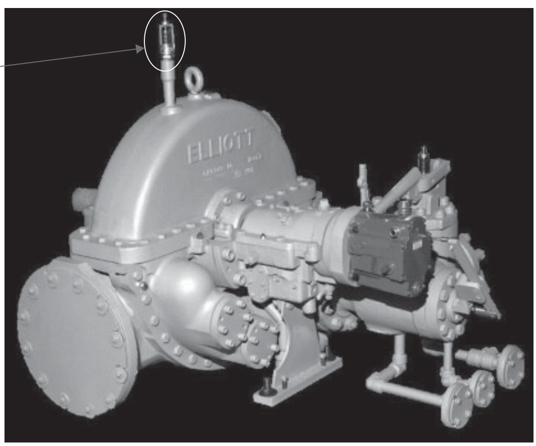


Figure 4.9 Steam turbine with a sentinel valve on top of the exhaust casing. (Courtesy of Elliott Group)

valve is closed. It is only there to provide an early warning signal in the event of a blocked-in exhaust condition. In the chapter on turbine start-up procedures (Chapter 7) it will be made clear that the operator should always open the exhaust valve on the turbine before opening the inlet steam valve. If the sentinel valve releases during start-up, it is necessary to take action quickly to trip the turbine, stopping the steam flow into the turbine.

Some end users have elected to remove these sentinel valves, so you may not see this valve on any of your turbine casings. Regardless of whether there is a sentinel valve or not, always confirm that there is a full flow relief valve between the turbine exhaust flange and the first block valve. If there is a full flow relief valve installed, then the turbine casing will be adequately protected from any overpressure situation. We recommend that each operator know all the details of these system before attempting to start-up the turbine.

As we have stated emphatically, there should always be a full flow relief valve installed between the turbine exhaust flange and first block valve in order to prevent an overpressure of the turbine casing and possible casing failure. Depending on the age of the turbine and facility you might have a different design or system arrangement. Therefore, the authors strongly recommend that operators know their specific turbine system so they have an understanding of the risk they are exposed to during start-up and operation.

4.6 Additional Advice

We want to reiterate the importance of learning as much as you can about your steam turbine's speed control system, overspeed trip system, and overpressure protection system. This knowledge will pay big dividends in the field during commissioning, start-ups, shutdowns, and troubleshooting efforts. In addition, operators should also learn the locations and functions of every block valve, drain valve, strainer, etc., around the steam turbines. Knowledge is a key to steam turbine operating success.

Questions

1. List three types of governors.

   a. ____________________________

   b. ____________________________

   c. ____________________________

2. What is the major difference between an electronic governor and a mechanical-hydraulic?

   a. ____________________________

3. List the four classes of governors and their maximum droop.

4. What is the only function of the overspeed trip system?

5. What protects the back pressure turbine from overpressuring in the casing?

Answers

1. List three types of governors.

   Mechanical governors, mechanical-hydraulic governors and electronic governors.

2. What is the single difference between an electronic governor and a mechanical-hydraulic?

   Electronic governors use magnetic speed tachometers to sense the turbine shaft speed.

3. List the four classes of governors and their maximum droop.

   A, B, C, & D. Maximum droop is 10%, 6%, 4% and 0.5%, respectively.

4. What is the only function of the overspeed trip system?

   Close the inlet steam valve when the turbine reaches the trip set point.

5. What protects the back pressure turbine from overpressuring in the casing?

   Full flow relief valve between the exhaust flange and first block valve.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

5

The Importance of Operating Procedures

The main goal of this book is to clearly explain the procedures that will ensure safe start-up and shut-down of steam turbine machine trains. There is always a right and wrong way to start up a process machine train. We all know that starting up a machine incorrectly can seriously damage a costly machine. In the following chapters, we will offer a series of operating procedures for steam turbines and steam turbine machine trains that cover common operational situations. Operating procedures provide a consistent basis for safely operating your equipment.

Start-ups and shutdowns must be performed under many different sets of circumstances. For example: In one situation, a start-up may be performed with a proven steam turbine under normal process conditions. Other times, a start-up may be a first time start-up of an unproven steam turbine and piping system. Similarly, shutdowns may be normal or may be rushed due to some type of operational emergency. In all of these situations, operations must have a set of procedures that guarantees these events are safe.

It is common to find a steam turbine in a process facility that is coupled to a centrifugal pump or compressor. In this type of machine train, both driver (steam turbine) and driven machine (centrifugal compressor or pump) operate at the same speed, unless there is a gear reducer required to drive the driven machine at a lower speed. In both cases, both machines in the train are either running or not running. When the steam turbine is brought up to minimum speed, the driven machine must operate at its minimum speed. Similarly, whenever the steam turbine is at full speed the driven machine must also be at its rated full speed. The operator must ask himself or herself before changing speed: Is the steam turbine and driven machine ready to operate at this new operating speed? For example: When bringing a steam turbine/pump train up to full speed it is necessary to ensure that the pump has sufficient suction head to prevent cavitation. (A pump suction head requirement is a function of speed and flow.) If there isn't sufficient suction head the pump will cavitate, vibrate, and possibly fail. This simple example illustrates that not only do we have to worry about damaging a steam turbine at start-up; we also have to worry about harming a compressor or centrifugal pump during start-ups.

5.1 Steam Turbine Start-up Risks

In the following chapters, we will describe how to start up and shut down general purpose steam turbines safely by taking prescribed steps based on proven best practices. By following the same steps, in the same order, every time a steam turbine is placed in service or taken out of service, operators can avoid the common pitfalls related to transient conditions. Just like piloting an airplane, where takeoffs and landings represent the highest risk events, start-ups and shutdowns represent the times of greatest risk to a steam turbine. High-risk times are periods when there is a realistic probability that an undesirable event can occur

An undesirable event is any situation fraught with risk. For example, driving over a pothole is an undesirable event because it can lead to anything from an irritating jolt to a bent wheel or front-end alignment issue. We cannot say for sure what will happen in all cases. The extent of the damage depends on the size and depth of the pothole and the speed of the car driving over it. We instinctively know we should avoid potholes because something bad can result from failing to do so.

Similarly, we know there are undesirable events we should always try to avoid around steam turbines. They include condensate carryover, piping strain, oil contamination, a lack of lubrication, and overspeed events. To truly appreciate the

Figure 5.1 Pothole.

importance of avoiding undesirable events, we will describe some of the potential issues that they can lead to:

1. Condensate carryover: This condition can greatly reduce the useful life of your turbine by rapidly eroding steam path components and reducing their overall efficiency.
2. Condensate slug: When a steam turbine is idle, condensate can build up in the inlet piping or casing if steam traps are not working or installed properly. Any sizable slug of condensate entering the steam turbine can knock out the thrust bearing, similar to hitting the rotor axially with a sledge hammer.
3. Casing distortion: Excessive piping loads or uneven casing heating can lead to casing distortion. There are numerous problems that this condition can result in, such as high vibration, internal rubbing, bearing failure, accelerated packing wear, etc.
4. Overspeed trip due to a malfunctioning governor: Any overspeed trip event has the possibility of leading to a full-blown rotor failure.
5. Lack of lubrication: Lubrication issues will lead to bearing failure and in some cases can result in major shaft damage.

6. Oil contamination: Water or solids in the lubricant will normally result in premature bearing failures. In the worst cases, shaft damage and even rotor damage can occur.

Steam turbines don't like transient conditions that expose them to high stresses, condensate carryover, and contamination. They like to operate at design temperatures, with clean lubrication, and at a constant, safe speed. We know from experience that to maximize steam turbine reliability we must avoid undesirable events mentioned here. The fewer the undesirable events to which we expose a steam turbine the fewer failures related to these conditions we can expect.

In general terms, to safely start up a steam turbine you must:

1. Completely warm up the steam turbine casing and associated piping.
2. Ensure that all condensate has been drained from the casing and inlet piping.
3. Check lubrication and sealing systems.
4. Bring the steam turbine up to minimum governor speed and hold the speed until the driven machine is ready for a process load.
5. Check the steam turbine and driven machine auxiliaries.
6. Once everything looks ready, you can increase speed.

5.2 Starting Centrifugal Pumps and Compressors

Whenever we have a steam turbine driving a centrifugal compressor and pumps, we must incorporate start-up and shutdown procedures that ensure low-stress start-ups for both the driver and driven machine. Just like steam turbines, centrifugal compressors and pumps can easily be damaged if care is not taken to minimize unwanted situations, such as cavitation, low flow- or high-flow conditions in pumps and surging or stonewall conditions in compressors.

Centrifugal pumps precautions: To operate centrifugal pumps reliably, they should only be operated liquid-full, properly lubricated, and close to their best efficiency point (BEP). Prior to start-up the following basic steps are normally required:

1. Fully open the suction and discharge valves

2. Completely vent the pump casing to ensure it is as vapor free
3. Ensure there is an adequate suction level
4. Ensure there is an adequate bearing lubrication level and/or pressure
5. Ensure the seal is properly vented and flushed
6. If there is not sufficient back pressure on the pump, you may need to pinch the pump's discharge valve to ensure the pump is operating close to its best efficiency point.

Centrifugal compressors precautions: To operate centrifugal compressors reliably, they should only be operated while properly lubricated, away from surge and away from stonewall. Prior to start-up the following basic steps are normally required:

1. Fully open the suction and discharge valves
2. Ensure the compressor casing is liquid free
3. Ensure that the compressor suction or surge vessel has no or a low liquid level and is fully operational so that there is no chance of liquid ingestion into the compressor
4. Ensure the surge protection system is fully operational

5. Ensure there is an adequate bearing lubrication level and/or pressure
6. Ensure the sealing system is operational
7. If there is not sufficient back pressure on the compressor, you may need to pinch the compressor's discharge valve to ensure it doesn't experience flow past the right side of its performance curve.

5.3 Steam Turbine Train Procedures

As a starting point, we have provided a basis for steam turbine and steam turbine train operating procedures. Special steam turbine situations are covered in the following chapters.

1. Chapter 6: "Overspeed Trip Testing": Overspeed trip testing is a high-risk procedure that is inherently dangerous. Any error in controlling the turbine speed could result in a serious mechanical failure or injury to operating personnel.
2. Chapter 7: "Centrifugal Pump and Centrifugal Compressor Start-ups with a Steam Turbine Driver": Starting up a steam turbine that is coupled to centrifugal pumps or centrifugal compressors is one of the most complex procedures operators will ever have to follow. These start-ups involve controlling steam

energy, thermal energy, fluid energy, and rotation energy within certain prescribed limits throughout a specific sequence of events in order to limit the risk of product releases or mechanical failures.

3. Chapter 8: "Centrifugal Pump and Centrifugal Compressor Shutdowns with a Steam Turbine Driver": Shutting down a steam turbine that is driving a centrifugal pump or compressor seems to be an innocuous endeavor on the surface. However, during shutdowns there are risks lurking just below the surface.
4. Chapter 9: "Installation, Commissioning and First Solo Run": The goal of this section is to provide operators with a general overview of items that need to be reviewed and witnessed during the equipment installation, commissioning and eventual start-up of a new steam turbine. The best practices provided have proven over time to result in years of successful long-term mechanical reliability.
5. Chapter 10: "Reinstating Steam Turbine after Maintenance": There are a number of potential problems that may be encountered when starting up a steam turbine after a major steam turbine repair. Extra care must be taken to break in packing, watch for high vibration levels and bearing temperatures, speed control problems, etc.

Your ultimate goal should be to take these procedures and customize them so that they cover your specific needs. Every rotating equipment train is unique and therefore requires a tailored procedure to cover special start-up and shutdown requirements. The less that is left to chance the less likely you will be met with a surprise. When it comes to procedures, details matter.

5.4 Training Options

We hope we have made a strong case for the importance of rotating equipment procedures for operators. To ensure that a culture of sound operator procedures takes hold in your facility, there must be 1) formal written procedures in place, 2) training in required procedures, and 3) continued practice of the procedures in a field setting.

Once your organization decides that training makes economic sense, here are some ways to train your operators:

- **Formal training in a classroom setting.** You can bring in a consulting firm to provide operators with classroom training composed of theory, proven reliability methods, and hands-on demonstrations. Self-paced training, either online or with study guides, is another proven option. There is a full array of self-directed training to be found on the web. Formal training should probably be provided every five years to ensure exposure to new technology and concepts.
- **Refreshers provided in-house.** You can also enlist the assistance of in-house machinery engineers or technicians for basic refresher training. This type of training should be provided every other year to ensure ongoing technical competence.
- **Hands-on "practicals"**. Senior operators can watch and evaluate junior operators as they start up process machine trains. Yearly "practicals" and field demonstrations should be encouraged.
- **Frequent reading of technical journals or textbooks**. This type of training should be provided to your operators on a continuous basis. Ensure there are enough copies

of current journals and textbooks that cover rotating equipment topics in your shops and control rooms for all to peruse.

- **Operator Certifications.** It makes good sense to ensure your training dollars are justified by requiring operators to prove they have learned and retained the key points of reliable rotating equipment operation. We recommend that certifications be required every five years or after new hires have completed their initial training. Ideally, certifications should be comprised of a series of questions covering theory and practice, as well as field exercises requiring that the candidates demonstrate detailed knowledge of their equipment and how to operate them reliably.

Remember that operators are the hands, eyes, ears, and noses of your processes. They are vital to your overall success. It's your choice; either prepare them for operating success or set them up for certain failure. Training is one of the most inexpensive means to improving your process reliability.

Questions

1. List three (3) undesirable events that can damage a steam turbine.

2. List the six (6) steps to ensure a reliable centrifugal pump start-up.

3. List the five (5) steps to ensure a reliable centrifugal compressor start-up.

4. To ensure a culture of sound operator procedures take hold in your facility, there must be:
   1) ______________________________,
   2) ______________________________, and
   3) ______________________________.

5. List five (5) training options.

Answers

1. List three (3) undesirable events that can damage a steam turbine.

   a. Condensate carryover

   b. Condensate slug

   c. Casing distortion

   d. Overspeed trip due to a malfunctioning governor

   e. Lack of lubrication

   f. Oil contamination

2. List the six (6) steps to ensure a reliable centrifugal pump start-up.

   a. Fully open the suction and discharge valves

   b. Completely vent the pump casing to ensure it is as free

c. Ensure there is an adequate suction level

d. Ensure there is an adequate bearing lubrication level and or pressure

e. Ensure the seal is properly vented and flushed

f. If there is not sufficient back pressure on the pump, you may need to pinch the pump's discharge valve to ensure the pump is operating close to its best efficiency point.

3. List the five (5) steps to ensure a reliable centrifugal compressor start-up.

   a. Fully open the suction and discharge valves

   b. Ensure the surge protection system is fully operational

   c. Ensure there is an adequate bearing lubrication level and or pressure

   d. Ensure the sealing system is operational

   e. If there is not sufficient back pressure on the compressor, you may need to pinch the compressor's discharge valve to ensure it doesn't experience flow past the right side of its performance curve.

4. To ensure a culture of sound operator procedures takes hold in your facility, there must be:

   1. Formal written procedures,

   2. Some type of training covering your procedures, and

3. Continued practice of the procedures in a field setting.

5. List five (5) training options.

   a. Formal training in a classroom setting.

   b. Refreshers provided in-house

   c. Hands-on "practicals"

   d. Frequent reading of technical journals or textbooks

   e. Operator certifications

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

6

Overspeed Trip Testing

Overspeed trip testing is a high-risk procedure that is inherently dangerous (see "Caution" below). Since we will be operating the turbine up to its trip speed during the following procedure, it is imperative that every step be followed to the letter. Any error in controlling the turbine speed could result in a serious mechanical failure or injury to operating personnel.

Caution:

An overspeed failure on a steam turbine is one of the most frightening industrial accidents encountered in industry. The results of such a failure are always very costly and can be fatal to personnel in the area at the time of failure. If the rotational speed of the turbine exceeds the rotor's safe operating limits due to a loss of speed control, the main shaft and wheels can be pulled apart by centrifugal force. In the worst cases seen in industry, the disintegrating parts penetrated the turbine housing and threw high-velocity pieces of metal in all directions.

The authors want to make it clear that all users need to read, understand and follow the manufacturer's recommendations for overspeed trip testing before attempting any overspeed trip testing. Discuss the procedure with the manufacturer if you have any questions. The procedure presented below should be viewed as additional safety recommendations which may be added to the manufacturer's procedure to perform a safe overspeed trip test. This procedure must only be performed by trained personnel and in accordance with the manufacturer's recommendations.

There are several definitions which we must understand before we start the procedure. The definitions are similar to the definitions in American Petroleum Institute (API) 611 and 612 documents.

The turbine **"maximum allowable speed"** (in revolutions per minute) is defined as: The highest speed at which the manufacturer's design will permit continuous operation. This is a limit put on the turbine speed by the manufacturer. Think of this as the mechanical limit of the turbine itself.

The turbine **"maximum continuous speed"** (in revolutions per minute): The speed at least equal to 105 percent of the highest speed required by any of the specified operating conditions. It is the highest speed for continuous operation which will satisfy the process conditions on the driven equipment, pump or compressor.

The trip speed (in revolutions per minute): The speed at which the independent emergency overspeed device operates to shut down the turbine. This is the speed at which the trip valve should actuate and prevent steam from entering the turbine.

Trip & Throttle Valve, also called T&T valve: A valve that not only stops the flow of steam, but also provides throttling for manual operation and speed control on a steam turbine.

Trip Valve: The valve that stops the flow of steam, fuel, or process fluid. This valve is either open or closed; it should not be throttled.

The only way to test an overspeed trip system is to perform a functional test by actually operating the steam turbine up to the **trip speed** to confirm that the mechanical safety trip system will actually stop the turbine rotor if the trip speed is reached—irrespective of circumstances.

6.1 Overspeed Trip Pre-test Checks

1. Make sure the area around turbine and shutdown valve is clear of obstructions and is accessible for the testing activates.
2. Only personnel involved in the testing should be in the area around the turbine and shutdown valves. If possible, personnel should stand at the turbine governor end during the test. Do NOT stand by the coupling end of the turbine during the test.
3. Under no circumstance should the rotor speed exceed the "Maximum Allowable Speed". If this happens, immediately shut down the turbine and perform an internal inspection of rotor for possible damage and loose interference fits.
4. A minimum of two independent speed indications must be used and cross checked to confirm they are reading the same RPM. This must be done with the turbine at low speed before the test is started. If speed indicators are not reading the same rpm, then stop the test and resolve this discrepancy between speed indications immediately. Do not proceed with the testing until both speed indicators are reading the same speed (rpm).

5. Reconfirm that all participants know what the trip speed is and what the Maximum Allowable Speed is from the manufacturer.
6. All participants must know:
   a. What will happen if the trip system does not work properly?
   b. What action each person will take to stop the steam from entering the turbine if the test is aborted.
   c. How the turbine will be tripped and by whom.

   All these details must be in the plan before the test is started.
7. Confirm that the driven equipment is uncoupled from the steam turbine.
8. Confirm that the speed governor is able to reach the overspeed trip setting. If the governor is unable to reach the overspeed trip speed, then the governor will have to be modified to achieve trip speed.
9. It is critical to understand that the Uncoupled Steam Turbine Overspeed trip test requires approximately 1 to 5% of the turbine's available power. Therefore very small changes in the inlet steam valve may cause very quick speed changes. Therefore, all speed increase must be done very slowly while observing the speed change. The uncoupled overspeed trip test is the highest risk procedure that can be done to any rotating

equipment. This is inherently a high-risk procedure and deserves all participants' undivided attention.

6.2 *Uncoupled* Overspeed Trip Test Procedure

Note: The valves referred to in this procedure are shown in Figure 6.1.

1. You must never lose control of the turbine speed during any part of this test. Always be in control of the steam inlet to the turbine.
2. Confirm that the trip and throttle valve will close quickly and not hang up when activated. While the turbine is at 0 rpm

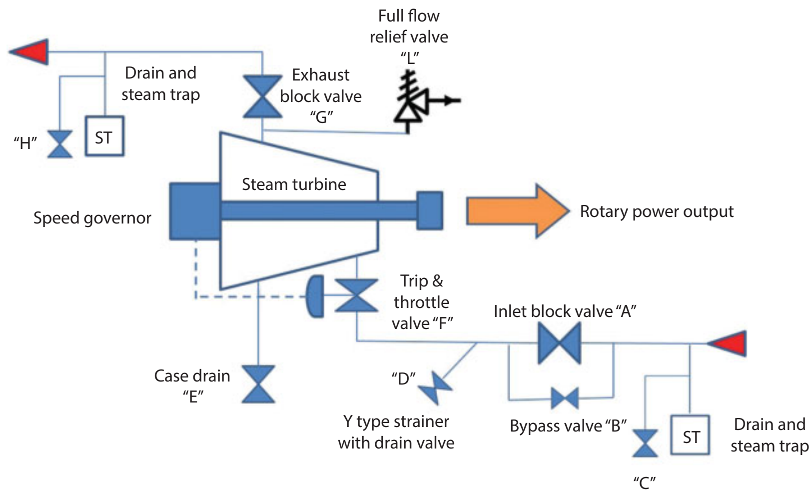


Figure 6.1 Steam turbine piping schematic.

and inlet steam valves are closed, manually reset the trip and throttle valve by raising the resetting lever arm until the knife edge is resting on the hand trip lever. Now manually trip the T&T valve by pulling on the hand trip lever arm until the resetting lever arm slides off the knife edge closing the trip valve. The valve should close quickly (less than 1.0 second) and without any hang-up during closing. If you can see the valve closing, it is too slow. Repair before proceeding with the test.

3. Now confirm both speed sensing devices are connected and are completely independent. The speed sensor can be digital tachometer, photo tachometer, magnetic speed sensor or keyphasor. The most important item is to make sure the two sensors read the same rpm at low speeds.
4. Reset the minimum governor speed lower by several hundred rpm. This will give you some margin since there will be no load on the turbine and small steam valve changes will result in large speed changes. For mechanical hydraulic governors you will need to turn the speed adjusting screw on the back of the governor to lower the speed set point. This will lower the minimum governor speed for the uncoupled test.
5. Confirm that the steam is dry up to the steam turbine inlet flange; this may

require cracking open the steam inlet header drain valve "C" to allow steam to flow, then close.
6. Confirm all liquids are drained from the turbine casing, open drain valve to confirm. Valves "E" and "D". Then close.
7. Open drain valve "H", confirm liquids are drained then close. Confirm the exhaust valve "G" is fully open.
8. Now open the trip and throttle valve "F" by latching the resetting lever arm on the knife edge of the hand trip lever. Slowly open the bypass valve "B" to allow dry steam into the turbine and allow the turbine to start turning. After the turbine starts to rotate, stop opening the bypass valve "B" and reconfirm that the speed sensors are in agreement. If they are in agreement then slowly open the bypass valve until the turbine is operating at its new lower minimum governor speed. Continue to fully open bypass valve "B" in ¼ turn increments while constantly monitoring the turbine speed. It is very important to make the valve position changes slowly and reconfirm speed with each move. When the governor valve is in control of the speed, opening the bypass valve "B" further will not increase the turbine speed.
9. Now with the bypass valve fully opened and governor in control of the speed slowly increase the turbine speed by

adjusting the governor speed setting. On mechanical hydraulic governors this will be a screw on the end of the governor (Figure 4.3 & 4.4). Note: On electronic governors this might be a speed adjustment on a local control panel or in the control room. No matter what system you are working with continue to increase the turbine speed. On each speed increase, RECONFIRM speed sensors are in agreement; if not, trip the turbine immediately. It is important to note that the person making the speed adjustments sees the speed sensor readouts or have constant updates via radio.

10. Very slowly increase the turbine speed with the governor speed adjustment until the trip speed is reached. Under no circumstances should you allow the speed to reach or go above the MAXIMUM ALLOWABLE SPEED. If the turbine does not trip before you get to this speed manually trip the turbine and allow it to stop completely. Then adjust the trip mechanism per the manufacturer's recommendations (Figure 4.6 & 4.7). If it does not trip then this is a failed attempt and must be documented for evaluation of future test interval changes.
11. For a successful trip you will need to document the RPM at which the turbine tripped.

12. Close the inlet steam valve bypass valve "B" so no steam pressure is on the trip and throttle valve.
13. Return the governor speed adjustment screw back to the new lower speed setting.
14. Reset the overspeed trip lever arm so the knife edge is resting on the trip lever.
15. Now repeat these steps 4 through 12 three times, recording the trip speed for each overspeed trip test.
16. After three successful trip tests, which meet the acceptance criteria below, you are ready to reinstall the coupling to the driven equipment. Once the equipment is returned to service you need to confirm that the governor speed setting is correct after the driven equipment is under full load. There will most likely need to be some adjustment to the speed setting on the governor.

6.3 Acceptance Criteria for Overspeed Trip Test

1. In order to perform an acceptable overspeed trip test, there must be at least three separate successful trips documented by those performing the testing. The actual trip speed target and tolerance used can depend on many factors, such as the class

of machine the steam turbine is driving, the governor class being used, and the manufacturer's design calculations. We will provide the users with advice on setting trips.

> "No single standard for trip tolerance exists. The total system is not designed for greater accuracy than the repeatability of the trip sensing weight. One source, API 617 (Centrifugal Compressors for Petroleum, Chemical and Gas Service industries, Sixth Edition) calls for the trip speeds of 115 percent of rated speed for the compressor drive, which is 110% of the maximum continuous speed. Tolerance is not clearly explained. Using the ±2 tolerance of the pin type overspeed trips gives ranges as shown in Table 6.1." (Ed Nelson and Perry Monroe, 26th Turbomachinery Symposium)

Table 6.1 Overspeed trip speed tolerances.

Operating speed (rpm)	Trip speed (rpm)	Speed tolerance (rpm)
3600	3960	±70
6000	6600	±120
9000	9900	±180

> The API-612 Special Purpose Steam Turbines specification recommends that overspeed test have a tolerance of ±1%.

The point here is that only the manufacturer will know what trip speed makes sense for an entire machine train and what trip tolerance applies for the speed control system being used. If you cannot locate the manufacturer's trip speed and tolerance information in the machine files, give them a call; never guess or use a rule of thumb that may not apply to your specific machine.

2. Before going to the field, the authors recommend you prepare a data collection sheet containing the manufacturer's recommended trip speed and trip tolerance in tabular form as shown in Table 6.2. After each trip event, check to see that the

Table 6.2 Example data from an overspeed trip test.

Trial number	Target trip speed (rpm)	Actual trip speed (rpm)	Deviation (rpm)	Speed deviation	Speed tolerance
1	4500	4480	–20	–0.44%	±2%
2	4500	4510	+10	+0.33%	±2%
3	4500	4505	+5	+0.111%	±2%

deviation value is within the trip tolerance, as shown in Table 6.2.

3. Trip speeds should be consistent and not trending in any one direction for all three tests. (The recorded readings in Table 6.2 do not appear to show any signs of drifting.)
4. Trending of the trip speeds can be reason for concern and should be investigated in more detail if each trip is consistently increasing or decreasing.
5. If the trip test fails to meet the above requirement then the testing intervals must be reduced.

Questions

1. How much of the available turbine power is required for an uncoupled overspeed trip test?
2. How many times should the overspeed trip test be done?
3. What is the overspeed trip test tolerance recommended by API 612 for "Special Purpose Steam Turbines"? What is your plant's trip tolerance?
4. At what point in the trip test procedure is the trip valve first tripped?
5. What happens if the trip test fails to meet the acceptance criteria?

Answers

1. How much of the available turbine power is required for an uncoupled overspeed trip test?

   1 to 5% of available turbine power.

2. How many times should the overspeed trip test be done?

   Three

3. What is the overspeed trip test tolerance recommended by API 612 for "Special Purpose Steam Turbines"? What is your plant's trip tolerance?

   API 612 recommends ±1%. Unknown to the authors but should be known to the plant operators.

4. At what point in the trip test procedure is the trip valve first tripped?

   Trip should be tested before any valves are opened.

5. What happens if the trip test fails to meet the acceptance criteria?

   The trip tests intervals must be reduced.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

7

Centrifugal Pump and Centrifugal Compressor Start-ups with a Steam Turbine Driver

Starting up a steam turbine that is coupled to centrifugal pumps or centrifugal compressors is one of the most complex procedures operators will ever have to follow. These start-ups involve controlling steam energy, thermal energy, fluid energy, and rotation energy within certain prescribed limits throughout a specific sequence of events in order to limit the risk of product releases or mechanical failures.

If flows are not properly controlled on the driven machine, a multitude of problems can be experienced. Here are two examples of flow-related problems: High uncontrolled flow on a pump can lead to cavitation and the inability to reach rated speed. Low flow on a centrifugal compressor could lead to a surge condition.

Successful completion of these procedures requires operators to understand:

1. The steam turbine piping arrangement
2. The steam turbine's design conditions
3. The driven machine's:
   a. Piping arrangement
   b. Fluid properties
   c. Supply conditions
   d. Process requirements
4. The driven machine's control systems, such as flow controls, spillbacks, surge control systems, etc.

A start-up must be considered a coordinated effort requiring multiple steps to bring the pump or compressor into service under the desired process conditions.

The following comprehensive procedure for starting up a centrifugal pump or compressor train represents the lowest risk method, based on the authors' experience. Not following the recommended start-up procedures precisely can result in abnormal mechanical stresses, temperatures, and vibration conditions capable of causing premature failures. These procedures should be augmented with the manufacturer's recommendations and the process facilities experiences.

7.1 Centrifugal Pump and Steam Turbine Start-up

Note: All valves referenced in the following procedure are identified in Figure 7.1

1. Communicate with all involved personnel and discuss what role they will have during the start-up.
2. Prior to the start-up, remove any tripping hazards or other safety concerns from the general location. Make sure personnel in the area are aware the turbine will be starting.

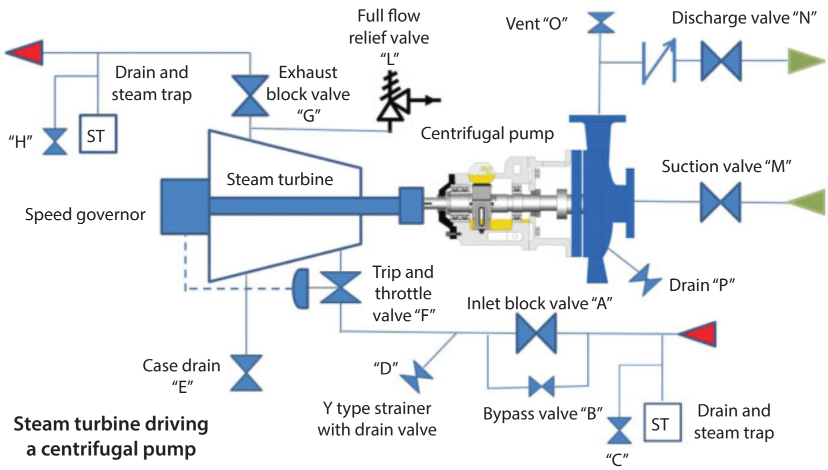


Figure 7.1 Typical steam turbine and centrifugal pump train.

3. Start the lube oil system, if applicable. Remember smaller general purpose turbines driving centrifugal pumps may have an oil bath lubrication system, so confirm that there is oil in the sight glass or that the oil sight glass reservoir is at the proper level for the pump and turbine. Confirm the lube oil cooling system is operating properly if supplied. If the pump has water cooled housings or bearings make sure the coolant is flowing normally.
4. Confirm that inlet, exhaust and drain valves are <u>ALL</u> closed. This line-up configuration is the first step in each start-up; all turbine valves should be closed.

5. Manually trip the overspeed system to confirm the trip mechanism will close the inlet valve if required. The trip mechanism should close smoothly and very fast (typically in less than 1 second). If it doesn't close properly, repair it before proceeding. It is critical to confirm that the trip system is functional before allowing any steam into the turbine. After confirming the trip system is functional and operates correctly, reset the trip system to open the trip valve "F".
6. Before beginning to line up the pump, first check that there is a correct liquid level in the supply vessel, tank, or sump. Confirm that the pump mechanical seal system is operational. There are many different sealing arrangements, so make sure you are aware of the details for the pump you are starting. If the sealing system has a water cooler, confirm that the cooler is operational. If the seal system uses flow from the pump discharge make sure all valves in this line are open.
7. Open the vent valve labeled "O".
8. Then, open the centrifugal pump suction valve labeled "M".
9. Once the suction valve is opened and a continuous stream of liquid comes from the vent valve it is time to close the vent valve "O". Caution: If this product is

hazardous the vent valve should drain into a closed system with a sight glass otherwise you may need to keep the vent valve open for several minutes after the suction valve is opened before closing to confirm the pump casing is vapor free.

10. Confirm that there are no leaks from the mechanical seal area, now that you have suction pressure on the mechanical seals.
11. Open the steam turbine case drains to drain condensate out of the turbine casing. The case drain valve is labeled "E".
12. Partially open the drain valve labeled "C". This will start steam flowing in the header and warm up the inlet system to the drain. When this valve is partially opened, steam and condensate will exit this valve from the steam header. It is important to allow the steam condensate to fully drain before proceeding to the next step. You can tell it is time to close valve "C" when you no longer see condensate coming from the valve and only see dry steam exiting the drain valve. Confirm drain valve "C" is closed.
13. Partially open the exhaust steam drain valve labeled "H". Once the condensate has drained out of the system, the exhaust line is warm, and condensate

cannot be seen coming from the valve, you are now ready to close the valve labeled “H”. Confirm drain valve “H” is closed.

14. Reconfirm casing drain “E” is partially open.
15. Partially open drain valve “D”.
16. Slowly start opening the exhaust block valve labeled “G” until you see steam flowing from the casing drain valves “E” and “D”. This will put exhaust pressure steam flowing in the turbine casing and exiting from the drain valves “E” and “D”. You will hear and see increased steam flowing from these valves when there is exhaust pressure inside the casing.
17. Once you see dry steam coming from the drain valves “E” & “D” it is time to close both of these drain valves.
18. Now fully open the exhaust block valve “G”. It is important that this valve is fully open before moving to the next step. This step is critical before opening any inlet valves because the turbine casing pressure is only rated for turbine exhaust pressures. The “full flow relief valve labeled “L” is installed to prevent accidentally over pressuring the turbine casing during start-ups and shutdowns. It should be confirmed that the relief valve “L” is

installed. NEVER open the inlet steam valve until the exhaust is fully opened. If for some reason the sentinel valve lifts or relieves steam you have made a mistake and you must stop the inlet steam to the turbine immediately. It should be noted that some users choose not to install sentinel valves so be aware of your specific turbine system before executing this start-up procedure.

19. Partially open the pump discharge valve labeled "N". Open the valve approximately ¼ open and see if the pump and turbine are turning backwards. If they are rotating backwards, then the check valve is leaking and should be repaired. If the shaft is not turning backwards then continue to fully open the discharge valve labeled "N". (Note: If initially there is no or low pressure in the pump discharge header, you will need to keep the pump discharge valve pinched, i.e., 1/4 open, to avoid a condition called runout. Runout is a condition when a pump operates at the end of its curve due to low or no back pressure, which results in a maximum horsepower draw. As pressure builds up in the discharge line, you can gradually open the pump discharge valve until it is fully open.)

20. Now with exhaust valve "G" fully opened, all drain valves closed, the trip valve and governor valves fully opened, the pump vent valve is closed, the pump suction and discharge valves opened. It is time to slowly open the steam turbine main inlet block valve "A". (**Note**: Before opening the main inlet steam valve, refer to the "additional start-up notes" below to see if any additional precautions may be required.) It is critical that you slowly open the block valve no more than ½ turn at a time. Continue to open the valve in ½ turn increments until you see the turbine start to rotate. Once the rotor starts to turn, open the inlet valve in ¼ turn increments and monitor the turbine speed continuously. Continue to open by ¼ turn increments until the governor takes control of the turbine speed. You will know the governor is in control when the operating speed is reached and further opening of the inlet valve "A" does not result in an increase in turbine speed (rpm). For larger steam turbines, you might need to hold at a slow roll speed, per step no. 21.
21. **Additional Start-up Notes**:
    a. For larger turbines (greater than 3000HP), you will typically slow roll

the turbine from 500 to 1000 rpm until the casing and rotor temperatures are stable before attempting to bring it up to full operating speed. The exact intermediate holding speeds are dependent on the critical speeds of the turbine rotor.

b. Never operate close to any known critical speeds for any length of time.

c. On smaller turbines that are controlled by typical TG (Mechanical-Hydraulic) governors, the speed will move directly to full speed or governor speed set-point.

22. After the governor takes control of the turbine speed, you are now ready to fully open the inlet block valve "A". Continue to open the inlet block valve in ½ turn increments and reconfirm there is no increase in turbine speed until the valve is fully opened.
23. Confirm the pump speed is steady, discharge pressure is correct, seals are not leaking and oil levels are correct. Make notes of any abnormal vibration, noise or excessive steam leakage before leaving the area.
24. Notify all personnel that the pump is now online in operation.

7.2 Centrifugal Compressor and Steam Turbine Start-up

Note: All valves referenced in the following procedure are identified in Figure 7.2.

1. Communicate with all involved personnel and discuss what role they have during the start-up.
2. Prior to the start-up, remove any tripping hazards or other safety concerns from the general location. Make sure personnel in the area are aware that the turbine and compressor will be starting.
3. Start the lube oil system, if applicable. Remember smaller general purpose turbines driving a centrifugal compressor may have an oil bath lubrication system, so confirm that there is oil in the sight glass or that the oil sight glass reservoir is at the proper level for the compressor and turbine. Confirm the lube oil cooling system is operating properly.
4. Confirm that steam turbine inlet, exhaust and drain valves are ALL closed. This line-up configuration is the starting point of each start-up; all turbine valves should be closed.

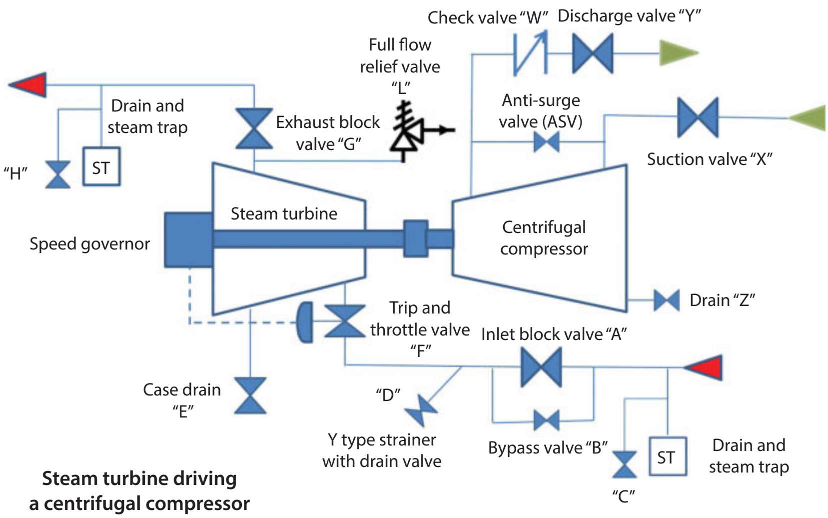


Figure 7.2 Typical steam turbine and centrifugal compressor train.

5. Manually trip the overspeed system to confirm the overspeed trip system mechanism will close the inlet valve if required. The trip mechanism should close smoothly and very fast (typically in less than 1 second). If it doesn't close properly, repair it before proceeding. It is critical to confirm that the trip system is functional before allowing any steam into the turbine. After confirming the trip system is functional and operates correctly, reset the trip system, which will open the trip valve "F".
6. Open the centrifugal compressor case drains labeled "Z". This will drain any

liquid which may have condensed out and then accumulated in the casing during shutdown. Once the liquids are drained from the casing, close the drain valve "Z". This may be done on a time basis or through a sight glass in the drain system. It must be confirmed that there are no liquids present in the compressor casing, as their presence can cause major damage to the compressor and its seals. If the process fluid is hazardous then this drain system must be a closed system.

7. There are many different sealing arrangements for compressors so make sure you are aware of the details for the specific compressor you are starting. If the sealing system has a cooler, confirm that the cooler is operational. Now confirm that the compressor mechanical or dry gas seal system has the correct configuration to start up the compressor. All valves, filters, and coolers must be lined up correctly and ready for operation.
8. Open the centrifugal compressor suction valve labeled "X".
9. Confirm that there are no leaks from the mechanical or dry gas seal area, now that you have suction pressure on the mechanical or dry gas seals. For dry gas seal

systems, check the primary leakage rate or pressure to confirm that the system is working properly.

10. Confirm that the anti-surge valve is fully opened, labeled "ASV". This valve must be opened to give the compressor discharge gas a path back to the suction of the compressor and prevent surging during start-up. Once this compressor is up to speed then this valve will slowly close to force gas through the discharge valve "Y". Most centrifugal compressors have a special control program or system which controls this anti-surge valve; therefore it is not something the operator has to manually open or close. However, the operator must understand what position the valve needs to be in for a compressor start-up.
11. Open the steam turbine case drains to drain condensate out of the turbine casing. The case drain valve is labeled "E".
12. Partially open the drain valve labeled "C". This will start steam flowing in the header and warm up the inlet system to the drain. When this valve is opened, steam and condensate will exit this valve from the steam header. It is important to allow the steam condensate to fully drain before proceeding to the next step. You can tell

it is time to close valve "C" when you no longer see condensate coming from the valve and only see dry steam exiting the drain valve. Confirm drain valve "C" is closed.

13. Partially open the exhaust steam drain valve labeled "H". Once the condensate has drained out of the system, the exhaust line is warm, and condensate cannot be seen coming from the valve, you are now ready to close the valve labeled "H". Confirm drain valve "H" is closed.
14. Reconfirm casing drain "E" is partially open.
15. Partially open drain valve "D".
16. Slowly start opening the exhaust block valve labeled "G" until you see steam flowing from the casing drain valves "E" and "D". This will put exhaust pressure steam flowing in the turbine casing and exiting from the drain valves "E" and "D". You will hear and see increased steam flowing from these valves when there is exhaust pressure inside the casing.
17. Once you see dry steam coming from the drain valves "E" & "D", it is time to close both of these drain valves.
18. Now fully open the exhaust block valve "G". It is important that this valve is fully open before moving to the next step. This

step is critical and needs to be done before opening any inlet valves because the turbine casing pressure is only rated for turbine exhaust pressures. The full flow relief valve labeled "L" is installed to prevent accidentally overpressuring the turbine casing during start-ups and shutdowns. NEVER open the inlet steam valve until the exhaust is fully opened. If the sentinel valve lifts or relieves you have made a mistake and you must stop the inlet steam to the turbine immediately. It should be noted that some users choose not to install sentinel valves so be aware of your specific turbine system before executing this start-up procedure.

19. Now with exhaust valve "G" fully opened, all drain valves closed, the trip valve and governor valves fully opened, the compressor suction valve and anti-surge valve fully open it is time to slowly open the main steam inlet block valve labeled "A". (**Note**: Before opening the main inlet steam valve, refer to the "additional start-up notes" below to see if any additional precautions may be required.) It is critical that you slowly open the block valve no more than ½ turn at a time. Continue to open the valve in ½ turn increments until you see the turbine start to rotate. Once

the rotor starts to turn, open the inlet valve in ¼ turn increments at a time and check the turbine speed (rpm) and monitor the turbine speed continuously. Continue to open by ¼ turn increments until the governor takes control of the turbine speed. You will know the governor is in control when the operating speed is reached and further opening of the inlet valve "A" does not result in an increase in turbine speed (rpm).

20. **Additional Start-up Notes**:
    a. For larger turbines (greater than 3000HP), you will typically slow roll the turbine from 500 to 1000 rpm until the casing and rotor temperatures are stable before attempting to bring it up to full operating speed. The exact intermediate holding speeds are dependent on the critical speeds of the turbine rotor.
    b. Never operate close to any known critical speeds for any length of time.
    c. On smaller turbines that are controlled by typical TG (mechanical-hydraulic) governors, the speed will move directly to full speed. These governors are set at the factory and may be adjusted in the field via the speed screw on the governor.

d. During the slow roll sequence, the compressor will have the "ASV" fully opened and gas will be recycling from the compressor discharge thru the "ASV" back to the suction of the compressor. Gas will be going in a circle from discharge back to suction.

21. After the governor takes control of the turbine speed, you are now ready to fully open the inlet block valve "A". Continue to open the inlet block valve in ¼ turn increments and reconfirm there is no increase in turbine speed until the valve is fully opened.
22. Now after the turbine is up to full speed and inlet steam valve "A" is fully opened, it is time to open the compressor discharge valve "Y". Start opening the "Y" discharge valve slowly in ½ turn increments to confirm that the compressor discharge pressure does not change during the valve opening. If the discharge pressure changes suddenly, then the check valve "W" is leaking and needs to be repaired. Continue to open the discharge valve until it is fully opened. Now the compressor suction valve is fully opened "X", anti-surge valve "ASV" is fully opened, the discharge valve "Y" is fully opened, and the compressor is at

full operating speed, it is time to slowly close the ASV. Closing the ASV will increase the compressor discharge pressure. As the compressor discharge pressure rises, there will come a time when the pressure upstream of the check valve is greater than the pressure downstream of the check valve "W". When the compressor discharge pressure exceeds the pressure downstream of the check valve. The check valve will open and process gas will start flowing into the process. Once the check valve is opened, process gas will begin moving forward and the ASV will continue to close until all the gas flow is forced through the compressor discharge and into the process. It should be noted that most anti-surge valve control systems will not allow the ASV to fully close if its closing would force the compressor into a surge condition.

23. Confirm the centrifugal compressor discharge pressure is correct, no seal leakage is present, and oil levels are correct. Make notes of any abnormal vibration, noise or excessive steam leakage before leaving the area.
24. Notify all personnel that the compressor is now online in operation.

Questions

1. When starting a steam turbine and centrifugal pump at what point is the pump suction valve opened?
2. When the pump discharge valve is opened and you see the pump turning backwards what does that tell you about the condition of the check valve?
3. What position should the anti-surge valve (ASV) be in when starting a centrifugal compressor?
4. When starting a centrifugal compressor when do you open the compressor discharge valve?
5. What is the last step after starting either a centrifugal pump or centrifugal compressor?

Answers

1. When starting a steam turbine and centrifugal pump at what point is the pump suction valve opened?

   Open suction valve labeled "M" after opening vent valve.

2. When the pump discharge valve is opened and you see the pump turning backwards what does that tell you about the condition of the check valve?

The check valve is leaking.

3. What position should the anti-surge valve (ASV) be in when starting a centrifugal compressor?

   The anti-surge valve (ASV) should be 100% open.

4. When starting a centrifugal compressor when do you open the compressor discharge valve?

   After the compressor and turbine are up to full speed.

5. What is the last step after starting either a centrifugal pump or centrifugal compressor?

   Notify all personnel that the pump or compressor is online and operating.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

8

Centrifugal Pump and Centrifugal Compressor Shutdowns with a Steam Turbine Driver

Shutting down a steam turbine that is driving a centrifugal pump or compressor seems to be an innocuous endeavor on the surface. However, during shutdowns there are risks lurking just below the surface. For example, dropping the load on a pump or compressor too quickly may result in overspeeding the steam turbine driver and possibly causing a trip. Never think of the trip mechanism as a control device; it is the last layer of protection.

An operating process train must be viewed with respect to avoid the risk of running the turbine or driven machine at an undesirable condition for too long, overheating the bearing by removing cooling too soon, or blocking in the steam turbine exhaust too soon, etc.

Similar to the recommendations made above, the operator should have a good knowledge of the pump or compressor piping and how it fits into the process. The operator should be aware of the current status of the process and what risks may be present. A shutdown should be a coordinated effort with other steps in the overall shutdown process.

The following comprehensive procedure for shutting down centrifugal pump or compressor trains represents the lowest risk method based on the authors' experience. Every step in the following procedures has a purpose and should be followed. These procedures should be augmented with the manufacturer's recommendations and the process facilities experiences.

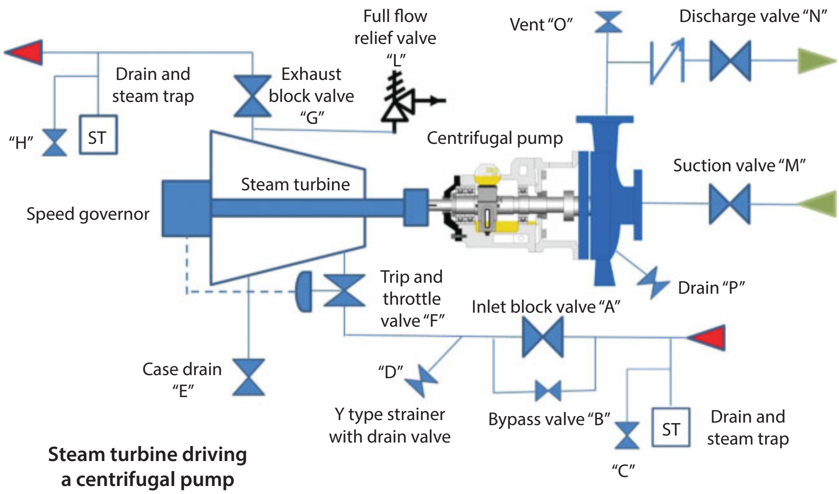


Figure 8.1 Typical steam turbine and centrifugal pump train.

8.1 Centrifugal Pump Steam Turbine Shutdown

Note: All valves referenced in the following procedure are identified in Figure 8.1.

1. Communicate with all involved personnel and discuss what role they will have during shutdown.
2. Make sure all personnel in affected area are aware the turbine and centrifugal pump are being shut down.
3. Confirm that the valves on the driven equipment are in the correct position before shutdown. Typically, centrifugal pumps will have a check valve between the discharge block valves to prevent reverse

flow on shutdown. Note: Be ready to manually close a pump's discharge valve if you suspect the check valve has failed or if you see the pump rotating backwards.

4. First, reduce the speed of the turbine and pump as much as possible. If this closes the pump discharge check valve then immediately proceed to step 5.
5. Manually trip the trip and throttle valve using the hand trip lever "F". After the trip, make sure the trip and throttle valve closes smoothly and quickly. If the valve does not operate smoothly, make sure this dangerous condition is corrected before the next start-up.
6. Completely close steam inlet block valve "A".
7. Close pump discharge valve "N".
8. Close pump suction valve "M".
9. Close steam turbine exhaust block valve "G".
10. Open steam turbine casing drains "E" and "D". At this point, basically all drains between the inlet block valve "A" and exhaust block valve "G" should be opened to drain any steam and condensate from the turbine casing.
11. Confirm that the open drain valves "E" and "D" are not leaking steam through the block valves. If steam is coming from these drains, this means the block valves are leaking and need to be repaired.

12. Once the steam and condensate stop exiting the drain valves ("E" and "D"), they should be closed. It is good practice to leave the valves in the closed position so at the next start-up everyone knows the normal condition of the valves.
13. If the pump and turbine have a pressure lubrication system, it should continue to operate for several hours to provide cooling to the system. If the bearings are water cooled, the cooling should continue to run for several hours to remove the heat from the lubrication and bearings.
14. If the sealing system has coolant as part of the sealing system, it should also operate for several hours to remove the heat, similar to step 13 above.
15. Notify all personnel that the pump is now shut down.

8.2 Centrifugal Compressor Steam Turbine Shutdown

Note: All valves referenced in the following procedure are identified in Figure 8.2.

1. Communicate with all involved personnel and discuss what role they will have during the shutdown.

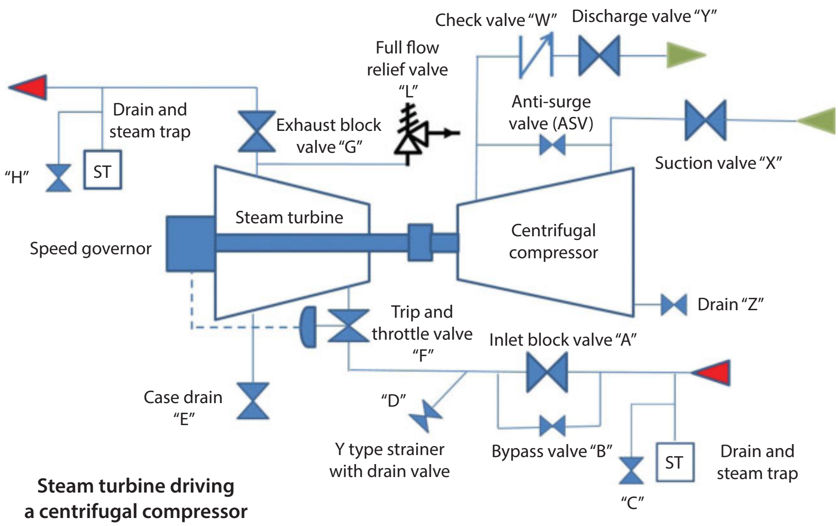


Figure 8.2 Typical steam turbine and centrifugal compressor train.

2. Make sure all personnel in affected area are aware the turbine and centrifugal compressor are being shut down.
3. Confirm that the valves on the driven equipment are in the correct position before shutdown. Typically, centrifugal compressors have a check valve between the discharge block valve and compressor discharge which prevents reverse flow on shutdown. Note: be ready to manually close a compressor's discharge valve if you suspect the check valve has failed or if you see the compressor and turbine rotating backwards.
4. First, reduce the speed of the turbine and compressor as much as possible. This may

automatically open the ASV valve fully to prevent surge on the compressor and this action will close the check valve on the compressor discharge. However, some control systems will allow the operator to initiate a shutdown which automatically opens the ASV fully before reducing the turbine and compressor speed. Once the ASV is opened and the discharge check valve is closed immediately proceed to step 5.

5. Manually trip the trip and throttle valve using the hand trip lever "F". After the trip, make sure the trip and throttle valve closes smoothly and quickly. If the valve does not operate smoothly, make sure this dangerous condition is corrected before the next start-up.
6. Completely close steam inlet block valve "A".
7. Close compressor discharge valve "Y".
8. Close compressor suction valve "X".
9. Close steam turbine exhaust block valve "G".
10. Open steam turbine casing drains "E" and "D". At this point, basically all drains between the inlet block valve "A" and exhaust block valve "G" should be opened to drain any steam and condensate from the turbine casing.
11. Confirm that the open drain valves "E" and "D" are not leaking steam through

the block valves. If steam is coming from these drains, this means the block valves are leaking and need to be repaired.

12. Once the steam and condensate stops exiting the drain valves ("E" and "D"), they should be closed. It is good practice to leave the valves in the closed position so at the next start-up everyone knows the normal condition of the valves.
13. If the compressor and turbine have a pressure lubrication system, it should continue to operate for several hours to provide cooling to the system. If the bearings are water cooled, the cooling should continue to run for several hours to remove the heat from the lubrication and bearings.
14. If the sealing system has coolant as part of the sealing system, it should also operate for several hours to remove the heat, similar to step 13 above.
15. Notify all personnel that the compressor and steam turbine are shut down.

Questions

1. During a shutdown of a centrifugal pump at what point do we trip the steam turbine?
2. In a pressure lubricated system when should the circulation lube oil pump be turned off?

3. During a shutdown of a centrifugal compressor, what position will the anti-surge valve be in after reducing the speed to minimum governor speed?
4. What position should the steam turbine valves be in after confirming all condensate is drained from the system?
5. On shutdown of a centrifugal compressor, what is done to close the trip valve?

Answers

1. During a shutdown of a centrifugal pump at what point do we trip the steam turbine?

   After reducing the speed to the minimum.

2. In a pressure lubricated system when should the circulation lube oil pump be turned off?

   The lube oil system should operate for several hours to provide cooling to the system.

3. During a shutdown of a centrifugal compressor, what position will the anti-surge valve be in after reducing the speed?

   The ASV should be fully opened immediately after the speed is reduced.

4. What position should the steam turbine valves be in after confirming all condensate is drained from the system?

   Drain valves should be closed.

5. On shutdown of a centrifugal compressor, what is done to close the trip valve?

   Manually trip the trip valve using the hand trip lever or control oil solenoid valve.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

9

Installation, Commissioning and First Solo Run

9.1 Introduction

The goal of this chapter is to provide operators a general overview of items that need to be reviewed and witnessed during equipment installation, commissioning and eventual start-up of a new steam turbine. We do not intend to give an exhaustive and all-inclusive list of engineering requirements, but want the operator to be able to observe and understand what should be done at each phase of an installation in accordance with industry best practices. These best practices have proven over time to result in years of successful long-term mechanical reliability.

9.2 Equipment Installation

In this section, we will review some general information that is critical to a successful steam turbine installation. However, we do not intend this section to be a design manual or engineering philosophy since API 686 can be referenced for those types of details. The material that follows is provided to show operators what they should expect to see when the foundation is prepared and the steam turbine is installed, well before it is ready to be started. Therefore, this section focuses on the basic observations that can be made by operators at the site which can maximize the chances of a trouble-free initial start-up.

The quality of the initial installation of any rotating equipment will have a direct impact on its lifetime reliability and availability. You have only one chance to properly install the equipment and once that is done you will have to live with the consequences of the installation for years to come. A good installation will provide years of trouble-free and safe operation, while a poor installation can result in years of headaches and frequent repairs. By following a few rules and basic concepts on what is needed to ensure a successful installation we can improve the long-term reliability by getting key items correct during the equipment installation.

9.2.1 Foundations

We always start with the foundation when installing machinery. A good foundation provides a base for the entire machine train. It provides adequate stiffness to control vibrations and maintains machine alignment. Many common machinery problems, such as excessive vibration, misalignment, soft foot (a condition where a machine mounting pad is misaligned relative to the other mounting pads) stem from poorly designed or installed foundations.

The concrete foundation must contain reinforcing steel rebar tied together along with the machine baseplate anchor bolts all supported within the rebar frame (see Figure 9.1). The concrete should cover all the rebar by at least 3 inches. All edges of the concrete foundation must be chamfered, preferably at a 45° angle. All of the equipment should fit on top of the concrete foundation without any part of the equipment or base hanging off the foundation edges. For centrifugal equipment, the mass of the concrete foundation must have at least 3 times the mass of the equipment that will be mounted on it. For reciprocating equipment, the foundation needs to have more mass and typical

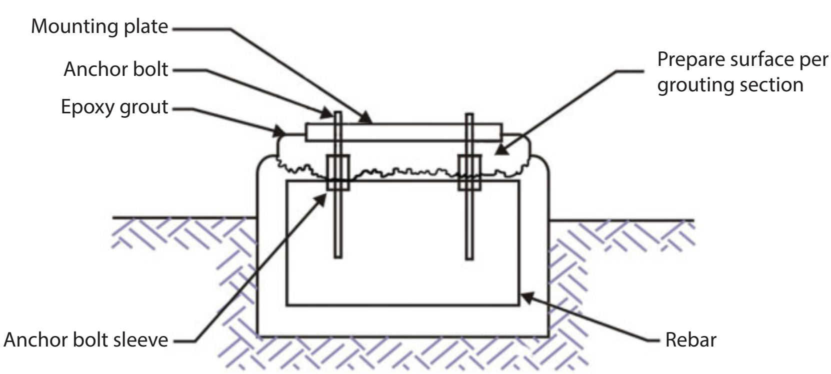


Figure 9.1 General overview of a typical equipment foundation which will support rotating equipment.

rule of thumb is 5 to 10 times the mass (weight) of reciprocating equipment being mounted on the foundation. In this book we will use mass and weight interchangeably, since on earth there is usually little if any difference between the two. An example to illustrate this concept is if the turbine and driven equipment weigh 1,000 lbs. then the mass of the concrete foundation supporting this equipment should be at least 3,000 lbs. (1000 lb × 3 for a turbine). Keep in mind that typical concrete weighs between 140 to 150 lbs/ft^3. To estimate the total concrete weight multiply the foundation length × width × height × 150 lbs/ft^3. Assume the foundation forms are 5 feet long by 4 feet wide and 2 feet deep, we can then calculate the estimated foundation weight/mass by 5 feet × 4 feet × 2 feet = 40 ft^3. multiply the 40 ft^3 × 150 lbs/ft^3 = 6,000 lbs which is greater than the 3,000 lbs and we should have enough concrete in the foundation to support the turbine, dampen vibration and maintain the alignment of the equipment. This is a rule of thumb and gives you a rough idea (estimate) that the foundation has enough mass/weight for the equipment it will support.

After pouring the concrete foundation you must allow the concrete to cure (set) for at least seven days before doing anything to prepare it for grouting.

9.2.2 Grouting

Grouting is the process of filling the void between the concrete and the machine baseplate. In other words the grout is the physical connection between

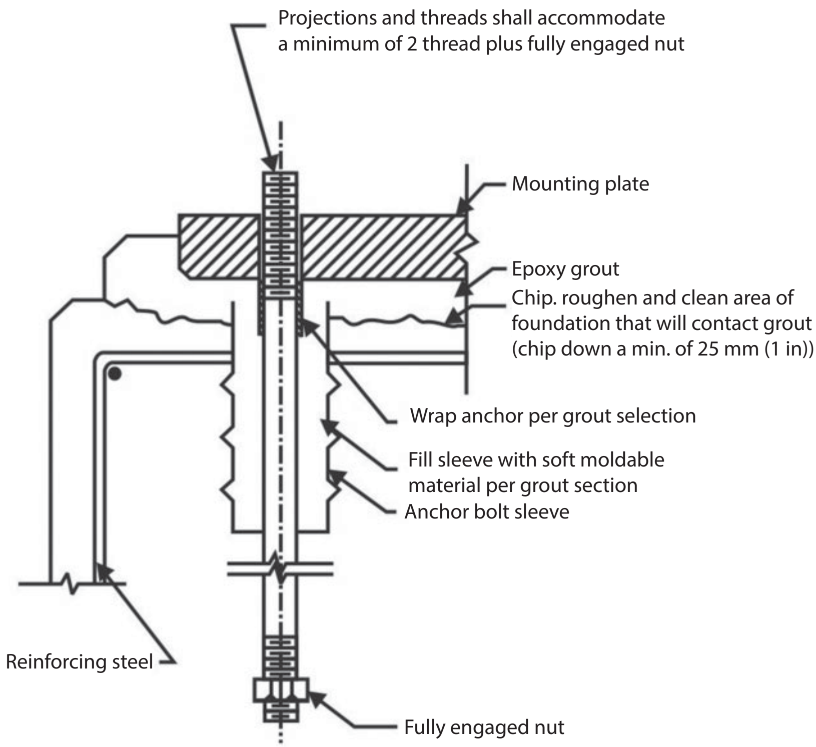


Figure 9.2 Notice the installation of the anchor bolt, mounting plate, rebar, chamfered edge for the concrete and grout, protective anchor bolt sleeve and mounting plate.

the underside of the baseplate/mounting plate and the concrete foundation. This grouting process will ensure that there are no voids in the grout underneath the baseplate or mounting plate Therefore, the primary purpose of grout is to ensure the two surfaces are mechanically connected and act as a complete foundation forming a rigid structural unit.

The majority of machinery being grouted today is done with some type of Epoxy grout. This type of grout has many desirable qualities like strength, expansion rates, ease of flowing during installation, and is generally easy to work with.

The grouting process begins with removing the top layer of the foundation which has been curing for seven days. In order to get a good bond between the concrete and grout the top layer (1 to 2 inches) of the foundation underneath the machine base-plate or soleplates must be removed by the chipping process. This top layer, called "laitance" has an accumulation of fine particles resulting in low quality concrete. Once the 1 to 2 inches of concrete surface are removed the concrete and underside of the baseplate or soleplates must be cleaned in order to remove oil, dirt, rust or any other foreign material.

The baseplate or soleplates will need to be set on the foundation and leveled in preparation for the grouting process. All mounting plates or sole plates that will be imbedded into the grout must have rounded or radius corners. The corner radius must be at least 2 inches in order to prevent cracks developing in the grout along these corners. See Figure 9.3 below.

The soleplate is a base plate that is grouted into the foundation in order to provide support and a leveling surface for the machinery base or equipment feet. The soleplates can also be used to assist in the leveling process by providing jackscrews on the four corners of each sole plate. See Figures 9.3 and 9.4.

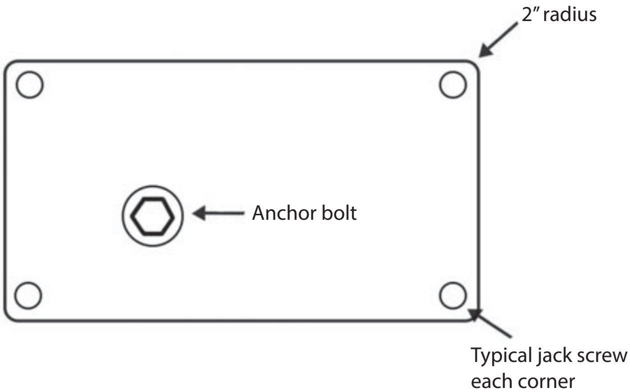


Figure 9.3 Typical soleplate. Notice that all the corners have a radius (rounded) to reduce stress areas in the grout. The radius corner should be at least 2 inches.

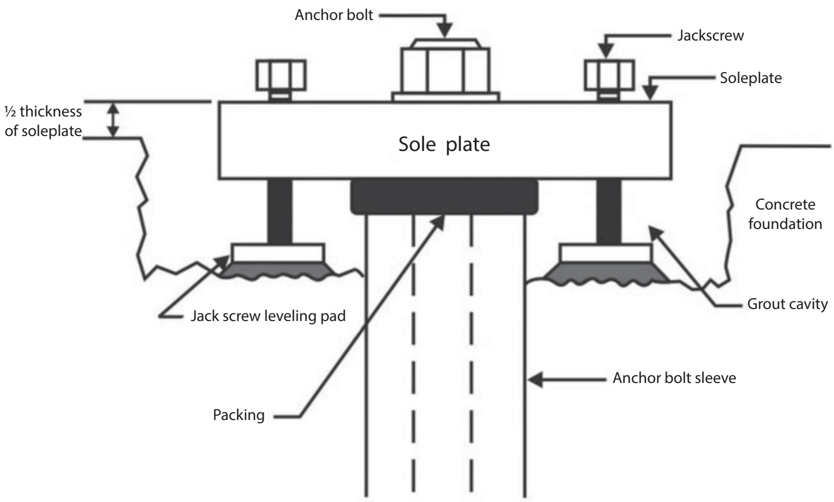


Figure 9.4 Typical grouting installation of soleplate.

After the baseplate or soleplates are mounted on the foundation they need to be leveled. This is done by using a precision machinist's level in both directions, lengthwise (direction of shafts) and crosswise (perpendicular to shafts) to within 0.005″ per foot of length for general purpose equipment (see Figures 9.5 and 9.6). The goal of the leveling exercise is to confirm that the soleplates or baseplates are level and the top of the soleplates are within the same plane within the specified tolerance. Any shiming of the soleplate or baseplate must be done with stainless steel shims. See Figure 9.7 for location of shims.

Figures 9.5 and 9.6 show details of how the leveling, flatness, and co-planar checks need to be done on the soleplates and baseplates to ensure that installed machines are properly aligned and supported. Leveling and flatness tolerances will be different depending on what type of equipment is

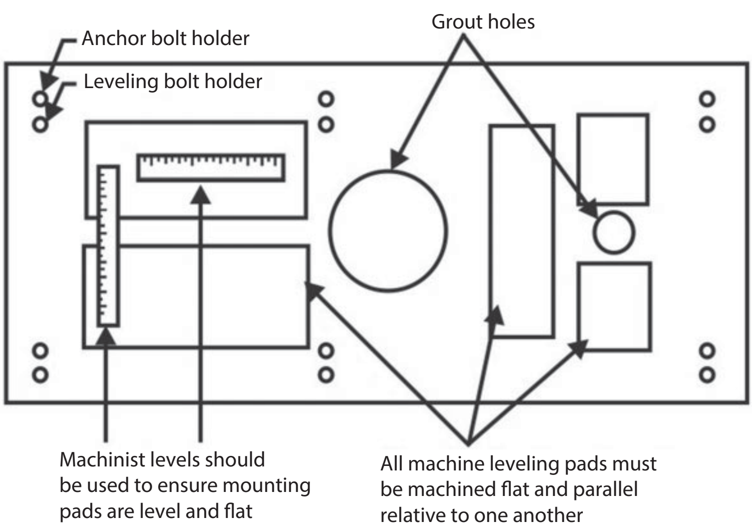


Figure 9.5 Machinist levels should be used to ensure all baseplate pads are level and flat. Leveling must be done in two directions, lengthwise (with shafts) and crosswise transverse (perpendicular to shafts).

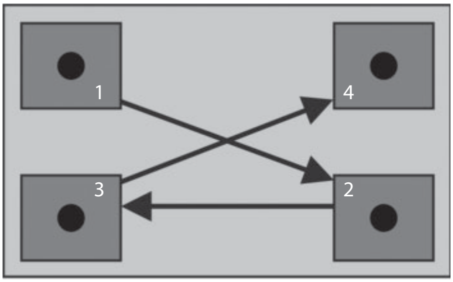


Figure 9.6 Machinist levels should be used to check the baseplate level, flatness and in the same plan in the lengthwise and crosswise directions.

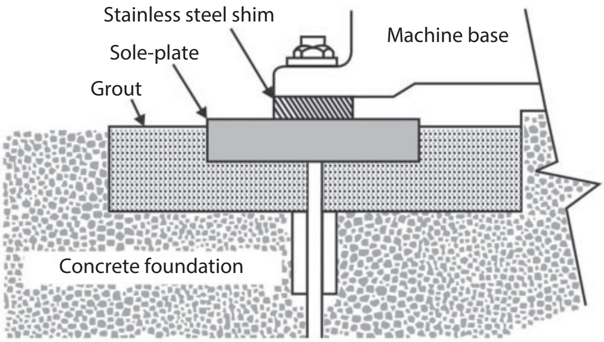


Figure 9.7 Cross sectional view of the foundation with a grouted in sole plate, stainless steel shims and machine base.

being installed. For our general purpose equipment, the level must be no greater than 0.005″ per foot of length. So if the length of the baseplate support or soleplate is 1 foot long and wide then the tolerance lengthwise is (0.005″ × 1 foot long = 0.005″) and the same for the crosswise tolerance.

A general method for assessing level and flatness of mounting pads can be seen in Figures 9.5 and 9.6 for general purpose equipment. If the entire baseplate is

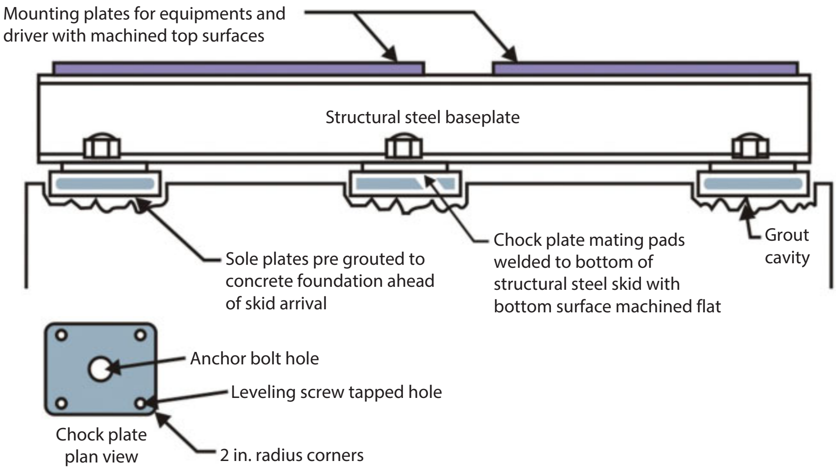


Figure 9.8 Typical mounting plate arrangement for baseplate mounted equipment. Notice the use of soleplates supporting the structural baseplate. The entire structural steel baseplate will be grouted in place.

not level then the baseplate jackscrews can be used to change the level of the machined surfaces on the baseplate. For API pump baseplates the surfaces are leveled to within 0.003″ per foot of length. If there is ever any discrepancy or issue on what tolerance to use always use the tighter or lower tolerance (0.003″/ft).

After the equipment baseplate has been grouted and the grout allowed to cure for at least three days the foundation will be ready to receive the turbine and driven equipment onto the baseplate or soleplate Figure 9.7. Once the turbine and equipment are set on the baseplate they will need to be leveled and aligned. Typically, each piece of equipment will have stainless steel shims under each foot to allow for alignment and adjustment during the alignment process. Once the equipment is set on the baseplate the piping to the equipment can be connected. The next section covers items which need to be considered.

9.2.3 Piping

The design of the steam turbine and driven equipment piping system is critical to their long-term reliability. The main concern for the steam piping and driven equipment piping is keeping the piping forces and moments below maximum acceptable levels. If the piping forces are too large they can push the turbine out of alignment with the driven equipment and distort the housing enough to result in the rotating parts contacting the stationary parts. There are several limits piping engineers and machinery engineers use to keep the piping forces low. They are stated in standards such as API and NEMA. These documents give very detailed procedures on how to calculate the maximum piping forces allowed on the nozzles of steam turbines, compressors and pumps. However, there are some very practical ways to perform field checks which will indicate whether the piping forces will be too large for the equipment. We will just simply look at the flange to mating flange alignment. A quick look at the Figures 9.9 and 9.10 will give you all the information you need. The pipe flange bolt holes should line up with the turbine flange bolt holes within 1/16″ (0.0625″); see Figure 9.9. This can easily be measured by attempting to install the bolts through the flange holes and see if they can be

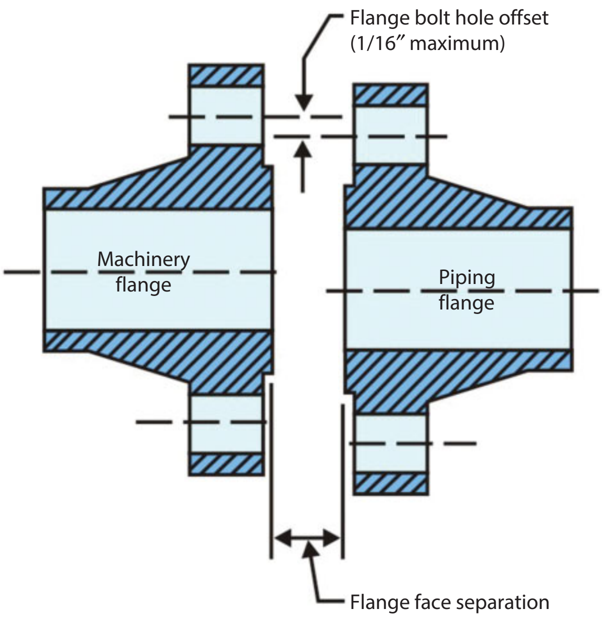


Figure 9.9 Equipment flange to pipe flange alignment requirements.

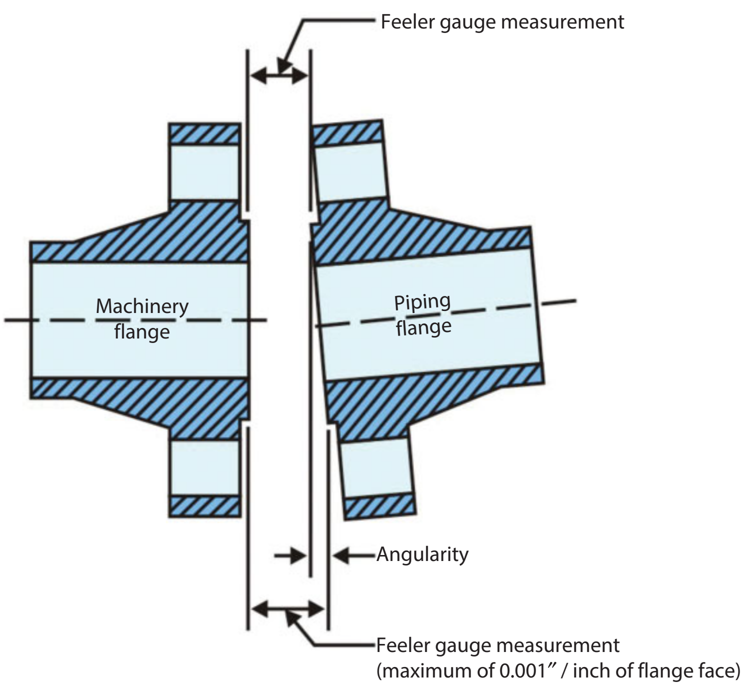


Figure 9.10 Piping alignment for parallel flanges.

inserted without any external force. If the do not line up within these tolerances then the piping should be modified to achieve this condition. You can also look at the outside diameter of the flanges and tell quickly if they are aligned without even installing any bolts.

The equipment and pipe flanges must be parallel to each other. As a rule we need to have the flange faces parallel to within 0.001″ per inch of pipe flange; see Figure 9.10. Example: if we have a 10″ flange the tolerance will be 0.001″/inch × 10″ = 0.010″, typically we can use 1/64″. Therefore, the flange can be out of parallel by only 0.010″ (1/64″) from one side of the flange to the other at the sealing surfaces. As a typical rule we want the sealing surface of a raised face flange to be within 0.010″ (1/64″) on all flanges below 10″. This can easily be confirmed with a feeler gauge on the sealing surfaces or on the raised face area of the flange. If the mating flanges are out of parallel they will have difficulty in sealing at the flange surfaces and the pipe stress may cause misalignment between the turbine and driven equipment.

Another very important method to confirm if the piping arrangement is inducing too much strain or force on the turbine is to measure the equipment shaft with a dial indicator while connecting the piping. When the bolts are tightened the pump or turbine shaft should not move any more than 0.002″. If the shaft has more than 0.002″ movement in any direction (horizontal or vertical) after the flange is tightened then there is too much force being put on the equipment flange Figure 9.11. This will cause poor

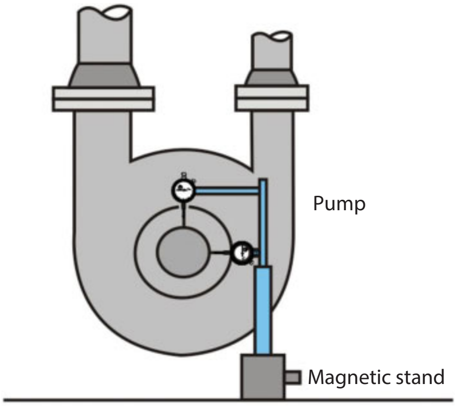


Figure 9.11 One method to check for excessive pipe strain on equipment is with dial indicators while the pipe to equipment flange is being made and bolts torqued.

shaft to shaft alignment, extremely poor reliability with labyrinth seals, carbon ring seals, mechanical seals and bearings. This strain should be prevented during installation. If unnoticed or unresolved it will result in many years of poor reliability.

9.3 Commissioning

The commissioning process is a methodical process that is meant to ensure equipment is tested and confirmed to function according to the design requirements. During this process, the systems and subsystems will be checked to ensure they are ready to be operated under full process conditions. Each system, which is made up of subsystems, will need to be checked and confirmed prior to integrating these subsystems into the larger system of machinery, piping, auxiliaries, and controls.

The basic commissioning process will confirm that the equipment will operate correctly and all the systems are working as they were designed to operate. Before we get to that point, each item making up the subsystems must be checked and double checked to confirm it is ready to operate, and then these smaller subsystems will be integrated into the larger system.

An example of this process is similar to what we do before we take a long trip in a car. We might confirm that we have a full tank of gasoline, confirm the tires have the correct air pressure and tread is in good condition, the spare tire in the trunk has the correct pressure, windshield wipers are in good condition, there is water in the windshield wiper reservoir and possibly change the engine oil before taking the trip. Think of each one of these items as a subsystem to the larger overall car system and the purpose of taking a long trip in the car. First we must check each subsystem and make sure they meet our requirements or manufacture specifications, like 32 psi in the tires, oil level in the full range, and we might check out the windshield wipers to confirm they do not leave uncleansed areas on the windshield during operation. These must all be functioning properly before we are ready for the larger system or driving the car on a long trip.

We will now review each of the critical subsystems required to start-up or perform the first solo steam turbine run. We will review in more detail the following items:

1. Steam blow to make sure the steam system and piping are clean.
2. Strainers in the steam and process system.
3. Lubrication flushing to clean the lube oil system.
4. Checks for hydraulic governor.

9.3.1 Steam Blowing

The purpose of a steam blow is to remove the foreign material from the steam piping before the piping is connected to the steam turbine. The steam-blowing process will remove rust, mill scale and weld slag from the inside of the pipe before we connect the piping to the inlet of the steam turbine. The procedure is to repeatedly bring the steam piping up to operating temperature and then allow the pipe temperature to return to ambient conditions before it is again brought to operating temperature or as close as possible. The repeated expansion, contraction and thermal shock by quickly raising the piping temperature and high steam velocity will remove particles during the steam-blowing process. This process should be completed a minimum of three times with good results on the steam targets before accepting that the piping is clean. The piping upstream of the turbine should have all strainers and other restictions removed. Then a temporary short pipe installed with a polished stainless steel or brass target attached to the outlet end of this temporary pipe, per Figures 9.12 and 9.13. The pipe with the target installed should be directed toward a

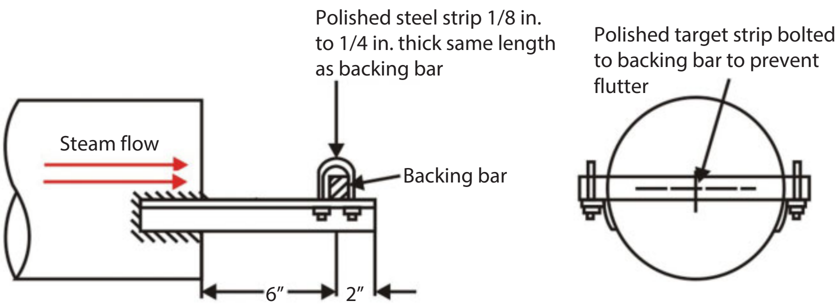


Figure 9.12 This is a typical bracket support for the polished target and shows the location of the target mounted at the exit of the steam piping. The target should be located in the middle of the steam blowing piping.

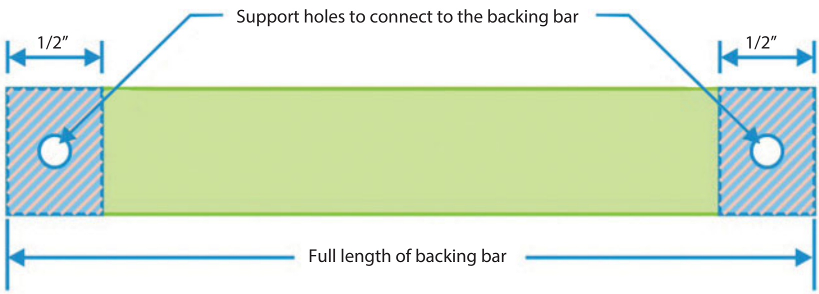


Figure 9.13 Typical target configuration, metal strip. The middle section in green is the only area to be viewed for the pass/fail criteria.

safe location. This target will be directly in the steam blow path and be impacted by foreign particles coming from the inside of the piping. These targets should be inspected after each steam blow and new polished targets reinstalled for the next steam blow. After two consecutive steam blows that have acceptable impact indications on the polished target the process is complete. This process can take many hours to complete and should not be done on any time frame other than the acceptance of the polished targets. See Figures 9.14 and 9.15 for target acceptance criteria details.

During the steam-blowing process the steam will be directly going to atmosphere without any back pressure so the steam velocity will be very high and the noise will be extreme. Therefore all personnel should wear extra hearing protection and stay clear of the steam exit pipe. The authors have seen steam blows which use a silencer on the exit piping to reduce the noise and contain any projectiles coming from the piping. Of primary concern is to direct the steam

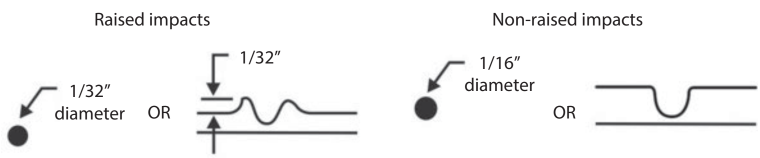


Figure 9.14 Examples of raised impact and non-raised impacts.

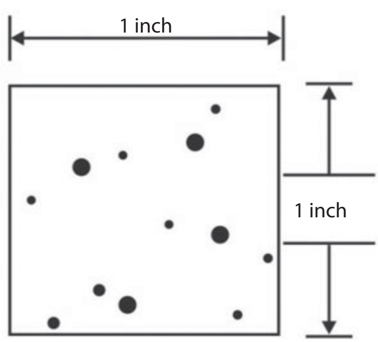


Figure 9.15 Acceptance criteria for any size cluster in a 1 inch by 1 inch square.

outlet flow away from equipment and toward a safe area.

The steam blowing pass/fail criteria is based on the amount of damage seen on the polished target surface. The 1/2″ area on each end of the polished target should be excluded from evaluation for impact damage and pass/fail criteria. The targets should be checked after each thermal cycle and steam blow to inspect the targets. There are some standard pass/fail criteria stated in API 686 which are as follows:

1. No raised pits or impacts.
2. Less than three pits in any square 1/8″ × 1/8″ and no pit shall be larger than 1/32″.
3. No more than five raised impacts larger than 1/64 inch in any 1″ × 1″ square of target surface.
4. Repeat the steam blows until the acceptance criteria are met.

9.3.2 Strainers

Temporary strainers should be installed upstream of the inlet flange to the steam turbine just upstream of the trip valve if possible. This will act as another barrier to any particles or objects in the piping that were not removed during the steam-blowing process. The typical temporary strainer maybe a conical strainer also known as a "Witches Hat" shown in Figure 9.16. It must be noted that to install this

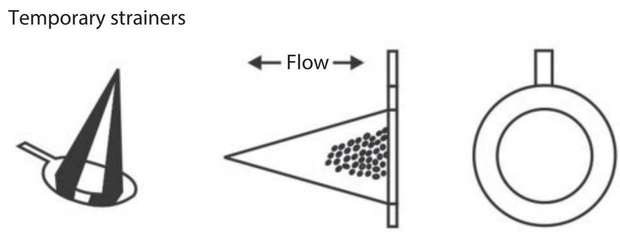


Figure 9.16 The pointed part of the strainer typically points toward the flow.

Table 9.1 Wire mesh dimensional information.

Always use stainless steel mesh			
Mesh	**Wire diameter (inch)**	**Opening size (inch)**	**% Open area**
4 × 4	0.063	0.187	56.6
8 × 8	0.047	0.078	38.9
20 × 20	0.016	0.034	46.2
40 × 40	0.01	0.015	36
60 × 60	0.0075	0.0092	30.5
100 × 100	0.0045	0.0055	30.3

Note: The larger the mesh number the smaller the opening

temporary strainer there needs to be a short piping spool engineered into the system so installation and removal of the temporary strainer can be done without moving the steam turbines. See Figure 9.16.

These types of temporary strainers have been used in many applications and they will most likely be installed in the suction pipes of pumps and compressors. Table 9.1 provides useful dimensional data for wire mesh that may be used in strainers.

9.3.3 Lubrication

Lubricating systems can vary widely in size, design, and complexity. In previous chapters we discussed forced lubricated systems as well as the oil sump and ring lubrication which is most common in general purpose steam turbines. The basic requirement for any lubricating system is to be clean. During the commissioning phase we inspect and confirm that the systems are clean and ready for the next step of the process.

The lube oil commissioning process for the general purpose steam turbine really depends on what type of lube oil system is being utilized. In most application general purpose steam turbines with oil sumps use a constant level oiler. Larger turbine systems will most likely employ forced lubrication systems. In either case, one of the first things which must be done is to understand what type of preservation has been used on the oil system by the manufacturer and confirm if this is compatible with the lube oil which will be used at the site. Since most preservatives now are compatible with the lube oil system this should not be an issue but if the preservation and lube oil are not compatible then you will have to remove all of the preservation before putting the oil into the system.

9.3.4 Oil Sump Lubrication

In the lube oil sump system we first confirm that the lube oil level is set to the correct level by the constant level oiler. We must also confirm that the oil level in the sump covers both of the oil rings at the bottom of the sump below the bearing. To check this you will need to remove the top of the bearing cap and inspect the oil level inside the bearing housing. Make sure that the oil level is covering both oil rings. See Figure 9.17 for the details. If the oil level is not correct then the oiler level adjustment inside the oiler must be adjusted to reset the level. Once the oil level is set correctly, you will need to drain the oil level out of the sump to remove all the oil. You will need to repeat this process twice to remove any contamination in the system and make sure the oil reservoir system, piping, and level oiler are working correctly. This process will confirm that the oil leveler is filling the sump when required. Each fill must be done with new oil—never reuse the oil during this process. Now rotate the oil rings to confirm they rotate easily and that there are no hang-ups or

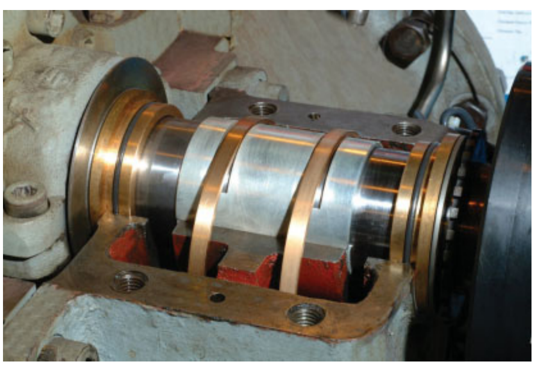


Figure 9.17 Notice the oil rings, red preservation coating inside the lube oil sump. (Courtesy of Elliott Group)

machine burrs to prevent smooth operation. Once this is confirmed replace the bearing cap. It must be stressed that each lube oil fill must be new and clean lube oil.

9.3.5 Flushing Pressure Lubricated System

As with the sump lubricated system, you will need to confirm with the manufacture what preservation has been applied to the system and if it is compatible with the lube oil that will be used at site. If it is NOT compatible then you will need to remove all the preservation before filling the system with the final oil to be used in operation.

Before starting the flushing procedure you will need to install 100-mesh screens in several locations throughout the lube oil piping system. One screen must always be installed on the lube oil return line to the oil reservoir and another at the entrance of each bearing or close to the bearing jumper lines (bypass piping or hose around the machinery bearings). Periodically remove these screens and see if they are clean or contain particles. You will need to have two screen samples indicating that the system is clean before stopping the flushing process.

In a pressure lubricated system there are most likely two external lube oil pumps which can be used to circulate the lube oil throughout the system. During the flushing process we must increase the lube oil velocity throughout the system to at least 15 to 20 feet per second—faster is better. This can typically be done by operating both of the lube oil pumps, main and standby simultaneously. The authors' experience with flushing is that operating both lube oil pumps at the same time is enough to increase the oil velocity in order to clean the system in a reasonable time without the complication of adding another larger pump to the system. If, however, the system has only one lube oil pump then a temporary pump will need to be connected to the system to increase the velocity during the flushing process.

During the flushing process you will also need to cycle the temperature of the oil system from maximum to the minimum temperature. You can either utilize the oil coolers or reservoir heater to provide the additional heat but you must cycle the oil temperature.

Oil system flushing check list:

1. Install bypass piping or hoses (called jumpers) around all the machinery bearings. You don't want to push contaminated oil with small particles into the bearing areas, gears or any close clearance area.
2. Remove any orifice plates in the lube oil system. There maybe orifices on the upstream side of the bearings so make sure you remove them if the bypass (jumper) around the bearings is downstream of the orifice.

3. Install 100-mesh screens at flange connections in several locations throughout the system. Always install one screen on the lube oil return line to the oil reservoir and at the entrance of each bearing or close to the bearing jumpers as possible. Periodically remove these screens and see if they are clean or contain particles. You will need to have two sets of screen samples indicating that the system is clean before stopping the process.
4. Confirm that the lube oil pumps both have strainers on the suction with at least 100-mesh screens during flushing. If not then install temporary strainers of wire mesh upstream of the pump in the suction line.
5. Some flushing procedures recommend removing the oil filters during the flushing process. However, I recommend they remain installed as they will be used to assist the cleaning up process. Just remember to put new filters in after the system is clean.
6. Operate both lube oil pumps at the same time.
7. Cycle the lube oil temperature from maximum to minimum several times during the flushing process.
8. After the lube oil system has been flushed and confirmed clean confirm all the orifices are reinstalled along with removing

all the jumpers on the system. Install new oil filters and remove all the 100-mesh screens.

9. Confirm that the automatic low pressure start-up of the auxiliary oil pump is set correctly. Return all the lube oil systems back to normal condition and operate one of the lube oil pumps with the auxiliary set on standby. Turn off the operating lube oil pump and confirm what pressure the auxiliary pump starts and note the lowest lube oil pressure seen in the system. This will all be done when the equipment is NOT running.

9.3.6 Hydraulic Governors

If the governor was used during the factory acceptance test, then the initial set-up is already complete and the main concern will be to drain the oil, refill to correct levels and adjust the speed settings as required. However, if the governor was not used during the factory test then more set-up work and time will be required.

If the governor is new and was not used during the factory acceptance test you will need to check the following items:

1. Confirm the drive-shaft rotational direction on the governor housing is the same as the direction of the steam turbine. The governor can be set up for clockwise or

counter-clockwise directions. The governor drive shaft rotation is set up for a single direction and will fail if set up incorrectly. The direction of rotation will be stamped on top of the governor and on the nameplate. Confirm that governor direction and the turbine direction are the same. If not, the governor rotation will have to be changed.

2. The governor speed setting is set at the factory for the rated speed. However, the speed adjusting screw should be reset to the lowest speed before initial start-up.
3. The linkage between the governor and the governor valve should be adjusted to allow for the full travel of the governor shaft. This is typically 40 degrees for full travel and if this adjustment is not correct then there may not be enough governor valve movement to allow no load and full load operation. Confirm the linkage operates smoothly, does not bind and is spring loaded in the shutdown direction. See Figure 9.18 below.
4. Once the steam turbine is operating with a load on the system the speed Droop should be checked and adjusted if required. There must be a load on the steam turbine before a Droop check can be done. Typically the governors will have a factory Droop setting of around 6%, which should be acceptable for most applications but it should be confirmed.

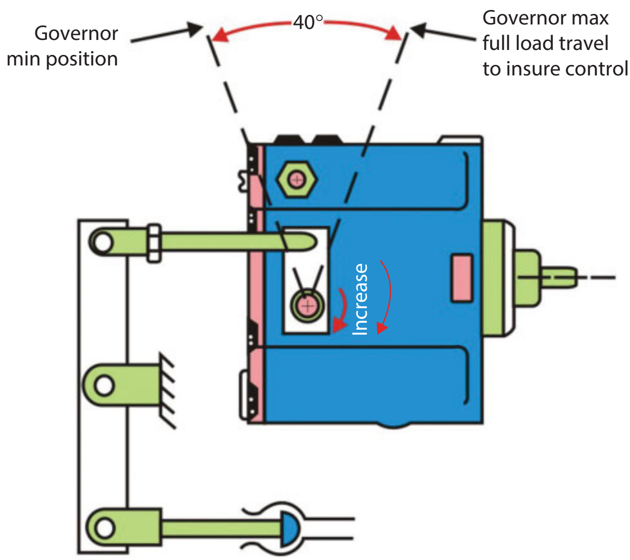


Figure 9.18 Full governor linkage movement from no-load to full load.

After these items have been checked and confirmed you are now ready for the first solo steam turbine run as outlined below.

9.4 Turbine First Solo Run on Site

The authors want to make it clear that all users need to read, understand and follow the manufacturer's recommendations for commissioning and start-up of the steam turbine before attempting to perform the first solo run. Discuss the procedure with the manufacturer if you have any questions. The procedure presented below should be viewed as additional recommendations and reminders which may be added to the manufacturer's procedure and/or the plant site procedures. This procedure must only be performed by trained personnel and in accordance with the agreed-upon procedures.

9.4.1 First Solo Run Pre-checks

1. Make sure the area around the turbine trip and block valves is clear of obstructions and accessible. Confirm any obstacles which may be a tripping hazard or hinder free movement around the turbine are removed from this area.
2. Only personnel involved in start-up should be in the area around the turbine and shutdown valves. If possible, personnel should stand at the turbine governor end if they must be close to the turbine. Do NOT stand by the coupling end of the turbine for the initial start-up.
3. Always have one person at the overspeed trip lever and shutdown valve.
4. A minimum of two independent speed indications must be used and cross checked to confirm they are reading the same turbine speed (rpm). If speed indicators are not reading the same rpm, immediately stop the process and resolve

this discrepancy between speed indications. Do not proceed with the start-up until both speed indicators are reading the same speed (rpm). This is very important for steam turbines which use electronic governors. There have been reports of electronic governors being programmed incorrectly with the wrong number of speed pickup teeth in the program, resulting in the turbine actual speed on the shaft being twice the speed readout from the electronic governor. Therefore independent speed confirmation is critical.

5. Reconfirm that all participants know the start-up procedure and what their responsibilities are for the start-up.
6. All participants must know:
   a. Who is the person in charge of the start-up and will make the decisions to stop the procedure? How will the decisions be communicated to all participants assuming high background noise?
   b. What happens if the main trip system does not work?
   c. What action will each person take to stop the steam from entering the turbine if something goes wrong?
   d. How will the turbine be tripped and by whom?

e. All these details must be in the plan before the test is started. This is not an exhaustive list but it shows what type of planning needs to be done before the steam turbine first solo run.

7. Confirm that the driven equipment is uncoupled from the steam turbine. Some couplings will need to have a solo plate installed on the steam turbine coupling half before you can solo the turbine. If this is required then follow the coupling manufacturer's solo plate installation instructions.
8. Confirm that the speed governor is set to the minimum possible speed.
9. It is critical to understand that the uncoupled steam turbine will require approximately 1 to 5% of the of turbine's available power. Very small changes in the inlet steam valve or bypass valve will cause very quick speed changes. Therefore, all speed increase must be done very slowly while observing the speed change indicators.
10. Confirm that the exhaust piping from the turbine has a properly functioning temperature measuring device, transmitter, gauge or handheld contact measuring instrument. The temperature should be measured as close as possible to the turbine exhaust flange. It must be noted that during a NO-LOAD run the exhaust temperature

will most likely exceed normal temperatures due to less energy being taken from the steam. Therefore you will need to confirm what the maximum temperature is allowed for the exhaust pipe class rating. If the piping temperature exceeds the pipe class rating then stop the process.

11. Confirm that the oil reservoir is full.
12. Confirm the governor oil is full, if required.
13. Confirm the coupling half on the steam turbine is secured by the solo plate or remove the coupling hub.
14. Confirm all commissioning activities have been done and results verified. If you don't know if something has been done correctly or in accordance with the procedure you must NOT proceed to the next step until all commissioning items can be reconfirmed and verified.
15. Reconfirm that all participants know what the trip speed is and what the Maximum Allowable Speed is from the manufacturer.
16. Confirm whether the steam turbine and governor have been operated together at the factory. If the unit has been run during the factory test you will need to collect the information taken during the factory test like the vibration levels, temperatures, overspeed tests results, and settings for the governor speed.

17. Review the overspeed procedure in chapter 6.

9.4.2 Steam Turbine First Solo Run Procedure (Refer to Figure 9.19)

1. Confirm all "First Solo Run Checks" complete from the list above.
2. Communicate to all personnel in the plant and specifically the affected area that the steam turbine is being started for the first time.
3. Start the lube oil system, if applicable. Remember smaller back pressure

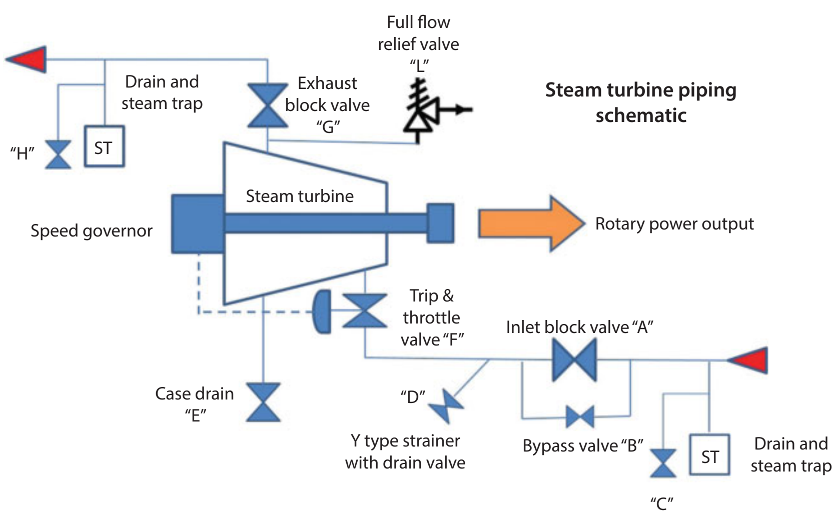


Figure 9.19 Uncoupled steam turbine.

turbines will likely have an oil bath lubrication system, so confirm that there is oil in the sight glass or that the oil sight glass reservoir is at the proper level. On pressure-lubricated systems, confirm the lube oil cooling system is operating properly.

4. If the lube oil system is a pressure-lubricated system with water or air coolers make sure they are operating and these subsystems have been commissioned properly.
5. If using a hydraulic governor confirm oil levels are in the normal range. If an electronic governor is being used confirm that the system has power and the electronics have been commissioned.
6. Make sure the governor speed setting, mechanical hydraulic or electronic, are set to the lowest possible speed setting.
7. Confirm that inlet, exhaust and drain valves are ALL closed. This is the starting point of each start-up; all turbine valves should be closed.
8. Confirm that two independent speed pick-ups have been installed on the turbine shaft, typically close to the coupling end of the turbine. These tachometers will be used to confirm the actual shaft speed and compare it to the electronic governor

readout if available. Both speed tachometers should be reading the same speed.

9. Rotate the turbine shaft by hand to confirm it is free to rotate.
10. Manually trip the overspeed system to confirm the trip mechanism will close the inlet valve if required. The trip mechanism should close smoothly and very fast (typically in less than 1 second). If it doesn't close properly, repair it before proceeding. It is critical to confirm that the trip system is functional before allowing any steam into the turbine. After confirming the trip system is functional and operates correctly, reset the trip system. At this point, the governor valve and trip valve will both be open "F".
11. Open the steam turbine case drains to drain condensate out of the turbine casing. The case drain valve is labeled "E".
12. Partially open the steam turbine main header drain valve labeled "C". This will start steam flowing in the header and warm up the inlet system to the drain. When this valve is opened, steam and condensate will exit this valve from the steam header. It is important to allow the steam condensate to drain before proceeding to the next step. When you no longer see condensate coming from the

valve and see dry steam, it is an indication to close the drain valve "C". Confirm drain valve "C" is closed.

13. Partially open the exhaust steam drain valve labeled "H". Once the condensate has drained out of the system, the exhaust line is warm, and condensate cannot be seen coming from the valve, you are now ready to close the valve labeled "H". Confirm drain valve "H" is closed.
14. Reconfirm casing drain "E" is partially open;
15. Partially open drain valve "D";
16. Slowly start opening the exhaust block valve labeled "G" until you see steam flowing from the casing drain valves "E" and "D". This will put exhaust pressure steam flowing in the turbine casing and exiting from the drain valves "E" and "D". You will hear and see increased steam flowing from these valves when there is exhaust pressure inside the casing.
17. Once you see dry steam coming from the drain valves "E" & "D" it is time to close both of these drain valves.
18. Now fully open the exhaust block valve "G". It is important that this valve is fully open before moving to the next step. This must be done before opening any inlet valves because the turbine casing pressure is only rated for turbine

exhaust pressures. That is the reason for the installation of the full flow relief valve labeled “L”. This full flow relieve valve is only required if something is done incorrectly and the steam turbine casing is accidentally over pressured. It should be confirmed that the relief valve “L” is installed. A good rule is to NEVER open the inlet steam valve until the exhaust is fully opened. If for some reason the sentinel valve lifts or relieves, you have made a mistake and must stop the inlet steam to the turbine immediately. It should be noted that some users choose not to install sentinel valves so be aware of your specific turbine system before executing this start-up procedure.

19. Now with exhaust valve “G” fully opened, all drain valves closed, the trip valve and governor valves fully opened, it is time to slowly open the bypass valve “B”. It is critical that you slowly open this bypass valve no more than 1/2 turn at a time. Once you see the steam turbine shaft turning under steam pressure stop opening the valve. It is important to remember that without any driven equipment load on the turbine the steam required to start the turbine will be small, so the smallest change in opening valve “B” will make a large difference in the turbine

speed. The solo turbine power will be approximately 1 to 5% of rated power.

20. Once the steam turbine is rotating, confirm that both independent speed tachometers are indicating the same rpm. If you have an electronic governor, confirm that the speed readings are all consistent.
21. Now bring the turbine up to (slow roll) 500 to 600 RPM range by opening the bypass valve "B".
22. Once the turbine speed is 500 to 600 rpm check around the turbine for oil leaks, steam leaks, loose pieces or parts, high vibration, high noise, anything that does not appear normal or might need further investigation. Operate at this speed for 1 hour. During the 1-hour period take vibration and temperature readings every 15 minutes on the bearings and temperature readings on carbon ring packing gland area. The carbon ring packing area should come up to temperature during this break in period. Document all vibration and temperature data for review later.
23. Now increase the turbine speed by once again opening the bypass valve "B" (1/2 turn at a time or by the governor speed increase) until you reach 1000 rpm, hold at that speed for 15 minutes then increase the turbine speed by 500 rpms every 15 minutes afterwards. If during

any speed increase there is a noticeable change in the vibration levels return to the lower speed and operate at that speed for an additional 30 minutes before proceeding to increase the speed on the 500 rpm/15 minutes rate. Note that at some point in the process the governor will reach its minimum governor speed setting and any further opening of the bypass valve will not increase the turbine speed. It is at this point you will have to increase the turbine speed by the governor; this will happen sometime before you reach the normal operating speed. The bypass valve may have to be opened further if the turbine governor is unable to reach the normal operating speed.

24. Once you reach the normal operating speed you will need to hold at that speed for a minimum of 1 hour. Again take vibration and temperature readings during this period every 15 minutes and document all readings. Take exhaust temperature readings and confirm the temperature does not exceed the pipe class rating.
25. After the 1-hour operating speed run, reduce the speed to the minimum operating speed via the governor, speed adjustment screw or electronic speed change. Operate the steam turbine on the minimum governor speed for 15 minutes.

26. Now manually trip the overspeed trip valve by pulling on the hand trip lever arm until the resetting lever arm slides off the knife edge closing the trip valve. The valve should close in less than 1.0 second and without any hang-up during closing. If you can see the valve closing, it is too slow. It should be repaired immediately.
27. Perform the overspeed trip testing of the steam turbine per instructions in chapter 6 in the overspeed trip procedure.
28. After there have been three successful overspeed trips per the procedures in chapter 6 you are ready to couple the steam turbine to the driven unit.

Questions

1. What are the first two steps in the steam turbine first solo run?
2. How much power is required from the turbine during the solo run?
3. How long does the steam turbine operate at slow roll, 500 to 600 rpm?
4. What is the governor speed setting at initial start-up during the solo run?
5. How fast should the overspeed trip valve close?
6. How many speed tachometers are required to measure the speed?

7. How do we know if a solo plate is required for the coupling hub on the steam turbine?
8. Why is it important to measure the exhaust temperature on the turbine?

Answers

1. What are the first two steps in the steam turbine first solo run?

   Confirm all "First Solo Run Checks" are complete and communicate to all personnel in the plant and that the steam turbine is being started for the first time.

2. How much power is required from the turbine during the solo run?

   The power is typically 1 to 5% of the rated power. Therefore small changes in the inlet steam bypass valve could result in drastic changes in speed.

3. How long does the steam turbine operate at slow roll, 500 to 600 rpm?

   Operate at this speed for 1 hour.

4. What is the governor speed setting at initial start-up during the solo run?

   The speed setting is set at the lowest possible speed.

5. How fast should the overspeed trip valve close?

   The overspeed trip valve should close in less than 1 second.

6. How many speed tachometers are required to measure the speed?

   We must have two independent speed tachometers to measure the shaft speed.

7. How do we know if a solo plate is required for the coupling hub on the steam turbine?

   Must refer to the coupling manufacturer's drawings or instruction manual.

8. Why is it important to measure the exhaust temperature on the turbine?

   Since there is NO load on the turbine the enthalpy (total heat content of a system) drop will be much lower and the exhaust steam temperature higher; it may be close to the inlet temperature. This elevated exhaust temperature may be too high for the piping class.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

10

Reinstating Steam Turbine after Maintenance

10.1 Turbine Reinstatment after Maintenance

After any major maintenance or repairs are done on the steam turbine you will need to follow the reinstatement procedure as outlined below. We define a major repair as repair involving the replacement of any of the follow items:

1. Shaft
2. Any steam path components – nozzle ring, reversing blades or rotating blades,
3. Bearings – radial or thrust
4. Governor valve or governor

5. Trip valve or any large component in this system
6. Carbon ring seals only if done with a new shaft and or gland housing
7. Coupling

We consider that any of these items will have a significant impact on the equipment reliability if they are not installed or replaced correctly. Therefore, any restart or reinstatement after these maintenance tasks are complete will require a more cautious approach to the first start-up after maintenance.

The procedure presented below should be viewed as additional recommendations and reminders that may be added to the manufacturer's procedure and/ or the plant site procedures. This procedure must only be performed by trained personnel and in accordance with the agreed-upon procedures.

10.2 Reinstatement after Maintenance Check List

1. Make sure the area around turbine trip and block valves are clear of obstructions and accessible. Confirm any obstacles which may be a tripping hazard or hinder free movement around the turbine are removed from this area.

2. Only personnel involved in start-up should be in the area around turbine and shutdown valves. If possible, personnel should stand at the turbine governor end if they must be close to the turbine. Do NOT stand by the coupling end of the turbine for the initial start-up.
3. Always have one person at the overspeed trip lever and shutdown valve.
4. A minimum of two independent speed indications must be used and cross checked to confirm they are reading the same turbine speed (RPM). If speed indicators are not reading the same rpm, immediately stop the process and resolve this discrepancy between speed indications. Do not proceed with the start-up until both speed indicators are reading the same speed (rpm). This is very important for steam turbines which use electronic governors. There have been reports of the electronic governor being programmed incorrectly which had the wrong number of speed pickup teeth in the program, resulting in the turbine actual speed on the shaft being twice the speed readout from the electronic governor. Therefore independent speed confirmation is critical.

5. Reconfirm that all participants know the start-up procedure and what their responsibilities are for this start-up.
6. All participants must know:
   a. Who is the person in charge of the start-up and will make the decision to stop the procedure? How will the decisions be communicated to all participants assuming high background noise?
   b. What happens if the main trip system does not work?
   c. What action will each person take to stop the steam from entering the turbine if something goes wrong?
   d. How will the turbine be tripped and by whom?
   e. All these details must be in the plan before the test is started. This is not an exhaustive list but it shows what type of planning needs to be done before the turbine's reinstatement.
7. Confirm that the driven equipment is uncoupled from the steam turbine. Some couplings will need to have a solo plate installed on the steam turbine coupling half before you can solo the turbine. If this is required then follow the coupling manufacturer's solo plate installation instructions.
8. Confirm that the speed governor is set to the minimum possible speed.

9. It is critical to understand that the uncoupled steam turbine will require approximately 1 to 5% of the turbine's available power. Therefore very small changes in the inlet steam valve or bypass valve will cause very quick speed changes. Therefore, all speed increase must be done very slowly while observing the speed change indicators.
10. Confirm that the exhaust piping from the turbine has a properly functioning temperature measuring device, transmitter, gauge or handheld contact measuring instrument. The temperature should be measured as close as possible to the turbine exhaust flange. It must be noted that during a NO-LOAD run the exhaust temperature will most likely exceed normal temperatures due to less energy being taken from the steam. Therefore you will need to confirm the maximum temperature allowed on this piping. If the piping temperature exceeds the pipe class rating then stop the process.
11. Confirm that the oil reservoir is full.
12. Confirm the governor oil is full, if required.
13. Confirm the coupling half on the steam turbine is secure by the solo plate or remove the coupling hub.

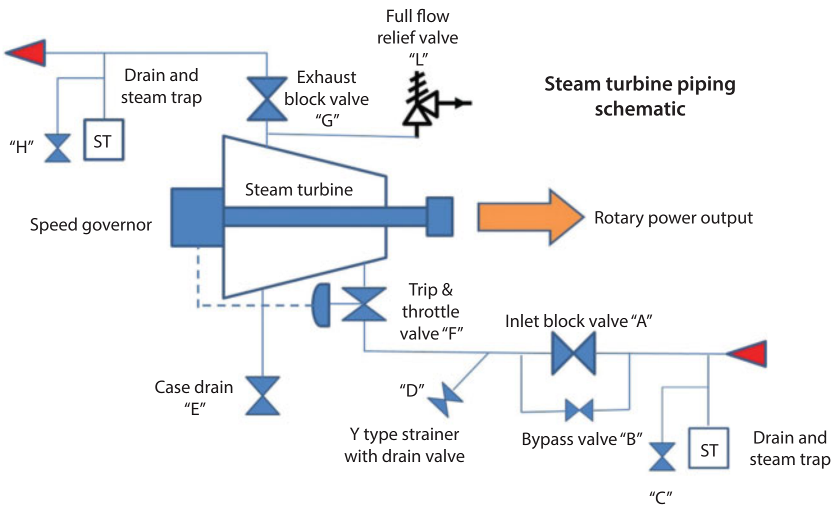


Figure 10.1 Uncoupled steam turbine.

14. Reconfirm that all participants know what the trip speed is and what the Maximum Allowable Speed is from the manufacturer.
15. Review the overspeed procedure in chapter 6.

10.3 Steam Turbine Reinstatement after Maintenance Procedure (Refer to Figure 10.1)

1. Confirm all reinstatement checks from the list above are complete.
2. Communicate to all personnel in the plant and specifically the affected area that the steam turbine is being started.

3. Start the lube oil system, if applicable. Remember smaller back pressure turbines will likely have an oil bath lubrication system, so confirm that there is oil in the site glass or that the oil sight glass reservoir is at the proper level. On pressure-lubricated systems, confirm the lube oil cooling system is operating.
4. If using a hydraulic governor confirm oil levels are in the normal range. If an electronic governor is being used confirm that the system has power.
5. Make sure the governor speed setting, mechanical hydraulic or electronic, are set to the lowest possible speed setting.
6. Confirm inlet, exhaust and drain valves are ALL closed. This is the starting point of each start-up; all turbine valves should be closed.
7. Confirm that one independent speed pick-up has been installed on the turbine shaft, typically close to the coupling end of the turbine. This tachometer will be used to confirm the actual shaft speed and give a speed readout during overspeed testing.
8. Rotate the turbine shaft by hand to confirm it is free to rotate.
9. Manually trip the overspeed system to confirm the system mechanism will

close the inlet valve when required. The trip mechanism should close smoothly and very fast (typically in less than 1 second). If it doesn't close properly, repair it before proceeding. It is critical to confirm that the trip system is functional before allowing any steam into the turbine. After confirming the trip system is functional and operates correctly, reset the trip system. At this point, the governor valve and trip valve will both be open "F".

10. Open the steam turbine case drains to drain condensate out of the turbine casing. The case drain valve is labeled "E".
11. Partially open the steam turbine main header drain valve labeled "C". This will start steam flowing in the header and warm up the inlet system to the drain. When this valve is opened, steam and condensate will exit this valve from the steam header. It is important to allow the steam condensate to drain before proceeding to the next step. When you no longer see condensate coming from the valve and see dry steam, it is an indication to close the drain valve "C". Confirm drain valve "C" is closed.
12. Partially open the exhaust steam drain valve labeled "H". Once the condensate

has drained out of the system, the exhaust line is warm, and condensate cannot be seen coming from the valve, you are now ready to close the valve labeled “H”. Confirm drain valve “H” is closed.

13. Reconfirm casing drain “E” is partially open.
14. Partially open drain valve “D”.
15. Slowly start opening the exhaust block valve labeled “G” until you see steam flowing from the casing drain valves “E” and “D”. This will put exhaust pressure steam flowing in the turbine casing and exiting from the drain valves “E” and “D”. You will hear and see increased steam flowing from these valves when there is exhaust pressure inside the casing.
16. Once you see dry steam coming from the drain valves “E” and “D” it is time to close both of these drain valves.
17. Now fully open the exhaust block valve “G”. It is important that this valve is fully open before moving to the next step. This must be done before opening any inlet valves because the turbine casing pressure is only rated for turbine exhaust pressures. That is the reason for the installation of the full flow relief valve labeled “L”. This valve is only required if something is done incorrectly and the steam turbine casing

is accidentally over pressured. It should be confirmed that the relief valve "L" is installed. NEVER open the inlet steam valve until the exhaust is fully opened. If for some reason the sentinel valve lifts or relieves, you have made a mistake and you must stop the inlet steam to the turbine immediately. It should be noted that some users choose not to install sentinel valves so be aware of your specific turbine system before executing this start-up procedure.

18. Now with exhaust valve "G" fully opened, all drain valves closed, the trip valve and governor valves fully opened, it is time to slowly open the bypass valve "B". It is critical that you slowly open this bypass valve no more than ½ turn at a time. Once you see the steam turbine shaft turning under steam pressure, stop opening the valve. It is important to remember that without any driven equipment load on the turbine the steam required to start the turbine will be small so the smallest change in opening valve "B" will make a large difference in the turbine speed. The solo turbine power will be approximately 1 to 5% of rated power.
19. Now bring the turbine up to (slow roll) 500 to 600 RPM range by opening the

bypass valve “B”. Confirm the speed with the independent tachometer.

20. Once the turbine speed is 500 to 600 rpm check around the turbine for oil leaks, steam leaks, loose pieces or parts, high vibration, high noise, anything that does not appear normal or might need further investigation. Operate at this speed for 15 minutes while taking the temperature and vibration readings on the bearings and carbon ring packing gland area.
21. Now increase the turbine speed by opening the bypass valve “B” (½ turn at a time or by the governor speed increase) until you reach 1000 rpm; hold at that speed for 10 minutes and take another set of temperature and vibration readings. If all is well then increase speed to 2000 rpm and hold for 10 minutes and take set of temperature and vibration data. If during any speed increase there is a noticeable change in the vibration levels return to the lower speed and operate at that speed for an additional 15 minutes before proceeding to increase the speed again. This process will break in the new carbon ring packing. It must be noted that at some point in the speed increasing process the governor will reach its minimum governor speed setting and

take control of the turbine speed. At this point you will have to increase the turbine speed by the speed adjusting screw on hydraulic governor (or electronic set point) since further opening of the bypass valve will not increase the turbine speed.

22. Once you reach the normal operating speed you will need to hold at that speed for a minimum of 10 minutes and again take vibration and temperature readings. Take an exhaust temperature reading and confirm the temperature does not exceed the pipe class rating.
23. After the 10 minutes of operation lower the governor speed setting to the minimum speed and manually trip the overspeed trip valve by pulling on the hand trip lever arm.
24. Confirm the trip valve closes quickly without any hang-up, typically less than 1.0 second. If you can see the valve closing, it is too slow. It should be repaired immediately.
25. Close the bypass valve and prepare the turbine for the overspeed trip testing. It is important to make sure that after major repairs or overhauls you need to perform the overspeed trip testing as outlined in chapter 6.

26. After there have been three successful overspeed trips per the procedures in chapter 6 you are ready to couple the steam turbine to the driven unit.

Questions

1. What are the first two steps in the Steam Turbine Reinstatement after Maintenance Procedure?
2. How much power is required from the turbine during the reinstatement process?
3. How long does the steam turbine operate at slow roll, 500 to 600 rpm?
4. What is the governor speed setting at start-up?
5. How fast should the overspeed trip valve close?
6. How many speed tachometers are required to measure the speed?
7. How do we know if a solo plate is required for the coupling hub on the steam turbine?
8. Why is it important to measure the exhaust temperature on the turbine?
9. How many successful overspeed trip tests do we need before we can couple the turbine to the driven unit?

Answers

1. What are the first two steps in the Steam Turbine Reinstatement after Maintenance Procedure?

    1. Confirm all steam turbine reinstatement after maintenance procedures are complete and
    2. communicate to all personnel in the plant that the steam turbine is being started.

2. How much power is required from the turbine during the reinstatement process?

    The power is typically 1 to 5% of the rated power. Therefore, small changes in the inlet steam bypass valve could result in drastic changes in speed.

3. How long does the steam turbine operate at slow roll, 500 to 600 rpm?

    Operate at this speed for 15 minutes while taking vibration and temperature readings.

4. What is the governor speed setting at start-up?

    The speed setting is set to the lowest possible speed.

5. How fast should the overspeed trip valve close?

    The overspeed trip valve should close in less than 1 second. If you see it close, it is too slow.

6. How many speed tachometers are required to measure the speed?

We must have one independent speed tachometer to measure the shaft speed.

7. How do we know if a solo plate is required for the coupling hub on the steam turbine?

   Refer to the coupling manufacturer's drawings or instruction manual.

8. Why is it important to measure the exhaust temperature on the turbine?

   Since there is NO load on the turbine the enthalpy (energy) drop will be much lower and the exhaust steam temperature higher; it may be close to the inlet temperature. This elevated exhaust temperature may be too high for the piping class.

9. How many successful overspeed trip tests do we need before we can couple the turbine to the driven unit?

   We need a minimum of three non-trending overspeed trips within the correct speed range.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

11

Steam Turbine Reliability

11.1 Repairs versus Overhauls

Before we discuss steam turbine reliability, we must first talk about the difference between a repair and an overhaul. If a system, such as a steam turbine and its controls, can be restored to operating condition after a failure by the repair or replacement of one or more components, we say it is a repairable system. Since steam turbines are typically designed to allow minor field repairs, such as the replacement of seals, bearings, governor etc., we can say they are repairable. After an extended time in operation, a steam turbine can no longer be repaired in the field, we say that it must be overhauled. An overhaul requires major work such as replacing blading due to erosion, repairing rotor bearing journals, repairing leaking split-lines, etc.

We will define a steam turbine repair as the in-field replacement of a component or components in the field and an overhaul as the removal of the entire steam turbine from the field as a unit in order to restore it back to factory specifications. Using these definitions, we will express the mean, or average, time between repairs as the MTBR and the mean, or average, time between overhauls as the MTBO.

11.2 Expected Lifetimes of Steam Turbines and Their Components

The table below lists expected lifetimes in hours and years of various components and mechanical systems. For comparison, the expected lifetimes of steam turbines are listed along with other types of process machinery. For example, the average lifetime of a centrifugal compressor is expected to be about 6.85 years, while the average lifetime of a steam turbine is somewhere between 5.71 and 7.42 years. The reader should note that this is the average of many different failure modes related to steam turbines. This should not be confused with the time between overhauls. From overhaul to overhaul there may be component failures that bring down the average lifetime of a steam turbine. (The authors have seen steam turbines routinely operate up to 10 to 12 years between major overhauls.)

11.3 Common Failure Modes

Between major overhauls there are four types of common failures experienced in steam turbines:

1. Steam packing leaks
2. Bearing failures, usually related to lubrication issues
3. Governor failures
4. Sticking trip and throttle valves

Steam turbine leaks:

One striking feature of Table 11.1 is that the expected lifetime of packing is significantly shorter than that of the expected lifetime of steam turbines. As seen in the "Expected Lifetime" table above, the average lifetime of packing can be greatly affected by the type of service that it is in and if tungsten carbide coatings are employed on bearing journals. Keep in mind that the average life (MTBR) of carbon ring packing is highly dependent on the 1) Steam quality, 2) Installation quality, 3) Installation design, 4) Operating procedures, and 5) PM/PDM procedures. Break-in procedures should always be carefully followed to ensure a proper break-in after packing replacement.

Bearing and lubrication failures:

Bearing failures are normally caused by lubrication contamination. To prevent these types of failures, you must install effective bearing housing seals,

Table 11.1 Expected lifetimes of process machines and components.

Machine or component type	Expected lifetime in hours			Expected lifetime in years		
	Low	Average	High	Low	Average	High
Compressors, centrifugal	20,000	**60,000**	120,000	2.28	**6.85**	13.70
Compressor blades	400,000	**800,000**	1,500,000	45.66	**91.32**	171.23
Compressor vanes	500,000	**1,000,000**	2,000,000	57.08	**114.16**	228.31
Diaphragm couplings	125,000	**300,000**	600,000	14.27	**34.25**	68.49
Gas turb. comp. blades/vanes	10,000	**250,000**	300,000	1.14	**28.54**	34.25
Gas turb. blades/vanes	10,000	**125,000**	160,000	1.14	**14.27**	18.26
Motors, AC	1,000	**100,000**	200,000	0.11	**11.42**	22.83
Pumps, centrifugal	1,000	**35,000**	125,000	0.11	**4.00**	14.27
Steam turbines (Barringer)	11,000	**65,000**	170,000	1.26	**7.42**	19.41
Steam turbines (NPRD & Davidson)	33,333	**50,000**	100,000	3.81	**5.71**	11.42
Steam turbine blades	400,000	**800,000**	1,500,000	45.66	**91.32**	171.23
Steam turbine vanes	500,000	**900,000**	1,800,000	57.08	**102.74**	205.48

Low pressure (<50 psi) steam turbine carbon ring packing (Reeves) (see note 3)	8760	**13140**	17520	1	**1.5**	2
Medium pressure (50 to 200 psi) steam turbine carbon ring packing (Reeves) (see note 3)	17520	**21900**	26280	2	**2.5**	3
High pressure (200 to 400 psi) steam turbine carbon ring packing (Reeves) (see note 3)	26280	**35040**	43800	3	**4**	5
Sleeve bearing	10,000	**50,000**	143,000	1.14	**5.71**	16.32
Roller bearings	9,000	**50,000**	125,000	1.03	**5.71**	14.27

[1] The basis for this table is Barriger's Weibull database: http://www.barringer1.com/wdbase.htm. The authors removed the Weibull shape factor data and only used the characteristics lifetimes to create this table.

[2] Note that these characteristic life-times are highly dependent on the1) Steam quality, 2) Installation quality, 3) Installation design, 4) Operating procedures, and 5) PM/PDM procedures.

[3] Note: High end carbon ring packing life readings assume TC has been applied to packing areas.

Source: **NPRD-95: Non-electronic Parts Reliability Data 1995**, Reliability Analysis Center, Rome, NY.

Davidson, John, 1998. **The Reliability of Mechanical System**, Mechanical Engineering Publications Limited for The Institution of Mechanical Engineers, London.

frequently inspect the packing for leaks, and test the lubrication oil for water content. Tattletale sight glasses are helpful in allowing you to stop contaminated or degrading oil.

Bearing failure rates can be significantly improved by utilizing a closed loop lubrication system with a reservoir, coolers, oil coolers, and flow control piping.

Governor failures and sticking T&T valves:

When a governor or its trip and throttle valve begin to fail, you will notice irregular or periodic speed fluctuations, differences in regulation between cold and warm operation, or the nominal speed cannot be achieved. These problems may be related to either a governor, linkage, or trip and throttle valve issue. Before attempting a repair on any of these components, first check to see you have a reliable steam supply. If the steam supply is not an issue, then check for governor oil to ensure that it is the correct type and is not contaminated and that the linkages or trip and throttle valves are not sticking.

It is very common to have to replace or refurbish the hydraulic governor on a general purpose steam turbine. For this reason it is highly recommended that a replacement governor be kept in warehouse stores.

11.4 Improvement Reliability by Design

To maximize steam turbine reliability, we must maximize the mean time between overhauls and maximize the mean time between repairs (MTBR) of steam turbine components. To this end operations and maintenance must strive to ensure their steam turbines are continuously supplied with high-quality steam. Operations and maintenance's secondary emphasis must be on maximizing the time between common failure modes mentioned above by optimizing design standards, operating procedures, repair standards, frequent inspections, and time-based maintenance.

Let's consider the effects that packing, coupling, and bearing lifetimes have on the overall MTBRs. In Table 11.2 below there are various steam turbine design configurations. For example, in the first row is a steam turbine with carbon rings, a lubricated coupling, and oil sump lubrication. In all cases, we assume a steam path lifetime of 15 years. (The steam path lifetime is defined as the operating hours required to erode steam path components, i.e., rotating and stationary blading, to the degree that steam turbine performance is significantly degraded.) In the column at the far right we calculate the average mean time between repairs for

Table 11.2 Mean time between repairs (in yrs.) for various design configurations.

Packing	MTBR1	Coupling	MTBR2	Brg lubrication	MTBR3		MTBR4	Overall
Carbon rings	3	Lubricated	6	Oil sump	3	Steam path	15	1.11
Carbon rings	3	Dry	20	Oil sump	3	Steam path	15	1.28
Carbon rings	3	Dry	20	Closed loop	20	Steam path	15	2.00
Carbon rings with TC coating	5	Lubricated	6	Oil sump	3	Steam path	15	1.30
Carbon rings with TC coating	5	Dry	20	Oil sump	3	Steam path	15	1.54
Carbon rings with TC coating	5	Dry	20	Closed loop	20	Steam path	15	2.73
Labyrinth packing	20	Lubricated	6	Oil sump	3	Steam path	15	1.62
Labyrinth packing	20	Dry	20	Oil sump	3	Steam path	15	2.00
Labyrinth packing	20	Dry	20	Closed loop	20	Steam path	15	4.62

the entire unit. The equation for the MTBR is as follows:

$$\frac{1}{MTBR_{overall}} = \frac{1}{MTBR_{Seals}} + \frac{1}{MTBR_{Coupling}} + \frac{1}{MTBR_{Bearings}} + \frac{1}{MTBR_{Steam\ path}}$$

To better understand this equation, let's calculate the $MTBR_{overall}$ for the steam turbine configuration represented in the first row of Table 11.2. This turbine has carbon rings (without a TC coating), a lubricated coupling, and oil sump lubrication. Plugging the component MTBR values found in the table, we get:

$$\frac{1}{3} + \frac{1}{6} + \frac{1}{3} + \frac{1}{15} = \frac{1}{MTBR_{overall}} = 0.9 = \frac{1}{1.11}$$

The result from our calculation means that the expected mean time between repairs for this steam turbine design is 1/0.9 or 1.11 years.

Now let's calculate the $MTBR_{overall}$ for the best case design scenario. For this case, we have labyrinth packing, a dry coupling, and a closed loop lubrication systems.

Plugging the component *MTBR* values found in the table, we get:

$$\frac{1}{20} + \frac{1}{20} + \frac{1}{20} + \frac{1}{15} = \frac{1}{MTBR_{overall}} = 0.216\, or\, 1/4.61$$

The result from this second calculation means that the expected mean time between repairs for this steam turbine design is 1/0.217 or 4.62 years. Now that you understand how this calculation is performed, you can perform your own calculations with your own data.

The reader can clearly see by reviewing this table that for various design configurations the overall MTBRs vary from 1.11 years to 4.62 years. This exercise demonstrates that the average time between steam turbine outages is not controlled by the time between overhauls but by the time between component failures. We can conclude that to maximize reliability of steam turbines we must strive to maximize the reliability of their weakest components, i.e., sealing systems, bearings, governor, and lubrication systems, etc.

Questions

1. What is the difference between a steam turbine repair and a steam turbine overhaul?
2. What are the average expected lifetimes of low pressure, medium pressure, and high pressure packing? (Refer to Table 11.1 in this chapter.)
3. List at least three (3) of the most common steam turbine failure modes.

4. List at least three (3) proven steam turbine design upgrades.

Answers

1. What is the difference between a steam turbine repair and a steam turbine overhaul?

   We define a steam turbine repair as the in-field replacement of a component or components in the field and an overhaul as the removal of the entire steam turbine from the field as a unit in order to restore it back to factory specifications.

2. What are the average expected lifetimes of low pressure, medium pressure, and high pressure packing? (Refer to Table 11.1.)

   a. Low pressure packing – 1.5 yrs.

   b. Medium pressure packing – 2.5 yrs.

   c. High pressure packing – 4 yrs.

3. List at least three (3) of the most common steam turbine failure modes.

   a. Steam packing leaks

   b. Bearing failures, usually related to lubrication issues

   c. Governor failures

   d. Sticking trip and throttle valves

4. List at least three (3) proven steam turbine design upgrades.

    a. Apply tungsten carbon coatings at the rotor packing ring areas

    b. Replace lubricated couplings with dry couplings

    c. Install bearing housing seals to prevent oil sump contamination

    d. In severe duty services, install a closed loop lubrication system

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

12

Introduction to Field Troubleshooting

Steam turbines and the process machines they drive do not always function as intended for a number of reasons: Perhaps the steam turbine is undersized for the applications and therefore cannot deliver the required power to the driven machine, or maybe there is a restriction in the steam supply line that limits steam flow and therefore output power, or the steam turbine base is not sufficiently rigid to control the shaking forces, which leads to incessant high vibration levels. In general, field problems can be caused by an assortment of factors, such as design problems, assembly errors, operator errors, or upset conditions, due to abnormal steam supply conditions, plugging, unexpected changes in the process load conditions, etc. When problems occur,

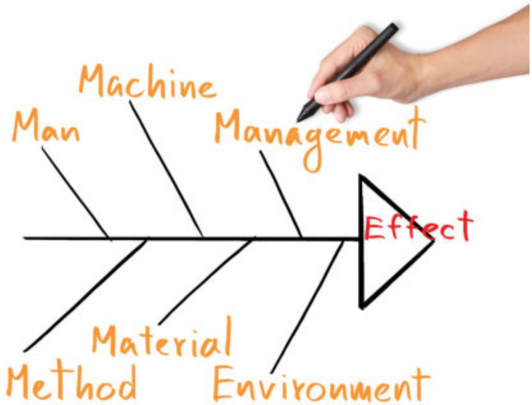


Figure 12.1 A fish bone diagram is one of many analysis tools that can be used when troubleshooting steam turbines.

it is important that their causes be identified in a timely manner in order that normal operations can be resumed as quickly as possible. This chapter will provide some basic troubleshooting tools you can use to assist in the problem-solving process.

Troubleshooting steam turbines can be challenging due to the fact that an observed problem may be rooted either in the driver end or the driven end. For example, if a steam turbine is unable to attain its design speed, the problem may be due to the inability of the steam turbine to provide sufficient power to the driven machine, or the problem may be due to an excessive process load, or the problem could be related to a controls issues. An example of a non-driver issue leading to a false steam turbine symptom is a pump that is severely cavitating. The sudden load changes due to cavitation could cause the steam turbine speed to become unsteady. This type of problem can only be corrected by resolving the process-end issue. It is important to keep an open mind when troubleshooting steam turbines and not focus on any one possible cause too soon in the investigation. Before focusing in on a turbine problem, convince yourself that the process load is normal and steady.

12.1 Common Symptoms

To troubleshoot, you must first characterize the nature of the problem, that is, you must clearly determine what your symptoms are. A symptom is an observable external effect that a machine or system problem is present. Here is a list of the most common complaints from users of steam turbines:

1. Steam turbine does not achieve rated power
2. Speed increases excessively when load is decreased
3. Excessive speed variation
4. Slow turbine speed acceleration
5. Governor not operating properly
6. Overspeed trip activates at normal operating speed
7. Overspeed does not trip at set speed
8. Excessive vibration or noise

12.2 Common Potential Causes

Once the symptom or symptoms are identified, you must next determine what potential causes can lead to your observed symptoms. Next, you need to methodically rule out potential cause until only one remains. This remaining potential cause is called the most probable cause. After some investigation and testing you should be able to uncover the actual cause of the problem. The true cause of the observed symptom(s) is called the root cause of your problem. Addressing a possible cause that is not the root cause will either have no effect or merely mask the real problem. Here is a listing of some of the most common potential causes of steam turbine problems:

1. Too many hand valves closed
2. Speed governor set too low
3. Inlet steam pressure too low
4. Exhaust pressure too high
5. Malfunctioning governor
6. Horsepower required by driven machine too high
7. Throttle valve not opening completely
8. Nozzles plugged
9. Inlet steam strainer plugged
10. Turbine steam pathway fouled due to poor steam quality
11. Throttle valve not closing completely
12. Throttle valve and valve seats cut or worn
13. Malfunctioning governor controls
14. Salt build-up on trip and throttle valve stem
15. Throttle assembly friction. (Replace components that are sticking or binding.)
16. Throttle valve looseness

17. Horsepower load too light with full inlet pressure
18. Rapidly changing load from the driven machine due to process conditions
19. Back pressure too low
20. High starting torque of driven machine
21. High rotational inertia of entire machine train
22. Restricted throttle valve travel
23. Governor not installed properly
24. Excessive vibration
25. Trip speed setting too low
26. Malfunctioning governor
27. Bad tachometer signal
28. Trip speed setting set too high
29. Overspeed trip valve unable to close. (Inspect trip valve.)
30. Misalignment
31. Worn bearing
32. Worn coupling. (Likely with gear type couplings.)
33. Unbalanced coupling
34. Unbalanced rotor
35. Piping strain. (Check cold piping fit up and ensure allowances have been made for thermal expansion.)
36. Excessive end play
37. Bent shaft
38. Excessive rubbing at shaft seal
39. Worn steam seals. Look for temperature increase on bearing housing.

In order to simplify the troubleshooting process, we have compiled the following field troubleshooting matrix (see Table 12.2). Keep in mind that only the most common symptoms have been included. As problems get more complex, we recommend that you work in a team setting to improve your chances of finding your root cause(s) quickly and efficiently.

12.3 Troubleshooting Example #1

Let's assume you have a steam turbine driving a vertical cooling water pump. You notice that you are not getting sufficient flow due to a low steam turbine speed. After verifying that the pump flow and discharge pressure are steady and that the pit level is sufficient to ensure adequate suction, you conclude you have a steam turbine issue.

You first select a group of possible causes related to "Steam turbine does not achieve rated power" and then write down all the "Possible Causes" for further review (see Table 12.1). Here you find that there are 10 possible causes of the problem. The next step is to systematically pare down the list by determining which potential causes are unlikely based on the information and data collected. This will leave you with the most likely cause, or root cause, of your problem. In this example, let's assume you eliminated all the possible causes except "Inlet steam strainer plugged." This would be sufficient cause to pull all steam strainers for inspection.

12.4 Troubleshooting Example #2

In this example, we will say that we are experiencing high vibration levels. By reviewing the

Table 12.1 Possible cause for "Steam turbine does not achieve rated power".

Symptom	Possible Cause (Advice)
Steam turbine does not achieve rated power.	
	1. Too many hand valves closed
	2. Speed governor set too low
	3. Inlet steam pressure too low
	4. Exhaust pressure too high
	5. Malfunctioning governor
	6. Horsepower required by driven machine too high
	7. Throttle valve not opening completely
	8. Nozzles plugged
	9. Inlet steam strainer plugged
	10. Turbine steam pathway fouled due to poor steam quality

troubleshooting table, we quickly find the following possible causes of this symptom:

1. Misalignment
2. Worn bearing
3. Worn coupling. (Likely with gear type couplings.)
4. Unbalanced coupling
5. Unbalanced rotor
6. Piping strain. (Check cold piping fit up and ensure allowances have been made for thermal expansion.)
7. Excessive end play
8. Bent shaft
9. Excessive rubbing at shaft seal
10. Worn steam seams. Look for temperature increase on bearing housing.

After some field checks, you have drawn the following conclusion:

1. Misalignment: *Alignment is found to be acceptable.*
2. Worn bearing: *Bearings were checked and OK.*
3. Worn coupling (Likely with gear-type couplings): *Coupling inspected and found to be OK*
4. Unbalanced coupling: *Coupling supplier has provided balance information, so this possibility is dropped for now.*

5. Unbalanced rotor: *Vibration analysis shows predominantly 1x vibration, which suggests imbalance in present.*
6. Piping strain (Check cold piping fit up and ensure that allowances have been made for thermal expansion): *Piping fit-up was checked earlier in the year and found to be fine.*
7. Excessive end play: *End play was found to be normal.*
8. Bent shaft: *Vibration analysis does not show high axial vibration to suggest the shaft is bent.*
9. Excessive rubbing at shaft seal: *Vibration analysis does not suggest an internal rub.*
10. Worn steam seams. Look for temperature increase on bearing housing: *No signs of a steam leak found on the casing.*

Based on the field findings, rotor imbalance is the most likely cause of the vibration. While the rotor is removed for balancing, it will be checked for straightness and signs of rubbing.

12.5 Steam Turbine Troubleshooting Table

Note: This troubleshooting table only applies to general purpose steam turbines rated at 1000 horsepower or less. It should not be applied to condensing turbine installations.

Instructions: Find the symptom that best describes your observation. Next record all the possible causes listed in the "Possible Cause" column. These are all the possible causes that should be investigated to determine the root cause of the problem.

Table 12.2 Common symptoms and their possible causes.

Symptom	Possible Cause (Advice)
Steam turbine does not achieve rated power.	
	1. Too many hand valves closed
	2. Speed governor set too low
	3. Inlet steam pressure too low
	4. Exhaust pressure too high
	5. Malfunctioning governor
	6. Horsepower required by driven machine too high
	7. Throttle valve not opening completely
	8. Nozzles plugged
	9. Inlet steam strainer plugged
	10. Turbine steam pathway fouled due to poor steam quality

(*Continued*)

Table 12.2 Cont.

Symptom	Possible Cause (Advice)
Speed increases excessively when load is decreased	
	1. Throttle valve not closing completely
	2. Throttle valve and valve seats cut or worn
	3. Malfunctioning governor
	4. Salt build-up on trip and throttle valve stem
Excessive speed variation	
	1. Governor droop adjustment required
	2. Malfunctioning governor controls
	3. Throttle assembly friction (Replace components that are sticking or binding)
	4. Throttle valve looseness
	5. Horsepower load too light with full inlet pressure
	6. Rapidly changing load from the driven machine due to process conditions
	7. Back pressure too low
Slow turbine speed acceleration	
	1. See all possible causes for "Insufficient power" above
	2. High starting torque of driven machine
	3. High rotational inertia of entire machine train

(*Continued*)

Table 12.2 Cont.

Symptom	Possible Cause (Advice)
Governor not operating properly	1. Restricted throttle valve travel
	2. Governor not installed properly
	3. Verify governor is designed for the proposed speed range
	4. Trip and throttle valve sticking due to salt build-up on stem
Overspeed trips activates at normal operating speed	
	1. Excessive vibration
	2. Trip speed setting too low
	3. Malfunctioning governor
	4. Incorrect tachometer signal
Overspeed does not trip at set speed	
	1. Trip speed setting set too high
	2. Bolt trip mechanism problem (Examine trip mechanism)
	3. Overspeed trip valve unable to close. (Inspect trip valve)
	4. Sticking trip and throttle valve due to salt build-up
Excessive vibration or noise	
	1. Misalignment
	2. Worn bearing

(*Continued*)

Table 12.2 Cont.

Symptom	Possible Cause (Advice)
	3. Worn coupling (Likely with gear type couplings)
	4. Unbalanced coupling
	5. Unbalanced rotor
	6. Piping strain (Check cold piping fit up and ensure allowances have been made for thermal expansion)
	7. Excessive end play
	8. Bent shaft
	9. Excessive rubbing at shaft seal
	10. Worn steam seams. Look for temperature increase on bearing housing.

12.6 Other Troubleshooting Approaches

A powerful tool available for improving the reliability of steam turbines is called the root cause analysis (RCA) or root cause failure analysis (RCFA) method. This difference between simple field troubleshooting and the RCFA method is that field troubleshooting helps you identify more obvious physical causes of an observed symptom, while the RCFA methodology digs deeper into state of affairs and attempts to uncover latent issues.

There are numerous RCFA methods on the market, such as "Tap Root," cause maps, fault trees, the "five why" methods, etc. Each of these methods offers its own advantages and disadvantages. We encourage readers to spend some time studying these methods in order to determine which one is best for their organization.

In order to provide the reader with a flavor of what RCFA are all about, we will provide an example of the simplest RCFA methods known as the "five why" approach. To employ the five why methods, the analyst simply asked "why" five times. Consider this example: A sleeve bearing fails due to lubrication contamination. We know that oil contamination is the physical root cause of the failure. If we ask why five times, we can uncover the latent root cause as follows:

Why? Bearing failed due to inadequate lubrication.

Why? Oil contamination due to water in oil.

Why? Excessive shaft packing leak.

Why? Shaft packing was worn out.

Why? Shaft packing ran too long. Perhaps we need an oil analysis program to detect water in the oil or a time-based replacement of the shaft packing.

As shown in this example, RFCA methods have the same goal of drilling down to the root cause or causes of a given failure mechanism. These methods become even more powerful when employed by interdisciplinary teams, which may be composed of operators, process engineers, machinery engineers, and a mechanics. The authors have personally participated on a number of these investigation teams and have found them to be an efficient way to analyze the more complex or costly problems. Your management should set failure or even cost criteria to determine when multidisciplinary RCFAs shall be performed.

When asked to participate in an RCA or RCFA team:

- Always keep an open mind.
- Remember that the RCFAs should be data driven and not agenda driven.
- Remember that finding the true root cause will make everybody's job a little easier.

References:

1. Website: http://www.taproot.com/
2. Website: http://reliability.com/industry/articles_db/
3. Website: http://www.thinkreliability.com/

Questions

1. List at least four (4) common symptoms experienced with steam turbines.
2. List at least six (6) common causes of steam turbine problems.
3. List the reasons a steam turbine may not be delivering rated power.
4. List the reasons a steam turbine may be experiencing excessive speed variation.
5. What do RCFA and RCA stand for?

Answers

1. List at least four (4) common symptoms experienced with steam turbines.

    a. Steam turbine does not achieve rated power

    b. Speed increases excessively when load is decreased

    c. Excessive speed variation

    d. Slow turbine speed acceleration

    e. Governor not operating properly

    f. Overspeed trip activates at normal operating speed

    g. Overspeed does not trip at set speed

    h. Excessive vibration or noise

2. List at least six (6) common causes of steam turbine problems.

    Here are 14 of the 39 common causes of steam turbine problems listed in this chapter:

    a. Too many hand valves closed

    b. Speed governor set too low

    c. Inlet steam pressure too low

    d. Exhaust pressure too high

    e. Malfunctioning governor

    f. Horsepower required by driven machine too high

g. Throttle valve not opening completely

h. Nozzles plugged

i. Inlet steam strainer plugged

j. Turbine steam pathway fouled due to poor steam quality

k. Throttle valve not closing completely

l. Throttle valve and valve seats cut or worn

m. Malfunctioning governor controls

n. Salt build-up on trip and throttle valve stem

3. List at least four (4) reasons a steam turbine may not be delivering rated power.

   a. Too many hand valves closed

   b. Speed governor set too low

   c. Inlet steam pressure too low

   d. Exhaust pressure too high

   e. Malfunctioning governor

   f. Horsepower required by driven machine too high

4. List at least three (3) reasons a steam turbine may be experiencing excessive speed variation.

   a. Governor droop adjustment required

   b. Throttle assembly friction (Replace components that are sticking or binding)

c. Throttle valve looseness

d. Horsepower load too light with full inlet pressure

5. What do RCFA and RCA stand for?

a. RCFA - Root cause failure analysis

b. RCA - Root cause analysis

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

13

Steam Turbine Monitoring Advice

Steam turbine temperatures, vibration levels, and speed all provide clues to its condition. Operators should always be vigilant to the performance and conditions of all their process machines, including steam turbines. This chapter briefly covers advanced steam turbine monitoring and troubleshooting methods that can keep them operating safely and efficiently and detect problems before a catastrophic failure can occur.

Figure 13.1 Operators should use their eyes, nose, ears, and sense of touch to monitor the condition of their steam turbines.

13.1 What Is the Steam Turbine Speed Telling You?

13.1.1 Is the Steam Turbine Running at the Correct Speed?

The speed of the turbine can be checked by several methods. One is by using a tachometer mounted on the turbine. A tachometer—comprised of a magnetic pick-up probe, toothed gear affixed directly to the turbine shaft, and a means of converting the gear teeth pulses to a rotational speed—is the best way to know the turbine speed. Speed can also be checked with a vibration reed tachometer or by capturing and inspecting the vibration spectrum, as the largest spectrum component is usually at running speed. Exercise extreme caution when using reed tachometers to adjust steam turbine speed. Reed tachometers should never be used for overspeed trip testing due to their unreliable nature and slow reaction to speed changes.

Most of the smaller turbines run in the 4000–7000 rpm range. A clue that the steam turbine speed is higher than the driven machines is the addition of a gear box for speed reduction. Gear boxes are usually found between steam turbine drives and large fans or pumps that run at 3600 or 1800 rpm. If the driven equipment is not providing sufficient pressure or flow, a speed check of the steam turbine is warranted.

13.1.2 Is the Speed Steady?

The control valve arm should be relatively steady if the speed is steady. If it is hunting or dithering, then the reason for the hunting must be found. The reason is usually one of two things. First, the governor may not be controlling the speed well. This scenario is more likely seen on general steam turbines with a hydraulic governor. Second, the turbine may be reacting to a shifting load on the driven machine, such as a centrifugal pump or compressor, and thus is being caused to hunt due to an unsteady load. One cannot automatically assume that the constant rhythmic change in speed is caused by a faulty governor.

13.1.3 Is a Speed Swing Acceptable?

Normal speed swing is determined by the acceptable output from the driven piece of equipment. If there is a swing, but the effects from the output machine are not causing problems for the process, it can be allowed to continue. However, incessant speed oscillations may lead to accelerated wear on valve stem packing, moving valve joints, valve stems, and all of the moving parts; this accelerated wear may eventually lead to a premature failure.

13.2 Assessing Steam Turbine Vibrations

13.2.1 What is Normal?

Generally, steam turbines run very smoothly. For comparisons and assessments, it is always good to know what the overall vibration levels are when all is considered OK. Less than 0.1 ips (2.54 mm/s) is a normal reading for general purpose steam turbines. Something significant has happened if vibration levels have doubled in a short time. More critical steam turbines may have noncontact probes installed to monitor shaft position and vibration. Vibration levels under 1.5 mils (38.1 μm) peak-to-peak should be considered normal.

Table 13.1 contains additional vibration guidelines for various classes of machines. The column on the far right titled "Steam turbines, gas turbines, generators, etc." provides advice about acceptable steam turbine vibration levels. Let's go through two basic examples: Let's say you obtained a field vibration measurement on a steam turbine of 0.11 inches per second (rms). First, you go down the in/sec (rms) column until you find 0.11. Then, you go to the far right column titled "Steam turbines, gas turbines, generators, etc." and read the comment. In this case, the comment reads "Newly Commissioned Machinery", which means the vibration level is what you would expect to see in a newly commissioned steam turbine. So this means that everything is fine. In this example, let's say you obtained a field vibration measurement on a steam turbine of 0.44 inches per second (rms). First, find the 0.44 inches per second (rms) value; then, go to the far right column titled "Steam turbines, gas turbines, generators, etc." and read the comment. In this case, the comment reads "Restricted Operation", which means at this vibration level you need to start planning your next repair in the near future.

13.2.2 What are Some Causes of Vibration in Steam Turbines?

Several issues can cause high vibration levels on steam turbines. We will discuss four (4) of the most common categories of vibration and their root causes:

1. High vibration due to imbalance, which usually shows up as a 1x vibration component in the vibration spectra, is due to a change in a rotor's balance condition. Imbalance is what causes a car tire to vibrate at high speeds after losing a balance weight or when clothes bunch up on one side of a washing machine during the

Table 13.1 ISO evaluation standard.

SI Units		**English Units**		**Machines < 15 Kw (20 HP)**	**Machines between 15 and 75 KW (20 to 100 HP)**	**Machines >75 Kw (100 HP)**	**Steam turbines, gas turbines, generators, etc.**
mm/ sec rms	**mm/ sec zero-peak**	**in/ sec rms**	**in/ sec zero-peak**				
0.28	0.40	0.01	0.02	Newly Commissioned Machinery	Newly Commissioned Machinery	Newly Commissioned Machinery	Newly Commissioned Machinery
0.45	0.64	0.02	0.03	Newly Commissioned Machinery	Newly Commissioned Machinery	Newly Commissioned Machinery	Newly Commissioned Machinery
0.71	1.00	0.03	0.04	Newly Commissioned Machinery	Newly Commissioned Machinery	Newly Commissioned Machinery	Newly Commissioned Machinery
1.12	1.58	0.04	0.06	Unrestricted Operation	Newly Commissioned Machinery	Newly Commissioned Machinery	Newly Commissioned Machinery
1.8	2.55	0.07	0.10	Unrestricted Operation	Unrestricted Operation	Newly Commissioned Machinery	Newly Commissioned Machinery

2.8	3.96	0.11	0.16	Restricted Operation	Unrestricted Operation	Unrestricted Operation	Newly Commissioned Machinery
4.5	6.36	0.18	0.25	Restricted Operation	Restricted Operation	Unrestricted Operation	Unrestricted Operation
7.1	10.04	0.28	0.40	Damage Occurs	Restricted Operation	Restricted Operation	Unrestricted Operation
11.2	15.84	0.44	0.62	Damage Occurs	Damage Occurs	Restricted Operation	Restricted Operation
18	25.46	0.71	1.00	Damage Occurs	Damage Occurs	Damage Occurs	Restricted Operation
28	39.60	1.10	1.56	Damage Occurs	Damage Occurs	Damage Occurs	Damage Occurs
45	63.65	1.77	2.51	Damage Occurs	Damage Occurs	Damage Occurs	Damage Occurs
71	100.42	2.80	3.95	Damage Occurs	Damage Occurs	Damage Occurs	Damage Occurs

Notes: 1) This evaluation standard, which is based on a commonly accepted ISO standard, is intended for machines operating with rotational speeds between 600 and 12,000 RPM. The standard only applies to overall (unfiltered) casing vibration readings in the frequency range of 10 to 1,000 Hz. 2) At no time should this guideline substitute for experience and good engineering judgment. 3) The most reliable method of determining alarm settings is trending vibration readings over time after establishing baseline values and understanding the normal variability in vibration to operating and ambient conditions.

spin cycle. Here are some common causes of steam turbine imbalance:

a. Poor steam quality can affect the mechanical integrity of the blading, which can cause the blades to fail and unbalance the steam turbine rotor.
b. Slugging of the turbine with water can result in blading and shroud bands damage, which will lead to imbalance.
c. In some cases, water slugging can also cause a bow in the shaft, which will grossly imbalance the rotor and elevate vibration levels.
d. A bent shaft can also result in a large imbalance due to a shift of rotating mass.

2. High vibration due to piping strain/casing distortion can show up as 1x and/or 2x vibration components in the vibration spectra. Inadequately supported and restrained steam piping will lead to excessive piping strain and casing distortion. Along with high vibration, you may also notice uneven wear patterns on the bearings.
3. High vibration due to driver to driven machine misalignment will result in high 1x or 2x components in the vibration spectra. When aligning the turbine, always take into account the expected vertical growth of both machines. Check the alignment when both machines are hot to ensure a good alignment.

4. High vibration due to a failing bearing. The most common cause of high vibration due to a bearing failure is accelerated wear resulting from oil contamination. An increasing bearing clearance affects the bearing film stiffness and therefore the overall rotor-dynamic performance. A simple lift check can be used to evaluate the amount of bearing wear. Normally, as a bearing fails, the oil in the oil bulb or sight glass will darken dramatically.

Table 13.2 can be used as a quick reference for analyzing the most common causes of steam turbine vibration. There are many other similar tables available that relate mechanical defects to likely frequency content.

13.3 Steam Turbine Temperature Assessments

13.3.1 Bearing Temperatures

Embedded thermocouples are useful for detecting high bearing temperatures caused by a failing bearing, lack of lubrication, lube oil contamination, etc. If high bearing temperatures are encountered, insure lubricating oil supply flow is present. Never rely on the lubricating oil temperature leaving the bearing as an indication of bearing health.

13.3.2 Oil Temperatures

Oil temperatures should be monitored and kept well below 140 °F (60 °C). In addition, it is very

Table 13.2 Steam turbine vibration analysis basics.

Mechanical Issue	Most Likely Frequency Content	Comment
Imbalance	1x	Horizontal and vertical amplitudes should be similar. If not, you may have a resonance situation.
Misalignment	1x or 2x	A high axial vibration level is a strong indication of machine to machine misalignment.
Piping Strain	1x or 2x	Uneven bearing wear is a further indication of piping strain.
Resonance	1x	Vibration levels are extreme sensitive to speed.

important to follow the manufacturer's recommendations on the temperature to start the turbine. See rules of thumb below. Always ensure that the oil is warm before starting. This is especially true in cold climates or with higher viscosity oils.

13.4 Common Governor Control Problems

Governors are not usually a source of problems. It is important to be aware of the kind of governor controlling the turbine. There are pure hydraulic designs, electronic designs, or a hybrid of the two. To insure reliable operation, it is wise to put hydraulic governors on the oil analysis program along with the turbine. Governors seldom get inspected unless they begin to malfunction; reactionary maintenance on equipment this important is not recommended. It is possible to change the oil of pure hydraulic governors "on the fly," i.e., in operation. However, you must be very careful to insure the oil level in the governor does not get too low or there will be a loss of speed control.

13.4.1 Steam Turbine Loss of Power

If you suspect a steam turbine has lost horsepower, check for the following common causes:

1. Check the inlet steam pressure to insure it is correct and not low.
2. Check the steam pressure at the nozzles to the first stage can indicate if there are problems with the stop valve screen.
3. If there are hand valves on the turbine, insure that they are all open.
4. Ensure that the trip and throttle valve is fully open.
5. If the losses have developed over a long time the turbine steam pathway may be fouled due to poor steam quality.

13.4.2 Steam Turbine Sealing

There are two common types of steam shaft seals. One is carbon packing or rings, which are prone to leaks. When completing an overhaul, remember that there

Figure 13.2 Typical self-contained mechanical-hydraulic governors used on small steam turbines. (Courtesy of Woodard Inc.)

are two sealing surfaces on carbon packing rings. The first is the shaft diametrical clearance; the second is the stuffing box face where the side of the carbon packing rests. Usually the diametrical shaft clearances are checked, but many times the stuffing box face condition is not. It is necessary for the stuffing box face to be flat in order for sealing to take place.

The second steam seal type is the labyrinth style. Sometimes both types of steam seals are present in the same turbine. This is especially true of general use turbines. Special use turbines usually only have the labyrinth type of seals. If any of these sealing system components do not function properly, steam can enter the lubricating oil and result in greatly reduced bearing lives.

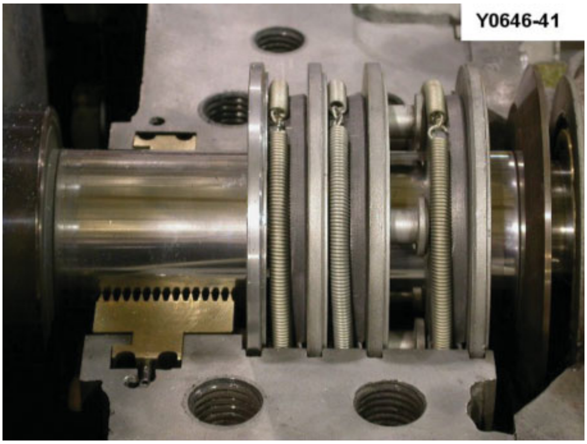


Figure 13.3 Carbon ring packing seals are shown on the right and labyrinth seal on the left.

13.4.3 Oil Analysis as it Applies to Steam Turbines

Monthly lubrication oil analyses are preferred, especially if the turbine has a history of water in the lubricating oil. If possible, take the sample in the return oil flowing from the turbine, not in the tank. This step will insure a more representative operating oil sample is collected, so that a more accurate oil analysis may be performed.

Here are some common oil-related problems to watch out for:

1. Unacceptable levels of contaminants, such as water and dirt, in the oil sample. High water levels may indicate a failing or ineffective steam seal. High levels of dirt may indicate a need for better bearing housing seals.

2. Increasing levels of wear metals. Increasing levels of metals are normally an indication of a failure bearing or seal.
3. When taking the oil sample look for signs of entrained air and/or indications of foaming. Foaming is often a sign of either breakdown in your additive package or oil contamination.
4. When taking the oil sample look for any signs of an oil/water emulsion. A stable emulsion in the oil sample indicates water in the oil and the inability of the oil to breakout the water. Signs of an emulsion may be an indication that your additives are degrading or failing.

13.4.4 Formation of Sludge and Varnish

High temperatures can cause a lubricant and its additives to degrade and form sludge and varnish. These degradation products are generally unstable in the oil and tend to form a visible coating on machine surfaces at the exact location where the oil has degraded (see Figure 13.4).

Over time, some of these deposits can thermally cure to a tough enamel-like coating. Other types of deposits, generally in cooler zones, remain soft or gummy, and may in some cases appear clear and grease-like. If varnishing is excessive, review your lubricant selection and ensure you have an adequate supply of oil to the affected bearing.

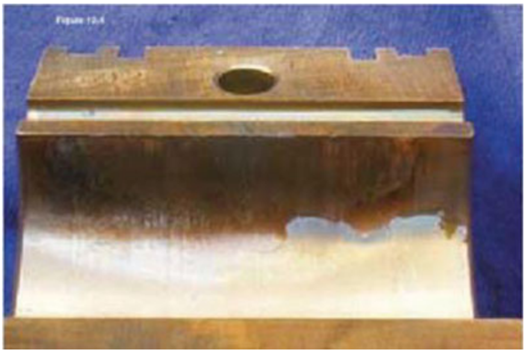


Figure 13.4 Varnish Formation on Plain Bearing and Shaft.

13.4.5 Steam Piping and Supports

Steam piping and piping supports are usually out of sight and out of mind. Because piping supports and restraints are not at eye level, they tend to be forgotten. There is also a tendency to assume the steam piping is designed and installed properly and therefore ignored. However, after many thermal cycles, supports and restraints can deteriorate, move out of place, and sometimes fail. With this in mind, operations and maintenance should commit themselves to perform regular inspections on pipe hangers, supports, guides, and restraints (see Figure 13.5).

During the piping installation:

- Always check pipe supports to insure that the shipping and hydro blocks are removed before the turbine is operated. Do not discard the pipe support hydro blocks as they will be needed if a hydro is required.

- Insure that the piping cannot put excessive loads on the turbine in any way.

Here are a few steam turbine piping tips to keep in mind during inspections:

- Pipe shoes should always be free to move, resting on their support and not out of place.
- Insure all drains are open and working before each turbine start-up.

13.4.6 Steam Turbine Supports

Most steam turbines and equipment that operate hot have a method of allowing for expansion due to heat. This is controlled so the tolerances and clearances of the equipment can be maintained from cold

Figure 13.5 Broken pipe hanger support.

to hot. Some steam turbines, usually the small general purpose ones, use a flex leg that moves from over the center of the support in one direction to over the center of support in the other direction once it is hot. Some special-use turbines use slide feet and guides. Some have grease fittings to keep them lubricated. These must be free to move otherwise, vibration levels could go up quickly for no apparent reason if they stick. It is not unusual to see a turbine that has been in service for a long time to have insulation and insulation wire wire fall onto the slide feet or guides and impede sliding motion. This area should be inspected and kept both clean and lubricated. This applies to compressors, fans, and pumps, as well as turbines.

13.4.7 Overspeed Trip Systems

These systems should be tested at least annually. Tests should be well documented and, when possible, the mechanism should be inspected if it is of the mechanical type. The entire system should be tested mechanically as well as electronically if it has both systems. It is not sufficient to test electronically and get an indication that a trip would have taken place. Poor steam quality from the boiler can result in an unwanted accumulation of solids on steam turbine blading. Deposits can build up on the control and stop valve stems, and prevent the steam valve from closing due to jamming between the stem and stem bushing.

A good practice is to use the trip mechanism to cause a shutdown when the turbine is going to be stopped for any reason. This practice allows most of the parts of the trip system to be tested as if a trip was to take place.

13.5 Other Inspections

1. Look for smoking insulation, which can mean lubricating oil is in the insulation and a potential fire could result. Look for the source of the oil as well.
2. It is not unusual to see steam turbines without insulation. However, all steam turbines should be covered with insulation to minimize internal condensation. With no insulation, it is possible to warp the turbine casing, causing misalignment between bearings and sometimes additional steam leaks. A lack of adequate casing insulation will increase condensation in the turbine, resulting in erosion of the turbine casing and blading.
3. Look for leaking sentinel valves. They represent a large expense in testing. A valve that is not working correctly or leaking results in a loss of steam, and thus turbine efficiency is decreased.
4. If the turbine uses a shim pack type of coupling, look for shim pieces under the coupling guard on the foundation. Their presence will indicate that a shim pack is coming apart. This information makes

inspecting what is cleaned up after a maintenance event very important.

5. If the turbine uses an external oil skid, check that only one pump is running. If the spare is running, find out why.
6. If oil pressures are low or both pumps are running, carefully touch the outlet side of the pressure relief valves on the oil reservoir and insure that the valves are not leaking through. If the inlet to the pressure relief valves and its outlet piping are at the same temperature, it is leaking through.
7. Touch the oil cooler inlet and outlet piping to insure there is a noticeable decrease in temperature across the cooler. Be careful not to get burned.
8. Check that the turbine shaft packing is not leaking excessively; otherwise, water could be entering the oil.
9. Insure that all slides and methods for allowing for expansion of the turbine from cold to hot are clean and unobstructed.

13.6 Good Rules of Thumb for Steam Turbines

1. When shaft displacement reaches a value of 60% of bearing clearance, damage will always be found on babbited bearings.

2. When vibration values double from "normal" values, something significant has happened and should be investigated.
3. Sentinel valves can be removed in most cases. They are only a tattletale and not a "safety" device. They are usually treated as a relief valve; more money is spent on them than should be, and for no good reason. A management of change (MOC) initiative should be introduced to thoroughly research the removal. When sentinel valves are leaking, they waste steam and money. Removal of the sentinel valve should only be done when a full flow relief valve is already installed between the turbine exhaust flange and first block valve in the exhaust.
4. If the turbine will not turn when steam is applied and then freely turns when all is heated up evenly, there are serious issues—e.g., internal alignment or labyrinth seal—and the reason should be sought. The start-up procedure for this turbine should be reevaluated as well.
5. Insure turbine lubricating oil is greater than 100 °F (37.8 °C) before attempting to start the turbine unless the manufacturer requires a different temperature.

6. The correct viscosity of turbine lubricating oil is generally dictated by the driven equipment—not the turbine. If a gear box is involved, and the same oil is used in both the turbine and the gearbox, insure the oil is thick enough for proper gear lubrication.

Questions

1. A clue that the steam turbine speed is higher than the driven machines is the addition of a ____________ for speed reduction.
2. ____________ ____________ (two words) should never be used for overspeed trip testing due to their unreliable nature and slow reaction to speed changes.
3. ____________ lubrication oil analyses are preferred, especially if the turbine has a history of water in the lubricating oil.
4. ____________ ____________ ____________ ____________ (four words) are preferred, especially if the turbine has a history of water in the lubricating oil.
5. When shaft displacement reaches a value of ____________ (%) of bearing clearance, damage will always be found on babbited bearings.

Answers

1. A clue that the steam turbine speed is higher than the driven machines is the addition of a __gear box__ for speed reduction.
2. __Reed__ __tachometers__ (two words) should never be used for overspeed trip testing due to their unreliable nature and slow reaction to speed changes.
3. __Monthly__ lubrication oil analyses are preferred, especially if the turbine has a history of water in the lubricating oil.
4. __Monthly__ __lubrication__ __oil__ __analyses__ (four words) are preferred, especially if the turbine has a history of water in the lubricating oil.
5. When shaft displacement reaches a value of __60%__ (%) of bearing clearance, damage will always be found on babbited bearings.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

14

Beyond Start-ups, Shutdowns, and Inspections

In the preceding pages, we have discussed proven methods you can use to avoid premature steam turbine failures and ensure long runs between repairs. These methods include learning 1) how to correctly start and stop steam turbines, 2) what to look for regarding a turbine's mechanical condition, and 3) how to watch for changing conditions that might indicate a deteriorating condition. In a nutshell, this reference book encourages safe steam turbine operations through basic education and constant vigilance. The authors hope this introductory training material has provided the required knowledge to perform your job satisfactorily and encourages you to continue learning about steam turbines.

Beyond basic turbine inspections and operating procedures, there are other steps an organization can take to ensure every steam turbine enjoys a long, reliable, and uneventful lifetime. Most of these steps are beyond your control, but it's good to be aware of safeguards and methods available to optimize the life-cycle costs of your steam turbines. These steps include:

1. Selecting the proper steam turbine for your specific application. All turbines should be:
   a. Efficient for the given steam conditions and operating speeds
   b. Free of critical speeds in the expected operation range
   c. Equipped with a reliable overspeed trip system
   d. Equipped with well-designed lubrication and sealing systems
   e. Designed with a heavy duty baseplate and provisions for thermal expansion
2. Installing all turbines on good foundation and piping that is well supported and restrained.
3. Confirming that a detailed piping analysis has been performed to ensure low piping stresses under operating conditions.
4. Following start-up and shutdown procedures that are consistent with the manufacturer's recommendations.

5. Developing and utilizing best in class predictive and preventative maintenance (PdM) programs. (Glossary A contains some recommended PdM programs for steam turbines.)
6. Performing failure analyses on premature failures in order to prevent recurrence.

However, even if we faithfully follow all these reliability improvement steps, all good things eventually come to an end. All steam turbines eventually wear out and fail to perform their required function. After many years of service, steam turbines will announce they are wearing out well before they fail catastrophically. Wear out symptoms include:

- Higher than normal vibration
- Loss of power or speed
- Higher than normal bearing temperatures
- Bearing particles in the oil
- Excessive packing leaks
- Casing steam leaks

When it is time to take a steam turbine out of service for repair, take the opportunity to restore it back to the manufacturer's standards as economically possible. Always demand the best repair available. Sub-par repairs will only result in frequent repairs and frustration.

Take-away: Take care of your steam turbines and they will take care of you.

Also of Interest

Check out these other titles from Scrivener Publishing

Hydrogeochemistry Fundamentals and Advances Volume 1: Groundwater Composition and Chemistry, by Viatcheslav V. Tikhomirov, ISBN 9781119160397. This three-volume set, beginning with this first volume on the fundamental composition and chemistry of groundwater, is the most comprehensive and up-to-date treatment available on hydrogeochemistry, one of the most important earth sciences in industry and environmental science. *NOW AVAILABLE!*

Project Management in the Oil and Gas Industry, by Mohammed A. El-Reedy, ISBN 9781119083610. The most comprehensive treatment of the processes involved in the management and construction of projects in the oil and gas industry. *PUBLISHING IN MARCH 2016.*

Acid Gas Extraction for Disposal and Related Topics, Edited by Ying Wu, John J. Carroll, and Weiyao Zhu, ISBN 9781118938614. This fifth volume in the series, Advances in Natural Gas Engineering, offers the most in-depth and up-to-date treatment of acid gas extraction for disposal, an important innovation in natural gas engineering. *PUBLISHING IN MARCH 2016.*

Pollution Control Handbook for Oil and Gas Engineering, Edited by Nicholas P. Cheremisinoff, ISBN 9781119117612. This handbook is intended to provide students, petroleum engineers, environmental managers, environmental engineers, and chemical engineers with practical information and calculation methods for pollution control, management, technologies, and practices, as well as a convenient source of information on equipment and process terminology, and overviews of U.S. and European Community regulations in the oil and gas sector. *PUBLISHING IN SPRING 2016.*

Hydraulic Modeling, by Victor Lyatkher and Alexander M. Proudovsky, ISBN 9781118946190 Combining mathematical and physical modeling, the authors of this groundbreaking new volume explore the theories and applications of hydraulic modeling, an important field of engineering that affects many industries, including energy, the process industries, manufacturing, and environmental science. *PUBLISHING IN SPRING 2016.*

Seismic Loads, by Victor Lyatkher, ISBN 9781118946244. Combining mathematical and physical modeling, the author of this groundbreaking new volume explores the theories and applications of seismic loads and how to mitigate the risks of seismic activity in buildings and other structures. *NOW AVAILABLE!*

Fundamentals of Biophysics, by Andrey B. Rubin, ISBN 9781118842454. The most up-to-date and thorough textbook on the fundamentals of biophysics, for the student, professor, or engineer. *NOW AVAILABLE!*

i-*Smooth Analysis: Theory and Applications*, by A.V. Kim, ISBN 9781118998366. A totally new direction in mathematics, this revolutionary new study introduces a new class of invariant derivatives of functions and establishes relations with other derivatives, such as the Sobolev generalized derivative and the generalized derivative of the distribution theory. *NOW AVAILABLE!*

Reverse Osmosis: Design, Processes, and Applications for Engineers 2nd Edition, by Jane Kucera, ISBN 9781118639740. This is the most comprehensive and up-to-date coverage of the "green" process of reverse osmosis in industrial applications, completely updated in this new edition to cover all of the processes and equipment necessary to design, operate, and troubleshoot reverse osmosis systems. *NOW AVAILABLE!*

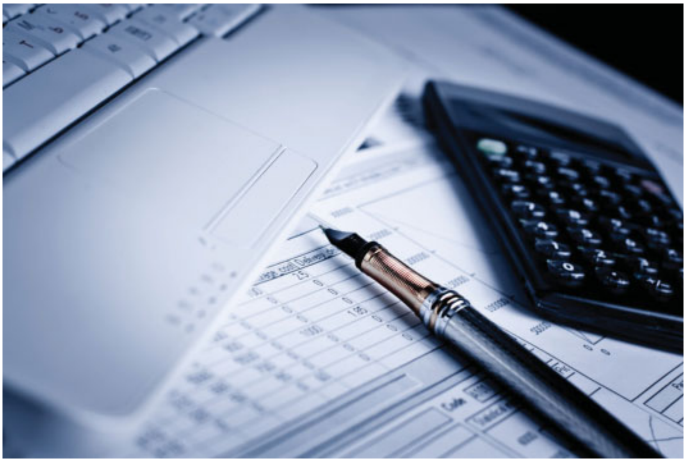
Pavement Asset Management, by Ralph Haas and W. Ronald Hudson, with Lynne Cowe Falls, ISBN 9781119038702. Written by the founders of the subject, this is the single must-have volume ever published on pavement asset management. *NOW AVAILABLE!*

Open Ended Problems: A Future Chemical Engineering Approach, by J. Patrick Abulencia and Louis Theodore, ISBN 9781118946046. Although the primary market is chemical engineers, the book covers all engineering areas so those from all disciplines will find this book useful. *NOW AVAILABLE!s*

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

Appendix A

An Introduction to Steam Turbine Selection



When the end user needs to select a general purpose back pressure steam turbine driver, an exchange of information on required turbine performance will be required by the purchaser. The manufacturer will need information on the basic turbine performance requirements, what power is required, equipment being driven, inlet steam pressures and temperatures, and the exhaust header pressures from the purchaser and how much steam is available. The manufacturer will then take this supplied data and review their standard equipment selections and match the customer requirements with one of their turbines. To arrive at a potential turbine selection, the turbine engineer must review manufacturer's charts and graphs to evaluate various options he has available for the internal components of the turbine. In addition, the manufacturer will also review historical references for similar applications that can be used to assure the engineer that the selected turbine will perform reliably at the site.

One of the first steps in selecting a steam turbine is calculating the ***Theoretical Steam Rate*** (*TSR*). The *TSR* is the amount of steam flow needed to drive the turbine at the specified steam conditions, assuming that the turbine is 100% efficient. However, as 100% efficiency is not possible it is referred to as the Theoretical Steam Rate. The *TSR* is expressed in units of pounds of steam per horsepower-hour (lb/hp-hr). Since the *TSR* is not the actual energy extraction we have available, we must make some corrections to compensate for the differences in theoretical and actual energy being extracted from inlet to exhaust steam conditions. To achieve this, we must calculate the *TSR* first, then divide by the steam turbine efficiency and then add the mechanical power losses of the seals, bearings, gearboxes, inlet valves and exhaust. We will call this corrected value the ***Actual Steam Rate*** (*ASR*), which is the steam rate we will need to operate the turbine at the plant site.

Theoretical Steam Rate (TRS) $= 2545/(h_1 - h_2)$

TSR units are pounds/horsepower- hours or (Lb/hp-hr)

2545 is a constant, (2545 Btu/hp-hr)

h_1 = enthalpy of steam at the inlet pressure and temperature.

British thermal unit/pound (Btu/lb)

h_2 = enthalpy of steam at the exhaust pressure and temperature.

British thermal unit/pound (Btu/lb)

The Btu or **British thermal unit** (Btu) is defined as the quantity of heat required to raise 1 lbm of water from 59.5 °F to 60.5 °F. Therefore 1 Btu = 778.17 ft lbf.

We need to define the enthalpy terms, h_1 & h_2, in more detail before we proceed.

The ***Enthalpy*** (h_1 and h_2) above is a thermodynamic property that is a measure of the heat energy in a system or total energy of the steam at the stated pressure and temperature. Since enthalpy is not a quantity that can easily be measured with a gauge or flow meter, we must use special tables and diagrams that give us the enthalpy of steam based on the pressure and temperature of the steam. Here, we will use the symbol of h_1 as the enthalpy at the inlet steam conditions and h_2 as the exhaust steam conditions. There are special steam tables and Mollier diagrams which provide the state of steam at various pressure and temperatures.

We will be using two sets of steam tables. One is called the ***superheated steam table*** and the other is the ***saturated steam table.***

The superheated steam tables will be used for the inlet steam conditions where the steam is always dry and it clearly has only one value on the table labeled "h", specific enthalpy of superheated steam.

The saturated steam tables will be used for the exhaust steam conditions. The data in the saturated steam tables always refers to steam at a particular saturation point, also known as the boiling point. This is the point where water (liquid) and steam (gas or vapor) can coexist at the same temperature and pressure. Because water can be either liquid or gas at its saturation point there are two measures of enthalpy; one is called enthalpy of saturated water (liquid) labeled as "h_f" and the other is called enthalpy of dry saturated steam (gas) labeled "h_g". Since this is not a thermodynamic course we will only use the value of "h_g"

when we are looking at the saturated steam tables in our examples. Our assumption is that the exhaust steam is always in the vapor phase. We know this is not always true but this requires more knowledge of thermodynamics.

See Tables A.1 and A.2 for sample of steam tables.

The ***steam tables*** will be used to find the enthalpy of the steam inlet and exhaust conditions, h_1 and h_2. For the inlet conditions we will use the superheated steam tables because the steam inlet must be in the superheated range and the steam condition in the exhaust will typically come from the saturated steam tables because the steam is saturated. Remember these tables are normally stated in absolute pressure, i.e., PSI absolute = pressure gauge reading + 14.7 psi. This topic was covered in previous chapters.

The ***Superheated Steam*** Table A.1 shows the steam conditions when it is superheated. At the top of each table is a pressure (P = 600) and the column on the left is the temperature in degrees F. For the inlet conditions, we will use the superheated table to find the enthalpy of the steam for our calculations. There are many more superheated steam conditions then the small section in Table A.1; you will need to find or purchase a complete set of steam tables if you need to see all the possible steam conditions.

Table A.1 Section of superheated steam table.

Superheated steam table				
	h **= BTU/lb**		***v*** **= ft³/lb**	
	600 psi		**700 psi**	
Temperature °F	***h***	***v***	***h***	***v***
500	1216	0.7946	XXX	XXX
550	1255	0.8748	1243	0.7274
600	1289	0.9452	1280	0.7926
650	1321	1.011	1313	0.852
700	1351	1.073	1344	0.9073
750	1379	1.132	1374	0.9595
800	1408	1.19	1403	1.011
850	1435	1.247	1431	1.06
900	1463	1.302	1459	1.109
950	1490	1.357	1487	1.157
1000	1518	1.411	1515	1.204
1100	1573	1.517	1570	1.296
1200	1628	1.622	1626	1.387
1400	1739	1.829	1738	1.565
1600	1854	2.033	1853	1.741
1800	1971	2.236	1970	1.915
2000	2091	2.438	2090	2.089

The ***Saturated Steam*** Table A.2 shows steam conditions when it is saturated, which we usually find in the turbine exhaust. Our definition of saturated is that the steam cannot accept any more moisture at the given pressure and temperature without liquid forming. In the table the two left most columns show

Table A.2 Section of saturated steam table.

Saturated steam table - pressure					
v_g & v_f = ft³/lb		h_g & h_f = BTU/lb			
Pressure (PSI)	**Temperature (°F)**	h_g	h_f	v_g	v_f
					x = 100%
120	341.3	1191	312.7	3.73	1.789
130	347.4	1193	319	3.457	1.796
140	353.1	1194	325.1	3.221	1.802
150	358.5	1195	330.7	3.016	1.809
160	363.6	1196	336.2	2.836	1.815
170	368.5	1197	341.3	2.676	1.821
180	373.1	1198	346.3	2.533	1.827
190	377.6	1199	351	2.405	1.833
200	381.9	1199	355.6	2.289	1.839
250	401	1202	376.2	1.845	1.865

Table A.2 Cont.

Saturated steam table - pressure					
v_g & v_f = ft³/lb		**h_g & h_f = BTU/lb**			
Pressure (PSI)	**Temperature (°F)**	**h_g**	**h_f**	**v_g**	**v_f**
300	417.4	1204	394.1	1.544	1.89
350	431.8	1205	409.9	1.327	1.912
400	444.7	1205	424.2	1.162	1.934
450	456.4	1206	437.4	1.033	1.955
500	467.1	1205	449.5	0.9283	1.975
550	477.1	1205	460.9	0.8423	1.994
600	486.3	1204	471.7	0.7702	2.013
700	503.2	1202	491.5	0.6558	2.051
800	518.4	1199	509.7	0.5691	2.087
900	532.1	1196	526.6	0.5009	2.123
1000	544.8	1192	542.4	0.4459	2.159
1200	567.4	1184	571.7	0.3623	2.232
1400	587.2	1174	598.6	0.3016	2.307
1600	605.1	1163	624	0.2552	2.386
1800	621.2	1150	648.3	0.2183	2.472
2000	636	1136	671.9	0.1881	2.565
2500	668.3	1092	730.8	0.1307	2.86
3000	695.5	1016	802.6	0.0842	3.432
3203.6	705.4	903	902.5	0.0505	5.053

the pressure and temperature for the 100% saturated steam. If for a given pressure we find the exhaust steam temperature is lower than the temperature listed in the table then we know the steam has formed liquids. Most turbine exhausts are designed to accept saturated steam and we will only consider the saturated condition in our examples, "h_g" column.

Specific volume (v) in the steam tables is simply the ratio of steam volume to its mass in that volume. It is the reciprocal of density or inversely proportional to density.

$$v = V/M = \text{Volume/Mass}$$

v = specific volume (ft^3/lb)

V = Volume (ft ^{3})

M = mass (lb)

P = density (lb/ft^3)

There are many resources on steam tables and how to use them as well as the Mollier diagrams, which show all conditions of the steam. These two sources of information have the same data but the Mollier diagram is in a graph. Our preference is to use the tables since we learned thermodynamics with steam tables. You are encouraged to explore these resources and to develop a better understand of how they can be used. Our examples below will only refer to the steam tables.

The turbine actual steam rate is the quantity of steam required by the turbine to develop the output power requirements in units of pounds/horsepower – hour (lb/hp-hr).

Actual Steam Rate (ASR) = *TSR*/turbine efficiency; *ASR* units are lb/hp-hr.

The typical single-stage, general purpose, back pressure turbine efficiency range is between 30 to 60%. The efficiency of a single-stage turbine is taken from the graph below and is based on something called the ***Velocity Ratio***. The velocity ratio is simply the ratio of the rotating blade speed (V_b) divided by the velocity of the steam leaving the nozzle ring (V_j) before it hits the rotating blades.

The ***velocity ratio*** is something the manufacturer will use to find the best speed, rotating wheel diameter and steam velocity for the specified steam conditions. There is much more information on how to calculate these ratios, but we will only use the Figure A.1 for reasonable single-stage turbine efficiencies in the 30 to 60% range.

The ***Total Mechanical Losses*** are the power losses due to the bearings for the turbine and driven equipment, carbon ring seals and mechanical seals. We recommend using an estimated power loss of 2 to 4% of the total power as a first estimate for the mechanical losses. Once the bearings and seals are selected a

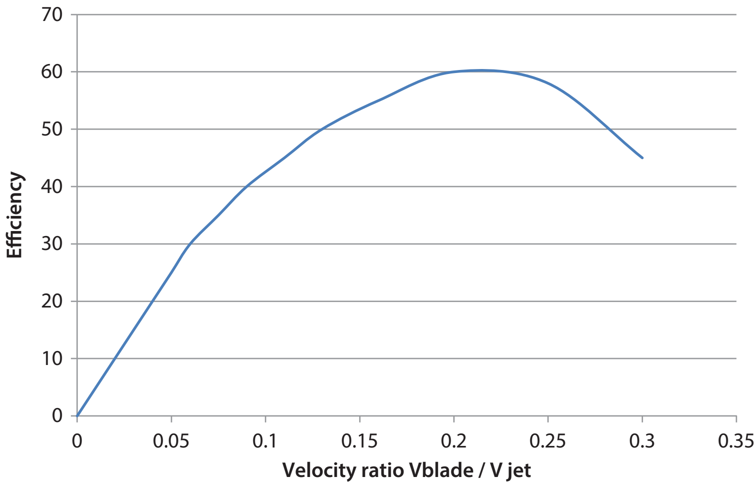


Figure A.1 Velocity Ratio vs turbine efficiency for single-stage turbine.

more accurate valve for the mechanical losses can be received from the manufacturer.

Now we will work several examples to develop a better understanding of how these concepts are used.

<u>Example 1: Theoretical Steam Rate</u>

Assume we have a single-stage steam turbine (60% efficient) with steam inlet conditions for 600 psia at 550 °F. The exhaust of the turbine is connected to the 150 psia steam system and we want to drive a 250 horsepower centrifugal pump with mechanical seals and hydrodynamic bearings. We want to know how much steam flow is required to power the pump and turbine.

a. ***TSR*** = 2545 btu/hp-hr/(h_1–h_2)

h_1 = 1255 btu/lb (steam enthalpy at 600 psia & 550 F). See superheated steam table above, enter 600 psia and 550 °F, then find the enthalpy column (h) which = 1255 btu/lb. This is the expected enthalpy at inlet conditions.

h_2 = 1195 btu/lb (steam enthalpy at 150 psia saturated steam conditions). See saturated steam table above, find 150 psia on the left column then read across to column hg = 1195 btu/lb. This is the expected enthalpy at saturated steam in the exhaust.

TSR = 2545 btu/hp-hr/(1255 btu/lb – 1195 but/lb)
= 2545 btu/hp-hr/60 btu/lb
= 42.42 lb/hp-hr

Now we take the *TSR* and divide by steam turbine efficiency to get a real number used to select turbines and size steam piping.

b. ***ASR*** = *TSR*/efficiency = 42.42 lb/hp-hr/ 60% efficiency.
= 42.42 lb/hp-hr/0.60 = 70.69 lb/ hp-hr, this is the actual steam rate needed.

Now we need to know all the mechanical losses.

c. **Total Mechanical losses** = seals & carbon rings + bearing; Note: Because this steam turbine has bearings, seals, and carbon rings we will assume the mechanical losses will run about 4% of the rated power. Therefore, the estimated losses in this example will be: 250 horsepower × 4% = 250 × 0.04 = = 10 hp.

Total hp required for the steam turbine and pump = 250 + 10 = 260 hp; this is the power needed by the steam turbine including losses from seal and bearings. More accurate mechanical loss values will be supplied by the manufacturer but a rough estimate for now is to use a power loss of 2 to 4%.

The inlet flow of steam required is given by the equation below;

d. **Steam weight flow** = *ASR* × Horsepower
= 70.69 lb/hp-hr × 260 horsepower
= 18,380.55 lb/hr.

From these calculations we can say that we need to have 18,380.55 lb/hr of steam at the inlet conditions supplied to the turbine to develop the 250 horsepower at the pump impeller.

Example 2: Horsepower calculation

Assume we have an excessive capacity of steam in the amount of 25,000 lb/hr and want to use it to produce electricity. How much electricity can we produce with this amount of steam?

Assume the steam conditions are 600 psia at 550 °F inlet conditions and exhausting into 150 psia steam header. Also assume we have a turbine efficiency of 60%.

We can rearrange the steam weight flow equation to find the available horsepower for a given steam weight flow and actual steam rate by the following equation.

Horsepower = Steam weight flow/*ASR*

HP = Steam weight flow/2545/(h_1–h_2)/0.60

a. **Horsepower** = [(25,000 lb/hr/(2545/(1255 btu/lb – 1195 btu/lb))/0.60]
   = 25,000 lb/hr/70.69 lb/hp-hr = 353.63 hp is the power that could be developed from this quantity of steam.

Now we need to consider the mechanical losses to find the total power available.

b. **Total Mechanical losses** (turbine & generator) = 353.63 hp × 2.25% = 353.63 × 0.0225 = 8 hp
   Power loss percentage is reduced because there are no mechanical seals.

Available horsepower to generate electricity
= 353.63 hp – 8 hp (losses)
= 345.63 hp

We can convert the 345.63 horsepower to kilowatts by multiplying by 0.746 to convert horsepower to kilowatts.

345.63 hp × 0.746 kW/hp = 257.84 kW; this is the actual power that could be generated given the steam conditions and horsepower losses.

Example 3: Impact to horsepower due to increased back pressure

It is important to know that an increase in steam turbine back pressure (or exhaust pressure) will reduce the horsepower that can be developed. Here is an example that drives this point home.

We will repeat example 2 above but will now assume that the back pressure on the turbine has been increased from 150 psia to 200 psia. What is the horsepower available now?

We have an excessive capacity of steam in the amount of 25,000 lb/hr, inlet conditions are 600 psia at 550 °F and exhausting into 200 psia steam header. Also assume we have a single stage with efficiency of 60%.

a. $\boldsymbol{TSR} = 2545/(h_1 - h_2)$,
$= 2545/(1255 \text{ btu/lb} - 1199 \text{ btu/lb})$, look at steam tables.
$TSR = 45.45$ lb/hp-hr

b. ***ASR*** = *TSR*/turbine efficiency
= 45.45 lb/hp-hr/0.60
= 75.74 lb/hp-hr
ASR = 75.74 lb/hp-hr

c. **Horsepower** = Steam weight flow/*ASR*
= 25,000 lb/hr/75.74 lb/hp-hr
Horsepower = 330 horsepower or 246.18 kW (330 hp × 0.746 kW/hp)

The impact of increasing the turbine back pressure from 150 psia to 200 psia is

353.63 hp – 330 hp = 23.63 hp. This is the power lost due to increasing the back pressure on the steam turbine by 50 psia.

The actual horsepower available to generate electricity must also consider the mechanical losses.

d. **Total mechanical losses** (turbine & generator) = 8 hp (same losses as example 2)

Therefore the actual horsepower available to generate electricity is = 330 hp – 8 hp (losses) = 322 hp or 240.1 kW.

<u>Example 4: Change in turbine efficiency</u>

We will repeat example 3 above but change the turbine efficiency from 60% to 35% and see what power is available.

a. ***TSR*** = 2545/($h1$ – $h2$),
= 2545/(1255 btu/lb – 1199 btu/lb), look at steam tables.
TSR = 45.45 lb/hp-hr

b. ***ASR*** = *TSR*/turbine efficiency (35%)
= 45.45 lb/hp-hr/0.35 = 129.85 lb/hp-hr
ASR = 129.85 lb/hp-hr

c. **Horsepower** = Steam weight flow/*ASR*
= 25,000 lb/hr/129.85 lb/hp-hr
Horsepower = 192.53 horsepower or 143.5 kW (192.53 hp × 0.746 kW/hp)

Therefore the impact of lowering the turbine efficiency from 60 to 35% is

330 hp – 192.53 hp = 137.47 hp. This is the power lost due to the lower turbine efficiency.

The actual horsepower available to generate electricity must also consider the mechanical losses.

d. **Total mechanical losses** (turbine & generator) = 8 hp (from example 2)

e. **The actual horsepower available** to generate electricity is = 192.53 hp – 8 hp (losses) = 184.53 hp or 137.6 kW.

Example 5: Repeat example 1 with increased inlet steam temperature

Raising the inlet steam temperature can affect the horsepower that is developed by a steam turbine. The larger the increase in the inlet steam temperature the greater the horsepower effect. For example, let's assume we have a single-stage steam turbine (60% efficient) with steam inlet conditions of 600 psia at 750 °F. The exhaust of the turbine is connected to the 150 psia steam system and we want to drive a 250 hp pump with mechanical seals and ball bearings. We want to know the steam weight flow required to power this pump and turbine.

a. ***TSR*** = 2545/(h_1–h_2)

h_1 = 1379 btu/lb, enthalpy at 600 psia & 750 °F. See superheated steam table above enter 600 psi absolute and 750 °F, then find the h column which = 1379 btu/lb. This is the enthalpy at inlet conditions.

h_2 = 1195 btu/lb, enthalpy at 150 psia saturated steam conditions. See saturated steam table above under 150 psi absolute then column hg = 1195 btu/lb. This is the enthalpy at exhaust conditions.

TSR = 2545/(1379 btu/lb – 1195 but/lb)
= 2545/(184 btu/lb) = 13.83 lb/hp-hr
TSR = 13.83 lb/hp-hr

b. ***ASR*** = *TSR*/efficiency = 13.83 lb/hp-hr/ 60% efficiency.
= 13.83 lb/hp-hr/0.60 = 23.05 lb/hp-hr, this is the actual steam rate needed.
ASR = 23.05 lb/hp-hr

Now we need to calculate the mechanical losses.

c. **Total mechanical losses** (turbine & pump) = seals & carbon rings + bearing = 10 hp (same as example 1)

Total hp required for steam turbine = 250 + 10 = 260 hp; this is the power needed by the steam turbine including loses from seals and bearings. These numbers are typically supplied by the manufacturer but a rough estimate is less than 2–4% of total horsepower.

The inlet flow of steam required is given by the equation below.

d. **Steam weight flow** = $ASR \times$ horsepower
= 23.05 lb/hp-hr
× 260 horsepower
= 5,993 lb/hr.

Steam weight flow = 5,993 lb/hr

This means that we need to have 5,993 lb/hr of steam at the inlet conditions supplied to the turbine to develop the 260 horsepower on the output of the turbine shaft in order to drive the pump.

We see from example 1 it took 18,380.55 lb/hr to develop 260 hp and by increasing the steam inlet temperature by 200 °F we reduced the steam required to 5993 lb/hr, a 67% decrease in steam weight flow. This can have a large impact on the steam inlet pipe size if the steam temperature can be increased.

Pipe Size for the Inlet and Exhaust

Once we have the required amount of steam needed in the turbine, we must then calculate the pipe size required to bring this amount of steam to the turbine and return it to the steam exhaust header. In order to size the pipe, we need information on the recommended steam velocity inside the pipe. For this we turn to NEMA standard. The maximum steam velocity in the piping for general purpose back pressure steam turbines is as follows;

1. Maximum recommended Inlet steam velocity = 175 feet/second
2. Maximum recommended Exhaust steam velocity = 250 feet/second

With these maximum velocity limits we can calculate the pipe diameter needed by the following equation.

$$D = [(\text{Steam weight flow (lb /hr)} \times \text{specific volume (ft}^3\text{/lb)} \times 0.051)/\text{steam velocity (ft/sec.)}]^{1/2}$$

Where:

D = diameter (inches)

Steam weight flow (lb/hr)

Specific Volume (ft^3/lb) – from the steam tables, first column symbol is v.

Steam velocity (ft/sec)

Example 6: Size of inlet steam pipe

The steam turbine has an inlet steam pressure of 700 psia at 700 °F; the exhaust pressure is 250 psia and connects to the steam header. The turbine efficiency is 45% and it is driving a 1,500 hp centrifugal compressor. Find the inlet and exhaust pipe sizes, steam weight flow required. Assuming the mechanical losses are 2.5% of required power.

a. ***TSR*** $= 2545/(h_1 - h_2)$
   Looking at the table for superheated steam enter 700 psia table, look for 700 °F

   $h_1 = 1344$ btu/lb

   $v_1 = 0.9073$ ft^3/lb = specific volume at inlet conditions, superheated table (v).

   Now look at the saturated steam tables under 250 psia, left most column.

   $h_2 = 1202$ btu /lb, column h_g is known as the enthalpy of saturated steam (think vapor).

   $v_2 = 1.845$ ft^3/lb = specific volume at exhaust conditions (v_g column).

b. ***TSR*** $= 2545/(h_1 - h_2)$
   TSR = 2545/(1344 btu/lb – 1202 btu/lb)
   = 17.92 lb/hp-hr
   TSR = 17.92 lb/hp-hr

c. ***ASR*** = *TSR*/efficiency = 17.92 lb/hp-hr/ 45% efficiency.
= 17.92 lb/hp-hr/0.45 = 39.82 lb/ hp-hr, this is the actual steam rate needed.
ASR = 39.82 lb/hp-hr

d. **Total mechanical losses** (turbine & compressor) = mechanical seals & carbon rings + bearing = estimate total mechanical losses are 2.5% × 1500 hp = 37.5 hp. This is a conservative estimate and may need to be refined by the manufacturer but a good estimate for now.

e. **The total horsepower required** by the steam turbine is = 1,500 hp + 37.5 hp = 1,537.5 hp

f. Calculate the **Steam Weight Flow** = *ASR* × horsepower

= 39.82 lb/hp-hr × 1,537.5 hp = 61,223.25 lb/hr

Steam weight flow = 61,235.32 lb/hr

g. **Calculate the size of the Inlet Steam Piping**

D = (Steam weight flow × specific volume × 0.051/inlet velocity)$^{1/2}$

= (61,235.32 lb/hr × 0.9073 ft^3/lb × 0.051/175 ft. /sec.)$^{1/2}$

D = 4.023 inches diameter. This is the internal diameter of the pipe. Use the pipe tables and find an inside diameter of 4.023 inches or greater to keep the steam velocity at 175 ft/sec or lower.

A 4 inch pipe of standard schedule (40) has an inside diameter of 4.026 inches, which would be the best fit for this service. However, if a heavier wall pipe is required due to higher temperatures and strength, then a schedule 80 or 160 might be required with an inside diameter is 3.826 and 3.438 inches, respectively, which would be too small. Therefore, you would most likely need a heavier walled pipe (schedule 80 or 160) and a 6-inch pipe with extra heavy wall. The inside diameter of a 6″ schedule 80 pipe is 5.761 inches and a schedule 160 pipe is 5.187 inches.

Assume we now use a 6″ schedule 80 for the steam turbine inlet steam piping, what is the new steam velocity? If we rearrange the pipe size equation and do some algebra we find the following:

h. **Velocity** = (steam weight flow × specific volume × 0.051)/ D^2

Assume pipe diameter is 6″ schedule 80, has an inside diameter of 5.761 inches
Velocity = (61,235.32 lb/hr × 0.9073 ft^3/lb × 0.051)/5.761^2 inches

Steam velocity = 85.35 ft/sec., this is well below the steam velocity limit and acceptable.

i. Now **calculate the size of the exhaust pipe**. Remember the exhaust velocity limit is = 250 ft./sec.

D = (steam weight flow × specific volume × 0.051/inlet velocity) $^{1/2}$

= (61,235.32 lb/hr × 1.845 ft^3/lb × 0.051/250 ft./sec) ^{½}

D = 4.80 inches diameter. Again this is the inside diameter of the pipe needed.

A 6 inch pipe any schedule (40, 80, and 160) are all larger than 4.80 inches so the exhaust pipe should be a 6″ diameter as the minimum size.

Shaft Size

The final steam turbine calculation we will examine is the sizing of the turbine shaft. Since the shaft size will determine the coupling size, carbon seals and bearing size, we need a good estimate of the shaft diameter that is required to transmit the horsepower from the steam turbine to the driven equipment.

The shaft diameter is calculated by using the following equation.

$$d = [(321{,}000 \times \text{Power})/(\text{Shear stress} \times \text{shaft speed})]^{1/3}$$

or

$$d = [(321{,}000 \times P)/(Ss \times N)]^{1/3}$$

You can obtain the shear stress (Ss) for the most common shaft materials used on general purpose steam turbines from Table A.3 below.

Where

d = shaft diameter (inches)

P = shaft horsepower (hp)

Ss = Shear Stress allowed in shaft material (psi)

N = shaft speed in rpm

Example 7: Shaft sizing

Repeat example 6 and find the shaft size assuming the shaft material is a) AISI C – 1040 and b) AISI – 4340. Assume the speed is 3,600 rpm.

a. The shaft diameter for AISI -1040 material at 3,600 rpm.
   $d = [(321{,}000 \times 1537.5 \text{ hp})/(5{,}000 \text{ psi} \times 3{,}600 \text{ rpm})]^{1/3}$

Table A.3 Common Steam Turbine shaft material.

Designation	Material	Maximum shear stress Ss (psi)
AISI -1040	Medium Carbon Steel	5000
AISI 4140	Chrome Moly Alloy	11500
AISI 4340	Nickel Chrome Moly Alloy	12500

$= [(493537500/18000000)]^{1/3}$

$= (27.418)^{1/3}$

d = 3.0154 inches: This is the minimum shaft size diameter that is recommended. It would most likely be a larger shaft in order to allow a margin of safety—using a 30% safety factor, we would use a 4″ diameter. Each manufacturer will use their own standard design approach and compare their preliminary design to what they have used on similar applications. This calculation is a good check to confirm the shaft size is not too small. If the shaft diameter for this application was 3″ then we would be requesting references for similar applications (power, temperature and pressure) for comparison.

b. The shaft diameter for AISI 4340 material at 3,600 rpm.

$d = [(321{,}000 \times 1537.5 \text{ hp})/(12{,}500 \text{ psi} \times 3{,}600 \text{ rpm})]^{1/3}$

$= [(493537500/45000000)]^{1/3}$

$= (10.9675)^{1/3}$

= 2.2216 inches, again the shaft should be larger, most likely using a 30% safety factor we could use a 3″ shaft diameter. The main point is that changing the shaft material to a stronger material will reduce the size of all the components that are dependent on the shaft, reducing the cost for bearings and seals.

Closing

The purpose of the design examples provided in this appendix is not to make you a steam turbine designer but to provide you with a flavor of what is involved in the design process. By going through these basic examples, you should begin to understand how a steam turbine designer thinks and the factors that he or she sees as important to the design process. We hope that with study and practice you will be able to better follow the design calculations presented by manufacturers and understand how factors like inlet pressure and temperature, exhaust pressure, and speed can significantly impact a steam turbine's performance.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

Appendix B

Glossary of Steam Turbine Terms

Antifriction bearing: An anti-friction bearing is a bearing that utilizes rolling elements between the stationary and rotating assemblies.

Automatic grease lubrication: A self-contained lubrication system often used to grease inaccessible places. It has a timing mechanism that can be electronic, chemical, or mechanical designed to disperse grease at periodic intervals.

Back pressure: Refers to pressure opposing the desired flow of a fluid in a confined place such as a pipe.

Back pressure steam turbine: A steam turbine that exhausts into a pressurized header.

Blades: The elements on a steam turbine rotor that are designed to generate torque by redirecting the steam flow.

Boiler: A process subsystem that uses a fired fuel or waste heat to turn condensate into high-pressure steam.

Boiler feedwater pump: A liquid pump that raises condensate pressure back to boil pressure so that it can be returned to the steam boiler.

British thermal unit: The Btu or British thermal unit is defined as the quantity of heat required to raise 1 lbm of water from 59.5 °F to 60.5 °F. Therefore, 1 Btu = 778.17 ft lbf.

Circulating lubrication system: A lubricating system usually containing a reservoir, a pump, and a filter, which may or may not have a heat exchanger. This type of system supplies oil to the lubricated item at very low or essentially no pressure. It is used when a control flow of clean lubricant is necessary to one or more places that may not be at the same level as the reservoir. It is very similar to a forced-feed lubrication system, but uses its pump to circulate oil only.

Condenser (steam turbine): A critical element of condensing steam turbines, its main purposes are to condense the exhaust steam from the turbine for reuse in the cycle and to maximize turbine efficiency by maintaining proper vacuum. As the operating pressure of the condenser is lowered (vacuum is increased), the enthalpy drop of the expanding steam in the turbine will also increase. This will increase the amount of available work from the turbine (electrical output). By lowering the condenser operating pressure, the following will occur:

- Increased plant efficiency
- Increased turbine output
- Reduced steam flow (for a given plant output)

It is therefore very advantageous to operate the condenser at the lowest possible pressure (highest vacuum).

Condensing steam turbine: A steam turbine designed so that the outlet steam expands below atmospheric pressure and then condenses while heating the cooling water in a condenser.

Electronic governor: A speed sensing and control system utilizing only high-speed electronic components, i.e., no mechanical parts.

Electronic trip system: A speed sensing and control system utilizing only high-speed electronic components designed to protect a steam turbine from overspeeding.

Enthalpy: A thermodynamic property that is a measure of the heat energy in a system or total energy of the steam at the stated pressure and temperature.

Exhaust nozzle: The nozzle that removes low pressure steam to a steam turbine casing.

Extraction steam turbine: A type of steam turbine that has the ability to "extract" a percentage of the total inlet steam flow at some intermediate pressure as required by the plant.

Forced feed lubrication: This system is very similar to the circulating system, but it does operate at a system pressure. It usually has a pressure regulating valve to maintain pressure on the system, plus coolers, multiple pumps, a pressure regulator, auto start of the standby pump, filters, and a reservoir. This system is required to remain at pressure, or the equipment it is supplying lubrication to will fail. There are usually safety switches that will cause the lubricated piece of equipment to shut down if the level in the tank falls below a set amount, or if the pressure in the system becomes too low.

General purpose steam turbine: A horizontal or vertical steam turbine used to drive equipment that is usually spared, i.e., non-critical, and relatively small in size (power).

Governor: The device which maintains rotational speed at a set value while the load demand (power extraction) varies.

Hot and cold alignment: The positioning of the turbine relative to the driven machinery. It is extremely critical that the shafts of turbine and the driven machine align in order to avoid excessive vibration and stresses on coupling device, the case and the bearings. Typically the initial mechanical alignment (cold align) must be adjusted as both the turbine and the driven machine come to operating temperature.

Impulse steam turbine: Steam turbine with fixed nozzles that orient the steam flow into high-speed jets. When the high-speed stream from the fixed nozzles impinges on the rotor blades, which look like little U-shaped buckets, a shaft torque is developed as the steam jet changes direction through the buckets.

Inlet nozzle: The nozzle that supplies high-pressure steam to a steam turbine.

Journal bearing: A tight-fitting, babbitted bearing used in critical pumps, compressors and motors.

Leakoff: Any small steam line piped to a drains that is used to control steam turbine leakage to the atmosphere.

Linkage: The mechanical elements designed to transmit the speed signal from the speed governor to the throttle valve.

Mechanical losses: Any parasitic losses inside of a rotating machine. Internal components such as bearings and seals cause drag that rob the machine train of horsepower.

Mollier diagram: A diagram that plots the total steam heat against entropy. This plot is also referred to as an enthalpy–entropy chart.

Oil mist lubrication: A system that consists of a tank, tubing to each item being lubricated, an atomizer, and various safety devices relating to flow and level in the reservoir. With this system there may or may not be an oil level in the lubricated piece of equipment. There are two general types of systems. One is pure mist and there is no lubricant reservoir in each piece of equipment. The other type is a purge mist system where there is a level in the lubricated piece of equipment and oil mist fills the "air" space above the reservoir.

Overspeed testing: A periodic uncoupled test of a gas or steam turbine driver that is conducted to ensure the overspeed prevention system is functioning properly. During this test, the driver is purposefully operated at or slightly above the trip speed. Extreme care should be exercised during this type of test. The failure of an overspeed trip system during an overspeed event can lead to catastrophic machine failure and extreme risk to human life.

Overspeed trip: A safety event where a steam turbine automatically shuts down to operation well above its design speed.

Poor steam quality: A condition where there is too much liquid, i.e., condensate, in the steam supply.

Packing: 1) Any material or device which seals by compression. Common types are U-packing, V-packing, Cup-packing, and A-rings; 2) The soft rings that mechanical seals replace to stop leakage. Packing must leak because it works on the theory of a series of pressure drops to reduce the stuffing box pressure to the point where the leakage is acceptable. A minimum of five rings of packing is required to do this.

Process waste heat recovery or condenser: A part of the process that recovers sufficient lower pressure steam heat to condense all the steam back to condensate.

Reaction steam turbines: Steam turbines with rotor blades that are arranged to form convergent nozzles that look like propeller blades. (Many reaction steam turbines use impulse shapes at the bottom of the blade and reaction at the top.) This type of turbine creates torque by using the reaction force produced as the steam accelerates through the nozzles formed by the rotating blades.

Ring lubrication: A lubrication method accomplished by using a large ring, usually brass, riding on the turning shaft. It dips down into the oil reservoir and, by viscous drag, brings oil up onto the shaft where it is distributed along the shaft to the bearing.

Rolling element bearing: Bearing whose low-friction qualities derive from multiple rolling elements (balls or rollers), with little lubrication.

Rotor: The entire rotating portion of a steam turbine.

Saturated Steam: Steam that cannot accept any more moisture at the given pressure and temperature without turning into a liquid.

Shear strength: The ability of a material to withstand a force that tends to produce sliding failure on a material.

Special purpose steam turbine: A horizontal steam turbine used to drive process equipment that is usually not spared, i.e., critical, and relatively large in size (power).

Specific volume (v): The ratio of steam volume to its mass in that volume. It is the reciprocal of density or inversely proportional to density.

Splash lubrication: This type of lubrication system usually consists of a reservoir of oil and some part of the spinning shaft and attachment, or the rolling elements of the bearing, that touch the oil and cause it to splash to allow lubrication to take place. There is a place to check the oil level, and it is most important for operators to ensure there is oil.

Steady-state conditions: A state where steam conditions are constant, speed is constant, and the load demands of the driven equipment are constant.

Steam rate: The quantity of steam required by the turbine to develop the required output power.

Steam quality: A measure of the amount of saturated steam that coexists with its condensate in a given system. Calculate by dividing the mass of steam by the total mass of steam and condensate.

Steam turbine governor: A speed controlling system used on steam turbines. Turbine speed is controlled as changes in the position of the governor varies steam flow. Variations in the power required by the driven machine and changes in steam inlet or exhaust conditions alter the speed of the turbine, causing the governor system to respond to correct the operating speed.

Superheat: Refers to the degrees above boiling point of a liquid at a given pressure. Steam feed to a steam turbine typically must have some degree of superheat. Otherwise, as pressure and temperature drops and power is extracted from it in the turbine, some water will begin to condense. This water is detrimental to efficiency and can be damaging to the internals.

Theoretical steam rate (TSR): The TSR is the amount of steam flow needed to drive the turbine at the specified steam conditions, assuming that the turbine is 100% efficient.

Thrust bearing: A bearing designed to support axial machine loads and locate the rotor or shaft axially.

Thrust bearings can employ either rolling elements or hydrodynamic films to support axial loads.

Tilt-pad bearing: A hydrodynamic bearing with multiple bearing pads that can individually align to the shaft by tilting. These bearings are more stable at high speed than cylindrical journal bearings.

Total mechanical losses: The power losses due to the bearings for the turbine and driven equipment, carbon ring seals and mechanical seals.

Trip and throttle valve: The valve in the steam supply line ahead of the governor valve. This valve is used as the activating element for the overspeed protection. It also serves as a manual throttle valve, which can be used for testing and start-up. It is designed to run full open in normal machine operation and is able to close very quickly. Typically, it is activated by hydraulic oil pressure; oil pressure loss fails closed and with oil pressure on, it can be operated manually.

Velocity ratio: The ratio of the rotating blade speed (V_b) divided by the velocity of the steam leaving the nozzle ring (V_j) before it hits the rotating blades.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

Appendix C

Predictive Maintenance Activity with Recommended Intervals

1. Vibration analysis – Monthly
2. Oil analysis – Monthly
3. Steam trap inspections – Monthly or quarterly

Preventative Maintenance Activities with Recommended Intervals

1. Periodic alignment checks – Once a year or after every repair
2. Time-based oil changes – Monthly
3. Piping inspections – As required

4. Bearing inspections – An annual bearing inspection is a good idea if you have experienced premature bearing failures.
5. Overspeed trip checks – An annual trip check is a good starting point. If the trip system is proven reliable, move the periodic inspection to 18 to 24 months.

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

Appendix D

Properties of Saturated Steam

Absolute Pressure (psia)	Gauge Pressure (psig)	Steam Temp. (°F)	Absolute Pressure (kPa absolute)	Gauge Pressure (kPa gage)	Steam Temp. (°C)
14.696	0.00	212	101.33	0.00	100.00
16	1.30	216.32	110.32	8.99	102.40
17	2.30	219.44	117.21	15.89	104.13
20	5.30	227.96	137.90	36.57	108.87
25	10.30	240.07	172.37	71.04	115.59
30	15.30	250.33	206.84	105.52	121.29
35	20.30	259.28	241.32	139.99	126.27
40	25.30	267.25	275.79	174.46	130.69
45	30.30	274.44	310.26	208.94	134.69
55	40.30	287.07	379.21	277.89	141.71
65	50.30	297.97	448.16	346.83	147.76
75	60.30	307.6	517.11	415.78	153.11
85	70.30	316.25	586.05	484.73	157.92

95	80.30	324.12	655.00	553.68	162.29
105	90.30	331.36	723.95	622.62	166.31
114.7	100.00	337.9	790.83	689.50	169.94
125	110.30	344.33	861.84	760.52	173.52
135	120.30	350.21	930.79	829.47	176.78
140	125.30	353.02	965.27	863.94	178.34
145	130.30	355.76	999.74	898.41	179.87
155	140.30	360.5	1068.69	967.36	182.50
165	150.30	365.99	1137.63	1036.31	185.55
175	160.30	370.75	1206.58	1105.26	188.19
195	180.30	379.67	1344.48	1243.15	193.15
215	200.30	387.89	1482.37	1381.05	197.72
240	225.30	397.37	1654.74	1553.42	202.98
265	250.30	406.11	1827.11	1725.79	207.84
300	285.30	417.33	2068.43	1967.10	214.07
400	385.30	444.59	2757.90	2656.58	229.22
450	435.30	456.28	3102.64	3001.32	235.71
500	485.30	467.01	3447.38	3346.05	241.67

(Continued)

Absolute Pressure (psia)	Gauge Pressure (psig)	Steam Temp. (°F)	Absolute Pressure (kPa absolute)	Gauge Pressure (kPa gage)	Steam Temp. (°C)
600	585.30	486.21	4136.85	4035.53	252.34
900	885.30	531.98	6205.28	6103.96	277.77
1200	1185.30	567.22	8273.71	8172.38	297.34
1500	1485.30	596.23	10342.14	10240.81	313.46
1700	1685.30	613.15	11721.09	11619.76	322.86
2000	1985.30	635.82	13789.51	13688.19	335.46
2500	2485.30	668.13	17236.89	17135.57	353.41
2700	2685.30	679.55	18615.84	18514.52	359.75
3606.2	3591.50	705.4	24863.87	24762.55	374.11

Operator's Guide to General Purpose Steam Turbines: An Overview of Operating Principles, Construction, Best Practices, and Troubleshooting. Robert X. Perez and David W. Lawhon.

Index