Volume III
FACILITIES and CONSTRUCTION ENGINEERING
Kenneth E. Arnold, Editor



PETROLEUM ENGINEERING HANDBOOK
Larry W. Lake, Editor-in-Chief

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Petroleum Engineering Handbook

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SOCIETY OF PETROLEUM ENGINEERS

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Petroleum Engineering Handbook

Larry W. Lake, Editor-in-Chief
U. of Texas at Austin

Volume III

Facilities and Construction Engineering

Kenneth E. Arnold, Editor
AMEC Paragon Inc.

Society of Petroleum Engineers

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Foreword

This 2006 version of SPE's *Petroleum Engineering Handbook* is the result of several years of effort by technical editors, copy editors, and authors. It is designed as a handbook rather than a basic text. As such, it will be of most benefit to those with some experience in the industry who require additional information and guidance in areas outside their areas of expertise. Authors for each of the more than 100 chapters were chosen carefully for their experience and expertise. The resulting product of their efforts represents the best current thinking on the various technical subjects covered in the *Handbook*.

The rate of growth in hydrocarbon extraction technology is continuing at the high level experienced in the last decades of the 20th century. As a result, any static compilation, such as this *Handbook*, will contain certain information that is out of date at the time of publication. However, many of the concepts and approaches presented will continue to be applicable in your studies, and, by documenting the technology in this way, it provides new professionals an insight into the many factors to be considered in assessing various aspects of a vibrant and dynamic industry.

The *Handbook* is a continuation of SPE's primary mission of technology transfer. Its direct descendents are the "Frick" *Handbook*, published in 1952, and the "Bradley" *Handbook*, published in 1987. This version is different from the previous in the following ways:

- It has multiple volumes in six different technical areas with more than 100 chapters.
- There is expanded coverage in several areas such as health, safety, and environment.
- It contains entirely new coverage on Drilling Engineering and Emerging and Peripheral Technologies.
- Electronic versions are available in addition to the standard bound volumes.

This *Handbook* has been a monumental undertaking that is the result of many people's efforts. I am pleased to single out the contributions of the six volume editors:

General Engineering—John R. Fanchi, Colorado School of Mines
Drilling Engineering—Robert F. Mitchell, Landmark Graphics Corp.
Facilities and Construction Engineering—Kenneth E. Arnold, AMEC Paragon
Production Operations Engineering—Joe D. Clegg, Shell Oil Co., retired
Reservoir Engineering and Petrophysics—Ed Holstein, Exxon Production Co., retired
Emerging and Peripheral Technologies—Hal R. Warner, Arco Oil and Gas, retired

It is to these individuals, along with the authors, the copy editors, and the SPE staff, that accolades for this effort belong. It has been my pleasure to work with and learn from them.

—Larry W. Lake

Volume III
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Preface

The science of facilities engineering did not exist in the early days of oil and gas development. Oil was produced to tanks, where gas was vented and water and sediments were allowed to settle to the bottom. In the early 1900s, anecdotal evidence indicated that oil recovery was higher when a separator preceded the tank than when oil flowed directly into the tank. The original separators had working pressures of approximately 150 psi with simple mechanical lever-operated controls.

With time, as deeper, higher-pressure wells were drilled and local distribution systems were developed to use the gas, separator working pressures increased. It was not until the mid-20th century that horizontal separators were first developed and tested to handle a growing need for high gas flow/low liquid flow separators.

At this point, facilities were not designed in a systematic way. For the most part, field personnel using empirically developed rules of thumb were able to "hook up" standard components based on slowly evolving experience with little or no disciplined thought. The need for documentation, quality control, and modern sensitivities to safety and environmental concerns were only beginning to be formed.

Since the 1950s, facilities have become more complex and more important for the overall economics of field-development decisions. The science of facilities engineering was born as the need and markets developed for heavy oil, waterflooding, sour oil and gas, high-pressure gas, and remote, offshore, and Arctic fields. Beginning in the late 1950s, oil companies began to recognize the need to hire, train, and employ facilities engineers as a distinct specialty.

The main objectives of a surface facility are to (1) separate the gas, oil, and water produced from the well; (2) process and treat the gas for sales, reinjection, or flaring; (3) treat the oil for sales; (4) treat the water for reinjection or disposal; and (5) provide for well testing. Besides performing these process tasks, a facility must provide (1) utilities (electric power generation and motor control center, instrument and power air, diesel fuel system, and helicopter fuel), (2) safety systems (process shutdown, fire and gas detection, fire fighting, escape and evacuation, and emergency gas disposal), (3) life support (quarters and recreation, potable water system, sanitary systems, food storage, and medical facilities), (4) operating and maintenance systems (cranes and lifting equipment, office, control room, spare-parts storage, and laboratory), and, of course, a foundation for all the equipment (e.g., site development, access, offshore platform).

Facilities engineering is a broad specialty embracing all of the classic engineering specialties such as civil, chemical, mechanical, and instrument/electrical, as well as the broad science of project management. In this one *Handbook*, it is impossible to cover in detail all of those disciplines in sufficient depth to make one an "expert" capable of complex facilities design. Rather, we have attempted to provide the non-facilities engineer with a basic understanding of the equipment and systems we use, how



they work, the relative advantages and disadvantages that aid in choosing between alternatives for a specific set of conditions, and a better understanding of the terminology so that those with a general knowledge can interface more effectively with experts in each of the different subspecialties.

I would like to personally thank the authors of the individual chapters; they have worked hard to reduce complex subjects to fit the page limits we have imposed on them. I don't think any of them realized when we began how long and difficult the task would be, and yet they all, more or less cheerfully, stuck with their commitments in the face of changing job assignments and much "helpful" criticism from the editors, Larry Lake, and me. I would also like to thank several individuals, who I will not embarrass by naming, who originally agreed to write chapters and who, because of changing job assignments or for personal reasons, were unable to complete their tasks. Their efforts are appreciated, and several of the authors have used some of their thoughts as building blocks for the final chapters.

I would like to further thank Larry W. Lake, whose vision, polite prodding, and embarrassing questions made this whole undertaking possible. He has read and commented on more drafts for this and the other volumes of the *Handbook* than any of us thought possible.

Finally, I am sure all the authors of this volume join me in thanking my secretary, Paula Weisinger, for keeping track of progress, making numerous phone calls and sending numerous e-mails, coordinating the word processing of several chapters and revisions, and generally keeping me in line.

—Kenneth E. Arnold

Exit

Volume III
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Larry W. Lake, Editor-in-Chief

Contents

1 **Oil and Gas Processing** - click to view
Mary Thro

2 **Oil and Gas Separators** - click to view
Robert W. Chin

3 **Emulsion Treating** - click to view
Kenneth W. Warren

4 **Water-Treating Facilities in Oil and Gas Operations** - click to view
Kevin Juniel and Hank Rawlins

5 **Gas Treating and Processing** - click to view
Edward Wichert

6 **Pumps** - click to view
Maurice I. Stewart, Jr.

7 **Compressors** - click to view
Robert A. Taylor

8 **Prime Movers** - click to view
Jim Strawn and Joe Lange

9 **Piping and Pipelines** - click to view
Ralph S. Stevens, III and Don May

10 **Safety Systems** - click to view
Maurice I. Stewart, Jr. and Kenneth E. Arnold

11 **Liquid and Gas Measurement** - click to view
Marsha Yon, Kevin L. Warner, and Tom Mooney

12 **Electrical Systems** - click to view
Dinesh Patel

13 **Oil Storage** - click to view
George H. Stilt

14 **Offshore and Subsea Facilities** - click to view
Patrick O'Connor, Justin Bucknell, and Minaz Lalani

15 **Project Management of Surface Facilities** - click to view
Gregory J. Kreider

Author Index - click to view

Subject Index - click to view

SOCIETY OF PETROLEUM ENGINEERS

Back Search Help

Chapter 1
Oil and Gas Processing

Mary Thro, SPE, AMEC Paragon Inc.

1.1 Starting From the Wells

Oil or gas wells produce a mixture of hydrocarbon gas, condensate, or oil; water with dissolved minerals, usually including a large amount of salt; other gases, including nitrogen, carbon dioxide (CO_2), and possibly hydrogen sulfide (H_2S); and solids, including sand from the reservoir, dirt, scale, and corrosion products from the tubing.

For the hydrocarbons (gas or liquid) to be sold, they must be separated from the water and solids, measured, sold, and transported by pipeline, truck, rail, or ocean tanker to the user. Gas is usually restricted to pipeline transportation but can also be shipped in pressure vessels on ships, trucks, or railroad cars as compressed natural gas or converted to a liquid and sent as a liquefied natural gas (LNG). This chapter discusses the field processing required before oil and gas can be sold.

The goal is to produce oil that meets the purchaser's specifications that define the maximum allowable water, salt, or other impurities. Similarly, the gas must be processed to meet purchaser's water vapor and hydrocarbon dewpoint specifications to limit condensation during transportation. The produced water must meet regulatory requirements for disposal in the ocean if the wells are offshore, reservoir requirements for injection into an underground reservoir to avoid plugging the reservoir, and technical requirements for other uses, such as feed to steam boilers in thermal-flood operations, or in special cases, for irrigation.

The equipment between the wells and the pipeline, or other transportation system, is called an oilfield facility. An oilfield facility is different from a refinery or chemical plant in a number of ways. The process is simpler in a facility, consisting of phase separation, temperature changes, and pressure changes, but no chemical reactions to make new molecules. In a refinery, the feed-stream flow rate and composition are defined before the equipment is designed. For a facility, the composition is usually estimated based on drillstem tests of exploration wells or from existing wells in similar fields. The design flow rates are estimated from well logs and reservoir simulations. Even if the estimates are good, the composition, flow rates (gas, oil, and water), pressures, and temperatures change over the life of the field as wells mature and new wells are drilled. Facilities have a design rate that is a best-guess maximum flow based on the number of wells, production profiles, and total oil or gas that can be produced from the reservoir. The actual production rates for a facility increase as the wells are completed up to the design rate. This rate will be maintained as long as possible by drilling additional wells; then,

oil and gas rates will decline, water rates will increase, and flowing pressure will decrease as the reservoir is depleted. The equipment must be designed to operate over a range of flow rates with uncertain compositions and temperatures.

1.2 Definition of Terms

The following definitions are used in this section of the *Handbook*.

Crude oil is a liquid hydrocarbon produced from a reservoir. Condensate is liquid hydrocarbon that condenses from the gas as pressure and temperatures decrease when the gas is produced from the reservoir up the tubing and out the wellhead choke. Condensate is usually lighter in color and lower in molecular weight and viscosity than crude oil; however, a light crude oil could have properties similar to a condensate.

Hydrocarbons are composed of many different "components" or molecules of carbon and hydrogen atoms. Starting with the lightest molecular weight, they are methane (CH_4), ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), pentane (C_5H_{12}), hexane (C_6H_{14}), and so on. As the ratio of carbon to hydrogen atoms increases, the molecules become "heavier" and have a greater tendency to exist as a liquid rather than a gas.

An oilfield facility is a collection of equipment that is used to separate the fluids that come out of an oil or gas well into separate streams that can then be sold and sent to a gas plant or refinery for further processing.

A process simulation is a calculation, usually done with a computer program that predicts how the components that make up the well fluids react to changes in pressure and temperature as they are processed through the facility. This is not a chemical reaction, but rather a simple phase change as liquids flash to vapor or vapors condense into liquid. As the pressure is reduced or the temperature is increased, the lighter molecules, such as methane and ethane, tend to boil off into the vapor phase, taking some of the midrange components with them. The remainder of the midrange and most of the heavier molecules stabilize as liquid.

Basic sediment and water (BS&W) is the percent by volume of water and solid impurities in the oil. Oil pipeline specifications range from 0.1 to 3%, with a typical Gulf of Mexico pipeline requirement of 1% by volume.

The bubblepoint, or true vapor pressure, is the point at which gas first appears within a liquid sample as the temperature is raised or the pressure lowered. The bubblepoint of a hydrocarbon liquid is a function of pressure, temperature, and the composition of the liquid.

Reid vapor pressure is the pressure at which a hydrocarbon liquid will begin to flash to vapor under specific conditions. It can be measured in the field according to a specific American Society for Testing and Materials standard and results in a pressure lower than the true vapor pressure.

The hydrocarbon dewpoint is the point at which hydrocarbon liquid first condenses from a gas sample when the temperature is lowered or the pressure is increased, and it depends on the composition of the gas. The water dewpoint is often specified for gas pipelines for hydrate and corrosion control. Depending on the history of the hydrocarbon fluid (i.e., the processing that has occurred upstream of the point in question), the hydrocarbon and water dewpoints may not be the same.

Hydrates are crystalline, ice-like solids that form in the presence of hydrocarbon gas and liquid water. Hydrates can form at temperatures significantly higher than the freezing point of water and can plug equipment and pipelines.

1.3 Function of a Facility

1.3.1 Main Process. The main function of an oil facility is to separate the oil, gas, water, and solids; treat the oil to meet sales specifications (e.g., BS&W, salt content, vapor pressure); mea-

sure and sample the oil to determine its value; and deliver it to the transportation system (i.e., the pipeline, truck, ship, or railroad car).

The gas must be treated for sales or disposal. In the past, disposal sometimes meant flaring or venting, but now gas that can't be transported is usually compressed for reinjection into the reservoir. Gas treating may involve only separation from the liquids, or it may include additional processes such as compression, dehydration, removing H_2S and CO_2; or gas processing to condense heavier components that can be transported as a liquid.

1.3.2 Secondary Process. In addition to processing the oil and gas for sale, the produced water and solids must be treated for disposal. For produced water, treating usually includes removal of dispersed and dissolved hydrocarbons and, in addition to separation or oil skimming, may include filtration, deionization, or pumping.

If treating of solids is required, it may include water washing and agitating the solids to remove the oil and then separating the water from them.

1.3.3 Auxiliary Systems. In addition to the process systems, auxiliary process heating and cooling may be required. Process heat is usually needed for oil treating and superheating fuel gas for use in gas turbine generators or compressors. Process cooling is usually required for gas compression.

While, if necessary, facilities can be run without electric power, power generation and electrical systems will usually be included for a facility that is large or complex or for living quarters that are provided for personnel.

All facilities require safety systems, including safety instrumentation and shutdown system; fire and gas detection; fire-fighting equipment; a means of evacuation, such as life rafts and escape capsules for offshore; and other equipment, depending on the location and complexity of the facility and whether it is manned.

1.4 Example Oil Facility

Fig. 1.1 is a block diagram of a simple oil facility. Each of the blocks is described here, except for gas dehydration, which is covered in Sec. 1.5, Gas Facilities.

1.4.1 Separation. The first step in the process is separating the gas from the liquid and the water from the oil. This is usually done in a separator—a pressure vessel into which the wellstream flows to allow the gas, oil, and water to separate because of gravity. Separators may contain inlet diverters, outlet vortex breakers, buckets, weirs, and mist extractors to aid separating the streams. See the chapter on Oil and Gas Separators in the Facilities and Construction Engineering section of this *Handbook* for a more detailed description of separator design.

A separator may be two-phase, separating gas from liquids, or three-phase, separating gas, oil, and water, which are removed through three outlets. The first separator in a facility that receives fluid from the wells is called a production, or high-pressure (HP), separator. If the production is at high pressure, (e.g., 500 to 1,200 psig) and if the oil from the separator is put directly into a pipeline, gas will flash as the pressure decreases owing to friction losses in the pipeline. Gas takes up a much larger volume than its equivalent mass of oil, so a pipeline sized for liquid flow will be undersized if some of the liquid flashes into gas, resulting in excessive velocities and pressure drop. For this reason, oil pipeline owners generally specify a maximum vapor pressure allowed to prevent the lighter components in the oil from flashing into gas. The process of reducing the vapor pressure in the oil to meet oil-pipeline specifications is called "stabilization."

For the simplest form of stabilization, the oil is put into an atmospheric tank for storage. This allows the gas to flash from the liquid in the tank when the pressure is reduced to atmospheric. This process would get the true vapor pressure of the oil down to atmospheric, or even

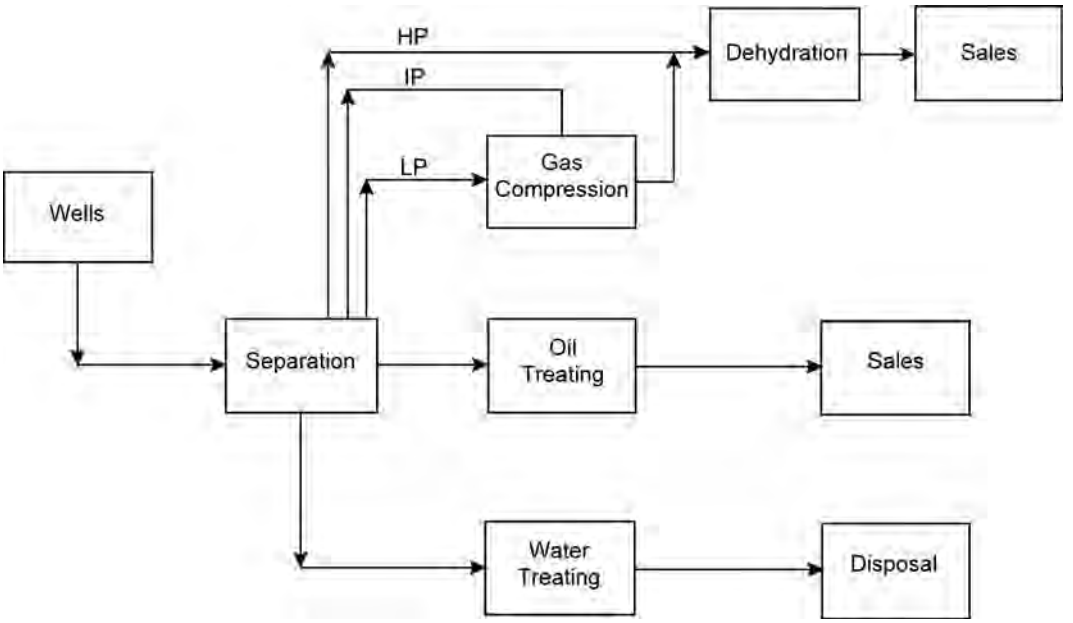


Fig. 1.1—Typical oil facility.

lower if some heating were added in addition to the pressure reduction, and could be used to make the oil meet pipeline specifications for vapor pressure. The gas that flashes in the tank must then be compressed back to the original pressure of the separator and combined with the separator gas.

If the oil is sent to an intermediate pressure (IP) separator instead of going directly into an atmospheric tank, the gas that flashes in the IP separator will be at a higher pressure, requiring less compression horsepower. In addition, the total amount of oil stabilized in the atmospheric tank is greater with an intermediate separation stage than with a single flash to atmospheric pressure. This is because of the gas/liquid equilibrium for the higher-pressure flash and the altered composition of the oil that is flashing in the tank.

While there still would be gas flashed as the liquid flowed from the IP separator to the tank, the quantity would be much smaller than in the first case in which liquid goes directly from the HP separator to the tank. Thus, adding a second stage of separation has two benefits: first, the horsepower required to compress the gas is lower because some of the gas flashes at higher pressure, and second, more stabilized oil will be produced. If we add a third, low-pressure (LP) stage of separation, the total liquid in the tank increases even further, with additional gas flashing at a higher pressure, reducing compressor horsepower. Fig. 1.2 shows a typical three-stage separation with flash-gas compression. Adding additional stages of separation and compression would increase liquids and reduce compression horsepower further; however, at this point, the capital cost of adding additional separation stages is generally not worth the small increase in hydrocarbon value.

A typical separation train might have a well producing into an HP separator at 1,100 psig, with the oil to an IP separator at 450 psig, an LP separator at 150 psig, and possibly an oil treater at 50 psig (see next section) before storage in an atmospheric tank. The separator pressures are chosen so that the flash gas from each stage of separation feeds into a stage of compression with reasonable compression ratios for each stage of the compressor. See the chap-

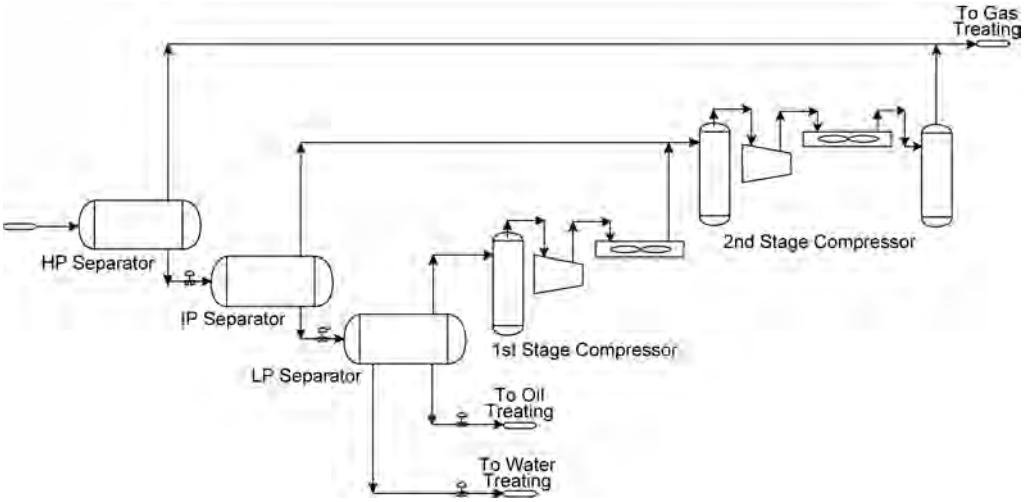


Fig. 1.2—Three-stage separation.

ter on Compressors in this volume of the *Handbook* for a discussion on compression ratios and calculation of compressor horsepower.

1.4.2 Oil Treating. No separation is perfect, there is always some water left in the oil. Water content can range from less than 1% water to more than 20% water in the oil by volume. The lower the API gravity (i.e., the higher the molecular weight and the oil viscosity), the less efficient the separation.

To get the last of the water out of the oil, the oil is processed through an oil treater or a treating system, as described in the chapter on Emulsion Treating in this section of the *Handbook*. A treater is similar to a separator, but with special features to help separate the water from the oil. Treaters or treating systems usually provide heat to reduce oil viscosity and large settling sections to allow the water time to settle from the oil, and may provide an electrostatic grid to promote coalescing of the water droplets. Conventional treaters usually have a front section with a heater in which the emulsion is heated and initial separation of the "free water" takes place. The oil then flows to a second section of the vessel, where additional coalescence and settling of the water droplets takes place. Gas is flashed (i.e., liberated) from the emulsion as the pressure is lowered and the temperature is raised from the upstream separator. For a conventional treater with a heater, free-water knockout section, and settling section, the water content in the oil can be reduced to less than 1%. An electrostatic treater, which is a conventional treater with an electrostatic grid in the settling section, can reduce the water content to 0.3 to 0.5% by volume.

The contract between the oil seller, who is normally the producer, and the purchaser, who may be a pipeline company, specifies the allowable water content, and may specify the maximum salt content in the crude oil. High water content can make corrosion problems worse in pipelines and other transportation systems and can cause problems with downstream processing. High salt content, which is caused by the salinity of the produced water left in the oil, may cause a refining problem when the water is boiled off in the refinery distillation unit.

The oil from the treater is usually sent into a dry oil tank, from which it is pumped through a sales meter for custody transfer, and then into a pipeline for transportation. For additional information, see the chapters on Storage Tanks, Pumps, and Instrumentation and Controls in this section of the *Handbook*.

1.4.3 Produced-Water Treating. As mentioned previously, separation is not perfect, and the amount of oil left in the water from a separator is normally between 100 and 2,000 ppm by mass. This oil must be removed to acceptable levels before the water can be disposed of. The regulatory requirements for oil-in-water content for overboard water disposal vary from place to place, and some locations do not allow any discharge of produced water. As an example, in the Gulf of Mexico outer continental shelf (U.S. federal waters), producers are limited to a maximum measurement of 42 ppm for any one sample and no more than 29 ppm average for a given month. In contrast, on shore, no discharge of produced water is permitted. In the case in which discharge is not permitted, produced water is usually injected into disposal wells.

Various types of equipment for water treating are described in the chapter on Water-Treating Facilities in Oil and Gas Operations in the Facilities and Construction Engineering section of this *Handbook*. Equipment types used in this case include water skimmers, plate coalescers, gas flotation devices, and hydrocyclones. Additional equipment, including desanders and filters, may be needed to remove solids before injection, as also described in the chapter on Water-Treating Facilities in Oil and Gas Operations.

Hydrocyclones require a pressure drop in excess of 100 psi to work well and would usually be placed between a separator and its water-level control valve. In addition to removing oil from the water, hydrocyclones have a tendency to coalesce the remaining oil droplets in the water streams, making the droplets easier to separate with the downstream equipment. Water skimmers use gravity separation to remove the remaining oil from produced water and are usually placed downstream of separators or hydrocyclones.

A good rule of thumb is to use two types of water-treating equipment for a gas facility and three types for an oil facility in which the oil may be more difficult to separate. For example, a water-treating system might consist of a hydrocyclone, followed by a water skimmer and a gas flotation cell.

1.5 Gas Facility

Fig. 1.3 is a block diagram of a simple gas facility. Each of the main blocks is described here.

1.5.1 Heating. Gas wells are often high pressure with a shut-in tubing pressure of 5,000 to 15,000 psig and a flowing tubing pressure in excess of 3,000 psig. This pressure must be reduced to the appropriate pipeline pressure at the point at which the gas flows through a wellhead choke. When gas pressure is reduced, the gas cools, liquids can condense, and hydrates can form. Hydrates are crystalline solids made up of hydrocarbon and water molecules and form in the presence of hydrocarbon gas and liquid water at temperatures significantly higher than the freezing point of water. These hydrates can plug the choke and flowline, so high-pressure gas wells usually require a line heater that contains the flowline and choke inside a hot water bath to keep the well from freezing. See the chapter on Phase Behavior of Water/Hydrocarbon Systems in *General Engineering*, Vol. I of this *Handbook*, for a more complete discussion of hydrates.

Hydrate formation can be inhibited by injecting a solvent, such as methanol, into the flowline. This is done for subsea and other wells in which a line heater is not possible. For most wells with high flow rates, the expense of the methanol makes a line heater the better choice.

1.5.2 Separation. The separator provides a place for any liquid to settle out from the gas. The separator pressure is set higher than the pipeline pressure so that the gas can go through the required cooling, treating, dehydration, and gas processing—each with some pressure drop—and arrive at the required pipeline pressure.

1.5.3 Cooling. If the gas flowing temperature is high, the temperature downstream of the choke may be high enough so that it will not be necessary to install a line heater upstream of

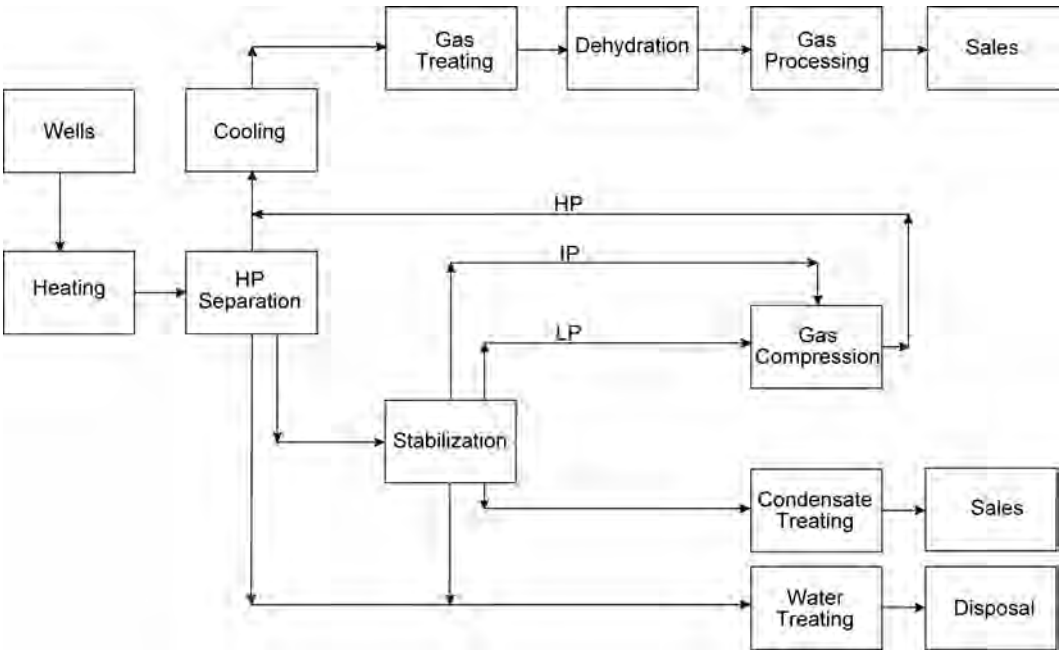


Fig. 1.3—Typical gas facility.

the HP separator. If the flowing tubing temperature is even higher, the hot gas leaving the HP separator could cause process and corrosion problems with the downstream treating system. In addition, the hot gas will carry more water vapor, which makes the dehydration system larger and much more expensive than if the gas were cooled first. Thus, it is sometimes necessary to install a gas cooler downstream of the first-stage separator.

The cooler may be an aerial cooler or a shell-and-tube exchanger that uses either direct seawater or a contained cooling-water loop, which is cooled by seawater or some other water source.

1.5.4 Gas Treating. Natural gas may have a number of impurities, such as H_2S and CO_2, which are referred to as "acid gases." Natural gas containing H_2S is called a sour gas; if the gas contains no H_2S, or if the H_2S has been removed, it is "sweet gas." The process of removing the H_2S, and possibly CO_2, is referred to as "sweetening."

H_2S gas is highly toxic. CO_2 forms a strong acid that is highly corrosive in the presence of water. Combined, they are corrosive; if the corrosion results in a leak, they can be deadly.

A common way to remove H_2S and CO_2 from natural gas is with an amine system, which uses a contact tower with trays or structured packing to pass the sour gas through the amine liquid, absorbing the H_2S and some of the CO_2. The amine is then regenerated in a stripping tower in which the H_2S and CO_2 are removed.

There are also several licensed physical solvent and batch processes (chemical or adsorption) available commercially.

For a more detailed description of gas treating, refer to the chapter on Hydrocarbon Testing in Ref. 1.

1.5.5 Gas Dehydration. To avoid water condensing in the gas pipeline with resulting corrosion and hydrate-formation problems, pipeline specifications usually limit the amount of water vapor in the gas. A standard pipeline specification in most of the southern U.S. is 7 lbm of

water per million standard cubic feet of gas (lbm/MMscf). This corresponds to a water dewpoint of approximately 32°F at 1,000 psi. In northern areas, or in very deep water in which temperatures outside the pipe could be much lower, it is common to see a specification of 4 lbm/MMscf (approximately 0°F dewpoint at 1,000 psi).

Water is often removed from gas with a glycol dehydration system, as described here. Other methods include solid-desiccant adsorption, refrigeration, and membrane permeation.

Glycol dehydration systems commonly use triethylene glycol to absorb the water vapor from the gas. This is done in a contact tower in which the lean, or dry, glycol flows by gravity from the top of the tower through trays or structured packing. The gas flows countercurrent up through the tower so that the driest gas contacts the driest glycol.

The dry gas exiting the tower is used to precool the lean glycol before it enters the tower. The gas then continues to sales or to further processing to remove natural-gas liquids (NGLs).

The rich, or wet, glycol exiting the bottom of the tower is regenerated in a continuous process. First, the rich glycol goes to a separator to remove any condensed hydrocarbons; then it is preheated and filtered before being sent to a "reboiler" or "regenerator."

The rich glycol is heated in the regenerator up to 390 to 400°F, and the water is boiled off. This vapor is either discharged directly to the atmosphere or is cooled and condensed to separate the small amount of hydrocarbon vapors from the water.

The resulting hot, lean glycol is then cooled through a cross exchanger with the cool, rich glycol coming from the contact tower. The cross exchanger makes the process more efficient and preheats the glycol going to the reboiler, which reduces the overall energy requirements. The reboiler may be heated by a gas-fired heater, electric heating elements, or a heat-medium system. For a more detailed description of gas dehydration, refer to the chapter on Dehydration in Ref. 1.

1.5.6 Gas Processing. The dry gas may be further processed to recover liquid hydrocarbons in the form of NGLs, LNGs, or liquefied petroleum gas (LPG). NGLs are hydrocarbon liquids, such as ethane, propane, butane, and natural gasoline, that can be separated from a natural-gas stream after the heavier hydrocarbon components have already been removed by separation at ambient temperatures. LPG is a mixture of hydrocarbons—principally butane and propane—that can be transported as a liquid under pressure, or at very low temperatures. and converted to gas on release of the pressure. LNG is a liquid composed of mostly methane that is liquefied to make it easy to transport if a pipeline is not feasible.

The most common processes used to separate NGL or LPG are lean-oil absorption, refrigeration, or turbo-expander plants. The lean gas remaining can be used as fuel, reinjected into the reservoir, or put into a pipeline.

1.5.7 Stabilization. Stabilization removes the light hydrocarbons from the liquid stream, either by reducing the pressure and letting the lighter components flash, as discussed previously, or by a combination of pressure reduction and heating. Most of the water will be removed during separation. The resulting stable condensate has a low vapor pressure so it can be stored in tanks for shipping at atmospheric pressure by truck, train, barge, or ship without excessive vapor venting. Often, there are vapor-pressure limitations that require liquid stabilization for pipeline shipments as well.

The water removed in the separation/stabilization process must be treated and disposed of, as described in the previous section on water treating.

1.5.8 Compression. The lighter components removed in the gas phase during the stabilization process will be at a lower pressure than the main gas stream. These components must be compressed to the HP-separator pressure so they can be processed with the rest of the gas.

1.6 Process Control

A separator operates through a continuous, rather than a batch, process. This means that the inlet stream constantly flows into the separator and that the gas and liquid must be removed at the same rate. For liquids, this is done by means of a level controller and level valve. The traditional level controller consists of a float on a spring. As the liquid level in the separator rises, the float rises until it closes a switch, which then opens the level valve to let out some liquid. When the level falls back down to the normal operating level, the switch opens again and drives the level valve closed. A two-phase separator uses a single liquid-level controller and level valve; a three-phase separator will have both an oil outlet with an oil-level controller and level valve and a water outlet with a water-level controller and level valve.

If the level valves control the liquid coming out of the separator, how is the gas controlled? Because the liquid is incompressible and the liquid level in the separator remains fairly constant, the gas is contained in an approximately constant volume. As more gas enters the separator, the pressure rises. A pressure controller is mounted on the separator-gas space or on the outlet-gas piping. The controller sends a signal to the pressure-control valve in the gas-outlet piping telling it to open when the pressure is higher than the set point. Pressure-control valves are usually modulating, which means that they gradually open wider as the pressure rises to a value higher than the set point and close as the pressure falls to a value lower than the set point.

In short, whatever amount of liquid comes into the separator, an equal amount must exit through the level-control valve. The level controller senses whether the liquid level is high or low and adjusts the level valve accordingly. Whatever amount of gas that comes in the inlet of the separator, an equal amount of gas must exit through the pressure-control valve. The pressure controller senses pressure in the separator, opening the pressure-control valve if the pressure gets higher than the desired set point and closing it if the pressure gets lower than desired. If the inlet stream shuts off, the outlet valves would all close, maintaining the pressure and level in the separator.

Detailed information on instrumentation and controls, including control-valve selection, is presented in the chapter on Instrumentation and Controls in this section of the *Handbook*.

1.7 Design Safety

If the process-control system operates correctly, operators use all manual valves correctly, and nothing breaks, there is no need for a safety system. However, controllers malfunction, valves leak, and operators make mistakes. The safety system is there to prevent overpressure and possible rupture of equipment, leaks, pollution, fire, injury to personnel, and damage to equipment. Ref. 2 provides a systematic way to ensure that all necessary safety equipment is in place. Two levels of protection normally exist in a safety system: primary and secondary.

1.7.1 Primary Protection. The primary protection is usually a sensor or switch on the equipment that detects the undesirable event. For example, equipment may have a pressure, level, or temperature switch to detect values that are too high or too low, based on the normal operating ranges. Once the undesirable event is detected, a safety shutdown system is required to shut down flow into the affected equipment.

1.7.2 Secondary Protection. In the event the primary protection fails to operate or operates too slowly to correct a problem, there is secondary protection consisting of a pressure safety valve (PSV) to prevent overpressure. A PSV is designed to open, relieving overpressure in a vessel or piping through “relief header” piping that directs the relieved fluids to a safe place for retrieval or disposal. Alternatively, secondary protection may consist of redundant sensors or switches, such as those used for primary protection, which may be located on downstream equipment or on the equipment in question.

A separator with a given operating pressure will have a "design" pressure or "maximum allowable working pressure" (MAWP) sufficiently greater than the operating pressures to prevent small fluctuations in the process from causing overpressure of the pressure vessel. As an example, in the staged-separation process, the operating pressure of each downstream separator will be lower than that of the separator flowing into it. This allows the system-design pressure to be reduced as well. When a higher-design-pressure system flows into a lower-design-pressure system, there is potential for overpressuring the downstream, lower-pressure-rated system. With multistage separators, the different operating pressures often lead to a different design pressure for the HP, IP, and LP separators and their associated piping. This introduces a hazard commonly referred to as "gas blowby." For example, if the liquid-level valve were to stick open, the liquid would flow out of the separator and the gas would "blow by" the liquid-control valve until the pressure equalized between the upstream and downstream separators. This equalized pressure could be higher than the design pressure of the downstream separator.

Safety systems must be designed to protect the lowest-pressure system in situations like the one outlined previously. Relief valves are normally provided on pressure vessels to protect against overpressure caused by "blocked discharge," which occurs when all outlets to the vessel are closed because of blockage or system shutdown. Relief valves must also be adequately sized to protect against overpressure caused by blowby. The gas-blowby rate may exceed the HP-system inlet flow rate for a short time because the HP separator is being blown down, in an uncontrolled manner, to the lower-pressure system. The flow rate must be calculated based on the upstream pressure, the control valve capacity at full open, any other flow restriction in the piping, and the downstream-vessel relief-valve set pressure. The calculated flow can then be used to adequately size the relief valve.

If the pressure difference between the two vessels is very large, the blowby rates will be correspondingly large. Consider, for example, an HP separator with a 1,480-psig MAWP in which the liquid flows to an atmospheric storage tank. The absolute pressure in the HP separator is 100 times that in the atmospheric storage tank (14.7 psia). Gas blowby from the HP separator expands to 100 times the original gas volume when it goes to atmospheric pressure. If the liquid-control valve from the separator has a 2-in.-diameter opening (3.14 $in.^2$), the vent on the tank must have 100 times the area to pass the same amount of gas (3.14 $in.^2$ or a 20-in. diameter vent). It is not a good idea to have an HP vessel dumping liquid to an atmospheric tank. This demonstrates yet another advantage of staged separation—reducing the amount of gas blowby possible between any two pressures.

In addition to primary and secondary protection for the process, an emergency support system is used to minimize the effects of escaped hydrocarbons. This system includes combustible gas detectors, fire detectors, smoke detectors, a containment system to collect leaking liquid hydrocarbons, and an emergency shutdown system to provide a method for the process-control system to initiate a platform shutdown. An in-depth discussion is presented in the chapter on Safety Systems in this volume of the *Handbook*.

References

1. *Engineering Data Book,* 12th edition, Gas Processors Suppliers Assn., Tulsa (2004).
2. *RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*, seventh edition, API, Washington, DC (2001).

SI Metric Conversion Factors

ft^3	×	2.831 685	E–02	= m^3
°F		(°F–32)/1.8		= °C
in.	×	2.54*	E+00	= cm
$in.^2$	×	6.451 6*	E+00	= cm^2
lbm	×	4.535 924	E–01	= kg
psi	×	6.894 757	E+00	= kPa

*Conversion factor is exact.

Chapter 2
Oil and Gas Separators

Robert W. Chin, CDS Separation Technologies Inc.

2.1 Introduction

This chapter is a discussion of the design of two- and three-phase gas/liquid separators used in the oil/gas industry. Vertical and horizontal configurations are considered. Various internals to enhance gas/liquid and liquid/liquid separation are described. Level control and platform motion issues are also discussed. This chapter presents typical equations for sizing the vessels along with worked examples.

2.1.1 General. The term "oil/gas separator" in petroleum terminology designates a pressure vessel used for separating well fluids produced from oil/gas wells into gaseous and liquid components. Separation is required for stage recovery of liquid hydrocarbons, producing saleable oil and gas streams, well testing, metering, and protection of pumps and compressors.

Separators are required to provide oil/gas streams that meet saleable pipeline specifications, as well as a water/solids stream for disposal. Typically, the oil must have less than 1% (by volume) water and less than 5 lbm water/MMscf gas. The water stream must have less than 29 ppm oil for overboard discharge in the Gulf of Mexico (GOM). Staged separation (depressurization) is required to maximize the liquid hydrocarbon volumes.

Fig. 2.1 shows a typical deepwater GOM process train. There are four stages of depressurization: high pressure (HP), intermediate pressure (IP), free water knockout (FWKO), and the degasser/bulk oil treater (BOT) combination. Bulk water is removed in the third stage, FWKO, and final dewatering is accomplished in the BOT. In the North Sea and other locations, water may be removed in the HP and/or IP vessels. The BOT is typically an electrostatic treater. Sometimes, the BOT will include a degassing section, eliminating the need for a separate degasser vessel. Typical deepwater GOM platform pressures are 1,500, 700, 250, and 50 psig for the HP, IP, FWKO, and degasser stages, respectively. **Fig. 2.2** shows the associated booster compressor unit and **Fig. 2.3** the glycol dehydration unit. Both systems make use of separators as a major component in their design. The separation equipment associated with water cleanup, such as hydrocyclones and flotation cells, is not shown. Additional descriptions of production facilities can be found in Ref. 1.

The primary functions of an oil/gas separator, along with separation methods, are summarized in **Table 2.1**. A separating vessel also may be referred to in the following ways: oil/gas separator; separator; stage separator; trap; knockout vessel, knockout drum, knockout trap, wa-

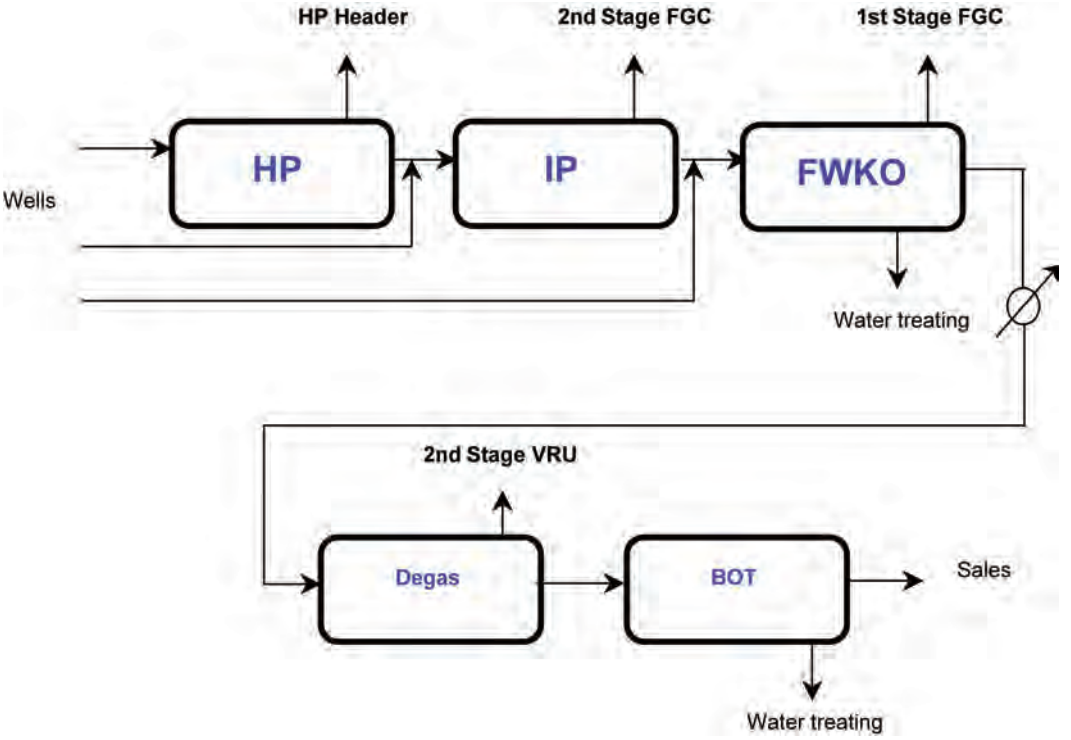


Fig. 2.1—Typical GOM production separation train consisting of HP, IP, FWKO, degasser, and BOT (courtesy of CDS Separation Technologies Inc.).

ter knockout, or liquid knockout; flash chamber, flash vessel, or flash trap; expansion separator or expansion vessel; scrubber (gas scrubber), dry or wet type; filter (gas filter), dry or wet type; and filter/separator.

The terms "oil/gas separator," "separator," "stage separator," and "trap" refer to a conventional oil/gas separator. These separating vessels are normally used on a producing lease or platform near a wellhead, manifold, or tank battery to separate fluids produced from oil/gas wells into oil/gas or liquid/gas. They must be capable of handling "slugs" or "heads" of well fluids. Therefore, they are usually sized to handle the highest instantaneous rates of flow.

A knockout vessel, drum, or trap may be used to remove only water from the well fluid or to remove all liquid (oil plus water) from the gas. In the case of a water knockout for use near the wellhead, the gas and liquid petroleum are usually discharged together, and the free water is separated and discharged from the bottom of the vessel.

A liquid knockout is also used to remove all liquid (oil plus water) from the gas. The water and liquid hydrocarbons are discharged together from the bottom of the vessel, and the gas is discharged from the top.

A flash chamber (trap or vessel) normally refers to a conventional oil/gas separator operated at low pressure, with the liquid from a higher-pressure separator being partially vaporized or "flashed" into it. This flash chamber is quite often the second or third stage of separation, with the liquid being discharged from the flash chamber to storage.

An expansion vessel is the first-stage separator on a low-temperature or cold-separation unit. This vessel may be equipped with a heating coil to melt hydrates, or a hydrate-preventing liquid (such as glycol) may be injected into the well fluid just before expansion into this vessel.

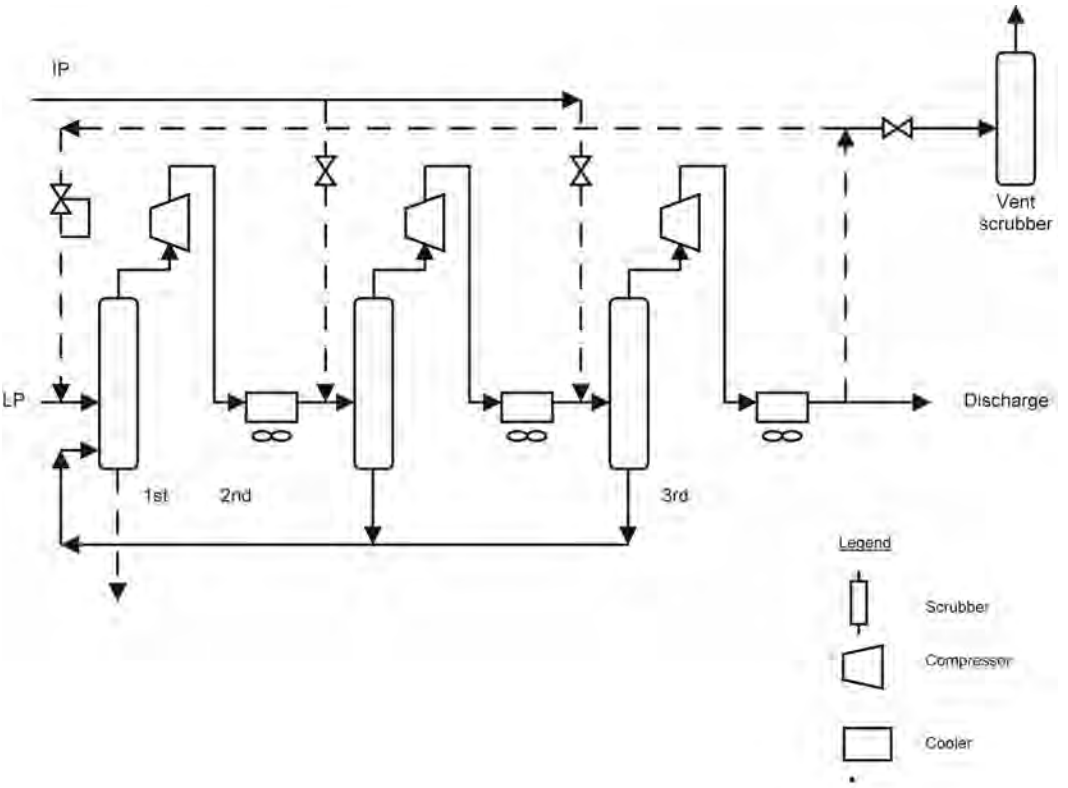


Fig. 2.2—Typical three-stage compressor train (courtesy of CDS Separation Technologies Inc.).

A gas scrubber is similar to an oil/gas separator. Usually, it handles fluid that contains less liquid than that produced from oil/gas wells. Gas scrubbers are normally used in compressor trains, gas gathering, sales, and distribution lines, where they are not required to handle slugs or heads of liquid, as is often the case with oil/gas separators. The dry-type gas scrubber uses mist extractors and other internals similar to oil/gas separators with preference shown to the coalescing-type mist extractor. The wet-type gas scrubber passes the stream of gas through a bath of oil or other liquid that washes dust and other impurities from the gas. The gas is flowed through a mist extractor, in which all removable liquid is separated from it. A "scrubber" can refer to a vessel used upstream from any gas-processing vessel or unit to protect the downstream vessel or unit from liquid hydrocarbons and/or water.

The "filter" (gas filter or filter/separator) refers to a dry-type gas scrubber, especially if the unit is being used primarily to remove dust from the gas stream. A filtering medium is used in the vessel to remove liquids and solids from the gas. A gas/liquid filter generally follows a scrubber to remove fine liquid drops. Separators are also classified by their design process conditions, which are shown in **Table 2.2**.

2.1.2 Well Fluids and Their Characteristics. This section outlines some of the physical characteristics of well fluids handled by oil/gas separators.

Crude Oil. Crude oil is a complex mixture of hydrocarbons produced in liquid form. The American Petroleum Inst. (API) gravity of crude oil can range from 6 to 50° API and viscosity from 5 to 90,000 cp at average operating conditions. Viscosities are nearly always smaller in the reservoir. Color varies through shades of green, yellow, brown, and black.

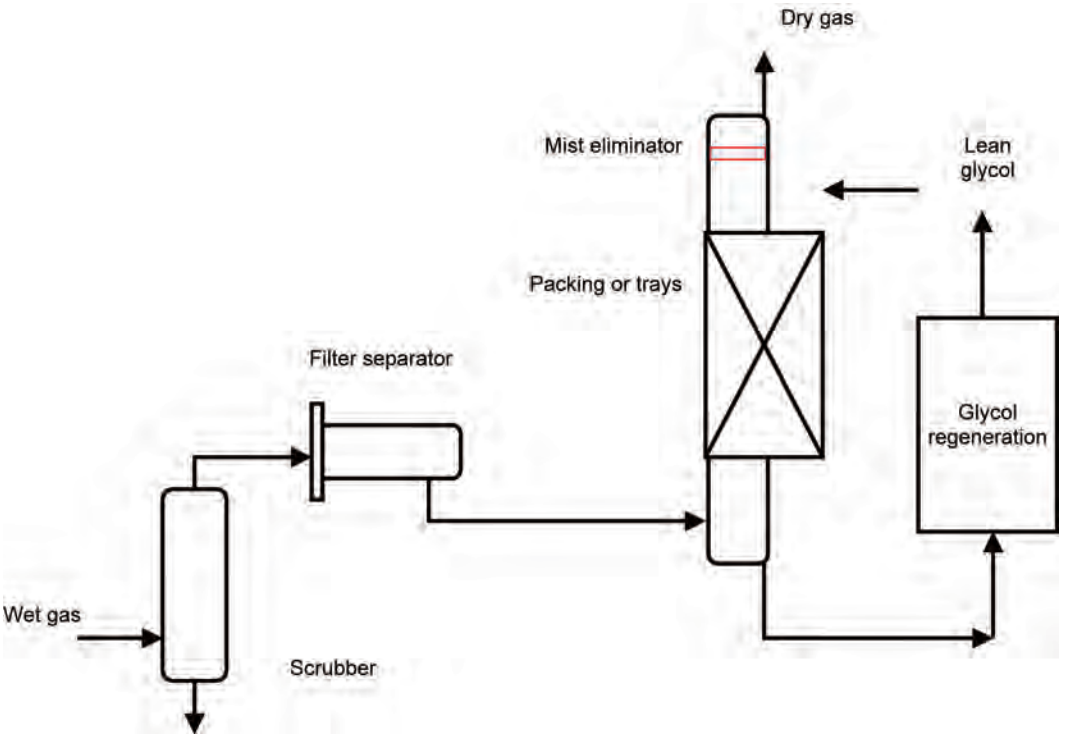


Fig. 2.3—Typical glycol dehydration system (courtesy of CDS Separation Technologies Inc.).

TABLE 2.1—INTERNAL DEVICES AND SEPARATION AIDS FOR SEPARATORS

Function	Method of Separation	Internal Devices and Separation Aids
Separation of oil from gas	Gravity	Mist extractors: impingement type; change of direction type; cyclones, filter cartridges; and washing
Separation of gas from oil	Gravity	Cyclones, plate packs, matrix packs, agitation, heat
Separation of water from oil	Gravity	Cyclones, plate packs, matrix packs, agitation, heat
Separation of oil from water	Gravity	Cyclones, plate packs, matrix packs, agitation, flotation
Separation of solids from liquids	Gravity	Cyclones, agitation, heat, flotation

Condensate. This is a hydrocarbon that may exist in the producing formation either as a liquid or as a condensable vapor. Liquefaction of gaseous components of the condensate usually occurs with reduction of well-fluid temperature to surface operating conditions. Gravities of the condensed liquids may range from 50 to 120° API and viscosities from 2 to 6 cp at standard conditions. Color may be water-white, light yellow, or light blue.

TABLE 2.2—TYPICAL PRESSURE AND TEMPERATURE CLASSIFICATIONS

Classification	Designation
Pressure	High pressure (HP) ~1,500 psi Intermediate pressure (IP) ~750 psi Low pressure (LP) ~250 psi
Temperature	Low temperature ~ –35°F High temperature ~ +200°F

Natural Gas. A gas is a substance that has no shape or volume of its own. It will completely fill any container in which it is placed and will take the shape of the container. Hydrocarbon gas, associated with crude oil, is referred to as natural gas and may be found as "free" gas or as "solution" gas. Specific gravity of natural gas may vary from 0.55 to 0.90 and viscosity from 0.01 to 0.024 cp at standard conditions.

Free Gas. Free gas is a hydrocarbon that exists in the gaseous phase at operating pressure and temperature. Free gas may refer to any gas at any pressure that is not in solution or mechanically held in the liquid hydrocarbon.

Solution Gas. Solution gas is homogeneously contained in oil at a given pressure and temperature. A reduction in pressure and/or an increase in temperature may cause the gas to be evolved from the oil, whereupon it assumes the characteristics of free gas.

Condensable Vapors. These hydrocarbons exist as vapor at certain pressures and temperatures and as liquid at other pressures and temperatures. In the vapor phase, they assume the general characteristics of a gas. In the vapor phase, condensable vapors vary in specific gravity from 0.55 to 4.91 (air = 1.0), and in viscosity from 0.006 to 0.011 cp at standard conditions.

Water. Water produced with crude oil and natural gas may be in the form of vapor or liquid. The liquid water may be free or emulsified. Free water reaches the surface separated from the liquid hydrocarbon. Emulsified water is dispersed as droplets in the liquid hydrocarbon. The water may be fresh or briny in nature and may contain undesirable gases such as CO_2.

Impurities and Extraneous Materials. Produced well fluids may contain such gaseous impurities as nitrogen, carbon dioxide, hydrogen sulfide, and other gases that are not hydrocarbon in nature or origin. Well fluids may contain liquid or semiliquid impurities such as water and paraffin. They may also contain solid impurities, such as drilling mud, sand, silt, and salt.

2.1.3 Separator Components. An oil/gas separator generally consists of essential components and features:

• A vessel that includes a primary separation device and/or section; secondary "gravity" settling (separating) section; mist extractor to remove small liquid particles from the gas; gas outlet; liquid settling (separating) section to remove gas from liquids, to separate water from oil, and to separate solids from the liquids; and oil outlet and water outlet.

• Adequate volumetric liquid capacity to handle liquid surges (slugs) from the wells and/or flow lines.

• Adequate vessel diameter and height or length to allow most of the liquid to separate from the gas so that the mist extractor will not be flooded.

• A means of controlling oil/water levels in the separator, which usually includes a liquid-level controller and a control valve on the oil/water outlets.

• A backpressure valve on the gas outlet to maintain a steady pressure in the vessel.

• Pressure relief devices.

TABLE 2.3—ADVANTAGES AND DISADVANTAGES OF HORIZONTAL AND VERTICAL SEPARATORS

	Horizontal	Vertical	Discussion
Separation:	Better		In a horizontal vessel, the drops or bubbles do not have to settle or rise through a countercurrent flow.
Solids:		Better	Solids are more easily removed from the bottom of a vertical vessel.
Motion Handling:		Better	Vertical vessels have smaller horizontal dimensions.
Foaming:	Better		Horizontal vessels provide more surface area for bubbles to escape.
Surges:		Better	A change in liquid level does not affect the gas capacity of the vessel.

In most oil/gas surface production equipment systems, the oil/gas separator is the first vessel the well fluid flows through after it leaves the producing well. However, other equipment such as heaters may be installed upstream of the separator.

2.1.4 Separator Orientation. Table 2.3 compares the advantages and disadvantages of vertical and horizontal separators. This table should be used as a guideline in selection.

2.1.5 Separator Performance. Separation performance depends on many factors, such as flow rates, fluid properties, internals, etc. The gas capacity of most gas/liquid separation equipment is sized on the basis of removing a certain size drop. The main unknown is the incoming drop-size distribution. Without this, the effluent quality cannot realistically be estimated. For example, a specification that the gas outlet should have less than 0.1 gal/MMscf liquid is somewhat difficult to guarantee because of the unknown drop-size distribution. Pressure drops across upstream piping components and equipment can create very small drops (1 to 10 μm) while coalescence in piping and inlet devices can create larger drops. A removal drop size of 10 μm for scrubbers is more realistic to specify. The same discussion applies to water-in-oil and oil-in-water specifications. To the author's knowledge, a correlation is not available to predict water-in-oil or oil-in-water concentrations. For example, prediction of whether a separator can produce an oil stream with less than 20%v water is generally based on experience or analogous separators.

The liquid capacity of most separators is sized to provide enough retention time to allow gas bubbles to form and separate out. More retention time is needed for separators that are designed to separate oil from water, as well as gas from liquid (three-phase compared to two-phase separators).

2.1.6 Internals. A major factor in separator performance is the internals that can affect flow distribution, drop/bubble shearing and coalescence, foam creation, mixing, and level control. The separator or scrubber is generally divided into three zones: inlet, gravity/coalescing, and outlet. Various types of internals for these three zones are discussed next.

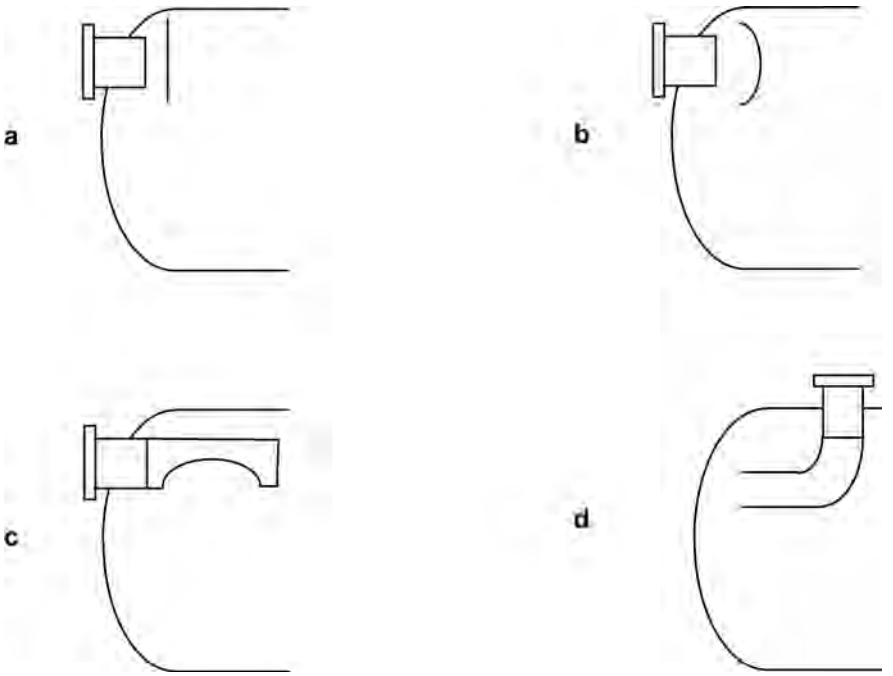


Fig. 2.4—Types of inlets that are commonly used but might negatively affect separation: (a) impact plate, (b) dished head, (c) half-open pipe, and (d) open pipe at vessel head (courtesy of CDS Separation Technologies Inc.).

Inlet Zone. *General.* Some type of inlet device is needed to obtain an initial bulk separation of liquid/gas. In most cases, gas will have already come out of solution in the pipeline, leading to the separator (because of pressure drop across an upstream choke or control valve). Hence, the majority of the gas is separated from the liquid in the inlet zone.

Inlets to production vessels have received less attention and "science" than the gas outlets. The main concept involves impacting the inlet stream on a surface, causing a momentum change, enabling the liquid droplets to fall and the gas bubbles to rise. Typical inlets, as depicted in **Fig. 2.4**, are flat impact plates, dished-head plates, half-open pipes, and open pipes directed at vessel heads.

These inlets, although inexpensive, may have the shortcoming of negatively affecting separation performance. The inlets previously mentioned are more appropriate for handling low-momentum fluids (momentum is density times velocity). However, for higher-momentum fluids, these inlets can cause problems. The flat or dished-head plates can result in small drops and foam. The open-pipe designs can lead to fluid short-circuiting or channeling.

Although inlet momentum is a good starting guideline for selection, the process conditions, as well as the demister choice, should also be considered. For example, if the liquid loading is low enough that a demister can handle all the liquid, then inlet devices can be applied beyond their typical momentum ranges.

Inlet Cyclones. In recent years, because of foaming issues and the need for higher capacities, cyclonic inlets are now becoming more widely used. See **Figs. 2.5a, 2.5b, and 2.6** for typical examples. The advantages of a cyclonic or vortex inlet are high allowable inlet momentums, defoaming characteristics, liquid/liquid coalescing benefits, gas demisting benefits, and high liquid levels.

The inlet cyclone can be used with inlet momentums, a factor of 10 higher than pipe inlets. Typically, pipe inlets are used for momentums (ρV^2, where ρ is bulk density, kg/m^3, and V is



Fig. 2.5a—Cyclone/vortex tube cluster: top (shell side) entry (courtesy of CDS Separation Technologies Inc.).

bulk velocity, m/s) less than 1,000 Pa. Inlet cyclones have been used successfully to 65,000 Pa. Although ρV^2 is energy, it is referred to as (transport of) momentum.

Because of the centrifugal flow, large foam bubbles are broken, liquid drops are removed from the gas phase, and liquid/liquid coalescence occurs within the cyclone. A problem with some cyclones is that a poorly designed liquid outlet can shear the liquids, offsetting the benefits of the coalescence and possibly making the situation worse. For cases in which a high liquid level is required in the separator, the inlet cyclone can be submerged up to the gas outlet level.

Depending on the flow rates, more than one cyclone tube may be required to rapidly degas the oil. This allows the use of a shorter oil retention time. Degassing is rapid, and large bubble foam is minimized or eliminated. Without the cyclonic inlet, foam can occupy a considerable volume in the separator. The use of a cyclonic inlet often allows foam to be ignored as a sizing consideration. Thus, for high-capacity crude-oil separators (which are the ones most limited by foam), the cyclone inlet can significantly reduce the required vessel liquid and foam holdup volume, size, weight, and cost.

A cyclone/vortex tube cluster, shown in **Fig. 2.5**, is a separator internal device that can be part of the original separator design or may be retrofitted into existing separators to increase capacity. In Fig. 2.5a, fluids enter the cyclones from a top shell side inlet nozzle and are split to the different cyclones. In Fig. 2.5b, incoming process fluids are accelerated in the manifold to a desired velocity. Each tube peels off a portion of that stream, which enters the tube tangen-

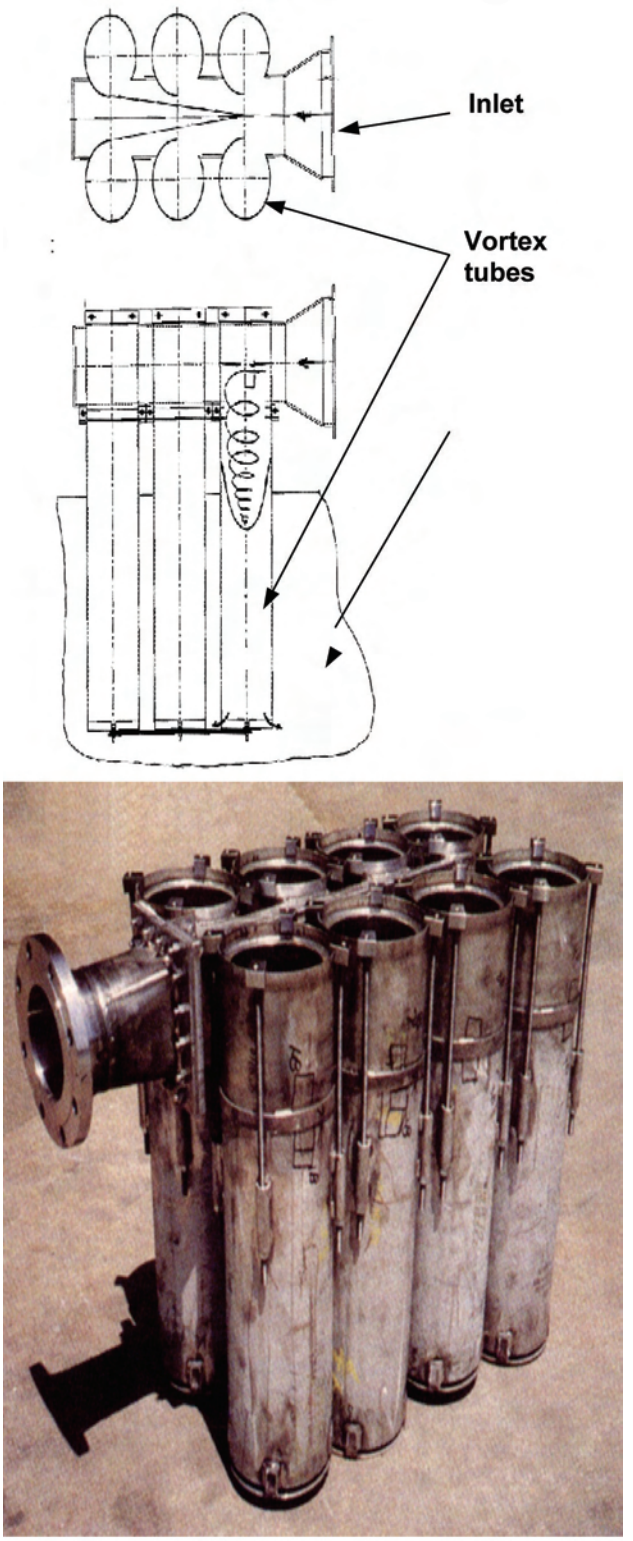


Fig. 2.5b—Cyclone/vortex tube cluster: side (head) entry (courtesy of Natco).

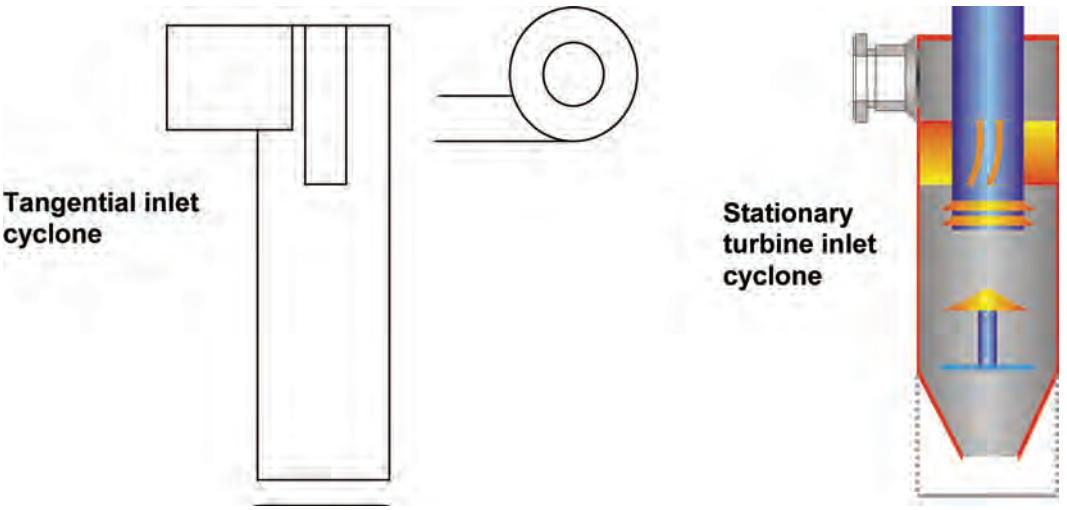


Fig. 2.6—Examples of inlet cyclones (courtesy of CDS Separation Technologies Inc.).

tially, generating rotational flow. In both cases, within each tube, the swirling fluids create a high force for separation of gas/liquid. The gas accumulates in the center, forming a gas core, exits through an orifice in the top of the tube, and flows into the separator gas phase. Liquids are slung to the tube wall, where they migrate downward as a continuous sheet. They exit the tube through a peripheral gap in the tube wall at the bottom and flow out into the separator liquid bath, in which the bottoms of the tubes are submerged.

Fig. 2.6 shows two different types of inlet cyclones. One cyclone has a simple tangential inlet with or without a gas vortex finder. In cyclones without a vortex finder, gas can escape quickly out the top. This has two effects: the loss of gas yields a lower centrifugal acceleration within the cyclone, and as the gas leaves the top, it carries liquid with it as well as shearing the liquid. More mist is generated, which may impact the downstream demister. With a tangential inlet, the fluids may also circle back on the inlet, disrupting the incoming flow. The bottom of the cyclone is submerged below a liquid level to prevent gas from blowing out the bottom (blow-by). A simple flat plate baffle beneath the liquid outlet spreads the flow out radially.

The other cyclone has stationary turbine blades used to provide spin. This has the advantage of lowering the shear on the fluids. Lower shear results in less mist generation and droplet shearing. In the liquid section, the liquid outlet with proprietary internals is designed to prevent gas from escaping. The bottom of the cyclone also provides some backpressure through low shear channel flow or a perforated cylinder. This additional backpressure allows the cyclone to operate at higher gas capacities than the first cyclone and, hence, with higher centrifugal accelerations. A bottom flat plate, in conjunction with the perforated cylinder, spreads the liquid flow out more uniformly.

The cyclonic-type inlet device is used to diffuse the momentum of the incoming feed stream and allows for the removal of any bulk liquids and solids that may be present. The cyclonic inlet device is designed such that it can operate at both high and low gas/oil ratios without the possibility of gas blow-by and excessive liquid re-entrainment into the gas phase.

The main characteristics to look for in an inlet cyclone are listed next.

• High liquid drainage capacity: This is necessary to prevent internal "choking" of the cyclone. In this case, the liquid carryover into the gas phase will be excessive, which could cause too high a liquid load on the downstream devices. Also, there would be considerable disruption to the internal flow field, which means the cyclone will not operate correctly.

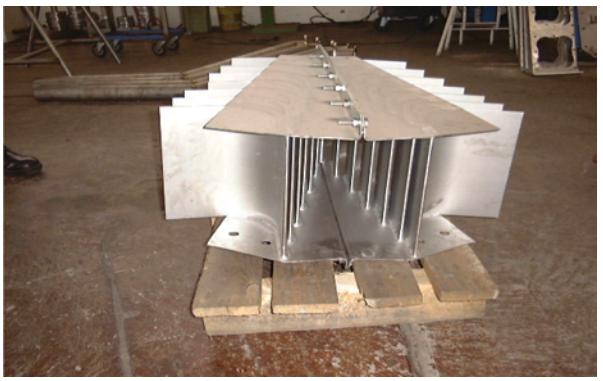


Fig. 2.7—Vane-type inlet device in which incoming fluids are "sliced" off to the sides (courtesy of CDS Separation Technologies Inc.).

• Low re-entrainment of liquid into the gas phase: This means that the downstream mist eliminating devices will not be overloaded. Also, the mist eliminating section will be working optimally; therefore, the best separation performance from the separator can be realized.

• Liquid re-entrainment: The main cause of liquid re-entrainment within the gas phase is "creep" that is caused by internal pressure differences causing liquid to move along internal surfaces. Within the cyclone, the effect of creep can be minimized by use of rings located around the gas vortex finder.

• Low shear forces on the re-entrained liquids in the gas: Low shear forces are beneficial, given that the droplet distribution of the re-entrained liquids leaving the cyclone is not too fine. The finer the droplets, the more difficult it becomes for the downstream mist eliminating section to remove them—hence, the overall liquid carryover from the separator increases.

• Low shear forces on the dispersed phase within the liquid outlet: Low shear forces are beneficial in that the droplet distribution of the dispersed phase liquid leaving the cyclone is not too small and does not form an emulsion. As the droplets get finer, it becomes more difficult for the downstream gravity settling devices to coalesce and remove them; hence, more is carried over in the exiting streams. This can be accomplished by ensuring that the liquid flow channels within the cyclone are relatively large and that any perforated holes are of the correct size to minimize shear.

• Minimum gas blow-by to the liquid outlet: Gas blow-by is seen when gas exits with the liquid phase from the bottom of the cyclone. If the amount of gas is considerable, a bubbling mass of liquid/gas is formed, which has a negative effect because of foam generation and mixing.

Care must be taken when designing inlet cyclones for separators. Cyclones are designed on the basis of a pressure balance between the pressure drop needed to force the gas up and out the top of the cyclone and that required to push the liquid out the bottom of the cyclone. If the gas pressure drop is higher than the liquid pressure drop, the liquid level inside the cyclone will be lower than that of the level of the surrounding liquid in the separator and vice versa. Flow rate turndown and changes in producing gas-to-oil ratio (GOR) then play important roles in the determination of the operating range of the cyclones. For example, cyclones may be properly designed for, say, 50,000 B/D of liquids at 1,000 GOR. However, if the GOR is actually 1,500, gas may blow out the bottom of the cyclones and create foam throughout the separator.

Vane Inlet. For applications of inlet momentum typically less than 9 kPa, a vane inlet can be used. **Fig. 2.7** shows a typical vane inlet.

The fluids are "sliced" off to either side while flowing through the inlet device. The spacing between the blades typically has been designed using computational fluid dynamics (CFD) to achieve uniform flow. Because the area of the vane inlet is several times larger than the

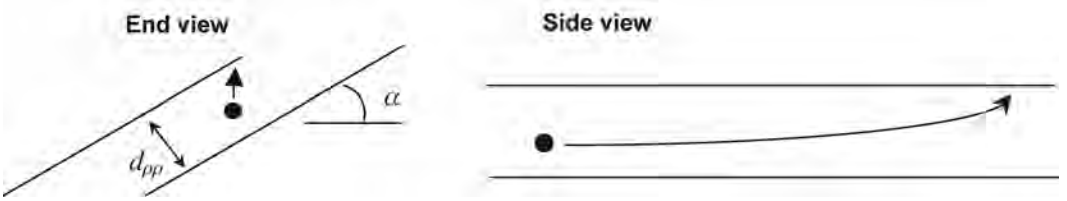


Fig. 2.8—Depiction of droplet rising between parallel plates (courtesy of CDS Separation Technologies Inc.).

inlet nozzle, the fluid velocities are much smaller, allowing for good gas/liquid separation as well as smooth entry into the vessel.

Flow Distribution. Regardless of the size of the vessel, short-circuiting can result in poor separation efficiency. Integral to any inlet device is a flow straightener such as a single perforated baffle plate. A full-diameter plate allows the gas/liquid to flow more uniformly after leaving the vane-type inlet, inlet cyclones, or even the impact plates. The plate also acts as an impingement demister and foam breaker as well.

Typical net-free area (NFA) ranges in the 10 to 50% range. As the NFA lowers, the shear of the fluids gets higher, so the NFA should be matched to the particular application. One concern of these plates is solids buildup on the upstream side. Generally, the velocities are high enough in the inlet zone to carry the solids through the perforations. In any case, a flush nozzle should be installed in the inlet zone. Other designs include flow straightening vanes. However, the open area is generally too high to be effective.

Gravity/Coalescing Zone. To assist in coalescing (and foam breaking), mesh, vanes, and/or plate/matrix packs are sometimes placed in the gas/liquid phases. These internals provide impingement or shearing surfaces for the dispersed phase.

For liquid/liquid coalescence in three-phase separators, FWKO, and other separators in which it is desired to have separate liquid outlets for oil/water, plate packs provide less turbulent/more laminar flow and a smaller distance over which drops have to settle. Plate packs also have been installed to promote degassing.

Laminar flow is indicated by the flow Reynolds number, which is defined as

$$\mathrm{Re} = \frac{\rho_c V_c d_h}{\mu_c}, \quad \text{..... (2.1)}$$

where

ρ_c = continuous phase density, kg/m^3;

μ_c = continuous phase dynamic viscosity, kg/(m·s) or N·s/m^2;

V_c = continuous phase velocity, m/s;

and

d_h = hydraulic diameter.

For a plate pack with a perpendicular gap spacing of d_{pp}, the hydraulic diameter is approximately equal to 2 d_{pp}. Transition to turbulent flow occurs in the Re range of 1,000 to 1,500.

To determine the drop size that can be removed, consider the schematic in **Fig. 2.8** of an oil droplet rising in a waterflow between plates. The distance a drop has to settle is $d_{pp}/\cos(\alpha)$, where d_{pp} is the perpendicular spacing of the plate, and α is the inclination angle. For liquids with "nonsticky" solids, the plate spacing and the angle of inclination can be increased to mitigate plugging.

For the plate pack to be effective, the drop must reach the plate before exiting the pack. A ballistic model of the drop results in

$$V_r = V_h \times \frac{d_{pp}}{L \cdot \cos \alpha}, \quad \text{..... (2.2)}$$

where

V_r = drop/rise velocity, m/s;

V_h = horizontal water velocity, m/s;

L = plate-pack length, m;

and

d_{pp} = plate-pack perpendicular gas spacing, m.

For a low-drop Reynolds number, the drop/rise velocity is given by Stokes' law, which is written as

$$V_r = \frac{(\rho_w - \rho_o) \times g \times D_o^2}{18\mu_w}, \quad \text{..... (2.3)}$$

where

ρ_w = water density, kg/m^3;

ρ_o = oil density, kg/m^3;

μ_w = water dynamic viscosity, kg/(m·s) or N·s/m^2;

g = gravitational acceleration, 9.81 m/s^2;

and

D_o = drop diameter, cm.

For a higher-drop Reynolds number, a more general form of Eq. 2.3 can be used. For a given plate-pack geometry and fluid conditions, the minimum drop that can be removed by the plate pack is obtained from Eqs. 2.2 and 2.3.

$$D_o = \sqrt{\frac{18\mu_w}{(\rho_w - \rho_o) \cdot g} \times \frac{V_h \cdot d_{pp}}{L \cdot \cos \alpha}}. \quad \text{..... (2.4)}$$

For water drops in oil, the water viscosity in Eq. 2.4 is replaced with the oil viscosity, and the horizontal velocity is that of the oil phase. Typical design drop size removal in plate packs is approximately 50 μm.

Other designs use mesh and matrix packing for liquid/liquid coalescing. However, plugging issues should be addressed when selecting the coalescer. In general, if solids are present in significant quantities, no coalescing internals are installed.

For the gas phase, matrix/plate packs and vanes have been used to aid in liquid drop coalescence or foam breaking. Vanes are discussed in the next section. The theory behind installing the high surface internals such as plate packs for foam breaking is that the bubbles will stretch and break as they are dragged along the surfaces. However, if most of the gas flows through the top portion of the pack, the foamy layer will not be sufficiently sheared, and the bubbles will meander through to the other end.

Gas Outlet Zone. Mist capture can occur by three mechanisms, as shown in **Fig. 2.9**. It should be kept in mind that there are no sharply defined limits between mechanisms. As the momentum of a droplet varies directly with liquid density and the cube of the diameter, heavier or larger particles tend to resist following the streamline of a flowing gas and will strike objects placed in their line of travel. This is inertial impaction, the mechanism responsible for removing most particles of diameter > 10 μm. Smaller particles that follow the streamlines may collide with the solid objects, if their distance of approach is less than their radius. This is

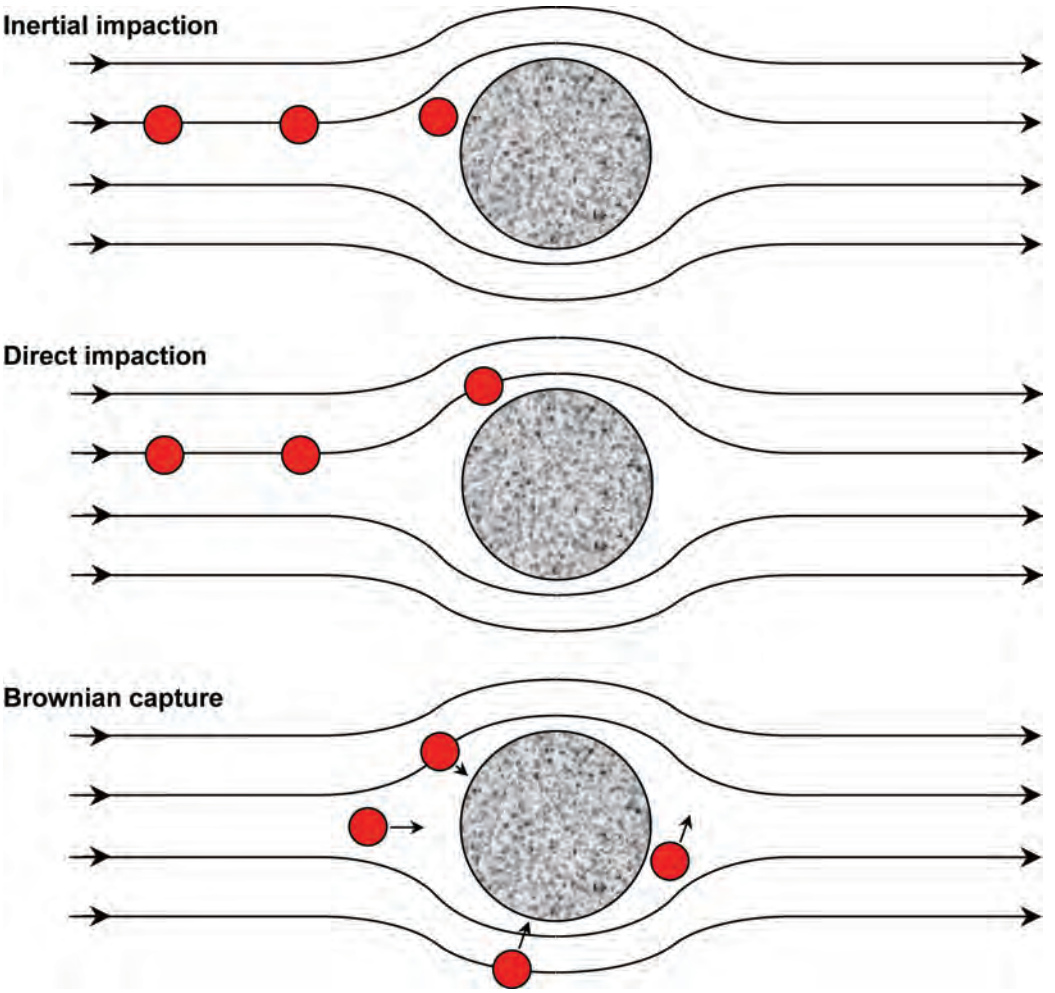


Fig. 2.9—Mechanisms of entrainment removal (courtesy of CDS Separation Technologies Inc.).

direct impaction. It is often the governing mechanism for droplets in the 1- to 10-μm range. With submicron mists, Brownian capture becomes the dominant collection mechanism. This depends on Brownian motion—the continuous random motion of droplets in elastic collision with gas molecules. As the particles become smaller and the velocity gets lower, the Brownian capture becomes more efficient. Almost all mist elimination equipment falls into four categories: mesh, vanes, cyclones, and fiber-beds.

The demisters can be sealed in the liquid or within a gas box with a liquid drain sealed in the liquid. In the later case, enough space must be provided between the bottom of the gas box and the liquid level to prevent siphoning of liquid up the drain tube.

Mesh. As a vapor stream carrying entrained liquid droplets passes through a knitted mesh, the vapor moves freely through the mesh. However, the inertia of the liquid droplets causes them to contact the wire surfaces, coalesce, and ultimately drain as large droplets.

The knitted mesh can be made in various materials and densities. See **Fig. 2.10**. Each manufacturer has its own method of knitting the mesh, which accounts for the differences in separation efficiency. Some meshes have different materials interwoven together to account for different fluids such as glycol and condensate. Other types use layers of different styles of meshes.

For general design, the mesh area can be determined with Eq. 2.5.

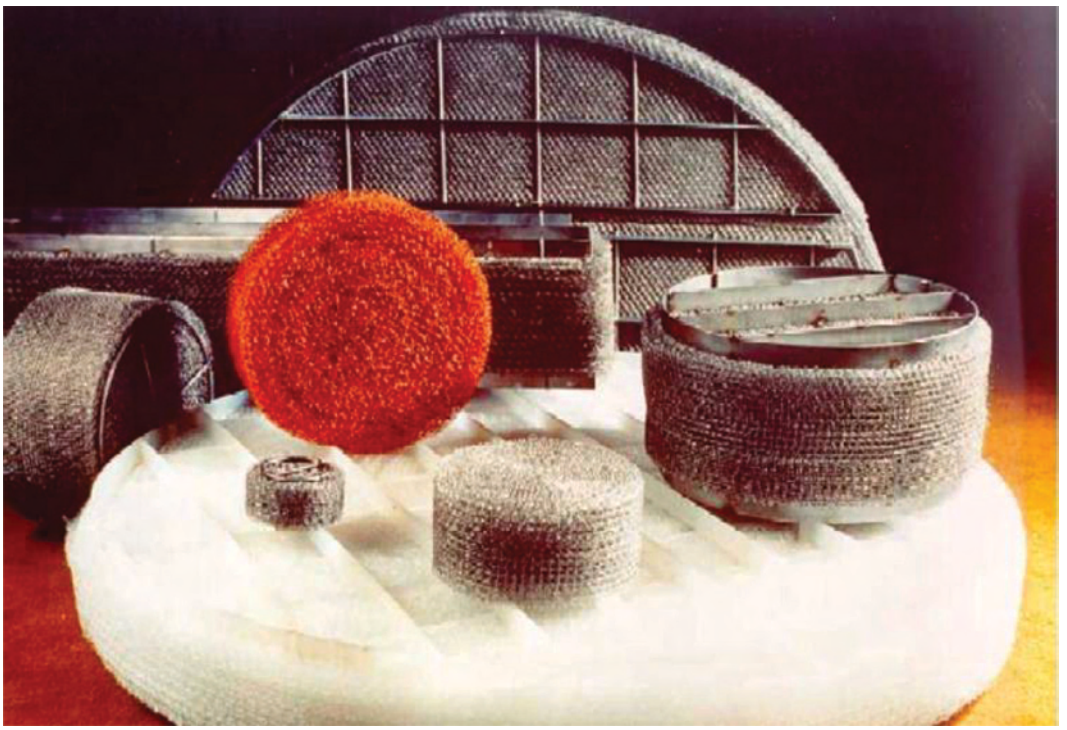


Fig. 2.10—Examples of mesh: stainless steel, polypropylene, and copper (courtesy of Koch Otto York).

$$V_m = K\sqrt{\frac{\rho_l - \rho_g}{\rho_g}}, \quad \text{..... (2.5)}$$

where

V_m = design velocity, m/s;

ρ_g = gas-phase density, kg/m^3;

ρ_l = liquid-phase density, kg/m^3;

and

K = mesh capacity factor, m/s.

The recommended value of K varies and depends upon several factors such as liquid viscosity, surface tension, liquid loading, and operating pressure. Each manufacturer has its own recommended values. For general sizing, a K value of 0.1 m/s can be used as a guideline. Pressure drops are generally a few inches of water (one inch of water equals 25 Pa.)

Vane-Type Mist Extractors. Vane-type mist extractors are widely used in oil/gas separators. They can be of many designs. **Fig. 2.11** shows typical single- and double-pocket vanes.

As the mist-laden gas stream passes through the parallel vane plates, it is forced to change direction several times. The mist droplets are separated by the subsequent centrifugal forces and are collected on the vane blades. The coalesced liquid film is then drained through hooks (single pockets) or slits (double pockets) on the blades.

In the double-pocket design, the liquid is more protected from being re-entrained by the gas. The double-pocket design also can be used in vertical flow, as shown in Fig. 2.11. This coalesced liquid film is then drained through slits ("double pockets") in the hollow blades, there-

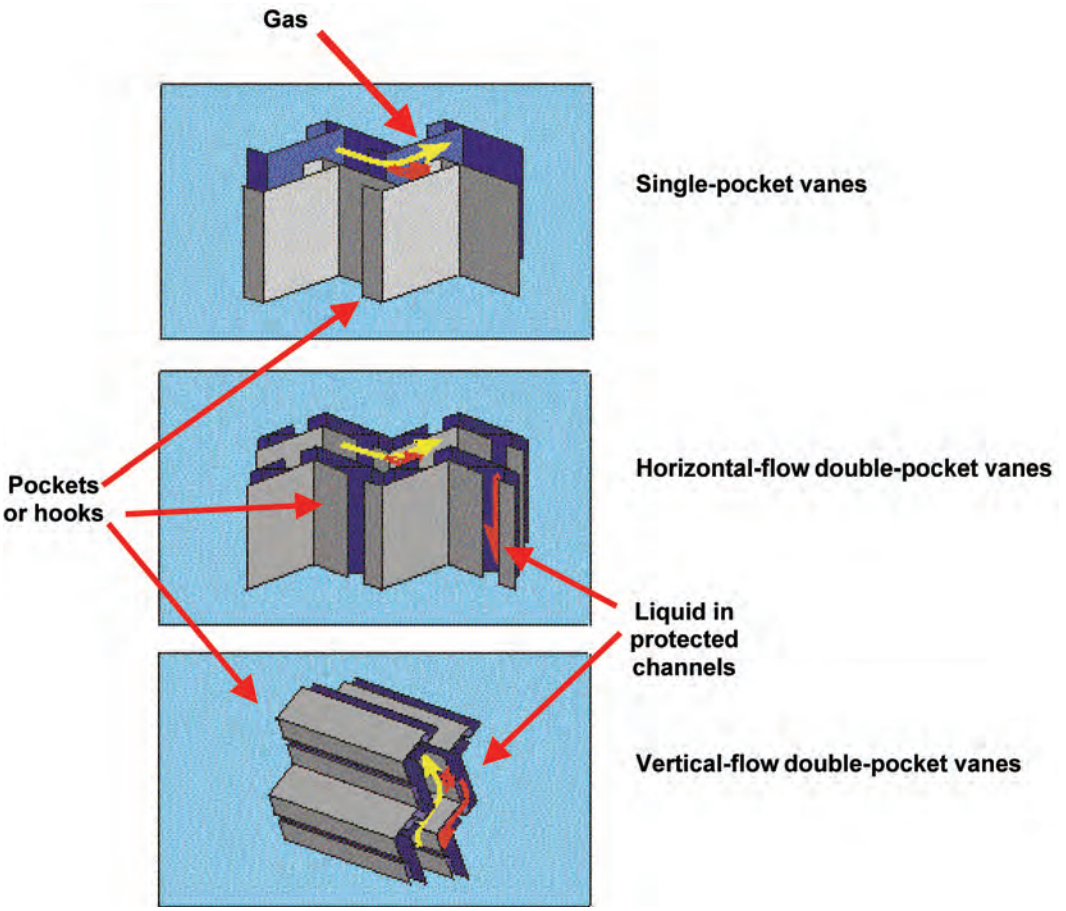


Fig. 2.11—Examples of pocketed or hooked vanes (courtesy of CDS Separation Technologies Inc.).

by reducing the gas disturbance. This leads to a higher throughput and greater efficiency in comparison with simpler vane-type separators.

The separating efficiency of a vane mist extractor depends on the number of vanes in the element, distance between the vanes, angle of the vanes, and size of liquid particles. It is claimed that this mist extractor will remove all entrained liquid droplets that are 8–10 μm and larger. However, this is generally true only for low pressures, on the order of a few hundred psi. If smaller liquid particles are present in the gas, an agglomerator should be installed upstream.

Eq. 2.5 can also be used as a guideline for sizing vane-pack areas. Typical K values are in the 0.15–0.25-m/s range.

Cyclones. Typical demisters in production vessels have generally been mesh pads and vane packs. However, axial-flow cyclones are becoming more frequently used because of their advantages: high efficiency at high pressures; high gas/liquid capacities; foam breaking; and nonfouling.

For instance, vane packs cannot remove droplets that are 10–20 μm at pressures greater than 500 to 600 psi. Additionally, cyclones have approximately 10 times the capacity of mesh pads and 4 times that of vane packs. Because of these features, the cyclones are suitable for upgrading existing vessels and for designing smaller, more compact new vessels. Because of their high centrifugal accelerations, the cyclones can be placed horizontally or vertically. Deposition is usually not a concern because of the high velocities. When cyclones are used in conjunction with mesh pads (as coalescers), high turndowns can be achieved.

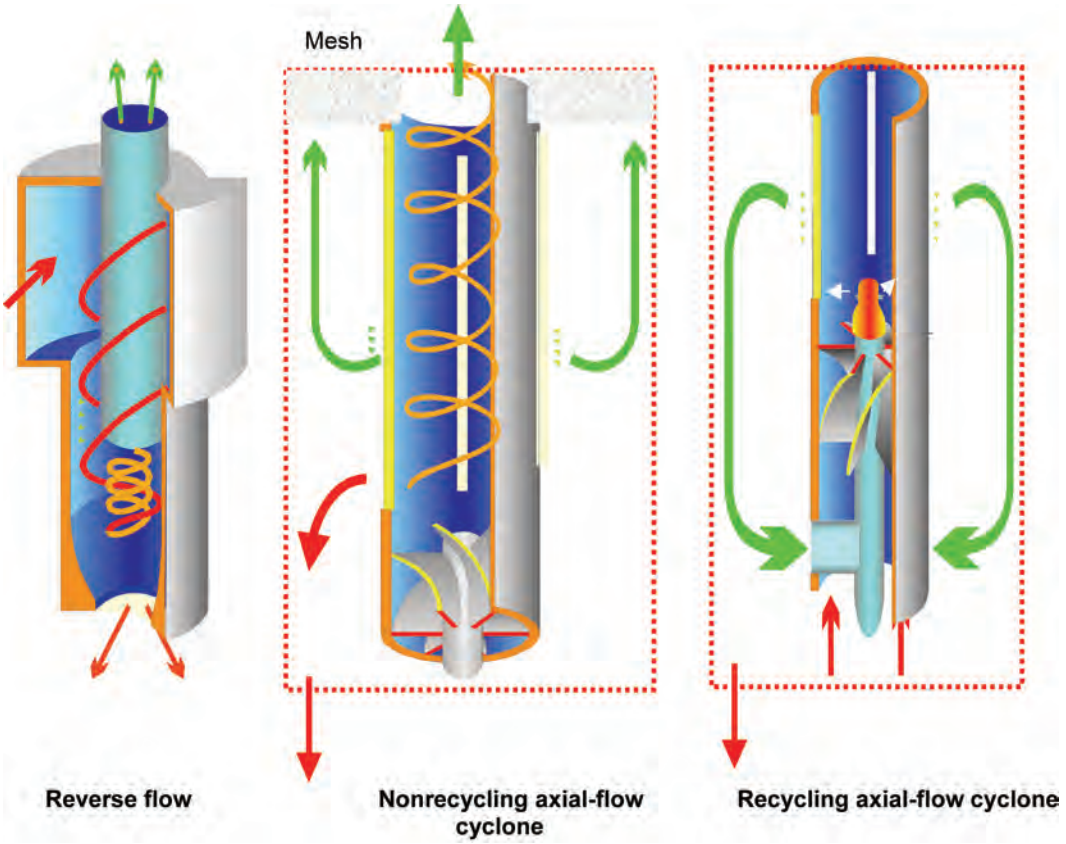


Fig. 2.12—Three types of demisting cyclones (courtesy of CDS Separation Technologies Inc.).

Fig. 2.12 shows three types of demisting cyclones: reverse flow, nonrecycling axial flow, and recycling axial flow. In the reverse flow cyclone, flow enters tangentially around the gas outlet tube. The flow travels down, with liquid being spun to the outer wall and draining out the bottom. The gas reverses direction and flows out the inner tube.

In axial flow cyclones, a stationary turbine in the tube spins the flow. Downstream of the turbine, the liquid film is removed through slits, along with some "secondary" purge gas. The liquid drops to the bottom of a box chamber enclosing the cyclone and flows out a drain tube. The main portion of the gas flows straight out of the cyclone. For nonrecycling axial flow cyclones, the secondary gas usually must be cleaned up by a mesh pad.

In the recycling cyclone, the purge gas is educed back into the center of the cyclone through the stationary turbine. (See Fig. 2.12.) A low-pressure region exists because of the spinning flow, similar to that in a tornado. In this way, the secondary purging gas is cleaned again, and there is no need for a mesh pad. The cyclone demisters have proprietary sizing rules. Typical drop size removal is approximately 5 to 10 μm.

In applying centrifugal force to separation, the separator size is determined by the flow capacity, among other factors. However, the amount of separating force that can be generated at a given rotational velocity decreases as the separator diameter increases. The result is that larger, higher-capacity centrifugal monotube units are less efficient than smaller ones for removing small-entrained mist droplets.

Fig. 2.13 shows a multitubular cyclone separator, in which the flowstream is processed through a bank of parallel cyclone tubes, each tube taking a fraction of the flow. Each tube

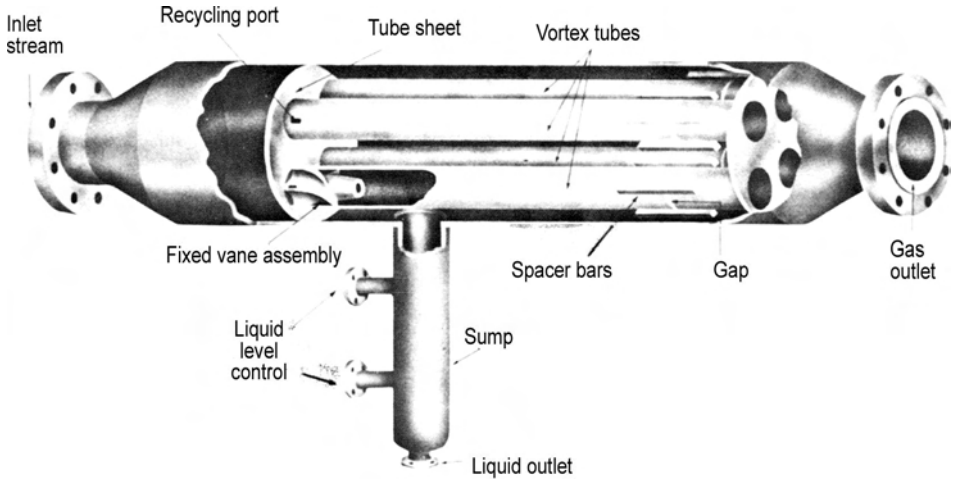


Fig. 2.13—Multicyclone tube bank (courtesy of Natco).

keeps a small diameter to maintain high separation efficiency. The unit shown is a recycling separator; that is, a slipstream of the gas is extracted with the liquid from the tubes and recycled to the tube inlet.

Centrifugal force may be used in conjunction with other separation mechanisms for removing oil mist from gas. As previously discussed, Fig. 2.5 shows two types of cyclone/vortex tube clusters installed in an otherwise conventional separator. Each vertical vortex tube handles a portion of the flowing stream, performing primary separation of entrained mist by means of centrifugal force. The vortex tube device is followed by a disengagement space, where any droplets of oil that have been caught and coalesced, but carried through, will rapidly settle. A mist extractor may be installed in the disengagement space, if needed.

Turndown should be considered when selecting the demister. However, it is difficult to compare turndown of cyclones, vane packs, and mesh because drop size removal is affected differently at varying gas rates.

Coalescers and Fiber Beds. For scrubbing purposes, filter coalescers merge, or coalesce, small droplets of liquid into larger drops (**Fig. 2.14**). Gas is forced to flow through several layers of filter media, each layer having a progressively larger mean pore opening. As droplets compete for the open pores, they coalesce, and the process continues until the larger drops continually collect and drain into a collecting sump. In addition, some coalescers have a patented oleophobic/hydrophobic treatment. Stated removal size is approximately 0.3 μm.

Fiber-bed mist eliminators use small-diameter fibers (0.02 mm) to capture the small droplets. These fiber beds use Browning diffusion or an impaction mechanism to remove drops as small as 0.1 μm. The fiber beds are typically packaged in a cylindrical shape, as shown in **Fig. 2.15**.

2.1.7 Special Problems. ***Foaming.*** When pressure is reduced on certain types of crude oil, tiny bubbles of gas are encased in a thin film of oil when the gas comes out of solution. This may result in foam, or froth, being dispersed in the oil and creates what is known as "foaming" oil. In other types of crude oil, the viscosity and surface tension of the oil may mechanically lock gas in the oil and can cause an effect similar to foam. Oil foam is not stable or long-lasting unless a foaming agent is present in the oil.

Whether crude oil is foamy is not well known. The presence of a surface active agent and process conditions play a part. The literature indicates organic acids as being a foaming agent.

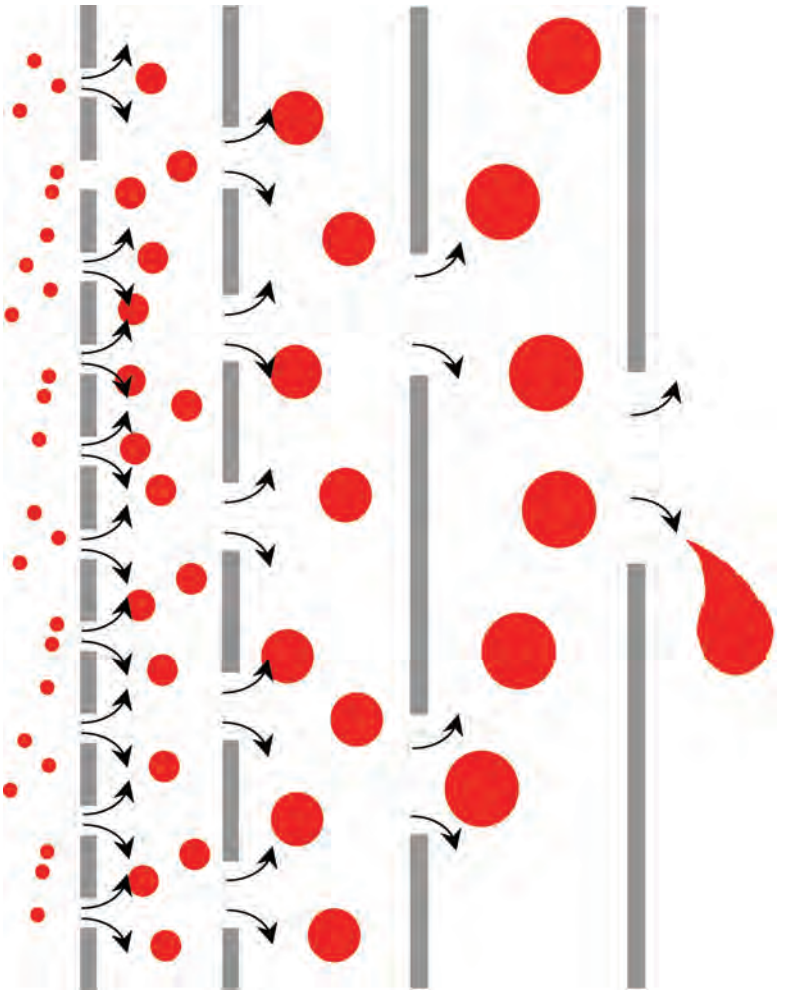


Fig. 2.14—Filter coalescence (courtesy of CDS Separation Technologies Inc.).

High-gravity oils and condensates typically do not result in foaming situations, as described in Ref. 2.

Foaming greatly reduces the capacity of oil/gas separators because a much longer retention time is required to adequately separate a given quantity of foaming crude oil. Foaming crude oil cannot be measured accurately with positive-displacement meters or with conventional volumetric metering vessels. These problems, combined with the potential loss of oil/gas because of improper separation, emphasize the need for special equipment and procedures in handling foaming crude oil.

The main factors that assist in "breaking" foaming oil are settling, agitation (baffling), heat, chemicals, and centrifugal force. These factors or methods of "reducing" or "breaking" foaming oil are also used to remove entrained gas from oil. Many different designs of separators for handling foaming crude oil have evolved. They are available from various manufacturers—some as standard foam handling units and some designed especially for a specific application.

Silicone- and fluorosilicone-based chemical defoamers are typically used in conjunction with cyclonic inlets to break foam. The chemical defoamer concentration is generally in the range of 5 to 10 ppm, but for many GOM crudes, 50 to 100 ppm is common.

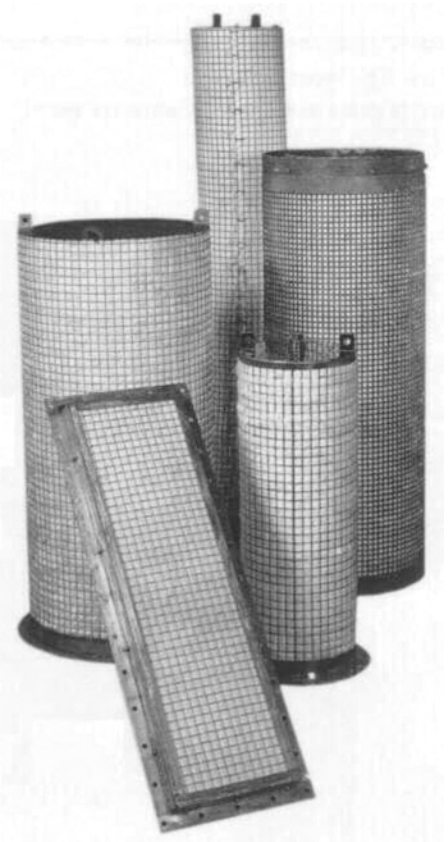


Fig. 2.15—Fiber-bed filter cartridges or panels (courtesy of Koch Otto York).

Fig. 2.16 is a gamma ray scan of a 48-in.-diameter horizontal gas separator showing the problems resulting from foam. The horizontal axis is signal strength, and the vertical axis is height within the separator. High signal strength indicates less mass or more gas. Less signal strength indicates more mass or liquid. As the chemical rate is decreased, the interface between gas/liquid becomes less defined. The bottom of the vessel becomes gassy (more signal), while the upper portion becomes foamy (less signal). Liquid carryover occurs as the foam is swept through the demister. Gas carry-under occurs as the bubbles cannot be separated.

Fig. 2.17 shows a horizontal separator used to process foamy crudes. The fluids flow through inlet cyclones, where the centrifugal action helps break the large bubbles. A perforated plate downstream of the inlet cyclones aids in promoting uniform flow as well as demisting and defoaming. Demisting cyclones in the gas outlet remove large amounts of the liquid that results from a foamy oil layer. The foamy oil pad results from the small bubbles that cannot be removed in the inlet cyclones.

In between the perforated plate and the demister, high-surface internals such as plate or matrix packs are sometimes installed to break the large bubbles. As previously discussed, the theory behind the high-surface internals is that the bubbles will stretch and break as they are dragged along the surfaces. However, if most of the gas flows through the top portion of the pack, the foamy layer will not be sufficiently sheared, and the bubbles will meander through to the other end.

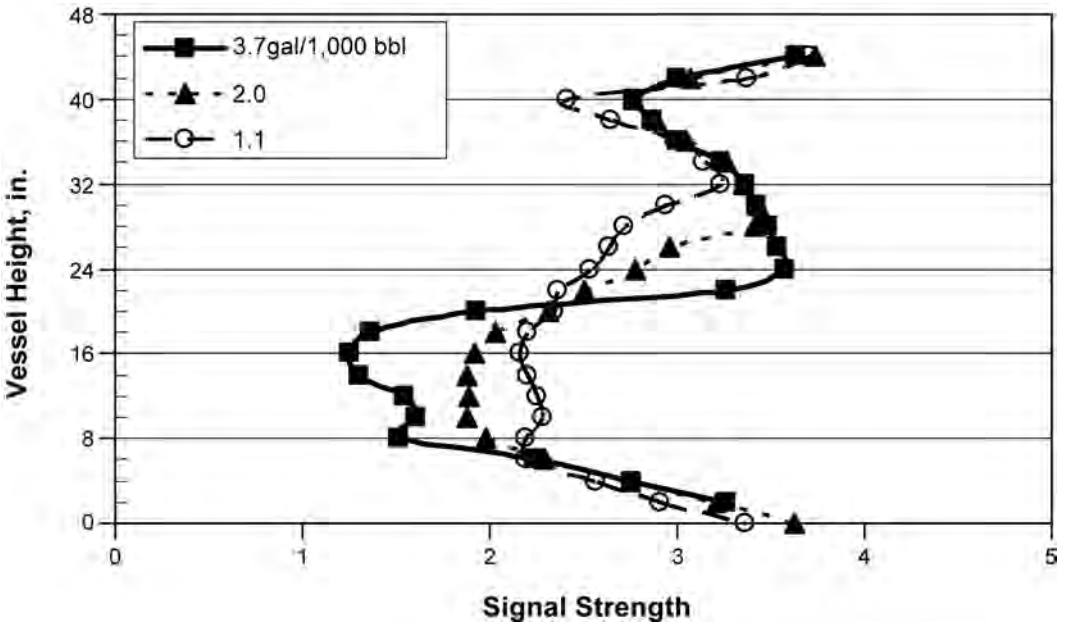


Fig. 2.16—Example of gamma scan results (courtesy of CDS Separation Technologies Inc.).

Paraffin. Paraffin deposition in oil/gas separators reduces their efficiency and may render them inoperable by partially filling the vessel and/or blocking the mist extractor and fluid passages. Paraffin can be effectively removed from separators by use of steam or solvents. However, the best solution is to prevent initial deposition in the vessel by heat or chemical treatment of the fluid upstream of the separator. Another deterrent, successful in most instances, involves the coating of all internal surfaces of the separator with a plastic for which paraffin has little or no affinity. The weight of the paraffin causes it to slough off of the coated surface before it builds up to a harmful thickness.

In general, paraffinic oils are not a problem when the operating temperature is above the cloud point (temperature at which paraffin crystals begin to form). The problems arise, however, during a shutdown, when the oil has a chance to cool. Paraffin comes out of solution and plates surfaces. When production is restored, the incoming fluid may not be able to flow to the plated areas to dissolve the paraffin. In addition, temperatures higher than the cloud point are required to dissolve the paraffin.

Solids and Salt. If sand and other solids are continuously produced in appreciable quantities with well fluids, they should be removed before the fluids enter the pipelines. Salt may be removed by mixing water with the oil, and after the salt is dissolved, the water can be separated from the oil and drained from the system.

Vertical vessels are well suited for solids removal because of the small collection area. The vessel bottom can also be cone-shaped, with water jets to assist in the solids removal. In horizontal vessels, sand jets and suction nozzles are placed along the bottom of the vessel, typically every 5 to 8 ft. Inverted troughs may be placed on top of the suction nozzles as well to keep the nozzles from plugging. A sand-jet system is shown in **Fig. 2.18**. This type of system is sometimes difficult to use while the vessel is in operation because of the effect of the jetting and suction on separation and level control. For vessels that must be designed to enable sand jetting while in service, see the discussion on Emulsion Treating in this section of the *Handbook.*

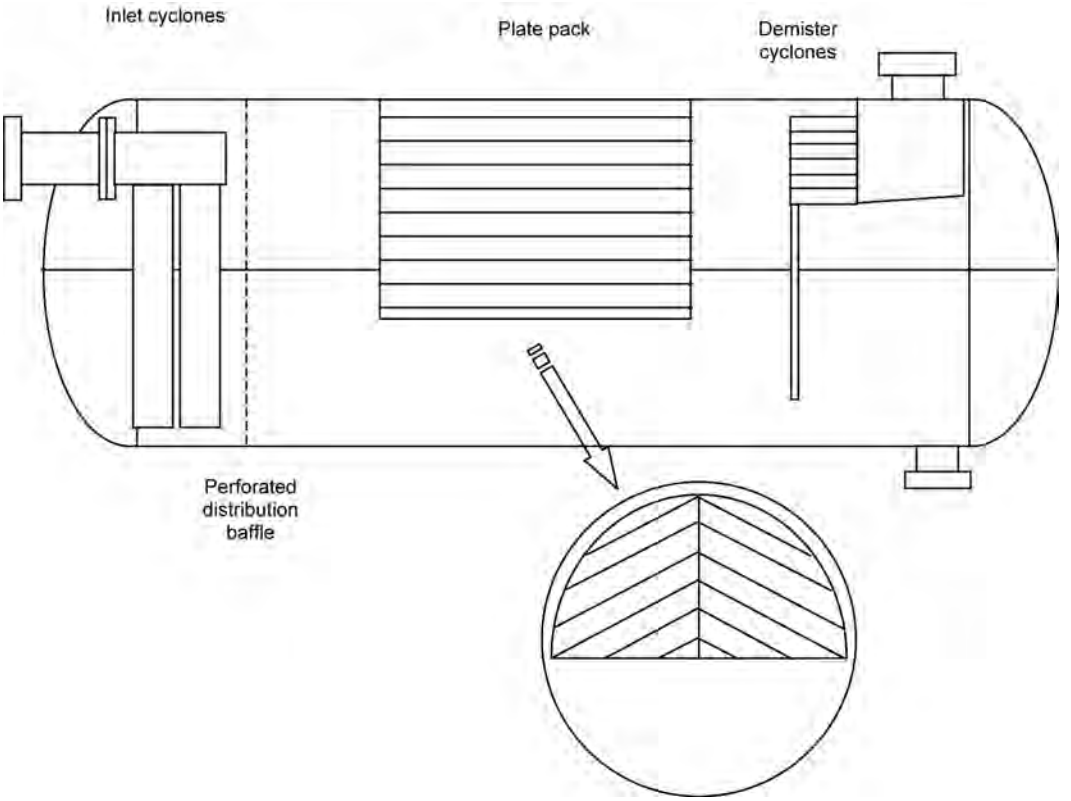


Fig. 2.17—Two-phase separator designed for foam breaking (courtesy of CDS Separation Technologies Inc.).

Corrosion. Produced well fluids can be very corrosive and cause early failure of equipment. The two most corrosive elements are hydrogen sulfide and carbon dioxide. These two gases may be present in the well fluids in quantities from a trace up to 40 to 50% of the gas by volume. A discussion of corrosion in pressure vessels is included in the chapter on Water Treating in this section of the *Handbook*.

Sloshing. Because of the action of waves or current on a floating structure, some excitation of the separator liquid contents will occur, resulting in internal fluid sloshing motions. It is particularly a problem in long horizontal separators. Sloshing degrades the separation efficiency through additional mixing, resulting in liquid carry-over in the gas line, gas carry-under in the liquid line, and loss of level control. In three-phase separators, oil/water and gas/liquid separation efficiency is degraded. It is therefore necessary to design internal baffle systems to limit sloshing. Emphasis is generally placed on internals for wave dampening in gas-capped separators because of the larger fluid motions.

The liquid level changes from end to end must be considered in the design of the inlet and outlet devices. Too low a liquid level can result in gas blow-by of inlet cyclones, whereas too high a liquid level can cause siphoning of liquid through the mist extractor.

Table 2.4 gives some estimates of the natural period of the liquid for vessels undergoing lengthwise motions (sway). The periods are in the order of 10s, which is similar to the period found for floating platforms such as tension leg platforms (TLP) and floating production, storage and offloading (FPSO) vessels under a 10-year storm condition.

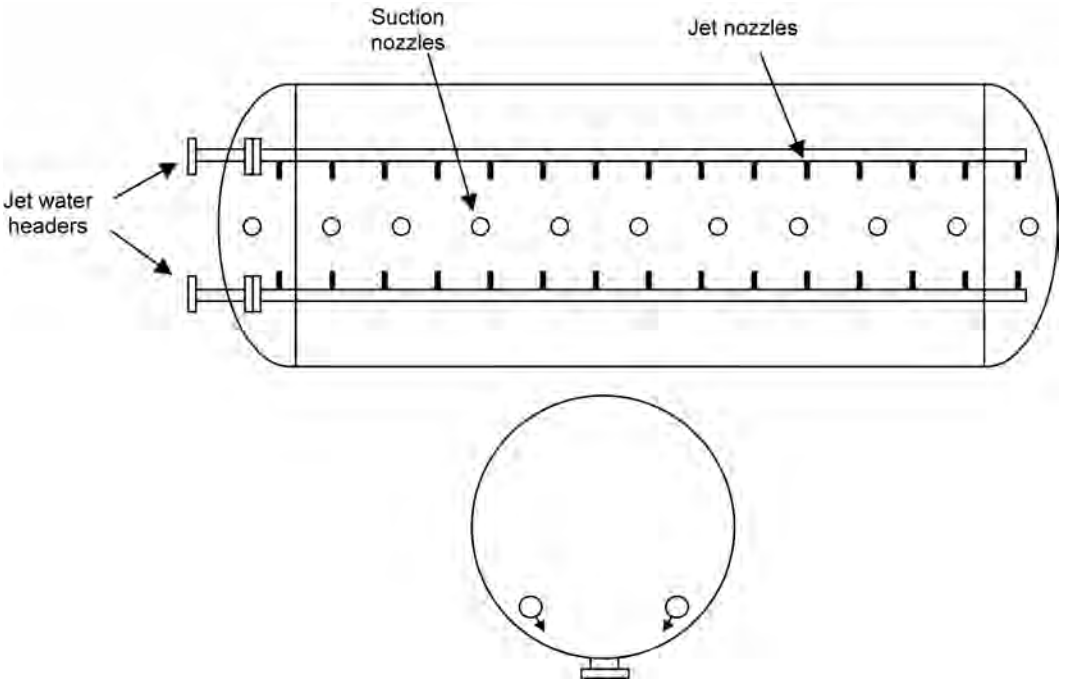


Fig. 2.18—Sand-jet system (courtesy of CDS Separation Technologies Inc.).

The alignment of the separators with the structure motion should be considered when designing the layout. For example, on TLP, the vessels are recommended to be aligned with their long dimension, perpendicular to the TLP prevailing motion. On ships, the magnitude and period of the pitch and roll should be considered when aligning the vessels. Normally, it is recommended to align the separators with their long dimension along the length of the ship.

The available literature, as described in Ref. 3, highlights two main features of wave-damping internals: elimination of the gas/liquid interface and shifting of the natural sloshing frequency of the separator away from the platform frequency. On some ships, fuel tanks fill with sea water, as the fuel is spent, to prevent problems associated with sloshing.

Shifting the natural frequency is usually accomplished by segmenting the vessel with transverse baffles. The baffles are perforated, can be placed throughout the liquid phase, or can be placed in the region of the oil/water interface. However, vessel access, solids collection, and mixing are major concerns. Horizontal perimeter baffles can be used, but they have disadvantages as well. Other baffle shapes include angled wings along the length of the vessel to mitigate waves because of roll as well as vertical perforated baffles down the length of the vessel. **Table 2.5** highlights the differences between horizontal and vertical baffles.

Level Controls. Stable control of the oil/water and gas/oil interfaces is important for good separation. The typical two-phase separator level settings are shown in **Table 2.6**. For three-phase operation, level settings are placed on both the oil/water interface and oil/gas interface levels.

Typically, the spacing between the different levels is at least 4 to 6 in. or a minimum of 10 to 20 seconds of retention time. The location of the lowest levels must also consider sand/solids settling. These levels are typically 6 to 12 in. from the vessel bottom. Minimum water/oil pad thicknesses are approximately 12 in. Note that these minimum settings may dominate the vessel sizing as opposed to the specified retention times.

TABLE 2.4—EFFECT OF VESSEL SIZE ON SLOSH FREQUENCY

Vessel Diameter, ft	Vessel End-End Length, ft	Depth, ft	Period, seconds
6	27	0.6	13.6
		1.2	9.7
		1.8	7.9
		2.4	6.9
		3	6.2
6	39	0.6	19.7
		1.2	13.9
		1.8	11.4
		2.4	9.9
		3	8.9
12	42	1.2	15.0
		2.4	10.6
		3.6	8.7
		4.8	7.6
		6	6.9

In a two- or three-phase horizontal separator with very little liquid/water, a boot or "double-barrel" separator configuration is used. All the interface controls are then located within the boot or lower barrel. Examples of these types of separators are shown in Sec. 2.2.

2.2 Examples of Separators

Some schematics of typical two- and three-phase separators are shown in **Figs. 2.19 through 2.26** in horizontal and vertical orientations. All figures listed are self-explanatory.

- Fig. 2.19: Horizontal two-phase separator with inlet diverter, perforated distribution baffle, and demister.
- Fig. 2.20: Horizontal two-phase separator enhanced for foam breaking with inlet cyclones, perforated distribution baffle, and cyclonic demisters.
- Fig. 2.21: Horizontal double barrel two-phase separator for low liquid rates.
- Fig. 2.22: Horizontal three-phase separator with flooded weir.
- Fig. 2.23: Horizontal three-phase separator with oil bucket and water weir, requiring no active interface control.
- Fig. 2.24: Horizontal three-phase separator with boot for low water rates.
- Fig 2.25: Vertical two-phase separator with inlet diverter and demister.
- Fig. 2.26: Vertical three-phase separator with inlet diverter and demister.
- **Fig. 2.27a**: Schematic of a central inlet separator, dual outlet designed for floaters.
- Fig. 2.27b: Dual-inlet, central-outlet separator. The liquid level in the center of the vessel is generally constant. Hence, the liquid level changes because platform tilt does not really affect the operation of the devices in the center of the vessel.
- **Fig. 2.28a**: Two-stage, vertical scrubber with inlet diverter, mesh coalescer, and cyclone demisters. This unit has a high turndown capacity (that is, the ability to operate effectively at

TABLE 2.5—ADVANTAGES AND DISADVANTAGES OF HORIZONTAL AND VERTICAL BAFFLES FOR SLOSH MITIGATION

Baffle description:	Horizontal baffle covering interface with exception of hole in center	Vertical perforated baffles
Vessel access:	Access to length of vessel available after removing plate near manway	Each baffle must have a man-way
Solids accumulation:	None	Potential for solids to accumulate at bottom
Installation:	Must be designed around internals and vessel manways.	More easily accommodates internals and vessel manways
Two-phase operation:	Excellent	Excellent
Three-phase operation:	Requires second baffle. Access to vessel becomes poor, and installation becomes more complex	Excellent
Level changes:	Not accommodating	Excellent operation at different levels

TABLE 2.6—TYPICAL SEPARATOR LEVEL SETTINGS

Designation	Description	Comments
LLAL	Low-low alarm level	This level ensures that gas will not exit with the liquid. Shutdown of operations occurs.
LAL	Low alarm level	LAL and HAL are typically alarms for the control room operators.
NLL	Normal liquid level	Liquid level can vary between LAL and HAL under normal operating conditions with NLL being the desired targeted level.
HAL	High alarm level	Surge volumes are normally contained between NLL and HAL.
HHAL	High-high alarm level	This level ensures that liquid does not exit with the gas. Shutdown of operations occurs.

much less than the design capacity) and a small droplet capture range. The inlet diverter removes bulk liquids. At low rates, the mesh pad acts as a separator and removes the mist. At higher gas rates, the mesh acts as an agglomerator, coalescing small drops into larger ones. The larger drops are re-entrained but caught by the cyclone demisters. Typical turndown is ~8 to 10.

• Fig. 2.28b: Single-stage cyclone scrubber for low liquid loading. The gas/liquid flows directly at the cyclones. This type of a scrubber is a compact unit with a three to five reduction in size and weight from a standard scrubber.

• **Fig. 2.29**: A schematic of a Gasunie cyclone separator. The separator is a stand-alone inlet cyclone in which the vessel shell itself is the outer wall of the cyclone. This separator is mainly used as a scrubber but can be applied for higher liquid loadings on the order of 10%v.

• **Fig. 2.30**: A gas/liquid cylindrical cyclone (GLCC) is a very simple and inexpensive centrifugal separation device. Rough separation is achieved under low-*g* conditions, the swirl being generated by the sloped tangential inlet. The slope helps keep the level down during small slug occurrence. It is often used for bulk separation in conjunction with well testing as shown. The

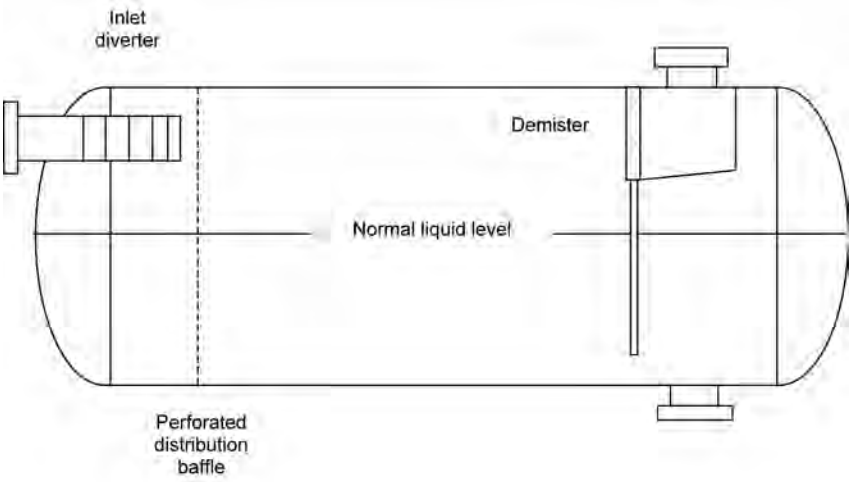


Fig. 2.19—Horizontal two-phase separator with inlet diverter, perforated distribution baffle, and demister (courtesy of CDS Separation Technologies Inc.).

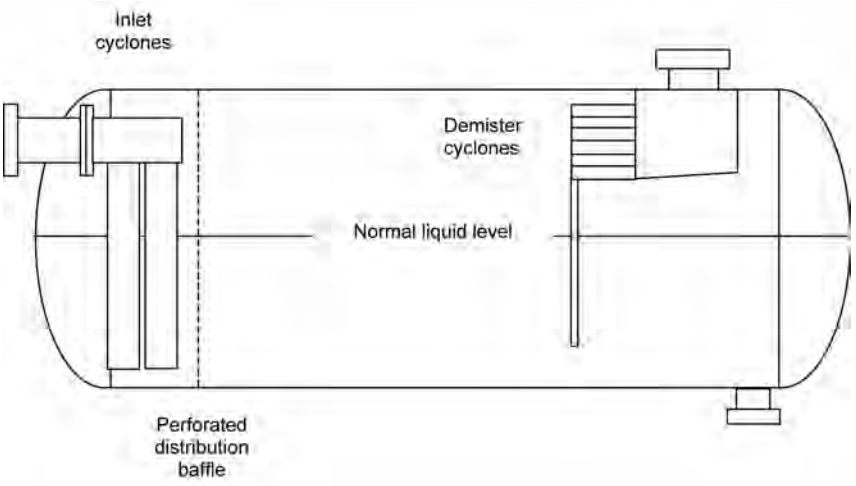


Fig. 2.20—Horizontal two-phase separator enhanced for foam breaking with inlet cyclones, perforated distribution baffle, and cyclonic demisters (courtesy of CDS Separation Technologies Inc.).

streams are temporarily separated, measured and analyzed, then recombined. With this arrangement, no level control is necessary because the levels are maintained by hydraulic balance.

• **Fig. 2.31**: A multitube cyclone inline separator, which causes a wet gas flowstream to be divided between a number of cyclone tubes. As the gas stream enters a tube, it encounters a spin generator. The spin generator is a stationary device consisting of a hollow core and a radial arrangement of curved blades that divert the gas stream into a rotating flow pattern. In the tube downstream of the spin generator, liquid is separated from the gas by being slung out against the tube wall by centrifugal force. Near the end of each tube, the liquid film encounters a peripheral gap in the tube wall. This gap allows the liquid to be pulled out of the tube into the annular space around the tubes, where it falls to the bottom and is discharged under level

control. The demisted gas stream continues through the tube, then recombines with that of the other tubes.

To coerce the liquid to exit through the tube-wall gap, a slipstream of gas is also withdrawn. The slipstream is induced to exit through the gap by maintaining a lower pressure in the outer annular space than that which is inside the tubes. This is done by constructing ducts between the annular space and the hollow core pieces of all the spin generators. The tails of these hollow cores are, in turn, open to the low pressure of the newly generated gas vortices. A gas slipstream of about 5% is recycled out of the tubes to pull liquid out, then back to the spin generator and out its tail end, where it joins the main gas stream.

2.3 Separator Sizing

2.3.1 General. The basic steps in separator design are listed next:

1. Estimate diameter and length on basis of liquid requirements. Considerations of design include drop size removal, retention time, coalescers (e.g., plate packs), surge volume, levels and alarms, and motion.
2. Calculate the gas cross-sectional area and vessel length. Considerations of design include drop size, removal, mist eliminator requirements, and velocity requirements.
3. Select vessel diameter and length to satisfy Steps 1 and 2.
4. Select inlet device and iterate.

Separators are typically sized by the droplet settling theory or retention time for the liquid phase. For the gas phase, the settling theory or requirements of the demister are used.

2.3.2 Settling Theory. In gravity settling, the dispersed phase drops/bubbles will settle at a velocity determined by equating the gravity force on the drop/bubble with the drag force caused by its motion relative to the continuous phase.

In horizontal vessels, a simple ballistic model can be used to determine a relationship between vessel length and diameter. In vertical vessels, settling theory results in a relation for the vessel diameter.

Horizontal Separators. Droplet settling theory, using a ballistic model, results in the relationship shown in Eq. 2.6. For liquid drops in gas phase

$$\frac{L_{\text{eff}} d^2 F_g}{h_g} = 421 \frac{TZQ_g}{P} \left[\left(\left| \frac{\rho_g}{\rho_l - \rho_g} \right| \right) \frac{C_D}{d_m} \right]^{1/2}, \quad \text{..... (2.6)}$$

where

d = vessel internal diameter, in.;
d_m = drop diameter, μm;
h_g = gas-phase space height, in.;
F_g = fractional gas cross-sectional area;
L_{eff} = effective length of the vessel where separation occurs, ft;
T = operating temperature, °R;
Q_g = gas flow rate, MMscf/D;
P = operating pressure, psia;
Z = gas compressibility;
ρ_l = liquid density, lbm/ft^3;
ρ_g = gas density, lbm/ft^3;

and

C_D = drag coefficient. (See Appendix A for calculation.)

For bubbles or liquid drops in liquid phase:

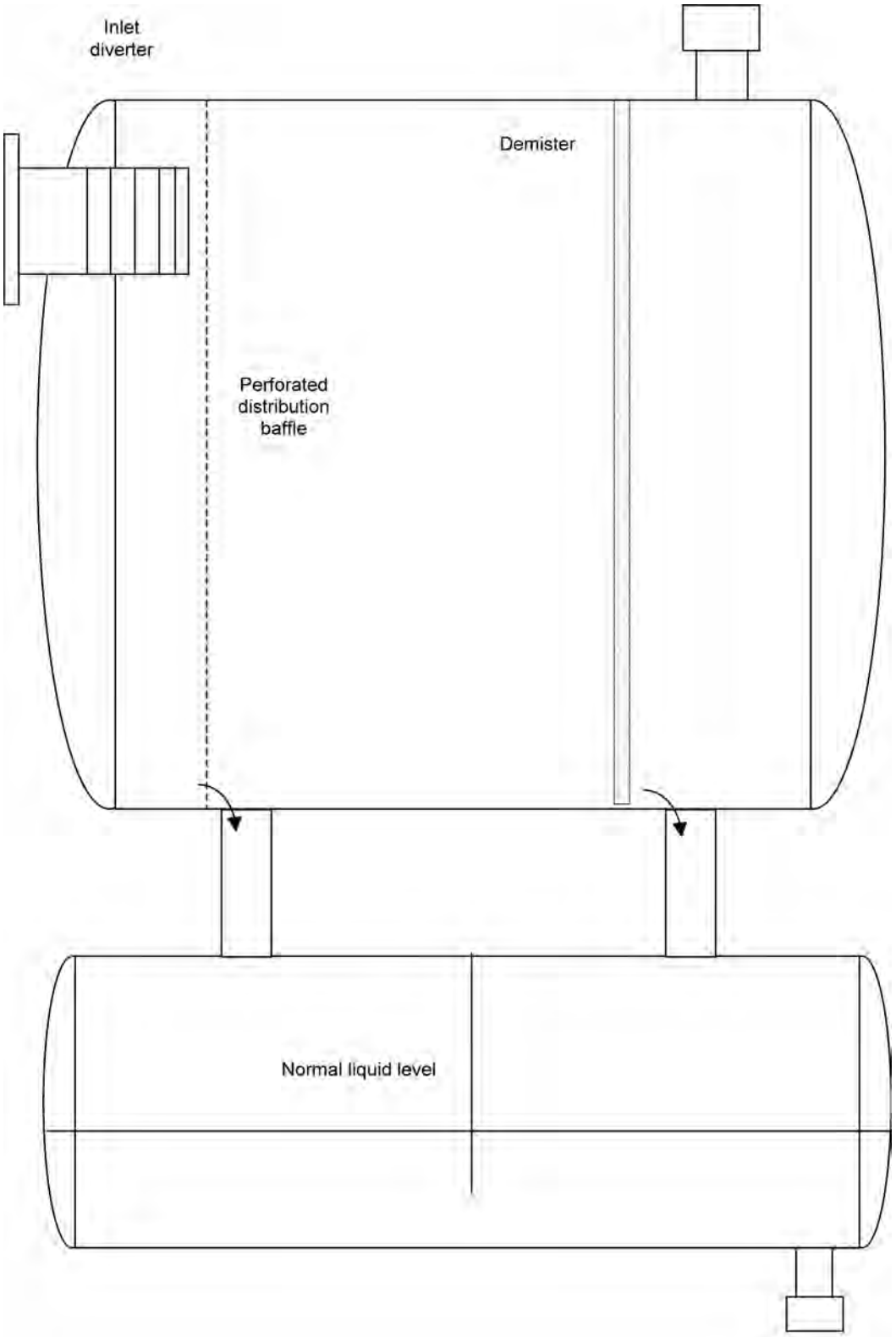


Fig. 2.21—Horizontal double-barrel two-phase separator for low liquid rates (courtesy of CDS Separation Technologies Inc.).

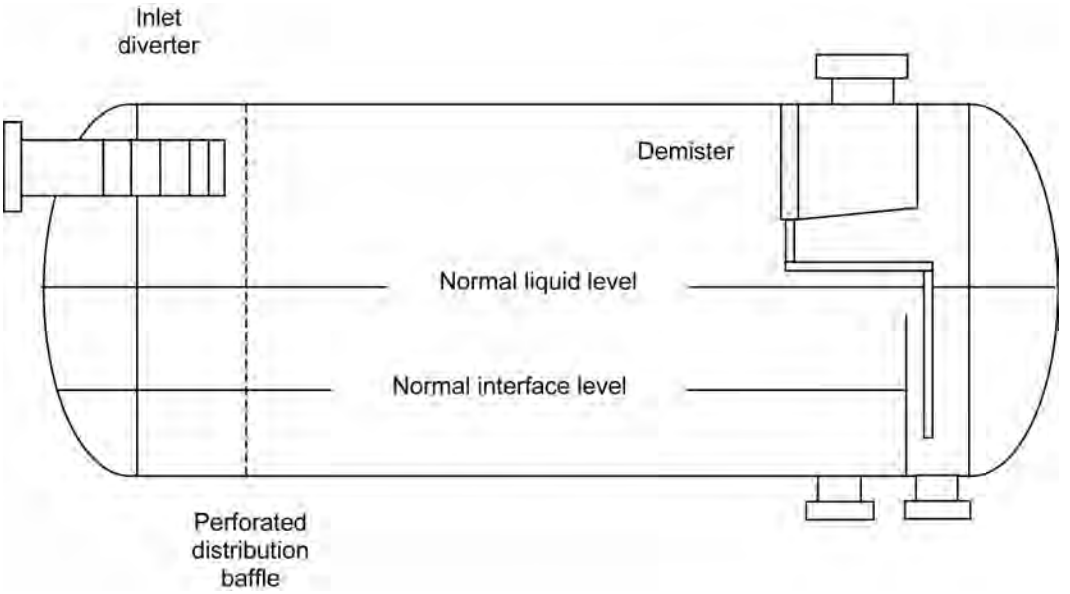


Fig. 2.22—Horizontal three-phase separator with flooded weir (courtesy of CDS Separation Technologies Inc.).

$$\frac{L_{\text{eff}} d^2 F_c}{h_c} = \frac{Q_c}{12}\left[\left(\left|\frac{\rho_c}{\rho_d - \rho_c}\right|\right)\frac{C_D}{d_m}\right]^{1/2}, \quad \text{..... (2.7)}$$

where

d_m = bubble or drop diameter, μm;
h_c = continuous liquid-phase space height, in.;
F_c = fractional continuous-phase cross-sectional area;
ρ_d = dispersed liquid-phase density, lbm/ft^3;
ρ_c = continuous liquid-phase density, lbm/ft^3;

and

Q_c = continuous liquid-phase flow rate, B/D.

For low Reynolds number flow, Eq. 2.7 can be further reduced to

$$h_c = \frac{0.00129 t_{rc} (\Delta\gamma) d_m^2}{\mu_c}, \quad \text{..... (2.8)}$$

where

t_{rc} = continuous-phase retention time, minutes,
μ_c = continuous-phase dynamic viscosity, cp,

and

$\Delta\gamma$ = specific gravity difference (heavy/light) of continuous and dispersed phases.

Vertical Vessels. Settling theory results in the following relationship. For liquid drops in gas phase,

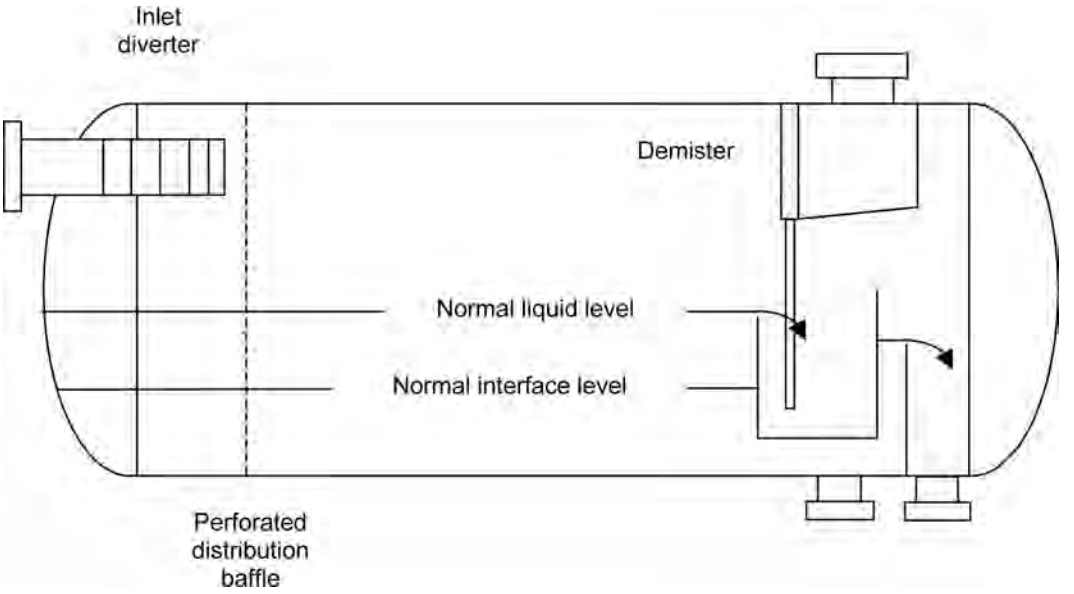


Fig. 2.23—Horizontal three-phase separator with oil bucket and water weir, requiring no active interface control (courtesy of CDS Separation Technologies Inc.).

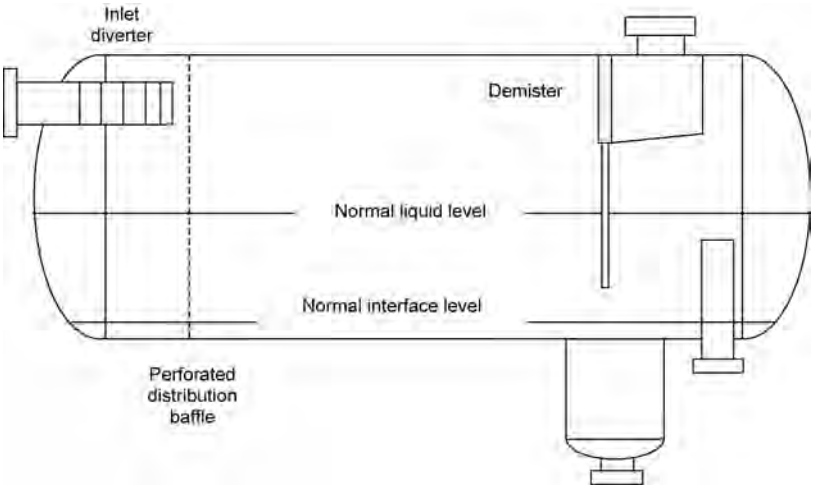


Fig. 2.24—Horizontal three-phase separator with boot for low water rates (courtesy of CDS Separation Technologies Inc.).

$$d^2 = 5{,}054\frac{TZQ_g}{P}\left[\left(\left|\frac{\rho_g}{\rho_l - \rho_g}\right|\right)\frac{C_D}{d_m}\right]^{1/2} \quad \text{..... (2.9)}$$

For bubbles or liquid drops in liquid phase,

$$d^2 = Q_c\left[\left(\left|\frac{\rho_c}{\rho_d - \rho_c}\right|\right)\frac{C_D}{d_m}\right]^{1/2} \quad \text{..... (2.10)}$$

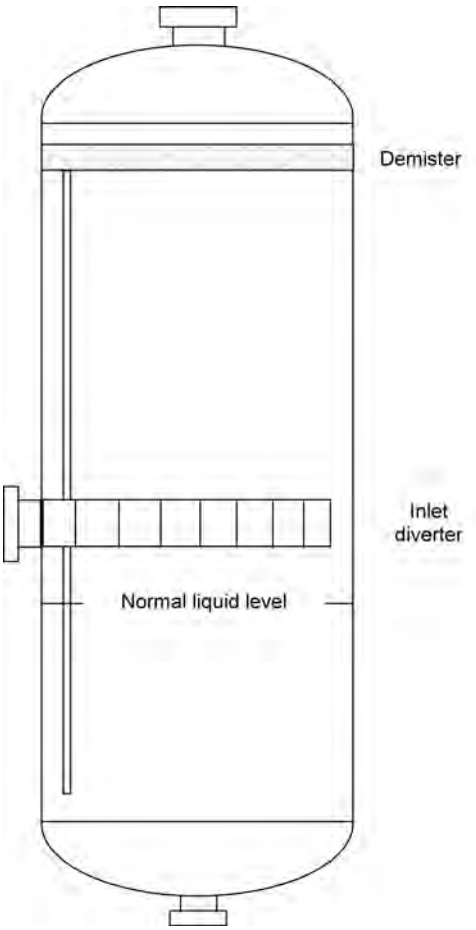


Fig. 2.25—Vertical two-phase separator with inlet diverter and demister (courtesy of CDS Separation Technologies Inc.).

Assuming low Reynolds number flow, Eq. 2.10 can be further reduced to

$$d^2 = 6{,}663\frac{Q_c \mu_c}{(\Delta\gamma)d_m^2} \quad \text{..... (2.11)}$$

Drop/Bubble Sizes. If drop or bubble removal is being used for sizing, consult **Table 2.7** for guidelines. Sizing the water phase by oil-drop removal is usually not effective. The water effluent quality is more likely dictated by the added chemicals. Hence, the water-phase volume is typically determined by a retention time, based on experience.

The oil drops to be removed from the gas stream also depend upon the downstream equipment. Flare scrubbers are typically designed for removal of drops that are a few hundred microns in size.

Compressor scrubbers are typically designed large enough so that a mist extractor, which can remove 10- to 20-μm drops and smaller, can fit inside the shell. Because the gas has already been conditioned by passing through an upstream separator containing a mist extractor, there is no need during normal operations to precondition the gas for the scrubber mist extrac-

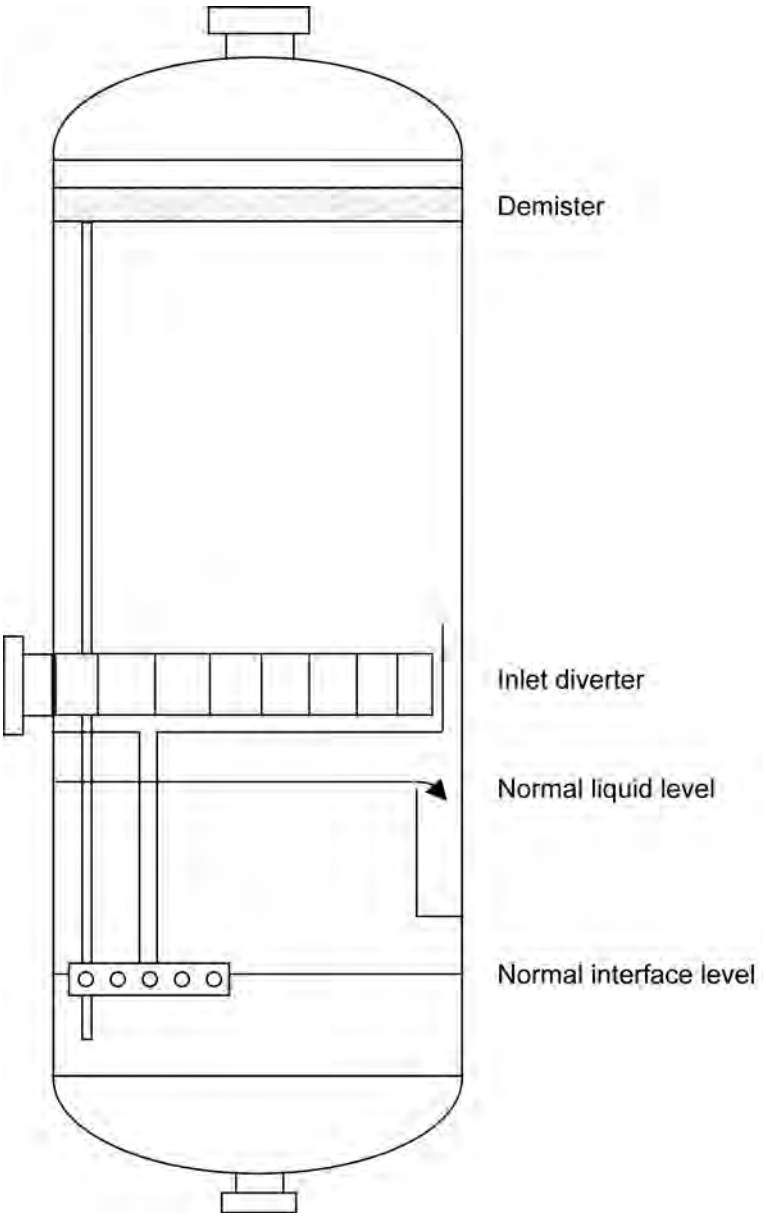


Fig. 2.26—Vertical three-phase separator with inlet diverter and demister (courtesy of CDS Separation Technologies Inc.).

tor by removing large droplets. The scrubber serves as a safety function to trap slugs of liquid that can occur as a result of failure (liquid carryover) from the upstream separator. Thus, the separator should be able to separate a slug and provide a high liquid level, which will allow the compressor to shut down prior to ingesting liquid. Normally, this is accomplished by sizing the vessel shell for a 300- to 600-μm drop removal.

2.3.3 Retention Time. ***Horizontal Vessels.*** The relationship of vessel diameter and length is given by

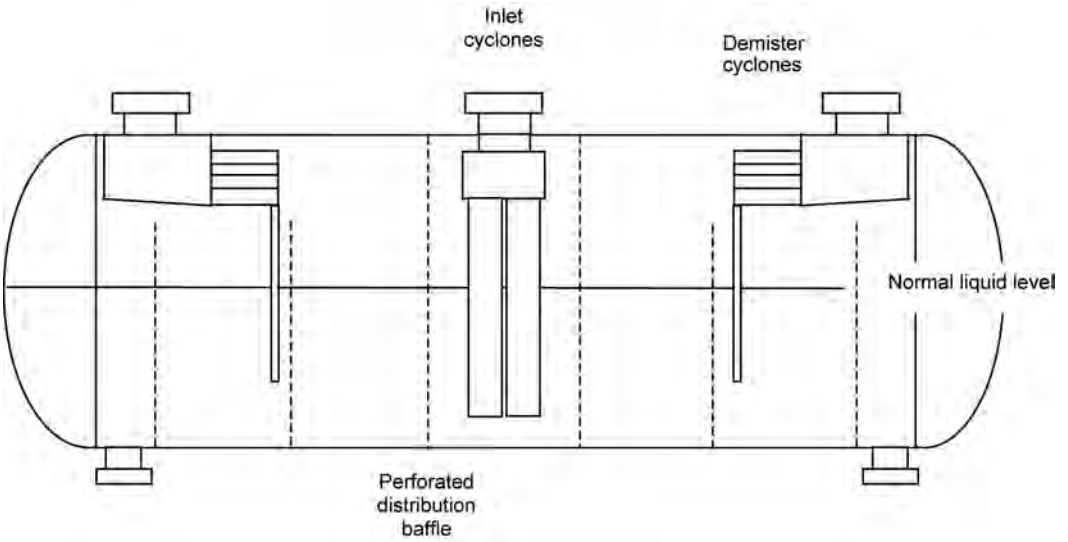


Fig. 2.27a—Two-phase separator with center inlet cyclones and dual outlets for a floating structure (courtesy of CDS Separation Technologies Inc.).

$$d^2 L_{\text{eff}} = \frac{t_{ro} Q_o + t_{rw} Q_w}{1.4 F_l}, \quad \text{..... (2.12)}$$

where

t_{ro} = oil retention time, minutes,

t_{rw} = water-retention time, minutes,

Q_o = oil flow rate, B/D,

Q_w = water flow rate, B/D,

and

F_l = fraction of vessel cross-sectional area filled by liquid.

Vertical Vessels. Similarly for vertical vessels, the relationship of vessel diameter and liquid pad heights is given by

$$d^2 (h_o + h_w) = \frac{t_{ro} Q_o + t_{rw} Q_w}{0.12}, \quad \text{..... (2.13)}$$

where

h_o = oil pad height, in.

and

h_w = water pad height, in.

2.3.4 Demister Sizing. As discussed previously, many types of demisters are limited by a maximum velocity given by

$$V_m = K_d \sqrt{\frac{\rho_l - \rho_g}{\rho_g}}, \quad \text{..... (2.14)}$$

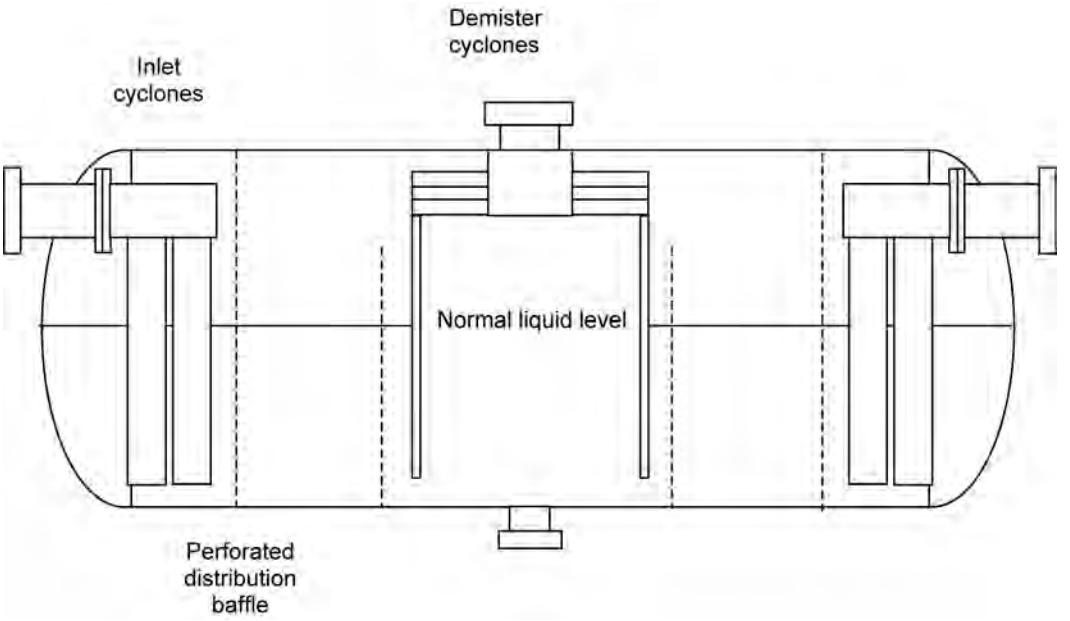


Fig. 2.27b—Two-phase separator with dual inlet cyclones and center demisting cyclones for a floating structure (courtesy of CDS Separation Technologies Inc.).

where

K_d = demister capacity factor, ft/sec and depends upon the demister type;

V_m = maximum velocity, ft/sec;

ρ_L = liquid density, lbm/ft^3;

and

ρ_g = gas density, lbm/ft^3.

For horizontal vessels, the required demister area (A_d) is given by

$$A_d = \frac{0.327\frac{TZQ_g}{P}}{K_d\sqrt{\frac{\rho_l - \rho_g}{\rho_g}}} \quad \text{..... (2.15)}$$

For vertical vessels, Eq. 2.1 is also valid. The vessel diameter is then obtained as

$$d^2 = \frac{60\frac{TZQ_g}{P}}{K_d\sqrt{\frac{\rho_g - \rho_l}{\rho_g}}} \quad \text{..... (2.16)}$$

For demisters (horizontal or vertical vessels) sealed in a gas box, in addition to the demister area, some height must be maintained between the bottom of the demister and the highest liquid level for the demister to drain. A pressure drop exists across the demister. If the liquid level is too high, the demister will not drain, and liquid siphoning can occur. A small hole is sometimes drilled into the drainpipe as a siphon breaker.

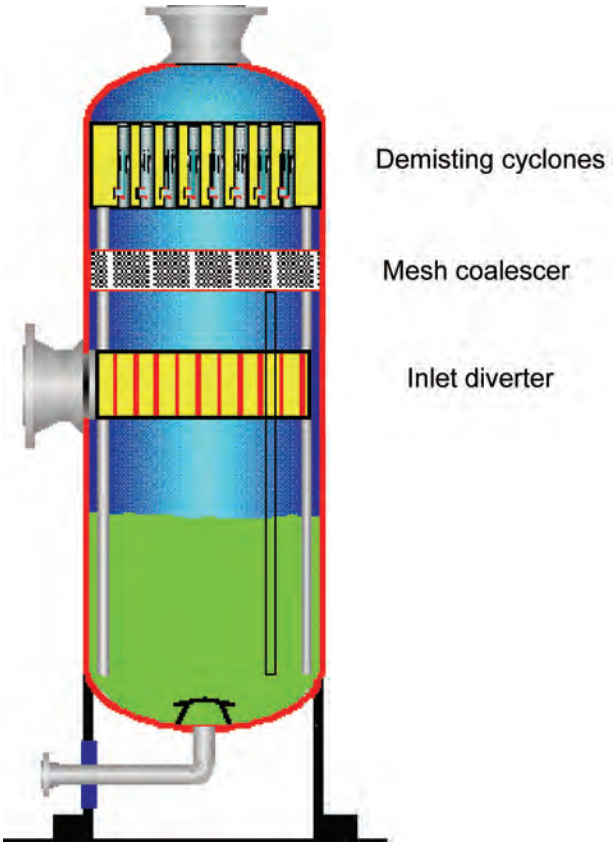


Fig. 2.28a—Two-stage vertical scrubber with inlet diverter, mesh coalescer, and cyclone demisters (courtesy of CDS Separation Technologies Inc.).

When using settling theory or demister sizing in horizontal vessels, one should also consider the gas velocity for re-entrainment. Too high of a gas velocity will result in liquid re-entrainment from the liquid surface, which may flood the demister and cause carryover. Typical gas velocities for re-entrainment are shown in **Table 2.8**.

2.3.5 Seam-to-Seam Length. ***Horizontal Vessels.*** The seam-to-seam length, L_{ss}, of the vessel should be determined from the geometry once a diameter and effective length have been determined. Length must be allotted for inlet devices, gas demisters, and coalescers. For screening purposes, the following approximations can be used.

$$L_{ss} = L_{\text{eff}} + \frac{d}{12}(\text{gas})$$

$$= \frac{4}{3}L_{\text{eff}} \ (\text{liquid}) \ . \quad \text{..... (2.17)}$$

The ratio of length to diameter is typically in the 3 to 5 range.

Vertical Vessels. The seam-to-seam length of the vessel should be determined from the geometry, once a diameter and height of liquid volume are known. Allowance must be made for the inlet nozzle, space above the liquid level, gas separation section, mist extractor, and for

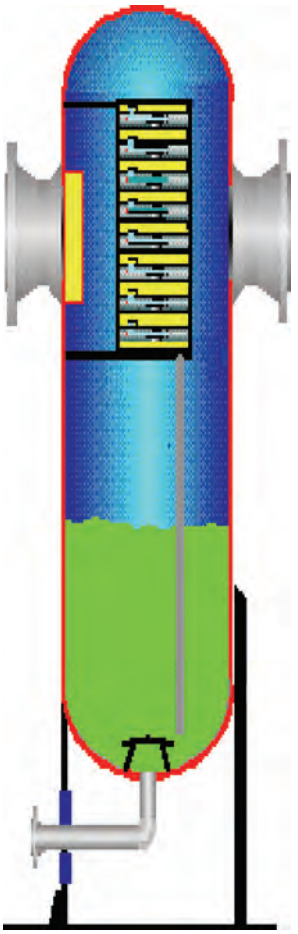


Fig. 2.28b—One-stage inline scrubber with demisting cyclones (courtesy of CDS Separation Technologies Inc.).

any space below the water outlet as shown in Fig. 2.31. For screening purposes, the following approximations can be used, where d is the vessel diameter).

$$L_{ss} = \frac{h + \text{nozzle ID} + \text{demister height} + 54}{12},$$

$$\text{or } L_{ss} = \frac{h + \text{nozzle ID} + d + \text{demister height} + 18}{12} \quad \text{..... (2.18)}$$

The ratio of height to diameter is typically in the 3 to 5 range for two-phase separators. For three-phase separators, the ratio is in the 1.5 to 3 range.

Additional consideration should be given for installation of the internals as well as man-way access. In glycol dehydration towers, a man-way is typically installed above the packing/trays and the demister. Access space must be allotted for installation of the equipment.

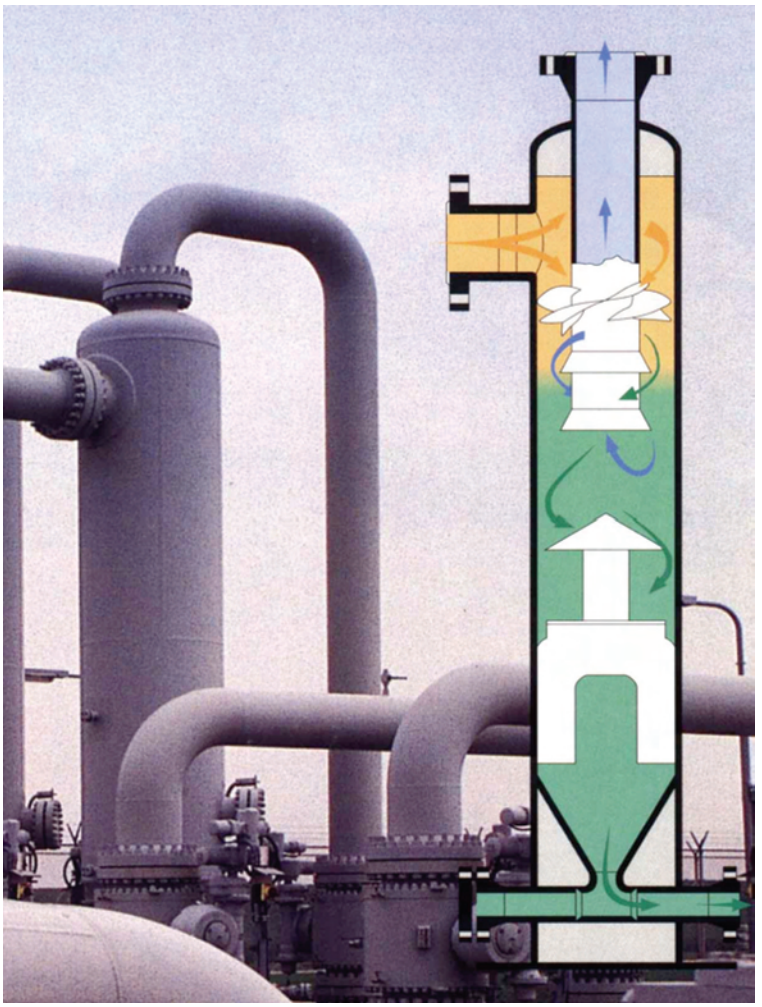


Fig. 2.29—Gasunie cyclonic scrubber (courtesy of CDS Separation Technologies Inc.).

2.3.6 Nozzle Sizing. Nozzles are generally sized by momentum or velocities. **Table 2.9** gives guidelines that can be used for sizing nozzles, where ρ_m is the bulk density and V_m the bulk velocity.

In addition, the API *RP14E*[4] on erosion velocity should be included. This relationship is also given by an inlet momentum criterion as $\rho_m V_m^2 = C^2$, where C is given as 100 for continuous service and 125 for intermittent service. The value of C can also vary with pipe material, solids loading, and service. See the chapter on Piping and Pipelines in this section of the *Handbook*. Vortex breakers are generally required on the liquid outlets. These are typically perpendicular plates, as shown in **Fig. 2.32**.

2.4 Examples of Separator Sizing

2.4.1 Example 2.1: Vertical Two-Phase Separator With a Mesh Pad Demister. ***Given Values.*** The given values for Example 2.1 are listed next.

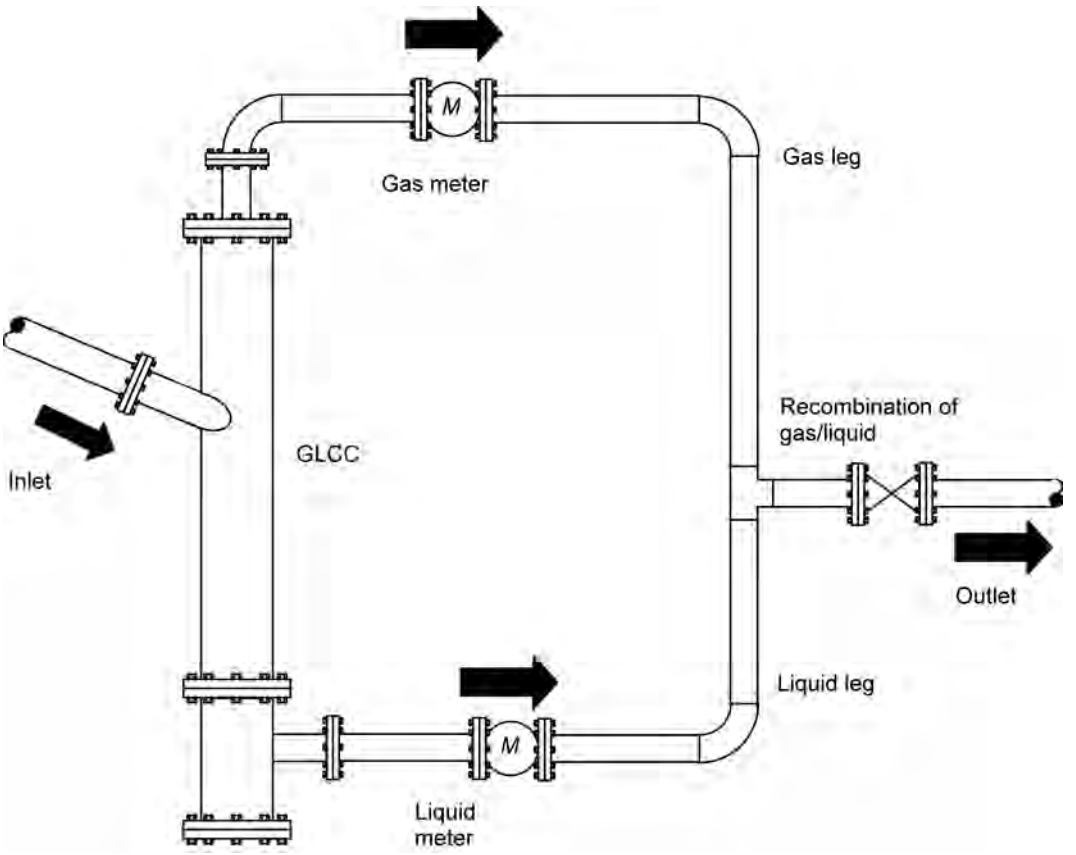


Fig. 2.30—GLCC separator (courtesy of Natco).

Gas rate	10 MMscf/D
Gas-specific gravity	0.6
Gas z-factor	0.84
Gas density	3.7 lbm/ft^3
Oil rate	2,000 B/D
Oil density	50 lbm/ft^3
Operating pressure	1,000 psia
Operating temperature	60°F
Mesh pad K-factor	0.35 ft/sec
Mesh pad thickness	6 in.
Liquid-retention time	1 minute
Inlet nozzle	4 in.

Step 1. Calculate the required mesh-pad area with Eq. 2.15. This mesh area will result in a vessel internal diameter of 15 in.

Step 2. Calculate the height for liquid retention time with Eq. 2.13. h_o = 74 in.

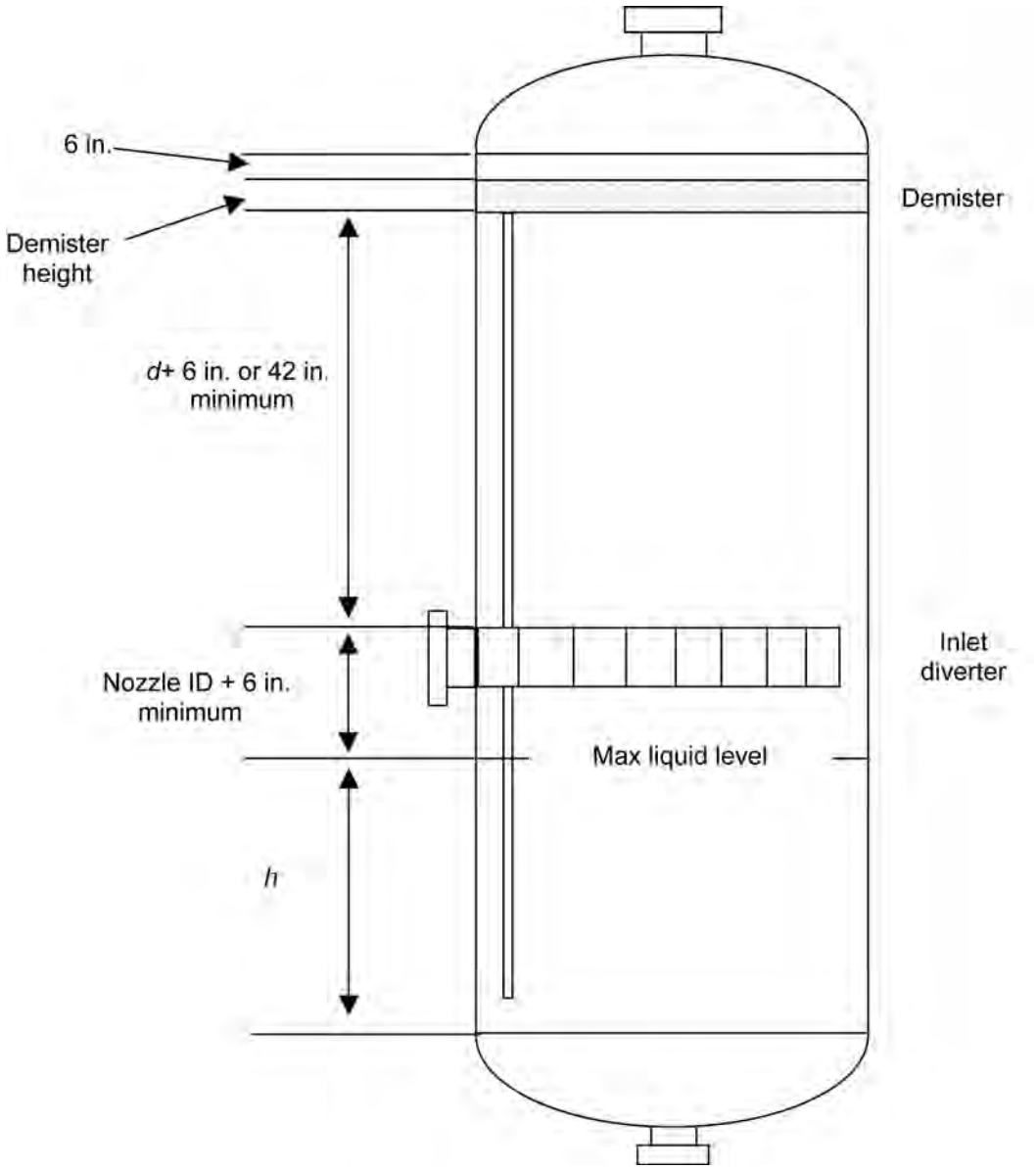


Fig. 2.31—Approximate shell length for vertical vessels (courtesy of CDS Separation Technologies Inc.).

Step 3. Compute seam-to-seam length with Eq. 2.18.

The L_{eff}/D ($D = d/12$) is 9.2 and is larger than the typical 3 to 5 range. Therefore, the internal diameter must be increased to reduce the L_{eff}/D ratio. **Table 2.10** shows L_{eff}/D for three different vessel IDs. A 24-in. ID vessel has the appropriate L_{eff}/D ratio. The selected vessel would then be 24 in. × 8 ft *SS* tall (after rounding up the height).

The mesh pad can be installed in two ways, if the 1.15 ft^2 is to be maintained. One, a full-diameter mesh pad can be installed with a blanking annular plate on top. Two, a cylindrical box with a 15-in. diameter can be installed around the gas outlet.

TABLE 2.7—TYPICAL DROP OR BUBBLE REMOVAL SIZES

Service	Drop or Bubble Size, μm
Removal of liquid drops from gas	Bulk: 100–300 Scrubbing: See below. Filter: 1
Removal of water from oil	Bulk: 500 Fine: 50
Removal of oil from water	Bulk: 100
Removal of gas from oil	Bulk: 200

TABLE 2.8—TYPICAL GAS VELOCITIES FOR RE-ENTRAINMENT OF LIQUIDS

Pressure, psig	Gas Re-Entrainment Velocity, ft/sec
1,500	2
750	3
250	5

TABLE 2.9—GUIDELINES FOR INLET AND OUTLET NOZZLE SIZING

Inlet nozzle:	$\rho_m V_m^2$, lbm/ft-sec^2
No inlet device:	600–700
Half-open pipe inlet:	1,000
Vane inlet spreader:	4,000–6,000
Inlet cyclones:	6,000–10,000
Gas outlet nozzle:	2,500
Liquid outlet nozzles:	velocity 3–6 ft/sec

2.4.2 Example 2.2: Horizontal Two-Phase Separator. Size a horizontal separator to remove 100 μm drops in the gas phase.

Given Values. The given values for Example 2.2 are listed next:

Gas rate	10 MMscf/D
Gas-specific gravity	0.6
Gas z-factor	0.84
Gas density	3.7 lbm/ft^3
Gas viscosity	0.012 cp
Oil rate	2,000 B/D
Oil density	50 lbm/ft^3

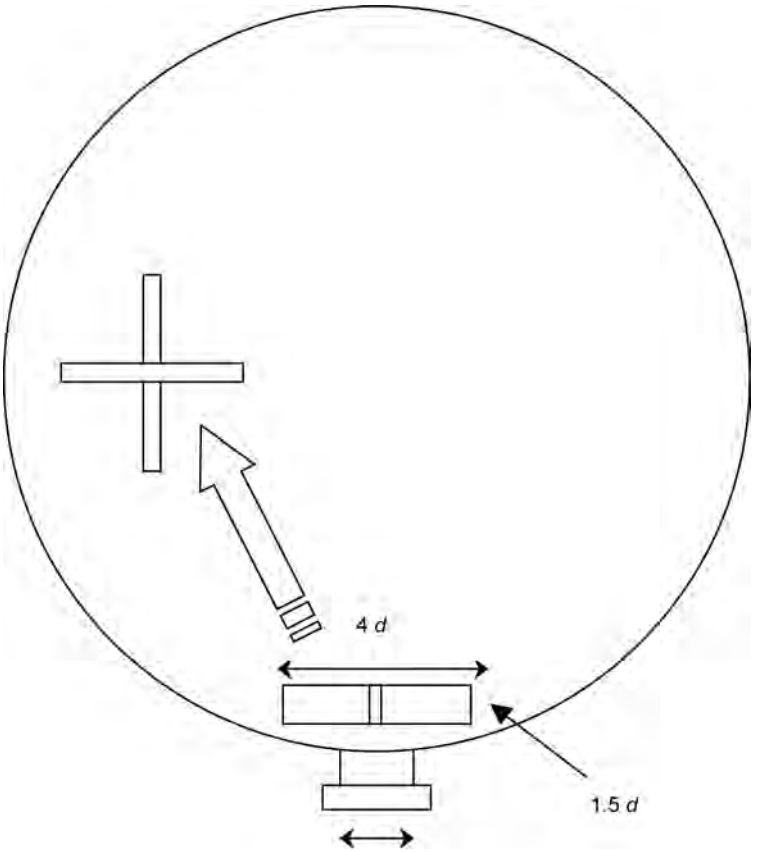


Fig. 2.32—Typical vortex breaker (courtesy of CDS Separation Technologies Inc.).

TABLE 2.10—CALCULATED VESSEL HEIGHTS FOR DIFFERENT VALUES OF DIAMETERS

D, in.	*L*, ft	12 *L*/*D*
15	11.5	9.2
18	9.6	6.4
24	7.75	3.9

Operating pressure	1,000 psia
Operating temperature	60 °F
Mesh pad *K*-factor	0.35 ft / sec
Mesh pad thickness	6 in.
Liquid retention time	1 minute
Inlet nozzle	4 in.
Vessel fill	50 % $\left(\text{Therefore, } F_g = 0.5 \text{ and } h_g = 0.5d.\right)$

Step 1. Calculate vessel diameter and length with Eq. 2.6 for gas capacity.

TABLE 2.11—CALCULATED VESSEL LENGTHS FOR DIFFERENT DIAMETERS BASED ON GAS CAPACITY

D, in.	L_{eff}, ft	L_{ss}, ft	$12\,L_{ss}/D$
16	3.86	5.2	3.9
20	3.09	4.8	2.9
24	2.56	4.6	2.3

TABLE 2.12—CALCULATED VESSEL LENGTHS FOR DIFFERENT DIAMETERS BASED ON LIQUID CAPACITY

D	L_{eff}	L_{ss}	$12\,L_{ss}/D$
20	7.1	9.5	5.7
24	5.0	6.6	3.3

$$\frac{L_{\text{eff}}d^2F_g}{h_g} = 421\frac{TZQ_g}{P}\left[\left(\left|\frac{\rho_g}{\rho_l-\rho_g}\right|\right)\frac{C_D}{d_m}\right]^{1/2}. \quad \text{..... (2.19)}$$

Assume $h_g = 0.5d$ so that $F_g = 0.5$.

$$\frac{L_{\text{eff}}d^2F_g}{h_g} = \frac{L_{\text{eff}}d^2(0.5)}{0.5h_d} = L_{\text{eff}}d\,. \quad \text{..... (2.20)}$$

From Appendix A, using a gas viscosity of 0.012 cp, $C_D = 1.42$.

$$\left[\left(\left|\frac{\rho_g}{\rho_l-\rho_g}\right|\right)\frac{C_D}{d_m}\right]^{1/2} = \left[\left(\left|\frac{3.7}{50-3.7}\right|\right)\frac{1.42}{100}\right]^{1/2} = 0.0337 \quad \text{..... (2.21)}$$

$$L_{\text{eff}}d = 421, \quad \text{and} \quad \left[\frac{(520)(0.84)(10)}{1{,}000}\right](0.0337) = 61.82 \quad \text{..... (2.22)}$$

Step 2. Calculate L_{eff} and $L_{ss} = L_{\text{eff}} + d/12$ for different values of d.

Step 3. Calculate the vessel diameter and length for liquid retention time with Eq. 2.12.

$$d^2L_{\text{eff}} = \frac{t_{ro}Q_o}{0.7} = 2{,}857.$$

Step 4. Calculate L_{eff} and $L_{ss} = L_{\text{eff}} + d/12$ for different values of d.

Step 5. Select vessel that satisfies both gas and liquid capacity.

A comparison of **Tables 2.11 and 2.12** shows that the liquid capacity is the dominant parameter. Hence, a 24-in. × 6.6-ft vessel is sufficient, as it has a slenderness ratio within the typical 3 to 5 range. This size should be rounded up to 24 in. × 7 ft.

2.4.3 Example 2.3: Vertical Three-Phase Separator. ***Given Values.*** The given values for Example 2.3 are listed next:

Gas rate	5 MMscf/D
Gas specific gravity	0.6
Gas z-factor	0.84
Gas density	3.7 lbm/ft^3
Oil rate	5,000 B/D
Oil density	50 lbm/ft^3
Oil viscosity	10 cp
Water rate	3,000 B/D
Water density	66.8 lbm/ft^3
Operating pressure	1,000 psia
Operating temperature	60 ° F
Liquid-retention time	10 minutes each phase
Inlet nozzle	12 in.
Drop removal from gas	100 μm

Step 1. Calculate vessel diameter based on gas capacity from Eq. 2.9.

$$d^2 = 5{,}054\frac{TZQ_g}{P}\left[\left(\left|\frac{\rho_g}{\rho_l - \rho_g}\right|\right)\frac{C_D}{d_m}\right]^{1/2} . \quad \text{(2.23)}$$

From the previous example:

$$\left[\left(\left|\frac{\rho_g}{\rho_l - \rho_g}\right|\right)\frac{C_D}{d_m}\right]^{1/2} = 0.0337 \quad \text{(2.24)}$$

$$d^2 = 5{,}054 \text{ and } \left[\frac{(550)(0.84)(5)}{1{,}000}\right][0.0337 = 392.35] . \quad \text{(2.25)}$$

$$d = 19.8 \text{ in} . \quad \text{(2.26)}$$

Step 2. Calculate the vessel diameter based on water drop removal from Eq. 2.11 for a 500-μm drop.

$$d^2 = 6{,}663\frac{Q_c \mu_c}{(\Delta\gamma)d_m^2} = 6{,}663 \times \frac{5{,}000 \times 10}{0.270 \times 500^2} = 4{,}936 \quad \text{(2.27)}$$

$$d = 70.3 \text{ in} . \quad \text{(2.28)}$$

At this point, we know that the water-drop removal is the dominant sizing parameter in comparison to the gas capacity.

TABLE 2.13—CALCULATED LIQUID LEVELS AND VESSEL HEIGHTS FOR DIFFERENT DIAMETERS

D, in.	$h_o + h_w$, in.	L_{ss}, ft	$12\,L_{ss}/D$
72	128	16.2	2.7
78	110	14.6	2.3
84	94.5	13.4	1.9
90	82.3	12.4	1.7
96	72.3	11.5	1.4
102	64.1	10.8	1.3

Step 3. Calculate liquid levels for retention time based on Eq. 2.13.

$$d^2(h_o + h_w) = \frac{t_{ro}Q_o + t_{rw}Q_w}{0.12} = 10 \times \frac{5{,}000 + 3{,}000}{0.12} = 666{,}667 \quad \text{(2.29)}$$

Table 2.13 shows liquid levels for different vessel diameters.

Step 4. Calculate vessel height from Eq. 2.17. Vales for L_{ss} are given in Table 2.4. Values for $12L_{ss}/d$ should be in the 1.5 to 3 range.

Step 5. Select a vessel size that satisfies gas capacity, water-drop removal, and liquid-retention time requirements. An 84-in. × 13.4-ft separator satisfies the requirements, so you would round up to an 84-in. × 13.5-ft vessel. Similarly, a 90-in. × 12.5-ft separator would also be satisfactory.

Nomenclature

A_d = required demister area
C = API *RP14E* erosion constant, $(\text{lbm/ft-sec}^2)^{1/2}$
C_D = drag coefficient (see Appendix A for calculation)
d = vessel internal diameter, in.
d_h = hydraulic diameter, in. (or consistent units for Eq. 2.1)
d_m = bubble or drop diameter, μm
d_{pp} = perpendicular spacing of plates, m
D = vessel diameter, ft
D_o = drop diameter, cm (or consistent units for Eq. 2.3)
F_c = fractional continuous-phase cross-sectional area
F_g = fractional gas cross-sectional area
F_l = fraction of vessel cross-sectional area filled by liquid
g = gravitational acceleration, cm/sec^2 (or consistent units for Eq. 2.3)
h = liquid height, in.
h_c = continuous liquid-phase space height, in.
h_g = gas-phase space height, in.
h_o = oil pad height, in.
h_w = water pad height, in.
K = mesh capacity factor, m/s or ft/sec
L = plate-pack length, m (or consistent units for Eq. 2.2)
L_{eff} = effective length of the vessel where separation occurs, ft
L_{ss} = seam-to-seam vessel length, ft
P = operating pressure, psia

Q_c = continuous liquid-phase flow rate, B/D
Q_g = gas flow rate, MMscf/D
Q_o = oil flow rate, B/D
Q_w = water flow rate, B/D
Re = Reynolds number
T = operating temperature, °R
t_{rc} = continuous-phase retention time, minutes
t_{ro} = oil-retention time, minutes
t_{rw} = water-retention time, minutes
V = bulk velocity, m/sec
V_c = continuous-phase velocity, m/s (or consistent units for Eq. 2.1)
V_m = design velocity, m/s (or consistent units for Eq. 2.5)
V_h = horizontal water velocity, m/s (or consistent units for Eq. 2.2)
V_r = drop rise velocity, m/s (or consistent units for Eq. 2.2)
Z = gas compressibility
α = inclination angle, degrees
$\Delta\gamma$ = specific gravity difference (heavy/light) of continuous and dispersed phases
μ_c = continuous phase dynamic viscosity, cp
μ_w = water dynamic viscosity, Poise (or consistent units for Eq. 2.3), kg/m-sec or N·sec/m^2
π = constant, 3.14159
ρ = density, kg/m^3 or lbm/ft^3
ρ_m = bulk density, kg/m^3 or lbm/ft^3
ρ_c = continuous liquid-phase density, kg/m^3 or lbm/ft^3
ρ_d = dispersed liquid-phase density, kg/m^3 or lbm/ft^3
ρ_g = gas density, kg/m^3 or lbm/ft^3
ρ_l = liquid density, kg/m^3 or lbm/ft^3
ρ_o = oil density, kg/m^3 or lbm/ft^3
ρ_w = water density, kg/m^3 or lbm/ft^3

Subscripts
m = bulk properties

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Appendix A—Drag Coefficients

The balance of drag and buoyancy is given as

$$C_D \rho_c \frac{\pi d_v^2}{4} \frac{V_T^2}{2} = \left| \rho_c - \rho_d \right| \frac{g \pi d_v^3}{6}, \quad \text{(A-1)}$$

where

V_T = terminal velocity, cm/sec;
C_D = drag coefficient of drop/bubble;
ρ_c = continuous phase density, g/cm^3;
ρ_d = dispersed phase density, g/cm^3;
g = gravitational constant, 981 cm/sec^2;

and

d_v = dispersed phase drop/bubble size, cm.

Eq. A-1 can be rewritten as

$$C_D \, \mathrm{Re}^2 = \frac{4}{3} \frac{d_v^3 \left| \rho_c - \rho_d \right| \rho_c g}{\mu_c^2} = \frac{4}{3} \mathrm{Ar}, \quad \text{(A-2)}$$

where

μ_c = continuous phase viscosity, g/(cm/sec) = poise,
Re = Reynolds number, $V_T \, d_v \, \rho_c / \mu_c$,

and

Ar = Archimedes number.

The drag coefficient is a function of the Reynolds number, Re, and is given by a curve-fit of data (up to a Reynolds number of 5,000) from *Perry's Chemical Engineers' Handbook.*[5]

$$C_D = (0.5423 + \frac{4.737}{\mathrm{Re}^{1/2}})^2 \quad \text{for} \quad \mathrm{Re} < 1 \quad \text{and} \quad C_D = 24 / \mathrm{Re} \, . \quad \text{(A-3)}$$

The form of Eq. A-3 was chosen to allow for an easy solution of Eq. A-3 for the Reynolds number as outlined by Darby in Ref. 6.

$$\mathrm{Re} = \left[\sqrt{19.075 + 2.129 \sqrt{\mathrm{Ar}}} - 4.3675 \right]^2 \quad \text{(A-4)}$$

The procedure then to calculate the drag coefficient is to calculate the Archimedes number, Ar, as defined in Eq. A-2; solve Eq. A-4 for the Reynolds number, Re; and solve Eq. A-3 for the drag coefficient, C_D.

Appendix Nomenclature

Ar	=	Archimedes number
C_D	=	drag coefficient of drop/bubble
d_v	=	dispersed phase drop/bubble size, cm
g	=	gravitational constant, 981 cm/sec^2
Re	=	Reynolds number, $V_T d_v \rho_c / \mu_c$
V_T	=	terminal velocity, cm/sec
μ_c	=	continuous phase viscosity, g/(cm/sec) = poise
ρ_c	=	continuous phase density, g/cm^3
ρ_d	=	dispersed phase density, g/cm^3

Appendix References

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SI Metric Conversion Factors

°API		141.5/(131.5 + °API)		= g/cm^3
bbl	×	1.589 873	E – 01	= m^3
cp	×	.01*	E – 03	= Pa·s
ft	×	3.048*	E – 01	= m
ft^2	×	9.290 304*	E – 02	= m^2
ft^3	×	2.831 685	E – 02	= m^3
ft/sec	×	3.048*	E – 01	= m/s
°F		(°F – 32)/1.8		= °C
gal	×	3.785 412	E – 03	= m^3
in.	×	2.54*	E + 00	= cm
lbm	×	4.535 924	E – 01	= kg
lbm/ft^3	×	1.601 846	E + 01	= kg/m^3
psi	×	6.894 757	E + 00	= kPa

*Conversion factor is exact.

Chapter 3
Emulsion Treating*

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3.1 Introduction

Most of the world's oil reservoirs now produce a mixture of oil and water. The liquids are subjected to shear forces through pumps or other lifting methods, or are sheared as they pass through pressure-reducing devices in the production line. The shear forces disperse one liquid into the other with variations in drop size and stability that are related to the shear force encountered and the physicochemical nature of the production stream. Such dispersions commonly are referred to as emulsions, although many are not true emulsions.

In a true emulsion, either the drop size must be small enough that forces from thermal collisions with molecules of the continuous phase produce Brownian motion that prevents settling, or the characteristics of the interfacial surfaces must be modified by surfactants, suspended solids, or another semisoluble material that renders the surface free energy low enough to preclude its acting as a driving force for coalescence.

Even in fields where there is essentially no initial water production, water cuts eventually might increase enough to make emulsion treatment necessary. Water content of the untreated oil varies from < 1 to > 90 vol%. Salt and basic-sediment-and-water (BS&W) contents are important crude-purchasing requirements. Purchasers limit these contents in the oil they purchase to reduce transportation costs, water treatment and disposal costs, and equipment corrosion.

Removing water from the stream decreases the salt content, but additional steps might be required to meet salt specifications. BS&W content limits vary according to local conditions, practices, and contractual agreements, but typically range from 0.2 to 3.0%. BS&W usually is predominantly water, but might contain solids, some of which are sand, silt, mud, scale, and precipitates of dissolved solids from the producing formation. Other sources of solids are corrosion products, bacterial debris, and precipitated petroleum fractions such as asphaltenes. Solids are troublesome and vary widely among producing fields, zones, and wells.

When water forms a stable emulsion with crude oil and cannot be removed in conventional storage tanks, emulsion-treating methods must be used. This chapter covers the procedures and equipment that are used in treating emulsions. See the chapter on Crude Oil Emulsions in the

*This chapter in the previous edition of the *Handbook*[1] was written by H. Vernon Smith (Meridian Corp.) and Kenneth E. Arnold (Paragon Engineering Services Inc.). Portions of their original material are retained in this edition.

General Engineering volume of this *Handbook* for detailed explanations of emulsions and their chemical treatment.

3.2 Emulsions

3.2.1 Definition of an Emulsion. Strictly speaking, an emulsion is a heterogeneous liquid that consists of two immiscible liquids, one of which is intimately dispersed as droplets in the other. In oilfield parlance, though, an emulsion is any liquid/liquid dispersion that does not readily separate. This latter definition is the one used in this chapter, with apologies to the purists who would call these fine dispersions, rather than emulsions.

The stability of the emulsion is controlled by the types and amounts of surface-active agent and/or finely divided solids, which commonly act as emulsifying agents, or emulsifiers. Emulsifying agents form interfacial films around the droplets of the dispersed phase and create a barrier that slows or prevents coalescence of the droplets.

The matrix of an emulsion is called the external (or continuous) phase. The portion of the emulsion that is in the form of small droplets is called the internal (or dispersed or discontinuous) phase. This chapter considers emulsions of crude oil and the water or brine that is produced with it.

In most crude-oil/water emulsions, the water is finely dispersed in the oil. Such a water-in-oil emulsion is referred to as a "normal" emulsion. The oil can be dispersed in the water to form an oil-in-water emulsion, which is known as an "inverse" or "reverse" emulsion.

Emulsions sometimes are interrelated in a more complex form. The emulsion might begin as either water-in-oil or oil-in-water, but become multistage with additional agitation. If it is water-in-oil initially, a water-in-oil-in-water emulsion can be formed if a small volume of the original water-in-oil emulsion is enveloped in a film of water. Multistage emulsions usually add appreciably to the problem of separating the emulsion into oil and water. The more violent the agitation, the more likely multistage emulsions are to form.

3.2.2 How Crude-Oil Emulsions Form. For an emulsion to form, the two liquids forming the emulsion must be immiscible, there must be sufficient agitation to disperse one liquid as droplets in the other, and an emulsifying agent must be present.

Most crude-oil emulsions are the water-in-oil type, although oil-in-water emulsions are encountered in some heavy-oil production (e.g., in areas of Canada; in Venezuela; and in California, U.S.A.). Oil-in-water emulsions generally are resolved in the same way as are water-in-oil emulsions, except that electrostatic treaters cannot be used on them.

The agitation that is needed to form an emulsion may result from the bottomhole pump; flow through the tubing, wellhead, manifold, or flowlines; the surface transfer pump; pressure drop through chokes, valves, or other surface equipment; or any combination of these. The more agitation present, the smaller the water droplets that are dispersed in the oil. Studies of water-in-oil emulsions have shown that water droplet sizes vary widely, from < 1 to approximately 1,000 μm. Emulsions with smaller water droplets usually are more stable and difficult to treat than are those with larger droplets.

Crude oils vary considerably in emulsifying tendency. Some form very stable emulsions that are difficult to separate. Others do not emulsify or form loose emulsions that separate quickly. In an untreated emulsion, the density difference between the oil and the water will cause a certain amount of water to separate from the oil by natural coalescence and settling; however, unless some form of treatment is used to accomplish complete separation, a small percentage of water probably will remain in the oil, even after extended settling. The remaining water will be in minute droplets that have extremely low settling velocities. These droplets also will be widely dispersed, so that they have little chance to collide, coalesce into larger droplets, and settle.

The amount of water that emulsifies with crude oil in most production systems can vary widely, ranging from < 1 to > 60 vol% (in rare cases). The most common range of emulsified water in light crude oils (i.e., above 20°API) is from 5 to 20 vol%, and in crude oils that are heavier than 20°API is from 10 to 35 vol%.

3.2.3 Emulsifying Agents. Emulsifying agents are surface-active compounds that attach to the water-droplet surface and lower the oil/water interfacial tension. Adding energy to the mixture by agitation breaks the dispersed-phase droplets into smaller droplets. The lower the interfacial tension, the smaller the energy input that is required for emulsification (i.e., the smaller the droplets that will form with a given amount of agitation). Some emulsifiers are asphaltic. Barely soluble in oil and strongly attracted to water, they come out of solution and attach themselves to the droplets of water as these droplets are dispersed in the oil. Asphaltic emulsifiers form thick films around the water droplets and prevent droplet surfaces from contacting when they collide, thus preventing coalescence.

Oil-wet solids (e.g., sand, silt, shale particles, crystallized paraffin, iron hydroxides, zinc compounds, aluminum sulfate, calcium carbonate, iron sulfide, and similar materials that collect at the oil/water interface) can act as emulsifiers. These substances usually originate in the oil formation, but can form because of an ineffective corrosion-inhibition program.

Most crude-oil emulsions are dynamic and transitory. The interfacial energy per unit of area is fairly high in petroleum emulsions compared to that in emulsions commonly encountered in other industries; therefore, they are thermodynamically unstable in that the total free energy will decrease if the dispersed water coalesces and separates. The interfacial film introduces an energy barrier that prevents the "breaking," or separation, process from proceeding.

An emulsion's characteristics change continually from the time of formation to the instant of complete resolution. Accordingly, aged emulsions can exhibit very different characteristics from those that fresh samples do. This is because any given oil contains many types of adsorbable materials and because the adsorption rate of the emulsifier and its persistence at the interface can vary. The emulsion characteristics also change when the liquid is subjected to changes in temperature, pressure, and degree of agitation.

3.2.4 Prevention of Emulsions. Excluding all water from the oil while the oil is produced and/or preventing all agitation of well fluids would prevent emulsion from forming; however, because these both are impossible, or nearly so, emulsion production must be expected from many wells. Sometimes, however, poor operating practices increase emulsification.

Operating practices that involve the production of excess water because of poor cementing or reservoir management can increase emulsion-treating problems, as can a process design that subjects the oil/water mixture to excess turbulence. Unnecessary turbulence can be caused by overpumping and poor plunger and valve maintenance in rod-pumped wells, by use of more gas lift gas than is needed, and by pumping the fluid where gravity flow could be used. To minimize turbulence, some operators use progressive cavity pumps, as opposed to reciprocating, gear, or centrifugal pumps. Other operators have found that some centrifugal pumps actually can cause coalescence if they are installed in the process without a downstream throttling valve. Wherever possible, pressure drop through chokes and control valves should be minimized before oil/water separation.

3.2.5 Stability of Emulsions. Generally, crude oils with low API gravity (high density) form more stable and higher-percentage-volume emulsions than do oils of high API gravity (low density). Asphaltic-based oils tend to emulsify more readily than do paraffin-based oils. High-viscosity crude oil usually forms a more stable emulsion than low-viscosity oil does. Emulsions of high-viscosity crude oil usually are very stable and difficult to treat because the viscosity of

the oil hinders movement of the dispersed water droplets and thus retards their coalescence. In addition, high-viscosity/high-density oils usually contain more emulsifiers than do lighter oils.

3.2.6 Effect of Emulsions on Fluid Viscosity. Emulsions always are more viscous than the clean oil in the emulsion. In oilfield emulsions, the ratio of the viscosity of an emulsion to that of the clean crude oil depends on the shear rate to which the emulsion has been subjected. For many emulsions and for the shear rates normally encountered in piping systems, this ratio can be approximated using Eq. 3.1,[1] if no other data are available.

$$\mu_e/\mu_o = 1 + 2.5f + 14.1f^2, \quad \text{..... (3.1)}$$

where μ_e = viscosity of emulsion, cp; μ_o = viscosity of clean oil, cp; and f = fraction of the dispersed phase.

3.2.7 Sampling and Analyzing Crude-Oil Emulsions. Crude-oil purchasers have established specifications that limit the amount of BS&W in the oil. These limits usually are strictly applied; if the amount of BS&W in an oil exceeds the specified limit, a purchaser might not accept the oil from the producer. The seller and buyer must agree on the procedure for sampling and analyzing the oil to provide consistent and mutually acceptable data.

Emulsion-treating unit or system performance can be monitored by periodically and regularly withdrawing and analyzing samples of the contents at multiple levels in the vessel or multiple points in the system. This is particularly beneficial when treating emulsions that involve viscous oils. Emulsion samples should be representative of the liquid from which they are taken, so emulsification should not be allowed to occur when the sample is extracted. For example, for samples obtained at the wellhead, manifold, or oil-and-gas separator, emulsification can occur because of the turbulence created while the sample is removed from the pressure zone to the sample container. Although such a sample might show a high percentage of emulsion, the oil and water in the system actually might not be emulsified.

Samples from a pressure zone can be taken without further emulsification of the liquids if the velocity of the discharging liquid is controlled. One method is to use a piece of small-diameter tubing that is 10 to 15 ft long. One end of the tubing is connected to a bleeder valve on the line or vessel from which the sample is to be extracted, and the other end is connected to the sample container. The bleeder valve is opened fully, and the sample is allowed to flow through the small-diameter tubing into the container. Emulsification caused by pressure differential may be largely eliminated by flow through small-diameter tubing; however, contact with the tubing walls might produce coalescence, or perturbations to the flow caused by the passage of solids or large water drops might produce emulsification.

Another method for withdrawing representative emulsion samples is to use a sample container that initially is filled with water and is equipped with valves at the top and bottom, with the top valve connected to the point from which the sample is to be extracted. The top valve of the container is opened first, and the container is pressured from the line. The valve at the bottom of the container then is opened, and the water is discharged into the atmosphere as the sample enters the container. No emulsification will occur in the container because there is no pressure drop between the source and sample container to cause turbulence. After the sample has been taken, pressure can be bled off through a third valve with little effect on the sample.

The BS&W content of crude oil is determined using small centrifuges that are driven by hand or by electric motor. A small measured volume of sample is diluted with solvent and placed in graduated glass containers that then are inserted into the centrifuge and spun for a few minutes at speeds of 2,000 to 4,000 rev/min. The oil, water, and solids are separated by

TABLE 3.1—METHODS TO AID DESTABILIZATION, COALESCENCE, AND/OR GRAVITY SEPARATION

Destabilization	Coalescence	Gravity Separation
Heating	Heating	Heating
Chemical	Agitation	Gravity settling
Distillation	Coalescing plates	Centrifugation
	Electrostatic field	
	Water washing	
	Filtering	
	Fibrous packing	
	Retention time	
	Centrifugation	

centrifugal force, and the percentages of each can be read directly from the graduated containers in which the sample is centrifuged.

These methods are described in the American Standards for Testing and Measurement publication *ASTM D-96* for field measurements[2] and *ASTM D-4007* for laboratory procedures.[3] Methods for taking and analyzing samples of crude oil for custody transfer are included in the API *Manual of Petroleum Measurement Standards*.[4]

Separating a crude-oil/water emulsion into its bulk phases of oil and water usually involves three basic steps: destabilization (coagulation), coalescence (flocculation), and gravity separation (sedimentation). Operation and design parameters such as proper chemical selection, chemical-injection rate, treating temperature and pressure, continuous-phase viscosity, flow rate, vessel size and design, and fluid levels can affect separation and can be adjusted to optimize the separation process.

Step 1: Destabilization (Coagulation). Counteracting the stabilizing effect of the emulsifier destabilizes an emulsion. To increase the probability of coalescence of dispersed water droplets on contact, the tough skin or film surrounding the dispersed water droplets must be weakened and broken. This usually is accomplished by adding heat and/or a properly selected, interfacially active chemical compound to the emulsion. (This primarily is the task of the chemical treatment program.)

Step 2: Coalescence (Flocculation). After the films that encase the dispersed droplets have been broken or sufficiently weakened, the droplets must coalesce into drops that are large enough to settle out of the continuous phase of oil. The rate of contact of dispersed water droplets needs to be high, but without creating high shear forces. This usually is accomplished by mechanically inducing collisions between drops or by subjecting the destabilized emulsion to an electrostatic field.

Step 3: Gravity Separation (Sedimentation). Next, there must be a quiet period of settling to allow the coalesced drops to settle out of the oil by gravity. This requires a sufficient residence time and a favorable flow pattern in a tank or vessel that will allow the coalesced drops of water to separate from the oil.

3.3 Emulsion-Treating Methods

An emulsion-treating unit or system will use one or more of the methods listed in **Table 3.1** to aid in destabilizing, coalescence, and/or gravity separation. Each of these treating methods is discussed separately below.

3.3.1 Heating. Using heat to treat crude-oil emulsions has four basic benefits:

• Heat reduces the viscosity of the oil, which allows the water droplets to collide with greater force and to settle more rapidly. The chart in **Fig. 3.1** can be used to estimate crude-oil viscosity/temperature relationships. Crude-oil viscosities vary widely, and the curves on this chart should be used only in the absence of specific data. If a crude oil's viscosity is known at two temperatures, it can be approximated at other temperatures by drawing a straight line along those temperature/viscosity points on the chart. Viscosity that is known at one temperature can be approximated at other temperatures by drawing a straight line parallel to the curves already on the chart. If the viscosity is unknown at any temperature, the chart's curves may be used. *API Spec. 12L*[5] recommends that crude oil be heated so that its viscosity is 50 cSt for dehydration. Viscosity should be < 7 cSt for desalting.

• Heat increases the droplets' molecular movement, which helps coalescence by causing the dispersed-phase droplets to collide more frequently.

• Heat might deactivate the emulsifier (e.g., dissolve paraffin crystals), or might enhance the action of treating chemicals, causing the chemical to work faster and more thoroughly to break the film around the droplets of the dispersed phase of the emulsion.

• Heat also might increase the density difference between the oil and the water, thus accelerating settling. In general, at temperatures below 180°F, adding heat will increase the density difference. Because most light oils are treated below 180°F, the effect of heat on gravity is beneficial. For heavy crudes (< 20°API), which normally are treated above 180°F, heat might have a negative effect on the density difference. In special cases, increased heat might cause the density of water to be less than that of oil. This effect is shown in **Fig. 3.2**.

Heating well fluids is expensive. Adding heat can cause a significant loss of the lower-boiling-point hydrocarbons (light ends). This causes "shrinkage" of the oil, or loss of volume. Because the light ends are boiled off, the remaining liquid has a lower API gravity and thus might have less value. **Figs. 3.3 and 3.4** illustrate typical gravity and volume losses, respectively, vs. temperature for 33°API crude. The vapor leaving the oil phase can be vented to a vapor recovery system or compressed and sold with the gas. Either way, there probably will be a net income loss.

The gas that is liberated when crude oil is treated also might create a problem in the treating equipment if the equipment is improperly designed. In vertical emulsion treaters and gun barrels, some liberated gas could rise through the coalescing section, creating enough turbulence and disturbance to inhibit coalescence. Perhaps more importantly, the small gas bubbles are attracted to surface-active material and, hence, to the water droplets; thus, they tend to keep the water droplets from settling and might even cause them to be discharged with the oil.

Fuel is required to provide heat, and so the cost of fuel must be considered. If the oil is above inlet-fluid temperature when it is discharged from the treating unit, it can be flowed through a heat exchanger with the incoming well fluid to transfer the heat to the cooler incoming well fluid. This will minimize evaporation losses and reduce fuel cost; however, it also will increase the vapor pressure of the crude, which might be limited by contract.

If properly done, heating an emulsion can greatly benefit water separation. Using less heat and a little more chemical, agitation, and/or settling space can obtain the most economical emulsion treatment.

In some geographic areas, emulsion-heating requirements vary in accordance with daily and/or seasonal atmospheric temperatures. Emulsions usually are more difficult to treat when the air is cooler—e.g., at night, during a rain, or in winter months. On the other hand, treatment, especially heating, might not be required in the warmer summer months. When the treating problem is seasonal, some emulsions can be resolved successfully by adding more chemical demulsifiers during winter months. The proper economic balance of heat and chemicals requires evaluation.

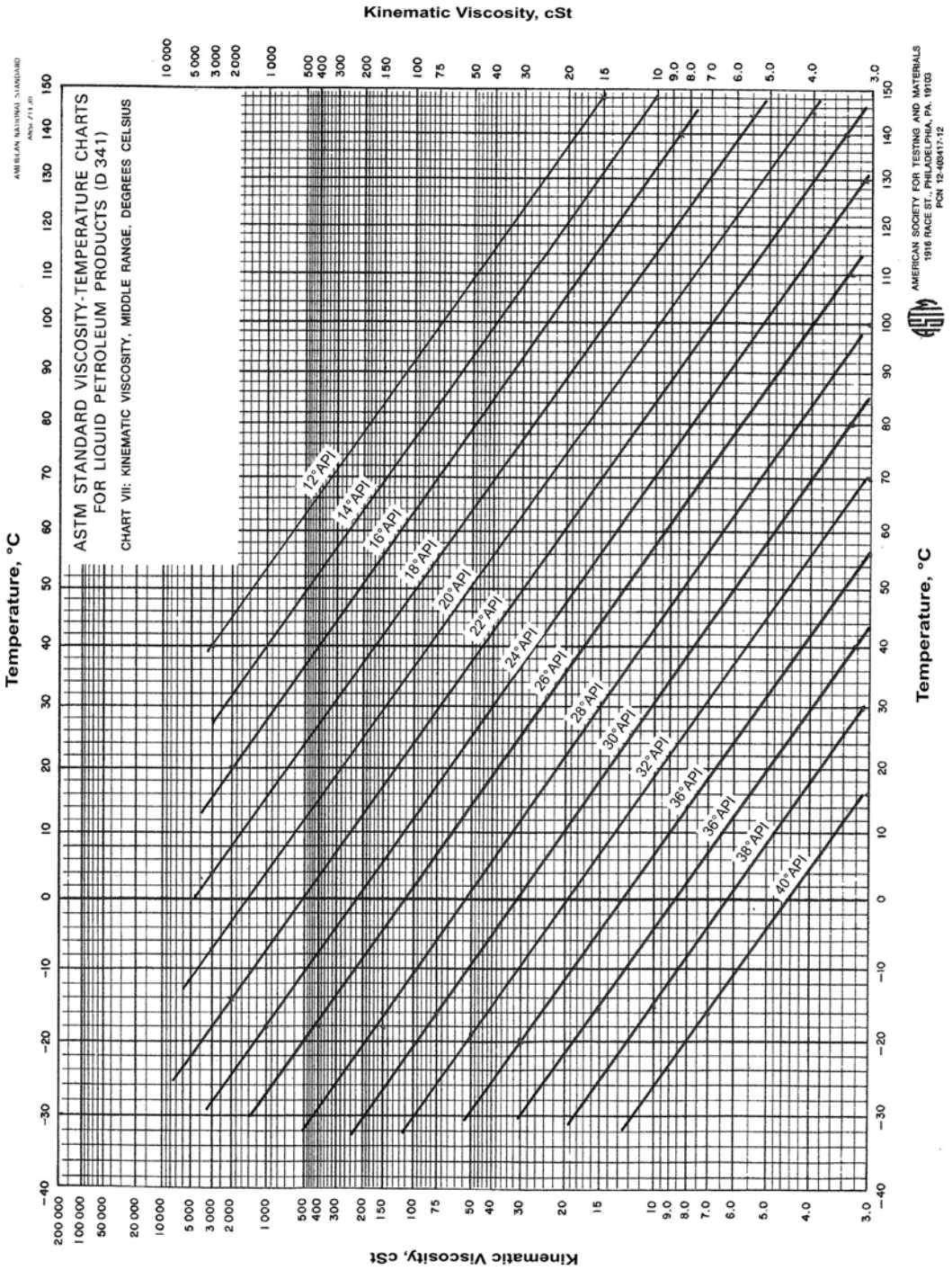


Fig. 3.1—Approximate viscosity/temperature relationships for crude oil. (Courtesy of AMEC Paragon.)

Crude-oil emulsions with similar viscosity ranges do not always require the same type of treating equipment or the same treating temperature. Emulsions that are produced from different wells on the same lease or from the same formation in the same field might require

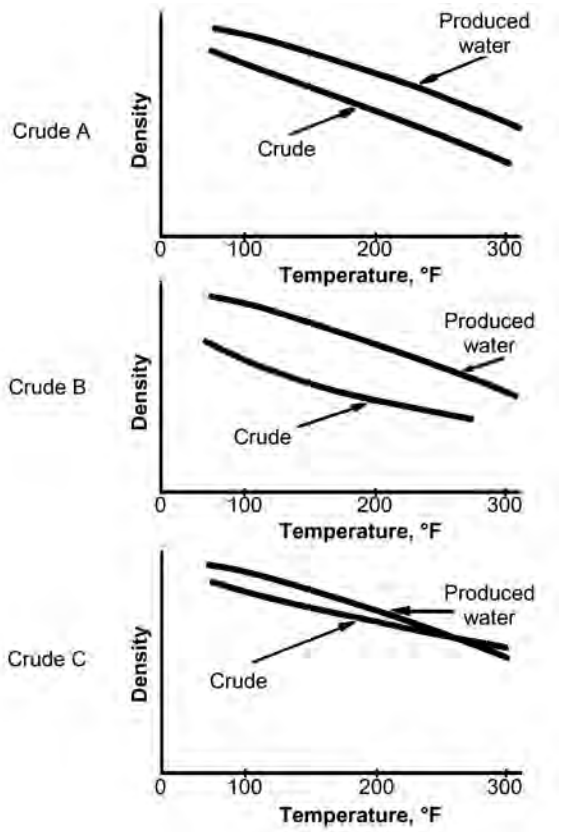


Fig. 3.2—Relationship of density with temperature for three crude oils.[1]

different treating temperatures. For this reason, treating temperatures should be tested so that the lowest practical treating temperature for each emulsion and treating unit or system can be determined by trial.

The heat input and thus the fuel required for treating depends on the temperature rise, the amount of water in the oil, and the flow rate. Because heating a given volume of water requires approximately twice the energy needed to heat the same volume of oil, it is beneficial to separate free water from the emulsion to be treated. Often this is done in a separate free-water-knockout (FWKO) vessel upstream of where heat is added. Sometimes it is accomplished in a separate section of the same vessel.

The required heat input for an insulated vessel (heat loss is assumed to be 10% of heat input) can be approximated using Eq. 3.2[1]:

$$Q = 16\Delta T(0.5q_o\gamma_o + q_w\gamma_w) \ , \quad \text{..... (3.2)}$$

where Q = heat input, Btu/hr, ΔT = temperature increase, °F, q_o = oil flow rate, B/D, q_w = water flow rate, B/D, γ_o = specific gravity of oil, and γ_w = specific gravity of water.

3.3.2 Chemical Demulsifiers. Dehydration chemicals, or demulsifiers, are chemical compounds that are widely used to destabilize, and assist in coalescence of, crude-oil emulsions.

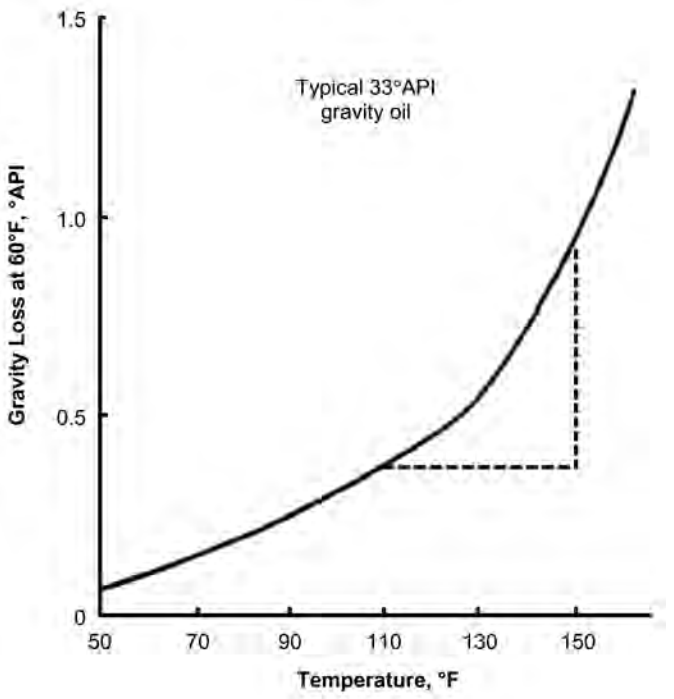


Fig. 3.3—API-gravity loss vs. temperature for 33°API crude oil.[1]

This treatment method is popular because the chemicals are easily applied, usually are reasonable in cost, and usually minimize the amount of heat and settling time required.

The chemical counteracts the emulsifying agent, allowing the dispersed droplets of the emulsion to coalesce into larger drops and settle out of the matrix. To work, demulsifiers must be injected into the emulsion; must mix intimately with the emulsion and migrate to all the protective films surrounding all the dispersed droplets; and must displace or nullify the effect of the emulsifying agent at the interface. For the oil and water to separate, there must also be a period of continual, moderate agitation of the treated emulsion to produce contact between and coalescence of the dispersed droplets, as well as a quiet settling period.

Four actions are required of a chemical demulsifier:

• Strong attraction to the oil/water interface. The demulsifier must be able to migrate rapidly through the oil phase to reach the droplet interface where it must counteract the emulsifying agent.

• Flocculation. The demulsifier must have an attraction for water droplets with a similar charge and bring them together. In this way, large clusters of water droplets gather, which under a microscope look like bunches of fish eggs.

• Coalescence. After flocculation, the emulsifier film remains continuous. If the emulsifier is weak, the flocculation force might be enough to cause coalescence; however, this usually is not true, and the demulsifier must enable coalescence by neutralizing the emulsifier and promoting rupture of the droplet interface film. In the flocculated emulsion, the film rupture causes increasing water-drop size.

• Solids wetting. Iron sulfides, clays, and drilling muds can be made water-wet, which causes them to leave the interface and be diffused into the water droplets. Paraffins and asphaltenes can be dissolved or altered by the demulsifier to make their films less viscous, or they can be made oil-wet so that they will be dispersed in the oil.

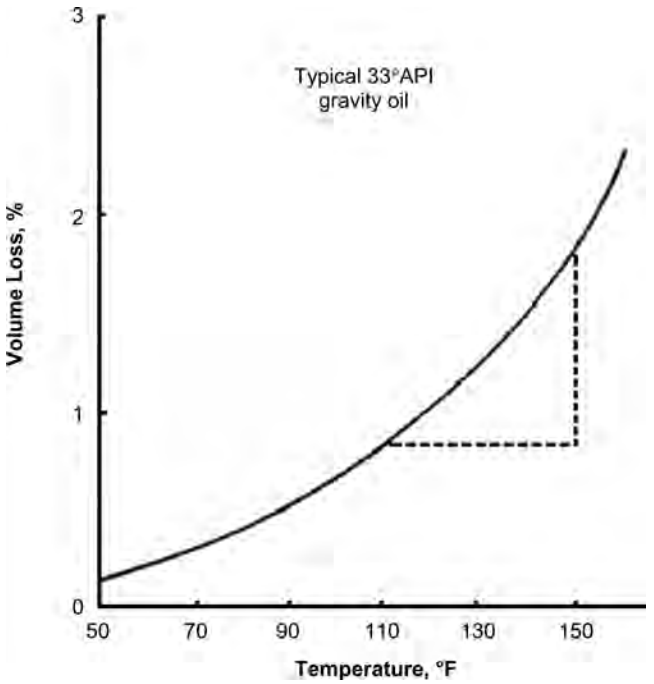


Fig. 3.4—Percent loss by volume vs. temperature for 33°API crude oil.[1]

The demulsifier should be selected with all functions of the treating system in mind. If the process is a settling tank, a relatively slow-acting demulsifier can be applied with good results. On the other hand, if the system is an electrostatic process in which some of the flocculation and coalescence is accomplished by the electric field, a quick-acting demulsifier is needed or the demulsifier might need to be added farther upstream (preferable). The time required for demulsifier action in a vertical emulsion treater normally is between that in a settling tank and that in an electrostatic treater.

As field conditions change and/or the treating process is modified, the chemical requirements might change. Seasonal changes can cause paraffin-induced emulsion problems. Well workovers might change solids content, which can alter emulsion stability. Thus, no matter how satisfactory a demulsifier is, it cannot be assumed to be satisfactory over the life of the field.

Applying heat to an emulsion after a demulsifier has been mixed with it increases the chemical's effectiveness by reducing the emulsion viscosity and facilitating more intimate chemical/emulsion mixing. Chemical reaction at the oil/water interface happens more rapidly at higher temperatures.

Where the demulsifier is injected into the emulsion is important. It should be injected into the emulsion and mixed so that it is evenly and intimately distributed throughout the emulsion when the emulsion is heated, coalesced, and settled in the treating system. It also should be injected in a continuous stream, with the chemical volume directly proportional to the emulsion volume.

Turbulence accelerates the diffusion of the demulsifier throughout the emulsion and increases the number and intensity of impacts between water droplets. Turbulence must persist long enough to permit the chemical to reach the interface between the oil and all the dispersed water droplets, but the intensity and duration of the turbulence must be controlled so that it will not cause further emulsification. Turbulence is the dynamic factor for emulsion formation; however, a moderate level of controlled turbulence causes the dispersed droplets to collide and

coalesce. Usually, this turbulence is provided by normal flow in surface lines, manifolds, and separators and by flow through the emulsion-treating unit or system.

One way to help disperse the chemical throughout the emulsion is to mix a small volume of chemical with a diluent and then to inject and mix the diluted chemical with the emulsion. The larger volume of the mixture can help to mix the chemical more uniformly and intimately with the emulsion.

Usually, the chemical is injected into a coupling that is welded in the side of the pipe, but when flow rates are low (< 3 ft/sec) or when laminar flow is encountered, this is not recommended. In such cases, an injection quill (which injects the chemical in the stream at a location that is removed from the wall), a chemical distributor (**Fig. 3.5**), and/or a static mixer (**Fig. 3.6**) are recommended. The static mixer is a series of staggered, helically convoluted vanes that use the velocity of the fluid to accomplish mixing.

When a tank of wet oil (oil that contains more than the permissible amount of water) accumulates, the tank contents can be treated by adding a small proportion of demulsifier, agitating or circulating the tank contents, and then allowing time for the water to settle in the tank. Trailer-mounted units that include a heater, circulating pump, and chemical injector are sometimes used for this method of tank treating. This batch-treatment method normally is used as an emergency measure.

Using too much treating chemical not only wastes the money spent on its purchase, handling, and injection, but also can increase the stability of the water-in-oil emulsion or of the oil-in-water emulsion in the produced water and increase the stability or the volume of the interfacial emulsion and/or sludge. Using too little treating chemical can fail to break the emulsion and can allow a quick buildup of emulsion and/or sludge. It also can cause an excessive need for heat to break the emulsion and for settling time to resolve the emulsion; can reduce the capacity of the treating equipment; can cause high water content in the crude oil and, therefore, the accumulation of unsalable oil and the resultant cost of retreating the crude; and can increase the difficulty of removing oil from the produced water.

3.3.3 Agitation. Agitation or turbulence is necessary to form a crude-oil emulsion. When turbulence is controlled, however, it can assist in resolving the emulsion. Agitation increases the number of collisions of dispersed particles of water and increases the probability that they will coalesce and settle from the emulsion. Be careful to prevent excessive agitation that will cause further emulsification instead of resolving the emulsion. Keeping the turbulence to moderate Reynolds numbers of 50,000 to 100,000 usually achieves good coalescing conditions.

The flow of emulsions at moderate Reynolds numbers through long pipelines has been shown to cause coalescence and to develop droplets > 1,000 μm in diameter. Using a tortuous flow path as in the serpentine-pipe flow-coalescing device shown in **Fig. 3.7** can decrease the pipeline length required for coalescence. Other devices that are described below have largely supplanted this technology.

3.3.4 Coalescing Plates. Properly designed and placed baffle plates can assist demulsification by evenly distributing emulsion in a vessel and causing gentle agitation that helps to coalesce the droplets by causing dispersed water particles to collide. Using too much baffling, however, can cause excessive turbulence, which might increase emulsification and impede water-droplet settling. Special perforated baffle plates that are properly placed inside treating vessels provide surfaces on which water droplets can coalesce. The emulsion flowing through the perforations creates slight agitation in the form of eddy currents, which causes coalescence. If the perforations are too small, however, shearing of the water droplets can occur, yielding a tighter emulsion.

Other baffle-plate designs also provide surfaces for water coalescence. The design shown in **Fig. 3.8** allows laminar flow through the plates, but provides directional changes to enable the

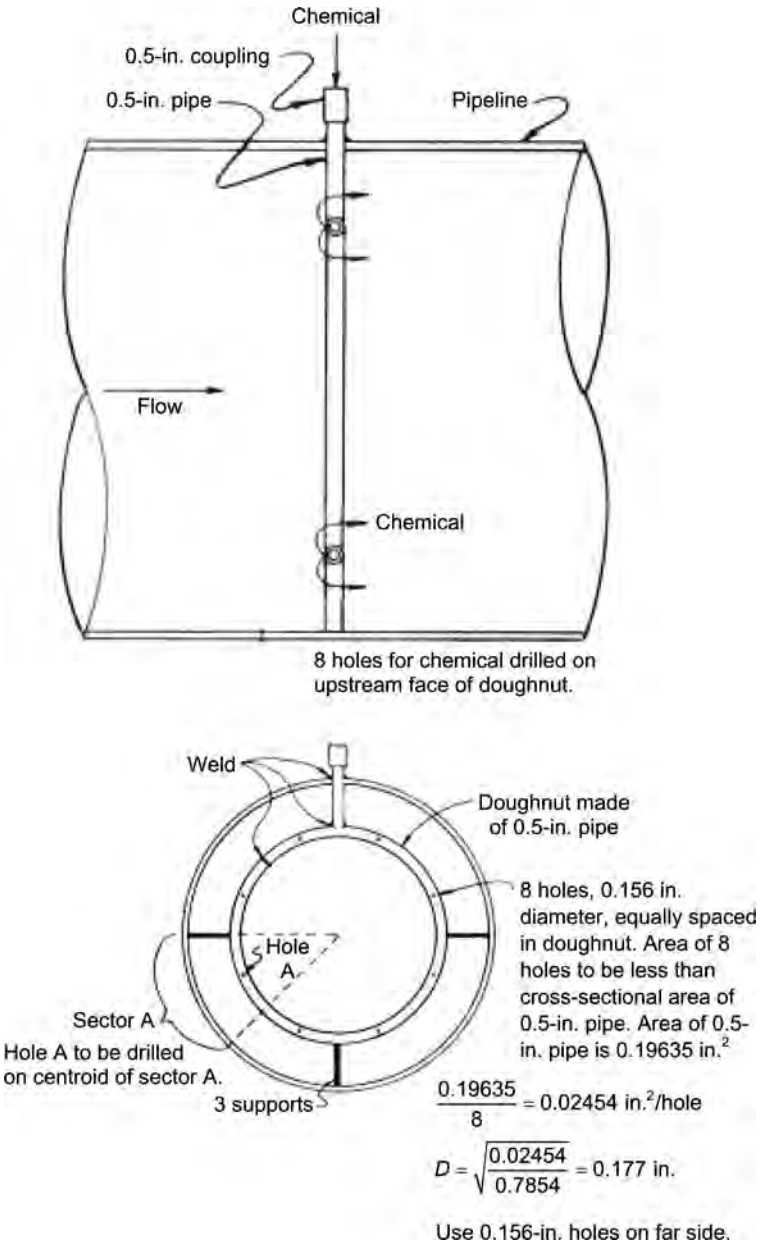


Fig. 3.5—Chemical distributor for flowlines 10 in. or larger (after Ref. 1).

water droplets to contact the plates and coalesce with a film on the surface of the plates. This type of plate can become plugged if used in situations with high paraffin deposition.

3.3.5 Electrostatic Coalescence. The small water drops that are dispersed in the crude oil can be coalesced by subjecting the water-in-oil emulsion to a high-voltage electrical field. When a nonconductive liquid (oil) that contains a dispersed conductive liquid (water) is subjected to an electrostatic field, one of three physical phenomena causes the conductive particles or droplets to combine:

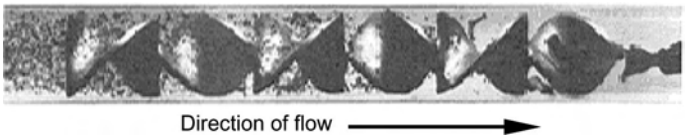


Fig. 3.6—Kinetic (static) mixer for mixing chemical demulsifier with emulsion. (Courtesy of Chemineer-Kenics, Dayton, Ohio.)

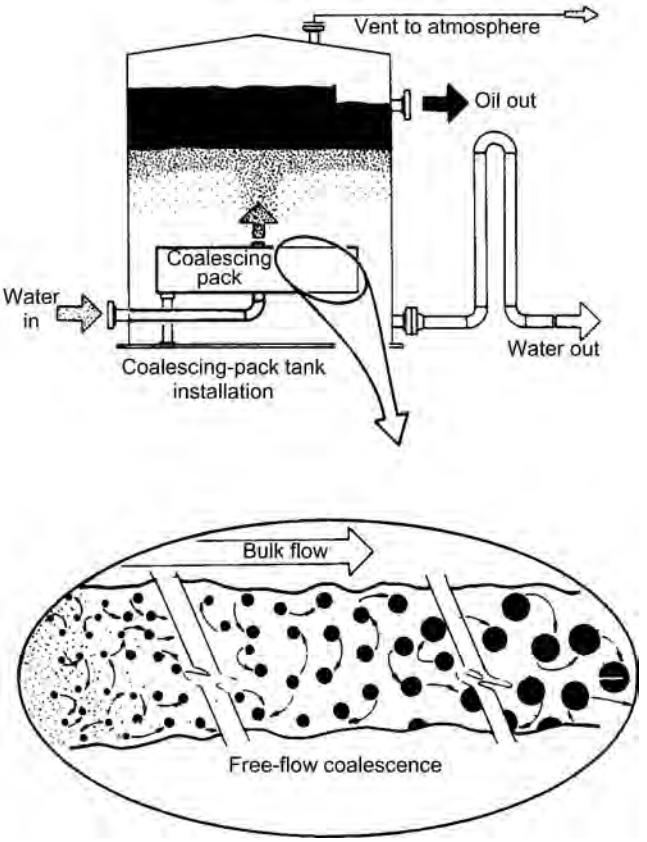


Fig. 3.7—The serpentine-pipe coalescing pack grows a larger drop size on the inlet separator of a gravity settler. (Courtesy of Natco Group Inc.)

1. The water droplets become polarized and tend to align themselves with the lines of electric force. In so doing, the positive and negative poles of the droplets are brought adjacent to each other. Electrical attraction brings the droplets together and causes them to coalesce.

2. An induced electric charge attracts the water droplets to an electrode. In a direct current (DC) field, the droplets tend to collect on the electrodes or bounce between the electrodes, forming larger and larger droplets until eventually they settle by gravity.

3. The electric field distorts and thus weakens the film of emulsifier surrounding the water droplets. Water droplets dispersed in oil that are subjected to a sinusoidal alternating-current (AC) field become elongated along the lines of force as voltage rises during the first half-cycle. As the droplets are relaxed during the low-voltage part of the cycle, the surface tension

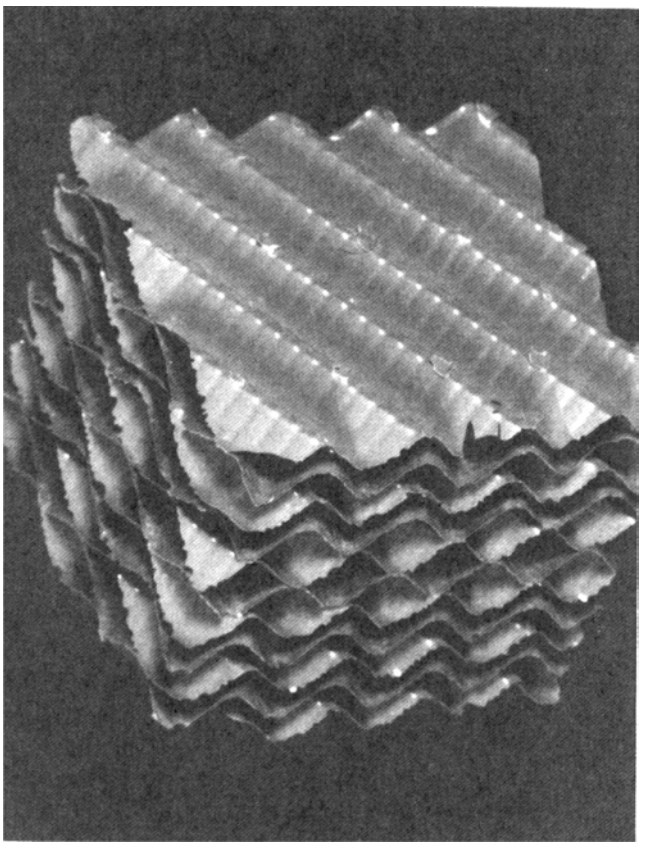


Fig. 3.8—Corrugated-plate pack, a special coalescing medium for crude-oil emulsions. (Courtesy of Natco Group Inc.)

pulls them back toward a spherical shape. This effect repeats with each cycle, weakening the film so that it breaks more easily when droplets collide.

Whatever the actual mechanism, the electrical field causes the droplets to move about rapidly, which increases the probability of collision with other droplets. Droplets coalesce when they collide at the proper velocity. The greater the voltage gradient, the greater the forces that cause coalescence; however, experimental data have shown that at some voltage gradient, rather than coalescing, the water droplets can be pulled apart, tightening the emulsion. For this reason, electrostatic treaters normally are equipped with a mechanism for adjusting the voltage gradient in the field.

In oil that contains a large quantity of water, there is a tendency toward "chaining"—the formation of a chain of charged water particles—which might form links between the two electrodes, causing short-circuiting. Chaining has been observed in emulsions that contain 4% or less water. If chaining causes excess power consumption, the voltage gradient is too large (i.e., the electrical grids of the electrostatic treater are too close together or the voltage is too high) for the amount of water being handled. The breaking out of solution of small amounts of gas also can create sufficient turbulence to impede sedimentation.

3.3.6 Water Washing. In some emulsion-treating vessels, separation of liquids and vapors takes place in the inlet diverter, flume, or gas boot that is located at the top of the vessel. The liquids flow by gravity through a large conduit to the bottom of the vessel. A spreader plate on the lower end of the conduit spreads the emulsion into many rivulets that move upward

through the water, accomplishing a water wash. After passing through the water wash, the emulsion flows to the upper portion of the vessel, where the coalesced water droplets settle out of the oil.

When an emulsion is flowed through an excess of its internal phase, the droplets of its internal phase tend to coalesce with the excess of the internal phase and thus be removed from the continuous phase. This is the principle on which a water wash operates. The water wash is more beneficial if the emulsion has been destabilized by a demulsifier and if the water is heated. The effectiveness of a water wash greatly depends on the ability of the spreader plate or distributor to divide the emulsion into rivulets, causing the emulsion to have maximum intimate contact with the water bath, so that its small drops of water can coalesce with the bulk water.

There is some danger of multiphase emulsion formation if the stream passes through an interface "rag" (unresolved emulsion and solids) layer.

If an emulsion-treating system or unit uses a water wash, it should be charged with water to facilitate initial operation. Water from the emulsion to be treated should be used if available; if not, extraneous water may be used.

3.3.7 Filtering. A filtering material with the proper pore-space size and the proper ratio of pore space to total area can be used to filter out the dispersed water droplets of a crude-oil emulsion by preferentially wetting the filtering material with oil and keeping it submerged in oil. A pack used in this manner is correctly called a filter because it filters out the liquid that it prevents from passing through. Filtering is not a widely used crude-oil-emulsion treatment method, however, because of the difficulty in obtaining and maintaining the desired filtering effect and because filtering materials easily become plugged by foreign material.

One filtering material, excelsior, is wood that has been cut into small shreds or fibers (and so frequently is referred to as "hay"). It formerly was used as a filter in emulsion treaters, but now is largely obsolete. Excelsior should be used at < 180°F treating temperature. Higher temperatures will delignify and deteriorate the excelsior and make it difficult to remove from the vessel.

When its fibers are properly sized and compacted, glass wool also can serve as a filtering material. Coating the glass wool with silicone enhances its filtering effect because the silicone-coated glass-wool fibers are more wettable by oil than are untreated ones. Glass wool is not widely used for filtering, however, because of its initial expense and its fouling problems. Likewise, other available plastic and metal porous filtering materials are not widely used because of the difficulty of obtaining and maintaining the proper pore size and because they easily become inoperable because of fouling.

3.3.8 Fibrous Packing. Fibrous coalescing packs are not commonly used in oil treating, but are discussed here for completeness and to differentiate between filtering and coalescence. A coalescing pack is a section or compartment in an emulsion-treating tank or vessel that is packed with a water-wetted material, causing the water in the emulsion to coalesce into larger drops. A coalescing pack works on the principle that two immiscible liquids with different surface tensions cannot simultaneously take possession of a given surface. When the dispersed droplets of water contact the water-wet coalescing material, they coalesce and adhere to the coalescing surfaces. Oil will pass through the pore spaces of the coalescing material. Separation of the two liquids in a coalescing pack, then, is caused not by filtering, but by the greater affinity of the water-wet coalescing material for the water droplets.

The film of oil that contains the emulsifying agent that surrounds the dispersed water particles must be broken before these droplets will adhere to a coalescing medium. This is done with demulsifying chemicals and/or heat and by repeated contact between the water particles and the surface of the coalescing materials while the emulsion flows through the pack. When

this film has been broken, the water particles will adhere to the surface of the coalescing material until they combine into drops that are large enough to settle out of the oil.

Glass wool can be used as coalescing material in emulsion-treating vessels, but it fouls easily and might cause channeling. Woven-wire mesh also can be used, but tends to be more expensive than glass wool.

3.3.9 Gravity Settling. Gravity settling is the oldest, simplest, and most widely used method for treating crude-oil emulsions. The density difference between the oil and the water causes the water to settle through and out of the oil by gravity. The gravitational force is resisted by a drag force from their downward movement through the oil. When these two forces are equal, a constant velocity is reached that can be computed from Stokes' law, Eq. 3.3[1]:

$$v = \frac{\left(1.78 \times 10^{-6}\right)\Delta\gamma_{ow} d^2}{\mu_o}, \quad \text{..... (3.3)}$$

where v = the downward velocity of the water droplet relative to the oil, ft/sec; d = the diameter of the water droplet, μm; $\Delta\gamma_{ow}$ = the specific-gravity difference between the water and the oil (water/oil); and μ_o = dynamic viscosity of the oil, cp.

Several conclusions can be drawn from Eq. 3.3:

• The larger the water droplet is, the greater is its downward velocity (i.e., the larger the droplet, the less time it takes to settle to the bottom of the vessel, and thus the easier it is to treat the oil).

• The greater the density difference between the water droplet and the oil, the greater is the downward velocity (i.e., the lighter the oil, the easier it is to treat the oil). For example, if the oil gravity is 10°API and the water is fresh, the settling velocity will be zero because there is no gravity difference.

• The higher the temperature, the lower the oil viscosity, and thus the greater the downward velocity of the water droplets. It is easier to treat the oil at high temperatures than at low temperatures (assuming a small effect on gravity difference because of increased temperature).

Gravity settling can be used alone only to treat loose, unstable emulsions; however, for stronger emulsions, gravity settling separates water from oil only when used with other treating methods that increase water droplet size by destabilizing the emulsion and creating coalescence.

3.3.10 Retention Time. In a gravity settler (e.g., an oil-treating tank or the coalescing section of an oil-treating vessel), coalescence will occur, but because of the small forces at work, the rate of contact between water droplets is low, and colliding droplets seldom coalesce immediately. Thus, the coalescence process occurs over time, but it follows a steep exponential curve in which successive doubling of retention time yields small, incremental increases in droplet size.

Adding retention time alone (beyond a small amount for initial coalescence) might not significantly affect the size of the water droplets that must be separated by gravity to meet the desired oil quality. Using a taller tank increases the retention time, but does not decrease the upward velocity of the oil or might not significantly increase the size of the water drops. Thus, the additional retention time gained by using the taller tank might not materially affect the water content of the outlet oil.

Using a larger-diameter tank also will increase the retention time and, more importantly, will slow the upward velocity of the oil, allowing smaller droplets of water to settle out by gravity. In this case, it might not be the increase in retention time that improves the oil quality, but rather the reduction in flow velocity, which decreases the size of the water droplets that can be separated from the oil by gravity.

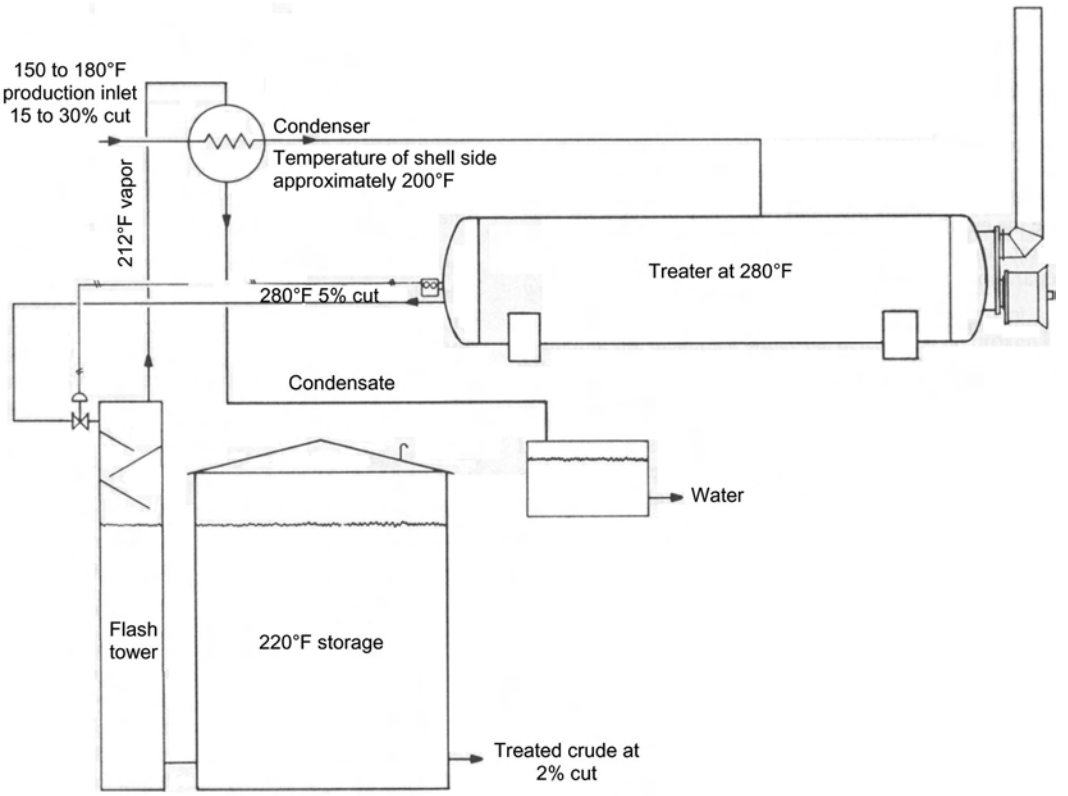


Fig. 3.9—Typical flash-distillation system for dehydrating emulsions of heavy viscous crude oils. (Courtesy of Hydrocarbon Research Inc., Long Beach, California.)

3.3.11 Centrifugation. Because of the density difference between oil and water, centrifugal force can be used to break an emulsion and separate it into oil and water. Small centrifuges are used to determine the BS&W content of crude-oil emulsion samples. A few centrifuges have been installed in oil fields to process emulsions, but centrifuges have not been widely used for treating emulsions because of high initial cost, high operating and maintenance costs, low capacity, and their tendency to foul.

3.3.12 Distillation. Distillation can be used to remove water from crude-oil emulsions. Along with lighter oil fractions, the water can be distilled by heating and then separated by appropriate means. The lighter oil fractions usually are returned to the crude oil.

The only current use of distillation is in the "flash system" that is used in 15°API and lower oil. Flash systems use the excess heat in the oil that is received from the treater or treating system and convert it to latent heat at or near atmospheric pressure. A surface condenser condenses the flashed steam in the cooler, incoming stream of raw crude, thus scavenging the excess heat that ordinarily would be wasted.

Fig. 3.9 shows a typical flash-distillation system for dehydrating emulsions of heavy viscous crude oils. It is very important in a flash system that the operating pressure be maintained high enough to keep the boiling temperature of the water in the emulsion at least 40°F above the bulk temperature. This will help prevent scale deposition on the heating elements.

The disadvantages of distillation are that it is expensive and that all the dissolved and suspended solids in the water remain in the oil when the water is removed by evaporation. For

these reasons, flash treating systems usually are limited to heavy crudes that must meet low BS&W pipeline specifications, as might be the case in cold climates.

3.4 Desalting

Most produced water contains salts that can cause problems in production and refining, when solids precipitate to form scale on process equipment. The salts also accelerate corrosion in piping and equipment.

The salt content of crude oil almost always consists of salt dissolved in small droplets of water that are dispersed in the crude. Sometimes the produced oil contains crystalline salt, which forms because of pressure and temperature changes and because of stripping of water vapor as the fluid flows up the wellbore and through the production equipment.

The salinity of produced brine varies widely, but for most produced water, it ranges from 5,000 to 250,000 ppm of equivalent NaCl. (See the chapter on Properties of Produced Water in the General Engineering volume of the *Handbook*.) Crude oil that contains only 1.0% water with a 15,000-ppm salt content has 55 lbm of salt per 1,000 bbl of water-free crude. The chemical composition of these salts varies, but nearly always is mostly NaCl, with lesser amounts of calcium and magnesium chloride. Salt content limits might be set by transportation requirements in the production field or shipping terminal, or by concerns over corrosion, fouling, or catalyst degradation in the refinery.

The purpose of a desalting system is to reduce the salt content of the treated oil to acceptable levels. When the salinity of the produced brine is not too high, merely ensuring that there is a low fraction of water in the oil can reduce salt content. In that case, the terms desalting and emulsion treating effectively have the same meaning, and the concepts and equipment described previously can be used.

The required maximum concentration of water in oil to meet a known salt specification can be derived from Eq. 3.4:

$$C_{so} = 0.35 C_{sw} \gamma_w f_w \, , \quad \text{..... (3.4)}$$

where C_{so} = the salt content of the oil, lbm/1,000 bbl; C_{sw} = the concentration of salt in produced water, ppm; γ_w = the specific gravity of produced water; and f_w = the volume fraction of water in crude oil.

In produced brine with a high salt concentration, it might not be possible to treat the oil to a low enough water content (< 0.2% is difficult to guarantee). A desalting system such as the one shown schematically in **Fig. 3.10** consists of a mixing device (in which fresh water is used to wash the crude oil) and any of the electrostatic treating systems described below (which then are used to dehydrate the oil to a low water content). Mixing dilution water with the produced water lowers the effective value of C_{sw} in Eq. 3.4. If a single-stage desalting system requires too much dilution water or is unable to reach the desired salt concentration, then a two-stage system is used, such as the one shown schematically in **Fig. 3.11**.

3.4.1 Mixing Efficiency. The mixing efficiency is the fraction of wash water that actually mixes with the produced water. In effect, the remainder of the water bypasses the desalting stage and is disposed of as free water. A mixing efficiency of 70 to 85% is considered the highest attainable. Because mixing efficiency depends on the probability of contact between the dilution water and entrained brine, it varies with the drop population in the crude oil. The effectiveness of this dilution reaction is determined by a variety of influences (e.g., mixing intensity and duration, diffusional transport, and interdrop-collision frequency).

3.4.2 Dilution Water. Enough dilution water must be available to satisfy mass-balance requirements for diluting the dispersed brine enough that the salt specification can be met while

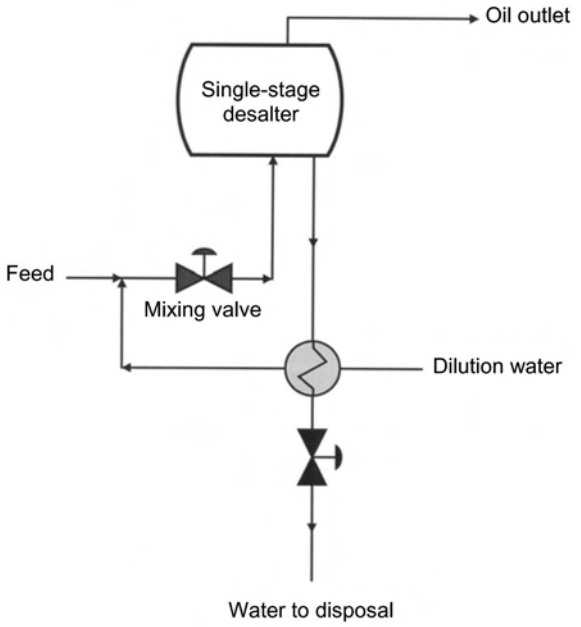


Fig. 3.10—Typical flow diagram for a single-stage desalter. (Courtesy of Natco Group Inc.)

considering the residual BS&W in the oil. Dilution-water quality also must be considered and can be a problem because of high pH, the presence of surfactants, and other conditions that can lead to increased emulsion stability.[6]

Obviously, to remove salt, the dilution water must have low enough salt content to achieve the required equilibrium concentration in the residual entrained water. Less obvious but also important is the need for dilution water to be of sufficient quality to avoid contributing to emulsification. Streams that contain considerable amounts of coke particles, suspended solids, iron sulfide, and/or emulsified oil should not be used. Neither should streams contain traces of surfactant chemicals or excess caustic soda. Limiting ammonia to < 200 ppm avoids fouling and corrosion in the crude-distillation unit overhead and limits pH excursions. Preferably, the pH of the dilution water should be < 9.0, and provision for acid injection for pH control should be made if higher values are expected. High pH might enhance the formation of stable emulsions, whereas pH values < 6.5 might raise concerns about corrosion within the desalter vessel. The dilution water should contain < 0.02 ppm oxygen and < 1 ppm fluoride and should be low in sodium salts, suspended solids, and hardness ions.

3.4.3 Water Recycle. Contact efficiency, or collision frequency, between drops of dispersed brine and dilution water is proportional to the drop populations. Increasing the number of dilution-water drops yields more efficient contact. Because quantities of available dilution water usually are limited, the effluent water often is recycled to increase drop population. Effluent water from the second-stage desalter is much less saline than the dispersed brine, so that it can be used for dilution water for the first stage, as shown in Fig. 3.11. This is known as interstage recycling.

Another recycle scheme, intrastage recycling, previously was limited because it requires mixing of the recycle water and the fresh water, thereby lessening the effectiveness of the fresh water; however, the advent of counterflow desalting made it feasible to inject recycle water ahead of the mixing valve of a single-stage desalter and to inject the fresh water into the coun-

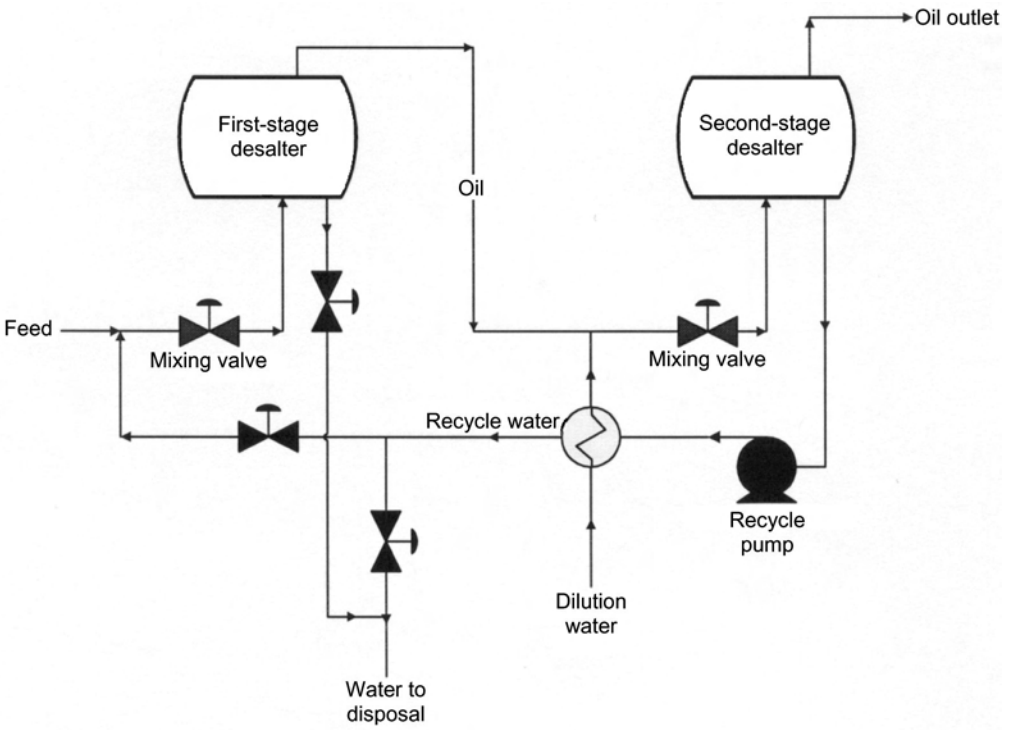


Fig. 3.11—Typical flow diagram for a two-stage desalter. (Courtesy of Natco Group Inc.)

terflow distributors, thereby increasing the drop population without raising the salinity of the fresh dilution water. With all recycle streams, be careful as to the quality of the water: if interface sludge or mud-wash solids are allowed to recycle, they might produce stable emulsions and cause rapid buildup of the interface-sludge layer. If this problem appears likely to occur, the recycle should be taken after an effluent water-cleaning device.

3.4.4 Effluent-Water Quality. The effluent water from a properly operating desalter, exclusive of mud-wash cycles, frequently is < 250 ppm oil in water. Field dehydrators might carry more oil in their effluent water, depending on the conditions of the crude oil being treated. Further clarifying the water requires additional retention time and different chemical treatment, both of which are more economically provided externally to the desalter vessel.

3.4.5 Water Solubility in Crude Oil. Water exhibits an appreciable solubility in crude oil at elevated temperatures. A rule of thumb is that approximately 0.4% water might be dissolved at temperatures of approximately 300°F, as shown in **Fig. 3.12** for a variety of crude oils. A desalter or dehydrator can separate only dispersed water and has no effect on water that is soluble at operating conditions; however, a significant quantity of soluble water can precipitate when the output is sampled through a sample cooler and the sample is further cooled while awaiting analysis. This precipitated water might be erroneously assumed to be dispersed water in the effluent oil.

A more insidious aspect of water solubilization occurs in the preheat train ahead of a desalter. As the oil is heated to operating temperature, water from the dispersed brine is solubilized into the oil phase while leaving behind precipitated salts. This can cause the formation of

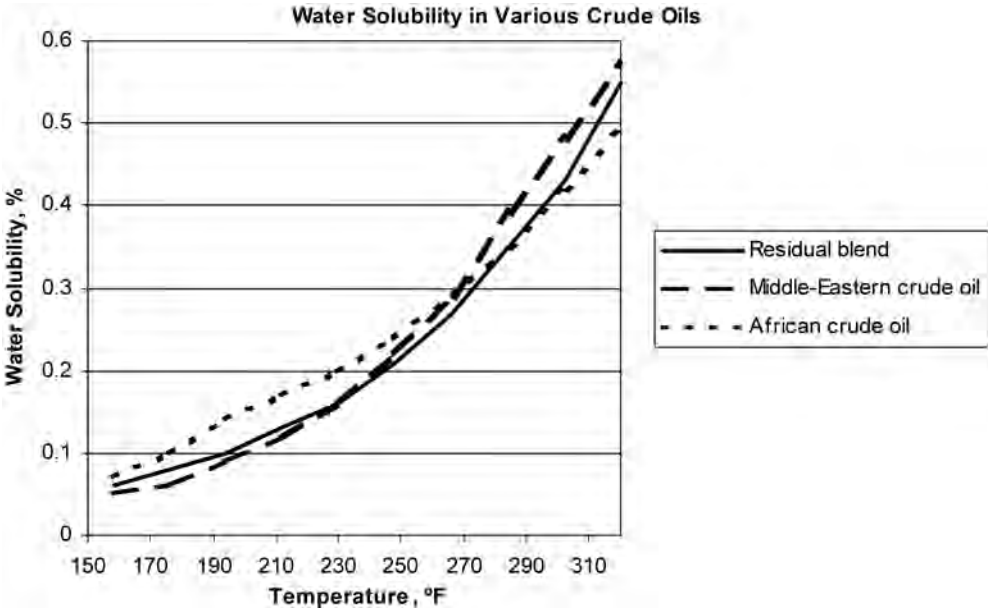


Fig. 3.12—Solubility of water as a function of temperature in various crude oils. (Courtesy of Natco Group Inc.)

crystalline salt, which is very difficult to remove from the oil. Injecting fresh water ahead of the preheat train can help offset this problem and can alleviate heat exchanger fouling.

3.4.6 Incompatibilities of Oils. Crude oils might contain semisoluble organic materials (e.g., waxes and asphaltenes), which can precipitate during processing and cause the production of troublesome sludges or the stabilization of emulsions. Wax precipitation can be controlled through temperature and chemicals, but asphaltenes are more troublesome. By definition, asphaltenes precipitate in hydrocarbons of the molecular weight of pentane; therefore, if light hydrocarbons are recycled as slop oil into a vessel that is processing asphaltic crude oil, serious sludge precipitation might result.

3.4.7 Analytical Methods. Several procedures currently are in use, depending on the values to be measured, the accuracy required, and the equipment available. BS&W measurements usually are done by centrifugation, as discussed in Sec. 2.7 above and as described in *ASTM D-96*[2] and *ASTM D-4007*.[3] Salt analysis by conductivity, as described in *ASTM D-3230*,[7] is a widely used technique for process monitoring and quality control. It is reliable at salt concentrations > 5 lbm/1,000 bbl and, with care, can be used at concentrations of from 2 to 5 lbm/1,000 bbl. At low salt levels, oil conductivity becomes a function of water content and pH, as well as of salt content. Because the ions responsible for pH changes are 2.6 to 4.6 times as conductive as chloride, the effects of minor pH changes far outweigh those of chloride-concentration changes. Other problems (e.g., variation in the composition of the salt mix in oils) also help to preclude the use of this method as a reliable indicator of absolute desalter performance at low effluent salt contents unless exacting calibration procedures are followed.

Laboratory results usually are obtained by analyzing total chloride ion, converting it to equivalent sodium chloride, and reporting it in lbm/1,000 bbl. At salt levels of 2 lbm/1,000 bbl and below, achieving meaningful and reproducible results requires great care. Of the several available salt-analysis methods, extraction and analysis of soluble salts has proved to be the most reliable, the one least subject to interference from other constituents.

Extraction and analysis of soluble salts involves diluting an oil sample with xylene and extracting the mixture with boiling deionized water. The extraction funnels then are placed in a water bath at 140 to 160°F for phase separation. If necessary, acidification, electrostatic cells, or chloride-free emulsion breaker may be used to enhance separation. The aqueous layer is removed and filtered if it is cloudy or if entrained oil is present. Then it is titrated with dilute silver nitrate (0.01N), using a chromate indicator under incandescent lighting. The titration procedure is known as the Mohr method and is described in API *RP 45*.[8] Endpoint recognition requires a practiced eye when using dilute titrant. If available, ion chromatography also may be used for chloride determination. Ion chromatography is extremely accurate for determining small quantities of chloride, but its equipment is more expensive than titration equipment. Because of the widespread occurrence of chloride in nature and the very small quantity being measured in this method, take care to avoid contaminating the sample during handling.

Another commonly used method is the spectrophotometric determination of the metals sodium, calcium, and magnesium. These techniques use atomic absorption or inductively coupled plasma and are accurate and highly automated; however, they do not distinguish between water-soluble salts and those that exist primarily in the oil phase (e.g., metal-organic compounds or mineral precipitates), so their results might relate poorly to desalter performance.

3.5 Emulsion-Treating Equipment

Designing equipment or a system for treating crude-oil emulsions and sizing each piece of equipment for a specific application requires experience and engineering judgment. Unfortunately, no ideal procedure so far exists to infer from measured properties of the emulsion the most economical treating process, taking into account treating temperature, chemical usage, and the physical size of the treating equipment. For now, an engineer must rely on experience and empirical data from other wells or fields in the area and on laboratory experiments.

For example, it is difficult to predict the economic balance between the amounts of chemical and heat to use to destabilize the emulsion and aid in coalescence. Almost all emulsion-treating systems use demulsifying chemicals. Generally, the lower the treating temperature, the more chemical that is required to treat the emulsion. In many areas of west Texas, U.S.A., and in the Gulf of Mexico, some operators do not add heat to treat the relatively light crudes that are produced, whereas other operators under the same conditions do add heat when treating similar crudes, to minimize chemical cost and the size of the emulsion-treating equipment.

Another economic balance to consider involves coalescence-promoting factors (e.g., chemicals, water wash, heat, and coalescing plates) and treating-vessel size. The larger the treating vessel, the smaller are the water droplets that are separable from the emulsion. Thus, using coalescing aids might reduce the required equipment size by increasing the size of the water droplet that must be separated from the oil to meet the required quality. Of course, the vessel-cost savings must be weighed against the increased capital and operating cost (e.g., fuel and increased maintenance because of plugging) of the coalescing aids.

For design purposes, bottle tests in the laboratory are useful for estimating treating parameters such as treating-temperature ranges, demulsifier volume, settling time, and retention time. Unfortunately, bottle tests are static in nature and do not model closely the dynamic effects of water droplet dispersion and coalescence that occur in the actual equipment because of flow through control valves, pipes, inlet diverters, baffles, and water-wash sections.

When evaluating empirical data from similar wells or fields, the designer should recognize that the emulsion-treatment temperature might not be as important as the viscosity of the crude oil at that temperature. By observing an existing system, knowing the viscosity of the crude oil at treating temperature, and calculating from the flow geometry and Stokes' law the minimum size of water droplet that can be settled from the crude oil, an oil-treating system can be designed that will heat the emulsion to the temperature required to obtain the same viscosity that exists in the sample field. Then the equipment described in the next section can be selected

and sized so that all water droplets that are larger than the calculated minimum diameter can be separated from the oil.

Because of the uncertainties in scaling up from laboratory data and inferring designs from empirical data from similar wells or fields, a new treating system should be designed with either larger equipment or more heat-input capacity than is calculated to be necessary. How much "overdesign" should be built into the treating system depends on how the cost of the extra capacity weighs against the risk of not being able to treat the design throughput.

Several types of equipment or systems might resolve an emulsion satisfactorily, but one might be superior to others because of design, operation, initial cost, maintenance cost, operating cost, and performance considerations. Of course, selecting the fewest pieces of equipment needed and/or the simplest design for each treating system will optimize initial and operating costs. In essence, use the combination of emulsion-treating methods that will provides the lowest chemical use, treating temperature, loss of light hydrocarbons, and overall treating cost, and the best performance. Furthermore, experience and empirical data are a guide as to the optimum combination, but field testing is required to confirm the selections.

Below are described emulsion-treating equipment and systems—FWKOs, storage tanks, settling tanks, vertical and horizontal emulsion treaters, and electrostatic coalescing treaters. Each treating system and its components are available in a wide variety of types, configurations, sizes, component selections and designs, and usages. The design and selection of all the components of a treating system should be made at the time of initial purchase and installation; however, because of the modular design of most emulsion-treating systems, if the selected equipment does not perform as desired or if operating conditions change, additional features usually can be added and/or operating procedures altered to obtain the desired results.

3.5.1 FWKOs. Where large quantities of water are produced, it usually is desirable to separate the free water before attempting to treat the emulsion. This is done using a separator known as an FWKO.

When oil and water are agitated moderately and then allowed to settle, three distinct phases normally will form: a top layer of essentially clean oil with a small amount of water dispersed as very small droplets, a bottom layer of relatively clean water (free water) with a small amount of oil dispersed as very small droplets, and a layer of emulsion in between. As coalescence occurs over time, the amount of emulsion will approach zero. The free water is the water that separates out in three to ten minutes. Free water still might contain small droplets of dispersed oil that might require treatment before disposal. (Equipment for that is discussed in the chapter on Water-Treating Facilities in Oil and Gas Operations in the Facilities Engineering section of the *Handbook*.)

FWKOs are designed as either horizontal or vertical pressure vessels, but predominantly horizontal. **Fig. 3.13** shows a horizontal FWKO. The fluid enters the vessel and flows against an inlet diverter. The sudden change in momentum causes an initial separation of liquid and gas, which prevents the gas from disturbing the settling section of the vessel. In some designs, the separating section contains a downcomer that directs the liquid flow to below the oil/water interface to aid in water-washing the emulsion.

The liquid-collecting section of the vessel provides time for the oil and emulsion to form a layer of oil at the top while the free water settles to the bottom. When there is appreciable gas in the inlet stream, a three-phase separator can be used as an FWKO. See the chapter on Oil and Gas Separators in this section of the *Handbook* for a description of vertical and horizontal three-phase separators.

A cone-bottom vertical three-phase separator is used when sand production is anticipated to be a major problem. The cone normally is at a 45 to 60° angle to horizontal. The cone can be the bottom head of the vessel or, for structural reasons, can be installed internally in the vessel. In the latter case, a gas-equalizing line must be installed to ensure that the vapor behind the

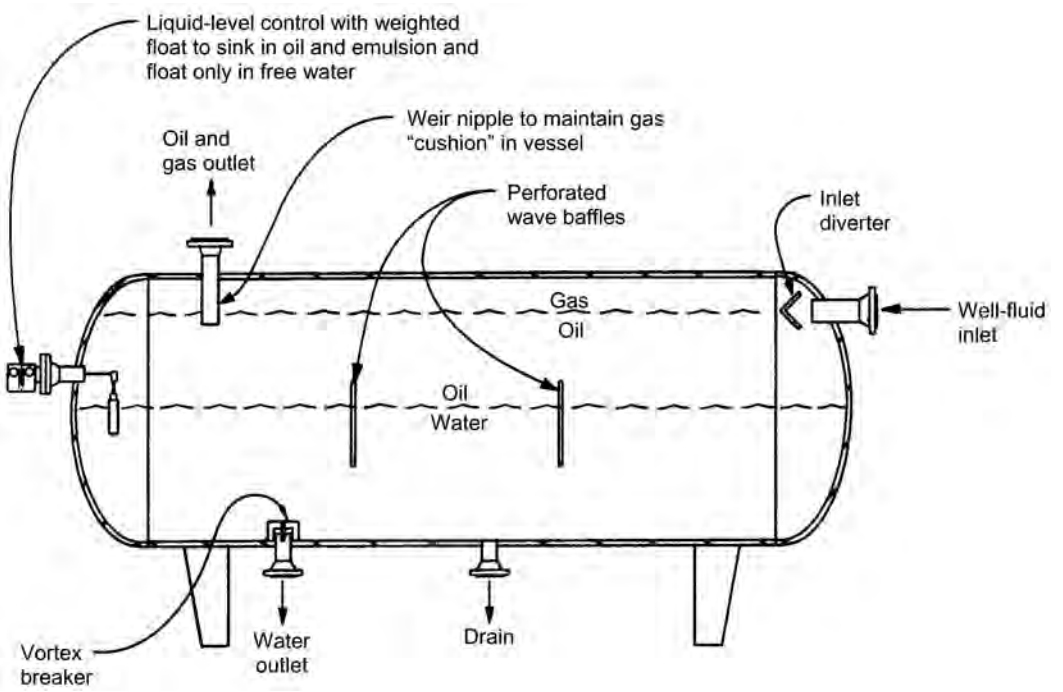


Fig. 3.13—Typical horizontal FWKO. (Courtesy of Energy Recovery Div., Daniel Industries Inc., Houston.)

cone always is in pressure equilibrium with the interior of the vessel. Water jets can be used to dislodge and flush the sand from the vessel.

Oil and water usually separate more quickly and completely in an FWKO when the liquid travels through the vessel horizontally rather than vertically. With vertical flow, the upward-moving stream of oil and emulsion retards the water's downward movement through it. Horizontal flow permits less-restricted downward movement of the water droplets.

It is possible to add a fire tube to an FWKO (Fig. 3.14) or to add heat upstream of the FWKO. In such cases, although the vessel might be called an FWKO, it actually performs the function of an emulsion treater.

Many configurations can provide baffles and maintain levels in an FWKO. A well-designed FWKO will perform the functions described above (i.e., degassing, water washing, and providing sufficient retention time and correct flow pattern for free water to be removed from the emulsion).

Once the free water has been removed, the oil might need further treatment. In many fields that produce light oil, a well-designed FWKO with ample settling time and an effective chemical-treating program can provide pipeline-quality oil; however, further emulsion treatment usually is required downstream of the FWKO.

3.5.2 Storage Tanks. Oil generally should be water-free before it is flowed into lease-storage tanks; however, if the oil contains only a small percentage of water and/or if the water and oil are loosely emulsified, the water could be allowed to settle to the bottom of the oil-storage tank and then be drawn off before oil shipment. This practice generally is not recommended or followed, but for small volumes of free or loosely emulsified water on small leases or for low-volume marginal wells, it might be a practical and economical procedure.

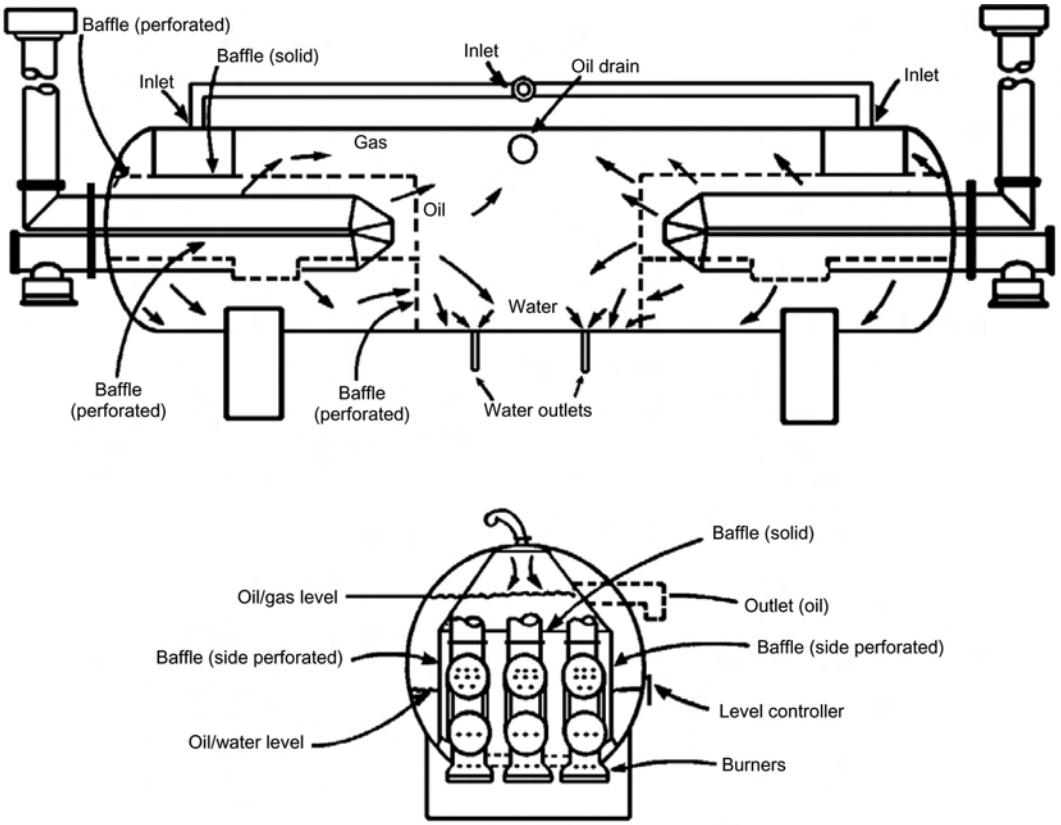


Fig. 3.14—Schematic view of FWKO with heating element in each end.[1]

When a storage tank is used for dehydration, the oil is flowed into the tank and allowed to settle. When the tank is full of liquid, flow into the tank is stopped or switched to another tank, and the full tank remains idle while water settles out of the oil. When the water has separated, it is drained from the bottom of the tank and the oil is gauged, sampled, and pumped or drained to a truck or pipeline. No water wash is used with the standard storage tank because its shallowness and the absence of a proper spreader would make a water wash of little or no benefit.

3.5.3 Settling Tanks. Settling tanks that are used to treat oil go by various names. Some of the most common names are gun barrel (named for the protrusion of its central flume), wash tank, and dehydration tank. Their design details differ from field to field and from company to company, but all contain most or all of the basic elements shown in **Fig. 3.15**.

In the separation tank, the emulsion enters a gas-separation chamber or gas boot where a momentum change causes separation of gas from the emulsion. Gas boots can be as simple as the piece of pipe shown in Fig. 3.15, or they can contain more-elaborate nozzles, packing, or baffles to help separate the gas. If there is much gas in the well stream, using a two- or three-phase separator upstream of the settling tank usually is preferable. In that case, the gas boot must separate only the gas that is liberated while the pressure decreases during flow from the separator to the settling tank.

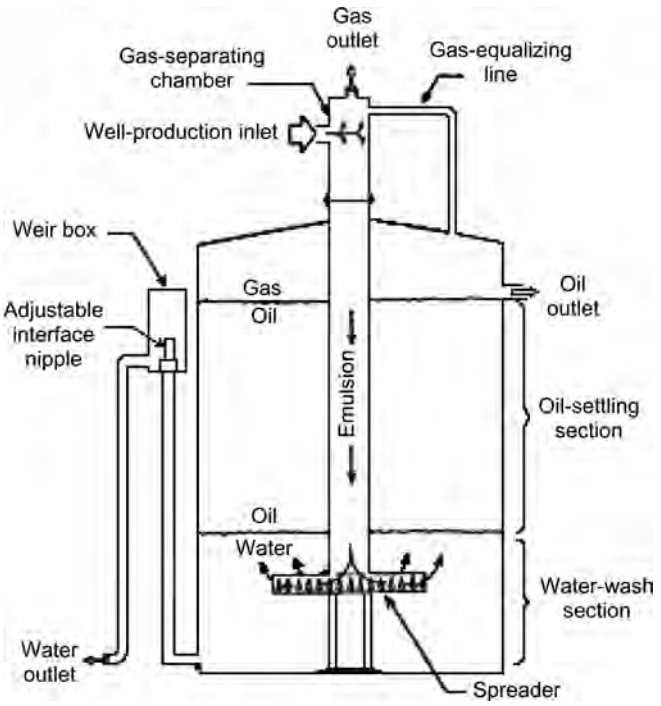


Fig. 3.15—Typical settling tank with internal downcomer (central flume) and emulsion spreader.[1]

A downcomer directs the emulsion below the oil/water interface to the water-wash section. Most large tanks minimize short-circuiting by using a spreader to distribute the flow over the entire cross section of the tank. The more the upward-flowing emulsion spreads out and approaches plug (or uniform) flow, the slower will be its average upward velocity and the smaller will be the water droplets that settle out of the emulsion.

There are many types of spreader design. Spreaders can be made by cutting slots in plate, using angle iron, or punching holes in pipe. By separating it into many small streams, the spreader increases the emulsion's intimate contact with the water and so promotes coalescence in the water-wash section (**Figs. 3.16 and 3.17**).

Most spreaders contain small holes or slots to divide the oil and emulsion into small streams. Large holes (3 to 4 in. in diameter) are much less effective at dividing the stream than small holes are (3/8 to 1 in. in diameter); however, a spreader should be designed so that it does not agitate the fluid so much that shearing of the water droplets in the emulsion takes place, causing the emulsion to become harder to separate. In addition, small holes become plugged with solids more easily and are difficult to clean.

As the emulsion rises above the oil/water interface, water droplets settle out from the oil by gravity. Because there might be very little coalescence above the oil/water interface, increasing the height of the oil-settling section above some minimum to help spread out the flow might not materially affect the outlet oil quality.

Sometimes oil collectors that are similar in design to oil spreaders are used to help establish plug flow. An oil collector must prevent vortexing and should collect oil from the top of the tank in a way that minimizes horizontal movement of the oil.

Some tanks discharge the water through a water collector that is designed to cause the flow of water to more nearly approach plug-flow conditions. The water outlet collector must prevent vortexing of the water and minimize horizontal movement of the water. The water outlet collec-

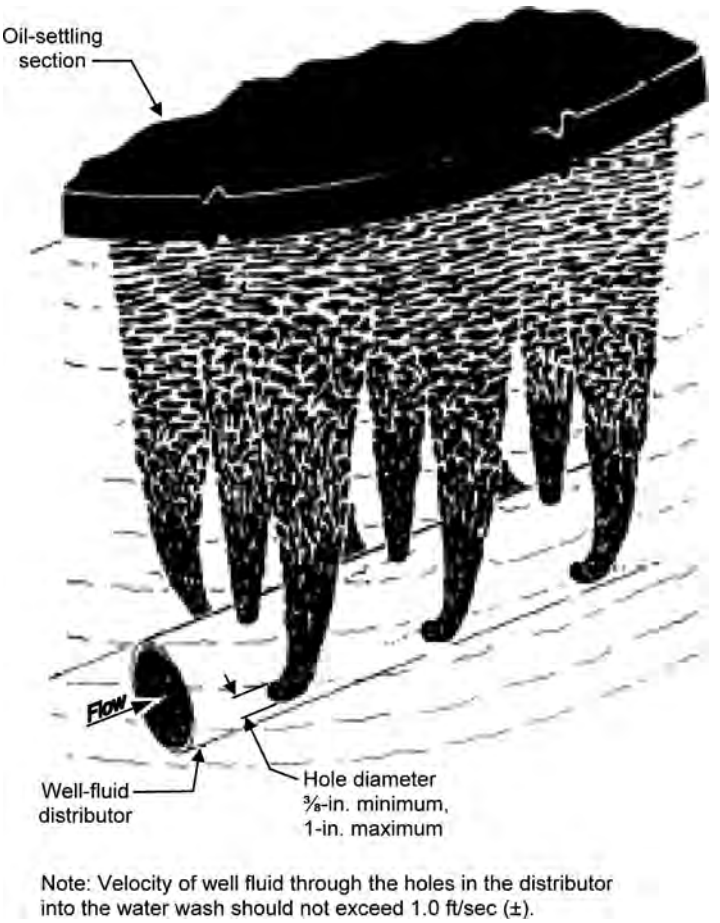


Fig. 3.16—Proper design of well-fluid inlet distributor for wash or gun-barrel tank, showing use of small holes in distributor (after Ref. 1).

tor should be located near the tank bottom. There must be enough vertical distance between it and the inlet spreader to allow sufficient clarification of the water, and it should be 6 to 12 in. above the tank bottom to allow for accumulation of sand.

Some tanks have elaborate sand-jetting and drain systems that sometimes are part of the water-collector system. Making these drains operate satisfactorily can be difficult because the water flow to each drain must be on the order of 3 ft/sec to suspend the sand. Sand drains might lengthen the time between tank cleanings, but the additional cost of sand drains in tanks might not be warranted.

In Fig. 3.15, the oil/water interface is established by an external adjustable weir, sometimes called a water leg. The height of the interface is determined by the fluid properties and by the difference in height between the oil outlet and weir. It may be calculated from Eq. 3.5:

$$h_{wd} = (h_{oo} - h_{ww})\frac{\gamma_o}{\gamma_w} + h_{ww}\ , \quad \text{..... (3.5)}$$

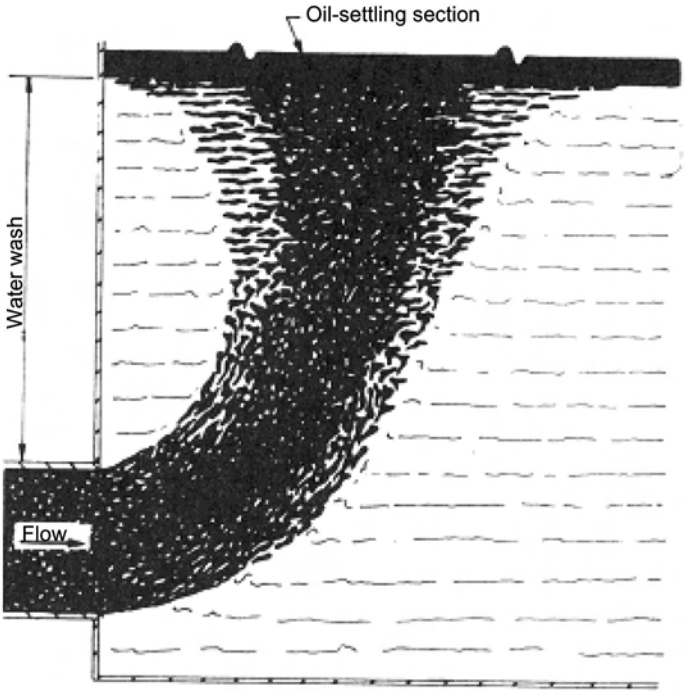


Fig. 3.17—Improper design of well-fluid inlet for wash or gun-barrel tank (after Ref. 1).

where h_{wd} = the height of water draw-off overflow nipple in the weir box above the tank bottom, ft; h_{oo} = the height of the clean oil outlet above the tank bottom, ft; h_{ww} = the desired height of the water wash in the tank above the tank bottom, ft; γ_o = the specific gravity of the oil; and γ_w = the specific gravity of the water.

Water legs are used successfully for emulsions where the gravity is above 20°API and there is sufficient difference in gravity between the oil and water. Marginal performance is obtained on oil between 15 and 20°API. Below 15°API, water legs normally are not used.

It also is common to control the oil/water interface with internal weirs or with an interface liquid-level controller and a water-dump valve. In heavy oils, electronic probes most often are used to sense the interface and operate a water-dump valve. In lighter oils, interface floats that sink in the oil and float in the water are more common.

Not all settling tanks contain all the sections and design details described so far. Which ones are used depends on the overall process selected for the facility, the emulsion properties, the flow rates, and the desired effluent qualities. Fig. 3.15 is representative of the majority of settling tanks currently in use, but some tanks have a different flow pattern. A series of parallel vertical baffles from the bottom of the vertical tank to above the oil level (**Fig. 3.18**) cause the flow of the emulsion to be largely horizontal rather than vertical, so that the water droplets fall at right angles, rather than countercurrent, to the oil flow. Some settling tank designs use a vortex or swirling motion at the inlet of the tank to aid in coalescence and settling and to minimize short-circuiting. Many settling tanks help the treatment process by adding heat to the liquid using a direct heater, an indirect heater, or a type of heat exchanger.

A direct-fired heater, sometimes referred to as a "jug" heater, is one in which the fluid to be heated comes in direct contact with the immersion-type of fire tube or heating element. Direct-fired heaters generally are used to heat low-pressure, noncorrosive liquids. These units normally are constructed so that the fire tube can be removed for cleaning, repair, or replacement.

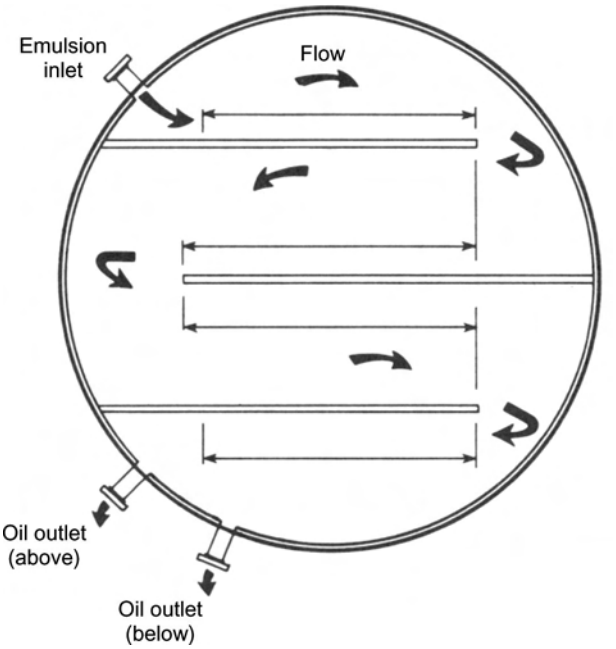


Fig. 3.18—Plan view of vertical tank with horizontal flow settling pattern.[1]

An indirect-fired heater is one in which the fluid passes through pipe coils or tubes that are immersed in a bath of water, oil, eutectic salt, or another heat-transfer medium that, in turn, is heated by an immersion-type fire tube that is similar to the one used in the direct-fired heater. Convection currents cause the contents of the bath of an indirect-fired heater to circulate. The immersion-type fire tube heats the bath, which heats the fluid that is flowing through coils that are immersed in the bath. When water is used as the bath, using water that is free of impurities will prolong the heater's life and prevent fouling of the surface of the fire tube and coils.

Indirect-fired heaters are less likely to catch fire than are direct-fired heaters and generally are used to heat corrosive and high-pressure fluids. They usually are constructed so that the fire tube and pipe coil are individually removable for cleaning and replacement. Indirect-fired heaters tend to be more expensive than direct-fired heaters.

Heat exchangers normally are used where waste heat is recovered from an engine, turbine, or other process stream or where fired heaters are prohibited. In complex facilities, especially offshore, a central heat-transfer system recovering waste heat and supplying it through heat exchangers to all process heat demands sometimes is more economical and might be the only way to meet established safety regulations.

Heating the entire stream of emulsion before it enters the settling tank is advantageous because:

• After the fluid is heated, it flows through piping and into the flume pipe or gas boot of the gun-barrel tank. This moderate agitation of the heated fluid can help water droplets to coalesce.

• The emulsion is heated before it reaches the gun barrel, which aids in removing gas from the oil in the gas boot. This helps maintain quiescence in the settling portion of the gun barrel.

• The heater and gun barrel can be sized independently, which allows flexibility in sizing the system.

• Water-wash volume in the gun barrel can be adjusted over a wide range, providing additional flexibility.

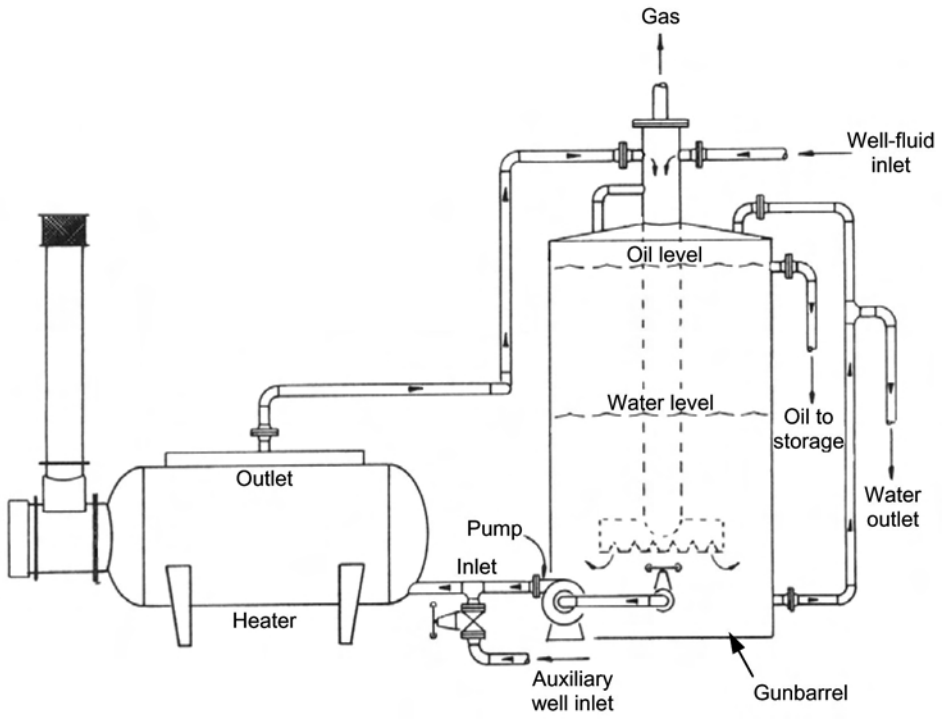


Fig. 3.19—Heater and gun barrel in forced-circulation heating method. (Courtesy of Energy Recovery Div., Daniel Industries Inc., Houston.)

• Continuous flow of fresh fluids through the heater tends to prevent coking and scaling and helps to keep the heating surface clean, which will prolong the heater's life.

Heat can also be supplied to the system by circulating the water in the water-wash section to a heater and back to the tank. The hot-water-wash section warms the incoming emulsion. A thermosiphon caused by density differences between the hot and the cold water can serve as the driving force for the circulation if the heat source is not far from the tank.

The water also may be pumped to the heater and circulated back through the flume, as shown in **Fig. 3.19**. In this system, the settling space in the gun barrel might be disturbed by gas released from the oil when it contacts the hot water. It has two advantages. First, the oil will not be overheated because it is heated by the water bath in the gun barrel and never contacts the heating element in the heater. This minimizes vapor losses from the oil and helps to maintain maximum oil gravity. It also minimizes coking and scaling. Second, this system is as safe from fire hazards as a system involving a fired vessel can be because only water flows through the heater. There is no oil or gas in the fired vessel.

Gun-barrel tanks also can be heated directly with a fire tube, as shown in **Fig. 3.20**, or with internal heat exchangers, using steam or other heat media. A fire tube is a U-tube direct-heating device that is inserted into a liquid to heat it. Heat exchangers can be either pipe coils or plate-type heating elements.

Most plate-type heating elements are 18 to 32 in. wide and 5 to 8 ft long. They usually are preferred over pipe coils because when they are immersed in oil, their heat-transfer coefficient is 10 to 20% higher than that of a corresponding area of pipe. Further, the gentle agitation from the convection flow of the oil up the surface of the plate-type element assists in coalescence. Plate-type heating elements are available with a wide range of pressure ratings. They

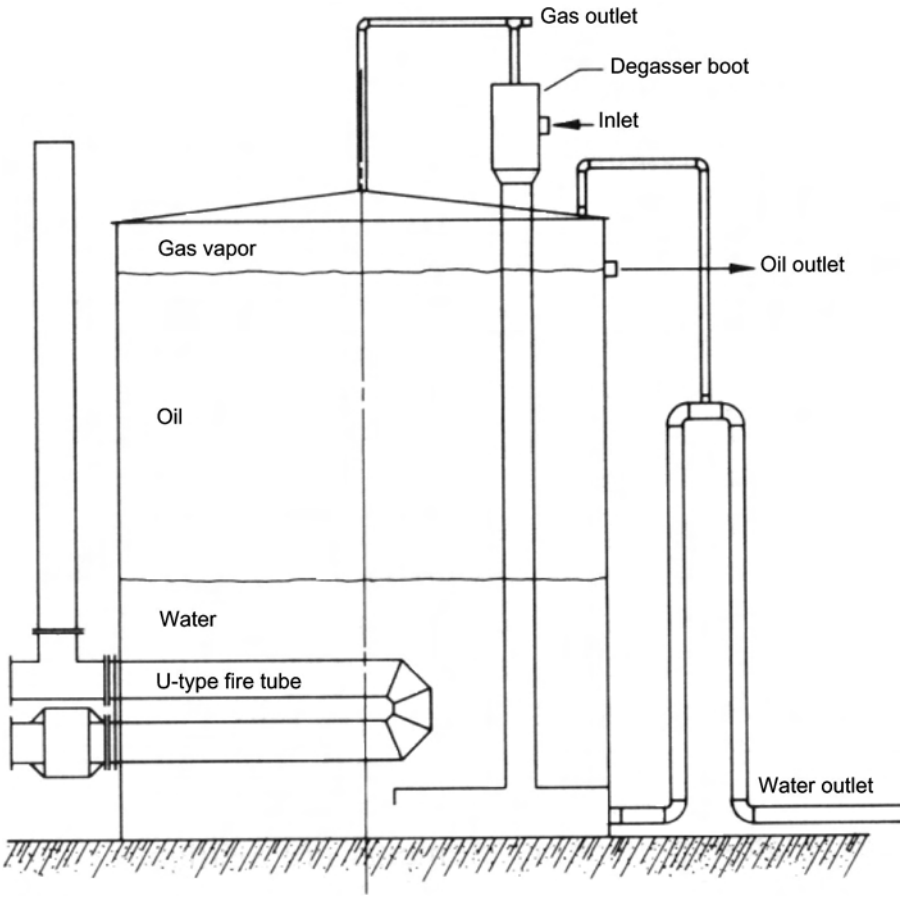


Fig. 3.20—Heated gun-barrel emulsion treater. (Courtesy of Natco Group Inc.)

can be purchased for steam service or hot-water service, but the same unit should not be used for both because the construction of the cells is different for these two heating media.

Pipe coils are popular because the materials used in their construction usually are available locally; however, they normally cost slightly more than plate-type exchangers, especially in larger installations.

When heated directly, settling tanks operate in a fashion similar to vertical and horizontal emulsion treaters.

3.5.4 Vertical Emulsion Treaters. The vertical unit is the most commonly used one-well-lease emulsion treater. In a typical vertical design (**Fig. 3.21**), flow enters into a gas separation section near the top of the treater. This section must be sized adequately to separate the gas from the liquid. If the treater is downstream of a separator, this section can be very small. The gas separation section should have an inlet diverter and a mist extractor.

The liquid flows through a downcomer to the bottom portion of the treater, which serves as an FWKO and water-wash section. If the treater is downstream of an FWKO, the bottom section can be very small. If the total wellstream is to be treated, the bottom section should be sized for sufficient retention time to allow the free water to settle out. This will minimize the amount of fuel gas needed to heat the liquid that rises through the heating section.

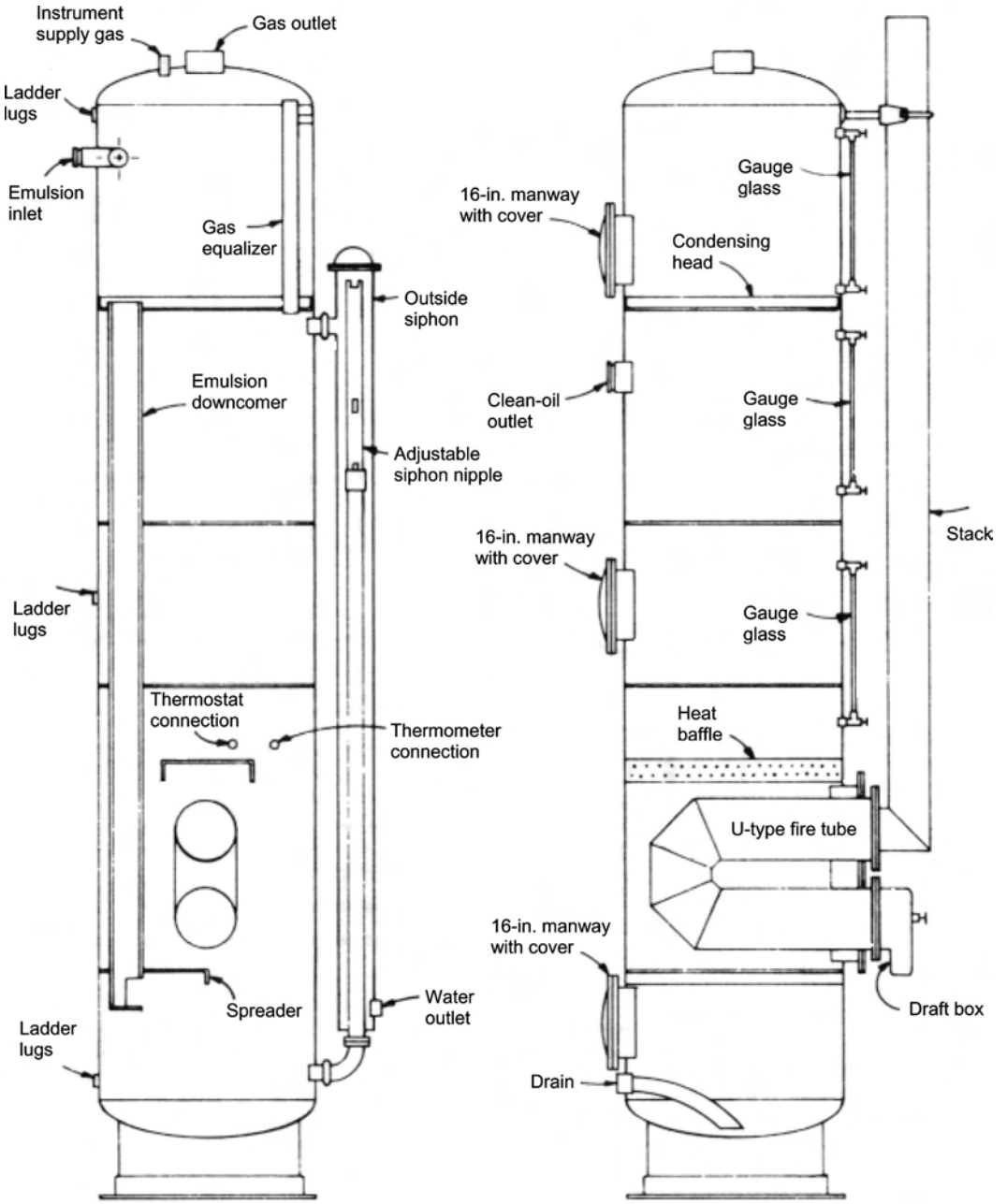


Fig. 3.21—Schematic view of typical vertical emulsion treater. (Courtesy of Natco Group Inc.)

The oil and emulsion flows upward around the fire tubes to a coalescing section that provides sufficient retention time to allow the small water droplets to coalesce and to settle to the water section. Treated oil flows out the oil outlet. Any gas that is flashed from the oil because of heating flows through the equalizing line to the gas space above. Pneumatic or lever-operated dump valves maintain the oil level. An interface controller or an adjustable external water leg controls the oil/water interface.

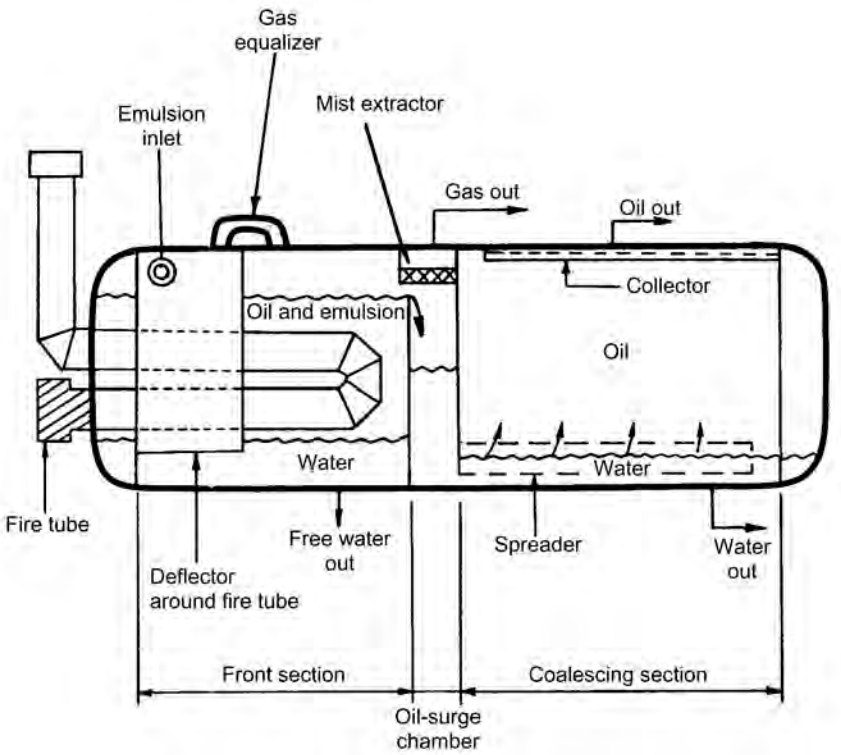


Fig. 3.22—Typical horizontal emulsion treater with vertical flow.[1]

Steam must be prevented from forming on the fire tubes. This can be done by using the "40° rule" (i.e., keeping the operating pressure equal to the pressure of saturated steam at a temperature that is equal to the operating temperature plus 40°F). In most treaters, the normal full-load temperature difference between the fire tube wall and the surrounding oil is approximately 30°F. The 40° rule, then, is desirable because it prevents flashing of steam on the wall of the fire tube and provides a 10°F safety margin.

Baffles and spreader plates may be placed in the coalescing section of the treater above the fire tubes. Originally, many treaters were equipped with excelsior or "hay" packs. In most applications, these might not be needed, but a manway may be provided in case a hay pack needs to be added in the field. Excelsior packs largely have been replaced with other coalescing media because of difficulties with disposal of the used excelsior.

Fig. 3.21 shows a treater with a fire tube, but it also is possible to use an internal heat exchanger to provide the required heat or to heat the emulsion before it enters the treater. For safety reasons, some offshore operators prefer a heat-transfer fluid and a pipe or plate heat exchanger inside the treater, rather than a fire tube.

3.5.5 Horizontal Emulsion Treaters. For most multiwell leases, horizontal treaters normally are preferred. **Fig. 3.22** shows a typical horizontal treater design. Flow enters the front section of the treater where gas is flashed. The liquid flows downward to near the oil/water interface, where it is water-washed and the free water is separated. Oil and emulsion rise past the fire tubes and flow into an oil-surge chamber. The oil/water interface in the inlet section of the vessel is controlled by an interface-level controller, which operates a dump valve for the free water.

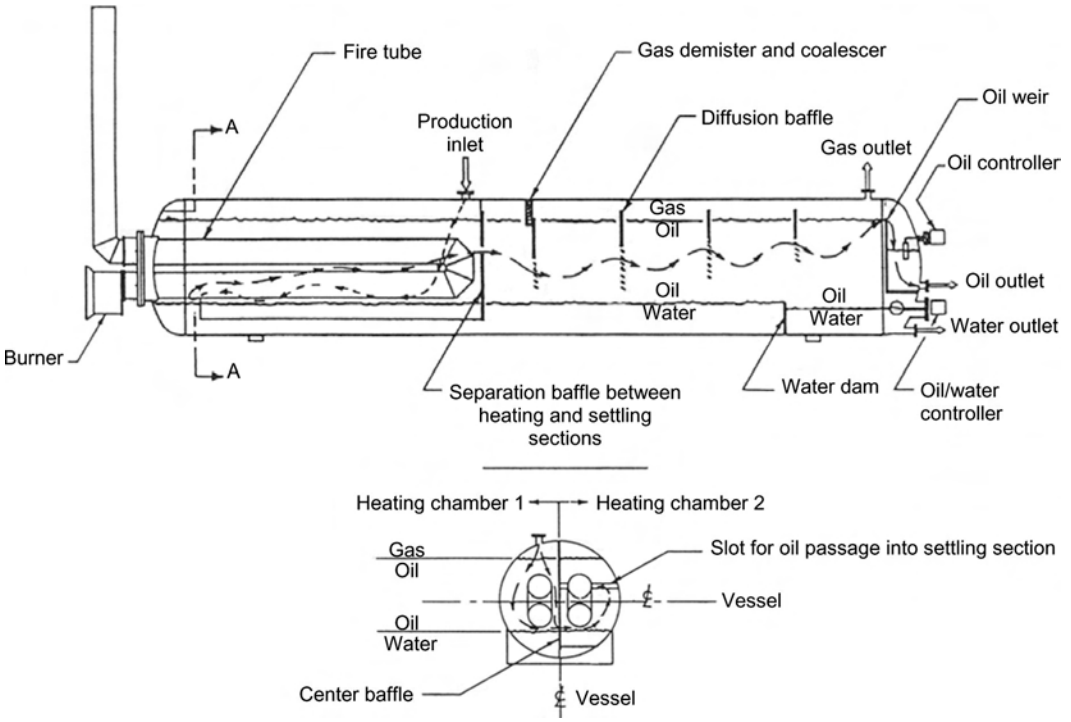


Fig. 3.23—Horizontal emulsion treater with horizontal flow. (Courtesy of Hydrocarbon Research Inc., Long Beach, California.)

The oil and emulsion flow through a spreader into the back, or coalescing, section of the vessel, which is liquid-packed. The spreader distributes the flow evenly throughout the length of this section. Treated oil is collected at the top through a collection device that is used to maintain uniform vertical flow of the oil. Coalescing water droplets fall through the rising oil. The oil/water interface level is maintained by a level controller and dump valve for this section of the vessel.

A level controller in the oil surge chamber operates a dump valve on the oil-outlet line, regulating the flow of oil out the top of the vessel and maintaining a liquid-packed condition in the coalescing section. Gas pressure on the oil in the surge section allows the coalescing section to be liquid-packed.

The inlet section must be sized to handle separation of the free water and the heating of the oil. The coalescing section must be sized to provide adequate retention time for coalescence to occur and for the coalescing water droplets to settle through the upward-flowing oil.

Fig. 3.23 shows another design of a horizontal emulsion treater with a different flow pattern, one that minimizes vertical flow of the emulsion. In this treater design, oil, water, and gas enter the top of the treater at the left side (facing the burners) and travel frontward and downward. Gas remains at the top, and oil and water are heated as required. Some heat is applied to the water in this section, but because this section has its own temperature controller, its temperature can be adjusted for optimum performance.

The cross section in Fig. 3.23 shows that the emulsion flows under a longitudinal baffle and through a large slot in the partition plate near the front of the treater at the bottom of the fire tube, where it is water-washed. In the right-side compartment of Section A-A, the oil and emulsion flow longitudinally up across the fire tube.

The separation baffle between the heating and settling sections blocks the passage of foam at the top and of emulsion at the bottom. Heated oil travels through a slot in a partition at approximately the centerline of the top fire tube. Free water is allowed to travel under the baffle. Accumulating emulsion at the interface rises to touch the fire tube, which is only 6 in. above the interface. The fire tube heats the emulsion pad, enhancing its coalescence, thereby maintaining a uniform emulsion-pad thickness.

Applying louvered or perforated baffles reduces channeling, skimming, and stratifying. Louvered baffles are stainless-steel sheets that are punched with a louvered pattern that ranges from 15 to 60% open area. They are solid at the top to prevent foaming, or skimming, and extend downward almost to the water. All the emulsion goes through the openings, which impede flow slightly to develop even flow distribution and help coalescence.

A weir and an oil box maintain the oil level in the treater. Water level in the treater is critical; thus, a weir is placed approximately 5 ft from the rear head seam to maintain the oil/water-interface level upstream of it. Adjusting the water-level controller that is downstream of this weir has no effect on the water level in the main treater body upstream of the weir.

Because the emulsion flow path in this design is essentially horizontal, the water particles are not opposed by the upflowing oil, as they are in a treater with a vertical flow pattern. This is especially important in heavy crudes, where the differential specific gravity between oil and water is small and where the settling velocity is low.

Other flow patterns are available if different baffle designs are used in horizontal treaters. The vertical and horizontal flow patterns described above are examples that illustrate the most generally applied concepts. Other methods for heating the emulsion can be used if it is desirable to eliminate the fire tubes.

3.5.6 Electrostatic Coalescing Treaters. ***AC Field Devices.*** The first applications of electrically induced flocculation used AC fields in the 12- to 23-kV range. The rapid reversal of polarity in an AC system (every 8.3 milliseconds with 60 Hz power) causes electrically induced corrosion reactions to remain reversible because the reaction products do not have time to diffuse away from the reaction site; however, the rapid reversal of the electrical field also precludes significant drop travel because of electrical forces. The flocculating effect of an AC field is caused by the stretching deformation from the polarization of the water drops. Because adjacent ends of two water drops are oppositely polarized, an attractive force exists that can cause coalescence if the drops are very close together (Fig. 3.24). The dipolar attractive force between drops of equal size can be expressed as follows after simplifying by incorporating typical values for the dielectric constants of water and oil:[9]

$$F = \frac{70\varepsilon E^2 r^6}{d_i^4}, \quad \text{..... (3.6)}$$

where F = the force of attraction, N; ε = dielectric constant, $C^2/N{\cdot}m^2$; E = the electric field gradient; V/m; r = the drop radius, m; and d_i = the interdrop distance, m.

This equation illuminates the advantages and the weaknesses of an AC field in electroflocculation. Note that the dipolar attractive force depends highly on drop size (as the sixth power exponent testifies), with limited benefit in the coalescence of small drops. Also note the rapid decline in dipolar force with interdrop distance. In an AC field, the efficacy of electroflocculation depends on the ability of diffusion and fluid flow to bring dispersed water drops into close proximity. The AC field is most effective at removing large drops that are close together, and does not significantly affect very small drops; therefore, the AC field is most effective on the high-water-content emulsion at the inlet of a separation vessel and on the collection of large

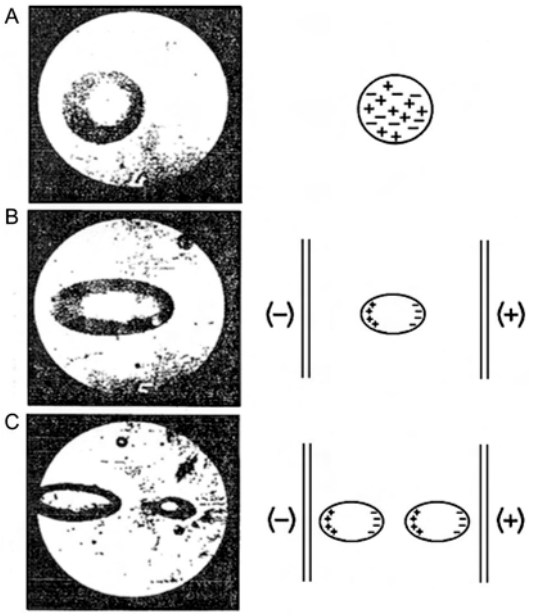


Fig. 3.24—Response of a water drop to an electrostatic field when (A) no field is applied, (B) a moderate field is applied, and (C) an intense field is applied with some drop shattering produced. (Courtesy of Natco Group Inc.)

drops that accumulate at the oil/water interface. The oscillating elongation of the drops produced by the AC field also ruptures whatever stabilizing films might have formed, which is particularly advantageous for resolving slowly condensing dispersions in the zone of hindered settling at the oil/water interface.

AC treaters usually use an arrangement of charged horizontal bar gratings or grids to establish the electric field within the vessel. A two-grid system, known as "single hot" AC, uses a lower, charged grid and an upper, grounded grid that are separated by 6 to 8 in. (sometimes adjustable) (**Fig. 3.25**). The incoming oil is introduced near the oil/water interface and flows upward through the grids to an outlet collector. The water layer also is grounded through the shell of the vessel. An AC field then is established between the water and the charged grid and between the charged grid and the grounded grid. Oil flows across both of these fields as it transits the vessel.

Newer designs, known as "double hot" and "triple hot" AC systems, use multiple charged grids to improve efficiency and throughput. A technique known as "high-velocity" AC also is used to spread the incoming emulsion between the energized electrodes. All these variations serve to increase the retention time of the dispersion within the most intense zone of the electric field, and they depend on diffusion to carry polarized drops within the range of dipolar forces (**Fig. 3.26**).

There is a limit to the usable field strength for coalescence. At very high field strengths, enough energy is imparted to the drops to induce shattering rather than coalescence. This instability limit is described by the following proportionality:[10]

$$E_c \le \varepsilon\left(\frac{\sigma}{d}\right)^{0.5}, \quad \text{..... (3.7)}$$

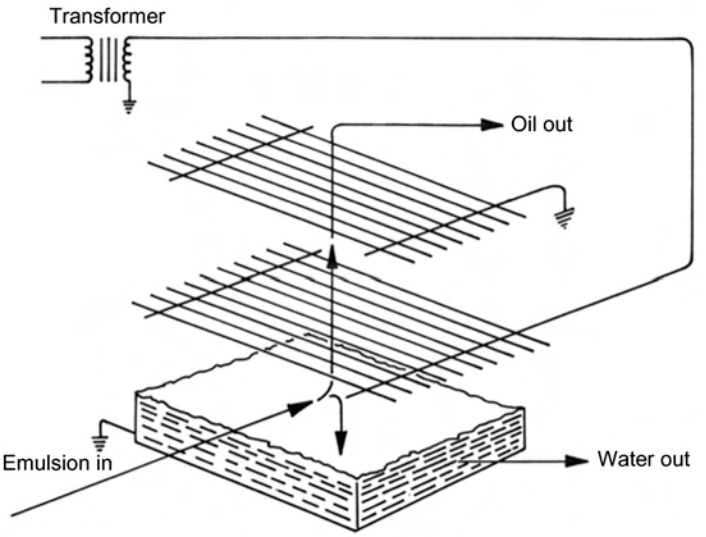


Fig. 3.25—A conventional AC electrostatic dehydrator. (Courtesy of Natco Group Inc.)

where E_c = the critical voltage gradient, V/m; ε = the dielectric constant, $C^2/N \cdot m^2$; σ = the interfacial tension, N/m; and d = the droplet diameter, m.

Transformers for AC treating usually are built with at least 16 and 23 kV secondary taps (connections to the secondary coil to allow the use of different output voltages). Single-phase transformers usually are used with multiple transformers that are wired for load balancing on large installations. In some cases, three-phase transformers are used with multiple grids that are wired to accept different phases. To protect the transformers during process upsets, an internal reactor equal to 100% of the transformer reactance is placed in series with the primary winding. As the load on the transformer increases, the voltage across the inductor increases, limiting the current to the transformer. A transformer with 100% reactance can tolerate a short circuit on its secondary output without overheating. An unfortunate side effect of this protection scheme is that when the process is most in need of power, the reactor prevents the transformer from delivering it.

Extended retention time in the high-intensity field also can be achieved by using an electrode array of vertically hung parallel plates with alternate plates that are charged and grounded (plate AC). Another benefit of this geometry is that it reduces electrical retardation of the settling water drops because the electrostatic field is perpendicular to the fluid flow. This technique has proved useful as the first stage of multistage systems in which the feed stream contains high levels of dispersed water.

Table 3.2 summarizes AC configurations and applications.

Combination AC/DC Treaters. In a DC field, the electrical forces are sustained and unidirectional, so that polarized drops can move along the lines of force of the field. For many years, the potential for galvanic corrosion when a DC field is impressed across a conductive liquid made DC fields applicable only to treatment of refined oils with high resistivity. In an AC field, the rapid reversal of polarity causes corrosion reactions to remain reversible, with no resultant net corrosion. In the early 1970s, a system was developed for combining the freedom from galvanic corrosion of the AC coalescer with the advantages of drop transport of the DC system.[11]

This device's electrodes are parallel plates that are connected to oppositely oriented diodes, so that alternate plates are oppositely charged. Because both diodes are connected to the same

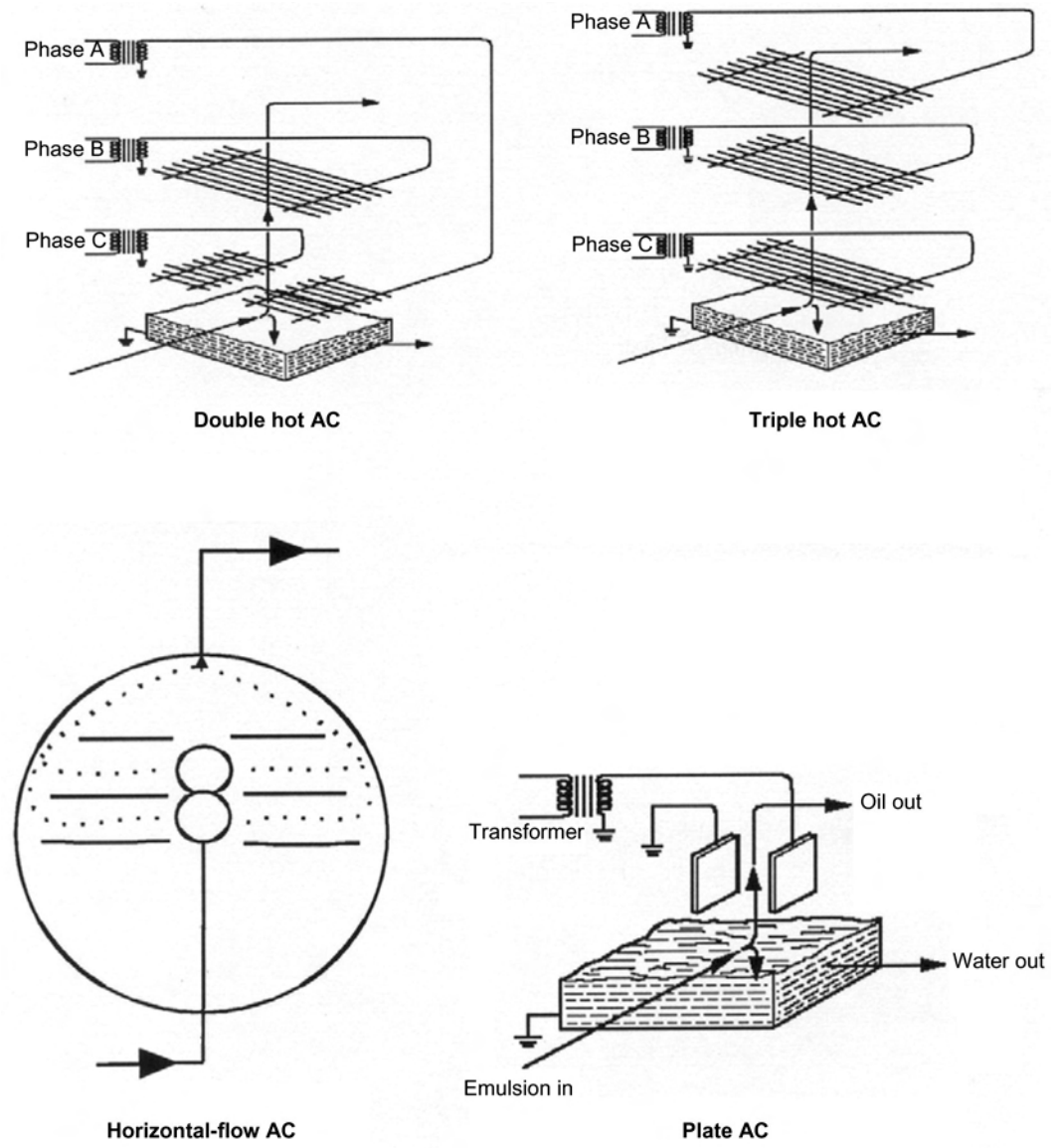


Fig. 3.26—Improved AC dehydrators that incorporate increased field depth. (Courtesy of Natco Group Inc.)

end of the transformer secondary winding, the plates are charged on alternate half cycles of the AC power supply (**Fig. 3.27**). The other end of the secondary winding is connected to ground, so that the electric field that is projected from the electrode array to the vessel remains AC. Also, the AC field still is available at the oil/water interface to assist in condensation of the settling dispersion, as well as to provide coalescence and settling of the loosely dispersed water fraction of the incoming crude oil.

The DC field then is available to supply translational energy to the very small drops, which approach the nearest plate, become charged, and are either coalesced onto the film on the electrode or repelled toward the opposite plate, to collide with its oppositely charged drops. Rapid coalescence ensues. Because the plates can only charge on alternate half cycles, the current between them is limited to discharge of capacitively stored energy and is unable to produce

TABLE 3.2—SUMMARY OF AC CONFIGURATIONS AND APPLICATIONS

Application	Field and refinery dehydration or desalting systems, particularly where inlet water concentration is high or outlet salt requirements are moderate.
Strengths	• Provides dipolar attraction for coalescence. • Disrupts stabilizing films by stretching action. • Tolerates relatively large water concentrations. • Assists in condensation of interface band dispersions.
Weaknesses	• Very limited drop movement. • Short-range attractive forces. • Low charge density on drops yields small attractive forces. • Little influence on small drops. • Electrostatic instability limits use of high-strength fields. • Depends on diffusional movement for coalescence of residual water.
Experience	Hundreds of units deployed in oilfield and refinery dehydration/desalting worldwide.
Improvements	Any of the configurations that increase retention in the high-intensity zone of the electrostatic field will improve performance.

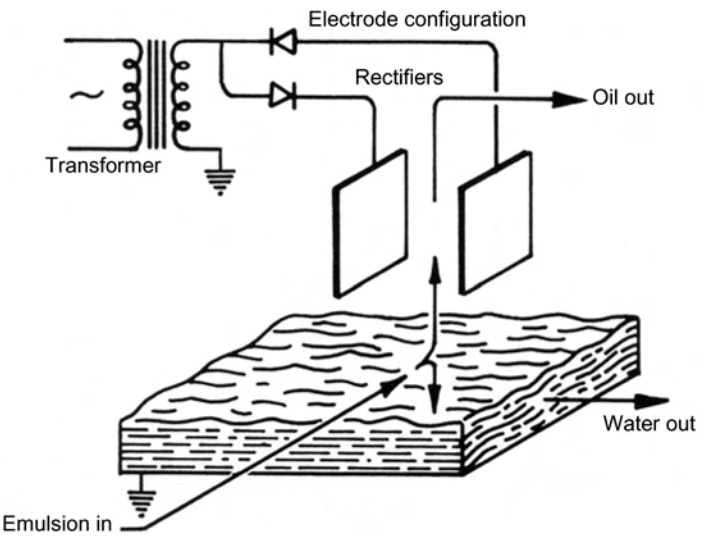


Fig. 3.27—Combination AC/DC dehydrator. (Courtesy of Natco Group Inc.)

significant electrolysis. These plates also are operating in relatively dry oil, which further limits current dissipation from them. This system is used widely for dehydration and desalting.

Transformers for AC/DC treaters are like those used for AC treaters, but also have an oil-filled secondary junction box that houses the diode packs.

Table 3.3 summarizes AC configurations and applications.

Combination Electrostatic/Mechanical Dehydrators. Fig. 3.28 shows a combination electrostatic/mechanical dehydrator that uses electrostatic and mechanical coalescing mechanisms. The

TABLE 3.3—SUMMARY OF AC/DC CONFIGURATIONS AND APPLICATIONS

Application	Refinery and oilfield dehydration/desalting systems that require dehydration to lower levels.
Strengths	• Dipolar attractive forces. • High charge density because of charge transfer to drops. • Electrostatic attraction beyond dipolar forces. • Produces drop transport rather than relying on diffusional movement. • Remains effective in coalescence of residual water. • Sustains higher flux because of increased coalescence. • Disrupts stabilizing films. • Reverts to AC mode during severe process upsets.
Weaknesses	• Maximum field strength dictated by electrostatic instability limit. • Loses DC component during severe process upsets.
Experience	More than 2,000 in use for dehydration and desalting applications in refineries and oil fields worldwide.
Improvements	Can be fitted with composite electrodes for high water tolerance and with a voltage controller for difficult or conductive oils. May be operated in pulsed mode to obtain maximum coalescence with difficult feed streams and to preserve effectiveness during process upsets.

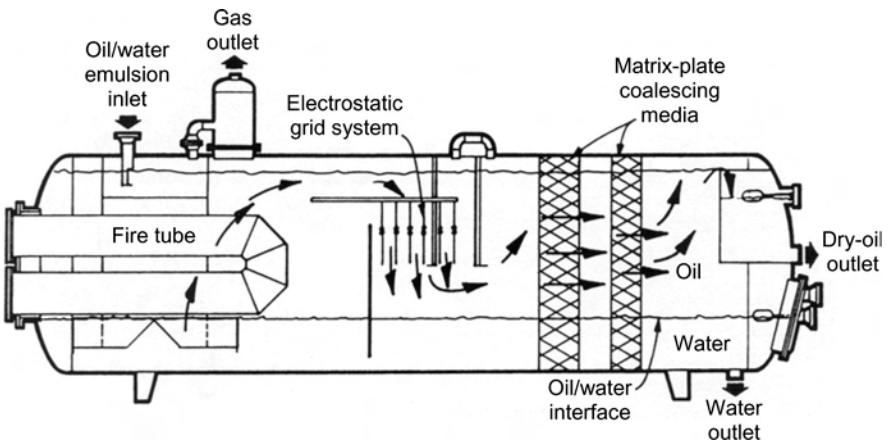


Fig. 3.28—An electromechanical heater-treater (dehydrator). (Courtesy of Natco Group Inc.)

electrostatic section is constructed like an AC/DC coalescer, but with two major differences: the flow through the electrodes is downward, and the flux is higher than with normal sizing criteria. These changes cause a downward acceleration on the settling water drops and a residual electrostatic charge on the drops after they move out of the electrode area. The liquids then flow horizontally through a matrix-plate coalescing section. The residual charge on the drops causes an attraction between the drops and the coalescing medium, thereby producing rapid coalescence.[12]

Table 3.4 summarizes available electrostatic/mechanical dehydrator configurations and applications.

TABLE 3.4—SUMMARY OF ELECTROSTATIC/MECHANICAL-DEHYDRATOR CONFIGURATIONS AND APPLICATIONS

Application	Oilfield crude oil dehydration systems for treating heavy or difficult emulsions, particularly where heat is limited or chemical usage is high.
Strengths	• Combines the coalescing forces of electrostatic and mechanical processes. • Voltage controller provides most efficient use of electrostatic field, with minimal upsets. • AC/DC field provides superior coalescence. • Composite electrodes provide high degree of water tolerance. • Sedimentation in concurrent flow minimizes adverse viscosity effects.
Weaknesses	• SCRs in transformer limit maximum primary voltage. • Voltage controller panel must be mounted within 1,500 ft of transformer. • Insoluble hydrocarbons (waxes, asphaltenes) can necessitate periodic cleaning of coalescer matrix-plate section.
Experience	Units now are in service in Canada and Russia on oils ranging from 12 to 39°API and with time in service up to 20 years.

Pulsed Field Treaters. Treaters may be fitted with a power supply that has a voltage controller. The controller combines a 35% reactance transformer with an electronic device that senses the load being drawn and adjusts the power to the transformer accordingly.[13] The power adjustment is made by silicon-controlled rectifiers (SCRs), which switch the power on and off rapidly so that very short bursts of high power are interspersed with "off" periods. Therefore, the transformer does not exceed its average heat dissipation rating. This allows power to be delivered to the process under upset conditions without compromising the integrity of the power supply. The controller also can be programmed to modulate power to the process.

This controller's action differs from a 100% reactor in that it reduces power on the basis of time rather than by variation of maximum voltage. Short bursts of high-intensity energy are applied to the emulsion with the duration of the pulses limited to maintain an average power output within the rating of the transformer. Research[14] indicates that much of the coalescing action of an electric field occurs during the rapid change of voltage with time (high dV/dt) during an electrical pulse; therefore, much of the electric field's coalescing ability is preserved during this pulsing action. The controller also allows programming of various electric-field vs. time profiles for cyclical operations.

Counterflow Desalters. Manipulating the drop-size/field-strength relationship allows the electric field to be used both to mix and to separate. Drops of dilution water that have been subjected to high field strength can be sheared to uniform sizes by the combination of translational shear and shattering because of charge-density instability. Then, as the field strength is lowered, they coalesce with the entrained brine and settle out (**Fig. 3.29**).

Because most of the contact between the brine and the dilution water occurs while they are coalesced together, multiple coalescence events contribute much more to contact efficiency than does greater shear in a mechanical device. Cycling the field strength allows the process to be repeated many times during the retention time of the drops within the electric field. As a result, the contact efficiency of a multistage mixer/settler can be realized using a single vessel.[15] Because the electrical force is concentrated on the dispersed phase, loss of energy because of shear of the continuous phase is reduced. Turndown and low dilution-water flow rates are readily accommodated.

Unlike conventional systems, which are restricted to concurrent flow by the nature of the mixing device, the electrostatic mixing system operates with countercurrent contact between the

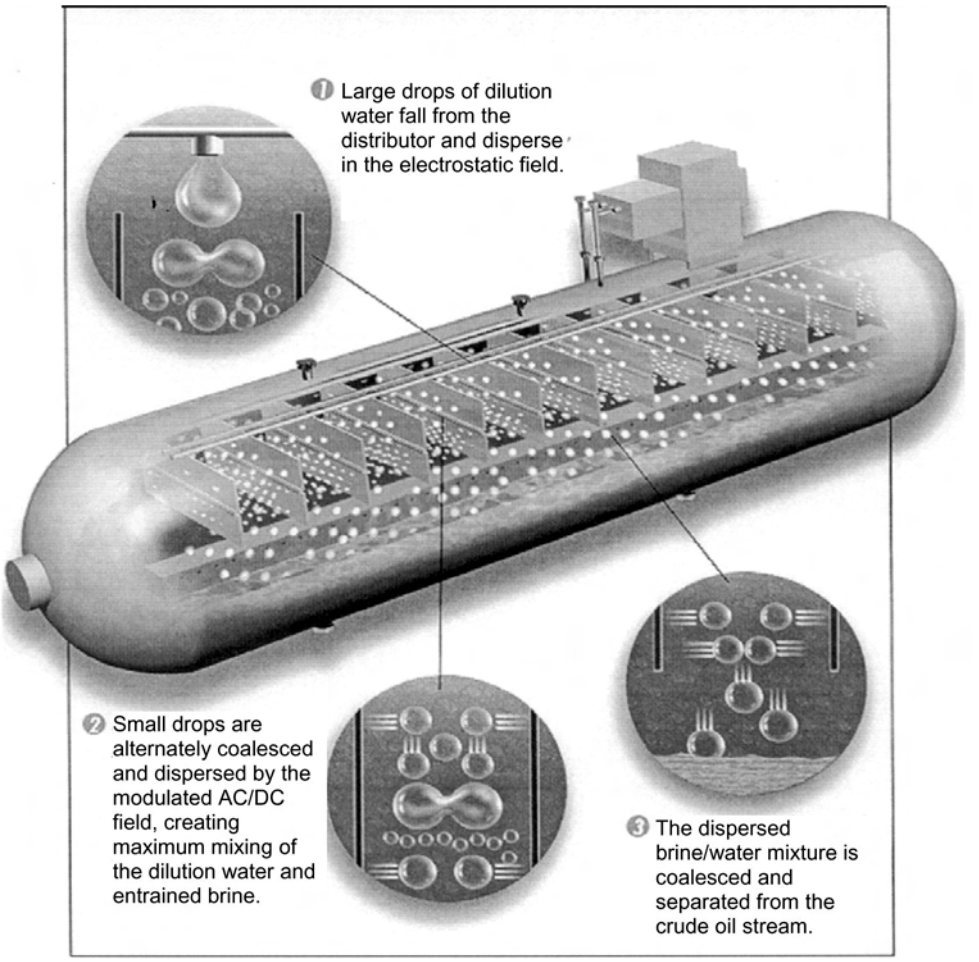


Fig. 3.29—Counterflow desalter showing the effect of the field on dilution water drops. (Courtesy of Natco Group Inc.)

dilution water and the crude oil. Countercurrent flow provides contact between the freshest water and the cleanest oil, which ensures maximum effectiveness of the dilution water. This flow pattern also places fresh water near the outlet, so that inadvertent carry-over will be free of salt.

A counterflow desalter such as the one in **Fig. 3.30** incorporates field-strength control, electrostatic mixing, and countercurrent flow. It uses composite electrodes and a voltage controller, both of which have been used effectively and reliably in oilfield dehydration systems for many years.

Using composite electrodes of varying conductivity is one of several approaches to controlling field strength. High field strength exists across zones of high electrode surface conductivity, and reduced field strength is found in the regions of low electrode surface conductivity. The desired conductivity patterns can be produced by using electrodes constructed of composite materials the surface composition of which can be adjusted in manufacture to provide these patterns. Such electrode plates have the advantage of maintaining a graduated field strength under a range of operating conditions. They also are self-limiting under arcing conditions. A metal grid array will be completely discharged by an arc, with loss of field in the entire vessel. Because an arc on a composite grid must be fed through a surface resistance, it is quickly

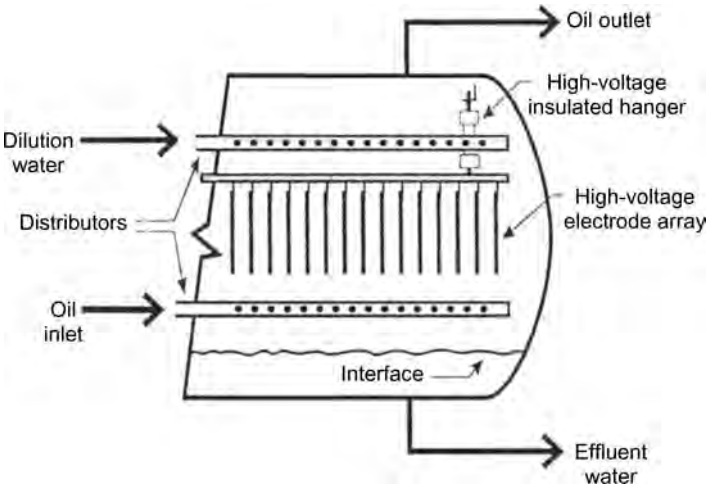


Fig. 3.30—Cut-away diagram of a counterflow desalter, showing the overhead dilution-water distributor. (Courtesy of Natco Group Inc.)

quenched, and only the plate area in the immediate vicinity of the arc is discharged. Slippage because of temporary loss of field is largely eliminated.

Another method for controlling field strength is to vary the transformer output voltage to create a time-based field decay, rather than a spatial variation in strength. Because this method is time-based, it easily can be tailored to the kinetic needs of the process. It also can be used to eliminate excessive "hold-up" of small drops in the zones of high field intensity, which could lead to arcing if unchecked. The electrostatic mixing process is most successful when both the composite plate technology and the modulating controller are used. The mixing and coalescing process has four stages, each of which has unique field-strength requirements for optimum performance (**Fig. 3.31**):

• Dispersing: A fast voltage ramp-up to the mixing voltage. This rapidly reduces the large drop population and coalesces small drops.

• Mixing: Sustained high-intensity field for maximum drop subdivision and dispersal.

• Coalescing: Voltage ramp-down permits optimum growth of drops. It is in this stage that most of the contact between the dilution water and the entrained brine occurs.

• Settling: Sustained low-intensity field for drop growth and sedimentation and for control of aqueous phase hold-up between the electrodes.

A voltage controller can be used to adjust these stages for optimum intensity and duration. Often it is necessary to effect a small compromise between dehydration (coalescing and settling) and contact efficiency (dispersal and mixing). The compromise is small because in the presence of countercurrent flow, the water carry-over that is produced by intense mixing is mostly fresh water, so that desalting efficiency is undiminished.

Countercurrent flow is essential for realizing the full benefit of multiple mixing and coalescing stages. Achieving this benefit requires introducing dilution water above the electrodes in the dry-oil zone. The water must remain as coarse drops in this area to prevent carry-over. Uniform distribution is desirable, although the electric field produces some distribution and will overcome mild maldistribution.

The simplest way of spreading the dilution water above the electrodes is through a system of laterals that have orifices sized to produce a small pressure drop at design flow rates. This system usually requires less dilution water because of increased contact efficiency. Injecting excess water into the feed stream sometimes provides other benefits (e.g., reduced upstream heat-

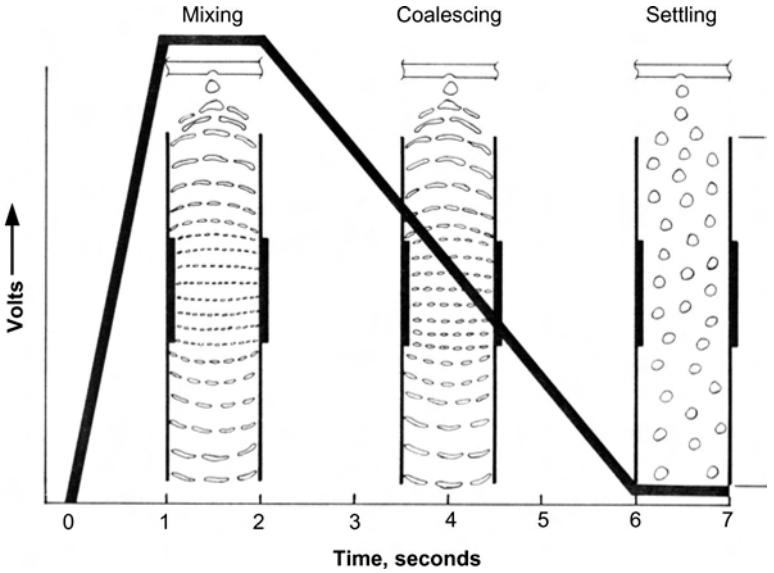


Fig. 3.31—Voltage modulation in counterflow desalting, showing drop breakup (mixing), drop growth (coalescence), and drop sedimentation (settling). (Courtesy of Natco Group Inc.)

exchanger fouling, satisfaction of solubility requirements of water in oil as the temperature increases, and crystalline-salt removal).

Power Consumption. The power expended in electrostatic coalescence is consumed largely by current flow through the conductive liquids. This power mostly is converted to resistive heating; little of it actually is used in the coalescence reaction. Transformers are sized according to power-flux criteria, and adjustments are made for known characteristics of the oil to be treated and the operating temperature. Remember, though, that dehydrator and desalter transformers are sized conservatively to allow them to operate in the lower 30% of their capacity to accommodate reactive losses associated with the transformer protection scheme. The operating load therefore is roughly 30% of the connected load.

Table 3.5 summarizes available counterflow-desalter configurations and applications.

3.5.7 Operational Parameters. ***Chemical Treatment.*** Chemical treatment with demulsifiers is used to counteract the natural surfactants present, and wetting agents or other chemicals sometimes are used to carry the suspended solids into the water layer. The presence of a band of emulsion in centrifuged samples indicates that further chemical treatment might be needed.

Operating Temperature. Operating temperature is used as the primary control of viscosity in an oil dehydrator or desalter. The lower the viscosity, the better the performance because drag on the settling drops is reduced. As a rule of thumb, the maximum viscosity for effective dehydration usually is assumed to be approximately 20 cSt, whereas the maximum viscosity for effective desalting is approximately 7 cSt. The temperatures at which these viscosities are obtained, therefore, are the minimum operating temperatures for these operations. Lower viscosities are desirable, but care should be taken not to adversely affect differential density between the phases, which also is a function of temperature.

Process Flux. The process flux is the volume of oil per unit of time that passes through a unit area as measured at the horizontal longitudinal plane through the vessel centerline. Because in most treaters the settling water drops must fall through the rising oil, the minimum drop size that is capable of achieving a net downward velocity increases as process flux increas-

TABLE 3.5—SUMMARY OF COUNTERFLOW-DESALTER CONFIGURATIONS AND APPLICATIONS

Application	Refinery or oilfield desalting systems that require maximum desalting performance, or operations with small amounts of dilution water or poor quality dilution water.
Strengths	• AC/DC field for superior coalescence. • Composite electrodes for maximum water tolerance. • Voltage controller minimizes process upsets. • Electrostatic mixing for multiple contacts. • Multistage contact through countercurrent flow. • Minimum dilution water usage. • High-strength electrode array resists motion. • Maximum washing of suspended solids by countercurrent dilution water. • Minimum outlet salt.
Weaknesses	• Larger transformer used to supply mixing energy. • Transformer input limited because of limitations of SCRs. • Voltage controller panel must be mounted within 1,500 ft of the transformer.
Experience	These systems have been installed in applications ranging from refinery desalting to turbine fuel treatment to floating production oil processing.
Improvements	Entrance bushings for very-high-voltage, composite material electrode plates for high-temperature applications, and controllers using the latest microprocessor technology have become standard features.

es; therefore, achieving high process flux (minimum vessel size) requires coalescing the drops to larger sizes, reducing the viscosity, and maximizing differential density to produce high sedimentation rates.

3.6 Subsystems

3.6.1 Power Supplies. ***Transformers.*** Transformers used in dehydrator and desalter power supplies must be capable of sustaining a short-circuited output without damage or overheating. This protection normally is derived by including a saturable core reactor sized commensurately to the reactance of the transformer winding in series with the primary winding of the transformer. As the primary current increases, the voltage drop across the reactor increases; therefore, failures in the vessel electrical components or process upsets causing high conductivity will not damage the transformer. Transformers in this service also experience high mechanical stresses from rapidly fluctuating loads and must be constructed with cores and windings that are mechanically solid and highly resistant to vibration.

Controllers. A weakness of electrostatic coalescers has been their means of protecting the electrical system in the event of excessive power requirements during short-term upsets. Unfortunately, the reactor-based protection scheme described above effectively reduces power input to the vessel precisely when it is most needed.

To counteract this, an electronic controller was developed that can sense the load demand and modify the power input to the transformer. This voltage controller differs from the reactor in that it reduces power on the basis of time rather than by uniformly diminishing output. Short bursts of high-intensity energy are applied to the emulsion, and the duration of the pulses is limited to maintain an average power output within the rating of the transformer. This action continues to provide coalescing energy even during times of process upset.

The voltage controller also assists with the necessary compromise between field strength required for adequate translation of small drops and field strength sufficient to produce subdivision of large drops. As drop size increases and the surface-to-bulk ratio decreases, surface tension becomes unable to maintain rigidity of the drop, and viscous drag on the moving drop causes deformation. As velocity or drop size increases, this deformation, in concert with electrically induced perturbations, becomes sufficient to cause the drop to shatter. At any given field strength, there is a range of stable drop sizes that is limited at the lower end by the ability of the field to transport the drop, and at the upper end by what drop size can be transported without shattering. An ideal arrangement would be a field with a high-intensity zone for coalescence of very small drops, followed by gradually decreasing field strength for shifting the equilibrium drop size range to large values. To accomplish this, the controller varies the transformer output voltage to create time-based field decay. In addition to providing optimum field strength for coalescence of a wide range of drop sizes, the controller also can be used to provide high-intensity fields that are suitable for both mixing (in the case of counterflow desalters) and dehydration.

3.6.2 Insulators. ***Entrance Bushings.*** Entrance bushings are insulated pressure-sealing devices that conduct high voltage into the desalter vessel. Bushings are constructed of perfluorocarbon because of its superior resistance to fouling by foreign substances such as suspended solids or precipitated organic materials. If such materials collect on the surface of the insulator, a resistive electrical path will form that will conduct a small current and produce localized heating. This heating can cause the formation of a carbonized track along the insulator surface that ultimately will cause insulator failure. The perfluorocarbon portion of the bushings must remain submerged during operation to avoid plasma erosion of the insulator material.

Electrode Hangers. Electrode hangers are insulating devices that mechanically support the electrostatically charged elements inside the treater or desalter vessel. They are available in two designs: standard hangers and high-temperature hangers.

Standard hangers use a 1-in. diameter perfluorocarbon rod with threaded end caps that are attached to swivels and J-hooks. They are widely used on oilfield treaters and desalters that operate at temperatures < 250°F. Loading is adjusted on the basis of temperature. Cast virgin perfluorocarbon is strongly recommended for this service. If extruded rod is used, ensure that "poker chip" discontinuities in density do not occur in the rod.

High-temperature hangers are used in applications with temperatures of up to 300°F. These are made of 2-in.-diameter cast virgin perfluorocarbon rod.

3.6.3 Electrodes. Electrodes are devices that provide direct contact between the electrical system and the process fluids. Often these are referred to as "grids" because of the nature of the electrodes that originally were used in AC field treaters and desalters. Several types of electrodes now are in general use.

Bar Grating, or Grids. Electrodes made of rectangular arrays of perpendicular steel rods or small-diameter pipes were the original grids of electrostatic treaters, and they remain in widespread use in AC field devices. Generally, several of these are hung in vertically separated horizontal planes above the longitudinal centerline of the vessel to increase liquid retention time in the most intense electrostatic field. The spacing between electrodes might be adjustable. These electrodes are inexpensive to construct and easy to carry into the vessel through a manway; however, the openings that are required to provide sufficient electrical clearance through each grid for the supports for the underlying grids can allow a portion of the process flow to bypass the intense area of the electrostatic field.

Steel Plates. Arrays of vertically hung, parallel plates with a plate-to-plate spacing of approximately 6 in. and a plate height of 6 to 10 in. may be used in an electrostatic vessel to

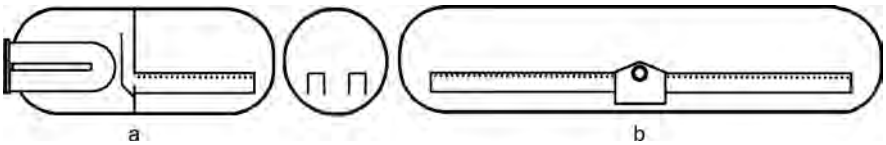


Fig. 3.32—Typical box-type inlet distributor in (a) a heater-treater and (b) an unheated dehydrator. (Courtesy of Natco Group Inc.)

achieve high retention time in the intense zone of the electrostatic field. Similar plates also are used to provide the combination AC/DC field.

Composite Plates. Electrostatic coalescence generally proceeds through a mechanism of drop polarization, alignment of the polarized drops, and chaining of these drops along the lines of force of the electrostatic field. These conductive chains lead to frequent electrical discharges or arcing between the electrodes. The arcs are a normal part of the process and, because they are submerged in oil, do not produce any damage; however, a steel electrode array is momentarily discharged by an arc, and if the arcs occur frequently enough (as in a wet emulsion), the electrodes might be discharged long enough to allow slippage of process fluids that have not had adequate exposure to the field.

Composite plate electrodes may be used to increase the water tolerance of the system under such conditions. These electrodes consist of plates of composite (fiber-reinforced plastic) construction with graphite fibers embedded in the central portion of the plate to impart conductivity along the length of the plate. The remainder of the plate contains filler materials that adsorb a layer of water on the plate surface. This adsorbed water layer then becomes the conductive medium along the height of the plate. Because such an adsorbed layer is highly resistive, any arcing that occurs is quenched quickly. As a result, only the immediate vicinity of the arc is discharged, and slippage is almost eliminated. Composite plates are used in all counterflow desalters, as well as on AC/DC processes for increased water tolerance.

3.6.4 Liquid Distribution Systems. ***Inlet Spreaders.*** A common type of inlet spreader is an inverted trough with distributor holes in the upper part of the trough (**Fig. 3.32**). Flow into the trough depresses the oil/water interface inside the trough to provide a hydrostatic head for creating uniform flow distribution. Changes in flow are reflected in changes in hydrostatic head, allowing for uniform distribution over a wide range of flow rates. Another advantage of the inverted trough is its ability to discharge free water and heavy solids directly out the bottom, without passing them through the shear of the orifices. The spreader is designed according to Eq. 3.8:

$$q = AC_o\sqrt{2gh(\gamma_w - \gamma_o)}\ , \quad \text{..... (3.8)}$$

where q = flow, ft^3/sec; A = the area of diffuser holes, ft^2; C_o = the orifice factor (0.6 to 0.7); g = gravitational constant = 32.2 ft/sec^2; h = head, ft; γ_w = the specific gravity of brine; and γ_o = the specific gravity of oil.

Another common spreader configuration uses perforated pipes as the inlet distributor (**Fig. 3.33**). Pipe spreaders are preferable when vessel motion might be a factor (e.g., in floating production systems). The number, size, and distribution of the orifices are chosen so as to achieve uniform distribution across the vessel. In recent years, application of computational-fluid-dynamics (CFD) techniques to spreader design have enabled the design of highly efficient spreaders. Commonly used pressure drop across distributor orifices is 5 to 6 in. of water column for inverted troughs and 0.5 to 1.0 psi for perforated pipes.

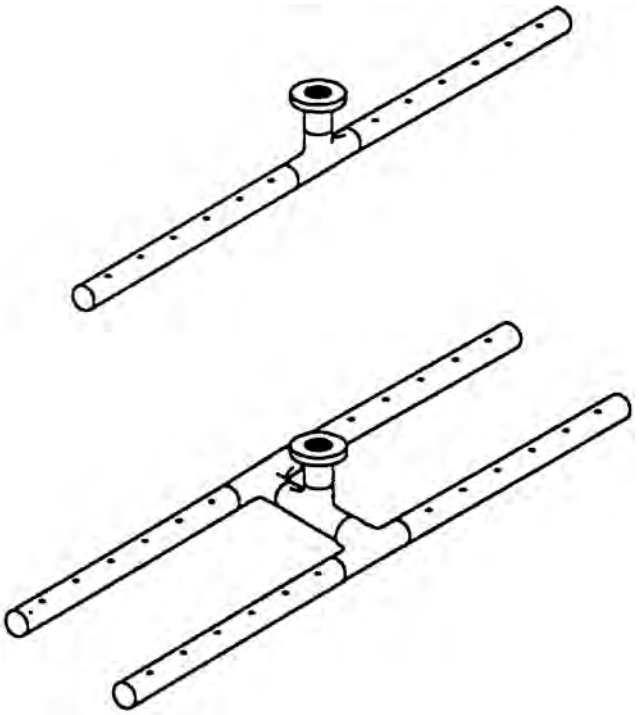


Fig. 3.33—Typical perforated-pipe inlet distributor and oil outlet collector. (Courtesy of Natco Group Inc.)

Outlet Collectors. Most vessel designs provide for a treated-oil collector in the upper part of the vessel. This collector is either a perforated pipe or a channel with perforations, and is designed according to Eq. 3.9:

$$q = 19.65 C_o n D^2 \sqrt{h} \ , \quad \text{..... (3.9)}$$

where D = hole diameter, in., and n = number of holes.

Dilution-Water Spreaders. Counterflow desalters incorporate a header/lateral spreader system for injecting dilution water above the electrodes. The electrostatic field provides some distribution of the counterflowing dilution water, and the size and spacing of the orifices are adjusted to assure uniform distribution.

3.6.5 Instrumentation and Safety Systems. ***Safety Grounding Floats.*** Safety grounding floats are floats that are mechanically linked to grounding switches inside the electrostatic-treating vessel. These devices ground the electrical systems inside the vessel upon loss of liquid level. They ensure that no electrically energized components are exposed to the gas phase and that the electrodes are not energized accidentally during personnel entry into the vessel.

Low-Level Shutdowns. Shutdown switches may be installed to shut off transformer power in the event of liquid-level loss, or to shut down the process in the event of high or low interface level. These switches may be located in external cages or inserted through nozzles.

Interface Controls. Several types of interface control are available, including weighted floats, capacitance probes, conductivity probes, and radio frequency (RF) probes. What control is selected for an application depends on crude oil characteristics, compatibility with central control systems, and operator preference. Many installations now use the RF probes. They can

be used for interface control, high- and low-level interface alarms, bottom-sediment detection, and upstream anticipation of feed-stream changes.

3.6.6 Solids-Removal Systems. Because dehydrator and desalter vessels are designed to promote sedimentation, suspended solids in the feed stream also tend to settle out of the liquid stream. If the solids are water-wetted and heavy, they tend to settle through the interface and collect on the bottom of the vessel. In an oilfield situation, these solids often consist primarily of fine sand, whereas in a refinery, they usually are fine silts. Corrosion products might be present in both. If the solids are oil-wetted or are of a density between that of oil and water, they tend to collect as a sludge layer at the oil/water interface and usually are accompanied by poorly resolved emulsions. Either case eventually requires removal of the solids from the vessel to prevent process upsets. These solids could consist of mud, silt, sand, salts, asphaltenes, paraffin, and other impurities that are produced with crude oil and accompanying water. When present in small quantities, these impurities add little to the treating problem; however, when present in appreciable quantities, they might make the treating problem difficult and expensive, and might require the use of special equipment and techniques.

It is good practice to equip all treating vessels with cleanout openings and/or washout connections so that the vessels can be drained and cleaned periodically. Larger vessels should be equipped with manways to facilitate cleaning them. Steam cleaning might be required periodically, and acidizing may be necessary to remove calcium carbonate or similar deposits that cannot be removed by hot water or by steam cleaning.

One of the most likely causes of difficulty in operating fired emulsion-treating vessels is the deposition of solids on fire tubes and nearby surfaces. If such deposits cannot be prevented, these surfaces should be cleaned periodically. The deposits insulate the fire tube, reducing heating capacity and efficiency. They also can cause accelerated corrosion and failure of the heater tubes.

Of the salts commonly found in oilfield waters, the chlorides, sulfates, and bicarbonates of sodium, calcium, and magnesium are predominant. The most prevalent of the chlorides is NaCl, followed by calcium and magnesium chloride. These salts can be found in nearly all water associated with crude oil. Salts seldom are found in the crude oil; when they are present, they are mechanically suspended, not dissolved, in it. An exception to this is organic salts (e.g., naphthenates).

Emulsion-heating equipment is particularly susceptible to scaling and coking. These depositional processes are distinct, but might occur simultaneously. Also, one can hasten the other.

Calcium and magnesium carbonates and calcium and strontium sulfates readily precipitate on heating surfaces in emulsion-treating equipment by decomposition of their bicarbonates and the resultant reduced solubility in the water carrying them. They are deposited in pipes, tubes, and fittings, and on the inside surface of treating vessels. Maximum deposition occurs on the hottest surfaces (e.g., heating coils and fire tubes).

Scale deposition also might occur when pressure on the fluid is reduced. This is the result of release of CO_2 from the bicarbonates in salt water, which forms insoluble salts that tend to adhere to surfaces of equipment that contain the fluid.

Coke generally is not a primary fouling material; however, when deposits of salt, scale, or any other fouling material build up, coking begins as soon as the insulating effect of the fouling material causes the skin temperature of the heating surface (fire tube or element) to reach 600 to 650°F. The coke that forms aggravates fouling and reduces heat transfer. Once coking starts, a burnout of the fire tube might follow quickly.

In areas where fluids cause considerable scaling or coking, such deposits can be minimized by decreasing the treating temperature or by using chemical inhibitors, properly designed spreader plates, and favorable fluid velocities through the equipment. Arranging the internals of the equipment so that all surfaces are as smooth and continuous as possible also will reduce such

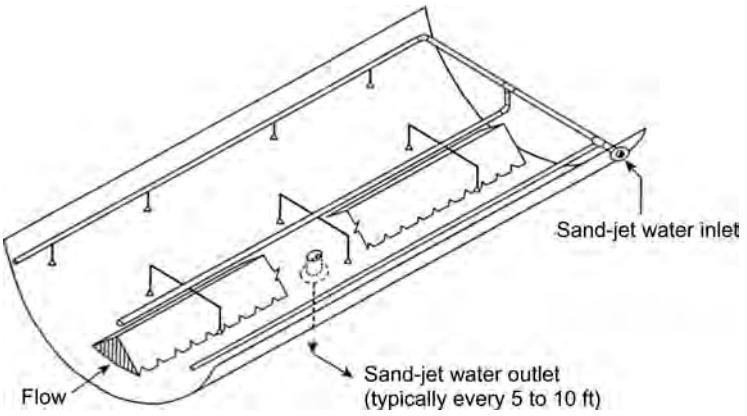


Fig. 3.34—Sand pans and water-jet system in a horizontal vessel. (Courtesy of Natco Group Inc.)

deposits. For trouble-free operation of equipment over a long time, the operator periodically should inspect the equipment internally and clean its surfaces as required.

Mud-Wash or Sand-Jet Systems. It is common to shut down and drain vessels periodically for cleaning. Sand can be removed from the unit with rakes and shovels or with a vacuum truck. The use of sand pans, automated water jets, and drain systems can eliminate or minimize the problem of sand and silt in emulsion-treating vessels, but it is very difficult to eliminate sand buildup in large-diameter tanks.

A sand pan is a special perforated or slotted box or enclosure that is located in the bottom portion of a vessel or tank. Sand pans are designed to cover the area of the vessel that the flow of discharging water will clean. Often they are designed to work with a set of water jets. The sand pans for horizontal vessels usually consist of elongated, inverted V-shaped troughs that are parallel with and on the bottom of the vessels and that straddle the vertical centerline of the vessel. In the design in Fig. 3.33, the sand pans have sides that make a 60° angle with the horizontal. The bottom edges of the sloping sides are serrated with 2-in. V-shaped slots and are welded to the interior of the shell of the treater. Most sand pans used in horizontal vessels are 5 to 10 ft long.

Sand pans without a water-jet system might satisfactorily remove sand from some vessels; however, vessels should be equipped with a water-jet system, in addition to sand pans, to assist sand removal from the vessel. **Fig. 3.34** illustrates typical sand pans with a water-jet system.

In vertical vessels, the sand pan can be a flanged and dished head approximately one-third the diameter of the vessel in which it is concentrically located. The sand pan usually is serrated around the periphery, where it is welded to the bottom head of the vertical vessel concentric with the water outlet.

Water jets usually are designed to flow 12 to 20 U.S. gal/min of water through each jet with a differential pressure of 35 to 100 psi. Standard jets are available for this service that have a 60° flat fan jet pattern. The jets usually are spaced on 12- to 24-in. centers. The water jet header is U-shaped so that the vessel is cleaned on both sides of the sand pan simultaneously. The water jets and sand-dump valves can be programmed to operate all at the same time or in sequential cycles.

One problem in removing sand from vessels is that very few, if any, water-discharge-control valves can withstand for long the abuse of sand-cutting during the water-discharge period. A partial solution is to arrange the instrumentation to open and close the water-discharge control valve on clean, sand-free water and to use special slurry-type valves.

The most sophisticated sand-removal systems use programmable logic controllers to select the proper time intervals between dumps and to automatically control the length of the water/sand-discharge period. The timing must be coordinated with the water-jet system and the normal water-dump controller. A properly designed sand-removal system with proper water jetting and water/sand dumping can operate for many years without needing to be shut down to clean out sand or to repair or replace the dump valve.

Most emulsion-treating systems that handle large volumes of sand should not rely on hand or nonprogrammed operation for sand removal. If the operator fails to activate the dump valve often enough, sand will cover the sand pans and plug or partially plug the water outlet, and the drains will become inoperative. With sand pans in the treater but without a programmer, large volumes of sand usually will cause trouble by plugging or partially plugging the water outlets and/or by cutting or wearing away the drain valve.

Because the amount and type of sand vary greatly, the length and frequency of the water jetting and dumping cycles must vary to suit local conditions. Most of the coarser sand will settle out in the inlet end of the treater; the fine sand will settle out near the outlet end of the treater. It might be necessary to cycle the water jets and drain valves near the inlet end of the treater three to four times more frequently than those near the outlet end. Many timers are set for 30 minutes between jetting and dumping cycles and for 20- to 60-second jetting and dumping periods.

In refinery settings, sand jets usually are referred to as mud-wash systems.

Interface-Sludge Drains. Interfacial buildup, sometimes referred to as sludge, is material that can collect at or near the oil/water interface of emulsion-treating tanks and vessels. Interfacial buildup can contain paraffin, asphaltenes, bitumen, water, sand, silt, salt, carbonates, oxides, sulfides, and other impurities mixed with unresolved emulsion. It can be removed from the vessel through a drain installed at the interface or by closing the water-dump valve and floating it out to a bad-oil tank for further processing or disposal. Interfacial buildup also can be discharged with the water by opening the water-drain valve, but this can create problems in the water-treatment plant.

Interface-sludge drains are collectors at the oil/water interface that are connected to discharge valves. Interface sludge tends to collect irregularly and often reaches an equilibrium depth that does not impair operation seriously; therefore, the need for draining interface sludge is best determined by regular monitoring of the interface depth and condition, using samples from the trycocks. The presence of a continuously increasing interface layer or one that contains a high concentration of suspended solids indicates a need for draining.

Draining must be done very slowly and must be carefully monitored to avoid drawing excess oil or water into the collectors. For this reason, it is best done manually. Properly used, interface-sludge drains can reduce the load on the downstream water-treatment facilities by redirecting the high-oil- and high-solid-content material into a slop-oil system, where it can be batch treated more effectively with heat and chemicals.

3.6.7 Mixing Devices. An important facet of desalting is achieving contact between the entrained water in the crude oil and the dilution water that is used to wash the oil.

Mixing Valves. Typically, the dilution water is added to the oil upstream of a valve. The water is injected into the oil flow line through a distributor. The differential pressure across the valve then is used to shear the water drops and mix the two phases.

Typical differential pressures are 5 to 20 psi. Although mixing valves generally are satisfactory, they do have some disadvantages. Mixing efficiency generally is low at extremes of phase ratio, so that using small quantities of dilution water (< 2%) might not be feasible; likewise, turndown in flow rate will require adjustment of the valve to maintain contact efficiency. More serious disadvantages include the requisite compromise between mixing efficiency and excessive emulsification and the energy wasted on shear of the continuous phase. Because very

small drops act as rigid spheres following flow streamlines, it is unlikely that they will achieve sufficient energy to participate in mechanically induced collisions; therefore, their contribution to the salt content of a crude oil represents a fraction unreachable by means of mixing valves.

Static Mixers. Mixing efficiency can be improved by adding static-mixer elements downstream of the mixing valve to achieve a more homogeneous blend of brine drops and dilution-water drops (Fig. 3.6). Static mixers are series of short, helical baffles mounted in a pipe, with adjacent baffles that have reverse twists. They continually blend the stream at low shear. Because increasing mixing efficiency by increasing the shear rate can lead to emulsification problems, the use of low-shear devices for blending the stream can be an asset, particularly with difficult crude oils. At best, a mixing valve/desalter combination can function as a single-stage mixer/settler.

Electrostatic Mixing. As discussed previously, the electrostatic field also can be used as a mixing device if it is programmed to exceed the critical voltage gradient during a portion of the treating cycle. This is the technique used to achieve mixing under counterflow conditions in the counterflow desalter.

3.6.8 Level Controllers and Gauges. Many liquid-level controllers are available for liquid/gas control and for oil/water-interface control in light-crude-oil (> 20°API) systems. For interfacial controllers in light crude oils, floats that sink in the oil but float in the water normally are used.

For heavy crude oils, electronic interface controllers have been used very successfully. They operate on the principle of the differences between oil and water electrical conductivity, electrical capacitance, or RF absorption. The most common type, capacitance probes, use the dielectric strength of the fluid in which they are immersed.

Standard-gauge glasses (reflex or transparent) are used on 20°API and higher crude oil. Reflex gauges normally are used for liquid/gas levels, and transparent gauges are used for oil/water levels. Pressure vessels normally use armored-gauge glasses, and tanks use tubular-gauge glasses. Some operators use the tubular-gauge glasses on low-pressure treating equipment. Tubular-gauge glasses normally are furnished on standard low-pressure vessels unless armored gauges are specified.

For API gravities below 20°API, gauge glasses are not recommended, particularly for interfacial service, because they are difficult or impossible to read. In lieu of gauge glasses, a system of sample valves (often called trycocks) is used, with the sample lines all piped to a single point just above a sample box. Generally, the lines are insulated to keep them warm. A nameplate clamped on each sample valve designates the elevation it represents in the treater. The sample box is fitted with a drain line piped to the sump.

3.6.9 Water-in-Oil Detectors (BS&W Monitors). Several companies manufacture BS&W monitors, devices for detecting and measuring the water content of crude oil. BS&W monitors typically are analog instruments that measure dielectric strength and are designed specifically for determining the water content of crude oil that contains a low percentage of water. They do not operate satisfactorily on streams that contain free water. The monitor provides a water reading that corresponds to the water content of the oil. It can be made to alert the operator, record the reading, and control the BS&W content level if the detected percentage exceeds the field-selectable preset limit.

3.7 Operational Considerations

3.7.1 Treating Emulsions From Enhanced Oil Recovery (EOR) Projects. Standard emulsion-treating procedures, equipment, and systems used during primary and secondary oil production might be inadequate for treating the emulsions encountered in EOR projects. EOR methods of oil production [e.g., in-situ combustion and steam, CO_2, caustic, polymer, and micellar (surfactant/

polymer) floods] might cause the production of emulsions that do not respond to treatment that normally is used in primary- and secondary-oil-production operations.

The emulsions from EOR projects usually are treated independently of the primary and secondary emulsions from the same fields. Emulsion-treating procedures, equipment, and systems have been and continue to be developed for use in these EOR projects.

3.7.2 Clarification of Water That Is Produced With Emulsions. Even though a normal (water-in-oil) emulsion exists in the oil-production system, produced water that is separated from crude oil usually contains small quantities of oil. This oil has been divided into small particles and dispersed in the water by agitation and turbulence caused by flow in the formation, into the wellbore, and through equipment; by reciprocation of sucker rods; and by surface transfer pumps. These small particles of oil are suspended in the water by mechanical, chemical, and electrical forces. In most systems, the amount of oil in the untreated produced water varies from an average low of 5 ppm to an average high of 2,000 ppm; however, in some water systems, oil contents as high as 20,000 ppm (2.0%) have been observed. These oil particles usually are between 1 and 1,000 μm in diameter, with most ranging between 5 and 50 μm.

Various methods can be used to remove oil from the produced water: chemicals, heat, gravity settling (skim tanks, API separators, etc.), coalescence (plate, pipe/free flow), tilted plate (corrugated) interceptors, hydrocyclones, flotation, flocculation, and/or filtering. The chapter on Water-Treating Facilities in Oil and Gas Operations in the Facilities Engineering section of the *Handbook* discusses the details of deoiling the produced water.

3.7.3 Burners and Fire Tubes. The design of burners and fire tubes is important because of the high cost of fuel and the operating problems that can occur when they malfunction. The burner should provide a flame that does not impinge on the walls of the fire tube, but that is almost as long as and is concentric with the fire tube. If the flame touches the fire-tube wall, hot spots can develop, which can lead to premature failure.

Burners should not be allowed to cycle on and off frequently because thermal stresses caused by temperature reversals can damage the fire tube. The combustion controls should be accessible and designed so that the operator can adjust the air and gas easily to achieve the optimum flame pattern and peak combustion efficiency.

A reliable pilot burner is required. Many operators and regulatory agencies require burner safety-shutdown valves that will shut off fuel to the burner in case of pilot failure.

API *RP 14C*[16] contains a basic description of recommended safety devices needed for fire- and exhaust-heated units. Consideration should be given to installing safety devices on onshore and offshore fired treaters. Such safety devices include process high-temperature shutdown devices, burner-exhaust high-temperature shutdown devices, low-flow devices and check valves for heat exchangers, high- and low-pressure shutdown sensors, pressure-relief valves, flame arresters, fan-motor-starter interlocks on forced-draft burners, etc.

Every gas-fired crude-oil heating unit should use fuel gas from which liquids have been "scrubbed." In large facilities, a central fuel-gas scrubber or filter can provide such fuel gas to all fired units. Many small facilities are equipped with individual fuel-gas-scrubber vessels for each fired unit. These individual scrubbers typically are 8 to 12 in. in diameter and 2 to 4 ft tall, and contain a float-operated shutoff valve. If liquid enters the scrubber, the float closes a valve and stops gas flow to the burners of the heating unit, thus preventing oil from entering the combustion chamber and thus possibly preventing a fire.

Most fire tubes that transfer heat to crude oil or emulsion are sized to transfer 7,500 Btu/hr per ft^2, although some manufacturers use heat-transfer rates as high as 10,000 Btu/hr per ft^2. Fire tubes that transfer heat to the water-wash section of a treater, such as in a vertical treater, are sized for 10,000 Btu/hr per ft^2, although some manufacturers use heat-transfer rates as high

as 15,000 Btu/hr per ft^2. These higher rates should be used with caution, though, because they can be overly optimistic and thus might lead to undersizing of the required fire-tube area.

The temperature controller, fuel-control valve, pilot burner, main burner, combustion-safety controls, and fuel-gas scrubber should be on a schedule of preventive maintenance, including periodic inspection and cleaning as required.

Deposits of soot, carbon, sulfur, and other solids should be removed from the combustion space periodically to prevent heating-capacity reduction and combustion-efficiency loss. On oil-fired units, the combustion controls, burner nozzles, combustion refractory, air/fuel-control linkages, oil pump, oil preheater, pressure and temperature gauges, and O_2 and/or CO_2 analyzers should be inspected and maintained periodically.

3.7.4 Corrosion. Emulsion-treating equipment that handles corrosive fluids should periodically be inspected internally to determine whether remedial work is required. Extreme cases of corrosion might require a reduction in the working pressure of the vessel, or repair or replacement of vessel and piping. Ultrasonic tests can measure the wall thickness of vessels and piping to detect the existence and extent of corrosion.

Mitigating or controlling corrosion of emulsion-treating equipment usually is accomplished by excluding oxygen, using corrosion inhibitors, applying internal coating, and/or using special metallurgy.

Exclusion of Oxygen. Corrosion rates in most oilfield applications can be kept low if O_2 is excluded from the system. Take care in the process design to install and maintain gas blankets on all tanks and to exclude rainwater from the system. Recycled water from sump systems and storage tanks is a prime source for O_2 entry into the process.

Corrosion Inhibitors. Corrosion inhibitors are materials that, when added in small amounts to an environment that potentially is corrosive to a metal or alloy, effectively reduce the corrosion rate by diminishing the tendency of the metal or alloy to react with the solution. As liquid solutions or compounds, inhibitors can be injected into the flow stream in the flowline, manifold, or production system. The potential for corrosion inhibitors to act as emulsifying agents should be recognized when they are applied.

Cathodic Protection. Sacrificial galvanic anodes commonly are used for cathodic protection. They are made of a metal the relative position of which in the galvanic series causes it to provide sacrificial protection to the steel vessel. Most galvanic anodes that are used in emulsion treaters are 3 to 6 in. in diameter and 3 to 4 ft long, and usually are sized to last 10 to 20 years. Multiple anodes usually are installed in each vessel. They are considered expendable and always are installed in the vessel through a flange or quick coupling so that they can be replaced easily when expended.

The galvanic anodes must be installed so that they are immersed in the water, which serves as an electrolyte. They will not protect the treater if they are immersed in the oil. The anodes must "see" all metal surfaces that are to be protected (i.e., there must be no obstructions between the anodes and the surfaces they are to protect). Each anode should be located as near as is practical to the center of the compartment or area they are to protect.

An impressed-electric-current cathodic-protection system also can be used to inhibit corrosion. It is a direct electric current that is supplied by a device that uses a power source external to the electrode system. The DC current can be obtained by rectifying an AC current. When resistivity of the electrolyte is > 25 Ω·cm, an impressed-current system should be considered; however, impressed-current systems are difficult and costly to maintain and usually require skilled technicians.

Electrical current-density requirements for cathodic protection of emulsion-treating vessels usually range from 5 to 40 mA/ft^2 of bare-water-immersed steel.

Internal Coating. Emulsion-treating vessels can be coated internally for protection from corrosion. It is important that the internal surfaces and the welds of the vessels be properly prepared to receive the coating. A coating system must be able to withstand the physical and chemical environment to which it will be exposed. Coating specifications, application techniques, and final inspection also are very important considerations. Coating alone should not be relied on to prevent corrosion, though, because most coating systems contain some "holidays" (breaks in the coating) or are damaged in shipping or installation.

Steel tanks can be galvanized or lined in the field with fiberglass or other coatings. Some operators use fiberglass tanks in their emulsion-treating process, whereas others feel that using fiberglass creates an unnecessary fire hazard.

Special Metallurgy. In particularly severe environments, such as where large quantities of CO_2 are expected and where O_2 cannot be eliminated from the system practically, corrosion can be minimized by using stainless-steel vessels or an internal stainless cladding in carbon-steel vessels. In most low-pressure applications, stainless-steel vessels are less expensive than clad vessels. It might also be less expensive to use a stainless-steel vessel than one that is internally coated because of the labor required to prepare and coat the internal surfaces of the vessel.

3.8 Economics of Treating Crude-Oil Emulsions

The objective of operating oil-producing properties is consistently to deliver the maximum volume of highest-API-gravity oil to the pipeline at the lowest possible cost. Emulsions should be prevented wherever feasible and, when unpreventable, should be treated at the lowest cost.

Implementing the following nine directives can minimize the occurrence and treatment cost of emulsions:

• Eliminate production of water with oil where possible and practical.

• Minimize the investment in emulsion-treating equipment by studying the treating problem and selecting appropriate treating methods, equipment, and procedures. The emulsion-treating system should be as small as possible, yet capable of adequately handling treating requirements on the lease. A treating system may be oversized initially to allow for future development, lease expansion, and/or increased water production. Such future needs may be anticipated when purchasing treating equipment; however, a needlessly oversized system incurs unnecessary expense and accomplishes nothing more than a properly sized system does.

• Where feasible, minimize the amount of oil that is lost with discharged water, and salvage oil from interfacial sludge and tank bottoms. Oil might be discharged with the water as it flows from FWKOs, emulsion treaters, gun barrels, and other treating vessels. The fraction of oil is low, and the oil usually is dispersed in small droplets. Sometimes this oil is pumped with the water to disposal wells or delivered to operators of water disposal companies without recovery or without being credited to the lease. Such oil loss can be minimized by maintaining proper operating variables with adequately sized and maintained vessels and controls and by properly designed water-treating systems.

• Minimize chemical-treating costs by using the most appropriate chemical demulsifier compound(s), the optimum quantity of chemical, the proper location and method of injection of chemical, the proper means of intimately mixing chemical with emulsion, and the proper use of heat. Treatment chemicals are not recoverable and are an ongoing expense. Some crude oil can be adequately treated by use of chemical injection with coalescence and/or settling without heat; however, some emulsions require an increased temperature during the coalescing and settling period. A proper balance of chemical and heat helps to provide the most economical and efficient treating system. The chemicals must be intimately mixed with emulsion so that a minimum amount of chemical will provide maximum benefit. Chemicals can be wasted by being injected into the oil in large slugs, rather than being intimately mixed with the emulsions.

• Ensure that chemicals added to the produced fluids are compatible. Some corrosion inhibitors can cause emulsions or affect the action of oil-treating chemicals. Chemicals used in produced-water-treating systems might be recycled to the oil-treating system with the skimmed oil and cause emulsion-treating problems there.

• Conserve gravity and volume of oil by using the optimum treating temperature, cooling the oil before discharging it to storage, discharging vent gases from treating vessels through cooler oil in stock tanks, maintaining slight gas pressure on treating-system and storage tanks, and using vapor-recovery equipment on vessels and tanks. Resolve crude-oil emulsions at the lowest effective temperature. Excessive heat drives condensable vapors from the oil, and they are discharged with the gas. Loss of these light ends lowers the API gravity of the oil and simultaneously reduces the oil volume. A further disadvantage of overheating is the increased maintenance on treating systems that is caused by hot spots, salt deposition, scaling, and increased corrosion rate, especially of the fire tubes.

• Use all treating equipment to the best advantage. Constant and careful observation, testing, supervision, and record keeping will allow emulsion-treating equipment to be used to maximum efficiency. Transferring equipment and making alterations or additions to the treating system can enable more effective use of existing equipment.

• Practice preventive maintenance to minimize irretrievable loss of oil production because of downtime for equipment repairs. The more complex the treating system, the greater is the possibility of mechanical failure. Oversized and overly complex systems have a greater failure frequency than do more-appropriately designed, simpler, and more-compact systems.

• Exchange information on treating methods and results among company personnel and with other operators, engineering firms, vendors, and chemical-treating companies. Sharing such experience among personnel who are responsible for handling treating problems will lead to lower treating costs.

Cost records are important in oil emulsion-treating operations. Achieving optimum operation of emulsion-treating equipment at minimum cost requires keeping proper records of operating temperatures, pressures, fuel and/or power consumption, chemical usage, performance, etc. Such records should be kept on a daily, weekly, or monthly basis, and should be reviewed regularly and made available for supervisory personnel.

Cost records are important for determining whether an existing system should be modified or should be replaced. Which of these is justified will depend on the efficiency of the system, which is determined using accurate and reliable cost and performance records. Cost records on existing methods or systems assist in determining the type and size of treating systems for new leases. Treatment cost records should make it possible to determine current operating costs, probable installation costs for new systems, and probable future operating costs of similar systems.

Each operator determines what is to be charged to emulsion-treating costs. **Table 3.6** outlines items that may be considered part of the database for a cost-accounting system. Some of these items will not apply to all treating systems, and some operators will elect to group some of the categories. A comprehensive general listing is given for those who wish to consider all items of cost. Special systems and conditions might require additional cost items.

Complete and accurate treatment cost records must consider all factors listed in Table 3.6.

Equipment-investment costs must include the initial cost of all equipment used, including the costs of transporting it to the location and erecting and installing it, and of readying the system for operation. It also includes such items as pipe and pipefittings, valves, grade work, foundations, and fencing.

The labor costs should include supervisory personnel, cost of company and contract labor, and other labor required to obtain, install, and put the treating system into operation. Operating costs should be kept separately from maintenance costs and should include such items as supervisory labor, operating labor, chemicals, fuel, and miscellaneous supplies. Maintenance costs

TABLE 3.6—COSTS OF EMULSION TREATING

Equipment Investment Costs

Material	Labor To Install Equipment	Other Expenses
• Treating equipment and facilities • Auxiliary equipment, controls, and accessories	• Company labor • Contract labor	• Surface rights • Special services • Other

Operating Costs

Material	Labor	Other Expenses
• Chemicals • Chemical injection equipment • Diluents and solvents • Testing apparatus • Depreciation allowances • Other	• Supervisory • Operator or pumper • Steaming or cleaning crew • Company crew • Contract • Other	• Equipment rental • Fuel (gas or liquid) • Electricity • Transportation • Laboratory expenses • Other

Maintenance Costs

Material	Labor	Other Expenses
• Maintenance • Replacements and additions • Repairs	• Supervisory • Pumper or operator • Mechanic • Painting • Company crew • Contract • Other	• Equipment rental • Transportation • Other

Overall System Performance

- Volume of oil treated
- Water content of treated oil
- Volume of water produced
- Volume of water treated
- Volume of oil salvaged from water treatment
- Remarks or observations

should include the cost of maintaining and repairing all treating equipment (e.g., cleaning, repairing, and painting).

The overall-system-performance section of the record should include an accurate record of the volume of oil treated and the volume of water separated, treated, and handled. This part of the record also should include reference to troubles experienced with the system, as well as a commentary on day-to-day performance of the unit or system.

Nomenclature

A = area of diffuser holes, L^2, ft^2
C_o = orifice factor (0.6 to 0.7), dimensionless
C_{so} = salt content of the oil, m/L^3, lbm/1,000 bbl
C_{sw} = concentration of salt in produced water, ppm
d = droplet diameter, L, m or μm
d_i = interdrop distance, L, m
D = diameter of distributor holes, L, in.

E = electric field gradient, mL/qt^2, V/m
E_c = critical voltage gradient, mL/qt^2, V/m
f = fraction of the dispersed phase, dimensionless
f_w = volume fraction of water in crude oil, dimensionless
F = force of attraction, mL/t^2, N
g = gravitational constant, L/t^2, 32.2 ft/sec^2
h = head, L, ft
h_{oo} = height of the clean oil outlet above the tank bottom, L, ft
h_{wd} = height of water draw-off overflow nipple in the weir box above the tank bottom, L, ft
h_{ww} = desired height of the water wash in the tank above the tank bottom, L, ft
n = number of holes
q = flow rate, L^3/t, ft^3/sec
q_o = oil flow rate, L^3/t, B/D
q_w = water flow rate, L^3/t, B/D
Q = heat input, m/T/t, Btu/hr
r = drop radius, L, m
t = time, t, sec
v = downward velocity of the water droplet relative to the oil, L/t, ft/sec
V = voltage, mL^2/qt^2, V
γ_o = specific gravity of oil, dimensionless
γ_w = specific gravity of water, dimensionless
ε = dielectric constant, $q^2/mL^3/t^2$, $C^2/N{\cdot}m^2$
μ_e = viscosity of emulsion, m/Lt, cp
μ_o = viscosity of clean oil, m/Lt, cp
σ = interfacial tension, m/t^2, N/m
ΔT = temperature increase, T, °F
$\Delta\gamma_{ow}$ = specific gravity difference between the oil and water (water-oil), dimensionless

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SI Metric Conversion Factors

°API		141.5/(131.5+°API)		= g/cm^3
bbl	×	1.589 873	E – 01	= m^3
Btu/hr	×	2.930 711	E – 01	= W
Btu/hr·ft^2	×	3.154 591	E – 03	= kW/m^2
cSt	×	1.0*	E + 00	= mm^2/s
cp	×	1.0*	E – 03	= Pa·s
ft	×	3.048*	E – 01	= m
ft^2	×	9.290 304*	E – 02	= m^2
ft^3	×	2.831 685	E – 02	= m^3
°F		(°F + 459.67)/1.8		= K
in.	×	2.54*	E + 00	= cm
lbm	×	4.535 924	E – 01	= kg
mA	×	1.0*	E – 03	= A
psi	×	6.894 757	E + 00	= kPa

rev/min	×	1.666 667	E – 02 = rev/s
rev/min	×	1.047 198	E – 01 = rad/s
U.S. gal	×	3.785 412	E – 03 = m^3

*Conversion factor is exact.

Chapter 4
Water-Treating Facilities in Oil and Gas Operations

Kevin Juniel, Natco Group Inc., and **Hank Rawlins,** U. of Missouri-Rolla

4.1 Introduction

Multiple types and sources of water streams are encountered in oil and gas operations; the two primary ones are produced and surface water. Produced water is the brine that comes from the oil reservoir with the produced fluids; surface water encompasses fresh (river or lake) and saline (seawater) sources.

Water sources are treated for disposal, injection as a liquid, or injection as steam with three types of facilities. Produced water is treated in offshore operations for overboard disposal or injection into a disposal well, but when onshore, it is treated for surface disposal, liquid injection, or steam injection. In all instances, the produced water must be cleaned of dispersed and dissolved oil and solids to a level suitable for environmental, reservoir, or steam-generation purposes. Surface water is treated offshore for liquid injection and onshore for liquid- or steam-injection purposes. In all instances, the surface water must be cleaned of dispersed and dissolved solids to a level suitable for reservoir or steam-generation purposes.

In oil-producing operations, it is often desirable to inject water or steam into the formation to improve oil recovery. Water injection for this purpose is called a waterflood; when properly implemented, it will maintain reservoir pressure and significantly improve the oil recovery vs. primary production. Steam injection, known as a steamflood, will reduce the viscosity of oil and further enhance the oil recovery. See the chapter on Steam Injection in the Reservoir Engineering and Petrophysics volume of this *Handbook*.

In offshore areas, governing regulations specify the maximum hydrocarbon and solids content in the water allowed in overboard discharges. Some studies have estimated that during the life of a well, 4 to 5 bbl of water are produced for every barrel of oil, making this fluid the largest volume of produced product in the oil and gas industry.[1]

This chapter discusses the equipment and design criteria used in common water-treatment systems for disposal or injection. In addition to the removal of dispersed or dissolved hydrocarbons and solids, the water-treatment engineer may be concerned with chemical treatment, material selection, and solids disposal, which are also covered.

4.2 Produced-Water Discharge or (Steam) Injection

4.2.1 Separating Free Hydrocarbons From Water. Produced water typically enters the water-treatment system from a two- or three-phase separator, free-water knockout, gun barrel, heater treater, or other primary-separation-unit process. This water contains small concentrations (100 to 2000 mg/L) of dispersed hydrocarbons in the form of oil droplets. Because the water flows from this equipment through dump valves, control valves, chokes, or pumps, the oil-particle diameters will be very small (< 100 μm).

Theory. Treatment equipment to remove dispersed oil from water relies on one or more of the following principles: gravity separation (often with the addition of coalescing devices), gas flotation, cyclonic separation, filtration, and centrifuge separation. In applying these concepts, one must keep in mind the dispersion of large oil droplets to smaller ones and the coalescence of small droplets into larger ones, which takes place if energy is added to the system. The amount of energy added per unit time and the way in which it is added will determine whether dispersion or coalescence will take place.

Gravity Separation. Stokes' law, shown in Eq. 4.1, is valid for the buoyant rise velocity of an oil droplet in a water-continuous phase.

$$v = g_c \frac{\Delta\rho (d_p)^2}{18\mu_L}, \quad \text{..... (4.1)}$$

where v = velocity of the droplet or particle rising or settling in a continuous phase, cm/s; $\Delta\rho$ = difference in density of the dispersed particle and the continuous phase, g/cm^3; g_c = gravity acceleration constant, cm/s^2; d_p = dispersed particle diameter, cm; and μ_L = viscosity of the continuous phase (liquid), g/cm·s.

Several immediate conclusions can be drawn from this equation.

1. The larger the diameter of an oil droplet, the greater its vertical velocity; that is, the bigger the droplet size, the less time it takes to rise to a collection surface and, thus, the easier it is to treat the water.

2. The greater the difference in density between the oil droplet and the water phase, the greater the vertical velocity; that is, the lighter the crude, the easier it is to treat the water.

3. The higher the temperature, the lower the viscosity of the water and, thus, the greater the vertical velocity; that is, it is easier to treat the water at high temperatures than at low temperatures.

4. Increasing the g-force imposed on the fluid (i.e., by centrifugal motion) will greatly increase the separation velocity.

The third conclusion requires further elaboration. Heat is the primary mechanism in oil-treating equipment to remove small water droplets from oil. The addition of heat significantly reduces oil viscosity, which prompts more rapid settling, and heat destabilizes water-in-oil emulsions. Heat is not commonly used in water treating because the percentage change in viscosity per degree of temperature change is much less in water than in oil. Water-in-oil emulsions tend to have a higher percentage of the dispersed phase than the oil-in-water emulsions; the dispersed phase tends to have larger-diameter droplets stabilized by heat-sensitive emulsifiers, and it takes twice as much heat input to raise a barrel of water as it takes to raise a barrel of oil to the same temperature.

Dispersion. Small oil droplets contained in the water-continuous phase are subject to the competing forces of dispersion and coalescence. An oil droplet will break apart when kinetic-energy input is sufficient to overcome the surface energy between the single droplet and the two smaller droplets formed from it. At the same time that this process occurs, the motion and

collision of oil particles cause coalescence to take place. Therefore, it should be possible to define statistically a maximum droplet size for a given energy input per unit mass and the time at which the rate of coalescence equals the rate of dispersion.

Eq. 4.2 provides one relationship for the maximum particle size that can exist at equilibrium.[2]

$$d_{\max} = 432\left(\frac{t_r}{\Delta p}\right)^{2/5}\left(\frac{\sigma}{\rho_w}\right)^{3/5}, \quad \text{..... (4.2)}$$

where $d_{\max}$ = diameter of the droplet above which only 5% of the oil volume is contained, σ = surface tension, ρ_w = density, Δp = pressure drop, and t_r = retention time.

The greater the pressure drop (and, thus, the shear forces that the fluid experiences in a given time period), the smaller the oil droplets will be. Large pressure drops, which occur in small distances through chokes, control valves, and instruments, result in small oil droplets and water that is harder to treat. A pressure drop of 50 to 75 psi will result in a maximum particle size of 10 to 50 μm.

Theoretically, the dispersion process is not instantaneous; however, from field experience, it appears to take place very rapidly. For conservative design purposes, it could be assumed that whenever large pressure drops occur, all droplets will disperse instantaneously.

Coalescense. Within water-treatment equipment, in which the energy input to the fluid is very small, the process of coalescence takes place; that is, small oil droplets collide and form bigger droplets. Because of the low energy input, these are not dispersed.

Coalescence can also occur in the pipe downstream of pumps and control valves. However, in such instances, the process of dispersion will govern the maximum size of stable oil droplets that can exist. For normal pipe diameters and flow velocities, particles of 500 to 5000 μm are possible.

The process of coalescence in water-treatment systems appears to be more time-dependent than the process of dispersion. When two oil droplets collide, contact can be broken before coalescence is completed because of turbulent pressure fluctuations and the kinetic energy of the oscillating droplets.

The time required to "grow" a large droplet from a relatively small droplet in a "quiet" gravity-settling tank is approximated by Eq. 4.3.

$$t = \frac{(d_d)^4}{2 f_V K_s}, \quad \text{..... (4.3)}$$

where d_d = droplet diameter, f_V = volume fraction of the dispersed phase, and K_s = empirical settling constant. While it is very difficult to determine K_s for an actual installation, the following qualitative conclusions can be drawn:

- A doubling of the residence time will cause an increase in droplet diameter of only 19%.
- The more dilute the dispersed phase, the greater the residence time needed to grow a given particle size (that is, coalescence occurs more rapidly in concentrated dispersions).

The addition of surfactant chemicals to the water stream can modify the surface tension of the oil droplets to aid in coalescence.

4.2.2 Gravity-Separation Devices. Water-treating equipment that makes use of gravity separation includes skim tanks, API separators, plate coalescers, and skim piles. These devices are very simple and inexpensive; however, because of the large residence times necessary for separation, they are heavy and require large footprints. These devices are commonly used on both

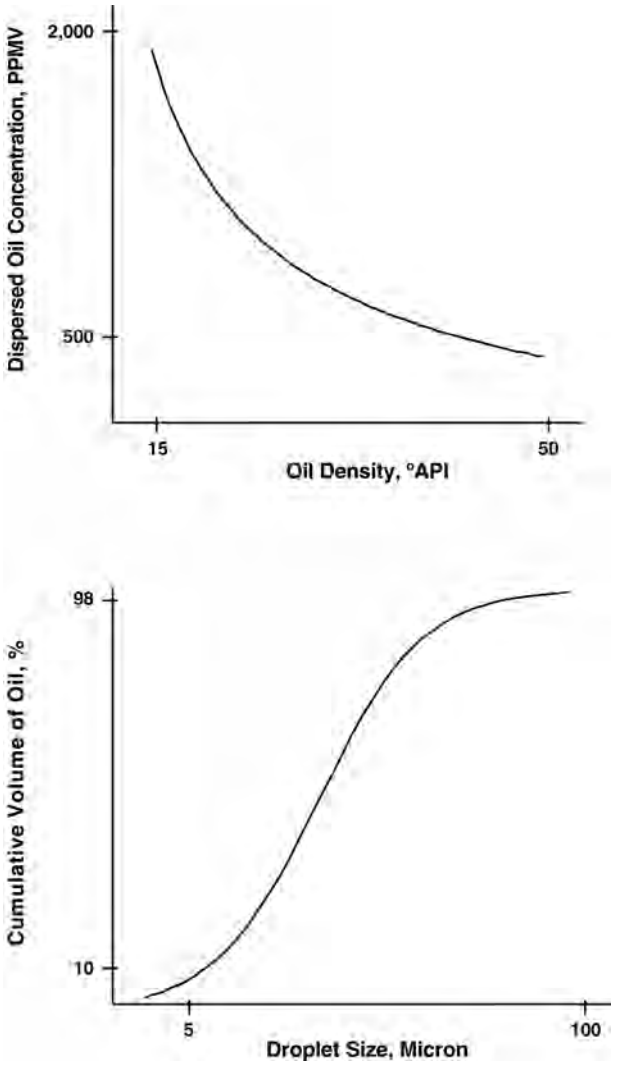


Fig. 4.1—Form of empirical curves for oil concentration and droplet-size distribution (representative estimate).

land-based and offshore fixed-structure facilities; however, they are motion-sensitive and find limited use on floating facilities.

It is necessary to know both the oil concentration in the influent water and the particle-size distribution to properly design a gravity separator to meet a certain effluent quality. This information can be determined accurately only by sampling the treated water stream. Laboratory testing can provide indicative data for scaleup and correlation, while curves, such as those shown in Fig. 4.1, can provide an initial estimate from which to work. These data will vary with the oil and water properties and process conditions.

Skim Tanks and Vessels. The simplest form of treatment equipment is a skim tank or pressure vessel. These are normally designed to provide large residence times during which coalescence and gravity separation can occur. They can be either pressure vessels or atmospheric tanks.

Skim tanks can be either vertical or horizontal in configuration. They may be set up for vertical downward flow of water with or without inlet spreaders or outlet collectors. They may also be designed as horizontal vessels in which the water enters on one side and flows over a weir on the far end.

In vertical vessels, the oil droplets must flow upward against the downward velocity of the water. For this reason, horizontal vessels are more efficient in gravity separation of the two liquid phases. In spite of this, vertical vessels and tanks are sometimes used for the following two reasons:

• Sand and other solids particles can be handled more easily in vertical vessels with either a water outlet or a sand drain off the bottom.

• Vertical vessels are less susceptible to high-level shutdowns caused by liquid surges. Internal waves resulting from surging in horizontal vessels can trigger a level float even though the volume of liquid between the normal operating level and the high-level shutdown is equal to or larger than that in a vertical vessel.

Tracer studies have shown that large skim tanks, even those with carefully designed spreaders and baffles, exhibit poor flow behavior and short circuiting. This is probably caused by such factors as density and temperature differences, deposition of solids, corrosion of spreaders, and flow dynamics. In one case, a tank with a design mean residence time of 33 hours had a breakthrough of the tracer with a peak within minutes of tracer injection.

As discussed previously, providing residence time to allow for coalescence does not appear to be cost-efficient. However, a minimum residence time of 10 minutes to 1 hour should be provided to ensure that surges do not upset the system and to provide for some coalescence.

Horizontal Pressure Vessel Sizing. The required diameter and length of a horizontal cylinder operating half full of water can be determined by the following equation:

$$d_i L_e = \frac{1{,}000 q_w \mu_w}{\Delta\gamma_{ow}(d_d)^2}, \quad \text{..... (4.4)}$$

where d_i = vessel internal diameter (ID), q_w = water flow rate, μ_w= water viscosity, d_d =oil-droplet diameter, L_e = effective length in which separation occurs (for design use of 75% seam-to-seam length), and $\Delta\gamma_{ow}$= difference in specific gravity between oil and water.

While Eq. 4.4 will govern the design, it is also necessary to check for adequate retention time.

$$t_r = 0.7\frac{(d_i)^2 L_e}{q_w}, \quad \text{..... (4.5)}$$

where t_r = retention time.

Vertical Cylindrical Vessel. The required diameter of a vertical cylindrical pressure vessel or tank can be determined from

$$(d_i)^2 = 6{,}691F\frac{q_w \mu_w}{\gamma_{ow}(d_d)^2}, \quad \text{..... (4.6)}$$

where F = a factor to account for turbulence and short circuiting. For small-diameter vessels (48 in. or less), F = 1.0. For larger diameters, F depends on the type of inlet and outlet spreaders, collectors, and baffles that are provided. Large tanks (10 ft or more in diameter) should be considered to have an $F > 2.0$, depending on the inlet and outlet conditions.

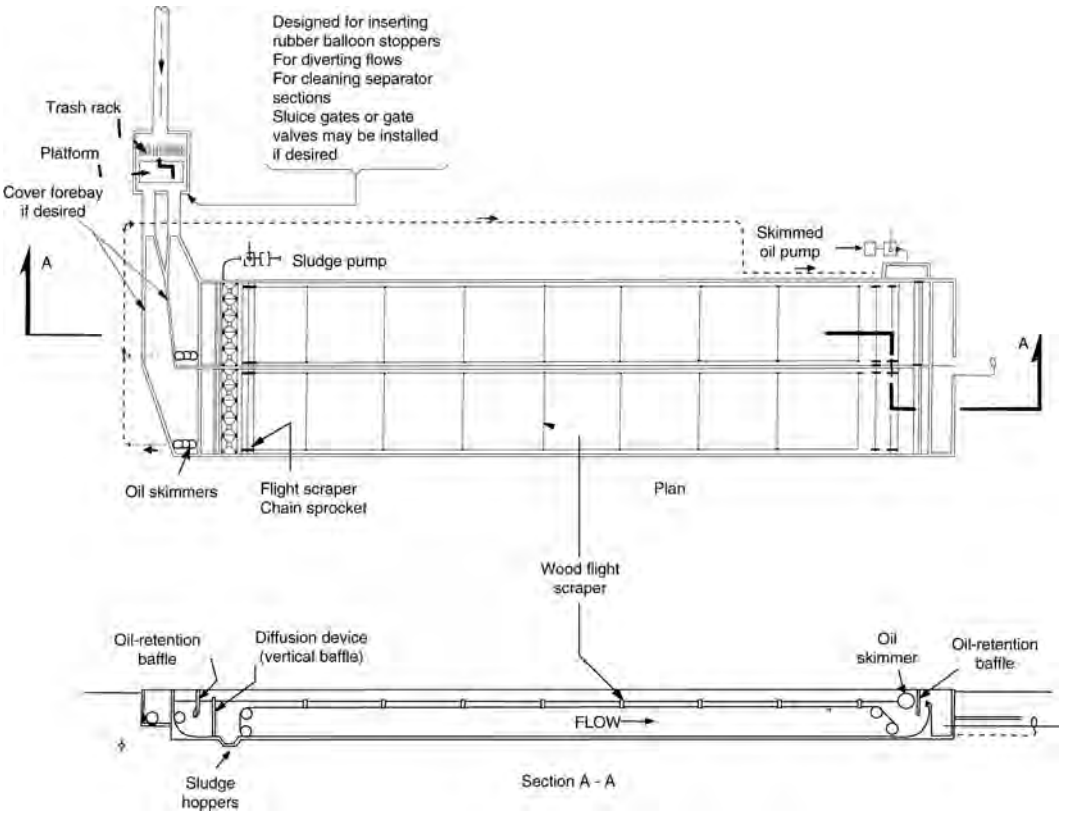


Fig. 4.2—API oil/water separator (reproduced courtesy of the American Petroleum Inst.).

The height of the water column can be determined from retention-time requirements as follows:

$$Z_w = 0.7\frac{t_r q_w}{(d_i)^2}\ , \quad \text{..... (4.7)}$$

where Z_w = the height of the water column.

API Separators. An API separator is the name given to a horizontal, rectangular cross-section, atmospheric oil skimmer that follows the sizing equations and guidelines included in the API *Manual on Disposal of Refinery Wastes*.[3] **Fig. 4.2** shows a typical API separator. The equations for sizing and their derivations are discussed in the Solids-Settling section of this chapter. API separators find limited use in offshore facilities because of their large size.

Plate Coalescers. Various configurations of plate coalescers, commonly called parallel plate interceptors (PPI), corrugated plate interceptors (CPI), or crossflow separators, have been devised. These coalescers depend on gravity separation to allow the oil droplets to rise to a plate surface, where coalescence and capture occur. Flow is split among a number of parallel plates spaced a short distance apart. To facilitate capture of the oil particles, the plates are inclined horizontally.

As shown in **Fig. 4.3**, an oil droplet entering the space between the plates will rise in accordance with Stokes' law; at the same time, it will have a forward velocity equal to the bulk water velocity. By solving for the vertical velocity that a particle entering at the base of the

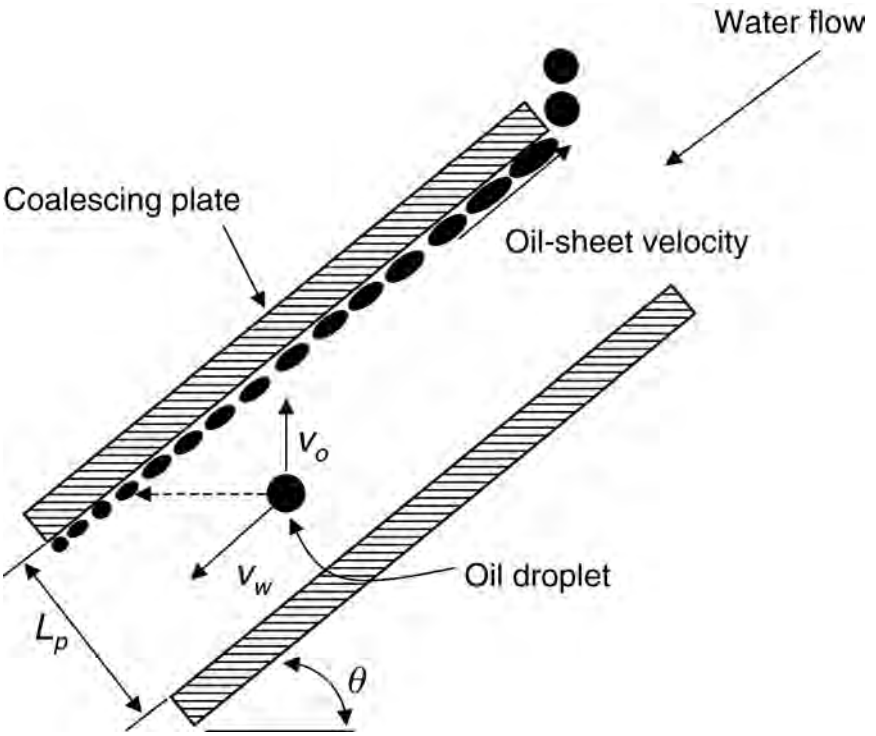


Fig. 4.3—Oil-droplet flow pattern in plate coalescer.

flow needs to reach the coalescing plate at the top of the flow, the resulting droplet diameter can be determined. A restriction is placed on the Reynolds number for the water to ensure that turbulence in this flow does not affect the oil layer on the coalescing plate.

General Sizing Equation. For a plate coalescer with flow either parallel or perpendicular to the direction of flow, the general sizing equation for the droplet-size removal is

$$(d_d)^2 = \frac{4.7 q_w L_p \mu_w}{\cos\theta Z_p B_p L \Delta\gamma_{ow}}, \quad \text{..... (4.8)}$$

where d_d = design oil-droplet diameter, q_w = bulk water flow rate, L_p = perpendicular distance between plates, μ_w= water viscosity, θ = angle of the plate with the horizontal, Z_p = height of the plate section perpendicular to the axis of water flow, B_p = width of the plate section perpendicular to the axis of water flow, L = length of plate section parallel to the axis of water flow, and $\Delta\gamma_{ow}$ = difference in specific gravity between oil and water. Experiments have indicated that on the basis of the hydraulic radius as the characteristic dimension, the Reynolds number for the flow regime cannot exceed 400. Thus, the maximum flow rate is given by

$$(q_w)_{\max} = \frac{1562 Z_p B_p}{L_p}. \quad \text{..... (4.9)}$$

PPI. The first form of plate coalescers was the PPI. This involved installing a series of plates parallel to the longitudinal axis of an API separator (a horizontal, rectangular cross-sectioned skimmer). The plates form a V when viewed perpendicular to the flow axis so that the

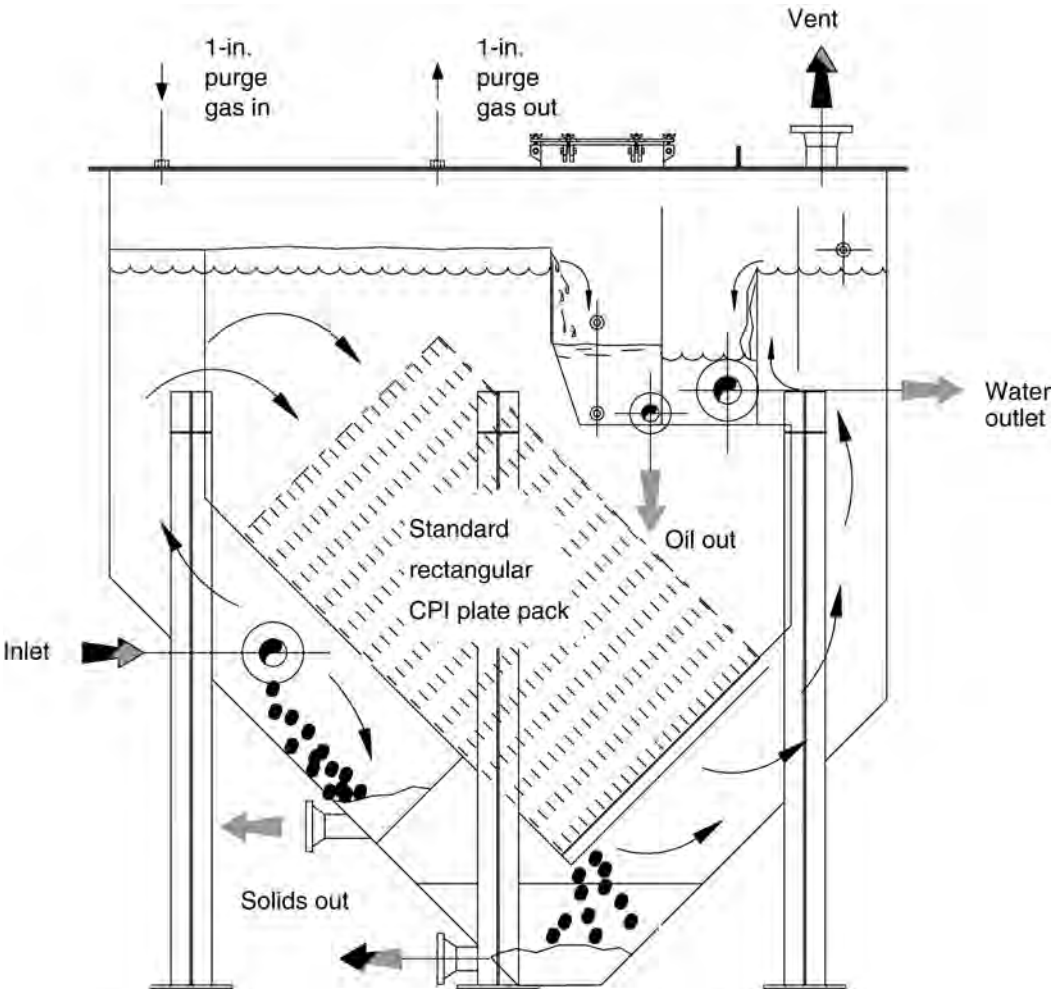


Fig. 4.4—CPI separator schematic and flow pattern (courtesy of Natco).

oil sheet migrates up the underside of the coalescing plate and to the sides. Sediments migrate toward the middle and down to the bottom of the separator, where they are removed.

CPI. The most common PPI form used in production facilities is the CPI. This is a refinement of the PPI in that it takes up less platform space (length) for the same particle-size removal and has the added benefit of making sediment handling easier. **Fig. 4.4** is a typical design with a corrugated plate.

In CPIs, the parallel plates are corrugated (like roofing material), with the axis of the corrugations inclined to an angle of 45°. The bulk water flow is forced downward; the oil sheet raises upward counter to the water flow and is concentrated in the top of each corrugation. When the oil reaches the end of the plate pack, it is collected in a vertical channel and brought to the oil/water interface. CPIs require frequent cleaning of the plate packs in which large amounts of sediment are handled.

Crossflow Devices. CPI configurations are available for horizontal water flow perpendicular to the axis of the corrugations in the plates. This allows the plates to be put on a steeper angle to facilitate sediment removal and to enable the plate pack to be packaged more conveniently in a pressure vessel. The latter benefit may be required if gas blowby through an upstream

dump valve could cause relief problems with an atmospheric tank (see the discussion on gas blowby in the Safety Systems chapter in this section of the *Handbook*).

Crossflow devices can be constructed in either horizontal or vertical pressure vessels. The horizontal vessels require less internal baffling because the ends of nearly every plate conduct the oil directly to the oil/water interface and the sediments to the sediment area below the water flow. The vertical units, although requiring collection channels on one end to enable the oil to rise to the oil/water interface and on the other end to allow the sand to settle to the bottom, can be designed for more efficient sand removal. Crossflow separators are used where sand is a considerable problem and are not removed in the process upstream of the CPI.

Practical Limitations. Stokes' law theory should apply to oil droplets as small in diameter as 1 to 10 μm. However, field experience indicates that 30 μm sets a reasonable lower limit on the droplet sizes that can be removed. At less than this size, small pressure fluctuations and platform vibrations tend to impede the rise of droplets to the coalescing surface; thus, the practical limit for sizing-plate coalescers is 30-μm removal.

Skim Pile. Skim piles are gravity water-treating devices used offshore. As shown in **Fig. 4.5**, flow through the multiple series of baffle plates creates quiescent zones that reduce the distance a given oil droplet must rise to be separated from the main flow.

Once in the quiescent zone, there is plenty of time for coalescence and gravity separation. The larger droplets then migrate up the underside of the baffle to an oil-collection system. Skim piles are used extensively to treat deck drainage of washdown or rainwater that has been contaminated with oil. They have the added benefit of providing some degree of sand cleaning. Sand traversing the length of a skim pile will abrade on the baffles and be water washed. This removes the free oil, which is then captured in the quiescent zone.

Skim Pile Sizing-Deck Drainage. Field experience has indicated that acceptable effluent is obtained with 20 minutes of retention time in the baffled section of the pile. Using this and assuming that 25% of the volume is taken up by the coalescing zones,[2]

$$(d_i)^2 L_{bs} = 19.1(q_w + 0.356 A_d q_r + q_{WD}) , \quad \text{..... (4.10)}$$

where d_i = pile internal diameter; L_{bs} = length of baffle section; q_w = produced-water rate if it is disposed in pile, B/D; A_d = deck area; q_r = rainfall rate; and q_{WD} = washdown rate.

Intermittent Flow. During periods of no flow, oil droplets rise to the area of the quiescent zone and become trapped and protected from being swept back into the flow stream when flow is resumed. The net effect of the baffles is to reduce this rise distance. Each time that flow is stopped as the water traverses the baffled section, more oil particles are trapped in the quiescent zone.

This phenomenon can be used when a skim pile is used downstream of a skim tank or CPI for further treating. With a snap-acting water dump on the influent, intermittent flow is established in the pile.

If t = the time in seconds for the dump cycle,

$$N_c = \frac{41.7(d_i)^2 L_{bs}}{q_w t} , \quad \text{..... (4.11)}$$

where N_c = the number of nonflow cycles that a particle sees as it traverses the baffle section.

If t_c = the time the valves are closed, the removal efficiency on any cycle of a particular drop size is

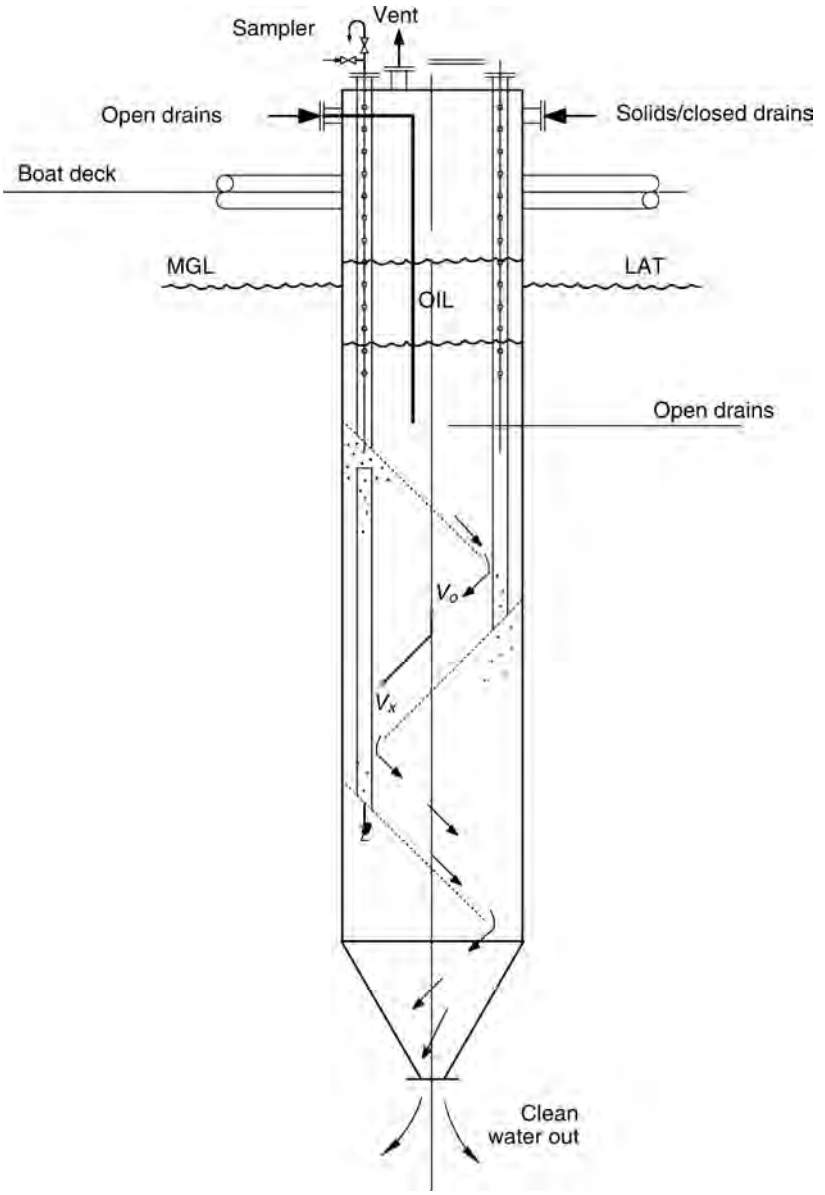


Fig. 4.5—Skim-pile flow pattern (courtesy of Natco).

$$E_{rc} = \frac{4.3 \times 10^{-5}(\Delta\gamma_{ow})(d_p)^2 t_c}{\mu_w d_i} \quad \text{..... (4.12)}$$

The overall removal efficiency of that particle size can then be determined by

$$E_{ro} = 1 - \left(1 - E_{rc}\right)^{N_c} \quad \text{..... (4.13)}$$

4.2.3 Gas Flotation Units. Flotation units do not rely on gravity forces for separating the oil droplets; in fact, the action of these units is independent of the oil-droplet size. In gas flotation

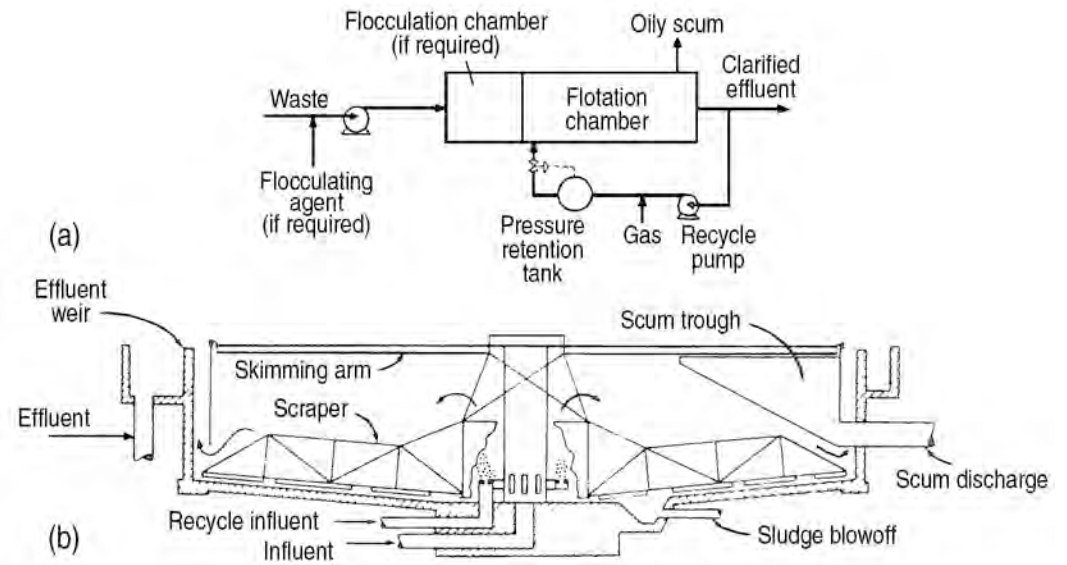


Fig. 4.6—Air flotation process (a); circular flotation chamber details (b). (Reproduced courtesy of the American Petroleum Inst.)

units, large quantities of small-diameter gas bubbles are injected into the water stream. The bubbles attach to the oil droplets suspended in the stream, causing them to rise to the water surface and form a froth layer. Experimental results have shown that very-small-diameter oil droplets in dilute suspensions can be removed easily by flotation. High percentages of oil removal are achieved.

Two distinct types of flotation units have been used, distinguished by the method employed in distributing small gas bubbles throughout the water. These are dissolved- and dispersed-gas units.

Dissolved-Gas Units. Dissolved-gas designs take a portion of the treated water effluent and saturate the water with natural gas or air in a contactor. The higher the pressure, the more gas that can be dissolved in the water. However, most units are designed for a contact pressure of 20 to 40 psig. Normally, 20 to 50% of the treated water is recirculated for contact with the gas.

The gas-saturated water is then injected into the flotation chamber, as shown in **Fig. 4.6**. The dissolved gas breaks out of solution in small-diameter bubbles when the flow enters the chamber, which is operated at near-atmospheric pressure.

Design parameters are recommended by the individual manufacturers but normally range from 0.2 to 0.5 scf/bbl of water to be treated and flow rates of treated plus recycled water of between 2 and 4 gal/min-ft^2. Retention times of 10 to 40 minutes and depths of between 6 and 9 ft are specified.

Dissolved-gas units have been used successfully in refinery operations in which air can be used as the gas and where large areas are available. In treating produced water for injection, it is desirable to use natural gas to exclude oxygen. This requires venting the gas or installing a vapor-recovery unit. Field experience with dissolved-natural-gas units has not been as successful as experience with dispersed-gas units.

Dispersed-Gas Units. In dispersed-gas units, gas bubbles are dispersed in the total stream either by use of an inductor device or by a vortex set up by mechanical rotors. **Fig. 4.7** shows a schematic cross section of such a unit.

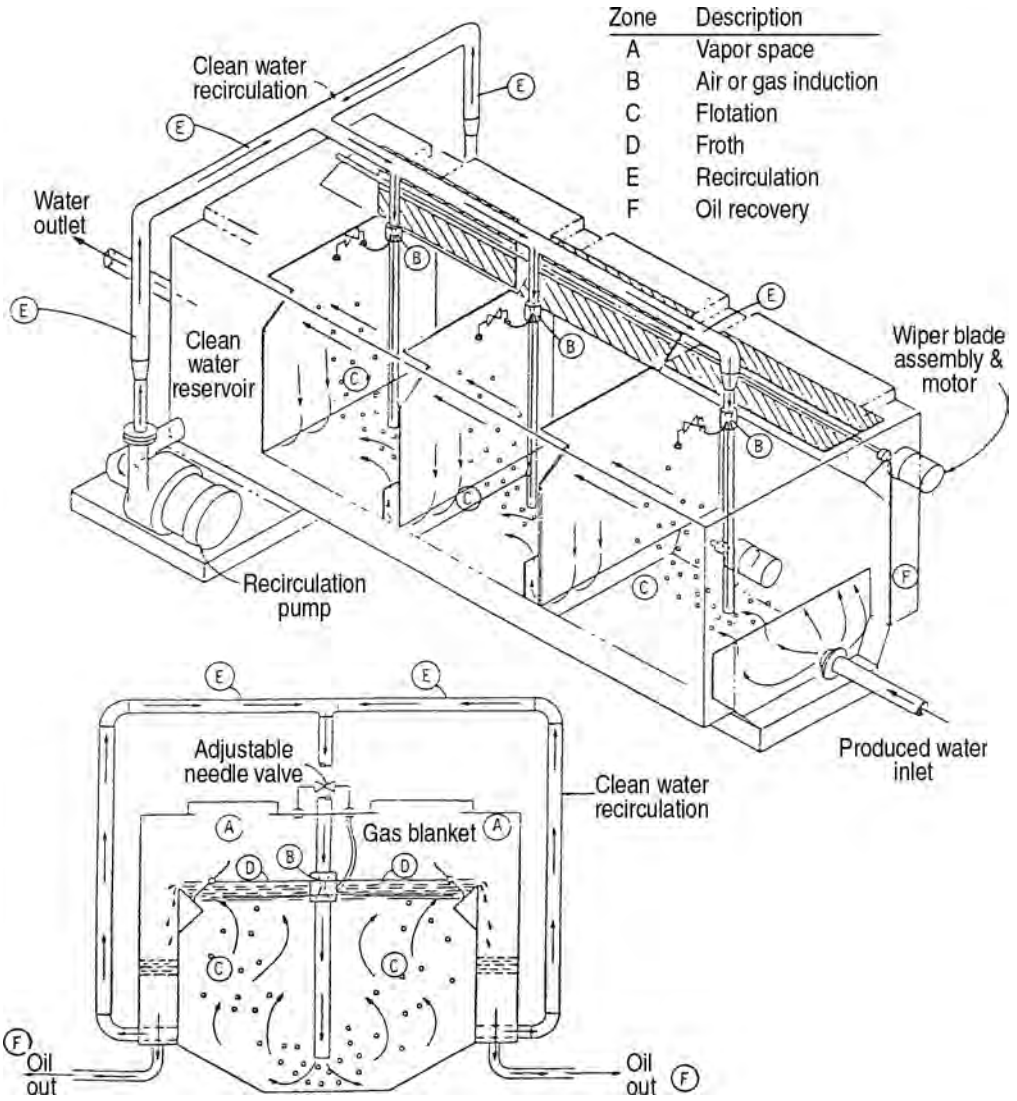


Fig. 4.7—Dispersed-gas unit with inductor device.

Most dispersed-gas units contain three or four cells. Bulk water flow moves in series from one cell to the other by underflow baffles. Field tests have indicated that the high intensity of mixing in each cell creates the effect of plug flow of the bulk water from one cell to the next; that is, there is virtually no short circuiting or breakthrough of a part of the inlet flow to the outlet weir box.

Efficient design of a dispersed-gas unit requires a high gas-induction rate, a small-diameter induced-gas bubble, and a relatively large mixing zone. Thus, the design of the rotor and internal baffles is critical to the unit efficiency. Field tests and theory both indicate that these units operate on a constant percent-removal basis. Within normal ranges, their oil-removal efficiency is independent of inlet concentration or oil-droplet diameter.

There are many different proprietary designs on the market. The most common designs have three to five separate cells in which gas is induced into the water stream. Each cell is designed for an approximately 1-minute retention time to allow the gas bubbles to break free

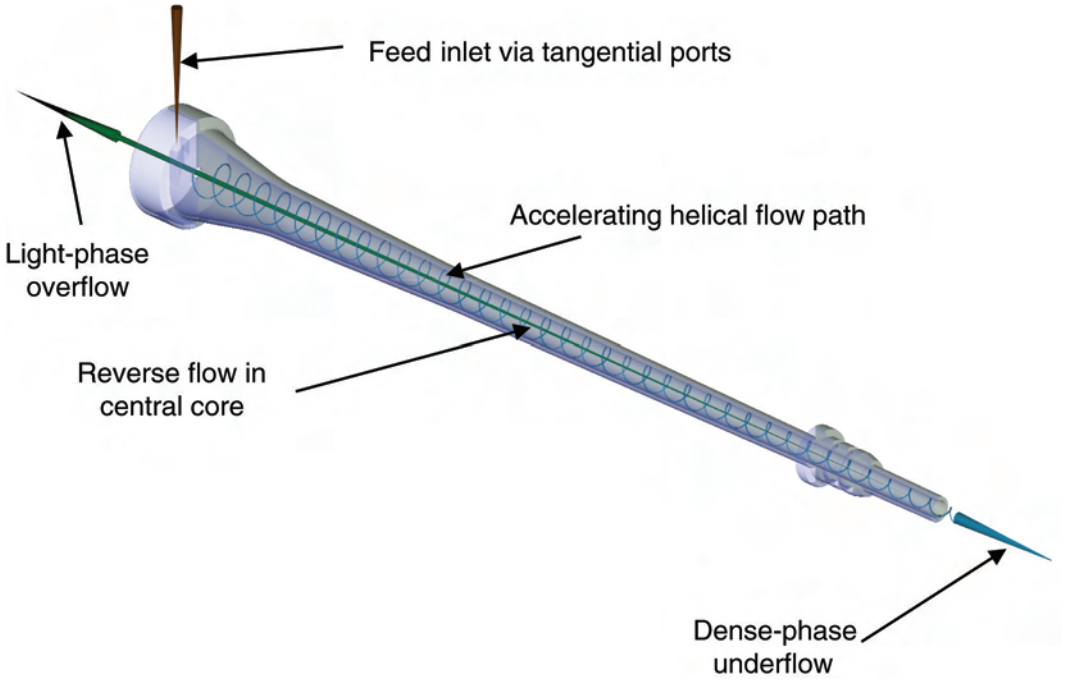


Fig. 4.8—Flow pattern of a deoiler hydrocyclone.

of the liquid and form the froth at the surface. Field experiments show that the designs can remove 50% of the oil in each cell. From Eq. 4.13, a three-cell unit is expected to have an overall efficiency of 87%, and a four-cell unit should have an efficiency of 94%. In practice, the typical efficiency of an installed four-cell unit is only approximately 90%.

Because the unit recycles the gas, a natural-gas blanket can be maintained easily with little or no venting. The low required retention times make this an ideal choice for offshore facilities, where space and weight are at a premium. However, in motion-sensitive installations, sloshing within each cell degrades the performance of the flotation cell.

4.2.4 Deoiling Hydrocyclones. Deoiling hydrocyclones, or "deoilers," provide the highest throughput-to-size ratio of any water-treating technology and are insensitive to motion or orientation. For a given capacity of water to be treated, deoilers will provide the smallest footprint and size of any water-treating technology. Deoilers use fluid-pressure energy to create rotational fluid motion, as shown in **Fig. 4.8**. This rotational motion causes relative movement of materials suspended in the fluid, thus permitting separation of these materials, one from another or from the fluid. In the case of produced-water deoiling, this process can remove small oil droplets from the water stream.

To obtain maximum benefits from a hydrocyclone system, it must be understood that the system must be incorporated differently into the overall process. Because hydrocyclones are pressure driven, they ideally should be located as close as possible to the oily water outlet of the three-phase separator. This location results in the simplest and most cost-effective installation with minimum operating cost. At the highest-pressure location in the process, the hydrocyclone will have maximum capacity because there is maximum pressure available. Furthermore, installing the hydrocyclones in this manner will return the best separation performance because the oily water has not yet been exposed to droplet-shearing pressure drops across level control valves.

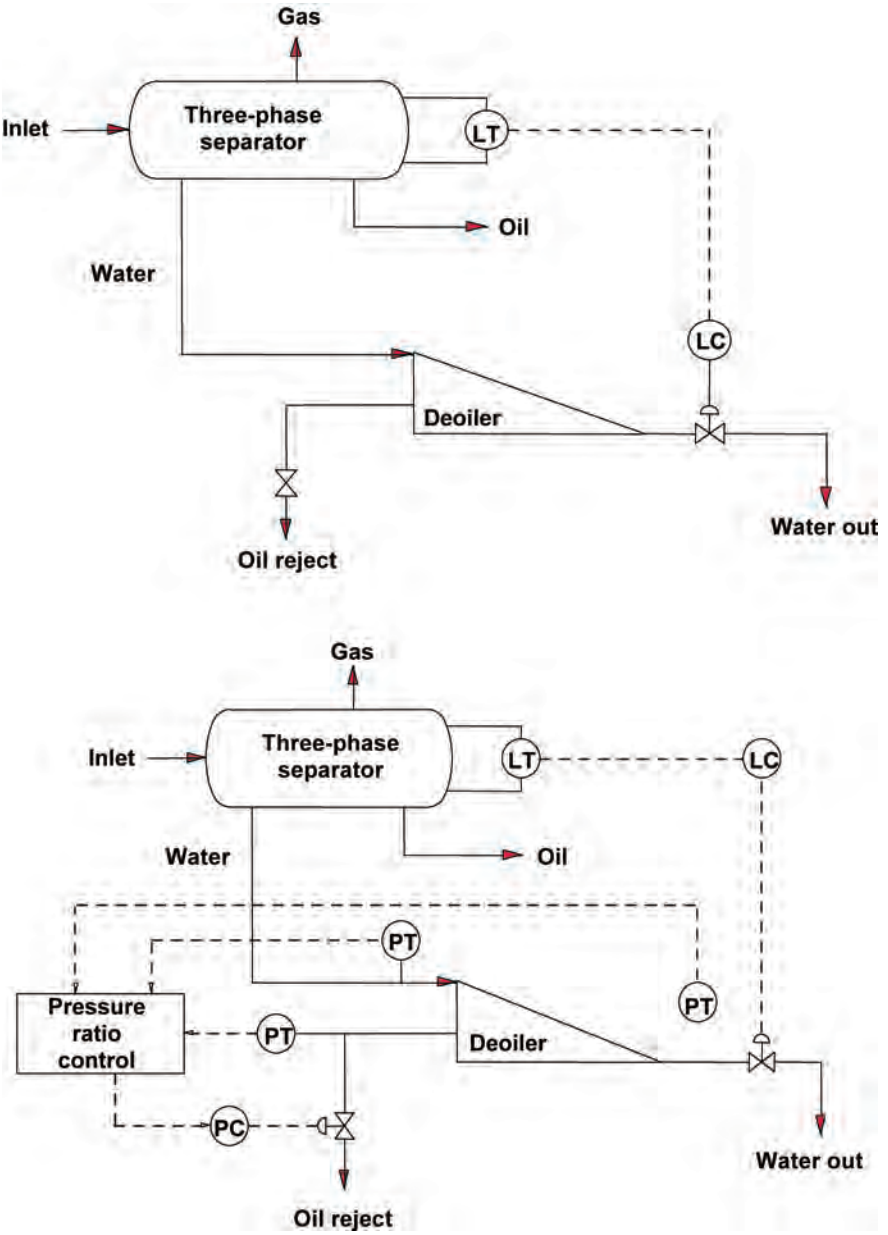


Fig. 4.9—Deoiler (a) throughput control and (b) pressure-ratio control.

An added advantage of deoiling hydrocyclones is the simplicity of their control systems, which normally use the standard interface-level control system of the three-phase separator, as shown in **Fig. 4.9**. The hydrocyclones are simply installed on the water outlet of the three-phase separator with the interface-level control valve downstream of the hydrocyclones on their water outlet. This control valve normally will control the flow rate through the deoiler in a proportional control mode. On/off control can be used for very low flow rates but is generally not recommended. In on/off control, there will be a surge of untreated water when the valve is first opened, until the flow stabilizes and there is adequate pressure drop through the hydrocyclone.

The overflow can be controlled by installing a valve on the overflow line that operates in parallel with the interface-level control valve or by using a simple pressure-control system that ensures a constant overflow rate, as shown in Fig. 4.9. This latter control system is referred to as the pressure-ratio control because it keeps a constant ratio between the two pressure drops in the deoiler: the inlet-to-overflow pressure drop and the inlet-to-underflow pressure drop.[4]

If the existing process pressure is less than 25 psig, it is recommended to boost the pressure by pumping the water to the hydrocyclone system. It is imperative that strict guidelines are followed when designing a pumped hydrocyclone system. Pump selection and operation are critical because the wrong pump type, or even the correct pump type operated incorrectly, can introduce considerable droplet shear.

Low-shear pumps provide the best performance in this application. Positive-displacement pumps can be low shear if they are equipped with low-shear check valves, as in the case of reciprocating pumps. Progressing cavity pumps can be excellent low-shear pumps, but they may require more maintenance than is acceptable. Centrifugal pumps are not typically low-shear ones, but some standard centrifugal pumps can be used very effectively for low-shear service. Because of their simplicity, reliability, and relatively low cost, centrifugal pumps are the recommended pumps to feed hydrocyclone systems.

When selecting a centrifugal pump for a deoiler system, almost any brand can be used as long as the following are observed.[5]

- The pump is of closed impeller design.
- Pump operation is near the maximum on the efficiency curve (at least 70%).
- Maximum speed is 1,750 rpm.
- Maximum pressure boost per stage is 75 psi.

Pumps should be controlled by either a recycle loop or a variable-speed control, with the latter typically being more costly. Recycle control is the simplest way of preventing deadhead. The easiest method is for the pump to feed the hydrocyclones directly with the level-control valve from the source vessel located at the water discharge from the hydrocyclone.

4.2.5 Centrifuges. Disc-stack centrifuges for produced-water cleanup have been in use for the past 10 years.[6] They are used primarily for difficult applications to remove very small droplets of oil and for cases in which the fine-oil droplets do not coalesce easily. The disk-stack centrifuge consists of a frame, drive motor, transmission, separator bowl, and inlet/outlet arrangements, as shown in **Fig. 4.10**. The separation process takes place inside the rotating bowl at up to 6,000 g-forces. Produced water is introduced in the center of the bowl through the feed pipe and is accelerated to full rotational speed. The bowl is fitted with special inserts, which shorten the settling distance for oil droplets to 0.5 mm. The annular channels can be regarded as parallel separation vessels. The oil flows toward the center of the bowl against the upper side of the disc. Water and sediment flow outward against the underside of the disc. Disc-stack centrifuges can effectively remove oil droplets as small as 1 to 2 μm, and units are available at 15,000 B/D capacity each.[7]

4.2.6 Walnut-Shell Filters. Media-type filters, covered later in this chapter, are used for removal of fine solids from water. A specific type of media filter that uses walnut shells is used specifically for removing residual dispersed hydrocarbons from produced water. This type of filter is shown in **Fig. 4.11**.

Besides the media type, walnut-shell filters differ from sand filters in the method of backwashing. Recent improvements include the use of mechanical agitation or walnut-shell recirculation in the backwash cycles. The induced shearing or rubbing action removes most of the oil and solids from the walnut shells. Because of the effective oil- and solid-removal procedure, the use of surfactant chemicals generally has been eliminated. Another important improvement is that the walnut-shell filters have significantly reduced the waste volume to approximately

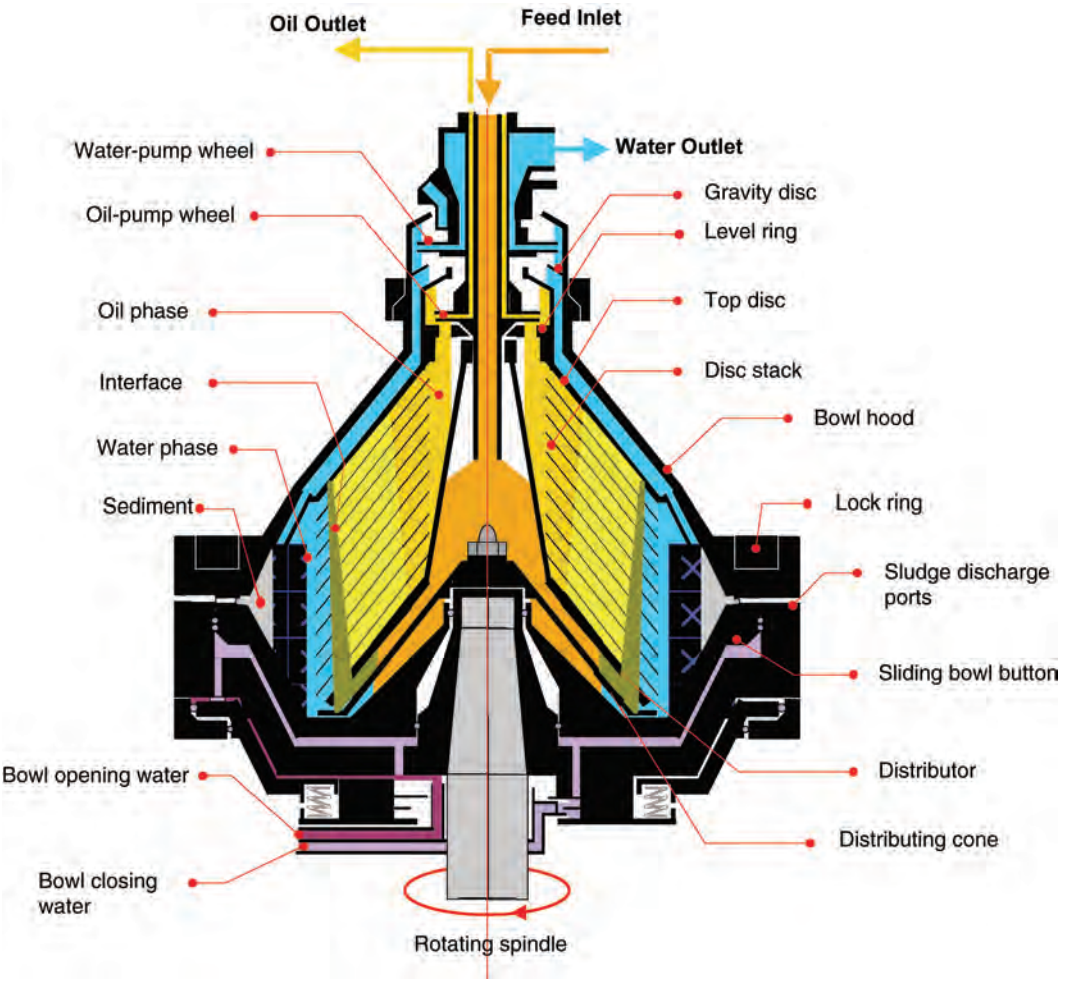


Fig. 4.10—Disc-stack centrifuge for produced-water cleanup (courtesy of Alfa Laval Inc.).

1% of the total throughput. This relatively small amount of backwash waste has made it possible for offshore application, where space for a waste-handling system is limited.

In low-temperature applications, heavy crude may be difficult to remove during the backwash cycle. Chemicals or heat are often required to clean the walnut shells before their reuse. In a steamflood field, the produced water is generally warm or hot, and a chemical or warm-water wash may not be required. For the previous reasons, walnut-shell filters have grown in acceptance with steamflood fields.

4.2.7 Removing Dissolved Hydrocarbons From Water. As mentioned previously, when oil is produced from underground formations, water is also produced. In fact, the amount of water that comes to the surface will, with time, exceed the amount of oil. Because the produced water stream is considered a waste product, it is more economical for offshore operators to dispose of produced water near the producing platform in the ocean. It should be noted that dissolved or water-soluble hydrocarbons are present in all produced-water streams. The amount of water-soluble hydrocarbons varies depending on the properties of the hydrocarbon, the operating conditions (particularly temperature and pressure), the reservoir characteristics, and other



Fig. 4.11—Walnut-shell filters applied in a steamflood operation.

factors. It also should be noted that other kinds of dissolved organic matter are present in produced water. In general, water-soluble organic matter falls into one of the following classes: aliphatic hydrocarbons; phenols; organic acids; and aromatic compounds, such as benzene and toluene.[8,9]

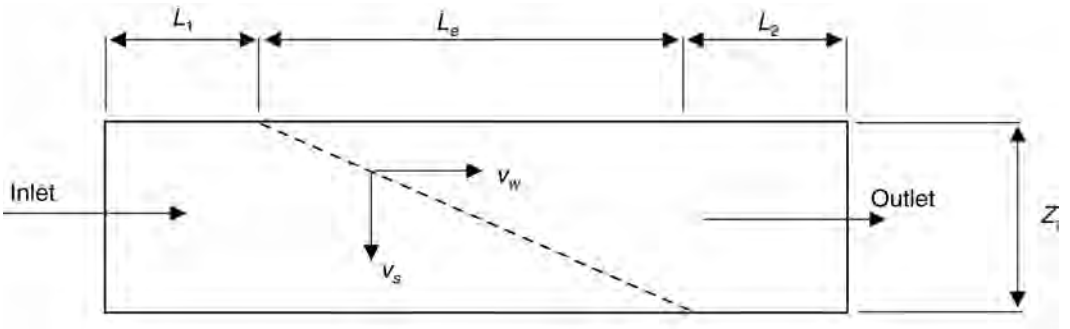
Hydrocarbon discharges are, in most cases, regulated by a government agency such as the U.S. Environmental Protection Agency (EPA). The goal of these regulatory bodies is to minimize the impact that produced-water discharges have on the local environment. Therefore, the EPA and other regulatory bodies around the world set limits for the amount of total hydrocarbons, or "oil and grease," contained in the produced water discharged from offshore platforms. These limits usually are expressed in terms of milligrams per liter (mg/L) of the contaminant in the disposal stream. The EPA currently sets the limit of oil and grease in water discharged into federally regulated areas of the Gulf of Mexico at 42 mg/L daily maximum and 29 mg/L monthly average, per Natl. Discharge Pollution Elimination System (NPDES) General Permit #28000.[9] Research into the environmental impact (toxicity) of dissolved hydrocarbons concludes that discharges into a body of water from responsibly operated facilities will have a negligible environmental impact.[10] This conclusion is based on research showing that low levels of dissolved hydrocarbons are assimilated quickly into the ecosystem of the receiving body. Furthermore, responsibly operated facilities provide means for the contaminants in produced water to be diluted quickly to levels well within toxicity limits. As an example, discharged water from a North Sea platform is diluted between 50 and 400 times within 40 to 70 seconds after discharge.[11]

TABLE 4.1—METHODS FOR REMOVING DISSOLVED ORGANIC COMPONENTS FROM PRODUCED WATER

Type of Treatment	Advantages	Disadvantages
pH Adjustment	• Ease of application • Well understood • Continuous operation • Minimal waste to handle • Comparatively lower operating costs	• Increased corrosion potential • Increased scaling tendency • Handling of dangerous material
• Mineral acids • Patented mineral-acid blends		
Adsorption/Absorption	• High removal efficiency • No corrosion of equipment • No scale deposition	• Must dispose of spent material • Comparatively higher operating costs • Potential to foul the bed of material • Process not well understood by operators • Not easy to make adjustments
• Activated carbon • Organoclays		

The measurement of oil and grease must be considered to understand the criteria for determining whether removal of dissolved hydrocarbon material is necessary. Using the EPA as an example, the current EPA-approved measurement techniques are EPA Method 413.1 or 1664. Both methods are gravimetric—Method 413.1 uses freon as a solvent, and Method 1664 uses *n*-hexane. These methods involve pH reduction to less than 2 (to precipitate the dissolved hydrocarbons), extraction of the dispersed and dissolved components from the produced water with the solvent, extract separation, and solvent vaporization, leaving a residue considered to be the "oil and grease" component. However, there are two reasons that these methods do not accurately measure the total amount of hydrocarbons in the produced water. First, the solvent removes not only the dispersed and dissolved hydrocarbons but also the nonhydrocarbon organic matter, such as phenols, organic acids, alcohols, and ketones. Second, during the evaporation step of the measurement technique, low-molecular-weight volatile hydrocarbons [alkanes and aromatic hydrocarbons, such as benzene, toluene, ethylbenzene and xylenes (BTEX)] flash off. Hence, "oil and grease," as defined by the EPA measurement techniques, excludes some hydrocarbon components from vaporization and includes some nonhydrocarbon components from extraction by a nonselective solvent.[8,9]

It is apparent that for an offshore oilfield operator to meet the federally imposed discharge limits, most of the dispersed oil will have to be removed before the discharge point. The foregoing discussion in "Separating Free Hydrocarbons From Water" contains a review of the types of equipment and processes commonly used to remove the dispersed-oil constituents. Furthermore, if the amount of dissolved organic matter is sufficiently high, it also may be necessary to remove the dissolved organic material to comply with the total oil and grease discharge limit. At present, most of the operating facilities worldwide are meeting compliance standards by removing only the dispersed hydrocarbons. However, there are operators that must also remove the dissolved organic material to be compliant. In these instances, some of the more common methods used for offshore applications are pH adjustment with stock mineral acids or patented mineral/acid blends and the use of adsorption/absorption materials (activated carbon). Each method has inherent advantages and disadvantages, as shown in **Table 4.1**.



L_1 = Inlet distribution section
L_e = Effective settling section
L_2 = Outlet gathering section
v_w = Water velocity
v_s = Settling velocity

Fig. 4.12—Model for calculation of sedimentation flume capacity.

4.2.8 Separating Suspended Solids From Produced Water. The water being treated may have suspended solids, such as formation sand, rust from piping and vessels, and scale particles. It may be necessary to remove these solids to prevent wear in high-velocity areas, solids from filling up vessels and piping and interfering with instruments, and oil-coated solids from being discharged overboard. These solids can be separated from the water stream by gravity settling, hydrocyclone desanders, filters, or centrifuges. Furthermore, once the solids are removed, they must be handled in a manner sufficient to comply with spatial, operational, and environmental constraints. Handling steps may include separation, accumulation, cleaning, dewatering, and haulage.

Gravity Settling. Solid particles, because of their heavier density (compared to water) and net negative buoyant force, will settle to the bottom with a terminal velocity that can be derived from Stokes' law, as shown in Eq. 4.1. This equation applies strictly to creeping flow regimes in which the Reynolds number is less than unity; this is mainly concerned with spheres of very small diameter surrounded by a liquid. For very small particles, the inertial forces are much less than the viscous forces because of the low particle mass, and the particle does not enter into a turbulent settling regime. This equation can be used to size a tank, vertical or horizontal pressure vessel, rectangular sedimentation chamber, or device of any other configuration to allow a particle of a certain diameter and specific gravity to settle under natural gravity conditions.

Most sedimentation basins are rectangular flumes with length-to-width ratios of 4:1 or greater to limit crossflow. The width of the flow channel can be determined by setting the time required for a particle to settle from the top of the flume to the bottom equal to that required for the water to traverse from the inlet of the flume to the outlet, as shown in **Fig. 4.12**. This can be expressed as

$$b = \frac{36 q_w \mu_w}{\Delta\gamma (d_p)^2 L_e}, \quad \text{..... (4.14)}$$

where b = width (breadth) of the flow channel (ft), q_w = water flow rate, and L_e = effective length.

Note that the width and length of the settling chamber are independent of its depth. The API *Manual on Disposal of Refinery Wastes*[3] recommends a turbulence and short-circuiting factor of between 1.3 and 1.8, depending on the ratio of water velocity to solids-settling velocity. Using a factor of 1.8, Eq. 4.14 can be rewritten as

$$b = \frac{65 q_w \mu_w}{\Delta\gamma (d_p)^2 L_e} \quad \text{..... (4.15)}$$

API also recommends that the water velocity be limited to 15 times the settling velocity or 3 ft/min, whichever is less. The settling velocity can be calculated from Eq. 4.1, and the water velocity can be calculated from

$$v_w = 6.5 \times 10^{-5} \frac{q_w}{h_f b} \quad \text{..... (4.16)}$$

where v_w = velocity of water, and h_f = height of the flume. For practical considerations, b should be between 6 and 20 ft, and the ratio of h_f to b should be between 0.3 and 0.5.

The flume can be concrete-lined or constructed as a soil pit; solids that settle in the bottom of the flume can be cleaned out with a bucket. A mechanical sludge scraper run on chain could be installed to concentrate the solids in one location for easy removal.

Desanding Hydrocyclones. Desanding hydrocyclones, called desanders, offer the highest throughput-to-size ratio of any solids-removal equipment. **Fig. 4.13** shows the basic operation of a desander. By definition, all hydrocyclones operate by pressure drop. The feed, a mixture of liquids and solids, enters the cyclone through the volute inlet at the operating feed pressure. The change in flow direction forces the mixture to spin in a radial vortex pattern. Because of the angular acceleration of the flow pattern, centrifugal forces are imparted on the solid particles, forcing them toward the internal wall of the cone. The solids continue to spin in a radial vortex pattern, down the length of the cone, and discharge through the apex, creating the underflow stream. Because of cone convergence, the liquid flow is reversed and sent upward through the vortex finder to create the overflow stream. The solids that exit through the apex collect into an accumulation chamber and are periodically purged, while the overflow discharges continually.

The particle size that is separated depends on the pressure drop through the desander, and the pressure drop, in turn, is dependent on the flow rate. Thus, there is a minimum flow and pressure drop that must be provided for each desander to settle a certain particle size. For general comparison information, in a produced-water-treatment application, a 0.5-in. (10-mm) desander will have a separation size of 5 μm, while a 30-in. (750-mm) desander will have a separation size of 100 μm. The practical limit for sand separation from water by a hydrocyclone is 10 μm. An estimation of particle separation size by a desander can be calculated from the following equation:[12]

$$x_{98} = \frac{0.0094 D^{1.18} \exp^{6.3c}}{Q_f^{0.45} (\rho_s - \rho_l)^{0.5}} \quad \text{..... (4.17)}$$

where x_{98} = particle size at 98% efficiency, D = internal diameter of the cyclone, c = solids concentration, Q_f = feed volumetric flow rate, ρ_s = solid density, and ρ_l = liquid density.

The previous equation is based on a fixed hydrocyclone geometry relationship, and the desander geometry is unique to each manufacturer. The design is typically scalable in that the

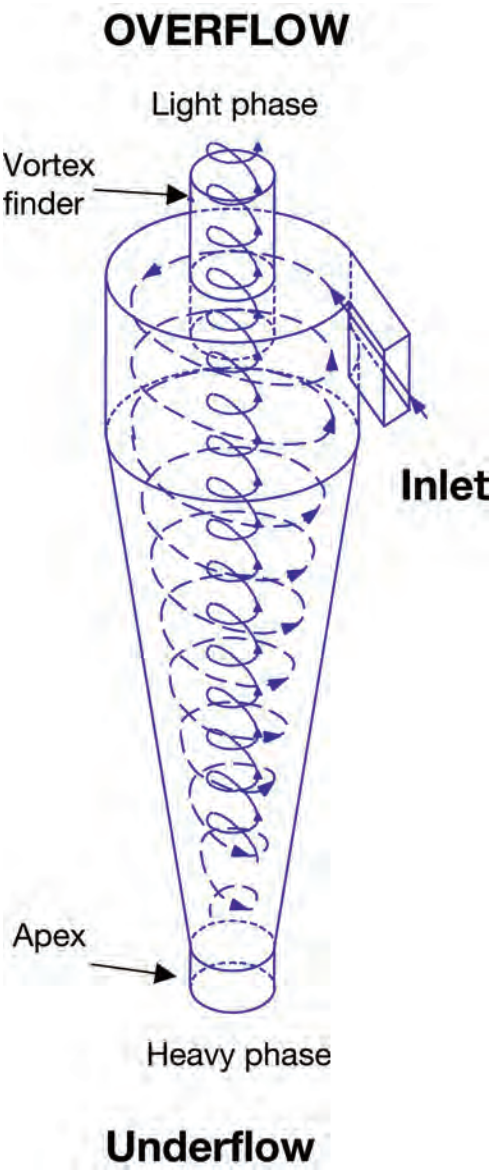


Fig. 4.13—Flow patterns of a desander hydrocyclone.

inlet area, vortex-finder diameter, length, and apex diameter are proportional to the internal diameter (D). A desander acts as a fixed orifice in the flow stream, with the pressure drop proportional to the flow rate. Each manufacturer can provide a pressure-drop curve, so that the pressure drop is known for a given flow rate. As such, the pressure drop and flow rate are used interchangeably.

The desander pressure drop is the main operating parameter that practically can be changed on line to influence separation efficiency. The desander can operate in a wide pressure-drop range and, thus, inherently has a high turndown ratio. The minimum operating pressure drop for a desander is 5 psig. At less than this value, the fluid does not contain enough energy to form the proper vortex flow pattern. No theoretical maximum pressure drop exists, but 100 psi is recommended as a practical maximum to balance wear and recovery.

TABLE 4.2—SELECTION CRITERIA FOR DESANDER TYPES

Selection Criteria	Vessel	Liner
Inlet solids concentration >1%	Yes	No
Very large solids present (>5 mm)	Yes	No
Fine-particle recovery (<20 μm)	No	Yes
System design rating >900# ANSI	No	Yes
Vessel fabricated of any metal	Yes	Yes
Liner material available in ceramic	Some	Yes
Pressure vessel subjected to wear mechanism	Yes	No
Replaceable wear components	Yes	Yes
Inherent turndown of >3:1	Yes	Yes
Available in package design (turndown >50:1)	No	Yes

Fig. 4.14 shows the two types of desanders that are commonly used in water systems—the vessel style and the liner style. The criteria in Table 4.2 are used to select the proper style.[13]

Because of the simpler design (i.e., without ceramic liners or tube sheets), the vessel desander has a lower capital cost when compared to the liner design. In most applications, though, the deciding factor is the required separation size, which is why most conventional desanders in oil and gas production are of the liner design.

Filtration. To avoid plugging the injection formation, it may be necessary to separate small-diameter suspended particles by filtration. Filters cannot handle the volume of solids that can be handled by sedimentation and desanders, but they are the only practical method for separating very fine particles (< 10 μm). By properly choosing the filter element, filters can remove fine solids in the 0.5- to 50-μm range and are used as a form of secondary treatment. The three types of filters commonly used are cartridge, media, or diatomaceous-earth filters. Because filtration is more commonly used with injection of surface water, this technology is covered in further detail here.

Centrifuges. Centrifuges are used on drilling rigs to separate low-gravity drill solids and to reclaim high percentages of heavy solids. They have not found wide use in producing operations because of the high maintenance associated with their use. Normally, if it is desirable to separate solid particles with a diameter less than that resulting from sedimentation or desanders, filters are used.

4.2.9 Solids Handling. Once solids separation is identified as a need in a produced-water system, facilitating the solids handling becomes an important need in overall system design. Systems are based on modular designs that can be built to handle a very wide range of process needs for either land-based or offshore systems. These systems should be manufactured to require minimal operator intervention and, in case of hazardous disposal, minimal contact.

Solids handling can be broken down into five areas[13]:

• Separate. Separation is defined as diverting the solids and liquids contained in a mixed slurry stream to different locations. The solids are removed from the produced-water stream by a gravity vessel (tank bottoms or vessel drain), desander, sand-jet system, or filter dump.

• Collect. Collection is defined as gathering all separated solids into a central location and physically isolating them from the production process. By collecting the solids in one location,

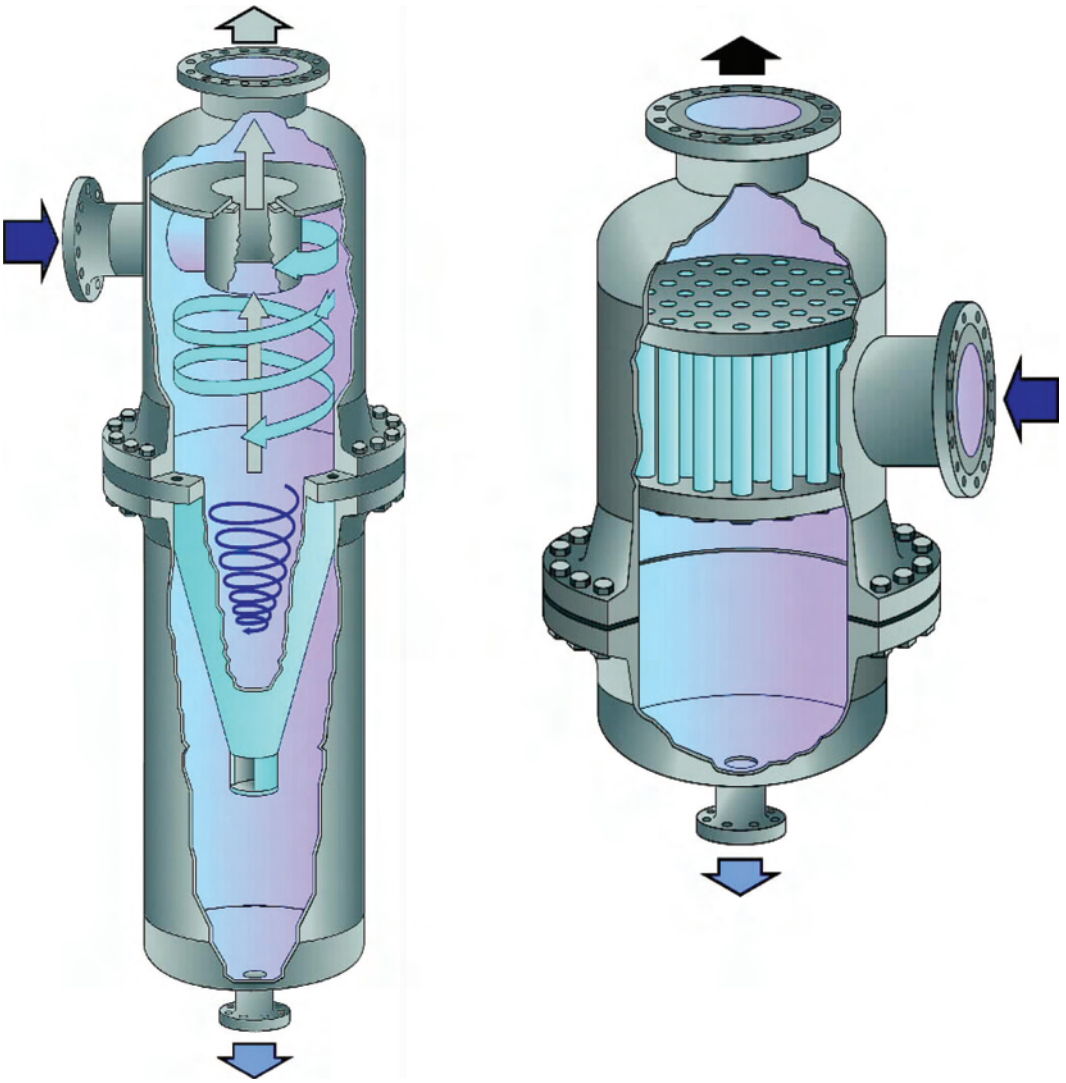


Fig. 4.14—Schematic of vessel-style and liner-style desanders (courtesy of Krebs Engineers).

a simpler system can be designed to isolate the solids from the process. Collection can be as simple as a desander accumulator vessel or a dedicated sump tank.

• Clean. In many cases, the sand may require cleaning of adsorbed oil or chemicals before further handling. Sand-cleaning systems are offered as modular add-on packages or integrated into the separation system.

• Dewater. The total volume of sand slurry to be transported and disposed of can be greatly reduced by a dewatering step, which involves removing the liquids from the collected (cleaned) solids slurry. A range of systems is available to provide dewatering from a sand-drainage bag to a filter press or screw classifier. The goal is to reduce the liquid to less than 10% by volume.

• Haulage. Haulage is a simple term used to define removing, hauling, and disposing of the solids. The design of the haulage system will be dependent upon location (land-based or off-shore) and disposal requirements (i.e., disposal well, overboard, landfill, road surfacing, etc.).

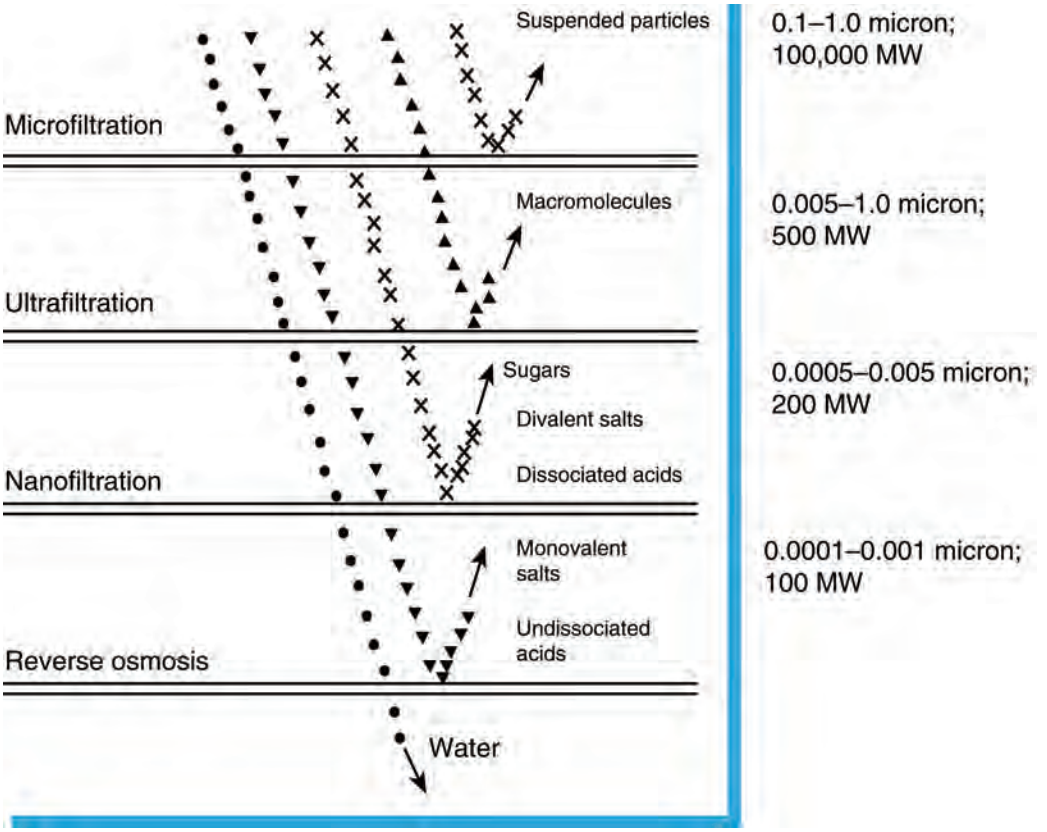


Fig. 4.15—Performance of membrane types.

Offshore systems typically involve crane-to-boat-to-truck transport, while land-based systems may use a truck to a landfill.

Every solids-handling and -disposal system will be different because of economics, environmental and hazardous regulations, location, and total solids to be handled.

4.2.10 Removing Dissolved Solids From Water. Various chemical compounds are dissolved in water as ions to form an aqueous solution. The term "dissolved solids" is used to describe these ions in water; some of the more common are silica, calcium, and magnesium. When water is thermally evaporated or treated with membranes, these ions become saturated and exceed their solubility in water. They will then precipitate or crystallize to form scale. Scale formation plugs piping and fouls the water-handling system, steam-generator tubes, and membranes. Scaling sometimes can be controlled with an inhibitor chemical; however, when this does not work, these ions should be removed from the system. The dissolved ions can be removed from water with membranes, ion exchange, and hot or warm softening.

Membranes. Membranes are predominantly used to remove species of salts and organics from water. Reverse osmosis (RO) can remove 95 to 99% of the metallic ions, such as sodium and potassium salts, as well as a relatively high percentage of organic material. Nanofiltration (NF) can remove most divalent ions, such as sulfate and nitrate, from water. An RO membrane can remove most of the dissolved solids or ions from the water, as shown in Fig. 4.15. Comparatively, NF membranes can remove divalent ions but allow monovalent ions to pass through. Ultrafiltration and microfiltration can remove only the submicron-size suspended particles and are not effective for removing soluble ions.

The performance of a membrane unit can be expressed by the following equation.

$$Q_{pf} = K_f K_T K A \Delta p_{\text{avg}} , \quad \text{..... (4.18)}$$

where Q_{pf} = permeate flow, K_f = fouling factor, K_T = membrane temperature-correction factor, K = permeate flow coefficient at standard temperature, A = membrane area, and Δp_{avg} = average transmembrane pressure drop. Because of the presence of various impurities in water, the membrane gradually will become fouled, and the permeate flow will decrease, measured by the fouling factor, K_f. For a clean, new membrane, the fouling factor is 1.0. This value will decrease gradually, and the membrane element will need to be cleaned. Generally speaking, the membrane element requires cleaning when the fouling factor is decreased approximately 10 to 15%, or when it reaches a value of less than 0.85.

The water flow coefficient, K, is a function of the water/membrane chemistry interaction, especially pH. Normalized permeate rates are higher at a pH of 11 than at 7. Although in general, the water flow coefficient cannot be predetermined, the variation of K_T with temperature is known for each membrane and can be used to normalize permeate-flow data at different temperatures. At any point in the RO system, the transmembrane pressure drop is the difference between the brine hydraulic pressure and the system osmotic pressure plus the permeate pressure. As the brine concentration increases from the feed to reject ends of the membrane system, the transient pressure decreases.

Various types of membrane configurations are available. The most common types are plate and frame, hollow-fiber, monolithic-tubular, tubular, and thin-film-composite spiral-wound, as shown in **Figs. 4.16 through 4.20**. The thin-film-composite spiral-wound membranes have been used successfully to treat brackish oilfield produced waters.[14–16]

It is desirable to produce a high fraction of good-quality permeate water to reduce the amount of concentrate water for disposal. For practical purposes, a 75% recovery of the permeate water can be achieved without seriously fouling the membranes. This level of removal efficiency is relatively high for most of the inorganic and organic materials, as shown in **Table 4.3**.[17] Trace metal removal is also relatively high, as shown in **Table 4.4**.[18]

Ion Exchange. The ion-exchange process is used to remove specific ions from solution. Its primary application in produced-water treatment is the removal of calcium and magnesium ions, which make up the "hardness" in water. Ion exchange used for this purpose is called "water softening." It also can be used to remove residual minerals and, in this instance, is called demineralization.

Water Softening. The water-softening process is used in the oil industry for steamflood operations. To operate reliably at high temperatures and pressures, steam generators require a very low hardness content in the feed water. Scale precipitation can coat the heating tubes, causing localized overheating and tube failure. **Fig. 4.21** shows a typical water-softener bank used in steamflood operations. For this case, the divalent ions, calcium and magnesium, are exchanged with the sodium ions from an ion-exchange resin. After the exchange, the ion-exchange resin is saturated with the divalent ions. It is regenerated with a higher-concentration brine solution, which is rich in sodium ions. This brine solution is generally a 10 to 20% salt (sodium chloride) solution.

There are two types of water-softening resins commonly used in the oilfield for steam generation: strong and weak acid resins. A typical strong acid resin is the sodium zeolite cation-exchange resin, consisting of a synthetic zeolite material that contains numerous cation-exchange sites. These sites primarily contain sodium (Na) ions. The zeolite resin is commonly expressed as "Z," and its ion-exchange reaction with the hardness material, either calcium or magnesium, is shown in the following reactions:

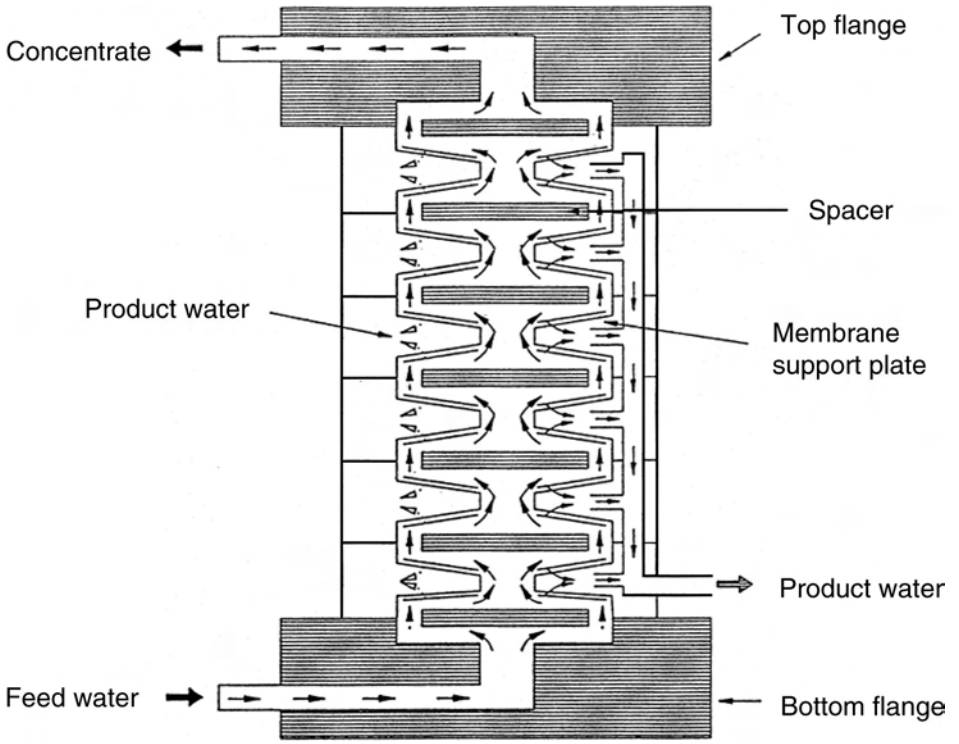


Fig. 4.16—Plate and frame membrane system.

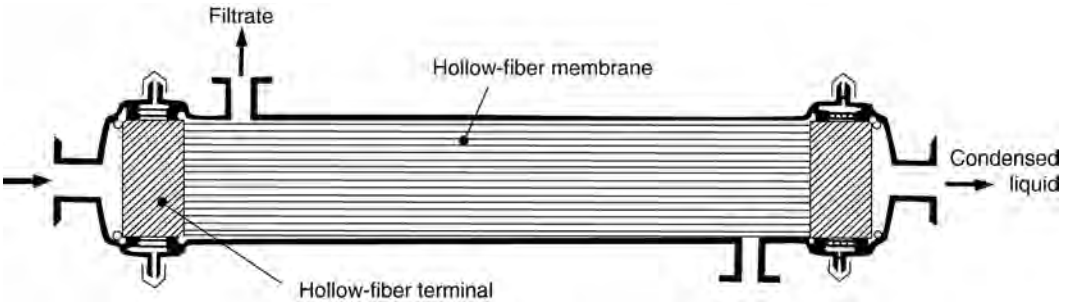


Fig. 4.17—Hollow-filter-membrane system.

$$Na_2Z + CaCl_2 \rightarrow CaZ + 2NaCl\ . \quad \text{..... (4.19)}$$

$$Na_2Z + MgCl_2 \rightarrow MgZ + 2NaCl\ . \quad \text{..... (4.20)}$$

The strong acid resin generally is used for removing the hardness materials from water with relatively low sodium contents or total dissolved solids (TDS). This type of resin attracts the calcium and magnesium ions and exchanges them with a sodium ion upon regeneration. However, as the sodium content in the feed water increases (on the basis of the previous formula), the reaction will go in reverse and start to regenerate during the softening process. This partial regeneration is called the "hardness leak." The hardness leak is pronounced for the

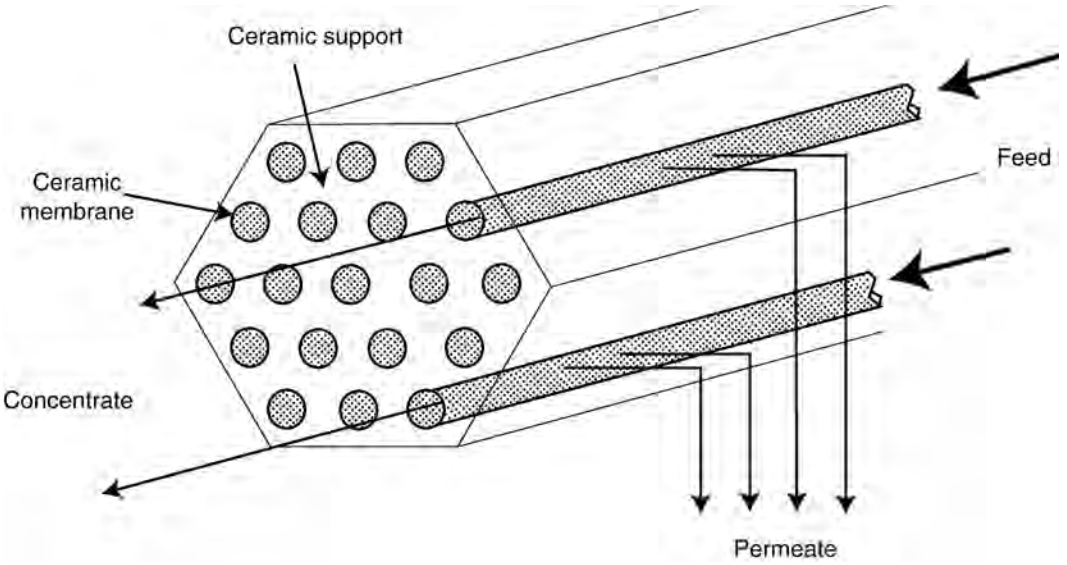


Fig. 4.18—Monolithic tubular membrane module (ceramic construction).

strong acid resins when the TDS of the feed water is greater than approximately 5,000 to 7,000 ppm. Hence, when the concentration of TDS exceeds this limit, strong acid resins are no longer effective.

The sodium ion used for regeneration is common salt (NaCl). During regeneration, the high concentration of salt in the brine exchanges the hardness material, such as calcium ion, with sodium, as shown in the following reaction.

$$CaZ + 2NaCl \rightarrow Na_2Z + CaCl_2 \ . \quad \text{..... (4.21)}$$

The source for regeneration is generally sea salt, produced by the evaporation of seawater; however, rock salt from the land-mining process is sometimes used. The quality of salt is important, and its impurities should be studied before use to minimize operational problems.

The weak acid resins are generally used for removing hardness materials from water with higher sodium content or TDS. The weak acid resin can handle produced water with TDS up to 30,000 to 40,000 mg/L. Its regeneration program uses an acid, such as hydrochloric acid, followed by a base, such as sodium hydroxide. The capital cost of a process of weak acid resins increases in comparison with processes using strong acid resins because of the use of an acid and a base during regeneration, which requires using linings in the vessels and corrosion-resistant piping. Similarly, the operating cost of processes that use weak acid resins increases in comparison with processes using strong acid resins because of the higher cost of the regenerating materials (acids and bases for the weak acid resins vs. a salt solution for the strong acid resins).

Softening the economic breaking point between weak acid resins and strong acid resins is approximately 7,000 mg/L of TDS. When the TDS measures between 5,000 and 7,000 mg/L, there is slight hardness leakage, but the water with a small amount of hardness materials could be treated with a chelant, such as EDTA or NTA, or a combination of chelant and polymeric scale-suppressant chemicals. However, when the TDS is greater than 7,000 mg/L, the hardness leakage would be too much, and a chelant program might become uneconomical.

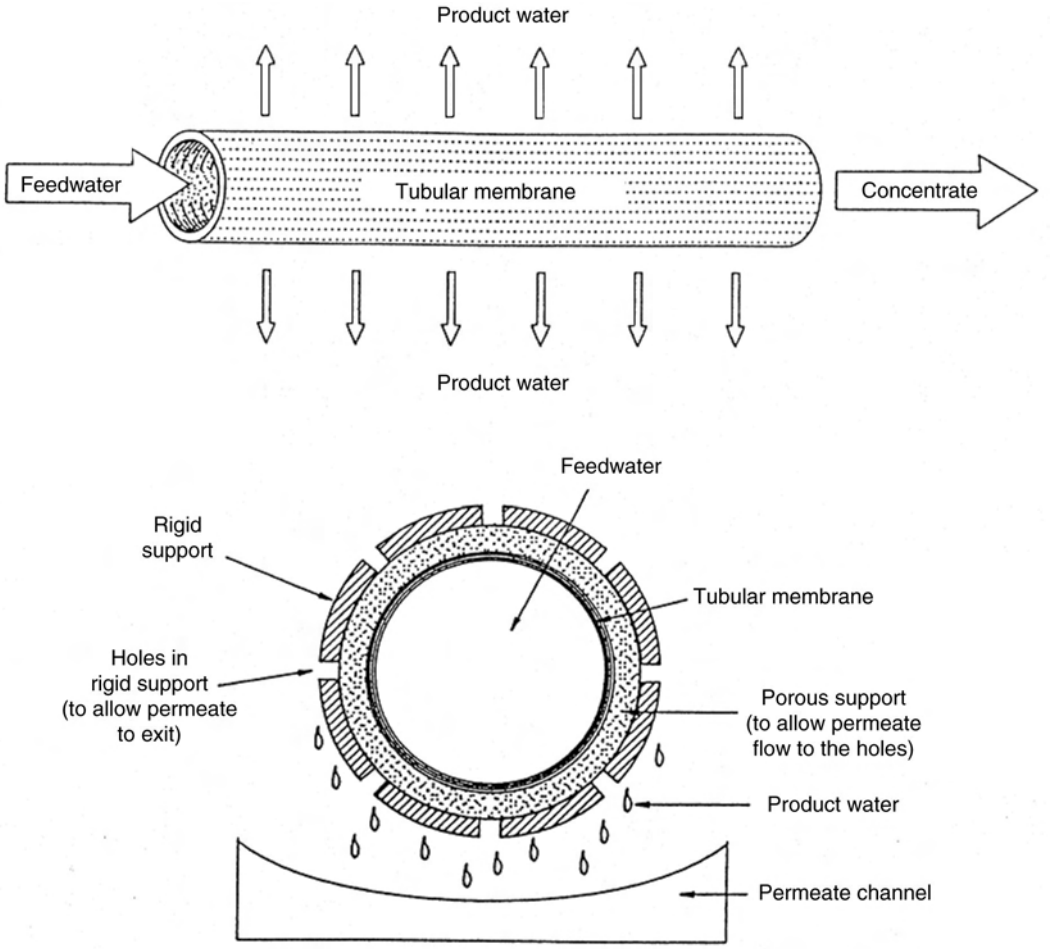


Fig. 4.19—Tubular membrane module (polymeric construction).

Demineralization. Using ion-exchange resins to remove residual minerals from water is called demineralization. This process is generally used for polishing water after membranes, softening, or warm-lime treating. When the minerals are removed, this water can be used in boilers for steamflooding or in steam turbines for electrical generation. The demineralization process uses various types of ion-exchange resins to achieve different results, as summarized in Table 4.5.

Treating produced water with a demineralization system as the final stage for polishing allows it to be used in cogeneration plants for electrical production. Additionally, the produced steam can be used for steamflooding. Because of the use of acid and base chemicals for regeneration, the cost of a demineralization system is relatively high. It can be used only for polishing good-quality water from other pretreatment processes and is generally uneconomical to apply to raw water treatment.

Hot- and Warm-Lime Softening. Hot- and warm-lime-softening processes are other technologies used to remove the hardness and silica ions from produced water for steam generation. The advantages of these systems are that they can process a large amount of water in a relatively small unit, and their applicability, unlike zeolite softeners, is not limited by the water's TDS.

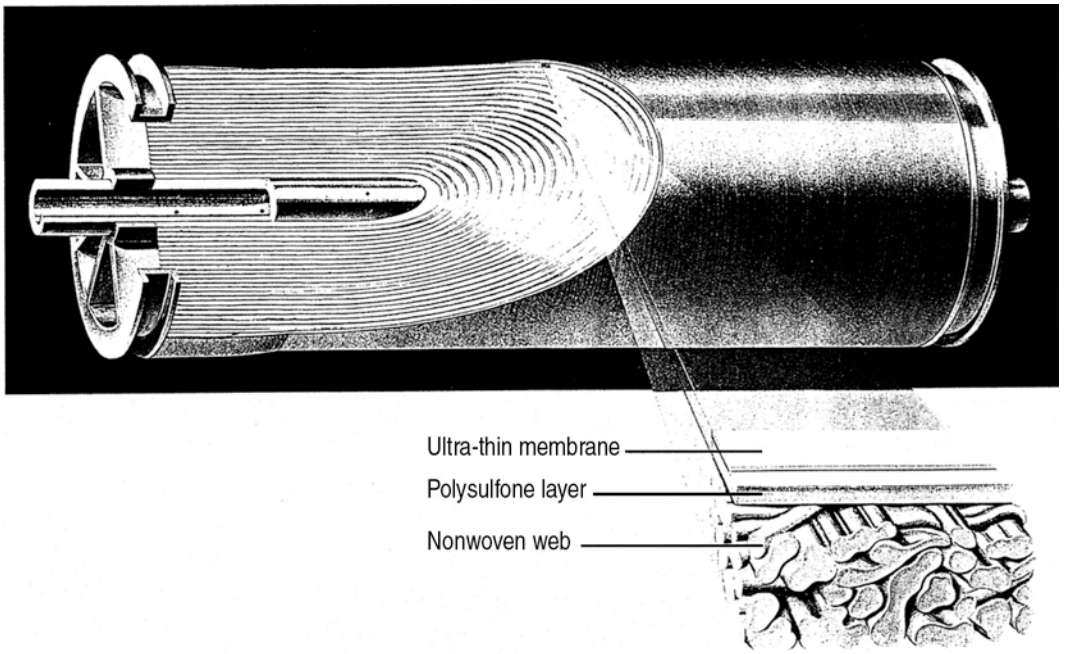


Fig. 4.20—Thin-film-composite spiral-wound membrane module.

The design of one type of the hot-lime process is shown in **Fig. 4.22**. Normally, a residence time of 1 hour is specified. Produced water is heated up to or greater than 212°F by spraying at the top of the unit. The lime (calcium oxide) is premixed in water as slurry and fed immediately below the spray. It reacts quickly with the hardness materials in water to form precipitates; this mixture flows to the bottom part of the vessel through a downcomer pipe to contact with the remaining sludge. At the bottom, the flow is reversed, and the water rises slowly through a blanket of previously formed sludge. The intimate contact increases the efficiency of the softening process. The basic reaction is shown as follows.

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O \ . \quad \text{..... (4.22)}$$

$$Mg(HCO_3)_2 + 2Ca(OH)_2 \rightarrow 2CaCO_3 + Mg(OH)_2 + 2H_2O \ . \quad \text{..... (4.23)}$$

The reaction products, calcium carbonate ($CaCO_3$) and magnesium hydroxide [$Mg(OH)_2$], are precipitated and removed as sludge. This reduces both the total hardness and TDS. When the carbonate is short in the feed water or the system contains noncarbonate hardness ions, soda ash should be used. Its reaction is shown as follows:

$$CaSO_4 + Na_2CO_3 \rightarrow CaCO_3 + Na_2SO_4 \ . \quad \text{..... (4.24)}$$

$$MgSO_4 + Na_2CO_3 + Ca(OH)_2 \rightarrow Mg(OH)_2 + CaCO_3 + Na_2SO_4 \ . \quad \text{..... (4.25)}$$

When soda ash is used, the final product still contains the soluble noncarbonate ions; hence, it does not reduce the TDS. The sludge or the precipitated solids from the lime process are periodically blown down from the unit. The treated water is processed with a filter before sending

TABLE 4.3—MEMBRANE-REMOVAL EFFICIENCY FOR ORGANIC AND INORGANIC MATERIALS

Typical Compound/Solute Rejection by FT30 Membrane

Solute	Molecular Weight	Rejection, %	Solute	Molecular Weight	Rejection, %
1,1,1-Trichloroethane	133	98	Cadmium sulfate	208	97
1,2-Dibromoethane	173	15	Caffeine	174	99
1,2-Dichloroethane	99	37	Calcium chloride	111	99
1,2,3-Trichlorobenzene	181	>57	Calcium nitrate	164	95
1,2,4-Trichlorobenzene	181	96	Carbon tetrachloride	153	98
1,2,4-Trimethylbenzene	120	57	Cesium chloride	168	97
1,2-Dichlorobenzene	147	70–92	Chlorobenzene	112	0–50
1,3-Dichlorobenzene	147	66–69	Chloroform	119	71–90
1,4-Dichlorobenzene	147	61	cis-1,2-dichlorethylene	97	20
1-Chlorododecane	204	87	Clofibric acid	214	>99
1-Methylnaphthalene	142	67	Copper sulfate	160	99
2,2', 5,5'-Tetrachlorobiphenyl	290	46	Cyclohexanone	98	95
2,4,6-Trichlorophenol	197	100	Dibromochloromethane	208	79
2,4-Dichlorophenol	163	93	e-Caprolactum	113	85
2,6-Dimethylphenol	122	92	Ethanol	46	38–70
2,6-Di-tert-butyl-4-methylphenol	220	96	Ethyl benzene	106	71
3,8-Dimethylphenol	122	92	Formaldehyde	30	35
3-Hydroxy-capric acid	188	>98	Furfural	96	35
3-Pentanone	86	74	Glucose	180	98–99
4-Ethylphenol	122	84	Glycine	188	78
4-Isopropylphenol	136	84	Heptaldehyde	114	100
5-Chlorouracil	146	88	Humic acid		98
Acetic acid	60	45	Hydrochloric acid	36	28
Acetone	58	70	Isophorone	138	96
Aluminum nitrate	213	86	Isopropanol	60	90
Aluminum sulfate	342	89	Lactic acid (pH 2)	90	94
Aniline	93	64–75	Lactic acid (pH 5)	90	99
Anthraquinone	208	93	Magnesium chloride	120	98
Benzene	78	19	Magnesium sulfate	120	99
Benzoic acid	122	92	Manganese (II) sulfate	151	97
Benzothiazole	135	79	Methanol	32	25
Biphenyl	154	91	Methyl ethyl ketone	72	73
Bis (2-Ethylhexyl) phthalate	390	94	Methyl isobutyl ketone	100	98
Bromodichloromethane	163	79	Naphthalene	128	80
Bromoform	94	>67	Nickel chloride	130	96–99

*Used with permission from The Dow Chemical Co.

it to the steam generators. The backwash water from the filters is returned to the unit. When the unit is operated at a temperature of less than 212°F, it is classified as a warm-lime softener.

TABLE 4.3—MEMBRANE-REMOVAL EFFICIENCY FOR ORGANIC AND INORGANIC MATERIALS (CONTINUED)

Typical Compound/Solute Rejection by FT30 Membrane

Solute	Molecular Weight	Rejection, %	Solute	Molecular Weight	Rejection, %
Nickel sulfate	155	97–99	Sodium iodide	150	97
o-cresol	108	84	Sodium Mono-H phosphate	142	98
o-xylene	106	67	Sodium nitrate	85	93–98
p & m xylene	106	38	Sodium orthophosphate	164	99
Pentachlorophenol	266	>86	Stearic acid	204	71
Phenol—80%	94	65	Strontium chloride	158	96
Phosphoric acid	96	94	Succinic acid	118	35
Quinoline	129	97	Sucrobe	342	99
Silica	60	98	Sulfuric acid	98	84
Sodium acetate (1%)	82	88	Tetrachloroethylene	165	68–80
Sodium bicarbonate	84	98	Tin (II) sulfate	215	85
Sodium bromide	103	96	Tributyl phosphate	266	49
Sodium chloride	58	99	Trichloroethylene	131	30–43
Sodium cyanide	49	95	Trimesic acid	210	96
Sodium Di-H phosphate	120	98	Urea	60	70
Sodium fluoride	42	98	Zinc chloride	136	93
Sodium hydrogen sulfate	120	76	Zinc sulfate	161	98

One type of warm-lime softener is shown in **Fig. 4.23**. This warm-lime unit has two compartments. In the reaction zone, or the first compartment, the lime and magnesium oxide slurry is fed together with the produced water. A mixer moves very slowly to keep the influent mixture in contact with the slurry in this compartment. This contact promotes precipitation of both hardness materials and silica. The treated water flows upward and overflows into the clarification zone, or the second compartment. The sludge separates from the water and sinks to the bottom of the clarification zone. The treated water flows upward through a set of clarification weirs to prevent any sludge flowing out of the system. The bottom sludge is recycled with an external pump back to the reaction zone. This unit can be used for removing both silica and hardness ions from produced water.

Silica Removal. Silica fouls steam generators and RO membranes when its concentration exceeds the solubility limit. Its solubility data are plotted in **Fig. 4.24**. The silica solubility also depends upon the pH of the water. The silica solubility increases significantly at higher pH values.[19] Silica scale is generally deposited on the inside of the radiation section tubes. This deposit acts as an insulator for the tube and reduces its heat transfer. More seriously, the tube can overheat from the flame and cause tube failures. Based on the previous analysis, it is necessary to remove silica and control its concentration in the feed water for the RO-membrane and steam-generation systems.

Silica can be removed with the warm- or hot-lime softeners described previously. In a steamflood operation, the produced water generally is at greater than 170 to 180°F; hence, the warm-

TABLE 4.4—REMOVAL EFFICIENCY OF TRACE METALS BY MEMBRANES

Rejection of Trace Metal by B-9 Permeators*	
Metal	%Rejection
As^{+3}	60
As^{+5}	>95
Ba^{++}	>95
Cd^{++}	>95
Cr^{+6}	>95
Cu^{++}	>95
Se^{+4}	>95
Se^{+6}	>95
Zn^{+2}	>95

*Based on information from DuPont.

Note: test conditions used were for dilute solutions: feed pressure—400 psig; feed temperature—25°C; Conversion—75%.

lime-softening unit is adequate for handling it. However, the option of using the hot-lime process exists. The chemical reaction for silica removal is still unknown, and the key is to use an adequate amount of lime and magnesium oxide and recycle the slurry to promote an intimate contact with the incoming water for a better reaction and better use of the chemicals. Silica also can be removed at lower temperatures (60 to 80°F), generally referred to as the cold-lime process.

4.2.11 Steam Production. A steamflood uses high-quality steam injected into an oil reservoir. The quality of steam is defined as the weight percent of steam in the vapor phase to the total weight of steam. The higher the steam quality, the more heat is carried by this steam. High-quality steam provides heat to reduce oil viscosity, which mobilizes and sweeps the crude to the producing wells. As the heat is absorbed by the crude and formation, the steam condenses, mixes with the crude and formation water, and is produced with the crude. This hot produced water is then separated from the crude, treated, and injected as steam to complete an entire steamflood cycle. This section discusses the process and equipment for water treatment for steam production.

Water-Treating Processes for Steam Production. A typical water-treatment process for steam production is shown in **Fig. 4.25**. Separators or tanks remove the bulk water from oil. The oily water is then treated with flotation cells to remove most of the dispersed oil (95%). The treated water contains < 10 mg/L of oil and suspended solids. Final water polishing is done by filtration, such as sand, multimedia, or walnut-shell filters, to reduce the oil and suspended solids to < 1 mg/L. The clean water is treated by water softeners to reduce the total hardness to < 0.5 mg/L so that it can be fed into the steam generators.

If the produced water has high silica content, a warm-lime or hot-lime process should be used to remove silica to the desirable level. If the produced water has high TDS, either RO or weak acid softeners should be used to soften it for steam generation. Recently, an RO process was used to treat produced water to meet drinking and irrigation quality.[14,15] A similar process has been used for generating electricity after polishing with a demineralization treatment.[16]

Chemical treatment is generally required to maintain the integrity of equipment and improve the quality of water for steam generation. Depending upon the needs, this treatment could include corrosion and scale inhibitor, oxygen scavenger, water clarifier, coagulant, and biocide treatment.



Fig. 4.21—Softener banks are used in the steamflood fields. The tall units are primary softeners, and the short units are polisher softeners. Both units are using strong acid resins.

TABLE 4.5—DEMINERALIZER RESIN TYPES AND APPLICATIONS

Type of Resin	Ions Removed	Regeneration Method
Weak acid cation	Sodium	Acid
Weak base anion	Sulfate, chloride, nitrate, etc.	Ammonia or soda ash
Strong base anion	Silica	Caustic soda

Quality of Water for Steam Production. High-quality water is necessary for maintaining a reliable, continuous steam-injection program. Although there is no specification for heavy metal ions, these materials should be kept low to minimize poisoning of ion-exchange resins. The quality of water required for steam generators operating at a steam quality of 70 to 80% is shown here:

- Total hardness: < 0.01 mg/L.
- Oil content: < 0.5 mg/L.
- Total suspended solids: < 0.5 mg/L.
- Total iron: < 0.5 mg/L.

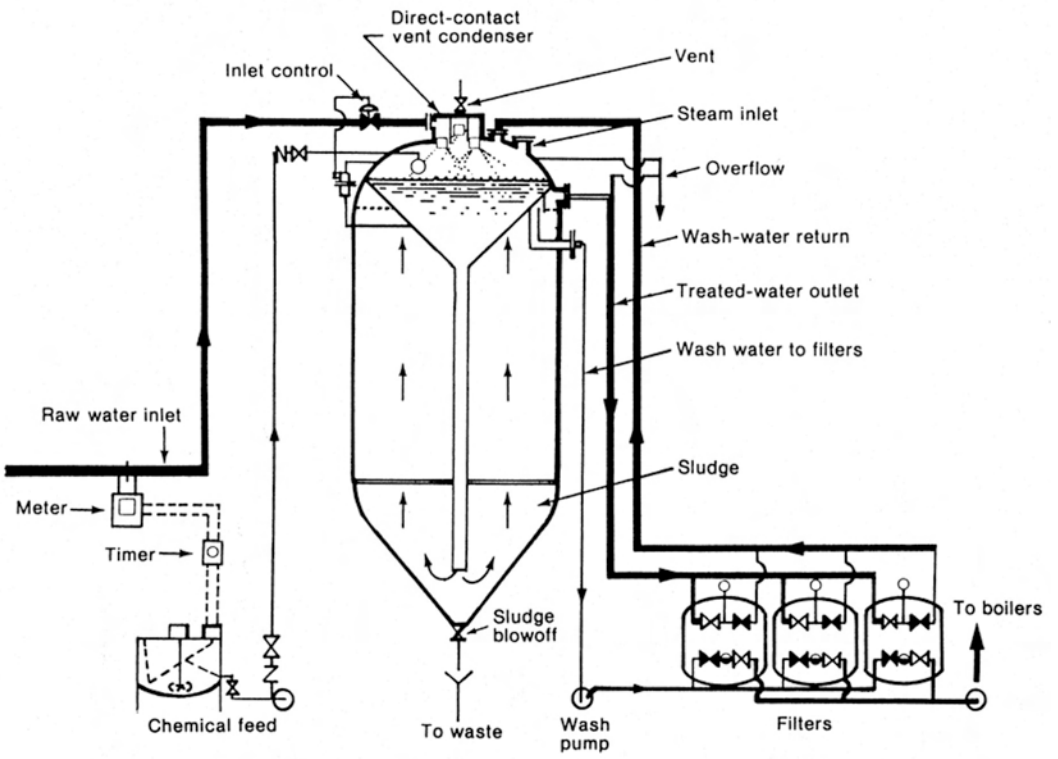


Fig. 4.22—Schematic of the hot-lime process.

- Oxygen content: < 0.02 mg/L.
- Silica concentration: < 200 mg/L.

Steam Generators. Steam generators are used to produce steam for the steamflood. The most popular steam generators are the 25- and 50-MMBtu/hr units. The 25-MMBtu/hr units are used as mobile units and provide steam for cyclic-steaming or remote-injection wells. The 50-MMBtu/hr units provide steam from a central banked location, which simplifies the water- and fuel-treatment plants and the steam-distribution system. Moreover, if exhaust-gas scrubbing is required, the scrubber system can also be centralized. Significant savings can be realized by centralizing these units.

A typical steam-generator and system flow schematic is shown in **Figs. 4.26 and 4.27**. It consists of a convection section and a radiant section. The convection section is designed to preheat the softened feed water, and the radiant section further heats the steam pipe for generating steam. A steam generator produces 60 to 80% quality steam, depending on the reservoir requirements. Higher-quality steam can be generated if good-quality water and fuel gas are used. When the required steam quality reaches 90%, control becomes difficult, and the chance of overheated pipe increases because of the relatively low liquid phase near the pipe effluent.

Depending on the reservoir requirement, steam-injection rate, and tightness of the formation, steam-injection pressures vary from field to field. A steam generator can be operated at a pressure of approximately 2,700 to 3,000 psig and can be designed specially for a higher operating pressure if required. The operating temperature changes with the corresponding pressure. The correlation can be seen in a typical steam chart found in many mechanical engineering textbooks. This chart contains thermodynamic information about the steam. At a certain steam

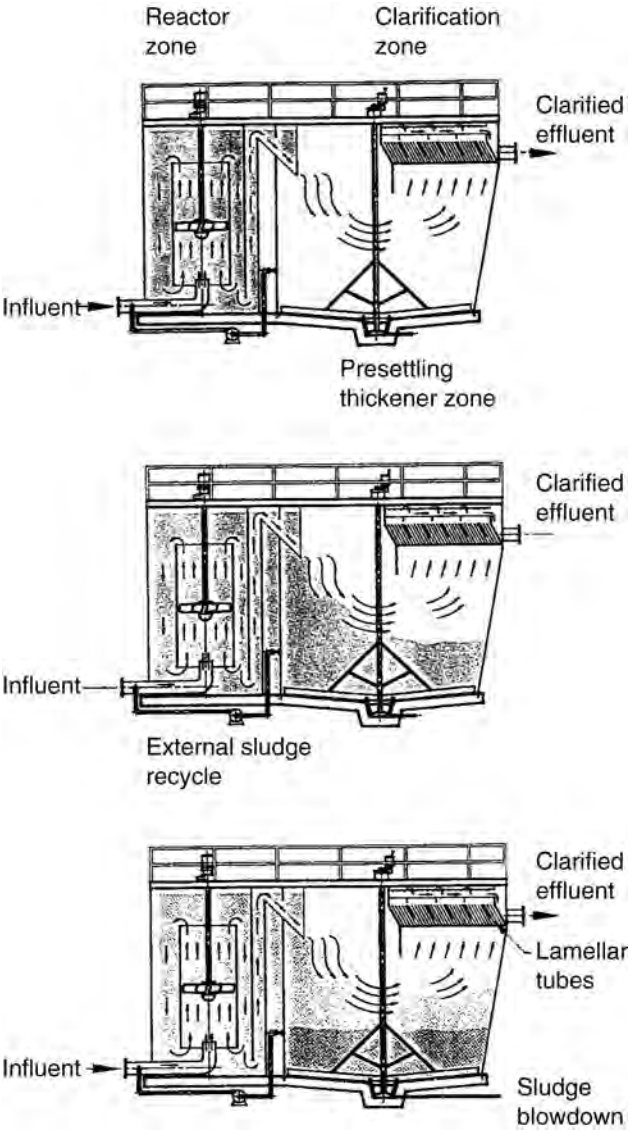


Fig. 4.23—Schematic of the warm-lime process.

quality, pressure, and temperature, the steam delivers a specific amount of heat to the reservoir, according to the steam chart. Poor-quality feed water will scale the steam generators, causing poor heat transfer or plug-up. High-hardness feed water will cause calcium carbonate, magnesium carbonate, or sulfate scales. A high iron concentration in the feed water will cause iron carbonate or oxide scales in either the convection or radiant section. A high silica concentration will cause silica scale in the radiant section. Other types of scale are also present, such as complex compounds or scales induced by produced fines, silt, or injected chemicals.

Because of various operating and maintenance conditions, a steam-generator bank usually has a finite percentage of downtime, which is generally factored into the design so that a constant steam flow can be assured. A well-operated field can have steam-generator downtime as low as 5%.

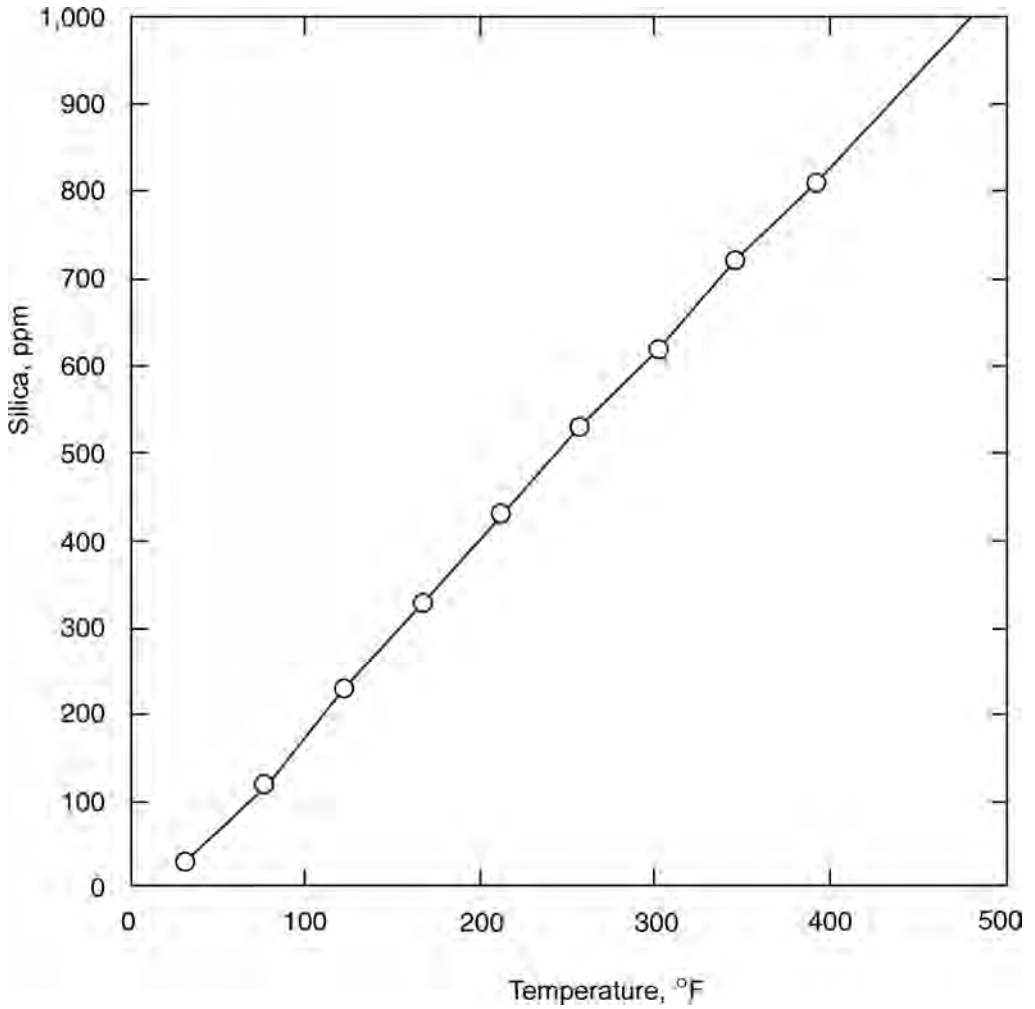


Fig. 4.24—Solubility of silica in water.

Steam Distribution. After steam leaves the generators, it is transported and distributed by pipelines to steam injectors. This pipeline network is generally insulated to reduce heat loss and to provide safety for the people working in the area. Because the steam generators are not generating 100% steam, the pipeline flow consists of a vapor phase and a liquid phase. Depending on the steam-flow rate, pipe size, temperature, and pressure, the steam may flow with different flow patterns. A phenomenon known as phase splitting is known to occur at piping junctions, branches, and tees, resulting in widely varying steam qualities at the steam injectors in any large steamflood project. Inconsistent steam delivery results in inconsistent heat delivery to the reservoir, interfering with the optimization of steam-injection rates, oil recovery, and project economics.

Various designs exist in the literature[20,21] for handling the phase-splitting problems. One company has developed a patented steam-splitting device[22] to control steam distribution,[23–25] as shown in **Fig. 4.28**. This device controls the steam quality delivered to the "branch" (side flow) of a junction, while the "run" quality (straight-through flow) is uncontrolled.[24,25] As a result, this device's control of the branch steam quality is almost independent of changes in the

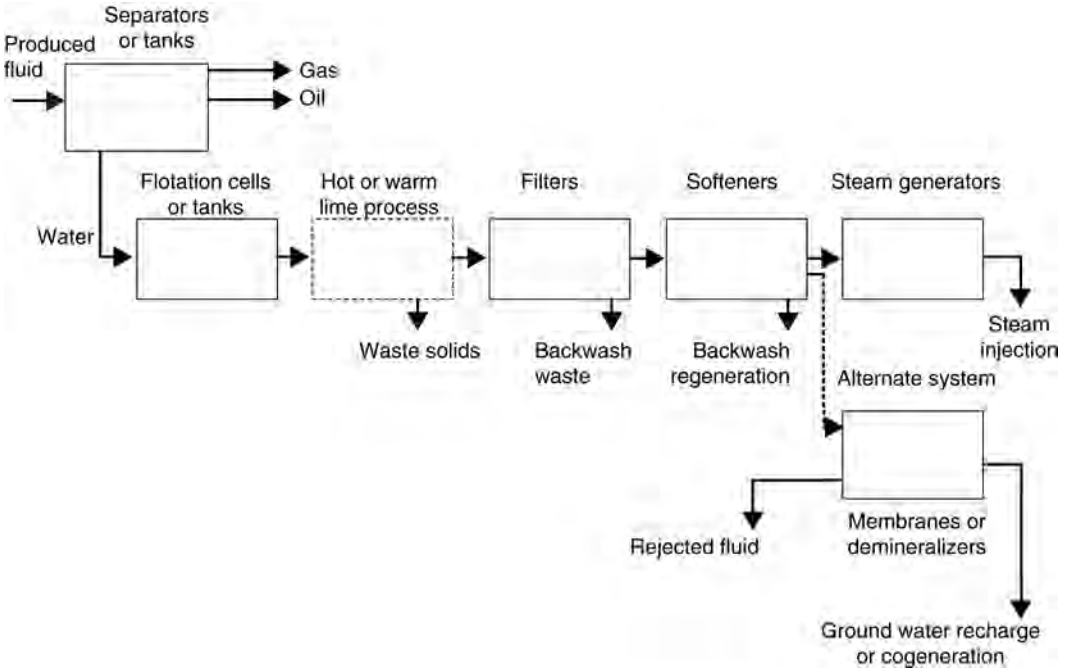


Fig. 4.25—A typical water-treatment process for steam generation.

flow rate through the branch.[25] Although the device itself is not used to control either the branch or run flow rate (chokes or control valves at the injection wells are necessary for rate control), the uniformity of steam quality provided by this device makes rate control more reliable.

Steam Injectors. Steam injectors are used to inject steam into the formation. There is a concentric pipe design, made of an inner pipe for transporting steam down to the reservoir, which uses the casing as the outer pipe. The casing is cemented to the injection well with a special blend of cement, including silica flour. This cement can withstand large amounts of heat with minimal expansion. The well casing design prevents heat loss to the surroundings. The inner injection tubing holds heat from steam, and the air/steam gap between the inner pipe and casing acts as an insulator to reduce heat loss. Deep injection wells are equipped with insulation tubing around the outside of the steam pipe. This insulation tubing is specially designed with a vacuum in the jacket to provide additional heat insulation.

4.3 Surface-Water Treatment for Injection

In many operations worldwide, surface waters are injected into producing formations to enhance oil recovery. The types of surface waters used range from seawater (salt water) to lake water (brackish) to river water (fresh water). Surface-water injection is an attractive option for the following reasons:

- In many cases, surface water is easily accessible and readily available without high-cost well-drilling and well-completion activities.
- Surface-water supplies are considered inexhaustible.
- Most surface-water supplies can be used without having to pay fees or taxes.
- The use of surface water creates very little environmental impact or concern.

Surface water, however, must be treated to remove undesirable components before injection. The most common types of contaminants are solids (sand), dissolved gas (oxygen), biological material (plankton and bacteria), and dissolved solids (sulfate). Treatment of surface

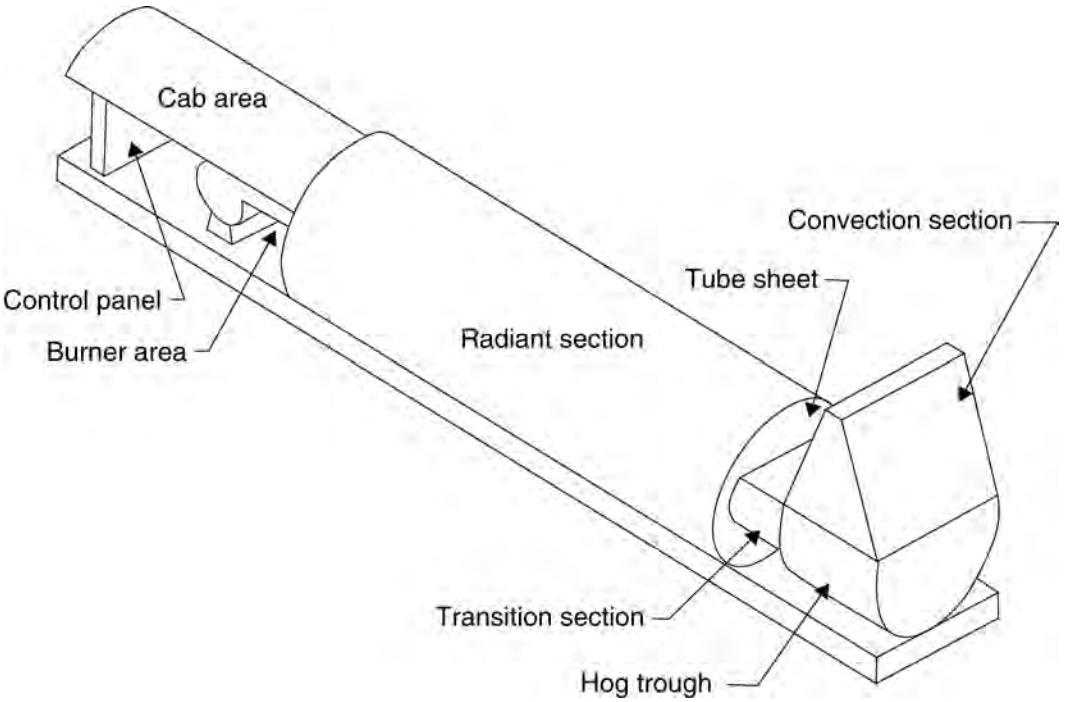


Fig. 4.26—A typical steam generator consists of a convection and a radiant section.

water for injection requires a specially designed system made up of various components to remove or control any contaminants in the water. The system is engineered to perform the required treatment in the most cost-effective and environmentally sensitive manner. A typical system is shown in **Fig. 4.29**. Commonly used methods for removal or control of these contaminants are discussed in this section.

4.3.1 Separating Suspended Solids From Injection Water. Surface waters normally contain suspended solids particles that, if injected into the producing formation, will plug the injection well. The type, concentration, and particle-size distribution of suspended solids in water will vary depending on the source of the surface water. For example, river-water sources tend to have higher concentrations of suspended solids (100 to 1,000 mg/L), whereas deep offshore water sources tend to contain rather small amounts (5 to 50 mg/L). Furthermore, the suspended solids found in river water tend to be inorganic (silica-based), whereas the suspended solids found in the oceans tend to be organic (primarily bacteria). Hence, the treatment methods also vary depending on the source. Solids-removal equipment generally may be classified as primary (coarse) or secondary (polishing) removal devices. **Table 4.6** lists the solids-removal devices commonly used to treat surface water for injection.

The terms "primary" and "secondary" refer to both the amount and the size range of suspended solids to be removed. Primary removal considers solids concentrations greater than approximately 100 mg/L and solids particle sizes greater than 50 μm. Secondary removal refers to suspended solids concentrations of less than 100 mg/L and solids particle sizes less than 50 μm.

Primary (Coarse) Solids Removal. *Solid/Liquid Hydrocyclones.* As mentioned previously, solid/liquid hydrocyclones, or desanders, can be classified as primary or bulk-removal devices designed to handle larger particle sizes and higher solids concentrations. These units provide an

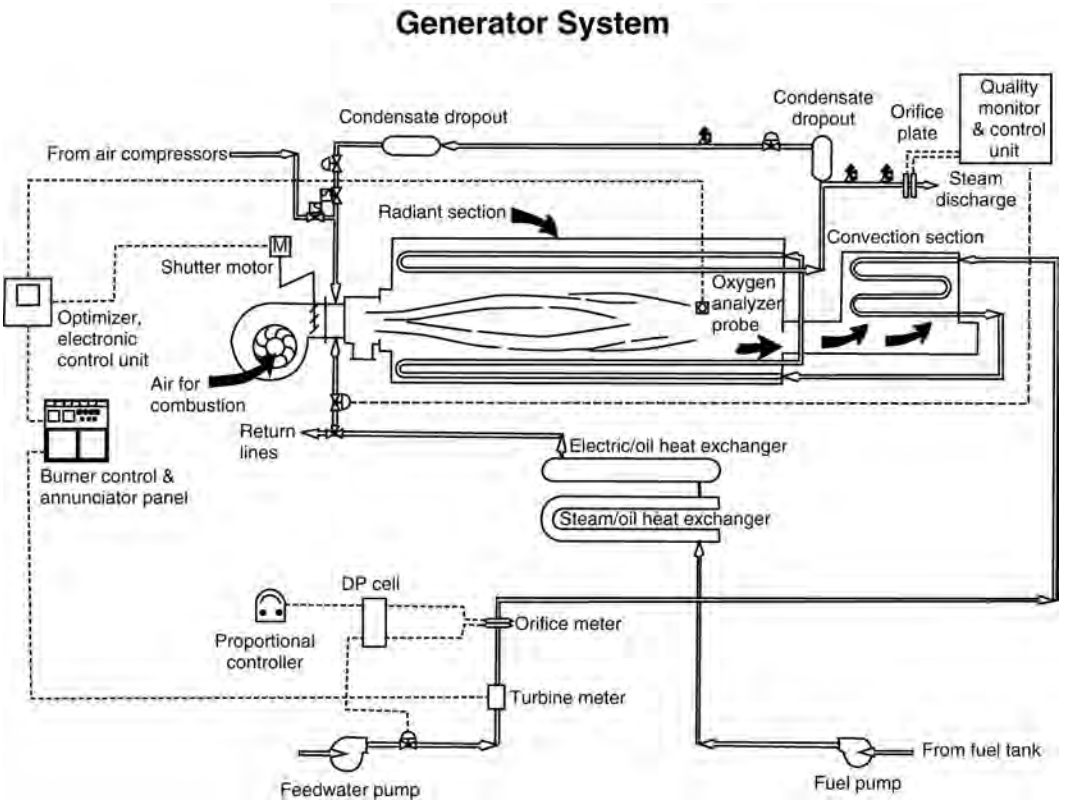


Fig. 4.27—Flow schematic of a steam-generation system.

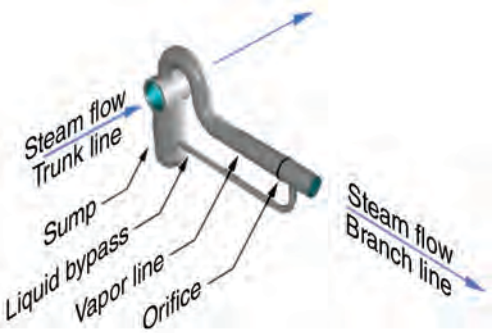


Fig. 4.28—A steam-distribution device that can split the steam flow to a branch line and keep the steam quality unchanged.

inexpensive first pass at removing 50- to 100-μm solids. They are more commonly used with river waters to remove silt and sand; please refer to Sec. 4.2.8 for more details.

Coarse Strainers. Coarse strainers are devices designed for applications that require the removal of large solids (> 250 μm). Strainers mechanically remove or screen out solids particles based on size alone. Many of the strainers commonly used in water-injection systems employ either a basket-style straining device or a wire-wound cylindrical element. During filtra-

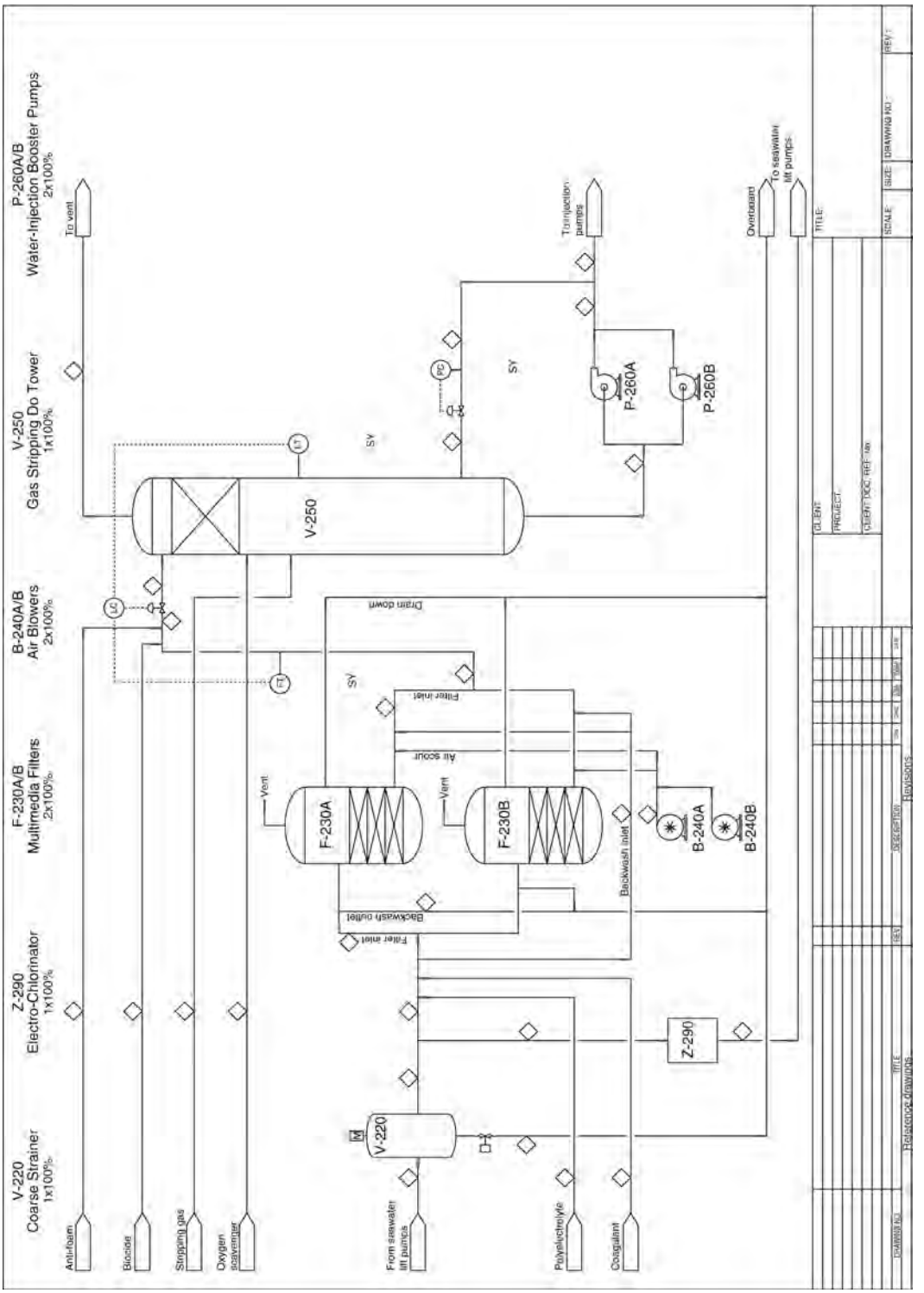


Fig. 4.29—A typical water-injection system.

TABLE 4.6—COMMONLY USED EQUIPMENT FOR SUSPENDED SOLIDS REMOVAL FROM SURFACE WATER

Device	Primary Removal	Secondary Removal	Removal Size (μm)
Solid/liquid hydrocyclone	✓	✓	Coarse, >100 Fine, >10
Coarse strainers	✓		>50
Sand filters		✓	>10
Mixed-media filters		✓	>2
Cartridge filters		✓	>0.5

tion, the strainer screen fills up with material, which leads to a gradual increase in pressure drop. This increase in differential pressure means that each strainer must be backwashed periodically to remove accumulated solids. This period can be varied, and the program time will be established during commissioning. Backwashing occurs while the strainer remains on line without interruption in the forward flow. Either the basket or wire-wound design can be automated for online self-cleaning of the solids that build up. This is a useful feature because it affords continuous operation of the plant, even during the cleaning cycle.

Secondary (Polishing) Solids Removal. *Solid/Liquid Hydrocyclones.* As discussed previously, solid/liquid hydrocyclones also can be used for polishing. Desanders in this application can practically remove solids up to 10 μm in diameter, the lower limit for hydrocyclone technology.

Granular-Media Filters. The majority of large-flow-rate polishing filter applications involve the use of granular-media filtration. Granular-media filters, also called sand filters, contain a bed of graded sand, gravel, anthracite, or graphite. The beds may be of a single medium or may be graded from coarse to fine media to allow for greater solids loading. Sand filters are good for separating 25-μm particles, but some manufacturers claim that their filters are good for 5- to 10-μm separation.

During filtration, the particulate matter carried by the water is trapped within the filter media. Because of the carefully selected grades of media, this entrapment occurs right through the top two layers. The increase in pressure drop across the filter is gradual because the solids collection occurs through the filter bed. It also means that the filters can easily cope with sudden increases in the solids content of the seawater without blinding. This increase in differential pressure, however, means that each filter must be washed to remove the accumulated solids, normally achieved by washing each filter in rotation (e.g., in a 24-hour period, one filter backwash would start every 8 hours).

The media are arranged in a pressure vessel for either downflow filtration and upflow backwash, as shown in **Fig. 4.30**, or for upflow filtration and upflow backwash. Conventional downflow filters are limited to flow rates of 2 to 5 gal/min-ft^2 and total solids loads (before backwashing) of ½ to 1½ lbm/ft^2. With appropriately designed distribution systems, high-rate filters can be operated at 7 to 15 gal/min-ft^2. This higher loading forces the solids farther into the bed, allowing for solids loadings of between 1 and 4 lbm/ft^2. Upflow filters have a greater capacity for solids loading; flow tends to loosen the bed, allowing for greater penetration of the solids (up to 6 lbm/ft^2 of solid loading). However, because of the danger of losing the bed, upflow filters are limited to flow rates of 6 to 8 gal/min-ft^2 and require longer backwashing time and more backwash fluid.

Two modes of filter-backwash control are available: manual (used during commissioning or troubleshooting) and automatic (normal operating selection). When a filter is selected to manual, the operator can select any stage in the backwash sequence (i.e., a drain-down stage), initiate that stage, and run it for the required amount of time. When a filter is set to automatic,

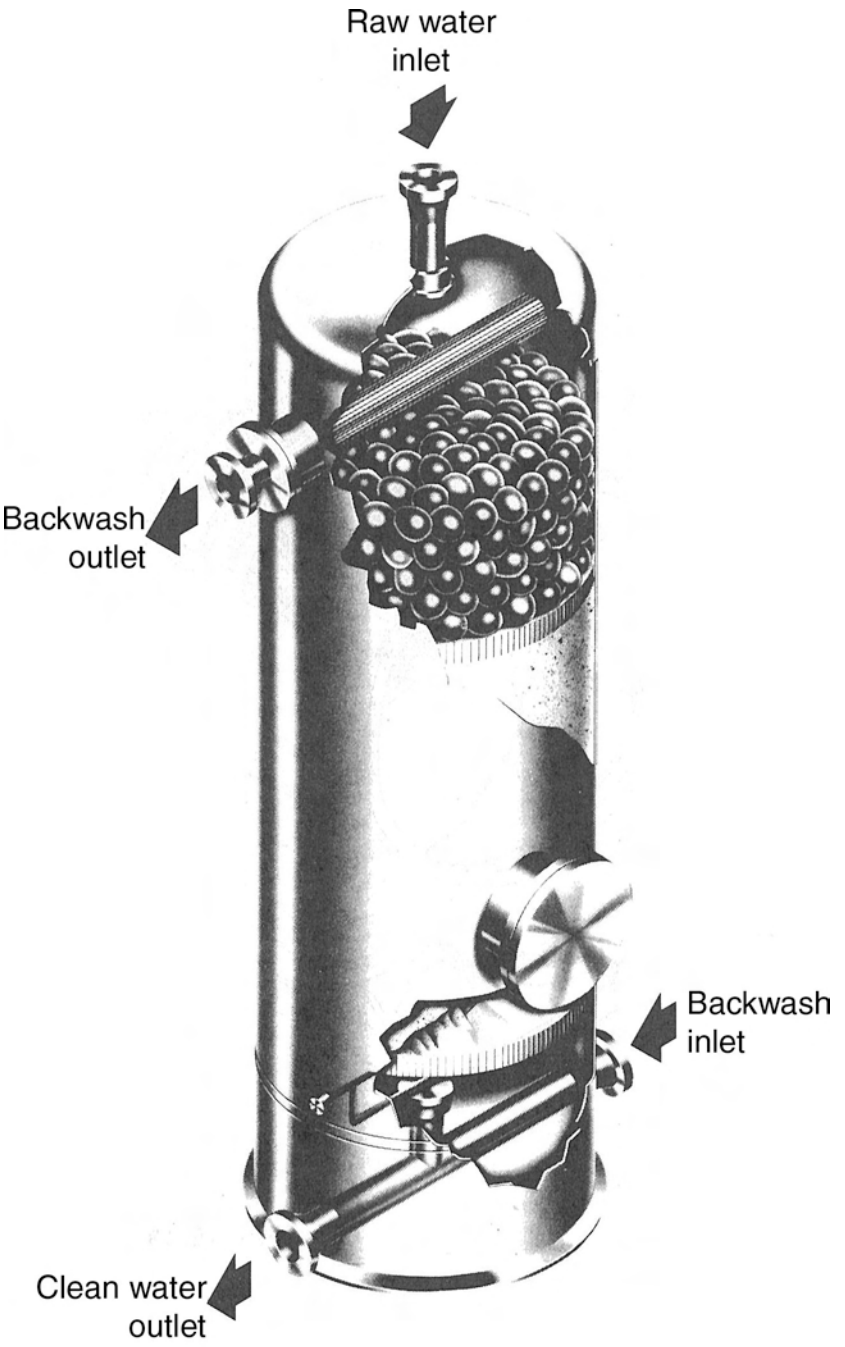


Fig. 4.30—Sand filter.

the filter will be backwashed automatically when the backwash interval time starts it, when a high differential pressure occurs, or when the operator starts an autobackwash.

Cartridge Filters. Cartridge filters are simple to install, require no backwash, and are capable of removing solids particles 2 μm or larger in diameter. Their drawback is that they can take only very low solid loadings, and the cartridges must be disposed of after use. The filter

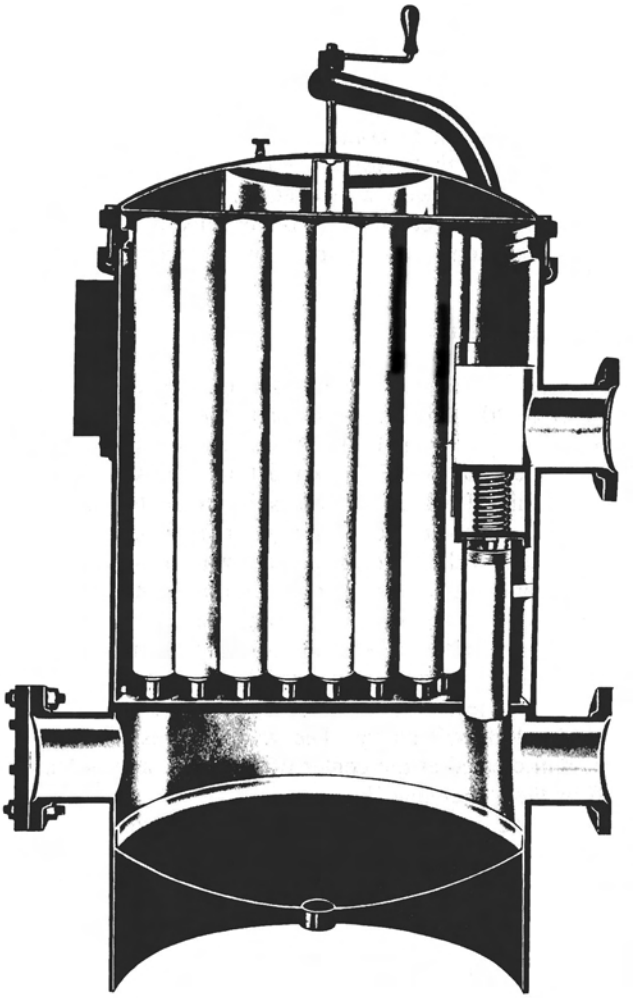


Fig. 4.31—Cartridge filter.

vessel must be taken out of service and depressurized, and the cartridges must be replaced whenever the volume of solids trapped causes the differential pressure to exceed a predetermined maximum (usually 25 psi). Some modern cartridge filters can be backwashed.

Fig. 4.31 shows a typical cartridge filter. The cylindrical filters are encased in a pressure vessel. Flow enters the vessel and flows from the outside of the cartridge to the center, where it enters a perforated pipe that is open on the bottom. A bypass mechanism is included that will automatically allow flow to pass from the inlet to the outlet chambers if the differential pressure exceeds the capacity of the cartridges.

Table 4.7 indicates the particle size that can be separated and the recommended flow rate through various standard-size cartridges. Molded fiberglass has the least solid-storage area, and pleated wire screen or paper has the most.

4.3.2 Dissolved-Gas Removal (Oxygen). Surface water (fresh or saline) will contain dissolved oxygen that must be removed by the water-treating facility. Oxygen in concentrations of 0.5 ppm in hydrogen-sulfide-free water and 0.01 ppm in water containing hydrogen sulfide is generally considered to be sufficient to cause corrosion problems in the facilities and bacteria-

TABLE 4.7—CARTRIDGE-FILTER TYPES USED FOR TREATMENT OF BRINE

Cartridge Type	Particle Size (microns)	Flow Rate (gal/min)*
Pleated wire screen	80	12
Pleated cellulose paper	5–10	4
Rolled laminated cotton and acrylic excelsior	5–10	2–3
Molded fiberglass	2	6

*3-in. × 36-in. element.

plugging problems in an injection reservoir. For this reason, attempts are made to exclude oxygen from produced-water systems by maintaining gas blankets on all tanks. However, these systems sometimes must be designed to handle rainwater, which may introduce dissolved oxygen in sufficient quantities to require removal. All seawater contains oxygen, and while the location of surface-water intakes can be arranged to minimize the oxygen content, oxygen will have to be removed in almost all cases.

Some water sources contain ammonia, H_2S, or CO_2, which must be removed. Chemical scavengers, gas stripping, or liquid extraction are capable of removing these dissolved gases. It is beyond the scope of this chapter to deal with the design of the complex processes and equipment that can be used in removing all dissolved gases. Because oxygen is the most common contaminant, we will briefly describe the treatment process commonly used to remove dissolved oxygen.

Oxygen Scavengers. The use of chemical scavengers for dissolved-oxygen removal from water is covered in the Water-Treating Chemicals section of this chapter (Sec. 4.4).

Gas Stripping. The basic principle used in gas stripping is that the quantity of oxygen dissolved in the water is directly proportional to the partial pressure of the gas that is in contact with the water (Henry's law). Because partial pressure of the gas is a function of the mole fraction of that gas, the addition of other gases to the solution will decrease the partial pressure of oxygen and, thus, the concentration of oxygen in the water.

In a typical gas-stripping column, natural gas or steam is introduced in the base of a packed or trayed column (similar to a glycol contactor used in gas dehydration) and flows upward countercurrent to the water. The water is introduced in the top of the column and flows downward.

If natural gas is used, the oxygen-contaminated gas from the top of the tower can be used for fuel, compressed for inclusion in the sales gas stream, or vented, depending on the process design, environmental regulations, and gas sales contract. Stripping-gas usage of 2 to 5 scf/bbl is common.

It also is feasible to strip oxygen from water with a concurrent flow. This is common in cases in which lift gas is used as the artificial-lift mechanism for obtaining the water from a reservoir or subsea source. The gas is sometimes injected into the water with a static mixer in concurrent flow in a pipe. While this may require more stripping gas, it may be more economical from the standpoint of equipment cost, space, and weight when the value of the stripping gas is low. Stripping-gas usage in concurrent flow can be in excess of 10 scf/bbl.

Before entering the contactor column, water (from the media-filter package) is treated with an antifoam chemical. Seawater has a high foaming tendency, which can seriously affect the performance of the column. The seawater is then fed to the mass-transfer section (containing the packing or trays) of the column for oxygen removal. Water enters the column near the top through an inlet-distribution header, which ensures an even flow across the full-tower cross section. From the distributor, the water flows down through the packing or trays. The objective

of the mass-transfer section is to create a large surface area over which the water forms a thin film, promoting intimate contact with the fuel gas and enhancing mass transfer. After passing through the mass-transfer section, the water falls into the column sump, where a chemical oxygen scavenger is added to reduce the oxygen content to acceptable levels. During normal operation, when the filters are not backwashing, the level in this sump is used to control the flow rate of the water entering the top of the contactor.

Vacuum Deaeration. Because the partial pressure of oxygen in water is a function of the total pressure of the system, applying a vacuum to the water/gas system can reduce the partial pressure of oxygen. Vacuum deaerators can be combined with either countercurrent or concurrent stripping gas to provide very low oxygen concentrations in the water. Stripping-gas usages of a fraction of a cubic foot per barrel are common. Vacuum stripping towers are used where no stripping gas is available; where the available stripping gas contains contaminants, such as CO_2 and H_2S; or where stripping gas has a high value. The disadvantages of vacuum-deaeration systems include high power costs (to operate the vacuum pumps) and high maintenance to the system to ensure that oxygen does not enter the system through seals, gaskets, or pipe joints.

Compact Deoxygenation. The weight and space allotted to production equipment are of major concern to operators, especially in offshore applications. In response to this sensitivity, oilfield equipment vendors have developed compact deoxygenation systems. At present, there are two systems in commercial use.[*,26–28]

One system uses a wet combustion catalytic process to consume the dissolved oxygen in the water. The operating principle of this system is simple—hydrogen (produced and injected into the water stream) and oxygen (contained in the water) react in the presence of a palladium catalyst (contained in a pressure vessel) to produce water molecules. The major system components are:

- The palladium catalyst.
- The inline mixer.
- The hydrogen generator skid.
- The liquid-filled catalyst vessel.

Oxygenated water enters the inlet piping of the system and is measured with an accurate flowmeter. The measured-water flow-rate value is registered by the system controls, and a signal is sent to the hydrogen generator. Based on the inlet water flow rate, a proportional amount of hydrogen is produced and injected into the water upstream of the mixer. It should be noted that the hydrogen reacts with any free chlorine in the water (i.e., from the electrochlorinator); therefore, an additional amount of hydrogen is produced to make up for this loss. The static mixer ensures good dissolution of the hydrogen gas into the water. The water/hydrogen mixture is then routed to the catalyst vessel, where contact with the palladium catalyst is achieved. The oxygen in the water is reacted with the dissolved hydrogen gas in the presence of the palladium catalyst to produce water molecules.

Hydrogen is produced by the electrolysis of an ultrapure freshwater stream to produce H_2 and O_2 gases. The H_2 gas is separated for injection into the water stream, while the O_2 gas is vented to a safe location. A local programmable logic controller (PLC) controls the process for preparing the ultrapure water. The same PLC is used to regulate the production of hydrogen in proportion to the measured flow rate of the incoming oxygenated water.

An alternative compact deoxygenation system uses a high gas/water ratio stripping process in either a concurrent or countercurrent mode. The stripping gas used is nitrogen instead of natural gas. In either mode, the oxygen-laden stripping gas is regenerated in a catalytic purification vessel by means of a reaction of the oxygen with methanol in the presence of a palladium

* Place, M.C. Jr.: "Catalytic Oxygen Removal—A Light Compact Water Deoxygenating System," Shell Oil Co., unpublished internal document (1993).

catalyst to produce CO_2 and water. Compressed air is used as makeup gas to replace nitrogen losses from the system.

In the concurrent mode, deoxygenation occurs within two stages of mixers. Nitrogen gas is injected into the water stream in a concurrent manner upstream of the mixer. The mixer creates intimate contact between the oxygenated water and the stripping gas. As discussed previously, the oxygen will diffuse out of the water according to Henry's law. Located downstream of each mixer is a partially liquid-filled disengagement vessel. Once inside the vessel, the oxygen-rich nitrogen gas is separated from the water and removed through the gas outlet at the top of the vessel. Stripping gas for the first-stage mixer is taken from the gas outlet of the second-stage disengagement vessel after compression. The oxygen-rich nitrogen gas from the first-stage disengagement vessel is routed to a catalytic deoxidizer to remove the oxygen. Regenerated nitrogen from the deoxidizer is then routed to the second-stage mixer.

In the countercurrent system, the oxygenated water is routed to the top of a partially liquid-filled deaerator column in the same manner as described previously. The column is equipped with water inlet distribution piping, mass-transfer packing, inlet distribution piping for the nitrogen stripping gas, and a sump section. A major difference between the compact system and the traditional gas-stripping system described earlier is that the oxygen-rich nitrogen is deoxygenated and recycled to the stripping-gas inlet of the column. As mentioned previously in the description of the concurrent system, the oxygen-rich gas from the top of the column is routed to a catalytic deoxidizer to remove the oxygen.

Either system allows a substantial reduction (20 to 50%) in the weight and space of the deoxygenation equipment. The reduced weight and space requirements translate into reduced structural and support steel on the deck. Because either system can be provided as skid-packaged units, the amount of site work is reduced, and the need for special cranes or other special lifting requirements is minimized.

4.3.3 Biological Control. Surface water contains biological constituents (primarily bacteria) that can contaminate the water-injection system. Because bacteria have the ability to multiply rapidly into colonies, they can cause plugging of surface and downhole equipment and injection-well formations, promote corrosion of surface piping and downhole tubulars, and generate H_2S that can cause pitting corrosion. Therefore, it is essential to develop a means to control the growth of bacteria in surface-water-injection systems. Bacterial growth is controlled mainly by chemical biocides, the most common of which is chlorine, which may be added directly or produced in-situ from seawater. Direct-added chemicals are covered in Sec. 4.4.

Because of its high chloride content, seawater can be electrolyzed with a hypochlorite generator or an electrochlorinator to produce hypochlorite (OCl^-). Chlorine production in this way makes for a very convenient, inexpensive, and reliable source of bactericide. Chlorine from the electrochlorinator is continuously dosed into the seawater lift-pump intake to prevent marine fouling within the system, making up the injection-water-treatment system.

The hypochlorite generator produces chlorine in the form of sodium hypochlorite at a rate equivalent to a concentration of approximately 5 ppm. The electrolyzer is fed with seawater from the coarse-filtration outlet. The chlorine is generated by electrolysis in a single electrolytic cell. The amount of sodium hypochlorite formed is proportional to the amount of direct current passed through the seawater. The byproduct, hydrogen gas, is released and diluted to less than 2% mixture (less than the explosive limit) and vented to atmosphere.

4.3.4 Sulfate Removal. Seawater contains approximately 2,800 to 3,000 mg/L of sulfate ion.[29] Using seawater for injection into a producing reservoir for pressure maintenance or for waterflooding can cause problems if the formation water contains significant levels of calcium, barium, or strontium. Depending on the pressure and temperature of the system, these ions react with sulfate to produce either calcium sulfate, barium sulfate, or strontium sulfate scale.

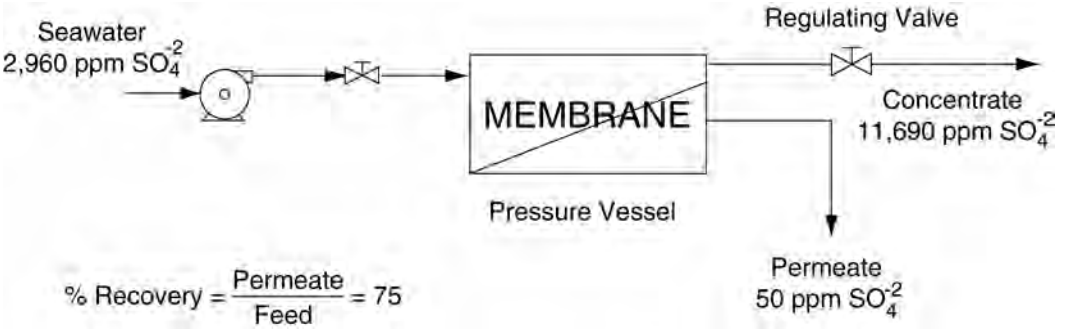


Fig. 4.32—Simplified nanofiltration diagram for sulfate removal.

Both barium sulfate and strontium sulfate scales are extremely hard to dissolve in acid and equally hard to remove by mechanical means. Hence, once these types of scale deposit in either the production tubulars or the surface process piping, the likely result is that the well or platform may have to be shut in while the affected piping is replaced. One solution to this problem is to remove or reduce the amount of sulfate ion in the seawater before it is injected.

The process for removing sulfate ions from seawater is based on NF membrane separation. NF is a membrane process that selectively removes sulfate ions to produce reduced-sulfate seawater. The process is similar to RO, used extensively worldwide for seawater desalination; however, the NF membrane has a larger pore size and possesses a slight negative charge and, thus, can reject divalent ions (e.g., sulfate). Furthermore, NF membrane has a better feed-to-permeate conversion at 75% of the inlet flow rate; that is, for every 100 bbl of seawater fed to the system, 75 bbl of low-sulfate water are produced, and 25 bbl of high-sulfate water are rejected.* NF refers to a specialty membrane process that rejects particles in the approximate size range of 1 nanometer (10 Angstroms), hence the term "nanofiltration."

The concept has been proven technically by its successful application in a west Africa seawater injection plant with a capacity in excess of 330,000 B/D. The design point for a sulfate ion in the treated seawater is 40 mg/L at 20°C seawater temperature. At this level of sulfate removal, it is expected that the amount of barium sulfate scale would be reduced from 50 to 7 kg per 1,000 bbl of produced water.[30]

A simplified process diagram is shown in **Fig. 4.32**. With a booster pump, pressurized saline feed water is continuously pumped to the module system. Within the module, consisting of a pressure vessel (housing) and a membrane element, the feed water will be split into a low-saline product, called permeate, and a high-saline brine, called concentrate or reject. A flow-regulating valve, called a reject valve, controls the percentage of feed water going to the concentrate stream and the permeate that will be obtained from the feed.

Normally, the plant is divided into two membrane arrays staged in a 2:1 configuration. Each array is operated at 50% conversion, with the reject from the first array being fed to the second array for further treatment. The product streams from both the first and second arrays are then combined for injection into the formation, while the concentrate stream from the second array is rejected. Because each array is operated at 50% conversion, the combined product streams constitute 75% of the inlet flow rate (75% total conversion to product).

The seawater temperature is the most significant parameter affecting the design of sulfate-removal membrane systems. Lower sulfate levels in the product stream result in lower seawater feed temperatures; however, lower seawater feed temperatures require higher pressure drops through the membrane to maintain the desired flux rate and vice versa. Therefore, a balance

* Weston, R.: "Engineering Design of a Sulphate Removal Package," Axsia Serck Baker Ltd., internal document (December 1995) 3.

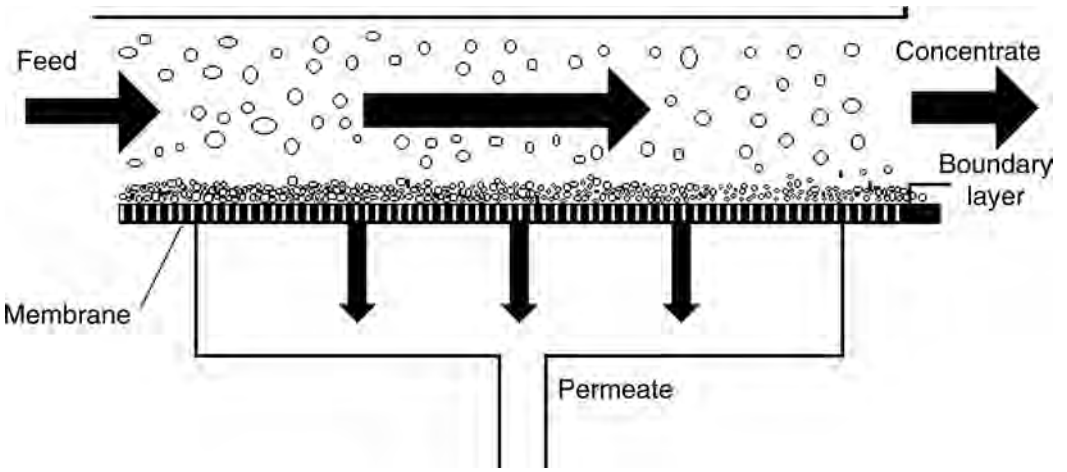


Fig. 4.33—Material (scale) buildup on a membrane module.

must be established between the desired sulfate level of the product stream and the energy available for use to raise the seawater temperature or to increase the seawater feed pressure.

Proper pretreatment of the feed water supplied to the NF membrane is required to maximize the efficiency and life of the membrane elements and to ensure trouble-free operation. Pretreatment requirements include the following:

- Removal of fine suspended solids that can plug or block the membrane surface.
- Prevention of biological growth on the membrane surface.
- Prevention of scale formation on the membrane surface during concentration of the feed water.
- Removal of any oxidizing biocides (e.g., chlorine) that can damage the membrane.
- Pressurization as required to achieve NF separation.

The sulfate-reduction package is part of a system that is designed to achieve all these objectives. For instance, both specially designed media-filter systems and cartridge filters are used to remove solids from the seawater upstream of the membrane elements. Furthermore, as sulfate is removed from the seawater along the length of each membrane element, the dissolved-solids content of the concentrate increases. As a result, the scaling tendency of the concentrate increases, as shown in **Fig. 4.33**. To avoid the deposition of scale on the membrane surface, antiscaling chemicals are injected into the seawater upstream of the membrane system. In addition, an organic biocide is dosed into the seawater to control the growth of bacteria in the membrane, and a dechlorination chemical (bisulfite) is injected into the seawater to neutralize any strong oxidizers (chlorine).

Despite these efforts to keep the membranes clean, the membranes will foul with time as the plant is operated. Therefore, membrane elements must be taken out of service on a routine basis for a deep clean with special cleaning chemicals. These chemicals are designed to remove deeply embedded scale and bacterial fouling with minimal damage to the membrane-element materials. It is possible to prepare a membrane-monitoring system to provide feedback to the operators that indicates the need for deep chemical cleaning of the membrane elements.

4.4 Water-Treating Chemicals

Chemicals play an important role in the oil-producing operation. They assist oil/water/gas separation, aid in fluid transport, protect treating equipment, and improve the quality of the gas, oil, and water. In water treating, they aid in producing suitable water for discharge or injection. A wide range of chemicals is available for water treating, and this section details the main class-

TABLE 4.8—COMMON WATER-TREATING CHEMICALS AND THEIR DOSAGE RATES

Chemical	Purpose	Dose Rate	Dose Point
Sodium hypochlorite	Biocide filtration aid	5 ppm as free Cl, continuous	200 m upstream of media filter
Polyelectrolyte	Flocculant (filter aid)	2 ppm, continuously	Upstream of media filters
Coagulant	Flocculant (filter aid)	1 ppm as iron (Fe), continuously	Upstream of media filters
Oxygen scavenger	Dissolved oxygen removal	10 ppm, continuously	Top of deaerator sump
Biocide	Bacteria control	500 ppm, 4 hours per week	Booster pump discharge line to injection pumps
Scale inhibitor	Scale control	10 ppm, continuously	Booster pump discharge line to injection pumps
Antifoam	Foam prevention in deaerator tower	2 ppm, continuously	Upstream of deaerator tower

es. These include water clarification, scale inhibition, corrosion protection, bacterial control, oxygen scavengers, antifoam, and cleaning surfactants.

A chemical-injection package enables various types of chemicals to be dosed into the water stream to optimize the treatment process. In many operations, each chemical-injection stream is equipped with two dedicated pumps, a duty and a standby pump, both of which are rated for 100% capacity. Storage-tank capacity is designed to allow the plant to run for several days between refills. Tank-construction materials can be carbon steel, stainless steel, or other material appropriate to withstand the action of the stored chemicals.

General dosing rates and injection points for the main chemical classes are listed in **Table 4.8**. These rates provide guidelines for sizing injection pumps and chemical-storage tanks.

4.4.1 Water Clarification (Flocculants). The purpose of water clarification is to improve the water quality to meet discharge or injection requirements. Water-clarification chemicals aid in coagulating and flocculating the oil and solid particles into larger ones to enhance their separation from water. Increasing the particle or droplet size significantly enhances the removal efficiency of skim tanks, hydrocyclones, filters, and centrifuges. The commonly used water-clarification chemicals may be classified as inorganic coagulants or polyelectrolites, but polyelectrolites are used normally as a secondary coagulant and filter aid.

Most of the inorganic coagulants and polyelectrolites can be dissolved and ionized in water. Their ion charges attract oil droplets and solid particles with opposite charges. Oil droplets grow by coalescence, and solid particles grow by forming flocs. The larger oil droplets or larger solid flocs are easier to separate. Particle separation from water follows from Stokes' law in that larger particles separate more quickly from water.

Inorganic coagulants include aluminum, iron, and copper salts. Except in the case of sodium aluminate, most of the common aluminum and iron coagulants are acid salts and require pH adjustment to reach the best operating range. For instance, aluminum coagulants require a minimum pH of 6 to 7, while iron salts are effective in a pH range of 5 to 11. These chemicals are very effective in promoting coagulation of oil and solids particles; however, excessive use or improper application of these chemicals will form undesirable oily gel-type settlements and occasionally cause malfunction of the monitoring/controlling instrument. The inorganic or low-molecular-weight coagulant is effective in the range of 10 to 45 ppm.

Ferric sulfate may be used as a coagulant. The large size of the positively charged cation, Fe_3^+, upsets the stability of the colloid, and the finest solids become entrapped by the precipitat-

ed ferric hydroxide. In the overall reaction, ferric sulfate consumes bicarbonate ions (or alkalinity) and can cause a pH reduction at higher dosage levels.

Polyelectrolites refers to all water-soluble organic polymers. The polyelectrolites are long chain molecules, frequently polyamines or polyacrylamides. Their overall charge and size destabilize colloids and provide agglomeration of solids (flocculation). In water treating, the term "polyelectrolyte" is generally used in reference to two types of chemicals. The first type is the polymeric primary coagulant; these chemicals are cationic, with relatively low molecular weight (<500,000). The other type of polyelectrolite is the polymeric flocculant or coagulation aid, which may be anionic, cationic, or approaching a neutral charge. Typical molecular weight may be as high as 20,000,000. Polyelectrolites serve to bridge particles together. Only a small amount of this polymeric chemical is needed to produce a significant effect on the oil droplets and solids. The normal application concentration for this chemical is 1 to 5 ppm.

4.4.2 Scale Inhibition. As the water stream flows through the treatment system, its pressure, temperature, and composition will change. Pressure and temperature changes affect the solubility of the chemical components in water and may form scale. Depending on the composition of the water, various types of scales can be formed in the pipelines, equipment, control system, and pumps. Scale formation leads to equipment failure, plugging, and contamination. The most common types of scales found in produced or seawater systems are carbonate, sulfate, phosphate, ammonium, sulfide, oxide, silica, and metallic-silicate complexes.

Several methods have been developed for determining the scale tendency of water systems. The current trend is to use several different approaches to calculate the water scale tendency and obtain a range of conditions in which scale could form in the system. Once the scale tendency is established, scale inhibitors are selected for treating the system.

4.4.3 Chemical Types. Various chemicals have been developed to inhibit scale formation in water. Selection of scale inhibitors is dependent on the type of scale to be inhibited and the operating conditions, such as the temperature and pressure of the system. The commonly used scale inhibitors are classified into the following types.

Chelants. Chelant compounds form soluble complexes with divalent compounds, such as calcium and magnesium, or with trivalent metals. The most common chelants are EDTA and NTA. These compounds are used frequently in steam-generator treatment because they are thermally stable at elevated temperatures. Stoichiometric levels are necessary for the use of chelants in controlling scale formation.

Polyacrylates. The polyacrylates contain the carboxylic acid group. Depending upon its composition, it is thermally stable to a relatively high temperature and can be used to control scale as well as suspended material.

Phosphonates. These organic phosphorous compounds have been used for controlling iron or hardness salts and form inhibitive films along metal surfaces. It is normally thermally stable to 250°F but can go higher in the absence of oxygen.

Polyphosphates. Polyphosphates of various chain lengths are used for controlling hardness and iron scales. They are very effective chemicals; however, their thermal stabilities are lower than the phosphonates.

4.4.4 Selection Methods. Depending upon the application, various methods are used for the selection of scale inhibitors. Factors such as thermal stability, absorption characteristics of the environment, and time of exposure are tested to determine a chemical's effectiveness at in-situ conditions. Commonly used methods are the thermal-stability and dynamic scale-inhibition tests.

Thermal-Stability Test. This method evaluates the thermal stability and scale inhibition at the same time. NACE *TM0374-2001*[31] gives the general test procedure.

Dynamic Scale-Inhibition Test. The ability of an inhibitor to prevent scale is its primary function in an application. Dynamic tube-blocking tests permit ranking of inhibitors to prevent scale. Different temperatures can be used to mimic changing field conditions.

4.4.5 Chemical Effect Mechanisms. Scale inhibitors vary in type and mode of action. Individual chemicals operate with one or more of the following mechanisms.

Sequestering. These compounds bind to one of the species that would precipitate, making it unavailable for precipitation. A common example is EDTA, which forms a claw-like arrangement attached to calcium ions called a chelate, preventing it from being precipitated as calcium carbonate or sulfate.

Dispersion. These compounds can actually disperse scale already attached to surfaces. They can be used to clean up scaled systems but must be used with caution because they could result in releasing suspended solids that could block the formation.

Crystal Modifiers. These compounds, such as complex phosphates, interfere with the crystal growth of the scale, preventing further growth.

Threshold Effects. This refers to the ability of many inhibitors to hold considerable quantities of scale-forming compounds in solution when present only in very small concentrations themselves.

4.4.6 Corrosion Protection. Corrosion is defined as the destruction of metal by either chemical or electrochemical reaction in the given environment. Because piping and processing equipment are normally made of metals that are in contact with produced water or seawater, chemical or electrochemical reactions will occur. The type of metal, water pH, dissolved oxygen, dissolved salts, and acid gases in water all have a significant effect on the corrosion rate, as do temperature, pressure, and fluid velocity.

Corrosion inhibitors reduce the corrosion rate by interrupting the electrochemical corrosion cell setup between the metal and the liquid or by stopping the deterioration of metal by a chemical reaction. One method of interrupting the electrochemical cell is to form a film on the metal surface, which stops the transfer of ions. One method of chemical protection uses an absorption inhibitor, such as a surface-active amine, which forms a chemisorption bond to the metal, rendering it incapable of dissolving into the fluid.

There are two types of film-forming inhibitors—aestivating and precipitating. The aestivating inhibitors promote the formation of a passive film to protect the metal surface. The precipitating inhibitors react with the corroded metal and deposit a barrier film on the metal surface. Phosphates and silicates are precipitating inhibitors.

In addition, various scavenger chemicals have been developed for removing corrosion-aiding components from the produced-water systems. Oxygen and hydrogen sulfide scavengers effectively remove these respective components from the water by combining them into the scavenger chemicals (see Sec. 4.4.9).

Corrosion inhibitors are selected by laboratory or field tests. Laboratory testing and evaluation have the advantage of being quicker and less expensive; however, inhibitor selection should always be verified by a field test. The most commonly used laboratory and field methods are the wheel, copper-ion displacement, and stirred autoclave tests, along with electrical probes and corrosion coupons.

Wheel Test. The laboratory wheel test is the mostly commonly used method in the oil industry. This apparatus consists of an enclosed rotating disc that holds bottles containing the test water, each with corrosion inhibitor in various concentrations, and a steel coupon in each bottle. The disc is spun at 25 to 30 rpm to cause agitation of the fluid and coupons; the temperature inside the enclosure can be varied to match the process conditions. The tested metal coupons are weighed before and after exposure to determine the weight loss.

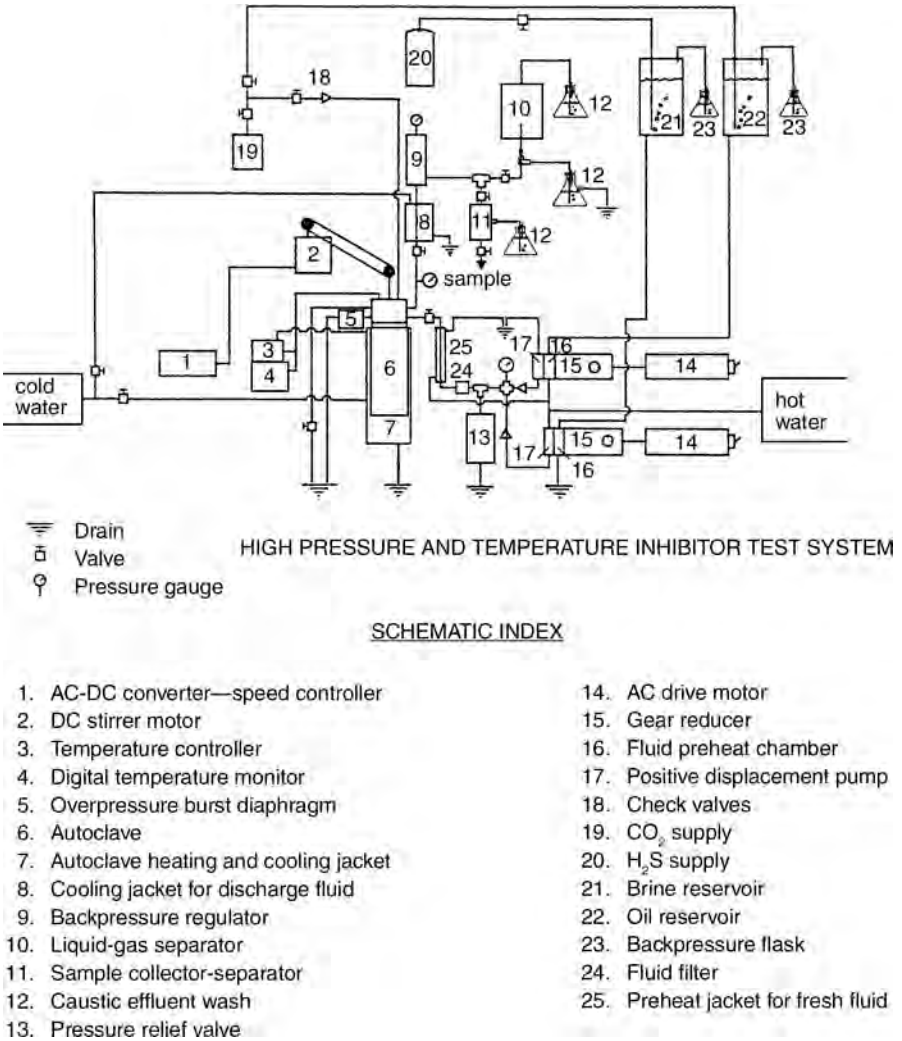


Fig. 4.34—Flow schematic of the autoclave test unit.

Copper-Ion Displacement Test. Used to determine the effectiveness of a protective film created by a corrosion inhibitor, in this test, the minimum concentration of inhibitor needed to form a persistent and protective film is determined. The test procedure requires first dipping a shim stock iron metal sample (¼ × 6 in.) into a 5% NaCl solution for 5 minutes. This metal is then dipped into an inhibitor solution of known concentration for 5 minutes with stirring and finally into a 10% $CuSO_4$ solution for 30 seconds. The results are observed for copper plating with a magnifying glass. This method is subject to temperature limitation, and its results are semiquantitative.

Stirred Autoclave Test. For high-pressure and high-temperature applications, it is necessary to use a high-pressure method, such as the stirred autoclave test. A stirred autoclave can be tested to 500°F and 5,000 psia. In addition, it can be used to test various oil/water ratios and concentrations of H_2S and CO_2. The test may be performed under either static or dynamic conditions. A schematic diagram of the autoclave test unit is shown in **Fig. 4.34**.

Electrical Probes. These provide a direct reading of the corrosion rate. Both polarization resistance and electrical resistance-type probes can be used for these evaluations. An electrical probe is the most widely used device for field evaluation. These probes can be applied at any point in the produced-water system to evaluate inhibitor performance and compare it with the background corrosion before application. The probe application is very quick, but it provides a corrosion rate only at the point and time of measurement. In most cases, the probes are used in combination with the corrosion-coupon measurement.

Corrosion Coupons. Corrosion coupons can be put into the operating process to directly measure the corrosion rate. The advantage of the corrosion coupon is that it is exposed to the true condition of the water system and measures the accumulated results for a time. It is especially valuable when the system has multiphase- or transient-flow conditions. The coupons can be placed at various points of the produced-water system; they are made from the metal of interest and placed in the system for a time (usually 1 to 6 months) to measure the accumulated corrosion of the system. The coupons are weighed before and after the exposed period.

4.4.7 Bacteria Control. Both surface and produced water contain biological constituents (primarily bacteria) that can contaminate the water-treatment or -injection systems. Because bacteria have the ability to multiply rapidly into colonies, they can cause plugging of surface and downhole equipment and injection-well formations, promote corrosion of surface piping and downhole tubulars, and generate H_2S that can cause pitting corrosion. Therefore, it is essential to develop means to control bacteria growth in surface-water-treatment systems.

Bacteria are unicellular, microscopic organisms that can be found in a wide variety of conditions, in both oxygen-containing systems (aerobes) and systems without oxygen (anaerobes). The one factor common to all bacteria is their requirement for water, which provides a means of carrying food to the bacterial cells and taking away waste products.

Seawater has predominantly aerobic bacteria, such as iron-oxidizing bacteria, some slime formers, and other bacteria, such as the hydrocarbon oxidizers. The growth of these species will be reduced by the dosing of chlorine (itself a biocide) to the intakes and by the deaeration process. However, anaerobic bacteria, such as sulfate reducers and other slime-forming bacteria, are present in seawater and, following the removal of oxygen and chlorine in the residence/deaeration tank, may proliferate rapidly, causing associated problems including corrosion and biofouling.

API Spec. RP-38[32] presents two culturing techniques for counting both aerobic and sulfate-reducing (anaerobic) bacteria, and both techniques count planktonic bacteria. “Planktonic” are the bacteria found swimming or floating in the water system. API *Spec. RP-38* states that aerobic bacteria greater than 10,000 bacteria/mL and anaerobic bacteria levels greater than 1 bacteria/mL are considered significant if they are associated with physical changes in the system, such as increasing injection pressures, decreasing water quality, and plugging. Current studies indicate that a count of all bacteria types at key points in the system is necessary to determine the extent of the problem and to monitor the treatment progress.

The types of biocide available are varied and are selected on the basis of kill rate to anaerobic bacteria, kill rate to aerobic bacteria, and ability to penetrate surface films. Some of the typical compounds used as biocides include quaternary ammonium compounds, aldehydes, amines, chlorinated phenols, organometallic compounds, and sulfur organic compounds. In seawater systems, chlorine is the primary biocide used.

Chlorine. Many years of operational experience have shown that chlorine is very effective in controlling bacterial growth. Chlorine in water takes on various forms according to the pH of the water. The types of chlorine present in the water include Cl_2, HOCL, and OCl^-. In a seawater system, it is possible to generate hypochlorite (OCl^-) in situ through electrolysis of the seawater, as discussed previously.

Sodium hypochlorite is dosed to the inlet of the lift pumps at such a level as to give a free chlorine residual of 0.5 to 1 ppm Cl_2 upon exiting the filter. Chlorine is a very strong oxidizing agent and reacts with many materials. Once it reacts, it is no longer available to kill bacteria. Chlorine may react with ferrous iron, hydrogen sulfide, organic compounds, and sulfite ions (present in the oxygen scavenger chemicals).

4.4.8 Biocide Testing. To evaluate a biocide, a bacteria culture is first obtained from the field. The culture is usually a mixed strain of the organisms that can grow in the media used. If a field culture is not available, cultures of bacteria can also be obtained from a commercial laboratory. One or more of the following methods are then used to select a biocide.

Bacteriostatic Test. This test is used for preliminary screening of biocides and involves exposing a bacteria sample to a known concentration of biocide. The test is performed in broth bottles with a range of biocide concentrations that are incubated for 15 days. Afterward, the bottles are observed for bacterial growth. The minimum concentration that shows no bacteria growth is the effective concentration.

Planktonic Time Kill Test. This test involves putting the field sample into a known concentration of biocide for a specific contact time, then counting the bacteria that were not killed. The effectiveness of the chemical is determined by comparing the results to a blank determination in which no biocide is present. A biocide concentration that results in a 99% or better kill is considered to be effective. The kill rate is calculated with the lowest number in the population range for the blank and the highest number in the bacteria population range observed for each biocide concentration.

Sessile Bacteria Time Kill Test. This test uses a mild steel coupon that has been exposed to a bacteria culture for at least 14 days. This period is sufficient to allow for the development of a sessile population on the surface of the coupon. The contaminated coupon is then used in the time kill test.

Once a biocide has been selected, a field test is conducted. In general, batch treatment is more economical than continuous treatment. However, the effectiveness and economics of chemicals are dependent on field producing conditions.

It should be noted that generally, because of the enormous complexity and density of microorganisms, there is no single biocide that is completely effective. For this reason, and because bacteria can adapt themselves (i.e., build up an immunity) to a biocide, it is customary to use alternate slugs of different biocides or biocide blends.

4.4.9 Oxygen Scavenger. Chemical scavengers are used to remove dissolved oxygen from waterflow streams of less than 10,000 B/D. There are a number of compounds commercially available to remove dissolved oxygen, and all can be considered as a source of sulfur dioxide or sulfite. These include sodium sulfite (Na_2SO_3), sulfur dioxide (SO_2), sodium bisulphate ($NaHSO_3$), sodium metabisulfite ($Na_2S_2O_5$), and ammonium bisulfite (NH_4HSO_3). Ammonium bisulfite is commonly used on river and aquifer water systems because it is relatively stable to the atmosphere (solutions in storage tanks will not absorb oxygen from the air), and its rate of reaction with dissolved oxygen is catalyzed by the trace of metals, particularly iron, in the water. It is, thus, the most convenient chemical to use. To speed the reaction rate, a catalyst such as cobalt is often required.

4.4.10 Antifoam. Some water systems (e.g., seawater) have a tendency to create foam when subjected to high pressure-drop or turbulence conditions. This foaming is very unpredictable and can cause enormous problems, particularly in deaerator columns. In the deaerator, foaming may result in failure of the level control on the base of the column and reduced oxygen-removal efficiency.

Antifoam chemicals are polyglycols or silicones contained in a solvent that is fully water-soluble or water-dispersible. At dose levels usually less than 1 ppm, they act by decreasing the surface tension of bubbles so that they expand and coalesce. They are dosed to the inlet of the deaerator before the inlet distributor. In water-injection systems, the polyglycols are preferred because silicones produce fine precipitates, which can cause injectivity loss. However, silicones may be required in difficult applications, usually in low-temperature vacuum systems or when the foaming tendency is very high.

4.4.11 Surfactant. Surfactants are normally water-based alkaline cleaners that are biodegradable. These chemicals are used as detergents in cleaning oil films from equipment surfaces. A common use for surfactants is to aid in cleaning media filters. Because of its physical properties, oil is not easily removed from media filters during normal backwashes. To properly remove oil, a surfactant is slug-dosed into the media filter inlet and flushed into the bed. The combination of detergent and air scour breaks the viscous bond between the anthracite and oil and allows the particles to separate. The oil is removed during the subsequent backwash steps.

4.5 Material Selection for Water-Treating Equipment

4.5.1 Material Produced-Water Systems. Selection of materials for produced-water-treating equipment must take into account the pressure rating of the application, the corrosivity and erosivity of the fluid, and the end location. The primary problem constituents in produced water are salt, hydrogen sulfide, carbon dioxide, and sand. Proper material selection is critical for long operation life and minimal maintenance. A small increase in capital expenditure for an optimum material selection can greatly reduce the mean time to maintenance or failure, thus greatly saving on operating expenses.

4.5.2 Normal Service Materials. Ordinary carbon steel is by far the most important alloy in the oil and gas industry because it accounts for more than 98% of the construction materials used in produced-water systems.[33] As a general rule, every attempt should be made to use steel, such as modifying the process with corrosion inhibitors in the fluid or coating the steel. Even though the chloride content can be higher than seawater, piping and vessel equipment used to treat normal produced water is usually manufactured from carbon steel because the oxygen level is very low. Carbon dioxide in the water stream may present a problem because it will form carbonic acid, which is corrosive to carbon steel, even in the absence of oxygen. As little as 1 ppm carbon dioxide in pure water will lower the pH to 5.49, sufficient for a corrosion problem.[34] A corrosion inhibitor or coating must be used in this case to protect the carbon steel.

Piping Systems. The most commonly used material for piping systems in produced-water treatment is carbon steel. Piping systems for produced water are normally designed to the American Soc. of Mechanical Engineers (ASME) standard B31.3 for process piping and use ASME specification SA-106 carbon steel piping. Because of its strength, this material can withstand high pressures and is commonly available in diameters up to 48 in.

Steel pipe has excellent impact resistance and flexural strength. It is susceptible to both internal and external corrosion. When oxygen is excluded from the system, which is the normal case for produced water, internal corrosion may not be a problem. External corrosion is normally fought with a coating system. For pipe exposed to salt air, a three-coat epoxy-paint system is often specified. Underwater pipe may be protected by a thin-film-epoxy, coal-tar-epoxy, or extruded-plastic system. Thin-film epoxy is more popular because of its greater toughness to potential handling and installation damage.

Vessel Fabrication. Vessels and other equipment to handle produced water are most commonly fabricated from carbon steel. Small pressure vessels (< 48 in.) can be made from

seamless pipe (SA-106), and larger pressure vessels are fabricated from rolled plate (SA-516). These grades of steel exhibit a yield strength of at least 60,000 psi, which can easily be fabricated into inexpensive, large, high-pressure-containing components. Nonpressure-vessel applications normally use carbon steel plate (SA-516 or SA-36).

Much like a carbon steel piping system, the vessels must be protected from internal and external corrosion. Produced water normally contains insignificant amounts of oxygen, which greatly minimizes internal corrosion. If oxygen is present, sacrificial anodes (normally of aluminum) can be used within a pressure vessel. External corrosion is normally combated with a coating system. In offshore, salt-air environments, a three-coat epoxy-paint system is most commonly used.

4.5.3 Materials for Severe Service Environments. Severe service environments are encountered increasingly as oil and gas production embraces more difficult production situations. Materials have been developed to handle highly corrosive well products (CO_2 and H_2S) at high production temperatures and pressures. The two most common classes of metals used in highly corrosive applications are stainless steels and superalloys. These materials may be expensive; however, they may provide the only acceptable long-term solution.

The most common stainless steels used are 316 and 316L (UNS S31600 and S31603), providing moderate resistance to chloride and H_2S and good resistance to CO_2. The L grade is used for components that require welding. For higher chloride and H_2S resistance, duplex (UNS 31803) and superduplex stainless steel (UNS 32750) are finding increased use. Extreme conditions are being met by the use of Incoloy* 625 (UNS N06625) and 825 (UNS N08825), which are nickel-based superalloys. [UNS refers to the "unified numbering system" that is a standard practice of the American Soc. for Testing and Materials (ASTM) for commercial metals and alloys.]

4.5.4 Materials for Erosion Protection. Material selection for erosion protection (i.e., sand) is dependent on the type of wear exhibited. There are two main mechanisms for wear—impact and sliding abrasion. Impact wear occurs where the particles directly impinge against the material surface from a near-perpendicular angle. These particles may hit the surface once and bounce off. Sliding wear occurs where the particles move parallel to the material surface and rub repeatedly against the material substrate. Each mechanism abrades the material surface differently; therefore, appropriate materials are suggested for each.

Impact Wear. To accommodate impact wear, a material is needed that will absorb the impact without breaking. Leaded tees are used in piping to make 90° turns. The soft lead absorbs particle impact without wearing into the steel pipe. Elastomer rubbers provide good impact resistance but find limited use in produced-water applications because of dissolution in the presence of hydrocarbons. Nitrile rubber overcomes this hindrance because it displays a moderate resistance to hydrocarbons[35] and can be used to internally line vessels or pipe.

Sliding Wear. Material hardness is the main characteristic used to accommodate sliding wear. If the material substrate is harder than the abrading material, ideally, no wear will occur. The most common solid present in produced water is sand, which is primarily quartz (SiO_2). The two groups of materials used to handle sliding wear are hard metals and ceramics.

Hard Metals. Metals are used in cases of moderate sliding-wear protection and where some toughness is required. The most economical hard metal is white iron, which is a high iron-carbide-content cast iron. White iron is used for slurry pump impellors and casings, and corrosion-resistant grades are available. A slightly less hard metal that is also commonly used is Stellite,†

* Incoloy is a registered trademark of Special Metals Corp.

† Mark of Deloro Stellite, Swindon, U.K.

a cobalt alloy that finds large use in smaller, intricate-wear applications. Both white iron and Stellite are cast materials, difficult to machine, and not as hard as quartz.

Ceramics. The best commercial materials to handle this type of wear are ceramics. Ceramic materials are brittle (and, therefore, hard to work with) and expensive, but in cases of sliding wear, they provide the maximum erosion protection. The most common ceramic used is alumina (Al_2O_3), which can be cast into intricate sections or made into tiles for hand lining. This is the most common material for manufacturing desander liners. Additional common, though more expensive, ceramics are silicon carbide (SiC) and tungsten carbide (WC). These materials provide 5 to 10 times higher wear resistance than alumina but are correspondingly more expensive.[36] Diamond films provide the best protection possible but find limited use in large-scale erosion protection because of the cost. The ceramics listed above are harder than quartz.

4.5.5 Materials for Seawater Systems. The selection of materials for equipment in seawater treating must take into account the pressure rating of the application, the corrosivity of the fluid, and the end-use location. Seawater contains approximately 3.5% salt (sodium chloride) and is slightly alkaline (pH 8). It is a good electrolyte and can cause severe corrosion.[37,38] Oxygen content, liquid velocity and temperature, and the presence of biological organisms affect the corrosion rate. In most oil and gas seawater-handling systems, oxygen content is the biggest concern in designing for corrosion protection because the dissolved oxygen greatly accelerates the corrosion rate. Typical pipe-transport velocities are in the range of 3 to 12 ft/sec, which will have a minimal effect on corrosion but will minimize the ability of fouling organisms to attach themselves to the piping materials. Generally, erosion resistance is not a major factor in handling seawater because the solids are not very erosive.

Metals for Piping and Vessels. For untreated seawater, exotic metals such as titanium, Hastelloy C, and copper-nickel (70-30 or 90-10) must be used to prevent severe corrosion.[37] Stainless steel (Type 316 or 304) will exhibit severe pitting in a flowing seawater application. This can be reduced somewhat by upgrading to duplex stainless steel. Vessels can be made of standard carbon steel but must be lined with an internal coating to prevent corrosion. Common materials for internal vessel coating are neoprene rubber or glass-flake-filled, amine-cured epoxy. Both epoxy lining and neoprene are good to 200°F.[39,40] Standard carbon steel piping can be used on seawater after removal of dissolved oxygen.

Plastic Piping. Plastic pipe is the most common material for low- to moderate-pressure raw seawater service. It has a pressure rating up to 450 psig, depending on the pipe size. Plastic pipe is not susceptible to either internal or external corrosion in seawater service, it has a low friction factor, and its light weight makes it easy to install. In general, plastic pipe can be purchased in accordance with the following API specifications: *Spec. 5LE* for polyethylene line pipe (PE), *Spec. 5LP* for thermoplastic line pipe [polyvinyl chloride (PVC) and chlorinated polyvinyl chloride (CPVC)], and *Spec. 5LR* for reinforced thermosetting resin line pipe (RTRP).

Because of the superior strength and greater resistance to internal pressure and hydrocarbons, fiber-reinforced plastic (FRP) is the most commonly used material for this service. This pipe is available as a filament-wound fiberglass-reinforced vinyl ester material, usually with a resin-rich reinforced liner. It is available up to a 16-in. nominal pipe size and a pressure rating from 150 to 450 psig (this decreases with pipe diameter).[41] FRP pipe has the disadvantage of being very brittle, which can lead to damage during installation. Ultraviolet (UV) light, or sunlight, can degrade the physical strength of FRP by attacking the resin-glass bond. Pigments or dyes are incorporated into the resin to form a barrier for UV penetration into the laminate, which maintains degradation to a surface-only attack. In certain cases, an overwrap, such as an organic veil layer, can be used to provide even greater UV resistance.[41]

4.5.6 Materials for Steam Systems. Of primary concern with steam transport systems are temperature and pressure. Corrosion is usually not a major issue in clean, dry steam systems because the dissolved solids and gases are removed before steam generation. Corrosion can be a problem if the steam is not fully dried and if the water content concentrates boiler water chemicals. Plain carbon steel is resistant to general corrosion by clean, deaerated steam up to 850°F. For higher temperatures, high-strength, low-alloy (HSLA) steel is needed, such as 2¼Cr-1Mo, which is good to 1,200°F.[42] Generally, erosion resistance is not a major factor in these systems because steam from a boiler is free of solids. Proper material selection is critical for long operation life and minimal maintenance.

Nomenclature

A = membrane area, ft^2
A_d = deck area, ft^2
b = Eq. 4.14
B_p = width of the plate section perpendicular to the axis of water flow, ft
c = solids concentration, fraction by volume
d_d = droplet diameter, μm
d_i = vessel ID, in.
d_i = pile ID, in.
d_{max} = droplet diameter, μm
d_p = dispersed particle diameter
D = ID of cyclone, in.
E_{rc} = Eq. 4.12
E_{ro} = Eq. 4.13
f_V = volume fraction of the dispersed phase
F = factor accounting for turbulence and short-circuiting
g = g-force acceleration factor
g_c = gravity acceleration constant
h_f = height of flume, ft
K = permeate flow coefficient at standard temperature, gal/D-psi-ft^2
K_f = fouling factor
K_s = empirical settling constant
K_T = membrane temperature-correction factor
L = length of the plate section parallel to the axis of water flow, ft
L_{bs} = length of baffle section, ft
L_e = effective length in which separation occurs, ft
L_p = perpendicular distance between plates, in.
L_1 = inlet-distribution section
L_2 = outlet-gathering section
N_c = number of nonflow cycles that a particle sees as it traverses the baffle section
q_r = rainfall rate, in./hr
q_w = water flow rate, BWPD
q_{WD} = washdown rate, B/D
Q_f = feed volumetric flow rate, m^3/s
Q_{pf} = permeate flow, gal/D
t = time, seconds
t_c = time valves are closed
t_r = retention time, minutes

v = velocity, ft/s
v_s = settling velocity
v_w = velocity of water, ft/s
x_{98} = particle size at 98% efficiency, m
Z_p = height of the plate section perpendicular to the axis of water flow, ft
Z_w = height of water column, ft
Δp = pressure drop, psi
Δp_{avg} = average transmembrane pressure drop, psi
$\Delta\gamma$ = difference in specific gravity relative to water
$\Delta\gamma_{ow}$ = difference in specific gravity between oil and water
$\Delta\rho$ = difference in density of the dispersed particle and the continuous phase
σ = surface tension, dynes/cm
ρ_l = liquid density, kg/m^3
ρ_s = solid density, kg/m^3
ρ_w = density, g/cm^3
μ_L = viscosity of the continuous phase (liquid)
μ_w = water viscosity, cp
θ = angle of the plate with the horizontal

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SI Metric Conversion Factors

Å	×	1.0*	E – 01	= nm
°API		141.5/(131.5 + °API)		= g/cm^3
bbl	×	1.589 873	E – 01	= m^3
Btu	×	1.055 056	E + 00	= kJ
cp	×	1.0*	E – 03	= Pa s
dyne	×	1.0*	E – 02	= mN
ft	×	3.048*	E – 01	= m
ft^2	×	9.290 304*	E – 02	= m^2
ft^3	×	2.831 685	E – 02	= m^3
°F		(°F – 32)/1.8		= °C
gal	×	3.785 412	E – 03	= m^3
in.	×	2.54*	E + 00	= cm
in.^{3}	×	1.638 706	E + 01	= cm^3
lbm	×	4.535 924	E − 01	= kg
psi	×	6.894 757	E + 00	= kPa

*Conversion factor is exact.

Chapter 5
Gas Treating and Processing

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5.1 Objectives of Gas Treating and Processing

Natural gas is a mixture of many compounds, with methane (CH_4) being the main hydrocarbon constituent. When natural gas is produced from an underground reservoir, it is saturated with water vapor and might contain heavy hydrocarbon compounds as well as nonhydrocarbon impurities. In the raw state, natural gas cannot be marketed, and, therefore, it must be processed to meet certain specifications for sales gas. Additionally, it might be economical to extract liquefiable hydrocarbon components, which would have a higher market value on extraction as compared with their heating value if left in the gas.

Before the optimum design of any gas treating plant can be decided, at minimum, one must know the raw gas production capability to the plant; composition of separator inlet gas and condensate, and relative condensate/gas rates; specifications for the residue gas; and rate of gas sales.

The end user of natural gas needs to be assured of two conditions before committing to the use of gas in a home or factory: the gas must be of consistent quality, meeting sales gas specifications; and the supply of gas must be available at all times at the contracted rate.

Gas treating facilities, therefore, must be designed to convert a particular raw gas mixture into a sales gas that meets the sales-gas specifications, and such facilities must operate without interruption.

5.2 Typical Sales-Gas Specifications

Specifications for sales gas describe the required physical properties of the gas such that it can be transported under high pressure through long distance pipelines at ground temperature without forming liquids, which could cause corrosion, hydrates, or liquid slugs into downstream equipment. Limits on the content of certain nonhydrocarbon compounds are also specified. While the specific limits for each item might vary among transmission companies or customers, the overall specifications for sales gas generally include:

- Maximum hydrocarbon dewpoint temperature at a pressure of 800 psig.
- Maximum allowable CO_2 content.
- Maximum allowable H_2S content and total organic sulfur content.
- Maximum allowable water-vapor content.
- Maximum allowable temperature of gas leaving the plant.

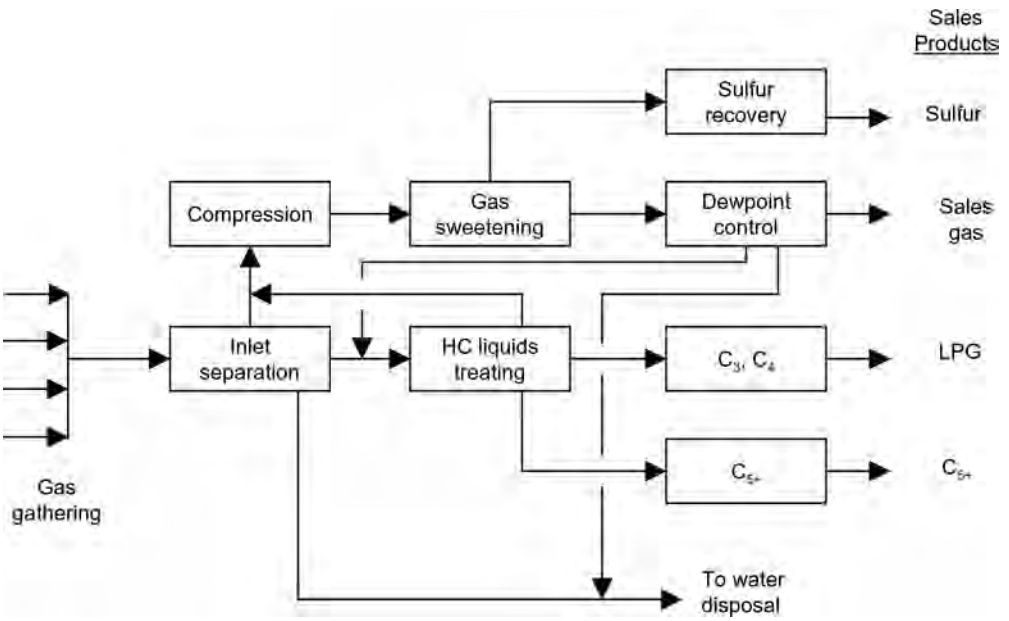


Fig. 5.1—Schematic drawing of typical gas plant processes.

- Minimum pressure to enter the gas transmission grid.
- Minimum heating value.
- Free of dust, treating chemicals, and other contaminants from the process plant.

In long distance transmission of sales gas by pipeline, the pressure is usually less than 1,000 psig. It is important that no liquids form in the line because of condensation of either hydrocarbons or water. Hydrocarbon liquids reduce the pipeline efficiency and might hold up in the line to form liquid slugs, which might damage downstream compression equipment. Condensed water can do the same. Additionally, water could form solid complexes (hydrates), which accumulate and block the line. The dewpoint temperature at any pressure is the temperature at which either hydrocarbons or water condense upon cooling of the gas. Thus, the specifications for sales gas include limits on the hydrocarbon dewpoint temperature, as well as limits on the water vapor content of the gas.

Knowing the specifications, and knowing the required sales gas flow rate and the composition of the raw gas and condensate entering the plant, the various process vessels can be designed, and the optimum process conditions of pressure and temperature can be specified.

Depending on the composition of the inlet fluids and the price at the plant gate, other sales products might be recovered in the plant as well. These could be ethane, propane, butane and pentanes-plus, which also must meet stringent specifications concerning purity. The possible processing steps, as illustrated in **Fig. 5.1**, are inlet separation, compression, gas sweetening, sulfur recovery or acid gas disposal, dehydration, hydrocarbon dewpoint control, fractionation and liquefied petroleum gas (LPG) recovery, and condensate stabilization.

Except for gas sweetening, the processing steps involve no chemical reactions. The gas/liquid product specifications are achieved by separating the compounds through changing the physical conditions of temperature and pressure to which the fluids are exposed. Contact with other compounds, such as glycol and absorption oil, affects the relative solubilities of certain compounds, thereby achieving separation from the main gas stream. Exposure to dry compounds, such as silica gel or molecular sieves, separate some compounds from the gas stream

by physical adsorption. Distillation is used to separate the various hydrocarbon compounds into liquid fractions on the basis of differences in their volatilities.

5.3 Sour Gas Sweetening

5.3.1 Definition of Sour Gas. Sour gas is natural gas that contains hydrogen sulfide (H_2S). A natural gas is "sour" when the H_2S content of the gas mixture exceeds the limit imposed by the purchaser of the gas, usually a transmission company or the end user. Generally, the limit for H_2S content is one grain of H_2S per 100 scf of sales gas. The limit for H_2S content in sales gas in some areas is ¼ grain of H_2S per 100 scf of gas. The mass specification of one grain per 100 scf converts a volumetric limit of 16 ppm. Sour natural gases can contain H_2S in concentrations from several ppm to over 90%.

While the foregoing defines sour gas from a sales gas perspective, the standards and regulations applying to sour gas service and operations may use a different definition. In this respect, the National Association of Corrosion Engineers (NACE), which developed the standards for materials for use in sour service, defines sour gas service, to which their standards apply, on the basis of partial pressure of H_2S and total pressure. NACE Standard MR0175 applies to natural gas systems having a partial pressure of H_2S of 0.05 psia or greater, at an absolute pressure above 65 psia. If the partial pressure of H_2S is at or above these limits, the steel and other equipment exposed to the sour gas must meet the conditions specified in NACE Standard MR0175 for sour service.

5.3.2 Other Sulfur Compounds. While H_2S is the compound responsible for designating a natural gas as sour, there are other sulfur compounds, also present in sour gas, in much smaller concentrations. The sales gas specifications normally set a limit of 5 grains per 100 scf of gas for total sulfur content. Thus, sweetening solvents must be able to remove other sulfur compounds, as well as H_2S, from the sour gas to meet the total sulfur limitation. Some of the other common sulfur compounds found in sour natural gas are mentioned next.

Mercaptans are compounds that occur naturally in sour gas. They are hydrocarbon compounds that have a sulfur atom inserted between a carbon atom and a hydrogen atom. Methyl, ethyl, propyl, and butyl mercaptan are some examples. Mercaptans have a strong offensive odor, and certain mixtures of manufactured mercaptan, such as tertiary butyl mercaptan and isopropyl mercaptan, as well as others, are added to sweet natural gas to odorize the gas prior to domestic or commercial consumption.

Carbon disulfide (CS_2) and carbonyl sulfide (COS) might also be present in gases containing H_2S, but usually only in small concentrations. These compounds also have a strong sour gas odor and are largely extracted from the sour gas in the sweetening operation.

5.3.3 CO_2 Removal. Virtually all sour natural gases also contain CO_2, but the converse is not true: many natural gas mixtures can contain CO_2 without any H_2S. CO_2 and H_2S are called "acid gases," or collectively "acid gas," as both gases are slightly soluble in water and form a mildly acidic solution. Most regenerative processes used for H_2S removal from natural gas also remove CO_2. If a natural gas contains amounts of CO_2 in excess of the sales gas limit, but no H_2S, there are specific processes available for CO_2 removal.

5.3.4 Overview of Sweetening Process. Sour natural gas compositions can vary over a wide concentration of H_2S and CO_2, as well as a wide variation in concentration of the hydrocarbon components. If the H_2S content exceeds the sales gas specification limit, the excess H_2S must be separated from the sour gas. The removal of H_2S from sour gas is called "sweetening." The

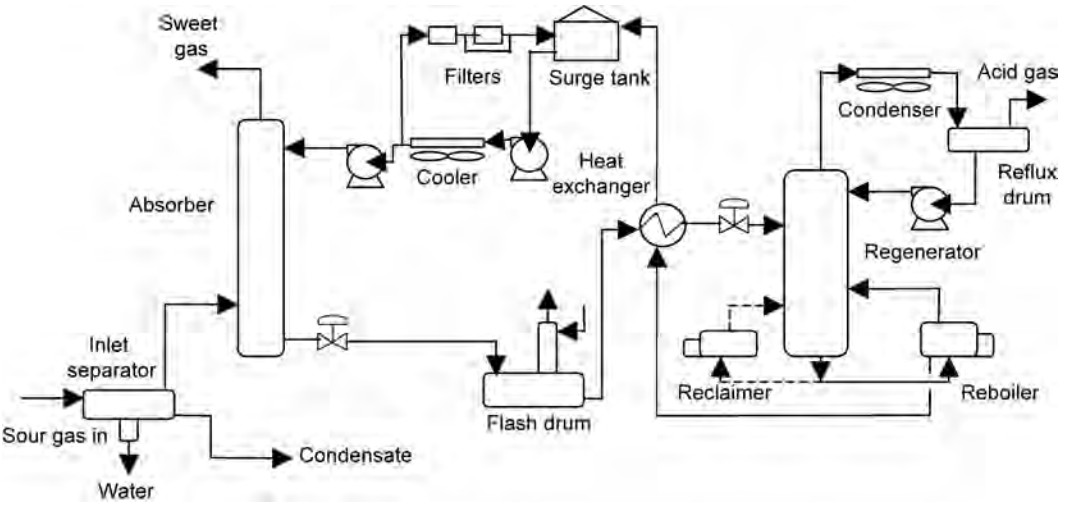


Fig. 5.2—Schematic drawing of sweetening process equipment.

process selected for sweetening a sour gas depends on the general conditions: H_2S and mercaptan concentration in the sour gas, and sales gas H_2S and total sulfur limits; maximum design flow rate; raw gas inlet pressure; requirement for sulfur recovery; and acceptable method of waste products disposal.

The selected process must be cost effective in meeting the various specifications and requirements. Throughout the world, regulations generally limit the flaring of H_2S. Sweetening of gas streams containing very low concentrations of H_2S can be done in many ways, depending on the general conditions. If the sour gas stream contains more than 70 to 100 pounds of sulfur/day in the form of H_2S in the inlet gas to a sour plant, a regenerative chemical solvent is usually selected for the sweetening of the sour gas stream. For very low H_2S content sour gas, a scavenger chemical is usually used. In such cases, the chemical is consumed, and the method for ultimate disposal of the spent chemical is a consideration.

5.3.5 Typical Process Equipment for Sweetening Sour Gas With a Regenerative Solvent. A schematic drawing of typical process equipment for sweetening sour gas with regenerative solvent is shown in **Fig. 5.2**. The first vessel is the inlet separator, which performs the important function of separating the fluid phases on the basis of density difference between the liquid and the gas. The sour gas flows from the separator into the lower part of the absorber or contactor. This vessel usually contains 20 to 24 trays, but for small units, it could be a column containing packing. Lean solution containing the sweetening solvent in water is pumped into the absorber near the top. As the solution flows down from tray to tray, it is in intimate contact with the sour gas as the gas flows upward through the liquid on each tray. When the gas reaches the top of the vessel, virtually all the H_2S and, depending on the solvent used, all the CO_2 have been removed from the gas stream. The gas is now sweet and meets the specifications for H_2S, CO_2, and total sulfur content.

The rich solution leaves the contactor at the bottom and is flowed through a pressure letdown valve, allowing the pressure to drop to about 60 psig. In some major gas plants, the pressure reduction is accomplished through turbines recovering power.[1] Upon reduction of the pressure, the rich solution is flowed into a flash drum, where most dissolved hydrocarbon gas and some acid gas flash off. The solution then flows through a heat exchanger, picking up heat from the hot, regenerated lean solution stream. The rich solution then flows into the still,

where the regeneration of the solvent occurs at a pressure of about 12 to 15 psig and at the solution boiling temperature. Heat is applied from an external source, such as a steam reboiler. The liberated acid gas and any hydrocarbon gas not flashed off in the flash drum leave the still at the top, together with some solvent and a lot of water vapor. This stream of vapors is flowed through a condenser, usually an aerial cooler, to condense the solvent and water vapors. The liquid and gas mixture is flowed into a separator, normally referred to as a reflux drum, where the acid gas is separated from the condensed liquids. The liquids are pumped back into the top of the still as reflux. The gas stream, consisting mainly of H_2S and CO_2, is generally piped to a sulfur recovery unit. The regenerated solution is flowed from the reboiler or the bottom of the still through the rich/lean solution heat exchanger to a surge tank. From here, the solution is pumped through a cooler to adjust the temperature to the appropriate treating temperature in the absorber. The stream is then pumped with a high-pressure pump back into the top of the absorber, to continue the sweetening of the sour gas.

Most solvent systems have a means of filtering the solution. This is accomplished by flowing a portion of the lean solution through a particle filter and sometimes a carbon filter as well. The purpose is to maintain a high degree of solution cleanliness to avoid solution foaming. Some solvent systems also have a means of removing degradation products, by having an additional reboiler for this purpose in the regeneration equipment hook-up. In some designs, the rich solution is filtered after it leaves the surge drum.

5.3.6 Sweetening Solvents. The desirable characteristics of a sweetening solvent, used in the process just discussed, are outlined next.

- Required removal of H_2S and other sulfur compounds must be achieved.
- Pickup of hydrocarbons must be low.
- Solvent vapor pressure must be low to minimize solvent losses.
- Reactions between solvent and acid gases must be reversible to prevent solvent degradation.
- Solvent must be thermally stable.
- Removal of degradation products must be simple.
- The acid gas pickup per unit of solvent circulated must be high.
- Heat requirement for solvent regeneration or stripping must be low.
- The solvent should be noncorrosive.
- The solvent should not foam in the contactor or still.
- Selective removal of acid gases is desirable.
- The solvent should be cheap and readily available.

Unfortunately, there is no one solvent that has all the desirable characteristics. This makes it necessary to select the solvent that is best suited for treating the particular sour gas mixture from the various solvents that are available.[2] The sour natural gas mixtures vary in H_2S and CO_2 content and ratio; content of heavy or aromatic compounds; and content of COS, CS_2, and mercaptans.

While most of the sour gas is sweetened with regenerative solvents, for slightly sour gas, it may be more economical to use scavenger solvents or solid agents.[3] In such processes, the compound reacts chemically with the H_2S and is consumed in the sweetening process, requiring the sweetening agent to be periodically replaced.

5.3.7 Regenerative Chemical Solvents. Most of the regenerative chemical sweetening solvents are alkanolamines, which are compounds formed by replacing one, two, or three hydrogen atoms of the ammonia molecule with radicals of other compounds to form primary, secondary, or tertiary amines respectively.[4] Amines are weak organic bases that have been used for many years in gas treating to remove CO_2 and H_2S from natural gas as well as from synthesis gas. These compounds combine chemically with the acid gases in the contactor to form unstable salts. The salts break down under the elevated temperature and low pressure in the still.

TABLE 5.1—MAIN CHEMICAL SOLVENTS USED IN GAS SWEETENING

Solvent	Acronym	Formula	Molecular Weight
Primary Amines:			
Monoethanolamine	MEA	$HOC_2H_4–NH_2$	61.08
Diglycolamine	DGA	$H(OC_2H_4)_2–NH_2$	105.14
Secondary Amines:			
Diethanolamine	DEA	$(HOC_2H_4)_2–NH$	105.14
Diisopropanolamine	DIPA	$(HOC_3H_6)_2–NH$	133.19
Tertiary Amines:			
Triethanolamine	TEA	$(HOC_2H_4)_3–N$	148.19
Methyldiethanolamine	MDEA	$(HOC_2H_4)_2–NCH_3$	119.16
Alkaline Salt:			
Potassium Carbonate	Hot Pot	K_2CO_3	138.21

Because the chemical reactions are reversible by changing the physical conditions of temperature and pressure between absorber and still, amines are highly suitable for removing the acid gases from the hydrocarbon gas stream. However, sometimes nonreversible reactions take place to a minor degree, forming degradation compounds. Such degradation compounds must be periodically removed by distillation. This occurs in a reclaimer vessel. Primary amines are more prone to forming degradation compounds than the other solvents.

Another chemical solvent, potassium carbonate (K_2CO_3), has also been used for removing H_2S and CO_2 from manufactured or natural gas. It is not widely accepted in the sour natural gas industry, but it is periodically mentioned in the literature as finding some application under specific conditions. This chemical solvent was originally developed by the U.S. Bureau of Mines for removing CO_2 from manufactured gas. **Table 5.1** lists the regenerative chemical solvents generally used for sweetening sour gas and gives the acronyms, chemical formulas, and molecular weights.

5.3.8 Primary Amines. ***Monoethanolamine (MEA).***[5] MEA was the earliest amine used for sweetening sour gas. It is a stronger base than DEA and also has a higher vapor pressure than DEA; therefore, vapor losses are higher than for DEA. MEA forms nonregenerative (degradation) compounds with CO_2, COS, and CS_2, which is a disadvantage, as the degradation compounds must be removed periodically to lessen the corrosion rate. A reclaimer is usually incorporated in an MEA sweetening train to periodically remove the degradation products from the solution by distillation. MEA has been used for more than 60 years in process applications, and the process operation and problem areas are well understood. Solution strengths of MEA are usually in the range of 15 to 22% by weight MEA in water. Mol loadings (moles of acid gas picked up in the contactor per mole of solvent circulated) are generally in the range of 0.25 to 0.33 moles acid gas per mol of MEA.

Diglycolamine (DGA). The DGA process was developed by The Fluor Corp. in the 1950s, which called the process the Econamine Process. The advantage of DGA over MEA appears to be the lower solution circulation rate owing to the higher solvent concentration, resulting in higher acid gas pickup per volume of solution circulated.[6] This yields capital savings, as the regeneration equipment is smaller for DGA than for MEA. Disadvantages appear to be degradation of the chemical with CO_2 and greater solubility of heavier hydrocarbons in the solution, as compared to MEA. This is a serious drawback if the acid gas stream is fed to a Claus plant, as additional air is required for the combustion of the hydrocarbons. Also, this dilutes the sulfur compounds in the sulfur recovery train. Solution strength is on the order of 50 to 70% by weight of DGA in water, with mol loadings in the range of 0.3 to 0.4 moles of acid gas per mole of DGA circulated. The DGA process train usually includes a reclaimer.

5.3.9 Secondary Amines. ***Diethanolamine (DEA).***[7] DEA became a popular sour gas treating solvent in the 1960s after it was developed for such application in France. It can be used at higher concentrations than MEA. DEA has the advantage of picking up more acid gas per solution volume circulated, thus effecting some energy saving in circulation and regeneration. It does not form the nonregenerative products with COS and CS_2 as is the case with MEA, which is another advantage over MEA. DEA is also generally less corrosive than MEA. Solution strength is usually in the 25 to 40% range, with mol loadings of 0.35 to 0.63.

Diisopropanolamine (DIPA). This secondary amine is not used by itself as a sweetening solvent but is part of the Sulfinol solvent formulation.

5.3.10 Tertiary Amines. ***Triethanolamine (TEA).*** TEA is not in general use for gas sweetening.

Methyldiethanolamine (MDEA).[8] MDEA reacts more slowly with CO_2 than the previously described amines. It forms a slightly different salt with CO_2 from those of the other amines, at a lower rate of reaction. The difference in the rates of reaction with H_2S and CO_2 gives MDEA a desirable feature over other amines, namely selectivity of H_2S over CO_2. This is an attractive feature in cases where it is not necessary to remove all the CO_2 from the gas stream. By leaving some of the CO_2 in the natural gas, the circulation rate of the solution can be reduced, or the treating capacity of an existing unit can be increased with MDEA as compared with DEA.

MDEA concentrations are on the order of 30 to 50% by weight, with mol loadings of 0.40 to 0.55 moles acid gas per mol of amine. As a tertiary amine, MDEA is naturally a weaker base and is, therefore, less corrosive than the primary and secondary amines. The energy required for regeneration is also less than the requirement for the other amines.

5.3.11 Proprietary Amine Solvent Formulations. By making use of the difference in the rates of reaction between MDEA and the acid gases, several proprietary solvents have been developed that are suited for preferential extraction of H_2S, with only partial removal of CO_2. These proprietary formulations usually contain MDEA plus other amines at various concentrations in aqueous solutions to tailor them for specific applications. Several chemical companies have developed such proprietary solvents.[3]

5.3.12 Hot Potassium Carbonate (K_2CO_3) (Hot Pot).[9] The potassium carbonate process was developed for removing CO_2 from manufactured gas. It reacts with both acid gases. Because the contacting of the sour gas occurs at very high temperatures, such as 195 to 230°F in this process, it is sometimes referred to as the "hot pot" process. It requires lower heat input for regeneration and, therefore, is somewhat less costly to operate than some amine processes. Also, no heat exchanger is required in the regeneration equipment. The process has difficulty in meeting the H_2S specification of the treated gas, if the H_2S/CO_2 ratio is not extremely small. This process is significant for treating gas with a large concentration of CO_2. The chemistry of the process can be enhanced by the addition of various catalysts, and this has resulted in the process being referred to by various trade names.

5.3.13 Computer Simulation of Sweetening Processes. The design and optimization of sweetening processes can be done by computer, using programs such as HYSIM from Hyprotech of Calgary, which contains AMSIM from D.B. Robinson and Associates Ltd. of Edmonton, Alberta; ProTreat from Optimized Gas Treating Inc. of Houston; TSWEET from Bryan Research and Engineering Inc. of Bryan, Texas; and proprietary programs from the chemical supplier.

5.3.14 Estimating Solution Circulation Rate. The circulation rate or the acid gas pickup by the solution can be estimated with the next two formulas.

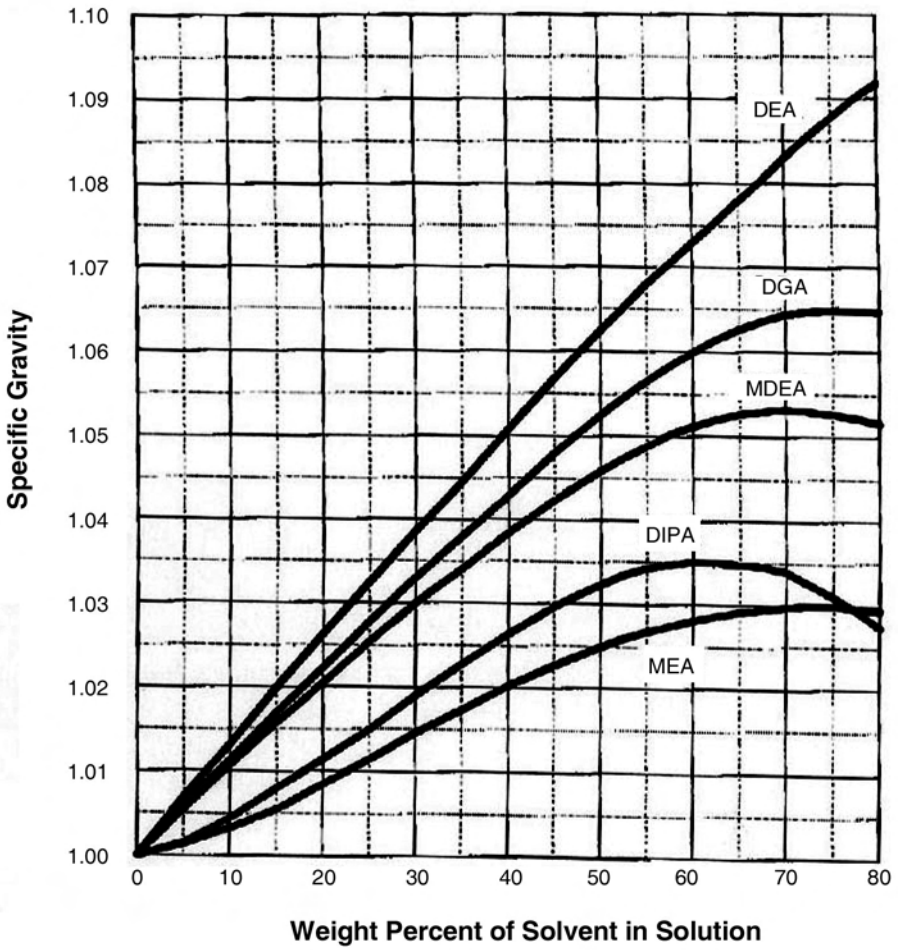


Fig. 5.3—Specific gravity of aqueous amine solutions (after *Engineering Data Book of Gas Processors Suppliers Association and Gas Processors Association*[10]).

$$\text{Circulation rate}: \quad \text{US gal/min} = 0.219 \times MW_a \times Q \times AG/(ML \times SG_a \times W_s) \ . \ \ldots\ldots\ (5.1)$$

$$\text{Acid gas pickup}: \quad \text{scf/gal} = 31.72 \times ML \times SG_a \times W_s / MW_a \ . \ \ldots\ldots\ (5.2)$$

The specific gravity of the amine solutions is shown in **Fig. 5.3**.[10] The specific gravity of potassium carbonate may be approximated by 1 + weight fraction K_2CO_3 in solution.

5.3.15 Types of Operating Problems. The main problems that can be encountered in the operation of sour gas treating facilities using chemical solvents are failure to meet H_2S specification for sales gas; solution foaming in the contactor or regenerator; corrosion in pipes and vessels; and solvent losses.[11]

Failure to Meet H_2S Sales-Gas Specifications. Treated gas that does not meet the H_2S specifications is not admitted into the sales-gas transmission lines. Potential causes for "going sour" are a change in the acid gas concentration of feed gas; a change in the feed gas temperature; too hot lean amine solution; too low solvent concentration in solution; inadequate regeneration of solution; insufficient contact in absorber; too low amine circulation rate; too low absorber

pressure; too high concentration of degradation products; too high inlet gas rate; mechanical damage or problems in absorber; and foaming.

Solution Foaming. Solution foaming occurs when gas is mechanically entrained in liquid as bubbles.[12] The tendency to form bubbles increases with decreasing surface tension of the solution owing to interference of foreign substance at the surface of the solution on the tray. Foaming is thought to be caused by factors such as: liquid hydrocarbons entering the contactor with the sour gas; acidic amine-degradation products; treating chemicals from wells or gathering system; treating chemicals from makeup water; compressor oil; and fine solid suspensions, such as iron sulfide.

While solids suspended in the solution by themselves might not cause foaming, it is thought that they tend to stabilize the foam. The results from foaming can be severe upsets in the process tower, leading to carryover and loss of chemical, and possible damage to downstream process equipment or material. The best way to reduce the propensity for foaming is to ensure that the sour gas entering the contactor is clean, free of condensed liquids, and that the solution is cleaned up by mechanical and carbon filtration. The addition to the solution of antifoam agents is sometimes effective in controlling the foaming tendency of the solution. However, this does not solve the basic problem. Too much antifoam in the solution can actually add to the foaming problem.

Corrosion. Corrosion is common in most amine plants. It is necessary to control the corrosion rate by the addition of corrosion inhibitor and by use of stainless steel in certain pieces of process equipment. In the case of MEA solutions, corrosion rates tend to increase with increasing solution strengths beyond about 22% MEA, as well as with high levels of amine degradation products in the solution. Most of the process piping and vessels in amine plants are built with carbon steel, meeting NACE MR0175 guidelines.

It is not possible to predict with certainty where corrosive attack will take place. Experience has shown that the most likely areas for corrosive attack are those where the temperatures are high, such as in the top part of the still, the reboiler tubes, and heat exchangers, as well as some connecting piping. Hydrogen blisters are sometimes evident after many years of service in the shell of the contactor or still. Hydrogen-induced cracking can also occur in welds in the vessels or piping after many years of service. Corrosion/erosion can occur in areas where fluid velocities are high, such as in the return line from the reboiler, at the point of entry of the reboiler vapors into the still, and downstream of pressure letdown valves.

Corrosion rates in amine systems, especially MEA systems, generally increase with increasing temperature; increasing amine concentration; increasing mole loadings; and pure acid gas as compared with CO_2 and H_2S mixtures.[13] MEA is generally much more corrosive than DEA, and MDEA is only slightly corrosive.

Use of Corrosion Inhibitors. The use of corrosion inhibitors is a common practice to reduce the attack on steel by H_2S and CO_2 in aqueous environments. In most sour gas sweetening installations, a corrosion inhibitor is continuously injected into the sweetening solution.

Solvent Loss. In all regenerative solvent systems, it is necessary to periodically add pure solvent to the solution because of the loss of solvent during operation. Solvent losses in gas treating systems can occur because of vaporization, entrainment, degradation and removal of degradation products, and mechanical losses.

Solvents used in gas treating, like any other liquids, have a vapor pressure that increases with temperature. In a gas sweetening system, there are three vessels where gas and liquid streams separate: contactor, flash tank, and reflux drum. By far the largest gas stream is the one leaving the contactor. To reduce the solvent losses from this source, a water wash process is usually applied to the treated gas downstream of the contactor. Solvent losses from the flash tank are usually quite small, as the amount of gas leaving this vessel is usually small when compared to the total plant stream. When the solution is regenerated in the still, some solvent

leaves the still overhead with the acid gas stream and the water vapor. Upon cooling the still overhead stream and condensing most of the water and amine, the liquid is returned to the top of the still as reflux, which also recovers most of the solvent. Nevertheless, some solvent vapor leaves the top of the reflux drum with the acid gas stream. Lower reflux drum temperatures reduce solvent losses at this point.

Entrainment of solvent occurs during foaming or under high gas velocity situations. By preventing foaming and by staying within design throughput, entrainment losses can be avoided.

In amine systems, some degradation of the solvent occurs. Primary amines are most susceptible to this problem, and such systems require special separation equipment to periodically remove the degradation products that contribute to corrosion. The degradation products are mainly caused by irreversible reactions between the solvent and CO_2.

The most serious losses of solvent usually result from mechanical actions or problems. These include filter changeouts, drips from pumps or flanges, and vessel cleaning and draining.

5.4 Physical Solvents

In addition to the chemical solvents, there are also physical solvents available for extracting the acid gases from natural gas. Physical solvents do not react chemically with acid gases but have a high physical absorptive capacity. The amount of acid gas absorbed is proportional to the partial pressure of the solute, and no upper limit, owing to saturation, is evident, as is the case with chemical solvents. Hence, they are mainly suited for sour gases with high acid gas content at high contacting pressures. The physical absorption solvents have the advantage of regeneration by flashing upon reduction of pressure and, therefore, do not require much heat in the stripping column. This makes physical solvents useful as bulk-removal processes, followed by final cleanup using a chemical solvent because physical solvents have difficulty in achieving the H_2S limit specified for sales gas. Unfortunately, they also tend to absorb heavier hydrocarbons, which is a disadvantage if the acid gas is fed to a Claus plant for sulfur recovery.

There are several physical solvents mentioned in the literature. **Fig. 5.4** is a process schematic of a typical physical solvent process. A brief description of the more prominent physical solvent processes is discussed next.

5.4.1 Selexol Process.[14] The Selexol process was developed by Allied Chemical Corp. The solvent is dimethyl ether of polyethylene glycol and is usually used in its pure form. It has a preference for H_2S over CO_2, and, therefore, some CO_2 remains in the gas stream, depending on the mole loading of the solvent. Several stages of flashing are provided for in the regeneration step, to allow the absorbed hydrocarbons to evolve from the solution. The flashed gases from the initial flash stages are compressed and returned to the inlet of the absorber. Selexol is noncorrosive and also removes water vapor from the gas stream.

5.4.2 Fluor Solvent Process.[15] The solvent in this process is propylene carbonate and was developed in the late 1950s by The Fluor Corp. This solvent also has a greater affinity for H_2S than for CO_2 and also dehydrates the feed gas. Absorptive capacity is highly temperature dependent, favoring the lower temperature.

5.4.3 Purisol.[16] The Purisol solvent process was developed in Germany by Lurgi. The solvent used is N-methylpyrrolidone, which has a high absorptive capacity for the acid gases.

5.5 Hybrid Process

5.5.1 Sulfinol.[17] The Shell Sulfinol process is a hybrid process using a combination of a physical solvent, sulfolane, and a chemical solvent, DIPA or MDEA. The physical solvent and one of the chemical solvents each make up about 35 to 45% of the solution with the balance being

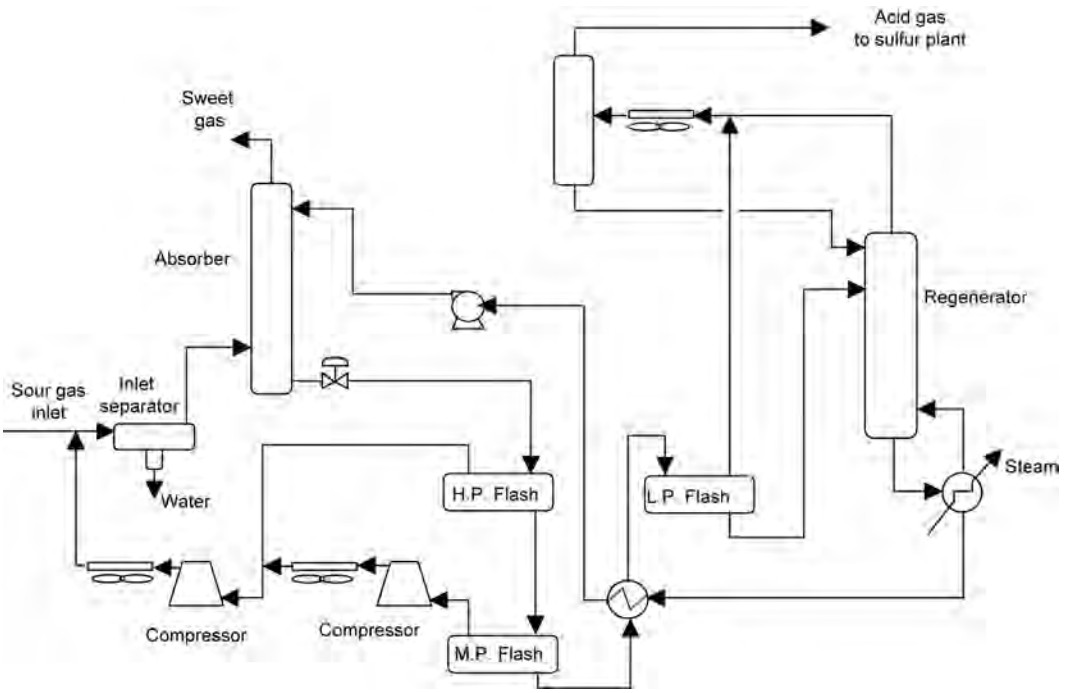


Fig. 5.4—Schematic drawing of physical solvent process equipment.

water. The sulfinol process is economically attractive for treating gases with a high partial pressure of the acid gases, and it also removes COS, CS_2, and mercaptans. Other advantages are good heat economy, low losses because of low vapor pressure, and absence of corrosion. A disadvantage of this process is that the sulfolane absorbs heavier hydrocarbons from the gas, some of which are then contained in the acid gas feed stream to the sulfur plant. Thus, the Sulfinol process is best suited for very sour, lean gas.

5.6 Reduction/Oxidation (Redox) Process

5.6.1 Sulferox.[18] Typical Sulferox process equipment is illustrated in Fig. 5.5. In this process, the sour gas is contacted in a small contactor in cocurrent flow with a water solution containing about 4% ferric iron ions, held in solution by proprietary chelate ligand. The H_2S ionizes in the solution, and the ferric iron ions exchange electrons with the sulfur ions to form ferrous iron ions and elemental sulfur. The gas and the solution leave the contactor and are flowed into a separator. The gas out of the separator is sweet and requires further treating for dew-point control. The solution is flowed into additional vessels for separating the elemental sulfur and for restoring the ferrous iron ions back to the active ferric iron state by contacting the solution with air. The chemistry is illustrated next.

$$\text{Sweetening}: 2Fe^{+++} + 2H^{+} + S^{=} \rightarrow 2Fe^{++} + S^{\circ}\downarrow + 2H^{+}.$$

$$\text{Regeneration}: 2Fe^{++} + {}^{1}/_{2}O_2 + 2H^{+} \rightarrow 2Fe^{+++} + H_2O.$$

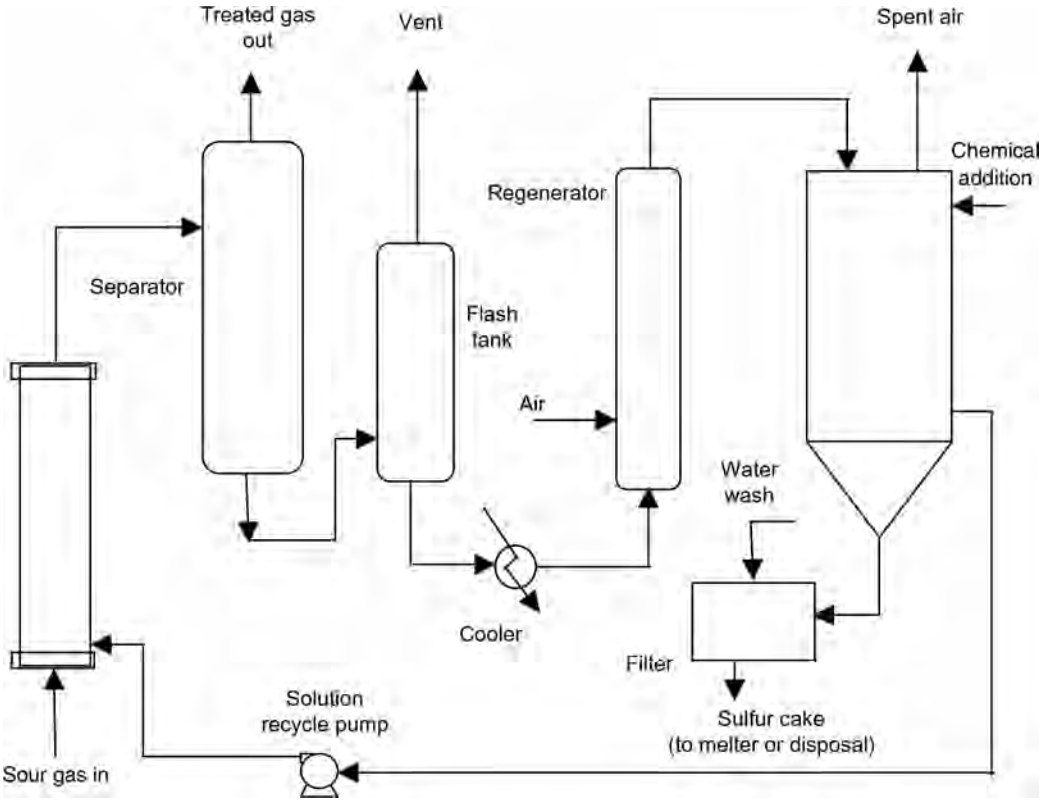


Fig. 5.5—Schematic drawing of typical Sulferox process equipment.

TABLE 5.2—SUMMARY OF H_2S SCAVENGING SOLVENTS

Trade Name	Chemical Base	Application Method	Disposal Method	Problems
Scavinox	Formaldehyde	60% in methanol	Deep well	Foul odor
Chemsweet	ZnO	Water slurry	Approved landfill	Disposal
Slurrisweet	Fe_2O_3	Water slurry	Approved landfill	Disposal
Sulfa-check	$NaNO_2$	Water solution	Deep well	NO_x, disposal
Sulfa-scrub	Triazine	Chemical in line or tower	Deep well	High expense

5.7 Nonregenerative Chemical Solvent (Scavenger) Processes

When the gas is only slightly sour, that is to say, contains only a few ppm of H_2S above the specification limit, a simpler sweetening process might have economic advantages over the typical processes described in the previous sections.[19] These processes scavenge the H_2S from the sour gas, with the chemical being consumed in the process. It is, therefore, necessary to periodically replenish the chemical, as well as dispose of the end product of reaction containing the sulfur. **Table 5.2** gives a summary of some common chemicals used for this purpose. The process equipment consists of a tower containing a solution of the chemical, or the chemical is in suspension in water. The sour gas is bubbled through the solution, and the chemical reacts with the H_2S. The chemicals do not react with CO_2.

The Sulfa-scrub process is a more recent development.[20] The chemical used in this process is triazine. The end product is beneficial as a corrosion inhibitor and is water soluble. As a result, disposal of the end product is convenient, as it is simply added to a water-disposal system. Sulfa-scrub can be injected into the flowline at the well, and it reacts with the H_2S while the gas is flowing to the plant. Thus, there might not be a requirement for a treating tower.

5.8 Dry Sweetening Processes

While the sweetening of sour gas is predominantly done with regenerative solvents, there are also some dry processes that can be used for this purpose. Because these processes are batch processes, two or more towers are usually used, so that one tower can be taken out of service for chemical charge replacement without interruption of gas flow.

5.8.1 Iron Sponge (Iron Oxide).[21] Iron sponge consists of wood chips that have been impregnated with a hydrated form of iron oxide. The material is placed in a pressure vessel through which the sour gas is flowed. Because this is a batch process, usually two vessels are installed —one in service and the other on standby. The H_2S reacts with the iron oxide to form iron sulfide. In due course, the iron oxide is consumed. While it is possible to regenerate the iron sulfide with air to restore the iron oxide, in practice this is not done. Instead, the tower containing the spent iron sponge is taken out of service, and the standby tower is placed in service. The spent iron sponge is moistened with water, removed, and disposed of at an approved disposal site, and the tower is filled with a new charge of iron sponge. Care has to be exercised in handling the spent material in the dry state, as it is pyrophoric. When dry iron sulfide is exposed to air, a spontaneous chemical reaction between the iron sulfide and oxygen takes place —oxidizing the iron sulfide to iron oxide and emitting sulfur dioxide into the air.

5.8.2 SulfaTreat (Iron Oxide).[22] Several years ago, a new iron-oxide-based dry product with the trade name of SulfaTreat was introduced for sweetening sour gas. The product is placed in towers, as illustrated in **Fig. 5.6**, through which the sour gas is flowed. The gas stream should have a superficial gas velocity of no more than 10 ft/minute, and the temperature of the gas should be between 70 and 110°F. The gas must be water saturated at the tower conditions of temperature and pressure. SulfaTreat has a different molecular structure from that of iron sponge and, upon reaction with H_2S, forms iron pyrite instead of iron sulfide. The charge of SulfaTreat is replaced when consumed.

This process is usually installed in a two-tower configuration, as shown in Fig. 5.6. The slightly sour gas is flowed through both towers in series. The H_2S content is monitored in the gas between the two towers. When the concentration of H_2S starts to increase in this gas, it is an indication that the SulfaTreat chemical in the first tower is consumed. This tower is then temporarily bypassed, and a fresh charge of chemical is installed. The tower containing the new chemical charge becomes the second tower in the continuation of the operation.

5.8.3 Molecular Sieves.[23] Molecular sieves are crystalline compounds created from alumina silicates, with controlled and precise structures, which contain pores of uniform size. These compounds have an affinity for various molecules, especially for polar compounds such as water, H_2S, and CO_2. The pore size can be controlled during the manufacturing process and can be tailor-made for specific molecules, such as H_2S. Molecular sieves can, therefore, be used for removing water from sour gas, or they can also be used for sweetening sour gas that exceeds the H_2S specification by a few ppm. The process requires two or three towers filled with molecular sieves, one of which is used for adsorption, while the others are being regenerated by the application of a hot gas stream. Sweetening with molecular sieves is suitable for large volume, very low H_2S concentration gas.

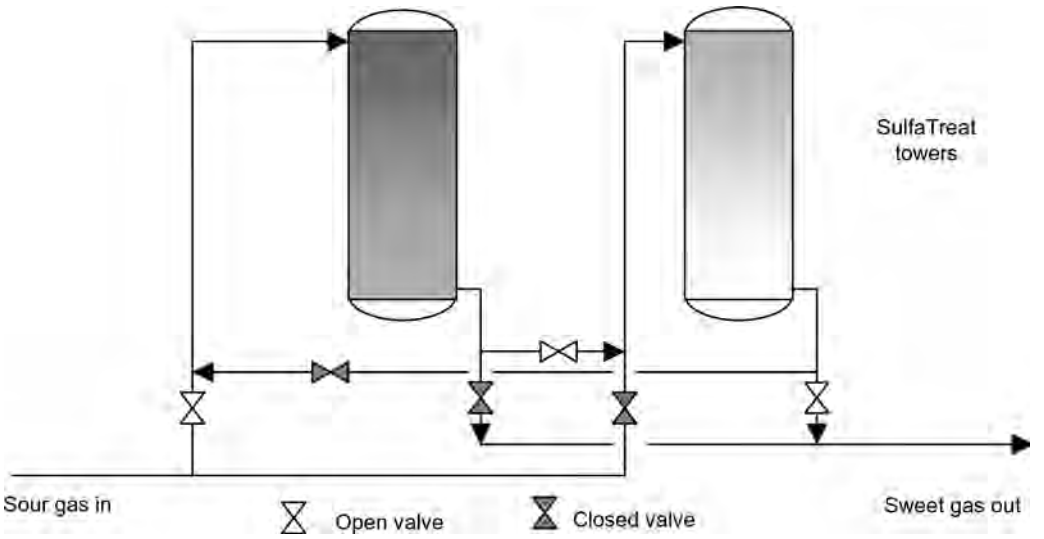


Fig. 5.6—Schematic drawing of typical SulfaTreat process equipment.

5.9 Screening Program for Optimum Process Selection

The Gas Research Institute (GRI) of Chicago, now called the Gas Technology Institute (GTI), has performed large scale investigations of redox and scavenger sweetening processes. The results have been compiled in reports and papers, which are available from GTI. Furthermore, computer screening programs have been prepared, and these are also available for a nominal fee. The two programs dealing with scavenger process selection are CalcBase™ and SeleXpert™. Information on these programs can be accessed on the GTI website: http://griweb.gastechnology.org/, then search for "H_2S scavenger."

5.10 Dehydration of Natural Gas

Dehydration of natural gas means extracting water vapor from the gas to a specified maximum limit for residual water content. There are various processes available for dehydration, such as absorption with glycol; adsorption with dry desiccant; absorption with a deliquescent salt; and refrigeration and hydrate suppression with a chemical.

5.11 Dehydration With Glycol

All raw natural gas is fully saturated with water vapor when produced from an underground reservoir. Because most of the water vapor has to be removed from all natural gas before it can be commercially marketed, all natural gas is subjected to a dehydration process. The water vapor content of natural gas at equilibrium saturation is shown in **Fig. 5.7**, which is based on the well-known McKetta and Wehe chart and expanded to 400°F on the basis of data of Olds, Sage, and Lacy.[24,25] As can be seen, the water content increases with increasing temperature and decreasing pressure. For gas sales in colder areas of North America, the specification limit for water content in the sales gas is 4 lbm/MMscf. In warmer, southern areas, the limit is generally 7 lbm/MMscf in sales gas. When natural gas is a feedstock to a turboexpander plant for high natural gas liquids (NGL) recovery, virtually all the water must be removed before chilling the gas to very low temperatures.

There are four glycols that are used in removing water vapor from natural gas or in depressing the hydrate formation temperature. **Table 5.3** lists these glycols and shows some of the properties of the pure material.[26] Ethylene glycol (EG) is not used in a conventional glycol

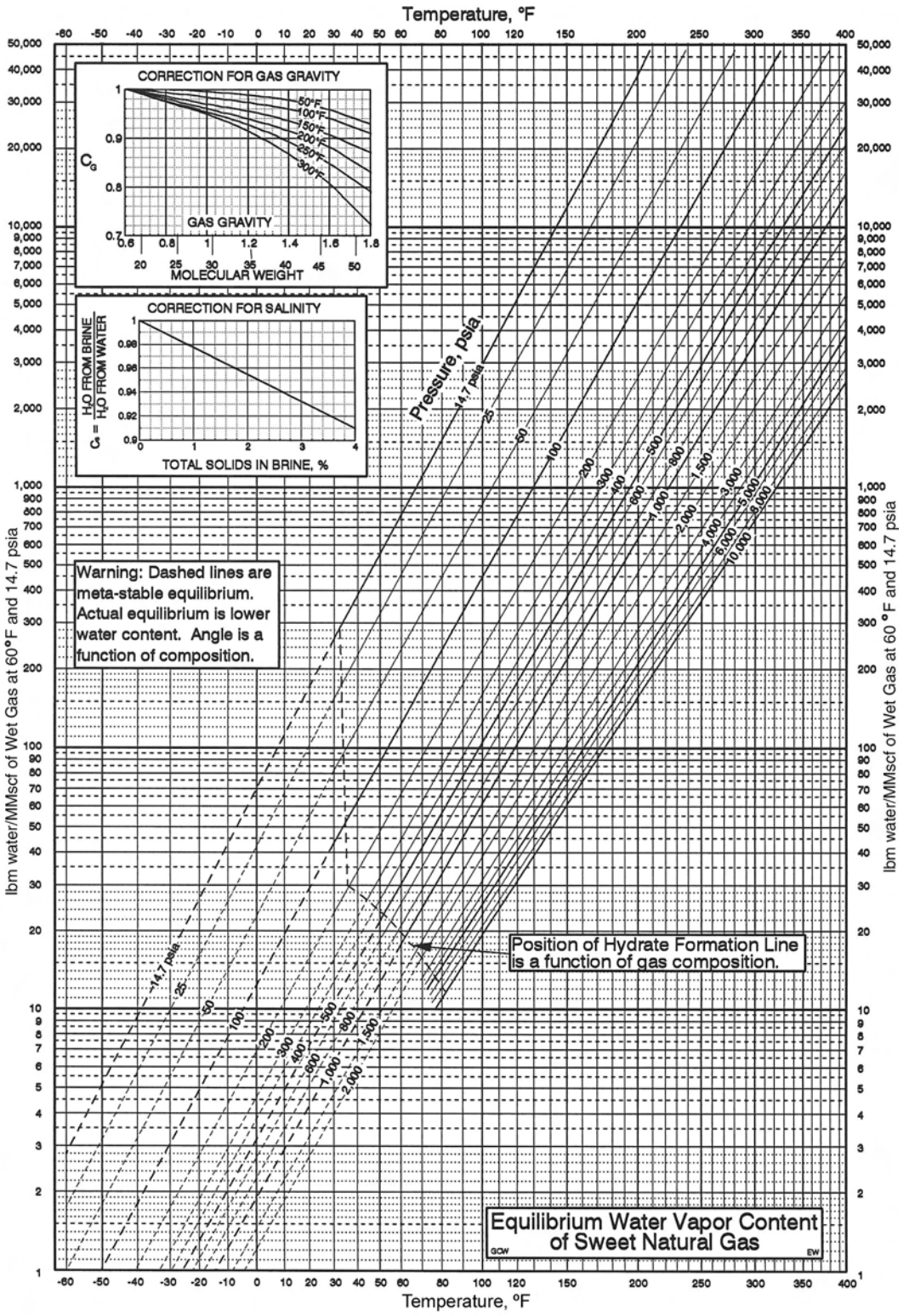


Fig. 5.7—Equilibrium water vapor content of sweet and natural gas (after McKetta and Wehe[24] and Olds *et al.*[25]).

dehydrator, as described in Sec. 5.12. The main use of EG in the dehydration of natural gas is in depressing the hydrate temperature in refrigeration units. Of the other three glycols, triethylene glycol (TEG) is the most commonly used glycol for dehydration of natural gas because of the advantages relative to diethylene glycol (DEG): TEG is more easily regenerated to a higher degree of purity; vapor losses are lower; and operating costs are lower.

Tetraethylene glycol would have to be regenerated at higher temperatures than TEG to reach the required purity for application in a glycol dehydration unit.[25] Thus, of the four glycols, TEG is the best suited for dehydration of natural gas. In glycol dehydration, TEG is usually referred to only as "glycol." Unless otherwise specified, that convention is used in the rest of this chapter.

5.12 Process Description

Fig. 5.8 is a schematic drawing of the typical process equipment for glycol dehydration. While the overall process equipment is similar for all glycol dehydration units, there can be considerable variation among installations.

The gas flows through a separator to remove condensed liquids or any solids that might be in the gas.[27] Some absorbers incorporate the separator in a bottom section of the vessel, in which case the gas then flows upward through a chimney tray into the glycol absorber portion of the vessel. The glycol contactor or absorber can contain trays, random packing, or structured packing. If it is a trayed vessel, it will contain several bubble-cap trays. Lean glycol is pumped into the upper portion of the contactor, above the top tray but below the mist eliminator. The trays are flooded with glycol that flows down from tray to tray in downcomer sections. The gas rises through the bubble caps and is dispersed as bubbles through the glycol on the trays. This provides the intimate contact between the gas and the glycol. The glycol is highly hygroscopic, and most of the water vapor in the gas is absorbed by the glycol. The rich glycol, containing the absorbed water, is withdrawn from the contactor near the bottom of the vessel above the chimney tray through a liquid level control valve and passes to the regeneration section. The treated gas leaves the contactor at the top through a mist eliminator and usually meets the specified water content.

The rich glycol can be routed through a heat exchange coil in the top of the reboiler column called the still. The heat exchange generates some reflux for the separation of the water from the glycol in the top of the still and also heats the rich glycol somewhat. In some installations, the rich solution passes to a flash tank operating at about 15 to 50 psig, which allows absorbed hydrocarbon gas to separate from the glycol. The glycol then flows into the still through a filter and a heat exchanger, exchanging heat with the regenerated glycol. It drops through a packed section in the still into the glycol reboiler vessel, where it is heated to the necessary high regeneration temperature at near atmospheric pressure. At the high temperature, the glycol loses its ability to hold water; the water is vaporized and leaves through the top of the still. The regenerated glycol flows to the surge tank, from where it is routed through the lean/rich heat exchanger to the glycol pump. The pump boosts the pressure of the lean glycol to the contactor pressure. Prior to entering the contactor, it exchanges heat with the dry gas leaving the contactor or some other heat exchange medium.

5.13 Function of the Inlet Separator

The first and foremost piece of equipment that the gas flows through is the inlet separator. This vessel can be a separate, detached vessel, or, on smaller units, built in to the bottom of the contactor. Its function is to separate any condensed liquid from the gas before the gas enters the contactor. If the gas does not contain condensate (liquid hydrocarbon), the vessel is a two-phase separator. If the gas is a rich gas, with some condensate as well as liquid water forming at the inlet conditions of pressure and temperature in the separator, then a three-phase separator is installed. It is absolutely essential that no liquid, condensate, or water enters the

TABLE 5.3—PHYSICAL PROPERTIES OF GLYCOLS

Glycol Name	Formula	Molecular Weight	Boiling Point, 760 mm, °F	Vapor Pressure, 77°F, mm Hg	Relative Density, 77°F	Freezing Point, °F	Pour Point, °F	Viscosity, cp, 77°F	Decomposition Temperature, °F
Ethylene Glycol	HOC_2H_4OH	62.1	387.1	0.12	1.110	8	—	16.5	329
Diethylene Glycol	$HOC_2H_4OC_2H_4OH$	106.1	472.6	< 0.01	1.113	17	–65	28.2	328
Triethylene Glycol	$HO(C_2H_4O)_2H_4OH$	150.2	545.9	< 0.01	1.119	19	–73	37.3	404
Tetraethylene Glycol	$HO(C_2H_4O)_3C_2H_4OH$	194.2	597.2	< 0.01	1.112	22	–42	39.9	428

absorber section. The separator is usually equipped with a mist eliminator section in the top of the vessel. As the gas moves through the mist eliminator section, small droplets that might be in the gas will coalesce on the fine wire mesh and form larger droplets that drop down through the gas into the liquid section below.

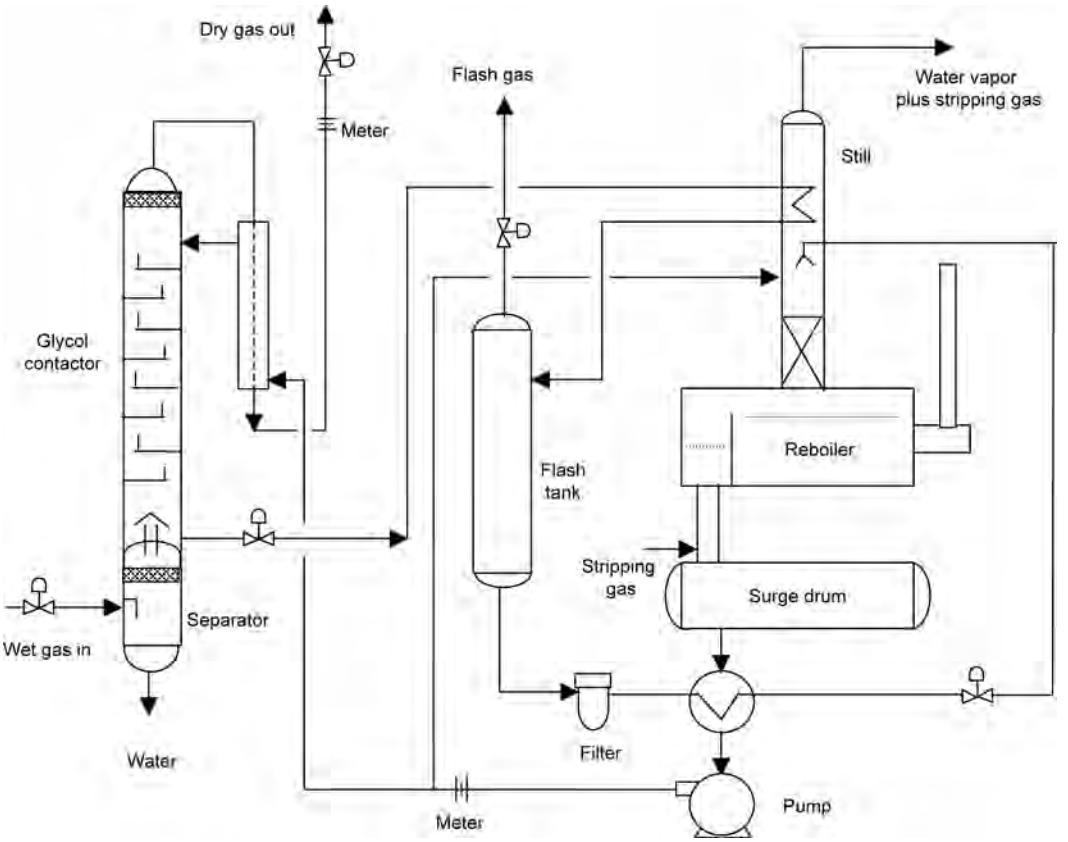


Fig. 5.8—Schematic drawing of typical glycol dehydration equipment.

The inlet separator is equipped with liquid level controls, allowing the accumulated liquids to exit the vessel through a level control valve. If for some reason the liquid level in the vessel should rise above a certain limit, a high-level alarm or shutdown automatically occurs.

5.14 Function of the Contactor or Absorber

The contactor is the vessel in which the mass transfer of the water occurs from the gas to the glycol. Most of the water vapor is extracted from the gas phase into the liquid glycol phase. For this to occur, it is necessary to create a large surface area between the gas and the liquid glycol. This is accomplished with specific internal equipment configurations, such as through the installation of trays, structured packing, or random packing.

The most common trays used in this application are bubble cap trays, as illustrated in **Fig. 5.9**. The gas flows from below each tray through the bubble cap and forms small bubbles of gas in the glycol liquid that flows across and on top of each tray. After flowing across one tray, the glycol flows down to the next tray below through a downcomer, which ensures that the gas cannot bypass any tray. The gas bubbles provide the large surface area needed to effect the transfer of the water from the gas to the glycol. Because of the short contacting time on each tray, equilibrium in mass transfer is not reached—several trays are needed in a contactor to bring about the necessary dehydration of the gas. In the design of dehydrators, the calculations make use of theoretical equilibrium stages for determining how many times the gas and glycol must be contacted. Because of the dynamic conditions, equilibrium in mass transfer is not reached—approximately four actual trays are used for each theoretical equilibrium stage. In

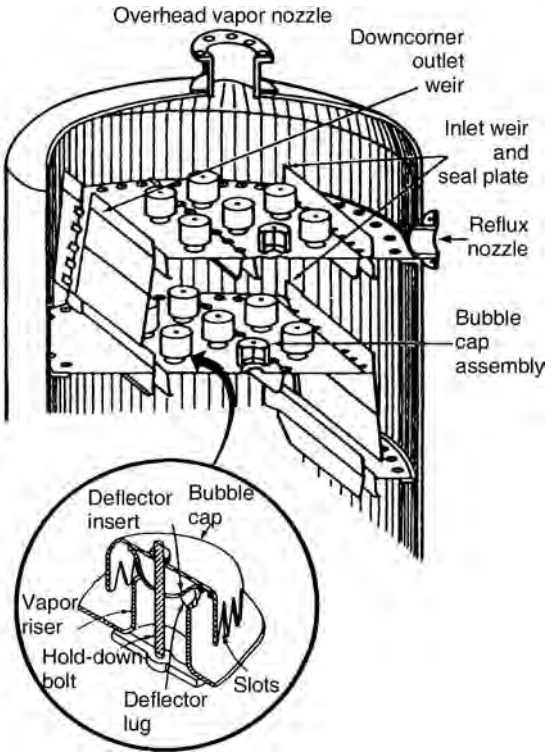


Fig. 5.9—Illustration of bubble cap and bubble cap tray in contactor (after *Engineering Data Book of Gas Processors Suppliers Association and Gas Processors Association*[10]).

practice, about 6 to 10 trays are installed in a contactor, usually spaced 24 in. apart. In more recent designs, 12 to 14 trays are installed in glycol absorbers to minimize glycol circulation.

Structured packing consists of arrangements of corrugated steel internals, over which the glycol flows downwards as a thin film. Elements of structured packing are illustrated in **Fig. 5.10**. The gas flows upward through the structured packing and is in intimate contact with the large surface area of the glycol that flows downward as a film on the packing. This creates a very efficient model for mass transfer to occur.[28] The design for the height of the packing required is related to the number of theoretical stages required. The suppliers of structured packing have developed the relationship of packing height per theoretical equilibrium stage. When using structured packing, it is essential that the glycol be evenly distributed across the top of the packing. To ensure that the large surface area is provided by the downward flowing glycol, it is also essential that the steel be thoroughly clean, so that all of the steel is wetted by the glycol.[29]

Similarly, random packing of various types can also be used in glycol contactors to create the surface area for mass transfer. Various types of random packing are illustrated in **Fig. 5.11**. Again, the total height of the packing in the vessel is related to the number of theoretical stages used in the design and the height of packing per theoretical stage. The suppliers of the packing have correlations for packing height per theoretical stage.

5.15 Function of the Reboiler

The rich glycol leaving the absorber must be regenerated to a high purity so that it can be recirculated to the absorber to continue its dehydration function. The regeneration is accomplished in the reboiler and the still column above the reboiler.

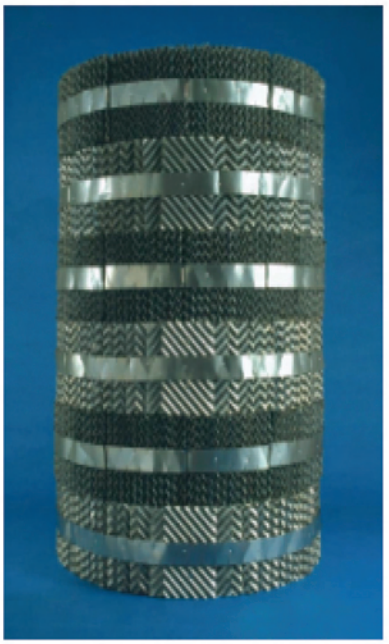


Fig. 5.10—Illustration of structured packing elements (courtesy of Koch-Glitsch).

The rich glycol is preheated through heat exchange with the regenerated glycol and enters the top of the still at atmospheric pressure. By heating the glycol in the still and reboiler to near its boiling point, the glycol releases virtually all of the absorbed water and any other compounds and is then cooled for reuse. The heat is usually supplied through a fire tube in the reboiler in which natural gas is burned. The fire tube is always submerged in the glycol by having the glycol flowing from the reboiler over a weir or pipe, which is higher than the top of the fire tube.

5.16 Water Dewpoint Depression

Water dewpoint is the temperature at any given pressure at which the natural gas is saturated with water. Because sales gas generally has a maximum water content specification in mass per unit volume (e.g., 4 lbm/MMscf), it is necessary to determine from Fig. 5.7 the dewpoint temperature at the contactor pressure. For example, if the treating pressure were 1,000 psia, then the dewpoint temperature for 4 lbm/MMscf would be about 18°F. If the treating pressure were 500 psia, the dewpoint temperature would be about 5°F.

The overall objective of dehydration is to remove a sufficient amount of water from the natural gas so that the specification for maximum allowable water content in the treated gas is met. If the gas has not been processed, then the gas entering the glycol contactor is fully saturated with water at the pressure and temperature of the separator ahead of the contactor. The dewpoint depression to achieve is the lowering of the dewpoint temperature from the separator temperature to a temperature at the separator pressure where the water content meets the specified limit for the dehydrated gas. The next example shows the difference in dewpoint depression and the amount of water to be removed per MMscf, if the gas is entering the glycol

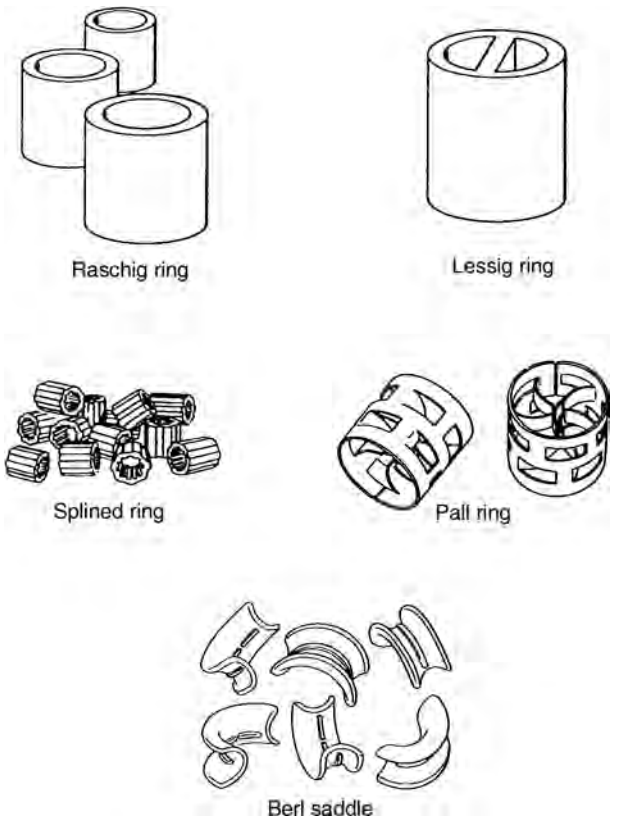


Fig. 5.11—Illustration of types of random packing (after *Engineering Data Book of Gas Processors Suppliers Association and Gas Processors Association*[10]).

contactor at 90°F and at 1,000 psia or at 500 psia. The water content specification in this example is 4 lbm per MMscf for the treated gas.

Examples of water dewpoint depression for two operating pressures are shown at 90°F.

Water content at 1,000 psia and 90°F = 45 lbm/MMscf (Fig. 5.7).

Dewpoint temperature for 4 lbm/MMscf and 1,000 psia = 18°F (Fig. 5.7).

Water to remove = 45 – 4 = 41 lbm/MMscf.

Dewpoint depression = 90°F – 18°F = 72°F.

Water content at 500 psia and 90°F = 78 lbm/MMscf.

Dewpoint temperature for 4 lbm/MMscf and 500 psia = 5°F.

Water to be removed = 78 – 4 = 74 lbm/MMscf.

Dewpoint depression = 90°F – 5°F = 85°F.

Fig. 5.12 provides a correlation of the equilibrium water dewpoint when gas is in contact with triethylene glycol of various purities at different contacting temperatures.[29] In actual operations, equilibrium is not achieved on any tray. To enhance the transfer rate of the water from the gas to the glycol, an approach temperature to equilibrium of 10 to 20°F is used in designing glycol dehydration units. For example, assuming a 10°F approach is realistic, to achieve the dewpoint temperature of 18°F at 1,000 psia contacting pressure, an equilibrium dewpoint of 8°F (18°F minus 10°F approach) is used in the design of the glycol dehydration unit. At a 90° F contacting temperature, the glycol purity must be about 98.8% to achieve this equilibrium dewpoint, according to Fig. 5.12. At a contacting pressure of 500 psia and 90°F on the other hand, the glycol purity must be about 99.3% to depress the water dewpoint to –5°F with an

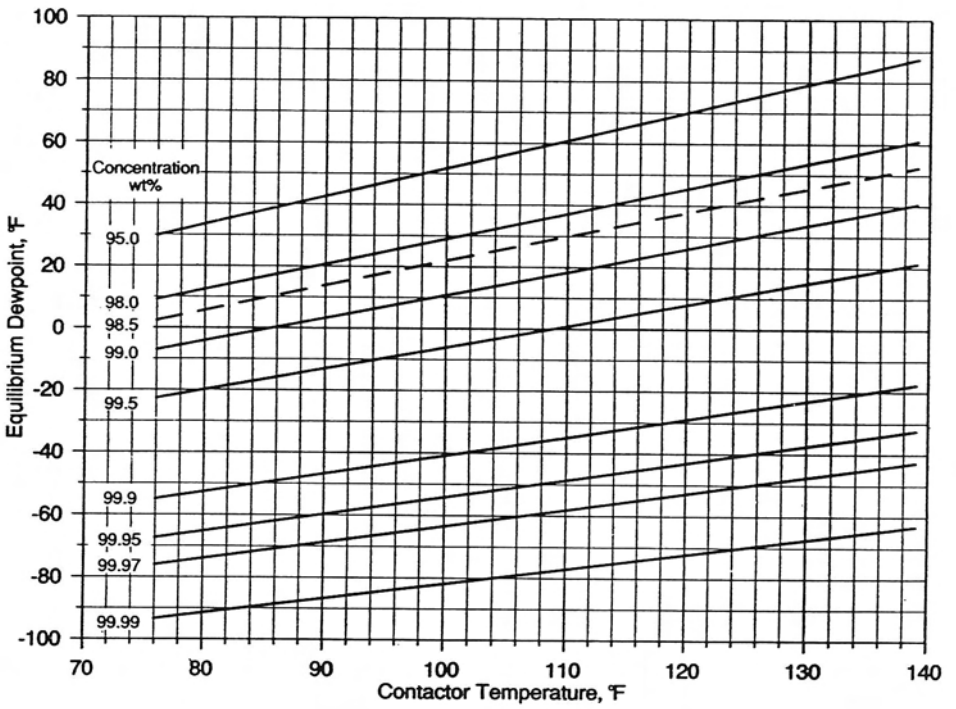


Fig. 5.12—Equilibrium water dewpoint vs. temperature at various TEG concentrations (after *Engineering Data Book of Gas Processors Suppliers Association and Gas Processors Association*[10]).

approach of 10°F. The lower the water dewpoint temperature requirement is for the treated gas, the higher the glycol purity has to be.

5.17 Glycol Regeneration

The degree of water removal from natural gas by glycol, or the depression of the water dewpoint of the gas, depends on certain conditions: glycol purity; glycol circulation rate (up to a certain limit); number of contacting stages (trays) or packing height; and amount of water in the inlet gas, which depends on the pressure and temperature of the gas.

These parameters must be considered at the design stage of the contactor, in addition to the maximum rate, pressure, and temperature of the gas. The higher the glycol purity, the more effective is the dewpoint temperature depression. If the glycol purity is insufficient, increasing the glycol circulation rate will not necessarily achieve the desired dehydration of the gas.

5.18 Glycol Purity Enhancement Methods

In some operating situations, a high glycol purity is required that cannot be achieved by the temperature in the glycol reboiler alone. There are several ways of enhancing the purity of the glycol beyond what is achieved in the reboiler.[10] One such method is the application of a small amount of stripping gas in the regenerating section. **Fig. 5.13** shows the effect of using stripping gas to enhance the purity of the lean glycol solution.[10] Stripping gas is simply a small stream of natural gas that is flowed into the hot glycol. The flow of this gas is usually regulated manually with a small needle valve and is measured by means of a small rotameter.

There are a couple of ways of flowing this gas into the hot glycol. One way is simply to flow the gas into the glycol below the overflow line from the reboiler to the surge drum or directly into the glycol in the reboiler vessel through a perforated pipe below the fire tube. The

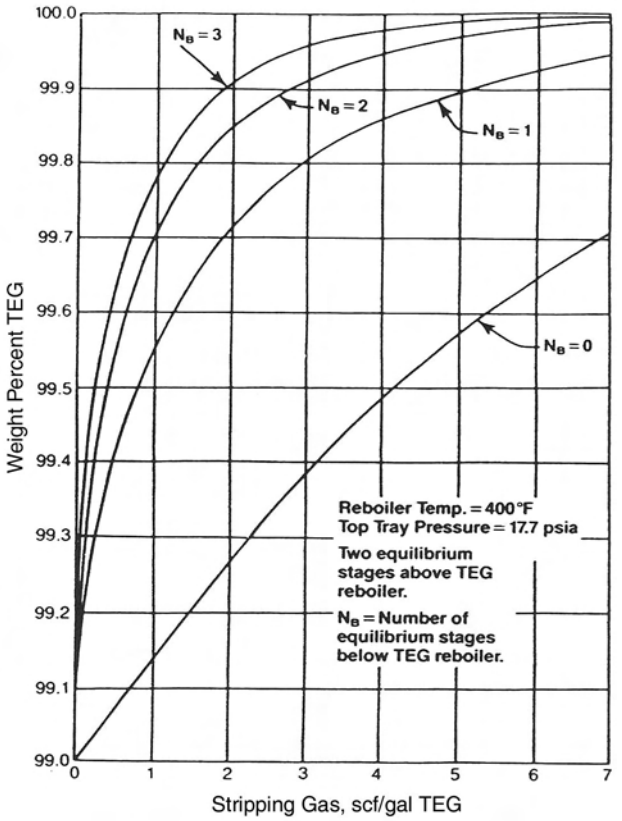


Fig. 5.13—Effect of stripping gas on TEG concentration (after *Engineering Data Book of Gas Processors Suppliers Association and Gas Processors Association*[10]).

other way is to install a small packed column between the reboiler and the surge drum and admit the gas at the base of this column. By contacting the hot glycol with natural gas, an additional small amount of water is "stripped" from the glycol into the gas, increasing the purity of the lean glycol. If a packed column is used as a contacting means between the glycol and the stripping gas, the stripping efficiency is considerably improved, as seen in Fig. 5.13.

The stripping gas that is added to the glycol in the regeneration section is emitted into the atmosphere with the released water vapor, unless the vapors from the still columns are routed to a heater or an incinerator, or are captured by a compressor and recompressed.

5.19 Components of the Glycol Circulating System

5.19.1 The Glycol Circulating Pump. The circulation of glycol is done with a reciprocating pump. The pump is driven by an electric motor, natural gas pressure, or the high-pressure, rich glycol returning from the contactor.

Electric-motor-driven pumps are usually employed in central dehydration facilities where electric power is available. In field installations, a natural gas powered pump or a glycol powered pump can be used. In the latter case, the high pressure, rich glycol, with the assistance of a small amount of high pressure gas, flowing out of the contactor, is used to provide the power needed to stroke the pump. The required pump rate in field dehydration units is usually small, and, therefore, a single plunger pump is normally used. When the gas rate is large, duplex or triplex pumps are used.

The main problems with glycol pumps are leaks through the packing around the plunger, as well as sticking check valves. If the packing gland nut is tightened too much, the rod may get scored. Usually, a small pan is placed under the pump or the plunger portion of the pump to contain the leaked glycol.

5.19.2 Heat Exchange. Because glycol must be relatively cool when entering the absorber and is heated to near its boiling temperature for regeneration, the liquid is continuously subjected to heating and cooling. To minimize the use of energy in the regeneration of the glycol at high temperature, several heat-exchange opportunities are built into most glycol circulating systems. Heat exchange usually occurs in certain locations: coil in the top of the reboiler still; coil in the surge tank or separate heat exchanger between rich and lean glycol; and pipe-in-pipe heat exchanger ahead of the glycol absorber or a coil in the top of the absorber.

In some cases, an additional heat exchanger is necessary to exchange heat with air, to cool the lean glycol ahead of the contactor. It is necessary to limit the temperature of the lean glycol to only a few degrees above the temperature of the gas to increase the absorption of the water by glycol. Too high a glycol temperature reduces the transfer of water from the gas to the glycol, and the water dewpoint may not be met. This is frequently the problem in summer operations, in which the gas is dehydrated after compression. On hot days, the glycol, as well as the gas, might be above normal temperatures. Usually, by exchanging heat with the dried gas through a double pipe exchanger or through a coil in the top of the contactor in small units, the temperature of the glycol is adjusted to a few degrees above the temperature of the gas leaving the contactor.

5.19.3 Filters. It is very important to maintain the glycol in as clean a condition as possible. For this reason, filters are always incorporated in a glycol circulating system. These filters are usually particulate filters and carbon filters.

The particulate filters are intended to remove solids down to a 5-μm diameter. Solids can occur from corrosion in the glycol system. Carbon filters are designed to remove dissolved impurities, such as compressor oil or condensate from the glycol solution. Particulate filters are usually installed on the rich glycol side and are in operation all the time. Carbon filters may be bypassed most of the time, if there is no dissolved hydrocarbon in the glycol. Impurities in the glycol solution might promote foaming in the contactor or still.

5.19.4 Surge Drum. Because the glycol that is being circulated might not always flow evenly at the same rate throughout the system, a vessel, the surge drum, is required that can handle any surges in the circulation rate. The reboiler always contains a liquid level above the fire tube. Glycol levels in the absorber or flash tank are essentially constant but might fluctuate slightly. Thus, there is a need for a vessel that can absorb slight temporary differences in circulation flow between the various vessels, as well as the thermal expansion of the glycol upon startup.

The surge drum is usually located below the reboiler, or at least at a level below the glycol in the reboiler. The glycol level in the surge drum is important because in some instances there is a heat exchange coil in the surge drum, as explained earlier. The level of glycol in the surge drum should be about at the two-thirds full level. The liquid level in the surge drum is an item that is usually checked by the operators. If the level is lower than normal, this might be the first indication of trouble, such as high glycol losses with the treated gas, losses with the vapors leaving the reboiler still, holdup in one of the vessels, or leaks in the piping.

5.19.5 Strainer. A strainer should always be installed upstream of the suction of the glycol pump. The glycol strainer ensures that no solid particles enter into the glycol pump. The main

problem with solids entering the pump is that they might lodge in the suction or discharge valves and prevent the pump from pumping at maximum efficiency.

5.19.6 Glycol Flash Tank. Whenever gas is in contact with a liquid at elevated pressures, such as natural gas and glycol in the contactor, some of the gas physically dissolves in the liquid. The greater the contacting pressure, the more gas dissolves in the liquid. Thus, some natural gas dissolves in the glycol in the absorber in addition to the water vapor. When the glycol reaches the flash tank, its temperature has been raised through the coil in the reboiler still, and the pressure in the flash tank is at a much lower level, generally between 15 to 50 psig, than the pressure in the contactor. In light of these changed conditions of pressure and temperature between the absorber and flash tank, most of the dissolved gases evolve from the glycol in the flash tank.

On larger systems, the glycol flash tank can be designed as a three-phase separator to help remove any condensate that becomes entrained in the glycol. This bulk separator increases the operating life of the downstream filters.

5.19.7 Glycol Piping. All the vessels through which glycol is circulated are interconnected with steel piping. Glycol is a substance that is prone to leak through threaded connections in piping, as well as through the packing on glycol pump plungers. For this reason, some operators prefer welded piping rather than threaded piping for the glycol system. There are, however, many threaded glycol systems that have provided leak-free service.

Because the pump rate is usually small, the piping in most field installations is of small diameter. It is important to check the piping for leaks and to repair them as soon as possible.

5.20 Instrumentation and Controls

Most glycol dehydration units are sufficiently automated that they can operate unattended. The degree of automatic control of the equipment can vary considerably and depends largely on the specifications by the owner company. The discussion in this section highlights the main control points, which may be considered as the minimum control of a dehydration unit. The controls relate mainly to gas flow, temperatures, pressures, glycol circulation, and lean glycol concentration. Pressure gauges should be installed on all vessels, including the reboiler, and on the discharge side of the pump. Similarly, thermometers should be installed on all vessels, as well as ahead and after all heat-exchange equipment on both cold and hot lines.

5.20.1 Control of Gas Flow. Gas flow is usually controlled with a flow control valve upstream of the inlet separator. The operator can set the flow to a certain rate. If the set rate is not met, then the valve opens fully and allows the available gas flow to enter the separator and the contactor. Downstream of the contactor, there may be a meter, which meters the gas flow, or the meter may also be located upstream of the separator. At some point downstream of the contactor, there usually is a back-pressure valve. This valve ensures that the pressure in the contactor is steady without abrupt changes. The pressure is set above the downstream line pressure to ensure steady operation of the contactor.

5.20.2 Lean Glycol Circulation Rate. To achieve the required water dewpoint depression, it is necessary to circulate a certain amount of lean glycol per pound of water to be removed from the gas. The rate of glycol circulation depends on several conditions, which are all interrelated. These conditions are lean glycol purity, after regeneration, which depends on the reboiler temperature and whether or not stripping gas is used, with zero or one stage contacting for the stripping gas; water content of the gas, which depends on gas temperature and pressure in the inlet separator; number of actual trays (or equivalent packing height) in the contactor; and the design approach temperature in the contactor.

In general, a circulation rate of 3 to 5 gal of lean glycol per pound of water to be removed from the gas is required. If the glycol purity is not sufficiently high, any larger circulation rate might not give the necessary dewpoint depression.

Usually there is an attempt to match the circulation rate to near the minimum required rate to achieve the necessary drying. Overcirculation has disadvantages: the heat load on the regenerator is increased, requiring more fuel gas consumption; the lean glycol returning to the contactor is at a higher temperature because of less efficient heat transfer; more hydrocarbons are absorbed, especially compounds such as benzene, toluene, ethyl benzene, and xylene (BETX), if these compounds are present in the gas; and additional acid gas is absorbed, if sour gas is being dehydrated.

Because there is concern about the absorption of other compounds besides water, as well as for energy efficiency, the glycol circulation rate should be set to remove the required water only. In field installations, using gas driven pumps, the pumps are set to the required pump rate by a gas control valve. This is usually a manually operated needle valve. The manufacturer of the pump provides a chart for the pump that shows the pump rate in volumetric units per time vs. the number of strokes of the plunger per minute.

5.20.3 Reboiler Temperature. The temperature of the glycol in the reboiler determines largely the purity to which the glycol is regenerated. However, there is a limit on the temperature to which the glycol can be heated. This limit is a few degrees below the decomposition temperature, as shown in Table 5.3, because above this temperature, the glycol molecule breaks down. In light of this, the normal temperature in which TEG is heated in the reboiler is about 380 to 390°F. This temperature range results in a lean glycol purity of just under 99% on a mass basis, the other 1% being water.

Thus, it is very important to control the reboiler temperature to the range of 380 to 390°F or some other range that provides adequate regeneration of the rich glycol. In most glycol dehydration units, the heat for regeneration is supplied by burning a small amount of the gas in a fire tube in the reboiler vessel. The size of this vessel is determined by the maximum design rate of glycol circulation, and the size of the fire tube itself is designed for a limit on the heat flux from the fire through the steel tube to the glycol on the shell side of the fire tube. The larger the fire tube, the lower is the heat transfer rate per unit area. The flame should be burning along most of the tube, as opposed to an intense flame at the front of the burner. The fire tube should be designed for a heat transfer rate per square foot of fire tube no greater than 7,000 Btu/h.[30]

A thermowell located in the shell of the reboiler and immersed in the glycol is equipped with a temperature regulator that controls the instrument gas supply to a control valve on the fuel gas supply line to the burner. By setting the regulator at the desired temperature, the gas flow to the burner is automatically controlled, resulting in a narrow operating temperature range for the reboiler. A pilot light ignites the gas to the main burner when the controller allows the gas to flow. The reboiler controls also include a high-temperature shutdown and a shutdown of the fuel supply in case of pilot-light failure.

Most glycol reboilers are equipped with a flame arrestor at the air inlet to the burner. The flame arrestor consists of a tightly wound metal sheet, with sufficient space between the wound metal to allow sufficient air through the arrestor into the burner. If an external source of flammable vapors is sucked in with the air through the flame arrestor, such vapors will not ignite outside of the flame arrestor, as the temperature of the gas is cooled below the ignition point, thus preventing a backflash or explosion.

5.20.4 Liquid Level Controls. The main liquid level of concern is the level of the condensed liquids in the inlet separator. This vessel can be a two-phase or a three-phase separator. It is very important that no condensed liquid flows with the gas into the contactor. If condensate or

salt water gets into the contactor, the result could be foaming or deposits of salt occurring on the fire tube. Heavy hydrocarbons will eventually gum up the packing in the reboiler column or plug the filter. Flashing of hydrocarbons in the still could damage the packing in the still column. In light of this, most glycol units are equipped with high-level alarms and shutdowns, which activate when the liquid level is exceeded in the inlet separator.

The glycol level in the contactor is also important, as any increase in level above the gas inlet pipe can result in interruption of circulation of glycol because of insufficient glycol returns. Both liquid levels, in the inlet separator and the contactor, are controlled by conventional liquid level floats and outlet valves.

Where a flash tank is employed, it is again important to ensure that the level of the glycol be maintained at a set level. The liquid outlet valve must be the throttling type, as opposed to snap acting, to ensure a smooth and steady flow of rich glycol to the regenerator. The glycol level in the surge drum should be at about 2/3 to 3/4 full. In small units, the heat-exchanger coil is in the surge drum and has to be totally submersed to be effective in heat transfer.

5.20.5 Pressure and Temperature Indicators. All vessels are usually equipped with pressure gauges, as well as pressure relief valves. An operator checking the operation of the glycol unit can quickly see the pressure at which each vessel is operating. The same cannot, in many instances, be said about the temperature, especially in the glycol lines upstream and downstream of each heat exchanger. Ample installation of dial thermometers on the glycol lines is helpful but lacking in many cases. Thermometers are usually installed in the inlet separator and the reboiler. As a minimum, additional thermometers should be installed on the glycol line ahead of the contactor after the heat exchanger and ahead of the reboiler still. Ideally, dial thermometers are installed on all lines entering and leaving the heat exchange equipment.

5.21 Contactor Design Considerations

While the contactor provides the intimate contact between the gas and the glycol, it also must have a diameter sufficiently large that there is separation between the gas and liquid phases. The gas flows upward, and any liquid glycol droplets that might form must be able to fall down through the gas stream. The basic equation requires the determination of the maximum superficial gas velocity in the tower. The contactor towers are equipped with a mist extractor installed at the top of the tower. The suppliers of packing have the correlations for packing height per theoretical stage.

The allowable superficial gas velocity in the tower using bubble cap trays is determined by[10]

$$V = K\left(\frac{\rho_l - \rho_g}{\rho_g}\right)^{0.5} . \quad \text{..... (5.3)}$$

The density of the gas at contactor condition of pressure and temperature is determined by

$$\rho_g = 2.70\frac{P\gamma}{zT} . \quad \text{..... (5.4)}$$

The internal diameter of the vessel is approximated by Eq. 5.5, on the basis of the allowable gas velocity in the vessel, as determined by Eq. 5.3.

$$d = 7.75\left(\frac{QTz}{PV}\right)^{0.5} . \quad \text{..... (5.5)}$$

Design engineers make use of these formulas, with proprietary adjustments, to determine the diameter for maximum gas flow through the absorber. The height of the vessel is determined by the number of theoretical stages used in the design, the spacing between the trays, and the relationship between the theoretical stages and the number of actual trays or packing height. Additionally, there is space provided below the bottom tray and above the top tray for disengaging between the gas and the glycol. A stainless steel mesh mist eliminator is installed near the top of the vessel. The contactors are also designed to very stringent codes, with respect to shell thickness requirement related to the maximum operating pressure rating. These items are stamped on a plate attached to each contactor.

5.22 Water Dewpoint Determination

It is always of interest to know that the dehydration unit is performing as required and that the exit gas meets the necessary dewpoint specification. If the gas has to meet sales gas requirements for water content, the dewpoint temperature that has to be met at the operating pressure of the contactor can be obtained from Fig. 5.7. This merely allows the operator to determine the appropriate dewpoint temperature. To determine the actual dewpoint temperature, a dewpoint tester instrument is usually used.

Before electronic instruments were commonplace, the water dewpoint of natural gas was usually determined with a U.S. Bureau of Mines dewpoint tester. Currently, there are several different types of electronic instruments on the market that determine the amount of water in the gas, as opposed to determining the condensation temperature of the water. Such instruments need very clean gas to function properly. A slipstream is taken of the gas to be tested and is usually filtered to remove any impurities.

One brand of electronic dewpoint testers makes use of a metal oxide layer that adsorbs water molecules. By measuring the electrical impedance across the adsorbed metal oxide surface, a reading of the amount of adsorbed water is obtained. The amount of adsorbed water is in balance with the small amount of water in the surrounding gas. Thus, a direct readout is obtained of the moisture content of the gas being tested.

5.23 Normal Operation Checklist

While glycol dehydration units are designed to operate unattended, periodic inspection of the equipment and its operation is necessary. All items listed next should be checked.

- Check the still column vent. Water vapors should be visible. There should be no pressure on the reboiler. Ensure that there is no ice buildup in winter.
- Check the lean glycol temperatures across all heat exchangers and in the reboiler.
- Check the pump operation, strokes per minute, and lubrication oil.
- Check the operation of the glycol filter for pressure drop. Change the filter if necessary.
- Check the glycol level in the surge drum. Add makeup glycol if necessary.
- Check the stripping gas rate. Adjust rate as required.
- Check the liquid levels in the inlet separator, contactor, and flash tank.
- Drain any fluid from the fuel gas scrubber.
- Check the operation of the burner in the fire tube. Check sight glass to ensure it is not broken and gasket is in good shape; clean if necessary.
- Check equipment for liquid leaks, and repair if required.

5.24 Trouble Diagnosis

Glycol dehydrators usually operate trouble free. However, there are some problem areas that can occasionally occur.

5.24.1 Foaming. One of the more serious problems is foaming. The cause of foaming is usually difficult to determine. However, if the solution is not continuously cleaned by filtration,

certain materials can cause foaming. One of the more common causes of foaming is entrained hydrocarbon liquids. It is essential that the inlet separator provide good separation between condensed liquids and gas going to the contactor. Antifoam agent is usually a temporary solution, and the real problem must be identified and corrected.

5.24.2 Corrosion. Corrosion is usually caused by degradation products in the glycol, which can be generated by too high a skin temperature of the fire tube in the reboiler.

5.24.3 Not Meeting Water Dewpoint. There can be many reasons for not meeting the required water dewpoint depression. The first step is to check the water dewpoint temperature with a dewpoint tester. A high water dewpoint can be caused by:

- Gas inlet temperature higher than design.
- Gas inlet pressure lower than design, combined with normal or higher temperature.
- Insufficient glycol circulation owing to too low a pump rate or a low glycol level in the surge drum, check valves on suction or discharge of pump not holding, or suction strainer plugged.
- Insufficient glycol regeneration because of a too low reboiler temperature, high water in inlet separator carrying water into absorber, a leak in the rich/lean glycol exchanger, insufficient stripping gas, or fouled stripping column packing.
- Foaming in absorber: check liquid level in inlet separator, place charcoal filter in service, or temporarily cut back throughput, if necessary.

5.25 Environmental Concerns

Upon the regeneration of the rich glycol to lean glycol, the water that was absorbed in the contactor is released in the regenerator, and in the past was vented into the atmosphere. Unfortunately, the glycol not only absorbs water in the contactor, it also physically absorbs hydrocarbons and acid gas. The absorptivity of paraffinic hydrocarbons, such as methane, ethane, etc. is not great. However, the aromatic hydrocarbons such as benzene, toluene, ethylbenzene, and xylene (BTEX) are more easily absorbed. The problem with these vapors is that they are considered carcinogenic, and all contribute to atmospheric pollution.

5.26 Glycol Dehydrator BTEX and VOC Emission Control

The quantity of BTEX and volatile organic compounds (VOC) emitted from natural gas processing facilities has become a major environmental concern over the past decade.[31] With passage of the 1990 amendments to the Clean Air Act in the United States and similar regulations in the rest of the world, several regulatory programs were established to control BTEX and VOC emissions from the still vent of glycol dehydration systems.

Most environmental regulations that were promulgated have focused on two main areas that affected the oil and gas industry. The first area was the reduction of VOC and nitrous oxide (NO_x) emissions, which were known to react together in the presence of sunlight and create what is commonly referred to as smog. The second area was a list of hazardous air pollutants (HAP) that were to be controlled, most of which were found to be carcinogenic compounds. Among the list of HAP were the four BTEX compounds, which are commonly found in natural gas streams.

To minimize emissions of these vapors to the atmosphere, several emission control processes have been developed by the gas industry.[32] One such method is to recover condensable compounds and to use the remaining vapors as part of the fuel gas supply to the reboiler. **Fig. 5.14** illustrates the process equipment. The vapors emitted from the glycol reboiler still column are cooled in a natural or forced draft air cooler to temperatures below 120°F. The condensed liquids are collected in a small two-phase separator and pumped back into the process system for recovery of saleable hydrocarbon liquids. Noncondensable gas from the two-phase separator

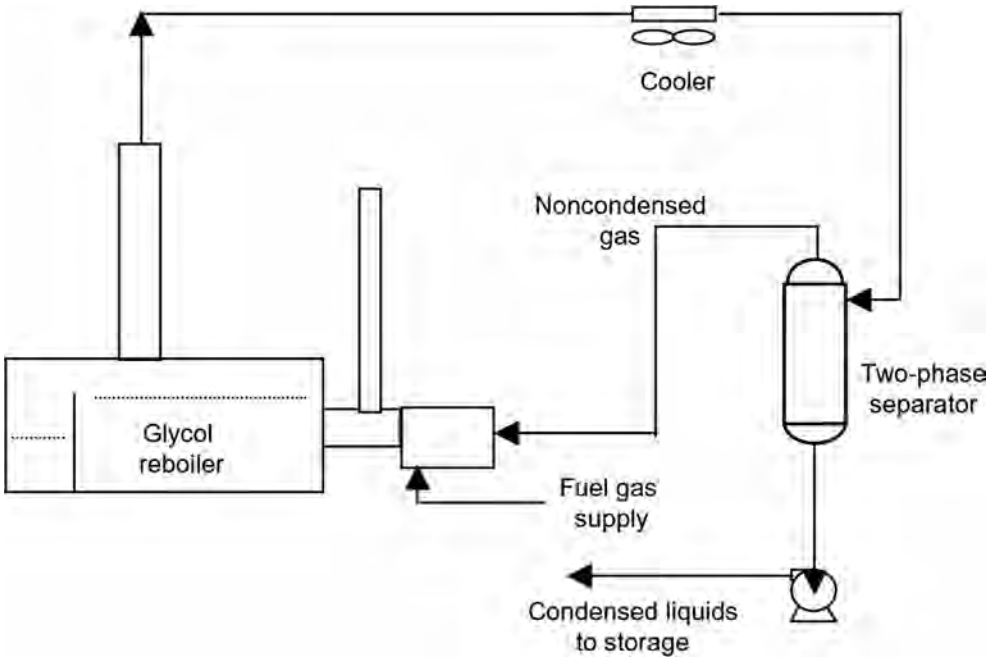


Fig. 5.14—Schematic drawing of reboiler vapor conservation equipment.

is burned in the glycol reboiler firebox to reduce fuel gas consumption and to achieve an overall minimum destruction efficiency of 99.7%.

It is important that all emission control devices be engineered with proper controls for safe operation. Safety controls should be used as a minimum. A level safety high (LSH) should be installed on the two-phase separator to prevent condensed hydrocarbon liquids from going into the reboiler firebox, if the condensed liquid pump fails. An in-line flash arrestor should be installed in the noncondensable gas piping to prevent flame propagation from the reboiler firebox back into the BTEX system. A pressure safety valve (PSV) should be installed on the glycol reboiler or emission control device to protect the system from overpressure. Block and bleed valves should be installed in the noncondensable gas piping to protect the glycol reboiler during a high-temperature situation.

GTI has sponsored research in the area of emission controls from glycol units.[33,34] A computer program has been developed that is designed in part to estimate the amount of BTEX absorbed in a conventional glycol unit. The program is called GLYCalc™ and is available from GTI at a nominal cost.

5.27 Dry Desiccant Dehydration

While dehydration with glycol is the most common process used to meet the water dew- point specification for sales gas, under certain conditions solid adsorbents are also used for this purpose. Materials with a great affinity for water are silica gel, Sorbead, alumina, and molecular sieves.

These solid compounds are prepared as round or slightly elliptical beads having a diameter of about 4 to 6 mm, and in the case of molecular sieves, are also manufactured in small cylindrical forms, about 2 to 3 mm in diameter and about 6 to 8 mm long. Each of these compounds has its own characteristic affinity and adsorptive capacity for water, and the designer has to chose the material best suited for the purpose.

Silica gel is silicon dioxide (SiO_2), manufactured as small round beads with a large pore surface area onto which the water, contained in the vapor phase in the gas, is adsorbed by the desiccant at relatively low temperatures. The affinity for water is temperature dependent, and the affinity for water is broken at high temperatures, such as 390°F. It is necessary to avoid liquid water droplets from contacting the silica gel, as liquid water damages the desiccant. Thus, it is important to have effective gas/liquid separation ahead of a dry desiccant unit. Sorbead is also a silica gel product that contains about 3% aluminum oxide (Al_2O_3) that makes the gel more resistant to damage from water droplets. Certain manufacturers of Sorbead desiccants provide different grades of Sorbead, such as grade R for regular natural gas drying and grade WS for additional damage resistance from water droplets. A tower filled with Sorbead contains mainly Sorbead R and is topped off with a one-foot-thick layer of Sorbead WS to offer degradation protection from water droplets.

Alumina is used mainly for drying air. Molecular sieves are artificial zeolites that are manufactured so that they result in solids with uniform small pore spaces. They have a great affinity for water. Molecular sieves are usually installed in applications in which very low residual water content is required, such as ahead of a low temperature hydrocarbon extraction process. Molecular sieves are suitable for drying very sour natural gas that also contains aromatic compounds.[35] The heavier hydrocarbons might be difficult to remove from the silica gel during the regeneration step.

Adsorptivities and design water contents are best obtained from the vendors of the desiccant. In general, design water adsorption is on the order of 8 to 12 lbm of water per 100 lbm of silica and Sorbead desiccants. When new, the adsorption capacity is higher than these numbers. However, when desiccant ages with a number of regeneration cycles, a good design value is about 8 to 10 lbm of water per 100 lbm of desiccant.

5.28 Typical Process Equipment

Fig. 5.15 illustrates the typical equipment for a dry desiccant process for dehydrating natural gas. Two towers are required for gas dehydration. As the gas flows through one tower containing the solid desiccant, water is adsorbed onto the surface of the material. After adsorbing for several hours, the material becomes fully saturated with water. For this reason, the process incorporates two towers. While one tower is on adsorption, the other tower is being regenerated by the application of heat through a small slipstream of gas and subsequent cooling. The regeneration time is slightly less than the adsorption time of the first tower. Thus, when one tower is fully saturated, the second tower has been fully regenerated. The towers are then switched, and the process of drying the gas continues uninterrupted.

To design a silica gel dehydration system, it is necessary to select the duration of the on-stream time per tower before switching towers. This is usually 8 to 12 hours for fully water-saturated gas. After establishing the cycle time and the amount of water to be removed from the gas during one cycle, the bulk volume of desiccant can be estimated. The diameter of the tower is designed on the basis of the superficial gas velocity, and the height of the tower is determined by dividing the cross-sectional area of the tower by the determined bulk volume of the desiccant. The vendors of the desiccant usually provide the design criteria and perform the design.

5.29 Dehydration With Deliquescing Desiccants

Deliquescing desiccants are salts that adsorb water vapor; the water then condenses and dissolves the salt. The water drops down as brine and is removed from the vessel. In the past, the common deliquescing desiccant was calcium chloride ($CaCl_2$).[36]

Deliquescing desiccants have been used to dehydrate natural gas since the early 1920s. Early desiccant systems were plagued with numerous operational problems, such as channeled gas flow and bridging, which caused washouts and velocity problems within the desiccant bed and

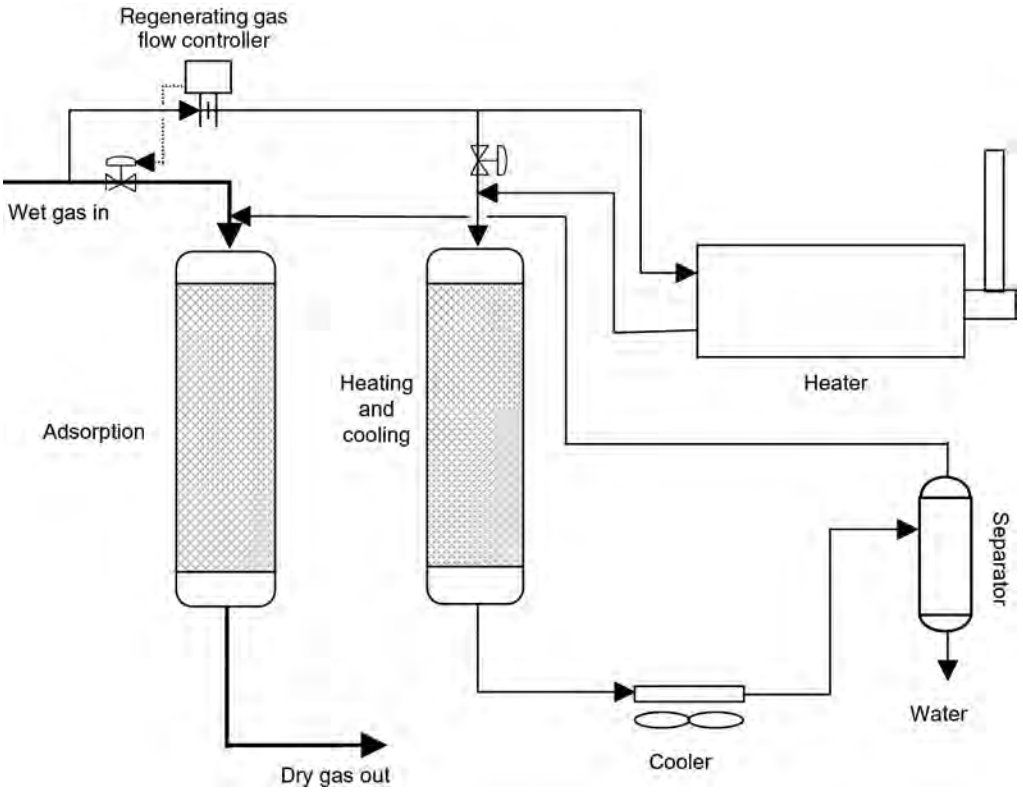


Fig. 5.15—Schematic drawing of typical dry desiccant dehydration process.

ultimately resulted in inadequate dehydration of the gas stream. Almost all the operational problems associated with the early systems can be attributed to the poor quality of desiccant that was used. Early desiccants were made in briquette form and were very soft, crumbly, and porous. The shape of the briquettes was irregular and, when partially consumed, became more irregular. As gas flowed through the desiccant bed, it found the easiest path and bypassed the rest of the bed. Once started, this process accelerated desiccant consumption in the flow zone, and a channel would form through the desiccant bed. The drying process stopped because wet gas no longer contacted the desiccant. Also because of its porous nature, gas could penetrate through the briquette, causing it to hydrate internally. This caused the briquette to expand and bloom, making the desiccant fuse together into a hard mass. The operator had to mechanically break up the bed, which was not easy.

Significant advancements have been made over the past 10 years to greatly improve deliquescing desiccant dehydration. New dry-forming technology produces a hard, nonporous, low permeability desiccant. Hydration can only occur on the outside of the desiccant, which helps to maintain its general shape as it is consumed. Flow efficiency remains relatively constant as the desiccant bed is consumed.

Fig. 5.16 shows a typical improved gas dehydration system using deliquescing desiccants. Gas containing water vapor enters the bottom of the vertical dehydration vessel and flows up through a series of full diameter diffusion baffles, which evenly distribute the gas stream across the diameter of the vessel. As the wet inlet gas stream flows up through the desiccant bed, the desiccant starts to hydrate, removing water vapor from the gas stream. This water accumulates on the desiccant surface and drips off the desiccant into the vessel sump as the hygroscopic brine on the desiccant surface continues to remove water vapor from the gas

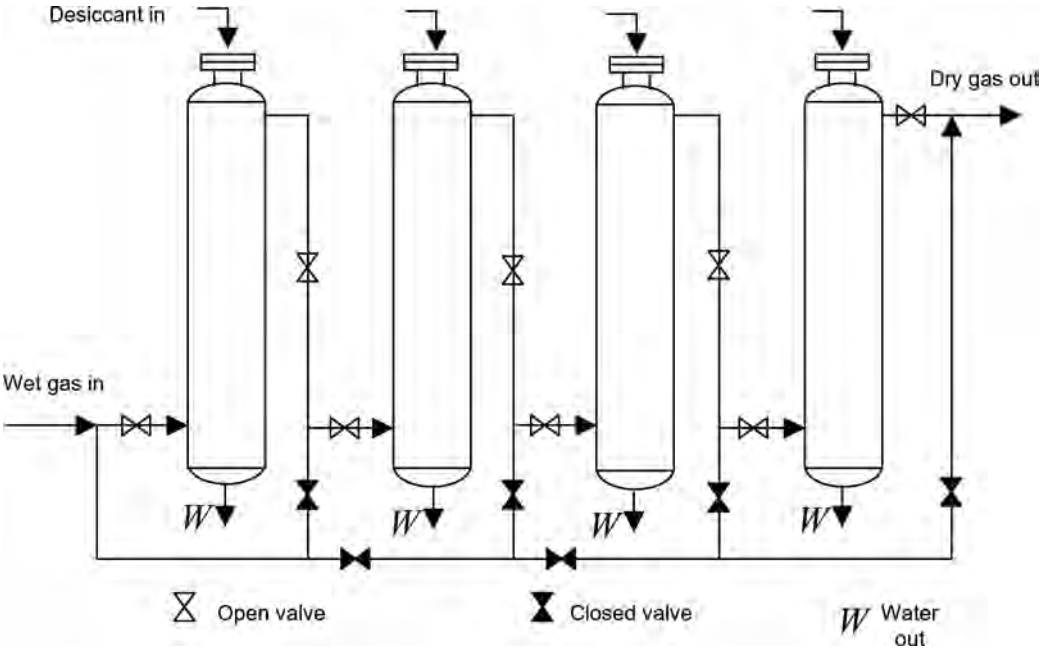


Fig. 5.16—Schematic drawing of multistage deliquescing desiccant dryer.

stream. This process, known as "deliquescing," causes desiccant salts to dissolve into the fresh water accumulating on the desiccant. Desiccant is consumed at a rate based on the dilution factor of each desiccant formulation.

The ability of each desiccant to remove water vapor is based on the vapor pressure difference between the hydrate of the metal halide salt used in the desiccant and the partial pressure of water vapor in the inlet gas stream. Gas exiting the vessel top has been dried to a point consistent with the equilibrium point of each desiccant. There are several different hygroscopic grades of desiccant available. Selection of the correct desiccant is based on the inlet gas conditions and the required outlet moisture content. If more hygroscopic grades are needed, it is normally more economical to use several grades in series, flowing from lowest grade to highest in separate vessels, rather than using a high desiccant grade in one vessel. An exception is for very low flow rates such as instrument or fuel gas in which operating-cost savings might not offset additional equipment costs incurred by using multiple vessels.

As desiccant is consumed, new desiccant must be added periodically by isolating and depressurizing the vessel, removing the top service closure and pouring desiccant into the vessel. This interval is predictable, and if necessary, the vessel is simply oversized to provide a longer interval between service operations.

One of the most hazardous operations is the opening of vessels that have been previously under pressure. Even with a safety interlock, a small amount of pressure could remain trapped in the vessel. Small "telltale" vents can become plugged, giving the operator a false sense that there is no internal pressure. When opening such a system, bolts should be loosened but not removed until the pressure seal is broken and a knife can be inserted into the pressure-containing cavity.

Water removed from the gas combines with salts in the desiccant to form brine water, which accumulates in the sump. This brine is removed (typically with automatic controllers) to brine storage, where it can normally be disposed of as common oilfield brine. There are no other products or emissions. Desiccant is not typically affected by high Btu gas; however, inlet

gas should flow through standard filters or separators to remove liquids, as required in any dehydration process design.

Because deliquescing desiccant systems are closed, there are no VOC or BTEX emissions. Because equipment is relatively simple compared to glycol systems, capital cost is normally less than that of TEG systems. This is especially true if emission control systems are required with the TEG unit. Deliquescing desiccant systems are very simple to operate and require minimal maintenance. There are no moving parts other than a diaphragm-operated dump valve used to discharge brine water, and 100% turndown is possible with desiccant dehydration. However, the cost associated with manually refilling the desiccant can be substantial, as can be the maintenance cost associated with very corrosive brine.

The operating cost associated with a deliquescing desiccant system is directly proportional to the amount of water vapor removed from the inlet gas stream. Operating cost is lower for high-pressure and low-temperature gas streams in which small quantities of water vapor exist. Compared to conventional TEG dehydration, more gas can be sold with desiccant dehydration because there is no fuel or pump gas consumption.

5.30 Water Dewpoint and Hydrocarbon Dewpoint Control

5.30.1 Short-Cycle Dry Desiccant Process. Some processes can be used to control the water content as well as remove heavier hydrocarbons from natural gas. The short-cycle dry desiccant process can be used in this way.

This process is similar to the dry desiccant adsorption process covered in dehydration. It is usually selected for a gas stream that is fairly lean in propane and butane but contains sufficient amounts of C_5^+ so that the hydrocarbon dewpoint is not met. Silica gel is generally the preferred adsorbent.

There are basically two differences between using this process for water dewpoint control and for hydrocarbon dewpoint control, namely that three towers are required for hydrocarbon dewpoint control, and the cycle time for the towers is short, usually 20 to 30 minutes as compared to 8 hours or longer for dehydration. The desirable feature of the short cycle adsorption unit is that it recovers about 60 to 70% of the pentanes-plus in the gas stream and meets both the hydrocarbon and water dewpoints.

Fig. 5.17 shows the arrangement of a typical three-tower, short-cycle hydrocarbon recovery unit. While one tower is on adsorption, the other two towers are on their heating and cooling cycles. Usually, the towers switch every 20 to 30 minutes. The length of the cycle time depends on the design of the facility.

There are many factors that influence the performance of a short-cycle unit. First and foremost, the separator ahead of the unit must remove all liquids and solids in the gas. A slug of liquid into the bed would damage the adsorbent and perhaps necessitate a changeout. The adsorption temperature should be as low as possible without causing hydrates ahead of the unit, to adsorb more of the heavier hydrocarbons. Proper regeneration of the bed is very important. A portion of the process stream is used for this purpose. Regeneration gas temperatures are in the order of 480 to 530°F. The tower should be heated to an outlet gas temperature of 390°F.

While adsorbing and desorbing are important, the adequate condensing of the desorbed hydrocarbons is also very important. If the condensing is inefficient, the heavier hydrocarbons have no means of exiting from the gas stream. In warm climates, this is a major problem, requiring that the condenser be conservatively sized. Upon condensing, the liquids must be separated from the lighter hydrocarbons in the regeneration stream. Conservatively-sized vertical separators are usually used in this service.

The design of the short-cycle dry desiccant units is usually performed by the seller of the desiccant. The seller develops the computer software and tests the simulation results in actual applications. Thus, the design results from the vendor are quite reliable.

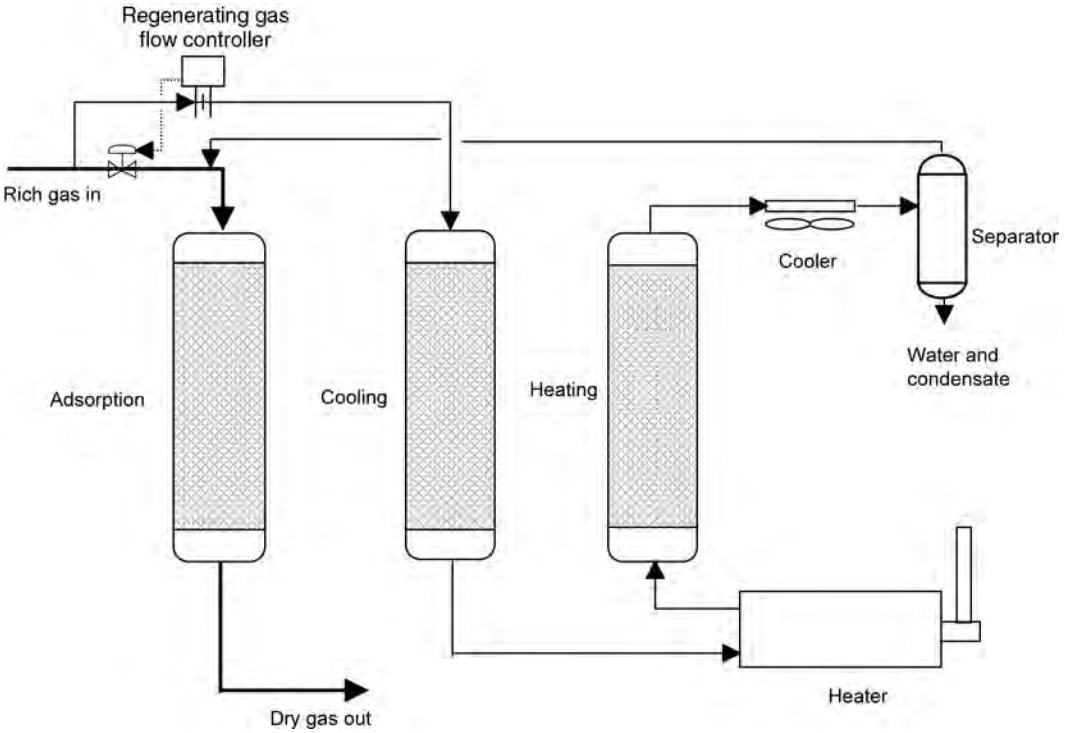


Fig. 5.17—Schematic drawing of typical dry desiccant dewpoint control process.

5.31 Dewpoint Control by Refrigeration

The refrigeration process is used in gas plants to remove heat from certain process streams. Refrigeration in natural gas treating is a process that serves a dual dewpoint control function—namely, it is used to meet the hydrocarbon dewpoint as well as the water dewpoint specification for residue or sales gas. The temperature to which the gas is cooled depends first on meeting these dewpoint specifications. This is the minimum cooling requirement. Cooling the gas to lower temperatures than the minimum temperature for dewpoint control has to be justified by the economics of liquefied petroleum gas (LPG) recovery. This requires a cost analysis of the value of additional LPG recovery versus increased capital and operating costs. Additional recovery of LPG is achieved by chilling the gas to colder temperatures, such as –20 to –30°F, or by contacting the gas stream with lean oil in an absorption tower.

Refrigeration is basically pumping heat from one medium to another. Heat by itself can only flow from a higher temperature medium to a lower temperature medium. Thus, refrigeration is a process that provides the cooling medium to which the gas is exposed. Refrigeration systems generally operate trouble free but can drop in efficiency, which requires investigation.[37]

Fig. 5.18 shows the typical refrigeration equipment for natural gas cooling. The heat exchanger cools the incoming gas to the refrigeration unit by exchanging heat with the cold gas, which has been chilled to the design cold temperature in the propane chiller.

Because the gas entering the refrigeration unit is normally saturated with water vapor and the temperature to which the gas is cooled is substantially below the hydrate point of the gas, some means of preventing hydrate formation must be instituted. The formation temperature of hydrates at a given pressure can be suppressed by the addition of chemicals, such as methanol or glycol. In conventional refrigeration units, the common chemical used for hydrate suppression in the process gas is monoethylene glycol, usually referred to as ethylene glycol, EG, or

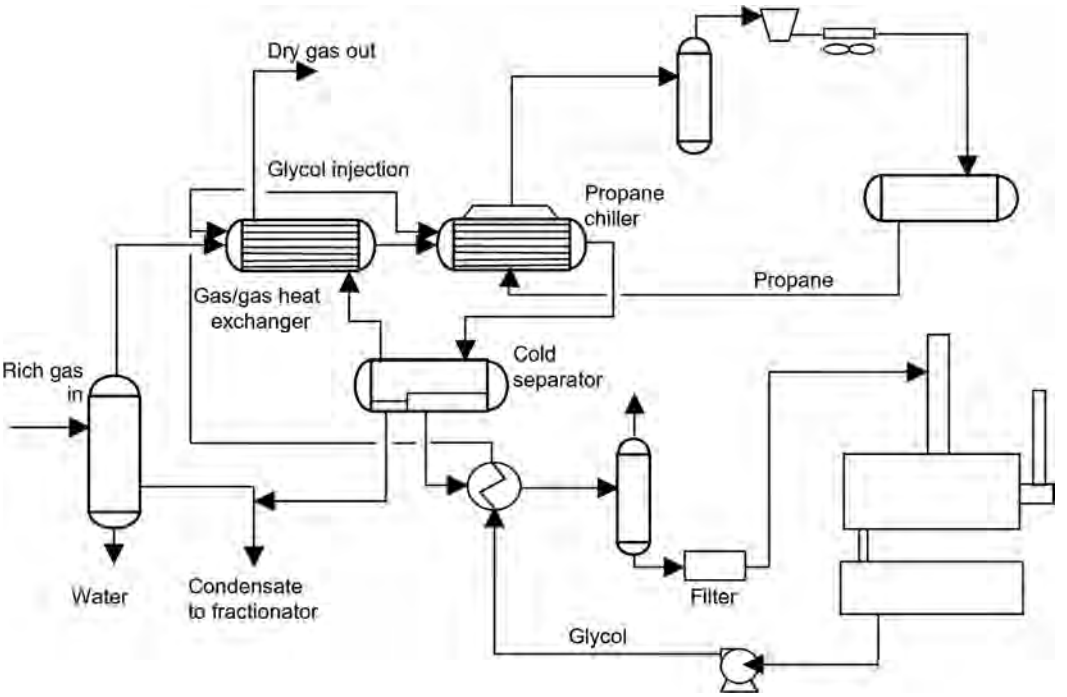


Fig. 5.18—Schematic drawing of typical refrigeration dewpoint control process.

simply glycol. Glycol must be added to the natural gas being cooled at two points: the inlet to the gas/gas heat exchanger and the inlet to the propane chiller. It is important to evenly distribute the glycol in the gas stream so that all gas is protected from freezing. This requires spraying the regenerated glycol evenly on to the tube sheet in these two vessels so that some glycol flows through each tube with the gas.

Propane, or some other refrigerant, boils in the chiller at a very low, controlled temperature, removing heat from the gas stream and, thereby, condensing a portion of the gas. The cold gas, condensate, and glycol flow from the chiller to a three-phase separator. The condensate goes to a fractionation unit. The gas is sufficiently cooled so it meets both the hydrocarbon and water dewpoints. It exchanges heat with the incoming gas to the refrigeration process.

The rich glycol is separated from the hydrocarbon gas stream in a three-phase separator and is routed to a regenerator. The concentration of the regenerated glycol is usually on the order of 75 to 80% glycol, with the balance being water. Sufficient glycol is injected at the two injection points to result in a mixture of water and glycol to depress the hydrate temperature to the required level, which for design purposes is the refrigerant boiling temperature.

The amount of glycol to be injected requires a determination of the hydrate temperature depression and a calculation of the rich glycol concentration by the Hammerschmidt equation. (See the chapter on Phase Behavior of Water/Hydrocarbon Systems in the General Engineering volume of this *Handbook*.)

As mentioned, the refrigeration effect is brought about by the vaporization of a refrigerant, such as propane, in the chiller. Propane is suited for this application, as it boils at temperatures near and below ambient temperatures. The vaporization of propane or boiling requires heat to effect the phase change from liquid to vapor—namely the latent heat of vaporization. By controlling the pressure at which the boiling of the propane takes place, the desired refrigeration temperature, down to about –40°F, is achieved.

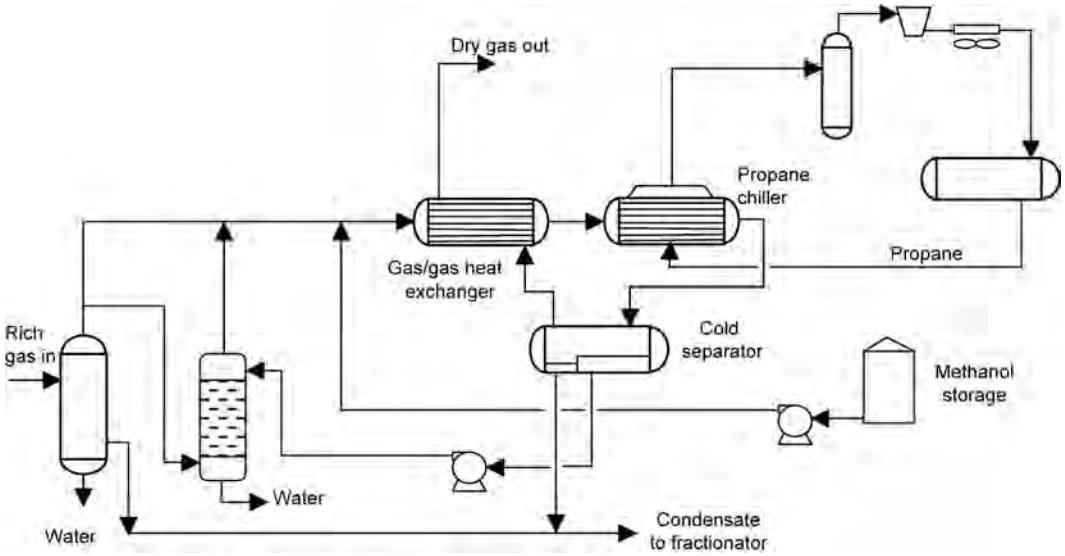


Fig. 5.19—Schematic drawing of typical IFPEXOL dewpoint control process.

5.32 The IFPEXOL Process

By using glycol to prevent hydrates from forming in the refrigeration process, a glycol regeneration process step must be incorporated in the overall equipment scheme, as shown in Fig. 5.18. This includes an additional capital and operating cost burden to the refrigeration process. This cost burden can perhaps be somewhat reduced by using a relatively new innovation called the IFPEXOL process, which is illustrated in **Fig. 5.19**.

In the IFPEXOL process, the prevention of hydrates in the heat exchanger and chiller is achieved by the addition of methanol to the natural gas stream being cooled.[38] Normally, the methanol is recovered by a distillation process. However, the separation of methanol from water is somewhat difficult. In the IFPEXOL process, an innovative step is used that recovers most of the methanol for hydrate suppression without regeneration.

As seen in Fig. 5.19, the inlet gas stream is split into two streams. One portion of the inlet stream is contacted countercurrently with the rich methanol-water solution pumped to a small contactor from the cold separator. Because the gas stream is already saturated with water, it does not pick up any additional water. However, it contains no methanol at the inlet to this contactor. As the gas is in intimate contact with the methanol/water solution, most of the methanol leaves the water and enters the relatively warm hydrocarbon gas phase. This conserves most of the injected methanol. This gas stream joins the other stream before entering the gas/gas heat exchanger. Additional methanol is injected into this stream as required to depress the hydrate temperature of the process gas in the chiller to the boiling temperature of the propane. Because the methanol is contained in the vapor phase, the distribution of liquid methanol onto the tube sheet is not important, as is the case with glycol injection. As the gas cools inside the heat exchanger and chiller tubes, methanol condenses with the water and prevents the formation of hydrates.

Methanol losses occur from the exiting chilled gas as well as in solution in the condensed hydrocarbon liquids. Recovery of the methanol in the liquid hydrocarbons is achieved with a water wash system.[39] Advantages of the IFPEXOL process are simpler process equipment and operation, as compared with glycol injection and regeneration. Furthermore, as discussed earlier, glycol absorbs some hydrocarbons, including the BTEX compounds, which are released into the atmosphere upon the regeneration of the glycol. Extra steps must be taken to avoid the

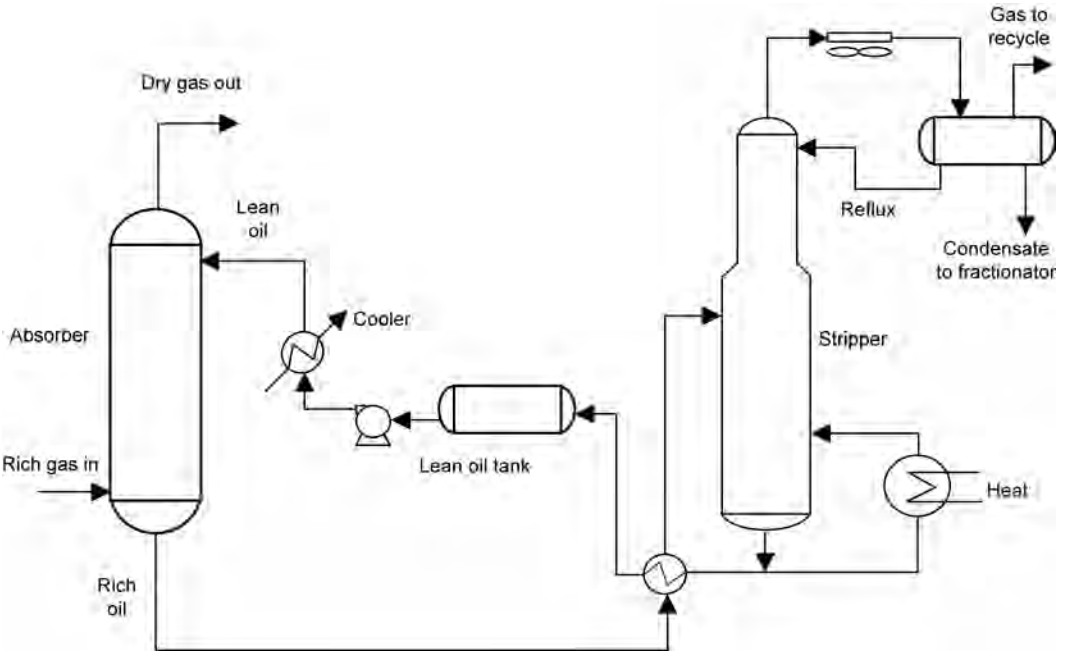


Fig. 5.20—Schematic diagram of lean oil absorption process.

release of the compounds into the atmosphere. In the IFPEXOL process, there are no emissions into the atmosphere. The main drawback to this process is the continuous loss of methanol, which has to be continuously made up from fresh supply. The IFPEXOL process is also suited for offshore operations where mass and space are limited.

5.33 NGL Extraction Methods

5.33.1 Lean Oil Absorption. Hydrocarbon liquids can be extracted from natural gas by contacting the gas with a light oil of uniform molecular weight. The fraction of each compound going into solution in the oil increases with decreasing volatility of the compound at the absorber pressure and temperature. Thus, while perhaps only a small percentage of the methane in the gas might go into solution, over 50% of propane, perhaps over 80% of butane, and so on, goes into solution in the oil. The lighter components, methane and ethane, are then rejected in the regeneration process of the oil, thereby capturing the absorbed propane and heavier compounds upon regeneration of the oil.

A simple lean oil absorption process is illustrated schematically in Fig. 5.20. The rich gas enters the absorption tower near the bottom and flows upward through the tower, which contains trays or packing. As the gas flows upward in the tower, it is in intimate contact with the oil, which enters the tower near the top. When the gas leaves the tower at the top, it has been stripped of most of the heavier compounds. The rich oil is then flowed to the stripping section, where the oil is heated to release the absorbed hydrocarbons. The vapors leaving the top of the stripper are cooled, condensing most of the propane and heavier hydrocarbons. The vapors from the reflux separator are compressed and recycled to the rich gas or to the sales gas.

Simple lean oil absorption processes operate at ambient temperatures. More complex lean oil absorption processes can be designed and operated at lower than ambient temperature. By contacting the chilled gas from a refrigeration unit in an absorber with cooled absorption oil, more of the components in the gas go into solution than in a process operated at ambient tem-

peratures. The rich oil leaves the bottom of the tower through a level control valve, exchanges heat with the regenerated lean oil stream, and enters a rich oil flash tank, operating at about half the pressure of the absorption tower. Large amounts of the absorbed lighter compounds, such as methane and ethane, flash off and are routed to recompression. In recovery facilities for propane and heavier hydrocarbons, the oil then enters a deethanizer column, where the balance of the absorbed methane and ethane are rejected. These gases are flowed to a presaturator vessel and then to a recompressor, where they are joined with the main treated gas stream. From the deethanizer tower, the lean oil is flowed to the still, where the separation of the oil and the balance of the absorbed compounds takes place. Upon regeneration, the lean oil flows through heat exchangers and a cooler to a presaturator vessel where it becomes partially saturated with methane and ethane. It is then pumped back to the high pressure absorber. Another cooling step is included to ensure that the lean oil temperature is no higher than the gas temperature to maximize absorption. The design of the overall process is now performed by computer, as the material and heat balance calculations are quite intricate and require rigorous mathematical treatment.

5.34 The Turbo-Expander Process

The turbo-expander process for treating natural gas streams for high liquids recovery was developed in the early 1960s. Its main application was to improve the recovery of ethane from natural gas, as ethane is an important feed stock for the petrochemical industry. The process achieves very low temperatures and, therefore, liquefies a substantial portion of the ethane and heavier compounds in natural gas. The various fractions of the liquid stream are recovered by distillation.

The turbo expander removes energy from the near isentropic expansion of a gas stream, which results in a drop in pressure and temperature by extracting useful mechanical energy. By using an expander to recover energy from the high pressure gas, the refrigeration effect is enhanced, and the reduction in gas temperature is greater than can be obtained by simple isenthalpic (Joule-Thomson) expansion across a valve.

Turbo-expander process configurations can vary greatly. They all incorporate various heat exchangers. The gas entering the turbo-expander process must be dehydrated upstream of the plant to a very low water content so that no hydrates form when the low temperatures are reached by the gas being processed. This usually requires a glycol dehydration unit for removing most of the water, followed by a molecular sieve unit to remove virtually all of the water from the feed gas. Gas pretreatment can also include CO_2 and H_2S removal.

Fig. 5.21 is an illustration of a relatively simple turbo-expander facility. There are many other arrangements possible, depending on the gas composition and the desired level of liquids recovery. Whether the turbo expander is likely the best choice for recovering ethane and heavier hydrocarbons from natural gas requires considerable analysis.[40,41]

5.34.1 Gas Preconditioning. Expander processes for NGL recovery can chill the gas as low as –160°F. To dry the gas to this low a water dewpoint temperature requires the use of molecular sieves in drying towers as illustrated in Fig. 5.15. A common class of molecular sieve used for deep drying has a pore opening of 4 Å. Instead of drying the gas with molecular sieves, it is also possible to prevent potential freezing problems with the addition of minor amounts of methanol into the gas stream upstream of the chilling section.[42]

5.34.2 Turbo-Expander Design. The design of a turbo-expander unit involves detailed heat and material balances and many flash calculations. Such design calculations are performed by computer.

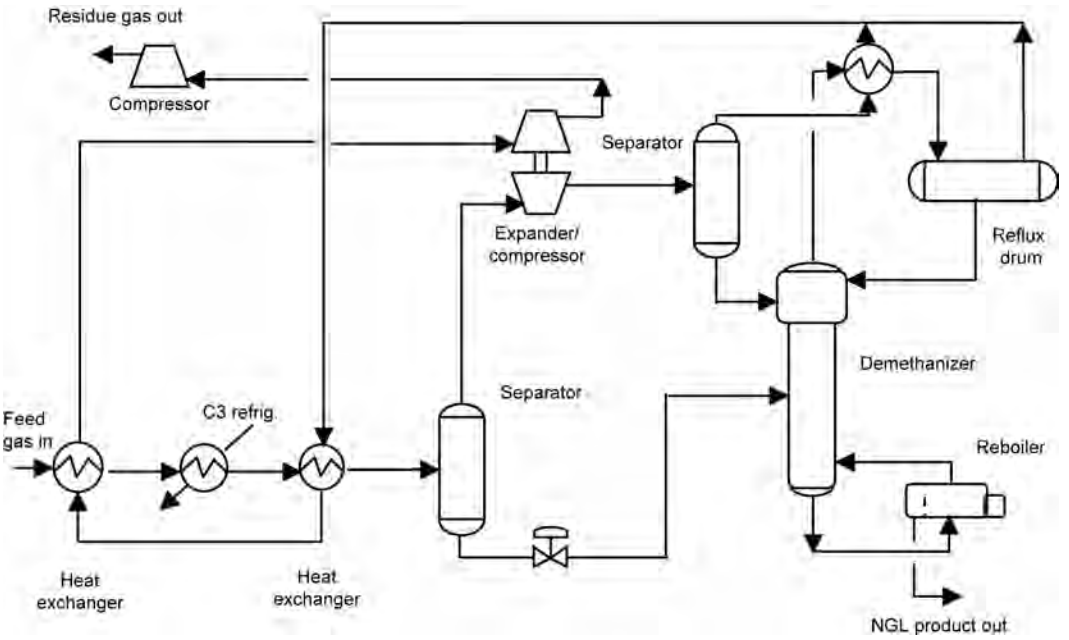


Fig. 5.21—Schematic drawing of turbo-expander equipment.

5.35 Joule-Thomson Expansion

Cooling of natural gas can also be achieved by expanding high pressure gas to a lower pressure across an expansion valve.[43] This is a constant enthalpy process, and the amount of the temperature reduction depends on the pressure ratio of initial pressure divided by the final pressure, the absolute pressures and the starting temperature, as well as the gas composition. This is a practical method to cool gas and extract hydrocarbon liquids if there is a lot of "free" pressure available. It is also a more practical process than the turbo-expander process for low gas rates, especially if the gas rates fluctuate.

Fig. 5.22 is a schematic drawing of a typical Joule-Thomson expansion process. The main process equipment is the expansion valve or choke. The high-pressure gas enters through an inlet separator, which removes the condensed water and any liquid hydrocarbons. The gas streams out of the separator, then flows through a heat exchanger, exchanging heat with the cooled, low-pressure gas. Some water and perhaps some hydrocarbon will condense in the heat exchanger from the high-pressure gas stream. The high-pressure gas then flows through the expansion valve, which drops the pressure of the gas to the design pressure. Simultaneously, a reduction in temperature occurs. Depending on the gas composition and the pressure and temperature of the gas mixture, a certain amount of the mixture will condense and form a liquid hydrocarbon stream. Water will also condense to the equilibrium water content of the gas at the final pressure and temperature.

If the resulting temperature of the gas after the heat exchanger or upon expansion is below the hydrate temperature at the operating pressure, hydrates form unless the gas has been dehydrated. To avoid the formation of hydrates in water saturated gas, a chemical hydrate inhibitor is added to the gas stream ahead of the heat exchanger. The chemical usually used to depress the hydrate temperature is ethylene glycol, but diethylene glycol can also be used. Fig. 5.22 shows the flow of the glycol and includes a reconcentration step. Ethylene glycol is usually regenerated to a lean concentration of about 75 or 80% by weight and is circulated at a rate such that the resulting final glycol concentration is sufficient to depress the hydrate forming

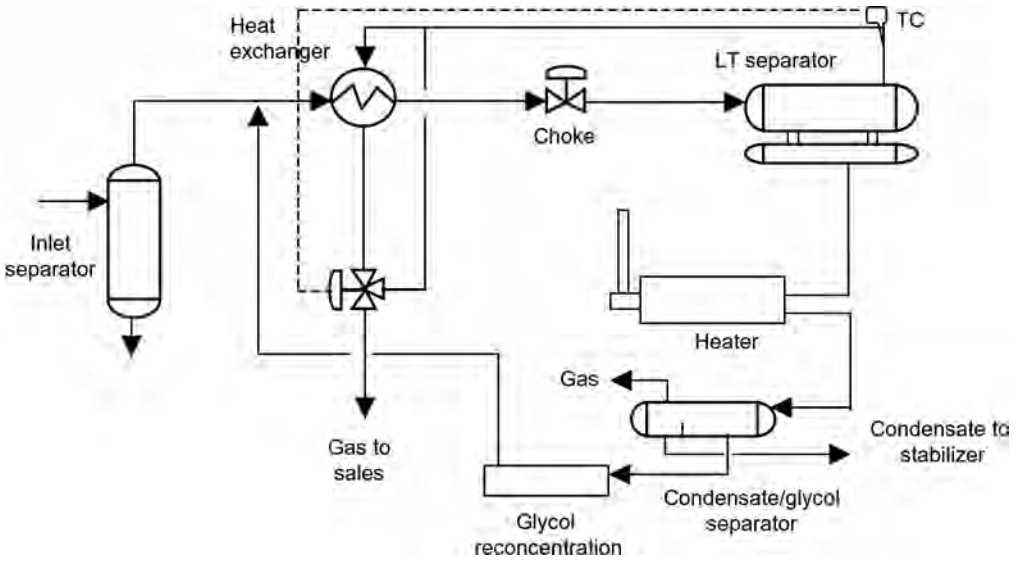


Fig. 5.22—Schematic drawing of Joule-Thomson expansion equipment.

temperature to about 5°F below the hydrate temperature of the gas at the final pressure. The required lean glycol circulation rate is determined by the Hammerschmidt equation (see the chapter on Phase Behavior of Water/Hydrocarbon Systems in the General Engineering volume of this *Handbook*) and depends on the water content of the gas, the concentration of the lean glycol, and the necessary hydrate temperature depression.

A bypass line around the heat exchanger on the cold gas out of the low temperature separator allows for the control of the degree of cooling of the process gas. To aid the separation between the cold condensate and glycol, a heater can be included in the equipment. After heating, the liquids are flowed into a three-phase separator, where the small amount of gas, the condensate, and the rich glycol are separated. The glycol is then reconcentrated with a conventional reboiler and still and is re-injected into the process gas stream.

5.36 Membrane Processing for CO_2 Removal

When natural gas contains a high concentration of CO_2, the options for reducing the CO_2 concentration to acceptable levels are either to use a regenerative solvent, such as an amine, potassium carbonate or Selexol, or to install a membrane separation process.

Separation by means of membrane technology makes use of thin layers of polymeric material.[44] This polymeric material can be manufactured in two main types—porous and nonporous. The porous membrane makes use of differences in diffusion rates and acts like a sieve in separating molecules based on relative size. The main application of this type of material is the separation of small molecules such as hydrogen or helium from gas mixtures. The nonporous membrane promotes the separation by dissolving some compounds in the polymeric material and allowing these compounds to diffuse through the material more rapidly than hydrocarbon compounds, which do not dissolve but diffuse through the material. In natural gas separation, the nonporous material is used. The compounds specifically found in natural gas, which have the ability to dissolve in the polymeric material, are the polar compounds—CO_2, H_2S, and H_2O. Hydrocarbons also diffuse through such membranes, but at a much lower rate.

The membrane material is manufactured as a very thin film, which has no strength. It is supported in applications by a porous layer, through which the gas molecules that have passed through the membrane (permeate) flow to the low pressure side. In one type of application, the

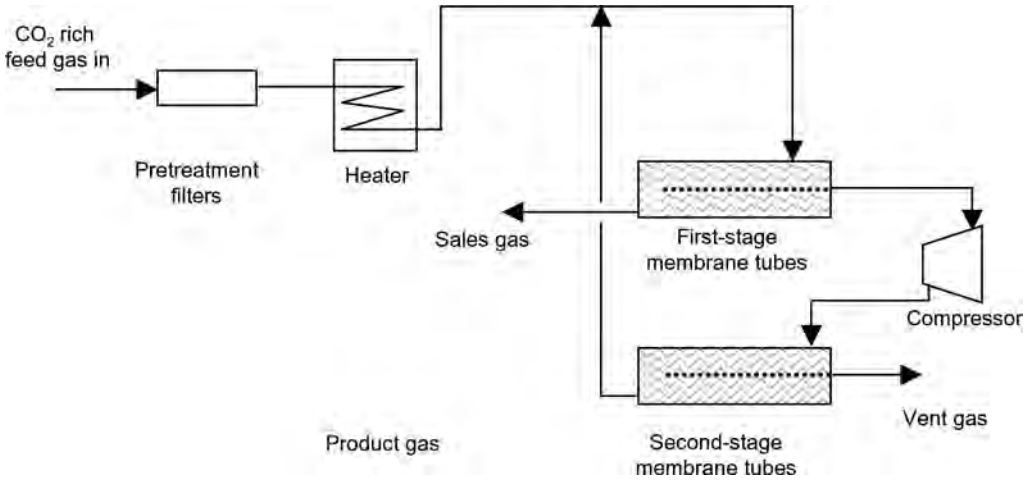


Fig. 5.23—Schematic drawing of two-stage membrane separation process equipment.

membrane and the porous permeate spacer are spirally wound around a perforated tube. A third layer is included in such construction, which is a porous feed spacer. The high-pressure gas (feed) flows through the feed spacer and is in contact with the membrane. The permeate dissolves in and/or diffuses through the membrane layer into the permeate spacer. It then flows through the permeate spacer into the perforations in the steel tube, which forms the shaft of the spirally wound layers. The high-pressure gas passes through the feed spacer to the other end, with very little pressure drop.

In the natural gas industry, membrane technology is used mainly to reduce the concentration of CO_2 from very high concentrations to acceptable levels, such as less than 2%.[45] If H_2S is present, most of the H_2S will separate. Because the sales gas specification for H_2S can be as low as 4 ppm, membrane separation is usually not sufficient to meet the specification for this compound. This process may meet the stringent specification for H_2S only if the concentration of H_2S is very low to begin with, such as perhaps 50 ppm or less.

While CO_2 is the main target for removal in natural gas processing with membranes, hydrocarbons also diffuse through the membranes. Because hydrocarbons are the valuable sales products, various process schemes are used to minimize the loss of hydrocarbons. The amount of hydrocarbon in the permeate after one pass through a permeable membrane facility depends on gas composition; system pressures (high and low); gas flow rate; and total surface area of membrane exposed to high-pressure gas.

While the permeation and potential loss of hydrocarbon is a disadvantage of membrane separation processes, there are many advantages over the alternatives for reducing CO_2 content. The advantages are low capital investment, as compared with regenerative solvent processes; ease of installation; simple operation, as the feed gas simply flows through the facility with little pressure loss; low weight and space requirements, which are important in offshore installations; low environmental impact; and no utilities requirement.

The loss of hydrocarbon in the permeate can be reduced by compressing the permeate to a high pressure and subjecting it to a second stage of separation with a membrane.[46] The resulting high-pressure stream from the second stage is then added to the high-pressure feed gas to the first stage, as shown in **Fig. 5.23**. Other permeable membrane schemes use the membrane process for bulk removal of CO_2, followed by an amine system for final cleanup.

In treating rich gas with membranes for CO_2 removal, it is necessary to preheat the feed stream so that no condensation occurs because of the high-pressure drop through the mem-

brane. The service life of the membrane material is critical to evaluating process economics relative to other methods. Service life depends on feed quality (e.g., liquid carryover, solids content, etc.) and the care with which the system is operated. In the absence of other data from similar operations, a service life of 3 to 5 years should be considered.

The analysis and design of permeable membrane systems can be investigated with a computer program available at a nominal cost from the Gas Research Institute of Chicago, now called the Gas Technology Institute (GTI). Their program MemCalc™ is a PC-based program that simulates the performance of membranes for removing CO_2 from natural gas. The program has been evaluated by several operators of membrane process facilities.

Nomenclature

AG = percent acid gas, %
d = internal diameter, inches
K = coefficient
ML = mole loading, moles/mole
MW = molecular weight, lbm/mole
P = pressure, psia
Q = gas flow rate, MMscf/d
SG = specific gravity of solution (water = 1)
T = absolute temperature, °R
V = superficial gas velocity, ft/sec
W = weight percent of solvent in solution, %
z = gas compressibility factor, dimensionless
γ = gas specific gravity (air = 1)
ρ = density, lbm/ft^3

Subscripts

a = amine
g = gas
l = liquid
s = solvent

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SI Metric Conversion Factors

Å	×	1.0*	E – 01	= nm
Btu	×	1.055 056	E + 00	= kJ
cp	×	1.0*	E – 03	= Pa s
ft^3	×	2.831 685	E – 02	= m^3
ft/sec	×	3.048*	E – 01	= m/s
°F		(°F – 32)/1.8		= °C
gal	×	3.785 412	E – 03	= m^3
in.	×	2.54*	E + 00	= cm
lbm	×	4.535 924	E − 01	= kg
psi	×	6.894 757	E + 00	= kPa

*Conversion factor is exact.

Chapter 6
Pumps

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6.1 Fluid Principles and Hydraulics

6.1.1 Types of Fluids. Pumps are used to move fluids, which include liquids, dissolved gases, and solids. Gases include dissolved air and hydrocarbon vapors. Solids include sand, clay, corrosion byproducts, and scale. The most common types of liquids pumped in upstream operations are crude oil, condensate, lube oils, glycols, amines, and water. Each fluid has different physical properties that must be taken into consideration when sizing and selecting a pump. The most important physical properties are suction pressure, specific gravity, viscosity, vapor pressure, solids content, and lubricity.

6.1.2 Types of Pumps. A pump can be defined as "a mechanical device that adds energy to a fluid to increase its flow rate and static pressure."[1] This process can be accomplished with positive-displacement pumps or kinetic-energy pumps.

Positive-Displacement Pumps. Positive-displacement pumps add energy to a fluid by applying force to the fluid with a mechanical device such as a piston, plunger, or diaphragm. There are two types of positive-displacement pumps: reciprocating and rotary. Reciprocating pumps use pistons, plungers, or diaphragms to displace the fluid, while rotary pumps operate through the mating action of gears, lobes, or screw-type shafts.

Kinetic-Energy Pumps. Kinetic energy (energy associated with motion) is added to a liquid to increase its velocity and, indirectly, its pressure. Kinetic-energy pumps operate by drawing liquid into the center of a rapidly rotating impeller. Radial vanes on the impeller throw the liquid outward toward the impeller rim. As liquid leaves the impeller, it comes in contact with the pump casing or volute. The casing is shaped to direct liquid toward a discharge port. The casing slows the liquid and converts some of its velocity into pressure. There are three classes of kinetic-energy pumps: centrifugal, regenerative-turbine, and special-effects pumps. The centrifugal-pump category includes radial-, axial-, and mixed-flow designs. Centrifugal pumps account for more than 80% of pumps used in production operations because they exhibit uniform flow, are free of low-frequency pulsations, and are not subject to mechanical problems. **Fig. 6.1** illustrates pumps commonly used in upstream production operations.

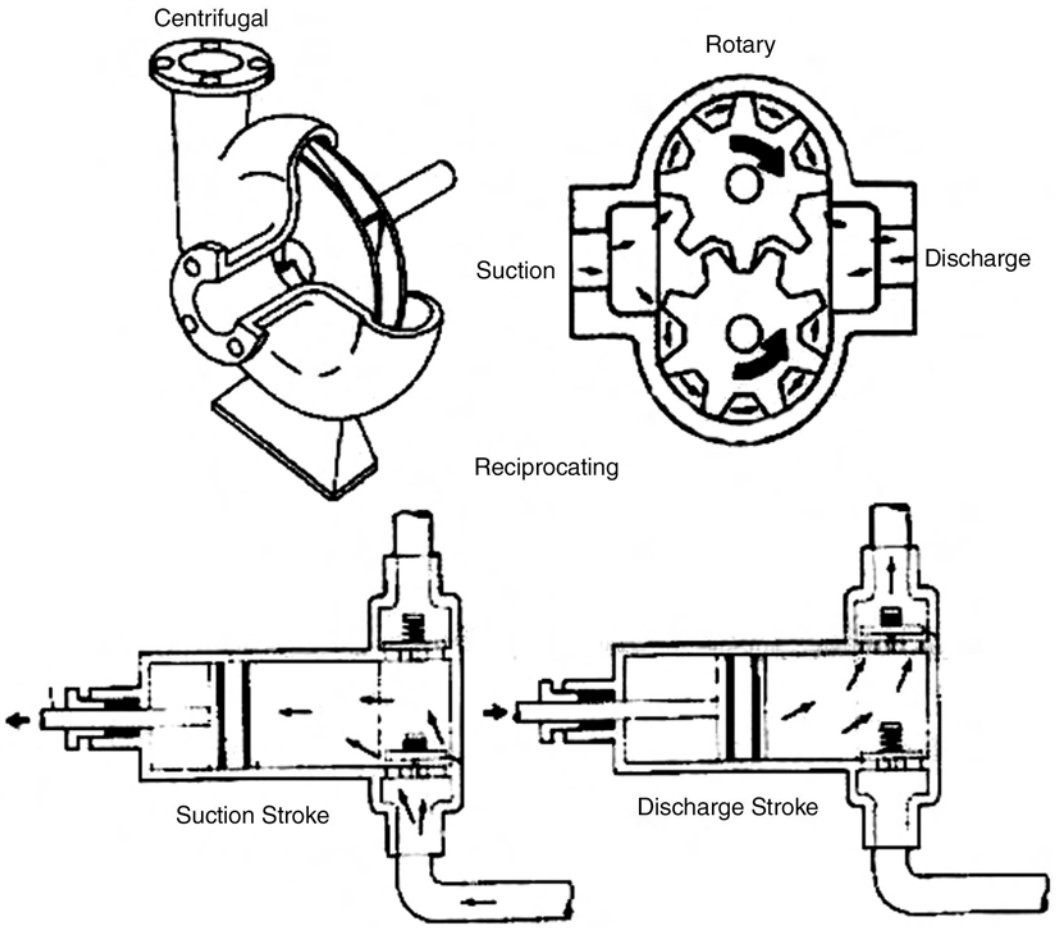


Fig. 6.1—Pumps commonly used in production operations.

6.1.3 Pumping-System Design. Designing any pumping service involves three major activities: process design, mechanical design, and vendor selection.

Process Design. The first step in process design is to obtain a design flow rate. The design flow rate should be selected after considering all flow variations, such as startup conditions, future expansion, and maximum anticipated flow. The next step is to determine the liquid properties critical to pump design. These properties include specific gravity, temperature, viscosity, pour point, etc. Values are required at pumping conditions and, in some cases, at ambient conditions as well. The next step is to calculate available suction conditions such as rated suction pressure, maximum suction pressure, and net positive suction head available (NPSHA). (See Sec. 6.2.3 for information on NPSHA.) Once the available suction conditions have been established, the effect of the selected control system on pump performance requirements must be determined (see Sec. 6.3.10). The next step is to calculate the minimum discharge-pressure requirements of the pump. The last step is to calculate the total dynamic head (TDH) at the specific gravity corresponding to rated pumping temperature.

Mechanical Design. The first step in mechanical design is to determine the design pressure and temperature required for the pump and its associated piping. Once this is done, a pump type and materials of construction are selected. The next step is to determine the sparing (back-up) requirements, the need for parallel operation and control-system details. Then select a shaft-

seal type and determine the requirements for an external flushing or sealing system and estimate the power requirements and choose a driver (motor, engine, or turbine) for the pump. Lastly, document the design by including calculations, studies, design specifications, utility requirements, and estimate summary.

Vendor Selection. Factors that have the greatest influence on the selection of the most cost-effective pump type include capacity, TDH, maintenance, viscosity, and capacity control. Within the general type selections, a particular construction style is most influenced by discharge pressure, NPSHA, fluid temperature, and space and weight limitations.

6.2 Hydraulic Principles

6.2.1 Introduction. Hydraulics deals with the mechanical properties of water and other liquids and the application of these properties to engineering. Hydraulics is divided into two areas: hydrostatics (fluids at rest) and hydrodynamics (fluids in motion).

6.2.2 Hydrostatics. A liquid has a definite volume when compared to a gas, which tends to expand to fit its container. When unconfined, a liquid seeks the lowest possible level. Because of its fluidity, a liquid will conform to the shape of its container.

Pressure. The pressure existing at any point in a liquid body at rest is caused by the atmospheric pressure exerted on the surface plus the weight of the liquid above that point. This pressure is equal in all directions.

Temperature. For most liquids, an increase in temperature decreases viscosity, decreases specific gravity, and increases volume. Temperature affects the type of pump construction, material selection, corrosive properties of the fluid, and the pump's flange pressure/temperature rating.

Air Properties. Air is a mixture of oxygen, nitrogen, and other compounds. The standard pressure of air is defined at 60°F, 36% relative humidity, and sea level. The weight of a column of air above the Earth's surface at 45° latitude and sea level is 14.696 psia (29.92 in. of mercury). Atmospheric pressure decreases by approximately 0.5 psi for each 1,000 ft of elevation above sea level.

Head. The relationship of head to pressure is expressed as

$$h = 2.31 p / \gamma , \quad \text{..... (6.1)}$$

where h = height of the fluid column above a reference point, and p = pressure. The head of liquid is not related to the area occupied by the liquid. **Fig. 6.2** illustrates types of head.

$$\gamma = \rho_f / \rho_w , \quad \text{..... (6.2)}$$

where γ = specific gravity of the liquid, ρ_f = density of the liquid being pumped, and ρ_w = density of water at standard conditions of temperature and pressure.

It is important to realize that although the heads of different liquids are the same, their pressures are different because of the differences in specific gravities. For example, assume three 100-ft-tall tanks filled with gasoline, water, and molasses, respectively. The pressure measured at the bottom of each tank is different because of the differences of specific gravities of gasoline (0.75), water (1.0), and molasses (1.45).

Centrifugal-Pump Considerations. Operating pressure is expressed in feet of the liquid that is being pumped. Suction and discharge pressures are expressed as suction head and discharge head, respectively. Pressures are expressed in feet of head, because it is more important to

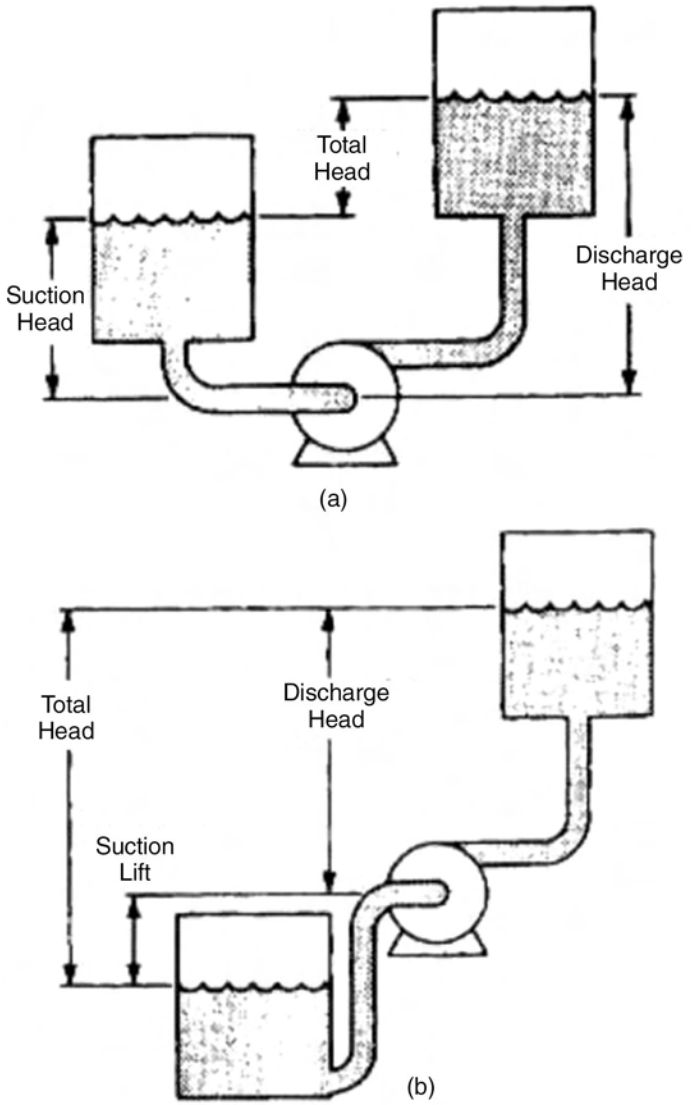


Fig. 6.2—Types of head.

know how much a pump can raise the liquid it is pumping, rather than the amount of pressure the pump is adding to the liquid.

Positive-Displacement-Pump Considerations. Operating pressures are almost always expressed in terms of pressure (psi).

Static Head, Static Lift, and Submergence Terminology. Fig. 6.3 illustrates the relationship between static head, static lift, and submergence. Static head is the vertical distance between a liquid level and a datum line, when the supply is above the datum. Static lift is the vertical distance between a liquid level and a datum level, when the datum is above the liquid. Datum line is the centerline of the pump inlet connection, or the horizontal centerline of the first-stage impeller in vertical pumps.

Theoretical Lift. A pump that develops a perfect vacuum at its suction end can lift a column of water 34 ft. This vertical distance is called theoretical lift. The pressure to lift the

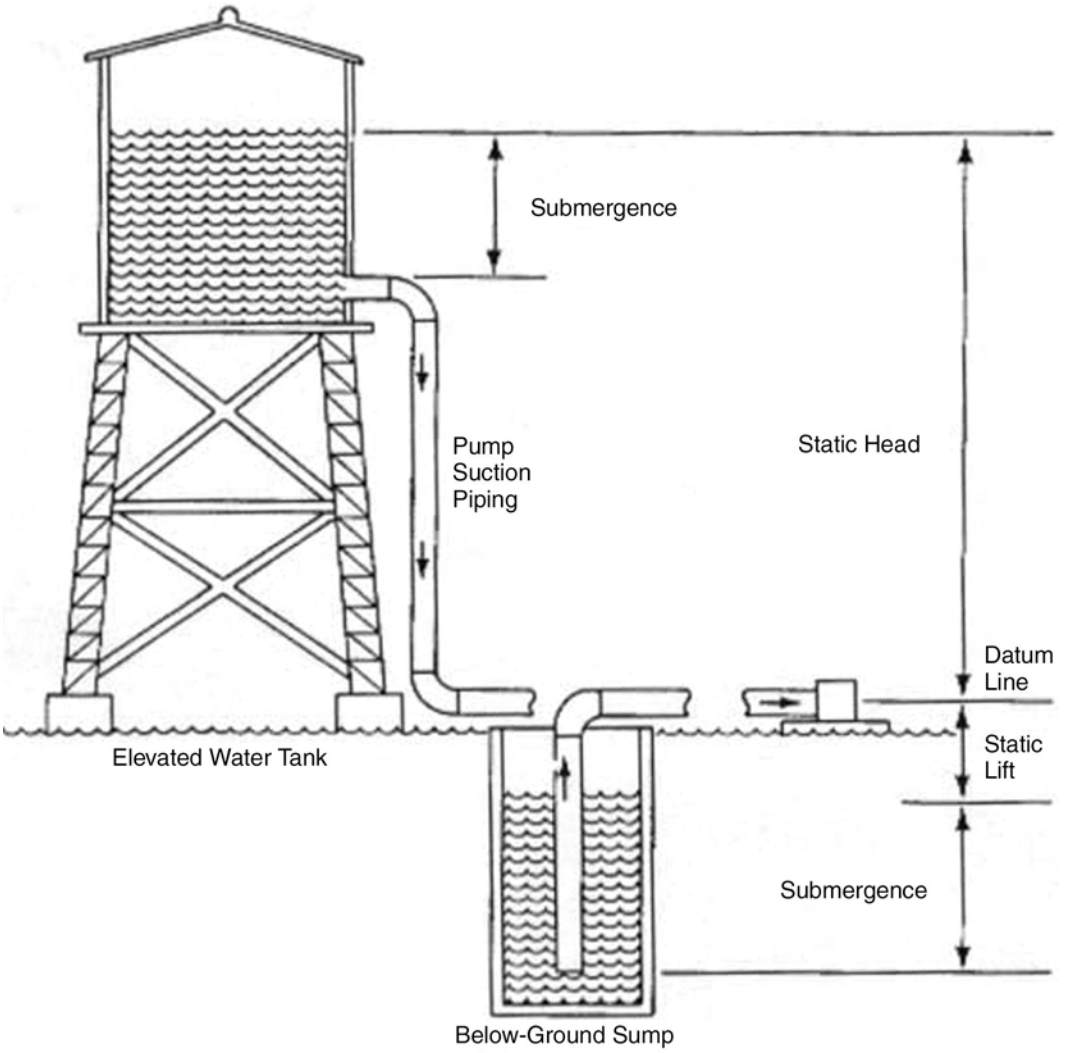


Fig. 6.3—Relationship between static head, static lift, and submergence.

liquid comes from atmosphere pressure. At sea level, atmosphere pressure is approximately 14.7 psia.

Actual Suction Lift. Because a perfect vacuum is never achieved and because some lift is lost to friction in the suction line, the maximum actual suction lift for a positive-displacement pump is approximately 22 ft. The maximum actual suction lift for a centrifugal pump is approximately 15 ft when pumping water from an open air tank. Positive-displacement pumps can operate with lower suction pressures or high suction lifts because they can create stronger vacuums. Suction lift will be greater if the pressure in a closed tank is greater than atmospheric pressure.

Submergence. Submergence is often confused with either suction static head or static lift. For vertical pumps, submergence relates the liquid level to the setting of the pump. For horizontal pumps, submergence relates to the height of liquid level necessary in the source vessel or tank to prevent the formation of vortexing and the resulting flashing of vapors in the pump suction.

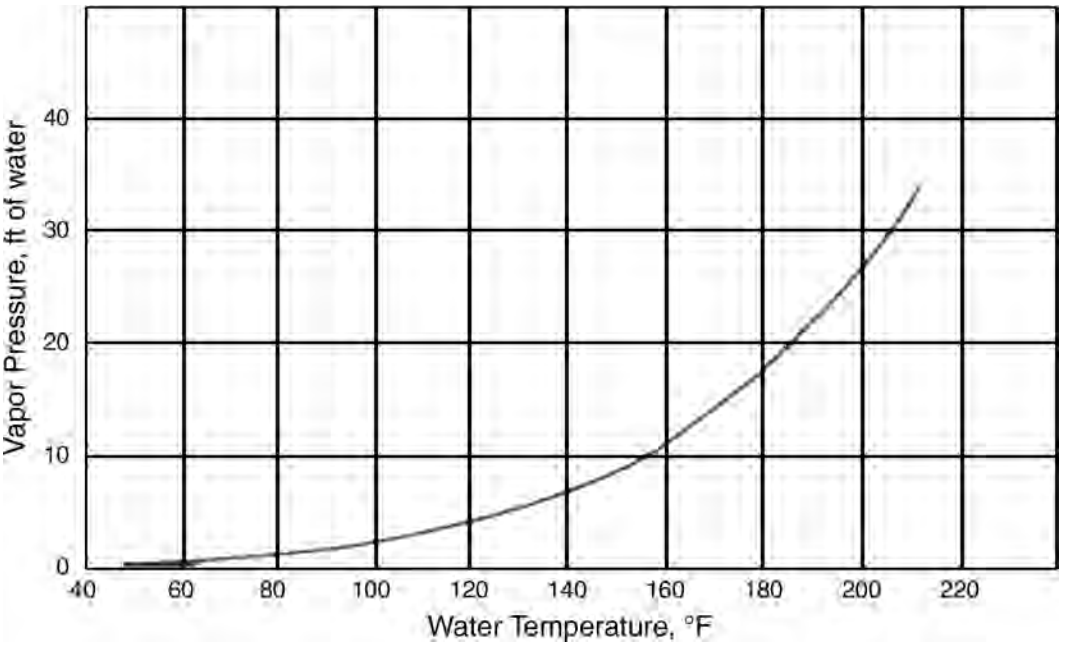


Fig. 6.4—Vapor pressure of water for various temperatures.

Vapor Pressure. As the pressure on a liquid is decreased, there is a tendency for the bubbles of vapor to be liberated. The vapor pressure of a liquid is the pressure at which the first bubble of vapor appears at a given temperature. At 60°F, the vapor pressure of water is 0.3 psia (0.7 ft). At 212°F, the vapor pressure of water is 14.7 psia (34 ft). **Fig. 6.4** illustrates the vapor pressure of water for various temperatures. For other fluids, refer to standard references (e.g., Ref. 1).

Suspended Solids. The amount and type of suspended solids entrained in the liquid can affect the characteristics and behavior of that liquid. Increased concentrations of solids increase the specific gravity, viscosity, and abrasiveness of a liquid. The type and concentration of suspended solids can affect the style of pump selected and the materials of construction. Suspended solids also affect the selection of impeller design in centrifugal pumps, which in turn affects the wear rate, efficiency, and power consumption.

Dissolved Gases. Small amounts of dissolved gases have little effect on flow rate or other pumping requirements. If large amounts of gas enter the liquid through piping leaks or as a result of vortexing in vessels, the specific gravity of the liquid will decrease. Dissolved gases can also reduce the amount of NPSHA at the pump suction. (See Sec. 6.2.3 for a discussion of NPSHA).

Viscosity. Viscosity offers resistance to flow because of friction within the fluid. Viscosity levels have a significant impact on pump type selection, efficiency, head capacity, and warm-up. High-viscosity liquids decrease a centrifugal pump's efficiency and head performance, while increasing the power requirements. The viscosity of all liquids varies with temperature. For viscosities of liquids, refer to standard industry references (e.g., Ref. 1).

Corrosivity. The corrosive nature of the fluid being pumped has a bearing on pump type selection, materials of construction, and corrosion allowance. Special mechanical seals and flushing arrangements may be required.

6.2.3 Hydrodynamics. Hydrodynamics is the study of fluids in motion. Bernoulli's equation states that

$$v_1^2/2g + p_1/\rho + Z_1 = v_2^2/2g + p_2/\rho + Z_2 + h_f\ , \quad \text{..... (6.3)}$$

where v = average velocity of the liquid in the pipe, g = acceleration of gravity, p = pressure, ρ = density, Z = height above a datum, and h_f = friction loss between points 1 and 2. Subscripts 1 and 2 refer to locations along a pipe. An examination of each of the terms in Eq. 6.3 provides a better understanding of the general equation for modeling a pumping system.

Velocity Head. Velocity head is the potential energy that has been converted to kinetic energy. Velocity head can be expressed as

$$v^2/2g = 0.00259Q^2/d^4 \quad \text{..... (6.4)}$$

$$\text{or}\ \ v^2/2g = 0.0155v^2\ , \quad \text{..... (6.5)}$$

where Q = flow rate, and d = inside pipe diameter.

The velocity head increases the amount of work required of a pump. The velocity head is usually not included in actual system calculations when piping velocities are kept within the prescribed limits of 3 to 15 ft/sec. The velocity head is included in the total dynamic head on the centrifugal-pump curves.

Pressure Head. The energy contained in the liquid is expressed as pressure head and expressed as p/ρ in Eq. 6.3.

Elevation Head. The energy contained in the liquid as a result of its elevation relative to a datum is called the elevation head and is expressed as Z in Eq. 6.3.

Head Losses. Head losses are potential energy that has been lost because of frictional resistance of the piping system (pipe, valves, fittings, and entrance and exit losses). Unlike velocity head, friction head cannot be ignored in system calculations. Head loss values vary as the square of the flow rate. Head losses can be a significant portion of the total head. See the chapter on Piping and Pipelines in this volume of the *Handbook* for a discussion of pressure drop (i.e., head losses in piping).

Control Losses. Control losses occur on the discharge side of a centrifugal pump that has been equipped with a backpressure valve to control flow rate. As the liquid flows through the control valve, energy is lost. Next to static head, control losses are frequently the most important factor in calculating the pump's total dynamic head. For pump applications, control losses are treated separately from head losses, even though they are included in the h_f term in Eq. 6.3.

Acceleration Head. Acceleration head is used to describe the losses associated with the pulsating flow of reciprocating pumps. Theoretically, acceleration head should be included in the h_f term of Eq. 6.3. Ref. 1 discusses the calculation of acceleration head.

Total Dynamic Head. TDH is the difference between the pumping system's discharge head and suction head. It is also equal to the difference in pressure-gauge readings (converted to feet) across an existing operating pump (discounting velocity head).

Suction Head. Suction head is defined as the sum of the suction-vessel operating gauge pressure (converted to feet), the vertical distance between the suction-vessel liquid level and the pump reference point, less head losses in the suction piping [discounting change in velocity,

$$(p_{f1} \times 2.31)/\gamma\ , \quad \text{..... (6.6)}$$

and acceleration head]. Suction head can be expressed as

$$H_s = (p_1 \times 2.31/\gamma) + H_1 - (p_{f1} \times 2.31/\gamma)\,, \quad \text{..... (6.7)}$$

which can be reduced to

$$H_s = [(p_1 - p_{f1}) \times 2.31]/\gamma + H_1\,, \quad \text{..... (6.8)}$$

where H_s = suction head of liquid being pumped, p_1 = suction-vessel operating pressure, H_1 = height of liquid suction vessel above pump reference point, and p_{f1} = pressure drop resulting from friction in the suction piping.

Discharge Head. Discharge head is defined as the sum of the discharge-vessel operating gauge pressure (converted to feet), the liquid level in the discharge vessel above the pump reference point, pressure drop because of friction in the discharge piping, and control losses (discounting velocity head). It can be expressed as

$$H_d = [(p_2 \times 2.31)/\gamma] + H_2 + [(p_{f2} \times 2.31)/\gamma] + [(P_c \times 2.31)/\gamma]\,, \quad \text{..... (6.9)}$$

which can be reduced to

$$H_d = \{[(p_2 + p_{f2} + P_c) \times 2.31]/\gamma\} + H_2\,, \quad \text{..... (6.10)}$$

where H_d = discharge head of liquid being pumped, p_2 = discharge-vessel operating pressure, H_2 = operating or normal height of liquid in the discharge vessel above the pump reference, p_{f2} = pressure drop resulting from friction in the discharge piping, and P_c = discharge flow-control-valve losses.

Calculating TDH. The pump TDH is the difference between the suction and discharge heads.

$$H_{td} = H_d - H_s\,, \quad \text{..... (6.11)}$$

which can be substituted as

$$H_{td} = \{[(p_2 - p_1 + p_{f1} + p_{f2} + P_c) \times 2.31]/\gamma\} + H_2 - H_1\,, \quad \text{..... (6.12)}$$

where H_{td} = total dynamic head required of a pump.

Net Positive Suction Head (NPSH). NPSH is defined as the total suction head in feet of liquid (absolute at the pump centerline or impeller eye) less the vapor pressure (in feet) of the liquid being pumped.

Net Positive Suction Head Required. Net positive suction head required (NPSHR) is defined as the amount of NPSH required to move and accelerate the liquid from the pump suction into the pump itself. It is determined either by test or calculation by the pump manufacturer for the specific pump under consideration. NPSHR is a function of liquid geometry and the smoothness of the surface areas. For centrifugal pumps, other factors that control NPSHR are the type of impeller, design of impeller eye, and rotational speeds. NPSHR is determined on the basis of handling cold water. Field experience coupled with laboratory testing have confirmed that centrifugal pumps handling gas-free hydrocarbon liquids and water at elevated temperatures will operate satisfactorily, with harmless cavitation and less NPSHR than would be required for cold water.

Net Positive Suction Head Available. NPSHA must be equal to or greater than NPSHR. If this is not the case, cavitation or flashing may occur in the pump suction. Cavitation occurs

when small vapor bubbles appear in the liquid because of a drop in pressure and then collapse rapidly with explosive force when the pressure is increased in the pump. Cavitation results in decreased efficiency, capacity, and head and can cause serious erosion of pump parts. Flashing causes the pump suction cavity to be filled with vapors and, as a result, the pump becomes vapor locked. This usually results in the pump freezing up, which is called pump seizure.

NPSHA is not a function of the pump itself but of the piping system for the pump. It can be calculated from

$$H_A = \left\{[(p_1 + p_A - p_{va} - p_{f1}) \times 2.31]/\gamma\right\} + H_1 , \quad \text{..... (6.13)}$$

where p_A = atmospheric pressure and p_{va} = liquid vapor pressure at pumping temperature.

NPSHA decreases with increases in liquid temperature and pipe friction losses. Because pipe friction losses vary as the square of the flow, NPSHA also varies as the square of the flow. Thus, NPSHA will be the lowest at the maximum flow requirement. Accordingly, it is important to recognize the need for calculating NPSHA (and NPSHR) at maximum flow conditions as well as maximum fluid temperature, not just at design conditions. Unless subcooled, a pure-component hydrocarbon liquid is typically in equilibrium with the vapors in a pressure vessel. Thus, increases in the vessel operating pressures are almost fully offset by a corresponding increase in the vapor pressure. When this occurs,

$$H_A = H_1 - (p_{f1} \times 2.31)/\gamma . \quad \text{..... (6.14)}$$

NPSH Margin. The NPSH margin is NPSHA less the NPSHR. The Hydraulic Inst. recommends an NPSH margin of 3 to 5 ft.[1]

When a new system offers insufficient NPSH margin for optimum pump selection, either the NPSHA must be increased, the NPSHR must be decreased, or both. To increase the NPSHA, one can raise the liquid level, lower the elevation of the selected pump, change to a low-NPSHR pump, or cool the liquid. To reduce the NPSHR, one can use different design impellers or inducers or use several smaller pumps with lower NPSHRs in parallel.

When an existing pumping system exhibits insufficient NPSH margin, it is too late to use these solutions without going through an expensive change. Most of these problems can be traced to suction flow restrictions (orifice plates, plugged strainers, partially closed valves, etc.) and inadequate source-tank liquid levels.

Power Requirements. Once the TDH has been calculated, the power requirements can be determined with

$$P_B = P_H / e . \quad \text{..... (6.15)}$$

For kinetic-energy pumps,

$$P_B = (q \times H_{td} \times \gamma)/3{,}960e . \quad \text{..... (6.16)}$$

For positive-displacement pumps,

$$P_B = (q \times \Delta p)/1{,}714e, \quad \text{..... (6.17)}$$

where P_B = brake horsepower, and e = the pump efficiency factor obtained from the pump manufacturer. For electric-motor-driven pumps, the energy consumption can be estimated with

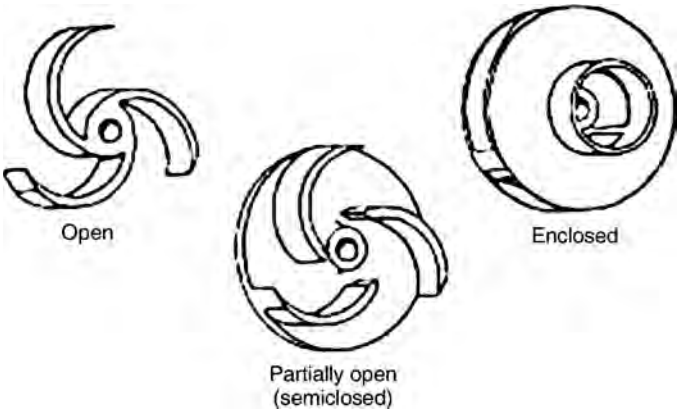


Fig. 6.5—Basic types of impellers.

$$E/t = 17.9P_B/e_m \ . \quad \text{..... (6.18)}$$

6.3 Centrifugal Pumps

6.3.1 Introduction. Centrifugal pumps are the most commonly used kinetic-energy pump. Centrifugal force pushes the liquid outward from the eye of the impeller where it enters the casing. Differential head can be increased by turning the impeller faster, using a larger impeller, or by increasing the number of impellers. The impeller and the fluid being pumped are isolated from the outside by packing or mechanical seals. Shaft radial and thrust bearings restrict the movement of the shaft and reduce the friction of rotation.

6.3.2 Basic Classifications. Centrifugal pumps are designed with respect to the number of suctions (single or double), number of impellers (single, double, or multistage), output, and impellers (type, number of vanes, etc.). Most impellers are arranged from one side only and are called single-suction design. High-flow models use impellers that accept suction from both sides and are called double-suction design.

6.3.3 Impeller Types. The efficiency of a centrifugal pump is determined by the impeller. Vanes are designed to meet a given range of flow conditions. Fig. 6.5 illustrates the basic types of impellers.

Open Impellers. Vanes are attached to the central hub, without any form, sidewall, or shroud, and are mounted directly onto a shaft. Open impellers are structurally weak and require higher NPSHR values. They are typically used in small-diameter, inexpensive pumps and pumps handling suspended solids. They are more sensitive to wear than closed impellers, thus their efficiency deteriorates rapidly in erosive service.

Partially Open (Semiclosed) Impellers. This type of impeller incorporates a back wall (shroud) that serves to stiffen the vanes and adds mechanical strength. They are used in medium-diameter pumps and with liquids containing small amounts of suspended solids. They offer higher efficiencies and lower NPSHR than open impellers. It is important that a small clearance or gap exists between the impeller vanes and the housing. If the clearance is too large, slippage and recirculation will occur, which in turn results in reduced efficiency and positive heat buildup.

Closed Impellers. The closed impeller has both a back and front wall for maximum strength. They are used in large pumps with high efficiencies and low NPSHR. They can operate in suspended-solids service without clogging but will exhibit high wear rates. The closed-

impeller type is the most widely used type of impeller for centrifugal pumps handling clear liquids. They rely on close-clearance wear rings on the impeller and on the pump housing. The wear rings separate the inlet pressure from the pressure within the pump, reduce axial loads, and help maintain pump efficiency.

6.3.4 Number of Impellers. ***Single-Stage Pumps.*** The single-stage centrifugal pump, consisting of one impeller, is the most widely used in production operations. They are used in pumping services of low-to-moderate TDHs. The TDH is a function of the impeller's top speed, normally not higher than 700 ft/min. Single-stage pumps can be either single or double suction. The single-stage pump design is widely accepted and has proved to be highly reliable. However, they have higher unbalanced thrust and radial forces at off-design flow rates than multistage designs and have limited TDH capabilities.

Multistage Pumps. The multistage centrifugal pump consists of two or more impellers. They are used in pumping services of moderate-to-high TDHs. Each stage is essentially a separate pump. All the stages are within the same housing and installed on the same shaft. Eight or more stages can be installed on a single horizontal shaft. There is no limit to the number of stages that can be installed on a vertical shaft. Each stage increases the head by approximately the same amount. Multistage pumps can be either single or double suction on the first impeller.

6.3.5 Impeller Axial Loading. A single-suction, enclosed or semienclosed impeller is inherently subject to continual end thrust. The thrust is directed axially toward the suction because of the low pressures that exist in the impeller eye during pump operation. This thrust is handled with a thrust bearing. The larger the TDH and the larger the impeller-eye diameter, the larger the thrust. Excessive thrust results in bearing and seal damage.

Thrust can be reduced by designing a single-stage impeller for a double suction. In multistage pumps, thrust can be reduced by facing half the impellers in one direction and half in the other. Balancing holes can be used in single-suction, single-stage pumps. The impeller is cored at the rear shroud to allow high-pressure liquid to flow back to the impeller eye.

6.3.6 Impeller Radial Loading. As the fluid leaves the top of the rotating impeller, it exerts an equal and opposite force on the impeller, shaft, and radial bearings. At the best-efficiency point (BEP), the sum of all radial forces nearly cancels each other out. At capacities below or above the BEP, forces do not cancel out completely because the flow is no longer uniform around the periphery on the impeller. Radial forces can be significant. Heavy-duty radial bearings may be required in lieu of the manufacturer's standard when pump operation departs significantly from the BEP.

6.3.7 Pump Specific Speed. Pump specific speed is the speed in revolutions per minute required to produce a flow of 1 gal/min with a TDH of 1 ft, with an impeller similar to the one under consideration but reduced in size. The pump specific speed links the three main components of centrifugal-pump performance characteristics into a single term. It is used to compare two centrifugal pumps that are geometrically similar. Pump specific speed can be calculated from

$$N_s = \frac{N\sqrt{q}}{\left(H_{td}'\right)^{0.75}}, \quad \text{..... (6.19)}$$

where N_s = pump specific speed, N = pump rotative speed, q = pump capacity, and H_{td}' = TDH per stage at the BEP.

The pump specific speed is always calculated at the pump's point of maximum efficiency. The number is used to characterize a pump's performance as a function of its flowing parame-

ters. Normally, it is desirable to select the impeller with the highest specific speed (smallest diameter). This may be offset by the higher operating cost associated with higher speeds and greater susceptibility to cavitation damage.

Impellers With Low Specific Speeds (500 to 4,000). Radial-flow impellers typically have low specific speeds. Radial-flow impellers are narrow and relatively large in diameter and are designed for high TDHs and low flow capacity. The pumped fluid undergoes a 90° turn from inlet to outlet of the impeller.

Impellers With Median Specific Speeds (4,000 to 10,000). Mixed-flow impellers typically have medium specific speeds and are wider and smaller in diameter than radial-flow impellers. They exhibit medium TDH and medium flow capability. They are typically used in vertical multistage pumps and downhole electrical submersible pumps, which require small diameters.

Impellers With High Specific Speeds (10,000 to 16,000). Axial-flow impellers typically have high specific speeds. In these impellers, the liquid flow direction remains parallel to the axis of the pump shaft. Axial-flow impellers are used for high flow and low TDH applications. They are most commonly used for water irrigation, flood control, pumped storage power-generation projects, and as ship impellers.

6.3.8 Pump-Performance Curves. When a pump manufacturer develops a new pump, the new pump is tested for performance under controlled conditions. The results are plotted to show flow rate vs. head, efficiency, and power consumption. These graphs are known as performance curves. Under similar operating conditions, an installed pump is expected to demonstrate the same performance characteristics as shown on the performance curves. If it does not, this indicates that something is wrong with the system and/or pump. Comparison of actual pump performance with rated performance curves can help determine pump malfunction.

Curve Performance. The impeller shape and speed is the primary determinant of pump performance. Fig. 6.6 illustrates a generalized centrifugal-pump curve. Head, NPSHR, efficiency, horsepower, and brake-horsepower (BHP) requirements vary with flow rate. The TDH is greatest at zero capacity (shutoff head) and then falls off with increasing flow rates. The horsepower curve starts out at some small value at zero flow, increases moderately up to a maximum point, and then tapers off slightly. The pump efficiency curve starts out at zero, increases rapidly as flow increases, levels off at the BEP, and decreases thereafter. The NPSHR is a finite value at zero flow and increases as the square of the increase in flow rate.

Curve Parameters. It is best to operate the pump at the BEP, but this is not normally feasible. Alternatively, the pump should operate only in the area of the curve closest to the BEP and only in the moderately sloping portion of the head curve. Operating in the flat or steeply sloping portions of the curve results in wasted energy and flow control instability. Pumps that run at or near BEP run smoother and have better run lives. Any time the actual flow drops to less than 50% of the BEP flow, it is wise to consult the manufacturer because shaft deflections may increase dramatically (especially with single-stage overhung-design pumps), which could lead to higher maintenance costs and to failures.

Pumps in Parallel. Fig. 6.7 illustrates the shape the TDH-vs.-capacity curve assumes when identical pumps are operated in parallel and series. Parallel operation occurs where multiple pumps are piped to the same suction and discharge lines. The combined flow rate is the total of the individual pump flows at the TDH. In most cases, the head capacity curves of the parallel pumps are the same, or nearly so. It is not necessary for the curves to be the same as long as each pump operating in parallel can put out the desired TDH.

All centrifugal pumps discharging to an elevated or pressurized vessel and all centrifugal pumps operating in parallel should have check valves in the event of a pump shutdown to keep the pump from spinning backwards. (The danger is a sheared shaft on restart attempt.)

Driver size should be selected so that overloading does not occur at any point across the entire pump curve. Flow orifices or meters should be provided in each pump's discharge line

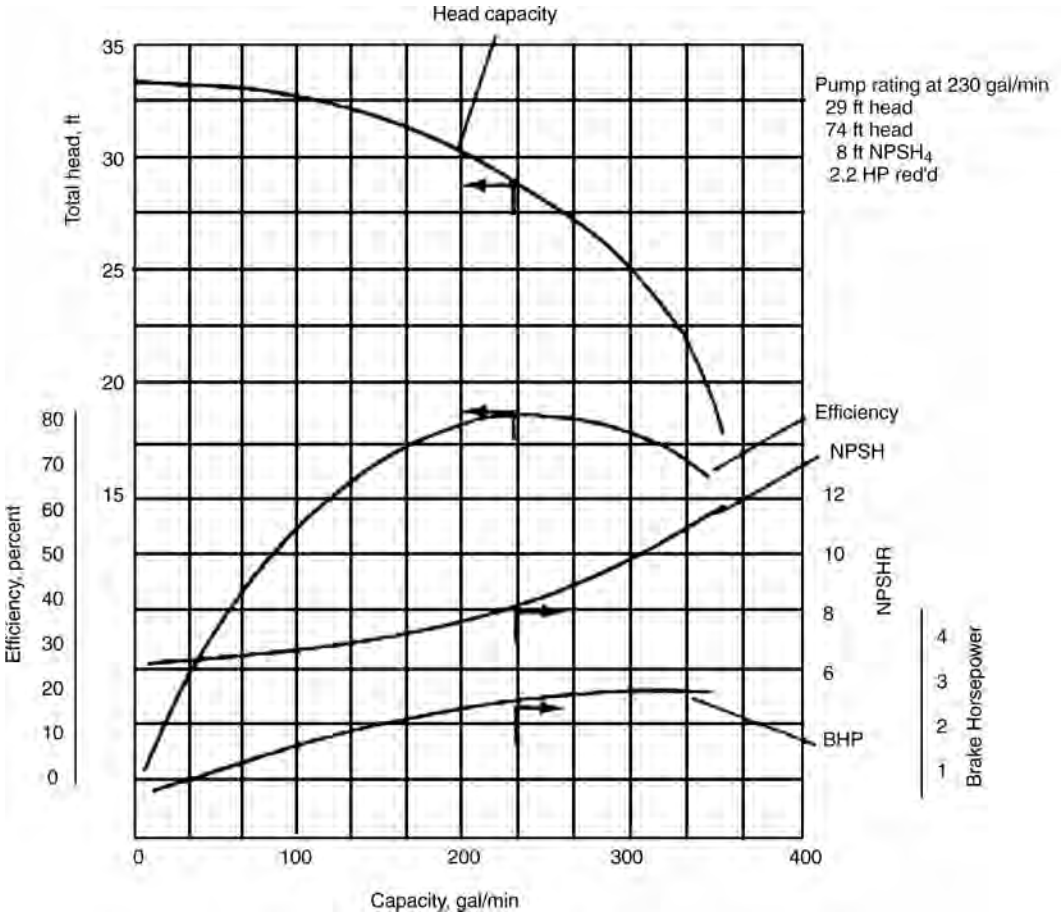


Fig. 6.6—Characteristic pump-performance curve.

for verification of flow rates. Suction and discharge piping should be arranged as symmetrically as practical so that all pumps have the same NPSHA.

Series Operation. Series operation is used when a single pump cannot develop the total TDH required. It is also used when a low NPSHR is used to feed a larger pump that requires an NPSHR that cannot be provided from an atmospheric tank or vessel operating at its bubble-point. In series operation, the combined head is the sum of the individual-pump TDHs at the same flow.

6.3.9 System Head Curves. The system head curve is a graphical representation of TDH required to be furnished by the pump vs. the flow rate through the piping system. It consists of a constant (static) and an increasing (variable) portion. **Fig. 6.8** illustrates an example of a typical system head curve.

The constant portion represents the static head difference between the suction and the discharge at zero flow and is equal to

$$H_{ws} = \{[(p_2 - p_1) \times 2.31]/\gamma\} + (H_2 - H_1) \ . \quad \text{..... (6.20)}$$

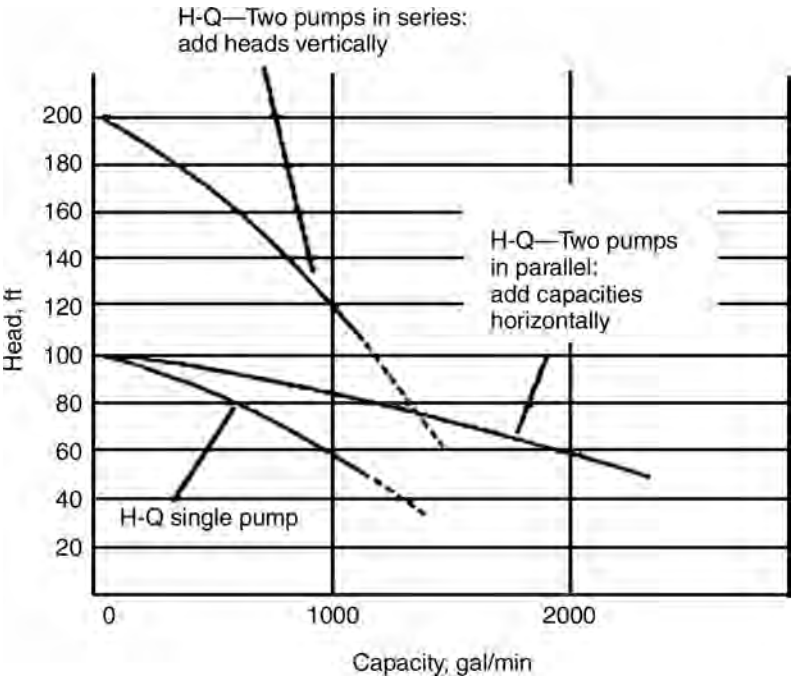


Fig. 6.7—Head capacity curve for parallel and series pump operation.

The variable portion represents the head required to overcome friction as a result of flow. It varies as the square of the flow and is equal to

$$H_V = [(p_{f1} + p_{f2} + P_c) \times 2.31]/\gamma\,, \quad \text{..... (6.21)}$$

where p_{f1} = pressure drop resulting from friction in the suction piping, p_{f2} = pressure drop resulting from friction in the discharge piping, and P_c = discharge flow-control-valve losses.

6.3.10 Regulation of Flow Rate. It is unusual for a system to require operation at a single fixed flow rate. A pump will deliver only the capacity that corresponds to the intersection of the TDH capacity and system head curves. To vary the capacity, one must change the shape of one or both curves. The head-capacity-curve shape can be changed by altering the pump speed or impeller diameter. The system-head-curve shape can be changed by the use of a backpressure throttling valve (see Sec. 6.3.11).

The effects of operating at significantly reduced capacity may lead to operating at much less than the BEP, higher energy consumption per unit capacity, high bearing loads, temperature rise, and internal circulation. These results can be minimized with the use of a variable-speed driver or with the use of several parallel pumps for the total capacity and sequentially shutting down individual units as demand requires.

Higher bearing loads will exist for any flow that departs from the BEP, especially for single-stage, single-suction pumps. This can be anticipated by specifying certain types of heavy-duty and long-life bearings. If the temperature of the pumped fluid rises and the flow rate through the pump decreases, minimum-flow recirculation can be used (see Sec. 6.3.12). The manufacturer generally provides the minimum continuous required flow rate for any pump selection. Operating between the BEP and minimum required flow rate generally avoids all the problems discussed.

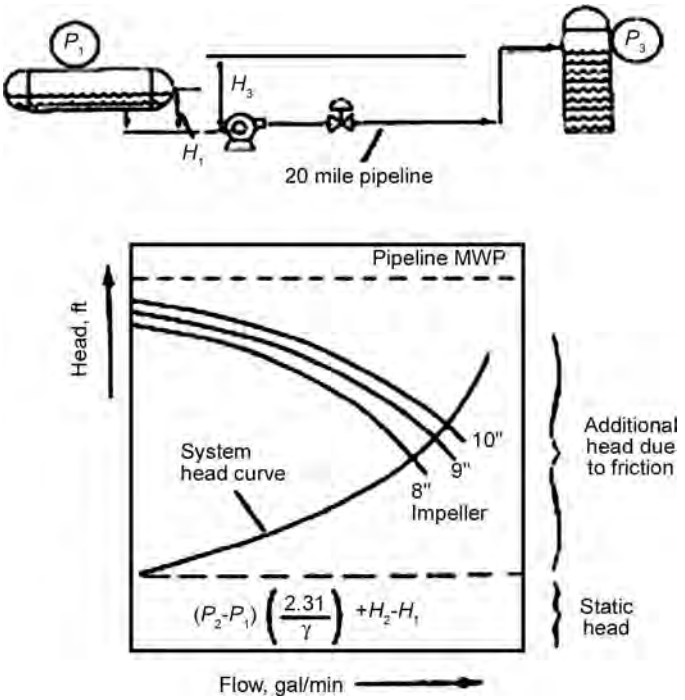


Fig. 6.8—Example of a typical system head curve.

6.3.11 Backpressure Valves. The difference between the TDH developed by the pump and the head required by the system head curve represents lost energy. Because most centrifugal pumps are driven by constant-speed electric motors, throttling is the only practical method of regulating capacity. The backpressure valve imposes a variable amount of loss on the system head curve. Closing the valve increases control losses and causes the system head curve to slope up more steeply to intersect the TDH capacity curve at the desired capacity. Opening the valve decreases the control losses and causes the system head curve to slope downward and intersect the TDH capacity curve at a higher capacity. With the valve completely open, the capacity is governed only by the intersection of the two curves.

6.3.12 Minimum-Flow Recirculation Valve. The recirculation valve prevents the buildup of excessive amounts of heat within the casing. A minimum-flow recirculation valve should be installed if the pump piping system contains a backpressure valve that could close and result in less than the minimum continuous flow at which the pump can safely operate. A recirculation valve is often used in installations in which the pump piping contains an automatic shutdown discharge valve that could fail in the closed position, or a discharge block valve that can be inadvertently closed. The recirculation valve should be upstream of the first block valve or control valve downstream of the pump. On small pumps, an orifice is usually installed on the recirculation, which continuously recirculates a fixed flow of liquid back to the suction. A control valve costs more but will modulate the recirculation to assure only minimum flow and thus result in less energy loss.

6.3.13 Changing Performance. The maximum head that a centrifugal pump can develop is determined by speed, impeller diameter, and number of stages. Thus, to change the head of a pump, one or more of these factors must be changed. Speed can be changed with different gears, belts, or pulleys, or by installing a variable-speed driver. The impeller diameter can be

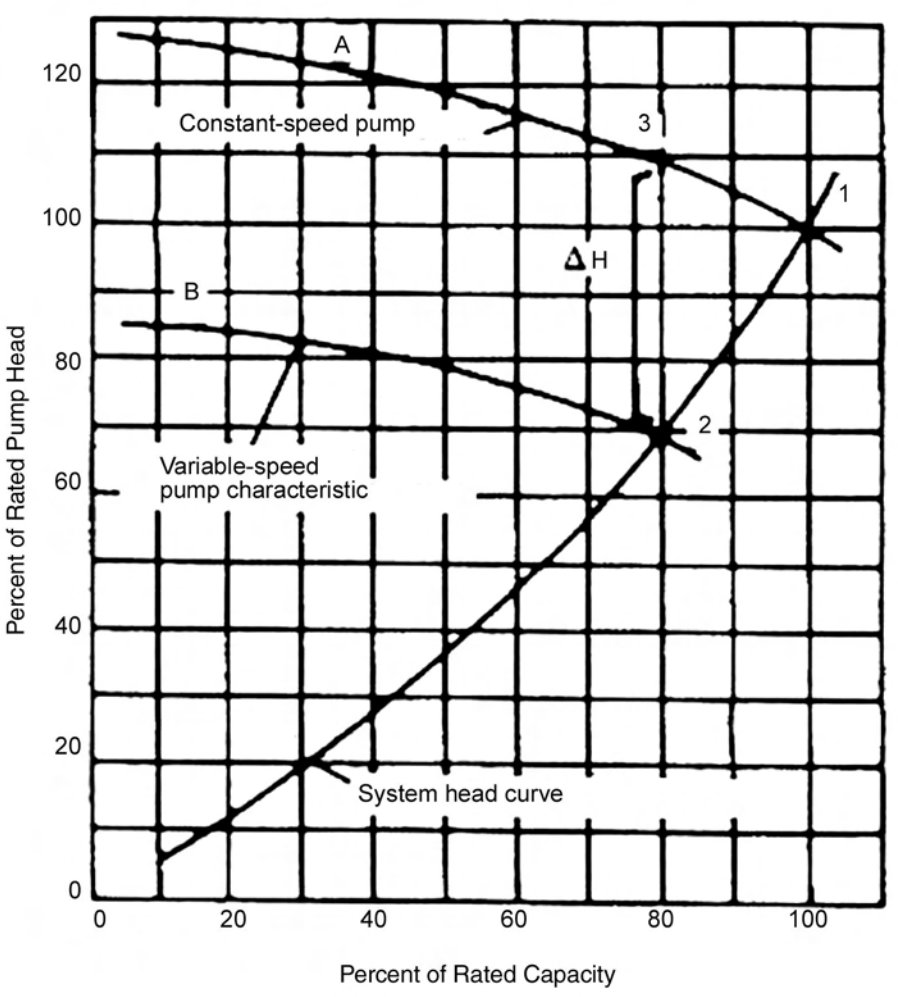


Fig. 6.9—Head/capacity-curve comparison of constant- and variable-speed pump.

altered for large permanent changes. The number of impellers can be changed by replacing existing impellers with spacers or dummy impellers.

6.3.14 Variable-Speed Control. Most motor-driven centrifugal pumps are operated at constant speed. A direct-current or variable-frequency alternating-current motor control can maintain nearly the same pump efficiency over a larger speed range. Variable-speed control makes it possible to eliminate the backpressure throttling requirements to adjust system head.

Fig. 6.9 illustrates the head-capacity-curve relationship of a constant-speed and variable-speed pump. The pump is operating at 100% of its capacity, and the TDH is represented by Point 1 on the graph. If it becomes desirable to reduce the capacity to 80% of the rated capacity, the constant-speed-pump operation will move to Point 3. Point 3 requires 110% of the head and 92% of the BHP required at Point 1, and thus, additional backpressure would be required to force the system curve to intersect the pump curve at this point.

A variable-speed driver could, in effect, find a TDH capacity curve that intersects the system curve at Point 2. Point 2 requires only 70% of the head and 73% of the power required at Point 1. Thus, at 80% capacity, the constant-speed pump would operate at Point 3 and the

variable-speed pump at Point 2. The potential energy savings is represented by the difference between 92 and 73% of horsepower, or 19%.

6.3.15 Affinity Laws. The affinity laws are used to predict what effect speed or impeller-diameter changes have on centrifugal-pump performance. The laws are based on dimensional analysis of rotating machines that shows, for dynamically similar conditions, certain dimensionless parameters remain constant. These relationships apply to all types of centrifugal and axial machines.

For a change in pump speed, the following changes in pump performance can be determined:

$$q_2 = q_1(N_2 / N_1) , \quad \text{(6.22)}$$

$$H_{td2} = H_{td1}(N_2 / N_1)^2 , \quad \text{(6.23)}$$

$$\text{and } P_{B2} = P_{B1}(N_2 / N_1)^3 , \quad \text{(6.24)}$$

where N_1 = old speed, and N_2 = new speed. For a change in diameter, the following performance changes can be determined:

$$q_2 = q_1(D_2 / D_1) , \quad \text{(6.25)}$$

$$H_{td2} = H_{td1}(D_2 / D_1)^2 , \quad \text{(6.26)}$$

$$\text{and } P_{B2} = P_{B1}(D_2 / D_1)^3 , \quad \text{(6.27)}$$

where D_1 = old diameter, and D_2 = new diameter. For a change in both diameter and speed, the following changes in pump performance can be determined:

$$q_2 = q_1(D_2 / D_1)(N_2 / N_1) , \quad \text{(6.28)}$$

$$H_{td2} = H_{td1}(D_2 / D_1)^2(N_2 / N_1)^2 , \quad \text{(6.29)}$$

$$\text{and } P_{B2} = P_{B1}(D_2 / D_1)^3(N_2 / N_1)^3 , \quad \text{(6.30)}$$

Predictions for speed changes are fairly accurate throughout the range of speed changes. However, predictions for diameter changes tend to be accurate for diameter change of only ± 10% because changing the diameter also changes the relationship of the impeller to the pump casing. Thus, for a 10% increase in either diameter or speed, the flow will increase by 10%, TDH by 21%, and the BHP by 33%.

The efficiency is assumed to be constant in all the previous calculations. **Fig. 6.10** illustrates a graphic example of reduced operating parameters because of speed reducers.

6.3.16 Pump Priming. Most centrifugal pumps have a flooded suction. The source is above the pump suction, and atmospheric pressure is sufficient to maintain fluid at the pump inlet at all times. Sometimes the pump must take suction from a source that is below the centerline of the pump. Atmospheric pressure alone will not always keep the suction flooded. Conventional centrifugal pumps are not self-priming. Thus, they are not capable of evacuating vapor from the casing so that fluid from the suction line can replace the vapor. Self-priming pumps are

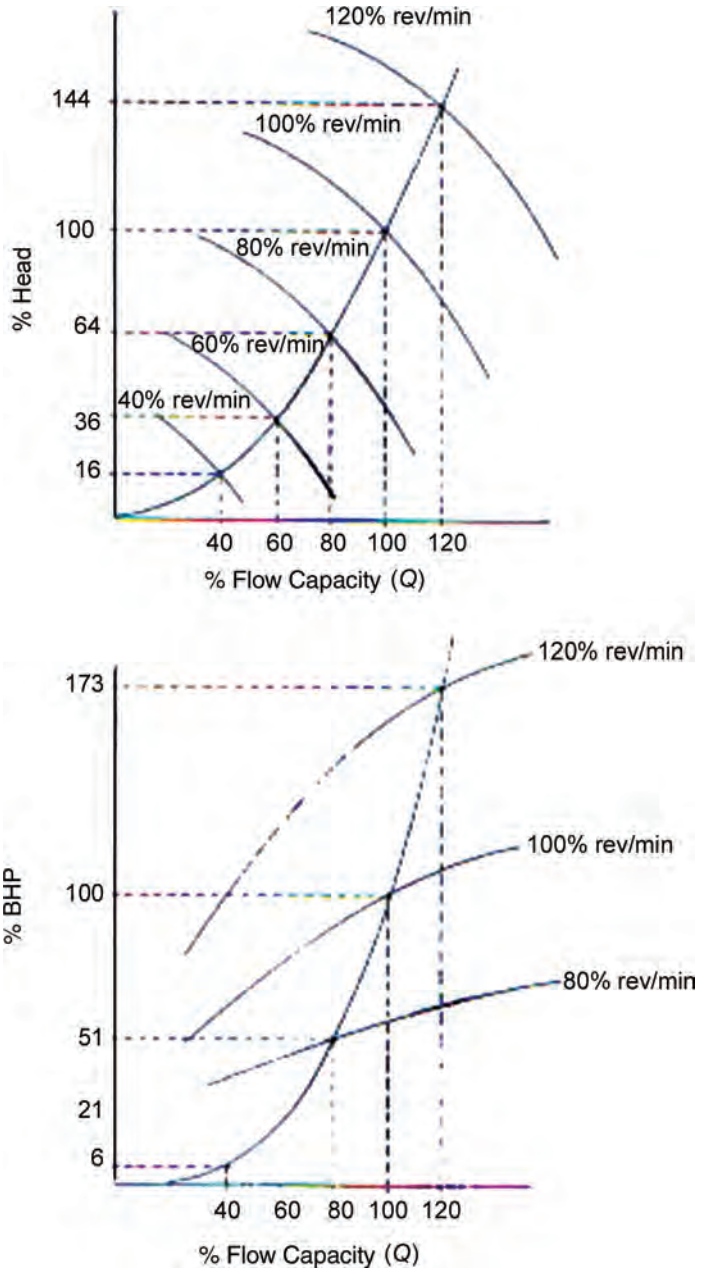


Fig. 6.10—Example of reduced operating parameters as a result of speed reducers.

designed so that an adequate fluid volume for repriming is always retained within the pump casing, even if fluid drains back to the source.

6.3.17 Installation Considerations. A centrifugal pump is a piece of precision machinery that must not be subjected to external strains beyond those it was designed to encounter. It must be installed in the intended position, carefully aligned, and free from piping forces and moments.

Foundations. Generally, foundation design is not critical. Vibration in a centrifugal pump is minimal unless an engine driver is used. As a general rule of thumb, the foundation should

be able to handle three times the weight of the pump, driver, and skid assembly. The manufacturer is the best source for determining the required foundation size.

Piping Design. Poor piping design and installation is a common cause of poor centrifugal-pump performance or failure. Poor piping can result in cavitation, performance dropout, impeller failure, bearing and mechanical seal failures, cracked casings, and leaks, spills, and fires.

Suction Piping. Suction piping is more important than discharge piping.

Fluid-Source Inlet. When the fluid source is above the pump (static head), the source vessel should contain a weir to minimize turbulence, a vortex breaker to eliminate vortexing and vapor entrainment, and a nozzle sized to limit exit velocity to 7 ft/sec or, preferably, less. When the fluid source is below the pump (static lift), the sump, basin, or pit should be designed to provide even velocity distribution in the approach or around the suction inlet and should be sufficiently submerged to prevent vortexing.

Pipe Size and Elimination of Air Pockets. Piping should be at least one nominal pipe size larger than the pump suction flange. Velocities should be less than 2 to 3 ft/sec, and the head loss as a result of friction should be less than 1 ft per 100 ft of equivalent piping length. Suction lines should be short and free of all unnecessary turns. For flooded suctions, piping should be continuously sloping downward to the pump suction so that any vapor pockets can migrate back to the source vessel. For static lifts, the piping should be continuously sloping upward with no air pockets (install gate valves in horizontal position). Where air pockets cannot be avoided, the use of automatic vent valves is recommended.

Upstream Elbow Considerations. When making upstream orientation changes, only long-radius elbows should be used. They should not be connected directly to the pump suction flange, and a minimum of at least two to five pipe diameters of straight pipe should be between the suction flange and the elbow and between successive elbows. This reduces swirl and turbulence before the fluid reaches the pump. Otherwise, separation of the leading edges may occur, with consequent noisy operation and cavitation damage.

Basket Strainers. Conditions may dictate that permanent strainers be installed in the suction piping. If permanent strainers are not required, temporary cone-type strainers should be installed at least for initial startups. Basket strainers should have at least 150% flow-area screens.

Eccentric Reducers. Reducers are required when making a transition from one pipe size to another and in going from the suction-pipe size to the pump flange. Reduction at the pump should be limited to one nominal size change (e.g., 8 to 6 in.). If two or more nominal pipe size reductions are required, it is best to locate any remaining changes several pipe diameters away from the pump inlet. Eccentric reducers should be used, if possible, and should be installed with the flat side up. Concentric reducers should not be used for horizontal suction lines because they could trap vapor that can be pulled into the pump and cause cavitation or vapor lock. Concentric reducers can be used for vertical suction lines and horizontal lines with flooded suction.

Discharge Piping. *Minimum Flow Bypass.* The minimum-flow bypass (or “recirculation”) protects the pump from temperature buildup when the pumping rates are low. They should be designed to handle the pump’s minimum flow capacity at minimum discharge pressure with a line restrictor to adjust flow. Small pumps are usually controlled by an orifice or choke tube. For large pumps in which a continuous bypass would consume excessive power, a control valve actuated (opened) by low flow is used.

Check Valves. Check valves are essential to minimize backflow, which can damage the pump. Selection should take into account the effect of water hammer. Water hammer is the transient change in static line pressure as a result of a sudden change in flow. Items that can start the sudden change in flow include the starting or stopping of a pump or the opening or closing of a check valve.

Slow-closing check valves are acceptable on systems with a single pump and long lengths of pipe. Fast-closing check valves are required with multiple pumps operating in parallel and at high heads. As a general guideline, lift ("swing") check valves are slow unless they are spring loaded. Tilting-disk check valves are fast closing but are more expensive and have a higher pressure drop than swing check valves. When fast-reacting check valves are required, pressure-drop considerations should be secondary.

6.4 Positive-Displacement Pumps

6.4.1 Introduction. Positive-displacement pumps were developed long before centrifugal pumps. Liquid is positively displaced from a fixed-volume container. Positive-displacement pumps are capable of developing high pressures while operating at low suction pressures. They are commonly referred to as constant-volume pumps. Unlike centrifugal pumps, their capacity is not affected by the pressure against which they operate. Flow is usually regulated by varying the speed of the pump or by recycle. Positive-displacement pumps are divided into two groups: rotary and reciprocating pumps.

6.4.2 Rotary Pumps. Rotary pumps are normally limited to services in which the fluid viscosity is very high or the flow rate too small to be handled economically by other pumps. Rotary pumps are commonly used to circulate lube oils through engines, turbines, reduction gears, and process-machinery bearings. Rotary pumps displace a fixed quantity of fluid for every revolution of the driver shaft. They have different pumping elements such as vanes, lobes, gears, and screws. Fig. 6.11 illustrates three (internal gear, external gear, and screw) of the most commonly used rotary pumps in production operations.

Most manufacturers rate rotary pumps by capacity (i.e., throughout). Capacity is the total liquid displacement of the pump less slip. Slip is the quantity of fluid that leaks from the higher-pressure discharge to the lower-pressure suction. Slip occurs because all rotary pumps require clearances between the rotating elements and pump housing. These clearances provide a leak path between the discharge and suction sides. A pump with large clearances, because of machining tolerances or wear, exhibits a proportionally larger slip. Rotary pumps cannot move nonlubricating fluids such as water or fluids containing hard or abrasive particles. Rotary pumps can move large quantities of air or vapor for short periods of time without losing prime.

Rotary pumps are self-priming but are not designed to run dry for long periods. For best operation, there must be enough fluid at the suction port to keep the pumping chamber completely filled.

Fig. 6.12 illustrates the relationship between speed, volumetric efficiency, and displacement of a rotary positive-displacement pump. The principles of operation of some of the more common types of rotary pumps are described next.

Sliding Vane. A set of vanes is mounted in a rotor in which the vanes slide in and out of the rotor. The rotor is mounted off center in the casing. As the vanes rotate past the suction port, they slide out of the rotor while maintaining constant contact with the casing. Springs or sealer rings help hold the vanes against the casing, thus the vanes make a close seal, or fit, against the casing wall. Trapped fluid is forced from the suction port to the discharge port.

The sliding-vane design is capable of delivering medium capacity and head. They deliver a constant flow rate for a set rotor speed. They work well with low-viscosity fluids and are somewhat self-compensating for wear. They are not suitable for use with highly viscous fluids (thicker fluids interfere with the sliding action of the vanes). A large wear area results from the friction fit between the vanes and the cylinder.

Flexible Vane. The flexible vane is similar to the sliding vane except that the vanes are generally a soft, pliable material and are integral with the rotor. As the rotor turns, the vanes bend and conform to the eccentric shape of the cylinder. They are simple, inexpensive, and are

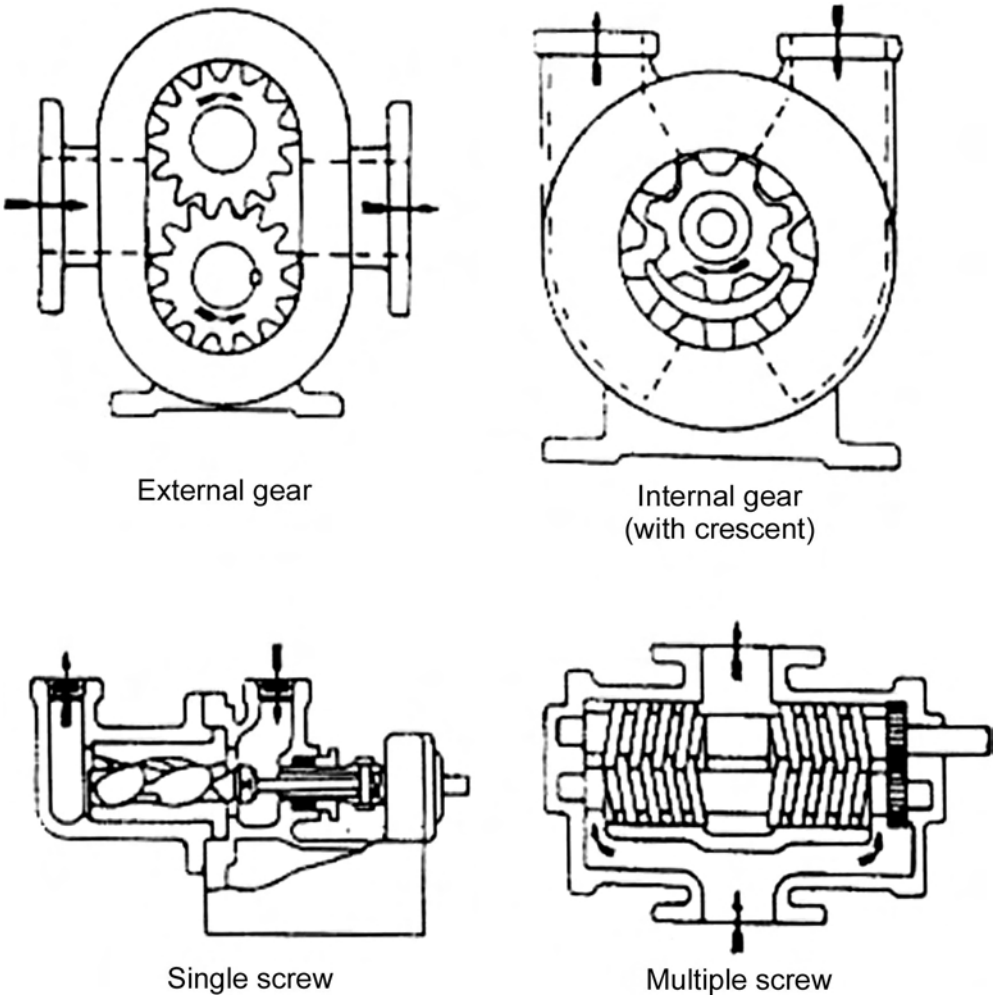


Fig. 6.11—Commonly used rotary pumps.

capable of developing a vacuum. They should not be allowed to run dry and should be used only with low-temperature fluids and in low-head applications.

External Gear. The external gear consists of two equal-sized meshing gears, one a driver and the other an idler, that rotate inside a housing. As the gears unmesh at the suction side of the pump, a vacuum is formed. Pressure forces the fluid into the pump where the fluid is carried between the gear teeth and the case to the discharge port. At the discharge, the meshing of the gear teeth creates a boundary that prevents the fluid from returning to the suction. Gear pumps operate equally well when driven in either direction. Precautions should be taken to ensure that the shaft rotation is correct when special features, such as built-in relief valves or a bleed back of the shaft seal, are used.

There are also models that use multiple sets of gears on one shaft to produce more capacity. External-gear pumps are compact in size and can produce high pressures. They are well suited for highly viscous fluids. They are easily manufactured in a broad range of materials to ensure compatibility with the pumped fluids. Because of their close tolerances, they are limited to clean-fluid applications.

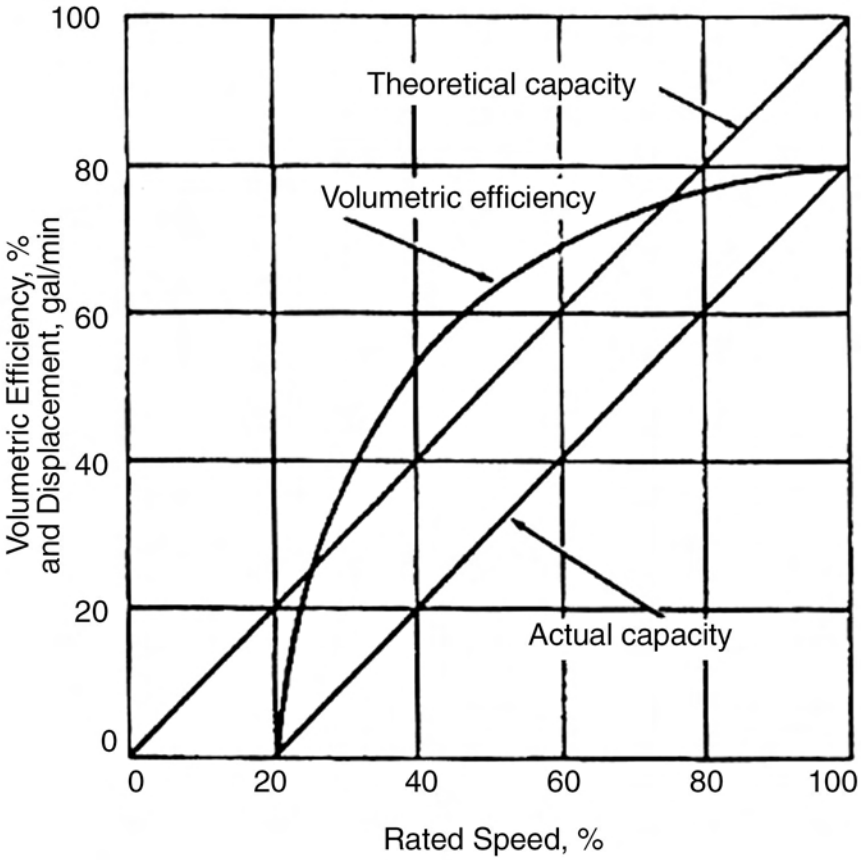


Fig. 6.12—Relationship between speed, volumetric efficiency, and displacement of a rotary positive-displacement pump.

Internal Gear. The internal-gear pump is similar in principle to the external gear except the drive shaft turns a ring gear with internal teeth. The external gear tooth (idler) rotates on an offset center and meshes with the drive gear through only a segmental arc of rotation. A fixed crescent-shaped filter occupies the space between internal- and external-gear-tooth tips opposite the mesh point. As the gear teeth disengage at the input port, fluid enters and is trapped in the tooth space of each gear and is carried to the discharge port. The meshing of the two gears and the elimination of the tooth space forces fluid from the pump.

Lateral gear pumps are used in low-head applications. They are limited to a maximum back-pressure of 100 psi and require a pressure-relief valve on the discharge side. Because small clearances exist, they cannot handle liquids that contain solids. The manufacturer should always be consulted before any gear pump is used with fluid-handling solids.

Lobe. Lobe pumps operate in the same manner as gear pumps except the rotating elements have two, three, or four lobes instead of gear teeth. Lobes cannot drive each other, so timing gears are used. The lobes never come into contact with each other so the pump can be allowed to run dry. Lobes are used where product integrity must be maintained and in applications in which liquids are shear sensitive. The large volume created between the casing and lobes allows many products to be pumped without damaging the product itself. A major advantage is that there is no metal-to-metal contact between the lobes, thus the possibility of traces of iron, steel, or other pump-construction materials ending up in the product because of wear is greatly

reduced. On the other hand, they are more expensive than gear or vane pumps and are difficult to repair and maintain.

Screw. Screw pumps can be single-rotor (progressive cavity) or multiple-rotor (intermeshing) design. Screw pumps are relatively high-speed pumps but, because of the reversal of flow required to enter the suction passage, NPSH can often be a problem. Screw pumps are used for high-head applications; thus, they are the most common rotary-pump type in use in producing operations.

Single Screw. In the single-screw design, the fluid is trapped between the treads of a rotating screw and the treads of the internal stationary element. These pumps are used for viscous liquids and liquids with high solids content. They can produce significant suction lift and relatively high pressures. They can handle fluids ranging from clean water to sludges without changing clearances or components. On the other hand, they are expensive, bulky, and difficult to maintain, and replacement parts are expensive.

Multiple Screw. In the multiple-screw design, the fluid flows between a central drive screw and one or more idler screws in a close-fitting housing. In two-screw pumps, both shafts are driven with timing gears. In three-screw pumps, the screw treads are cut so one screw can drive the other two. The rotation of the screws produces a vacuum at the inlet, moves the fluid through the pump, and delivers the fluid to the discharge. In small sizes, they are used to supply lubricating oil to engines and industrial machinery. In intermediate sizes, they are used in office buildings as a source of hydraulic energy to operate elevators. In large sizes, they are used to load and unload barges and tankers.

6.4.3 Reciprocating Pumps. Reciprocating pumps move liquid by means of a constant back-and-forth motion of a piston, plunger, or diaphragm within a fixed volume or cylinder. Reciprocating pumps can handle viscous and abrasive fluids. They are low-speed machines when compared with centrifugal and rotary pumps. They offer higher efficiencies, generally 85 to 94%, thus they require less horsepower. Reciprocating pumps are best suited for high-pressure and low-volume applications. They frequently require pulsation dampeners because of the pulsating nature of the flow. They have higher installed costs (usually offset by higher efficiencies) and higher maintenance costs than centrifugal or rotary pumps.

Plunger and Piston Pumps. In plunger pumps, a plunger moves through a stationary packed seal and is pushed into and withdrawn from a liquid cavity. In piston pumps, a piston moving back and forth within a liquid cavity pushes the fluid from the cylinder. Movement of either the plunger or piston creates an alternating increase and decrease of flow. As the plunger or piston moves backward, the available volume in the cylinder increases and a suction valve opens to allow the liquid to enter the cylinder through a one-way suction valve. As the plunger or piston moves forward, the volume available in the cylinder decreases, the pressure of the liquid increases, and the liquid is forced out through a one-way discharge valve.

Efficiencies remain high regardless of head or speed (tend to decrease slightly with increasing speed). Because reciprocating pumps run at lower speeds than centrifugal or rotary pumps, they are better suited for handling viscous liquids. They are capable of producing high pressures and large capacities and are self-priming. On the other hand, they require more maintenance because of the large number of moving parts. They are heavier in weight and require more floor space than centrifugal or rotary pumps. In addition, they are poor at handling liquids containing solids that tend to erode valves and seats. Plunger and piston pumps require larger NPSHs because of pulsating flow and pressure drop through the valves. As a result of pulsating flow, they require special attention to suction- and discharge-piping design to avoid both acoustical and mechanical vibrations.

Diaphragm Pumps. Fig. 6.13 shows a typical fluid (gas-, air-, or liquid-powered) diaphragm pump. Its principle of operation is similar to plunger and piston pumps except that, instead of a plunger or piston, there is a flexible pulsating diaphragm that displaces the liquid.

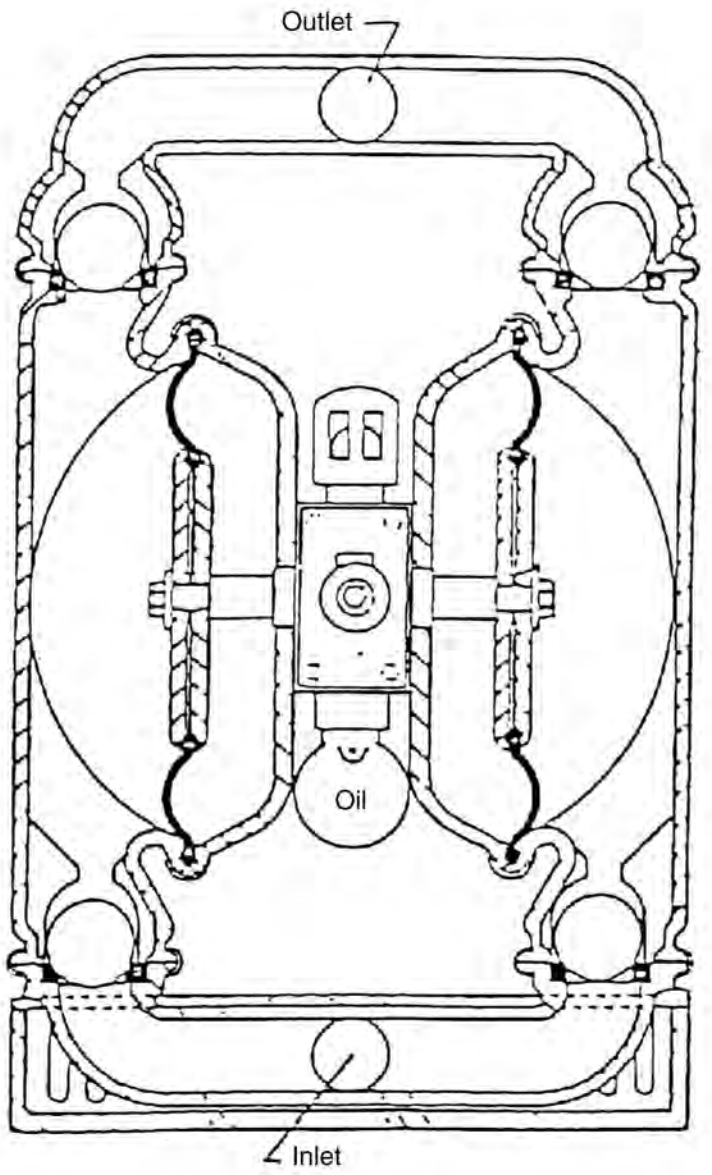


Fig. 6.13—Diaphragm pump.

Varying power-fluid pressure on one side of the diaphragm causes the diaphragm to deflect alternatively drawing liquid into the pump-side chamber or discharging the liquid from the pump-side chamber. Diaphragm pumps are capable of pumping liquids that are viscous, erosive, corrosive, or that contain large amounts of solids. In addition, diaphragm pumps are self-priming, can run periodically without liquids, and are inexpensive to repair because they have no stuffing box and have few moving parts.

Diaphragm pumps are limited to small flow rates (90 gal/min), moderate discharge pressures, and moderate temperatures. They require frequent maintenance and exhibit fatigue failure with time. Leaks can cause a hazard by mixing power fluid with the process fluid. Gas-/air-powered diaphragm pumps are commonly used as sump pumps.

It is possible to use a diaphragm to power a plunger or piston pump. This type of pump is often used for chemical injection because it is well suited for low volume and large-head applications, and the speed can be controlled by a throttling valve on the power fluid.

6.4.4 Reciprocating-Pump Performance Considerations. Reciprocating pumps are constant-volume pumps. Variations in discharge pressures do not affect flow rate. Because these pumps continue to deliver the same capacity, any attempt to throttle the discharge flow may overpressure the pump casing and/or the discharge piping. Thus, no reciprocating pump should ever be started or operated with the discharge block valve closed. Flow is regulated by speed.

Capacity. The capacity of a reciprocating pump is the cylinder displacement less slip. For a single-acting cylinder, cylinder displacement can be determined from

$$s = \frac{\left(A \times L_s \times N \times m\right)}{231} . \quad \text{..... (6.31)}$$

For double-acting cylinders, the cylinder displacement can be determined by

$$s = \frac{\left[(2A - a) \times L_s \times N \times m\right]}{231} , \quad \text{..... (6.32)}$$

where s = cylinder displacement, A = plunger or piston area, a = piston-rod cross-sectional area, L_S = stroke length, N = speed, and m = number of pistons or plungers.

Slip is the loss of capacity as a percentage of the cylinder displacement because of volumetric efficiency, stuffing-box losses, and valve losses. Volumetric efficiency (not to be confused with mechanical efficiency) is normally 95 to 97%. Efficiency is also reduced when pumping a light hydrocarbon that has some degree of compressibility.

The pump capacity can be determined from

$$q = \frac{s(100 - S)}{100} , \quad \text{..... (6.33)}$$

where q = pump capacity.

Speed. Speed is the primary factor that determines both the capacity of a reciprocating pump and its maintenance costs. Running at high speeds shortens packing life and increases acceleration and deceleration forces on all moving components. Operating below the maximum "rated" speed may be advantageous when the pump is operated unattended, when there are no spares and no standby, when there is a high penalty for down time, when unit maintenance is poor, when long life is desired, and when the NPSH margin is low. Operating at the maximum rated speeds requires clean, cool fluids; excellent piping layout with rigidly fixed piping; good NPSH margin; solid foundation; well-designed suction and discharge pulsation dampeners; and good maintenance. Whenever it becomes necessary to operate above the maximum rated speeds, very close attention should be given to all design, operation, and maintenance details.

6.4.5 Installation Guidelines. If positive-displacement pumps are properly installed and operated, satisfactory performance can be realized for a long time. These pumps are manufactured in a variety of designs for many different services. Each manufacturer's instructions should be followed carefully for specific machines or application equipment. The following discussion relates to general installation guidelines for positive-displacement reciprocating pumps.

Foundations and Alignment. Most pump foundations are constructed of reinforced concrete. The pump and driver are bolted to a cast iron or steel base plate, which is secured to the concrete foundation with anchor bolts. Small pumps need a foundation large enough to accommodate the base-plate assembly. Large pumps require a foundation that is three to four times the weight of the pump and driver.

Anchor-Bolt-Sleeve Installation. Each anchor bolt is fitted with a washer and passed through a pipe sleeve that has a diameter three to four times greater than the bolt. The bolt-sleeve unit is set into the concrete at the predetermined base-plate hole positions. The flexibility in the sleeve washer unit allows minor adjustments to be made in the bolt position before final tightening even after the concrete foundation has set.

Metal-Shim Adjustments. Metal shims are used to position the pump on the foundation. Adjustments are made until the pump shaft and flanges are completely level. Alignment between the pump and driver is then adjusted before connecting the pump to the suction and discharge lines. The latter should have been aligned during the initial positioning of the base plate.

Grouting. Because of pipe strain, the entire pump assembly should be rechecked for alignment once the piping has been securely bolted. If the drive alignment has not been changed by bolting the piping, the space between the base plate and concrete foundations is filled with grouting. Grouting should be sufficiently fluid to fill all the available space under the base plate.

Operating-Temperature Considerations. It is essential that the alignment between the piping, pump, and driver not change. Ideally, alignments should be made at the operating temperature after initial cold alignment of the pumping system, thus eliminating any alignment changes because of thermal expansion.

Piping. Next to the selection of operating speeds, proper piping design is the most important consideration in pump-installation design. Poor piping is often the result of inattention to details, which can lead to more than average down time, higher maintenance costs, and loss of operating-personnel confidence.

Suction piping should be direct, free of bends, as short as possible, and at least one nominal pipe size larger than the pump-suction connection. Directional piping changes should be made with long-radius elbows. A full opening block valve should be installed in the suction piping. The suction vessel should have sufficient retention time for the evolution of free gas and should be equipped with a vortex breaker at the discharge nozzle. The suction and bypass lines should enter the vessel below the minimum liquid level.

Suction piping should be large enough so that the velocity limits are not exceeded. Eccentric reducers with the flat side up should be used instead of concentric reducers. Suction piping should include a suction strainer and a pulsation dampener. Suction strainers should not be installed unless regular maintenance can be assured. A fluid-starved condition resulting from a plugged strainer can cause more damage to the pump than solids ingestion.

The discharge piping should be direct, free of excessive bends, and at least one nominal pipe size larger than the pump-discharge connection. Directional piping changes should be made with long-radius elbows. Concentric reducers may be used, but they should be placed as near to the pump as practical. To facilitate priming and starting, a bypass (recycle) line with check valve and block valve should be installed to the suction source. If a pulsation dampener is not included in the initial installation, a flanged connection should be provided if pulsation attenuation may be required. A relief valve should be installed upstream of the discharge block valve, in case overpressurization in the discharge piping occurs.

Pulsation Considerations. Flow from a reciprocating pump is not uniform. The oscillating motion of the plungers creates disturbances (pulsations) that travel at the speed of sound from the pump cylinder to the piping system. Pulsations are a function of the pump's piston/plunger

velocity, internal valves, and operating speed. Pulsations cause the pressure level of the system to fluctuate with respect to time.

Suction pulsations can cause the pressure level to drop instantaneously below the fluid vapor pressure, which results in cavitation. Caviation can cause failure of pump parts such as valves, crossheads, rods, etc. and high piping vibrations and failures of vents, drains, and gauge lines. Normal pipe clamps and supports may not be effective in controlling these vibrations.

Pulsations can be amplified by the acoustical resonances of the piping system, which results in pump fluid-end failures and piping failures because of the shaking caused by pressure pulsation. For simple piping layouts and low-to-moderate pump speeds, pulsation dampeners are used to attenuate the effects of pulsating flows. Pulsation dampeners are normally installed on both the suction and discharge. Dampeners can be liquid-filled; gas-cushioned, or tuned acoustical filters. For complicated and multiple-pump piping and high pump speeds, acoustical filters are used.

The design of a pulsation-dampening system is beyond the scope of this chapter. Special expertise is needed for analyzing and controlling pulsations in multipump installations.

6.5 Pump Drivers

6.5.1 Overview. Pump drivers include electric motors, steam turbines, expansion turbines, gas turbines, and internal-combustion engines.

6.5.2 Electric Motors. Three-phase alternating-current induction motors are the most commonly used driver for pumps because of the desirable characteristics of electricity as a power source and because the standard rotative speeds (1,750 and 3,500 rev/min) are well suited for driver centrifugal pumps. See the chapter on Electrical Systems in this volume of the *Handbook* for further discussion.

6.5.3 Steam Turbines. Large gas plants containing boilers use steam turbines to drive large pumps such as lean-oil pumps, boiler feed-water pumps, and solvent-circulation pumps. It is a common practice to select a turbine rated at pump speed and power requirements and to rely on the inherent flexibility of the turbine to provide for a margin of error.

6.5.4 Expansion and Hydraulic Turbines. High-pressure process streams in gas plants commonly have pressure reduced for further processing. This energy can be recovered by expansion turbines, which in turn drive pumps or generators. If the stream to be expanded is liquid (i.e., rich oil or solvents), the type of turbine is generally a centrifugal pump with the inlet and outlet reversed and is called a hydraulic turbine. If the stream to be expanded is gas, the type of turbine is called an expander.

High-pressure liquid enters the hydraulic turbine through the centrifugal pump's discharge flange and the low-pressure fluid exits through the pump's suction flange. Hydraulic turbines have proved economical when the developed power exceeds 160 BHP, the flow exceeds 200 gal/min, and the inlet pressure exceeds 200 psig.

The most important design consideration is handling flow and pressure-differential fluctuations so that adequate shaft power can be provided to the driven equipment at all times. This is done in one of two ways: a supplemental electric motor can be provided in tandem with the hydraulic turbine, or a continuous bypass can be installed around the hydraulic turbine that absorbs all process flow variation, always leaving the minimum required flow through the turbine.

A critical factor in the design of the hydraulic turbine is the rate of gas evolution as it flows through the turbine. Design specifications should include a complete analysis of the liquid stream so that the designer can optimize the flow passages. A pump failure by overspeed exists when the flow through the driver pump is suddenly reduced or stopped before flow

through the turbine is shut off. To avoid this type of failure, an overspeed trip device should be specified.

Hydraulic turbines normally use mechanical shaft seals identical to those applied to pumps. External flushing is generally required to either prevent gas evolution within the mechanical seal area or to minimize dirt and other solids from entering this seal area.

6.5.5 Gas Turbines. The trend toward plants with minimal operator attendance indicates that steam may become obsolete. Gas-fired turbines are the logical choice to replace the steam turbine for large pump drives. See the chapter on Prime Movers in this volume of the *Handbook* for further details.

6.5.6 Internal-Combustion Engines. Internal-combustion engines are used to drive pumps when other power is not available or when a standby energy source is desirable. The most common application in upstream production operations is for fire water pumps and for crude-oil shipping pumps in offshore applications. See the chapter on Prime Movers in this volume of the *Handbook* for further details.

Nomenclature

a = piston-rod cross-sectional area, L^2, in.^{2}
A = plunger or piston area, L^2, in.^{2}
d = inside pipe diameter, L, in.
D_1 = old diameter, L, in.
D_2 = new diameter, L, in.
e = the pump efficiency factor obtained from the pump manufacturer, fraction
e_m = motor efficiency, fraction
E = electrical energy, mL^2/t^2, kW-hour
g = acceleration of gravity (32.17 ft/sec^2 at sea level), L/t^2, ft/sec^2
h = height of the fluid column above a reference point, L, ft
h_f = friction loss between Points 1 and 2, L, ft
H_A = net positive suction head available, dimensionless
H_d = discharge head of liquid being pumped, L, ft
H_s = suction head of liquid being pumped, L, ft
H_{td} = total dynamic head required of a pump, L, ft
H_{td}' = TDH per stage at the BEP, ft
H_V = the head required to overcome friction as a result of flow, L, ft
H_{ws} = the static difference between the suction and the discharge at zero flow, L, ft
H_1 = height of liquid suction vessel above pump reference point, L, ft
H_2 = operating or normal height of liquid in the discharge vessel above the pump reference, L, ft
L_S = stroke length, L, in.
m = number of pistons or plungers
N = pump rotative speed, rev/min
N_s = pump specific speed, dimensionless
p = pressure, m/Lt^2, psi
p_A = atmospheric pressure, m/Lt^2, psia
p_{f1} = pressure drop resulting from friction in the suction piping, m/Lt^2, psi
p_{f2} = pressure drop resulting from friction in the discharge piping, m/Lt^2, psi
p_{va} = liquid vapor pressure at pumping temperature, m/Lt^2, psia

p_1 = suction-vessel operating pressure, m/Lt^2, psig
p_2 = discharge-vessel operating pressure, m/Lt^2, psig
P_B = brake horsepower, horsepower
P_c = discharge flow-control-valve losses, psi
P_H = hydraulic horsepower, horsepower
q = pump capacity, L^2/t, gal/min
Q = flow rate, L^2/t, gal/min
s = cylinder displacement, gal/min
S = slip, percent
t = time, t, days
v = average velocity of the liquid in the pipe, L/t, ft/sec
Z = height above a datum, L, ft
γ = specific gravity of the liquid, dimensionless
ρ = density, m/L^3, lbm/ft^3
ρ_f = density of the liquid being pumped, m/L^3, lbm/ft^3
ρ_w = density of water at standard conditions of temperature and pressure (62.34 lbm/ft^3), m/L^3, lbm/ft^3

Subscripts

1, 2 = locations along a pipe

References

1. *Hydraulic Institute Engineering Data Book,* second edition, Hydraulic Inst., Parsippany, New Jersey (1991).

SI Metric Conversion Factors

ft	×	3.048*	E − 01	= m
ft^3	×	2.831 685	E − 02	= m^3
°F		(°F − 32)/1.8		= °C
gal	×	3.785 412	E − 03	= m^3
hp	×	7.460 43	E − 01	= kW
in.	×	2.54*	E + 00	= cm
lbm	×	4.535 924	E − 01	= kg
psi	×	6.894 757	E + 00	= kPa

*Conversion factor is exact.

Chapter 7
Compressors

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7.1 Introduction

This chapter provides an overview of the primary categories of natural gas compressor services and a description of the different classifications and types of compressors available to the industry. Adiabatic and polytropic compression theory are discussed with supporting definition of terminology. Specific topics relating to compression theory include power requirement, isentropic exponent, compressibility factor, intercooling, adiabatic and polytropic efficiency, actual and standard volume flow rates, mass flow rates, inlet and discharge pressures, inlet and discharge temperatures, and adiabatic and polytropic head. Major components and construction features of centrifugal and reciprocating compressors are emphasized. Installation, safety, and maintenance considerations also are discussed.

For centrifugal compressors, the performance characteristic curve is presented with emphasis on process control of capacity by speed variation, suction throttling, or variable inlet guide vanes. Process control to avoid operation in a damaging surge condition is also addressed.

The discussion on reciprocating compressors includes a description of process configuration for multistage units, as well as an explanation of the concepts of speed control, inlet throttling, recycling, pressure relief, blowdown, and distance piece venting and draining.

7.1.1 Overview. Compressors used in the oil and gas industry are divided into six groups according to their intended service. These are flash gas compressors, gas lift compressors, reinjection compressors, booster compressors, vapor-recovery compressors, and casinghead compressors.

Flash Gas Compressors. Flash gas compressors are used in oil handling facilities to compress gas that is "flashed" from a hydrocarbon liquid when the liquid flows from a higher pressure to a lower pressure separator. Flash gas compressors typically handle low flow rates and produce high compression ratios.

Gas Lift Compressors. Gas lift compressors are frequently used in oil handling facilities where compression of formation gases and gas lift gas is required. Gas lift compressor duty is frequently of low to medium throughput with high compression ratios. Many gas lift compressors are installed on offshore facilities.

Reinjection Compressors. The reinjection of natural gas is employed to increase or to maintain oil production. Reinjection compressors can be required to deliver gas at discharge

pressures in excess of 10,000 psi. Reinjection compressors also are used for underground storage of natural gas. Compressors, applied to these services, have large compression ratios, high power requirements, and low volume flow rates.

Booster Compressors. Gas transmission through pipelines results in pressure drop because of friction losses. Booster compressors are used to restore the pressure drop from these losses. Selection of these compressors involves evaluating the economic trade-off of distance between pipeline boosting stations and life-cycle cost of each compressor station. Booster compressors also are used in fields that are experiencing pressure decline. Most centrifugal pipeline booster compressors are gas turbine driven, although the use of variable-speed motor drives is becoming more prevalent. Low-speed integral gas engine reciprocating compressors also are used for gas transmission applications. Booster compressors typically are designed for high throughput rates and low compression ratio. Many booster applications can be configured in a single-stage centrifugal compressor.

Vapor Recovery Compressors. Vapor recovery compressors are used to gather gas from tanks and other low-pressure equipment in the facility. Often the gas from a vapor recovery compressor is routed to a flash gas, gas lift, or booster compressor for further compression. Low suction pressures, high compression ratios, and low gas throughput rates characterize these compressors.

Casinghead Compressors. Casinghead compressors are usually used with electric submersible pumps and rod pumps where formation gas is required to be separated downhole and then transported through the annulus. Often the compressor discharge is routed to either a booster or flash gas compressor or to a low-pressure gathering system. Like vapor recovery compressors, casinghead compressors operate with low suction pressures, high compression ratios, and low gas throughput rates.

7.2 Classification and Types

Compressors are classified into two major categories—positive displacement and dynamic (kinetic) compressors. Positive displacement compressors are further divided into reciprocating and rotary types. Reciprocating compressors are positive-displacement machines in which the compressing and displacing element is a piston having a reciprocating motion within a cylinder. Rotary compressors are positive-displacement machines in which the compressing and displacement are affected by the positive action of rotating elements. (Note: For positive displacement compressors, the focus of this chapter is on reciprocating compressors.)

Dynamic compressors are continuous-flow machines in which a rapidly rotating element accelerates the gas as it passes through the element, converting the velocity head into pressure, partially in the rotating element and partially in stationary diffusers or blades. Dynamic compressors are further divided into centrifugal, axial-flow, and mixed-flow types. (Note: Out of these three types of dynamic compressors, only centrifugal compressors are addressed in this text.)

7.2.1 Reciprocating Compressors. There are two types of reciprocating compressors—high speed and low speed. The high-speed category also is referred to as "separable," and the low-speed category also is known as "integral."

The American Petroleum Institute (API) has produced two industry standards, API *Standard 11P* and API *Standard 618,* which are frequently employed to govern the design and manufacture of reciprocating compressors.

7.2.2 Separable Compressors. The term "separable" is used because this category of reciprocating compressors is separate from its driver. Either an engine or an electric motor usually drives a separable compressor. Often a gearbox is required in the compression train. Operating speed is typically between 900 and 1,800 rpm.

Separable units are skid mounted and self-contained. They are easy to install, offer a relatively small initial cost, are easily moved to different sites, and are available in sizes appropriate for field gathering—both onshore and offshore. However, separable compressors have higher maintenance costs than integral compressors.

Fig. 7.1 is a cross section of a typical separable compressor. Fig. 7.2 shows a separable engine-driven compressor package.

7.2.3 Integral Compressors. The term "integral" is used because the power cylinders that drive the compressor are mounted integrally with the frame containing the compressor cylinders. Integral units run at speeds of between 200 and 600 rpm. They are commonly used in gas plants and pipeline service where fuel efficiency and long life are critical. Integral compressors may be equipped with two to ten compressor cylinders with power ranging from 140 to 12,000 hp.

Integral compressors offer high efficiency over a wide range of operating conditions and require less maintenance than the separable units. However, integral units usually must be field-erected and require heavy foundations and a high degree of vibration and pulsation suppression. They have the highest initial installation cost.

Fig. 7.3 is a cross section of a typical integral compressor. Fig. 7.4 shows an integral compressor package.

7.2.4 Rotary Positive Displacement Compressors. The two most common types of rotary positive displacement compressors are vane compressors and screw compressors.

Vane Compressors. The vane-type compressor consists of a cylindrical rotor with longitudinal slots in which radial sliding vanes are fitted. The rotor is positioned eccentrically within a cylindrical housing. The spaces between adjacent vanes form pockets of decreasing volume from a fixed inlet port to a fixed discharge port. Compressor inlet and discharge valves are not employed in the design. A vane compressor always compresses the gas to the design pressure defined by the manufacturer, regardless of the pressure in the system in which the compressor is discharging.

Screw Compressors. The screw compressor, also known as a helical-lobe or spiral-lobe compressor, is a positive displacement rotary design that compresses gas between intermeshing helical lobes and chambers in the compressor housing. Screw compressors do not use valves. Their compression ratio is determined by the wrap angle of the lobes and the location of the opening edges of the discharge port. Of the various compressor types, screw compressors are best able to accommodate liquid carryover.

7.2.5 Centrifugal Compressors. In a centrifugal compressor, energy is transferred from a set of rotating impeller blades to the gas. The designation "centrifugal" implies that the gas flow is radial, and the energy transfer is caused from a change in the centrifugal forces acting on the gas. Centrifugal compressors deliver high flow capacity per unit of installed space and weight, have good reliability, and require significantly less maintenance than reciprocating compressors. However, the performance characteristic of centrifugal compressors is more easily affected by changes in gas conditions than is the performance of reciprocating compressors.

The physical size (diameter) of a centrifugal compressor is determined by the volumetric flow rate at the inlet. The compression ratio (or head) determines the number of stages (length). The rotating speed of a centrifugal compressor is an inverse function of diameter to maintain a desired peripheral speed at the outer diameters of the impellers regardless of the physical size of the compressor. Very large (i.e., high-volume) flow compressors may operate at speeds as low as 3,000 rpm. Conversely, low-volume flow compressors may operate at speeds up to 30,000 rpm. Power requirement is related to mass flow, head, and efficiency.

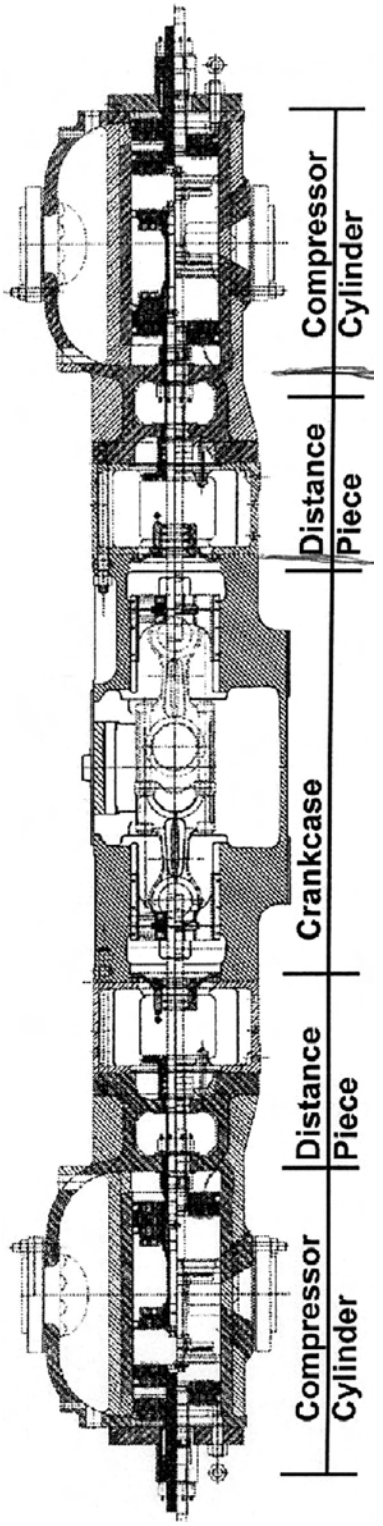


Fig. 7.1—Cross section of a separable compressor (courtesy of Dresser-Rand).

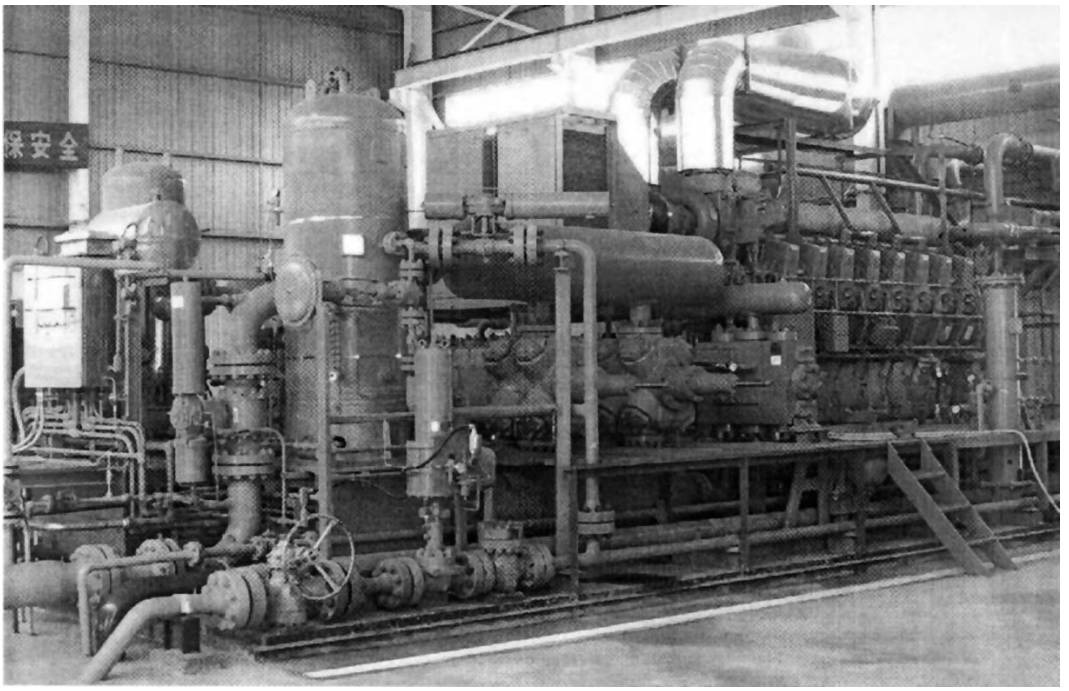


Fig. 7.2—Separable engine compressor package (courtesy of Dresser-Rand).

Depending on the particular application, centrifugal compressor powers can range from as low as 500 hp (400 kW) to more than 50,000 hp (40 MW).

At low volume flow rates, the width of the gas passages in a centrifugal compressor becomes narrow, and the effects of friction become significant, resulting in reduced efficiency. For this reason reciprocating compressors often are more appropriate for low-volume flow applications. For further discussion of this subject, see Sec. 7.3.11.

The API has produced an industry standard, API *Standard 617,* which is frequently used to govern the design and manufacture of centrifugal compressors. A typical centrifugal compressor package is shown in **Fig. 7.5**. The compressor shown is mounted on a single baseplate and is driven by an electric motor.

7.3 Compression Theory

Both positive displacement and dynamic compressors are governed by a few basic principles derived from the laws of thermodynamics. See the chapter on thermodynamics in the General Engineering volume of this *Handbook* for a basic discussion of thermodynamics. This section defines terminology and discusses the operating principles essential for understanding compressor design, operation, and maintenance.

7.3.1 Isentropic (Adiabatic) Compression. An adiabatic process is one in which no heat is added or removed from the system. Adiabatic compression is expressed by

$$P_1 V_1^k = P_2 V_2^k \ , \qquad (7.1)$$

where

$k = C_p / C_v$ = ratio of specific heats, dimensionless.

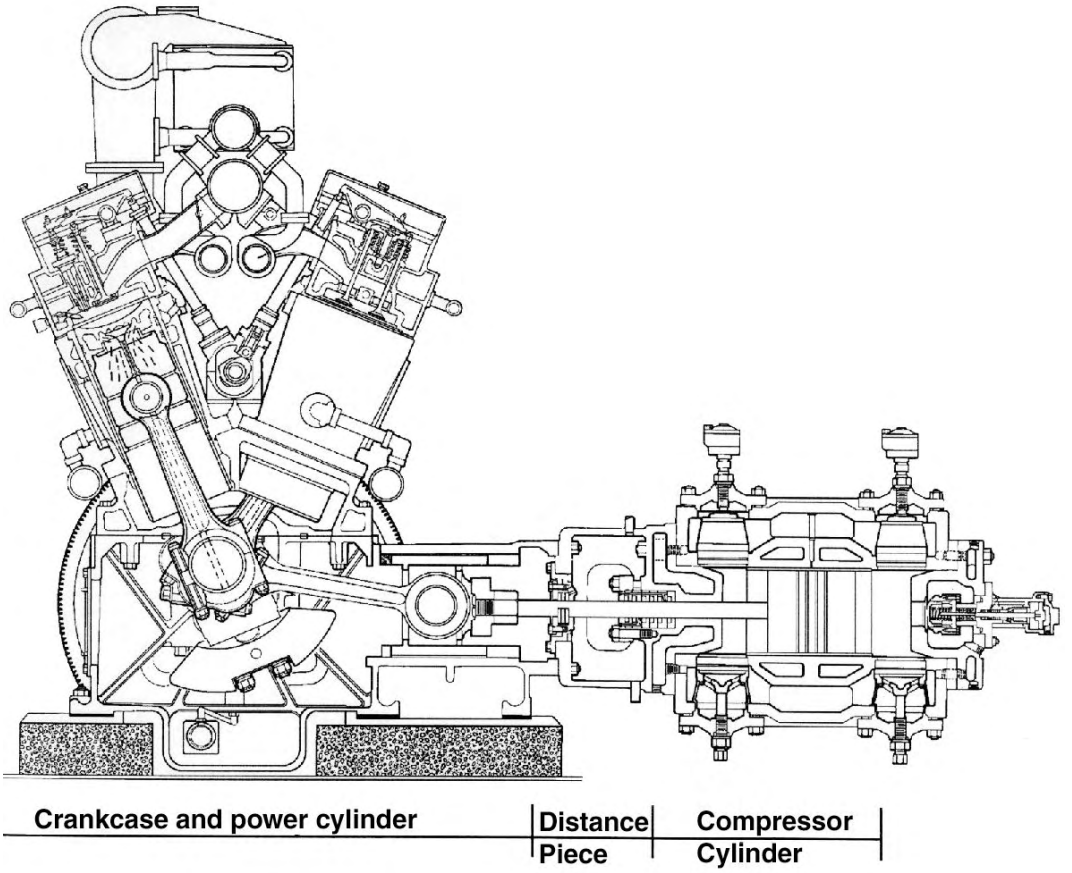


Fig. 7.3—Cross section of an integral compressor (courtesy of Dresser-Rand).

Although compressors are designed to remove as much heat as possible, some heat gain is inevitable. Nevertheless, the adiabatic compression cycle is rather closely approached by most positive displacement compressors and is generally the base to which they are referred.

7.3.2 Polytropic Compression. A polytropic process is one in which changes in gas characteristics during compression are considered. Dynamic compressors generally follow the polytropic cycle as defined by the formula

$$P_1 V_1^n = P_2 V_2^n \ , \quad \text{..... (7.2)}$$

where

n = polytropic exponent.

The polytropic exponent n is experimentally determined for a given type of machine and may be lower or higher than the adiabatic exponent k. Because the value of n changes during the compression process, an average value is used.

When inlet and discharge pressures and temperatures are known, the polytropic exponent can be determined from the relationship

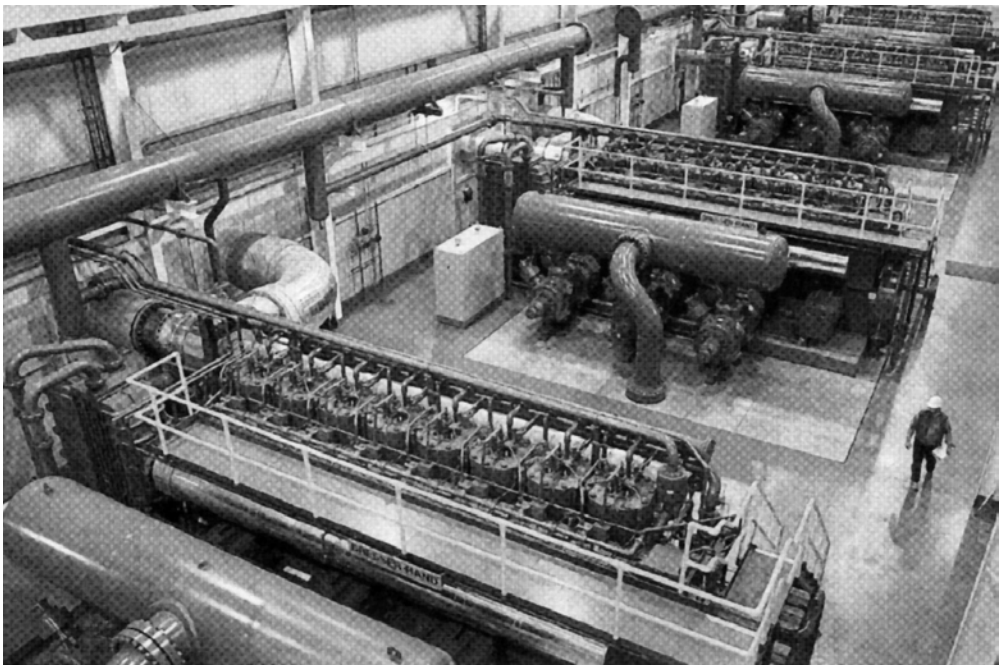


Fig. 7.4—Integral reciprocating compressor package (courtesy of Dresser-Rand).

$$T_2/T_1 = (P_2/P_1)^{(n-1)/n} . \quad \text{..... (7.3)}$$

7.3.3 Head. Head is simply the work expressed in foot pounds per pound of gas or N-m/kg. At a given compressor speed and capacity, the head developed by a centrifugal compressor is the same regardless of the nature of the gas being compressed. The pressure rise produced by the given amount of head varies with the density of the gas.

Isentropic (Adiabatic) Head. In an isentropic compression process, head is calculated by Eq. 7.4.

$$H_{is} = 53.3 z_{avg}(T_s/S)[k/(k-1)][(P_d/P_s)^{(k-1)/k} - 1] , \quad \text{..... (7.4)}$$

where

H_{is} = isentropic head, ft-lbf/lbm,
z_{avg} = average compressibility factor, dimensionless,
T_s = suction temperature, °R,
S = gas specific-gravity (standard atmospheric air = 1.00),
P_d = discharge pressure, psia,

and

P_s = suction pressure, psia.

Polytropic Head. In a polytropic compression process, head is defined by

$$H_p = 53.3 z_{avg}(T_s/S)[k\eta_p/(k-1)][(P_d/P_s)^{(k-1)/(k\eta_p)} - 1] , \quad \text{..... (7.5)}$$

where

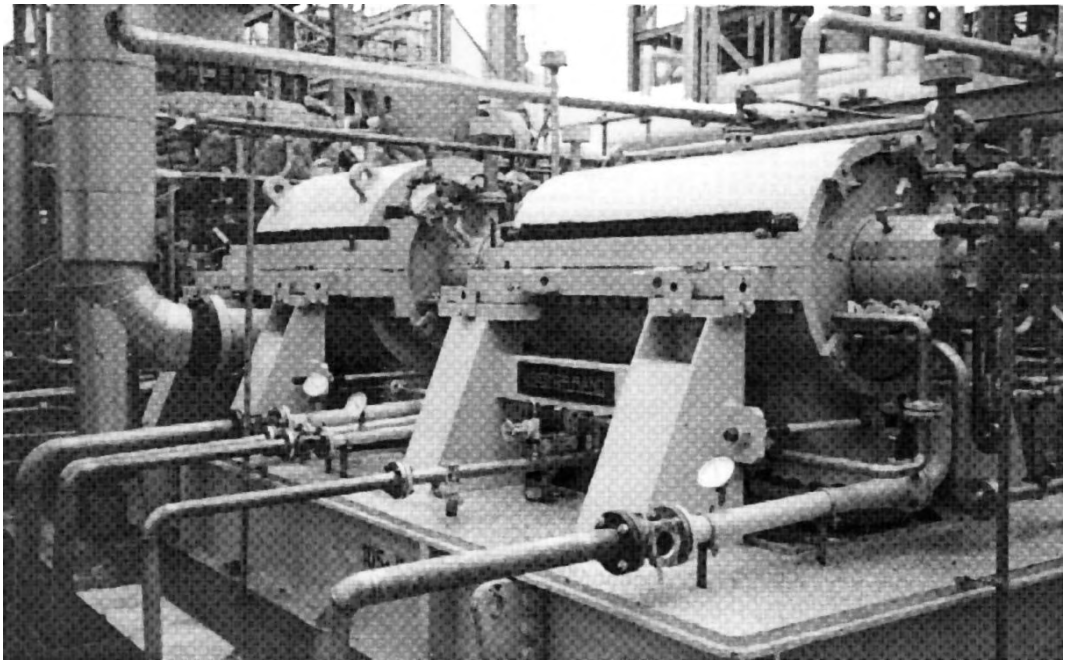


Fig. 7.5—Two-case centrifugal compressor package (courtesy of Dresser-Rand).

H_p = polytropic head, ft-lbf/lbm,
and
η_p = polytropic efficiency.

7.3.4 Adiabatic (Isentropic) Efficiency. Adiabatic efficiency is defined as the ratio of work output for an ideal isentropic compression process to the work input to develop the required head.

For a given compressor operating point, the actual or predicted isentropic efficiency can be calculated with Eq. 7.6.

$$\eta_{is} = T_s[(P_d / P_s)^{(k-1)/k} - 1] / (T_d - T_s) , \quad \text{..... (7.6)}$$

where
η_{is} = isentropic efficiency,
T_s = suction temperature, °R,
T_d = discharge temperature (actual or predicted), °R,
and
k = ratio of specific heats, C_p / C_v.

7.3.5 Polytropic Efficiency. The efficiency of the polytropic compression process is given by

$$\eta_p = [(k-1)/k)(\ln P_d / P_s)] / \ln (T_d / T_s) , \quad \text{..... (7.7)}$$

where
η_p = polytropic efficiency.

7.3.6 Compressibility Factor. The perfect gas equation derived from Charles' and Boyle's laws makes it possible to determine the weight of a given gas as determined by the equation

$$PV = NRT\ , \quad \text{..... (7.8)}$$

where

P = pressure,

V = volume,

N = number of moles,

R = constant for a specific gas,

and

T = temperature.

In reality, all gases deviate from the ideal gas laws to some degree. This deviation is defined as a compressibility factor, z, applied as a multiplier to the basic formula. Therefore, Eq. 7.8 is modified to include the compressibility factor as shown next.

$$PV = zNRT\ . \quad \text{..... (7.9)}$$

7.3.7 Flow (Capacity). Compressor flow (capacity) can be specified in three ways: mass (weight) flow, standard volume flow, and actual (inlet) volume flow.

Mass (Weight) Flow. Mass flow is expressed as mass per unit of time, most often pounds-mass per minute (lbm/min) or kilograms per minute (kg/min). Mass flow is a specific value independent of gas properties and compressor inlet conditions. Mass flow can be specified on either a wet (water vapor included) or dry basis.

Standard Volume Flow. Standard volume flow is the most common term used by the industry to describe volumetric flow because it is independent of actual gas pressures or temperatures. It is the volume per unit of time using pressures and temperatures that have been corrected to "standard" conditions. These conditions apply to pressure, temperature, molecular weight, and compressibility. The standards must be known and held constant. For purposes of this text, the standard conditions used are

pressure = 14.7 psia,

temperature = 60 °F,

compressibility = 1.00,

and

molecular weight = MW of subject gas.

Standard volume flow is usually dry and expressed in millions of standard cubic feet per day (MMScf/D).

Actual (Inlet) Volume Flow. Actual volume flow is defined as the amount of volume per unit of time at the inlet to the compressor. Actual volume flow is normally expressed in actual cubic feet per minute (ACFM) or actual cubic meters per hour (m^3/hr). When gas composition and pressure and temperature are known, the specification of actual volume is appropriate because the fundamental performance characteristic of the compressor is sensitive only to actual volume flow at the inlet (see Sec. 7.4.2).

Mass flow can be converted to actual volume flow with Eq. 7.10.

$$\text{ACFM} = WRT_s z_s / 144 P_s MW\ , \quad \text{..... (7.10)}$$

where

W = mass flow, lbm/min.,

R = universal gas constant = 1,545,

MW = molecular weight,

T_s = suction temperature, °R,

z_s = compressibility at inlet,

and

P_s = absolute suction pressure, psia.

Standard volume flow can be converted to actual volume flow with Eq. 7.11.

$$\text{ACFM} = 19.6 z_s T_s Q_g / P_s \,, \quad \text{..... (7.11)}$$

where

Q_g = standard volume flow, MMscf/D.

7.3.8 Compression Ratio. Compression ratio, R_c, is simply the absolute discharge pressure divided by the absolute suction pressure. As expressed in Eq. 7.3, temperature ratio increases with pressure ratio. Temperature limits related to the mechanical design of compressors often will dictate the maximum pressure ratio that can be achieved in a stage of compression. (Refer to Sec. 7.3.9 for a related discussion on intercooling.)

7.3.9 Intercooling. Where large pressure ratios are needed, splitting the compression duty into one or more stages with intercooling between stages can be the most energy efficient arrangement. The energy savings must be compared with the capital and maintenance investment necessary to provide the cooling. In addition to the thermodynamic benefit, intercooled compression systems result in lower discharge temperatures, which reduce the need for special compressor materials.

7.3.10 Power Requirement. The total power requirement of a compressor for a given duty is the sum of the gas power and the friction power. The gas power is directly proportional to head and mass flow and inversely proportional to efficiency. Mechanical losses in the bearings and, to a lesser extent, in the seals are the primary source of friction power.

For centrifugal compressors, the gas power can be calculated as

$$GHP = W H_p / 33{,}000 \eta_p \,, \quad \text{..... (7.12)}$$

where

GHP = gas power, horsepower,

W = mass flow, lbm/min.,

and

H_p = polytropic head, ft-lbf/lbm.

For reciprocating compressors, the gas power can be calculated as

$$GHP = [(0.004367)(P_1 / V_1)(k / k - 1)(P_2 / P_1^{k-1/k} - 1)] / CE \,, \quad \text{..... (7.13)}$$

where

P_1 = inlet pressure, psia,

V_1 = inlet volume, ACFM,

P_2 = discharge pressure, psia,

and

CE = compression efficiency (assume 0.85 for estimating purposes).

7.3.11 Compressor Selection. Proper selection of the compressor type and number of stages can be accomplished only after considering a number of factors. (For the purposes of this chapter, discussion is limited to centrifugal vs. reciprocating compressors.) Basic information needed for the proper selection includes volume and mass flow of gas to be compressed, suc-

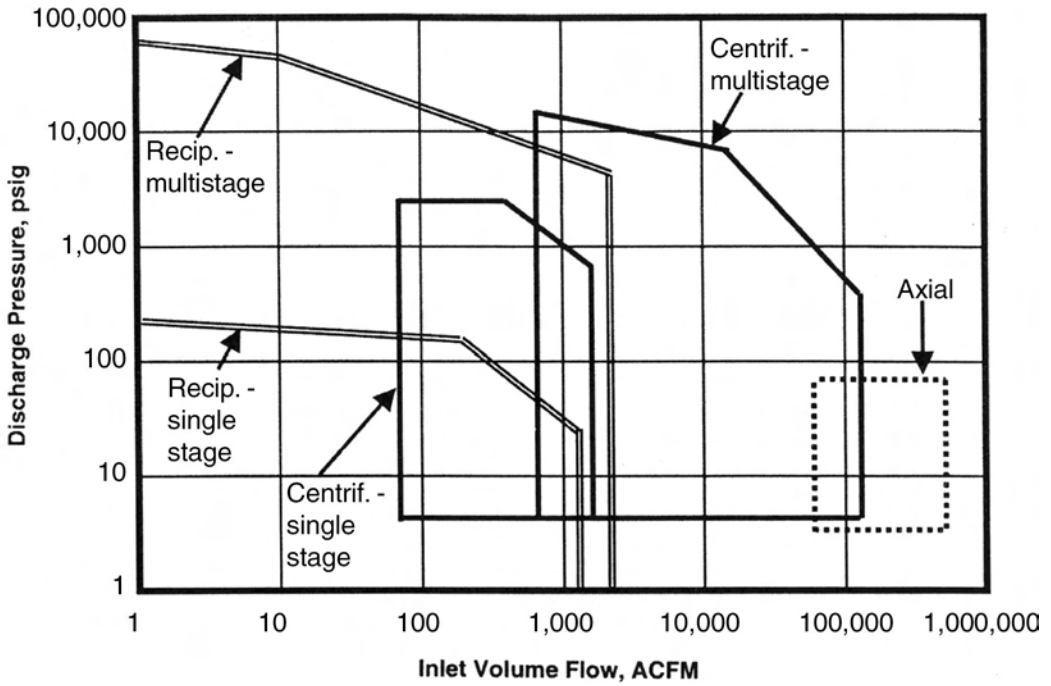


Fig. 7.6—Compressor selection. Areas indicate regions of best performance (courtesy of Dresser-Rand).

tion pressure, discharge pressure, suction temperature, gas specific gravity, and available types of drivers.

The required volume flow and discharge pressure define a point on a graphic representation of compressor coverage, as shown in **Fig. 7.6**. Examination of this chart reveals that, in general, centrifugal compressors are appropriate for high flow applications, and reciprocating compressors are better suited to low flow rates.

7.3.12 Number of Stages of Compression. Using the specified overall pressure ratio and suction temperature (and an assumed efficiency), the discharge temperature for compression of gas with a known k value in a single stage can be estimated by rewriting Eq. 7.7.

$$\ln(T_2/T_1) = \left\{[((k-1)/k)(\ln(P_2/P_1))]\right\}/\eta_p\,, \quad \text{..... (7.14)}$$

where

T_2 = estimated absolute discharge temperature, °R,
T_1 = specified absolute suction temperature, °R,
P_1 = specified absolute suction pressure, psia,
P_2 = specified absolute discharge pressure, psia,
k = ratio of specific heats,
η_p = assumed polytropic efficiency,
≈ 0.72 to 0.85 for centrifugal compressors,
and
≈ 1.00 for reciprocating compressors.

If the single-stage discharge temperature is too high (typical limit is 300 to 350 °F), it is necessary to configure the compression equipment in more than one stage. Calculating the compression ratio per stage with Eq. 7.15 does the evaluation of a multistage design.

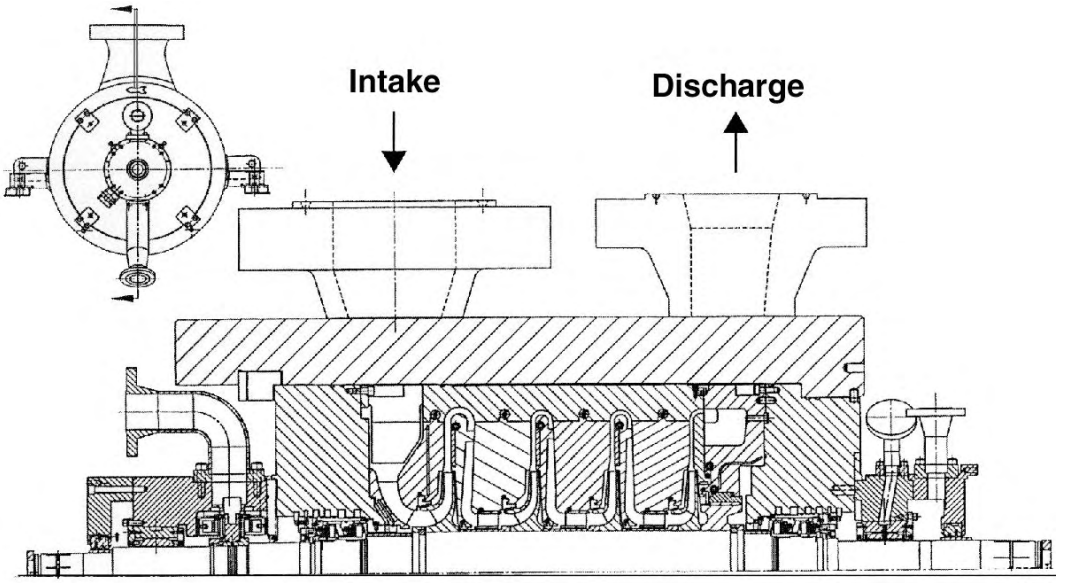


Fig. 7.7—Straight-through (inline) centrifugal compressor cross section (courtesy of Dresser-Rand).

$$R_{sect} = (P_2 / P_1)^{1/n} , \quad \text{..... (7.15)}$$

where

R_{sect} = compression ratio per section,

and

n = number of sections.

Using the previous equations and prudent assumptions, it is possible to determine the minimum number of stages required to accomplish a given overall compression ratio without exceeding temperature limits.

7.4 Centrifugal Compressors

Multistage centrifugal compressors can be arranged in a variety of flowpath configurations employing from one to ten impellers, depending on the head required for the process duty. When intercooling is not needed, the arrangement is usually a straight-through (inline) configuration. For applications that require intercooling, the resulting two-section compressor may be configured in either an inline (compound) or back-to-back arrangement. For high-flow/low-head applications, a double-flow configuration is sometimes employed. In a double-flow arrangement, half of the flow enters the compressor through an inlet connection at each end of the casing and exits the casing through a common discharge connection in the center. All of these configurations described are beam-type designs in which the impellers are located between the radial bearings.

Single-stage centrifugal compressors may be configured as a beam design or with an overhung impeller arrangement. In the overhung configuration, the impeller is located at the nondrive end of the shaft (outboard of the nondrive end radial bearing).

7.4.1 Major Components. The major components of various centrifugal compressor flowpath configurations are illustrated in **Figs. 7.7 through 7.10**. This section describes the major elements of centrifugal compressors.

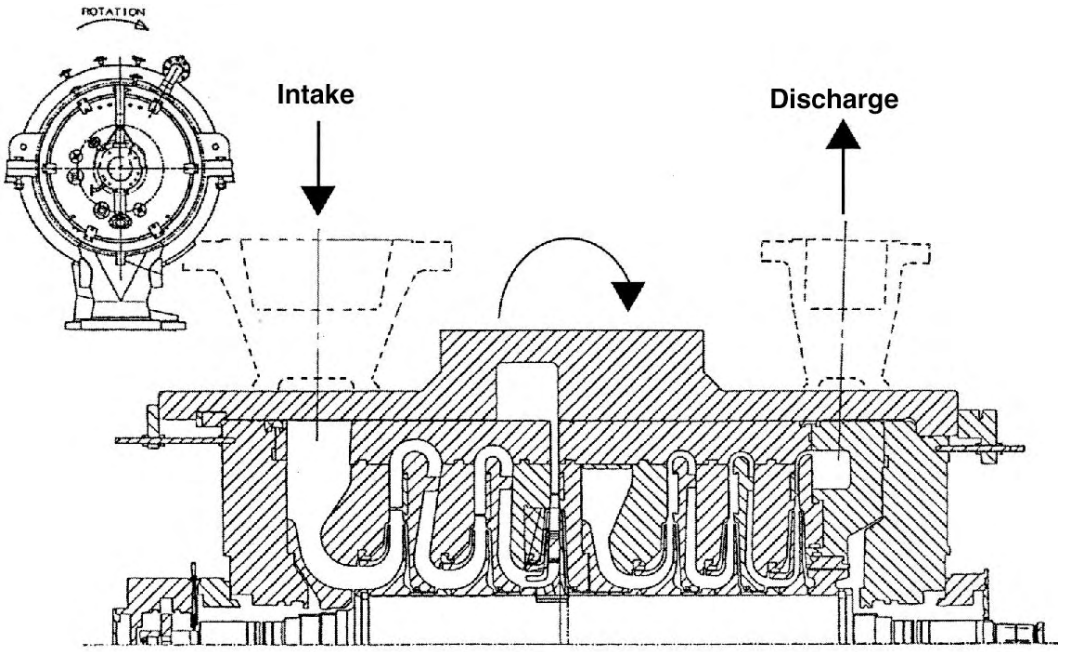


Fig. 7.8—Inline (compound) centrifugal compressor cross section (courtesy of Dresser-Rand).

Case (Casing or Housing). The case (casing or housing) is the pressure-containing component of the compressor. The case houses the stationary internal components and the compressor rotor. Bearings are attached to the case to provide both radial and axial support of the rotor. The case also contains nozzles with inlet and discharge flange connections to introduce flow into and extract flow from the compressor. The flange connections must be properly sized to limit the gas velocity as necessary. The case is manufactured in one of two basic types: horizontally or vertically split. Construction can be cast (iron or steel), forged, or fabricated by welding.

Horizontally (Axially) Split Case. A horizontally split case is split parallel to the axis of the rotor. The upper half of the case is bolted and doweled to the lower half. Access to the internals of the compressor for inspection and maintenance is facilitated with this case design (especially when the process piping connections are located on the bottom half of the case). The horizontally split design is inherently pressure-limited to prevent gas leakage at the case split joint.

Vertically (Radially) Split Case. This case is split perpendicular to the axis of the rotor. Heads (end covers) are installed at both ends for pressure containment. The vertically split case configuration is capable of handling higher pressures than the horizontally split type. The rotor and stationary internals are assembled as a cylindrical inner bundle that is inserted axially through one end of the case. Inspection and maintenance of a radially split centrifugal compressor require that the inner bundle be removed for disassembly. Removal of the inner bundle requires that sufficient space be provided in the layout of the compressor installation.

Rotor Assembly. The compressor rotor is fundamentally an assembly of impellers mounted on a steel shaft. Miscellaneous hardware such as a thrust balance drum (balance piston), impeller spacers, seal sleeves, a thrust disc, and one or two couplings are additional rotor components. A typical compressor rotor is pictured in **Fig. 7.11**.

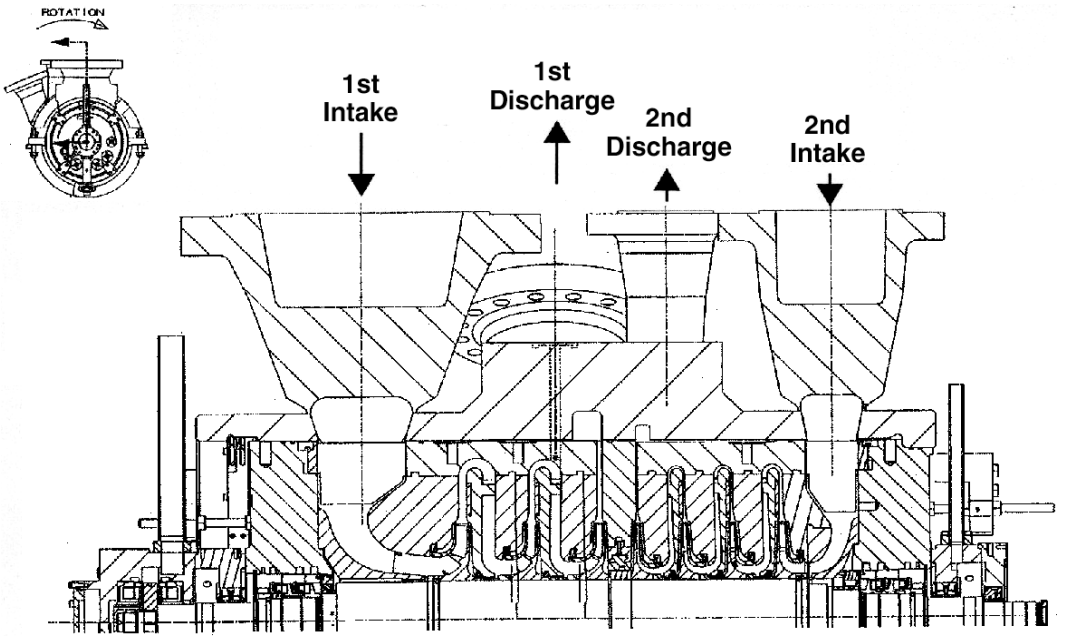


Fig. 7.9—Back-to-back centrifugal compressor cross section (courtesy of Dresser-Rand).

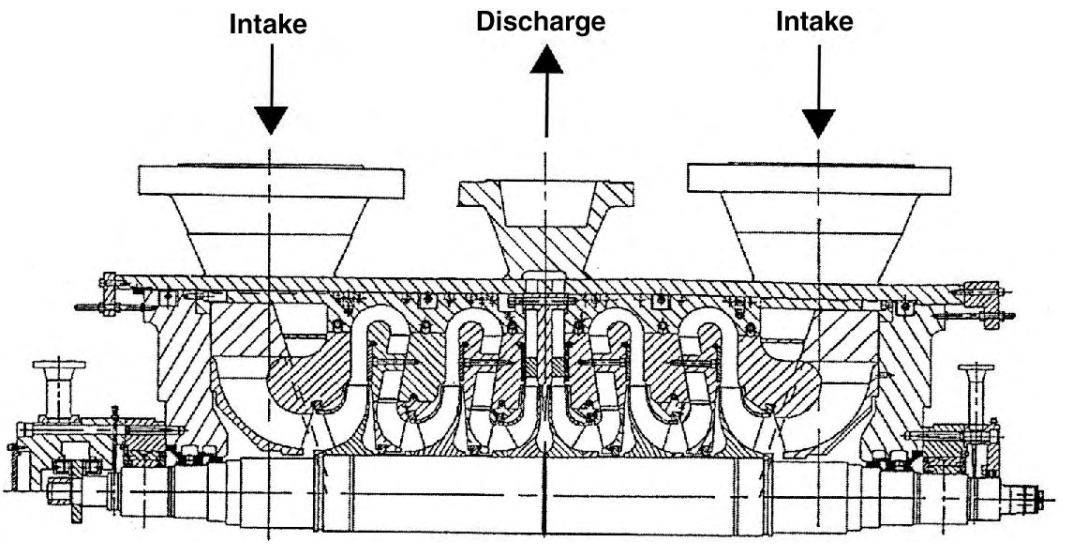


Fig. 7.10—Dual-flow centrifugal compressor cross section (courtesy of Dresser-Rand).

The impellers impart velocity to the gas with blades that are attached to a rotating disc. The impeller blades are forward-leaning, radial, or backward-leaning (with respect to the direction of rotation) depending on the desired performance characteristic curve. Backward-leaning blades tend to provide the widest operating range with good efficiency. They are the most commonly used blade shape. Proper sizing of the impeller flow channels is determined by the volumetric flow rate to control gas velocities through the impeller. This means that, in a multi-

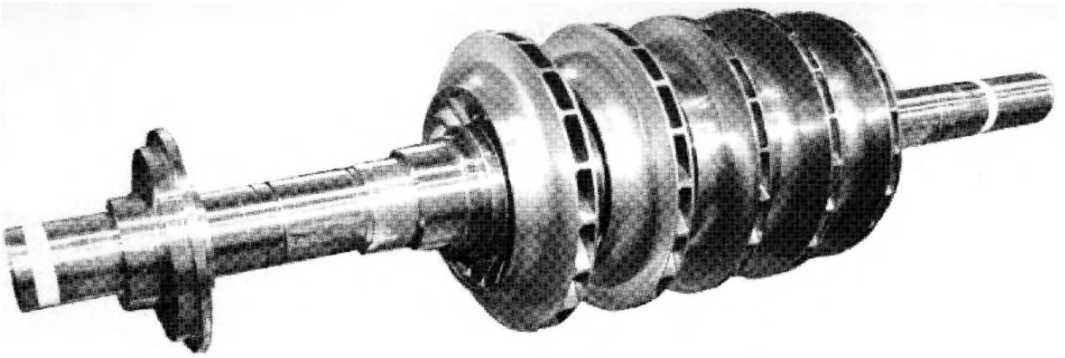


Fig. 7.11—Example compressor rotor assembly (courtesy of Dresser-Rand).

stage compressor, the impellers must be properly sized for peak performance and properly matched to accommodate the volumetric flow rate reduction through the compressor. Impellers can be of the open type without a cover plate or the closed type that incorporates a cover plate attached to the blades. Most multistage compressors use the closed-type impeller design. Impeller construction can be riveted, brazed, electron beam welded, or welded conventionally. For most applications, high-strength alloy steel is selected for the impeller material. Stainless steel is often the material of choice for use in corrosive environments. Because the impellers rotate at high speeds, centrifugal stresses are an important design consideration, and high-strength steels are required for the impeller material. For gases containing hydrogen sulfide, it is necessary to limit the impeller material's hardness (and therefore strength) to resist stress corrosion.

Multistage centrifugal compressor rotors have natural resonant frequencies that must be outside the operating speed range. Rotordynamic design considerations can limit the maximum number of stages per case or, stated another way, limit the maximum speed for a given number of stages.

Stationary Components. After the gas enters the compressor through the inlet nozzle, it must be directed to the inlet of the first stage impeller in a way that uniformly distributes the flow to the impeller at a desired velocity. A system of internal stationary components is designed to deliver the gas to the first impeller with minimal pressure drop. Stationary inlet guide vanes are normally positioned adjacent to the impeller inlet. Variation of the inlet guide vane angles can be employed to adjust the flow capacity of the compressor's performance characteristic curve. However, a variable inlet guide vane system introduces mechanical complexity as well as additional sealing considerations (see the subsection on Flow Control in Sec. 7.4.5).

The gas exits the impeller at high velocity and enters a diffuser passage. The diffuser is an important part of the stationary flowpath that usually comprises two parallel walls forming a radial flow channel. In the diffuser, the gas velocity decreases and dynamic pressure is converted to static pressure. Diffusers can be either vaneless or vaned. After exiting the diffuser passage, the flow encounters a return bend, which creates a 180-degree turn in the direction of flow (i.e., from radially outward to radially inward). Following the return bend, the flow enters a vaned return channel that directs the flow inward to the next impeller. The function of the return channel is (in the same manner as the first stage inlet system) to uniformly deliver flow to each impeller with minimal losses. The inlet guide vanes are located at the exit of the return channel. The components that form the return channel are called "diaphragms," and the diffuser passages are the spaces between adjacent diaphragms. Inlet guide vanes can be attached to a separate piece fitted into the diaphragm or an integral part of the diaphragm.

Following the last stage impeller, the gas must be collected and delivered to the discharge flange. The stationary component, typically used for this purpose, is a discharge volute. The

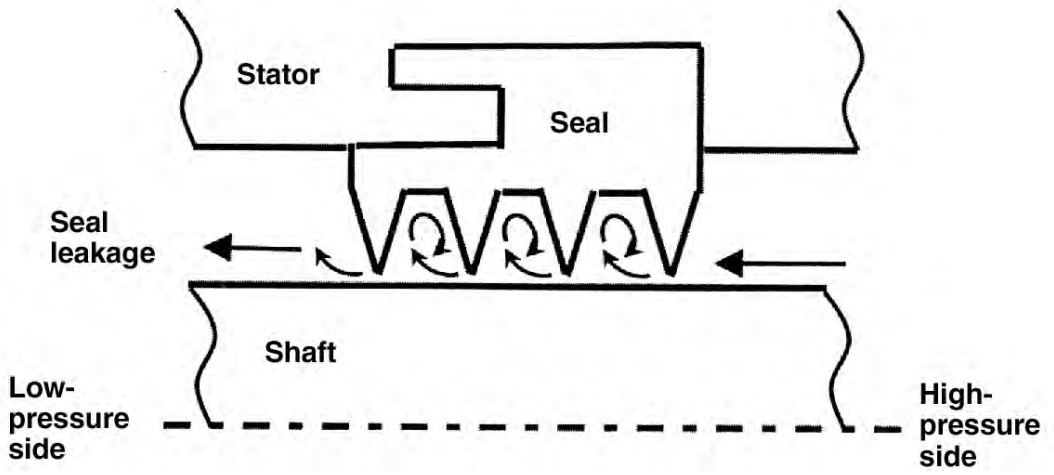


Fig. 7.12—Labyrinth seal (courtesy of Dresser-Rand).

volute must be well matched to the discharge nozzle to minimize pressure losses. Discharge nozzle velocities also must be kept within limits to avoid excessive noise levels. All of the stationary components previously described play an important role in overall compressor performance.

Bearings and Seals. Centrifugal compressors are equipped with two radial (journal) bearings to support the rotor weight and position the rotor concentrically within the stationary elements of the compressor. One thrust bearing also is used to ensure that the compressor rotor is maintained in its desired axial position. The thrust bearing usually is a "double-acting," tilt-pad design installed at both sides of a rotating thrust disc. Proper rotor axial position is thereby assured regardless of the direction of the net axial pressure forces acting on the rotor.

Two distinct categories of compressor seals are used: internal seals and shaft seals. Internal seals minimize internal recirculation losses between stages and across the thrust balance drum. Labyrinth type seals are customarily used for this purpose to maximize operating efficiency. Shaft seals are required to seal the gas inside the compressor at the point where the compressor rotor shaft penetrates the case. This vital sealing function is necessary to prevent escape of process gas to the environment surrounding the compressor. Dry gas seals are the most commonly used type of shaft seal. Liquid film seals are sometimes used.

Labyrinth Seals. Labyrinth-type seals are used to minimize recirculation losses within the compressor. A labyrinth seal consists of a number of teeth (knife-edges) that can be either stationary or rotating. Stationary labyrinth teeth are fitted to the compressor stationary components very close to the compressor rotor (see **Fig. 7.12**). Sealing action is the result of flow resistance caused by repeated throttling across the labyrinth teeth. Labyrinth seals are designed so that one of the two adjacent parts (labyrinth teeth and rotor) is relatively soft. The softer material yields on contact without damage to the harder material. Compressor manufacturers select labyrinth seal clearances that are as tight as practical to minimize leakage while avoiding heavy rubbing with the rotor.

Dry Gas Seals. Beginning in the late 1980s, the compressor industry began to embrace the application of dry gas seal technology to the critical function of shaft sealing. The seal consists of a rotating disc running very close to a stationary ring. The rotating disc face contains special grooves that generate an axial ("lift") force during rotation. The stationary ring is backed by a quantity of coil springs that force it tightly against the rotating disc when the compressor is at rest. The lift force compresses the coil springs slightly, resulting in the very small running

clearance between the two faces. This small clearance effectively limits gas leakage from the compressor seals. The small amount of gas leakage exits the compressor through auxiliary seal piping, where it is then either sent to a flare system or to some other recovery system. Usually the two compressor seals (inlet and discharge ends of the compressor) are subjected to the gas suction pressure. A thrust balance line (see further discussion in the section on bearings) subjects the discharge end dry gas seal to inlet pressure, thereby avoiding the need to seal the higher discharge pressure.

Dry gas seals require clean and dry gas for reliable operation. Seal gas is normally taken from the compressor discharge and then cooled and filtered as part of an external seal gas processing system. A seal reference pressure is measured just inboard of the dry gas seal, and a pressure regulating valve supplies the seal gas to the sealing faces at a pressure slightly above the reference pressure. This system ensures that the seals are not exposed to untreated process gas containing liquids or particulate matter that could damage the seals. Although dry gas seals are relatively expensive, their auxiliary system is less complex, physically smaller, and less expensive than the auxiliary system required by the predecessor liquid film design.

Liquid Film Seals. Liquid film seals can be of the bushing type or mechanical contact type. The bushing type is a very simple and rugged design that incorporates two adjacent seal rings (bushings) at each end of the compressor. A sealing fluid is introduced into the space between the seal rings at a pressure slightly above the process gas pressure inboard from the inner ring. The pressure differential across the inner ring is assured by an overhead seal oil tank pressurized by compressor suction pressure. The elevation above the compressor of the oil level in the tank assures the required seal ring pressure differential. For almost all centrifugal compressors equipped with liquid film seals, the sealing fluid is the same light turbine oil as that used to lubricate the bearings. Therefore, the auxiliary seal oil system needed to supply the seal oil can be combined with (or separate from) the auxiliary lube oil system.

The inner seal ring is designed to minimize oil leakage into the process side. Inner seal leakage (also called sour oil leakage) mixes with the process gas and is drained from the compressor as an oil/gas mixture. A labyrinth seal inboard of the sour oil drain is installed to prevent seal oil from contaminating the process gas. The oil/gas mixture drains into a degassing tank where the gas is removed so that the oil can be sent to a seal oil reservoir for reuse.

The outer seal ring breaks serve to inhibit flow as pressure is reduced to an atmospheric drain. This drain is common with the bearing oil drain when a combined oil system is used. When the lube and seal oil systems are separate, a buffered labyrinth seal is placed between the lube and seal oil drains to ensure that there is no oil carryover from one system to the other.

Mechanical contact seals employ a stationary carbon ring against a rotating seal face. Oil is also used as the sealing medium in mechanical contact seals. The sealing oil is introduced by a pressure-regulating valve that is maintained at 25 to 40 psi above the seal reference pressure. One advantage of mechanical contact seals is a significantly reduced sour oil leakage compared with the bushing design. Unlike oil film seals, mechanical contact seals can be supplied with a feature that allows the compressor to maintain case pressure during shutdown without requiring that the auxiliary seal oil system be operating. Mechanical contact seals, however, are relatively complex.

Bearings. The radial bearings most often used in centrifugal compressors are the tilting pad type and are continuously lubricated with light turbine oil. Before tilting pad designs, sleeve type bearings were commonly used. The tilting pad bearing design provides rotor-dynamic characteristics that help assure smooth and reliable mechanical operation. Radial bearings are sized to be large enough to support the rotor weight, yet small enough to operate at sufficiently low peripheral speeds required to limit operating temperature to acceptable levels. Some centrifugal compressors are equipped with magnetic radial bearings. These bearings suspend the rotor by electromagnetic force to center the rotor within an air gap at the bearing. Use of magnetic

bearings eliminates the need for an auxiliary lube oil system; however, the magnetic bearing control system also requires cooling.

The pressure rise in each of the stages of a centrifugal compressor creates an axial thrust force that acts toward the inlet end of the compressor. Depending on the overall pressure rise in the compressor, these thrust forces can be significant. An inline configuration employs a thrust balance drum (balance piston) to generate a thrust force to oppose ("balance") the sum of the impeller thrust forces. Located at the discharge end of the compressor, the balance piston is a simple disc-shaped element installed on the compressor shaft and equipped with a seal around its outer diameter. The space adjacent to the outboard face of the balance piston is subjected to compressor suction pressure as created by an auxiliary thrust balance line. The inboard surface of the balance piston is subjected to what is essentially the compressor discharge pressure. The resulting pressure differential across the balance piston creates an axial force toward the discharge end, thus opposing the impeller thrust forces. Proper selection of the balance piston diameter results in small net thrust force and allows use of a reasonably small thrust bearing to absorb the residual thrust forces and maintain proper rotor axial positioning.

Like the radial bearing, the thrust bearing is usually a tilting-pad design lubricated with light turbine oil. Some thrust bearing designs employ a system of leveling blocks behind each tilting pad to ensure uniform load distribution. As with the radial bearings, magnetic thrust bearings also are available.

7.4.2 Compressor Performance. The performance characteristic of a centrifugal compressor is graphically presented in the form of a family of curves that collectively are known as a performance map or operating envelope. An example of a performance map is given in **Fig. 7.13**. In the example map, the inlet volume flow is plotted along the *x*-axis and the head or pressure ratio is plotted along the *y*-axis. The "approximate surge limit" depicted at the left side of the map defines the minimum flow necessary to avoid a potentially damaging surge condition (see Sec. 7.4.3). At the extreme right portion of the map is the "stonewall" (choke) limit (see Sec. 7.4.4). Each of the family of curves from the surge limit to the stonewall represents the flow vs. pressure characteristic at a given compressor speed. The slope of the curve varies with the number of stages, becoming steeper with an increasing number of stages. The elliptical curves (dashed lines) denote compressor efficiency. The design point is at 100% speed, and the compressor components are selected so that the design point has a safe margin from surge and stonewall, as well as optimum efficiency.

7.4.3 Surge. The surge limit defines the flow at which, for a given speed, the operation of the compressor becomes unstable. At flow rates below the surge limit the characteristic curve actually droops toward zero flow after having reached its maximum point at the surge limit. Because operation below the surge limit is unstable, this portion of the curve is not shown in Fig. 7.13. When the flow is reduced below the surge limit, the pressure at the discharge of the compressor exceeds the pressure-making capability of the compressor, causing a momentary reversal of flow. When this flow reversal occurs, the pressure of the discharge system is reduced, allowing the compressor to resume delivering flow until the discharge pressure again increases, and the surge cycle repeats. Surging usually creates a clearly audible noise. Prolonged operation in this unstable mode can cause serious mechanical damage to the compressor. When operating in a surge condition, the compressor discharge temperature increases significantly and the compressor experiences erratic and severe vibration levels that can cause mechanical damage—particularly to the internal seals.

A compressor can be brought out of surge in a number of ways. The most obvious is to increase flow (see the subsection on Antisurge Valves in Sec. 7.4.5). Decreasing discharge pressure and/or increasing speed are other ways to move out of a surge condition.

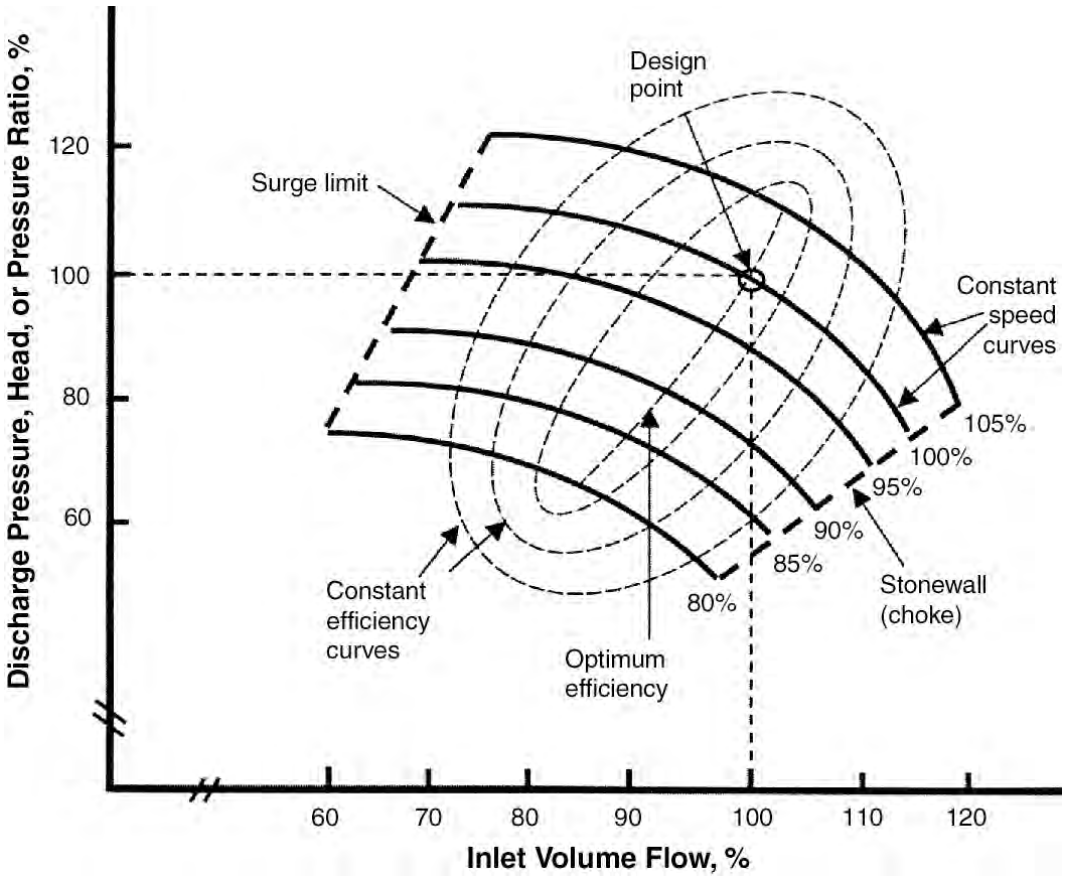


Fig. 7.13—Centrifugal compressor performance map (courtesy of Dresser-Rand).

Compressor manufacturers usually perform an aerodynamic performance test before delivering the compressor. Determination of the compressor's actual surge limit is a very important aspect of the manufacturer's shop testing program.

7.4.4 Stonewall (Choke). The stonewall limit of the performance curve defines the flow at which the gas velocity at one of the impellers approaches the velocity of sound for the gas at the conditions within the compressor where this sonic condition is first encountered. At the stonewall (or choke) flow the pressure vs. volume curve becomes essentially vertical, and it is not possible to develop head or pressure at any greater flow. When the required operating flow exceeds the stonewall limit, the only remedy is to reconfigure the compressor with impellers (and matched stationary hardware) designed for larger flow rates.

7.4.5 Process Installation. A centrifugal compressor may be configured with one of a variety of process connection arrangements. For grade-mounted installations, the process connections are most often positioned on the upper half of the casing with the process piping connected from above the compressor. In some installations, horizontal (side) connections are employed. The horizontal connection arrangement is frequently used in booster compressors for gas transmission. A radial split case design (see the subsection on Case in Sec. 7.4.1) is preferred for these two arrangements. Another arrangement is the mezzanine-mounted configuration. With this type of installation, the compressor connections are on the lower half of the casing, and

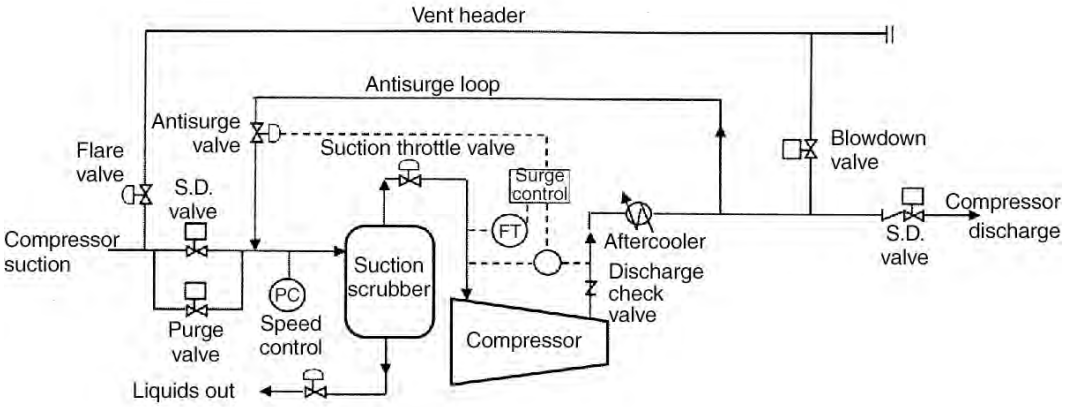


Fig. 7.14—Example centrifugal compressor process flow diagram (courtesy of Dresser-Rand).

the process piping is connected from underneath the compressor. If the operating pressures are sufficiently low, an axial split case design is appropriate (see the subsection on cases). To achieve optimum performance, it is necessary to install the compressor with a sufficiently long straight section of inlet piping upstream of the compressor inlet flange. Most compressor manufacturers require that the length of this straight section be at least two times the inlet flange diameter.

The compressor must be well integrated into the entire process so that start-up, operation, and shutdown can be safely controlled. The next section provides a description of control concepts and the process equipment required. (Refer to **Fig. 7.14** for a typical process flow diagram.) The individual elements of the control and safety system illustrated in Fig. 7.13 are discussed in this section.

Flow Control. Most compression processes require the compressor to deliver a relatively constant discharge pressure over a range of capacities. However, the centrifugal compressor characteristic curve from Fig. 7.13 shows that the pressure ratio, in fact, varies continuously with flow. The process can control either suction or discharge pressure. If one is fixed, the other will vary as dictated by the compressor characteristic curve. The three methods of maintaining a constant discharge pressure for varying capacity are discussed next.

Speed Control. Centrifugal compressor drivers are either of the fixed or variable speed type. Most steam or gas turbines and those electric motors equipped with a variable frequency drive system are all available as variable speed drivers. For a given discharge pressure, compressor capacity may be increased by merely increasing the speed of rotation. Conversely, capacity may be decreased by reducing compressor speed. Capacity control by speed variation is the most effective way to maximize the operating flexibility of a centrifugal compressor.

Suction Throttle Valves. A fixed-speed motor is often the least expensive driver for a centrifugal compressor. When designing a centrifugal compressor driven by a fixed-speed motor, it is necessary to establish the speed based on the operating condition that requires the largest capacity for the required discharge pressure. When operating at lower capacities, the compressor inherently delivers a greater discharge pressure (for a given process suction pressure) than desired. The solution to this problem is to install a throttle valve at the inlet of the compressor. Suction pressure reduction by throttling increases the pressure ratio required to deliver a given discharge pressure. The economic trade-off for this method of capacity control is additional compressor power vs. additional capital expenditure for a variable speed driver.

Variable Inlet Guide Vanes. As discussed in the subsection on Stationary Components in Sec. 7.4.1, the compressor performance characteristic curve can be adjusted by changing the

direction of the flow of gas into the impeller. When a system of variable inlet guide vanes is employed, it is possible to adjust the inlet guide vane angles to maintain a desired discharge pressure over a range of capacity. Practical design limitations make it difficult to install variable vanes at all stages other than the first stage. For single stage compressors, this method of control is sometimes quite effective. However, for multistage compressors, the range of control is less effective and becomes even less so with increasing numbers of stages.

Antisurge Valves. As discussed in Sec. 7.4.3, avoiding surge is extremely important. The installation of an antisurge (recycle) valve and its associated control devices is required. The antisurge valve is located in a recycle line connecting the compressor discharge to the inlet. For multisection compressors, it is good practice to install a separate recycle line with an antisurge valve for each of the compressor sections. Instrumentation is required to measure the flow to each section, and a surge controller must initiate the opening of the recycle valve when reduced capacity approaches the surge limit. The capacity at which the antisurge valve begins to open is usually set to be about 10% larger than the actual surge limit.

For variable speed compressors, the surge limit curve (see Fig. 7.13) defines the relationship between the surge limit and the operating speed. The logic programmed into the antisurge controller maintains the 10% safety margin, regardless of speed. This can be depicted graphically by a line parallel to the surge limit curve and is typically called the "control line."

The gas recycled through the antisurge valve also must be cooled because its source is the compressor discharge. If uncooled, the suction temperature will increase by mixing the hotter recycled gas with the main process inlet gas.

Flare Valve. The flare valve protects upstream equipment from overpressurization that may occur because of a flow increase and prevents overloading of the compressor driver. For a constant discharge pressure system, an increase in flow results in an increase in suction pressure. Higher suction pressures deliver more mass flow and, therefore, increase the power required to operate the compressor. The presence of a suction throttle valve also can contribute to an increase in pressure upstream from the compressor. Thus, flare valves are particularly important in installations with inlet throttling.

Shutdown Valve. Shutdown valves are installed at both the suction and discharge to enable the compressor to be isolated during shutdown periods. To satisfy safety concerns, the shutdown valves should be located outside any building or enclosure. Automatic control of the shutdown valves is usually employed.

Blowdown Valve. At shutdown, after the shutdown valves have isolated the compressor, the pressure in the compressor settles out to a level determined by a variety of factors. A blowdown valve is used to depressurize the compressor upon shutdown. Automatic control of the blowdown valve is recommended for high-risk locations and for compressors that are fitted with liquid film seals. When liquid film seals are employed, the compressor must be depressurized before the overhead seal tanks have been drained.

Discharge Check Valve. Placement of a check valve at the discharge of each section of compression can minimize or eliminate backflow through the compressor. Should backflow occur, it is possible for the compressor to experience potentially damaging reverse rotation. The presence of discharge check valves also provides the benefit of isolating each of the antisurge recycle loops (see the subsection on Antisurge Valves above).

Relief Valve. The compressor develops its maximum pressure ratio when operating at both its maximum continuous speed and the surge control capacity. If the suction pressure increases for any reason, the discharge pressure correspondingly increases to the value given by the performance map for the speed and capacity in question. A pressure relief valve is installed to protect against overpressurization of downstream equipment by the compressor.

Purge Valve. Before startup, it is necessary to purge air from the compressor and piping system. A purge valve is installed as a bypass to the suction shutdown valve for this purpose.

Purging must be done with a low flow rate to prevent the purge gas from initiating compressor rotation. For this reason, the purge valve is small.

Discharge Coolers. A discharge cooler (after cooler) is required if the temperature of the gas at the compressor discharge exceeds that required for the next step in the process.

Suction Scrubbers. Erosion of compressor components can be caused by ingestion of excessive liquid. To prevent erosion damage, suction scrubbers are installed to remove liquids that condense in the gas suction line because of cooling or that result from an upstream-process upset resulting in liquid carryover to the gas suction line.

Vent Valve. A manual vent valve is installed between the compressor discharge and the discharge check valve to allow the compressor to be isolated from the vent header for maintenance. Once the compressor is shut down and blown down to the vent header, the blowdown valve can be closed and the vent valve opened. If the blowdown valve were kept open, there is a possibility that gas in the vent header would flow into the compressor system, endangering the maintenance operation.

Safety and Monitoring Devices. Centrifugal compressors are equipped with instrumentation to monitor mechanical health. Vibration monitoring is accomplished by eddy current probes installed at each of the compressor bearings. Vibration amplitude is measured at each radial bearing, and the axial position of the rotor is measured at the thrust disc or shaft end. The trend of radial vibration amplitude provides insight into the condition of the compressor regarding rotor balance and alignment. When a problem arises, the vibration frequency spectrum can also be analyzed to provide useful diagnostic information. The axial position probe monitors the state of thrust bearing wear. Each of the bearings is also fitted with temperature-sensing devices. By trending the thrust bearing pad temperatures, it is possible to discern the condition of the internal seals because changes in seal condition affect thrust loads and, therefore, bearing temperature. Alarm and shutdown settings for high bearing vibration and temperature are established in the compressor control system.

External to the compressor are numerous other alarm and shutdown safeguards. As a minimum, low lube oil pressure, low seal gas pressure differential, overspeed, high discharge gas temperature, high and low suction and discharge pressures, and high liquid level in the suction scrubber are monitored and will initiate a shutdown when necessary.

7.4.6 Maintenance. When properly designed, operated, and protected, centrifugal compressors are capable of long sustained runs with very little maintenance. The components most prone to wear are the bearing pads and internal labyrinth seals. Fouling of the internal surfaces can occur in some services causing a degradation of performance. The vibration and bearing temperature monitoring instrumentation, described in the subsection on safety and monitoring devices, provides valuable information to the operator about the probable condition of the compressor bearings. Excessive wear of the internal labyrinth seals can occur when the compressor experiences high vibration excursions from process upsets or operation in a surge condition. Worn internal seals cause a degradation of compressor performance similar to that caused by fouling.

Unless there is an identified problem with the compressor, maintenance is generally carried out during planned turnarounds. As a minimum, the easily accessible compressor bearings and shaft endseals are inspected and replaced with spares, if necessary. Complete disassembly is required to inspect the compressor internals. The auxiliary lube and seal systems require maintenance of miscellaneous items such as seal gas filters, lube oil pump seals, oil filters, etc.

7.5 Reciprocating Compressors

7.5.1 Major Components. Reciprocating compressors are available in a variety of designs and arrangements. Major components in a typical reciprocating compressor are shown in **Fig. 7.15**.

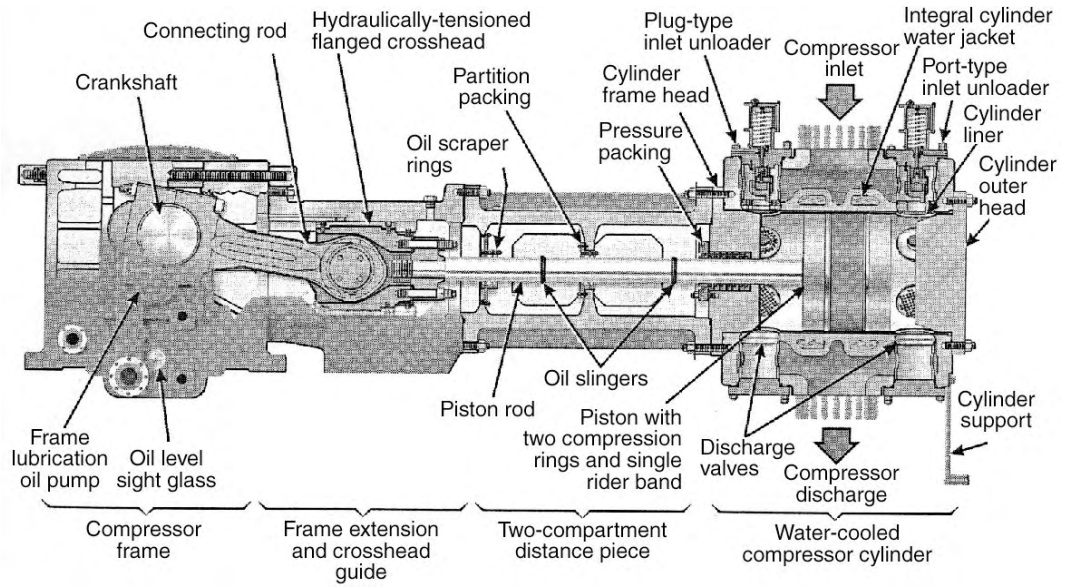


Fig. 7.15—Reciprocating compressor components (courtesy of Dresser-Rand).

Frame. The frame is a heavy, rugged housing containing all the rotating parts and on which the cylinder and crosshead guide is mounted. Compressor manufacturers rate frames for a maximum continuous horsepower and frame load (see the subsection on Rod Load in Sec. 7.5.2).

Separable compressors are usually arranged in a balanced-opposed configuration characterized by an adjacent pair of crank throws that are 180 degrees out of phase and separated by only a crank web. The cranks are arranged so that the motion of each piston is balanced by the motion of an opposing piston.

Integral compressors typically have compressor and engine-power cylinders mounted on the same frame and are driven by the same crankshaft. Cylinders in integral compressors are usually arranged on only one side of the frame (i.e., not balanced-opposed).

Cylinder. The cylinder is a pressure vessel that contains the gas in the compression cycle. Single-acting cylinders compress gas in only one direction of piston travel. They can be either head end or crank end. Double-acting cylinders compress gas in both directions of piston travel (see **Fig. 7.16**). Most reciprocating compressors use double-acting cylinders.

Choice of cylinder material is determined by operating pressure. Cast iron is normally used for pressures up to 1,000 psi. Nodular iron is used for pressures up to 1,500 psi. Cast steel is usually used for pressures between 1,500 and 2,500 psi. Forged steel is selected for cylinder operating pressures greater than 2,500 psi.

A cylinder's maximum allowable working pressure (MAWP) should be rated at least 10% greater than the design discharge pressure (minimum 25 psi). The additional pressure rating allows a high-pressure safety sensor (PSH) to be set above the design discharge pressure, and for a relief valve (PSV) to be set at a pressure above the PSH.

Wear compatibility of the rubbing parts (piston rings and cylinder bore, piston rod and seal rings, etc.) is also a criterion for selecting materials. Cylinders experience wear at the point of contact with the piston rings. In horizontal arrangements, cylinder wear is greatest at the bottom because of piston weight. Thermoplastic rings and rider bands are used in most reciprocating compressors to reduce such wear.

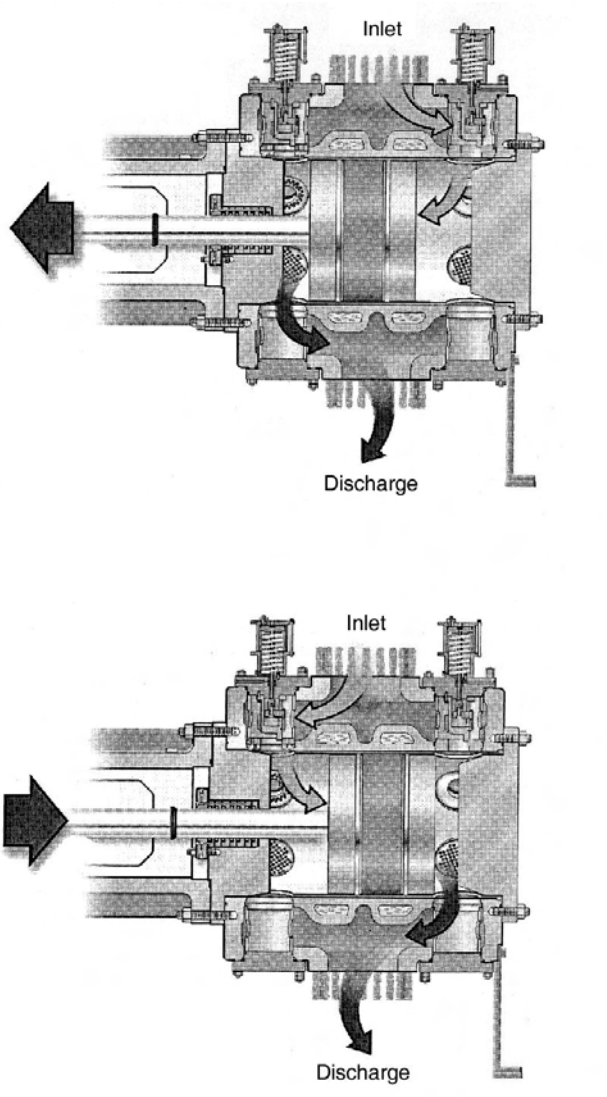


Fig. 7.16—Double-acting cylinders (courtesy of Dresser-Rand).

Cylinders are frequently supplied with liners to reduce reconditioning costs. Liners are pressed or shrunk in place to ensure that they do not slip. Replacement of a cylinder liner is much less expensive than replacing an entire cylinder. In addition, performance can be adjusted to new requirements by changing the inside diameter of the liner. However, cylinder liners increase the clearance between the valve and the piston, diminish the effectiveness of jacket cooling, and decrease compressor capacity from a given diameter.

Distance Piece. The distance piece provides separation between the compressor cylinder and the compressor frame. Fig. 7.17 illustrates API *Standard 11P* and API *Standard 618* distance pieces. Distance pieces can be contained in either a single- or double-compartment arrangement. In the single-compartment design, the space between the cylinder packing and the diaphragm is lengthened so that no part of the rod enters both the crankcase and cylinder stuffing box. Oil migrates between the cylinder and the crankcase. If oil contamination is a

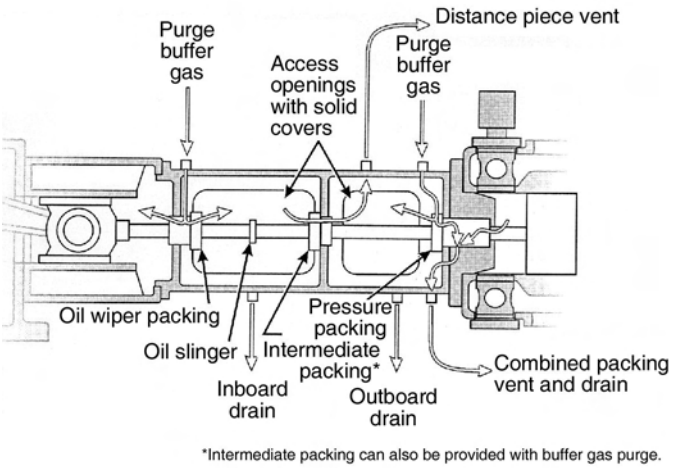


Fig. 7.17—Two-compartment distance piece showing packing and buffer gas arrangement (courtesy of Dresser-Rand).

concern, an oil slinger can be provided to prevent packing lube oil from entering the compressor frame. For toxic service, a two-compartment design may be used. No part of the rod enters both the crankcase and the compartment adjacent to the gas cylinder.

The packing case should be vented to the first stage suction or a vent gas system. Distance pieces contain a vent to evacuate additional leaking process gas from the packing. The diaphragm and packing are designed to keep gas from entering the crankcase. Effective venting is required to ensure that the process gas does not contaminate crankcase oil.

Each compressor should be equipped with a separate vent and drain system for distance pieces and packing. Distance piece and packing vents should be piped into an open vent system that terminates outside and above the compressor enclosure at least 25 ft horizontally from the engine exhaust. The distance piece drain should be piped into a separate sump that can be manually drained. The sump should be vented outside and above the compressor enclosure. Lube oil from the sump can be mixed with crude oil or, under certain circumstances, must be transported for disposal or recycling.

Crankshaft. The crankshaft rotates around the frame axis and drives the connecting rod, piston rod, and piston (see **Fig. 7.18**).

Connecting Rod. The connecting rod connects the crankshaft to the crosshead pin.

Crosshead. The crosshead converts the rotating motion of the connecting rod to a linear, oscillating motion that drives the piston.

Piston Rod. The piston rod connects the crosshead to the piston.

Piston. The piston is located at the end of the piston rod and acts as the movable barrier in the compressor cylinder. Selection of material is based on strength, weight, and compatibility with the gas being compressed. The piston is usually made of a lightweight material such as aluminum or from cast iron or steel with a hollow center for weight reduction. Thermoplastic wear (or rider) bands often are fitted to pistons to increase ring life and reduce the risk of piston-to-cylinder contact. Cast iron usually provides a satisfactorily low friction characteristic, eliminating the need for separate wear bands.

Wear bands distribute the weight of the piston along the bottom of the cylinder or liner wall. Piston rings minimize the leakage of gas between the piston and the cylinder or liner bore. Piston rings are made of a softer material than the cylinder or liner wall and are replaced

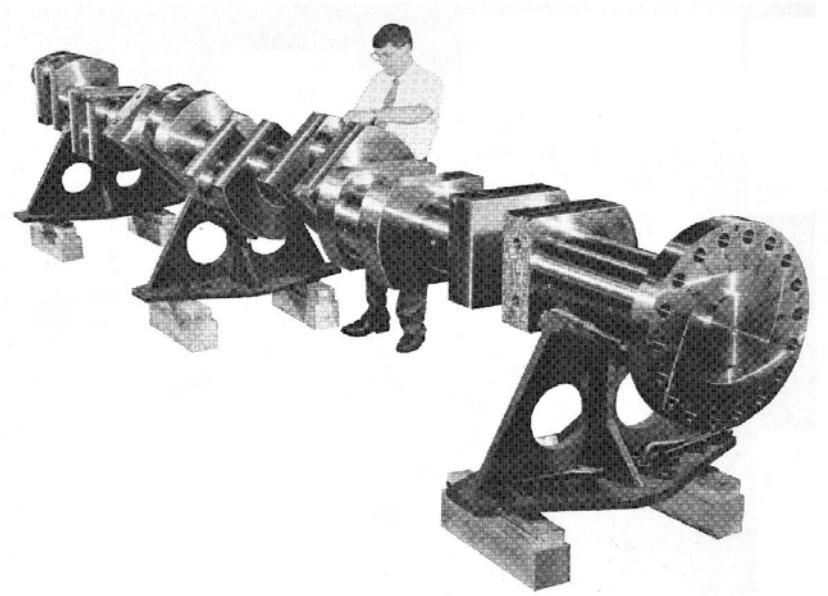


Fig. 7.18—Crankshaft assembly (courtesy of Dresser-Rand).

at regular maintenance intervals. As the piston passes the lubricator feed hole in the cylinder wall, the piston ring gathers oil and distributes it over the length of the stroke.

Bearings. Bearings located throughout the compressor frame assure proper radial and axial positioning of compressor components. Main bearings are fitted in the frame to properly position the crankshaft. Crank pin bearings are located between the crankshaft and each connecting rod. Wrist pin bearings are located between each connecting rod and crosshead pin. Crosshead bearings are located at the top and bottom of each crosshead.

Most of the bearings in reciprocating compressors are hydrodynamic lubricated bearings. Pressurized oil is supplied to each bearing through oil supply grooves on the bearing surface. The grooves are sized to ensure adequate oil flow to prevent overheating.

Piston Rod Packing. Piston rod packing provides the dynamic seal between the cylinder and the piston rod. The packing consists of a series of non-metallic rings mounted in a case and bolted to the cylinder. The packing rings work in pairs and are designed for automatic wear compensation. Because each pair of rings accommodates a limited amount of pressure differential, multiple pairs are required depending on the pressure required by the application. To safely vent gas leakage through the packing, the vent port is usually located between the two outer ring assemblies (see the subsection on Distance Piece in Sec. 7.5.1).

Auxiliary connections to the packing may be required for cooling water, lubricating oil, nitrogen purging, venting, and temperature measurement. Lubrication must be finely filtered to avoid damage that would result from small particulate matter entering the case. The lubricating oil is normally injected into the second ring assembly, with pressure moving the oil along the shaft.

Compressor Valves. The essential function of compressor valves is to permit gas flow in the desired direction and to block all flow in the opposite (undesired) direction. Each operating end of a compressor cylinder must have two sets of valves. The set of inlet (suction) valves admits gas into the cylinder. The set of discharge valves is used to evacuate compressed gas from the cylinder. The compressor manufacturer normally specifies valve type and size.

Plate valves constructed from rings connected by webs into a single plate are a common valve type. Depending on the sealing plate material, plate valves are capable of handling pres-

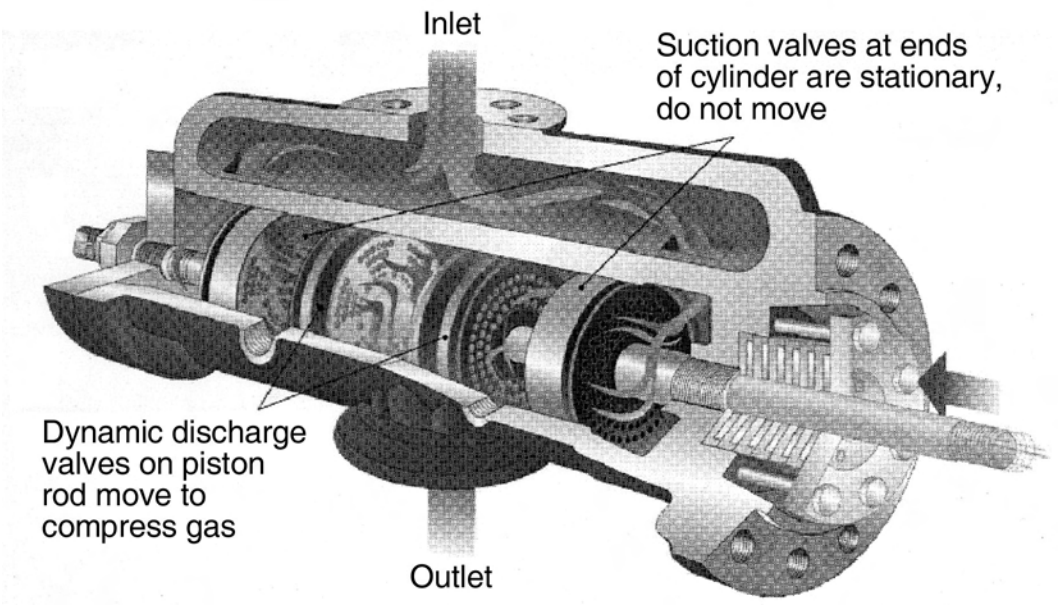


Fig. 7.19—Valve-in-piston design (courtesy of Dresser-Rand).

sures as high as 15,000 psi, differential pressures to 10,000 psi, speeds to 2,000 rpm, and temperatures to 500°F. Plate valves do not perform well in the presence of liquids.

Concentric ring valves are capable of handling pressures to 15,000 psi, differential pressures to 10,000 psi, speeds to 2,000 rpm, and temperatures to 500°F. Advantages of concentric ring valves include moderate parts cost, low repair cost, and the ability to handle liquids better than plate valves.

Poppet-style valves generally provide performance that is superior to both plate and concentric ring valves. The poppet style uses separate, round poppets to seat against holes in the valve seat. This type of valve offers high lift and low pressure drop, resulting in higher fuel efficiency. Poppet valves are widely used in pipeline, gas conditioning, and processing facilities. Metallic poppets work well at pressures to 3,000 psi, differential pressures to 1,400 psi, speeds to 450 rpm, and temperatures to 500°F. Thermoplastic poppets can be applied to applications with pressures to 3,000 psi, differential pressures to 1,500 psi, speeds to 720 rpm, and temperatures to 400°F.

Most compressors have valves mounted in the cylinders. A relatively new design concept places the valves in the piston. The valve-in-piston design (**Fig. 7.19**) operates with low valve velocities and provides longer life cycles and reduced maintenance time.

7.5.2 Compressor Performance. Compressor capacity and horsepower are affected by piston displacement and cylinder clearance. The flow capacity of a given cylinder is a function of piston displacement and volumetric efficiency. Volumetric efficiency is a function of cylinder clearance, compression ratio and the properties of the gas being compressed. Compressor capacity may be calculated with any of the following three equations.

$$q_a = E_v(PD)\ , \quad \text{..... (7.16)}$$

$$q_g = 35.4[(q_a P_s)/(T_s Z_s)]\ , \quad \text{..... (7.17)}$$

and

$$Q_g = 0.051[(q_a P_s)/(T_s Z_s)] , \quad \text{..... (7.18)}$$

where

q_a = inlet capacity of the cylinder at actual inlet conditions, Acf/min,
E_v = volumetric efficiency,
PD = piston displacement, Acf/min,
q_g = inlet capacity of the cylinder, scf/min,

and

Q_g = inlet capacity of the cylinder, MMscf/D.

Piston Displacement. Piston displacement is defined as the actual volume of the cylinder swept by the piston per unit of time. Displacement is commonly expressed in actual cubic feet per minute (Acf/min). Calculation of the piston displacement is a straightforward procedure that depends on the type of compressor configuration. Single-acting cylinders can have either head-end or crank-end displacement. Eqs. 7.19 and 7.20 are used to calculate displacement of single-acting cylinders.

Single-Acting Cylinder (Head-End Displacement).

$$PD = (d_c^2 SN)/2{,}200 , \quad \text{..... (7.19)}$$

where

PD = piston displacement, Acf/min,
S = stroke, in.,
N = compressor speed, rpm,

and

d_c = cylinder diameter, in.

Single-Acting Cylinder (Crank-End Displacement).

$$PD = [(d_c^2 - d_r^2)SN]/2{,}200 , \quad \text{..... (7.20)}$$

where

PD = piston displacement, Acf/min,
S = stroke, in.,
N = compressor speed, rpm,
d_c = cylinder diameter, in.,

and

d_r = rod diameter, in.

Double-Acting Cylinder Displacement. Double-acting cylinder displacement is calculated with Eq. 7.21.

$$PD = [(2d_c^2 - d_r^2)SN]/2{,}200 , \quad \text{..... (7.21)}$$

where

PD = piston displacement, Acf/min,
S = stroke, in.,
N = compressor speed, rpm,
d_c = cylinder diameter, in.,

and

d_r = rod diameter, in.

The methods used to change piston displacement include changing compressor speed, removing or deactivating suction valves in a double-acting cylinder, and changing the diameter of the cylinder liner and piston.

Unloading one end can significantly reduce the capacity of a double-acting cylinder. The best method to unload a cylinder is to deactivate or remove the suction valves from one end to prevent that end from compressing gas. Depending on the frequency of unloading and the molecular weight of the gas, a port or plug unloader is the next best method of unloading a cylinder. A doughnut replaces one suction valve of three or more valves per corner, and only one unloading device is required per cylinder end. With concentric ring-type valves, it is possible to place a plug unloader in the center of a suction valve for unloading. Depending on the molecular weight of the gas, both port and plug unloaders reduce BHP/MMscf/D and significantly improve the reliability of the unloading system.

If the suction valve is held open with finger depressors during the compression stroke, gas will flow through the open valve back into the suction gas passage, and no gas will be discharged from the end of the cylinder containing the unloaded suction valve. Deactivation of the valves may be performed manually while the compressor is shut down or by using a valve unloader or lifter while the compressor is in operation. Control of the valve unloader can be manual or automatic by a diaphragm that unloads the compressor using a suction pressure sensor. Diaphragm actuators are more reliable than manual lifters or unloaders.

Unloading both ends of the same cylinder may cause the cylinder to overheat; thus, it is best to unload only one end of a double-acting compressor cylinder. In most cases, it is preferable to remove the suction valve when unloading the head end of a cylinder to assure load reversal in the rods. (See the subsection on Rod Load in Sec. 7.5.2.)

Clearance Volume. Clearance volume is the space remaining in the compressor cylinder at the end of the stroke. Clearance is made up of spaces in valve recesses and the space between the piston and cylinder end. At the completion of each compression stroke, the compressed gas trapped in the clearance space expands against the piston and adds to the force of the return stroke. **Fig. 7.20** is a pressure vs. volume (P-V) diagram illustrating the effect of clearance.

Expansion of the gas trapped in the clearance space occurs before the suction valve opens to admit new gas into the cylinder. As a result, part of the piston displacement occurs before the suction valve opens. The compression process in reciprocating compressors is nearly isentropic, so the energy required to compress the gas in the clearance space is recovered when the gas expands at the end of the compression stroke. For this reason, changes in the clearance space do not affect the compressor power.

Clearance volume is expressed as a percentage of piston-swept volume using one of the following configuration-dependent equations.

Single-Acting Cylinder (Head-End Clearance).

$$\%\, C = 127[C_{HE} / (d_c^2 S)] , \quad \text{..... (7.22)}$$

where

$\%C$ = cylinder clearance, %,

C_{HE} = head-end clearance, in.^{3},

d_c = cylinder inside diameter, in.,

and

S = stroke length, in.

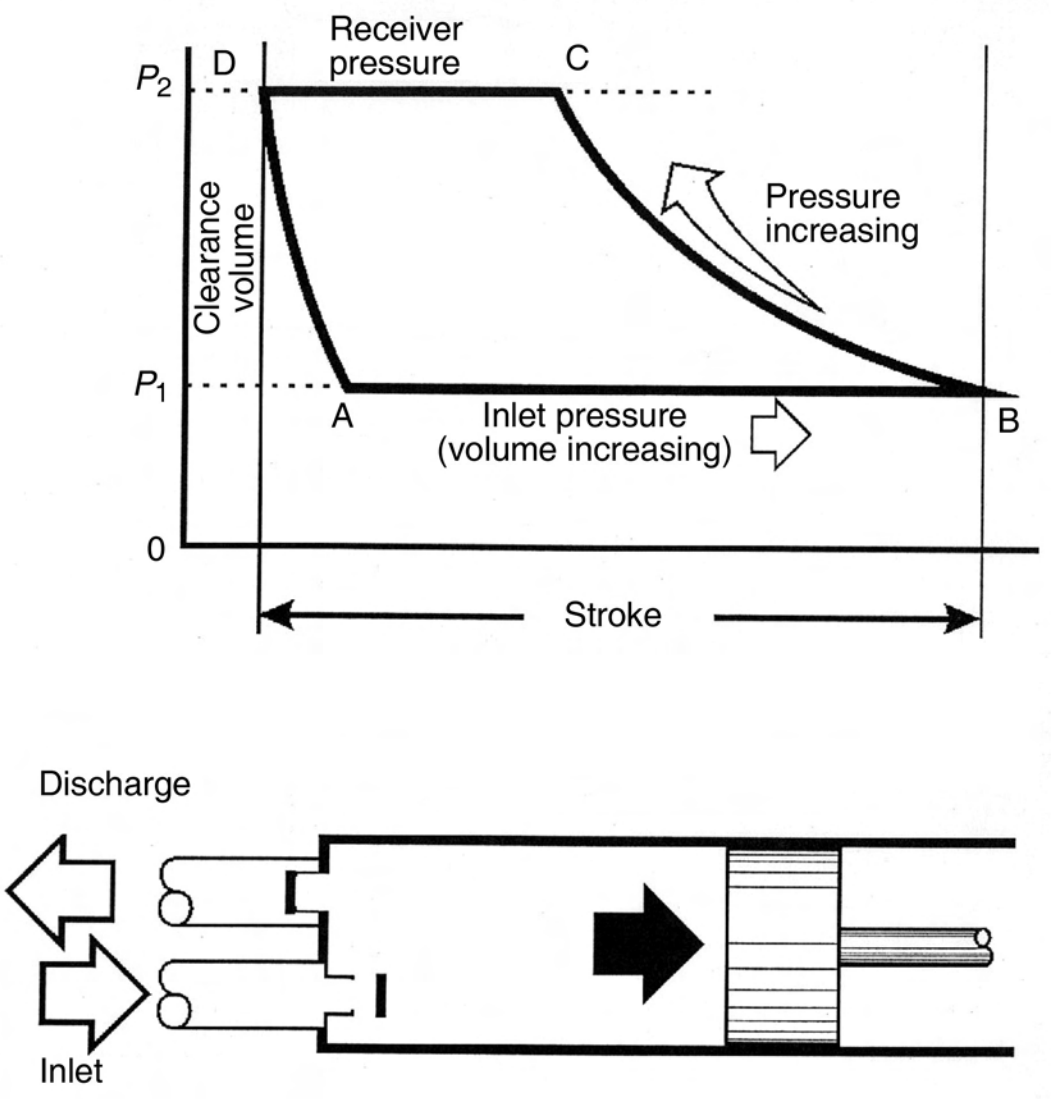


Fig. 7.20—Reciprocating compressor *PV* diagram (courtesy of Dresser-Rand).

Single-Acting Cylinder (Crank-End Clearance).

$$\%\, C = 127[C_{CE}/(d_c^2 - d_r^2)S)]\,, \quad \text{..... (7.23)}$$

where

$\%C$ = cylinder clearance, %,

C_{CE} = crank-end clearance, in.^{3},

d_c = cylinder inside diameter, in.,

d_r = rod diameter, in.,

and

S = stroke length, in.

Double-Acting Cylinder (Head-End and Crank-End Clearance).

$$\%\ C = 127\left\{(C_{HE} + C_{CE})/[d_c^2 + (d_c^2 - d_r^2)S]\right\}\ , \quad \text{..... (7.24)}$$

where

$\%C$ = cylinder clearance, %,
C_{HE} = head-end clearance, in.^{3},
C_{CE} = crank-end clearance, in.^{3},
d_c = cylinder inside diameter, in.,
d_r = rod diameter, in.,

and

S = stroke length, in.

Clearance can be added to a cylinder as fixed-volume clearance pockets, variable clearance pockets, or split-valve yokes.

A fixed-volume clearance pocket is normally a volume bottle permanently attached to the cylinder. Fixed volume also can be added by a side-passage clearance plug consisting of a flange with a variable length plug inserted into a passage built into the side of the cylinder. A fixed-volume clearance pocket may be continuously open or may be controlled to be either open or closed. Control can be by manual hand wheel or automatic actuator. An actuator control allows the clearance pocket to be opened or closed from outside the cylinder while the compressor is in operation.

Variable clearance pockets allow a variable amount of clearance to be added to the cylinder and can be attached to either the head end or crank end of the cylinder. Most often, variable clearance pockets are attached to the head end, as shown in **Fig. 7.21**.

Excessive clearance in a compressor cylinder can cause slamming of the discharge valves. If too much clearance is present, no gas will be discharged. Rapid overheating can occur because no cool suction gas enters the cylinder.

Volumetric Efficiency. Volumetric efficiency is the ratio of the actual volume of gas (Acf/min) drawn into the cylinder to the piston displacement (cf/min). This ratio is less than unity because of three fundamental effects. First, the gas is heated during admission to the cylinder. Second, there is leakage past valves and piston rings. And third, there is re-expansion of the gas trapped in the clearance volume from the previous stroke. Of these three, re-expansion has, by far, the greatest effect on volumetric efficiency.

Compressor manufacturers have not reached consensus on an appropriate calculation method because measurement of these effects is extremely difficult. Recognizing this, the next approximate equation may be used to estimate volumetric efficiency.

$$E_v = 96 - R - C[(R^{1/k})(Z_s^2/Z_d^2 - 1)] - L\ , \quad \text{..... (7.25)}$$

where

E_v = volumetric efficiency,
R = compression ratio,
C = cylinder clearance, % of piston-swept volume,
Z_s = inlet compressibility factor,
Z_d = discharge compressibility factor,
d_r = rod diameter, in.,
k = ratio of specific heats, C_p/C_v,

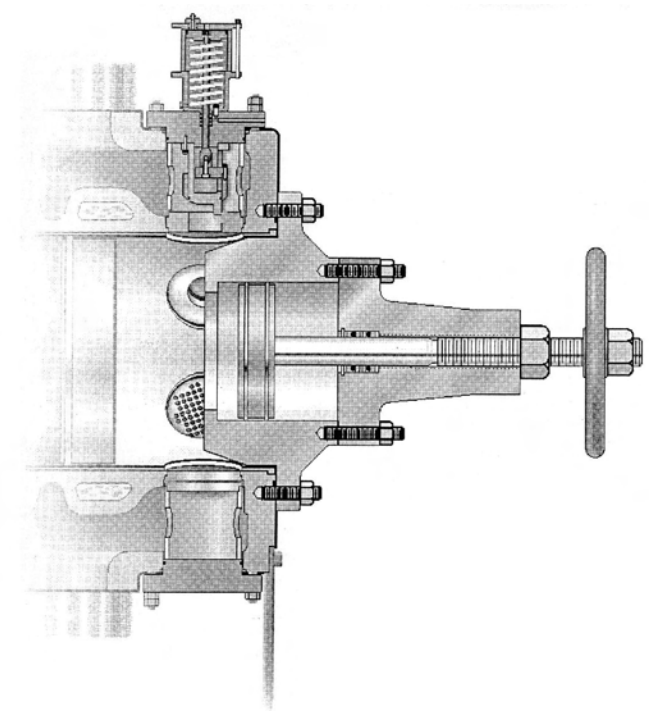


Fig. 7.21—Manual variable volume clearance pocket (courtesy of Dresser-Rand).

L = slippage of gas past piston rings, % (1% for high-speed separable, 5% for nonlubricated compressors and 4% for propane service),
and
96 = allowance for losses because of pressure drop in valves.

Rod Load. Rod loads consist of gas loads caused by pressure and inertia loads that result from acceleration and deceleration of the piston, piston rod, crosshead, and approximately one-third of the connecting rod weight. Manufacturers specify a maximum rod load to protect the compressor because overloading the rods can severely damage the compressor. Loads must be evaluated for normal operating conditions and also during upset conditions. Rod loading must be reviewed at minimum suction pressure and relief valve pressure to assure an adequate safety margin.

Rod load reversals must be of sufficient magnitude to provide lubrication to the crosshead pin bushing. The bushings are lubricated by the pumping action of the opening and closing of bearing clearance that occurs when the rod load reverses from tension to compression. Operation without rod reversals also can severely damage the compressor.

Rod loads for the various compressor configurations are calculated with the following equations.

Single-Acting Cylinder (Head End).

$$RL_c = a_p(P_d - P_u) + a_r P_u \ . \quad \text{..... (7.26)}$$

$$RL_t = a_p(P_u - P_s) - a_r P_u \ . \quad \text{..... (7.27)}$$

Single-Acting Cylinder (Crank End).

$$RL_c = a_p(P_u - P_s) + a_r P_s \ . \quad \text{(7.28)}$$

$$RL_t = a_p(P_d - P_u) - a_r P_d \ . \quad \text{(7.29)}$$

Double-Acting Cylinder.

$$RL_c = a_p(P_d - P_s) + a_r P_s \ . \quad \text{(7.30)}$$

$$RL_t = a_p(P_d - P_s) - a_r P_d \ . \quad \text{(7.31)}$$

RL_c = rod load in compression, lbf,
RL_t = rod load in tension, lbf,
a_p = cross-section area of piston, in.^{2},
a_r = cross-section area of rod, in.^{2},
P_d = discharge pressure, psia,
P_s = suction pressure, psia,
and
P_u = pressure in unloaded end, psia.

Other Performance Factors. *Suction Pressure.* At constant discharge pressure with compression ratios greater than 2.0, the compression ratio decreases as the suction pressure increases. A decrease in compression ratio reduces the power requirement per unit of flow. The capacity of the cylinder, however, increases with suction pressure at a faster rate, resulting in an overall increase in power. To avoid overloading the driver, additional clearance must be added to reduce cylinder capacity.

Suction Temperature. Cylinder capacity is inversely proportional to absolute suction temperature. As temperature decreases, more standard cubic feet fill the cylinder. Thus, a 10°F reduction in suction temperature increases compressor mass flow by almost 2%. Precooling the gas can be an effective way to increase cylinder capacity.

Discharge Pressure. Changes in discharge pressure have little effect on cylinder capacity. Volumetric efficiency varies slightly with compression ratio, and the required power is directly proportional to the change in compression ratio.

Ratio of Specific Heats (k). An increase in k value produces an increase in the volumetric efficiency as defined by Eq. 7.25. Thus, a given compressor cylinder has a higher actual capacity when compressing natural gas (k = 1.25), compared with its capacity when compressing propane (k = 1.15). The higher capacity, when compressing natural gas compared to propane, results in greater power consumption as well.

Speed. Cylinder capacity is directly proportional to compressor speed. It is common practice to adjust compressor speed (within reasonable limits) to maintain desired suction pressure. Reduction of driver speed lowers fuel consumption and operating costs.

Performance Maps. Performance maps can be developed for a specific compressor with base conditions held constant. **Fig. 7.22** illustrates that as suction pressure increases, both inlet flow rate and power increase for constant discharge pressure and temperature. At very low ratios, the power may actually decrease with increasing suction pressure.

7.5.3 Process Installation. The compressor is an integral part of a complete compression system. **Fig. 7.23** is a typical process flow diagram for a reciprocating compressor installation.

Recycle Valve. Compressor suction pressure decreases as the flow rate decreases until the gas expands to satisfy the flow required by the cylinder. The increase in compression ratio

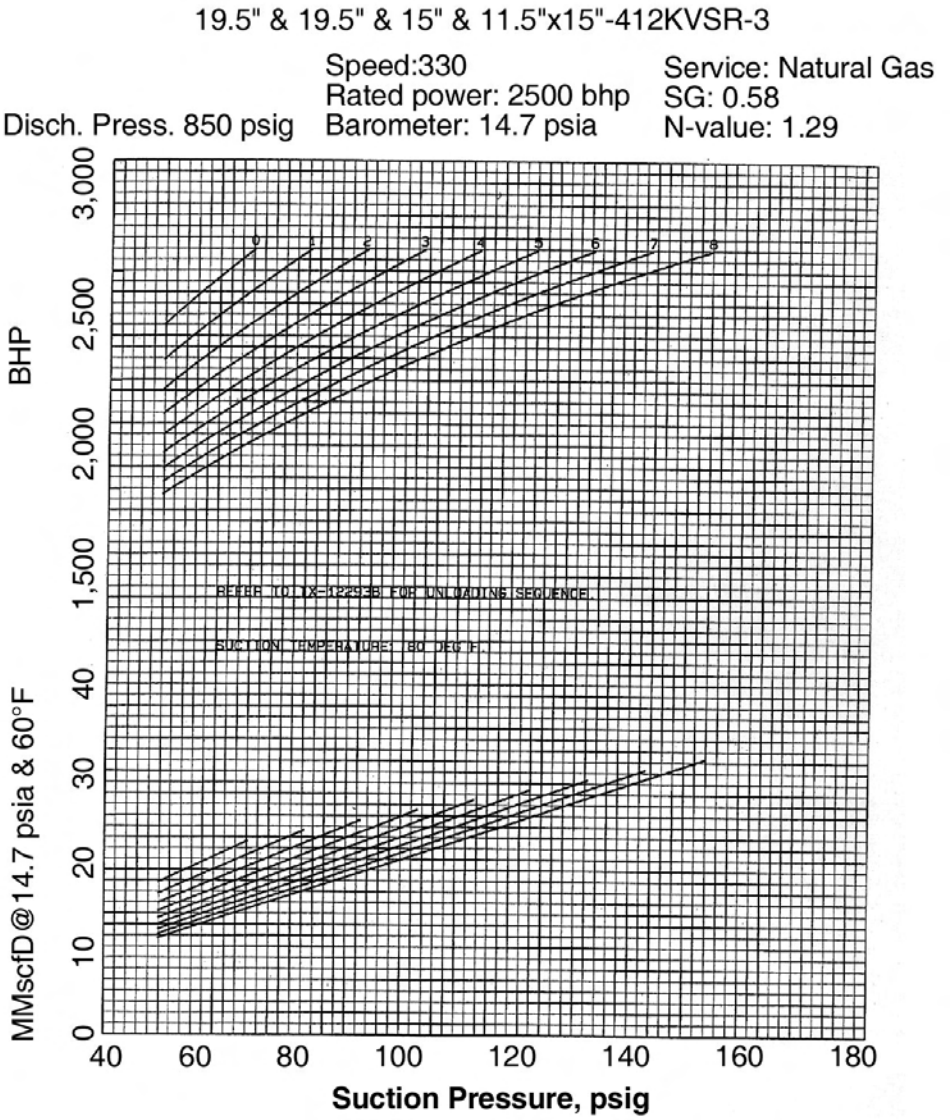


Fig. 7.22—Reciprocating compressor map with eight stages of unloading (courtesy of Dresser-Rand).

caused by reduction in suction pressure results in an increase in discharge temperature. Thus, the recycle valve in the system must be set to prevent low suction pressure from creating excessive discharge temperature. In addition, rod load limits may dictate the minimum acceptable suction pressure for a compressor installation. Where possible, recycle valve should be downstream of gas coolers.

Blowdown Valve. The blowdown valve relieves trapped pressure when the compressor is shut down for maintenance. Valve control is typically automatic but is sometimes manual at some small, onshore compressor installations.

Suction Scrubber. Ingestion of liquids into the compressor through the inlet gas stream can cause damage to the compressor internals. For this reason, an adequately sized suction scrubber with provisions for draining is required. The scrubber may be part of the pulsation control

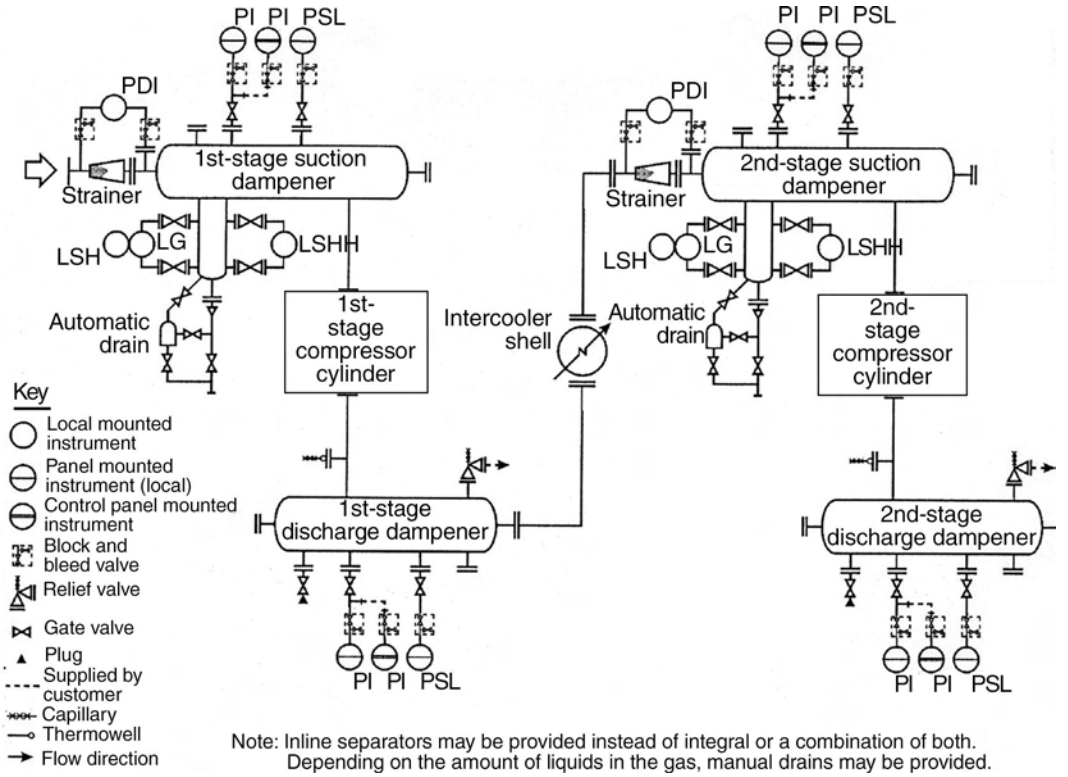


Fig. 7.23—Compressor process flow diagram with integral (pulsation vessel) separator (courtesy of Dresser-Rand).

when properly planned (see Sec. 7.5.4). If the inlet stream is near saturation, horizontally-oriented cylinders and bottom-connected discharge nozzles are recommended.

Relief Valves. Pressure relief valves set at a margin of 10% above the highest stage discharge pressure, or a minimum of 15 to 25 psi, provide static pressure protection for piping and coolers. Relief valve setting should never exceed the cylinder maximum allowable working pressure (see the subsection on cylinders in Sec. 7.5.1). Caution should be taken to ensure that all suction side gas piping, cylinders, and relief valves are rated for settle-out pressures in closed-loop refrigeration or low gas temperature services.

7.5.4 Pulsation. The flow of gas through a reciprocating compressor inherently produces pulsation because the suction and discharge valves are not open for the entire compression stroke. Pulsation damping is needed to create a more uniform flow through the compressor to assure uniform loading and to reduce piping vibration levels.

Pulsation Control Devices. If long, straight runs of piping of the same diameter as the compressor cylinder line connection can be provided, and the stage power is less than 150 hp, separate volume bottles or pulsation vessels may not be required. For most applications, volume bottles or pulsation vessels with internal baffles and/or choke tubes should be located as close to the cylinder as possible for optimum valve reliability. The addition of orifices at key locations in the piping can also reduce piping pulsations. Several different bottle-sizing formulae are available. Typical bottle sizes are five to ten times the cylinder swept volume.

Pulsation Design. Digital piping pulsation analysis is a relatively low-cost method to ensure that a piping system is designed to meet acceptable pulsation levels (typically 2 to 7% peak to peak). The piping system layout must identify locations and volumes of knockout

drums, bottles, coolers, and relief valves. The analysis should include the first major vessel or volume upstream and downstream of the compressor. Double-acting and single-acting (if applicable) operating conditions should be analyzed.

7.5.5 Vibration Considerations. Imbalance of the rotating elements in the compressor cause mechanical vibration. Counterweights on the crankshaft and arranging cylinders in pairs on both sides of the crankshaft (in plain view) can minimize but not eliminate imbalance forces. Thus, there will always be mechanical vibrators that must be taken into account in foundation design.

Piping Vibration. The compressor process gas piping must be properly designed and installed to avoid problems associated with excessive vibration. It is important that the natural frequency of all pipe spans is greater than the compressor pulsation frequency. The compressor pulsation frequency is calculated with Eq. 7.32.

$$f_p = (N/60)^n , \quad \text{..... (7.32)}$$

where

f_p = compressor pulsation frequency, cycles/sec,

N = compressor speed, rpm,

N = cylinder factor,

= 1 for single-acting cylinder

and

= 2 (for double-acting cylinder).

Piping should be securely tied using short pipe spans that are not uniform in length. Adequate pulsation damping helps prevent piping-related vibration problems.

Foundation Design. For large integral compressors, or for compressors installed on complex structures or soft soils, it is best to perform a dynamic design using the imbalance forces provided by the manufacturer. The details of performing such an analysis are beyond the scope of this handbook.

For high-speed compressors installed in areas with soils that can support a pickup truck, the following rules are useful.

- Weight of concrete foundation should be at least three to five times the equipment weight.
- Use soil bearing for a design that is less than 50% of that allowable for static conditions.
- It is generally better to increase length and/or width rather than depth to meet weight requirements.
- For rectangular block, at least 40% of height (but not less than 18 in.) should be embedded in undisturbed soil.
- Concrete should be poured into a "neat" excavation without formed side faces.

7.5.6 Cylinder Cooling. The heat of compression and friction between the piston rings and the cylinder add heat to the cylinder. Removing some of this heat is beneficial to the performance and reliability of the compressor in several ways. Cylinder cooling reduces losses in capacity and power caused by suction gas preheating. It also removes heat from the gas, thereby lowering the discharge temperature of the gas. Cylinder cooling also promotes better lubrication for longer life and reduced maintenance. When water is used as the cooling medium, uniform temperatures are maintained around the cylinder's entire circumference, reducing chances for thermal distortion of the cylinder.

Care must be taken to avoid condensation that can result from excessive cooling. This can be assured by maintaining the cylinder jacket coolant temperature at least 10°F above the suction gas temperature.

Insufficient cooling can lead to reduced capacity and fouling of the cylinders. For this reason, it is recommended that the cylinder not be more than 30°F above the suction gas temperature.

Cooling Systems. *Air Cooled.* Air-cooled systems are used for small throughputs and low heat loads. Cooling fins provide a sufficient surface area to cool the cylinder.

Static. Static systems are sometimes used on small compressors to assist air-cooled systems. Cooling fluid functions as a static heat sink and acts more as a heat stabilizer than a cooling system. Some heat is transferred from the system by conduction to the atmosphere.

Thermosiphon. The driving force for a thermosiphon derives from the change in density of the cooling fluid from the hot to cold sections of the system. API *Standard 618* permits use of this system when discharge gas temperatures are below 210°F or when temperature rise across the cylinder is less than 150°F.

Pressurized. Pressurized cooling systems are the most common. In locations where cooling water is not available, a self-contained, closed cooling fluid system may be used. The system consists of a circulating pump, surge tank, and a fan-cooled radiator or air-to-liquid heat exchanger. The radiator may have multiple sections—one for cylinder coolant, one for cooling lube oil, and one (or more) for cooling discharge gas. The cooling fluid is either water or a mixture of water and ethylene glycol. The crankshaft usually drives the circulating pump.

7.5.7 Lubrication. ***Frame Lubrication.*** The frame lubrication system delivers oil to the frame bearings, connecting rod bearings, and crosshead shoes. Some frame lubrication systems also supply oil to the packing and cylinders. For most reciprocating compressors, the lubrication system is integral with the frame.

Splash Lubrication. Splash lubrication systems distribute lubricating oil by the splashing of the crank through the lubricant surface in the pump. Dippers may be attached to the crankshaft to enhance the effect. Splash systems are used on small, horizontal, single-stage compressors with power demands up to 100 hp. Low initial cost and minimal operator attendance are the two main advantages of splash systems. The main disadvantages are that splash systems are limited to small frame sizes and that the oil cannot be filtered.

Pressurized Lubrication. The most common type of frame lubrication is the pressurized system. Oil enters passages drilled into the crankshaft and flows through the main shaft and crank pin bearings. A pressurized lubrication system consists of the components discussed next.

Main Oil Pump. The main oil pump is driven by the crankshaft or may be separately driven. It is typically sized to deliver 110% of the maximum anticipated flow rate. When speed reduction is used for capacity control, care must be taken to ensure that this pump provides adequate lubrication at the minimum operating speed.

Auxiliary Pump (Optional). An auxiliary pump is provided to back up the main pump. The auxiliary pump is usually driven by an electric motor and is designed to start automatically when oil supply pressure falls below a specified level.

Prelube Pump (Optional). A prelube pump supplies oil to the bearings before the compressor is started. This assures that the bearings are not dry at startup. Because this function is provided by the auxiliary pump, a prelube pump is required only when the system does not have an auxiliary pump.

Oil Cooler. The oil cooler ensures that the temperature of the oil supply to the bearings does not exceed the maximum value required to protect the bearings from wear. A typical maximum oil supply temperature is 120°F. Jacket cooling water in a shell and tube heat exchanger is often used to cool the lubricating oil.

Oil Filter. Oil filters protect the bearings by removing particulates from the lubricating oil. Some systems are equipped with dual, full-flow oil filters with transfer valves. Transfer valves allow switching from one filter to the other so that the filters can be cleaned without shutting down the compressor.

Overhead Tank. The overhead tank provides oil to the bearings if a pump fails. The oil from the overhead tank is gravity-fed to the bearings. The tank must be sized to provide oil until the compressor has completely shut down. The tank is usually equipped with a level indicator.

Piping. The components of the lubrication system are connected by piping. Cleanliness and corrosion resistance are important considerations. Galvanized piping should be avoided because of possible corrosion. Carbon steel piping should be pickled or mechanically cleaned and coated with a rust inhibitor. Stainless steel piping should be used downstream of the filters. The piping system should be designed to avoid any pockets in which dirt or debris could accumulate. Socket welded piping should be avoided for this reason. Before initial startup, the lube oil system should be flushed with lube oil at approximately 170°F. A 200-mesh screen should be added to the system, and flushing should continue until the mesh is clean. Safety instrumentation should include a crankcase low oil level switch, a low oil pressure shutdown switch, and a high oil temperature switch.

For compressors with integral engine drivers, it is recommended that the compressor and driver be lubricated with separate systems so that combustion gases from the engine do not contaminate the lube oil. In this case, the packing and cylinder lubrication is provided by the compressor lubricating system. For installations in very cold environments, immersion or in-line heaters and special lubricating oils should be considered.

Cylinder and Packing Lubrication. The quantity of oil required to lubricate the packing and cylinders is small when compared with the bearing oil requirements. While the quantity is small, the oil pressure necessary to supply oil at the packing and cylinders is high. A small plunger pump (force-feed lubricator) is used at each stage of compression. Divider blocks are used to distribute the flow of oil between the cylinders and the packing. The oil can be supplied from either the frame lubricating system or from an overhead tank. Compatibility of the oil with the process gas must be checked to protect against contamination.

7.6 Summary

In the preceding pages, we've reviewed the fundamental designs of compressors and compressor components used throughout the natural gas industry. Such equipment is an integral part of that industry, maximizing the ability of producers and distributors to access, recover, and deliver energy resources to meet demand anywhere in the world.

The diversity of design and application of compression equipment reflects not only the specialized needs of the industry, but also the adaptability of compression engineers to fulfill industry requirements. Because many compressors are designed to meet the rigid performance requirements of their owners ("engineered to order"), engineers have ample opportunity to apply their skills.

Although this chapter has been confined to basic principles, many dramatic design innovations have kept pace with industry demands for greater capacity, efficiency, safety, and environmentally acceptable performance under a remarkably broad range of operating conditions. In fact, it is a rarity to find conditions under which a properly engineered compressor cannot function as designed.

Nomenclature

a_p = cross-sectional area of piston, in.^{2}
a_r = cross-sectional area of rod, in.^{2}
C = cylinder clearance, %
C_{CE} = crank-end clearance, in.^{3}
C_{HE} = head-end clearance, in.^{3}
d_c = cylinder diameter, in.

d_r = rod diameter, in.
E_v = volumetric efficiency
f_p = compressor pulsation frequency, cycles/sec
H_{is} = isentropic head, ft-lbf/lbm
H_p = polytropic head, ft-lbf/lbm
k = ratio of specific heats
L = slippage of gas past piston rings, %
MW = molecular weight
N = compressor speed, rpm
P = pressure
P_1 = specified absolute suction pressure, psia,
P_2 = specified absolute discharge pressure, psia
P_d = discharge pressure, psia
PD = piston displacement, Acf/min
P_s = absolute suction pressure, psia
P_u = pressure in unloaded end, psia
q_a = inlet capacity of the cylinder at actual inlet conditions, Acf/min
q_g = inlet capacity of the cylinder, scf/min
Q_g = inlet capacity of the cylinder, MMscf/D
R = compression ratio
RL_c = rod load in compression, lbf
RL_t = rod load in tension, lbf
S = gas specific gravity (standard atmospheric air = 1.00)
T = temperature
T_1 = specified absolute suction temperature, °R
T_2 = estimated absolute discharge temperature, °R
T_d = discharge temperature (actual or predicted), °R
T_s = suction temperature, °R
V = volume
V_1, V_2 = volumes at pressures 1 and 2
W = mass flow, lbm/min
x = x-axis
y = y-axis
z = compressibility factor
z_{avg} = average compressibility factor, dimensionless
z_s = compressibility at inlet
Z_d = discharge compressibility factor
Z_s = inlet compressibility factor
η_{is} = isentropic efficiency
η_p = assumed polytropic efficiency

Superscripts

k = ratio of specific heats, C_p/C_v
n = polytropic exponent

General References

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SI Metric Conversion Factors

ft	×	3.048*	E – 01	= m
°F		(°F – 32)/1.8		= °C
hp	×	7.460 43	E – 01	= kW
in.	×	2.54*	E + 00	= cm
$in.^2$	×	6.451 6	E + 00	= cm^2
$in.^3$	×	1.638 706	E + 01	= cm^3
lbf	×	4.448 222	E + 00	= N
lbm	×	4.535 924	E – 01	= kg
psi	×	6.894 757	E + 00	= kPa
°R		(°R/1.8)		= K

*Conversion factor is exact.

Chapter 8
Prime Movers

Jim Strawn* and **Joe Lange,** Waukesha Engine, Dresser Inc.

8.1 Introduction

In the energy industry, pumping units, compressors, chillers, and other forms of related equipment are driven by prime movers. The most common prime movers in the oil and gas industry are natural gas turbines and reciprocating engines. Steam turbines can also be used. Steam turbines are not common in field operations and are used primarily in plants; therefore, they are not discussed in this chapter. Electric motors are not considered "prime" movers and are discussed in the chapter on Electrical Systems. Each type of prime mover has unique characteristics that make it appropriate for an application on the basis of site conditions and fuel energy availability.

8.2 Reciprocating Engines

The availability and economics of the prime mover fuel source and horsepower requirements frequently dictate that reciprocating internal combustion engines be selected to drive energy industry equipment. This section focuses on the reciprocating internal combustion engine and explores the difference between engine speeds, types of engine aspiration, and typical expected exhaust emissions.

The three main types of engine combustion—two stroke, four stroke, and diesel—are discussed in the following paragraphs. All three types of engine combustion convert the chemical potential energy found in the fuel to mechanical kinetic energy. The combustion cycle and fuel type required to complete this task are what distinguish the three engine types from each other.

8.2.1 Two-Stroke Cycle. Two-stroke cycle engines or two-cycle engines complete their combustion cycle in two piston strokes that are accomplished with one revolution of the crankshaft. The two strokes are the power and compression strokes. The two-stroke engine is unique because it does not control the release of exhaust or the admission of an air/fuel mixture into the cylinder with a traditional valve arrangement, one intake and one exhaust.

As shown in **Fig. 8.1**, the process of filling the cylinder with an air/fuel mixture and exhausting the burned gases occurs almost simultaneously near the end of the power stroke. As the piston moves downward during the power stroke, first the exhaust port is uncovered and

*Deceased.

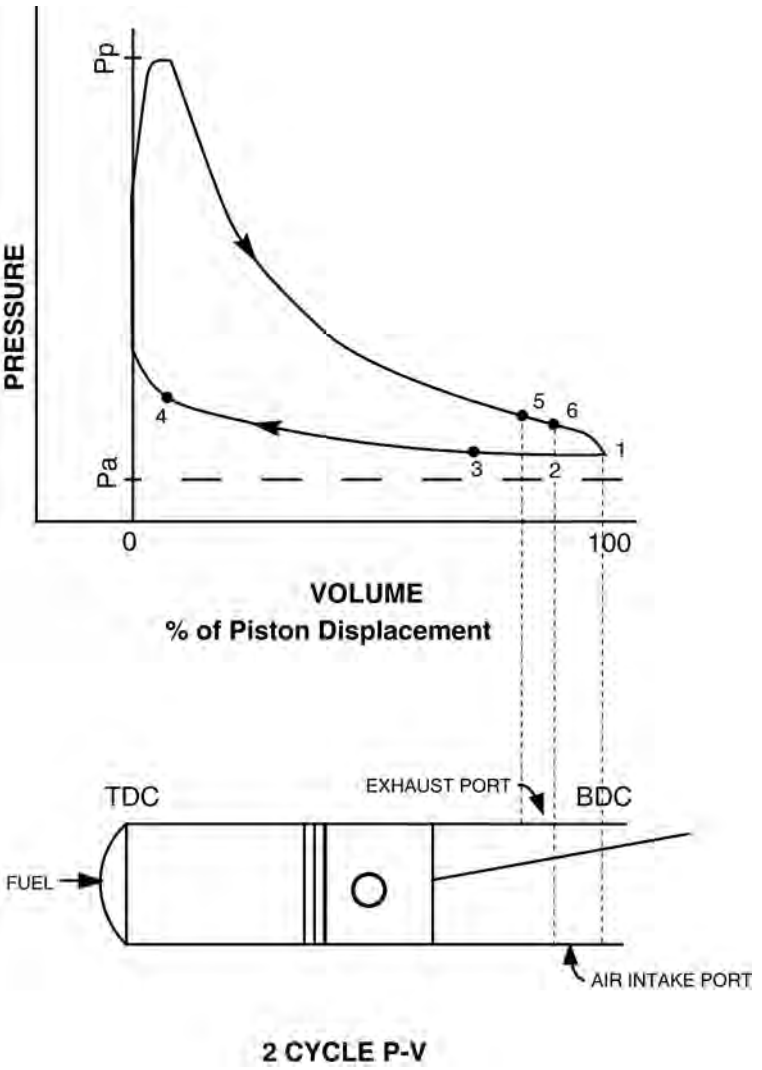


Fig. 8.1—Idealized *P-V* diagram for a two-cycle engine. Numbers signify the beginning of various events in the two-stroke cycle. For example, 1 through 4 are the compression stroke and 4 back to 1 is the combustion/expansion stroke. Exhaust gas is evacuated between 5 and 6 when the exhaust port is open and fuel mixture is drawn in between 6 and 1 when the intake port is open.

then the intake port is uncovered. These ports allow the exhaust to escape under its own pressure and then be displaced by the incoming air/fuel mixture. Because some of the air/fuel mixture can be lost in this process, some two-stroke engines are equipped with fuel injection systems that raise their fuel efficiency close to that of a four-stroke engine. The compression stroke compresses the air/fuel mixture that is then ignited by a spark plug. The burning of the air/fuel mixture pushes the piston through the power stroke. As the power stroke reaches its end, the cycle begins again.

Lubricating a two-stroke engine is also unique compared with other engines because the engine does not have a traditional valve arrangement that separates the crankcase from the combustion chamber. Lubrication of the engine is accomplished by an auxiliary lubricator that injects a prescribed amount of oil into critical areas. Another method, commonly used on small

two-stroke engines, is to combine a prescribed amount of oil with the fuel so that it lubricates the engine as the air/fuel mixture passes through the crankcase.

Most two-stroke engines are the slow to mid-speed variety (400 to 700 rpm), primarily because of lubricating concerns and because the crankshaft is turning only once per cycle. Some of the largest engines in the world are two-stroke engines. As engine size and power increase, the size and weight of the internal components also increase, which limits their ability to reciprocate quickly. Therefore, the two-stroke engine design works well for large high-power engines with its slower speed and fewer strokes. There are two-stroke engine models rated well in excess of 5,000 brake hp (BHP).

8.2.2 Four-Stroke Cycle. A four-stroke cycle engine is commonly called a four-cycle engine. Four-cycle engines complete their combustion cycle in four strokes of the piston that are accomplished with two revolutions of the crankshaft, as shown in **Fig. 8.2**. The four strokes are intake, compression, power, and exhaust. The four-cycle engine controls the release of exhaust and the admission of a fresh charge or air/fuel mixture using a traditional valve arrangement, one intake and one exhaust. These valves are located in the engine head or block and are typically actuated with camshaft(s) and push rods.

The intake stroke moves the piston to create an expansion of the combustion chamber volume. The intake valve is opened during the intake stroke, and an air/fuel mixture is drawn into the cylinder. The compression stroke compresses the air/fuel mixture, which increases the energy potential of the mixture. The compressed air/fuel mixture is then ignited by a spark plug, and the burning of the air/fuel mixture pushes the piston through the power stroke. The exhaust valve then opens, and the piston pushes the exhaust gases out of the cylinder through the exhaust stroke. One revolution of the crankshaft completes the intake and compression strokes. The second revolution of the crankshaft completes the power and exhaust strokes, ending the four-stroke cycle.

A four-cycle engine is lubricated through a pressurized oil system. Typically, oil is stored in an oil pan or sump. An oil pump draws oil from the sump and sends pressurized oil through a filter and then to all engine bearings and moving parts. The oil then returns to the oil sump. In a four-cycle engine, the fuel system and air/fuel mixture are always kept separate from the crankcase and oil.

Most four-cycle engines used in the energy industry are the mid- to high-speed variety (900 to 2000 rpm). Higher speeds are allowed with four-cycle engines because of the pressurized lubrication systems and smaller reciprocating components. The four-cycle design works well for most applications below 20,000 BHP, where speed and fuel efficiency are concerns. Higher speeds are preferred in numerous energy industry applications. For compression applications, higher speeds mean more turns for the compressor and more gas transferred in a given time. For electrical power generation applications, higher speeds mean a more steady production of electricity at any given frequency. Typically, four-cycle engines used in the energy industry are rated up to about 20,000 BHP. The numbers in Fig. 8.2 indicate the beginning for each of the four main events of the four-stroke engine cycle. The intake stroke is designated 1, where volume is increasing and pressure remains low. The rest of the cycle is illustrated as a combination of pressure and volume changes.

8.2.3 Diesel Cycle. The diesel cycle also completes its work in four strokes, making it a four-cycle engine. However, the difference between a diesel and a typical four-cycle engine is the cause of the air/fuel mixture ignition. Diesel engines do not have spark plugs like two and four-cycle engines. The diesel engine uses a high compression ratio and the resulting heat for the ignition of the diesel/air mixture. Natural gas cannot be used in a diesel cycle because ignition temperature is too high.

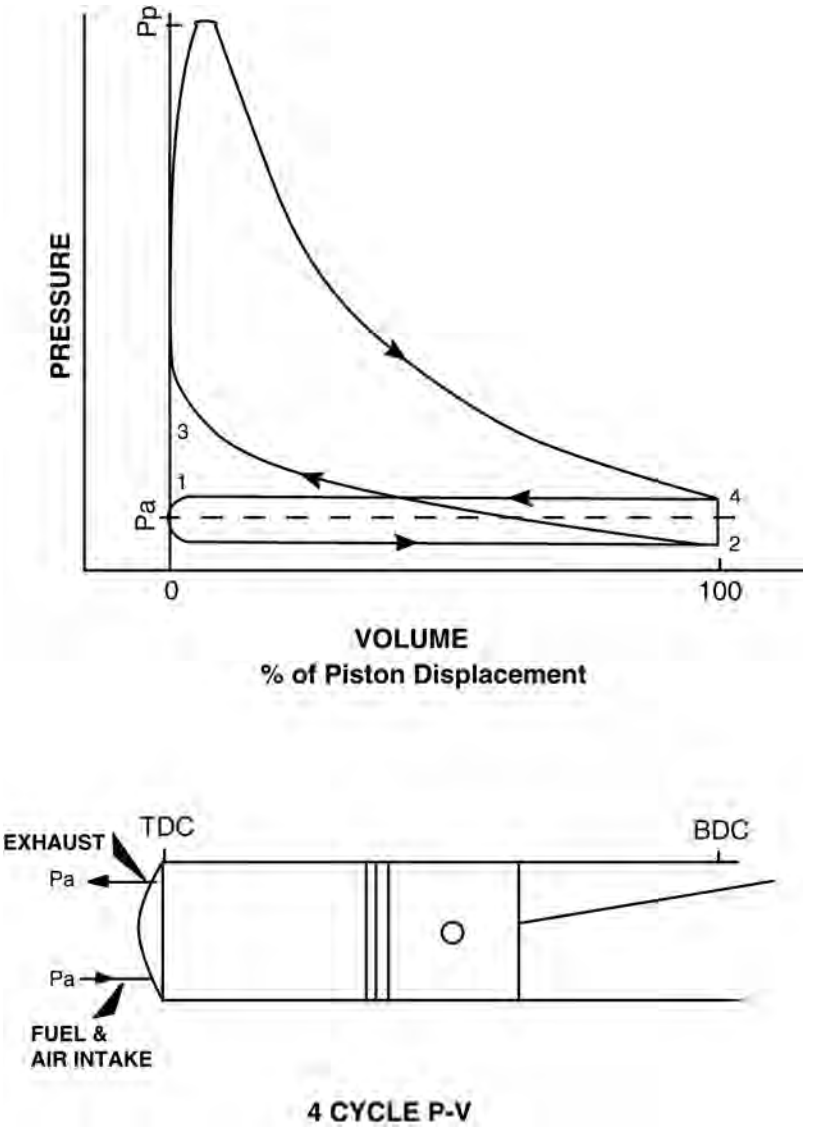


Fig. 8.2—Idealized *P-V* diagram for a four-cycle engine. Top dead center (TDC) is the position where the piston is at the top of the cylinder (maximum compression). Bottom dead center (BDC) is the position where the piston is at the bottom of the cylinder (maximum expansion).

The intake stroke moves the piston to create an expansion of the combustion chamber volume. The intake valve is opened during the intake stroke, and fresh air is drawn into the cylinder. The compression stroke compresses the fresh air, which increases the kinetic energy of the air, resulting in a high temperature. A fuel injection valve then injects a prescribed amount of diesel fuel into the cylinder. The injected fuel mixes with the hot compressed air in the cylinder. The heat ignites the fuel without a spark, and the burning of the mixture pushes the piston through the power stroke. The exhaust valve then opens, and the piston pushes the exhaust gases out of the cylinder through the exhaust stroke. One revolution of the crankshaft completes the intake and compression strokes. The second revolution of the crankshaft completes the power and exhaust strokes, ending the four-stroke diesel cycle.

Four-stroke diesel engines can have compression ratios beyond 22:1, double that of a nondiesel engine. Air in the cylinder is subjected to this very high compression ratio. The result is a buildup of heat in the compressed volume of air. The heat generated by compressing air to such an extent results in enough heat to ignite the fuel. The temperatures in a cylinder can be in excess of 1,000°F.

A benefit to diesel technology is high mechanical efficiencies. Diesel engines can have an efficiency of > 40%. This level of efficiency is caused by the high temperatures and unique ignition of the diesel/air mixture. Diesel engines are commonly found in very large high-powered, slower-speed applications like seaworthy cargo ships. Diesel engines are also commonly found in all of the same applications that four-cycle non-diesel engines are found. The major differences are the fuel system and availability of that fuel.

8.2.4 Naturally Aspirated vs. Turbocharged. Regardless of the type of engine selected to be a prime mover, one issue that needs to be addressed is whether the engine will be naturally aspirated or turbocharged. Either option has advantages and disadvantages.

Naturally aspirated engines breathe directly from the environment, which means that air enters the cylinder under atmospheric pressure. During the intake stroke, the open area in the combustion chamber expands, resulting in reduced pressure. In a naturally aspirated engine, the atmospheric pressure causes the intake air to flow naturally from high to low pressure and into the combustion chamber. Because a naturally aspirated engine relies on atmospheric pressure, it is more prone to being affected by altitude changes. Power may be lost at higher altitudes because of the less dense air and lower atmospheric pressure.

In a turbocharged engine, the intake air is compressed with a turbine that is driven by exhaust gases. A turbocharged engine breathes the compressed air that is at a higher pressure than atmospheric pressure. Because the intake air is compressed, a more dense air enters the cylinder during the intake stroke. The effect is more power from the same cylinder size because more fuel is needed to match the extra air molecules of the dense compressed air. More fuel and air in the cylinder means more potential energy to compress and burn. Turbocharged engines have a better chance of maintaining power levels at higher altitudes. This stability results because the engine breathes compressed air, leaving the work of the altitude increase to the turbocharger and not the engine.

However, two advantages of the naturally aspirated engines are fewer parts and less complex applications. The naturally aspirated engine does not have a turbocharger and all of the related equipment, including an intercooler, auxiliary water piping, turbocharger lube oil plumbing, waste-gate valves, and bypass valves. Another advantage is the ability to burn a wider range of fuels. Because the firing pressures of naturally aspirated engines are lower than turbocharged engines, naturally aspirated engines are able to burn richer fuels [i.e., those with higher calorific content (Btu/ft^3)] and maintain power levels. The lower firing pressures also allow a longer engine life cycle. The longer life cycle and less complex fuel system sometimes make the naturally aspirated engine preferable for remote, minimal-maintenance applications in which ease of maintenance is required.

8.2.5 Exhaust Emissions. Deterioration of the atmosphere from gaseous pollutants is an important environmental issue. All engine types produce emissions of some form and are possibly subject to emission regulation. Local, state, and national governments continue to enact stricter exhaust emission requirements to reduce atmospheric deterioration. Two ways to reduce atmospheric deterioration are to limit the power of engines and to require low emissions levels from an engine. Many applications are subject to emission control regulations.

The six main emission pollutants are classified into six different categories:

NO_x (oxides of nitrogen)

CO (carbon monoxide)

HC (hydrocarbons)
SO_x (oxides of sulfur)
CHO (aldehydes)
PM_{10} (particulate matter 10 μm and smaller)

NO_x consists of nitric oxide (NO) and nitrogen dioxide (NO_2) molecules formed when nitrogen (N_2) and oxygen (O_2) react with each other. This reaction requires a high combustion temperature and the presence of N_2 and O_2 in the combustion chamber as a fuel is burned. NO_2 is harmful to humans and animals because it reduces breathing capacity and the ability of the blood to carry O_2. When NO_x is exposed to sunlight, it acts as a precursor in the formation of harmful lower atmosphere ozone (O_3).

Carbon monoxide (CO) is formed by incomplete combustion of a fuel. Incomplete combustion occurs when there is insufficient O_2 to complete the combustion of the fuel molecule or when the combustion is quenched near a cold surface in the combustion chamber. Carbon monoxide is a poisonous gas that causes nausea, headache, and fatigue; in heavy enough concentrations, CO can even cause death. In the upper atmosphere, CO reacts with O_3 to produce CO_2. This reduces the O_3 in the upper atmosphere. Ozone in the upper atmosphere screens harmful sunrays from reaching the Earth's surface.

The burnable components of any fuel are the hydrocarbons (HC). A small fraction of HCs will pass through the combustion chamber and retain their original form in the exhaust. The nonmethane HCs (any HC other than methane) can react with the NO_x in the lower atmosphere, acting as a precursor for the formation of photochemical smog.

Oxides of sulfur are formed when sulfur-containing compounds are oxidized in the combustion chamber. These compounds can be found in the lube oil or in the fuel of an engine. Oxides of sulfur enter the atmosphere and combine with water to form sulfuric acid. These acids return to Earth as acid rain.

Aldehydes (CHO) are formed during the combustion of liquid fuels and lube oil in an engine. Therefore, CHO levels from gas-fueled engines are extremely low compared with liquid-fueled engines like diesel. Aldehydes contribute to photochemical smog and eye irritation.

Particulate matter is also formed during the combustion of liquid fuels and engine lubricants. Particulate matter is often seen as black smoke coming from diesel engines. Some regulatory agencies have labeled particulate matter from diesel engines as a possible carcinogen.

A popular method for reducing and controlling emission levels is to use catalyst reduction and air/fuel ratio control. A catalyst is a substance that promotes a chemical reaction to convert emissions into harmless, naturally occurring compounds without chemically changing itself. A catalyst operates two ways: it either oxidizes (oxidation catalyst) or reduces (reduction catalyst) the emission component. Catalyst reduction can be applied to either a rich-burn or lean-burn engine. The discussion of rich-burn engines vs. lean-burn engines applies primarily to gas-fueled engines. Liquid-fueled engines are generally rich-burn engines.

Rich-burn engines operate at near-stoichiometric combustion at a point where the air/fuel ratio is nearly 16:1. Stoichiometric combustion occurs when there is a correct proportion of O_2 and fuel so that they completely react in the combustion process, thus maximizing fuel efficiency and capturing the most power from the fuel. However, operating at near-stoichiometric combustion produces the highest levels of emissions. Today, most rich-burn engines entering the field use some form of catalyst aftertreatment for emissions. Catalyst performance in a rich-burn engine depends on the composition of the exhaust entering the catalytic converter.

Many rich-burn engines with a catalyst use an air/fuel ratio controller. An air/fuel ratio controller generally monitors the amount of O_2 in the exhaust stream, compares it with a desired set point, and then changes the air/fuel ratio accordingly. When the air/fuel ratio of an engine is controlled and held at an ideal setting, the chemical reaction occurring inside the catalyst is maximized. Many catalysts can have a reduction efficiency of > 90%.

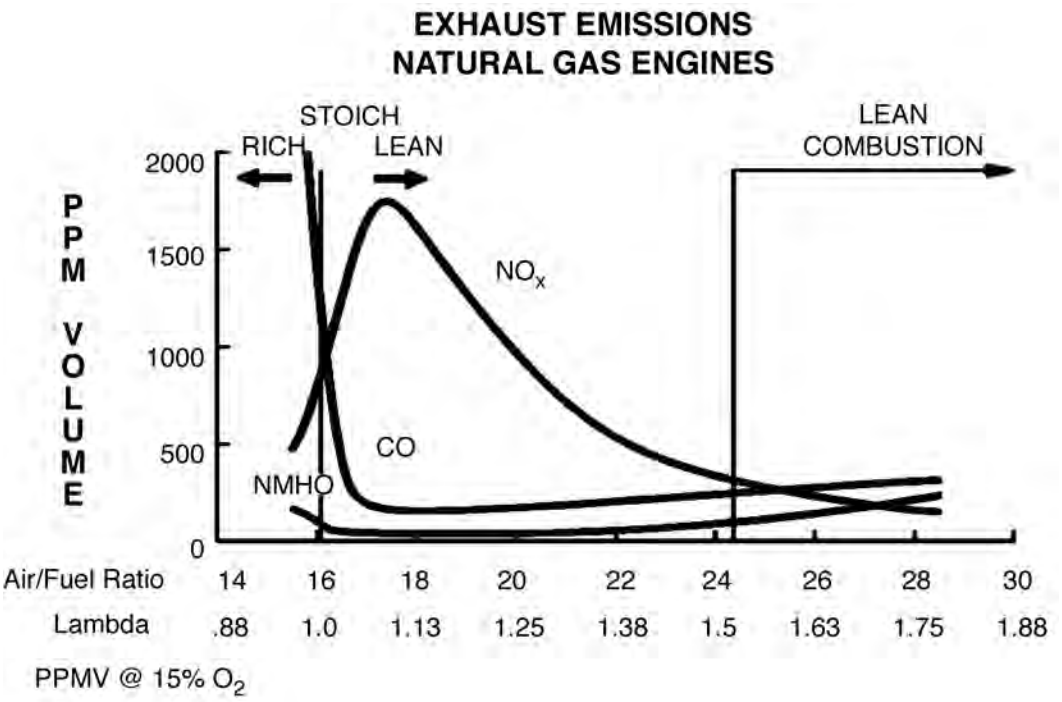


Fig. 8.3—Exhaust emissions of natural gas engines. Parts per million volume (PPMV) is a measure of amount of emission indicating how many parts out of 1 million there are of a particular emission when measured on a volume basis. 15% O_2 is a reference oxygen level that must accompany PPMV reporting. Oxygen percentage has a direct impact on PPMV number.

Lean-burn engines operate well beyond a 16:1 stoichiometric air/fuel ratio. They can have air/fuel ratios of 24:1 up to 32:1. A lean-burn engine with a 32:1 air/fuel ratio has twice as much O_2 than is needed for the fuel in the combustion chamber. However, having the excess O_2 ensures that fuel molecules will have a better opportunity to react with the needed O_2 for complete combustion of the fuel. Lean-burn engines consistently have lower NO_x and CO emissions primarily because of the excess O_2 in the combustion chamber and lower exhaust temperatures, which inhibit the formation of NO_x emissions. Generally, lean-burn engines do not use catalyst aftertreatment for emissions because the emission levels usually are low enough to meet regulations. An air/fuel ratio controller is typically not used with a lean-burn engine because the exhaust composition does not need to be maintained for a catalytic converter. However, if further emission reduction is needed, a selective catalyst can be used with a lean-burn engine. A common selective catalyst system injects ammonia urea (NH_3) to react with NO_x. The ammonia is consumed in the reaction to leave the emissions of N_2 and H_2O. These applications need to be considered with caution. A selective catalyst reduction system is expensive compared with a rich-burn oxidizing catalyst. A selective catalyst reduction system also requires on-site storage of hazardous ammonia.

Fig. 8.3 illustrates NO_x and CO emission output versus excess air/fuel ratio and excess air ratio for natural gas engines. Note the impact that air/fuel ratios have on rich-burn engine emissions compared with the impact on lean-burn engines. Air/fuel ratio controllers are very important in rich-burn engine applications in which emissions need to be controlled.

8.2.6 Engine Families and Interchangeability. Regardless of the engine type or engine manufacturer, families and parts interchangeability will most likely play a role in a particular

product lineup. Engine manufacturers generally group their products into engine families that are designated by engine, bore, and block type. Sometimes, they are separated to service different markets or different horsepower ranges. Within each engine family are parts interchangeability and commonality from both a manufacturing and a marketing standpoint. Engine manufacturers make parts common within a family so that the same part can be used in multiple engine models. Thus, the manufacturer has to have tooling and engineering support for only one part rather than multiple parts within the same family.

Marketing and sales departments use parts commonality and interchangeability as selling points. For example, gas compression sites may have more than one engine on site, and a power generation distributor may have more than one engine in its lease fleet. If the engines are from the same family and have commonality between them, then many parts may be shared between the multiple engines, so a service truck or a parts warehouse needs to stock fewer parts. An on-site emergency parts supply will also be smaller because the few parts kept can support all the engines. Common parts between engines are usually pistons, cylinder liners, connecting rods, bearings, and valve drive components. Sometimes, within a given family, cylinder heads will be the same and interchangeable. Cylinder head interchangeability can be particularly useful if an engine fleet has many different engine sizes but is from the same family. Heads can be taken off one engine that is being upgraded and then, after servicing, put on a different engine.

8.2.7 Engine Fuels. Engine fuel can be in a liquid state like diesel, gasoline, and jet fuel, or it can be in a gaseous state such as natural gas, propane vapor, and biogas. Liquid fuels allow on-site fuel storage for applications such as road, sea, or air vehicles. Liquid fuels can also be used for applications in which sites are too remote for a gas utility to reach such as remote power generation. Liquid fuels provide the convenience of having fuel storage built into the equipment. A rental fleet may use base tanks under their units to allow easy relocation. Gaseous fuels, such as natural gas, make it convenient to connect to a utility gas supply to fuel large stationary engines. In these applications, fuel demand is too great for on-site fuel storage to be practical. Gaseous fuels such as biogas are a byproduct of trash decomposition or sewage treatment plant processes. Using this byproduct as a gaseous engine fuel captures energy that would normally be flared off and wasted.

8.3 Gas Turbine Engines

This section focuses on the gas turbine engine, the differences between types of turbines, and items to consider when they are applied as the prime mover. Gas turbines range in size from microturbines at < 50 hp (37.3 kW) to large industrial turbines of > 250,000 hp (190 kW).

As shown in **Figs. 8.4 and 8.5**, the "open" Brayton cycle, consisting of adiabatic compression, constant pressure heating, and adiabatic expansion, is the thermodynamic cycle for all gas turbines. The gas turbine is made up of an air compressor, combustor, and a power turbine, which produces the power to drive the air compressor and the output shaft. Air enters the compressor inlet at ambient conditions (Point 1), is compressed (Point 2), and passes through the combustion system, where it is combined with fuel and "fired" to the maximum cycle temperature (Point 3). The heated air is expanded through the gas producer turbine section (between Points 3 and 5), where the energy of the working fluid is extracted to generate power for driving the compressor, and expanded through the power turbine to drive the load (Point 7). The air is then exhausted to the atmosphere. A starting system is used to get the air compressor up to sufficient speed to supply air for combustion with the fuel injected into the combustor. A turbine's continuous-burning combustion cycle, combined with continuous rotation of the turbine rotor, allows virtually vibration-free operation, as well as fewer moving parts and wear points than other prime movers.

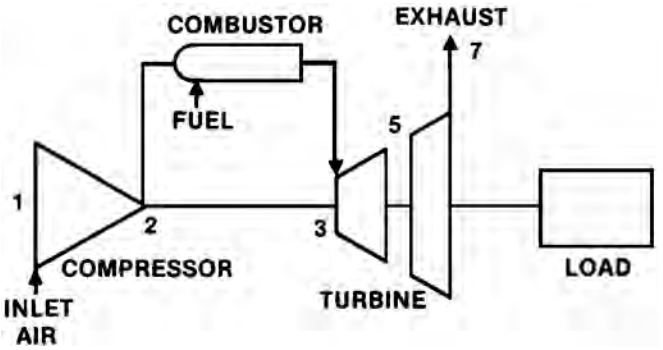


Fig. 8.4—Simplified simple-cycle gas turbine diagram.

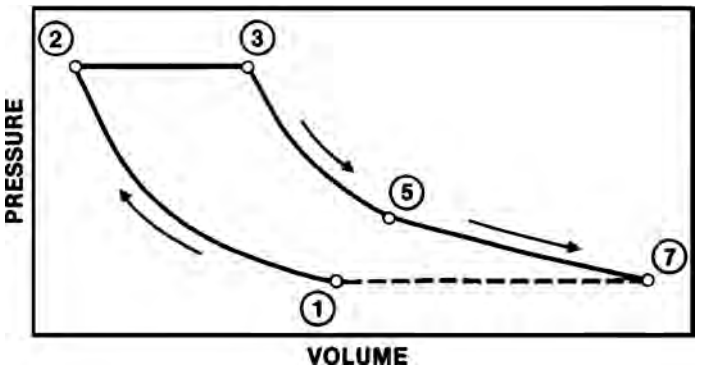


Fig. 8.5—Typical "open" Brayton cycle for gas turbines.

8.3.1 Maximum Cycle Temperature, TRIT. The output power of a gas turbine may be increased by increasing the maximum cycle temperature. The maximum cycle temperature is designated TRIT, which stands for turbine rotor inlet temperature. *API 616* defines rated firing temperature as the vendor's calculated turbine inlet temperature (TIT) immediately upstream of the first-stage turbine rotor for continuous service at rated power output. TRIT is calculated immediately upstream of the first-stage turbine rotor and includes the calculated effects of cooling air and temperature drop across the first-stage stator vanes.

8.3.2 Airflow. The output power of a gas turbine may also be increased by increasing the mass flow of air through the gas turbine. The geometry of the gas turbine, particularly the compressor, and the speed of the compressor dictate basic air mass flow. An increase in flow requires an increase in speed, which is limited to the maximum continuous running speed of any particular design. At a given speed, an increase in inlet air density increases air mass flow. Inlet air density increases directly with barometric pressure and inversely with ambient temperature.

The main parameters affecting output power are speed and TRIT for any given mechanical/aerodynamic design. Increasing any one of these parameters increases the output power capacity of the gas turbine. Speed and temperature may be dictated by the output power and heat rate desired within the constraints imposed by component life, cost, and technical feasibility.

8.3.3 Speed Limitations. As the speed of a gas turbine increases, the centrifugal forces on the rotating components increase. These forces increase the stress on the rotating components, par-

ticularly the disks, blades, and blade attachment to the disk. Component materials have stress limits that are directly proportional to their speed limits and should not be exceeded. Thus, the maximum continuous speed of the rotating element is a function of rotor geometry, component material properties, and safety design factors. It is the highest allowable speed for continuous operation.

8.3.4 Temperature Limitations. One way to increase output power is to increase the fuel flow and therefore TRIT. As TRIT increases, hot section components operate at higher metal temperatures, which reduces the time between inspection (TBI) of the gas turbine. Because the life of hot section materials is limited by stress at high temperature, there are limitations on the maximum temperatures for a given TBI. Material life decreases rapidly at higher temperatures. TBI is a function of time at TRIT and the rate of TRIT change during transients such as start-up. The creep or stress rupture limit is established by the material properties as a function of their stress level and operating temperature.

8.3.5 Rating Point. A rating point can be established for determining gas turbine performance for specified ambient conditions, duct losses, fuel, etc. The International Standards Organization defines its standard conditions as 59°F, 1.013 bar, and 60% relative humidity with no losses. This has become a standard rating point for comparing turbines of various manufacturers and designs.

8.3.6 Site Rating. The site rating is a statement of the basic gas turbine performance under specific site conditions, including ambient temperature, elevation, duct pressure losses, emission controls, fuel composition, auxiliary power takeoff, compressor air extraction, and output power level. For instance, an increase in ambient temperature reduces output power at a rate influenced by gas turbine design.

8.3.7 Inlet Air Temperature. Fig. 8.6 relates output power, fuel flow, exhaust temperature, and exhaust flow to inlet air temperature at optimum power turbine speed for an example gas turbine.

8.3.8 Performance Correction for Elevation. Site elevation affects power output, fuel flow, and airflow of all open-cycle gas turbines because of the reduction in inlet air density caused by reduced barometric pressure.

8.3.9 Increasing Turbine Efficiency. ***Simple Cycle.*** Most of the mechanical energy extracted from the gas stream by the turbine is required to drive the air compressor, with the remainder available to drive a mechanical load. The gas stream energy not extracted by the turbine is rejected to the atmosphere as heat.

Recuperative Cycle. In the recuperative cycle, also called a regenerative cycle, the compressor discharge air is preheated in a heat exchanger or recuperator, the heat source of which is the gas turbine exhaust. The energy transferred from the exhaust reduces the amount of energy that must be added by the fuel. In Fig. 8.7, the fuel savings is represented by the shaded area under 2 to 2′. The three primary designs used in stationary recuperators are the plate fin, shell and tube, and primary surface.

Combined Cycle. Adding a steam bottoming cycle to the Brayton cycle uses the exhaust heat to produce additional horsepower, which can be used in a common load, as shown in Fig. 8.8, or for a separate load. The shaded area represents the additional energy input.

8.3.10 Types of Gas Turbines. Turbine designs can be differentiated by type of duty, combustor types, shaft configuration, and degree of packaging.

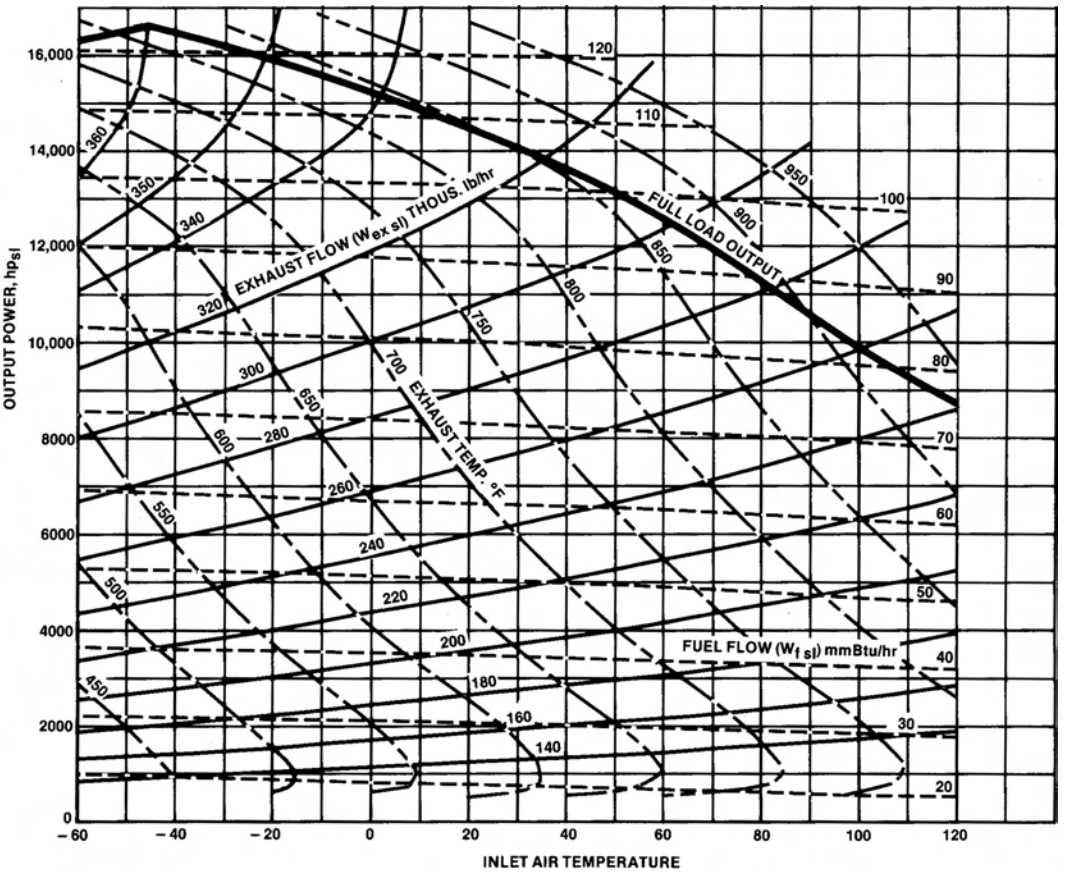


Fig. 8.6—Output power vs. compressor inlet air temperature.

Types of Duty. • *Aircraft Turbine Engines.* Aircraft turbine engines or jet engines are designed with highly sophisticated construction for light weight specifically for powering aircraft. These designs require maximum horsepower or thrust with minimum weight and maximum fuel efficiency. Aircraft turbines have roller bearings and high firing temperatures requiring exotic metallurgy. They can be operated on a limited variation of fuels. When a jet engine is used in an industrial application, it must be coupled with an independent power turbine to produce shaft power.

• *Heavy Industrial Gas Turbine Engines.* The basic design parameters for heavy industrial gas turbine engines evolved from industrial steam turbines that have slower speeds, heavy rotors, and larger cases than jet engines to ensure longer life. These gas turbines are capable of burning the widest range of liquid or gas fuels.

• *Light Industrial Gas Turbine Engines.* The basic design parameters and technology used in aircraft turbines can be combined with some of the design aspects of heavy industrial gas turbines to produce a lighter-weight industrial turbine with a life approaching that of a heavy industrial gas turbine. These engines are called light industrial gas turbine engines.

Combustor Types. • *Radial or Annular Combustor.* This combustor surrounds the gas turbine rotating parts and is integral to the engine casing (**Fig. 8.9**). Aircraft turbines and light industrial gas turbines use this design.

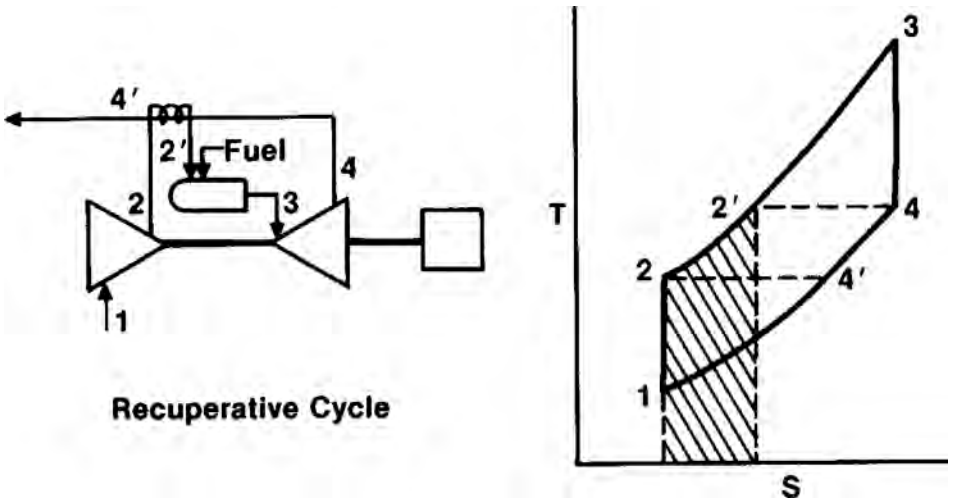


Fig. 8.7—Recuperated cycle.

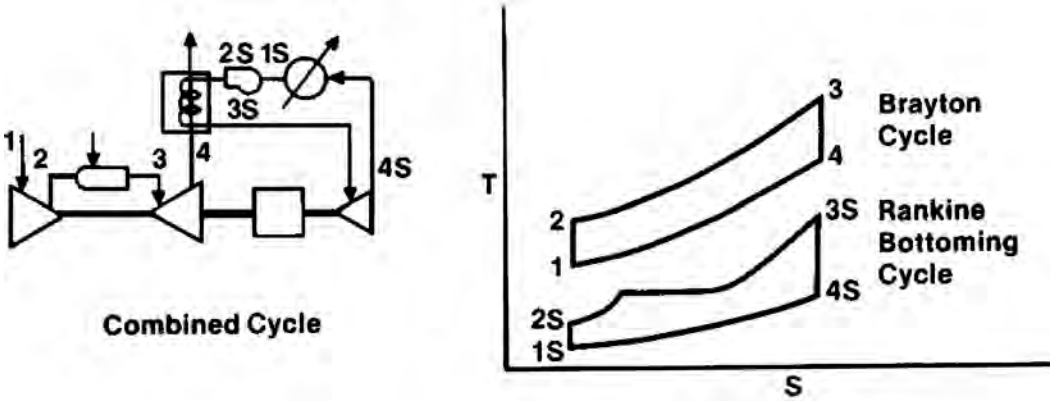


Fig. 8.8—Combined cycle.

• *Can Combustor.* This is a single- or multicombustion system that is separated from the rotating turbine as external combustion cans (**Fig. 8.10**). Designs using this type of combustor can burn a wider range of fuels.

Shaft Configuration. • *Single Shaft.* The gas turbine can have either a single-shaft or a two-shaft design. The single-shaft design consists of one shaft connecting the air compressor, gas producer turbine, and power turbine as one rotating element (Fig. 8.4). This design is best suited for constant-speed applications such as driving electric generators for a constant frequency.

• *Two Shaft.* The two-shaft design has the air compressor and gas producer on one shaft and the power turbine on a second independent shaft. This design provides the speed flexibility needed to cover a wider performance map of the driven equipment more efficiently. This allows the gas producer to operate at the speed necessary to develop the horsepower required by the driven equipment such as centrifugal compressors or pumps. Fig. 8.9 shows a cutaway view of a typical two-shaft gas turbine. Major components include the compressor, combustion system, gas producer turbine, and power turbine. This design includes a two-stage gas producer turbine and a two-stage power turbine.

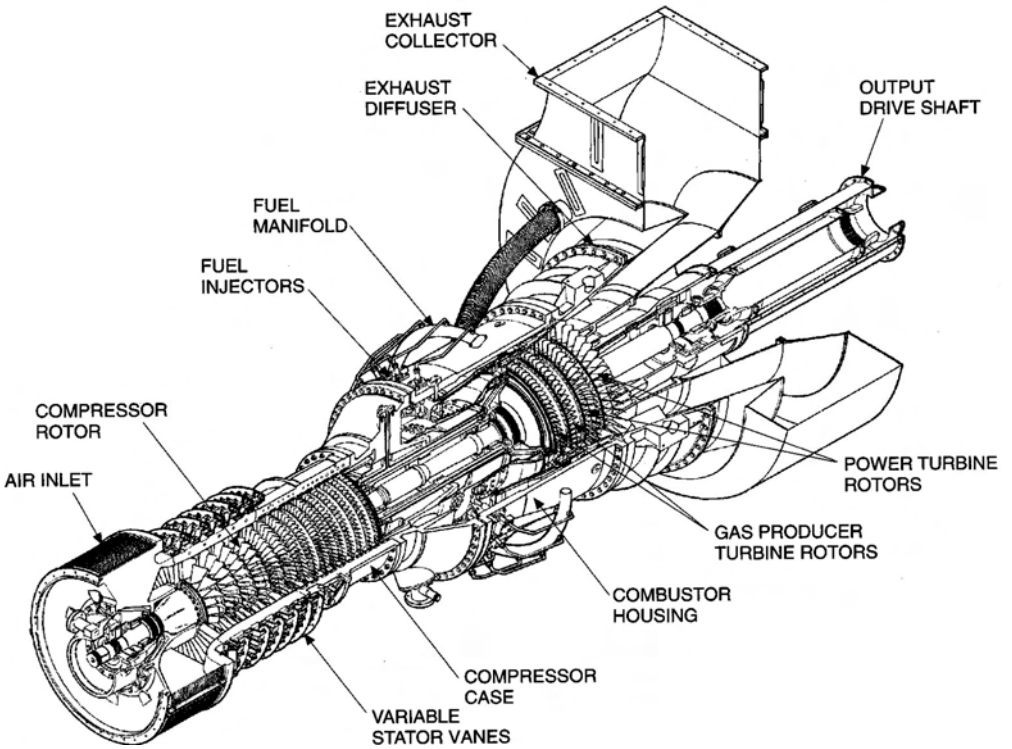


Fig. 8.9—Typical gas turbine cutaway.

Degree of Packaging. The norm for most gas turbines used in industry consists of incorporating the gas turbine into a base frame/skid with all the components required for the basic operational unit. This includes such systems as the start system, fuel system, lubrication system, local controls, and in some cases the gear box and driven equipment. Additional operationally required systems such as air inlet filtration/silencing, oil coolers, remote control systems, sound-attenuated enclosures, and exhaust silencers are all generally separate preengineered packaged systems that can be provided and customized by the turbine manufacturer.

8.3.11 Air Inlet System. ***Inlet Air Filtration.*** The quality of air entering the gas turbine is a very important design consideration. Turbine efficiency will decrease over time because of deposits building up on the turbine internal flow path and rotating blades. This buildup results in increased maintenance and fuel consumption. Selecting and maintaining the proper inlet air filtration system for the specific site conditions will affect the rate of decrease of efficiency over time.

Pressure Drop. It is critical to minimize the pressure drop of the air passing through the inlet ducting, inlet air filter, and inlet silencer (see below). Pressure loss on the atmospheric air entering the turbine greatly affects the performance of the gas turbine.

Noise Attenuation. The noise produced by a gas turbine is primarily in the higher-frequency ranges, which are not transmitted as far as the lower-frequency noises produced by slower-speed prime movers such as reciprocating engines. Most high-frequency noise produced by the turbine is generated in the air inlet, with a smaller amount coming from the exhaust. The sources of noise and method of attenuation are as follows:

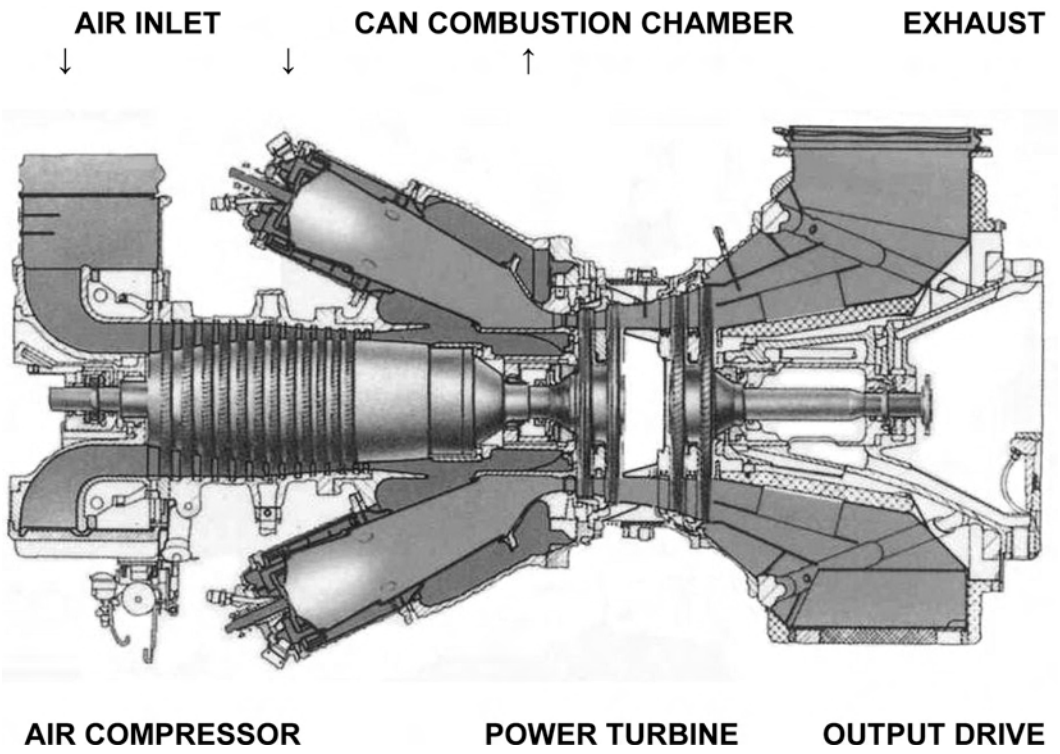


Fig. 8.10—Typical gas turbine with can combustor (cutaway).

• *Air Inlet.* The inlet silencer should be specifically designed to the noise profile of the gas turbine and the site requirements. This silencer is installed in the air inlet ducting between the air filter and the turbine air compressor inlet.

• *Exhaust.* The exhaust silencer should be specifically designed to the noise profile of the gas turbine and the site requirements. The exhaust stack height in conjunction with the silencer is an important consideration. Discharging the hot exhaust gases as high as practical reduces the measurable noise at ground level plus has the added benefit of reducing the chance of recirculation of the hot exhaust back into the air inlet. Pressure loss (backpressure) on the exhaust of the turbine greatly affects the performance of the gas turbine.

• *Casing/Gear Box/Driven Equipment.* Sound-attenuating enclosure(s) can be installed directly over the equipment such as skid-mounted walk-in enclosures or a building containing the equipment insulated to meet the requirements or both.

• *Oil Cooler.* The most common method of cooling the oil is the use of air exchanger/fan coolers. These generate fan noise that can be controlled with fan tip speed. The use of shell and tube water coolers can be noise-efficient if the cooling media is available.

8.3.13 Exhaust Emissions. Deterioration of the atmosphere by gaseous pollutants is an important environmental issue. The gas turbine by basic cycle design gives a cleaner combustion and produces a lower level of pollutant compared with other prime movers, which is a major advantage. The gas turbine pollutants that typically are regulated are oxides of nitrogen, carbon monoxide, unburned hydrocarbons, particulates, and sulfur dioxide. The solution to some, but not all, of these pollution problems lies within the gas turbine combustor. A brief discussion follows.

Oxides of Nitrogen (NO_x). Only two of the seven oxides of nitrogen are regulated: NO and NO_2, referred to collectively as NO_x. Almost all emission concerns involving prime movers relate to NO_x production and NO_x controls. The gas turbine is relatively clean compared with other prime movers. For example, gas turbines burning natural gas generally produce 4 to 12 times less NO_x per unit of power than reciprocating engines produce. However, NO_x is the major factor in permitting gas turbine installations.

Carbon Monoxide (CO). CO is also at a very low level in turbine exhaust because of the excess air in the combustion process. Therefore, it is usually not a problem. However, in some areas where the ambient level of CO is extremely high or when water injection is being used for NO_x control in the gas turbine, CO may be a factor in obtaining permits.

Unburned Hydrocarbons (UHC). Unlike reciprocating engines that produce a significant amount of UHC, gas turbines produce a low amount of UHC because the large amount of excess air involved in the gas turbine combustion process completely combusts almost all the hydrocarbons. Consequently, UHC emissions are rarely a significant factor in obtaining environmental permits for gas turbines.

Particulates. No particulate measuring techniques have been perfected that produce meaningful results on gas turbine exhausts. This is rarely a factor in obtaining permits for gas turbines when clean fuels are burned in the gas turbine.

Sulfur Dioxide (SO_2). Almost all fuel-burning equipment, including gas turbines, converts all the sulfur contained in the fuel to SO_2. This makes SO_2 a fuel problem rather than a problem associated with the characteristics of the turbine. The only effective way to control SO_2 is by limiting the amount of sulfur contained in the fuel or by removing the SO_2 from the exhaust gases by means of a wet scrubbing process.

The need to meet or surpass the emission standards set by federal, state, and local codes has required industrial gas turbine manufacturers to develop cleaner-burning turbines. Dry emission systems have been developed with lean-premix fuel injectors, special combustion technology, and controls for reducing emissions of NO_x and CO by creating lower maximum flame temperatures and more complete oxidation of hydrocarbon fuels. All industrial gas turbine manufactures have dry low emission products. The performance varies with the individual product because of differences in combustor design.

These lean-burn systems reduce the formation of NO_x and CO to very low levels, thus making it unnecessary to use expensive high-maintenance catalytic converters to eliminate NO_x and CO after they are formed. In extreme high-attainment areas, it may be necessary with some gas turbines to use selective catalytic converters to further reduce the level of NO_x and CO. The fuel of choice for the gas turbine is clean dry natural gas, which produces the cleanest exhaust.

8.3.14 Turbine Fuels. Gas turbines can operate on a wide variety of fuels. The fuel injection system, combustor, and control systems are designed to handle the fuel of choice.

• *Gas.* Turbines can operate on almost any combustible gas. Most operate on natural gas, propane vapor, or biogas. The fuel of choice for gas turbines to maximize engine life and create the lowest emissions is sweet natural gas free of sulfur, contaminants, entrained water, and liquid hydrocarbons.

• *Liquid.* Turbines can operate on almost any combustible liquids. Most operate on fuel oil, diesel, kerosene, or jet fuel. Large heavy industrial gas turbines can operate on all forms of liquid hydrocarbon fuels, including heavy crude oil.

• *Dual fuel.* Gas turbines can be used in dual-fuel operation in which the primary fuel such as natural gas can be switched to diesel for emergency backup.

8.3.15 Exhaust Heat. Gas turbines have most of the heat loss from the cycle going out the exhaust. This heat can be recovered and used to increase the overall thermal efficiency of the fuel burned. The most common method of exhaust heat use is in the production of steam.

General References

Barr, G.R. and Jones, M.D.: *Turbomachinery Development and Solar's Product Line Evolution*, TTS1, Solar Turbines Inc. (1989).

Gas Engine Emission Technology, third edition, form 536, Waukesha Engine, Dresser Inc. (1993).

Odom, F.M.: *Gas Turbine Generator Unit and Gas Compression System Performance Rating Philosophy*, TTS3, Solar Turbines Inc. (1984).

Slow Running 4 Cycle Cylinder, Waukesha Engine Product Training Center, Waukesha Engine, Dresser Inc.

SI Metric Conversion Factors

bar	×	1.0*	E+05	= Pa
Btu/ft^3	×	1.134 893	E+04	= J/m^3
°F		(°F–32)/1.8		= °C
hp	×	7.460*	E+02	= W

*Conversion factor is exact.

Chapter 9
Piping and Pipelines

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9.1 Introduction

Once oil and gas are located and the well is successfully drilled and completed, the product must be transported to a facility where it can be produced/treated, stored, processed, refined, or transferred for eventual sale. **Fig. 9.1** is a simplified diagram that illustrates the typical, basic "wellhead to sales" concept. The typical system begins at the well flow-control device on the producing "wing(s)" of the wellhead tree and includes the well "flowline," production/treating/storage equipment, custody-transfer measurement equipment, and the gathering or sales pipeline. Information and detailed discussions concerning petroleum production, treating, storage, and measurement equipment are located in various chapters of this *Handbook.*

The piping and pipeline systems typically associated with producing wells include, but are not limited to, the well flowline, interconnecting equipment piping within the production "battery," the gathering or sales pipeline, and the transmission pipeline. A brief description of the associated piping/pipeline systems is given next.

9.1.1 Well Flowline. The well flowline, or simply flowline, is the first "pipeline" system connected to the wellhead. The flowline carries total produced fluids (e.g., oil, gas, and production water) from the well to the first piece of production equipment—typically a production separator. The flowline may carry the well-production fluids to a common production battery, a gathering pipeline system, process facility, or other.

9.1.2 Interconnecting Piping. Interconnecting piping includes the piping between the various pieces of production/treating equipment such as production separators, line heaters, oil heaters, pump units, storage tanks, and gas dehydrators. The piping systems may also include headers, fuel systems, other utility piping, and pressure-relief/flare systems.

9.1.3 Gathering/Sales Pipeline. The pipe that delivers the well production to some intermediate or terminal location is the gathering or sales pipeline. The gathering pipeline literally "gathers" the production from producing wells and conveys the production to a collection system, a processing facility, custody-transfer (sales) point, or other.

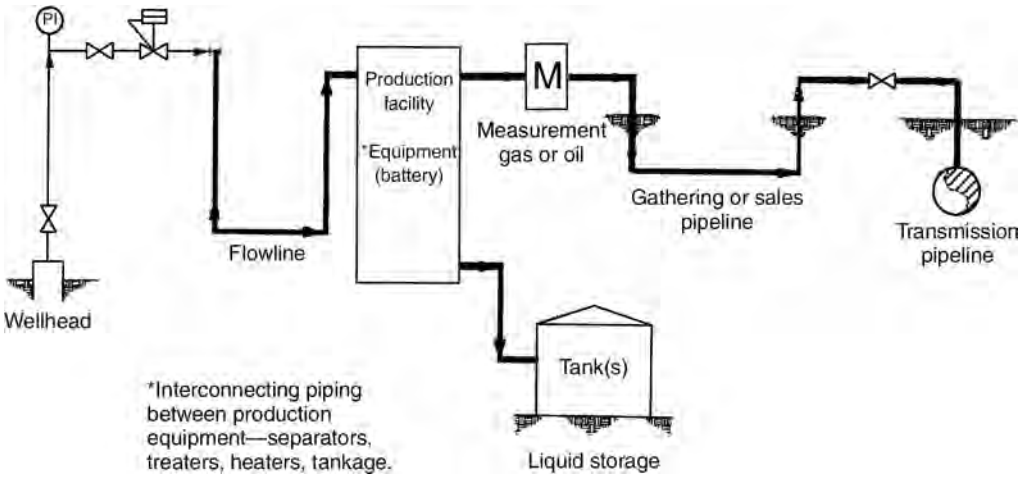


Fig. 9.1—Wellhead to sales (courtesy of AMEC Paragon).

9.1.4 Transmission Pipeline. The transmission pipeline is a "cross-country" pipeline that is specifically designed to transport petroleum products long distances. The transmission pipeline collects the specific petroleum products from many "supply" sources along the pipeline (such as gathering pipelines) and "delivers" the product to one or more end users. There are three general categories of transmission pipelines: natural gas, "product," and crude oil. Natural-gas transmission pipelines carry only natural gas. Product pipelines may carry a number of processed or refined petroleum products such as processed natural-gas liquids (e.g., butane and propane), gasoline, diesel, and refined fuel oils. Crude-oil pipelines convey unrefined crude oil from producing areas to large storage areas or directly to refineries.

9.2 Piping and Pipeline Systems' Pressure-Drop Formulas

The simplest way to convey a fluid, in a contained system from Point A to Point B, is by means of a conduit or pipe (**Fig. 9.2**). The minimum basic parameters that are required to design the piping system include, but are not limited to, the following.

- The characteristics and physical properties of the fluid.
- The desired mass-flow rate (or volume) of the fluid to be transported.
- The pressure, temperature, and elevation at Point A.
- The pressure, temperature, and elevation at Point B.
- The distance between Point A and Point B (or length the fluid must travel) and equivalent length (pressure losses) introduced by valves and fittings.

These basic parameters are needed to design a piping system. Assuming steady-state flow, there are a number of equations, which are based upon the general energy equation, that can be employed to design the piping system. The variables associated with the fluid (i.e., liquid, gas, or multiphase) affect the flow. This leads to the derivation and development of equations that are applicable to a particular fluid. Although piping systems and pipeline design can get complex, the vast majority of the design problems encountered by the engineer can be solved by the standard flow equations.

9.2.1 Bernoulli Equation. The basic equation developed to represent steady-state fluid flow is the Bernoulli equation which assumes that total mechanical energy is conserved for steady, incompressible, inviscid, isothermal flow with no heat transfer or work done. These restrictive conditions can actually be representative of many physical systems.

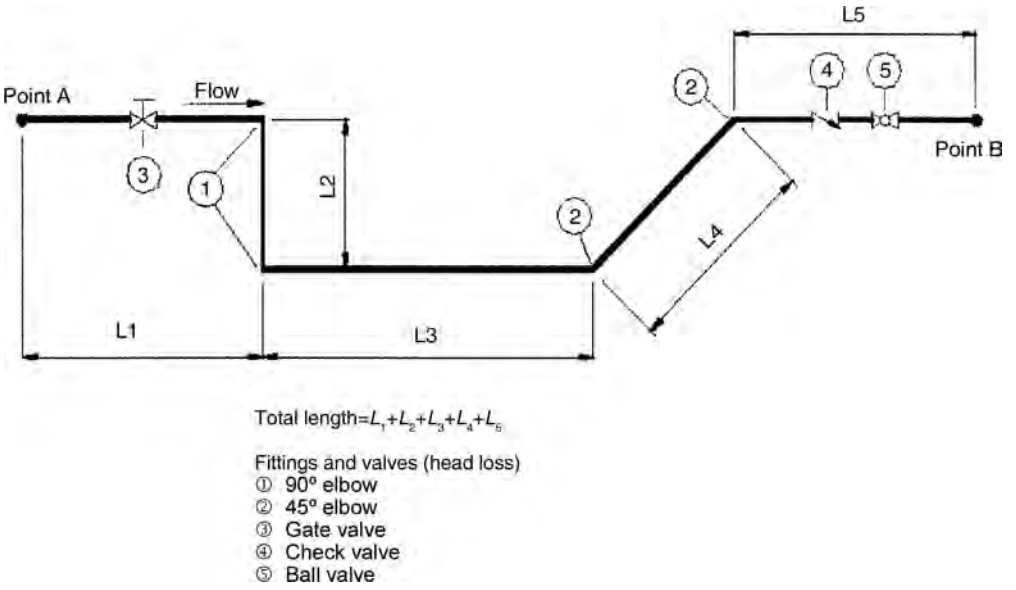


Fig. 9.2—Fluid-flow system (courtesy of AMEC Paragon).

The equation is stated as

$$Z_1 + \frac{144P_1}{\rho_1} + \frac{V_1^2}{2g} = Z_2 + \frac{144P_2}{\rho_2} + \frac{V_2^2}{2g} + H_L \text{ , } \quad \text{..... (9.1)}$$

where

Z = elevation head, ft,
P = pressure, psi,
ρ = density, lbm/ft^3,
V = velocity, ft/sec,
g = gravitational constant, ft/sec^2,

and

H_L = head loss, ft.

Fig. 9.3 presents a simplified graphic illustration of the Bernoulli equation.

Darcy's equation further expresses head loss as

$$H_L = \frac{fLV^2}{D2g} \text{ , } \quad \text{..... (9.2)}$$

and

$$\Delta P = 0.0013\frac{f\rho LV^2}{d} \text{ , } \quad \text{..... (9.3)}$$

where

H_L = head loss, ft,

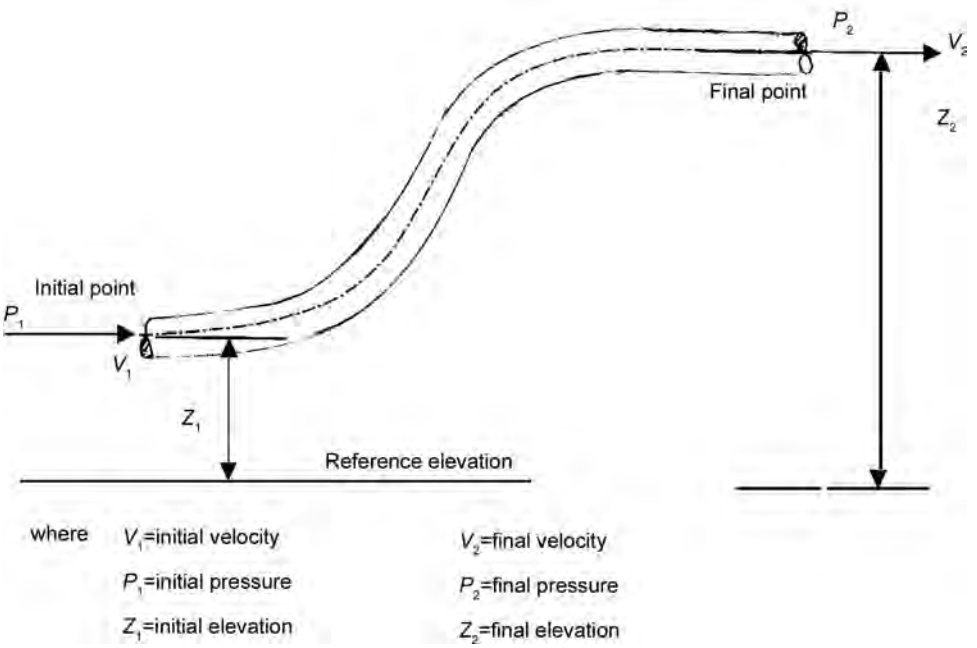


Fig. 9.3—Sketch for Bernoulli equation (courtesy of AMEC Paragon).

f = Moody friction factor, dimensionless,
L = pipe length, ft,
D = pipe diameter, ft,
V = velocity, ft/sec,
g = gravitational constant ft/sec^2,
ΔP = pressure drop, psi,
ρ = density, lbm/ft^3,
and
d = pipe inside diameter, in.

9.2.2 Reynolds Number and Moody Friction Factor. The Reynolds number is a dimensionless parameter that is useful in characterizing the degree of turbulence in the flow regime and is needed to determine the Moody friction factor. It is expressed as

$$\text{Re} = \frac{\rho V D}{\mu}, \quad \text{..... (9.4)}$$

where
ρ = density, lbm/ft^3,
D = pipe internal diameter, ft,
V = flow velocity, ft/sec,
and
μ = viscosity, lbm/ft-sec.
The Reynolds number for liquids can be expressed as

$$\text{Re} = \frac{92.1(SG)Q_l}{d\mu}, \quad \text{..... (9.5)}$$

TABLE 9.1—ABSOLUTE ROUGHNESS OF VARIOUS TYPES OF PIPE (courtesy of AMEC Paragon)

Type of Pipe (New, Clean Condition)	Absolute Roughness, *M*		
	(mm)	(ft)	(in.)
Unlined concrete	0.3–3.05	0.001–0.01	0.012–0.12
Cast iron (uncoated)	0.26	0.00085	0.0102
Galvanized iron	0.15	0.0005	0.006
Carbon steel	0.046	0.00015	0.0018
Fiberglass epoxy	0.0076	0.000025	0.0003
Drawn tubing	0.0015	0.000005	0.00006

Increase by factor of 2–4 to allow for age and use.

where

μ = viscosity, cp,

d = pipe inside diameter, in.,

SG = specific gravity of liquid relative to water (water = 1),

Q_l = liquid-flow rate, B/D,

and

V = velocity, ft/sec.

The Reynolds number for gases can be expressed as

$$\mathrm{Re} = 20{,}100\frac{Q_g S}{d\mu}, \quad \text{..... (9.6)}$$

where

μ = viscosity, cp,

d = pipe inside diameter, in.,

S = specific gravity of gas at standard conditions relative to air (molecular weight divided by 29),

and

Q_g = gas-flow rate, MMscf/D.

The Moody friction factor, f, expressed in the previous equations, is a function of the Reynolds number and the roughness of the internal surface of the pipe and is given by **Fig. 9.4**. The Moody friction factor is impacted by the characteristic of the flow in the pipe. For laminar flow, where Re is < 2,000, there is little mixing of the flowing fluid, and the flow velocity is parabolic; the Moody friction factor is expressed as $f = 64/\mathrm{Re}$. For turbulent flow, where Re > 4,000, there is complete mixing of the flow, and the flow velocity has a uniform profile; f depends on Re and the relative roughness (ϵ/D). The relative roughness is the ratio of absolute roughness, ϵ, a measure of surface imperfections to the pipe internal diameter, D. **Table 9.1** lists the absolute roughness for several types of pipe materials.

If the viscosity of the liquid is unknown, **Fig. 9.5** can be used for the viscosity of crude oil, **Fig. 9.6** for effective viscosity of crude-oil/water mixtures, and **Fig. 9.7** for the viscosity of natural gas. In using some of these figures, the relationship between viscosity in centistokes and viscosity in centipoise must be used

$$\gamma = \frac{\Phi}{SG}, \quad \text{..... (9.7)}$$

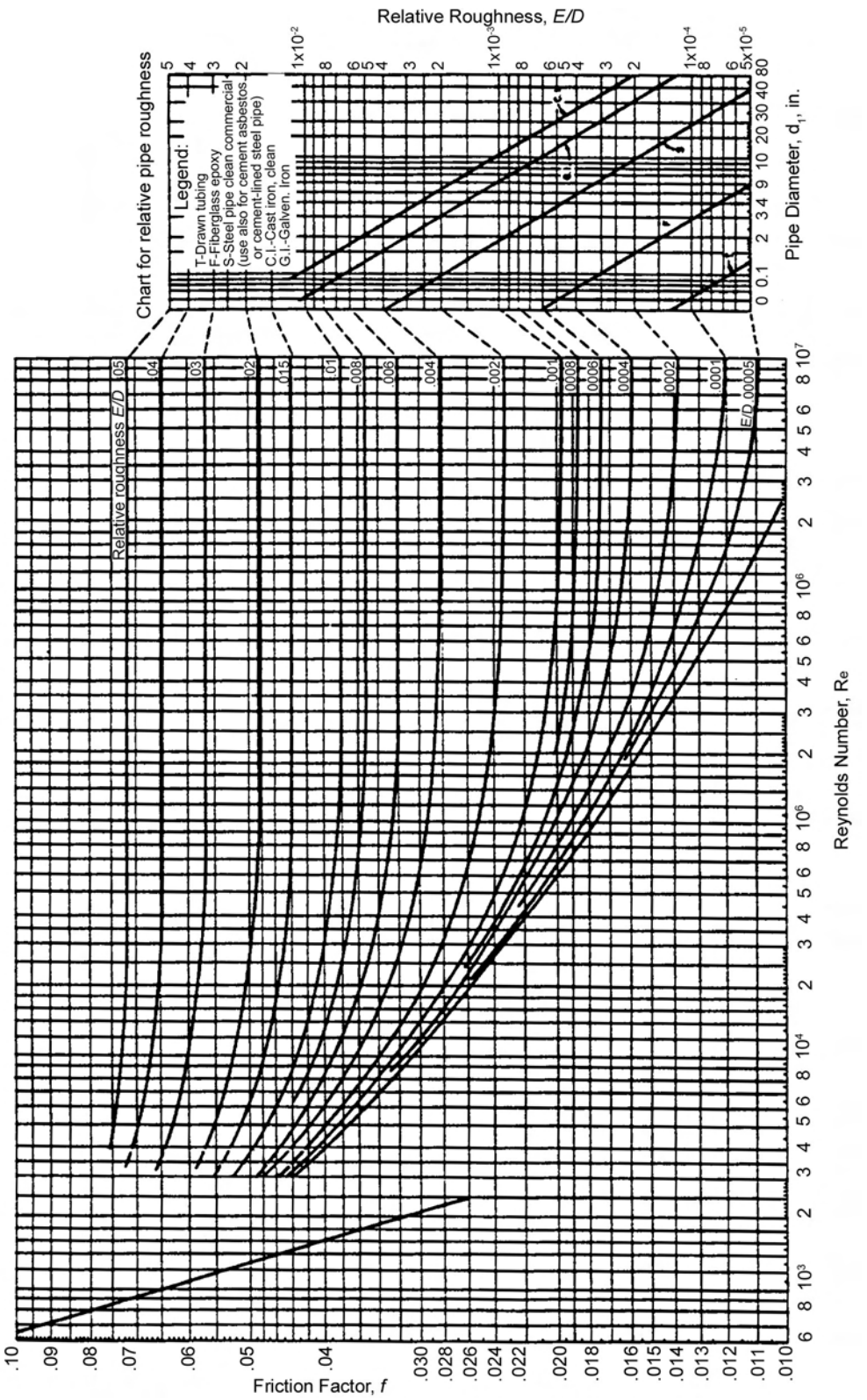


Fig. 9.4—Friction-factor chart (courtesy of AMEC Paragon).

where
γ = kinematic viscosity, centistokes,
Φ = absolute viscosity, cp,
and
SG = specific gravity.

9.2.3 Pressure Drop for Liquid Flow. ***General Equation.*** Eq. 9.3 can be expressed in terms of pipe inside diameter (ID) as stated next.

$$d^5 = (11.5 \times 10^{-6})\frac{f L Q_l^2 (SG)}{\Delta P}, \quad \text{..... (9.8)}$$

where
d = pipe inside diameter, in.,
f = Moody friction factor, dimensionless,
L = length of pipe, ft,
Q_l = liquid flow rate, B/D,
SG = specific gravity of liquid relative to water,
and
ΔP = pressure drop, psi (total pressure drop).

Hazen-Williams Equation. The Hazen-Williams equation, which is applicable only for water in turbulent flow at 60°F, expresses head loss as

$$H_L = 0.00208\left(\frac{100}{C}\right)^{1.85}\left(\frac{\text{gpm}}{d^{2.63}}\right)^{1.85}, \quad \text{and} \quad L = 0.015\frac{Q_L^{1.85} L}{d^{4.87} C^{1.85}}, \quad \text{..... (9.9)}$$

where
H_L = head loss because of friction, ft,
L = pipe length, ft,
C = friction factor constant, dimensionless (**Table 9.2**),
d = pipe inside diameter, in.,
Q_l = liquid flow rate, B/D,
and
gpm = liquid flow rate, gal/min.
Pressure drop can be calculated from

$$\Delta P = 0.43 H_L. \quad \text{..... (9.10)}$$

9.2.4 Pressure Drop for Gas Flow. ***General Equation.*** The general equation for calculating gas flow is stated as

$$w^2 = \left[\frac{144 g A^2}{V_1'\left(\frac{fL}{D} + 2\log_e \frac{P_1}{P_2}\right)}\right] \times \left[\frac{(P_1)^2 - (P_2)^2}{P_1}\right], \quad \text{..... (9.11)}$$

where

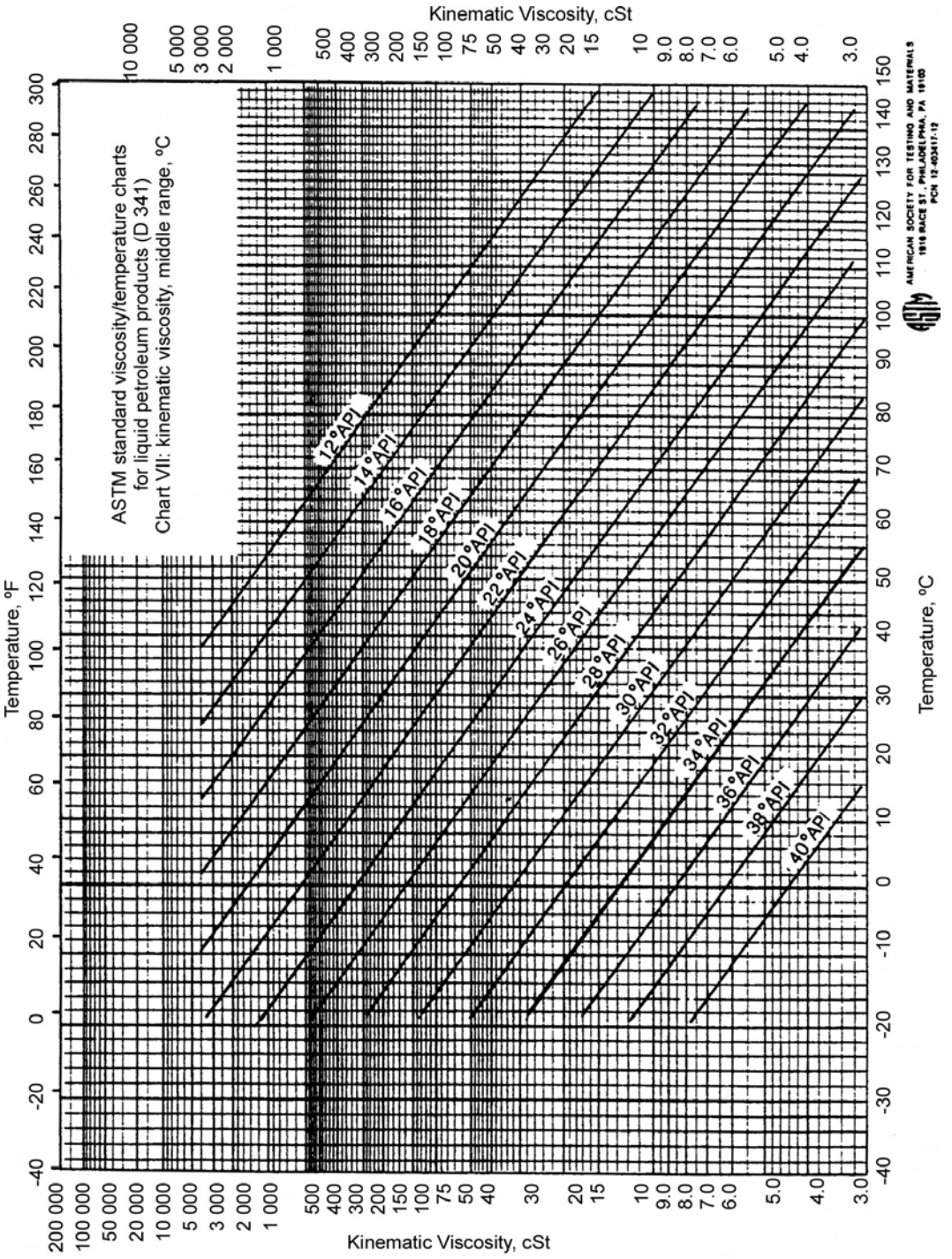


Fig. 9.5—Standard viscosity/temperature charts for liquid petroleum products (courtesy of ASTM).

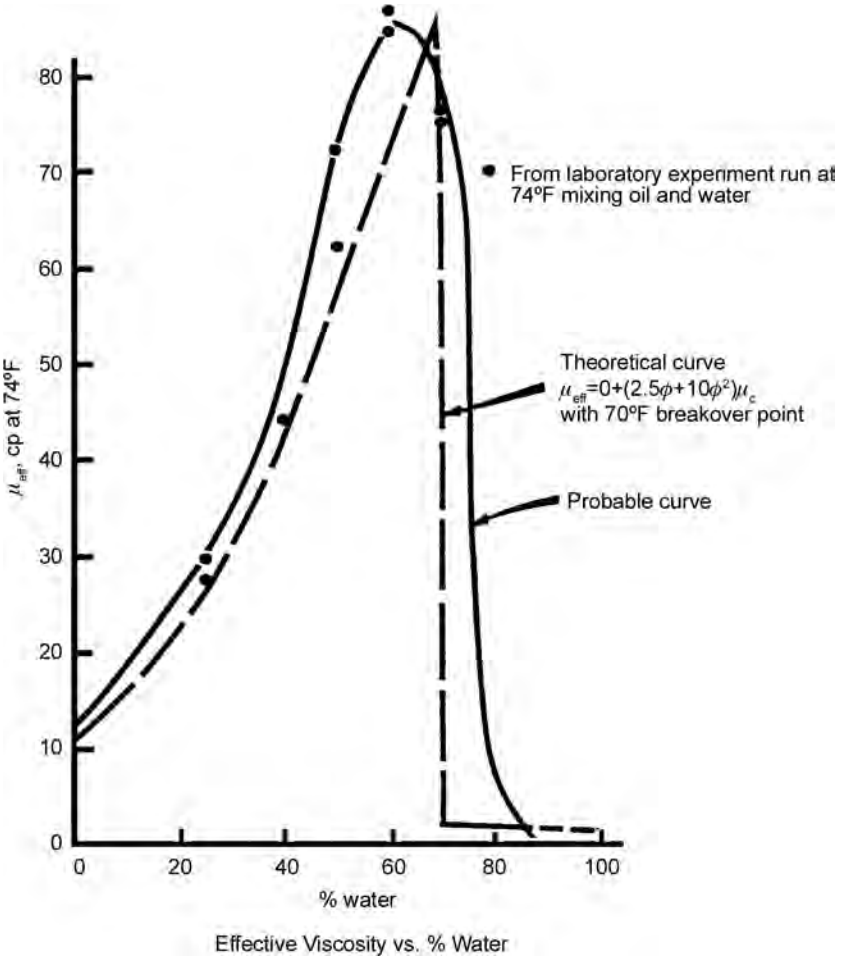


Fig. 9.6—Effective viscosity of an oil/water mixture (courtesy of AMEC Paragon).

w = rate of flow, lbm/sec,
g = acceleration of gravity, 32.2 ft/sec^2,
A = cross-sectional area of pipe, ft^2,
V_1' = specific volume of gas at upstream conditions, ft^3/lbm,
f = friction factor, dimensionless,
L = length, ft,
D = diameter of the pipe, ft,
P_1 = upstream pressure, psia,
and
P_2 = downstream pressure, psia.

Assumptions: no work performed, steady-state flow, and f = constant as a function of the length.

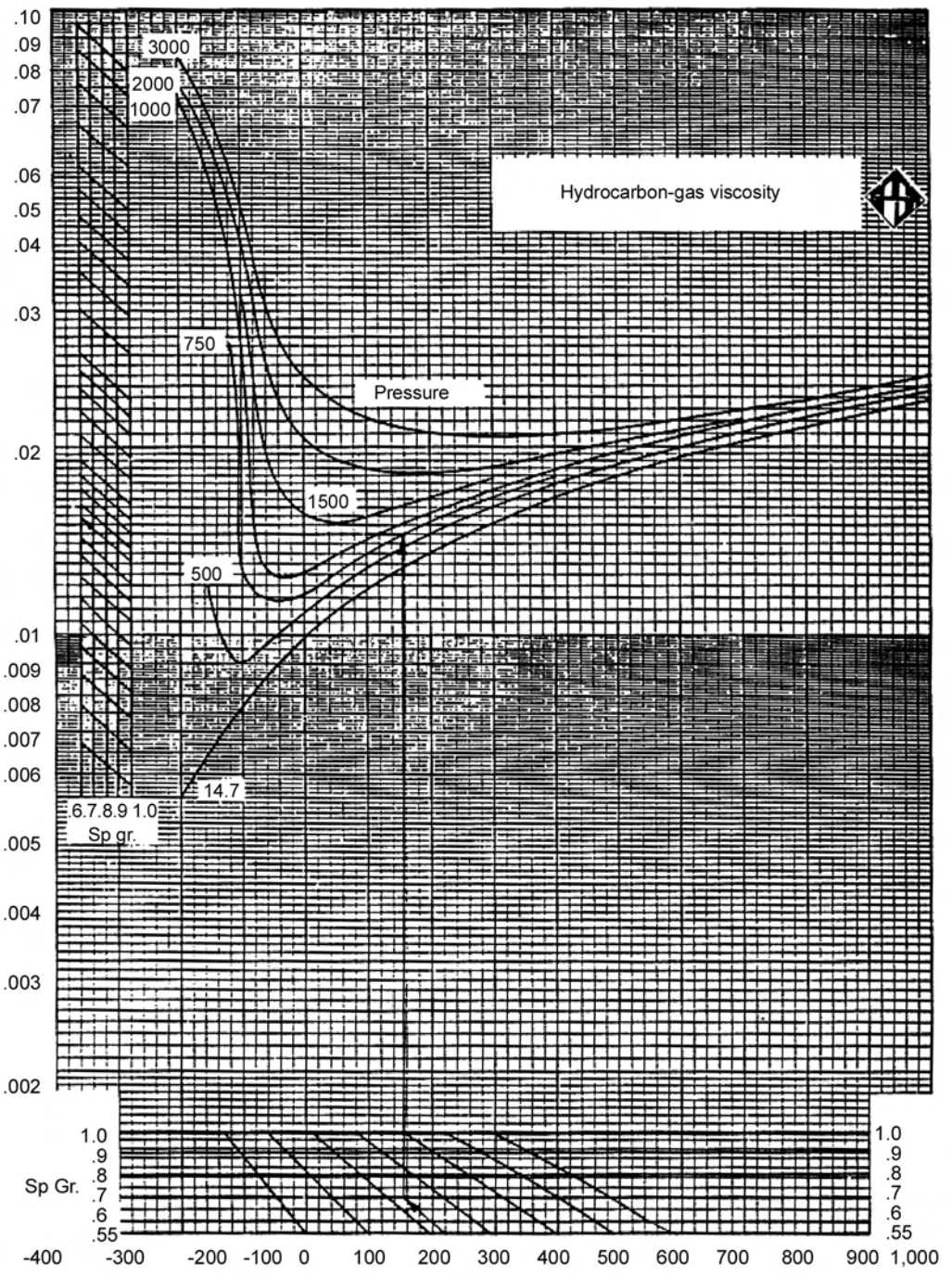


Fig. 9.7—Hydrocarbon-gas viscosity vs. temperature (courtesy Western Supply Co.).

TABLE 9.2—HAZEN-WILLIAMS *C* FACTORS (courtesy of AMEC Paragon)

Type of Pipe	Values of *C*		
	Range*	Average**	Common***
Welded and seamless steel	150–80	140	100
Cement	160–140	150	140
Fiber	—	150	140
Cement-lined iron	—	150	140
Bitumastic-enamel-lined iron	160–130	148	140
Copper, brass, lead, tin, or glass	150–120	140	130

* High: best, smooth, well laid; low: poor or corroded.
** Value for good, clean, new pipe.
*** Value used for design purposes.

Simplified Equation. For practical pipeline purposes, Eq. 9.11 can be simplified to

$$P_1^2 - P_2^2 = 25.2\left[\frac{SQ_g^2ZTfL}{d^5}\right], \quad \text{..... (9.12)}$$

where

P_1 = upstream pressure, psia,
P_2 = downstream pressure, psia,
S = specific gravity of gas,
Q_g = gas flow rate, MMscf/D,
Z = compressibility factor for gas, dimensionless,
T = flowing temperature, °R,
f = Moody friction factor, dimensionless,
d = pipe ID, in.,

and

L = length, ft.

The compressibility factor, Z, for natural gas can be found in **Fig. 9.8**.

Three simplified derivative equations can be used to calculate gas flow in pipelines. The Weymouth equation, the Panhandle equation, and the Spitzglass equation are all effective, but the accuracy and applicability of each equation falls within certain ranges of flow and pipe diameter. The equations are stated next.

Weymouth Equation. This equation is used for high-Reynolds-number flows where the Moody friction factor is merely a function of relative roughness.

$$Q_g = 1.1d^{2.67}\left[\frac{P_1^2 - P_2^2}{LSZT_1}\right]^{1/2}, \quad \text{..... (9.13)}$$

where

Q_g = gas-flow rate, MMscf/D,
d = pipe inside diameter, in.,
P_1 = upstream pressure, psia,
P_2 = downstream pressure, psia,
L = length, ft,
T_1 = temperature of gas at inlet, °R,

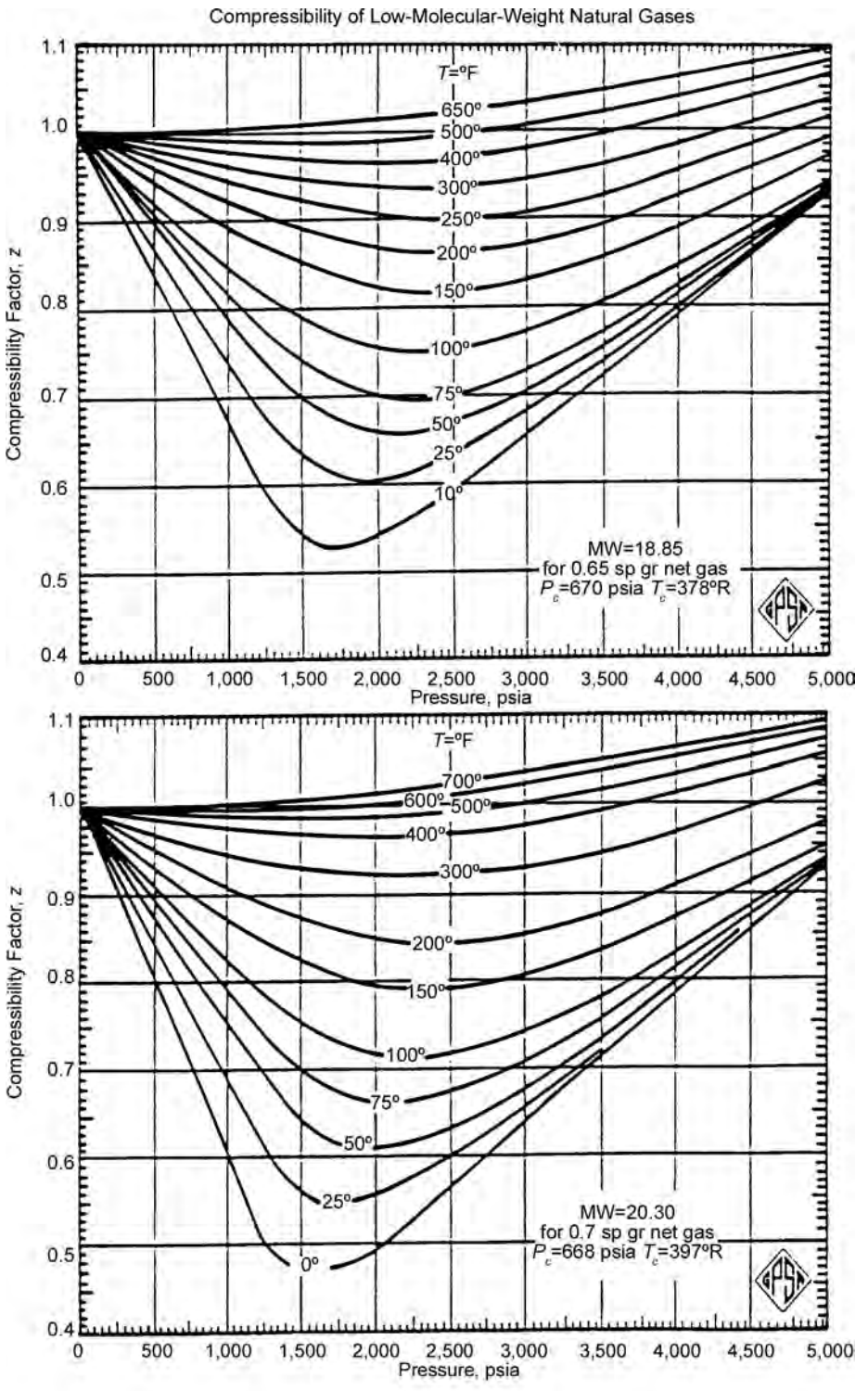


Fig. 9.8—Compressibility of low-molecular-weight natural gases (courtesy of Natl. Gas Processors Suppliers Assn.).

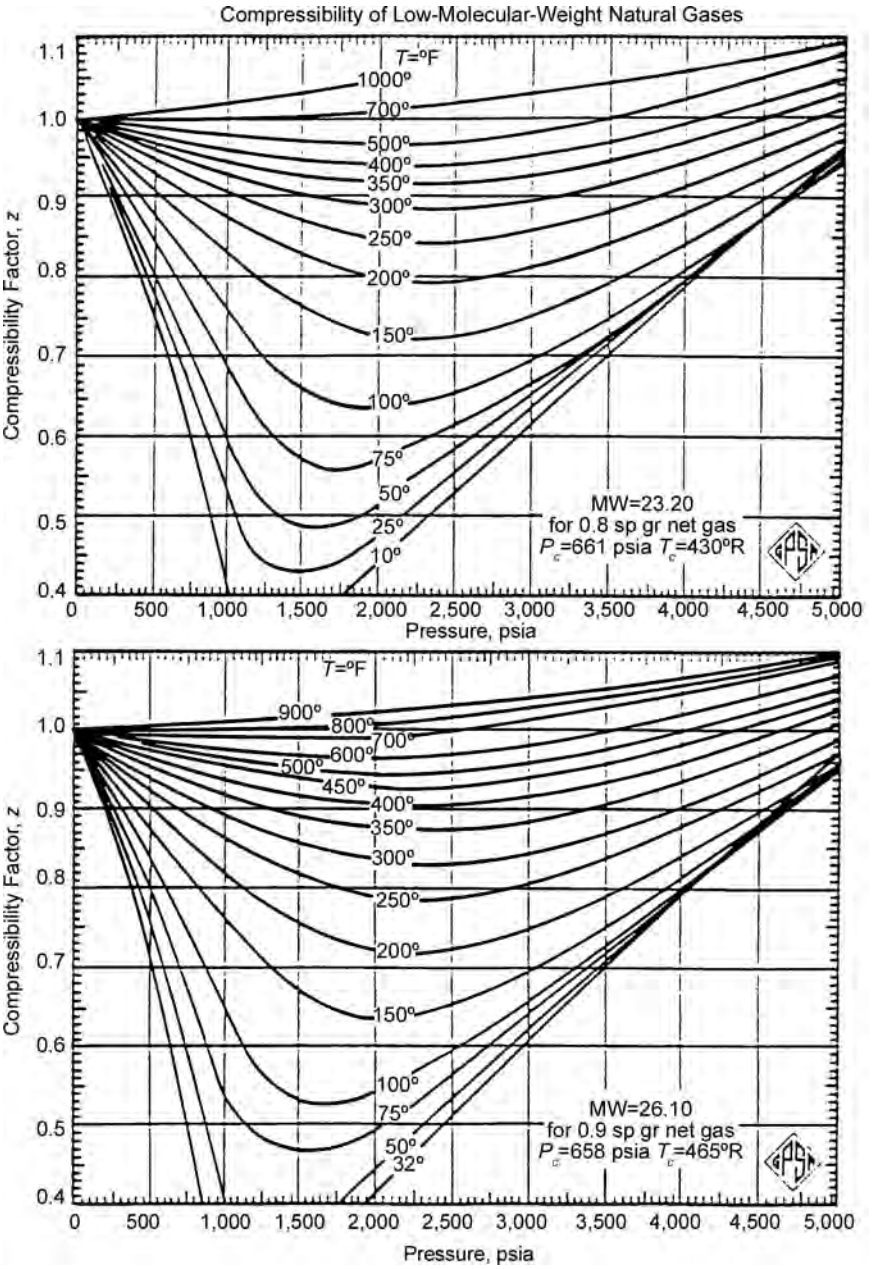


Fig. 9.8 (Continued)—Compressibility of low-molecular-weight natural gases (courtesy of Natl. Gas Processors Suppliers Assn.).

S = specific gravity of gas,

and

Z = compressibility factor for gas, dimensionless.

Panhandle Equation. This equation is used for moderate-Reynolds-number flows where the Moody friction factor is independent of relative roughness and is a function of Reynolds number to a negative power.

$$Q_g = 0.028E\left[\frac{P_1^2 - P_2^2}{S^{0.961}ZTL_m}\right]^{0.51} d^{2.53}, \quad \text{..... (9.14)}$$

where

E = efficiency factor (new pipe: 1.0; good operating conditions: 0.95; average operating conditions: 0.85),

Q_g = gas-flow rate, MMscf/D,

d = pipe ID, in.,

P_1 = upstream pressure, psia,

P_2 = downstream pressure, psia,

L_m = length, miles,

T_1 = temperature of gas at inlet, °R,

S = specific gravity of gas,

and

Z = compressibility factor for gas, dimensionless.

Spitzglass Equation.

$$Q_g = 0.09\left[\frac{\Delta h_w d^5}{SL\left(1 + \frac{3.6}{d} + 0.03d\right)}\right]^{1/2}, \quad \text{..... (9.15)}$$

where

Q_g = gas-flow rate, MMscf/D,

Δh_W = pressure loss, inches of water,

and

d = pipe ID, in.

Assumptions:

$f = (1+ 3.6/d + 0.03d)\ (1/100)$,

T = 520°R,

P_1 = 15 psia,

Z = 1.0,

and

ΔP = < 10% of P_1.

Application of the Formulas. As previously discussed, there are certain conditions under which the various formulas are more applicable. A general guideline for application of the formulas is given next.

Simplified Gas Formula. This formula is recommended for most general-use flow applications.

Weymouth Equation. The Weymouth equation is recommended for smaller-diameter pipe (generally, 12 in. and less). It is also recommended for shorter lengths of segments (< 20 miles) within production batteries and for branch gathering lines, medium- to high-pressure (+/– 100 psig to > 1,000 psig) applications, and a high Reynolds number.

Panhandle Equation. This equation is recommended for larger-diameter pipe (12-in. diameter and greater). It is also recommended for long runs of pipe (> 20 miles) such as cross-country transmission pipelines and for moderate Reynolds numbers.

Spitzglass Equation. The Spitzglass equation is recommended for low-pressure vent lines < 12 in. in diameter (ΔP < 10% of P_1).

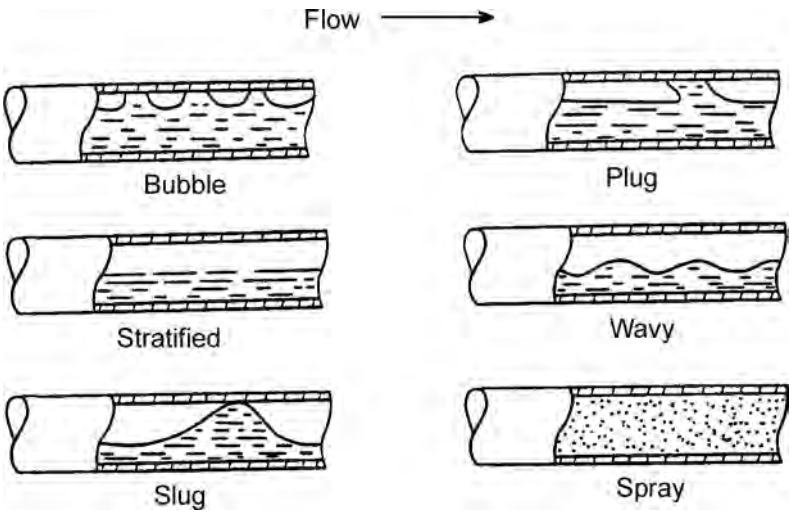


Fig. 9.9—Two-phase-flow patterns in horizontal flow (courtesy of AMEC Paragon).

The petroleum engineer will find that the general gas equation and the Weymouth equation are very useful. The Weymouth equation is ideal for designing branch laterals and trunk lines in field gas-gathering systems.

9.2.5 Multiphase Flow. ***Flow Regimes.*** Fluid from the wellbore to the first piece of production equipment (separator) is generally two-phase liquid/gas flow.

The characteristics of horizontal, multiphase flow regimes are shown in **Fig. 9.9**. They can be described as follows:

- Bubble: Occurs at very low gas/liquid ratios where the gas forms bubbles that rise to the top of the pipe.
- Plug: Occurs at higher gas/liquid ratios where the gas bubbles form moderate-sized plugs.
- Stratified: As the gas/liquid ratios increase, plugs become longer until the gas and liquid flow in separate layers.
- Wavy: As the gas/liquid ratios increase further, the energy of the flowing gas stream causes waves in the flowing liquid.
- Slug: As the gas/liquid ratios continue to increase, the wave heights of the liquid increase until the crests contact the top of the pipe, creating liquid slugs.
- Spray: At extremely high gas/liquid ratios, the liquid is dispersed into the flowing-gas stream.

Fig. 9.10[1] shows the various flow regimes that could be expected in horizontal flow as a function of the superficial velocities of gas and liquid flow. Superficial velocity is the velocity that would exist if the other phase was not present.

The multiphase flow in vertical and inclined pipe behaves somewhat differently from multiphase flow in horizontal pipe. The characteristics of the vertical flow regimes are shown in **Fig. 9.11** and are described next.

Bubble. Where the gas/liquid ratios are small, the gas is present in the liquid in small, variable-diameter, randomly distributed bubbles. The liquid moves at a fairly uniform velocity while the bubbles move up through the liquid at differing velocities, which are dictated by the size of the bubbles. Except for the total composite-fluid density, the bubbles have little effect on the pressure gradient.

Slug Flow. As the gas/liquid ratios continue to increase, the wave heights of the liquid increase until the crests contact the top of the pipe, creating liquid slugs.

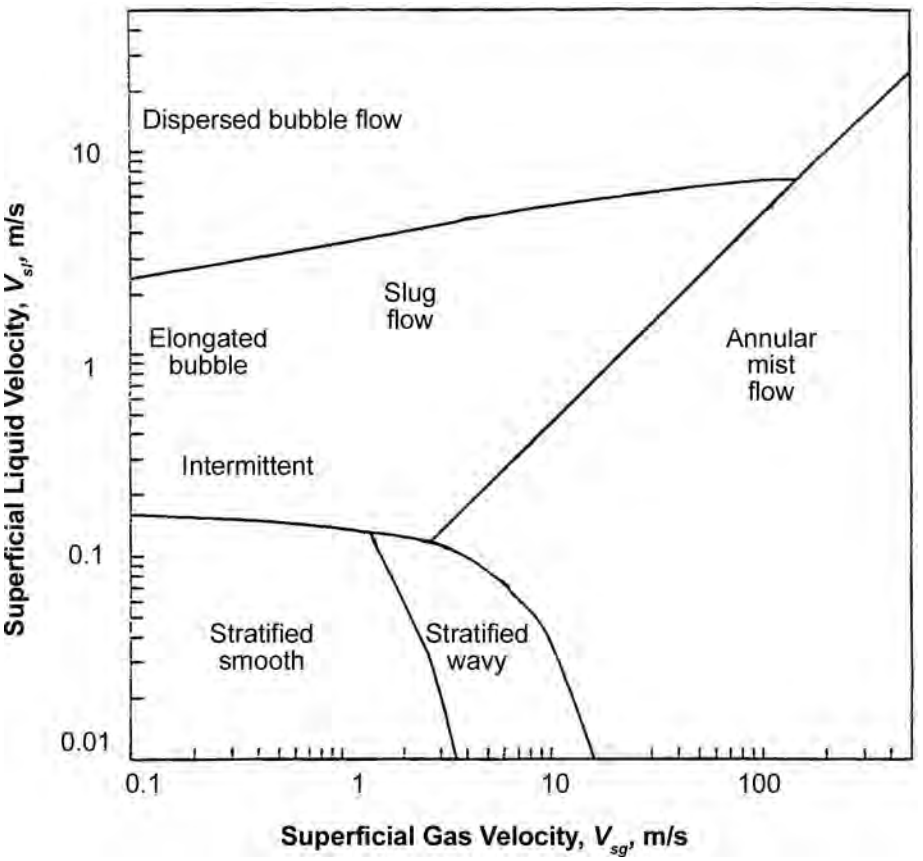


Fig. 9.10—Horizontal multiphase-flow map (after Griffith[1]).

Transition Flow. The fluid changes from a continuous liquid phase to a continuous gas phase. The liquid slugs virtually disappear and are entrained in the gas phase. The effects of the liquid are still significant, but the effects of the gas phase are predominant.

Annular Mist Flow. The gas phase is continuous, and the bulk of the liquid is entrained within the gas. The liquid wets the pipe wall, but the effects of the liquid are minimal as the gas phase becomes the controlling factor. **Fig. 9.12**[2] shows the various flow regimes that could be expected in vertical flow as a function of the superficial velocities of gas and liquid flow.

Two-Phase Pressure Drop. The calculation of pressure drop in two-phase flow is very complex and is based on empirical relationships to take into account the phase changes that occur because of pressure and temperature changes along the flow, the relative velocities of the phases, and complex effects of elevation changes. **Table 9.3** lists several commercial programs that are available to model pressure drop. Because all are based to some extent on empirical relations, they are limited in accuracy to the data sets from which the relations were designed. It is not unusual for measured pressure drops in the field to differ by ± 20% from those calculated by any of these models.

Simplified Friction Pressure-Drop Approximation for Two-Phase Flow. Eq. 9.16 provides an approximate solution for friction pressure drop in two-phase-flow problems that meet the assumptions stated.

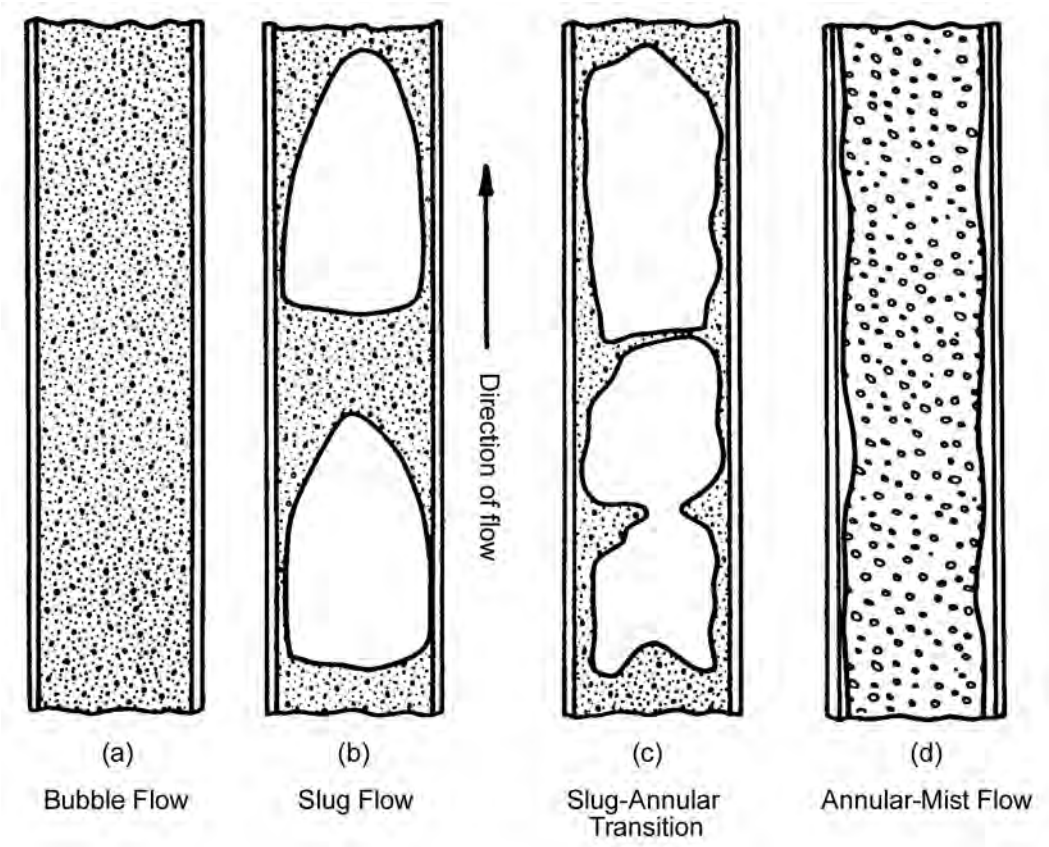


Fig. 9.11—Two-phase-flow patterns in vertical flow (courtesy of AMEC Paragon).

$$\Delta P = \frac{3.4 \times 10^{-6} f L W^2}{\rho_M d^5}, \quad \text{..... (9.16)}$$

where

ΔP = friction pressure drop, psi,
f = Moody friction factor, dimensionless,
L = length, ft,
W = rate of flow of mixture, lbm/hr,
ρ_M = density of the mixture, lbm/ft^3,

and

d = pipe ID, in.

The formula for rate of mixture flow is

$$W = 3{,}180 Q_g S + 14.6 Q_L (SG), \quad \text{..... (9.17)}$$

where

Q_g = gas-flow rate, MMscf/D,
Q_L = liquid flow rate, B/D,
S = specific gravity of gas at standard conditions, lbm/ft^3 (air = 1),

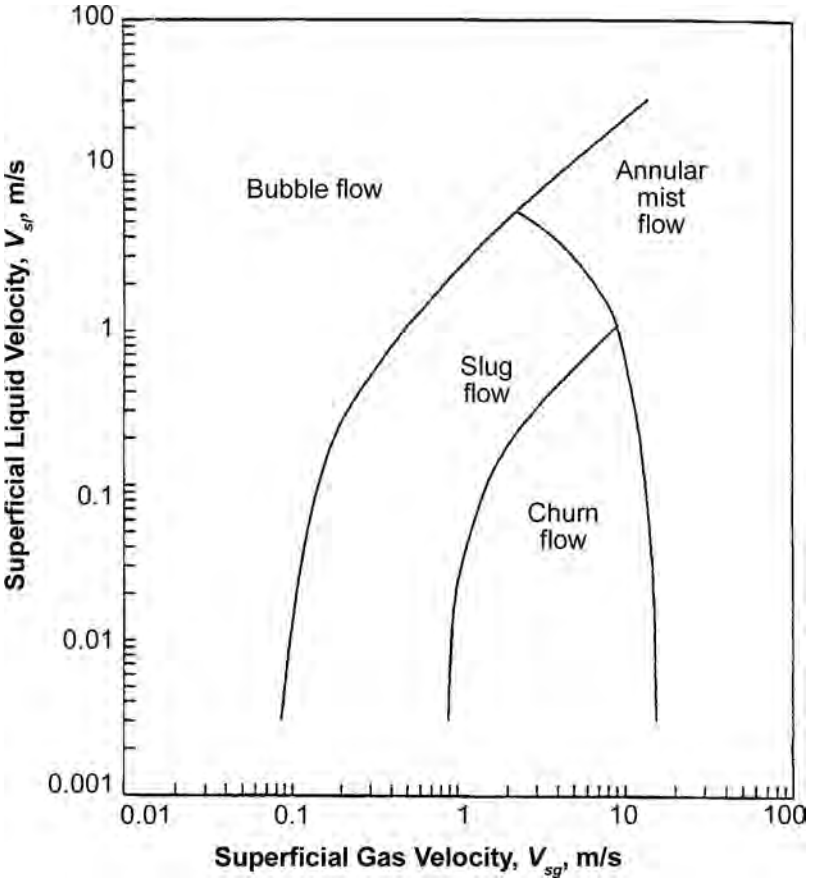


Fig. 9.12—Vertical-multiphase-flow map (after Yaitel *et al.*[2]).

and

SG = specific gravity of liquid, relative to water, lbm/ft^3.

The density of the mixture is given by

$$\rho_M = \frac{12{,}409(SG)P + 2.7RSP}{198.7P + RTZ}, \quad \text{..... (9.18)}$$

where

P = operating pressure, psia,

R = gas/liquid ratio, ft^3/bbl,

T = operating temperature, °R,

SG = specific gravity of liquid, relative to water, lbm/ft^3,

S = specific gravity of gas at standard conditions, lbm/ft^3 (air = 1),

and

Z = gas compressibility factor, dimensionless.

The formula is applicable if the following conditions are met:

- ΔP is less than 10% of the inlet pressure.
- Bubble or mist exists.
- There are no elevation changes.

**TABLE 9.3—HYDRAULIC-MODELING AND FLOW-ASSURANCE SOFTWARE*
(courtesy of AMEC Paragon)**

Multiphase Transient Simulation	Multiphase Steady-State Simulation	Single-Phase Gas/Liquid Transient Simulation
OLGA	Pipeflow, Wellflow	Pipeline Simulator
ProFES	PIPEPHASE	Winflo
	PIPESIM-SUITE	NATASHA PLUS
	GENNET-M	TLNET
	Flosystem	TGNET
	Prosper, Gap	
	Perform	

*This table lists the current, commercially available, state-of-the-art pipeline design and operations software for hydraulic modeling and flow assurance for single-phase, two-phase, and multiphase flow systems.

• There is no irreversible energy transfer between phases.

Pressure Drop Because of Changes in Elevation. There are several notable characteristics associated with pressure drop because of elevation changes in two-phase flow. The flow characteristics associated with the elevation changes include:

• In downhill lines, flow becomes stratified as liquid flows faster than gas.

• The depth of the liquid layer adjusts to the static pressure head and is equal to the friction pressure drop.

• There is no pressure recovery in the downhill line.

• In low gas/liquid flow, the flow in uphill segments can be liquid "full" at low flow rates. Thus, at low flow rates, the total pressure drop is the sum of the pressure drops for all of the uphill runs.

• With increased gas flow, the total pressure drop may decrease as liquid is removed from uphill segments.

The pressure drop at low flow rates associated with an uphill elevation change may be approximated with Eq. 9.19.

$$\Delta P_Z \approx 0.433(SG)\Delta Z\ , \quad \text{..... (9.19)}$$

where

ΔP_Z = pressure drop because of elevation increase in the segment, psi,

SG = specific gravity of the liquid in the segment, relative to water,

and

ΔZ = increase in elevation for segment, ft.

The total pressure drop can then be approximated by the sum of the pressure drops for each uphill segment.

9.3 Pressure Drop Caused by Valves and Fittings

One of the most important parameters affecting pressure drop in piping systems is pressure loss in the fittings and valves, which is incorporated in the system. For piping systems within production facilities, the pressure drop through fittings and valves can be much greater than that through the straight run of pipe itself. In long pipeline systems, the pressure drop through fittings and valves can often be ignored.

TABLE 9.4—RESISTANCE COEFFICIENTS (K_r) FOR VALVES, PIPES, AND FITTINGS (courtesy of AMEC Paragon)

Globe valve, wide open	10.0
Angle valve, wide open	5.0
Gate valve, wide open	0.2
Gate valve, half open	5.6
Return bend	2.2
Tee	1.8
90° weld elbow	0.9
45° weld elbow	0.4

9.3.1 Resistance Coefficients. The head loss in valves and fittings can be calculated with resistance coefficients as

$$H_L = K_r \frac{V^2}{2g}, \quad \text{..... (9.20)}$$

where

H_L = head loss, ft,

K_r = resistance coefficient, dimensionless,

D = pipe ID, ft,

and

V = velocity, ft/sec.

The total head loss is the sum of all $K_r\ V^2/2g$.

The resistance coefficients K_r for individual valves and fittings are found in tabular form in a number of industry publications. Most manufacturers publish tabular data for all sizes and configurations of their products. One of the best sources of data is the *Crane Flow of Fluids,* technical paper No. 410.[3] The Natural Gas Processors Suppliers Assn. (NGPSA) *Engineering Data Book*[4] and Ingersoll-Rand's *Cameron Hydraulic Data Book*[5] are also good sources of references for the information. Some examples of resistance coefficients are listed in **Tables 9.4 and 9.5**.

9.3.2 Flow Coefficients. The flow coefficient for liquids, C_V, is determined experimentally for each valve or fitting as the flow of water, in gal/min at 60°F for a pressure drop of 1 psi through the fitting. The relationship between flow and resistance coefficients can be expressed as

$$C_V = \frac{29.9d^2}{(K_r)^{1/2}}. \quad \text{..... (9.21)}$$

In any fitting or valve with a known C_V, the pressure drop can be calculated for different conditions of flow and liquid properties with Eq. 9.22.

$$\Delta P = 8.5 \times 10^{-4} \left(\frac{Q_L}{C_V}\right)^2 (SG), \quad \text{..... (9.22)}$$

where

TABLE 9.5—REPRESENTATIVE RESISTANCE COEFFICIENTS (K_r) FOR VALVES, PIPES, AND FITTINGS
(courtesy of Crane Co.)

PIPE FRICTION DATA FOR CLEAN COMMERCIAL STEEL PIPE WITH FLOW IN ZONE OF COMPLETE TURBULENCE

Nominal Size	½"	¾"	1"	1¼"	1½"	2"	2½", 3"	4"	5"	6"	8–10"	12–16"	18–24"
Friction Factor (f_t)	027	025	023	022	021	019	018	017	016	015	014	013	012

FORMULAS FOR CALCULATING "K" FACTORS* FOR VALVES AND FITTINGS WITH REDUCED PORT

- Formula 1

$$K_2=\frac{0.8\left(\sin\frac{\theta}{2}\right)(1-\beta^2)}{\beta^4}=\frac{K_1}{\beta^4}$$

- Formula 2

$$K_2=\frac{0.5(1-\beta^2)\sqrt{\sin\frac{\theta}{2}}}{\beta^4}=\frac{K_1}{\beta^4}$$

- Formula 3

$$K_2=\frac{2.6\left(\sin\frac{\theta}{2}\right)(1-\beta^2)^2}{\beta^4}=\frac{K_1}{\beta^4}$$

- Formula 4

$$K_2=\frac{(1-\beta^2)^2}{\beta^4}=\frac{K_1}{\beta^4}$$

- Formula 5

$$K_2=\frac{K_1}{\beta^4}+\text{Formula 1}+\text{Formula 3}$$

$$K_2=\frac{K_1+\sin\frac{\theta}{2}\left[0.8(1-\beta^2)+2.6(1-\beta^2)^2\right]}{\beta^4}$$

- Formula 6

$$K_2=\frac{K_1}{\beta^4}+\text{Formula 2}+\text{Formula 4}$$

$$K_2=\frac{K_1+0.5\sqrt{\sin\frac{\theta}{2}}(1-\beta^2)+(1-\beta^2)^2}{\beta^4}$$

- Formula 7

$$K_2=\frac{K_1}{\beta^4}+\beta\ (\text{Formula 2}+\text{Formula 4})\ \text{when}\ \theta=180°$$

$$K_2=\frac{K_1+\beta\left[0.5(1-\beta^2)+(1-\beta^2)^2\right]}{\beta^4}$$

$$\beta=\frac{d_1}{d_2}$$

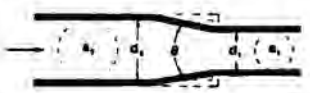
$$\beta^2=\left(\frac{d_1}{d_2}\right)^2=\frac{a_1}{a_2}$$

Subscript 1 defines dimensions and coefficients with reference to the smaller diameter.

Subscript 2 refers to the larger diameter.

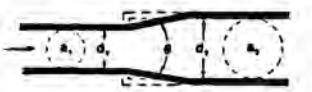
*Use "K" furnished by valve or fitting supplier when available.

SUDDEN AND GRADUAL CONTRACTION



If: $\theta \geq 45°$..... K_2=Formula 1
$45° < \theta \geq 180°$... K_2=Formula 2

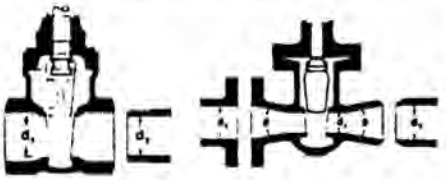
SUDDEN AND GRADUAL ENLARGEMENT



If: $\theta \geq 45°$..... K_2=Formula 3
$45° < \theta \geq 180°$... K_2=Formula 4

TABLE 9.5—REPRESENTATIVE RESISTANCE COEFFICIENTS (K_f) FOR VALVES, PIPES, AND FITTINGS (courtesy of Crane Co.) (continued)

GATE VALVES
Wedge Disc, Double Disc, or Plug Type



If: $\beta=1$, $\theta=0$……$K_1=8f_T$
$\beta<1$ and $\theta\geq45°$……K_2=Formula 5
$\beta<1$ and $45°<\theta\geq180°$…K_2=Formula 6

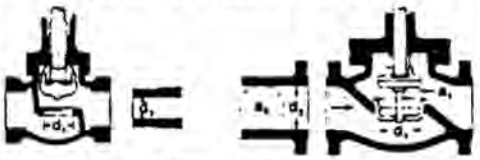
SWING CHECK VALVES



$K=100f_T$
Minimum pipe velocity (fps) for full disc lift
$=35\sqrt{V}$

$K=50f_T$
Minimum pipe velocity (fps) for full disc lift
$=60\sqrt{V}$ except
U/L listed=$100\sqrt{V}$

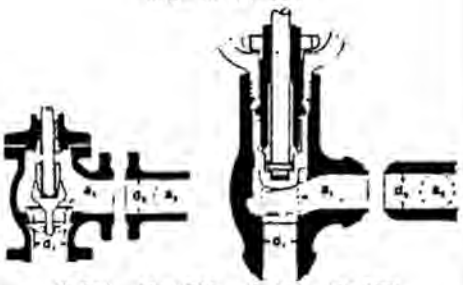
GLOBE AND ANGLE VALVES



If: $\beta=1$… $K_1=340f_T$



If: $\beta=1$… $K_1=55f_T$



If: $\beta=1$ $K_1=150f_T$ If: $\beta=1$…$K_1=55f_T$

All globe and angle valves, whether reduced seat or throttled,
If: $\beta<1$…K_2=Formula 7

LIFT CHECK VALVES



If: $\beta=1$… $K_1=600f_T$
$\beta<1$…K_2=Formula 7

Minimum pipe velocity (fps) for full disc lift
$=40\,\beta^2\sqrt{V}$



If: $\beta=1$… $K_1=55f_T$
$\beta<1$…K_2=Formula 7

Minimum pipe velocity (fps) for full disc lift
$=140\,\beta^2\sqrt{V}$

TILTING DISC CHECK VALVES



	$\alpha=5°$	$\alpha=15°$
Sizes 2 to 8"… K_1	$40f_T$	$120f_T$
Sizes 10 to 14"… K_1	$30f_T$	$90f_T$
Sizes 16 to 48"… K_1	$20f_T$	$60f_T$
Minimum pipe velocity (fps) for full disc lift=	$80\sqrt{V}$	$30\sqrt{V}$

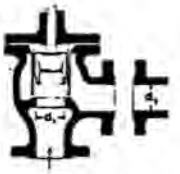
TABLE 9.5—REPRESENTATIVE RESISTANCE COEFFICIENTS (K_f) FOR VALVES, PIPES, AND FITTINGS (courtesy of Crane Co.) (continued)

STOP-CHECK VALVES (Globe and Angle Types)



If: $\beta=1 \ldots K_1=400f_T$
$\beta<1 \ldots K_2=$ Formula 7

Minimum pipe velocity for full disc lift
$=55\,\beta^2\sqrt{V}$



If: $\beta=1 \ldots K_1=200f_T$
$\beta<1 \ldots K_2=$ Formula 7

Minimum pipe velocity for full disc lift
$=75\,\beta^2\sqrt{V}$

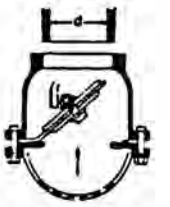
FOOT VALVES WITH STRAINER

Poppet Disc



$K=420f_T$
Minimum pipe velocity (fps) for full disc lift
$=15\sqrt{V}$

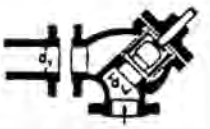
Hinged Disc



$K=75f_T$
Minimum pipe velocity (fps) for full disc lift
$=35\sqrt{V}$



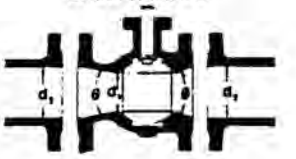
If: $\beta=1 \ldots K_1=300f_T$
$\beta<1 \ldots K_2=$ Formula 7



If: $\beta=1 \ldots K_1=350f_T$
$\beta<1 \ldots K_2=$ Formula 7

Minimum pipe velocity (fps) for full disc lift
$=60\,\beta^2\sqrt{V}$

BALL VALVES



If: $\beta=1$, $\theta=0$ ..... $K_1=3f_T$
$\beta<1$ and $\theta\geq45°$ ..... $K_2=$ Formula 5
$\beta<1$ and $45°<\theta\geq180°$ ... $K_2=$ Formula 6



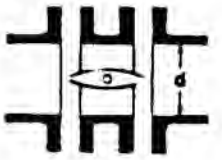
If: $\beta=1 \ldots K_1=55f_T$
$\beta<1 \ldots K_2=$ Formula 7



If: $\beta=1 \ldots K_1=55f_T$
$\beta<1 \ldots K_2=$ Formula 7

Minimum pipe velocity (fps) for full disc lift
$=140\,\beta^2\sqrt{V}$

BUTTERFLY VALVES



Sizes 2 to 8" ..... $K=45f_T$
Sizes 10 to 14" ... $K=35f_T$
Sizes 16 to 24" ... $K=25f_T$

TABLE 9.5—REPRESENTATIVE RESISTANCE COEFFICIENTS (K_r) FOR VALVES, PIPES, AND FITTINGS (courtesy of Crane Co.) (continued)

PLUG VALVES AND COCKS

Straight-Way 3-Way



If: $\beta=1$, $K_1=18f_T$ | If: $\beta=1$, $K_1=30f_T$ | If: $\beta=1$, $K_1=90f_T$

If $\beta<1$...K_2=Formula 6

MITRE BENDS



∝	K
0°	2f_T
15°	4f_T
30°	8f_T
45°	15f_T
60°	25f_T
75°	40f_T
90°	60f_T

90° PIPE BENDS AND FLANGED OR BUTT-WELDING 90° ELBOWS



r/d	K	r/d	K
1	20 f_T	8	24 f_T
1.5	14 f_T	10	30 f_T
2	12 f_T	12	34 f_T
3	12 f_T	14	38 f_T
4	14 f_T	16	42 f_T
6	17 f_T	20	50 f_T

The resistance coefficient, K_n, for pipe bends other than 90° may be determined as follows:

$$K_n=(n-1)\left(0.25\pi r/\tau\frac{r}{d}+0.5K\right)+K$$

n=number of 90° bends
K=resistance coefficient for one 90° bend (per table)

CLOSE PATTERN RETURN BENDS



K=50f_T

STANDARD ELBOWS

90° 45°



K=30f_T K=16f_T

STANDARD TEES



Flow thru run.....K=20f_T
Flow thru branch.....K=60f_T

PIPE ENTRANCE

Inward Projecting



K=0.78

r/d	K
0.00*	0.5
0.02	0.28
0.04	0.24
0.06	0.15
0.10	0.09
0.15 & up	0.04

*Sharp-edged

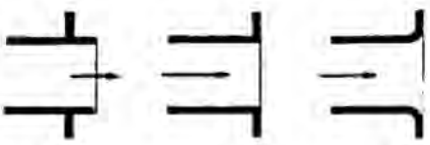
Flush



For K, see table

PIPE EXIT

Projecting Sharp-Edged Rounded



K=1.0 K=1.0 K=1.0

Q_L = liquid-flow rate, B/D,
and
SG = liquid specific gravity relative to water.

Again, the C_V is published for most valves and fittings and can be found in Refs. 3 through 5, as well as the manufacturer's technical data.

9.3.3 Equivalent Lengths. The head loss associated with valves and fittings can also be calculated by considering equivalent "lengths" of pipe segments for each valve and fitting. In other words, the calculated head loss caused by fluid passing through a gate valve is expressed as an additional length of pipe that is added to the actual length of pipe in calculating pressure drop.

All of the equivalent lengths caused by the valves and fittings within a pipe segment would be added together to compute the pressure drop for the pipe segment. The equivalent length, L_e, can be determined from the resistance coefficient, K_r, and the flow coefficient, C_V, using the formulas given next.

$$L_e = \frac{K_r D}{f}, \quad \text{..... (9.23)}$$

$$L_e = \frac{K_r D}{12 f}, \quad \text{..... (9.24)}$$

and

$$L_e = \frac{74.5 d^5}{f (C_V)^2}, \quad \text{..... (9.25)}$$

where
K_r = resistance coefficient, dimensionless,
D = diameter of the pipe, ft,
f = Moody friction factor, dimensionless,
d = pipe ID, in.,
and
C_V = flow coefficient for liquids, dimensionless.

Table 9.6 shows equivalent lengths of pipe for a variety of valves and fittings for a number of standard pipe sizes.

9.4 Selecting Pipe Wall Thickness

The fluid flow equations and formulas presented thus far enable the engineer to initiate the design of a piping or pipeline system, where the pressure drop available governs the selection of pipe size. (In addition, there may be velocity constraints that might dictate a larger pipe diameter. This is discussed in Sec. 9.5.)

Once the ID of the piping segment has been determined, the pipe wall thickness must be calculated. There are many factors that affect the pipe-wall-thickness requirement, which include the maximum and working pressures, maximum and working temperatures, chemical properties of the fluid, the fluid velocity, the pipe material and grade, and the safety factor or code design application.

If there are no codes or standards that specifically apply to the oil and gas production facilities, the design engineer may select one of the industry codes or standards as the basis of design. The design and operation of gathering, transmission, and distribution pipeline systems

TABLE 9.6—EQUIVALENT LENGTH OF VALVES AND FITTINGS IN FEET
(Courtesy of Natural Gas Processors Suppliers Assn.)

Nominal pipe size, in.	Globe valve or ball check valve	Angle valve	Swing check valve	Plug valve	Gate or ball valve	45° ell	Short rad. ell	Long rad. ell	Branch of Tee	Run of Tee	90° miter bends			Enlargement						Contraction					
														Sudden				Std. red.		Sudden				Std. red.	
														Equiv. L in terms of small d											
						Weld thrd	Weld thrd	Weld thrd	Weld thrd	Weld thrd	2 miter	3 miter	4 miter	$d/D=1/4$	$d/D=1/2$	$d/D=3/4$	$d/D=1/4$	$d/D=3/4$	$d/D=1/2$	$d/D=1/4$	$d/D=1/2$	$d/D=3/4$	$d/D=1/4$	$d/D=1/2$	$d/D=3/4$
1½	55	26	13	7	1	1 | 2	3 | 5	2 | 3	8 | 9	2 | 3				5	3	1	4	1	3	2	1	1	–
2	70	33	17	14	2	2 | 3	4 | 5	3 | 4	10 | 11	3 | 4				7	4	1	5	1	3	3	1	1	–
2½	80	40	20	11	2	2 | ..	5 | ..	3 | ..	12 |	3 | ..				8	5	2	6	2	4	3	2	2	–
3	100	50	25	17	2	2	6	4	14	4				10	6	2	8	2	5	4	2	2	–	–
4	130	65	32	30	3	3	7	5	19	5				12	8	3	10	3	6	5	3	3	–	–
6	200	100	48	70	4	4	11	8	28	8				18	12	4	14	4	9	7	4	4	1	1
8	260	125	64	120	6	6	15	9	37	9				25	16	5	19	5	12	9	5	5	2	2
10	330	160	80	170	7	7	18	12	47	12				31	20	7	24	7	15	12	6	6	2	2
12	400	190	95	170	9	9	22	14	55	14	28	21	20	37	24	8	28	8	18	14	7	7	2	2
14	450	210	105	80	10	10	26	16	62	16	32	24	22	42	26	9	–	–	20	16	8	–	–	–
16	500	240	120	145	11	11	29	18	72	18	38	27	24	47	30	10	–	–	24	18	9	–	–	–
18	550	280	140	160	12	12	33	20	82	20	42	30	28	53	35	11	–	–	26	20	10	–	–	–
20	650	300	155	210	14	14	36	23	90	23	46	33	32	60	38	13	–	–	30	23	11	–	–	–
22	688	335	170	225	15	15	40	25	100	25	52	36	34	65	42	14	–	–	32	25	12	–	–	–
24	750	370	185	254	16	16	44	27	110	27	56	39	36	70	46	15	–	–	35	27	13	–	–	–
30	–	–	–	312	21	21	55	40	140	40	70	51	44											
36	–	–	–		25	25	66	47	170	47	84	60	52											
42	–	–	–		30	30	77	55	200	55	98	69	64											
48	–	–	–	–	35	35	88	65	220	65	112	81	72											
54	–	–	–	–	40	40	99	70	250	70	126	90	80											
60	–	–	–	–	45	45	110	80	260	80	190	99	92											

are usually governed by codes, standards, and regulations. The design engineer must verify whether the particular country in which the project is located has regulations, codes, and standards that apply to facilities and/or pipelines.

The basic formula for determining pipe wall thickness is the general hoop stress formula for thin-wall cylinders, which is stated as

$$t = \frac{Pd_o}{2(H_s + P)}, \quad \text{..... (9.26)}$$

where

H_S = hoop stress in pipe wall, psi,
t = pipe wall thickness, in.,
L = length of pipe, ft,
P = internal pressure of the pipe, psi,

and

d_O = outside diameter of pipe, in.

9.4.1 Piping Codes. The following standards from the American Natl. Standards Inst. (ANSI) and the American Soc. of Mechanical Engineers (ASME) specify wall-thickness requirements.

- ANSI/ASME *Standard B31.1, Power Piping*.[6] This standard applies to steam piping systems.
- ANSI/ASME *Standard B31.3, Chemical Plant and Petroleum Refinery Piping*.[7] This standard applies to major facilities onshore and offshore worldwide.
- ANSI/ASME *Standard B31.4, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols*.[8] This standard applies to onshore oil pipeline facilities.
- ANSI/ASME *Standard B31.8, Gas Transmission and Distribution Piping Systems*.[9] This standard applies to gas transmission, gathering, and distribution pipelines onshore.

In the U.S, piping on offshore facilities is mandated by regulation to be done in accordance with ANSI/ASME *Standard B31.3*. Most onshore facilities are designed in accordance with ANSI/ASME *Standard B31.4* or *B31.8,* depending on whether it is an oil or gas facility. respectively. Some companies use the more stringent ANSI/ASME *Standard B31.3* for onshore facilities.

In other countries, similar standards apply with minor variations. For simplicity, we will discuss only the U.S. standards in this chapter. The engineer should check to see if there are different standards that must be applied in the specific location of the design.

9.4.2 Pipe Materials—Basics. There are some applications where plastic, concrete, or other piping materials are both desirable and acceptable. Utility systems such as those for water, sanitary or storm water, air, draining or low-pressure oil or gas service applications often use the nonsteel piping material systems. However, for the vast majority of the "pressure" piping systems encountered, steel pipe is required.

For petroleum applications, pipe materials that meet American Petroleum Inst. (API), American Soc. for Testing and Materials (ASTM), ASME, and ANSI standards are used most often. All of these standards have very rigid design, specification, chemistry, and testing standardization and manufacturing requirements. Modern steel pipe manufactured to these exacting standards assures both high quality and safety in design.

Steel pipe is available in a variety of commercial sizes ranging from nominal ⅛ up to 60 in. or greater. **Table 9.7** illustrates a number ANSI pipe schedules, for reference. The "nominal" commercial pipe sizes from ⅛ through 12 in. refer to the approximate ID measurement of Schedule 40 or "standard" wall, whereas nominal 14 in. and larger sizes refer to the outside

TABLE 9.7— ANSI PIPE SCHEDULES
(courtesy of Natural Gas Processors Suppliers Assn.)

UPPER FIGURES INDICATE WALL THICKNESS IN IN. LOWER FIGURES INDICATE WEIGHT PER FOOT IN LBM

PIPE SIZE	O.D. in IN.	5	10	20	30	40	STD.	60	80	XH	100	120	140	160	XXH
⅛	.405	.035 .1383	.049 .1863			.068 .2447	.068 .2447		.095 .3145	.095 .3145					
¼	.540	.049 .2570	.065 .3297			.088 .4248	.088 .4249		.119 .5351						
⅜	.675	.049 .3276	.065 .4235			.091 .5676	.091 .5676		.126 .7388	.126 .7388					
½	.840	.065 .5383	.083 .6710			.109 .8510	.109 .8510		.147 1.088	.147 1.088				.187 1.304	.294 1.714
¾	1.050	.065 .6838	.083 .8572			.113 1.131	.113 1.131		.154 1.474	.154 1.474				.218 1.937	.308 2.441
1	1.315	.065 .8678	.109 1.404			.133 1.679	.133 1.679		.179 2.172	.179 2.172				.250 2.844	.358 3.659
1¼	1.660	.065 1.107	.109 1.806			.140 2.273	.140 2.273		.191 2.997	.191 2.997				.250 3.765	.382 5.214
1½	1.900	.065 1.274	.109 2.085			.145 2.718	.145 2.718		.200 3.631	.200 3.631				.281 4.859	.400 6.408
2	2.375	.065 1.604	.109 2.638			.154 3.653	.154 3.653		.218 5.022	.218 5.022				.343 7.444	.436 9.029
2½	2.875	.083 2.475	.120 3.531			.203 5.793	.203 5.793		.276 7.661	.276 7.661				.375 10.01	.552 13.70
3	3.500	.083 3.029	.120 4.332			.216 7.576	.216 7.576		.300 10.25	.300 10.25				.437 14.32	.600 18.58
3½	4.0	.083 3.472	.120 4.973			.226 9.109	.226 9.109		.318 12.51	.318 12.51					.636 22.85
4	4.50	.083 3.915	.120 5.613			.237 10.79	.237 10.79	.281 12.66	.337 14.98	.337 14.98		.437 19.01		.531 22.51	.674 27.54
4½	5.0						.247 12.53			.355 17.61					.710 32.53
5	5.563	.109 6.349	.134 7.770			.258 14.62	.258 14.62		.375 20.78	.375 20.78		.500 27.04		.625 32.96	.750 38.55
6	6.625	.109 7.585	.134 9.289			.280 18.97	.280 18.97		.432 28.57	.432 28.57		.562 36.39		.718 45.30	.864 53.16
7	7.625						.301 23.57			.500 38.05					.875 63.08
8	8.625	.109 9.914	.148 13.40	.250 22.36	.277 24.70	.322 28.55	.322 28.55	.406 35.64	.500 35.64	.500 43.39	.593 50.87	.718 60.63	.812 67.76	.906 74.69	.875 72.42
9	9.625						.342 33.90			.500 48.72					
10	10.75	.134 15.19	.165 18.70	.250 28.04	.307 34.24	.365 40.48	.365 40.48	.500 54.74	.593 64.33	.500 54.74	.718 76.93	.843 89.20	1.000 104.1	1.125 115.7	
11	11.75						.375 45.55			.500 60.07					
12	12.75	.165 22.18	.180 24.20	.250 33.38	.330 43.77	.406 53.53	.375 49.56	.562 73.16	.687 88.51	.500 65.42	.843 107.2	1.000 125.5	1.125 139.7	1.312 160.3	
14	14.0		.250 36.71	.312 45.68	.375 54.57	.437 63.37	.375 54.57	.593 84.91	.750 106.1	.500 72.09	.937 130.7	1.093 150.7	1.250 170.2	1.406 189.1	
16	16.0		.250 42.05	.312 52.36	.375 62.58	.500 82.77	.375 62.58	.656 107.5	.843 136.5	.500 82.77	1.031 164.8	1.218 192.3	1.437 223.5	1.593 245.1	
18	18.0		.250 47.39	.312 59.03	.437 82.06	.562 104.8	.375 70.59	.750 138.2	.937 170.8	.500 93.45	1.156 208.0	1.375 244.1	1.562 274.2	1.781 308.5	
20	20.0		.250 52.73	.375 78.60	.500 104.1	.593 122.9	.375 78.60	.812 166.4	1.031 208.9	.500 104.1	1.280 256.1	1.500 296.4	1.750 341.1	1.968 379.0	
22	22.0		.250 58.07	.375 86.61	.500 114.8		.375 86.61	.875 197.4	1.125 250.8	.500 114.8	1.375 302.9	1.625 353.6	1.875 403.0	2.125 451.1	
24	24.0		.250 63.41	.375 94.62	.562 104.8	.687 171.2	.375 94.62	.968 238.1	1.218 296.4	.500 125.5	1.531 367.4	1.812 429.4	2.062 483.1	2.343 541.9	
26	26.0		.312 85.60	.500 136.2			.375 102.6			.500 136.2					
28	28.0		.312 92.26	.500 146.8	.625 182.7		.375 110.6			.500 146.8					
30	30.0		.312 98.93	.500 157.5	.625 196.1		.375 118.6			.500 157.5					
32	32.0		.312 105.6	.500 168.2	.625 209.4	.688 230.1	.375 126.7			.500 168.2					
34	34.0		.344 123.7	.500 178.9	.625 222.8	.688 244.8	.375 134.7			.500 178.9					
36	36.0		.312 118.9	.500 189.6	.625 236.1	.750 282.3	.375 142.7			.500 189.6					
42	42.0						.375 166.7			.500 221.6					
48	48.0						.375 190.7			.500 253.6					

diameter. A variety of steel pipe sizes, wall thicknesses, and material grades are available for petroleum piping and pipeline applications.

TABLE 9.8—THREAD ALLOWANCE CALCULATIONS FOR THREADED-PIPE-WALL THICKNESS
(courtesy of AMEC Paragon)

Nominal Pipe Size	t_{th}, in.
¼ – ⅜	0.05
½ – ¾	0.06
1 – 2	0.08
2½ – 20	0.11

TABLE 9.9—BASIC ALLOWABLE STRESS FOR GRADE B AND X-42 SEAMLESS PIPE
(courtesy of ANSI/ASME)

Temperature, °F	ASTM A206 & API 5L, Grade B	API 5L, Grade X42
–20 to 400	20,000	20,000
500	18,900	N/A
600	17,300	N/A
650	17,000	N/A

(For additional information, see ANSI/ASME *Standard B31.3*[1] Appendix A.)

Please note that the allowable internal pressure is the maximum pressure to which the piping system can be subjected. This could be significantly higher than the flowing pressure of the fluid in the pipe.

9.4.3 Wall-Thickness Calculations—Using *B31.3* Code. ANSI/ASME *Standard B31.3* is a very stringent code with a high safety margin. The *B31.3* wall-thickness calculation formula is stated as

$$t = t_e + t_{th} + \left[\frac{Pd_o}{2(SE + PY)}\right]\left[\frac{100}{100 - T_{ol}}\right], \quad \text{..... (9.27)}$$

where

t = minimum design wall thickness, in.,
t_e = corrosion allowance, in.,
t_{th} = thread or groove depth, in. (**Table 9.8**),
P = allowable internal pressure in pipe, psi,
d_O = outside diameter of pipe, in.,
S = allowable stress for pipe, psi (**Tables 9.9 and 9.10**),
E = longitudinal weld-joint factor [1.0 seamless, 0.95 electric fusion weld, double butt, straight or spiral seam APL 5L, 0.85 electric resistance weld (ERW), 0.60 furnace butt weld],
Y = derating factor (0.4 for ferrous materials operating below 900°F),
and
T_{ol} = manufacturers allowable tolerance, % (12.5 pipe up to 20 in.-OD, 10 pipe > 20 in. OD, API 5L).

Under ANSI/ASME *Standard B31.3,* the allowable pressure can be increased for certain instances. The conditions for the permissible increases in allowable pressure, according to *Standard B31.3,* are given next.

TABLE 9.10—BASIC ALLOWABLE STRESS FOR OTHER GRADES OF SEAMLESS PIPE (courtesy of ANSI/ASME)

Grade	Minimum Temperature	Allowable Stress Minimum Temperature to 100°F
API 5L-A	–20	16,000
API 5LX-42	–20	20,000
API 5LX-46	–20	21,000
API 5LX-52	–20	22,000
ASTM A-106-B	–20	20,000
ASTM A-333-6	–50	20,000
ASTM A-369-FPA	–20	16,000
ASTM A-369-FPB	–20	20,000
ASTM A-524-I	–20	20,000
ASTM A-524-II	–20	18,300

(For additional information, see ANSI *Standard B31.3*, Appendix A.)

• When the variation lasts no more than 10 hours at any one time and not more than 100 hours per year, it is permissible to exceed the pressure rating or the allowable stress for pressure design at the temperature of the increased condition by no more than 33%.

• When the variation lasts no more than 50 hours at any one time and not more than 500 hours per year, it is permissible to exceed the pressure rating or the allowable stress for pressure design at the temperature of the increased condition by not more than 20%.

9.4.4 Wall-Thickness Calculations—Using *B31.4* Code. The ANSI/ASME *Standard B31.4* code is somewhat less stringent than that of *Standard B31.3* because of the lower levels of hazard associated with liquid pipelines. The code for *Standard B31.4* is used often as the standard of design for crude-oil piping systems in facilities, such as pump stations, pigging facilities, measurement and regulation stations, and tank farms. The wall-thickness formula for *Standard B31.4* is stated as

$$t = \frac{Pd_o}{2(FES_Y)}, \quad \text{..... (9.28)}$$

where

t = minimum design wall thickness, in.,

P = internal pressure in pipe, psi,

d_O = OD of pipe, in.,

S_Y = minimum yield stress for pipe, psi (**Table 9.11**),

F = derating factor, 0.72 for all locations,

and

E = longitudinal weld-joint factor [1.0 seamless, ERW, double submerged arc weld and flash weld; 0.80 electric fusion (arc) weld and electric fusion weld, 0.60 furnace butt weld].

9.4.5 Wall-Thickness Calculations—Using *B31.8* Code. The ANSI/ASME Standard *B31.8* code is less stringent than that of *Standard B31.3,* but more stringent than that of *Standard B13.4.* The *B31.8* code is often used as the standard of design for natural-gas piping systems in facilities, such as compressor stations, gas-treatment facilities, measurement and regulation stations, and tank farms. The *B31.8* wall-thickness formula is stated as

TABLE 9.11—MINIMUM YIELD STRESS AND WELD-JOINT FACTOR (*E*) FOR COMMON SEAMLESS PIPE MATERIALS (courtesy of ANSI/ASME)

Specification	Grade	Specified Min. Yield Strength, psi (MPa)	Weld Joint Factor *E*
API 5L	A25	25,000 (172)	1.00
API 5L, ASTM A 53, ASTM A 106	A	30,000 (207)	1.00
API 5L, ASTM A 53, ASTM A 106	B	35,000 (241)	1.00
API 5LU	U80	80,000 (551)	1.00
API 5LU	U100	100,000 (689)	1.00
API 5L	X42	42,000 (289)	1.00
API 5L	X46	46,000 (317)	1.00
API 5L	X52	52,000 (358)	1.00
API 5L	X56	56,000 (386)	1.00
API 5L	X60	60,000 (413)	1.00
API 5L	X65	65,000 (448)	1.00
API 5L	X70	70,000 (482)	1.00
ASTM A 106	C	40,000 (278)	1.00
ASTM A 524	I	35,000 (241)	1.00
ASTM A 524	H	30,000 (207)	1.00
Furnace Butt Welded, Continuous Welded			
ASTM A 53	...	25,000 (172)	0.60
API 5L Classes I and II	A25	25,000 (172)	0.60
Electric Resistance Welded and Electric Flash Welded			
API 5L	A25	25,000 (172)	1.00
API 5L, ASTM A 53, ASTM A 135	A	30,000 (207)	1.00
API 5L, ASTM A 53, ASTM A 135	B	35,000 (241)	1.00
API 5L	X42	42,000 (289)	1.00
API 5L	X46	46,000 (317)	1.00
API 5L	X52	52,000 (358)	1.00
API 5L	X56	56,000 (386)	1.00
API 5L	X60	60,000 (413)	1.00
API 5L	X65	65,000 (448)	1.00
API 5L	X70	70,000 (482)	1.00
API 5LU	U80	80,000 (551)	1.00
API 5LU	U100	100,000 (689)	1.00
Electric Fusion Welded			
ASTM A 134	...	...	0.80
ASTM A 139	A	30,000 (207)	0.80
ASTM A 139	B	35,000 (241)	0.80

$$t = \frac{Pd_o}{2FETS_Y}, \quad \text{..... (9.29)}$$

TABLE 9.11—MINIMUM YIELD STRESS AND WELD-JOINT FACTOR (*E*) FOR COMMON SEAMLESS PIPE MATERIALS (continued)

Specification	Grade	Specified Min. Yield Strength, psi (MPa)	Weld Joint Factor *E*
Electric Fusion Welded (Cont.)			
ASTM A 671	...	Note (1)	1.00 [Notes (2), (3)]
ASTM A 671	...	Note (1)	0.70 [Note (4)]
ASTM A 672	...	Note (1)	1.00 [Notes (2), (3)]
ASTM A 672	...	Note (1)	0.80 [Note (4)]
Submerged Arc Welded			
API 5L	A	30,000 (307)	1.00
API 5L	B	35,000 (241)	1.00
API 5L	X42	42,000 (289)	1.00
API 5L	X46	46,000 (317)	1.00
API 5L	X52	52,000 (358)	1.00
API 5L	X56	56,000 (386)	1.00
API 5L	X60	60,000 (413)	1.00
API 5L	X65	65,000 (448)	1.00
API 5L	X70	70,000 (482)	1.00
API 5LU	U80	80,000 (551)	1.00
API 5LU	U100	100,000 (689)	1.00
ASTM A 381	Y35	35,000 (241)	1.00
ASTM A 381	Y42	42,000 (290)	1.00
ASTM A 381	Y46	46,000 (317)	1.00
ASTM A 381	Y48	48,000 (331)	1.00
ASTM A 381	Y50	50,000 (345)	1.00
ASTM A 381	Y52	52,000 (358)	1.00
ASTM A 381	Y60	60,000 (413)	1.00
ASTM A 381	Y65	65,000 (448)	1.00

NOTES:
(1) See applicable plate specification for yield point and refer to para. 402.3.1 for calculation of *S*.
(2) Factor applies for Classes 12 22, 32, 42, and 52 only.
(3) Radiography must be performed after heat treatment.
(4) Factor applies for Classes 13, 23, 33, 43, and 53 only.

(For additional information see ANSI/ASME *B31.4*[7] Table 10)

where

t = minimum design wall thickness, in.,
P = internal pressure in pipe, psi,
d_O = OD of pipe, in.,
S_Y = minimum yield stress for pipe, psi (**Table 9.12**),
F = design factor (see **Table 9.13** and discussion that follows),
E = longitudinal weld-joint factor (**Table 9.14**),

and

T = temperature derating factor (**Table 9.15**).

TABLE 9.12—SPECIFIED MINIMUM YIELD STRENGTH FOR STEEL PIPE COMMONLY USED IN PIPE SYSTEMS (courtesy of ANSI/ASME)

Spec. No.	Grade	Type [Note (1)]	SMYS, psi
API 5L [Note (2)]	A25	BW, ERW, S	25,000
API 5L [Note (2)]	A	ERW, S, DSA	30,000
API 5L [Note (2)]	B	ERW, S, DSA	35,000
API 5L [Note (2)]	X42	ERW, S, DSA	42,000
API 5L [Note (2)]	X46	ERW, S, DSA	46,000
API 5L [Note (2)]	X52	ERW, S, DSA	52,000
API 5L [Note (2)]	X56	ERW, S, DSA	56,000
API 5L [Note (2)]	X60	ERW, S, DSA	60,000
API 5L [Note (2)]	X65	ERW, S, DSA	65,000
API 5L [Note (2)]	X70	ERW, S, DSA	70,000
API 5L [Note (2)]	X80	ERW, S, DSA	80,000
ASTM A 53	Type F	BW	25,000
ASTM A 53	A	ERW, S	30,000
ASTM A 53	B	ERW, S	35,000
ASTM A 106	A	S	30,000
ASTM A 106	B	S	35,000
ASTM A 106	C	S	40,000
ASTM A 134	...	EFW	[Note (3)]
ASTM A 135	A	ERW	30,000
ASTM A 135	B	ERW	35,000
ASTM A 139	A	EFW	30,000
ASTM A 139	B	EFW	35,000
ASTM A 139	C	EFW	42,000
ASTM A 139	D	EFW	46,000
ASTM A 139	E	EFW	52,000
ASTM A 333	1	S, ERW	30,000
ASTM A 333	3	S, ERW	35,000
ASTM A 333	4	S	35,000
ASTM A 333	6	S, ERW	35,000
ASTM A 333	7	S, ERW	35,000
ASTM A 333	8	S, ERW	75,000
ASTM A 333	9	S, ERW	46,000

The design factor, *F,* for steel pipe is a construction derating factor dependent upon the location class unit, which is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Each separate dwelling unit in a multiple-dwelling-unit building is counted as a separate building intended for human occupancy.

To determine the number of buildings intended for human occupancy for an onshore pipeline, lay out a zone ¼-mile wide along the route of the pipeline with the pipeline on the centerline of this zone, and divide the pipeline into random sections 1 mile in length such that

TABLE 9.12—SPECIFIED MINIMUM YIELD STRENGTH FOR STEEL PIPE COMMONLY USED IN PIPE SYSTEMS (continued)

Spec. No.	Grade	Type [Note (1)]	SMYS, psi
ASTM A 381	Class Y-35	DSA	35,000
ASTM A 381	Class Y-42	DSA	42,000
ASTM A 381	Class Y-46	DSA	46,000
ASTM A 381	Class Y-48	DSA	48,000
ASTM A 381	Class Y-50	DSA	50,000
ASTM A 381	Class Y-52	DSA	52,000
ASTM A 381	Class Y-56	DSA	56,000
ASTM A 381	Class Y-60	DSA	60,000
ASTM A 381	Class Y-65	DSA	65,000

GENERAL NOTE:

This table is not complete. For the minimum specified yield strength of other grades and grades in other approved specifications, refer to the particular specification.

NOTES:
(1) Abbreviations: BW–furnace butt-welded; ERW–electric resistance welded; S–Seamless; FW–flash welded; EFW–electric fusion welded; DSA–double submerged-arc welded.
(2) Intermediate grades are available in API 5L.
(3) See applicable plate specification for SMYS.

(For additional information see ANSI/ASME *B31.8*,[9] Appendix D)

the individual lengths will include the maximum number of buildings intended for human occupancy. Count the number of buildings intended for human occupancy within each 1-mile zone. For this purpose, each separate dwelling unit in a multiple-dwelling-unit building is to be counted as a separate building intended for human occupancy.

It is not intended here that a full mile of lower-stress pipeline shall be installed if there are physical barriers or other factors that will limit the further expansion of the more densely populated area to a total distance of less than 1 mile. It is intended, however, that where no such barriers exist, ample allowance shall be made in determining the limits of the lower stress design to provide for probable further development in the area.

When a cluster of buildings intended for human occupancy indicates that a basic mile of pipeline should be identified as a Location Class 2 or Location Class 3, the Location Class 2 or Location Class 3 may be terminated 660 ft from the nearest building in the cluster. For pipelines shorter than 1 mile in length, a location class shall be assigned that is typical of the location class that would be required for 1 mile of pipeline traversing the area.

Location Classes for Design and Construction. *Class 1 Location.* A Class 1 location is any 1-mile section of pipeline that has 10 or fewer buildings intended for human occupancy. This includes areas such as wastelands, deserts, rugged mountains, grazing land, farmland, and sparsely populated areas.

Class 1, Division 1 Location. This is a Class 1 location where the design factor, *F,* of the pipe is greater than 0.72 but equal to or less than 0.80 and which has been hydrostatically tested to 1.25 times the maximum operating pressure. (See Table 9.13 for exceptions to design factor.)

TABLE 9.13—BASIC DESIGN FACTOR (*F*) FOR STEEL-PIPE CONSTRUCTION OF NATURAL-GAS SERVICE PIPELINES (courtesy of ANSI/ASME)

	Location Class				
	1				
Facility	Div. 1	Div. 2	2	3	4
Pipelines, mains, and service lines [see para. 840.2(b)]	0.80	0.72	0.60	0.50	0.40
Crossings of roads, railroads without casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.60	0.60	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.50	0.50	0.40
Crossings of roads, railroads with casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.72	0.72	0.60	0.50	0.40
Parallel encroachment of pipelines and mains on roads and railroads:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.80	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.60	0.50	0.40
Fabricated assemblies (see para. 841.121)	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges (see para. 841.122)	0.60	0.60	0.60	0.50	0.40
Compressor station piping	0.50	0.50	0.50	0.50	0.40
Near concentration of people in Location Classes 1 and 2 [see para. 840.3(b)]	0.50	0.50	0.50	0.50	0.40

For additional information, see ANSI *Standard B31.8.*

Class 1, Division 2 Location. This is a Class 1 location where the design factor, *F,* of the pipe is equal to or less than 0.72, and which has been tested to 1.1 times the maximum operating pressure.

Class 2 Location. This is any 1-mile section of pipeline that has more than 10 but fewer than 46 buildings intended for human occupancy. This includes fringe areas around cities and towns, industrial areas, and ranch or country estates.

Class 3 Location. This is any 1-mile section of pipeline that has 46 or more buildings intended for human occupancy except when a Class 4 Location prevails. This includes suburban housing developments, shopping centers, residential areas, industrial areas, and other populated areas not meeting Class 4 Location requirements.

Class 4 Location. This is any 1-mile section of pipeline where multistory buildings are prevalent, traffic is heavy or dense, and where there may be numerous other utilities underground. Multistory means four or more floors above ground including the first, or ground, floor. The depth of basements or number of basement floors is immaterial.

In addition to the criteria previously presented, additional consideration must be given to the possible consequences of a failure near a concentration of people, such as that found in a church, school, multiple-dwelling unit, hospital, or recreational area of an organized character

TABLE 9.14—BASIC DESIGN LONGITUDINAL JOINT FACTOR (*E*) FOR STEEL PIPELINES IN NATURAL-GAS SERVICE (courtesy of ANSI/ASME)

Spec. No.	Pipe Class	*E* Factor	Spec. No.	Pipe Class	*E* Factor
ASTM A 53	Seamless	1.00	ASTM A 671	Electric Fusion Welded	
	Electric Resistance Welded	1.00		Classes 13, 23, 33, 43, 53	0.80
	Furnace Butt Welded—Continuous Weld	0.60		Classes 12, 22, 32, 42, 52	1.00
ASTM A 106	Seamless	1.00	ASTM A 672	Electric Fusion Welded	
ASTM A 134	Electric Fusion Arc Welded	0.80		Classes 13, 23, 33, 43, 53	0.80
ASTM A 135	Electric Resistance Welded	1.00		Classes 12, 22, 32, 42, 52	1.00
ASTM A 139	Electric Fusion Welded	0.80			
ASTM A 211	Spiral Welded Steel Pipe	0.80	API 5L	Seamless	1.00
ASTM A 333	Seamless	1.00		Electric Resistance Welded	1.00
	Electric Resistance Welded	1.00		Electric Flash Welded	1.00
ASTM A 381	Double Submerged-Arc-Welded	1.00		Submerged Arc Welded	1.00
				Furnace Butt Welded	0.60

GENERAL NOTE:
Definitions for the various classes of welded pipe are given in para. 804.243.
For additional information, see ANSI *Standard B31.8*.

TABLE 9.15—BASIC DESIGN TEMPERATURE DERATING FACTORS (*T*) FOR STEEL PIPELINE IN NATURAL-GAS SERVICE (courtesy of ANSI/ASME)

–20 to 250°F	$T = 1.000$
300°F	$T = 0.967$
350°F	$T = 0.933$
400°F	$T = 0.900$
450°F	$T = 0.867$

For additional information, see ANSI/ASME *Standard B31.8*.[9]

in a Class 1 or 2 location. If the facility is used infrequently, the requirements of the following paragraph need not be applied.

Pipelines near places of public assembly or concentrations of people such as churches, schools, multiple-dwelling-unit buildings, hospitals, or recreational areas of an organized nature in Class 1 and 2 locations shall meet requirements for the Class 3 location.

The concentration of people previously referred to is not intended to include groups fewer than 20 people per instance or location but is intended to cover people in an outside area as well as in a building.

It should be emphasized that location class (1, 2, 3, or 4), as previously described, is the general description of a geographic area having certain characteristics as a basis for prescribing the types of design, construction, and methods of testing to be used in those locations or in areas that are respectively comparable. A numbered location class, such as Location Class 1, refers only to the geography of that location or a similar area and does not necessarily indicate that a design factor of 0.72 will suffice for all construction in that particular location or area (e.g., in Location Class 1, all crossings without casings require a design factor, *F,* of 0.60).

When classifying locations for the purpose of determining the design factor, *F,* for the pipeline construction and testing that should be prescribed, due consideration shall be given to the possibility of future development of the area. If at the time of planning a new pipeline this

TABLE 9.16—TYPICAL SURGE FACTORS FOR TWO-PHASE-FLOW PIPELINES (courtesy of API)

Service	Factor, %
Facility handling primary production from its own platform	20
Facility handling primary production from another platform or remote well in less than 150 ft of water	30
Facility handling primary production from another platform or remote well in greater than 150 ft of water	40
Facility handling gas lifted production from its own platform	40
Facility handling gas lifted production from another platform or remote well	50

For additional information, see API *RP14E*.[10]

future development appears likely to be sufficient to change the class location, this should be taken into consideration in the design and testing of the proposed pipeline.

9.4.6 Wall-Thickness Calculations—Comparisons. Additional comparison of *Standard B31.3* to both *B31.4* and *B31.8* indicates the following:

• ANSI/ASME *Standard B31.3* is more conservative than either *Standard B31.4* or *B31.8,* especially relative to API 5L, X-grade pipe and electric-resistance-welded (ERW) seam pipe.

• ANSI/ASME *Standard B31.8* does not allow increases for transient conditions.

• The ANSI/ASME *Standard B31.3* specification break occurs at the fence, whereas *B31.8*'s occurs at the "first flange" upstream/downstream of the pipeline.

Using ANSI/ASME *Standard B31.3* criteria for oil- and gas-facility piping will assure a very conservative design. However, the cost associated with the *Standard B31.3* piping design may be substantial compared to the other codes and may not be necessary, especially for onshore facilities.

9.5 Velocity Considerations

In choosing a line diameter, consideration also has to be given to maximum and minimum velocities. The line should be sized such that the maximum velocity of the fluid does not cause erosion, excess noise, or water hammer. The line should be sized such that the minimum velocity of the fluid prevents surging and keeps the line swept clear of entrained solids and liquids.

API *RP14E*[10] provides typical surge factors that should be considered in designing production piping systems. These are reproduced in **Table 9.16**.

9.5.1 Liquid-Line Sizing. The liquid velocity can be expressed as

$$V = 0.012\frac{Q_L}{d}, \quad \text{..... (9.30)}$$

where

Q_L = fluid-flow rate, B/D

and

d = pipe ID, in.

In piping systems where solids might be present or where water could settle out and create corrosion zones in low spots, a minimum velocity of 3 ft/sec is normally used. A maximum velocity of 15 ft/sec is often used to minimize the possibility of erosion by solids and water hammer caused by quickly closing a valve.

9.5.2 Gas-Line Sizing. The pressure drop in gas lines is typically low in gas-producing facilities because the piping segment lengths are short. The pressure drop has a more significant impact upon longer segments such as gas-gathering pipelines, transmission pipelines, or relief or vent piping.

The velocity in gas lines should be less than 60 to 80 ft/sec to minimize noise and allow for corrosion inhibition. A lower velocity of 50 ft/sec should be used in the presence of known corrosives such as CO_2. The minimum gas velocity should be between 10 and 15 ft/sec, which minimizes liquid fallout.

Gas velocity is expressed in Eq. 9.31 as

$$V_g = 60\frac{Q_g TZ}{d^2 P}, \quad \text{..... (9.31)}$$

where

V_g = gas velocity, ft/sec,
Q_g = gas-flow rate, MMscf/D,
T = gas flowing temperature, °R,
P = flowing pressure, psia,
Z = compressibility factor, dimensionless,

and

d = pipe ID in.

9.5.3 Multiphase-Line Sizing. The minimum fluid velocity in multiphase systems must be relatively high to keep the liquids moving and prevent or minimize slugging. The recommended minimum velocity is 10 to 15 ft/sec. The maximum recommended velocity is 60 ft/sec to inhibit noise and 50 ft/sec for CO_2 corrosion inhibition.

In two-phase flow, it is possible that liquid droplets in the flow stream will impact on the wall of the pipe causing erosion of the products of corrosion. This is called erosion/corrosion. Erosion of the pipe wall itself could occur if solid particles, particularly sand, are entrained in the flow stream. The following guidelines from API *RP14E*[10] should be used to protect against erosion/corrosion.

Calculate the erosional velocity of the mixture with Eq. 9.32.

$$V_e = \frac{C}{\rho_M^{1/2}}, \quad \text{..... (9.32)}$$

where C = empirical constant. ρ_M is the average density of the mixture at flowing conditions. It can be calculated from

$$\rho_M = \frac{(12409)(SG)P + (2.7)RSP}{(198.7)P + ZRT}, \quad \text{..... (9.33)}$$

where

SG = specific gravity of the liquid (relative to water),

and

S = specific gravity of the gas relative to air.

Industry experience to date indicates that for solids-free fluids, values of C = 100 for continuous service and C = 125 for intermittent service are conservative. For solids-free fluids where corrosion is not anticipated or when corrosion is controlled by inhibition or by employ-

ing corrosion-resistant alloys, values of C = 150 to 200 may be used for continuous service; values up to 250 have been used successfully for intermittent service. If solids production is anticipated, fluid velocities should be significantly reduced. Different values of C may be used where specific application studies have shown them to be appropriate.

Where solids and/or corrosive contaminants are present or where c values higher than 100 for continuous service are used, periodic surveys to assess pipe wall thickness should be considered. The design of any piping system where solids are anticipated should consider the installation of sand probes, cushion flow tees, and a minimum of 3 ft of straight piping downstream of choke outlets.

Once a design velocity is chosen, to determine the pipe size, Eq. 9.34 can be used.

$$d = \left[\frac{\left(11.9 + \frac{ZTR}{16.7P}\right)Q_L}{1{,}000V}\right]^{1/2}, \quad \text{..... (9.34)}$$

where

d = pipe ID, in.,
Z = compressibility factor, dimensionless,
R = gas/liquid ratio, ft^3/bbl,
P = flowing pressure, psia,
T = gas/liquid flowing temperature, °R,
V = maximum allowable velocity, ft/sec,

and

Q_L = liquid-flow rate, B/D.

9.6 Valve, Fitting, and Flange Pressure Ratings

Pipe fittings, valves, and flanges are designed and manufactured in accordance several industry standards including API, ASTM, ANSI/ASME and Manufacturer's Standardization Soc. (MSS) (large-diameter pipeline fittings/flanges). The piping components are designed and manufactured to the industry standards to ensure the consistency of the material properties and specifications; set uniform dimensional standards and tolerances; specify methods of production and quality control; specify service ratings and allowable pressure and temperature ratings for fittings manufactured to the standards; and provide interchangeability between fittings and valves manufactured to the standards.

Piping materials manufactured to these standards can be traced to the source foundry and the material composition verified. Material traceability is another important feature of standardization. Each fitting, valve, and flange can be certified as to the material, specification, and grade.

9.6.1 Pressure Ratings. ANSI *Standard B16.5, Steel Pipe Flanges and Flanged Fittings,*[11] has seven pressure classes: ANSI 150, 300, 400, 600, 900, 1500, and 2500. **Table 9.17** illustrates the maximum, nonshock working pressures for Material Group 1.1, which is the working group for most oil and gas piping and pipeline applications.

API *Spec. 6A*[12] prescribes seven pressure classes: 2,000, 3,000, 5,000, 10,000, 15,000, 20,000, and 30,000. API 2,000, 3,000, and 5,000 lbf have the same dimensions as ANSI 600, ANSI 900, and ANSI 1,500, respectively. When the API flange is bolted to an ANSI flange, the connection must be rated for the ANSI pressure rating. **Table 9.18** shows the temperature and pressure ratings for API-specification fittings.

API flanges are required for extreme high pressures and are typically used for wellheads. ANSI flanges are less costly and more available than the API flanges and are used in the production facility. Typically, API flanges are used in the flowline near the wellhead, but ANSI

TABLE 9.17—PRESSURE RATINGS VS. TEMPERATURE FOR MATERIALS GROUP 1.1-27, CLASS 150, 300, 400, 600, 900, 1500, AND 2500 (courtesy of ANSI/ASME)

Class	–20 to 100°F	200°F
150	285	260
300	740	675
400	990	900
600	1,480	1,350
900	2,220	2,025
1500	3,705	3,375
2500	6,170	5,625

Pressure ratings for temperatures between 100 and 200°F should be interpolated between the values at 100 and 200°F.

(Refer to ANSI/ASME *B16.5*[11] for definition of material groups and for specific pressure ratings for other material groups and temperatures.)

TABLE 9.18—PRESSURE RATINGS VS. TEMPERATURE FOR API FLANGES (courtesy of API)

TABLE G1
TEMPERATURE RATINGS

Classification	Operating Range (°F)
X	0 to 350
Y	0 to 650

TABLE G2
PRESSURE/TEMPERATURE RATINGS

	Temperature (°F)								
	0 to 250	300	350	400	450	500	550	600	650
Rated Working Pressure (psi)	2000	1955	1905	1860	1810	1735	1635	1540	1430
	3000	2930	2860	2785	2715	2605	2455	2310	2145
	5000	4880	4765	4645	4525	4340	4090	3850	3575

(For additional information, see API *Spec. 6A*.[12])

flanges are used downstream. Manifolds and production headers may be API or ANSI, depending upon the operating pressures.

9.6.2 Flange Types. Flanges come in a variety of neck connection configurations and face designs. Flange connections may be slip-on, threaded, socket weld, or weld neck. Slip-on, socket-weld, and threaded-neck flanges should not be used in most high-pressure applications, especially for pipe larger than 3- to 4-in. nominal pipe size. ANSI *Standard B31.3*[7] specifically recommends that slip-on flanges not be used where mechanical vibration or large temperature cycles are encountered. Weld-neck flanges are typically better in the higher-pressure oil and gas and pipeline applications.

The flange face, or the part of the flange that makes the physical connection, comes in several classifications: flat face, raised face (RF), and ring-type joint (RTJ), as shown in **Fig. 9.13**. Flat-face flanges are typically available only in low-pressure ANSI 150 flanges and are

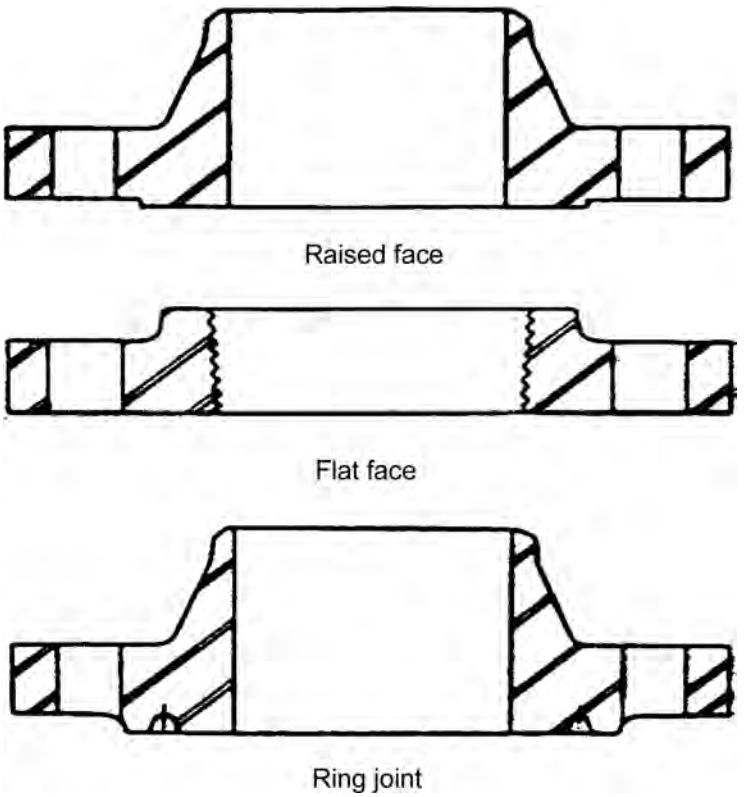


Fig. 9.13—Typical ASME/ANSI *B16.5* and MSS *SP 44* flange faces (courtesy of AMEC Paragon).

not used in high-pressure applications. RF and RTJ flanges are commonly used in the oil and gas and pipeline applications.

RF flanges are less expensive and easier to make up where tight clearances make it difficult to spread the flanges apart so that the ring may be inserted. RTJ flanges tend to seal better at higher pressures. API *RP14E*[10] recommends RTJ faced flanges in ANSI class 900 and higher. Onshore applications often use RF flanges in pressure class ratings as high as ANSI 2500. ANSI *Standard B16.5*[11] places no limitations on the application of RF flanges in pressure service.

9.6.3 Gasket Materials. Gasket materials for flat-face gaskets normally are 1/16 in. thick and made of composite materials. Asbestos was formerly used for gasket materials for both flat-faced and RF gaskets, but asbestos has been replaced because it is a hazardous material.

Spiral-wound gaskets, composed of a metal ring with wound internal composite rings, are typically used. The composite materials may include stainless steel and Teflon or other polytetrafluoroethylene (PTFE) type materials. A wide selection of winding materials is commercially available for a number of different fluids and applications. RTJ "ring" gaskets are typically made of cadmium-plated soft iron or low-carbon steel for ANSI 600 and ANSI 900 class flanges. 304 and 316 stainless-steel rings are frequently used in the higher-class ratings as well as for corrosive-service applications (such as H_2S and CO_2 service).

9.6.4 Bolting Materials. The typical carbon-steel bolt materials used in most flange bolting applications is ASTM A-193, Grade B-7. The companion nuts are typically ASTM A-194, Grade 2H. ASTM has specifications and grades for carbon-steel and alloy bolts and nuts for high-temperature, low-temperature, and extreme-service applications.

9.6.5 Pipe Fittings. Pipe fittings generally are categorized as threaded, socket weld, or butt weld. The threaded and socket-weld fittings are typically forged steel and are ASTM A-105 material and manufactured as per ANSI *B16.11, Forged Steel Fittings, Socket Welding, and Threaded.*[13] Socket-weld fittings have a groove where the pipe is inserted and weld material is used to fill the void and seal the connection. The pressure class ratings of forged-steel threaded and socket-weld fittings are 2,000 lbf (also known as standard); 3,000 lbf [also known as extra strong (XS)]; and 6,000 lbf [also known as double extra strong (XXS)], which refers to their allowable operating pressure at 100°F. The fittings are rated up to 700°F, where the rating effectively reduces the fitting operating pressures by ⅓. Generally, threaded fittings should not be used in piping systems for pipe larger in size than 2-in. nominal.

API *RP14E*[10] recommends that 1½-in. size fittings should be socket welded for hydrocarbon service above ANSI 600, hydrocarbon service above 200°F, hydrocarbon service subject to vibration, and glycol service. It also recommends that 2-in. and larger piping should be flanged with butt-weld fittings when in hydrocarbon or glycol service. Threaded fittings should be avoided in all applications where mechanical vibration (pumps and compressors) or cyclic thermal variations occur.

For most hydrocarbon service, ASTM A-106 Grade B seamless pipe or API 5L Grade B pipe is used with ASTM A105 flanges and threaded/socket-weld fittings; ASTM A-234 Grade WPB seamless, butt-weld fittings; ASTM A-193 Grade B-7 and A-354 Grade BC flange stud bolts; and ASTM A-194 Grade 2H nuts. In higher pressure where the pipe and fitting wall-thickness requirements become a cost factor (because of the extra weight of the steel), pipe and fittings manufactured to higher-strength steel specification and grade may be used. For example, if a design would require that 0.500-in. wall, A-106 Grade B pipe be used with A-234 Grade WPB seamless fittings, an API 5L Grade X65 pipe (say with a design wall thickness of 0.250 in. and companion grade butt-weld fittings) could be used to save wall thickness and weight, which would save cost for the materials. (Note: the higher-grade steel butt-weld fittings may cost slightly more than the more commonly available A-234 Grade WPB, but any cost differential is usually offset by the difference in physical weight saved—the price for carbon-steel pipe and fittings is essentially based on the weight of the steel.)

Most of the common Grade B steels are safe to operate down to –20°F. For colder-service conditions, A-106 and API 5L Grade B can operate to –50°F, if the maximum operating pressure is less than 25% of the maximum allowable design pressure, and if the combined longitudinal stress because of pressure, dead weight, and displacement strain is less than 6,000 psi. The common Grade B steels can be used in service to –50°F if the pipe and fittings are heat treated and Charpy impact tested. However, a number of other commonly available steel specifications and grades for pipe, flanges, valves, and fittings are available for low-temperature service without special testing. Some common steels available include ASTM A-333 Grade 1 (–50°F), A-334 Grade 1(–50° F), A-312 TP 304L (stainless steel, –425°F), and A-312 TP 316L (stainless steel, –325°F).

Pipe and butt-weld fittings in ASTM A-53 Grade B, A-106 Grade B, A-333 Grade1, and API 5L Grade B and the "X" grades (X42 through X65) are acceptable for H_2S service. Natl. Assn. of Corrosion Engineers (NACE) *Standard MR-01-75, Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment,*[14] Secs. 3 and 5, prescribes the requirements for steel pipe, valves, and fittings in such service.

9.6.6 Minimum Wall Thickness—Pipe and Fittings. The pressure and temperature requirements, and the chosen wall-thickness calculation formula, dictate the resulting pipe wall thickness required for the piping or pipeline design. The specification and grade of pipe and fitting materials selected for the design must be compatible with each other chemically (e.g., carbon content) so that the fittings can be welded to the pipe. In Sec. IX of the ASME Codes

for Welding,[15] base metals (pipe and fittings) have been assigned P-numbers and group numbers. Within the P-number groupings, ferrous base metals, which have specified impact test requirements, are classified in groups. The assigned P-numbers and group numbers are based essentially on comparable base-metal characteristics, such as composition, weldability, brazeability, and mechanical properties. The ASME/ANSI and ASTM material specifications for pipe and fittings will list the P-numbers and group numbers within the data. The group number and P-numbers for the materials to be welded should be compatible (see ASME Sec. IX, QW-420[15] to verify material compatibility). Typically, for most oil and gas production-facility and pipeline applications (Group 1), P-1 materials will be required. The various codes and standards may prescribe allowable tolerances for pipe-to-fitting thickness variances. The allowable operating pressure and temperature and wall thickness of the fitting must be compatible with the pipe design. The maximum allowable operating pressure and temperature of the weakest piping-system component will determine the maximum allowable operating pressure for the system.

In small diameter threaded piping systems, for mechanical strength, impact resistance, and corrosion resistance, the pipe should have at least a 0.25-in. wall thickness. For smaller pipe, it is recommended that ¾-in. and smaller pipe be Schedule 160, 2 to 3 in. Schedule 80, and 4 to 6 in. Schedule 40. ANSI/ASME *B31.3*[7] recommends that 1½-in. and smaller threaded pipe use a minimum Schedule 80 and 2 in. and larger use Schedule 40.

9.6.7 Branch Connections. Branch connections in piping systems must be designed for both pressure/temperature requirements and mechanical strength. Typically, a tee fitting should be used for branch connections unless the nominal branch pipe diameter is less than ½ of the nominal, main "run" pipe diameter. If a connection, other than a tee, is used for the branch, ANSI/ASME *B31.3*[7] requires that the branch connection be reinforced; a pipe coupling is used if the branch size is 2 in. or less and the branch is less than ¼ of the diameter of the pipe run, or an integrally reinforced, pressure-tested branch fitting (such as a weld-o-let, thread-o-let, or socket-o-let) is used. **Table 9.19** is an example branch-connection schedule that could be used to specify the proper choice of branch connection.

9.6.8 Valves. There are several types of isolation valves that are used in hydrocarbon service applications, including ball valves, gate valves, plug valves, globe valves, butterfly valves, diaphragm valves, and needle valves. **Table 9.20** describes some of the characteristics of the various isolation valves. Valves are designed and manufactured under many industry standards. For most hydrocarbon service, valves manufactured under API *Spec. 6F*[16] standards are used. Valves are designed and manufactured with a variety of end connections, body and trim materials, seat and seal materials, and operators. Valves are rated in accordance with the ANSI and API pressure class systems: ANSI 150, 300, 400, 600, 900, 1,500, and 2,500 and API 6A 2,000, 3,000, 5,000, 10,000, 15,000, 20,000, and 30,000. Valves used on the wellhead are typically API valves built to the same pressure ratings as the API flanges, whereas valves used in the production facility and pipelines are most commonly ANSI flange rated.

The options specified for isolation valves include:

- End connections: weld end, threaded (or screw) end, and flanged end (RF or RTJ).
- Body and trim: cast iron, ductile iron, carbon steel, stainless steel, and NACE.
- Seat and seal materials: PTFE, Fluroelastomer, Buna-N, Viton, Nylon, and others.
- Operator: lever, hand-wheel, gear, and automatic (extensions if needed).
- Fire safe rating: per API *Spec. 6FA.*[17]
- Pressure rating: ANSI/ASME or API.
- Mounting: floating or trunion (ball and plug valves).
- Port configuration: full, reduced, or regular port (ball, gate, and plug valve).
- Seating: double or single seat (ball and gate valve).

TABLE 9.19—BRANCH CONNECTION SCHEDULE FOR WELDING PIPING (courtesy of AMEC Paragon)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Nominal Branch Size (in.)	Nominal Run Size (in.)														
	½	¾	1	1½	2	2½	3	4	6	8	10	12	14	16	18
½	SWT	SWT	SWT	SWT	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC
¾		SWT	SWT	SWT	SOL	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC
1			SWT	SWT	SOL	SOL	SOL	6SC	6SC	6SC	6SC	6SC	6SC	6SC	6SC
1½				SWT	TR	SOL	SOL	SOL	6SC	6SC	6SC	6SC	6SC	6SC	6SC
2					T	RT	RT	RT	WOL	WOL	WOL	WOL	WOL	WOL	WOL
2½						T	RT	RT	WOL	WOL	WOL	WOL	WOL	WOL	WOL
3							T	RT	RT	WOL	WOL	WOL	WOL	WOL	WOL
4								T	RT	RT	WOL	WOL	WOL	WOL	WOL
6									T	RT	RT	RT	WOL	WOL	WOL
8										T	RT	RT	RT	RT	WOL
10											T	RT	RT	RT	RT
12												T	RT	RT	RT
14													T	RT	RT
16														T	RT
18															T

Legend
T–Straight Tee (Butt Weld)
RT–Reducing Tee (Butt Weld)
TR–Straight Tee and Reducer or Reducing Tee
WOL–Welded nozzle or equivalent (Schedule of Branch Pipe)
SOL–Socketweld couplings or equivalent–6000# Forged Steel
SWT–Socketweld Tee
6SC–6000# Forged Steel Socketweld Coupling (3/8 inch and smaller threadbolts or screwed couplings may be used for sample, gauge, test connection, and instrumentation purposes)

- Double block and bleed: ball and gate.
- Sealant fittings: ball and plug valves.
- Rising or nonrising stem and inside or outside yoke: gate valves.

Refer to manufacturer's literature for the various options available for specific valve types and their intended use.

The other type of valve commonly used is the check valve, which allows flow in one direction only. There are four types of check valves: swing, split disk, lift plug/piston, and ball. The swing check valve is suitable for nonpulsating flow and is not good for vertical-flow applications. The split-disk check valves are mounted between flanges (wafer configuration), but the operating springs are easily subject to failure. The lift-plug and piston check valves are good for pulsating-flow conditions—an orifice controls the plug or piston movement, and they are excellent in vertical flow conditions; however, the lift-plug/piston check valve can easily be cut out in sandy service and is subject to fouling with paraffin and debris. The ball check valve is typically used in 2-in. and smaller lines and can be used in vertical-flow applications, but it does have a characteristic of slamming shut upon flow reversal. Check valves are designed and manufactured under the same codes and standards as isolation valves. The pressure ratings, end connections, body materials, seals, etc. are the same as for isolation valves. Note: Check valves should never be substituted for a positive-shutoff isolation valve in any piping-system application. Under ideal service conditions, the best check valve in the perfect application will not guarantee a positive shutoff.

9.6.9 Control Valves and Pressure-Relief/Safety Devices. Automatic control valves and pressure-relief devices are an integral part of oil and gas facility and pipeline-system piping. Control valves typically are used to regulate pressure, temperature, and flow rate. Pressure-relief valves and devices prevent the piping system from exceeding the maximum allowable

TABLE 9.20—VARIOUS VALVE TYPES AND CHARACTERISTICS (courtesy of AMEC Paragon)

Ball Valves	Plug Valves	Gate Valves	Butterfly Valves	Globe Valves	Diaphragm (Bladder) Valves	Needle Valves
1/4 turn	1/4 turn	Many turns	1/4 turn	Many turns	Suitable for throttling slurry service	Miniature globe valves used for instrumentation systems
Temperature limited by elastomer	Temperature limited by elastomer seat	May vibrate from normal position	Not leak tight	Suitable for throttling	Temperature limited	Used for throttling small volumes
Not suitable for throttling	May need to be lubricated often	Unprotected rising stem can be hard to operate	Vibrate open unless lock on handle	Metal-to-metal seat		Metal-to-metal seat
	Torque varies—hard to automate	Not suitable for throttling	Inexpensive	Small stem movement—easy to automate		Easy to plug small passages
	Not suitable for throttling	Easy to automate with power piston	Can use to throttle where tight shutoff not required			
	Usually cheaper than ball	In high pressures or large sizes usually cheaper than ball or plug				

pressure. As piping-system components, control valves and pressure-relief valves come in a variety of configurations and materials and are rated in accordance with the ANSI and API pressure classes, flange ratings, and end connections. As with isolation and check valves, control valves and pressure-relief valves must be rated for the maximum allowable pressure of the interconnecting piping system.

9.7 Specification Pressure Breaks

Fluid flowing through a piping system can undergo pressure decreases by flowing through chokes and/or control valves. However, if flow were to stop, the pressure in the line would increase to the upstream pressure.

When fluid flows from a high-pressure source into a lower-pressure system, there is a distinct point where the system could be subjected to the higher pressure by activation of an isolation valve. This distinct point is called a specification "pressure break" point. Pipe valves and fittings upstream of this point must be designed to withstand the higher pressure.

The piping and equipment must be designed for the maximum possible source pressure that the system might experience. This means that any segment that can be isolated either intentionally or accidentally from a downstream relief device must be designed for the maximum upstream pressure to which it can be subjected. Typically, this "design" pressure will be set by

the set pressure of an upstream relief device, or the maximum pressure that can be developed by the upstream source (pump, compressor, or wellhead). Because pressure breaks occur at isolation valves, careful placement of isolation valves must be considered in multipressure piping-system designs.

API *RP14J, Design and Hazards Analysis for Offshore Production Facilities*[18] provides the following guidance for determining the proper maximum allowable pressure to use in designing a segment of a piping system and the location of specification breaks.

- Check valves may leak or fail open and allow communication of pressure from the high side to the low side. (Check valves should still be used to minimize backflow in case of a leak, but cannot be relied upon to prevent overpressure.)
- Control valves, including self-contained regulators, can be in either the open or closed position, whichever allows the piping segment to be exposed to the maximum pressure.
- Block valves can be positioned in either the open or closed position, whichever position creates the highest pressure.
- Locked open (or closed) valves can be considered always open (or closed), if the lock and key are maintained in accordance with a proper lockout and tagout procedure. A hazards analysis should be performed to determine if the risk associated with relying on the lockout/tagout procedure is justified.

High-pressure sensors alone do not provide sufficient protection from overpressure. The one exception is that API *RP 14C*[19] allows the use of two independent isolation valves on production flowline segments (see the chapter on Safety Systems in this volume of the *Handbook*). This should be approached with caution after thorough consideration of other alternatives.

Pressure-relief valves and rupture discs will always work because of the high reliability of their design. (In critical service, some operators require a backup relief valve or rupture disc to the primary relief device to increase reliability or to provide a spare).

In checking for spec-break locations, it is easiest to start at a primary pressure-relief valve (one designed for blocked discharge) and trace the upstream piping (including all branches) to the first block valve or control valve. It is then assumed the valve is closed, and the line is followed further upstream (including all branches) to the next pressure-relief valve or the source of pressure. The piping from the first block valve to the upstream pressure relief valve or source of pressure should be rated for the setting of the pressure-relief valve or maximum pressure of the source if no pressure-relief valves are present. Each branch upstream of the first block valve should be pressure rated at this highest pressure at every location, where it can be isolated from any downstream pressure-relief valve.

Fig. 9.14 shows an example of spec-break locations determined in this manner. **Fig. 9.15** shows how the spec breaks change if Valve 5 is added on the inlet to the low-pressure (LP) separator. Note: this changes the ratings of Valves B, D, and F in the manifold, as well as that of Valves 1 through 4 on the liquid outlet of the high pressure (HP) separator. **Fig. 9.16** shows that the pressure rating of Valves 1 through 4 do not need to be changed if the location of Valve 5 is changed. **Fig. 9.17** shows an alternative pressure rating scheme brought about by adding a relief valve upstream of Valve 5.

9.8 Pipe Expansion and Supports

9.8.1 Pipe Expansion. Steel piping systems are subject to movement because of thermal expansion/contraction and mechanical forces. Piping systems subjected to temperature changes greater than 50°F or temperature changes greater than 75°F, where the distance between piping turns is greater than 12 times the pipe diameter, may require expansion loops. ANSI/ASME *B31.3*[7] addresses the design requirements related to displacement strain because of thermal expansion, longitudinal sustained stresses, and computed displacement stress range.

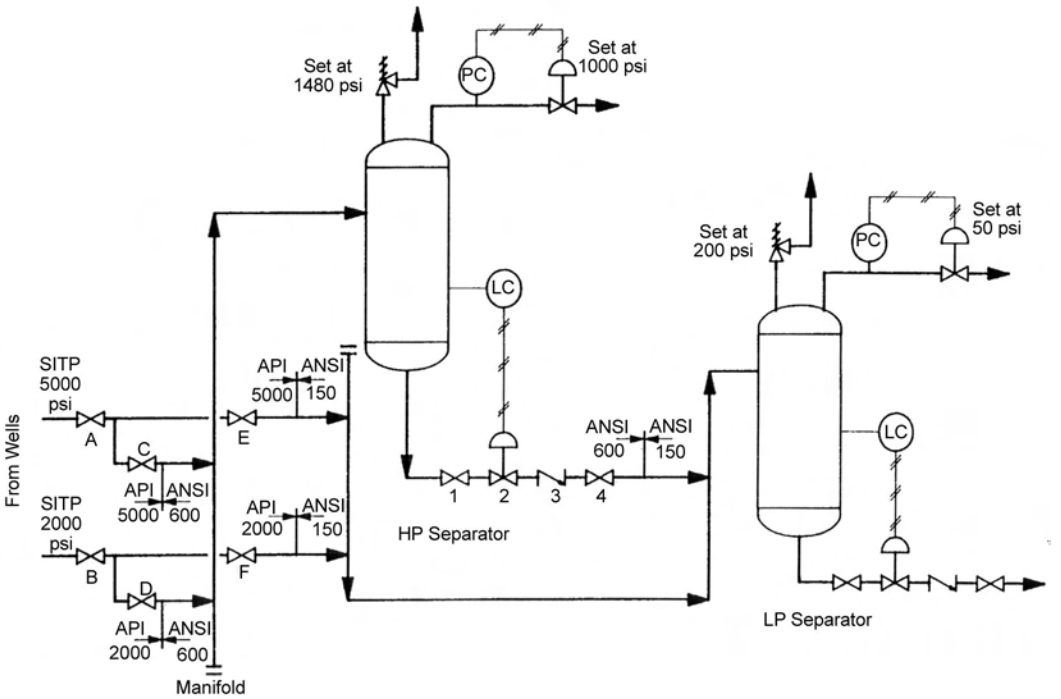


Fig. 9.14—Determination of pressure breaks. Example of spec break in accordance with API *RP14J* (courtesy of API).

Screening for expansion loops is not required by ANSI/ASME *B31.3*[7] if the piping system duplicates an existing system and can be readily judged as adequate by comparison to other piping systems and $DY/(L–U)\ 2 \leq 0.03$, where D is the nominal pipe size in inches, Y is the expansion to be absorbed by the piping in inches, L is the length of the pipe segment in feet, and U is the straight-line distance between anchors).

In the majority of oil and gas facility and pipeline applications, pipe expansion is not critical, as normal piping arrangements contain the numerous elbows and changes of direction. These make the piping system relatively flexible and allow the pipe to absorb the expansion; however, if the flowing temperatures are high or there is a significant variation in temperature, the normal piping configuration may not be adequate to handle the expansion and contraction of the piping systems. The design must be checked to verify that the piping configuration will absorb the expansion and, if not, that expansion loop will be incorporated as needed.

The calculation of both actual and allowable stresses in piping systems subject to movement and large temperature changes is complex and requires special expertise. There are a number of good computer programs that calculate stresses in piping systems and compare them to the stresses allowed by the specific piping code.

9.8.2 Pipe-Support Spacing. The proper location and spacing of above-ground-pipe supports can be determined as follows:

1. Assume that the hoop stress in the pipe is equal to the allowable stress, S_h, for the material at the design temperature.

2. According to Poisson's law, the axial stress can be no more than 0.3 S_h. The stress available for the bending moment is then 0.7 S_h.

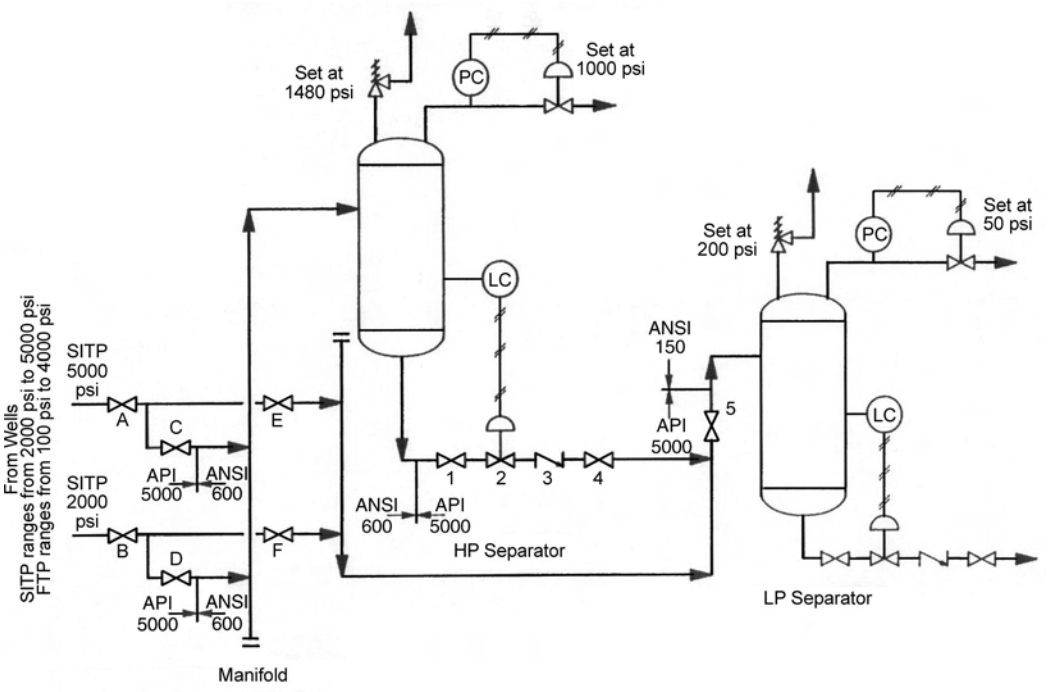


Fig. 9.15—Determination of pressure breaks. Same example of spec break in accordance with API *RP14J* as Fig. 9.14 except Valve 5 has been added on the inlet to the low-pressure separator and downstream of the high-pressure dump line, which changes the ratings of Valves B, D, and F on the inlet manifold as well as Valves 1 through 4 on the liquid outlet of the high-pressure separator (courtesy of API).

3. As an approximation, assume 0.25 S_h is used for the moment caused by the pipe to allow for stress concentrations and occasional loads.

4. Assuming the pipe can be modeled as a fixed beam,

$$L = \left[\frac{0.2 S_h Z}{W}\right]^{1/2}, \quad \text{..... (9.35)}$$

where

L = length between supports, ft,

S_h = allowable stress, psi,

Z = pipe-section modulus, in.^{3},

and

W = weight of pipe filled with water, lbm/ft.

Eq. 9.35 is merely a conservative approximation. A more liberal spacing can be determined by using one of the many pipe stress calculation programs.

9.9 Pipelines

9.9.1 Gathering Systems. The pipeline system that conveys the individual-well production or that of a group of wells from a central facility to a central system or terminal location is a

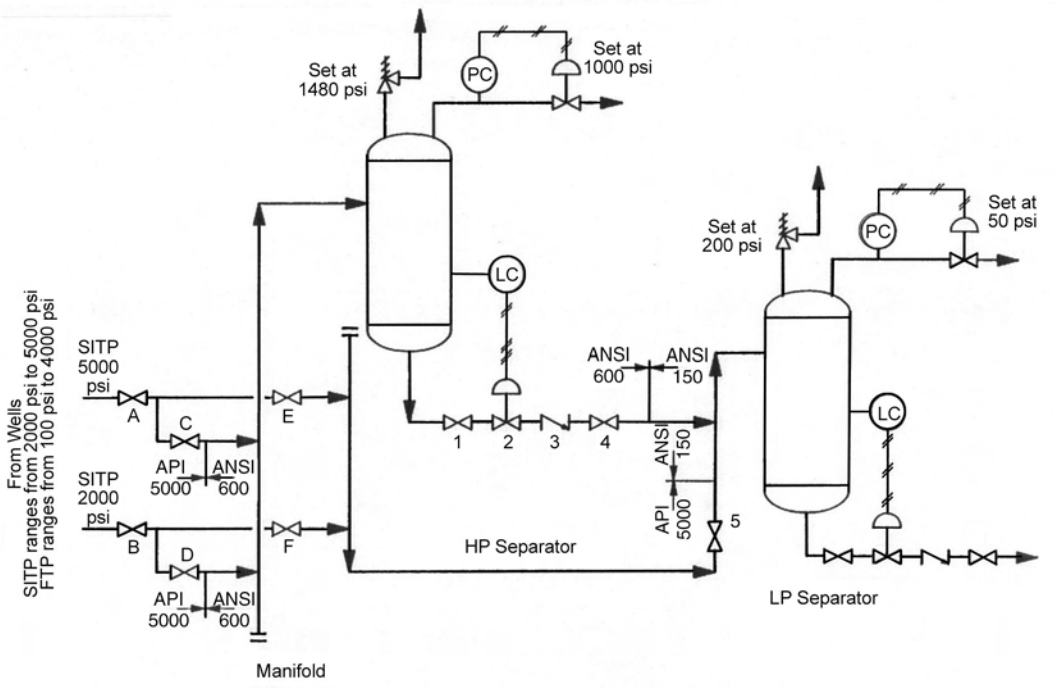


Fig. 9.16—Determination of pressure breaks. Same example of spec break in accordance with API *RP14J* as Fig. 9.14 except this shows that the pressure ratings of Valves 1 through 4 do not need to be changed if Valve 5 is located upstream of the dump line from the high-pressure separator (courtesy of API).

gathering pipeline. Generally, the gathering pipeline system is a series of pipelines that flow from the well production facilities in a producing field to a gathering "trunk" pipeline.

Gathering systems typically fall into one of four categories:

1. Single-trunk systems with "lateral" lines from each well production facility.
2. Loop systems, in which the main line is in the shape of a loop around the field.
3. The multiple-trunk system, in which there are several main lines extending from a central point.
4. Combinations of Categories 1 through 3.

Selection of the most desirable layout requires an economic study, which considers many variables, such as the type of reservoir, the shape of the reservoir, the way in which the land over the reservoir is being used, the available and permissible flow rate, the flowing and shut-in pressure and temperature, the climate and topography of the location, and the primary destination of the oil or gas.

Gathering systems typically require small-diameter pipe that runs over relatively short distances. The branch lateral lines commonly are 2 to 8 in. Gathering systems should be designed to minimize pressure drop without having to use large-diameter pipe or require mechanical pressure-elevation equipment (pumps for liquid and compressors for gas) to move the fluid volume. For natural-gas gathering lines, the Weymouth equation can be used to size the pipe.

9.9.2 Transmission Pipelines. "Cross-country" transmission pipelines will collect the product from many "supply" sources and "deliver" to one or more end users. There are three general categories of transmission pipelines: natural gas, "product," and crude oil. Natural-gas transmission pipelines carry only natural gas. Product pipelines may carry a number of processed or

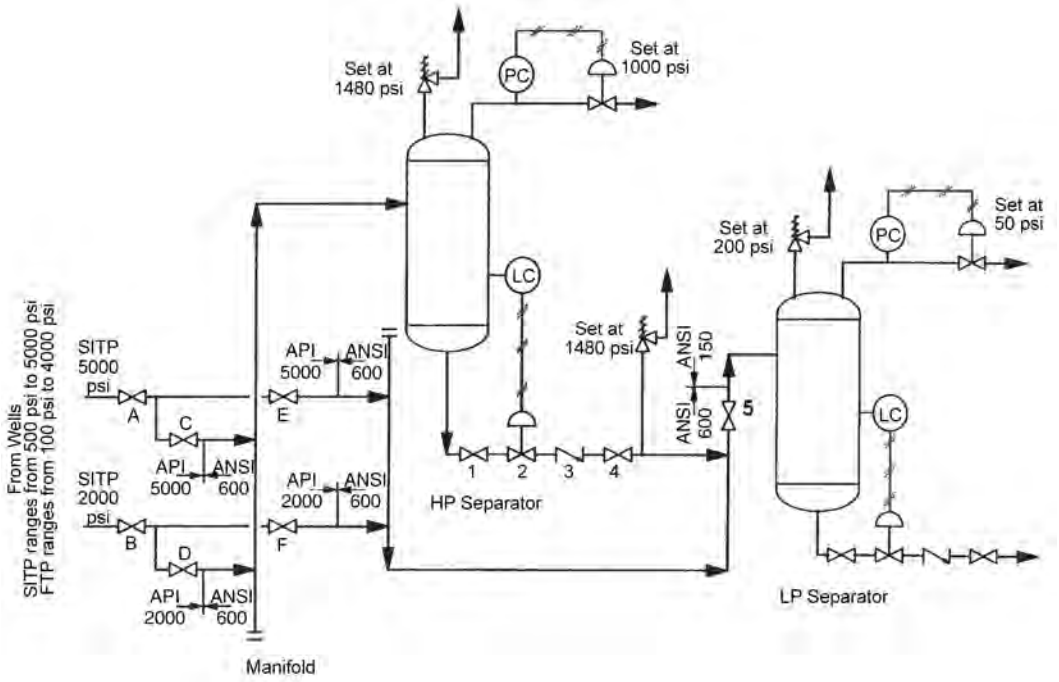


Fig. 9.17—Determination of pressure breaks. Same example of spec break in accordance with API *RP14J* as Fig. 9.14 except this shows an alternative spec-break scheme by adding a relief valve upstream of Valve 5 (courtesy of API).

refined petroleum products such as processed natural-gas liquids (e.g., butane and propane), gasoline, diesel, and refined fuel oils. Crude-oil pipelines convey unrefined crude oil from producing areas to large storage areas or directly to refineries. Transmission pipelines will generally require much larger pipe than gathering systems. Transmission systems normally are designed for long distances and will require pressure-boosting equipment along the route.

9.9.3 Onshore Pipelines. Many factors must be considered when designing, building, and operating a pipeline system. Once the basic pipe ID is determined using the applicable flow formula, the other significant design parameters must be addressed.

For U.S. applications, gathering, transmission and distribution pipelines are governed by regulations and laws that are nationally administered by the U.S. Dept. of Transportation (DOT). The regulations are contained in the Code of Federal Regulations (CFR) Title 49, Part 190[20] Enforcement Procedures, Parts 191[21] and 192[22] Natural Gas Pipelines, Part 193[23] Liquefied Natural Gas Pipelines, Part 194[24] Oil Pipelines Response Plans, Part 195[25] Hazardous Liquid Pipelines (e.g., crude oil and products), Part 198[26] State Grants, and Part 199[27] Drug Testing. The regulations incorporate the industry codes, guidelines, and standards including ANSI/ASME *B31.4, B31.8,* and others.

Internationally, many countries have adopted the U.S. regulations and the industry codes, guidelines, and standards. Some countries have different requirements, laws, and regulations, and each should be consulted prior to designing and building a pipeline. For the most part, these regulations are similar to those in the U.S., and, thus, the comments that follow, based on U.S. standards, are generally true in other countries as well. Even pipelines not specially covered by the regulations should be designed, constructed, and operated according to industry

codes, guidelines, and standards, as these are based on sound engineering and operating experience.

Pipe Selection and Wall Thickness. The type of pipe and wall thickness must be determined for each application. Following the design requirements of Part 192 for natural gas, Part 193 for liquefied natural gas (LNG), and Part 195 for crude-oil and products pipelines, the pipe materials and wall thickness can be determined using the applicable formula. As discussed in Sec. 9.2, the operating pressure (maximum and normal), operating temperature, other design factors (depending upon the type of pipeline and applicable regulation), and the pipe material will determine the wall thickness.

PVC, fiberglass, polypropylene, and other materials may be used in low-pressure and utility applications. ANSI/ASME *B31.4, B31.8,* and the DOT regulations allow the use of alternative materials in very restricted applications. However, steel pipe will be required in the majority of the oil and gas production and pipeline applications. ANSE/ASME A53[28] and A106[29] and API 5L[30] seamless, ERW, and submerged arc-welded (SAW) steel pipe are commercially available and most commonly used in pipeline systems. Seamless pipe is seldom used in pipeline applications because of the higher unit cost and limited availability. From a design and regulatory perspective, pipe made with ERWs and SAW seams is equivalent to seamless pipe and is less costly. Note: this is not true for piping systems designed in accordance with the ANSI/ASME *Standard B31.3.*[7]

Typically, for high-pressure pipelines, higher-grade pipe (such as API 5L, Grades X42, X52, X60, and X65) is selected because much-thinner-wall pipe can be used, which significantly reduces pipe costs. Construction-costs savings also are realized, as the welding time is reduced and material shipping/handling costs are reduced.

Material Selection. Pipe fittings, flanges, and valves must meet the specification and pressure class of the pipe selected for pipeline applications. The materials for pipelines commonly conform to industry codes and standards including ANSI/ASME *Standard B16.5,*[11] ANSI/ASME Standard *B16.9,*[31] ANSI/ASME *Standard B31.4,*[8] ANSI/ASME *Standard A105,*[32] ANSI/ASME *Standard A106,*[29] ANSI/ASTM *Standard A234,*[33] ANSI/ASTM *Standard A420,*[34] ANSI/ASTM *Standard A694,*[35] API Standard *6D,*[36] API *Standard 6H,*[37] MSS *Spec. 44*,[38] and MSS *Spec. 75.*[39] Pipe fittings can be matched to the higher grade API 5L, X Grade pipe. Detailed material information is discussed in Sec. 9.6.

Route Selection and Survey. Route selection is very important to successful pipeline design. Careful study of the terrain, natural obstacles (such as mountains, swamps, marshes, and rivers), manmade obstacles (such as highways, roads, railroads, and buildings), and population density is required. Topographic maps, aerial photography, satellite imagery, and property ownership maps, as well as physical inspection, are helpful aids in the routing process.

Constructability is an essential consideration when choosing the route. Typically, the minimum pipeline construction working right-of-way (ROW) for a 2-in. pipeline is 35 to 40 ft in width, and the working area should be reasonably level. Larger-diameter pipe requires wider ROW because the larger pipe requires bigger pipe-handling equipment (sidebooms), wider ditches and wider spoil piles. Eighty- to 100-ft wide construction working ROWs are typical for 4- to 12-in. pipe, and 200-ft plus construction ROW widths are common for pipe up to 30 to 36 in. The proposed route must be surveyed to determine the exact length of the proposed pipeline, determine the physical terrain, locate natural and manmade obstacles, and verify property boundaries. Once a workable route is confirmed, the acquisition of the ROW and regulatory permits begins.

ROW. The acquisition of private and public ROW and associated governmental permits is a major component of the pipeline process. Oil and gas leases often have provisions that allow the producer to install wells, flowlines, production facilities, and processing and storage facilities without having to acquire additional ROW or facility properties. However, producers do

not have the right to cross public roads, highways, railroads, rivers, jurisdictional creeks/streams, wetlands, or pre-existing easements or ROWs. Gathering and transmission pipelines have to purchase the ROW, or easement, that is required for the pipeline system. Typically, easements, which grant the pipeline owner the right to operate and maintain the pipeline and appurtenant facilities, are purchased. In some instances, the ROW may be purchased "in fee" where the easement is acquired as a property.

Permits and Special Considerations. Permits are required to install pipelines across public highways, roads, streets, and any other public conveyance. The permits must be acquired from the federal, state, or local authority that has jurisdictional authority. Special easements or permits must be acquired from railroads and other pipelines as well.

There are special design requirements for pipe installed across the highways, roads, streets, and railroads, which are stipulated in ANSI *B31.4, B31.8,* and the DOT regulations. Heavier-wall pipe (required because of lower design derating factors), casing, hydrostatic and nondestructive testing and other special requirements are stipulated in the applicable regulations, codes, and industry standards.

Special installation requirements are common, as few highways, public roads, or streets, if any, can be open-cut and ditched. Railroads will not allow conventional, open-cut ditch installation. The pipeline must be installed by wet or dry boring methods, tunneling, or horizontal-directional-drilling (HDD) methods. These methods are described later.

Environmental requirements have a major impact upon the pipeline industry. Pipelines can not be constructed in certain defined wetlands, marshes, swamps, rivers, creeks, or streams where the pipeline installation and operation could affect sensitive ecologies and environments. In the U.S., the U.S. Army Corps of Engineers (COE) has the primary jurisdictional authority over these areas, and other federal agencies, such as the U.S. Fish and Wildlife Service, have secondary jurisdiction. All states now have environmental or similar agencies that also have jurisdiction in many of these areas. Internationally, many countries now have laws and regulations that protect the natural resources. Historically significant sites, archeological sites, endangered species, and many other related issues require investigation before finalizing the route selection. Special permits must be acquired to work in and around sensitive areas. In the U.S., permits from COE are required for crossing of rivers, navigable streams/creeks, wetlands, and other regulated waters.

The environmental and natural resource regulations and requirements not only apply to regulated gathering, transmission, and distribution pipelines but also apply to flowlines and production facilities constructed within oil and gas leases. The potential cost impacts of these issues must be given serious consideration in the pipeline design process.

Corrosion Prevention. Steel pipe and pipeline facilities must be protected from the effects of external and internal corrosion. Nonferrous piping materials, such as fiberglass, PVC, and polypropylene, do not undergo the same corrosive effects and require little attention. Industry codes and standards and the DOT regulations require that pipelines, appurtenances, and facilities be protected from the effects of corrosion. NACE has standards prescribing the corrosion protection required for pipelines—NACE *Standard MR01-76,*[40] *RP200,*[41] and *RP572.*[42]

Internal Corrosion. Internal corrosion may be caused by the presence of CO_2, water, H_2S, chlorides (salt water), bacteria, completion fluids, or other substances in the produced hydrocarbon. When CO_2 or H_2S is mixed with oxygen and/or water, acids are formed that attack and destroy the steel. When CO_2 or H_2S is mixed with oxygen and/or saltwater, extreme corrosion occurs. Certain types of bacteria often found in producing formations can also attack and destroy the steel. Any of the internal corrosives, separately or in combination, can cause leaks and severe blowouts.

The potential corrosives usually can be identified from a chemical analysis of the produced hydrocarbons. In instances where high concentrations of CO_2, H_2S, or other highly corrosive

chemicals are present, additional pipe wall thickness may be added in the pipe design to allow for the potential corrosive effects. This is not normally recommended, as corrosion could be localized and the rate difficult to predict. In most cases, the removal of oxygen and water from the fluid is sufficient to combat potential corrosion. Where this is not practical, corrosion-inhibition chemicals, internal coatings, and corrosion-resistant materials are used.

Internal corrosion also can be caused by erosion or wear. Excessively high velocities in liquid and multiphase fluid systems can erode or wear the internal pipe wall as well as fittings and valves. The conditions that cause mechanical erosion can be mitigated through proper pipe sizing and design.

The corrosive effects of the hydrocarbon fluid may change over time as the chemistry of the produced fluid changes or as bacteria develop that were not present earlier. Where unknown corrosives develop after operations have commenced, chemical treatment may be the best solution.

External Corrosion—Underground Piping. External corrosion affects buried pipe and above-ground pipe. Buried pipe is subjected to cathodic actions and galvanic actions. Above-ground pipe is subjected to atmospheric corrosion and galvanic actions.

Cathodic actions occur when steel pipe is buried below ground. Ferric and other materials, such as soils, have small electrical potentials. In the natural process of converting metals back to their elemental or native state, electrolytic conduction takes place. Unprotected, the steel pipe becomes an anode (positively charged) and transfers material, by means of electrons, to the cathode (negatively charged) material, which is the soil or surrounding medium. The pipe metal literally flows away by means of the electric current between the anode and cathode. Water contained in the soils and other media serves as the electrolyte to help promote the electron transfer.

To counteract cathodic actions, pipe is coated with anticorrosive materials and cathodic protection systems are placed on the pipeline. The coating must provide an effective "insulation" against the environment but must be tough enough to withstand the operating temperatures, be resistant to the soil, and withstand physical handling.

There are a number of coating systems that are economical and commercially available, which include extruded systems (polyethylene or polypropylene over asphalt mastic or butyl adhesives), tape coats (polyethylene, polyvinyl, or coal tar over butylmastic adhesive), fusion bonded epoxy (thin film), and coal-tar epoxy. Fusion bonded epoxy (FBE) coatings are the most popular coating systems because they are excellent insulators; are hydrocarbon, acid, and alkali resistant; are unaffected by temperature; do not require a primer; and can be applied over finished welds (field joint). Tape-coating systems and coal-tar enamel systems are becoming less and less popular. Tape coating is difficult to apply and is especially difficult to use on large-diameter pipe. A number of tape-coated systems have experienced failures over relatively short spans of time because of improper application. Coal-tar epoxy is becoming less desirable because of some health and environmental concerns caused during application.

In addition to the anticorrosion pipe-coating systems, cathodic protection systems are added to the pipeline to protect the pipe where breaks in the coating system occur. The cathodic protection system employs either an impressed current or sacrificial anode to protect the underground pipe. The cathodic protection system reverses the electrolytic conduction process and uses an impressed electrical current or another metal object (sacrificial anode) to make the pipe a cathode. In simplified terms, the impressed current reverses the natural flow of electrons from the pipe to the surrounding medium to prevent the loss of metal ions. The sacrificial anode made of a higher potential metal, such as magnesium, is in contact with the pipe and the surrounding medium. The anode gives up its electrons (metal) in place of the steel pipe.

Sacrificial-anode systems are simpler and less expensive than impressed current systems. Onshore pipelines generally use magnesium, and offshore pipelines use zinc or aluminum an-

odes. Impressed current systems are much more complex and require external power sources and AC/DC power inverters or rectifiers to provide the current to the pipe.

The design of cathodic protection systems requires specialized training and can be very complicated. Detailed soil surveys must be conducted to determine the electrical potential and resistivity of the soils or surrounding medium, pipe-to-soil potentials, and a number of other criteria. System design should be done by a cathodic protection expert.

Galvanic Corrosion. Another important facet of the anticorrosion system is prevention of galvanic corrosion. Galvanic corrosion is caused by the interface of dissimilar metals with different electrolytic potentials. The dissimilar metals will gain or lose electrons from or to each other resulting in one of the metals effectively flowing away and losing material. Steel pipe that undergoes abrupt changes in the medium will behave somewhat as dissimilar metals and cause galvanic actions. Pipe transitioning from below ground to above ground may experience galvanic-like corrosion. Mating materials such as carbon steel with stainless steel will cause the carbon steel to corrode.

Insulating flanges or joints can be used to counteract the effects of galvanic actions. Efforts should be made to avoid the interface of the dissimilar materials in the system design.

Atmospheric Corrosion. The effects of atmospheric corrosion are readily apparent. Bare steel exposed to moisture, salt, chemicals (pollution), heat, cold, or air (oxygen) will corrode rapidly. Piping and equipment exposed daily to the elements must be protected with anticorrosion coatings. Good paint coating systems, such as epoxies, and regular maintenance will normally provide adequate protection to the above-ground facilities.

Facilities exposed to severe service, such as offshore, may require more-extensive protection systems. There are a number of alternative coating systems that are discussed in the offshore pipeline section.

Welding and Pipe Joining. The methods used to connect the joints or pipe segments are very important and are critical to the pipeline design. ANSI/ASME *Standards B31.3,*[7] *B31.4,*[8] and *B31.8,*[9] as well as the DOT regulations, specify welding and joining methods for pipe. Each type of pipe material has joining or coupling methods designed to ensure that the joint is as strong as, or stronger than, pipe joint. Fiberglass, PVC, and other types of plastic pipe may have bell- and spigot-type joints that are mechanical, threaded, or glued. Polypropylene and polyethylene pipe, which is used frequently in very-low-pressure hydrocarbon applications, use a fusion-welded joint. However, the majority of the hydrocarbon pipeline applications require steel pipe.

For the majority of steel pipeline applications, welding is the preferred method of joining the pipe. API *Standard 1104*[43] and ASME Sec. IX of the boiler and pressure vessel codes specify the requirements for the welding of steel pipe. Manual and automatic welding processes are used on pipelines both onshore and offshore. Shielded metal-arc welding (SMAW), or "stick" welding, is the most common manual process used on carbon-steel pipelines, but the development and use of higher-grade carbon-steel pipe (e.g., API 5L X65 and X70) have required the development of welding processes and metallurgy compatible with the high-carbon alloys. Stainless steels and other alloys may require special welding processes.

The development of reliable and economical automatic welding machines has had a significant impact on the pipeline industry as well. The automatic welders may be external or internal for large-diameter pipe.

Each weld joint must be designed and a welding procedure specification (WPS) developed for the pipe. Each WPS specifies the type of pipe to be welded (specification, grade, etc.), the type and specification the of the pipe joint [e.g., specify bevel(s), angle, shoulder, and spacing/alignment], the material thickness or range of thickness applicable, the type and size of welding rods, the position and direction of the weld, the voltage/amperage, pre-/post-heat, stress relieving, etc. The WPS must be physically proved by actually welding a test "nipple" and

conducting destructive testing in accordance with the API and/or ASME requirements. Once the specification is proven, a procedure qualification record (PQR) is recorded verifying the WPS. Welders must be qualified to perform the welds in accordance with either API *Standard 1104*[43] or ASME Sec. IX.[15] Each welder will perform a test weld using the WPS for the pipe and will qualify under the procedure. API *Standard 1104,*[43] ASME Sec. IX,[15] and DOT specify and define welder qualifications.

There are other acceptable methods for joining pipe. Steel pipe may be threaded and coupled or may have various mechanical joints. Threaded-steel-pipe application is generally limited to small diameters, 4 in. and less. Larger pipe is difficult to properly couple, and threaded line pipe in large diameter is not readily available. Fiberglass pipe used in the industry may be threaded or have solvent-welded joints. PVC may have solvent-welded joints or may have bell-and-spigot mechanical joints. Industry codes and standards, as well as DOT regulations, recognize the other joining methods but limit the use of pipe other than steel.

Pipeline Construction Process. Conventional, onshore pipeline construction process is described next.

ROW Clearing/Preparation. Before initiation of construction activities, any sedimentation, erosion control, construction fencing, and other preparation is completed. All vegetation is cleared and grubbed, topsoil is removed (if required), and the working ROW is graded.

Pipe Stringing. Once the ROW has been prepared, the pipe is loaded on flatbed trucks. Before unloading, pipeline skids (typically 4-in. × 6-in. × 4-ft hardwood timbers) are dropped along the ROW to be placed under the pipe. The trucks are driven down the ROW, and the pipe is unloaded, joint by joint/end to end, by sidebooms or cranes.

Ditching. The ditch is excavated along the pipeline centerline using ditching machines, excavators, backhoes, and other excavation equipment. Pipelines are normally buried with a minimum of 36 in. of cover (DOT regulatory requirement). In consolidated rock, the minimum cover varies between 18 and 24 in. The cover for Class 1 locations is 18 in.; the cover for Classes 2 to 4 (railroads, highways, and public roads) is 24 in.

Welding. The pipe strung along the ROW is welded in a progressive manner. Sidebooms will work along the ROW lifting the pipe while a crew aligns the pipe in preparation for the "stringer bead" weld. Generally, a welder or welders (depending upon the size of the pipe) will work with the alignment crew, align the pipe, and apply the initial weld "bead." A group of welders will follow immediately behind the stringer welder(s) and apply the "hot pass" bead or seal weld. Additional welders will follow to apply the final passes of weld material.

Field Joint and Anticorrosion Coating and Inspection. When the welding is completed, field joint crews clean the weld areas and the short, adjacent bare steel on either side of the weld, and apply the field joint coating. Any nondestructive testing of the welds, such as *X*-ray, will be completed before application of the field joint coating. Following the completion of the field joint coating, the pipe is inspected with "holiday" detection equipment (low-voltage DC equipment that shows where the pipe coating and field joints have failures or breaches), and anomalies and breaches in the coating are repaired.

Pipe Lowering. Upon completion of the field joint application and coating inspection, the pipe is lowered and placed into the ditch by sidebooms or other lowering equipment.

Backfill, Cleanup, and Restoration. Following completion of the pipe lowering, the ditch is backfilled, and the ROW is cleaned and dressed. The ROW is finely dressed, grass and vegetation replanted, and any special remediation measures or cleanup requirements are completed.

Highway, Road, Railroad, and River Crossings. Highway, road crossings are seldom installed using conventional, open trench methods. Typically, these crossings are installed using a wet bore or dry bore method. The boring is done by rigs that are similar to very small drilling rigs, laid horizontally, and placed in pre-excavated boring level "pits." The boring rig drills underneath the crossing area, and the pipe or casing is installed. The wet method uses a boring

rig and circulates water or drilling fluid through a drill stem to open a small pilot hole, then pulls a pipe or casing-sized cutting head back to the rig, cutting a hole large enough to place the pipe or casing. The dry bore method is similar, but the casing or carrier pipe is fitted with a cutting head and is used to drill the hole and is left in place when the drill is completed. The hole is drilled dry and does not use any water or fluid to assist the drilling operation. Railroad crossings are never open cut and are always bored. Typically, railroads require that the borings be made with the dry bore method. Both wet and dry bore methods are limited on the distance that they are effective and practical.

River crossings are now typically installed using the HDD method. Open-cut trenching of rivers may be allowed by the U.S. Corps of Engineers, but HDD installations have become more economical. The HDD method uses a computer-controlled rig that controls a directional wet-bore pilot drill that can be accurately steered from the rig. The directional drill can bore a pilot hole up to a mile or more and ream a hole back to the rig large enough to install the carrier pipe. The "drill" string or pull section of pipe is welded together on the drill exit side, pretested, then pulled back to the rig side following the backreamer.

The HDD method may be used to install long highway and road crossings, such as interstate highways and freeways. The wet- and dry-bore methods are limited to several hundred feet in length, which requires multiple borings to cross the distances typically required to cross interstate highways and freeways.

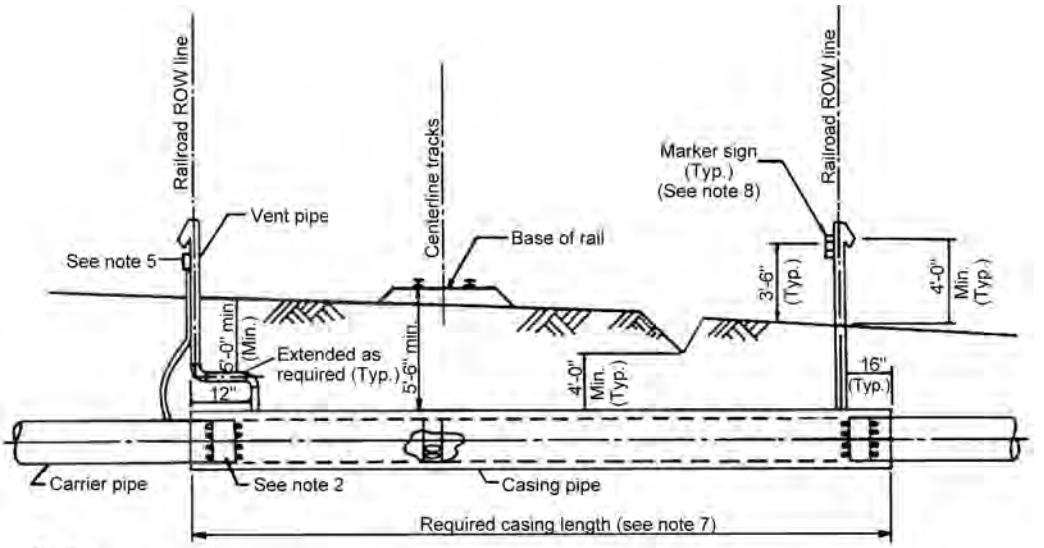
Tie-ins. A crew, or crews, is typically deployed that makes all pipeline tie-ins along the construction corridor. The tie-in crew makes the final welds at junctures where the progressive welding cannot make the final welds. Tie-ins are made at locations such as highway, road, railroad, and river and creek crossings and at drag sections, etc. The tie-in crew typically has excavation and pipe handling equipment and dedicated welders.

Construction Details. **Figs. 9.18 through 9.28** illustrate typical construction details. The Occupational Safety and Health Admin. (OSHA) is an agency under the DOT and provides additional federal rules and regulations concerning the design, construction, and testing of pipelines.[44,45]

9.9.4 Offshore Pipelines. Offshore pipeline design differs primarily in the requirements of the environment and the installation process. Pipe used in offshore applications is subjected to high bending stresses—potential crushing forces on pipe installed in deep water and a low-density environment. Until recently, the pipeline size was severely limited, but technological developments and improved construction methods have enabled offshore pipelines to continue to increase in size and capacity. Pipelines are being constructed in deeper and deeper waters. Pipelines up to 28-in. diameter are now being installed in the deepwater applications up to 7,000 ft of water.

Design. The piping materials used in the offshore pipelines are essentially the same as those used in onshore pipelines. When a pipeline is designed according to ANSI/ASME *Standard B31.8,* a 0.72 design factor is used for most of the pipeline wall-thickness calculation, and a 0.50 design factor is used in the riser pipe and often the first 300 ft of pipe adjacent to the riser. Pipe greater than 10-in. nominal size installed in low-density saltwater will generally tend to float. Sometimes this can be overcome by using more wall thickness than otherwise necessary to make the pipe heavier. It is normally more economical to use a concrete weight coating or to lay the line wet to get the required on-bottom stability. Generally, pipe is designed to have a specific gravity of 1.35.

The pipe has to be designed with enough wall thickness to handle the internal operating pressure, the bending stresses, and the external crushing forces. High-strength, high-grade pipe, such as API 5L Grade X65 and greater, is often used for construction, structural, operational, and economical considerations.



Notes:
1. Casing pipe shall be installed covered with one coat of T.C. mastic unless otherwise stipulated by applicable permit.
2. Install casing seals and insulators as shown on drawing number.
3. Install vent cap with screen furnished by company on casing vents.
4. Cut vent hole and weld vent pipe to casing pipe prior to inserting carrier pipe. Vent pipe below ground shall be covered with one coat of T.C. mastic or equal. Vent pipe above ground shall be painted in accordance with specifications.
5. Install cathodic protection station on one vent pipe as on drawing.
6. The location of cased crossings will be noted on alignment sheets.
7. Crossing installation shall be in accordance with applicable permit and permit drawing.
8. Company to furnish marker signs. Contractor to bolt sign to vent pipe.
9. Casing shall be steel, of minimum dimensions shown by table, with watertight joints.
10. Trenching shall not be permitted within 25 ft measured perpendicularly to the center line of any track.
11. Holes shall be dry bored or dry tunneled. Void between casing and bored hole shall be completely filled with a 1 to 10 mixture of cement and sand.

Table

Pipe	Casing		Vents
Nominal Diameter	Minimum Nominal Diameter	Minimum Wall Diameter	Pipe Size
1" thru 3 1/2"	Pipe diameter plus 2"	3/16"	2"
4" thru 9"	Pipe diameter plus 3"	3/16"	2"
10" thru 14"	Pipe diameter plus 4"	1/4"	3"
15" thru 24"	Pipe diameter plus 5"	5/16"	4"
25" thru 34"	Pipe diameter plus 6"	3/8"	6"
36" thru 48"	Pipe diameter plus 8" water line service	Corrugated metal pipe, 8 gauge	8"

Fig. 9.18—Typical cased railroad-crossing ROW (courtesy of AMEC Paragon).

The minimum bending radius calculation for concrete coated pipe is expressed in Eq. 9.36.

$$R = EC / S_B \text{ , } \quad \text{(9.36)}$$

where

R = bending radius, in.,

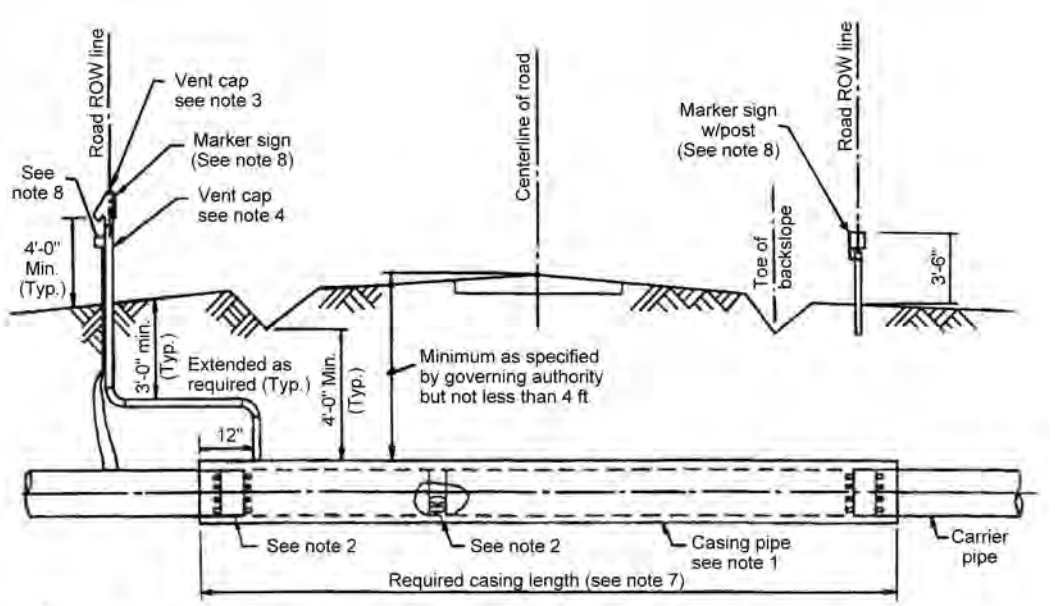
E = modulus of elasticity for concrete = 3,000,000 psi,

C = pipe radius + enamel thickness + concrete thickness, in.,

and

S_B = 2,500 psi.

The minimum bending radius for steel is expressed as



Notes:
1. Casing pipe shall be installed covered with one coat of T.C. mastic unless otherwise stipulated by applicable permit.
2. Install casing seals and insulators as shown on drawing number.
3. Install vent cap with screen furnished by company on casing vent, vents to be located on high end of casing.
4. Cut vent hole and weld vent pipe to casing pipe prior to inserting carrier pipe. Vent pipe below ground shall be covered with one coat of T.C. mastic or equal. Vent pipe above ground shall be painted in accordance with specifications.
5. Install cathodic production station on one vent pipe as on drawing number.
6. The location of cased crossings will be noted on alignment sheets.
7. Crossing installation shall be in accordance with applicable permit and permit drawings as required by highway or county engineer.
8. Company to furnish marker signs. Contractor to bolt to vent pipe and marker post.
9. Boring shall be done by an approved method and the casing shall be advanced at a rate approximately equal to the rate of boring. Where boring is not practical, due to rock strata or other obstructions, the engineer shall first approve all plans for construction by "open cut", tunneling, or other methods.
10. In refilling the trench excavated for the pipeline, adjacent to hard surfaced roads or highways and access roads where trenching is permitted, the trench shall be promptly backfilled in a proper and workmanlike manner so as to leave no holes or obstructions therein and so as to furnish and provide proper drainage.
11. Casing shall be steel, of minimum dimensions shown by table, with watertight joints.

Table

Pipe	Casing		Vents
Nominal Diameter	Minimum Nominal Diameter	Minimum Wall Diameter	Pipe Size
1" thru 3 1/2 "	Pipe diameter plus 2"	5/16 "	2"
4" thru 9"	Pipe diameter plus 3"	3/16 "	2"
10" thru 14"	Pipe diameter plus 4"	1/4 "	3"
15" thru 24"	Pipe diameter plus 5"	5/16 "	4"
25" thru 34"	Pipe diameter plus 6"	3/8 "	6"
36" thru 48"	Pipe diameter plus 8" water line service	Corrugated metal pipe, 8 gauge	8"

Fig. 9.19—Typical cased highway/road-crossing ROW (courtesy of AMEC Paragon).

$$R = EC/(f)(S_Y) - PD/4t\ , \quad \text{..... (9.37)}$$

where

S_Y = pipe specified minimum yield strength, psi,
P = design pressure, psi,
D = pipe OD, in.,
t = pipe wall thickness, in.,

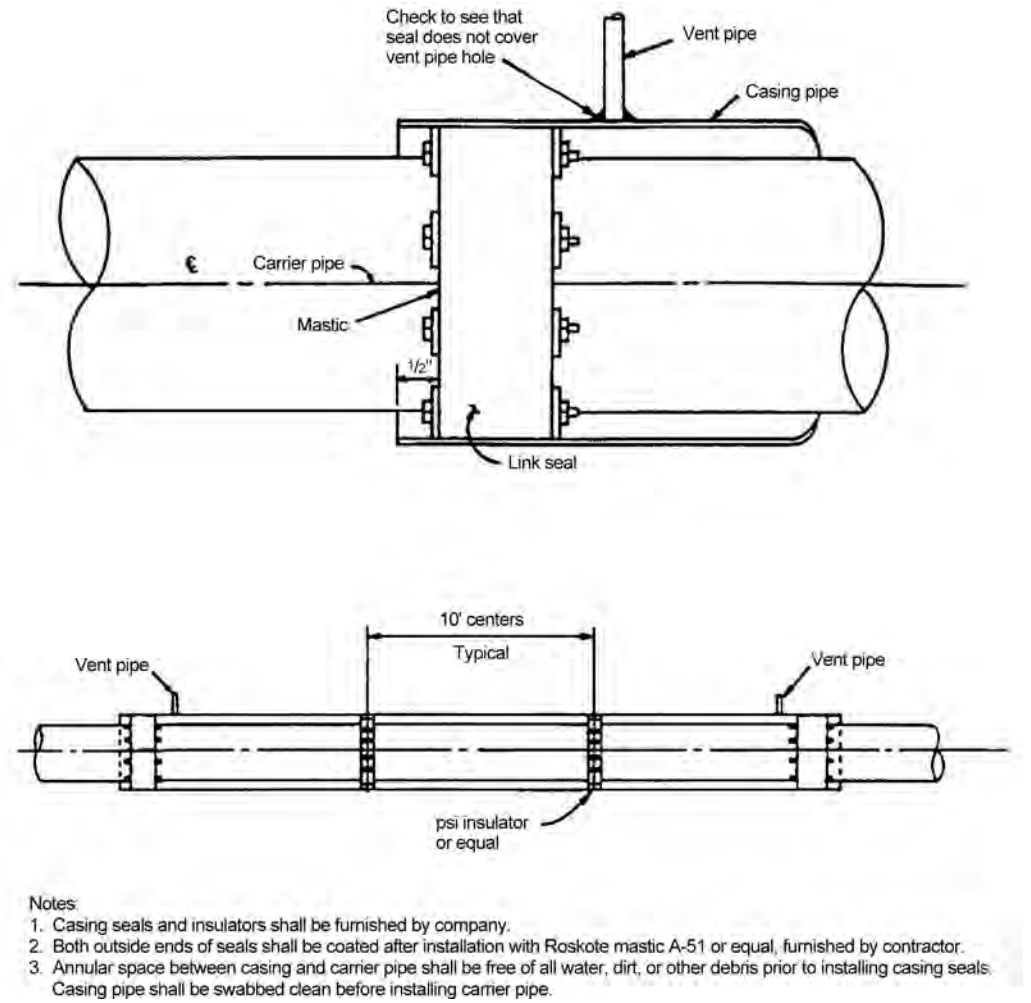
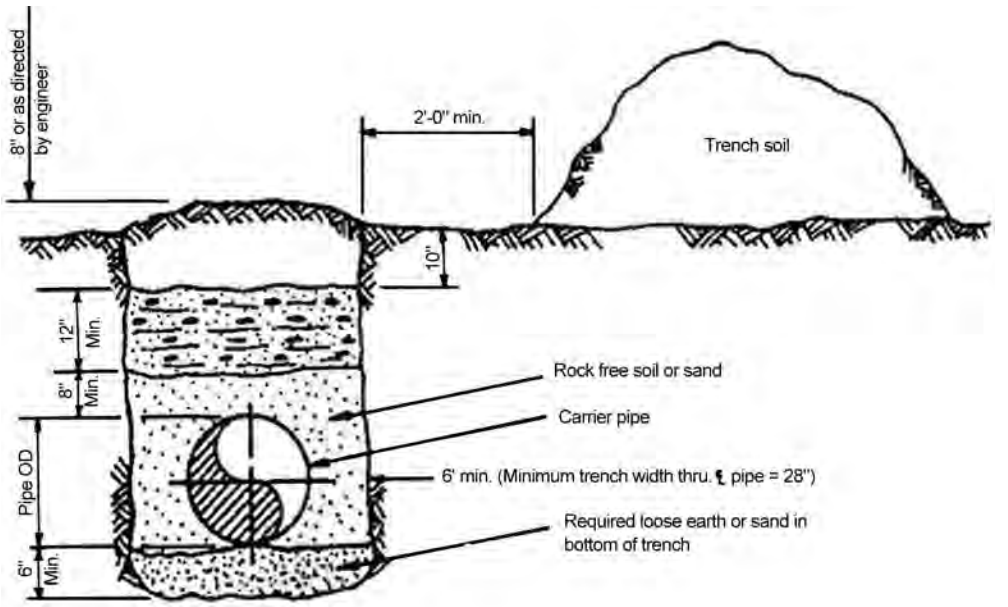


Fig. 9.20—Typical details for casing seal, insulator, and vent piping for Figs. 9.18 and 9.19 (courtesy of AMEC Paragon).

R = bending radius, in.,
E = modulus of elasticity for steel = 30,000,000 psi,
C = pipe radius, in.,
and
f = stress factor: use 75 to 85% for offshore design.

In deep water, computer programs are available to calculate the tension that must be kept on the pipe to maintain an acceptable bending radius. This is a complex calculation and must take into account the specific capabilities of the lay barge. In deep water, laying stresses and collapse stresses may determine the wall thickness. In addition, buckle arrestors may be required to restrict the length of a buckle, should one be caused by an installation problem (e.g., loss of adequate tension).

Construction. Offshore pipelines are constructed using lay barges or special ships. Each operation of the pipeline construction process, with the exception of pipe burial, takes place on the lay barge. Pipe is stored, prepared, welded, field joint coated, inspected, and lowered from the lay vessel. The pipe is lowered from the rear of the barge using a sophisticated system of



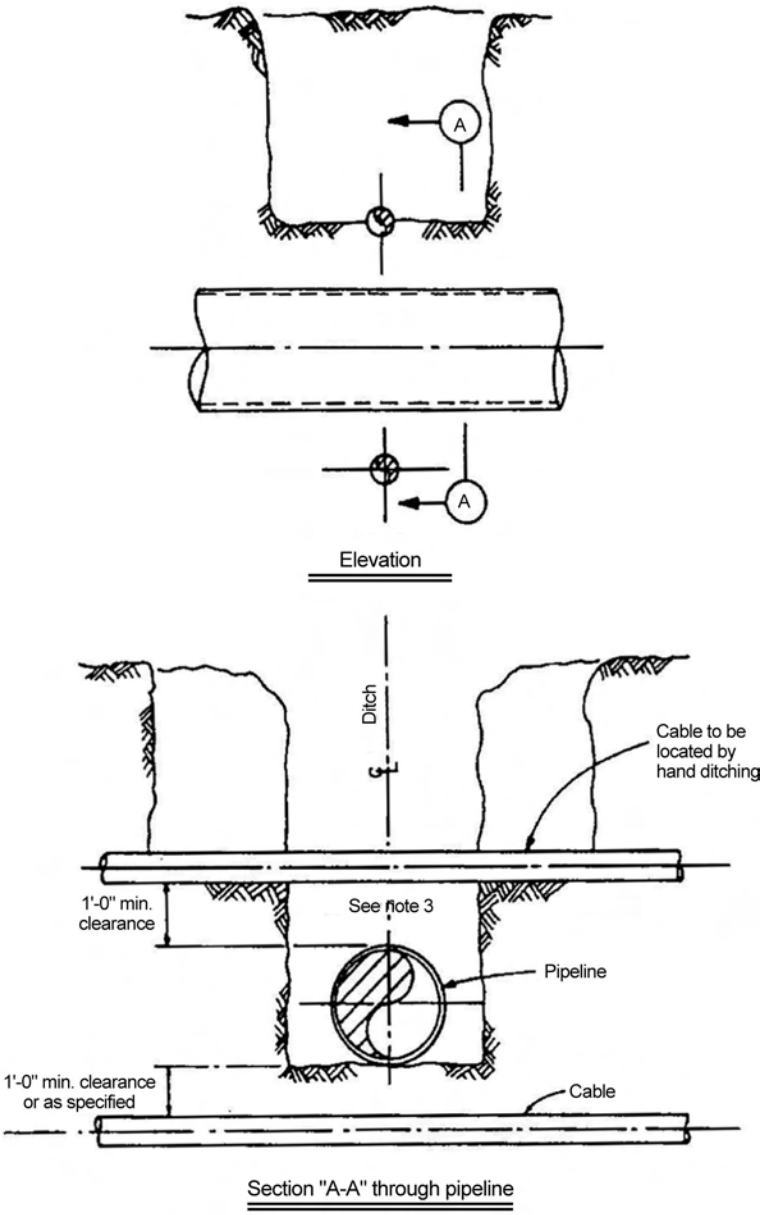
Notes:
Except where greater cover is required in the specifications, on certain drawings, in the construction line list, in permits, in right-of-way agreements, or by applicable codes and governmental regulations, the required minimum cover over the top of the coated pipe when lowered in shall be as follows:

1. When in trench other than "solid rock trench," the required minimum cover shall be thirty-six inches (36").
2. When in "solid rock" the required total cover over the lowered pipe shall be twenty four inches (24"), provided, however, that in no case shall the top of the pipe be less than four inches (4") beneath the top of the solid rock strata, in its original formation. This requirement shall apply except where the total cover over the lowered pipe is equal to or is greater than thirty-six inches (36").
3. The above requirement notwithstanding when located in industrial, commercial, or residential areas the required cover in "solid rock" shall be thirty inches (30"), and in other than "solid rock" shall be forty-eight inches (48"), and when the pipeline is located under borrow ditches at public roads and borrow ditches at railroads the required cover shall be forty-eight inches (48"), drainage ditches, streams, and rivers shall have a minimum required cover of sixty inches (60").
4. Where the pipeline is located within fifty feet (50') of any private dwelling or industrial building or place of public assembly in which persons work, congregate, or assemble, the cover required under paragraph three shall apply.
5. No rock to a depth of eighteen inches (18") or no rock to a depth less than that of the rock in adjacent undisturbed areas, whichever is less.
6. In all cases "depth of cover" shall be measured as the shortest dimension from the top of the coated pipe to the normal ground level.

Fig. 9.21—Typical details for pipeline burial (courtesy of AMEC Paragon).

dynamic positioners, rollers, cable tensioners, floats, and a long, adjustable boom or stinger. The pipe is strung out behind and below the lay barge and assumes an S-shape or J-shape. In an S-lay, the pipe is made up horizontally on the barge allowing for several welding stations. The pipe leaves the barge over a stinger that controls the curvature of the "overbend." Tension in the barge anchors controls the radius of curvature of the "sag bend", which returns the pipe to horizontal on the seafloor. In very deep water, it is no long possible to control the overbend with a stinger and, thus, a J-lay is used where the pipe leaves the barge vertically. A J-lay requires a tower on the barge to hold a length of pipe while all the welding is done at one location.

No matter which system is used, the pipe experiences tremendous bending forces caused by the weight of the pipe, the motion of the vessel, and the radius of the bends. The radius is

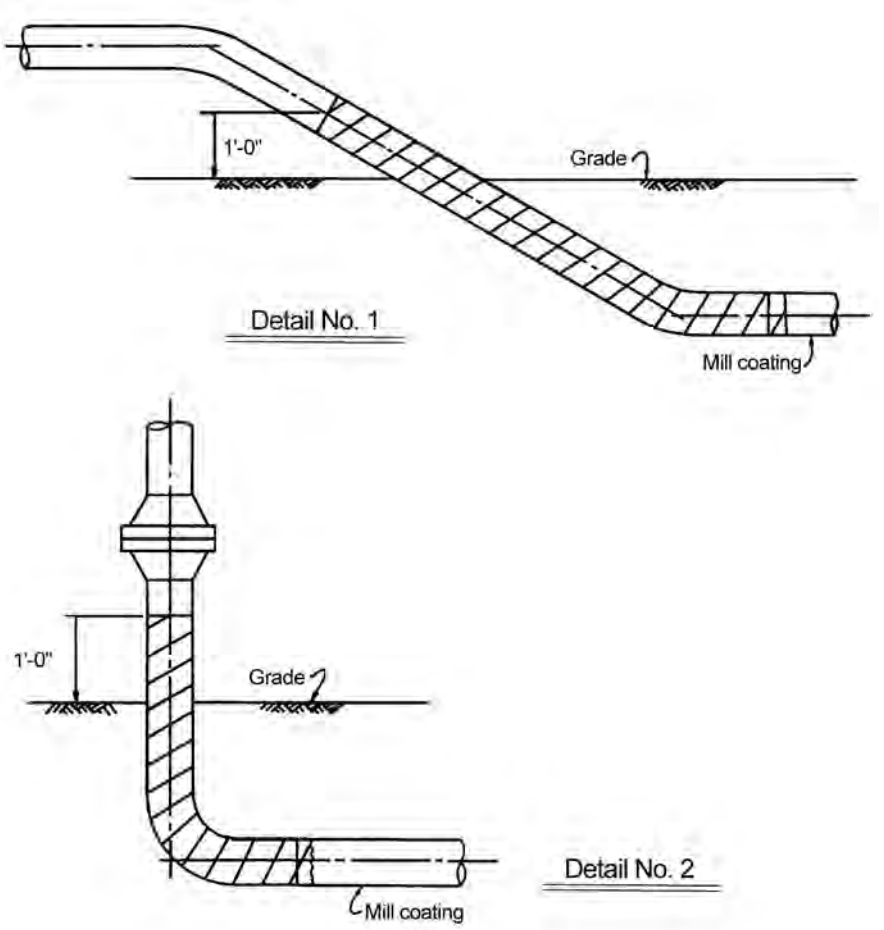


Notes:
1. Cable owner to be notified in sufficient time to be on hand during installation.
2. Test leads 8 line markers to be installed as required.
3. Support as required by cable owner.

Fig. 9.22—Typical details for minimum clearance between multiple pipeline crossings (courtesy of AMEC Paragon).

controlled by tensioner systems. The pipe must be designed so that stress, caused by axial tension and bending moment, is within allowable limits.

The rate of progress of the lay, the roughness of the sea, and other factors can cause the pipe to buckle. The deeper the lay, the greater is the potential to buckle the pipe. Pipe can be



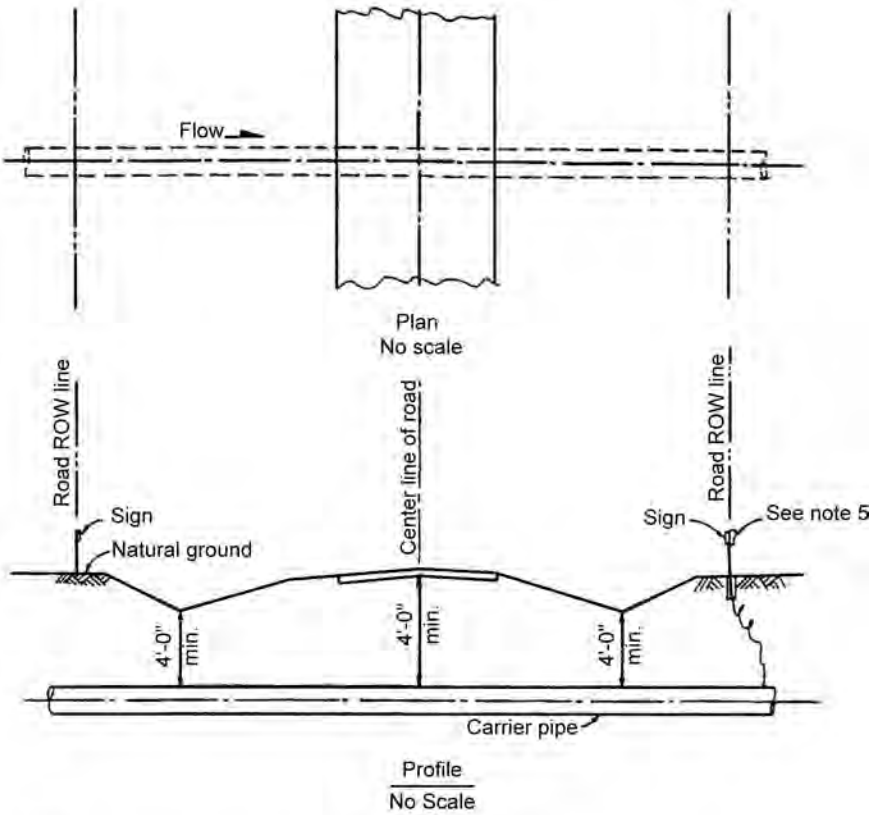
Protective Coating Application

1. Sandblast bare pipe to near white finish.
2. Apply a single coat of cold mastic (2 ½ mils dry).
3. Cover all below grade piping with tape primer from mill coating to a point 1 ft above the grade line.
4. Apply protective tape with a ½ width lap over primed surface.
5. All coating to be applied as per manufacturer's recommendation.
6. Above ground piping to be coated per coating specifications.
7. All materials to be furnished by contractor.

Fig. 9.23—Typical details for pipeline coating in transition area, just below and just above grade elevations (courtesy of AMEC Paragon).

laid in shallow water, 50 ft or less, with a spud barge or jack-up barge. The spud and jack-up barges operate in a fashion similar to the lay barge.

Pipe burial is performed with a plow or a jet. Plows are used in deep water and denser clays and can be used concurrently with the lay barge. Jet systems can be used in water up to

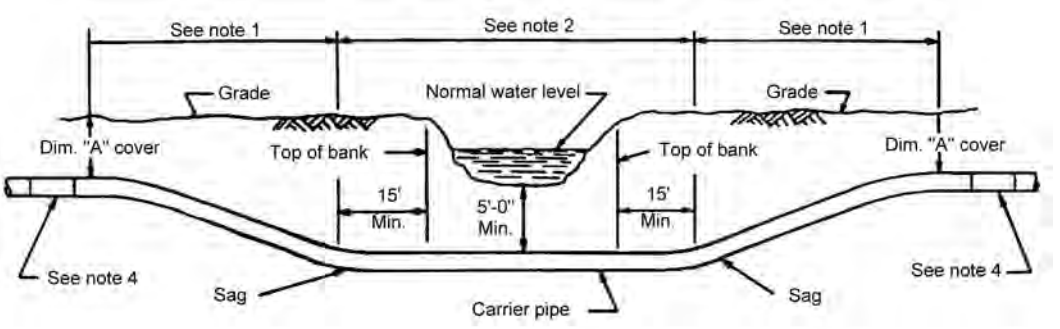


Notes:
1. Pipeline trench is to be open cut. The trench is to be backfilled and road surface repaired with proper materials and in accordance with county highway department requirements and regulations. Surplus soil is to be properly disposed of.
2. Top of pipe is to be a minimum depth of 4 ft below the bottom of road ditches and a minimum depth of 4 ft below the road surface.
3. Pipe crossings are to be located and indentified by above ground pipeline markers set in roadway fences, and in the absence of fences in the roadway ROW lines (Ref. dwg. no. KGB-9012).
4. Construction contractor is to comply with the respective county highway requirements and regulations.
5. Cathodic test station shall be installed as shown on dwg. no.

Fig. 9.24—Typical uncased highway/road-crossing ROW (courtesy of AMEC Paragon).

depths of approximately 300 ft. Divers can hand jet a pipe in shallower waters, but more often, a jetting machine is used to bury the pipe after it is laid. In shallow waters (50 ft or less), a dredge can be used to excavate the pipe trench.

In the U.S., the minimum cover required over the pipeline, in depths up to 200 ft, is 36 in. There is no requirement for pipe burial in water deeper than 200 ft. Typically, pipe is buried with 5 ft of cover for the first 300 ft outward from the platform riser, 16½ ft in anchorage areas, and 10 ft in fairways. Foreign pipelines are generally crossed over, and it may be necessary to lower the foreign line. A minimum of 18-in. separation must be maintained, and often rubber coated, articulated concrete mats are placed between the lines.



Note:
1. Pipe shall be laid to extra depth at these locations, to prevent excessive bending, at no additional cost to company.
2. Pipe shall be level under stream channel at depth shown.
3. Construction contractor shall furnish and install concrete weights as directed by company representative.
4. Install transition pieces if required.
5. Pipe wall thickness and grade as specified on engineering drawings.
6. Normal pipe depth to be minimum of 5'-0" or as specified on engineering drawings.
7. More stringent requirements of applicable permits and design drawings shall be followed.
8. Locations for stream crossings will be noted on the alignment sheets or as designated by company engineer.
9. Dimension "A" as per job specifications.
10. This drawing is applicable to all small-stream or ditch crossings not shown individually designed on other accompanying drawings.

Fig. 9.25—Typical uncased small-stream-, canal-, or ditch-crossing ROW (courtesy of AMEC Paragon).

Corrosion Control. The same corrosion protection and cathodic protection principles that apply to onshore pipelines also apply to offshore pipelines. The line pipe is typically coated with an FBE or similar system, and if additional weight is needed, it will have an overcoat of concrete.

Above-water piping is typically coated with a multicoat epoxy paint system. A special section of pipe with a vulcanized rubber coating bonded to the pipe, "Splashtron," is often used in the highly corrosive splash zone at the water/air interface.

Sacrificial zinc or aluminum anodes are mounted to the pipe in a bracelet configuration. The anodes are typically designed for a minimum 20-year service life. It is very difficult to design and maintain an impressed current system on a long offshore pipeline.

9.10 Pipeline Pigging

Pipeline pigs are devices that are placed inside the pipe and traverse the pipeline. Pigs may be used in hydrostatic testing and pipeline drying, internal cleaning, internal coating, liquid management, batching, and inspection. Fig. 9.29 shows several types of pipeline pigs.

Pigs are used during hydrostatic testing operations to allow the pipeline to be filled with water, or other test medium, without entrapping air. The pig is inserted ahead of the fill point, and water is pumped behind the pig to keep the pipe full of water and force air out ahead of the pig. Pigs are then used to remove the test waters and to dry the pipeline.

Operations may conduct pigging on a regular basis to clean solids, scale, wax buildup (paraffin), and other debris from the pipe wall to keep the pipeline flow efficiency high. In addition to general cleaning, natural-gas pipelines use pigs to manage liquid accumulation and keep the pipe free of liquids. Water and natural-gas liquids can condense out of the gas stream as it

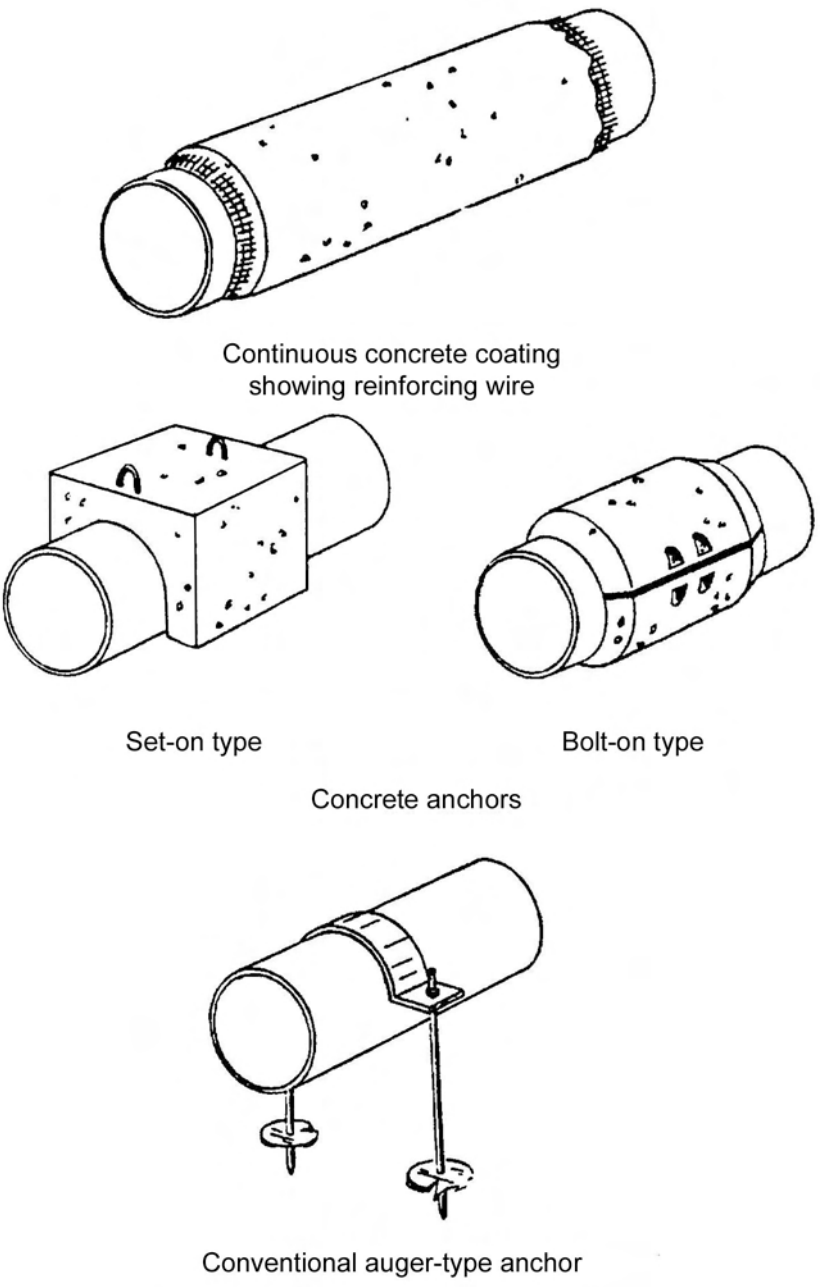


Fig. 9.26—Various types of density anchors and conventional mechanical anchor (courtesy of AMEC Paragon).

cools and contacts the pipe wall and pocket in low places, which affects flow efficiency and can lead to enhanced corrosion.

Pigs are used in product pipelines to physically separate, or "batch," the variety of hydrocarbons that are transported through the line. Product pipelines may simultaneously transport gasoline, diesel fuel, fuel oils, and other products, which are kept separated by batching pigs.

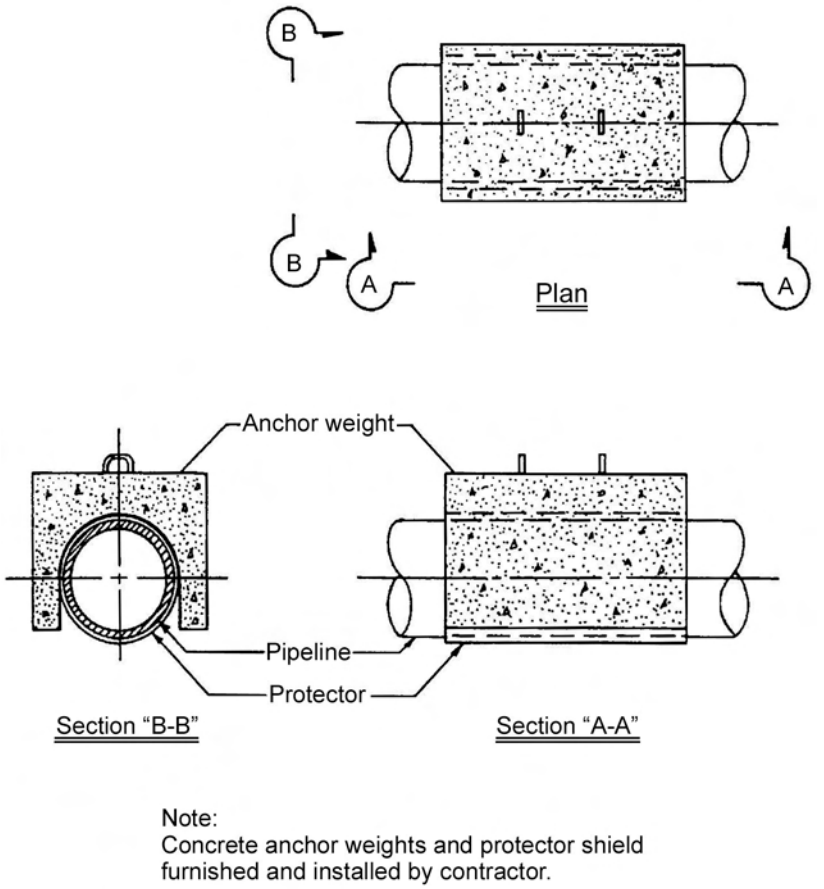


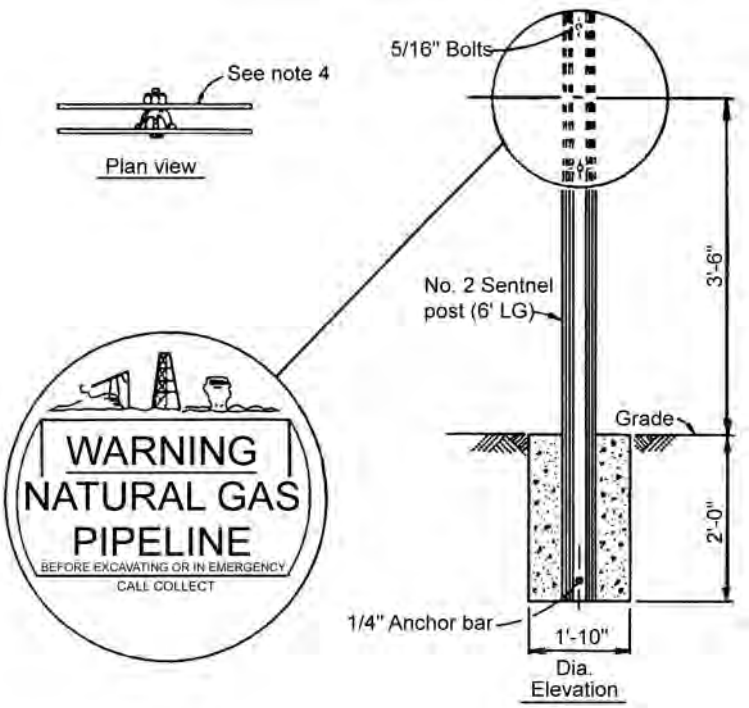
Fig. 9.27—Typical set-on reinforced-concrete pipeline weights (courtesy of AMEC Paragon).

Crude-oil pipelines are sometimes pigged to keep water and solids from accumulating in low spots and creating corrosion cells. This can be especially necessary when flow velocities are less than 3 ft/sec. Multiphase pipelines may have to be pigged frequently to limit liquid holdup and minimize the slug volumes of liquid which can be generated by the system.

Pigs may be used to apply internal pipe coatings, such as epoxy coating materials, in operating pipelines. Pigs may also be used with corrosion inhibitors to distribute and coat the entire internal wetted perimeter.

Pigs are being used more frequently as inspection tools. Gauging or sizing pigs are typically run following the completion of new construction or line repair to determine if there are any internal obstructions, bends, or buckles in the pipe. Pigs can also be equipped with cameras to allow viewing of the pipe internals. Electronic intelligent, or smart, "pigs" that use magnetic and ultrasonic systems have been developed and refined that locate and measure internal and external corrosion pitting, dents, buckles, and any other anomalies in the pipe wall.

The accuracy of location and measurement of anomalies by the intelligent pigs has continued to improve. Initially, the electronics and power systems were so large that intelligent pigs could be used only in lines 30 in. and greater in size. The continued sophistication and miniaturization of the electronic systems used in the intelligent pigs has allowed the development of smaller pigs that can be used in small-diameter pipelines. Newly enacted DOT pipeline-integri-



Notes:

1. Markers with posts installed as shown to be located at the following:
   a. On both sides of road crossing where there are no casing vents.
   b. All potential excavation sites such as streams, rivers, drainage ditches.
   c. At property lines without a fence where requested by company engineer.
   d. At other special locations designated by company engineer.
2. Hole for concrete to be dug by hand only.
3. Sign to be furnished by company, all other materials to be furnished by contractor.
4. Where ground markers are installed at property line without fences and at other special locations designated by company engineer, two signs facing opposite directions shall be installed on a single post.

Fig. 9.28—Typical natural-gas pipeline warning sign for installation at railroad, highway/road, ditch crossings, property lines, etc. (courtesy of AMEC Paragon).

ty regulations and rules acknowledge the effectiveness of the intelligent pigs and incorporate their use in the pipeline-integrity testing process.

9.10.1 Pig Launchers and Receivers. Pigging facilities and considerations should be incorporated into the pipeline system design. Basic pigging facilities require a device to launch the pig into the pipeline and a receiver system to retrieve the pig as shown in Fig. 9.30. The launcher barrel is typically made from a short segment of pipe that is one to two sizes larger than the main pipeline and is fitted with a transition fitting (eccentric reducer) and a special closure fitting on the end. The barrel is isolated from the pipeline with full-port gate or ball valves. A "kicker" line, a minimum of 25% capacity of the main line, is tied from the main pipeline to the barrel, approximately 1½ to 2 pig lengths upstream of the transition reducer, to provide the fluid flow to "launch" the pig into the pipeline. The barrel is fitted with blowdown valves, vent

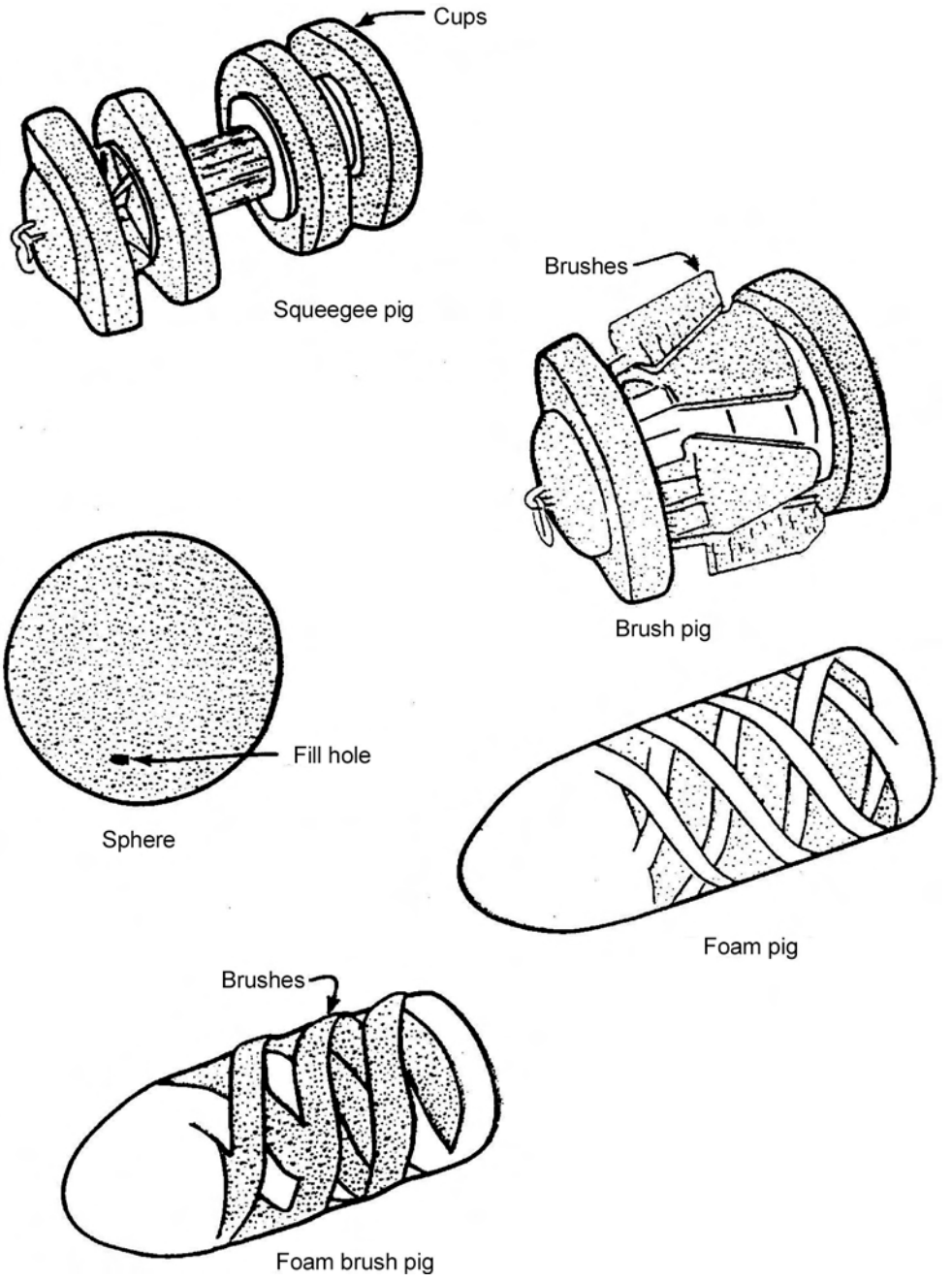
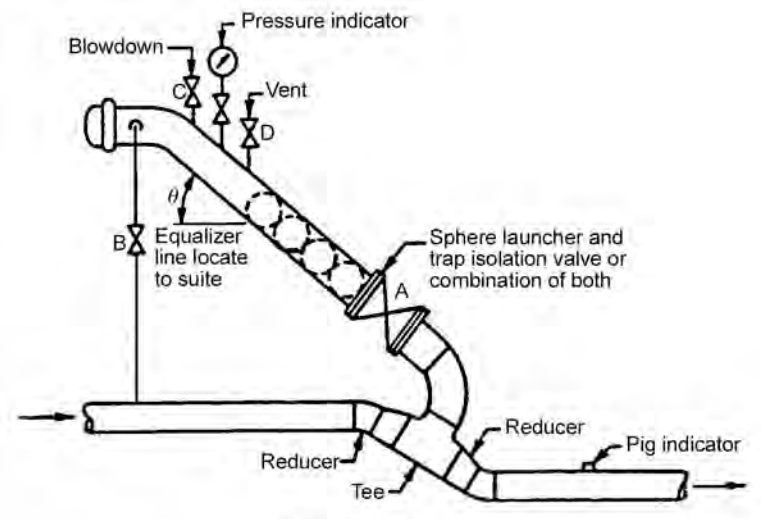


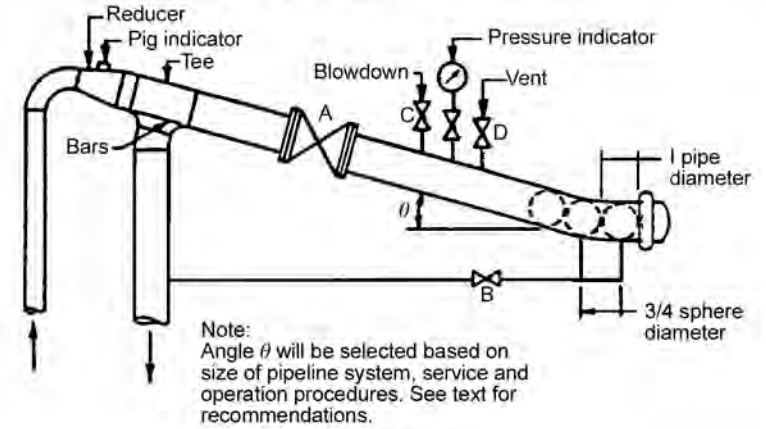
Fig. 9.29—Types of pigs (courtesy of AMEC Paragon).

valves, and pressure gauges on the top and drain valves on the bottom. The length of the barrel is determined by the length and number of pigs to be launched at any one time. Receivers have many of the same features.

A typical hinge-type closure for pig launching and receiving traps consists of a forged hub, a hinged blanking head, split-yoke clamps, operating bolts, and a self-energizing O-ring gasket. Materials of construction are in accordance with ASTM specifications and manufacture com-



Launcher



Receiver

Table II

Nominal Diameter (inches)	Angle of Launcher Mechanism (detrees)	Angle of Magazines (degrees)
4 to 5	45	15
10 to 20	20	10
22 to 48	20	5

Fig. 9.30—Typical sphere launcher and receiver traps (courtesy of AMEC Paragon).

plies with applicable rules of the ANSI code for pressure piping and with the ASME boiler and pressure vessel code. Most important is the pressure warning safety device with yoke positioning plate. This safety device provides visual and mechanical assurance that the yokes are in the correct position over the head for commencement of operations. Additionally, the devices serve the purpose of alerting the operator to any residual pressure in the pig launcher or receiver trap should he inadvertently attempt to open the closure before all pressure has been relieved. A pressure warning device is located at each of the yoke splits with one of the positioning lugs attached to each yoke half. Tightening the holding screw on the nipple provides a

seal and locks the hinged positioning plate on the positioning lugs. Loosening the holding screw breaks the seal and provides a means by which the operator can determine whether the pig launcher or receiver trap has been completely relieved of internal pressure. Continued loosening of the hold screw will allow disengagement of the positioning plate from the positioning lugs, permitting the yoke halves to be spread and the closure to be opened. There are several manufacturers of end closures, but most often Tube Turns or Modco closures are used worldwide.

Elbows and pipe bends installed in the pipeline should have a minimum radius of three times the main-line pipe diameter—3D bends. Intelligent pigs may require greater radius to diameter elbows and bends because of the longer length of the pigs. Tees installed in the pipeline with an outlet size 75% of the main-line ID should be equipped with bars across the tee outlet to prevent the pigs from attempting to turn into the tee and lodging in the line. Hot taps greater than 6-in. diameter added to the pipeline should be barred. If possible, tees should not be installed adjacent to one another. Check valves should be full open, and the pigs or spheres should be sized such that the pig or sphere is larger than the "bowl" cavity of the check valve.

9.10.2 Pig Selection. Pig runs of between 50 to 100 miles are normal, but pig runs exceeding 200 miles should be avoided as the pig may wear and get stuck in the line. Cleaning pigs may be constructed of steel body with polyurethane cups or discs and foam pigs with polyurethane wrapping, solid urethane disc, and steel body with metallic brushes. Drying pigs are usually low-density foam or multicup urethane. The intelligent pigs may be magnetic flux leakage, ultrasonic, elastic/shear wave, transponder/transducer, or combinations thereof. Internal-coating pigs are generally multicup urethane type. Batching pigs are typically bidirectional, multidisk rubber, which maintain efficiency up to 50 miles. Pigs used for obstruction inspection are typically urethane, multicup type fitted with an aluminum gauge plate or a gel type.

Spheres are generally sized to be approximately 2% greater diameter than the pipe internal diameter. Cups and discs are typically sized to be $^1/_{16}$ to ⅛ in. larger in diameter than the pipe ID. Foam pigs have to be significantly oversized. Foam pigs 1 to 6 in. in diameter should be oversized by ¼ in.; foam pigs 8 to 16 in. in diameter should be oversized ⅜ to ½ in.; foam pigs 18 to 24 in. in diameter should be oversized ½ to 1 in.; and foam pigs 28 to 48 in. in diameter should be oversized 1 to 2 in.

9.10.3 Slug Catchers. The receiving end of the pipeline should have surge containment to accommodate the slugs of liquid carried by the pigs. For liquid lines, additional storage capacity (tankage) will provide surge containment. Gas and multiphase lines need specially designed "slug" catcher systems to handle the intermittent liquid slugs generated by the pigging activities. When a normal gas flow is pushing the pig through a gas pipeline, the velocity can be quite large and the flow rate of liquids being pushed ahead is given by

$$Q_L = 5{,}000 Q_g TZ / P \,, \quad \text{..... (9.38)}$$

where

Q_L = liquid-flow rate in front of the pig, B/D,

Q_g = gas-flow rate behind the pig, MMscf/D,

T = temperature, °R,

P = line pressure, psia,

and

Z = compressibility factor, dimensionless.

In most systems, the instantaneous liquid-flow rate and "energy" surge ahead of the pig will exceed the processing design capacity and capability of the receiving facility. The slug

catcher provides excess storage capacity within the receiving facility and helps dissipate the excess energy generated by the high-velocity liquid slug. The basic slug catcher is essentially a liquid-separation system where the incoming liquid enters a larger-diameter pipe or a vessel, which provides additional volume for the liquid surge and provides for separation of the vapor from the liquid stream. The additional volume provided by the slug catcher reduces the stream velocity and dissipates the excess energy produced by the liquid slug.

Another typical slug-catcher design employs an inline liquid header system attached to a series of horizontal liquid accumulators which may be several hundred feet in length. The liquid-slug stream enters the header and disperses into the accumulators, while the gas continues through the system and exits at the vapor-outlet collection header. The slug catcher may incorporate vortex breakers or other impingement devices to slow the liquid and mist extractors at the vapor outlet to capture entrained liquids. The liquid is transferred from the accumulators to the facility processing or storage. **Fig. 9.31** shows an example slug-catcher design.

The volume of the slug catcher is expressed as

$$(\text{Vol})_{SC} = (\text{Vol}) - Q_d T_R \,, \quad \text{..... (9.39)}$$

where

$(\text{Vol})_{SC}$ = volume of slug catcher, bbl,

Vol = volume of liquid holdup, bbl,

and

Q_d = design liquid dump rate from the slug catcher, B/D.

$$T_R = \text{Vol} / Q_L \,, \quad \text{..... (9.40)}$$

where T_R = time during which slug is processed, in days. The volume of the slug catcher should be designed with a minimum 25% safety factor.

9.11 Hydrostatic Testing and Nondestructive Testing and Inspection

Each pipeline system must be tested and inspected to ensure that the system can be operated safely. DOT regulations specify testing and inspection requirements as well as ANSI/ASME *Standard B31.3, B31.4,* and *B31.8* and API *Standard 1104,*[43] *571,*[46] and *574.*[47]

9.11.1 Hydrostatic Testing. The DOT regulations, Part 192, Subpart J, Paragraph 192.501 to 192.517; Part 193, Subpart D, Paragraph 193.2319 and 193.2323; and Part 195, Subpart E prescribe the pressure-testing and strength-testing requirements for natural-gas, LNG, and hazardous-liquids pipelines, respectively. The ANSI/ASME and API standards also prescribe testing requirements. Pneumatic testing is allowed for certain low-pressure pipeline systems, but the majority of pipelines are tested with water.

Before to conducting the hydrostatic testing, a profile of the test section should be developed showing the maximum and minimum elevations, the maximum allowable working pressure (MAWP) determined at the lowest elevation point, the location of the fill and pressure pump, minimum pressure required at the pressure pump determined by the maximum pressure at the lowest elevation, and water-source quality and discharge/disposal point. The profile of the test segment provides a graphical representation of the test segment, which helps the testing engineer determine the location of air bleed vents and the fill rate and pig velocity required to prevent air entrapment, and verify that the test will not overpressure or underpressure the pipe in the segment. The elevation differential can become a major consideration. When radical changes in elevation occur over short distances, it may be necessary to subdivide the original segment into shorter test segments. Each 100 ft of elevation difference represents approximate-

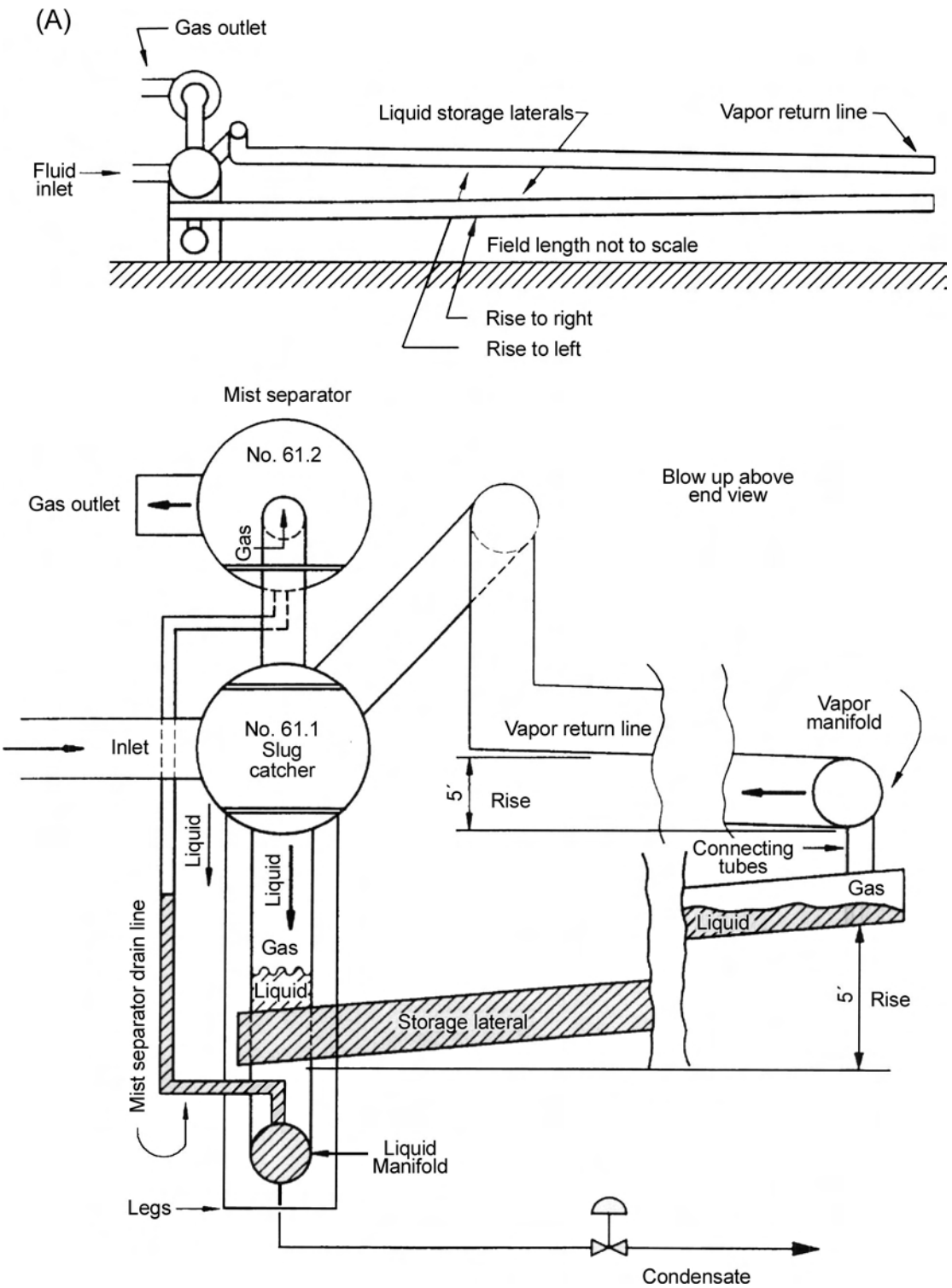


Fig. 9.31—Typical slug catcher for two-phase flow—front elevation (courtesy of AMEC Paragon).

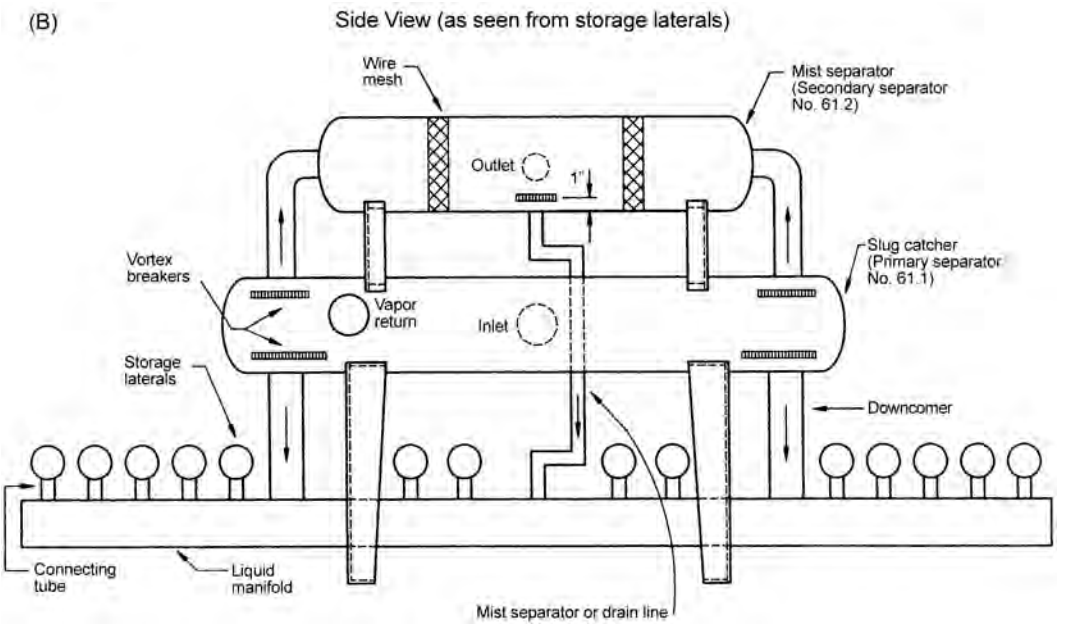


Fig. 9.31 (Continued)—Typical slug catcher for two-phase flow—front elevation (courtesy of AMEC Paragon).

ly 43.3 psi of pressure differential, which can result in high points being underpressured and low points being overpressured during the test. The test profile is also used to document the location of the fill pump, the test pump, the dead-weight gauge, and the pressure/temperature recording equipment. **Fig. 9.32** illustrates is a typical test profile segment.

The typical testing equipment that is needed to conduct the hydrostatic test is a temporary fill manifold complete with valves (pressure rated at a minimum of 1.5 times the maximum test pressure), dewatering manifold complete with valves (also pressure rated at a minimum of 1.5 times the maximum test pressure), foam or urethane pigs, low-pressure/high-volume fill pump with filtration equipment, high-pressure positive-displacement pump, certified dead-weight gauge(s), chart-type pressure recorder, chart-type temperature recorder for the water, chart-type temperature recorder for ambient air, pressure gauges rated at 50 to 75% of the maximum test pressure, compressed air or nitrogen source for dewatering, and discharge water filtration equipment. Temporary water-storage or holding tanks may be needed to supply reserve test water or serve as holding or settlement devices for dewatering.

Nondestructive Testing. Nondestructive testing and inspection of the welds is required by the DOT regulations Part 192, Subpart E, Paragraph 192.243[22] for natural-gas pipelines; Part 193, Subpart D, Paragraph 193.2321[23] for LNG lines; and Part 195, Subpart D, Paragraph 195.234[25] for hazardous-liquid lines. ANSI/ASME *Standards B31.3,*[7] *B31.4,*[8] and *B31.8*[9] also prescribe nondestructive requirements.

Inspection. Each of the regulations and industry codes requires visual inspection of welds and construction process.

9.12 Instrumentation and Control

Pipeline control systems may consist of simple devices such as automatic pressure-control valves to the sophisticated total supervisory-control-and-data acquisition (SCADA) control system. The SCADA system can monitor and control, on a real-time basis, an entire pipeline

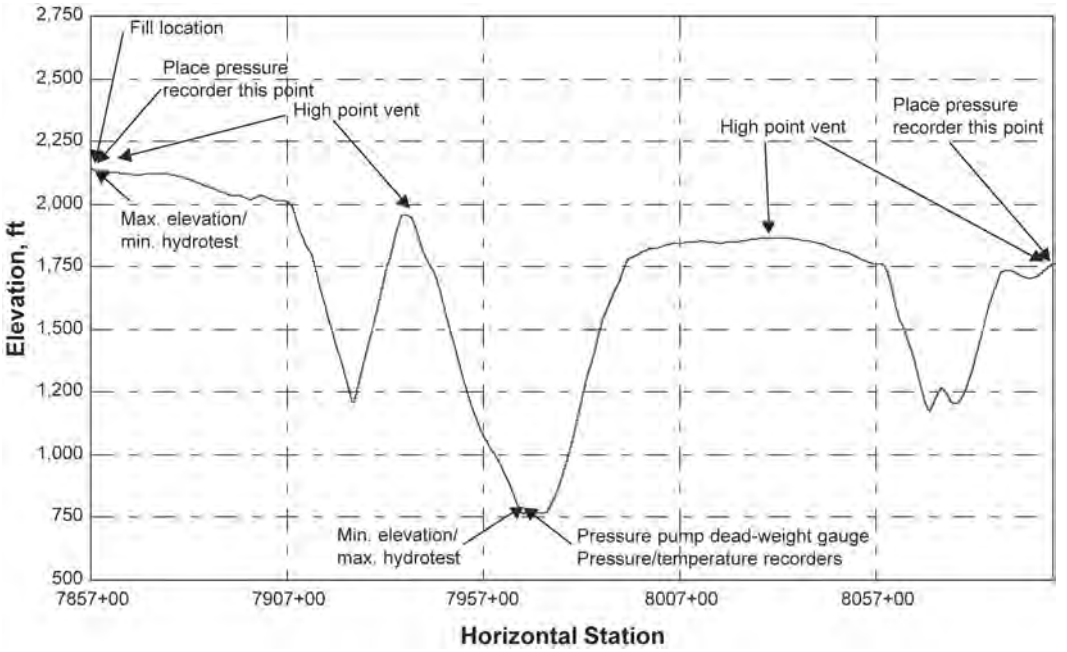


Fig. 9.32—Pipeline integrity testing—elevation vs. station number (courtesy of AMEC Paragon).

system. The SCADA system can open and close valves, start and stop pumps/compressors, monitor and control flow, sample the product, monitor and regulate pressures and temperatures, and perform many other functions. SCADA systems are typically neither needed nor practical for small, gathering pipeline systems.

Compressor stations, pump stations, and related facilities may require emergency isolation equipment to protect the pipeline. Emergency-shutdown (ESD) systems consist of automatic shutoff isolation valves located at the main inlet and outlet to the stations/facilities and coordinated pressure-relief systems between the isolation valves. The ESD system protects both the pipeline and facility by stopping the flow into and out of the facility and limits the feed source in the event of fire, explosion, or other emergency.

Basic pipeline instrumentation includes strategically located pressure gauges and pressure-monitoring instruments, temperature gauges and monitoring instruments, and pressure control/limitation and relief equipment.

Nomenclature

A = cross-sectional area of pipe, ft^2
C = pipe radius, in.
C_V = flow coefficient for liquids, dimensionless
d = pipe inside diameter, in.
d_O = outside diameter of pipe, in.
D = pipe diameter, ft
E = efficiency factor
f = Moody friction factor, dimensionless
F = design factor
g = gravitational constant, ft/sec^2
H_L = head loss, ft
H_S = hoop stress in pipe wall, psi

K_r = resistance coefficient, dimensionless
L = length, ft
L_e = equivalent length
L_m = length, miles
P = internal pressure of the pipe, psi
P_1 = upstream pressure, psia
P_2 = downstream pressure, psia
Q_d = design liquid dump rate from the slug catcher, B/D
Q_g = gas-flow rate, MMscf/D
Q_l = liquid-flow rate, B/D
R = gas/liquid ratio, ft^3/bbl
S = specific gravity of gas at standard conditions, lbm/ft^3 (air = 1)
S_B = 2,500 psi
SG = liquid specific gravity relative to water
S_h = allowable stress, psi
S_Y = pipe specified minimum yield strength, psi
t = pipe wall thickness, in.
t_e = corrosion allowance, in.
t_{th} = thread or groove depth, in.
T = gas flowing temperature, °R
T_1 = temperature of gas at inlet, °R
T_{ol} = manufacturer's allowable tolerance, %
T_R = time during which slug is processed, days
U = straight-line distance between anchors
V = flow velocity, ft/sec
V = maximum allowable velocity, ft/sec
V_1' = specific volume of gas at upstream conditions, ft^3/lbm
V_g = gas velocity, ft/sec
Vol = volume of liquid holdup, bbl
$(Vol)_{SC}$ = volume of slug catcher, bbl
w = rate of flow, lbm/sec
W = weight of pipe filled with water, lbm/ft
Y = derating factor
Z = compressibility factor for gas, dimensionless
γ = kinematic viscosity, centistokes
Φ = absolute viscosity, cp
Δh_W = pressure loss, inches of water
ΔP = friction pressure drop, psi
ΔP_Z = pressure drop because of elevation increase in the segment, psi
ΔZ = increase in elevation for segment, ft
μ = viscosity, cp
μ_c = viscosity of the continuous phase of the mixture, cp
μ_{eff} = effective viscosity, cp
ρ = density, lbm/ft^3
ρ_M = density of the mixture, lbm/ft^3

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SI Metric Conversion Factors

°API		141.5/(131.5 + °API)		= g/cm^3
bbl	×	1.589 873	E – 01	= m^3
cp	×	1.0*	E – 03	= Pa·s
ft	×	3.048*	E – 01	= m
ft^2	×	9.290 304*	E – 02	= m^2
ft^3	×	2.831 685	E – 02	= m^3
°F		(°F – 32)/1.8		= °C
in.	×	2.54*	E + 00	= cm
in.^{3}	×	1.638 706	E + 01	= cm^3
lbf	×	4.448 222	E + 00	= N
lbm	×	4.535 924	E – 01	= kg

mile	× 1.609 344*	E + 00	= km
psi	× 6.894 757	E + 00	= kPa

*Conversion factor is exact.

Chapter 10
Safety Systems

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10.1 Basic Safety Concepts

10.1.1 Introduction. Production facilities usually operate according to design. Oil and gas travel from the reservoir to the surface facilities where they are separated, cleaned, and measured and then sent through a pipeline to the end user. During most of this process, everything operates according to plan. Occasionally, problems occur, things break, malfunctions happen, settings change, horns go off, and shut-ins take place. Such problems usually can be solved quickly and easily without negative consequences. Unfortunately, some problems have the potential for serious consequences such as injury to personnel, pollution of the environment, and loss of company assets. Understanding, preventing, or minimizing potential negative consequences requires a fundamental understanding of basic protection concepts and safety analysis.

This chapter summarizes the basic protection concepts required for the safe design and operation of a production facility. The chapter begins by developing a hazard tree for a generic production facility and then illustrates how hazards analysis can be used to identify, evaluate, and mitigate process hazards. In addition, this chapter reviews the safety-analysis technique presented in the American Petroleum Inst.'s (API's) *Recommended Practice (RP) 14C*.[1] The chapter concludes with a discussion on relief-valve selection and sizing and vent, flare, and relief-systems design.

10.1.2 Basic Protection Concepts. Most threats to safety from production involve the release of hydrocarbons; therefore, the analysis and design of a production-facility safety system should focus on preventing such releases, stopping the flow of hydrocarbons to a leak if it occurs, and minimizing the effects of hydrocarbons should they be released.

Prevention. Ideally, hydrocarbon releases should never occur. Every process component is protected with two levels of protection: primary and secondary. The reason for two levels of protection is that if the first level fails to function properly, a secondary level of protection is available.

Shut-In. If hydrocarbon releases occur (and, in spite of our best efforts, they sometimes do), inflow to the release site must be shut off as soon as possible. The problem should not be exacerbated with the continued release of additional hydrocarbons. Protective shut-in action is

achieved by both the surface safety system (SSS) and the emergency support system (ESS). Shut-in systems are discussed in more detail in Sec. 10.2.8.

Minimizing. When hydrocarbons are released, their effects should be minimized as much as possible. This can be accomplished through the use of ignition-prevention measures and ESSs (i.e., the liquid-containment system). If oil spills from a process component, a release of hydrocarbons has occurred. A spill is never good, but component skids and deck drains (if offshore) minimize the effect of a bad situation when the spill would otherwise go into a freshwater stream or offshore waters.

10.1.3 Hazard Tree. A hazard tree identifies potential hazards, determines the conditions necessary for a hazard to exist, determines sources that could create this condition, and breaks the chain leading to the hazard by eliminating the conditions and sources. Because complete elimination is normally not possible, the goal is to reduce the likelihood of occurrence. With statistical analysis, the probability of occurrence can be determined. The effect of a safety procedure or device that reduces the probability of a condition or source occurring also can be quantified with this tool.

A hazard tree is somewhat subjective in that different evaluators may classify conditions and sources differently or they may carry the analysis to further levels of sources. The hazard tree helps the investigator focus attention on all of the aspects to be considered. No matter how the tree is formulated, conclusions reached concerning the design, maintenance, traffic patterns, lighting, etc., should be similar.

General-Production-Facility Hazard Tree. **Fig. 10.1** shows a hazard tree for a generic production facility. It should be equally valid for an offshore or onshore facility. The major hazards are those of oil pollution, fire/explosion, and injury.

Oil Pollution. Oil pollution derives from an oil spill that can be caused by one of the conditions shown in Fig. 10.1. If an oil spill were to occur, pollution could be avoided by installing adequate containment. Requirements for tank dikes, drip pans (offshore), and sumps reduce the probability of oil pollution from most small spills.

Fire/Explosion. An oil spill or gas leak can provide fuel for a fire/explosion. An ignition source and oxygen are also required. The use of gas blankets minimize oxygen entry while good electrical design minimizes ignition sources.

Injury. Injury can occur directly from an explosion, an out-of-control fire, or one of the other conditions shown in Fig. 10.1. If there is sufficient warning before a fire develops, there should be enough time to escape before injury occurs. If the fuel can be shut off and adequate fire-fighting equipment is present to control the fire before it becomes a large fire, the probability of injury is small.

The inability to escape increases the probability of injury from any of these conditions. All the conditions are more likely to lead to injury the longer personnel are exposed to the situation; therefore, escape routes, lighting, appropriate survival capsules/boats (if offshore), and fire barriers all lead to a reduction in the probability of injury.

Severity of Source. The hazard tree helps identify the severity of a source that can lead to a hazardous condition. Some of these sources are discussed here.

Overpressure. Overpressure can lead directly to all three hazards. It can lead directly and immediately to injury; it can lead to fire/explosion if there is an ignition source; and it can lead to pollution if there is insufficient containment. Because of the hazard potential, a very good level of assurance is needed that the probability of overpressure occurring is very small.

Fire Tubes. Fire tubes can lead to fire/explosion if there is a leak of crude oil or glycol into the tubes or if there is a failure of the burner controls. An explosion could be sudden and lead directly to injury; therefore, a high degree of safety is required.

Excess Temperature. Excess temperature can cause premature equipment failure at a pressure below its maximum design working pressure. Excess temperature can create a leak,

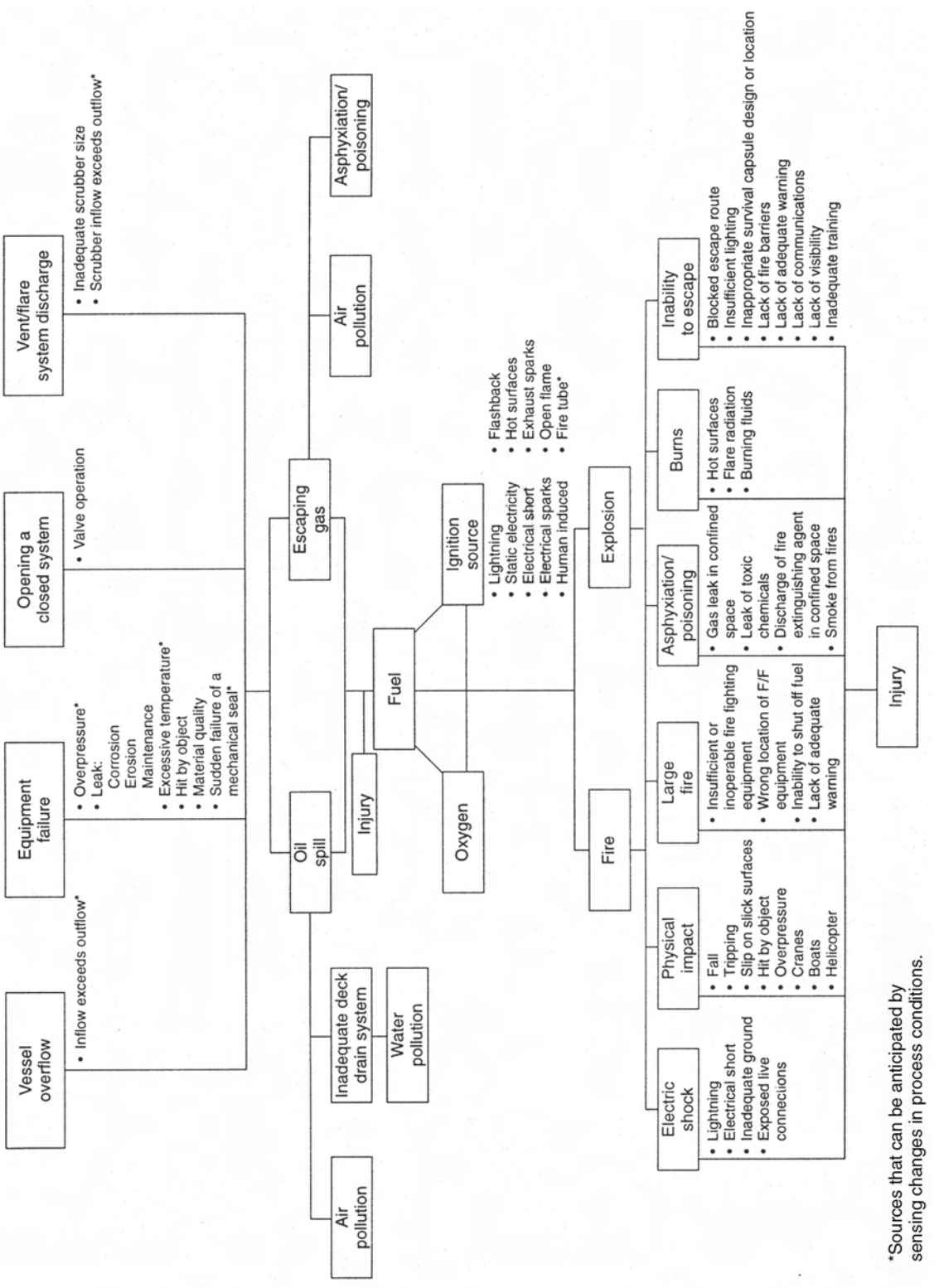


Fig. 10.1—Hazard tree for a generic production facility. (Courtesy of the American Petroleum Institute.[2])

potentially leading to fire/explosion if gas leaks or oil pollution if oil leaks. This type of failure should be gradual, giving off a warning as it develops, and thus does not require as high a degree of protection as those mentioned previously.

Leaks. Leaks rarely lead directly to personnel injury, but they can lead to fire/explosion if there is an ignition source and to oil pollution if there is inadequate containment. The immediacy and magnitude of the developing hazard will be less than with overpressure; thus, although it is necessary to protect against leaks, this protection will not require the same level of safety required for overpressure.

Inflow Exceeds Outflow. Inflow exceeding outflow can lead to oil pollution if there is inadequate containment and can lead to fire/explosion and, thus, to injury if an oil spill occurs. This condition is more time dependent and lower in magnitude of damage; therefore, an even lower level of safety will be acceptable.

Need for Other Protection Devices. The hazard tree also helps identify other protection devices to include in equipment design that may minimize the possibility that a source will develop into a hazardous condition. Additional protection devices that might be included are flame arrestors, stack arrestors, gas detectors, fire detectors, and manual shutdown stations. A hazards analysis can determine the need for safety devices and safety systems.

10.1.4 Hazards Analysis. A hazards analysis identifies potential hazards, defines conditions necessary for each hazard, and identifies the source for each hazard. A hazard tree identifies potential hazards and determines the conditions necessary for these hazards to exist. A hazards analysis starts at the hazard tree's lowest level and attempts to break the path leading back to the hazard by eliminating one of the conditions.

Many of the sources and conditions identified on the hazard tree require considerations that have nothing to do with the way the process is designed, such as escape paths, electrical systems, fire-fighting systems, and insulation on piping. A facility designed with a safety shutdown system is not necessarily "safe"; it has an appropriate level of devices and redundancies to reduce the risk of occurrence of those sources and conditions that can be anticipated by sensing change in process conditions. A hazard tree helps identify protection devices for inclusion in equipment design (e.g., flame/stack arrestors on fire tubes). Much more, such as maintenance, operating procedures, testing, and drills, is required if the overall probability of any one chain leading to a hazard is to be acceptable.

10.1.5 Primary Defense. The best defense against an undesirable event is the use of appropriate industry codes and design procedures. The defense also should ensure adequate inspection of the equipment and its fabrication into systems. If this is not done, sensors cannot sufficiently protect against overpressure, leaks, or other hazards.

10.2 API RP 14C

10.2.1 Overview. *RP 14C*[1] is a safety-analysis approach based on a number of traditional hazards-analysis techniques such as failure-mode-effects analysis (FMEA) and hazard-and-operability studies (HAZOPS). The purpose of a safety analysis is to identify undesirable events that might pose a threat to safety and define reliable protection measures that will prevent such events or minimize their effects should they occur. Potential threats to safety are identified through proven hazards-analysis techniques that have been adapted to hydrocarbon-production processes. Recommended protective measures are common industry practices proved through many years of operating experience. The hazards analysis and protective measures have been combined into a "safety analysis" for onshore and offshore production facilities.

The *RP 14C*[1] safety analysis is based on the following premises.

- Process components function in the same manner regardless of specific facility design.

• Each process component is analyzed for "worst case" input and output conditions.

• If fully protected when analyzed standing alone, the analysis will be valid for that component in any configuration.

• If every component is protected, the system will be protected.

• When components are assembled into a system, some devices can be eliminated.

The major benefits of this analysis are concise, easy-to-audit documentation; minimized subjective decisions; and consistent results.

The remainder of Sec. 10.2 explains the basic concepts of protection used in the analysis, discusses the methods of analyzing the process, and establishes design criteria for an integrated safety system. The entire production process is covered, and a step-by-step summary for performing a safety analysis is provided.

10.2.2 Process Variables. There are four main process variables in upstream production facilities: pressure, liquid level, temperature, and flow. A variable fluctuates between a lower and an upper extreme value. For example, the liquid level within a vessel can fluctuate from the bottom of the vessel (empty) to the top (full). Process variables allow movement of the fluids through the process components while simultaneously achieving the degree of separation required for sales or water disposal.

10.2.3 Process Components. A process component is any piece of equipment that handles hydrocarbons. Identifying all the components that handle hydrocarbons in a production facility would be overwhelming. Instead of listing components by their common name, *RP 14C*[1] lists components by their functions, thus decreasing the number of names from hundreds to only ten. Regardless of what a piece of equipment is called, it can be described as one of the following ten process components: wellheads and flowlines, wellhead injection lines, headers, pressure vessels, atmospheric vessels, fired and exhaust-heated components, pumps, compressors, pipeline, and shell-and-tube heat exchangers.

10.2.4 Normal Operating Ranges. Whenever hydrocarbons are present in a process component, each of the four main process variables take on some value. Values at which the variables can be found when things are going smoothly are called normal values. For example, the pressure on a flowline will fluctuate from reading to reading within a specified period of time (e.g., for a 1-hour period the readings may be 950 psi at 1300 hours, 1,010 psi at 1340 hours, and 979 psi at 1400 hours). As long as flow is occurring, the liquid level within a process component will be changing. For example, in a separator's oil bucket, the level will steadily rise until the dump valve opens and drains some of the oil, at which time the liquid level falls until the dump valve closes. Within each process component, each variable has a normal operating range instead of having a single normal value.

One of the cornerstones of facility protection lies in protecting each component against certain undesirable events that are closely related to the four main process variables. For example, if the pressure within a component were to become too high, a component could rupture; a pressure too low within a component could indicate a leak. A liquid level within a component that is too high or too low could cause problems as well as indicate equipment failure.

Production operators establish normal operating ranges. The principal concern with the four main process variables is that their sensing devices, which respond to conditions outside normal ranges, have enough time to respond before problems occur. For example, the normal range for a separator's liquid level can be wherever the operator wants it, provided that the level safety high (LSH) can shut off inflow before liquid overflow occurs and that the level safety low can respond before the level has completely disappeared and allows gas to flow out of the liquid outlet (gas blowby). The normal operating range for a component's pressure can

be established by attaching a pressure recorder to the component and recording the pressure variations over time.

Maintaining normal operating ranges requires normal process flow. When the four main process variables are kept within their normal ranges, process flow is occurring. Process flow is maintained by chokes, regulators, controllers, and the influence of the main process variables on each other; therefore, normal operating ranges are maintained by the same things.

10.2.5 Abnormal Operating Conditions. On average, process variables are found within their normal operating ranges, but horns do go off and shut-ins do occur. When chokes and controllers that normally keep the process variables in their normal ranges fail to function properly, the process variable being controlled can be outside its normal operating limits. Whenever a process variable exceeds its normal range, it is said to be in an abnormal condition. For example, in a component with a normal operating range of 800 to 900 psig, pressure greater than 900 psig or less than 800 psig are abnormal conditions. A liquid level above or below the point at which the dump valve opens or closes is an abnormal condition.

What is the significance of an abnormal condition? In reality, when the normal operating range is exceeded by only a small amount, it makes very little difference to the operation of the facility. However, the point is that if a variable exceeds its normal operating range at all, it could continue to escalate with potentially disastrous results. Operators are concerned mainly about the consequences that might result if abnormal conditions become extreme.

Consequences. Several consequences can result from abnormal operating conditions. At best, there will be only a horn and a shut-in. The most serious consequences are injury to personnel, pollution, and loss of company assets. Abnormal conditions do not always develop into a serious consequence, but it could happen. According to *RP 14C,*[1] serious consequences usually are preceded by some abnormal condition. Abnormal conditions that are not dealt with quickly can escalate into worst-case scenarios.

Causes. The major causes of abnormal conditions are equipment failure or malfunction and human error. Examples of equipment failure or malfunction are chokes that become enlarged through contact with excessive sand in the flow stream, dump valves that hang open or stay closed, and regulators or controllers that change adjustment because of vibration. Human error can occur if an operator repairing a dump valve does not want to shut in to finish the job and uses the dump valve's bypass line. If the operator fails to monitor the liquid level properly while the bypass valve is open, the liquid level in the component could get too high or too low. Human error also can occur if the operator monitored the level accurately but forgot to check to see if the newly repaired dump valve was operating properly.

Prevention. The actual causes of abnormal conditions are varied and numerous. *RP 14C*[1] provides an analysis technique to identify potential abnormal conditions and prevent them from occurring.

10.2.6 Effects of Hydrocarbon Releases. Abnormal operating conditions could result in injury to personnel, pollution, and loss of assets. Whenever any of these worst-case consequences is at its most serious, the release of hydrocarbons is usually involved. While pollution of any type is undesirable, hydrocarbon pollution is the most serious. The May 1989 *Exxon Valdez* incident is a prime example of the attention drawn to and the expenses involved with hydrocarbon pollution in navigable waterways. Injury to personnel on a major scale also usually involves the release of hydrocarbons. Hydrocarbon releases alone are often sufficient to cause injury to personnel (e.g., whenever H_2S is involved). Worst of all is a fire caused by or fed by hydrocarbon releases. An explosion or fire can cause extensive damage to equipment and personnel, which can result in extensive injury, pollution, and facility damage. Offshore platforms have melted to the water line because of released hydrocarbons, as occurred in the Piper Alpha incident in

the North Sea in the summer of 1988. Onshore facilities have been completely leveled to the ground because of released hydrocarbons, as occurred in the Phillips incident in Pasadena, Texas, in 1988.

10.2.7 Safety Devices. Safety devices offer a solution for hydrocarbon releases. Specific devices have been developed to protect production facilities. As these devices became more common, industry standards, such as names, symbols and identification, and installation locations, were established. *RP 14C Sec. 2*[1] summarizes surface-production-facility-related standards.

Names. Before installing a specific safety device, a standard way of referring to it is needed. *RP 14C* presents two groups of safety devices: "common" (i.e., typical oilfield) names such as check valve or pop-off valve and "proper" names from the Instrument Soc. of America (ISA), such as flow safety valve or pressure safety valve (PSV). With few exceptions, every ISA name includes the measured or initiating variable as the first part of the name and the word safety as the second part of the name. The third and usually final part of the name refers to either the device itself (i.e., valve or element) or to the type of function the device performs (i.e., high or low).

ISA device names usually are abbreviated with the first letter of each part of the name. If a single component has two or more of the same kind of device on it, each device is differentiated from each other by the addition of a number or letter following the device's letters (LSH1 and LSH2, for example). The same convention is used for all safety devices. See **Fig. 10.2**.[1]

Symbols. Process flow diagrams must show safety devices. A graphic symbol represents each safety device. These symbols save space on the diagram and make the appearance neater. **Fig. 10.3**[1] contains standardized symbols used in hydrocarbon-facility diagrams.

10.2.8 Production-Process Safety Systems. Production-process safety systems provide a more extensive level of protection than an individual device. They include end devices and auxiliary devices, which are important not only to the system itself but also to the safety of the facility. A brief overview of these systems follows.

Surface Safety System. The SSS consists mostly, but not exclusively, of sensing-type individual safety devices. Devices respond to one of the four major variables. The main purpose of the SSS is to prevent the initial release of hydrocarbons and to shut in additional flow of the hydrocarbons already released. The SSS consists of three major components: sensing devices, relay devices, and end devices. Some devices both sense and respond as an end device (check valves, relief valves, etc.).

The SSS incorporates various sensing devices. When an abnormal condition is detected, the sensing device sends a signal to an end device. The end device diverts or shuts off flow, sounds an alarm, or takes some other corrective action. For example, if a component's dump valve freezes in the closed position, the liquid level within the component will rise. When it rises high enough, the component's LSH will sense the high level and send a signal that shuts in the wells flowing into the component. The same signal usually will also sound an alarm to notify facility personnel of the shut-in.

Emergency Support System. The ESS consists of seven major subsystems, all of which help protect the facility and environment. The main purpose of ESSs is to shut in additional flow and minimize the effects of hydrocarbons that have already been released. The API realizes that hydrocarbon releases ideally would be prevented through the use of sensing devices (i.e., the SSS), but the API also knows that there will be times in which hydrocarbons are released in spite of the SSS. To address this problem, the API mandates a backup means of protecting the facility. The ESS is a major part of those backup efforts. The seven subsystems that make up the ESS are an emergency-shutdown (ESD) system, a fire-detection system, a combustible-gas detection system, adequate ventilation, a liquid containment system, sumps, and subsurface safety valves.

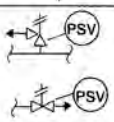
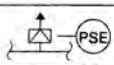
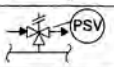
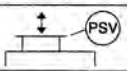
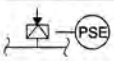
SENSING AND SELF-ACTING DEVICE				
VARIABLE	SAFETY-DEVICE DESIGNATION		SYMBOL	
	COMMON	INSTRUMENT SOCIETY OF AMERICA (ISA)	SINGLE DEVICE	COMBINATION DEVICE
Backflow	Check valve	Flow Safety Valve		
Burner flame	Burner-flame detector	Burner Safety Low		
Flow	High-flow sensor	Flow Safety High		
	Low-flow sensor	Flow Safety Low		
Level	High-level sensor	Level Safety High		
	Low-level sensor	Level Safety Low		
Pressure	High-pressure sensor	Pressure Safety High		
	Low-pressure sensor	Pressure Safety Low		
	Pressure-relief or safety valve	Pressure Safety Valve		
	Rupture disk or safety head	Pressure Safety Element		
Pressure or vacuum	Pressure/vacuum-relief valve	Pressure Safety Valve		
	Pressure/vacuum-relief manhole cover	Pressure Safety Valve		
	Vent	None		
Vacuum	Vacuum-relief valve	Pressure Safety Valve		
	Rupture disk or safety head	Pressure Safety Element		
Temperature	High-temperature sensor	Temperature Safety High		
	Low-temperature sensor	Temperature Safety Low		
Flame	Flame or stack arrestor	None		

Fig. 10.2—Safety-device identification examples. (Courtesy of the American Petroleum Institute.[1])

Other Support Systems. Two additional systems are required to make a facility as safe as possible. They are the pneumatic supply system and a system for discharging gas to the atmosphere (blowdown/vent). The pneumatic supply system provides the power to operate most of the other systems. The blowdown/vent system provides a means for directing unwanted gas

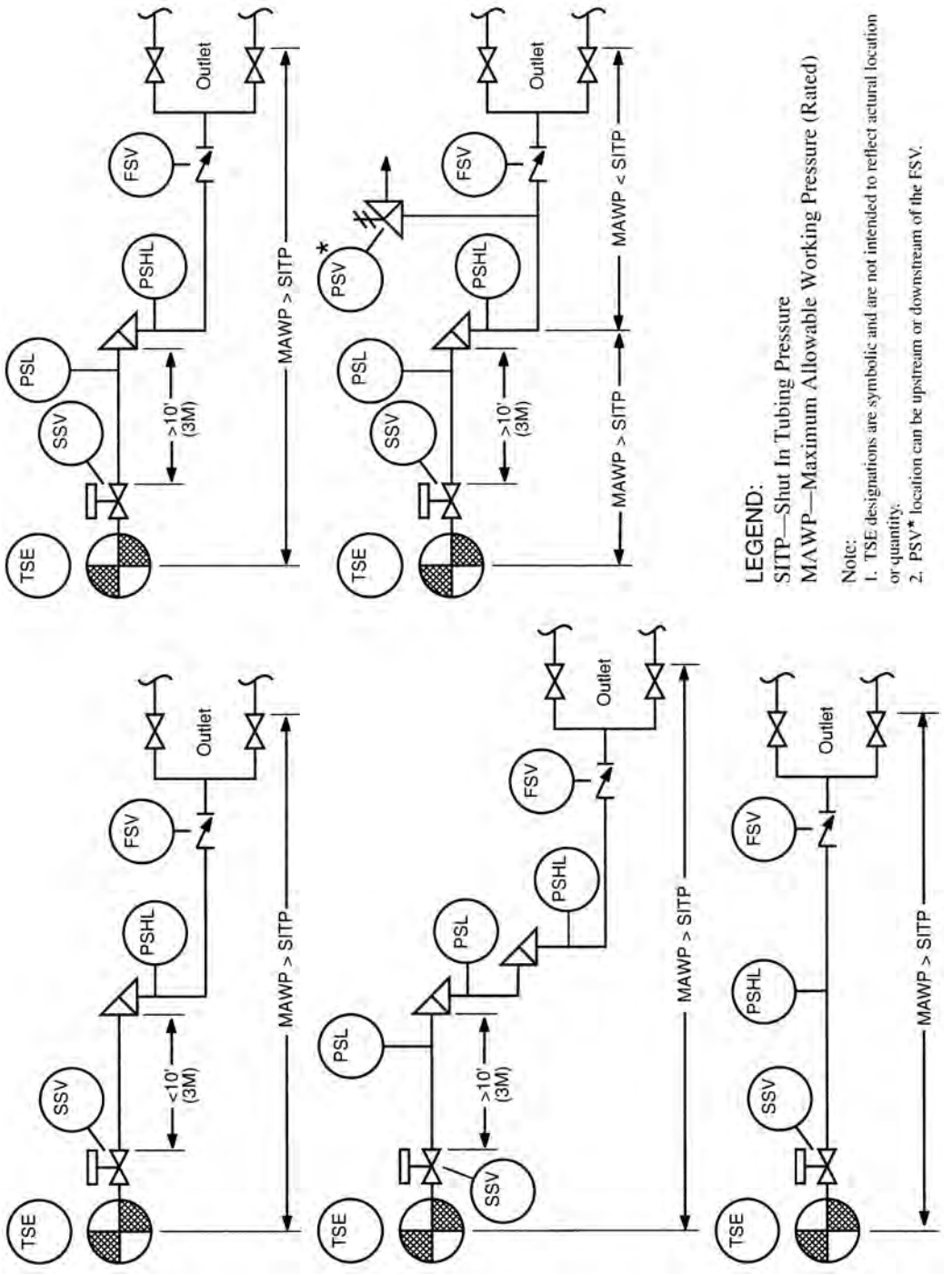


Fig. 10.3—Safety-device tables. (Courtesy of the American Petroleum Institute.[1])

away from the facility while capturing as many liquid hydrocarbons as possible and thereby reducing pollution levels.

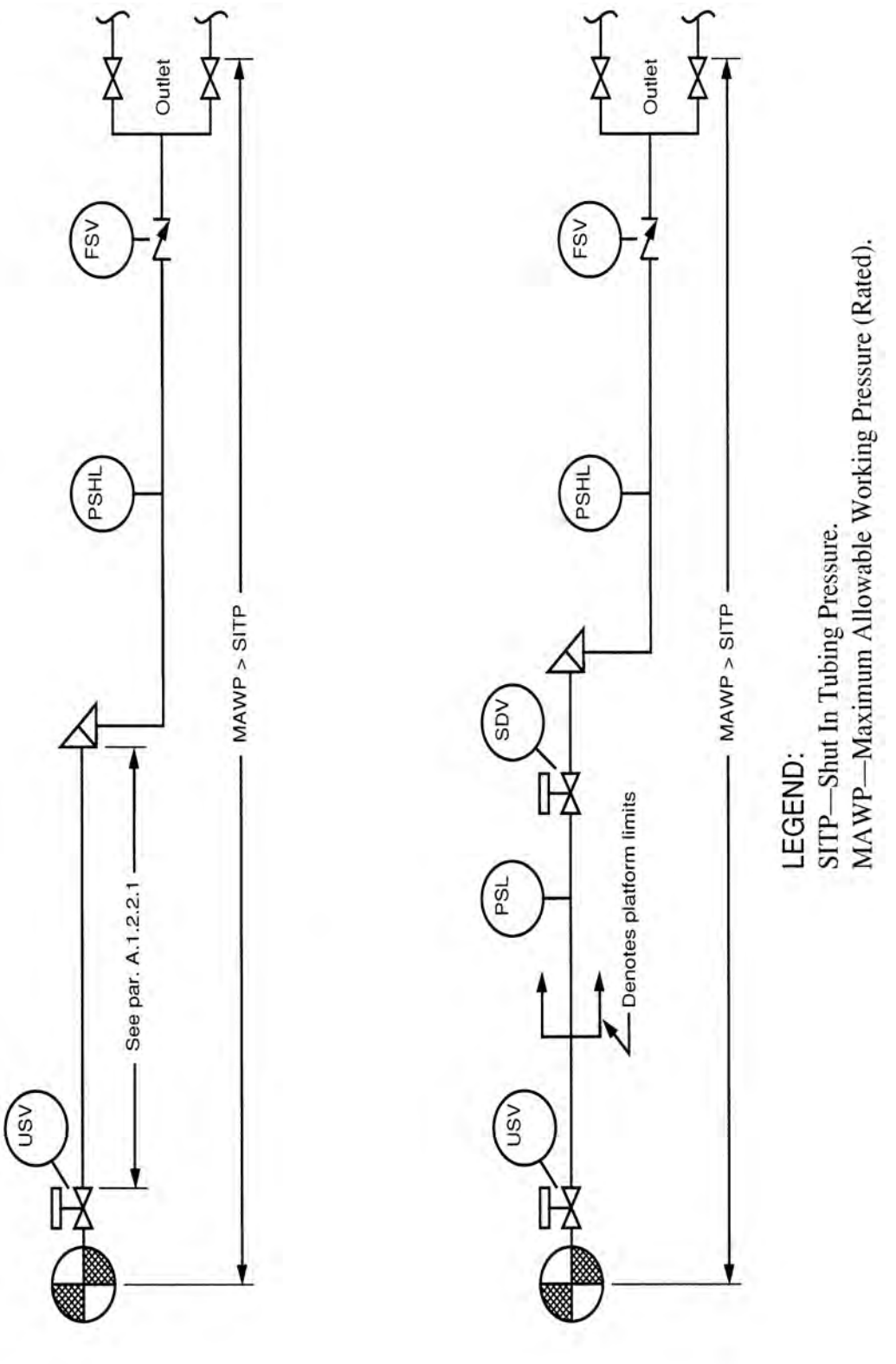


Fig. 10.3—Safety-device tables (continued). (Courtesy of the American Petroleum Institute.[1])

10.2.9 Ignition-Prevention Measures. Ignition-prevention measures are designed to prevent released hydrocarbons from being ignited, thereby minimizing the effects of released hydrocarbons. They accomplish this task through four approaches: ventilation, compliance with all applicable electrical codes, locating equipment in areas where exposure to inadvertently released hydrocarbons is minimized, and hot surface protection. Refer to *RP 14C,* paragraph 4.2.4,[1] for more information about these measures.

10.2.10 Undesirable Events. Abnormal operating conditions can lead to one or more undesirable events that, in turn, could lead to injury to personnel, pollution of the environment, and damage to the facility or its equipment. Safety devices and safety systems are added to prevent undesirable events and they provide the last chance to prevent worst-case consequences from occurring. At each stage, action can be taken to keep the main process variables from resulting in worst-case consequences. Chokes and controllers keep the variables within their normal ranges. Once the variables exceed their normal ranges, safety devices respond to keep the variables from getting further out of range. If the undesirable-event stage is reached, there are still ways of preventing or lessening the chance of the occurrence of worst-case consequences (e.g., ESS). Even though they occur less frequently than either normal or abnormal conditions, undesirable events are much more likely to lead to worst-case consequences than either of the other two conditions.

Eight undesirable events were identified by looking at all the possible ways injury, pollution, and loss of company assets could occur. The process was similar to that used to identify the ten process components. Each of the eight undesirable events was examined further to determine the most common causes of the undesirable event, the effects of the undesirable event, detectable abnormal conditions that usually precede the undesirable event, the most effective primary and secondary protective devices that could prevent the undesirable event, and the optimal location for the placement of the required safety device.

By studying each of these undesirable events, information can be gained to make a facility safe. For example, by knowing the possible causes of a particular undesirable event, those possible causes can be monitored and often corrected before they develop into an undesirable event. Knowing about the possible effects of each undesirable event allows for a more rapid or more appropriate response to the undesirable event. Information about the detectable abnormal condition provides a tool for better monitoring and provides information about which types of safety devices can be used to warn of an impending undesirable event. Primary and secondary protection information assists in determining which safety devices are best for that particular undesirable event. Location data provide information on where the safety devices must be positioned for the most effective protection.

RP 14C[1] does an excellent job of describing this information. It starts by defining an undesirable event as "an adverse occurrence in a process component which poses a threat to safety." There can be many different types of "threat(s) to safety." These can range from minor to the catastrophic. API defines undesirable events with catastrophic threats in mind.

The eight undesirable events identified by *RP 14C*[1] are overpressure, leak, liquid overflow, gas blowby, underpressure, excess temperature (fire and exhaust-heated components), direct ignition source, and excess combustible vapors in the firing chamber (fired components). The following issues are key points about undesirable events.

• Worst-case threats to safety originating in process components are usually preceded by one or more of the eight undesirable events.

• Each undesirable event has a cause that is usually, but not always, preceded by an abnormal condition. The abnormal condition, in turn, is usually detectable.

• Primary protection must be provided to either prevent the undesirable event from occurring or to minimize the effects of the undesirable event once it occurs.

• Secondary protection must be provided as a backup to the primary protection. Primary and secondary refer to levels of protection. While these levels are frequently provided by individual devices [e.g., pressure safety high (PSH)/pressure safety low, LSH/level safety low, PSV, etc.], levels of protection also can be provided by other means. For example, the secondary level of protection required for a leak in a pressure vessel is the ESS (and not individual devices).

• Undesirable events do not always cause injury, pollution, or damage, but they always have the potential to do so. To design a protection system to prevent or minimize injury, pollution, or damage, prevention efforts must be based on the assumption that undesirable events will cause these things.

10.2.11 Safety Analysis. Every process component can be grouped under one of the 10 process components listed in *RP 14C,*[1] and process-related causes of injury, pollution, and damage can be grouped under one of the eight undesirable events. A safety analysis ties these two things together and is a tool for ensuring that a facility is protected fully. A safety analysis examines every process component on the facility to determine which undesirable events could be associated with each component, which safety devices are required for the protection of the component, and what responses the safety devices must make to ensure adequate protection. The three main components of a safety analysis are safety-analysis tables (SATs), safety-analysis checklists (SACs), and safety-analysis function evaluation (SAFE) charts.

Safety-Analysis Tables. SATs examine each process component as if it was standing alone. SATs consider each undesirable event that could possibly affect the component and then, for each undesirable event, lists associated causes, detectable abnormal conditions, and required locations for installing the protection devices. By examining each component as if it was standing alone, an adequate degree of protection can be determined for each particular component. When this is done for every component on the facility, the entire facility will be adequately protected. Verifying that each and every component is protected without considering other components ensures the greatest degree of consistent protection.

Safety-Analysis Checklists. There are times when the safety devices called for in SATs are not needed because engineering controls eliminate the need for a particular device. For example, the SAT calls for a PSV to protect a wellhead flowline from overpressure. However, if the maximum allowable working pressure (MAWP) of the flowline and associated equipment is greater than the maximum shut-in tubing pressure of the well, the component is already protected and the device is not needed.

A SAT-required safety device also no longer may be required if the same degree of protection is provided by another device located elsewhere. For example, if a PSV has been installed on an upstream flowline segment and if that upstream PSV provides an adequate degree of protection for the downstream flowline segment and its equipment, then a second PSV located on the downstream flowline segment is redundant.

SACs provide a guideline for eliminating redundant devices while maintaining the required level of protection. If it was not possible to eliminate redundant devices, production facilities would contain many more devices without gaining any additional protection. The time and expense of purchasing, installing, and maintaining redundant devices would be significant and unnecessary. It is important to realize that when a device can be eliminated, the device is eliminated and not the required level of protection. Two levels of protection will always be required. The SAC ensures that both levels of protection are maintained, with as few individual devices as possible. **Fig. 10.4**[1] shows an example of an SAT and an SAC for a flowline segment.

Safety-Analysis Function-Evaluation Charts. SATs indicate which devices are needed on each component, and SACs determine which devices may be eliminated and what conditions must be met when eliminating the device. Neither SATs nor SACs indicate what the devices

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted line Downstream choke plugged Hydrate plub Upstream flow-control failure Changing well conditions Closed outlet valve	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure

a. High-Pressure Sensor (PSH).
   1. PSH installed.
   2. Flowline segment has a MAWP greater than maximum shut-in pressure and is protected by a PSH on a downstream flowline segment.
b. Low-Pressure Sensor (PSL).
   1. PSL installed.
   2. Flowline segment is between the well and the first choking device and is less than 10 ft (3 m) in length or, in the case of an underwater installation, reasonably close to that distance.
c. Pressure Safety Valve (PSV).
   1. PSV installed.
   2. Flowline segment has a MAWP greater than the maximum shut-in pressure.
   3. Two SDVs (one of which may be the SSV) with independent PSHs, relays, and sensing points are installed where there is adequate flowline volume upstream of any block valves to allow sufficient time for the SDVs to close before exceeding the MAWP.
   4. Flowline segment is protected by a PSV on upstream segment.
   5. Flowline segment is protected by a PSV on downstream component that cannot be isolated from the flowline segment, and there are no chokes or other restrictions between the flowline segment and the PSV.
d. Flow Safety Valve (FSV).
   1. FSV installed.
   2. Flowline segment is protected by FSV in final flowline segment.

Fig. 10.4—Safety-analysis table and safety-analysis checklist for a flowline segment. (Courtesy of the American Petroleum Institute.[1])

do or how the devices on one component relate to the devices on another component. SAFE charts are used to evaluate the function of each safety device and to document precisely what each safety device does. For example, the SAFE chart not only shows that a flowline PSH shuts off inflow, it indicates how it shuts off inflow (e.g., through the closing of a particular well's surface safety valve).

SAFE charts also indicate everything else that happens when a PSH trips. SAFE charts provide a mechanism for considering every component in the facility and then, for each component, to fully account for each required safety device. SAFE charts are used to ensure that the facility is as fully protected as it should be and also can be used as a troubleshooting tool. For example, if a particular shut-down valve (SDV) keeps closing and nothing is out of range when investigated, the SAFE chart could be consulted to determine which specific devices cause the SDV to close. Each device then could be checked to determine which one is responsible for the SDV closures.

10.2.12 Conducting a Safety Analysis. The following steps comprise the process for conducting a production-facility safety analysis.

• Obtain an accurate process flow schematic (i.e., one that shows every process component as well as relevant operating parameters). Once the flow schematic is located, it is necessary to

verify its accuracy because changes may have been made to the facility over a period of years that were not noted on the schematic. Verification involves walking around the facility to make sure that every process component located in the facility is pictured on the schematic. It also involves making sure that the flow schematic does not depict components that are no longer a part of the process facility and that maximum operating or working pressures are accurate. Failure to take this step jeopardizes the accuracy of both the flow schematic and the SAFE chart.

• Refer to each process component and the SATs to determine all required safety devices for each process component within the facility. Begin by referring to *RP 14C,* Appendix A-1 through A-10.[1] Consult the SAT for each process component shown on the corrected flow schematic. Make sure each safety device called for in each component's section is shown on the schematic. Follow the example found in *RP 14C,* Appendix E; that is, use "balloons" and ISA names for each device. Before consulting the SAT for a particular component, it is important to first read everything written about that component in *RP 14C.*

• Once each process component has been protected with the devices required by *RP 14C,*[1] consult the SACs in *RP 14C* to determine which, if any, devices provide redundant protection for each component. For each redundant device, make that device's solid-line balloon, which represents an installed safety device, into a dotted-line balloon, which represents an eliminated safety device. Remember, there will be adequate protection if there is an SAC reference number that applies to the situation. Look carefully at the descriptions following each SAC reference number, and determine if all the required conditions are met. If all the conditions are met, that particular device may be eliminated or the device may be left on the component. Remember, SACs allow for the elimination of redundant devices but do not require that they be eliminated. For those devices that will be eliminated, revise the schematic by replacing the solid-line balloon with a dotted-line balloon. See *RP 14C,* Appendix E.[1]

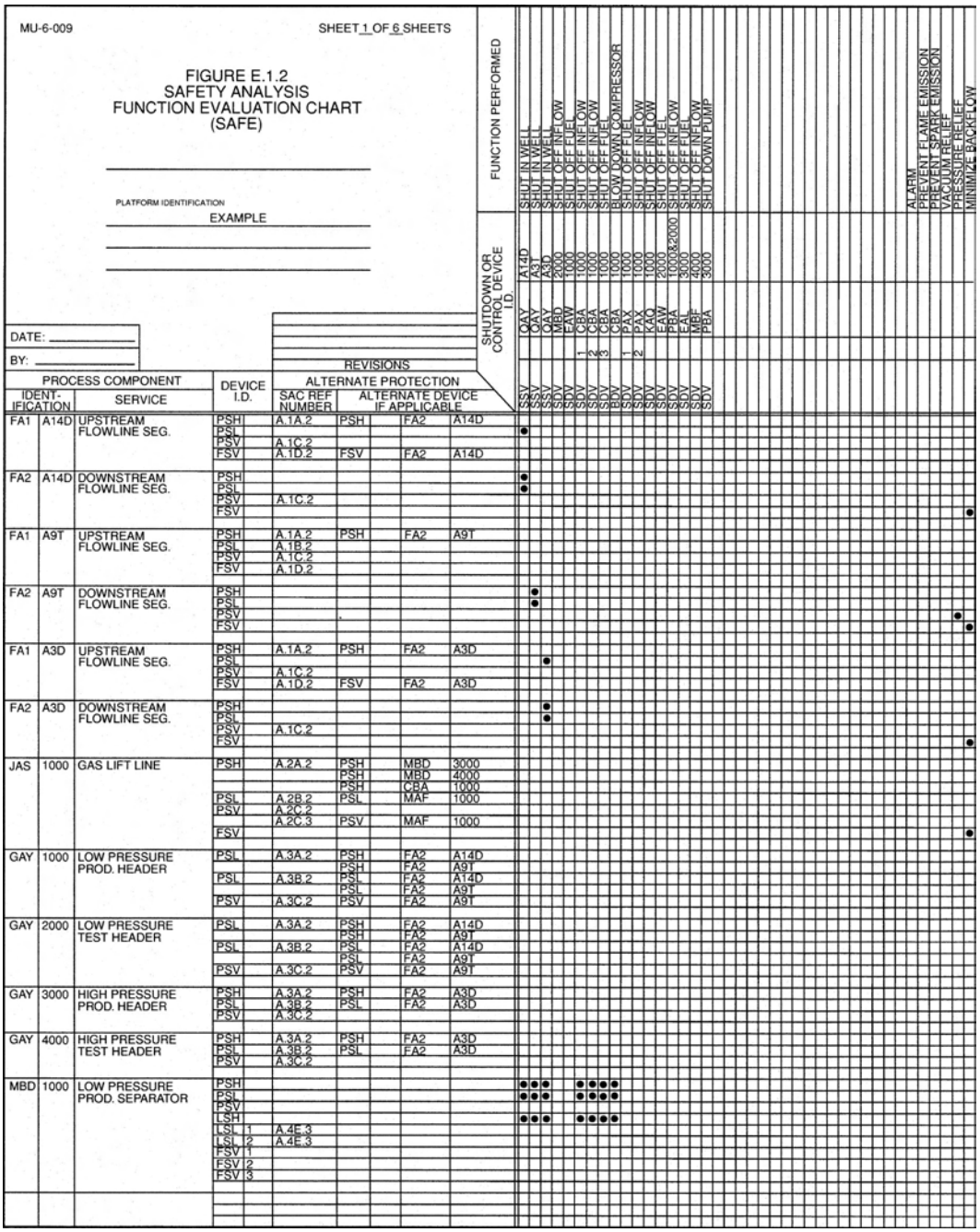
• Complete a SAFE chart for the facility; that is, fill out a blank SAFE chart with every component, safety device, and responding end device within the facility. Mark the SAFE chart to indicate the action taken by each safety device. In reality, completing a fresh, blank SAFE chart will seldom be required unless the initial safety analysis on a facility is being developed. Most often, an existing chart will be revised; however, knowing how to complete a fresh chart from scratch will make the job of revising an existing SAFE chart easier. Familiarity with SAFE charts enables them to be used to troubleshoot the facility.

The ability to complete a SAFE chart requires an understanding of how SAFE charts are arranged. SAFE charts are designed to be read horizontally and vertically. When read horizontally, the information pertains to all the process components within a facility plus their safety devices. When read vertically, the information pertains not only to the end devices affected by each safety device, but to their function as well (e.g., shut in well, minimize backflow, etc.). **Fig. 10.5** shows a typical SAFE chart.[1]

10.3 Relief Valves and Relief Systems

10.3.1 Introduction. A relief system is an emergency system for discharging gas during abnormal conditions, by manual or controlled means or by an automatic pressure-relief valve from a pressurized vessel or piping system, to the atmosphere to relieve pressures in excess of MAWP. The relief system may include the relief device, the collection piping, flashback protection, and a gas outlet. A scrubbing vessel should be provided for liquid separation if liquid hydrocarbons are anticipated. The relief-system outlet may be either vented or flared. If designed properly, vent or flare emergency-relief systems from pressure vessels may be combined.

Some facilities include systems for depressuring pressure vessels in the event of an emergency shutdown. The depressuring-system control valves may be arranged to discharge into the vent, flare, or relief systems. The possibility of freezing and hydrate formation during high-pressure releases to the atmosphere should be considered.



MU-6-009

SHEET 1 OF 6 SHEETS

FIGURE E.1.2
SAFETY ANALYSIS
FUNCTION EVALUATION CHART
(SAFE)

PLATFORM IDENTIFICATION
EXAMPLE

DATE:

BY:

REVISIONS

PROCESS COMPONENT IDENTIFICATION		PROCESS COMPONENT SERVICE	DEVICE I.D.	ALTERNATE PROTECTION SAC REF NUMBER	ALTERNATE DEVICE IF APPLICABLE		
FA1	A14D	UPSTREAM FLOWLINE SEG.	PSH	A.1A.2	PSH	FA2	A14D
			PSL				
			PSV	A.1C.2			
			FSV	A.1D.2	FSV	FA2	A14D
FA2	A14D	DOWNSTREAM FLOWLINE SEG.	PSH				
			PSL				
			PSV	A.1C.2			
			FSV				
FA1	A9T	UPSTREAM FLOWLINE SEG.	PSH	A.1A.2	PSH	FA2	A9T
			PSL	A.1B.2			
			PSV	A.1C.2			
			FSV	A.1D.2			
FA2	A9T	DOWNSTREAM FLOWLINE SEG.	PSH				
			PSL				
			PSV				
			FSV				
FA1	A3D	UPSTREAM FLOWLINE SEG.	PSH	A.1A.2	PSH	FA2	A3D
			PSL				
			PSV	A.1C.2			
			FSV	A.1D.2	FSV	FA2	A3D
FA2	A3D	DOWNSTREAM FLOWLINE SEG.	PSH				
			PSL				
			PSV	A.1C.2			
			FSV				
JAS	1000	GAS LIFT LINE	PSH	A.2A.2	PSH	MBD	3000
					PSH	MBD	4000
					PSH	CBA	1000
			PSL	A.2B.2	PSL	MAF	1000
			PSV	A.2C.2			
				A.2C.3	PSV	MAF	1000
			FSV				
GAY	1000	LOW PRESSURE PROD. HEADER	PSL	A.3A.2	PSH	FA2	A14D
					PSH	FA2	A9T
			PSL	A.3B.2	PSL	FA2	A14D
					PSL	FA2	A9T
			PSV	A.3C.2	PSV	FA2	A9T
GAY	2000	LOW PRESSURE TEST HEADER	PSL	A.3A.2	PSH	FA2	A14D
					PSH	FA2	A9T
			PSL	A.3B.2	PSL	FA2	A14D
					PSL	FA2	A9T
			PSV	A.3C.2	PSV	FA2	A9T
GAY	3000	HIGH PRESSURE PROD. HEADER	PSH	A.3A.2	PSH	FA2	A3D
			PSL	A.3B.2	PSL	FA2	A3D
			PSV	A.3C.2			
GAY	4000	HIGH PRESSURE TEST HEADER	PSH	A.3A.2	PSH	FA2	A3D
			PSL	A.3B.2	PSL	FA2	A3D
			PSV	A.3C.2			
MBD	1000	LOW PRESSURE PROD. SEPARATOR	PSH				
			PSL				
			PSV				
			LSH				
			LSL 1	A.4E.3			
			LSL 2	A.4E.3			
			FSV 1				
			FSV 2				
			FSV 3				

FUNCTION PERFORMED

SHUTDOWN OR CONTROL DEVICE I.D.

SHUT IN WELL	A14D	SSV
SHUT IN WELL	A9T	SSV
SHUT IN WELL	A3D	SSV
SHUT OFF INFLOW	MBD 2000	SDV
SHUT OFF FUEL	FAW 1000	SDV
SHUT OFF INFLOW	CBA 1000	SDV
SHUT OFF FUEL	CBA 1000	SDV
BLOW DOWN COMPRESSOR	CBA 1000	SDV
SHUT OFF FUEL	PAX 1000	SDV
SHUT OFF INFLOW	PAX 1000	SDV
SHUT OFF INFLOW	KAQ 1000	SDV
SHUT OFF FUEL	EAW 2000	SDV
SHUT OFF INFLOW	PBA 1000&2000	SDV
SHUT OFF FUEL	EAE 3000	SDV
SHUT OFF INFLOW	PBA 3000	SDV
SHUT DOWN PUMP	PBA 3000	SDV

ALARM
PREVENT FLAME EMISSION
PREVENT SPARK EMISSION
VACUUM RETIEF
PRESSURE RELIEF
MINIMIZE BACKFLOW

Fig. 10.5a—Safety-analysis function-evaluation chart. (Courtesy of the American Petroleum Institute.[1])

There are three main engineering considerations when designing or modifying a relief system:

• Determining the relief requirements of individual pieces of equipment and selecting the appropriate devices to handle the imposed loads.

• Designing a relief header system that will handle the imposed loads or expansion modifications.

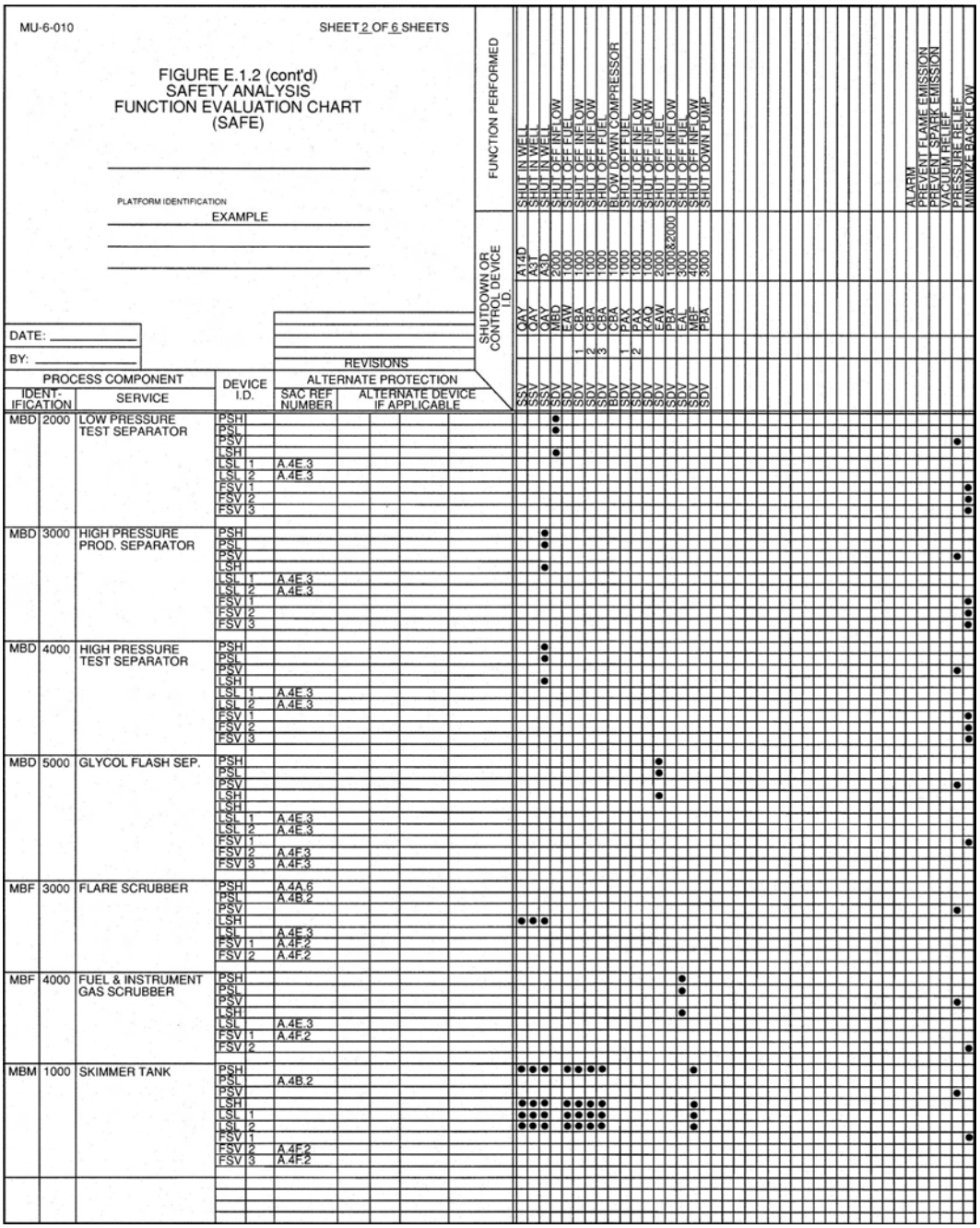


Fig. 10.5b—Safety-analysis function-evaluation chart (continued). (Courtesy of the American Petroleum Institute.[1])

• Defining reasonable total relief loads for the combined relief header or disposal system and designing an appropriate disposal system with minimum adverse impact to personnel safety, plant-process system integrity, and the environment.

MU-6-011 SHEET 3 OF 6 SHEETS

FIGURE E.1.2 (CONT'D)
SAFETY ANALYSIS
FUNCTION EVALUATION CHART
(SAFE)

PLATFORM IDENTIFICATION
EXAMPLE

DATE:
BY:

REVISIONS

PROCESS COMPONENT IDENTIFICATION	PROCESS COMPONENT SERVICE	DEVICE I.D.	ALTERNATE PROTECTION SAC REF NUMBER	ALTERNATE DEVICE IF APPLICABLE			
MAJ	2000	GLYCOL FILTER	PSH	A.4A.3	PSH	MBD	5000
			PSL	A.4B.4			
			PSV	A.4C.2	PSV		
			LSH	A.4D.3		(Thermal)	
			LSL	A.4E.2			
			FSV	A.4F.2			
MBF	6000	SUCTION SCRUBBER	PSH				
			PSL				
			PSV				
			LSH				
			LSL				
			FSV 1	A.4F.2			
			FSV 2				
MBF	7000	INTERSTAGE SCRUBBER	PSH				
			PSL				
			PSV				
			LSH				
			LSL				
			FSV 1	A.4F.2			
			FSV 2				
MBF	7500	INTERSTAGE SCRUBBER	PSH	A.4A.3		4 CBA	1000
			PSL	A.4B.3		4 CBA	1000
			PSV	A.4C.3	PSV	4 CBA	1000
			LSH				
			LSL	A.4E.3			
			FSV 1	A.4F.2			
			FSV 2				
MBF	8000	HIGH PRESSURE SCRUBBER	PSH	A.4A.3	PSH	MBD	3000
					PSH	MBD	4000
					PSH 6	CBA	1000
			PSL	A.4B.3	PSL	MBD	3000
					PSL	MBD	4000
					PSL 6	CBA	1000
			PSV				
			LSH	A.4D.2			
			LSL	A.4E.3			
			FSV 1				
			FSV 2				
MAF	1000	CONTACTOR	PSH	A.4C.3	PSH	MBD	3000
					PSH	MBD	4000
					PSH 6	CBA	1000
			PSL				
			PSV				
			LSH	A.4D.2			
				A.4D.3			
			LSL	A.4E.2			
			FSV 1				
			FSV 2	A.4F.3			
ABJ	1000	ATMOSPHERIC TANK	Vent				
			PSV				
			LSH				
			LSL				
ABJ	2000	GLYCOL SURGE TANK	Vent				
			PSV	A.5B.3			
			LSH	A.5C.2			
			LSL	A.5D.2			
ABH	1000	SUMP	Vent				
			PSV				
			LSH				
			LSL	A.5D.4			

SHUTDOWN OR CONTROL DEVICE I.D.	FUNCTION PERFORMED
A14D	SHUT IN WELL
A31	SHUT IN WELL
A3D	SHUT IN WELL
2000	SHUT OFF INFLOW
MBD	SHUT OFF FUEL
1000	SHUT OFF INFLOW
EAW	SHUT OFF FUEL
1000	SHUT OFF INFLOW
CBA	SHUT OFF FUEL
1000	SHUT OFF INFLOW
CBA	BLOW DOWN COMPRESSOR
1000	SHUT OFF FUEL
PAX	SHUT OFF INFLOW
1000	SHUT OFF INFLOW
KAQ	SHUT OFF INFLOW
1000	SHUT OFF FUEL
EAW	SHUT OFF INFLOW
2000	SHUT OFF FUEL
PBA	SHUT OFF INFLOW
1000&2000	SHUT OFF FUEL
EAE	SHUT OFF INFLOW
3000	SHUT OFF FUEL
PBA	SHUT DOWN PUMP
3000	

ALTERNATE PROTECTION
ALARM
PREVENT FLAME EMISSION
PREVENT SPARK EMISSION
VACUUM RETIEF
PRESSURE RELIEF
MINIMIZE BACKFLOW

Fig. 10.5c—Safety-analysis function-evaluation chart (continued). (Courtesy of the American Petroleum Institute.[1])

These considerations are interrelated in such a way that makes it impossible to establish a procedural guideline that would be valid for most cases. The design of one portion of a relief system must be considered in light of its effects on the relief system.

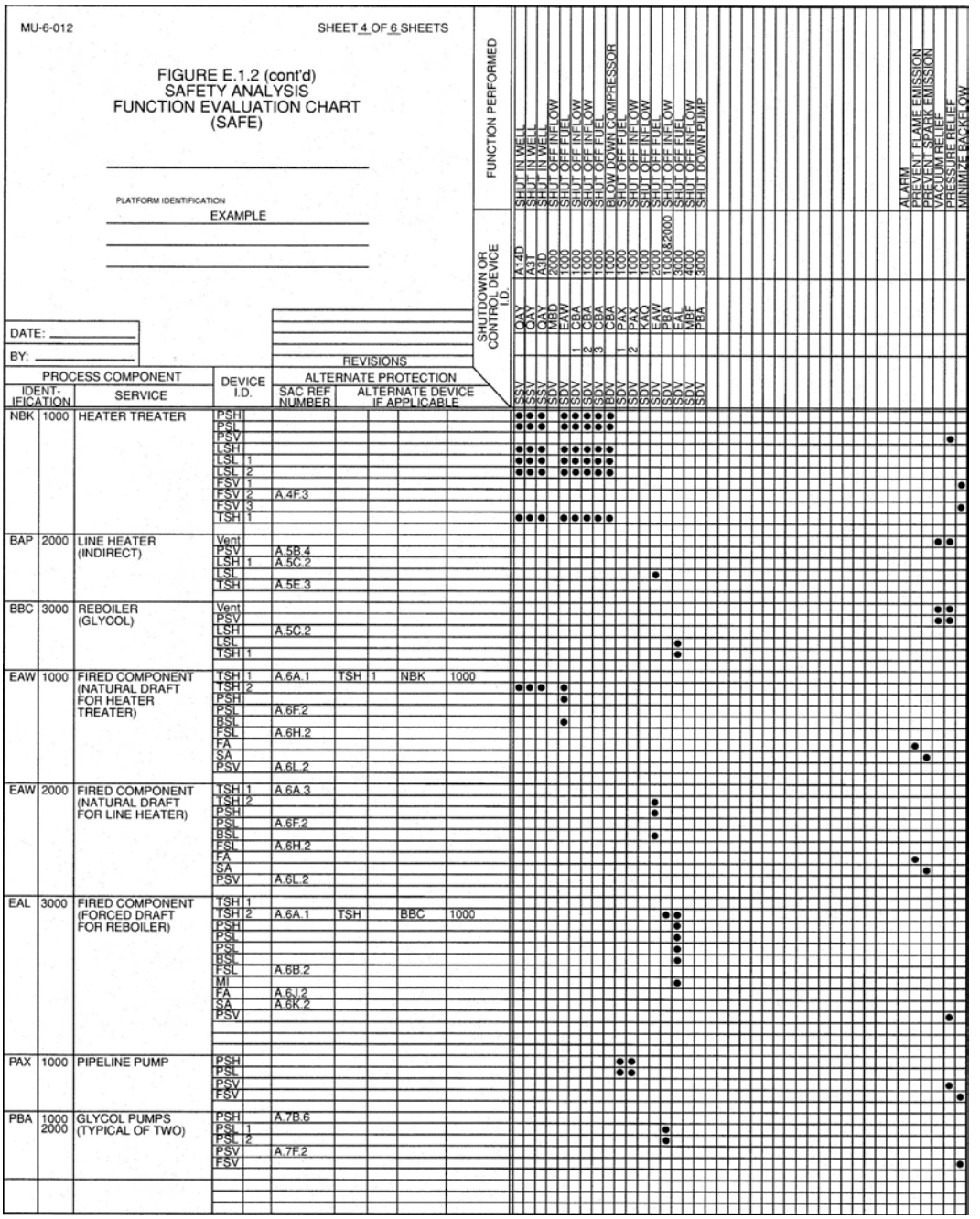


Fig. 10.5d—Safety-analysis function-evaluation chart (continued). (Courtesy of the American Petroleum Institute.[1])

10.3.2 Relief Device Selection. ***Determining Individual Relief Loads.*** There are a number of industry codes, standards, and recommended practices that provide guidance in the sizing, selection, and installation of relief devices and systems. The American Soc. of Mechanical Engineers (ASME) Pressure Vessel Code, Sec. VIII, Division 1, Paragraph UG-127, lists the relief-

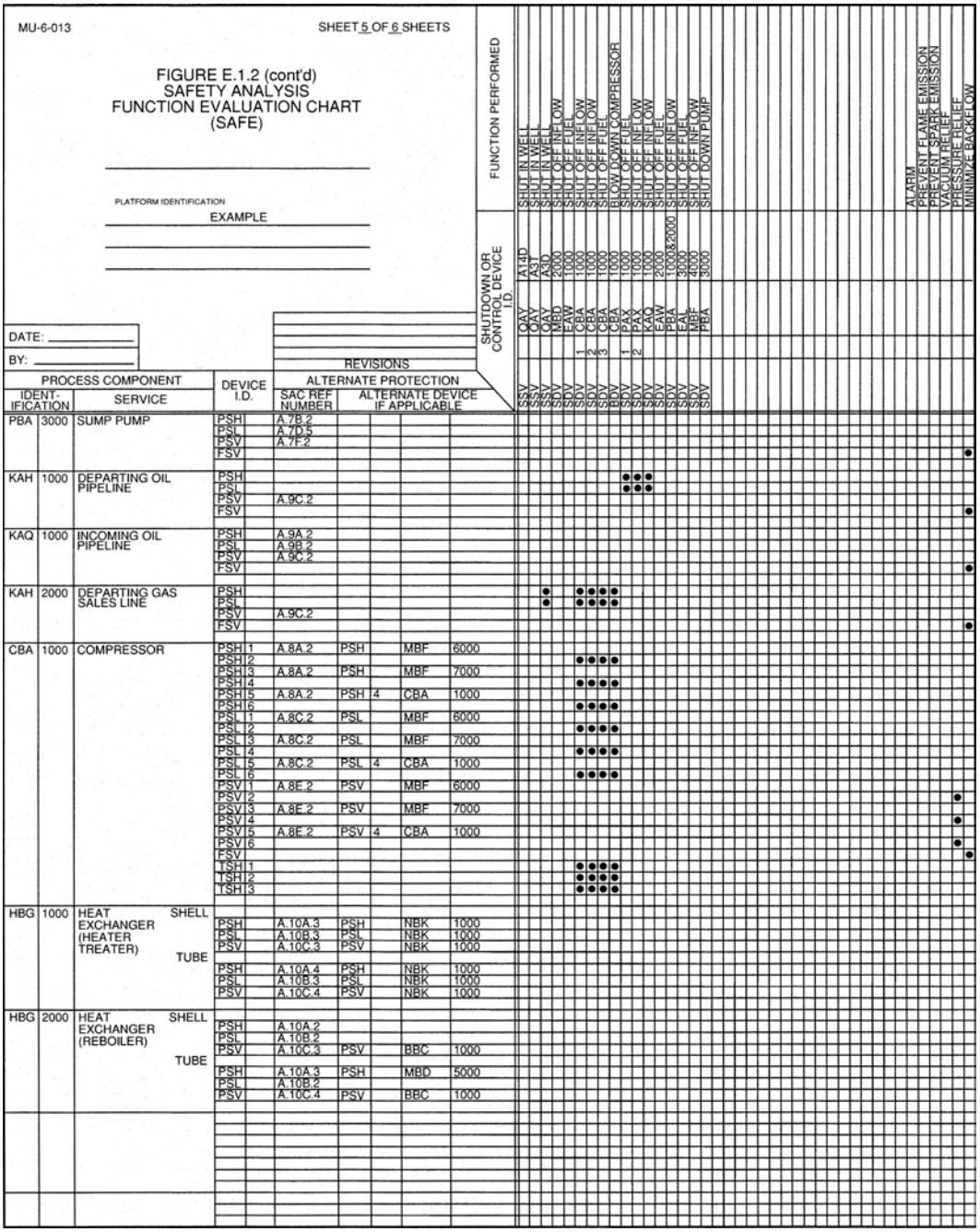


Fig. 10.5e—Safety-analysis function-evaluation chart (continued). (Courtesy of the American Petroleum Institute.[1])

valve code requirements.[3] *RP 520,* Part 1, provides an overview of the types of relief devices, causes of overpressure, relief-load determination, and procedures for selecting and sizing relief devices.[4] *RP 520,* Part 2, provides guidance on the installation of relief devices,[5] and *RP 521* provides guidance on the selection and design of disposal systems.[6]

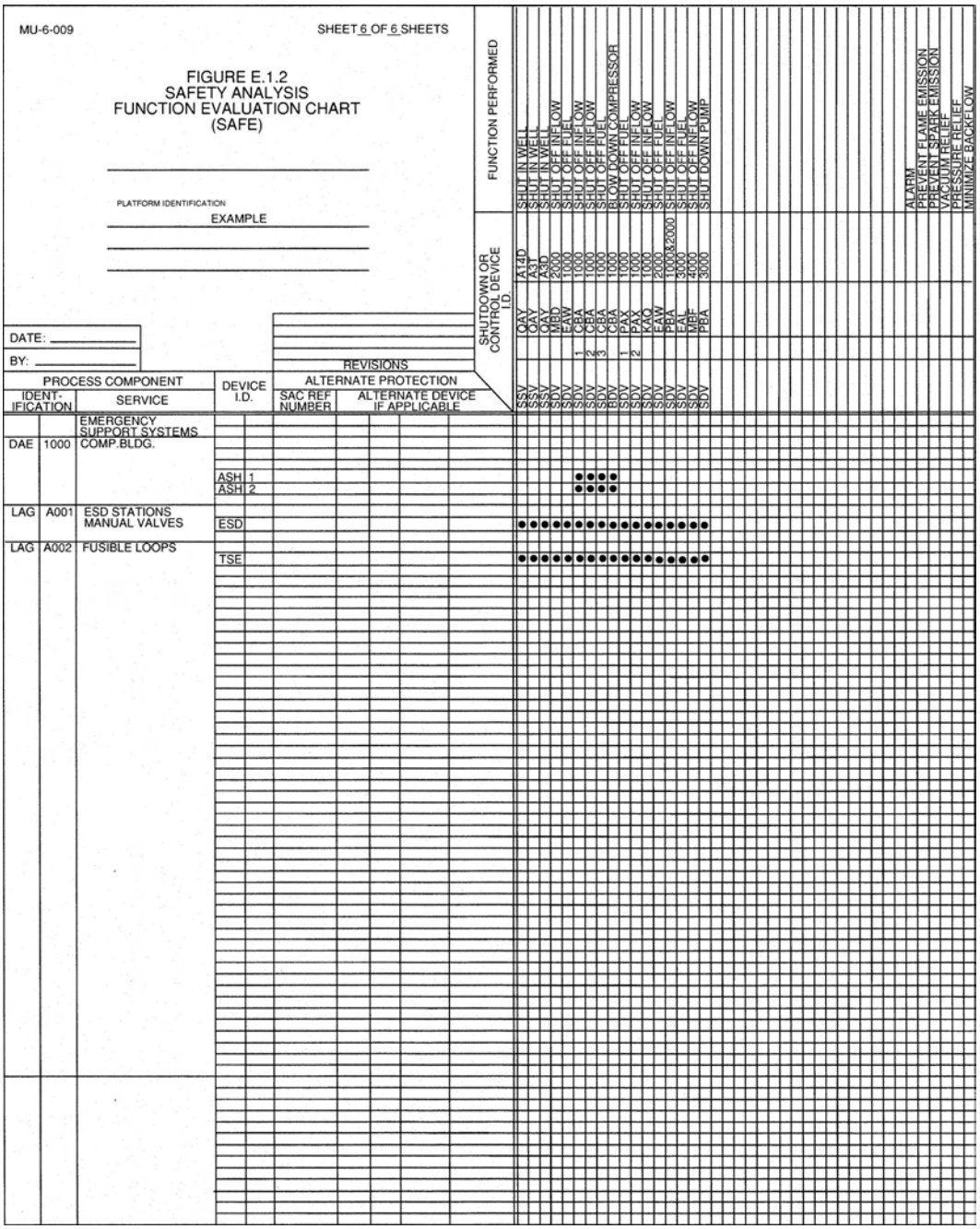


Fig. 10.5f—Safety-analysis function-evaluation chart (continued). (Courtesy of the American Petroleum Institute.[1])

Causes of Overpressure. The most common causes of overpressure in upstream operations are blocked discharge, gas blowby, and fire. When the worst-case relief load is caused by a control valve failing to open (blocked discharge), the relief device should be sized with full-sized trim in the control valve, even if the actual valve has reduced trim. When the worst-case relief load is caused by gas blowby, the relief device should be sized with full-sized trim in the

smallest valve in the liquid-outlet line, even if the actual valve has reduced trim. Many vessels are insulated for energy savings. Thermal insulation limits the heat absorption from fire exposure as long as it is intact. It is essential that effective weather protection be provided so that insulation will not be removed by high-velocity fire-hose streams.

Types of Pressure-Relief Devices. The two primary types of relief devices are the relief valve and rupture disk.

Relief Valves. The three basic types of pressure-relief valves are conventional spring loaded, balanced spring loaded, and the pilot operated.

• Conventional spring loaded. In the conventional spring-loaded valve (**Fig. 10.6**), the bonnet, spring, and guide are exposed to the released fluids. If the bonnet is vented to the atmosphere, relief-system backpressure decreases the set pressure. If the bonnet is vented internally to the outlet, relief-system backpressure increases the set pressure. The conventional spring-loaded valve is used in noncorrosive services and where backpressure is less than 10% of the set point.

• Balanced spring-loaded. The balanced spring-loaded valve (**Fig. 10.7**) incorporates a means to protect the bonnet, spring, and guide from the released fluids and minimizes the effects of backpressure. The disk area vented to the atmosphere is exactly equal to the disk area exposed to backpressure. These valves can be used in corrosive or dirty service and with variable backpressure.

• Pilot operated. The pilot-operated valve (**Fig. 10.8**) is combined with and controlled by an auxiliary pressure pilot. The resistance force on the piston in the main valve is assisted by the process pressure through an orifice. The net seating force on the piston actually increases as the process pressure nears the set point.

Rupture-Disk Devices. The rupture-disk device (**Fig. 10.9**) is a nonreclosing differential-pressure device actuated by inlet static pressure. The rupture disk is designed to burst at set inlet pressure. The device includes a rupture disk and a disk holder. The rupture disk may be used alone, in parallel with, or in conjunction with pressure-relief valves. They are manufactured in a variety of materials with various coatings for corrosion resistance.

Relief-System Considerations. The entire relief system must be considered before selecting the appropriate relief device. The relief headers should be designed to minimize pressure drop, thus allowing for future expansion and additional relief loads.

• Conventional spring-loaded-relief-valve considerations. Conventional valves require the relief header backpressure (superimposed plus built up) to be less than 10% of the set pressure of the lowest-set relief valve tied into the header.

• Balanced-spring-loaded-valve considerations. Balanced spring-loaded valves allow the use of smaller relief headers because of the larger pressure drops allowed, under maximum relief-flow conditions, as a result of higher allowable backpressure (40%). Balanced valves and relief headers are designed as a system to operate at a higher backpressure. The balanced valve is more expensive than conventional valves; however, the total cost of the use of balanced valves plus the smaller header system may be lower. Capacity is reduced at the larger backpressure, so it may not be the solution for all backpressure problems. In the bellows model, the bellows is a flexible pressure vessel that has a maximum backpressure limit that is lower in larger valve sizes. Bellows are available in a limited number of materials and may deteriorate rapidly under certain exposure conditions. Bellows should be checked periodically for leakage. A leaking bellow does not provide backpressure compensation, and it allows the relief header to leak to the atmosphere. The balanced valve commonly is used to tie a new low-pressure-relief load into an existing heavily loaded relief header or to protect the relief-valve top works from corrosive gases in the relief header.

• Pilot-operated-valve considerations. Pilot-operated valves should be considered for all clean services within their temperature limitations. They are well suited for pressures below 15

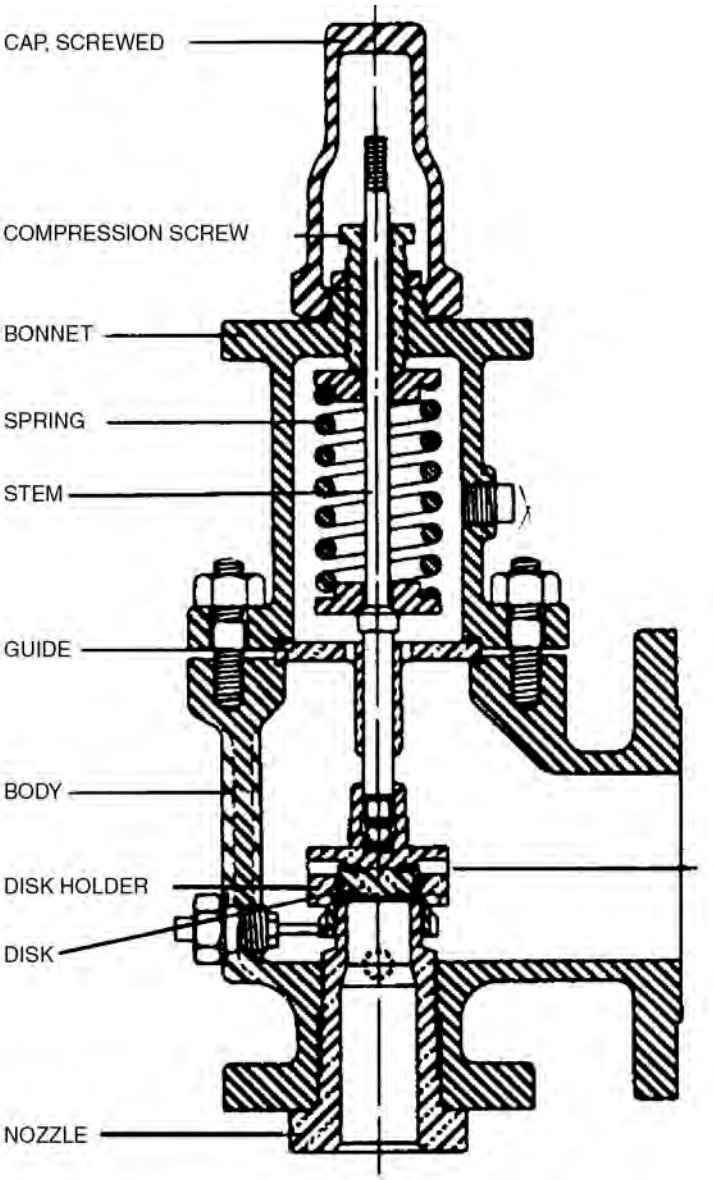


Fig. 10.6—Conventional spring-loaded pressure-relief value.

psig and are available with the pilot-pressure sensing line connected to either the valve inlet or to a different point. Pilot-operated valves provide tight shutoff with very narrow margins between operating pressure and set pressure.

Special Considerations. When selecting the appropriate relief devices to handle the imposed loads, several issues must be considered.

Set Pressure. Relief devices are normally set to relieve at the MAWP. The greater the margin between the set pressure and the operating pressure, the less likelihood there is of leakage. Aside from the requirements to compensate for superimposed backpressure, there is no reason to set a relief device at less than the MAWP.

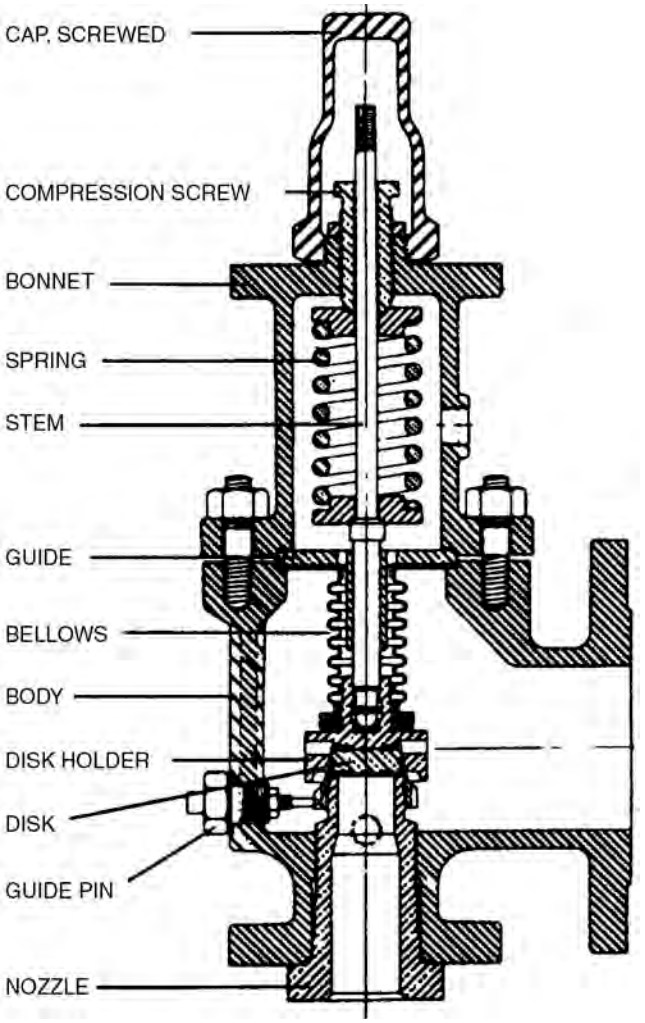


Fig. 10.7—Balanced spring-loaded pressure-relief value. (Courtesy of the American Petroleum Institute.[4])

Backpressure. The backpressure at the outlet of every relief device should be such that the device can handle its design capacity with the calculated backpressure under the design relief conditions.

Dual Relief Valves. It is common practice to install two relief valves in critical process applications where a shutdown cannot be tolerated. The intent is that if the first relief valve lifts and fails to reseat, a second relief can be switched into service before the first valve is removed for maintenance, without shutting down or jeopardizing the process. This is accomplished by piping the relief valves in parallel and by putting a "car sealed" full-port ball or gate block valve on the inlet and outlet of each relief valve. One set of block valves is sealed open and the other sealed closed. ASME-approved selector valves are available, which simplify relief-valve switching. This provides an interlock of parallel inlet and outlet block valves and ensures full protection for the process equipment.

Multiple Relief Valves. Multiple relief valves are required when the relief load exceeds the capacity of the largest available relief valve. It is good practice to install multiple relief valves

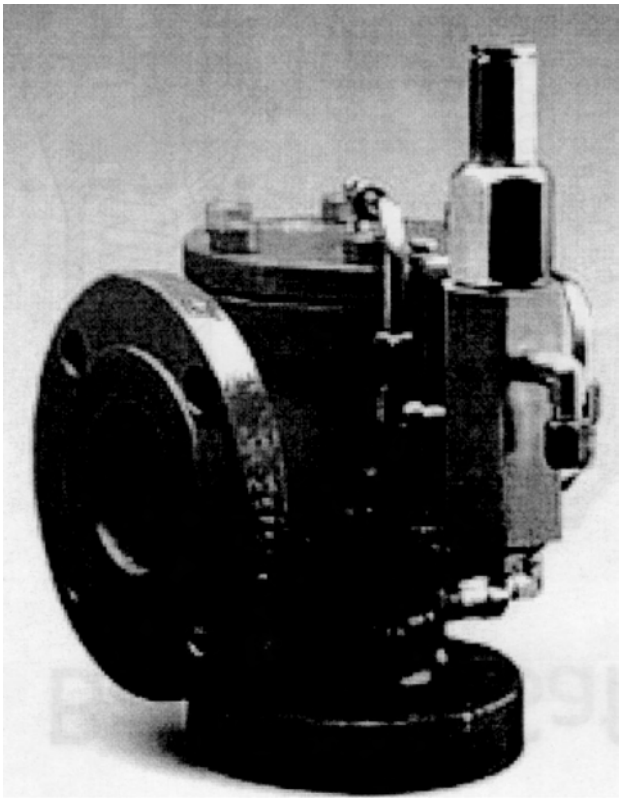


Fig. 10.8—Pilot-operated pressure-relief value. (Courtesy of the American Petroleum Institute.[4])

for varying loads to minimize chattering on small discharges. ASME Sec. VIII, Division 1,[3] and *RP 520,* Part 1[4] (see **Fig. 10.10**), both stipulate a 10% accumulation above the MAWP for a single relief valve and a 16% accumulation above the MAWP for multiple relief valves. The primary relief valve must be set at or below the MAWP. Supplemental relief valves should have staged pressures. The highest pressure may be set no higher than 105% above the MAWP. If different-sized relief valves are used, the smallest relief valve should be set to the lowest pressure.

Sizing the Relief Device. The most difficult factors for specifying a relief device are determining the limiting cause of pressure relief, determining the relief load and properties of the discharge fluid, and selecting the proper relief device. When the loads are known, the sizing steps are straightforward. *RP 520,* Part 1, provides formulas for determining the relief-valve orifice area for vapor, liquid, and steam relief.[4] **Fig. 10.11** shows standard orifices available by letter designation, orifice area, and body size. The size of a relief valve should be checked for the following conditions.

Blocked Discharge. One design condition for the sizing of a relief valve is to assume that it must handle the total design flow rate (gas plus liquid) into the component. It is possible to isolate a process component or piping segment for maintenance by blocking all inlets and outlets. On startup, all outlet valves could be left closed inadvertently. If the inlet source can be at a higher pressure than the MAWP of the process component, only a properly sized relief valve could keep the process component from rupturing as a result of overpressure.

Gas Blowby. On tanks and low-pressure vessels normally receiving liquids from higher-pressure upstream vessels, the maximum flow rate through the relief valve often is determined by

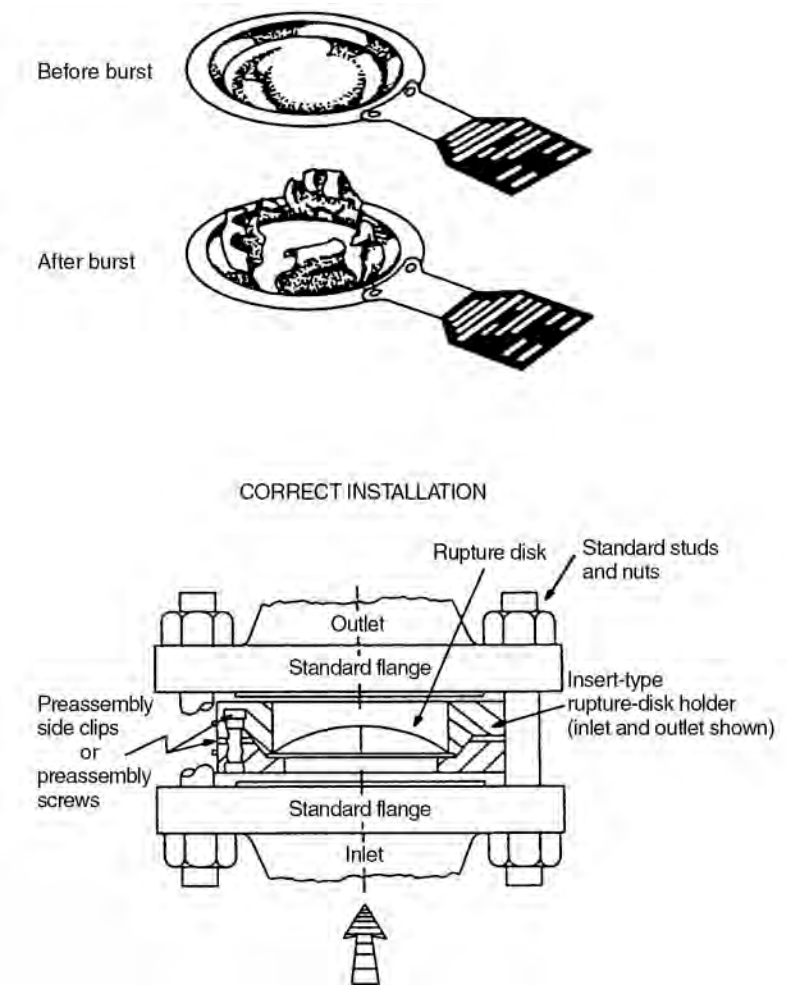
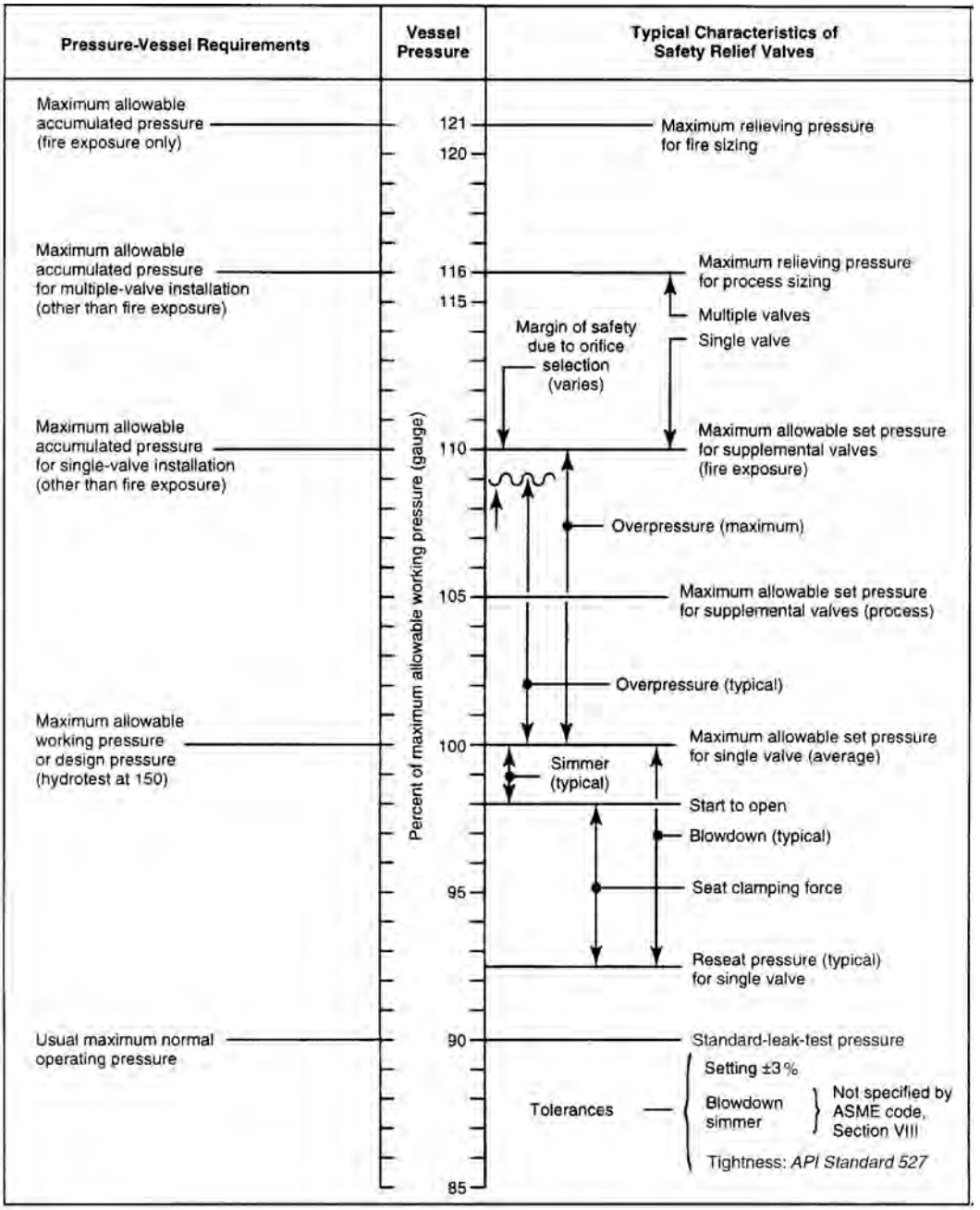


Fig. 10.9—Conventional rupture disk. (Courtesy of the American Petroleum Institute.[4])

gas blowby. This situation occurs when the level controller or level control valve of the upstream vessel fails in the open position or a drain valve from an upstream vessel fails in the open position, allowing liquid and/or gas to flow into the component evaluated. Under blowby conditions, both the normal liquid and gas outlets on the component being evaluated are functioning properly. However, the gas flow into the component could greatly exceed the capacity of the normal gas outlet. This excess gas flow must be handled by the relief valve to keep from exceeding the component's MAWP. Gas-blowby conditions also can occur when a pressure regulator feeding a component fails in the open position, creating a higher than designed inlet flow rate of gas.

Gas-blowby rate is the maximum that can flow given the pressure drop between the upstream component and the component being evaluated. In computing the maximum rate that can flow because of pressure drop, consideration should be given to the effects of control valves, chokes, and other restricted orifices in the line. A more conservative approach would be to assume that these devices have been removed or have the maximum-sized orifice that could be installed in the device.



Notes:
1. The operating pressure may be any lower pressure required.
2. The set pressure and all other values related to it may be moved downward if the operating pressure permits.
3. This figure conforms with the requirements of Section VIII, Division 1, of the ASME Code.
4. The pressure conditions shown are for safety relief valves installed on a pressure vessel (vapor phase).

Fig. 10.10—Pressure levels of pressure-relief values. (Courtesy of the American Petroleum Institute.[4])

Fire/Thermal Expansion. The pressure in process components exposed to the heat from a fire will rise as the fluid expands and the process liquid vaporizes. For tanks and large low-

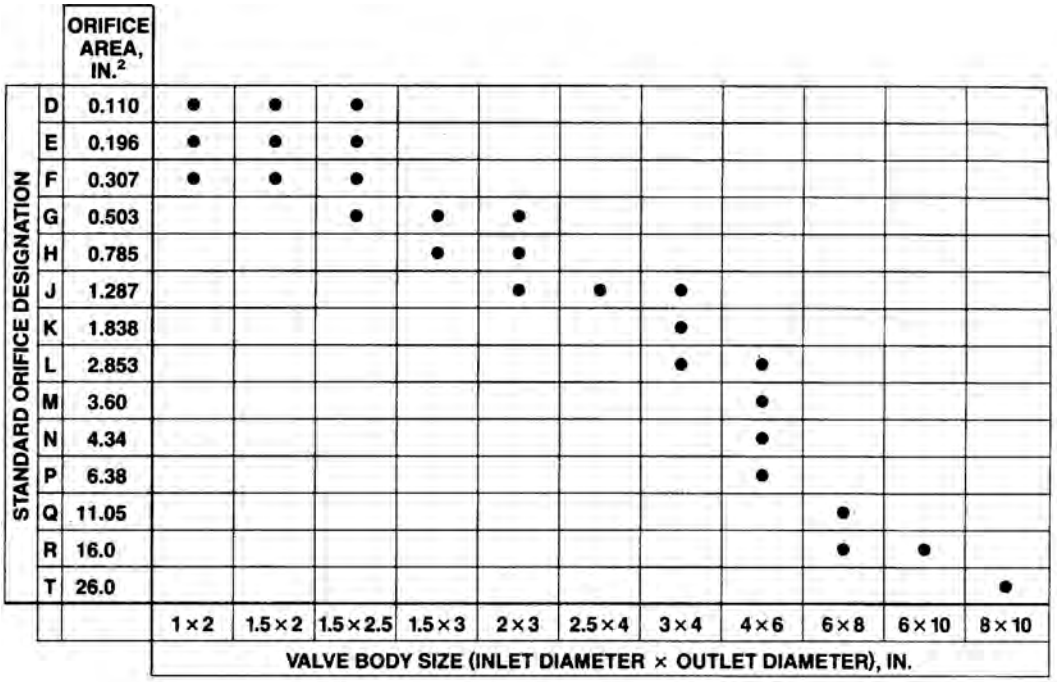


Fig. 10.11—Pressure-relief-value orifice designations.

pressure vessels, the need to vent the liberated gas may govern the size of the vent or relief valve. Fire sizing a relief valve only keeps pressure buildup to less than 120% of the MAWP. If the component is subjected to a fire for a long time, it may fail at a pressure less than the MAWP because a metal's strength decreases as temperature increases.

On components that can be isolated from the process, it is possible for the process fluid contained in the component to be heated. This is especially true for cold (relative to ambient) service or when the component is heated (such as a fired vessel or heat exchanger). It is also true for compressor cylinders and cooling jackets. The relief valves on such components should be sized for thermal expansion of the trapped fluids. This normally will not govern the final size selected unless no relief valve is needed for the other conditions.

Installation Considerations. The installation of a relief device requires careful consideration of the inlet piping, pressure-sensing lines (where used), and startup procedures. Poor installation may render the relief device inoperable or severely restrict the valve's relieving capacity. Either condition compromises the safety of the facility. Many relief-valve installations have block valves before and after the relief valve for in-service testing or removal; however, these block valves must be car sealed or locked open.

Inlet Piping. *RP 520,* Part 2,[5] and ASME code[3] limit the inlet pressure loss to a PSV of 3% of set pressure where the pressure loss is the total of the inlet loss, line loss, and block-valve loss (if used). Loss is calculated with the maximum rated flow through the relief valve. To minimize the inlet pressure drop to a relief valve, a conservative guideline is to keep the equivalent length-to-diameter ratio of the inlet piping to the relief valve at 5 or less. For pressure-drop limitations and typical piping configurations, refer to *RP 520,* Part 2.[5]

Discharge Piping. The discharge piping should be designed so that the backpressure does not exceed an acceptable value for any relief valve in the system. Piping diameters generally should be larger than the valve-outlet size to limit backpressure. Lift and set pressures of pilot-operated relief valves with the pilot vented to the atmosphere are not affected by backpressure;

however, if the discharge pressure can exceed the inlet pressure (e.g., tanks storing low-vapor-pressure material), a backflow preventer (vacuum block) must be used. The set pressure for balanced spring-loaded relief valves will not be as affected by backpressure as conventional spring-loaded relief valves are. Balanced relief valves will suffer reduced lift as backpressure increases.

Reactive Forces. On high-pressure valves, the reactive forces during relief are substantial and external bracing may be required. Refer to the formulas in *RP 520,* Parts 1[4] and 2[5] for computing these forces.

Tailpipe Considerations. Relief valves that are not connected to a closed relief system should have tailpipes to direct the relieving gases to a safe area away from personnel. The tailpipe should be sized for a maximum exit velocity of 500 ft/s. This ensures that the gas/air mixture is below the lower flammable limit or lower explosive limit at approximately 120 pipe diameters away from the tailpipe. Tailpipes should be supported at the bottom of the elbow. A small hole or a "weep hole" (minimum of ¼ in. in diameter) should be installed in the bottom of the elbow to drain liquids that enter through the tailpipe opening. The weep hole should be pointed away from process components, especially those classified as an ignition source.

Rapid Cycling. Rapid cycling can occur when the pressure at the valve inlet decreases at the start of the relief valve flow because of excessive pressure loss in the piping upstream of the valve. Under these conditions, the valve will cycle rapidly, a condition referred to as "chattering." Chattering is caused by the following sequence. The valve responds to the pressure at its inlet. If the pressure decreases during flow below the valve reseat point, the valve will close; however, as soon as the flow stops, the inlet-pipe pressure loss becomes zero and the pressure at the valve inlet rises to vessel pressure once again. If the vessel pressure is still equal to or greater than the relief-valve set pressure, the valve will open and close again. An oversized relief valve may also chatter because the valve may quickly relieve enough contained fluid to allow the vessel pressure to momentarily fall back to below set pressure, only to rapidly increase again. Rapid cycling reduces capacity and is destructive to the valve seat in addition to subjecting all the moving parts in the valve to excessive wear. Excessive backpressure also can cause rapid cycling, as discussed previously.

Resonant Chatter. Resonant chatter occurs when the inlet piping produces excessive loss at the valve inlet and the natural acoustical frequency of the inlet piping approaches the natural frequency of the valve's moving parts. The higher the set pressure, the larger the valve size, or the greater the inlet-pipe pressure loss, the more likely resonant chatter will occur. Resonant chatter is uncontrollable, that is, once started it cannot be stopped unless the pressure is removed from the valve inlet. In actual practice, the valve can break down before a shutdown can take place because of the very large magnitude of the impact force involved. To avoid chattering, the pressure drop from the vessel nozzle to the relief valve should not exceed 3% of the set pressure. *RP 520,* Part 2 covers the design of relief-valve inlet piping.[5] Pilot-operated relief valves with remote sensing pilots can operate with higher inlet-piping pressure drops.

Isolation (Block) Valves. There is no industry standard or RP for isolation valves, and practices vary widely. Installed isolation block valves allow the testing of spring-loaded relief valves in place, thus eliminating the need to remove the vessel from service while bench testing the relief valve, and allow the relief device to be isolated from the closed relief system when performing maintenance and repair. The ASME Unfired Pressure Vessel Code allows the use of isolation valves below relief valves.[3] *ASME Pressure Vessel Code,* Appendix M, describes special mandatory requirements for isolation valves. The ASME Boiler Code[3] prohibits them, and the U.S. Occupational Safety and Health Admin.[7] prohibits them on instrument air receivers. Because improper use of an isolation valve may render a relief valve inoperative, the design, installation, and management of these block valves should be evaluated carefully to

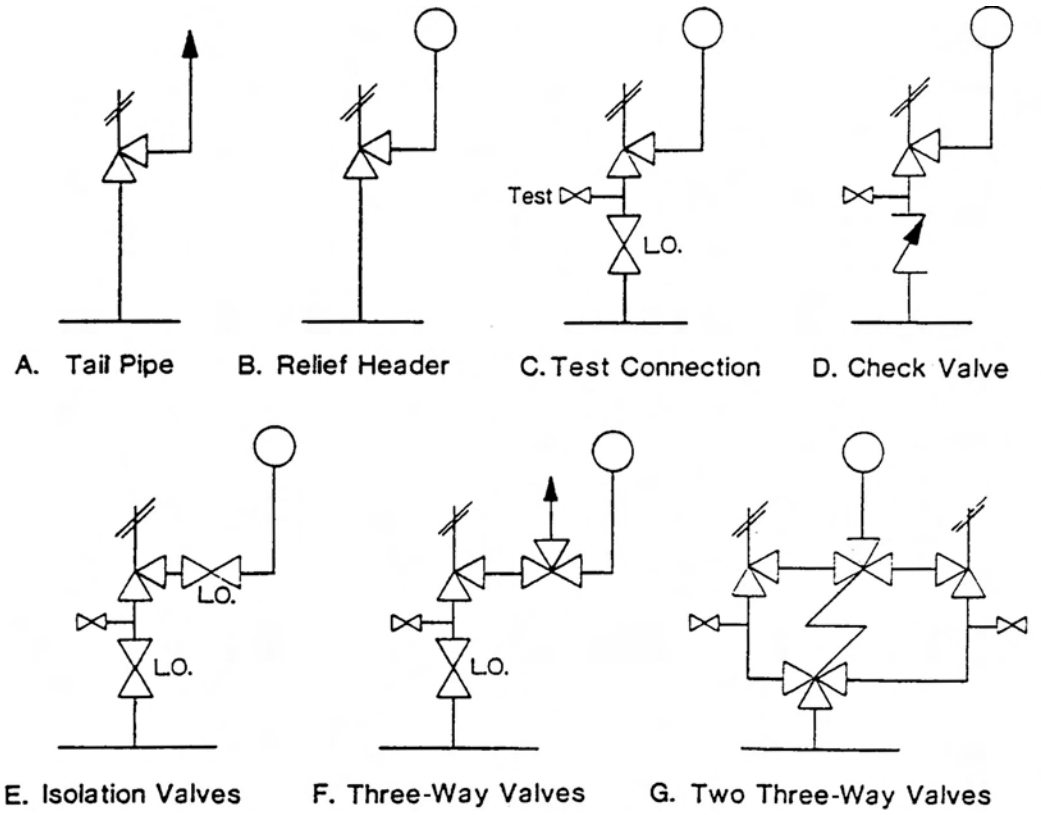


Fig. 10.12—Relief-valve configurations.

ensure that plant safety is not compromised. See *RP 520,* Part 2, for typical block-valve installations under relief valves.[5]

Relief-Valve Configurations. There is no industry standard or RP that addresses this topic. Some of the more common relief-value configurations are listed here and are shown in **Fig. 10.12**.

• Installation of full open isolation (block) valves upstream and downstream of relief valves. Isolation valves should be car sealed open (locked open), and a log should be kept. These valves should be discouraged where the potential overpressure is twice the maximum allowable pressure. A test connection should be provided on all spring-loaded relief valves. The installation of two relief valves (100% redundant) should be considered so that one relief valve can be left in service at all times.

• Installation of pilot-operated valves without isolation valves. This configuration allows for the testing of pilot set pressure only and requires full plant shut-in for relief-valve repair and maintenance.

• Installation of three-way valves with one port open to a tailpipe or a vent stack. This configuration allows for valve maintenance and repair without requiring plant shut-in and ensures a path to the atmosphere if the three-way valve is left in the wrong position.

• Installation of two two-way valves, connected by mechanical linkage, and two relief valves. This configuration provides all the advantages of isolation valves. In addition, it is impossible to isolate a process component by mistake. The only disadvantage of this configuration is the initial cost.

• Installation of a check valve in lieu of an isolation valve. This configuration is not allowed by the *ASME Pressure Vessel Code* because the check valve may fail or cause excessive pressure drop.[3]

Guidelines for Determining the Number of Relief Devices. There is no industry standard or RP for determining the number of relief devices, and installations vary widely. Sometimes there are two relief devices (100% standby) on vessels receiving production directly from the wells. The primary relief valve is set at MAWP. If the second relief device is another relief valve, the set pressure of the second relief valve is set 10% above the primary relief valve. If the second relief device is a rupture disk (entirely redundant against all possible relieving scenarios), the pressure is set at 15 to 25% above the primary relief device. This setting ensures that the rupture disk will not rupture when the design primary relieving rate is reached at the set pressure plus 10% overpressure. Primary and standby relief rates are considered adequate for fire sizing.

Some companies install two relief valves on all critical installations so that plant shutdowns are not required during testing and maintenance. If the secondary relief device is being counted on to provide any portion of any required relieving capacity (blocked discharge, gas blowby, fire, etc.), then the secondary device should be set in accordance with the rules of *RP 520,* Parts 1[4] and 2,[5] (i.e., ASME Sec. VIII, Division 1, paragraph UG-134).[3]

Liquid-Discharge Considerations. Condensed mists have liquid droplets that are less than 20 to 30 μm in diameter. Testing and experience have shown that with a slight wind, the envelope of flammability for this type of mist is the same as that for a vapor. Liquids will settle to grade, thus presenting a fire and pollution hazard; therefore, the relief device should be installed in the vapor space of process vessels with an LSH that alarms and shuts in flow when activated. The LSH should be set no higher than 15% above the maximum operating level, while the relief valve should be set no higher than the MAWP of the process component. Scrubbers and knockout drums should be installed in flare, vent, and relief lines to separate and remove liquid droplets from the discharge.

10.4 Flare and Vent Disposal Systems

10.4.1 Disposal-System Design. A flare or vent disposal system collects and discharges gas from atmospheric or pressurized process components to the atmosphere to safe locations for final release during normal operations and abnormal conditions (emergency relief). In vent systems, the gas exiting the system is dispersed in the atmosphere. Flare systems generally have a pilot or ignition device that ignites the gas exiting the system because the discharge may be either continuous or intermittent. Gas-disposal systems for tanks operating near atmospheric pressure are often called atmospheric vents or flares, and gas-disposal systems for pressure vessels are called pressure vents or flares. A flare or vent system from a pressurized source may include a control valve, collection piping, flashback protection, and a gas outlet. A scrubbing vessel should be provided to remove liquid hydrocarbons. A flare or vent system from an atmospheric source may include a pressure-vacuum valve, collection piping, flashback protection, and a gas outlet. The actual configuration of the flare or vent system depends on the hazards assessment for the specific installation.

RP 520, Part 1, Sec. 8,[4] and *RP 521,* Secs. 4 and 5,[6] cover disposal and depressuring system design. *RP 521,* Appendix C, provides sample calculations for sizing a flare stack. *RP 521,* Appendix D, shows a flare-stack seal drum, a quench drum, and a typical flare installation.[6]

10.4.2 Knockout Drums. *RP 521,* Paragraph 5.4.2, provides detailed guidance for the design of knockout drums (also called relief drums or flare or vent scrubbers).[6] All flare, vent, and relief systems must include a liquid knockout drum. The knockout drum removes any liquid

droplets that carry over with the gas relief sent to the flare. Most flares require that the particle size be reduced to a minimum of less than 300 μm. *RP 14J* suggests sizing for liquid droplets between 400 and 500 μm.[2] Most knockout drums are horizontal with a slenderness ratio (length-to-diameter ratio) between 2 and 4. A horizontal knockout drum must have a diameter large enough to keep the vapor velocity low enough to allow entrained liquids to settle or drop out.

Knockout drums operated at atmospheric pressure should be sized to handle the greatest liquid volume expected at the maximum rates of liquid buildup and pump out. *RP 521* suggests 20 to 30 minutes of liquid holdup.[6] This is not practical in upstream operations. In onshore operations, it is recommended to take 20% of the maximum potential liquid stream and provide a 10-minute liquid holdup. For offshore operations, it is recommended to provide normal separation-retention times (1 to 3 minutes on the basis of API gravity) and an emergency dump design to handle the maximum liquid flow with no valves. An emergency sump (disposal) pile is recommended to dispose of the liquid, and a seal in the pile is recommended to contain the backpressure in the drum.

Knockout drums normally are operated at atmospheric pressure. To maintain an explosion, the MAWP of the knockout drum usually is set at 50 psig. Stoichiometric hydrocarbon/air explosions produce peak pressures seven to eight times the normal pressure.

10.4.3 Flashback Protection. Flashback protection (the possibility that the flame will travel upstream into the system) should be considered for all disposal systems because flashback can result in pressure buildup in upstream piping and vessels. Flashback is more critical where there are tanks or pressure vessels with a MAWP less than 125 psig and in flare systems. *RP 520* discusses flashback protection for pressure vents and flares,[4] and *STD 2000* discusses atmospheric vents and flares.[8] *RP 14C* recommends that vents from atmospheric vessels contain a flame arrestor.[1] Because the flame arrestor can plug, a secondary pressure/vacuum valve without a flame arrestor should be considered for redundancy. The secondary system should be set at a pressure high enough and vacuum low enough so that it will not operate unless the flame arrestor on the primary system is plugged.

Pressure vents with vessels rated 125 psig and above normally do not need flashback protection. In natural-gas streams, the possibility of vent ignition followed by flash backpressures above 125 psig is minimal. When low-pressure vessels are connected to pressure vents, molecular or fluidic seals and purge gas often are used to prevent flashback. If relief valves are tied into the vent, the surge of flow when a relief valve opens could destroy a flame arrestor and lead to a hazardous condition. Also, there is a potential for flame arresters to become plugged. A means of flame snuffing should be considered for vent systems.

Flares have the added consideration of a flame always being present, even when there is a very low flow rate. They are typically equipped with molecular or fluidic seals and a small amount of purge gas to protect against flashback.

Seal Drums. Knockout drums are sized with the gas-capacity equations referred to in the chapter on the design of two- and three-phase separators in this section of the *Handbook*. Liquid seal drums are vessels that are used to separate the relief gases and the flare/header stack by a layer of liquid. Water (or water/glycol mixture) is normally the sealing fluid. The flare gas (or purge gas) is forced to bubble through a layer of water before it reaches the flare stack. This prevents air or gas from flowing backward beyond the water seal. Seal drums serve as a final knockout drum to separate liquid from the relief gases.

In a deep seal drum, the depth of the sealing fluid is designed to be equal to the staging pressure of the staged flare system. The sealing-fluid depth in most staging seal drums is typically in the range of 2 to 5 psig, which is equivalent to 5 to 12.5 ft of water column. In a shallow seal drum (conventional flashback prevention), the water seals have only a 6- to 10-in. water-column depth. It is important to design the deep seal drum with a proper gas velocity at

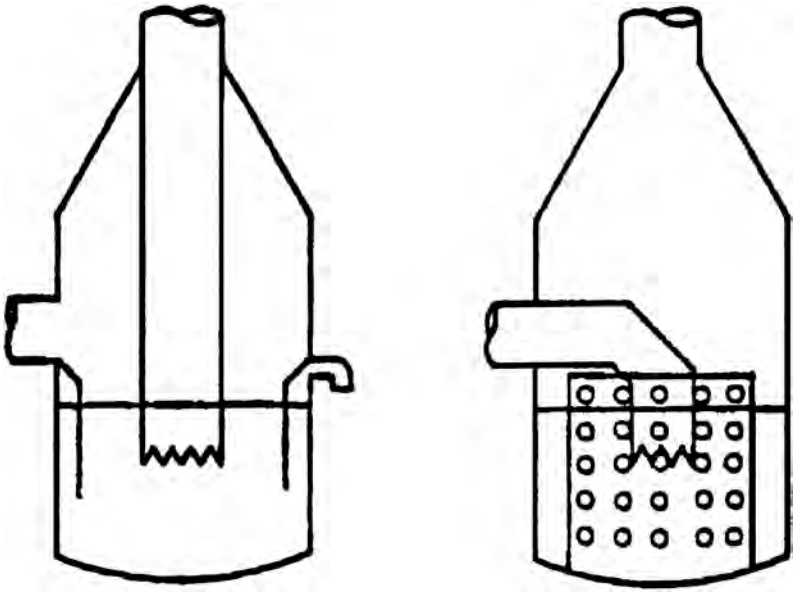


Fig. 10.13—Seal-drum configuration with (a) displacement seal and (b) perforated antislosh baffle.

the staging point to ensure that all the sealing fluid is displaced quickly at the staging pressure (an effect similar to a fast-acting valve actuator). It is also common to design the deep seal drum with a concentric overflow chamber to collect the displaced sealing fluid. The overflow chamber can be designed to flow back automatically into the sealing chamber once the gas velocity decreases below the rate required for closing off the second stage.

The depth of the liquid seal drum must be considered in calculating the relief-header backpressure. This depth is set by the flare supplier, but it usually can be altered somewhat, with the supplier's concurrence, to suit plant conditions. Typical seal depths are 2 ft for elevated flares and 6 in. for ground flares. The height of the liquid seal can be determined by

$$h = \frac{(144)p}{\rho}, \quad \text{..... (10.1)}$$

where h = height of liquid seal, p = maximum allowable header backpressure, and ρ = sealing-liquid density.

The vessel-free area for gas flow above the liquid level should be a minimum of 3 ft or three times the inlet pipe cross-sectional area to prevent surges of gas flow to the flare and to provide space for disengagement.

RP 521 states that surging in seal drums can be minimized with the use of V-notches on the end of the dip leg.[6] If the water sloshes in the seal drum, it will cause pulsations in the gas flow to the flare, resulting in noise and light disturbances. Thus, most facilities prefer either a displacement seal or a perforated antislosh baffle. **Fig. 10.13** shows seal-drum configurations.

Molecular Seals. Molecular seals cause flow reversal. They normally are located below the flare tip and serve to prevent air entry into the stack. Molecular seals depend on the density difference between air and hydrocarbon gas. Light gas is trapped at the top of the U-tube. A continuous stream of purge gas is required for proper functioning of the gas seal, but the amount of purge gas is much less than would be required without the seal. The main advantages over liquid seals are that they do not slosh and they produce much less oily water. Gas seal must be drained, and the drain loop must be sealed. Because a gas seal with an elevated

flare is required to keep air out of the flare stack, the liquid seal usually is omitted from an elevated-only flare system. If a vapor-recovery compressor is used, a liquid seal is used to provide a minimum header backpressure.

Fluidic Seals. Fluidic seals are an alternative to gas seals. Fluidic seals use an open wall-less venturi, which permits flow out of the flare in one direction with very little resistance but strongly resists counterflow of air back into the stack. The venturi is a series of baffles, like open-ended cones in appearance, mounted with the flare tip. The main advantages of fluidic seals are that they are smaller, less expensive, and weigh less, and thus have less structural load on the flare stack, than molecular seals. However, fluidic seals require more purge gas than molecular seals.

Flame Arrestors. Flame arrestors are used primarily on atmospheric vents and are not recommended on pressurized systems. Because of the acceleration of the flame, the flame arrestor must be installed approximately 10 pipe diameters from the exit, which prevents the flame from blowing through the arrestor. The length of the tube and surface area provided keep the metal cool. The major drawbacks of flame arrestors are that they are easily plugged, can become coated with liquid, and may not be strong enough for pressure-relief systems.

10.4.4 Flare Stacks. *RP 521,* Sec. 5.4.3, covers the design of elevated flares.[6] *RP 521,* Appendix C, provides examples of full design of a flare stack.[6] Most flares are designed to operate on an elevated flare stack or on angled booms on offshore platforms.

Elevated-Flare-Stack Designs. **Fig. 10.14** shows an example of an elevated-flare-stack design.

Self-Supported Stacks. This is the simplest and most economical design for applications requiring short-stack heights (up to 100 ft overall height); however, as the flare height and/or wind loading increases, the diameter and wall thickness required become very large and expensive.

Guy-Wire-Supported Stacks. This is the most economical design in the 100- to 350-ft height range. The design can be a single-diameter riser or a cantilevered design. Normally, sets of 3 wires are anchored 120 degrees apart at various elevations (1 to 6).

Derrick-Supported Stacks. This is the most feasible design for stack heights above 350 ft. They use a single-diameter riser supported by a bolted framework of supports. Derrick supports can be fabricated from pipe (most common), angle iron, solid rods, or a combination of these materials. They sometimes are chosen over guy-wire-supported stacks when a limited footprint is desired.

Offshore Flare-Support Structures. Because offshore production platforms process very large quantities of high-pressure gas, the relief systems and, therefore, the flare systems, must be designed to handle extremely large quantities of gas quickly. By nature, flares normally have to be located very close to production equipment and platform personnel or located on remote platforms. Maximum emergency-flare design is based on emergency shut in of the production manifold and quick depressurization of the system. Maximum continuous-flare design is based on loss of produced-gas transport, single compression shutdown, gas-turbine shutdown, etc. Typical flare mountings on an offshore platform are angled boom mounting (most common), vertical towers, or remote flare platforms. **Fig. 10.15** shows typical offshore flare-support structures.

Selection of the flare structure depends on such factors as water depth, the distance between the flare and the production platform, relief gas quantity, toxicity, allowable loading on the flare structure, location of personnel, location of drilling derrick, locations of adjacent platforms, and whether the flaring is intermittent or continuous.

Flare Booms. Flare booms extend from the edge of the platform at an angle of 15 to 45° and are usually 100 to 200 ft long. Sometimes two booms oriented 180° from each other are

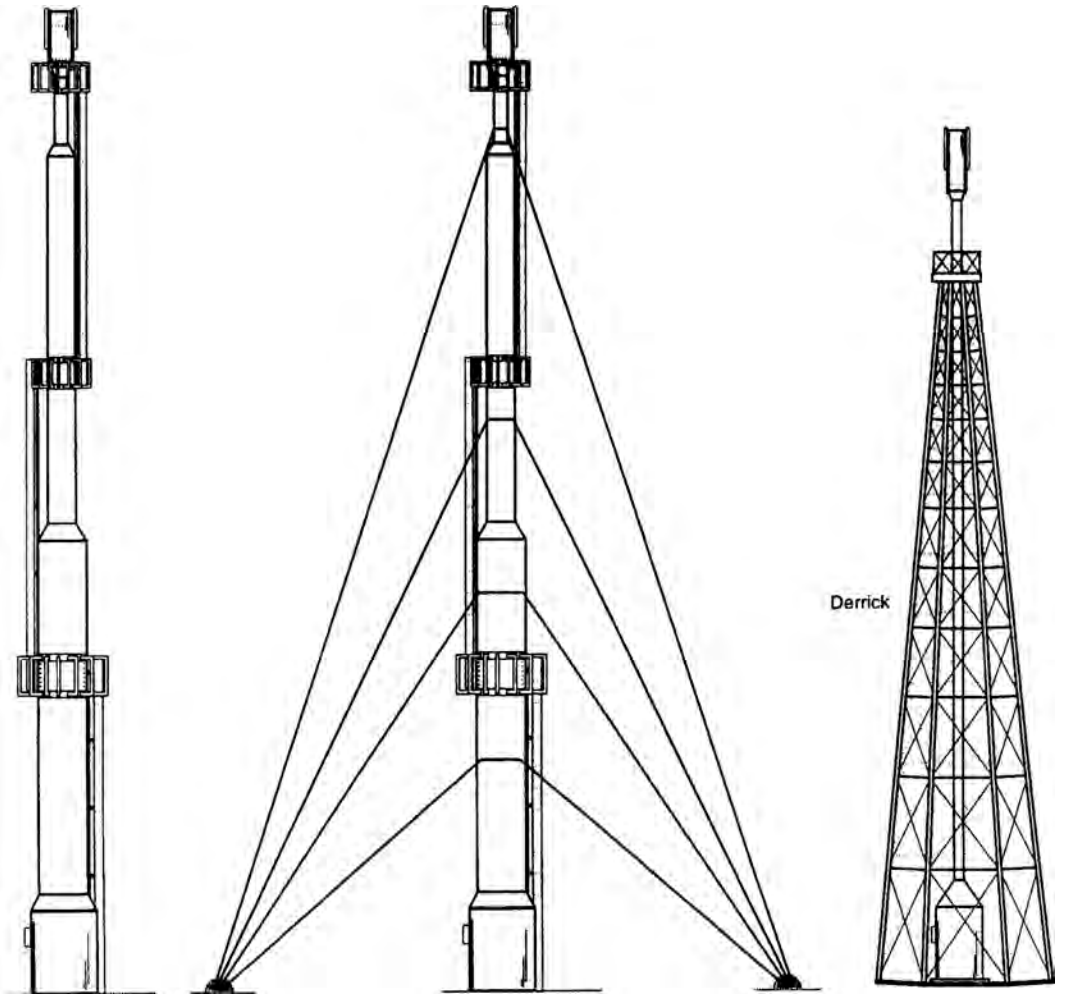


Fig. 10.14—Elevated flare stack configurations: (a) self-supported, (b) guyed supported, and (c) derrick supported.

used to take advantage of prevailing winds. **Fig. 10.16** shows a diagram of an offshore flare boom.

Derrick-Supported Flares. Derrick-supported flares (see **Fig. 10.17**) are the most common flare towers used offshore. They provide the minimum footprint (four-legged design) and dead load, which are critical design parameters for offshore flares and normally are used when space is limited and relief quantities moderate. Disadvantages of derrick-supported flares include possible crude-oil spill onto the platform, interference with helicopter landing, and higher radiation intensities.

Bridge-Supported Flares. In the bridge-supported flare (see **Fig. 10.18**), the production platform is connected to a separate platform that is devoted to the flare structure. Bridges can be as much as 600 ft long, and bridge supports usually are spaced approximately every 350 ft.

Remote Flares. Remote flares (see **Fig. 10.19**) are located on a separate platform connected to the main platform by a subsea relief line. The main disadvantage of remote flares is that any liquid carryover or subsea condensation will be trapped in pockets in the connecting line.

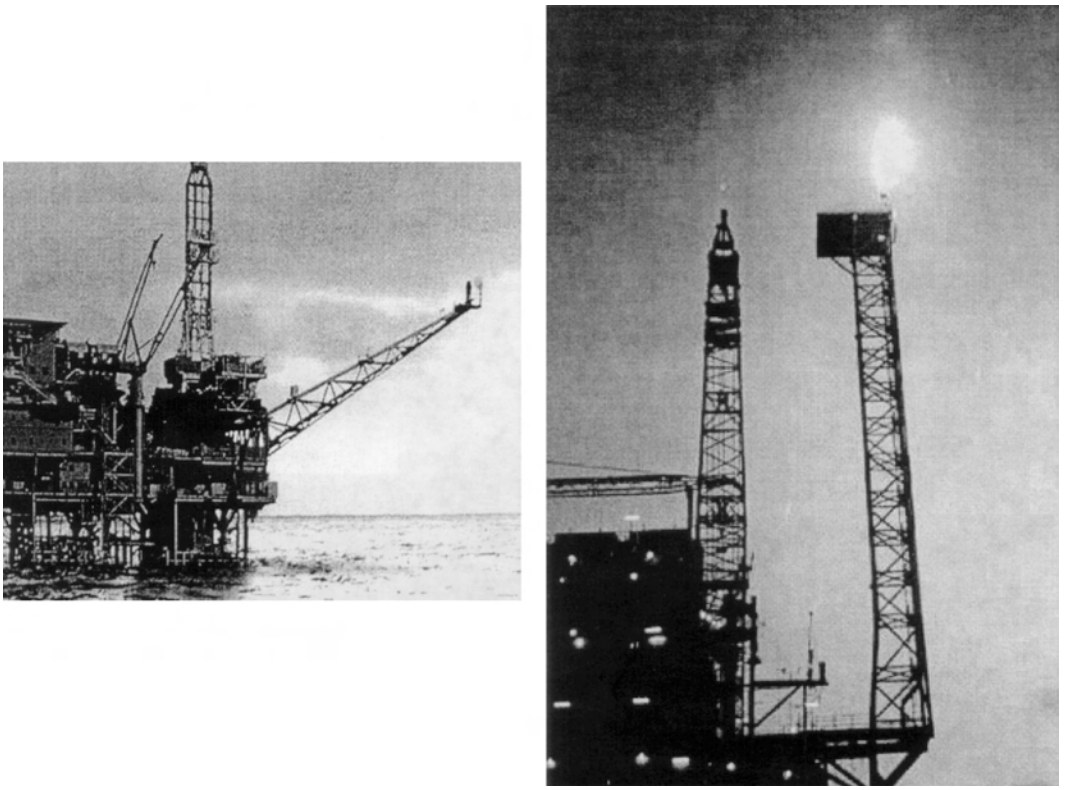


Fig. 10.15—Typical offshore flare-support structures: (a) angle flare boom and (b) vertical tower.

Flare-Stack Design Criteria. Important design criteria that determine the size and cost of flare stacks include flare-tip diameter and exit gas velocity, pressure-drop considerations, flare-stack height, gas dispersion limitations, flame distortion caused by lateral wind, and radiation considerations.

Flare-Tip Diameter and Exit Gas Velocity. The flare-tip diameter should provide a large enough exit velocity so that the flame lifts off the flare tip but not so large as to blowout the flare. The flare diameter and gas velocity normally are determined by the flare supplier. They are sized on the basis of gas velocity, although pressure drop should be checked.

Flare-Tip Diameter. Low-pressure flare tips are sized for 0.5 Mach for a peak, short-term, infrequent flow (emergency release) and 0.2 Mach for normal conditions, where Mach equals the ratio of vapor velocity to sonic velocity in that vapor at the same temperature and pressure and is dimensionless. These API 521 recommendations are conservative.[6] Some suppliers are designing "utility-type" tips for rates up to 0.8 Mach for emergency releases. For high-pressure flare tips, most manufacturers offer "sonic" flares that are very stable and clean burning; however, they do introduce a higher backpressure into the flare system. Smokeless flares should be sized for the conditions under which they are to operate smokelessly.

Velocity Determination. The sonic velocity of a gas can be calculated with

$$V_S = \left(\frac{1720kTZ}{S}\right)^{1/2} . \quad \text{..... (10.2)}$$

Gas velocity can be determined from

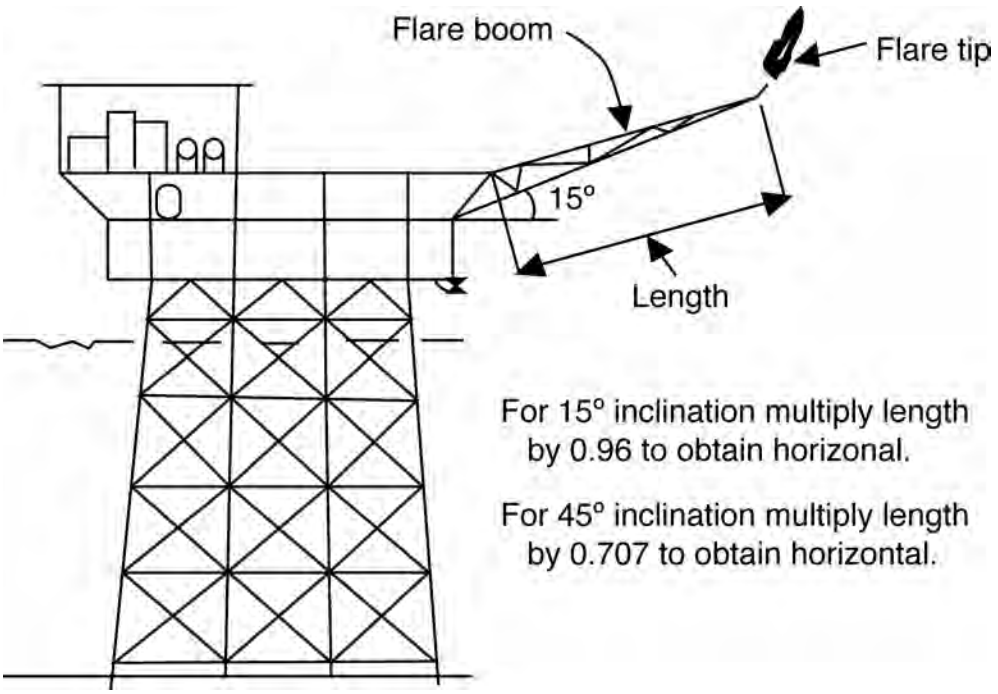


Fig. 10.16—Offshore flare boom.

$$V = \frac{\left(60 Q_g T Z\right)}{d_i^2 P_{CL}}, \quad \text{..... (10.3)}$$

and the critical flow pressure at the end of the relief system can be calculated with

$$P_{CL} = \frac{(2.02) Q_g}{d_i^2}\left(\frac{TS}{k(k+1)}\right)^{0.5}, \quad \text{..... (10.4)}$$

where d_i = pipe inside diameter, in.;
k = ratio of specific heats, C_P/C_V;
P_{CL} = critical pressure at flare tip, always ≥ 14.7, psia;
Q_g = gas-flow rate, MMscf/D;
S = specific gravity, ratio;
T = temperature, °R;
V = gas velocity, ft/s;
V_S = sonic velocity, ft/s;
and
Z = gas compressibility at standard conditions, where air = 1, psi^{-1}.

Pressure-Drop Considerations. Pressure drops as large as 2 psi have been used satisfactorily. If the tip velocity is too small, it can cause heat and corrosion damage. Furthermore, the burning of the gases becomes quite slow and the flame is influenced greatly by the wind. The low-pressure area on the downwind side of the stack may cause the burning gases to be drawn down along the stack for 10 ft or more. Under these conditions, corrosive materials in the

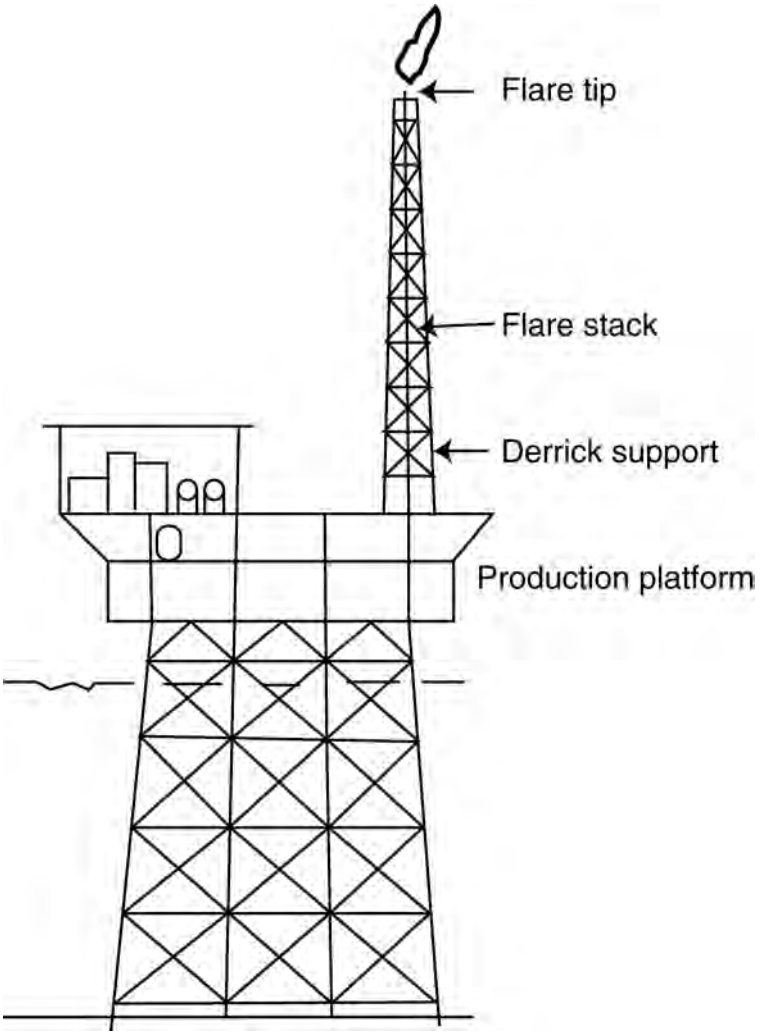


Fig. 10.17—Derrick-supported flare.

stack gases may attack the stack metal at an accelerated rate, even though the top 8 to 10 ft of the flare is usually made of corrosion-resistant material.

For conventional (open-pipe) flares, an estimate of the total flare pressure drop is 1.5 velocity heads, which is based on nominal flare-tip diameter. The pressure drop is determined by

$$\Delta P_W = \frac{\rho_g V^2}{(2g)(144)} = \frac{\rho_g V^2}{9{,}274}, \quad \text{..... (10.5)}$$

where g = acceleration due to gravity, 32.3 ft/s^2; V = gas velocity, ft/s; ΔP_W = pressure drop at the tip, inches of water; and ρ_g = density of gas, lbm/ft^3. **Fig. 10.20** shows a "quick-look" nomograph to determine the flare-tip diameter.

Flare-Stack Height. The height is generally based on the radiant-heat intensity generated by the flame. The stack should be located so that radiation releases from both emergency and long-term releases are acceptable and so that hydrocarbon and H_2S dispersion is adequate if the

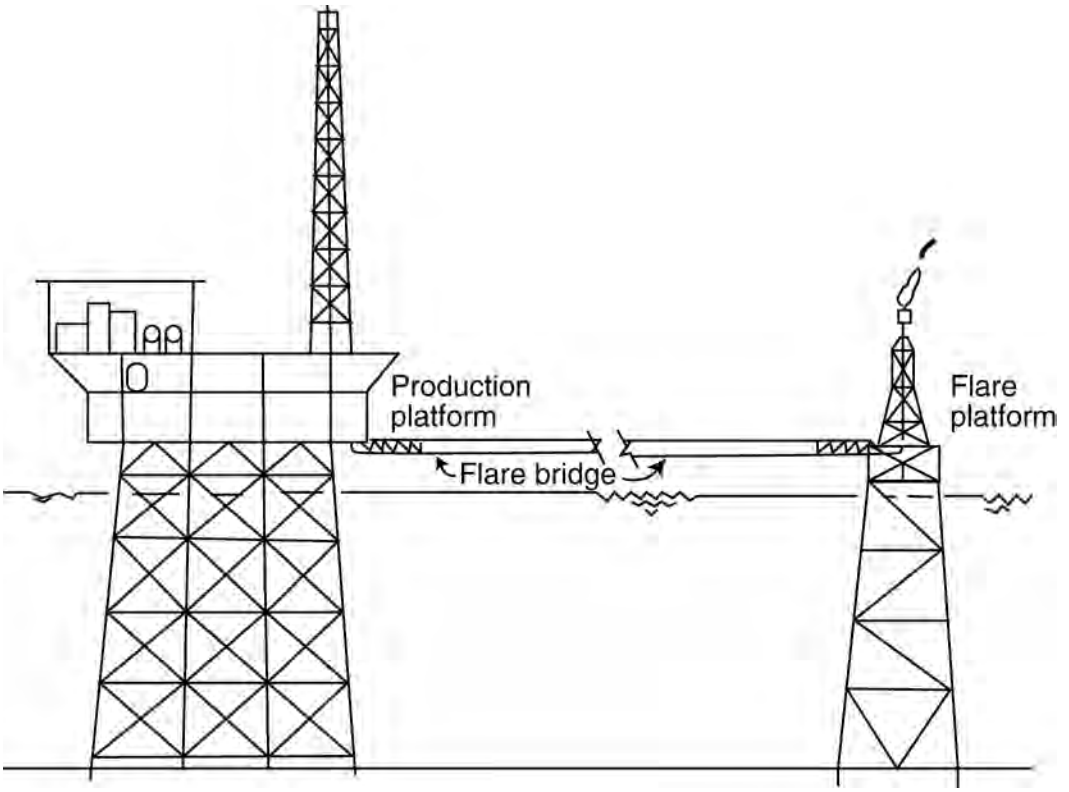


Fig. 10.18—Bridge-supported flare.

flame is extinguished. The stack also should be structurally sound and withstand wind, earthquake, and other miscellaneous loadings. *RP 521,* Appendix C, provides guidance on sizing a flare stack.[6]

The Hajek and Ludwig equation (see *RP 521*) may be used to determine the minimum distance from a flare to an object whose exposure to thermal radiation must be limited.

$$D = \left(\frac{\tau E Q}{4\pi K}\right)^{0.5}, \quad \text{..... (10.6)}$$

where D = minimum distance from the midpoint of the flame to the object being considered, ft;
E = fraction of heat radiated;
K = allowable radiation level, BTU/hr-ft^2;
Q = heat release (lower heating value), BTU/hr; and
τ = fraction of heat intensity transmitted, defined by Eq. 10.7.

Table 10.1 shows component emissivity, and **Table 10.2** shows allowable radiation levels. Humidity reduces the emissivity values in Table 10.1 by a factor of τ, which is defined by

$$\tau = 0.79\left(\frac{100}{r}\right)^{1/16}\left(\frac{100}{R}\right)^{1/16}, \quad \text{..... (10.7)}$$

where r = relative humidity, fraction;
R = distance from flare center, ft;

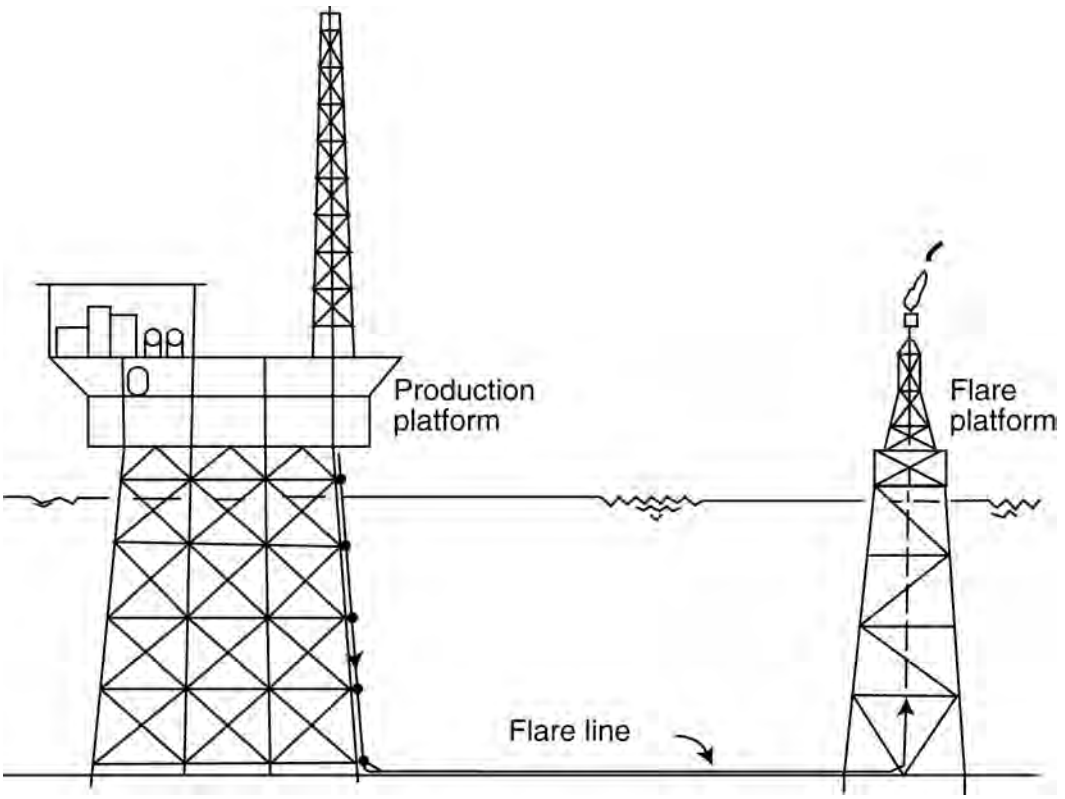


Fig. 10.19—Remote flare with subsea relief line.

and

τ = fraction of heat transmitted, in range of 0.7 to 0.9.

Gas Dispersion Limitations. In some cases, it may be desirable to check the stack height on the basis of atmospheric dispersion of pollutants. Where this is required, the authorities with jurisdiction normally will have a preferred calculation method.

Flame Distortion Caused by Lateral Wind. Another factor to be considered is the effect of wind tilting the flame, which varies the distance from the center of the flame. The center of the flame is considered to be the origin of the total radiant-heat release with respect to the plant location under consideration. **Fig. 10.21** gives a generalized curve for approximating the effect of wind.

Radiation Considerations. There are many parameters that affect the amount of radiation given off by a flare including the type of flare tip, whether sonic or subsonic (HP or LP) or assisted or nonassisted; emissivity of flame produced or flame length produced; amount of gas flow; heating value of gas; exit velocity of flare gas; orientation of flare tip; wind velocity; and humidity level in air.

Several design methods are used for radiation calculations. The most common methods are the API simple method and the Bruztowski and Sommers method. Both methods are listed in *RP 521,* Appendix C.[6] These methods are reasonably accurate for simple low-pressure pipe flares (utility flare) but do not accurately model high-efficiency sonic-flare tips, which produce short, stiff flames. The fourth edition of *RP 521* suggests that manufacturers' proprietary calculations should be used for high-efficiency sonic-flare tips.[6]

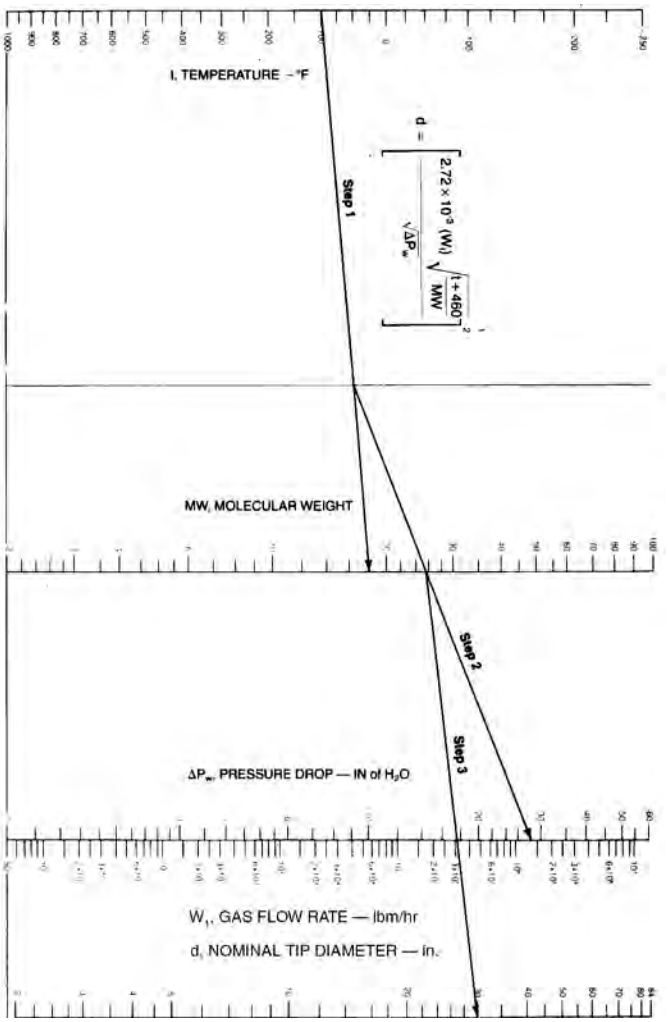


Fig. 10.20—Nomograph to determine flare-tip diameter.

Purge Gas. Purge gas is injected into the relief header at the upstream end and at the major branches to maintain a hydrocarbon-rich atmosphere in each branch, into the off-plot relief system, and into the flare stack. The gas volume typically is enough to maintain the following velocities: ft/s for density seals, 0.4 ft/s for fluidic seals, and 0.4 to 3 ft/s for open-ended flares. *RP 521* states that the oxygen concentration must not be greater than 6% at 25 ft inside the tip.[6] When there is enough PSV leakage or process venting to maintain the desired backpressure, no purge gas is injected.

Burn Pits. Burn pits can handle volatile liquids. They must be large enough to contain the maximum emergency flame length and must have a drain valve and pump (if required) to dispose of trapped water. The flare should be pointed down, and the pilot should be reliable. Because of the uncertainty regarding the effects of wind on the center of the flame, it is recommended that the greater of either 50 ft or 25% be added to the calculated required distance behind the tip. Burn pits should be at least 200 ft from property lines. A fence or some other positive means for keeping animals and personnel away from a potential radiation of 1,200 BTU/hr-ft^2 should be installed.

TABLE 10.1—EMISSIVITY (after API *RP 521*[5])

Component	Emissivity
Methane	0.11 to 0.15
Butane	0.22 to 0.33
Natural Gas	0.19 to 0.23

TABLE 10.2—ALLOWABLE RADIATION LEVELS* (after API *RP 521*[5])

	Allowable Radiation (Btu/hr-ft^2)		
Condition	*RP 521*	One Industry Method	NAO
Areas in which operators are not likely to be. Exposure limited to a few seconds.	5,000	5,000	—
Areas in which operators have access. Exposure limited to a few seconds.	3,000	1,200	—
Equipment indefinitely exposed.	5,000	1,000	3,000
Areas in which emergency action lasting up to 1 minute is necessary.	2,000	—	—
Areas in which emergency action lasting several minutes is necessary.	1,500	—	1,500
Personnel continuously exposed.	500	300	440

*Values assume an additional solar radiation of 200 to 300 Btu/hr-ft^2 is present. Normally design flare for 200 to 500 Btu/hr-ft^2.

Vent Design. The size of a vent stack must consider radiation, velocity, and dispersion.

Radiation. The vent should be located so that radiation levels from ignition are acceptable.

Velocity. The vent must have sufficient velocity to mix air with gas to maintain the mixed concentration below the flammable limit within the jet-dominated portion of the release. The vent should be sized for an exit velocity of at least 500 ft/s (100 ft/s minimum). Studies indicate that gases with velocities of 500 ft/s or more have sufficient energy in the jet to cause turbulent mixing with air and will disburse gas in accordance with the following equation.

$$\frac{W}{W_o} = 0.264\left(\frac{Y}{D_t}\right), \quad \text{..... (10.8)}$$

where W = weight flow rate of the vapor/air mixture at distance Y from the end of the tailpipe;

W_o = weight flow rate of the relief-device discharge, in the same units as W;

Y = distance along the tailpipe axis at which W is calculated;

and

D_t = tailpipe diameter, in the same units as Y.

Eq. 10.8 indicates that the distance Y from the exit point at which typical hydrocarbon relief streams are diluted to their lower flammable limit occurs approximately 120 diameters from the end of the discharge pipe. As long as a jet is formed, there is no fear of large clouds of flammable gases existing below the level of the stack. The distance to the lean flammability concentration limits can be determined from Figs. 10.3 through 10.5.[6] The horizontal limit is approximately 30 times the tailpipe diameter.

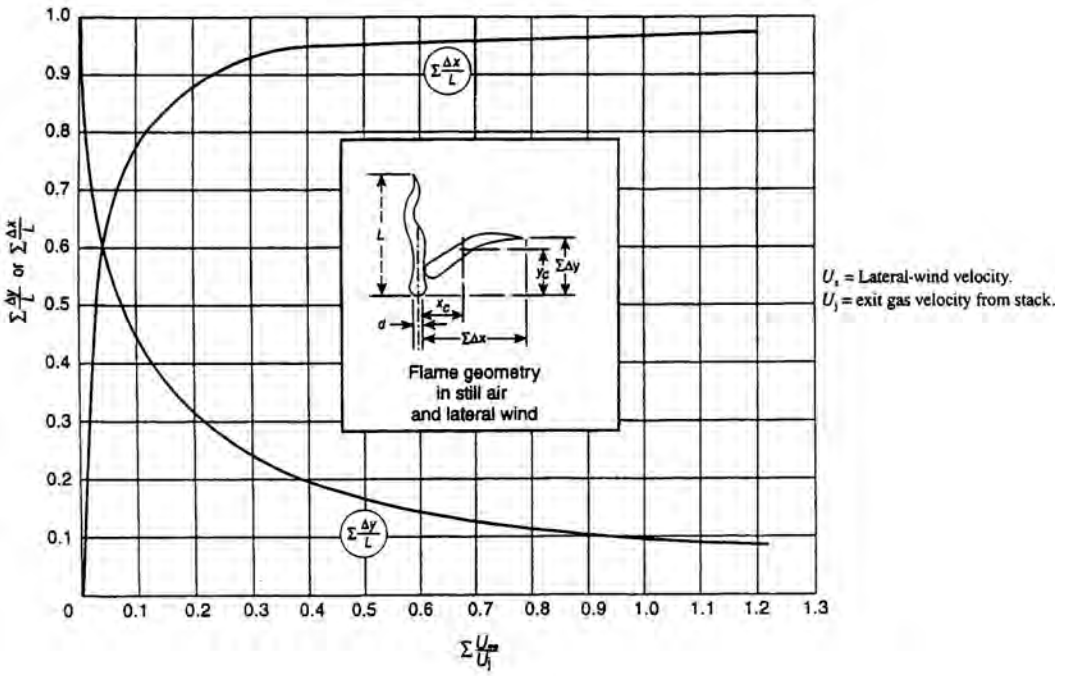


Fig. 10.21—Approximate flame distortion caused by lateral wind on jet velocity from flame stack. (Courtesy of the American Petroleum Institute.[6])

Industry practice is to locate vent stacks 50 ft horizontally from any structure running to a higher elevation than the discharge point. The stacks must vent at least 10 ft above any equipment or structure within 25 to 50 ft above a potential ignition source. Because the flame can be ignited, the height of the stack must be designed or the pit located so that the radiation levels do not violate emergency conditions.

Dispersion. The vent must be located so that dispersion is adequate to avoid potential ignition sources. The dispersion calculation of low-velocity vents is much more difficult and should be modeled by experts familiar with the latest computer programs. Location of these vents is very critical if the gas contains H_2S because even low concentrations at levels accessible by personnel could be hazardous. The location of low-velocity vents should be checked for radiation in the event of accidental ignition.

Nomenclature

C_p/C_V = specific heats at constant pressure and temperature, dimensionless
d = nominal tip diameter, L, in.
d_i = pipe inside diameter, L, in.
D = minimum distance from the midpoint of the flame to the object being considered, L, ft
D_t = tailpipe diameter, L, in the same units as Y
E = fraction of heat radiated
g = acceleration due to gravity, 32.3 ft/sec^2
h = height of liquid seal, L, ft
k = ratio of specific heats, C_P/C_V
K = allowable radiation level, BTU/hr-ft^2
L = flame length, L, ft

p = maximum allowable header backpressure, m/Lt^2, psi
P_{CL} = critical pressure at flare tip, m/Lt^2, psia
Q = heat release (lower heating value), BTU/hr
Q_g = gas-flow rate, MMscf/D
r = relative humidity, fraction
R = distance from flare center
S = specific gravity, fraction
t = temperature, T, °F
T = temperature, T, °R
$\underline{U}_x$ = lateral-wind velocity, L
$\underline{U}_j$ = exit gas velocity from stack, L
V = gas velocity, L/t, ft/sec
V_S = sonic velocity, L/t, ft/sec
W = weight flow rate of the vapor/air mixture at distance Y from the end of the tailpipe, mL/t
W_f = gas-flow rate, lbm/hr
W_o = weight flow rate of the relief device discharge in the same units as W, mL/t
x_c = horizontal distance from flare tip to flame center, L
y_c = vertical distance from flare tip to flame center, L
Y = distance along the tailpipe axis at which W is calculated, L
Z = gas compressibility at standard conditions, Lt^2/m, psi^{-1}
ΔP_W = pressure drop at the tip in inches of water
Δx = horizontal flame distortion caused by lateral wind, L, ft
Δy = vertical flame distortion caused by lateral wind, L, ft
ρ = sealing-liquid density, lbm/ft^3
ρ_g = density of gas, lbm/ft^3
τ = fraction of heat intensity transmitted

References

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3. "Pressure Vessels," *Boiler and Pressure Vessel Code,* Sec. 8, Divisions 1 and 2, ASME, New York City (2001).
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5. *RP 520, Design and Installation of Pressure Relieving Systems in Refineries, Part 2*, fifth edition, API, Washington, DC (2003).
6. *RP 521, Guide for Pressure-Relieving and Depressuring Systems*, fourth edition, API, Washington, DC (1999).
7. "Occupational Safety and Health Standards," regulations, 29 CFR Part 1910, U.S. Dept. of Labor, Washington, DC (March 1999).
8. *STD 2000,* Venting Atmosphere and Low-Pressure Storage Tanks—Nonrefrigerated and Refrigerated, fifth edition, API, Washington, DC (1999).

SI Metric Conversion Factors

Btu	×	1.055 056	E+00	= kJ
Btu/hr	×	2.930 711	E+01	= W
ft	×	3.048*	E−01	= m
ft/s	×	3.048*	E−01	= m/s
ft/s^2	×	3.048*	E−01	= m/s^2
ft^2	×	9.290 304	E−02	= m^2
ft^3	×	2.831 685	E−02	= m^3
°F		(°F − 32)/1.8		= °C
lbm	×	4.535 924	E−01	= kg
lbm/ft^3	×	1.601 846	E+01	= kg/m^3
psi	×	6.894 757	E+00	= kPa
°R		°R/1.8		= °K

*Conversion factor is exact.

Chapter 11
Liquid and Gas Measurement

Marsha Yon, Daniel Measurement & Controls Inc., **Kevin L. Warner** and **Tom Mooney,** Daniel Industries Inc.

11A Liquid Meters—Marsha Yon

11A.1 Introduction. Flow measurement begins with a properly operating flowmeter; however, measurement procedures and correct flow calculations equally contribute to good overall system performance. Guidelines for liquid hydrocarbon measurement are detailed in the American Petroleum Institute's (API's) *Manual of Petroleum Measurement Standards (MPMS),* a comprehensive, ongoing publication in which chapters are periodically revised and then released. Commonly referenced standards include: Chap. 4 "Proving Systems," Chap. 5 "Metering," Chap. 7 "Temperature Determination," Chap. 9 "Density Determination," Chap. 11 "Physical Properties Data," Chap. 12 "Calculation of Petroleum Quantities," Chap. 13 "Statistical Aspects of Measuring and Sampling," Chap. 14 "Natural Gas Fluids Measurement," and Chap. 21 "Flow Measurement Using Electronic Metering Systems."

The information in this chapter covers the characteristics of three types of flowmeters that are commonly used for the measurement of liquid hydrocarbons: the selection criteria for a flowmeter, the basics of field meter proving, and specifics on the design and operation of a lease automated custody transfer (LACT) system.

Liquid flowmeters can be classified in two general areas: (1) a positive displacement meter that continuously divides the flowing stream into known volumetric segments, isolating the segments momentarily and returning it to the flowing stream while counting the number of displacements; and (2) an inference meter that "infers" flow by measuring some dynamic property of the flowing stream. Typical inference meters are turbine meters that infer flow by monitoring impeller speed, orifice meters that monitor pressure differential, and the Coriolis meter, which senses the Coriolis force on vibrating tubes to infer flow rate.

11A.2 Positive Displacement Meters. Positive displacement (PD) liquid meters have long been the standard of measurement for liquid hydrocarbons such as crude oil. Over the years, numerous design improvements have resulted in an expanded product line that now serves industrial as well as petroleum applications.

Theory of Operation of PD Meters. A liquid meter is, in essence, a hydraulic motor with high volumetric efficiency that absorbs a small amount of energy from the flowing stream.

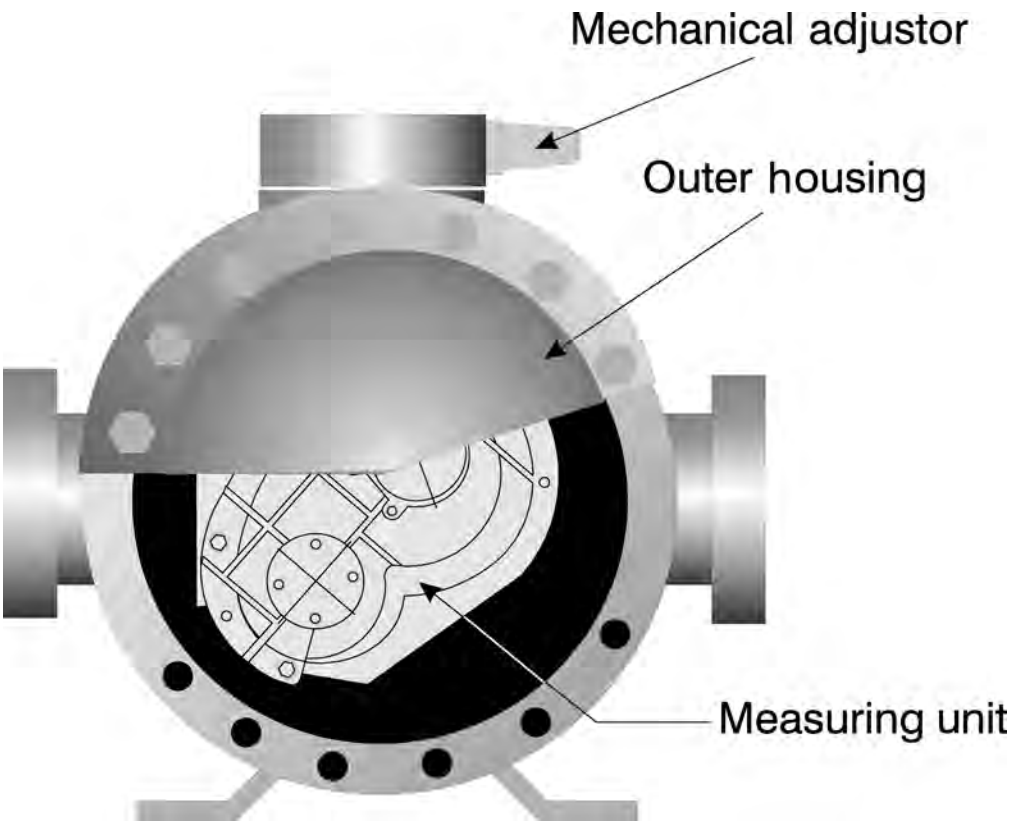


Fig. 11A.1—Components of a PD meter (courtesy of Emerson Process Management).

This energy is used to overcome internal friction in driving the meter and its accessories and is reflected as a pressure drop across the meter. Pressure drop is regarded as a necessary evil that must be minimized. Pressure drop across the internals of a PD meter actually creates a hydraulically unbalanced rotor, which causes rotation. A PD meter can be broken down into three basic components. These are the external housing, the measuring unit, and the counter drive train. See **Fig. 11A.1**.

The external housing is the pressure vessel that contains the product being metered. It can be a single- or double-case construction. A single-case meter has the housing and the measuring chamber walls as one integral unit. In double-case construction, the external housing is separate from the measuring unit and serves only as a pressure vessel. This type of construction has two major advantages: (1) the measuring chamber walls only sense the delta pressure across the meter inlet and outlet, which allows for thinner chamber walls with less distortion, and (2) system piping stresses that are absorbed in the external housing are not transmitted to the precision measuring element.

The measuring unit is a precision metering element and is made up of the measuring chamber and the displacement mechanism. The six PD designs most commonly used are the piston, sliding vane, oval, trirotor, birotor, and disc. See **Fig. 11A.2**.

The counter drive train is used to transmit the internal motion of the measuring unit into a usable output signal. Many PD meters use a mechanical gear train, which requires a rotary shaft seal or packing gland where the shaft penetrates the external housing. Other meters may use magnetic drive couplings, reed switch outputs (contact closure), and differential inductance

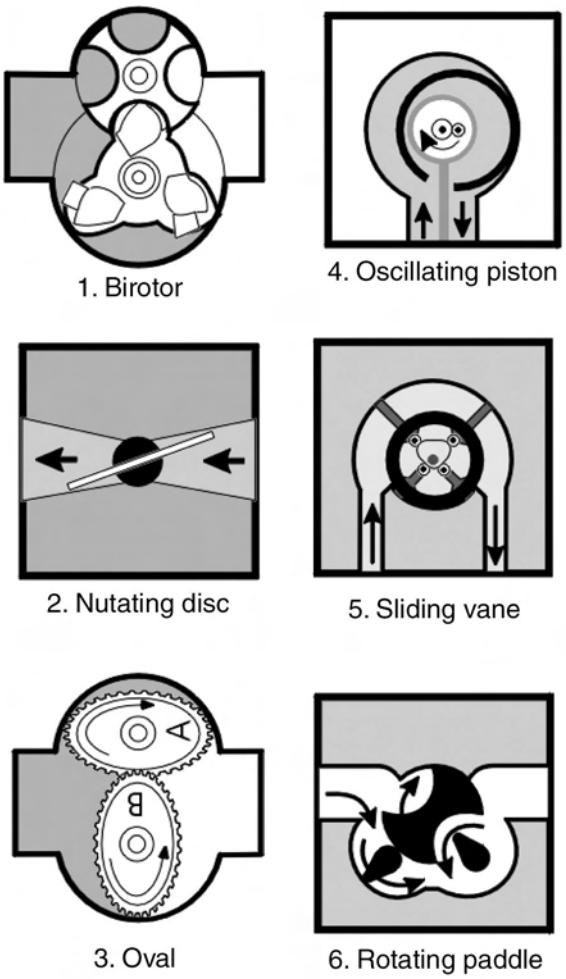


Fig. 11A.2—Types of positive displacement meters (courtesy of Emerson Process Management).

(DL) pickoffs. These last three offer the advantages of lower driving torque and no seals that could leak the product.

Design Considerations for PD Meters. Most hydrocarbons are metered using a capillary seal PD meter. In this design meter, the capillary action of the metered product forms a liquid seal between moving and stationary parts. This type of meter requires very close clearance dimensions and is sensitive to differential pressure.

Product slippage is the most crucial problem affecting the accuracy of a capillary seal PD meter. All capillary seal PD meters have some clearance between moving and stationary parts and some differential pressure across these clearances. For this reason, there will always be some product that is allowed to bypass the measuring chamber by "slippage" through these clearances. If slippage were constant at all operating conditions, it could be corrected by the counter drive train gearing and would cause no inaccuracy. However, it is not constant and does vary with flow rate, pressure drop, temperature, viscosity, and clearance dimensions.

11A.3 Turbine Flowmeters. Turbine flowmeters are an effective means of accurate measurement of liquid/gas products in many industries. Because of the turbine meter's versatility and

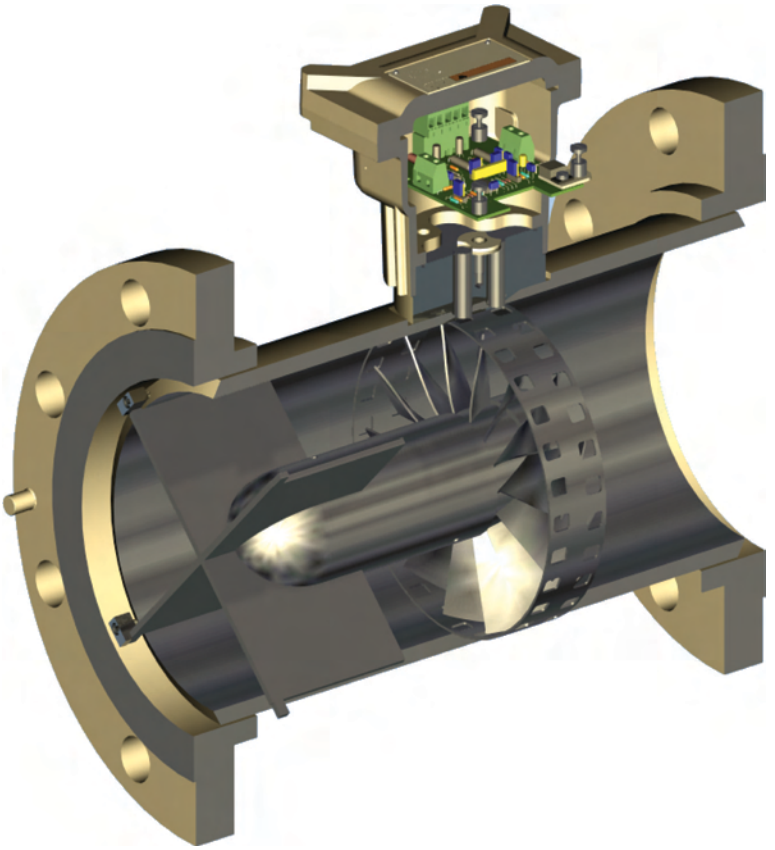


Fig. 11A.3—Typical turbine meter design (courtesy of Emerson Process Management).

flexibility in product metering applications, it is one of the most widely used technologies in flow measurement.

Turbine meters were invented in the 18th century by Reinhard Woltman, and at that time were used for water-flow measurement. In the 1950s, turbine meters were first used for hydrocarbon measurement for aeronautical applications within aircraft. In 1970, the API recognized the turbine meter in *MPMS* Chap. 5 Sec. 3, "Measurement of Liquid Hydrocarbons by Turbine Meters."[1] With these published standards, the turbine meter gained recognition as a custody-transfer metering technology acceptable for use in liquid-petroleum-products metering systems. These systems include crude-oil production and pipelines, petroleum product pipelines, refinery applications, tanker loading and unloading, crude-oil terminals, and refined-product loading-rack terminals. For additional information about turbine meters and their use in gas measurement, see Sec. 11B.3 of this chapter.

Theory of Operation of Turbine Meters. Turbine meters are inferential measurement devices. They infer the volumetric flow rate based on the mechanical properties of the meter and the physical properties of the measured fluid. Turbine meters are a combination of a mechanical assembly and electronic components to measure volumetric flow rates. See **Fig. 11A.3**.

The turbine meter consists of a rotor with multiple blades mounted on a free-running bearing system. Fluid flow through the meter impinges on the turbine blades, causing the rotor to rotate on its axis along the centerline of the turbine-meter housing. The angular velocity to the turbine rotor is directly proportional to the fluid's linear velocity through the meter housing.

Given the fixed cross-sectional area of the meter housing and the linear velocity of the fluid through this area, the volumetric flow rate can be calculated.

A voltage pulse signal is produced as the rotor blade passes a magnetic pickup coil mounted externally on the meter housing. Each pulse represents a discrete volume of liquid. The number of pulses per unit volume is called the meter's *K*-factor. The *K*-factor is determined during flow calibration and is unique to each and every meter. In smaller meter sizes, the unit of volume is typically given in gallons or liters. In larger meters, the unit of volume is typically given in barrels or cubic meters.

11A.4 Coriolis Flowmeters. A meter utilizing the Coriolis force to measure mass flow rate was first patented in 1978. Most Coriolis meters can measure the density of the fluid in addition to the mass flow rate. Therefore, because volume flow rate is equal to mass flow rate divided by density, the associated electronics package can be programmed to output the volume flow rate. At this point, Coriolis meters become volume flow rate meters and can provide an output similar to such other meters as positive displacement and turbine meters. For additional information about Coriolis meters and their use in gas measurement, see Sec. 11B.5 of this chapter.

Theory of Operation of Coriolis Meters. The Coriolis force as first identified in 1835 refers to the deflection relative to the Earth's surface of any object moving about the Earth. This force can also be produced on a vibrating tube(s). When a fluid moves through the vibrating tube(s), the Coriolis force causes the tube(s) to distort slightly. The degree of distortion is directly proportional to the mass flow rate of the fluid. Coriolis manufacturers use various proprietary techniques to monitor the magnitude of the distortion and process the measured signals into useable measurement information. As mass flow rate through the vibrating tube(s) increases, the offset in position or distortion monitored between the upstream and downstream portions of the tube(s) increases. See **Fig. 11A.4** for a typical Coriolis meter design. In addition to measuring the Coriolis force, most meters are capable of utilizing the frequency of vibration of the tube(s) to measure density.

Coriolis Sensor Considerations. Most manufacturers offer a comprehensive sizing program that provides information regarding accuracy, flow rate, pressure drop, and velocity with any given fluid and process condition.

Coriolis meters offer the advantage of a large turndown ratio—more than twice the turndown of a turbine meter. Flow velocity through a Coriolis meter is generally high. Velocity should always be considered when sizing a meter for an erosive fluid with high solids content and when considering piping limitations including pressure drop. The pressure drop across the meter should be known in order to select the proper size sensor. For example, a 4-in. meter can handle a rate of 2,500 bbl/hr but has a pressure drop at this rate of 13 psi (with a viscosity of 1 cp). Pressure drop should always be considered with any flowmeter that is operating near a fluid's equilibrium vapor pressure so that the fluid does not cavitate or flash at the metering point. Air or gas slugs do not damage the meter; however, Coriolis meters are not intended to meter multiphase fluids.

Coriolis Transmitter Considerations. Coriolis meters are electronic. They require power and some associated device that interprets the signals from the meter and provides useable digital, analog, or serial outputs. Most meters today have a separate device or transmitter, but advances in technology have produced meters that produce an output directly from the sensor. Whether in a separate housing or located on the meter, there is a central processing unit (CPU) that is programmed to provide the output required. The CPU is programmed with the meter's calibration coefficients and is programmed to output in the required units of measurement. Because there is no movement or mechanical action in the meter that can be utilized to produce a pulse, the CPU is also programmed to produce the pulse required for proving and for totalization.

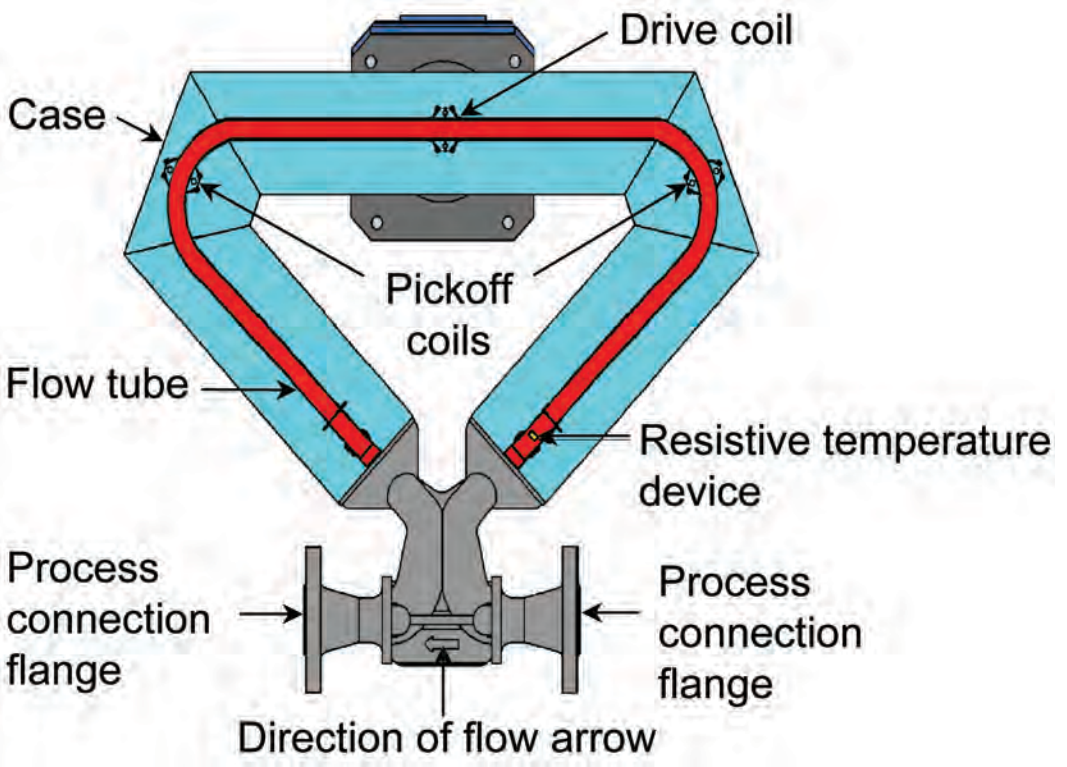


Fig. 11A.4—Components of a Coriolis meter (courtesy of Emerson Process Management).

Given the capabilities of electronics today, additional features such as alarm and control outputs, averaging, and calculation of relative density are easily a part of a Coriolis transmitter. Because the Coriolis meter is programmable, the means of configuring the meter should be understood in addition to the security of the device after installation in the field.

11A.5 Metering System Design. Certain basic installation requirements are needed for proper operation of a positive displacement meter or a turbine meter. As a minimum, strainers, adequate upstream and downstream straight pipe, flow conditioning, and a downstream control valve are required. These meters operate best with clean fluid streams. Debris in the flow stream that is allowed to pass through the meter limits the life of the meter. A strainer or filter upstream of the meter should be utilized. A properly sized strainer that captures the destructive debris and keeps pressure drop to a minimum is a vital piece of equipment in a metering system.

Positive displacement and turbine meters are susceptible to disturbances in the flow stream. Flow disturbances can be caused by any upstream piping configuration that results in distortion of the fluid flow profile. Elbows and bends in the pipe upstream of the meter can produce a bulk swirl in the flowing fluid, which, if left uncorrected, could result in very unreliable measurements. For this reason, it is recommended that the meter be installed in a properly-sized run of pipe (or specially manufactured meter tube for greater accuracy) with a minimum of 10 diameters of straight unobstructed pipe upstream of the meter and 5 diameters downstream. It is important that all flanged connections in the upstream section to the turbine meter, as well as the downstream section, be properly aligned. Proper alignment throughout the metering section eliminates offsets, steps, and gaskets protruding into the bore, all of which can disturb the flow pattern. Dowel pinning of flanges can also aid in proper alignment of the metering section.

The historical method of flow conditioning utilizes straightening vanes or tube bundles. While this method is adequate for eliminating the swirl component of the flowing fluid, it does nothing for the velocity flow profile. Several manufacturers can provide isolation flow conditioners that eliminate the swirl and form a uniform velocity flow profile of the fluid before the flowmeter.

Proving connections downstream of the meter should be provided to facilitate proving of the meter, with a properly calibrated proving meter or "prover," under conditions as close to the normal operating conditions as practical. See API *MPMS* Chap. 4 for further description of a prover. The proving connections consist of two tees separated by a block and bleed valve in the run of pipe downstream of the meter. Block valves are installed on the outlet of each tee to allow the prover to be attached and flow to be directed to it in series with the meter being "proved."

Following the proving connections, another essential component for proper operation of the metering system is a control valve. The control valve is important because it helps to maintain a minimum backpressure on the meter to prevent meter cavitations and product flashing.

Unlike meters with moving parts, the Coriolis meter can handle typical pipeline solids without damage to the meter; however, a strainer upstream of the meter is recommended to protect the meter prover. No straightening vanes or flow conditioning is required for a Coriolis meter; therefore, no straight pipe sections upstream or downstream of the meter are necessary. This makes a Coriolis meter ideal for tight locations, as are typical on offshore platforms and for bidirectional metering systems. Consideration should be given to the location of the meter electronics that generate the pulse output so that the proving connections and the transmitter are located in close proximity.

Valves to stop flow through the Coriolis meter are required. Verification that the meter registers zero flow in a nonflowing condition is required on initial installation. The zeroing procedure requires, as a minimum, a block and bleed valve downstream of the meter, and it is preferable to have a shutoff valve upstream to block the meter in during zeroing.

The Coriolis meter acts as a densitometer in addition to measuring flow. There is a considerable cost savings for metering systems that require both the measurement of flow and the measurement of density or gravity when the measurement can be made with a single instrument. Finally, the large turndown of a Coriolis meter can eliminate the use of a bank of several different size meters to cover the rates, again providing a cost savings for the metering system.

11A.6 Flowmeter Performance. Manufacturers typically state performance characteristics for flowmeters based on a factory calibration utilizing water or other stable fluid. "Accuracy" is the measure of how close to true or actual flow the meter indication may be. It is expressed as a percent of true volume for a specific flow range.

Linearity. Linearity is defined as the deviation of measurement from the meter's minimum flow rate specification to the maximum flow rate specification. It is generally expressed as a percentage. For example, a meter with a linearity statement of +/–0.25% means the meter factor for a given meter will not deviate more than 0.5% from the minimum to maximum flow rate.

Repeatability. Repeatability is the meter's ability to indicate the same reading under the same flow conditions. For custody transfer applications, a meter's repeatability is usually specified to be at least 0.05%.

Resolution. Resolution is another key parameter in a meter's performance criteria. Resolution is a measure of the smallest increment of total flow that can be individually recognized by the meter.

Turndown. Turndown is the meter's flow range capability. The flow range of the meter is the ratio of maximum flow to minimum flow over which the specified accuracy or linearity is maintained. For example, a meter with a minimum flow rate of 100 bbl/hr and a maximum

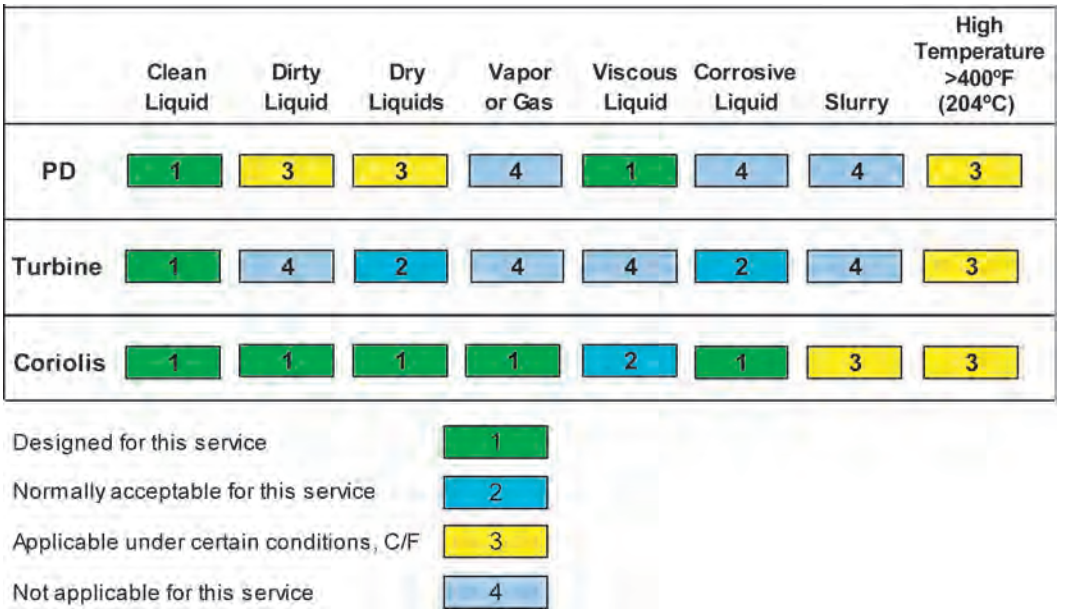


Fig. 11A.5—Flowmeter application guide (courtesy of Emerson Process Management).

flow of 1,000 bbl/hr is said to have a 10:1 turndown. For positive-displacement meters, excessively low rates tend to under-register flow as slippage increases. At excessively high flow rates, there is an increase in wear. A meter should operate optimally around the midpoint of its rated flow range.

11A.7 Flowmeter Selection. Fluid properties often dictate proper meter selection in a liquid application. Liquids such as anhydrous ammonia, refined hydrocarbons like gasoline or diesel, crude oil, and liquefied petroleum gas (LPG) have differing fluid properties such as density, viscosity, pour point, flash point, flowing temperature, and flowing pressure. All of these factors are important when specifying the requirements for the flowmeter. Fig. 11A.5 is a flowmeter application guide based on fluid properties.

Pressure drop through a meter is the amount of permanent pressure loss that is a result of the liquid passing through the meter. Meter manufacturers can provide data to compute expected pressure drop for a variety of liquids. As the viscosity and/or flow rate of the measured product increases, so does the amount of pressure drop. The specified design pressure of the system and the minimum and maximum operating pressures should be provided to the manufacturer. The maximum pressure is used to ensure that the mechanical rating of the meter is sufficient. The minimum pressure is needed to ensure that adequate pressure is available in the system to allow for pressure drop through the meter while maintaining the fluid in a liquid state—in other words, to prevent the product from flashing or changing to a gaseous state. Control valves or backpressure valves are often recommended to maintain sufficient pressure on the fluid as it is metered.

Fluid temperature and ambient temperature are factors to consider. If the product is very cold or very hot, it could well exceed the manufacturer's temperature limits for the electronics, as well as exceed the standard materials temperature range for the meter body or internal parts.

Flowmeters that have internal moving parts may be affected by changes in liquid density and viscosity. For light hydrocarbons, the minimum flow rate capability of the meter may need to be increased to maintain specified linearity and repeatability. Viscosity can also affect the

low end of the meter's flow range. The actual viscosity of the fluid at operating or flowing temperature is what is relevant. A crude oil may have a viscosity of 50 cSt at 60°F; however, the temperature of the crude at flowing conditions may be 80°F, which would significantly reduce the viscosity and increase the actual flow rate range of a given meter.

Chemical compatibility must be considered in the material selection of all internal wetted surfaces. Dry, abrasive products may require special lubricating systems that isolate bearings and gears from the product. Entrained solids are not readily passed by most flowmeters and should be removed by an appropriately meshed strainer upstream of the meter.

Most meters yield gross measurement inaccuracies with a product that contains either free or entrained air. Removal of this air with an appropriately sized air eliminator is essential. Large volumes of free air not only impair accuracy but can also overspeed and destroy a meter with moving parts.

As with all metering systems, the choice of flowmeter technology should be based on cost of ownership. Cost of one type of meter relative to another varies by size and manufacturer. The initial cost, however, is only one of several costs that should be considered. For example:

• Accuracy: consider a 16-in. pipeline meter flowing at 12,000 bbl/hr. With oil priced at $22/bbl, an improved accuracy of only .05% could result in a savings of U.S. $132 for every hour of operation.

• Maintenance: recurring costs in maintaining a meter can be a significant factor in overall meter cost.

11A.8 Meter Proving. Meter proving is the physical testing of the performance of a liquid meter in a liquid service. The main purpose of the test is to assure accuracy. The basic principles of proving a liquid meter are the same whether it is a Coriolis meter, turbine meter, or a positive displacement meter. Each type of meter has its own characteristics when being proved, but the basic principles are the same:

$$\text{Meter factor} = \frac{\text{prover known volume}}{\text{meter reading}} .$$

When proving a meter, the process-fluid conditions must be as stable as possible throughout the proving process. This includes temperature, pressure, flow rate, and density. Before starting a meter proving, let the liquid flow through the meter and prover long enough so that the conditions stabilize. Check for leaks or fluid bypassing around the prover or meter. The only way to obtain a reliable meter factor is to have all the liquid that is measured by the meter also measured by the prover.

When in the field, a meter's performance may change because of installation effects from piping, mechanical wear of the meter, and changes in the physical properties of the metered fluid. Therefore, the meter is proved to adjust for these changes, and the meter factor is applied when calculating the total net volume.

Meters are proved on a periodic basis determined contractually by the buyer and seller or by company policy. Some meters are proved for every batch transaction, which could be several times a day, while other meters may be proved as little as once a quarter. Regular proving ensures that the metering system is providing accurate flow data and confirms the integrity of the metering system.

11A.9 LACT Units. LACT units are designed for unattended custody transfer of crude oil from a seller to a buyer. Flow rate, operating pressure, gravity, and temperature of the oil determine the LACT design. Minimum pressure drop through the piping and components is desirable.

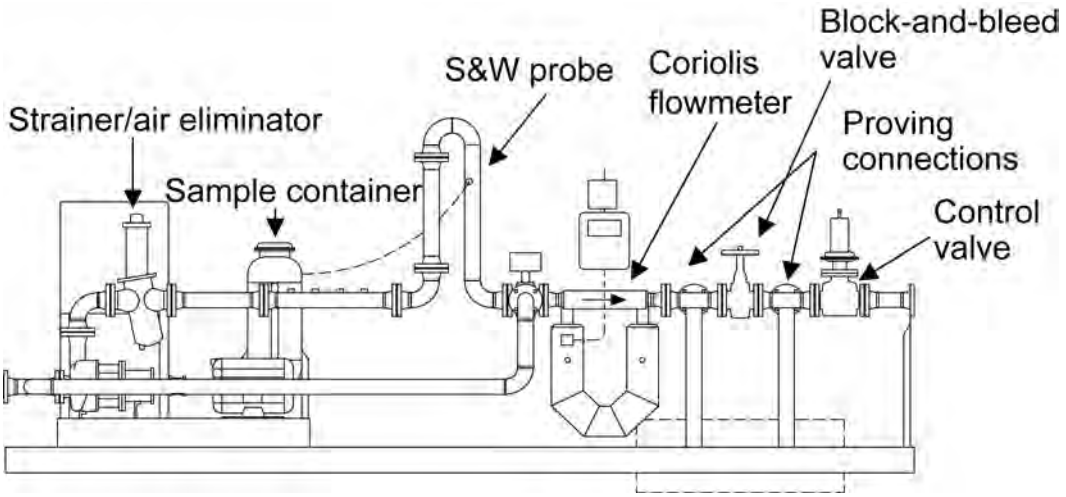


Fig. 11A.6—Typical LACT unit design (courtesy of Emerson Process Management).

LACT units have traditionally been fitted with positive-displacement meters, but a turbine meter can be used with certain types of fluid. New units being built today utilize Coriolis meters because they have no moving parts and can offer a lower cost. See Fig. 11A.4.

Positive displacement meters require certain accessories to read throughput. Large numeral counters equipped with a switch to operate a sample solenoid or provide a meter-failure circuit are common. Right-angle drives and photoelectric transmitters provide a pulse output for proving the meter. Positive-displacement meters must be equipped with some type of mechanical temperature-compensating device or an electronic temperature averager.

Coriolis and turbine meters are available with electronic transmitters that provide a local display, temperature averaging, a sample solenoid switch, and a high-frequency pulse for proving. Coriolis meters also provide an online measurement of observed gravity and calculate corrected gravity.

LACT Design Considerations. Centrifugal pumps are commonly used as charge pumps for LACT units, which typically operate at low enough pressures to allow the use of 150 series American Natl. Standards Inst. (ANSI) flanges. This type of pump provides a smooth flow without pulsation and does not require pressure relief protection. LACT units need a strainer before the pump to trap sediments. Failure to remove these sediments can cause damage to the pump and/or internal parts of the meter. The LACT unit should also have an air eliminator on a rise between the pump and meter to eliminate air or vapors from pumped liquids. Often, the strainer and air eliminator are contained in a single unit. (See **Fig. 11A.6**.)

LACT units are equipped with sediment and water (S&W) monitors that test the oil for the presence of water. The S&W probes are typically internally coated capacitance type for continuous monitoring. The monitor is used to detect unmerchantable oil, generally 0.5% water or more. The monitor sends a signal to an alarm panel that actuates a three-way divert valve that diverts the flow back to the tank to be treated again before it passes through the meter.

The sampling system is very important to the operation of an LACT. Sampler and S&W monitor locations are critical. They are normally installed in a vertical run of pipe downstream of an ell, where the flow is thoroughly mixed so that the probe and sampler "see" a representative sample. The sample probe can be placed downstream of a static mixer. Samplers should be paced by the meter and inject a common sample of 1.5 cm^3 per stroke into the sample container. The size of a sample container is determined by the throughput of the LACT. The

sample line from sampler to the sample container must be sloped downward toward the sample container with no high or low points in the line.

Downstream of the meter is a proving manifold. This manifold consists of three valves. The block and bleed is the inline valve and must be a double block and bleed type so it can be checked for leakage. Proving requires no leakage through this valve. The two bypass valves divert the flow through the prover and back into the line for full flow.

A backpressure valve should be installed downstream of the proving manifold to maintain a constant backpressure on the centrifugal charge pump, meter, and prover and assure constant flow rate through the LACT. A check valve is also needed downstream of the backpressure valve on an LACT unit so fluid cannot flow back from the pipeline and be metered twice.

Pressure gauges are needed on the pump discharge, at the air eliminator/strainer, and at the meter to check for normal operation. These gauges indicate if the strainer needs cleaning or if meter problems exist.

An electrical panel on the LACT controls the function of the unit. The control panel can be mounted on the skid in an explosion-proof enclosure or placed off skid. Newer units are being built with programmable controllers, thus eliminating relays and allowing better control of flow rate, pressure, and sampling.

LACT Operation and Maintenance Considerations.

- The meter and valve drains and all flanges must be checked for leaks.
- The strainer must be cleaned periodically to maintain normal flow rate.
- The S&W monitor should be recalibrated monthly or when a delivery is completed.
- PD meters require periodic maintenance of the gear train, packing gland, the counter, or right-angle drive.
- The block-and-bleed valve should be inspected at each proving for leakage. If a leak is detected, a proving should not be performed until the valve is repaired.
- The charge pump must be checked for excessive vibration or leaking seals. A drop in flow rate may occur if the impeller is partially plugged.

11A.10 Flow Calculations and Overall System Performance. Most flowmeters output a pulse that represents gross volume (volume at flowing conditions). Gross volume is then converted to net volume (volume at contract conditions) with the appropriate corrections for temperature, pressure, S&W, and meter factor. With custody transfer, line integrity, or allocation based on net volumes, it is critical to accurately measure all variables and to maintain all measurement equipment.

PLCs, SCADA equipment, and flow computers offer a huge benefit for real-time monitoring of measurement stations. They offer the advantage of being able to act in a timely manner upon information that can save thousands of dollars in revenue.

11B Gas Meters—Kevin L. Warner and Tom Mooney

11B.1 Introduction. It is widely accepted that global natural gas demand will continue to grow for the foreseeable future, possibly doubling every decade. Major new upstream developments, together with midstream transportation systems and downstream feedstock projects, are already progressing in all world areas. As this gas revolution evolves, there will be a dramatic rise in the requirement for high-accuracy measurement at every point in the gas value chain (Fig. 11B.1).

This value chain can be subdivided into four major categories within which metering is carried out: gas production, gas transmission, gas storage, and gas distribution. Within these categories, there is a huge array of different gas-metering applications and a similar number of potential solutions. This can lead to confusion when selecting the optimum solution for the application.

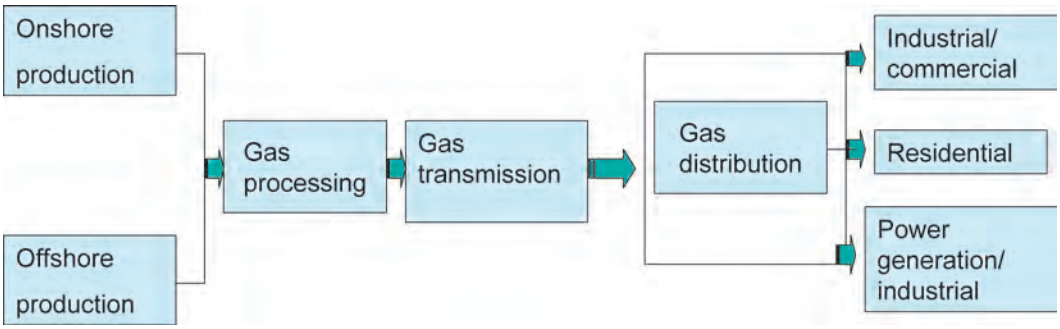


Fig. 11B.1—Gas value chain (courtesy of Daniel Industries).

Two of the traditional approaches have been to use orifice plates or turbine meters. Over the last few years, however, newer technologies, in particular ultrasonic and Coriolis meters, are being used more frequently. Since these are new technologies, many practitioners are unaware of how they compare with the traditional technologies, such as orifice and turbine meters. In particular, it can be difficult to know what flowmeter is most appropriate for a particular project, application, or specific set of circumstances. The aim of this chapter is to address this issue and hopefully provide some pointers to assist engineers with flowmeter selection within the four major categories.

11B.2 Orifice Meters. ***International Standards.*** As a result of its longevity and widespread usage in the industry, the orifice plate is an extremely well documented and regulated measurement device. There are two main standards for orifice metering: ISO *Standard 5167*[2] and AGA *Standard 3*.[3] This chapter is based around the requirements and guidance of ISO *Standard 5167*.[2]

Orifice Flowmeter Overview. The orifice flowmeter consists of a thin, flat plate sandwiched between flanges or installed in a dedicated fitting. The plate has a precise, sharp-edged orifice, bored concentric with the pipe axis. The flow pattern contracts as it approaches the orifice—the contraction continuing to a distance of approximately one orifice diameter downstream. This point of minimum cross section is called the *vena contracta.* Thereafter, the jet diverges to the full-pipe section.

A mathematical model, generated from experimental data, of the conditions in the meter stream must be applied to calculate the flow. Refining this mathematical model is a continual process. The uncertainty in the flow-rate measurement can be predicted in accordance with ISO *Standard 5167*.[2]

There are many ways of locating an orifice plate within a pipeline. These range from a simple orifice flange to a more specialized fitting, such as the long standing Daniel Senior Fitting, which permits removal of the plate under pressure (**Fig. 11B.2**). It should be noted that other manufacturers offer orifice fittings with the similar design objectives.

There are also guidelines as to how the orifice flowmeter should be mounted in the pipeline. Because the orifice flowmeter is particularly sensitive to flow profile distortions, care should be taken to ensure fully developed flow. ISO *Standard 5167*[2] provides details on meter tube design. **Fig. 11B.3** provides a representation of the "catch all" meter tube.

This tube incorporates a 2-diameter straightening vane within the 44-diameter upstream meter tube. Shorter meter-tube configurations may be achieved by using flow conditioners other than simple vanes. These devices may include shorter tube bundles in combination with a perforated "flow conditioning plate" or a thicker perforated plate as a standalone device.

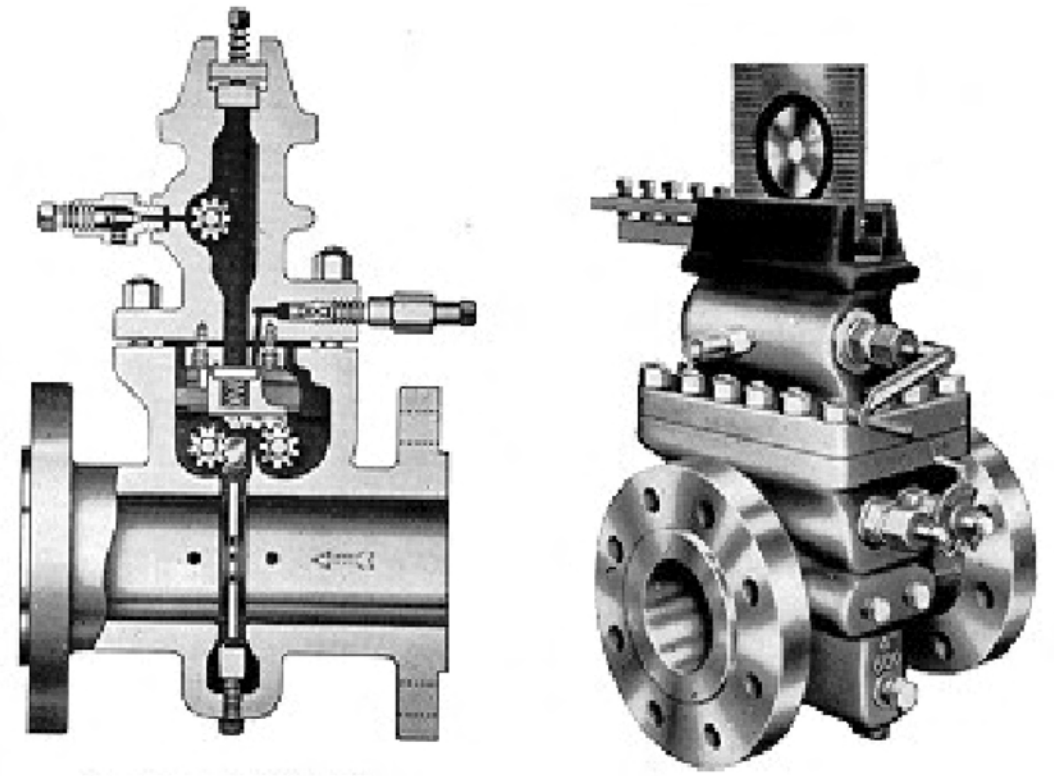


Fig. 11B.2—Orifice fittings (courtesy of Daniel Industries).

Theory of Operation. The installation of the orifice plate causes a static pressure difference between the upstream side and the throat or downstream side of the plate (**Fig. 11B.4**). The rate of flow can be determined from the measured value of this pressure difference and from knowledge of the flowing gas properties, upstream or downstream pressure, and gas temperature, as well as the circumstances under which the device is being used. There are modifications to generally accepted equations for flow rate calculations because of frictional pressure losses, expansibility factors, and other empirically derived coefficients. Various internationally recognized equations may be applied and normally take the form of a discharge coefficient and an expansibility factor. A full analysis may be found in ISO *TR 5168,* Annex E.[4]

Advantages and Disadvantages. All meter types have advantages and disadvantages. **Table 11B.1** summarizes them for orifice flowmeters.

Sizing. Orifice meter size is determined largely by the range of differential pressures that are deemed acceptable to measure. For example, a user who is willing to operate at differential pressures of 200 in. of water column would be able to flow more than 40% more gas through an identical device than a user who limits the differential pressure to 100 in. of water column. Similarly, the choice of beta ratio (the ratio of the outer diameter of the orifice plate and the diameter of the plate opening) will also impact the range of measurement. Typical sizing is accomplished by limiting beta ratios to values no larger than 0.65 and differential pressures between 10 and 100 in. of water column.

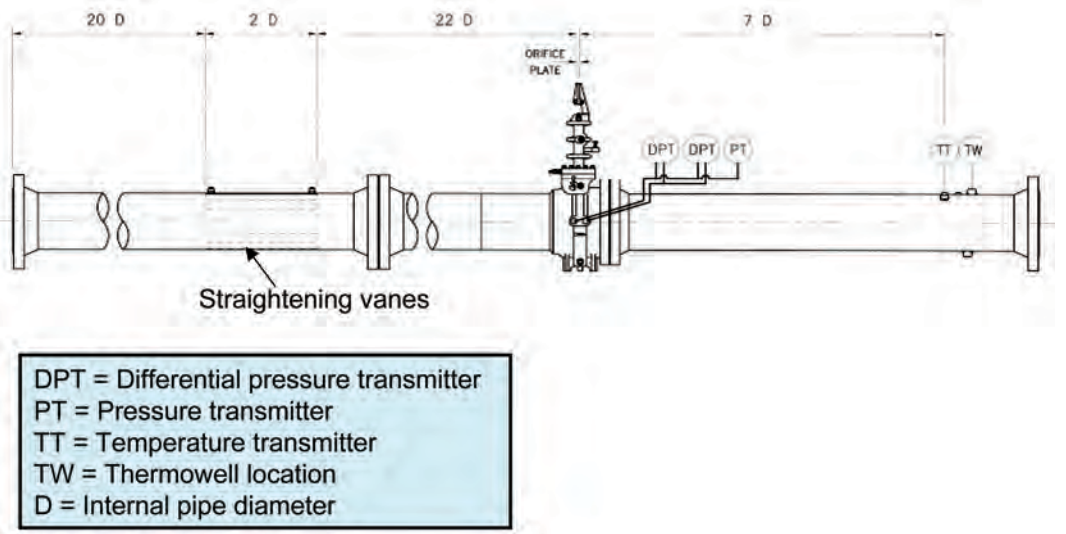


Fig. 11B.3—Typical ISO 1563 orifice meter tube (courtesy of Daniel Industries).

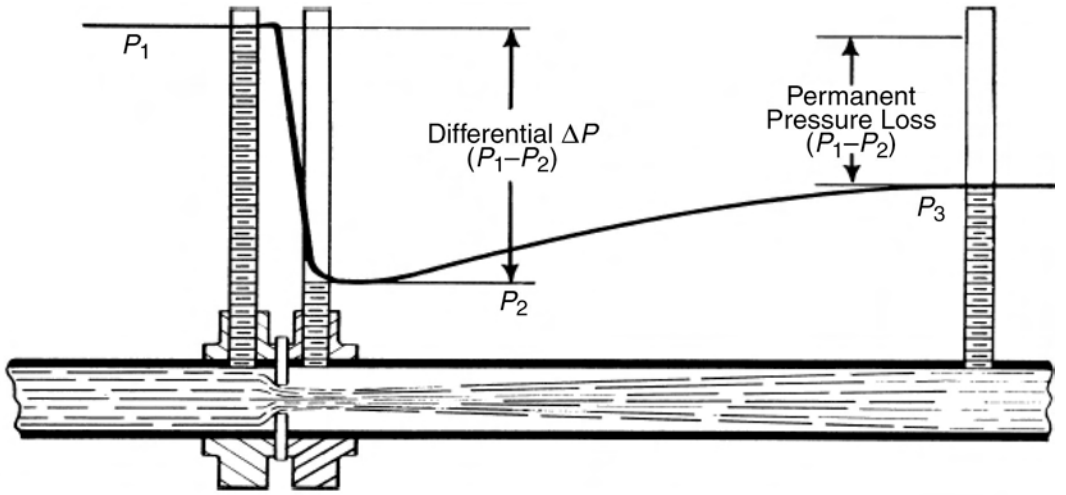


Fig. 11B.4—Orifice flowmeter pressure profile (courtesy of Daniel Industries).

11B.3 Gas Turbine Meter. ***International Standards.*** There are two main standards for turbine meters: ISO *Standard 9951, Measurement of Gas Flow in Closed Conduits: Turbine Meters*[5] and OIML *R32, Rotary Piston Gas and Turbine Gas Meters.*[6]

Turbine Meter Overview. A basic turbine meter consists of pressure-containing meter housing with end flanges; a set of internals, incorporating the turbine wheel and gearing mechanisms; and a means of counting the turbine wheel revolutions. A typical turbine meter has additional components such as flow conditioning devices, bearing lubrication mechanisms, and sophisticated mechanical and electrical counter systems. An exploded view of a turbine meter is given in **Fig. 11B.5**. For additional information about turbine meters and their use in liquid measurement, see Sec. 11A.3 of this chapter.

TABLE 11B.1—ADVANTAGES AND DISADVANTAGES FOR ORIFICE METERS

Advantages	Disadvantages
Well documented in standards	Pulsating flow
Industry acceptance	Low rangeability
Low unit capital cost	High pressure loss
No moving parts	Flow profile sensitive
Dry calibration acceptable	Requires long meter tube/flow conditioner
No limits on temperature, pressure, or size	Not self-cleaning
Mechanically robust	Can be damaged by high flow rates

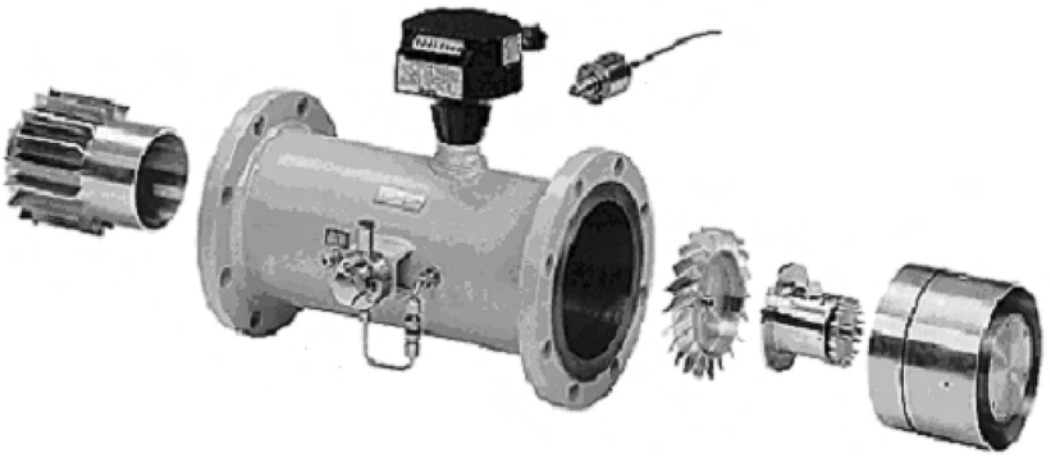


Fig. 11B.5—Gas turbine meter components (courtesy of Daniel Industries).

Like orifice meters, turbine meters should be mounted within a meter tube (**Fig. 11B.6**). Most modern turbine meters have integral flow conditioners. These conditioners help to remove swirl and much of the distortion from the flow profile, and hence, the overall straight length requirement upstream of the meter can be relatively small. A typical requirement is 5 diameters.

Theory of Operation. The operation of a turbine meter is based on the measurement of the velocity of gas. The flowing gas is accelerated and conditioned by the meter's straightening section. The integrated straightening vanes prepare the gas flow profile by removing undesirable swirl and asymmetry before the gas flows over the freely rotating turbine wheel. The dynamic forces of the flowing gas cause the rotor to rotate. The turbine wheel is mounted on the main shaft, with high-precision, low-friction ball bearings. The turbine wheel has helical blades that have a known angle relative to the gas flow. The gas flow drives the turbine wheel at an angular velocity, which, in the linear range of a well-designed meter, is proportional with the gas velocity. Using a gearing mechanism, the rotating turbine wheel drives the mechanical counter. In addition, the rotating blade can also be used to generate pulses via a proximity sensor. Each pulse detected is equivalent to a discrete volume of gas at actual conditions (i.e., the total number of pulses collected in any period of time represents the gross observed vol-

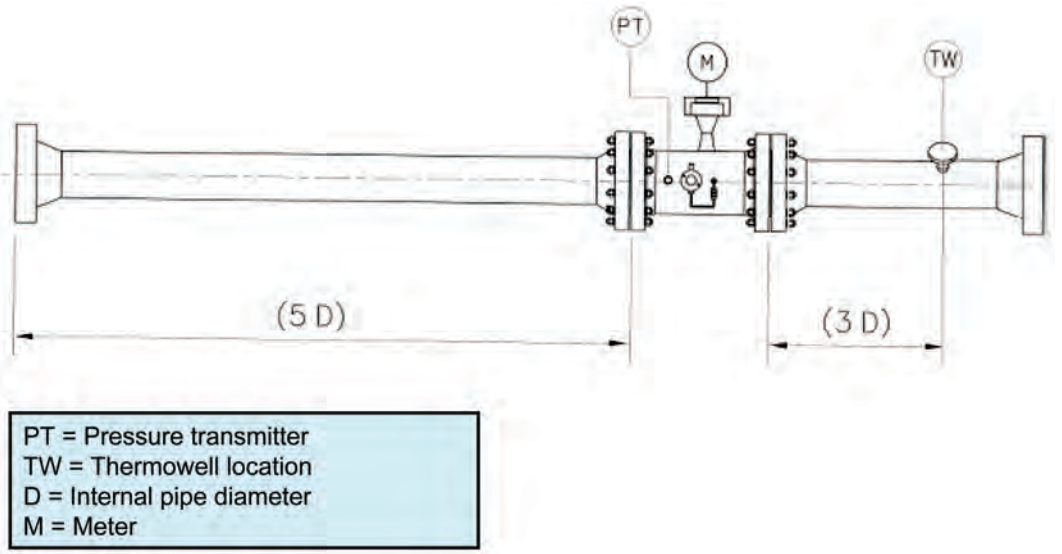


Fig. 11B.6—Gas turbine meter tube (courtesy of Daniel Industries).

TABLE 11B.2—ADVANTAGES AND DISADVANTAGES FOR TURBINE METERS

Advantages	Disadvantages
Good accuracy over linear flow range	Requires initial laboratory flow calibration
Industry acceptance	Relatively high pressure loss
Medium capital cost	Moving parts require maintenance
Medium rangeability at high pressure	Cannot tolerate dirty processes
Electronic output available	Possible damage because of overspeeding
Digital output, high repeatability	
Natural flow totalizer	

ume during that period). For each meter, a calibration characteristic (K factor) is required. This factor is expressed in pulses per volume and is given by the manufacturer.

The K factor is determined by means of a flow calibration. This flow calibration should be carried out over the entire operating range of the meter because the K factor may vary with flow. This variation with flow is the turbine meter's linearity. Once the K factor has been defined, the flow through the meter can be calculated because the two quantities are proportional.

Advantages and Disadvantages. The advantages and disadvantages for turbine meters are given in **Table 11B.2**.

Sizing. Gas turbine meter sizing varies from one manufacturer to the next; however, the variables to be considered are consistent. Gas turbine meters are velocity meters, and the upper velocity limit is essentially unchanged by pressure. Thus, a given size turbine meter will have an associated upper uncorrected flow rate limit. The range of the measurement is affected at the low end by the amount of mass flow through the meter. Thus, the range of a turbine meter



Fig. 11B.7—Ultrasonic gas flowmeter (courtesy of Daniel Industries).

is enhanced by increasing line pressure. For example, a 3-in. gas turbine meter might have a range of 30:1 at 200 psi but more than 60:1 at 500 psi.

11B.4 Ultrasonic Meters. ***International Standards.*** The situation with ultrasonic flowmeters and international standards is quite straightforward—there is none. There is, however, an ISO committee currently working to produce a standard: ISO *Standard TC30/SC5/WG1*.[7] In the meantime, there are several best practice guidance documents—the first to be released in 1998 was AGA *Report 9, Measurement of Gas by Multipath Ultrasonic Meters,*[8] and then, in 2000, BSI *7965, The Selection, Installation, Operation and Calibration of Diagonal Path Transit Time Ultrasonic Flowmeters for Industrial Gas Applications*.[9] Both of these documents are under review at the moment, and it is anticipated that a new revision will be issued in the near future.

Ultrasonic Meter Overview. A multipath transit time ultrasonic meter (USM) is basically a device that consists of three main components: the meter body (cylindrical pipe spool), transducer pairs (mounted in the pipe spool), and an electronic module (**Fig. 11B.7**).

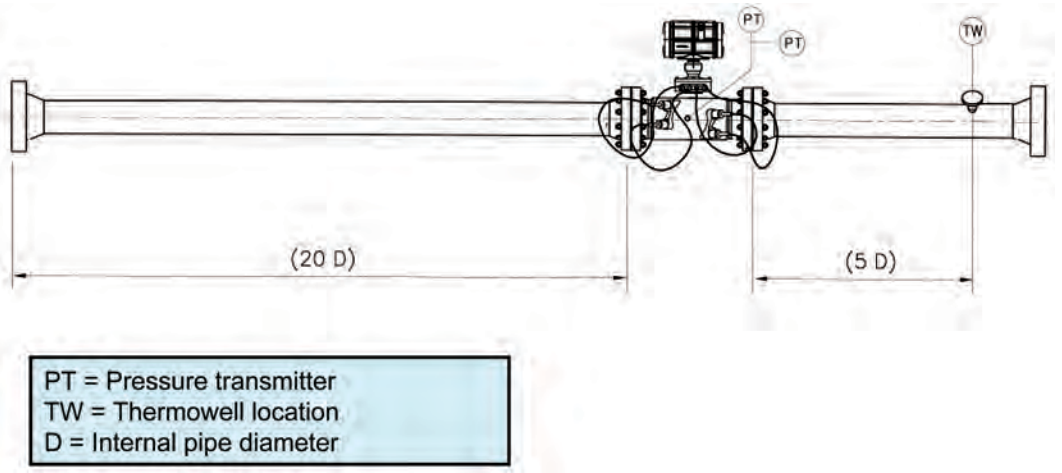


Fig. 11B.8—Gas ultrasonic flowmeter tube (courtesy of Daniel Industries).

USMs derive the volume flow of the gas by measuring the transit times of high-frequency sound waves. Transit times are measured for pulses propagating up and downstream across the gas stream at an angle with respect to the pipe axis. These transit times, together with the meter geometry, are used to calculate the average gas velocity on a particular chord. Multiple paths are used within ultrasonic meters to maximize accuracy in the overall average velocity measurement. These multiple paths also provide a certain degree of immunity to flow profile effects, such as asymmetry and swirl. The level of immunity offered by the multipath USM varies from one design to another, as shown by Grimley.[10] Despite the fact that the USM offers some immunity to flow profile distortions, they still require upstream straight lengths of pipe. A typical meter tube layout for a USM is shown in **Fig. 11B.8**.

Theory of Operation. As previously stated, USMs measure the transit times of high-frequency sound pulses. The transducers are mounted on the meter body at defined locations. **Fig. 11B.9** shows a schematic arrangement for a single path. The dimensions X and L are precisely determined during the meter manufacture. These measurements, together with the electronic characteristics of each transducer pair, characterize the ultrasonic flowmeter. The transit time for a signal, traveling with the flow, is less than that for a signal traveling against the flow. The difference in these times determines flow velocity.

It is also important to consider any additional uncertainty associated with the through-life stability of the USM. There are several influencing factors, one of which is wall roughness. It has been shown by Zanker[11] that changes in wall roughness can cause significant drift in USM meters that incorporate a center path bouncing configuration to determine gas velocity. With such chord configurations, the USM measures the velocity at the center of the pipe (i.e., the maximum velocity). To arrive at an average velocity, a correction factor based on the Reynolds number and wall roughness is used. Over time, the wall roughness changes, so the correction factor becomes more and more erroneous. This results in serious meter drift. This is just one influencing factor—to quantify all influences relies on a significant passing of time together with data gathering, so responsibility has to be placed on the manufacturer to demonstrate the meter's through-life stability.

Advantages and Disadvantages. There are a host of benefits offered by ultrasonic technology when compared with traditional measurement techniques such as the orifice or the turbine meter. The main benefits for ultrasonic flowmeters are shown in **Table 11B.3**.

Sizing. Ultrasonic meters operate over a specified velocity range, which is independent of gas temperature, pressure, or composition. Although limits vary from one manufacturer to an-

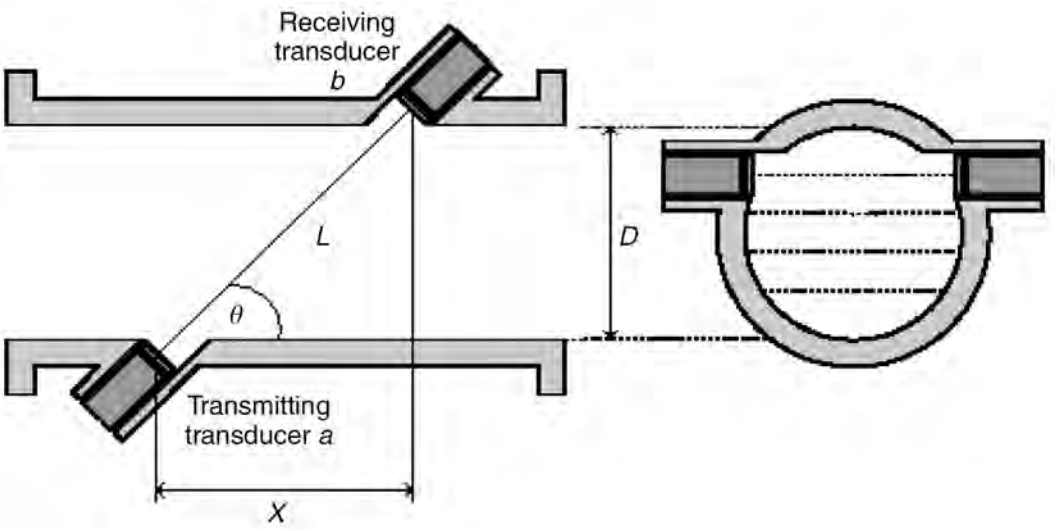


Fig. 11B.9—Gas ultrasonic flowmeter measurement diagram (courtesy of Daniel Industries).

TABLE 11B.3—ADVANTAGES AND DISADVANTAGES FOR ULTRASONIC METERS

Advantages	Disadvantages
No flow calibration required	Not fully accepted by industry
High accuracy	Susceptible to pressure and reduction valve noise
Sophisticated self-diagnostic capability	
Large rangeability	
No additional pressure drop	
No moving parts	
No maintenance	
Low operational cost	
Low installation cost multipath units	

other, typical guidelines limit the velocity range from about 3 ft/sec to about 70 ft/sec. Pressure ranges may impact the configuration of the meter because special ultrasonic transducers are sometimes specified for either high or low pressures. Caution should also be given to applications with carbon dioxide levels in excess of about 25% because CO_2 may absorb the ultrasonic signals.

11B.5 Coriolis Flowmeters. ***International Standards.*** Recent advances in the development and performances of Coriolis meters have meant that the measurement of the mass flow rate of gases, such as natural gas for custody transfer applications, is now a reality. This has been reflected by the large acceptance of this technology within the natural gas industry. As an example, Micormotion has supplied 5,000 Coriolis meters for natural gas applications in the last 3 years. This industrial acceptance motivated ISO to develop a standard through the ISO Technical Committee—ISO *Standard TC30/SC12*.[12] In addition to this ISO standard, there is also an engineering technical report prepared by AGA entitled *Coriolis Flow Measurement for Natural*

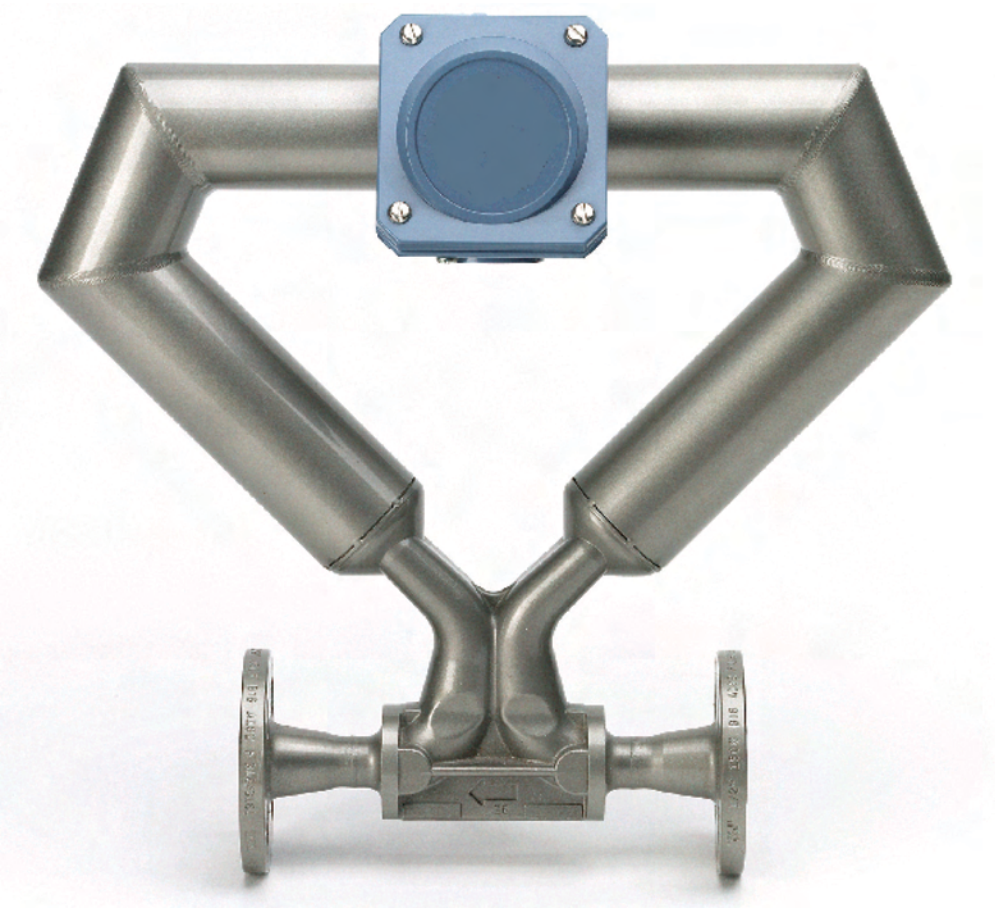


Fig. 11B.10—Coriolis flowmeter (courtesy of Micro Motion Inc.)

Gas Applications.[13] For additional information on Coriolis meters and their use in liquid service, see Sec. 11A.4 of this chapter.

Although there is no ISO standard for natural gas measurement using Coriolis measurement, some countries have issued type-approval certificates for natural gas measurement using Coriolis meters. These countries include: The Netherlands (Netherlands Inst. for Metrology and Technology), Germany (Physickalisch-Technische Burdessarstalt), Canada (Measurement Canada), and Russia (Gosstandard).

Coriolis Meter Overview. A Coriolis meter comprises two main parts: a sensor (primary element) and a transmitter (secondary element). See **Fig. 11B.10**. With this design, the gas flows through a U-shaped tube. The tube is made to vibrate in a perpendicular direction to the flow. Gas flow through the tube generates a Coriolis force, which interacts with the vibration, causing the tube to twist. The greater the angle is twisted, the more the flow increases. The sensing coils, located on the inlet and outlet, oscillate in proportion to the sinusoidal vibration. During the flow, the vibrating tubes and gas mass flow couple together because of the Coriolis force, causing a phase shift between the vibrating sensing coils. The phase shift, which is measured by the Coriolis meter transmitter, is directly proportional to the mass flow rate. The vibration frequency is proportional to the flowing density of the flow. However, the density measurement from the Coriolis meter is not normally used as part of the gas measurement

TABLE 11B.4—ADVANTAGES AND DISADVANTAGES FOR CORIOLIS METERS

Advantages	Disadvantages
Mass flow	Potential erosion because of abrasive particles
Liquid calibration for gas use	High pressure loss may affect turn-down ratio
Insensitive to flow distortions/profile	Sensitive to vibration close to operating frequency
Linear—good range	Sensitive to pulsations close to operating frequency
Accurate for Btu	Only available in small sizes
Flowing density-meter health diagnostic	
No wearing parts	
Elimination of T_f, P_f, and Z_f uncertainties	
Bidirectional	

station. Like other meters, the Coriolis is usually mounted in a meter tube. Because the device is insensitive to flow disturbances, there is no requirement for any form of flow conditioning, straight lengths, or meter tube.

Theory of Operation. Coriolis meters operate on the principle that if a particle inside a rotating body moves in a direction toward or away from the center of rotation, the particle generates inertial forces that act on the body. Coriolis meters create a rotating motion by vibrating a tube or tubes carrying the flow, and the inertial force (Coriolis force) that results is proportional to the mass flow rate. By measuring the amount of inertial force or deflection, it is possible to infer the mass flow rate. It is this phenomenon that is harnessed within the Coriolis flowmeter.

It is also important to consider any additional uncertainty associated with the through-life stability of the Coriolis meter. There are two main influencing factors: the change in flow-tube structural characteristics caused by erosion of the tube wall by abrasive particles and the coating of the flow tube by debris. Abrasion of the flow tubes by abrasive particles can directly affect the flow calibration of the meter. Coating of the flow tubes by debris is only a concern at low fluid flow velocities when the meter is not self-cleaning. This influence does not affect the meter's calibration and only affects the meter's zero. It can be corrected by regular zero checks for drift and zeroing, if required. Both of these influences can be identified as occurring under flowing conditions by monitoring the drift in flowing density over time.

Advantages and Disadvantages. The advantages and disadvantages for Coriolis meters are shown in **Table 11B.4**.

Sizing. Gas Coriolis meters, like all Coriolis meters, are mass devices. The sensitivity of the meter to measure small amounts of mass flow determines the low end of the metering range. The upper end of the measurement range is most often determined by the largest acceptable pressure loss. The pressure loss across the meter increases with flow rate and the corresponding velocity through the meter. Velocities through the meter can be a substantial fraction of the speed of sound but clearly should not exceed about 0.5 Mach.

References

1. "Measurement of Liquid Hydrocarbons by Turbine Meters," *Manual of Petroleum Measurement Standards,* fourth edition, API, Washington, DC (2000) Chap. 5, Sec. 3.
2. *Standard 5167, Measurement of Fluid Flow by Means of Pressure Differential Devices—Part 1: Orifice Plates, Nozzles and Venturi Tubes Inserted in Circular Cross-Section Conduits Running Full,* ISO, Geneva, Switzerland (1991).
3. "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids," Report No. 3, AGA, Washington, DC (2000).
4. *Standard 5168, Measurement of Fluid Flow—Evaluation of Uncertainty of a Flow Rate Measurement,* ISO, Geneva, Switzerland (1978).
5. *Standard 9951, Measurement of Gas Flow in Closed Conduits: Turbine Meters,* ISO, Geneva, Switzerland (1994).
6. *R 32, Rotary Piston Gas Meters and Turbine Gas Meters,* OIML, Paris (1989).
7. Standard *TC30/SC5/WG1, Measurement of Gas Flow in Closed Conduits—Ultrasonic Meters,* ISO Technical Committee, Geneva, Switzerland.
8. "Measurement of Gas by Multipath Ultrasonic Meters," Report No. 9, AGA, Washington, DC (1998).
9. *BSI 7965:2000, The Selection, Installation, Operation and Calibration of Diagonal Path Transit Time Ultrasonic Flowmeters for Industrial Gas Applications,* BSI, London (2000).
10. Grimley, T.: "Ultrasonic Meter Installation Configuration Testing," paper presented at the 2000 AGA Operations Conference, Denver, 7–9 May.
11. Zanker, K.: "The Effects of Reynolds Number, Wall Roughness and Profile Asymmetry on Single and Multipath Ultrasonic Meters," paper presented at the 1999 North Sea Flow Measurement Workshop, Gardermoen, Norway, 25–28 October.
12. *Standard TC30/SC12, Measurement of Fluid Flow in Closed Conduits—Mass Methods,* ISO Technical Committee, Geneva, Switzerland.
13. "Coriolis Flow Measurement for Natural Gas Applications," technical report, AGA, Washington, DC.

SI Metric Conversion Factors

bbl	×	1.589 873	E – 01	$= m^3$
cp	×	1.0*	E – 03	= Pa·s
cSt	×	1.0*	E – 06	$= m^2/s$
°F		(°F – 32)/1.8		= °C
ft	×	3.048*	E – 01	= m
in.	×	2.54*	E + 00	= cm
$in.^3$	×	1.638 706	E + 01	$= cm^3$
psi	×	6.894 757	E + 01	= kPa

*Conversion factor is exact.

Chapter 12
Electrical Systems

Dinesh Patel, AMEC Paragon

12.1 Introduction

The electrical system of a typical oil field consists of power generation, power distribution, electric motors, system protection, and electrical grounding. The power is either generated on site or purchased from a local utility company. To ensure continuous production from an oil field, it is of utmost importance that the associated electrical systems be designed adequately. This chapter covers essential topics in the design and operation of the electrical system and discusses the construction and specification of electric motors.

12.2 Electrical Codes and Standards

Various organizations in the U.S. and other countries have developed many electrical codes and standards that are accepted by industry and governmental bodies throughout the world. These codes and standards provide guidelines or rules for design and installation of electrical systems. **Table 12.1** lists some of the major local and international codes and standards used in the oil field. Refer to other electrical codes and standards, as well, as appropriate to your needs.

Also, U.S. regulatory agencies have established some requirements for the design, installation, and operation of offshore production platforms. **Table 12.2** lists some of these governmental codes and regulatory documents. Other state and/or municipal regulations also may apply.

12.3 Power Sources

The required power for the oil field is either generated on site by engine- or turbine-driven generator sets or purchased from a local utility company. The engines or turbines may use diesel or natural gas as a fuel. Some units are dual-fueled, using natural gas and diesel. Natural-gas-fueled prime movers are most practical for normal power generation for most applications. Diesel is used where natural gas is unavailable and for units that provide black-start and emergency power.

Some remote oil fields lack access to utility power lines and require on-site power generation. In such cases, in addition to normal generators, a standby generator might be needed to provide emergency power and black-start capability. Sometimes, a standby generator is designed to handle the total facility electrical load, but usually it is designed only for essential loads.

TABLE 12.1—MAJOR LOCAL AND INTERNATIONAL CODES AND STANDARDS USED IN OIL FIELDS

American Petroleum Inst. (API)	
RP 14F	*Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations*[1]
RP 500	*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2*[2]
RP 505	*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2*[3]
RP 540	*Electrical Installation in Petroleum Processing Plants*[4]
RP-2003	*Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*[5]
American Natl. Standards Inst. (ANSI)	
C37.12	*For AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis—Specification Guide*[6]
C37.20.1	*Standard for Metal-Enclosed Low Voltage Power Circuit Breaker Switchgear*[7]
C37.20.2	*Standard for Metal-Clad and Station-Type Cubicle Switchgear*[8]
C37.12.70	*Terminal Markings and Connections for Distribution and Power Transformers*[9]
C84.1	*Voltage Rating for Electrical Wiring and Equipment (60Hz)*[10]
Canadian Standards Assn. (CSA)	
C22.1	*Canadian Electrical Code, Part I*[11]
Intl. Electrotechnical Commission (IEC)	
50 (426)	*International Electrotechnical Vocabulary (IEV)—Chapter 426—Electrical Apparatus for Explosive Atmospheres*[12]
331	*Fire-Resisting Characteristics of Electrical Cables*[13]
529	*Degrees of Protection Provided by Enclosures (IP Code)*[14]
Inst. of Electrical and Electronics Engineers (IEEE)	
Std. 100	*Standard Dictionary of Electrical and Electronics Terms*[15]
Std. 141	*Electrical Power Distribution for Industrial Plants*[16]
Std. 142	*Grounding of Industrial and Commercial Power Systems*[17]
Std. 242	*Protection and Coordination of Industrial and Commercial Power Systems*[18]
Std. 315	*Graphic Symbols for Electrical and Electronics Diagrams*[19]
Std. 446	*Emergency and Standby Power Systems for Industrial and Commercial Applications*[20]
Std. 485	*Sizing Large Lead Storage Batteries for Generating Stations and Substations*[21]
Illuminating Engineering Soc. (IES)	
RP-1	*American National Standard Practice for Office Lighting*[22]
RP-7	*American National Standard Practice for Industrial Lighting*[23]
Instrument Soc. of America (ISA)	
S 5.1	*Instrumentation Symbols and Identification*[24]
S 12.0.01	*Electrical Apparatus for Use in Class I, Zone 0 and Zone 1 Hazardous (Classified) Locations: General Requirements*[25]
RP 12.1	*Recommended Practice for Electrical Instruments in Hazardous Atmospheres*[26]
Natl. Electrical Manufacturers Assn. (NEMA)	
MG 1	*Motors and Generators*[27]
MG 2	*Safety Standard for Construction and Guide for Selection, Installation, and Use of Electrical Motors and Generators*[28]
MG 10	*Energy Guide for Selection and Use of Polyphase Motors*[29]
Natl. Fire Protection Assn. (NFPA)	
30	*Flammable and Combustible Liquids Code*[30]
70	*National Electrical Code (NEC)*[31]
78	*Lightning Protection Code*[32]
496	*Standard for Purged and Pressurized Enclosures for Electrical Equipment in Hazardous (Classified) Locations*[33]
497	*Recommended Practices for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Area*[34]

TABLE 12.2—MAJOR GOVERNMENTAL CODES AND REGULATORY DOCUMENTS REGARDING THE DESIGN, INSTALLATION, AND OPERATION OF OFFSHORE PRODUCTION PLATFORMS

U.S. Dept. of the Interior (U.S. DOI)	
30 CFR Part 250	*Oil and Gas and Sulfur Operation in the Outer Continental Shelf*[35]
U.S. Dept. of Transportation (U.S. DOT)	
49 CFR Part 190	*Pipeline Safety Regulations*[36]
49 CFR Part 191	*Pipeline Safety Regulations*[37]
49 CFR Part 192	*Pipeline Safety Regulations*[38]
49 CFR Part 195	*Pipeline Safety Regulations*[39]
U.S. Occupational Safety and Health Admin. (OSHA)	
29 CFR Part 1910, Subpart H	*Process Safety Management of Highly Hazardous Chemicals*[40]
29 CFR Part 1910, Subpart S	*Electrical (OSHA)*[41]
29 CFR Part 1926, Subpart K	*Electrical Construction (OSHA)*[42]
United States Coast Guard (USCG)	
33 CFR Part 67, Subchapter C	*Aids to Navigation*[43]
46 CFR Part 110-113, Shipping Subchapter J	*Electrical Engineering*[44]

When commercial power is purchased from a utility company, an electrical substation generally is installed near the oilfield facility. Most local utility companies bring their power into their main substation(s) through high-voltage overhead transmission lines from a large generating plant in a remote area. From the main substation(s), the utility company distributes power to end users through medium-voltage overhead lines. The power from the distribution line voltage is converted to facility distribution voltage by step-down transformers in the facility's electrical substation or on the utility poles. Large facilities generally have an on-site electrical substation and an overhead or underground power distribution network, whereas a small facility might be furnished power from a pole-mounted transformer through underground distribution.

The power from the on-site generating plant or the utility transformer is connected to facility switchgear and then to motor-control centers that further distribute power to electrical loads in the facility.

12.4 Sizing and Selection of the Power Supply

The first step in sizing the power supply requirements is to develop a detailed load summary for the entire facility. **Table 12.3** shows an example of a load summary. The load summary contains every facility electrical load and its duty, efficiency, load factor, and power factor. The total of these loads is the total connected load of the facility. The generating system rarely is sized on the basis of the connected load, however, because doing so can lead to the generating system being oversized. The actual running load can be significantly lower than the connected load. An oversized generating system is less efficient and might require excessive maintenance because of operation of prime movers at light loads for a long period of time. Diesel engines are especially susceptible to this.

Table 12.3 further categorizes loads as continuous, intermittent, and spare on the basis of their duty cycle. Continuous loads are energized in normal production operation and generally include all process motors; facility lighting; living accommodations; heating, ventilating, and air conditioning (HVAC) loads, etc. Intermittent loads are cyclical and operate only part of the

TABLE 12.3—TYPICAL ELECTRICAL LOAD SUMMARY

Project: Platform XYZ
Location: Gulf of Mexico
Project no.: 1234

Load type: continuous = C, intermittent = I, spare = S

Rev.:
Date:
By:

Tag no.	Load description	Connected hp	Voltage/ phases	Connected kW	Load factor	Load type C / I / S	C load kW	I load kW	S load kW
	4,160-V loads								
PBE-4100	Oil shipping pump 1	500	4,160/3	414.40	0.90	C	373.00	0.00	0.00
PBE-4200	Oil shipping pump 2	500	4,160/3	414.40	0.90	C	373.00	0.00	0.00
PBE-4300	Oil shipping pump 3	500	4,160/3	414.40	0.90	S	0.00	0.00	373.00
PBA-3200A	Closed drain pump 1	25	480/3	20.72	1.00	C	20.72	0.00	0.00
PBA-3200B	Closed drain pump 2	25	480/3	20.72	1.00	S	0.00	0.00	20.72
MBK-3000	Oil treater transformer		480/3	20.00	1.00	S	0.00	0.00	20.00
PBE-4400	Oil boost pump 1	100	480/3	82.89	1.00	C	82.89	0.00	0.00
PBE-4500	Oil boost pump 2	100	480/3	82.89	1.00	C	82.89	0.00	0.00
ZZZ-4500	Oil tank VRU	40	480/3	33.16	0.90	C	29.84	0.00	0.00
CAL-5010	Flare air blower 1	5	480/3	4.14	1.00	C	4.14	0.00	0.00
CAL-5020	Flare air blower 2	5	480/3	4.14	1.00	S	0.00	0.00	4.14
ZZZ-8100A	Instrument air compressor	100	480/3	82.89	1.00	C	82.89	0.00	0.00
ZZZ-8100B	Instrument air compressor	100	480/3	82.89	1.00	I	0.00	82.89	0.00
	Chemical injection pump 1	1	480/3	0.83	1.00	C	0.83	0.00	0.00
	Chemical injection pump 2	1	480/3	0.83	1.00	C	0.83	0.00	0.00
	Facility lighting transformer	--	480/3	150.00	0.80	C	120.00	0.00	0.00
	Switchgear building HVAC	--	480/3	200.00	0.75	C	150.00	0.00	0.00
	Quarters HVAC	--	480/3	150.00	0.75	C	112.50	0.00	0.00
	Quarters power transformer	120	480/3	150.00	0.75	C	112.50	0.00	0.00
	T/GEN 1 lube oil cooler fan 1	5	480/3	4.14	1.00	I	0.00	4.14	0.00
	T/GEN 1 lube oil cooler fan 2	5	480/3	4.14	1.00	I	0.00	4.14	0.00
	T/GEN 1 lube oil cooler fan 3	5	480/3	4.14	1.00	OI	0.00	0.00	0.00
	T/GEN 1 enclosure vent fan	10	480/3	8.29	1.00	C	8.29	0.00	0.00
	T/GEN 1 AC pre/post pump	2	480/3	1.66	1.00	I	0.00	1.66	0.00
	T/GEN 1 starter	100	480/3	82.89	1.00	I	0.00	82.89	0.00
	T/GEN 1 lube oil heater	--	480/3	4.50	1.00	I	0.00	4.50	0.00
	Total load:			2,439.00			1,554.00	180.00	418.00

	kW	kVA at 0.8 PF
Connected load:	2,439	3,049
Normal continuous load:	1,554	1,943
Maximum continuous load (=cont.+0.6*int):	1,662	2,078

VRU = vapor recovery unit, T/GEN 1 = turbine generator unit 1, PF = power factor, cont. = continuous, and int. = intermittent.

time (e.g., sump pumps, pre-/post-lube pumps, and air compressors). Spare loads are standby loads and operate only when the main unit fails. Spare loads are not considered when sizing the power requirements.

The maximum power demand normally is calculated as 100% of the continuous loads, plus 40 to 60% of the intermittent loads. In determining minimum generator capacity, a 20% allowance for future growth generally is added to the maximum power demand. Additionally, a voltage-dip analysis during motor starting is recommended if the facility load has a large motor or a group of motors that start simultaneously. A motor-starting voltage dip of > 15% generally is considered high and should prompt an evaluation of ways to reduce it. A large voltage dip will cause lights to flicker and might even cause some motor contactors to drop out because of insufficient coil-holding voltage. Reducing the voltage dip might involve increasing the generator size; however, reduced-voltage starting methods such as auto-transformer starters, electronic soft starters, and variable frequency drives also might be used to reduce the required capacity of generators.

Generators are rated in kilowatts (kW) and are designed to carry loads of up to their kW rating continuously, as long as the kilovolt ampere (kVA) rating is not exceeded. Most generators are designed for a 0.8 power factor at sea level and 40°C ambient temperature. The kVA capacity of a generator is determined by dividing the kW by the power factor of the generator. (See the Power Factor and Use of Capacitors section later in this chapter for a discussion of power factor.)

To eliminate the possibility of arcing, the generators that are used in the oil field generally are the revolving-field, brushless exciter type. On larger units, select a shaft-mounted permanent-magnet-generator (PMG) option to provide constant voltage to the generator-voltage regulator. On smaller units, a residual-magnetism exciter generally is used. Generators normally are provided with static-voltage regulators to maintain 1% voltage regulation from no load to full load.

The generator windings should be vacuum-pressure-impregnated (VPI) for high-humidity environments. The winding design temperature rise normally is limited to NEMA Class B (80°C over 40°C ambient), but NEMA-Class-F insulation normally is specified for a longer insulation life.

Generator voltage must be selected on the basis of the size of the loads and the total power requirement of the facility. Facilities with motors of 250 hp and higher should use a medium voltage (4.16 kV and higher) generator. For facilities with motors smaller than 250 hp, 480-V generation generally is sufficient. The most commonly used voltages for power generation are 480; 600; 2,400; 4,160; and 13,800 V.

In the case of purchased power from the utility, calculate the maximum load demand of the facility in kVA and select a proper kVA rated utility transformer to provide power to the facility. The transformer winding should be made of copper, and the desired transformer impedance should be 5.75% or less. Generally, oil-filled types of transformer are used for the power transformers. Dry, air-cooled types of transformer generally are used only for transformers in lighting and small-power applications. Even when the power is purchased from a utility, a standby generator generally is needed for emergency power in case utility power is lost. The standby generator normally powers the critical loads for shutdown, life saving, and personnel protection.

12.5 Electrical-Distribution Systems

The electrical-distribution system furnishes electrical power and partial protection of the electrified oil field and consists of a primary system and a secondary system. It is important to the economics and longevity of the overall system that distribution be designed adequately before installation.

12.5.1 Primary Distribution System and Voltages. To reduce power losses, electricity distributed to an oil field is brought to the field at higher voltages of between 4,000 and 15,000 V. This higher-voltage distribution system is called a primary system. Higher voltages allow the use of smaller conductors, but require more expensive transformers. Even so, when the

primary system must deliver electrical power over a long distance, a higher voltage generally is favored because the lower cost of the smaller cable over the longer distances offsets the higher costs of the transformers and protective equipment.

An electrified oil field has a high degree of exposure to electrical storms. Electrical storms cause high static voltages and, sometimes, high transient voltages, the latter being caused by lightning. Static lines and lightning arresters are used to reduce the damage to electrical equipment by the static voltages and lightning strikes.

During electrical storms, the formation of rain clouds creates a difference in potential between the cloud and the earth. Above-ground primary electrical systems in a storm's vicinity might inherit a high static-voltage level that, if not reduced by properly sized and grounded lightning arresters, can cause motor-winding-insulation damage.

When the potential difference between the cloud and the earth becomes large enough, there will be an electrical discharge, or lightning strike. If lightning strikes the primary system, it will create high transient voltages. These voltages must be arrested by lightning arresters; otherwise, the insulation of the motors will fail, as will other electrical equipment in the system, including transformers and reclosures.

12.5.2 Secondary Electrical System. The secondary electrical system includes devices that operate at the same voltage as the motors, including the transformer at the end of the primary system, the cables, the disconnect switches, and the controls. In general, the voltage of all the devices within the secondary system should not be greater than 600 V.

A special case of the secondary system is the installation of a 796-V system. This voltage is obtained by Y-connecting three transformers, each with a secondary voltage of 460 V, yielding a line-to-line voltage of 796 V at the motor. (The Y connection is discussed below.) The 796-V system is used to reduce line drop to the motor; however, many operators who installed 796-V systems years ago have since converted to 460-V operation because, although operating at 796 V requires less current than operating at 460 V, this benefit is more than offset by the 796-V system overstressing the insulation of motors and control components.

The secondary system consists of one or more transformers that convert the primary-system voltage to the motor-operating voltage. Voltage from the transformer is provided to the motor starters through a fused disconnect switch or a circuit breaker. The motor starter provides for control and protection of the motor itself.

Wherever the secondary system uses overhead cables, it is exposed to electrical storms. As discussed earlier, because static and lightning strikes can damage the insulation of the electrical equipment, it is desirable to install lightning arresters at the transformer.

All the devices in the secondary part of the system should be sized to allow full loading of the motors without thermal damage to the equipment. Sizing of this equipment also should consider the protection of the electrical devices. Select fuses, circuit breakers, transformers, and wire sizes on the basis of the full-load rating of the motors.

Distribution Transformers. Distribution transformers reduce the primary high voltage to a lower voltage used by the motors. The distribution transformers are rated from 3 to 500 kVA. Transformers larger than 500 kVA are classified as power transformers.

To obtain full-load capability of the transformers and the motors, it is desirable to use three single-phase transformers in place of a single three-phase transformer. One advantage of using three single-phase transformers is the convenience of replacing one, should it fail.

Distribution transformers can be connected in several different configurations to deliver three-phase power: wye-delta, delta-delta, delta-wye, wye-wye, and open-delta **(Figs. 12.1 through 12.3)**. All these configurations are used in the oil field, although some have distinct advantages.

Wye-Delta. The most desirable transformer connection is the wye-delta. The transformer primary is wye-connected, and the secondary is delta-connected. Though it is done in many cases, the primary winding of the transformer, known as the Y point, should not be grounded

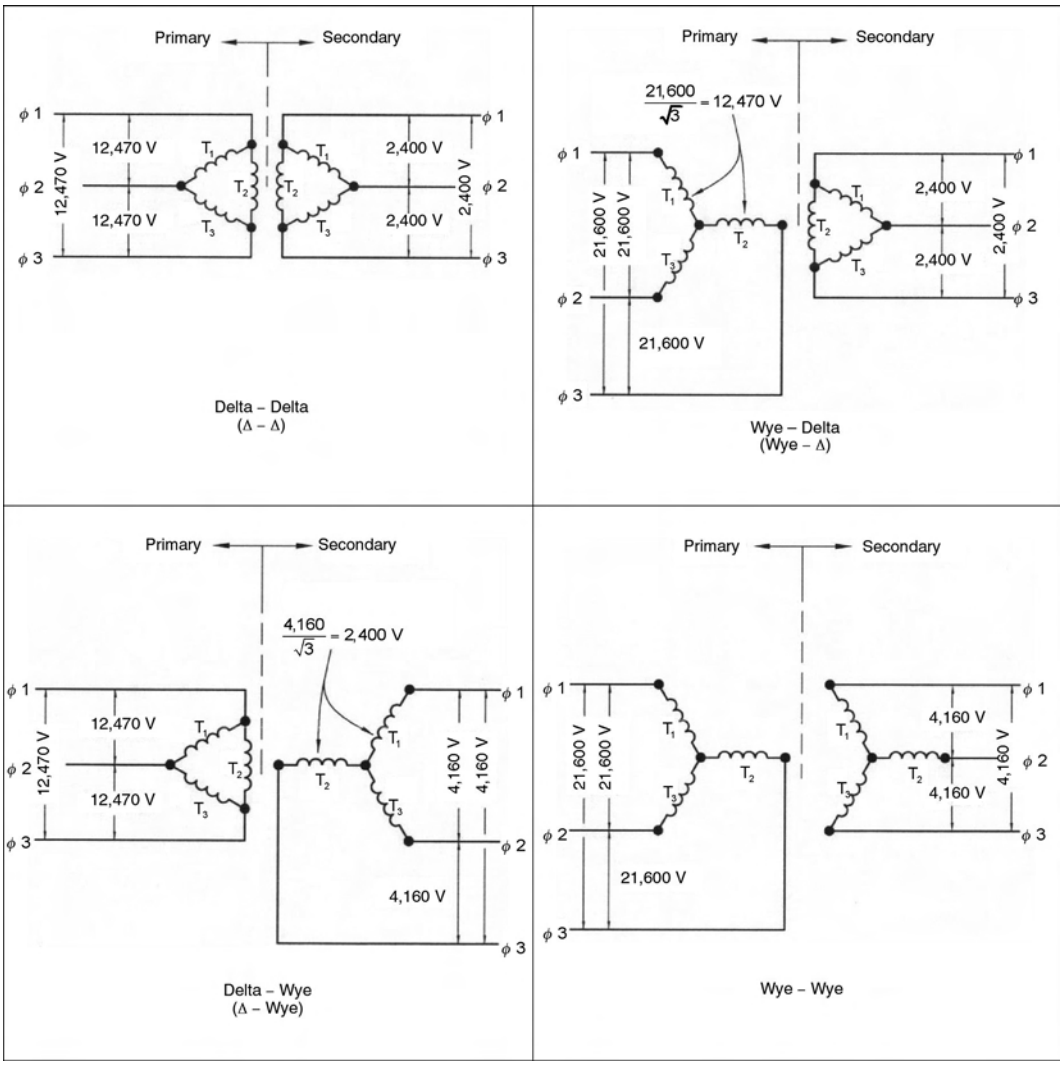
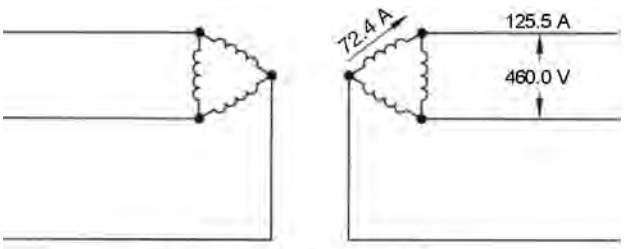


Fig. 12.1—Typical transformer connections (courtesy of AMEC Paragon). T_1, T_2, and T_3 are three winding connections, and Φ = phase.

at the wellsite because if one of the primary wires were to go to ground at some point in the primary system, the ground wire at the wellsite might be at primary voltage to ground potential, creating a danger of electrical shock for personnel. The transformer "ground" should not be connected to the grounding system at the pumping unit because the latter includes the enclosures for the electrical equipment.

The wye-delta connection has the advantage of allowing harmonic voltages in the system to have a self-canceling effect in the delta-connected secondary. It is not necessary for three single-phase units connected wye-delta in a three-phase bank to have equal impedances; however, it is important for the primary to have balanced voltage because unbalanced primary voltages can cause circulating currents in the delta secondary.

Delta-Delta. In a delta-delta connection, the primary and secondary windings both are delta-connected. Delta-delta is an acceptable transformer connection, although not as desirable as wye-delta. The delta-delta connection requires all units in a three-phase bank to have impedances



Each transformer, kVA	33.3
Total kVA	100.0
Line volts	460.0
Line amps	125.5
Transformer amps	72.4
Phase amps	72.4

Fig. 12.2—Three transformers, delta-delta connected (after Ref. 45, Chap. 10).

with less than a 10% differential. If a delta-delta connection is used, none of the endpoints or midpoints of the primary or secondary winding should be tied to the ground system at the wellsite. If any is, and if the ground is not satisfactory, the ground wire could be at a potential anywhere from zero to the line-to-ground voltage available at the transformer.

Delta-Wye. The delta-wye connection is undesirable because it allows a harmonic voltage in the distribution system to be applied to the motor and its control system. Harmonic voltages can cause erratic behavior of control components, as well as excess motor heat. If a delta-wye system is used, neither the primary nor the secondary windings of the transformer should be connected to the ground system at the motor. If grounds are attached to any part of this winding, they might be subject to the same voltage discussed under delta-delta. It is not necessary for the impedance of each unit in the three-phase transformer bank to be the same.

Wye-Wye. The wye-wye connection is the least desirable because harmonic voltages in the system are unable to circulate in the transformer winding. If harmonic voltages exist, they will be transmitted to the motor and its control system. If a wye-wye connection is used, no part of the transformer winding should be connected to the ground system at the wellsite. If a primary circuit has a phase-to-ground fault, a grounded wye will carry ground-fault current. This connection does not require transformers to have equal impedance. Using a delta secondary will eliminate harmonic voltage in the motor and its control system. It is not necessary for transformers to have equal impedances.

Open-Delta. The open-delta is an incomplete delta-delta and is possible when three single-phase transformers are connected in delta-delta fashion to provide the three-phase power. If one of the three transformers on the delta-delta connection is removed, the connection is an open-delta circuit. This type of connection provides unsatisfactory performance of induction motors. The open-delta connection will have unbalanced voltages, which prevents utilization of full-load rating of the transformer and motor.

At no-load and with balanced voltages supplied to this transformer, the output will be a balanced three-phase voltage. While this two-transformer system is loaded, the impedance changes, providing an unbalanced voltage to the motor. Using the two-transformer open-delta connection does not allow full use of transformer kVA and the output rating of the motor.

Figs. 12.2 and 12.3 compare a three-transformer delta connection and an open-delta transformer connection.

In the open-delta connection, the total kVA is only 57% of the original 100 kVA. The two 33.3-kVA transformers remaining in the circuit would have a total of 66.6 kVA. With one unit removed, the remaining units with 66.6 kVA provide only 57.7 kVA, or only 86.6% of the

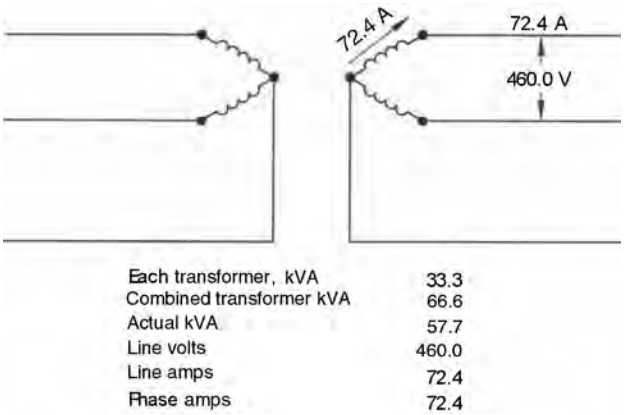


Fig. 12.3—Two transformers, open-delta connected (after Ref. 45, Chap. 11).

rating. This example shows that the transformers used in open-delta connections must be derated to obtain the desired kVA rating of an open-delta connection system.

While the open-delta-connected transformers are loaded, the voltage shifts from a balanced voltage at low load to a seriously unbalanced voltage at rated load. Unbalanced voltages will contain a negative sequence component of voltage. When applied to a three-phase induction motor, this causes excessive heating in the rotor, as well as some lost torque in the motor. Unbalanced voltages cause unbalanced currents.

Unbalanced voltage causes a 3 to 5 times greater current imbalance. This means, for example, that for a 3% voltage imbalance, a current imbalance of 9 to 15% can be expected. Such unbalanced conditions require that the motor be derated. **Fig 12.4** can be used to determine the derating factor for percent voltage imbalance at the motor terminals. It shows, for example, that for a 5% voltage imbalance, the motor will operate at 75% of capacity.

Many older oilfield installations use open-delta transformer connections. The only way the open-delta transformer will operate successfully is if both the transformers and the motors are oversized to handle the load. An open-delta transformer connection should be used only briefly and in an emergency situation in which one transformer has failed. For this emergency condition, the transformer and motor must be derated.

Sizing of the distribution transformer is a very important part of satisfactory operation of rod-pumping motors. The industry rule of thumb for sizing transformers is 1 kVA per connected hp. Because of the cyclic nature of oilwell pumping loads, some operators use 0.9 kVA/hp. Ultrahigh-slip motors do not have horsepower ratings; therefore, to determine the required kVA, use a factor of 0.75 times the full-load current of the motor in the high-torque mode.

12.6 Electrical Grounding

Electrical grounding can be classified one of two types: system grounding and equipment grounding. System grounding includes grounding of the power supply neutral so that the circuit protective devices will remove a faulty circuit from the system quickly and effectively. Requirements for system grounding are covered in detail in the *Natl. Electrical Code (NEC)*,* Chap. 2, Article 250.[31] Equipment grounding includes grounding of the noncurrent-carrying conductive part of electrical equipment and of enclosures that contain electrical equipment for personnel safety.

* *Natl. Electrical Code* and *NEC* are registered trademarks of the Natl. Fire Protection Assn. Inc., Quincy, Massachusetts 02269.

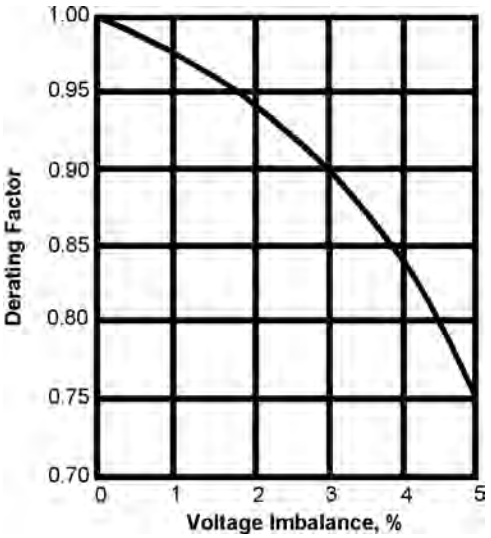


Fig. 12.4—Effects of unbalanced voltages on performance of three-phase induction motors. (Reprinted from *Motors and Generators, MG-1-1978,* by permission of the Natl. Electrical Manufacturers Assn., © 1978; all rights, including translation into other languages, reserved under the Universal Copyright Convention, the Berne Convention for the Protection of Library and Artistic Works, and the International and Pan American Copyright Conventions.)

Equipment grounding is a very important aspect of the electrical system. Grounding of electrical equipment has two purposes: to ensure that persons in the area are not exposed to dangerous, electric-shock voltage, and to provide current-carrying capability that can accept ground-fault current without creating a fire or explosive hazard.

To protect personnel from electric shock, all enclosures that house electrical devices that might become energized because of unintentional contact with energized electrical conductors should be effectively grounded. If the enclosure is grounded adequately, stray voltage will be reduced to safe levels. If the enclosures are not grounded properly, unsafe voltages could exist, which could be fatal to the operating personnel.

The lightning arresters installed in electrical systems cannot operate satisfactorily unless they are grounded well. Under elevated static voltage or lightning strikes, lightning arresters will short-circuit the above-normal voltages to ground. If the lightning arresters are not grounded properly, elevated voltage will enter the windings of transformers, control, and/or motors, causing component failures.

Obtaining a satisfactory ground can present some difficulties. Wellheads normally can be considered an excellent grounding source through the well casing. Ground rods can vary from acceptable in moderately wet soils to very inadequate in dry soils. Whenever possible, use the wellhead for grounding of the secondary electrical system. If a wellhead is not available, ground rods can be used.

In designing an electrical grounding system, follow these directions:

1. For personnel safety, ground to the wellhead or to properly installed ground rods all the secondary-electrical-system devices. This includes the transformer tank, disconnect switch enclosure, motor control, and motor frame.

2. Ground to the wellhead or to properly installed ground rods all secondary lightning arresters. Use different conductors to ground the secondary enclosures and lightning arresters. The wire that grounds the lightning arresters should be a continuous, unbroken cable that is no smaller than No. 6 wire.

3. Primary lightning arresters also should be grounded at a utility primary ground, and not to the secondary ground or the wellhead.

4. Do not attach utility static wires or grounding of transformer connections to the wellhead. If connected to the wellhead, this can adversely affect the cathodic protection of well casing and production tubing. This part of the electrical system might include many miles of line exposure and many grounds that could influence the corrosion of the production equipment. Grounds for this part of the system should be grounding rods or ground pads located at the bottoms of the utility poles. Other satisfactory grounds are wells drilled or ground mats constructed for this purpose at the electrical substation.

5. If possible, install ground rods at each location for each of the separate grounding wires run to the wellhead. During the servicing of the wells, the wellhead grounds may be removed. When service work is completed, reconnect these wellhead grounds.

6. Do not connect grounds of telephone systems to the grounds of motors. Induction motors can generate harmonic voltages that can cause noise on telephones when they share common grounds.

12.7 Voltage Drop in Electrical Systems

The electrical system of an oil field should be economically designed, yet capable of delivering the required current at adequate voltage to all motors for starting and running. When the load current flows through copper or aluminum wire, voltage drop occurs in the wire because of resistance of the wire, as indicated by Ohm's law:

$$E = IR , \quad \text{..... (12.1)}$$

where E = voltage, V; I = current, A; and R = resistance, Ω.

Voltage loss in the wire reduces the available voltage at the load terminals for motors and other loads. Most electrical loads operate at designed efficiency at their rated voltage. Reducing voltage supplied to electrical equipment reduces its efficiency or output and might even reduce its ability to start under full-load condition. For example, a 5% reduction in applied voltage at its terminals reduces the power output of an electric motor by 10%.

The voltage drop in the conductor depends on the amount of current flowing through the conductor and the conductor resistance, or impedance. The conductor resistance is directly proportional to the length of the wire and inversely proportional to the size of the wire. For the same-sized wire, the voltage drop increases with the increase in conductor length:

$$R = \frac{\rho L}{A} , \quad \text{..... (12.2)}$$

where R = resistance, Ω; ρ = conductor resistivity, Ω-circular mil/ ft; L = conductor length, ft; and A = cross-sectional area of conductor, circular mil. (A circular mil is the area of a circle with 1 mil diameter, and a mil = 0.001 in.)

The *NEC* gives the maximum allowable voltage drop in branch or feeder circuit conductors as 3%. The total maximum allowable voltage drop on both feeders and branch circuits to the farthest outlet is 5%.[31]

In addition to the voltage drop caused by load current, a voltage drop during the starting of a large induction motor also must be calculated. Large induction motors and industrial synchronous motors (see the section on Motors in this *Handbook*) draw several times full-load current from their power supply under full voltage across the line starting. The starting power factor ranges from 0.15 to 0.50 lagging, which causes an inrush current as high as 6 to 7 times the full-load current of the motor. This large current flowing through motor impedance, cable

impedance, and all other impedances between the supply and the motor causes a significant voltage drop. Undesirable effects of this voltage drop include dimming lights or lamp flicker, control relay or contactor dropout (de-energizing), and inability to start motor.

12.7.1 Motor-Starting Voltage Drop (Off a Transformer). Determining the percent voltage drop (ΔE) on a motor fed by a transformer bank, which is fed by an infinite utility bus, requires knowing the transformer impedance (Z), the three-phase impedance of the cable between the transformer and the motor (Z_c), and the motor-starting impedance (Z_m). The approximate formula to determine the percent voltage drop is:

$$\Delta E = \left(1 - \frac{Z_m}{Z_t}\right)100 \ , \quad \text{..... (12.3)}$$

where Z_t = total impedance, in Ω, given as:

$$Z_t = Z + Z_c + Z_m \ , \quad \text{..... (12.4)}$$

for which

$$Z = \frac{10 Z_{tr} E_t^2}{P_t} \ , \quad \text{..... (12.5)}$$

where Z_{tr} = transformer impedance, %; P_t = transformer-rated kVA; and E_t = transformer voltage, kV. For Eq. 12.4, the cable impedence is calculated as:

$$Z_c = \sqrt{3}(R \cos\theta + X \sin\theta) \ , \quad \text{..... (12.6)}$$

where R = cable resistance, Ω; X = cable three-phase reactance, Ω; θ = the power factor angle; and cos θ = power factor. (See the Power Factor and Use of Capacitors section later in this chapter for a discussion of power factor.)

For Eq. 12.4, the motor-starting impedance is calculated as:

$$Z_m = \frac{1{,}000 E_m^2}{P_m} \ , \quad \text{..... (12.7)}$$

where E_m = motor voltage, kV, and P_m = motor-starting kVA.

12.7.2 Motor-Starting Voltage Drop (Off a Generator). The voltage drop while starting a motor off a limited-capacity generator is an important factor in sizing the generator and determining the starting method for the motor. The generator cannot supply the large motor inrush current without a momentary voltage falloff while the voltage regulator works to increase excitation and to re-establish the voltage level.

The magnitude and duration of voltage drop depends on the size of the motor and its inrush current, the kVA capacity of the generator, the performance characteristics of the voltage regulator, and the amount of initial load on the generator before starting the motor. Most new installations use fast-response solid-state voltage regulators, which considerably reduce the amount and duration of voltage drop.

Along with large voltage drop, another problem encountered during motor starting is possible excessive kilowatt loading of the generator prime mover. The motor input horsepower during its acceleration period creates a large load, which reflects to the prime mover of the generator. If large enough, this load will stall the prime mover in the worst case, or cause it to shut down because of overload and/or temperature rise.

In determining the voltage drop when starting a motor off a generator that has limited capacity, the motor-feeder-cable impedance generally is disregarded because its impact on the calculation is negligible. Also, the resistance component of the generator impedance and motor impedance is neglected because reactance values are far greater than the resistance values. The voltage drop therefore is a simple ratio of the reactances in the circuit.

The approximated formula to determine the percent voltage drop when starting a generator is:

$$\Delta E = \left(1 - \frac{X_m}{X_m + X_g}\right)100 , \quad \text{..... (12.8)}$$

where X_m =motor reactance during starting, Ω, and X_g = generator reactance, Ω. In Eq. 12.8, X_m is calculated as:

$$X_m = \frac{1{,}000E_m^2}{P_m} . \quad \text{..... (12.9)}$$

In Eq. 12.8, X_g is calculated as:

$$X_g = \frac{10X_d^{'}E_g^2}{P_g} , \quad \text{..... (12.10)}$$

where $X_d^{'}$ = the transient reactance of the generator, %; P_g = generator kVA; and E_g = generator voltage, V.

The presence of initial load on the generator before starting a motor could have substantial effect on the voltage drop, depending on the amount and nature of the load. A constant impedance load (e.g., resistors or lights) might increase the voltage drop only slightly, but might cause a longer time to recover voltage to normal value. Many generator manufacturers provide graphs, personal computer (PC)-based programs, and data to determine voltage drop during motor starting on their generators, with and without an initial load.

12.8 Power Factor and Use of Capacitors

The electrical power required to drive a motor has three components: reactive power (P_r, kVAR), active power (P_a, kW), and apparent power (P_{ap}, kVA). The active power is the actual amount of work done by the motor and measured for billing purposes. The reactive power is the power required to magnetize the motor winding or to create magnetic flux, and is not recordable. The apparent power is the vector sum of kilowatts and kilovars and is the total amount of energy furnished by the utility company. The power triangles shown in **Fig. 12.5** illustrate the relationships between these terms.

The power factor (F_p) is the ratio of active power to apparent power:

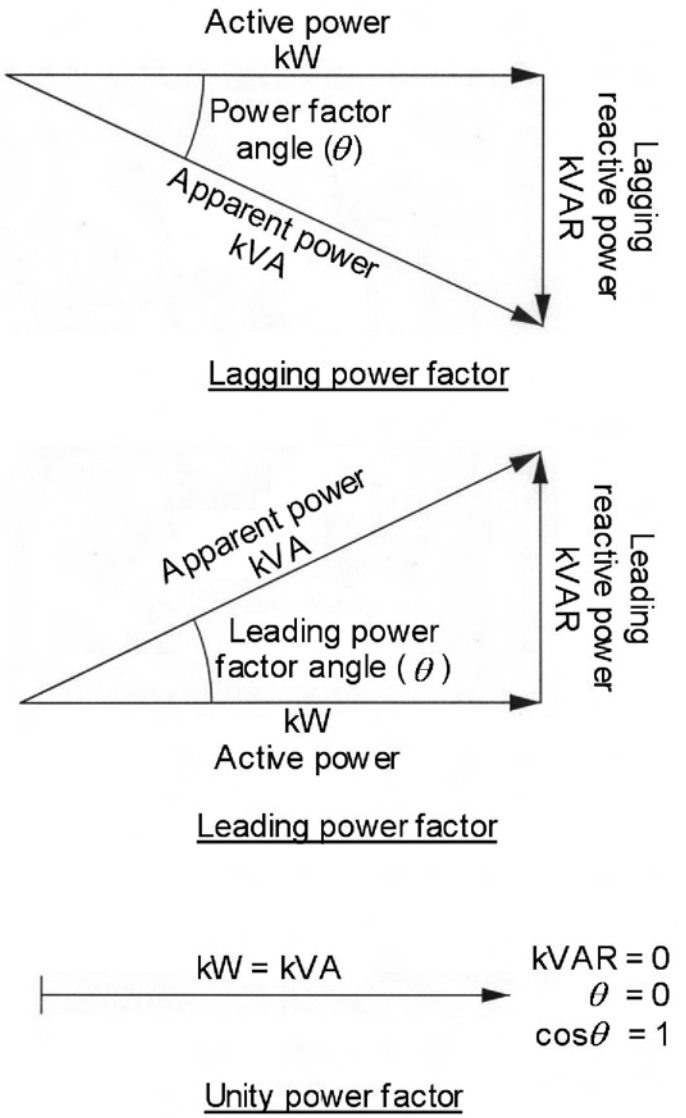


Fig. 12.5—Power triangles (courtesy of AMEC Paragon).

$$F_p = \cos\theta = \frac{P_a}{P_{ap}} = \frac{\text{kW}}{\text{kVA}} \quad \text{..... (12.11)}$$

The power factor is "leading" in loads that are more capacitive and "lagging" in loads that are more inductive (e.g., motor or transformer windings). In a purely resistive load, F_{ops} = 1 (unity), such that $P_a = P_{ap}$ (kW = kVA) and no reactive power is present. When F_p < unity, reactive power is present and more power is required to produce work, as seen in the following equation:

$$P_{ap} = \frac{P_a}{\cos\theta} \quad \text{..... (12.12)}$$

The reactive power of a motor is approximately the same from no load to full load. When a motor is operating at full load, the active/reactive power ratio is high, and thus the power factor of the motor is high. A lightly loaded motor has a low active/reactive power ratio, which causes the power factor to be low. At low power factors, more power will be required from the utility company than actually is needed by the load. This translates into higher energy cost and the need for larger generation units and transformers. Some utility companies charge a substantial penalty to their customers for low power factors (generally < 0.95). Also, low power factors might cause more voltage drop in the system, which causes the motors to operate sluggishly and the lights to dim.

It is essential that the power factor of the system be maintained as high as possible (close to unity). Removing the reactive power from the system can make this possible. Power-factor-correction capacitors are used for this purpose. A motor requires inductive or lagging reactive power for magnetizing. Capacitors provide capacitive or leading reactive power that cancels out the lagging reactive power when used for power-factor improvement. The power triangles in **Fig. 12.6** show how capacitors can improve the power factor for a motor. The improved power factor changes the current required from the utility company, but not the one required by the motor.

Capacitors should not be selected as a means of correcting poor power factors that are the result of oversized motors or unbalanced pumping units. Choosing a capacitor for this purpose might cause overcorrection, which can result in a leading power factor. A leading power factor, in turn, might cause overvoltages that would cause control-component failure or power-cable failure. This potential problem generally is avoided by connecting the capacitors downstream of the motor contactors and switching them on and off, along with the motor contactors.

Power factor correction capacitors could be applied to each individual motor to correct the power factor of that motor, or could be a single unit connected to the main bus of the switchgear. In the latter case, the unit should have power-factor-sensing circuits that automatically determine the amount of capacitance required for maintaining a preset power factor. The required amount of capacitors are automatically added to or removed from the switchgear bus to maintain the required power factor.

The cyclic kW load on a pumping-unit motor can cause the power factor to vary from 1.0 to near zero if excessive adverse pumping conditions exist.

12.9 Hazardous-Area Classification

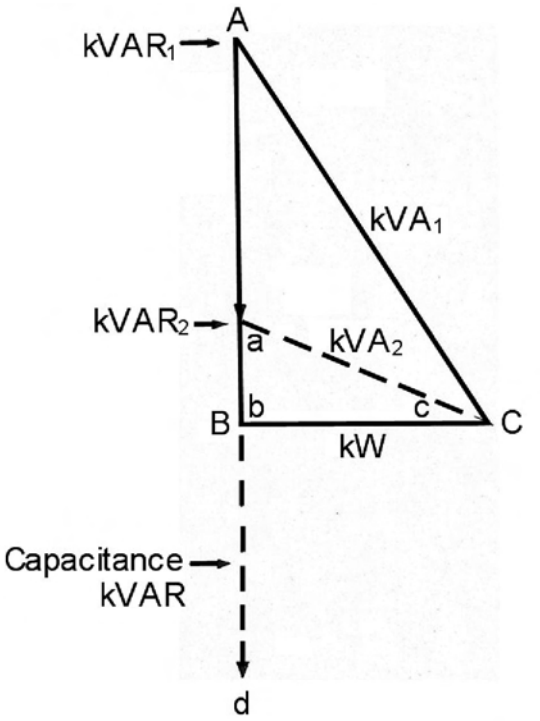
Production facilities contain, or may contain, flammable gases and vapors in normal operations. In the right concentration with air, these can form an explosive environment that is ignitable by hot surfaces, electrical arcs, and sparks. To prevent this from happening, facilities must be classified properly, so that all electrical equipment and systems are properly selected and installed.

12.9.1 North American Standards. In the U.S., facilities are classified according to *NEC,*[31] and a nationally recognized testing laboratory must approve all arcing electrical equipment installed in the classified areas.

The four steps involved in hazardous area classification are:

1. Determine the type of hazard or "class" that might be present—combustible gas (Class I), combustible dust (Class II), or fibers (Class III).
2. Identify the specific "group" for the hazardous substance (Group A through Group G).
3. Determine the degree of the classification (Division 1 or Division 2).
4. Determine the extent of the classified locations.

Groups A through G are acetylene, hydrogen, ethylene, propane/methane, metal dust, coat dust, and grains/fibers, respectively. Almost all classifications in oil and gas facilities are Class I, Group D. Class I locations are those in which flammable gases or vapors are or might be present in the air in the quantities sufficient to produce explosive or ignitable mixtures.



	Without capacitance kVAR 1	With capacitance kVAR 2
kW	50	50
kVA	91	56
Individual kVAR	76	26
Capacitance kVAR	0	50
Power factor	0.55	0.90
Line amps	114	70

A–B–C	Power triangle before correction.
b–d	Amount of capacitance kVAR used for power factor correction.
A–a	Capacitance kVAR subtracted from motor kVAR.
a–b–c	Power triangle with power factor correction.

Fig. 12.6—Power triangle showing power factor correction (after Ref. 45, Chap. 10).

Class I locations are either Division 1 or Division 2, or are unclassified:[2,31]

Class I, Division 1. Locations (1) in which ignitable concentrations of flammable gases or vapors can exist under normal operating conditions, (2) in which ignitable concentrations of such gases or vapors may exist frequently because of repair or maintenance operations or because of leakages, or (3) in which breakdown or faulty operation of equipment or processes might release ignitable concentrations of flammable gases or vapors and might also cause simultaneous failure of electrical equipment in such a way as to directly cause electrical equipment to become a source of ignition.

Class I, Division 2. Locations (1) in which volatile, flammable liquids or flammable gases are handled, processed, or used, but in which the liquids, vapors, or gases normally will be confined within the closed containers or closed system from which they can escape only in case of accidental rupture or breakdown of such containers or systems, or in case of abnormal operation of equipment; (2) in which ignitable concentrations of gases or vapors normally are prevented by positive ventilation, and which might become hazardous through failure or abnormal operation of the ventilation equipment; or (3) which are adjacent to a Class I, Division 1 location, and to which ignitable concentrations of gases or vapors might occasionally be communicated unless such communication is prevented by adequate positive-pressure ventilation from a source of clean air, and effective safeguards against ventilation failure are provided.

Unclassified. All areas in a facility that are not Division 1 or Division 2 are considered unclassified. Arcing electrical equipment in the unclassified areas need not be explosion-proof. General-purpose enclosures are accepted in these areas.

API RP 500[2] shows typical examples of classifications of equipment in oil and gas production facilities, including the extent of the classified areas around such equipment. **Figs. 12.7 through 12.11** provide examples of classified locations in a typical oil-and-gas-production facility.

Refer to *API RP 500*[2] and the *NEC*[31] for further details regarding hazardous-area classification.

12.9.2 International Electrotechnical Commission (IEC) Standards. Whereas the classification based on the *NEC* and API standards is used in the U.S. and a few other countries in the world, an IEC-created zone classification system is widely accepted elsewhere.

The IEC zone classifications basically are:

Class I, Zone 0. Locations (1) in which ignitable concentrations of flammable gases or vapors are present continuously or (2) in which ignitable concentrations of flammable gases or vapors are present for long periods of time.

Class I, Zone 1. Locations (1) in which explosive or ignitable concentrations of flammable gases or vapors are likely to exist under normal operating conditions; (2) in which ignitable concentrations of flammable gases or vapors may exist frequently because of repair or maintenance operations or because of leakages; (3) in which equipment is operated or processes are carried on, of such a nature that equipment breakdown or faulty operations could result in the release of ignitable concentrations of flammable gases or vapors and cause simultaneous failure of electrical equipment in a mode to cause the electrical equipment to become a source of ignition; or (4) that is adjacent to a Class I, Zone 0 location, from which ignitable concentrations of gases or vapors could be communicated, unless such communication is prevented by adequate positive-pressure ventilation from a source of clean air, and effective safeguards against ventilation failure are provided.

Class I, Zone 2. Locations (1) in which ignitable concentrations of flammable gases or vapors are not likely to occur in normal operation and if they do occur will exist only for a short period; (2) in which volatile, flammable liquids, flammable gases, or flammable vapors are handled, processed, or used, but in which the liquids, gases, or vapors are confined within closed containers or a closed system from which they can escape only in case of accidental rupture or breakdown of such containers or system, or as a result of the abnormal operation of

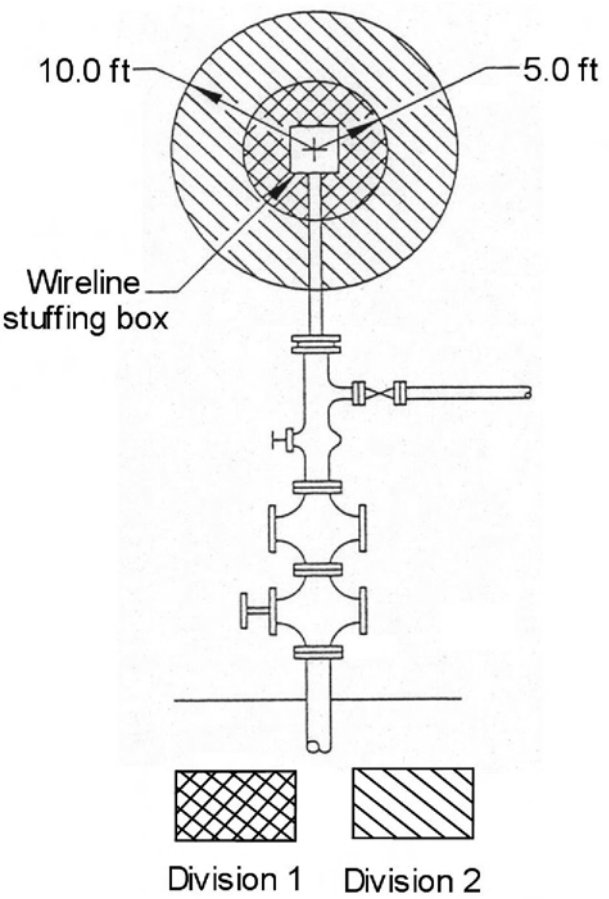


Fig. 12.7—Nonenclosed, adequately ventilated well on which work is being performed (modified from Ref. 2).

equipment with which the liquids or gases are handled, processed, or used; (3) in which ignitable concentrations of flammable gases or vapors normally are prevented by positive mechanical ventilation, but which may become hazardous because of failure or abnormal operation of the ventilation equipment; or (4) which are adjacent to a Class I, Zone 1 location from which ignitable concentrations of flammable gases or vapors could be communicated unless such communication is prevented by adequate positive-pressure ventilation from a source of clean air, and effective safeguards against ventilation failure are provided.

Unclassified. All areas in the facility that are not Zone 0, Zone 1, or Zone 2 are considered unclassified. Arcing electrical equipment in unclassified areas need not be explosion-proof. General-purpose enclosures are acceptable in these areas.

The IEC zone classification also differs from North American standards in its grouping of the hazardous gases or vapors as either Group I or Group II. Group I is for use in describing atmospheres that contain firedamp (a mixture of gases, composed mostly of methane, found underground, usually in mines). Group II covers all other flammable gases. Group II is subdivided into IIC, IIB, and IIA, according to the nature of the gas or vapor:

• Group IIC is equivalent to a combination of Class I, Group A and Class I, Group B in the *NEC* system.

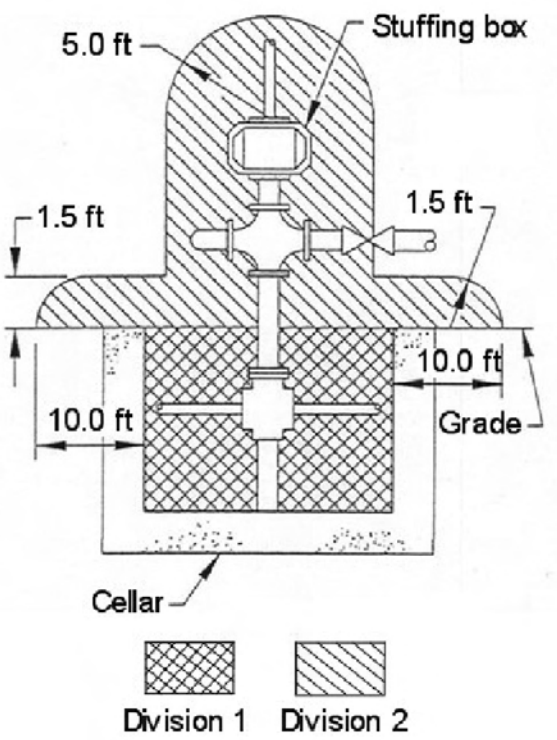


Fig. 12.8—Nonenclosed beam-pumping well in an adequately ventilated area with an inadequately ventilated cellar (modified from Ref. 2).

- Group IIB is equivalent to Class I, Group C in the *NEC* system.
- Group IIA is equivalent to Class I, Group D in the *NEC* system.

See *NEC,* Chap. 5, Article 505[31] for further details of the IEC zone classifications.

12.10 Alternating-Current (AC) Motors

AC motors are used worldwide in many residential, commercial, industrial, and utility applications. Motors transform electrical energy into mechanical energy. An AC motor may be part of a pump, fan, or other form of mechanical equipment. AC motors are found in a variety of applications, from those that require a single motor to special applications that require several motors working in concert.

All AC motors are made up of a magnetic circuit formed by a stationary member called a stator and a rotating member known as rotor. The stator and rotor are separated by an air gap. The stator has primary windings that are connected to the power source and develop a rotating magnetic field. The rotor has secondary windings that rotate in the magnetic field created by the stator windings. This causes currents to flow in the secondary windings and causes development of a secondary magnetic field. How the rotors are designed and how the currents are made to flow determines the type of motor and its performance characteristics. Two types of AC motors are widely used in the oil and gas industry: induction and synchronous.

The National Electrical Manufacturers Association (NEMA) sets the standards for a wide range of electrical products, including motors. NEMA is associated primarily with motors used in North America. NEMA's standards (see NEMA Standard Publication No. MG 1[27]) represent general industry practices and are supported by manufacturers of electrical equipment. The NEMA standards might not apply to some large AC motors that are built to meet the requirements

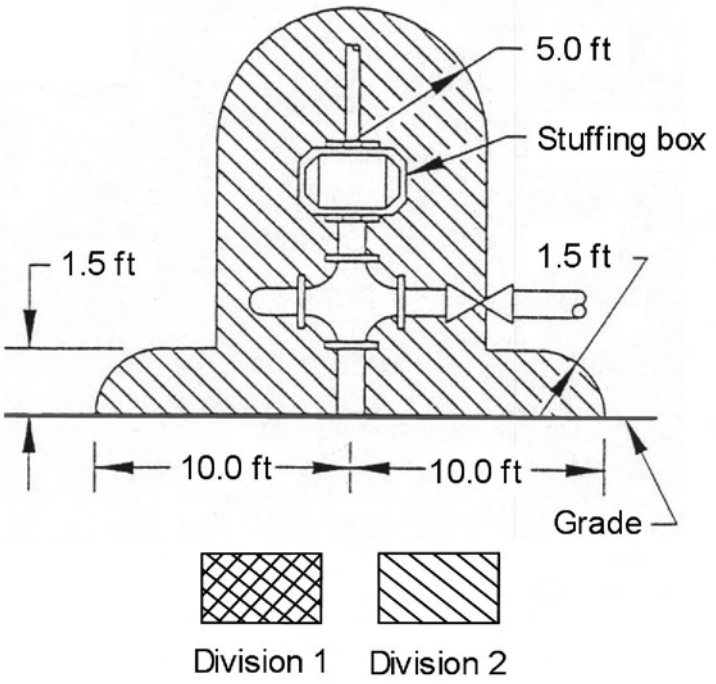


Fig. 12.9—Nonenclosed beam-pumping well in an adequately ventilated area without a cellar (modified from Ref. 2).

of a specific application. Such motors are referred to as "above-NEMA." The American Petroleum Institute (API) and the Institute of Electrical and Electronic Engineers (IEEE) also have standards for NEMA-sized and above-NEMA motors.

12.10.1 Induction Motors. AC induction motors are widely used in the oil and gas industry because of their simplicity, reliability, and low cost. Induction motors are either single-phase or three-phase. This discussion will center on the three-phase, 460-VAC (volts-alternating-current) induction motors. In an induction motor, the actual rotor speed always is less than that of the rotating magnetic field. Fig. 12.12 shows a typical induction motor and labels its three basic parts: stator, rotor, and enclosure.

Stator Construction. The stator and the rotor are electrical circuits that perform as electromagnets. The stator is the stationary electrical part of the motor. The stator core of a NEMA motor is made up of several hundred thin laminations that are stacked together to form a hollow cylinder. Coils of insulated wire are inserted into slots of the stator core.

Each group of coils and the steel core it surrounds form an electromagnet. Electromagnetism is the principle behind motor operation. The stator windings are connected directly to the power source.

Rotor Construction. The rotor is the rotating part of the electromagnetic circuit. The most common type of rotor is the "squirrel cage" rotor, so called because it is reminiscent of one of the exercise wheels found in the cages of pet rodents. Other types of rotor construction are mentioned later in the chapter.

The squirrel-cage rotor consists of a stack of steel laminations that has evenly spaced conductor bars around its circumference. The stacked laminations form the rotor core. Aluminum is die-cast in the slots of the rotor core to form the series of conductors around the rotor's

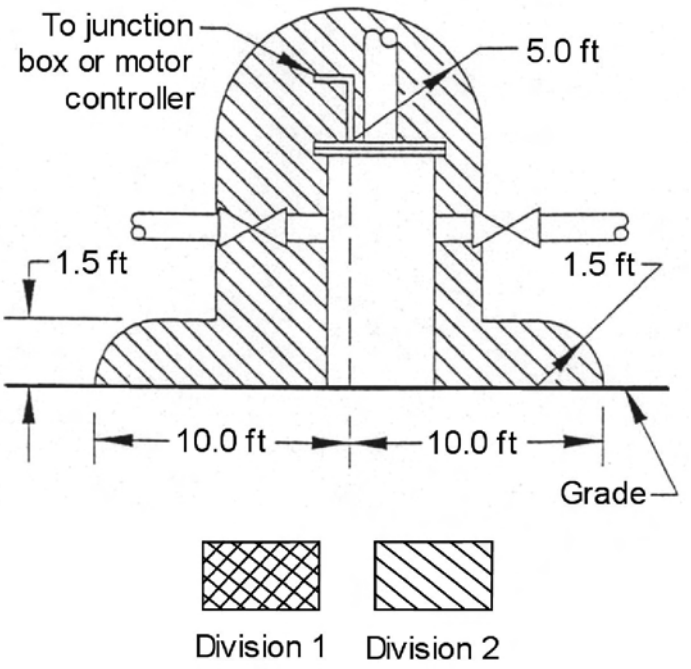


Fig. 12.10—Electrical submersible pumping well in a nonenclosed, adequately ventilated area without a cellar (modified from Ref. 2).

perimeter. Current flow through the conductors forms the electromagnet. The conductor bars are mechanically and electrically connected with end rings. The rotor core mounts on a steel shaft to form a rotor assembly.

The wound rotor is another type of induction-motor-rotor construction. A major difference between the wound rotor motor and the squirrel-cage rotor is that the conductors of the wound rotor consist of wound coils instead of bars. These coils are connected through slip rings and brushes to external variable resistors, as shown in Fig. 12.13. The rotating magnetic field induces a voltage in the rotor windings that increases the resistance of the rotor windings. This increase in resistance allows less current flow in the rotor windings, which decreases motor speed. Conversely, decreasing the resistance allows more current flow, and so increases motor speed.

Wound-rotor induction motors are used in applications of certain types of pump, in mine hoists, mills, and applications where speed reduction is required in the drive application.

Stator-Coil Arrangement. The schematic in Fig. 12.14 illustrates the relationship between the stator coils. The coils operate in pairs. This example uses six coils, a pair for each of the three phases. The coils are wrapped around the soft iron core material of the stator. These coils are referred to as motor windings. Each motor winding becomes a separate electromagnet. The coils are wound in such a way that when current flows in them, one coil in a pair is a north pole and the other a south pole. For example, if A1 were a north pole, then A2 would be a south pole. When the current reverses, so does the polarity of the poles.

12.10.2 Rotor Rotation. ***Principle of Rotation.*** To see how a rotor works, use a magnet mounted on a shaft in place of the squirrel cage rotor, as shown in the upper image in Fig. 12.15. Energizing the stator windings establishes a rotating magnetic field. The magnet has its own magnetic field that interacts with the rotating magnetic field of the stator. The north pole of the

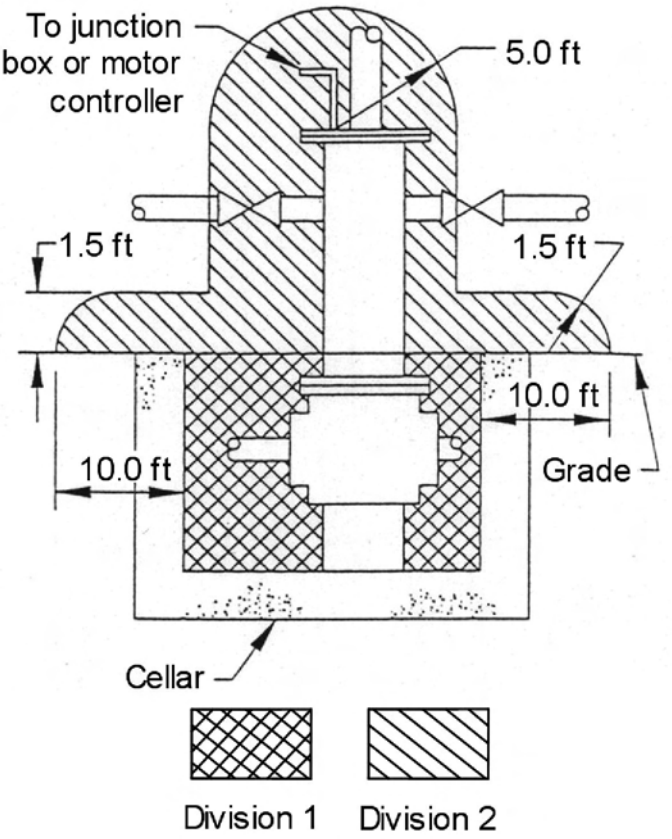


Fig. 12.11—Electrical submersible pumping well in a nonenclosed, adequately ventilated area with an inadequately ventilated cellar (modified from Ref. 2).

rotating magnetic field attracts the south pole of the magnet, and vice versa. As the rotating magnetic field rotates, it pulls the magnet along, causing it to rotate. Motors that use this design are known as permanent-magnet synchronous motors.

The squirrel-cage rotor acts essentially the same as the magnet. When power is applied to the stator, current flows through the winding, causing an expanding electromagnetic field (emf) that cuts across the rotor bars.

When a conductor, such as a rotor bar, passes through a magnetic field, it induces a voltage (an emf) in the conductor. The induced voltage causes a current flow in the conductor. The current flows through the rotor bars and around the end ring, producing magnetic fields around each rotor bar. In an AC circuit, the current continuously changes direction and amplitude. The resultant magnetic field of the stator and rotor continuously change. The squirrel-cage rotor becomes an electromagnet with alternating north and south poles.

The lower image in Fig. 12.15 illustrates one instant in time during which current flow through winding A1 produces a north pole. The expanding field cuts across an adjacent rotor bar, inducing a voltage. The resultant magnetic field in the rotor tooth produces a south pole. As the stator magnetic field rotates, the rotor follows.

Synchronous Speed. The speed of the rotating magnetic field is referred to as the synchronous speed (N_s). Synchronous speed is equal to 120 times the frequency (f), divided by the number of poles (P):

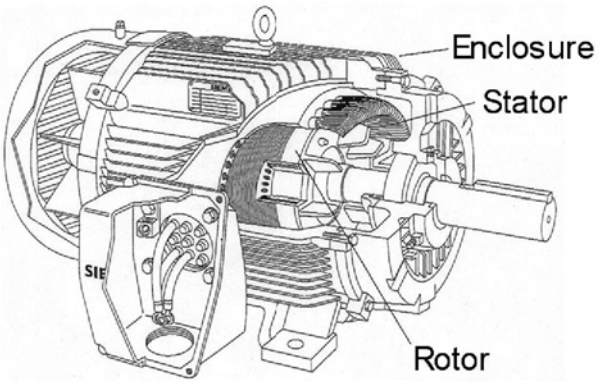


Fig. 12.12—Typical induction motor (courtesy of Siemens Energy and Automation Inc. and Houston Armature Works Inc.).

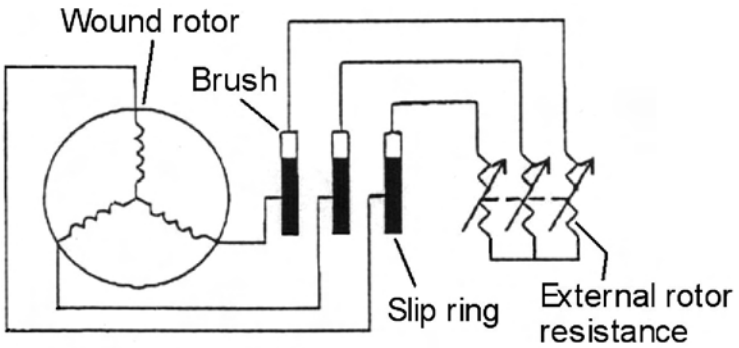


Fig. 12.13—Wound-rotor-motor diagram (courtesy of Houston Armature Works Inc.).

$$N_s = \frac{120f}{P} \quad \text{..... (12.13)}$$

If the frequency of the applied power supply for the two-pole stator is 60 Hz, then the synchronous speed is 3,600 rev/min:

$$N_s = \frac{(120)(60)}{2} = 3{,}600.$$

Synchronous speed decreases as the number of poles increases. **Table 12.4** shows the synchronous speed at 60 Hz for different numbers of poles.

Slip. The relative difference in speed between the rotor (N) and the rotating magnetic field (N_s) is called slip. There must be some slip because if the rotor and the rotating magnetic field were turning at the same speed, no relative motion would exist between the two, such that no lines of flux would be cut and no voltage would be induced in the rotor. Slip is necessary to produce torque and depends on load—an increase in load will cause the rotor to slow down, ergo increase the slip. Conversely, a decrease in load will cause the rotor to speed up, and so will decrease slip. Slip (S) is expressed as a percentage and can be determined by:

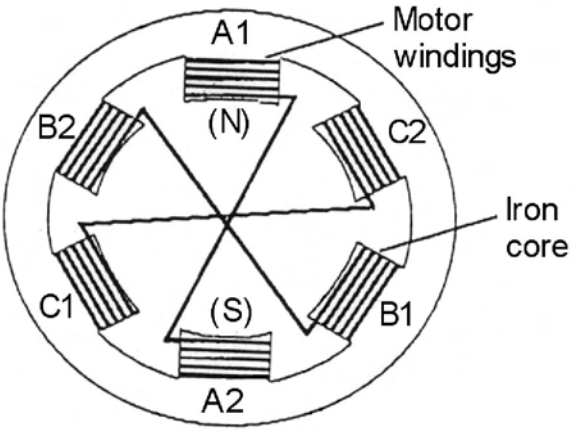


Fig. 12.14—Typical motor-winding diagram (courtesy of Houston Armature Works Inc.).

$$S = \frac{N_s - N}{N_s} 100 \ , \quad \text{..... (12.14)}$$

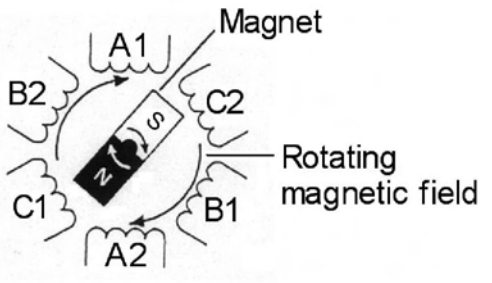
where N = rotor speed, rev/min. For example, a four-pole motor operated at 60 Hz has a synchronous speed of 1,800 rev/min. If the rotor speed at full load is 1,765 rev/min, then slip is 1.9%:

$$S = \frac{1{,}800 - 1{,}765}{1{,}800} 100 = 1.9\ \% \ .$$

12.10.3 Synchronous Motor. The synchronous motor is another type of AC motor. Like an induction motor, it has a stator and a rotor. Its stator winding closely resembles that of an induction motor, and it, too, receives AC power from the power source to drive the connected load.

Synchronous motors are available with various rotor designs to fit different applications. In one type, for example, the rotor is constructed somewhat like a squirrel-cage rotor. In addition to rotor bars, it has coil windings for providing direct-current (DC) excitation, as shown in **Fig. 12.16**. The coil windings are connected to an external DC power supply by slip rings and brushes. Like a squirrel-cage motor, a synchronous motor is started by applying AC power to the stator; however, DC power then is applied to the rotor coils after the motor reaches maximum speed. This produces a strong, constant magnetic field in the rotor, which locks in step with the rotating magnetic field of the stator. Because the rotor turns at the same speed as synchronous speed (speed of the rotating magnetic field), there is no slip. The speed of rotation of the motor is constant in a synchronous motor, and does not vary with load, as in an induction motor.

Synchronous motors are designed to operate at unity (1.0) power factor or 0.8 leading power factor. By varying the DC excitation of the motor, the power factor of the motor can be varied widely. Overexcited synchronous motors operate at leading power factor and provide reactive kVAR-like capacitors. This yields an improved power factor for the power-supply system. Because most utility companies bill their industrial customers on the basis of their kVAR use, rather than kW, an improved power factor provides large savings for the customer.



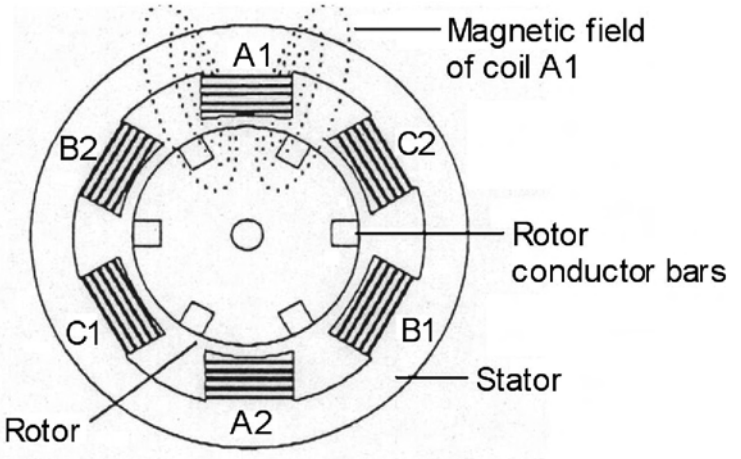


Fig. 12.15—Principle of motor rotation (courtesy of Houston Armature Works Inc.).

TABLE 12.4—SYNCHRONOUS SPEED FOR VARIOUS POLE MOTORS

Number of poles (P)	Synchronous speed (N_s)
2	3,600
4	1,800
6	1,200
8	900
10	720

Synchronous motors initially were used as a way to raise the power factor of systems that have larger induction-motor loads; now, however, they are used because they can maintain the terminal voltage on a weak power system, are lower cost, and are more efficient than equivalently sized induction motors.

12.11 Motor Specifications

A motor's nameplate provides important information relevant to its selection and application. Fig. 12.17 is the nameplate from a 30-hp AC motor. It gives specifications for the load and operating conditions, as well as for motor protection and efficiency.

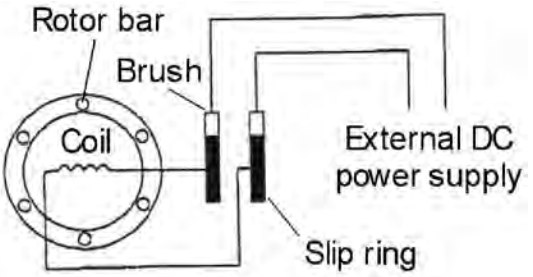


Fig. 12.16—Synchronous-motor diagram (courtesy of Houston Armature Works Inc.).

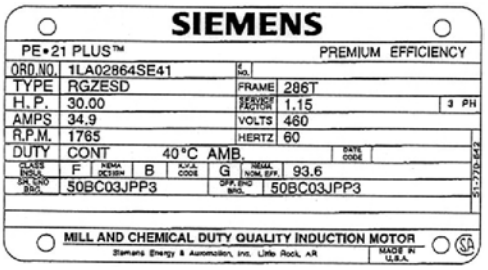


Fig. 12.17—Typical motor nameplate (courtesy of Siemens Corp.).

12.11.1 Voltage and Amps. AC motors are designed to operate at standard voltages and frequencies. This sample motor is designed for continuous-duty operation in a 460-VAC, three-phase system. At full-load, this motor would draw a 34.9-A current.

12.11.2 Horsepower and Kilowatts. U.S.-manufactured AC motors generally are hp-rated, whereas European-manufactured equipment generally is kW-rated.

In kW, the power formula for a single-phase motor is:

$$P_a = \frac{EIF_p}{1{,}000}. \quad \text{..... (12.15)}$$

The power formula for three-phase motor is:

$$P_a = \frac{EIF_p 1.732}{1{,}000}. \quad \text{..... (12.16)}$$

The motor manufacturer provides the voltage, current, and power factor of the motors.

12.11.3 Base Speed. Base speed is the nameplate speed—given in rev/min—at which the motor develops the rated horsepower at the rated voltage and frequency. It indicates how fast the output shaft will turn the connected equipment when fully loaded and supplied with the proper voltage and frequency. The base speed of the motor in Fig. 12.17 is 1,765 rev/min at 60 Hz.

12.11.4 Service Factor. The service factor is a multiplier that may be applied to the rated power to allow a motor to be operated at higher than its rated hp. A motor designed to operate at its nameplate hp rating with a service factor of 1.0 would operate continuously at 100% of

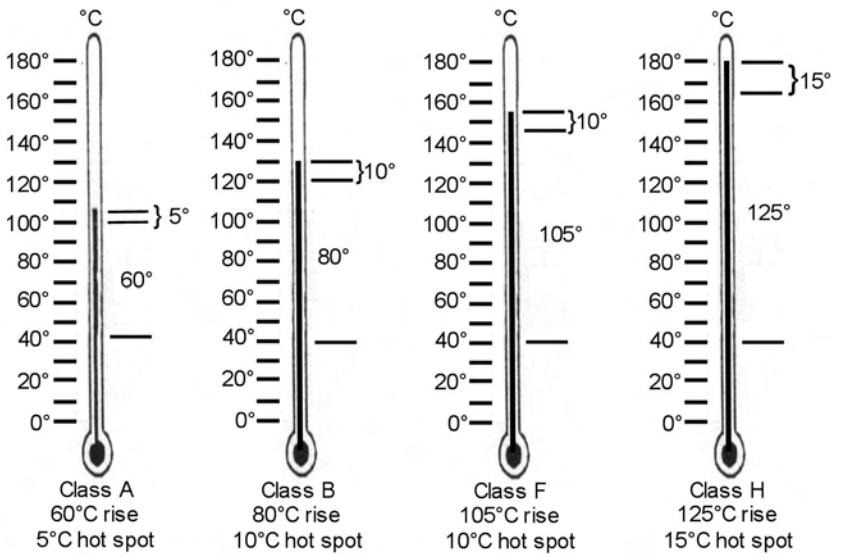


Fig. 12.18—Motor-winding insulation classes (courtesy of Houston Armature Works Inc.).

its rated hp without exceeding its operating temperature. Some applications might require a motor to exceed its rated hp. In such cases, a motor with a service factor of 1.15 can be specified, allowing the motor be operated 15% higher than its nameplate hp. For example, with a 1.15 service factor, the 30-hp motor in Fig. 12.17 can be operated at 34.5 hp. Note, however, that any motor operating continuously at a service factor > 1.0 will have a reduced life expectancy compared to one operating it at its rated hp. This is because of high winding temperature, which causes motor-winding insulation to age thermally at approximately twice the rate that occurs for a motor with a 1.0 service factor.

12.11.5 Insulation Classes. NEMA has established motor-winding-insulation classes to meet motor-temperature requirements found in different operating environments. The four insulation classes are A, B, F, and H, as illustrated in **Fig. 12.18**. Class-F insulation is most commonly used. Class-A insulation seldom is used. Before a motor is started, its windings are at ambient temperature (the temperature of the surrounding air). NEMA has standardized on an ambient temperature of 40°C within a defined altitude range for all motor classes.

Temperature will rise in the motor as soon as the motor is started. Each insulation class has a specific allowable temperature increase. The combination of ambient temperature and allowed temperature increase equals the maximum winding temperature in the motor. For example, a motor with Class-F insulation has a maximum temperature increase of 105°C when operated at a 1.0 service factor. The maximum winding temperature is 145°C (40°C ambient plus 105°C rise). A margin is allowed to provide for the motor's "hot spot," a point at the center of the motor's windings where the temperature is higher.

The operating temperature of a motor is important to efficient operation and long life. Operating a motor above the limits of the insulation class reduces its life expectancy. For example, a 10°C increase in the operating temperature can decrease the motor's insulation life expectancy as much as 50%.

The motor in Fig. 12.17 has Class-F insulation and is rated for continuous duty at 40°C ambient.

TABLE 12.5—LOCKED-ROTOR CODE LETTERS[31]

Code letter	kVA/hp with locked rotor
A	0 to 3.14
B	3.15 to 3.54
C	3.55 to 3.99
D	4.00 to 4.49
E	4.50 to 4.99
F	5.00 to 5.59
G	5.60 to 6.29
H	6.30 to 7.09
J	7.10 to 7.99
K	8.00 to 8.99
L	9.00 to 9.99
M	10.00 to 11.19
N	11.20 to 12.49
P	12.50 to 13.99
R	14.00 to 15.99
S	16.00 to 17.99
T	18.00 to 19.99
U	20.00 to 22.39
V	22.40 and up

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12.11.6 Motor Design. NEMA has established standards for motor construction and performance. Standard NEMA designs are NEMA A, NEMA B, NEMA C, and NEMA D. NEMA B motors are the most commonly used. (See the NEMA Motor Design section below for more details of the NEMA designs.) Additionally, NEMA has assigned frame sizes for all three-phase induction motors built to NEMA standards. This includes motors from 0.5 to 250 hp. Each frame size has a specific frame design, set of dimensions, full-load amperage, efficiency, and power factor. See *NEMA MG 1*[27] for the details of frame sizes.

The motor in Fig. 12.17 is a NEMA B design and has a NEMA 286T frame designation.

12.11.7 Locked-Rotor Code Letters. NEMA has assigned code letters A through V to designate the locked-rotor kVA per horsepower. This is an amount of power drawn by the motor when it is started. **Table 12.5** gives the designations of each code letter.

The motor in Fig. 12.17 is code letter G and has 5.6 to 6.29 locked-rotor kVA/hp.

12.11.8 Efficiency. AC motor efficiency is expressed as a percentage. It is an indication of how much of the input electrical energy is converted to output mechanical energy. The nominal efficiency of the motor in Fig. 12.17 is 93.6%. The higher the percentage, the more efficiently the motor converts the incoming electrical power to mechanical horsepower. A 30-hp motor with a 93.6% efficiency would consume less energy than a 30-hp motor with an efficiency rating of 83.0%. This can mean a significant saving in energy cost. In addition to

lower energy costs, lower operating temperature, longer life, and lower noise levels are typical benefits of high-efficiency motors.

12.12 NEMA Motor Characteristics

12.12.1 Standard Motor Designs. Motors are designed with certain speed-torque characteristics to match speed-torque requirements of various loads. A motor must be able to develop enough torque to start, accelerate, and operate a load at rated speed. The relationship between horsepower (H), torque (T, lbf-ft), and motor speed (N_m, rev/min) is given by:

$$H = \frac{TN_m}{5{,}250} \quad \text{..... (12.17)}$$

NEMA has established class designations for motors on the basis of motors' starting-torque and accelerating loads. The four standard NEMA designs are NEMA A, NEMA B, NEMA C, and NEMA D. NEMA A motors usually are used for applications that require extremely high efficiency and extremely high full-load speed. NEMA A-design motors are special and are not used very often. NEMA B-design motors are considered to be normal-torque motors. They are used for low-starting-torque loads, such as with centrifugal pumps and fans. NEMA C and NEMA D motors are used for applications that require high starting torque (e.g., positive-displacement pumps and compressors).

12.12.2 Speed/Torque Curve. The graph in **Fig. 12.19** shows a typical speed/torque curve for a NEMA-B motor. Such curves show the relationship between motor speed and torque produced by a motor from the moment it is started until the time it reaches full-load torque at the rated speed.

12.12.3 Starting Torque. Starting torque (Fig. 12.19, A) is also known as locked-rotor torque. It is developed when the rotor is held at rest with the rated voltage and frequency applied, a condition that occurs whenever a motor is started. When the rated voltage and frequency are applied to the stator, there is a brief time before the rotor turns. During this time, a NEMA B motor develops approximately 150% of its full-load torque.

12.12.4 Accelerating Torque and Breakdown Torque. As a motor accelerates, torque decreases slightly (Fig. 12.19, A to B) before beginning to increase. As speed continues to increase, torque increases until it reaches a maximum at approximately 200% (Fig. 12.19, B to C). This torque is referred to as accelerating (or pull-up) torque. If this maximum is beyond the motor's torque capability, the motor will then stall or abruptly slow down. Point C on the graph in Fig. 12.19 is referred to as the breakdown (or pull-out) torque.

12.12.5 Full-Load Torque. Full-load torque is the torque that develops when the motor is operating with the rated voltage, frequency, and load. The speed at which full-load torque is produced is the slip speed or the rated speed of the motor (Fig. 12.19, D)

12.12.6 Starting Current and Full-Load Current. Starting current also is referred to as locked-rotor current and is measured from the supply line at the rated voltage and frequency with the rotor at rest. Full-load current is the current measured from the supply line at the rated voltage, frequency, and load, with the rotor up to speed. Starting current typically is 600 to 650% of full-load current on a NEMA B motor. As the rotor comes up to speed, the starting current decreases to the rated full-load current **(Fig. 12.20)**.

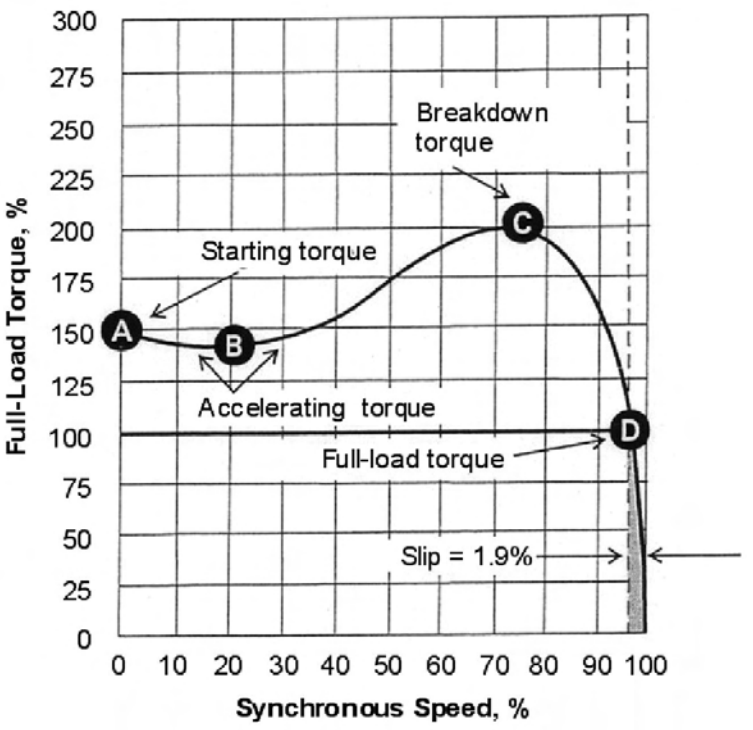


Fig. 12.19—Typical speed/torque curve for a NEMA-B induction motor (courtesy of Houston Armature Works Inc.).

12.12.7 Special Design Motors. Multispeed motors and motors used in variable-speed applications are special motors that are uniquely designed or selected to fulfill specific load requirements. NEMA design classifications are not applicable to these specialized motors.

12.13 Methods of Motor Starting

Various methods are used for starting the electric motors. The most common method is full-voltage starting; motor torque and current from standstill to full speed are highest when the full-voltage starting method is used. The other starting methods (e.g., autotransformer, wye-delta, part-winding, and soft) provide reduction of both motor current and torque during the starting period.

12.13.1 Full-Voltage Starting. In full-voltage starting (also called across-the-line starting), the motor is connected directly to the power source through the motor starter. When used to start an induction motor, the starting current for this method can be as high as 5 to 7 times the full-load current. This might cause excessive undesirable voltage drop in the system. In the case of a large induction motor starting at full voltage on a limited-capacity power-supply system, the voltage drop during motor starting must be calculated [see the Motor-Starting Voltage Drop (Off a Transformer) and Motor-Starting Voltage Drop (Off a Generator) sections earlier in this chapter]. Consider reduced-voltage starting methods if the voltage drop during starting is > 15% of the rated voltage.

12.13.2 Autotransformer Starting. Autotransformer starting is a reduced-voltage starting method, commonly referred to as an RVAT (reduced-voltage autotransformer). During starting,

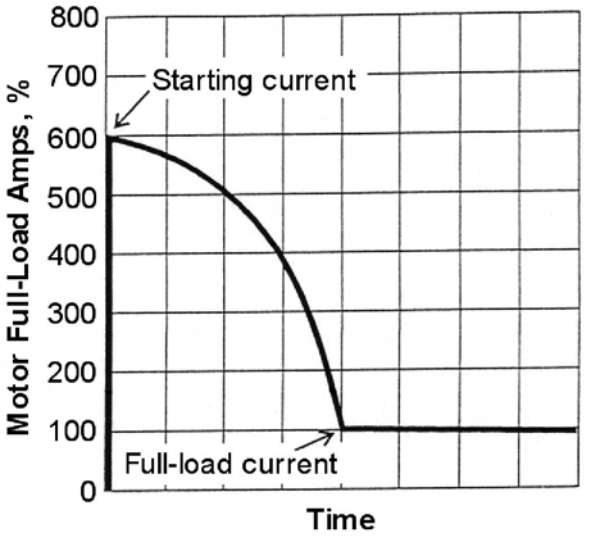


Fig. 12.20—Starting current and full-load current (courtesy of Houston Armature Works Inc.).

TABLE 12.6—AUTOTRANSFORMER TAP SETTINGS WITH RESPECTIVE LOCKED-ROTOR TORQUE AND LOCKED-ROTOR CURRENT

Tap, %	LRT, %	LRA, %
50	25	27
65	42	45
80	64	66

Courtesy of Houston Armature Works Inc.

the applied voltage can be reduced below the line voltage, and the motor is switched to full-line voltage upon reaching full speed. Both the motor-starting current and the torque will be reduced to below the values of an across-the-line starter. The most desirable starting current and starting torque can be selected by reconnecting the motor leads to the 50, 65, or 80% output taps on the autotransformer. The starting characteristics of the motor load and allowable accelerating times determine the best tap connection for each application.

Table 12.6 gives the starting torque and starting current as the percentage of full-voltage starting for the three tap settings of the autotransformer. In Table 12.6, %LRT (locked-rotor torque) is the starting torque expressed as a percentage of the values of an across-the-line start, and %LRA (locked-rotor ampere) is the starting current drawn from the power lines, expressed as a percentage of the values of an across-the-line start.

12.13.3 Wye-Delta Starting. In the wye-delta starting method, the motor windings are wye-connected (star-connected) during the starting and acceleration period. Once the motor approaches full-load speed, the windings are delta-connected for normal running operation. The transition from wye to delta may be an open or a closed transition type. Because the starting torque for this method is one-third of full-load torque, it is used when low starting torque is acceptable.

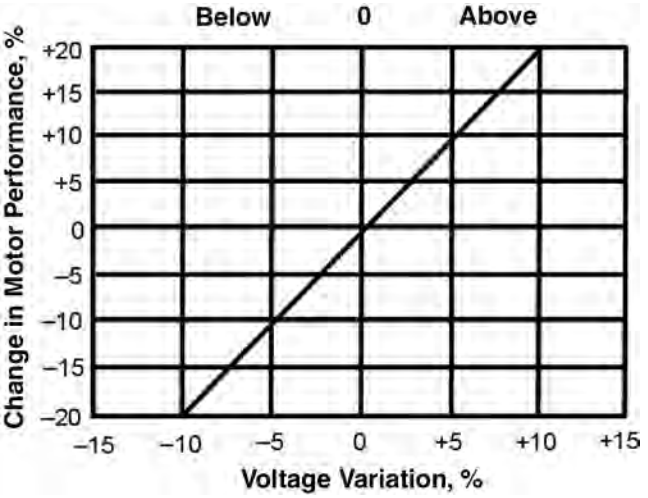


Fig. 12.21—Effect of voltage variation on motor torque (courtesy of Houston Armature Works Inc.).

12.13.4 Part-Winding Starting. Part-winding starting sometimes is used for lower-horsepower, higher-speed types of induction motors. In this method, a full voltage is applied to only part of the suitably designed stator winding during starting. After accelerating on the part-winding for a short time, the remainder of the stator winding is connected and the motor continues to accelerate to full speed. The starting torque for this method is approximately 50% of full-voltage starting, and the starting current is approximately 60 to 70% of full-voltage starting.

12.13.5 Soft Starting. Soft starting is a reduced-voltage starting method that uses solid-state, programmable starters. The starters provide smooth, stepless acceleration of the induction motors from zero to full speed over an adjustable time period. The starting torque of the motor varies as the square of the applied voltage. As the voltage is reduced, the torque is reduced to the level required to accelerate the motor and load to full speed. The acceleration time is set through "ramp" control to bring the motor to full speed over a desired length of time.

12.14 Derating Factors

Factors such as voltage and frequency variation, altitude, and temperature can affect the operation and performance of an AC motor enough to lower its rated capability, and should be considered when selecting a motor.

12.14.1 Voltage Variation. AC motors are designed to operate on standardized voltages and frequencies. A small variation in supply voltage can affect motor performance significantly. Fig. 12.21 shows that when the supply voltage is 10% below the rated voltage of the motor, the motor has 20% less starting torque. This reduced voltage might prevent the motor from getting its load started or keep it from running at its rated speed. A 10% increase in supply voltage, on the other hand, increases the starting torque by 20%, which might cause damage during startup (e.g., a conveyor might lurch forward at startup). Voltage variation causes similar changes in a motor's starting amperage, full-load amperage, and temperature rise.

12.14.2 Frequency. Variation in the frequency at which a motor operates causes changes mainly in its speed and torque. For example, a 5% increase in frequency causes a 5% increase in full-load speed and a 10% decrease in torque (Table 12.7). AC motors should operate successfully at their rated load with a combined variation in voltage and frequency of up to 10% above or below the rated voltage and the rated frequency, provided that the frequency variation does not

TABLE 12.7—CHANGE IN FULL-LOAD SPEED AND TORQUE WITH CHANGE IN FREQUENCY

Frequency change, %	Full-load speed change, %	Starting torque change, %
+5	+5	–10
–5	–5	+11

Courtesy of Houston Armature Works Inc.

TABLE 12.8—ALTITUDE-RELATED DERATING FACTORS

Altitude, ft	Derating factor
3,300 to 5,000	0.97
5,001 to 6,600	0.94
6,601 to 8,300	0.90
8,301 to 9,900	0.86
9,901 to 11,500	0.82

Courtesy of Houston Armature Works Inc.

exceed 5%; however, performance within this combined variation range might not be the same as the standards established for operation at the rated voltage and frequency.

12.14.3 Altitude and Temperature. The NEMA standards for allowable temperature increase for motor winding insulation discussed in the Insulation Classes section of this chapter is based on motor operation at or below an altitude of 3,300 ft and at a maximum ambient temperature of 40°C. For operation at altitudes of > 3,300 ft (at 40°C ambient), most motors must be derated because of temperature increase in the windings, as shown in **Table 12.8**. Some motors (Class A or B insulated) can be operated successfully at altitudes of > 3,300 ft in locations where a decrease in ambient temperature compensates for the increase in temperature rise. Also, motors with a service factor of 1.15 or higher will operate satisfactorily at a 1.0 service factor at a 40°C ambient temperature at altitudes of between 3,300 and 9,000 ft.

12.15 AC Motor Drives

Many applications require variable-speed motors. The easiest way to vary the speed of an AC induction motor is to use an AC drive to vary the applied frequency. AC drives commonly are known as variable frequency drives (VFDs). VFDs are microprocessor-based controllers that incorporate an electronic control section, an electromagnetic and semiconductor power section, and typical components that are used with standard motor controllers. VFDs can provide voltage to motors at frequencies of from < 1 Hz to approximately 120 Hz. Currently, they are available for motors ranging from 0.33 hp to thousands of horsepower. Operating a motor at other than the rated frequency and voltage affects motor current and torque. The following sections provide further discussion on this subject.

12.15.1 Volts per Hertz Ratio. The output torque for a motor is determined on the basis of the ratio of the motor's applied voltage and applied frequency, known as the volts per hertz (V/Hz) ratio. A typical AC motor manufactured for use in the U.S. is rated for 460 VAC and

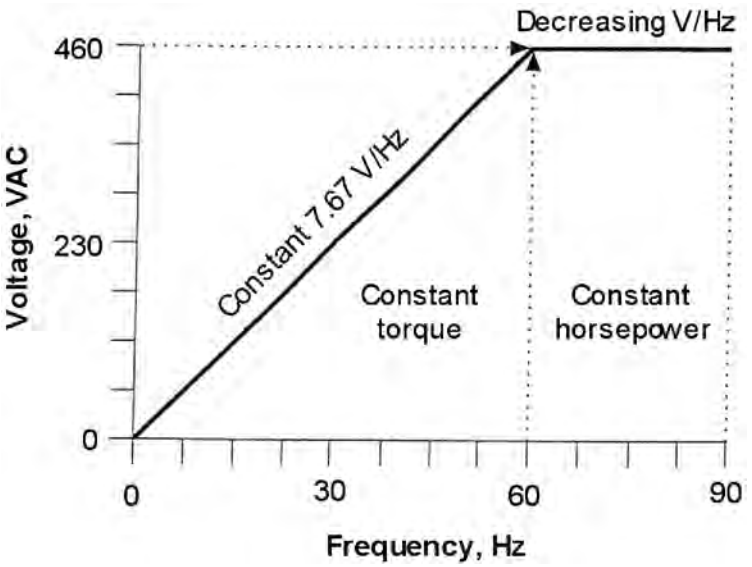


Fig. 12.22—Constant torque and constant horsepower (courtesy of Houston Armature Works Inc.).

60Hz, and thus has a 7.67 V/Hz ratio. Failure to maintain the proper V/Hz ratio will affect motor torque, temperature, speed, noise, and current draw.

For example, increasing the frequency without increasing the voltage will cause an increase in speed and a decrease in air-gap flux density. The air-gap flux density decrease causes motor torque to decrease because torque is directly proportional to the magnetic flux density in the motor's air gap.

Thus, for a motor to produce its rated torque at variable speeds, it also is necessary to control the voltage and frequency supplied to the motor. A VFD maintains a preset V/Hz ratio in supplying power to a motor at the variable speeds.

12.15.2 Constant Torque Load. AC motors running on an AC line operate with a constant flux because voltage and frequency are constant. Motors operated with constant flux are said to have constant torque. An AC drive can operate a motor with a constant flux of from zero to the motor's rated nameplate frequency (typically 60 Hz), which is the constant-torque range. As long as a constant V/Hz ratio is maintained, the motor will generate constant torque. AC drives change the frequency to vary the speed of the motor and change voltage proportionately to maintain constant flux. The V/Hz ratio can be kept constant for any speed up to 60 Hz. See **Fig. 12.22**.

Some examples of constant torque loads are conveyors, positive-displacement pumps, extruders, hydraulic pumps, and packaging machinery.

12.15.3 Constant Horsepower Load. Some applications require a motor to be operated at above base speed. Such applications need less torque at higher speeds, yet require voltage to be no higher than the rated nameplate voltage because the motor insulation deteriorates exponentially at higher-than-rated voltage. VFDs are designed to maintain a constant V/Hz ratio and torque up to 60 Hz. As **Table 12.9** shows, the V/Hz ratio decreases at above 60 Hz because VFDs are designed to maintain constant voltage above 60 Hz. When the V/Hz ratio decreases, the air-gap flux decreases, causing a decrease in the torque. Because the motor horsepower is directly proportional to the torque and speed of the motor, it remains constant while torque

TABLE 12.9—V/Hz RATIOS AT VARIOUS FREQUENCIES

Frequency, Hz	V/Hz
30	7.67
60	7.67
70	6.60
90	5.10

Courtesy of Houston Armature Works Inc.

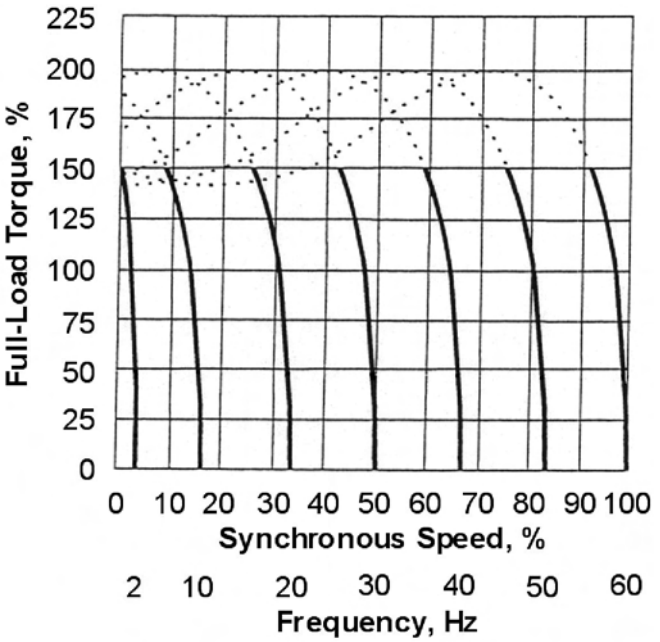


Fig. 12.23—Speed (frequency) vs. full-load torque (courtesy of Houston Armature Works Inc.).

decreases in proportion to the increase in frequency. As such, a motor that is operated above its rated frequency is operating in a region known as constant horsepower (see Fig. 12.22).

12.15.4 Reduced Voltage and Frequency Starting. A NEMA B motor that is started by connecting it to the power supply at full voltage and full frequency will develop approximately 150% starting torque and 600% starting current (Fig. 12.19). The same motor started with a VFD at reduced voltage and frequency develops approximately 150% torque and current. **Fig. 12.23** shows that the torque/speed curve shifts to the right as frequency and voltage are increased. The dotted lines on the torque/speed curve represent the portion of the curve not used by the drive. The drive starts and accelerates the motor smoothly as frequency and voltage are gradually increased to the desired speed. A VFD drive that is properly sized to a motor is capable of delivering 150% torque at any speed up to the speed that corresponds to the incoming line voltage.

Some applications require a starting torque > 150%. A conveyor, for example, might require a 200% rated torque for starting. If a motor is capable of 200% torque at 200% current, and the drive is capable of 200% current, then 200% motor torque is possible. Typically,

drives are capable of producing 150% of the drive nameplate rated current for 1 minute. A load that needs more starting torque than a drive can deliver requires a drive with a higher current rating. It is appropriate to supply a drive with a higher continuous horsepower rating than the motor when high peak torque is required.

12.15.5 Selecting a Motor. AC drives often have more capability than the motor. Drives can run at higher frequencies than might be suitable for an application. At frequencies above 60 Hz, for example, the V/Hz ratio decreases and the motor cannot develop 100% torque. Drives also can run at lower speeds than might be suitable. For example, a self-cooled motor might not develop enough air flow for cooling at reduced speeds and full load. Each motor must be evaluated according to its own capability before selecting it for use on an AC drive.

Harmonics, voltage spikes, and voltage rise times of AC drives are not identical. Some AC drives have more sophisticated filters and other components that are designed to minimize undesirable heating and insulation damage to the motor. This must be considered when selecting an AC drive/motor combination. Motor manufacturers generally will classify certain recommended motor selections on the basis of experience, required speed range, type of load torque, and temperature limits.

12.15.6 Distance Between Drive and Motor. The distance between the drive and the motor must also be considered. All motor cables have line-to-line and line-to-ground capacitance. The longer the cable, the greater the capacitance. Some types of cables (e.g., shielded cable or cables in metal conduit) have greater capacitance. The charging current in the cable capacitance causes spikes in the output of AC drives; higher voltage and higher capacitance cause higher current spikes. Voltage spikes caused by long cable lengths can shorten the life of the AC drive and motor. When considering an application in which distance might be a problem, contact the VFD manufacturer for its recommendations.

12.15.7 Service Factor on AC Drives. A high-efficiency motor with a 1.15 service factor is recommended when used on an AC drive. The 1.15 service factor is reduced to 1.0 because of heat associated with harmonics of an AC drive.

12.16 Matching AC Motors to Load

One way to evaluate whether the torque capabilities of a motor meet the torque requirements of the load is to compare the motor's speed/torque curve with the speed/torque requirements of the load.

12.16.1 Load-Characteristics Tables. Use a load-characteristics table to find the torque characteristics of various types of loads. **Table 12.10** is an example of such a table, although it contains only a partial list of load types. *NEMA MG 1*[27] is one—and a complete—source of typical torque characteristics.

12.16.2 Calculating Load Torque. The most accurate way to obtain torque characteristics of a given load is to obtain them from the equipment manufacturer.

12.16.3 Centrifugal Pump. When a motor accelerates a load from zero to full-load speed, the amount of torque it can produce changes. Throughout acceleration, the motor must produce more torque than required by the load. **Fig. 12.24** graphs speed/torque curves for a NEMA B motor with a centrifugal-pump load. The pump load curve shows that the centrifugal pump only requires approximately 20% of full-load torque to start. The torque dips slightly after the pump is started, then increases. This typically is defined as a variable torque load. The pump

TABLE 12.10—LOAD CHARACTERISTICS

Load description	Load torques as percent full-load drive torques		
	Breakaway	Accelerating	Peak Running
Actuators			
Screw-down (rolling mills)	200	150	125
Positioning	150	110	100
Agitators			
Liquid	100	100	100
Slurry	150	100	100
Blowers, centrifugal			
Valve closed	30	50	40
Valve open	40	110	100
Blowers, positive displacement, rotary, bypassed	40	40	100
Calenders, textile or paper	75	110	100

Courtesy of Houston Armature Works Inc.

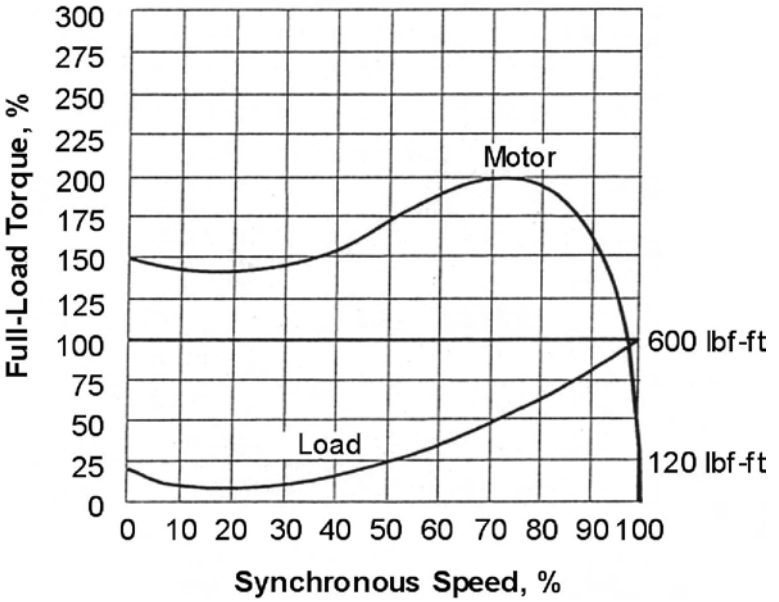


Fig. 12.24—Speed/torque curve for a NEMA-B motor with a centrifugal pump load (courtesy of Houston Armature Works Inc.).

will operate at the speed where the torque required by the pump equals that furnished by the motor.

12.16.4 Screw-Down Actuator. Fig. 12.25 graphs speed/torque curves for a NEMA-B motor with a screw-down actuator load. The actuator-load curve shows that the starting torque of a screw-down actuator is approximately 200% of full-load torque. Comparing the load's requirement with the NEMA B-design motor of equivalent horsepower shows that the load's starting

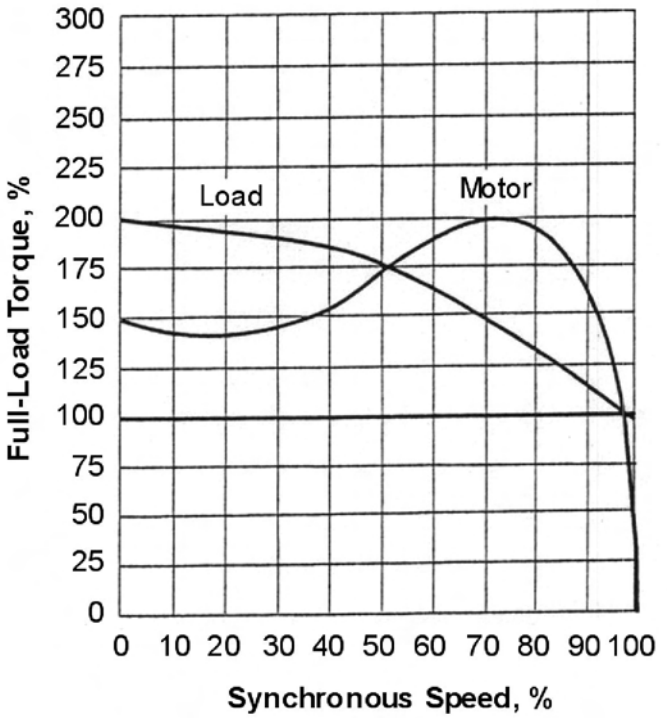


Fig. 12.25—Speed/torque curve for a NEMA-B motor with a screw-down actuator load (courtesy of Houston Armature Works Inc.).

torque requirement is greater than the motor's capability. The motor therefore will not start and accelerate the load.

One solution would be to use a higher-horsepower NEMA B motor. A less-expensive solution might be to use a NEMA D motor of the same horsepower requirements as the load. A NEMA D motor would start and accelerate the load easily, as shown in Fig. 12.26.

The motor selected to drive the load must have sufficient torque to start, accelerate, and run the load. If ever the motor cannot produce the required torque, it will stall or run in an overloaded condition. This will cause it to generate excess heat and typically to exceed current limits, causing protective devices to disconnect the motor from the power source. If the overload condition is not corrected, or the proper motor not installed, the existing motor eventually will fail.

12.17 Enclosures

An enclosure protects a motor from contaminants in the environment in which it is operating. In addition, the type of enclosure affects the cooling of the motor. Enclosures are categorized as either open or totally enclosed, and there are different types of enclosures within each category.

12.17.1 Open Drip-Proof (ODP). Open enclosures permit cooling air to flow through the motor. The rotor has fan blades that help move the air through the motor. One type of open enclosure is the ODP enclosure. In an ODP enclosure, the vent openings prevent liquids and solids that fall from above at angles up to 15° from vertical from entering the interior of the motor and damaging the operating components. When the motor is not in the horizontal position, such as when it is mounted on a wall, a special cover might be necessary to protect it.

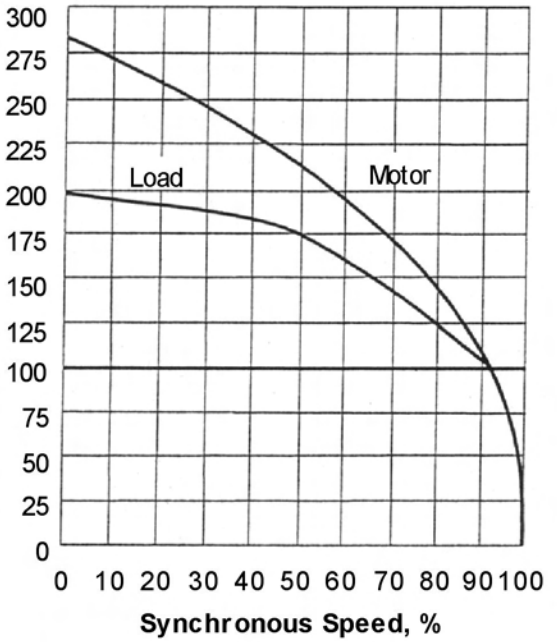


Fig. 12.26—Speed/torque curve for a NEMA-D motor with a screw-down actuator load (courtesy of Houston Armature Works Inc.).

An ODP enclosure can be specified when the environment is free from contaminants and where wind-driven rain is not a consideration.

12.17.2 Totally Enclosed Nonventilated (TENV). Sometimes, the air surrounding the motor contains corrosive elements, dust, sand, and other debris that can damage the internal parts of a motor, or the motor is exposed to wind-driven rain or seawater spray. A totally enclosed motor enclosure is not airtight, but it restricts the free exchange of air between the inside of the motor and the outside. A seal where the shaft passes through the housing keeps out water, dust, and other foreign matter that could enter the motor along the shaft. The absence of ventilating openings means that all heat dissipates through the enclosure through conduction.

Most TENV motors are fractional horsepower in size. TENV motors can be used indoors and outdoors.

12.17.3 Totally Enclosed, Fan-Cooled (TEFC). Totally enclosed, fan-cooled enclosures are similar to TENV enclosures, except that an external fan is mounted opposite the drive end of the motor. The fan provides additional cooling by blowing air over the exterior of the motor to dissipate heat more quickly. A shroud covers the fan to prevent anyone from touching it. With this arrangement no outside air enters the interior of the motor. TEFC motors can be used in dirty, moist, or mildly corrosive operating conditions, or where wind-driven rain is anticipated.

12.17.4 Explosion-Proof (XP). Explosion-proof motor enclosures are similar in appearance to TEFC motors, but are designed to contain an inside explosion and to prevent ignition of specified gases or vapors surrounding the motors.

12.18 Mounting

12.18.1 NEMA Dimensions. NEMA has standardized frame-size motor dimensions, including bolt-hole sizes, mounting-base dimensions, shaft height, shaft diameter, and shaft length. Existing motors can be replaced without reworking the mounting arrangement. New installations are easier to design because the dimensions are known. Letters are used to indicate where a dimension is taken. For example, the letter "C" indicates the overall length of the motor, and "E" represents the distance from the center of the shaft to the center of the mounting holes in the feet. Motor manufacturers provide tables in the motor-data sheet that reference the letter to find the desired dimension.

NEMA categorizes standard frame sizes as either fractional or integral. Fractional frame sizes are designated as 45 and 56, and mainly include horsepower ratings of < 1.0. Integral (or medium) horsepower motors are designated by frame sizes that range from 143T to 445T. A "T" in the motor frame size designation of integral horsepower motors indicates that the motor is built to current NEMA frame standards. Motors built before 1966 have a "U" in the motor frame size designation, indicating that they were built to previous NEMA standards.

The frame-size designation is a code to help identify key dimensions. For example, the first two digits are used to determine the shaft height. The shaft height is the distance from the center of the shaft to the mounting surface, given in inches. To calculate the shaft height, divide the first two digits of the frame size by four. For example, a 143T frame size motor has a shaft height of 3.5 in. (14 ÷ 4).

The third digit in the integral "T" frame-size number is the NEMA code for the distance between the center lines of the mounting bolt-holes. The dimension is determined by matching the third digit in the frame number with a table in *NEMA MG-1*.[27]

12.19 Above-NEMA Motors

12.19.1 Sizes. Motors that are larger than the NEMA frame sizes are referred to as above-NEMA motors. These motors typically range in size from 200 to 10,000 hp.

There are no standardized frame sizes or dimensions for above-NEMA motors because above-NEMA motors typically are constructed to meet the specific requirements of an application.

12.19.2 Torque. The customer typically supplies specifications for starting torque, breakdown torque, and full-load torque on the basis of speed-torque curves obtained from the driven-equipment manufacturer; however, there are some minimum torques that all large AC motors must be able to develop. These are specified by *NEMA MG-1*[27]:

- Locked-rotor torque ≥ 60% of full-load torque.
- Pull-up torque ≥ 60% of full-load torque.
- Maximum torque ≥ 175% of full-load torque.

12.19.3 Altitude and Ambient Temperature. Above-NEMA motors require the same adjustment for altitude and ambient temperatures as do integral frame-size motors. When the motor is operated at an altitude of above 3,300 ft, a higher class of insulation should be used or the motor should be derated. Above-NEMA motors with Class-B insulation can be modified easily for operation in ambient temperatures between 40° and 50°C. Operation at ambient temperatures of > 50°C requires special modification at the factory.

12.19.4 Enclosures for Above-NEMA Motors. Environmental factors also affect large AC motors. Enclosures used on above-NEMA motors are different from those on integral frame-size motors.

ODP. The ODP enclosure for an above-NEMA motor provides the same amount of protection as the one for the integral frame-size open motor. As with the integral frame-size ODP, the above-NEMA ODP provides the least amount of protection for the motor's electrical components and typically is used in contaminant-free environments.

Horizontal Drip-Proof Weather-Protected Type I. The horizontal drip-proof weather-protected type I enclosure is an open enclosure with ventilating passages that are designed to minimize the entrance of rain, snow, and airborne particles that could come into contact with the electrical and rotating parts of the motor. All air inlets and exhaust vents are covered with screens. It is used on indoor applications in low-humidity environments.

Horizontal Drip-Proof Weather-Protected Type II. Horizontal drip-proof weather-protected type II enclosures are open enclosures with vents that are constructed so that high-velocity air and airborne particles blown into the motor are discharged without entering the internal ventilating passages that lead to the electrical parts of the motor. The intake and discharge vents are designed to have at least three 90° turns and to maintain the air velocity at < 600 ft/min. It is used outdoors on motors that are not protected by other structures.

TEFC for Above-NEMA Motors. A TEFC enclosure for an above-NEMA motor functions the same way as the TEFC enclosure for integral frame-size motors. It is designed for indoor and outdoor applications in which internal parts must be protected from adverse ambient conditions. Above-NEMA TEFC enclosures are available for motors up to 900 hp on 580 frames and up to 2,250 hp on 708 to 880 frames.

Totally Enclosed, Air-to-Air Cooled (TEAAC). Motors using the totally enclosed, air-to-air cooled enclosure use the air-to-tube type of heat exchangers for cooling.

Totally Enclosed, Water-to-Air Cooled (TEWAC). In some situations, the motor frame cannot adequately dissipate heat, even with the help of a fan. The totally enclosed, water-to-air cooled enclosure cools the motor using a water-to-air heat exchanger and thus requires a steady supply of water.

Totally Enclosed, Fan-Cooled, Explosion-Proof. Large AC motors also are used in hazardous environments. The totally enclosed, fan-cooled, explosion-proof enclosure meets or exceeds all applicable Underwriter's Laboratories (UL) Standard 1203 requirements for hazardous (Division 1) environmental operation.[46]

Nomenclature

A = cross-sectional area of conductor, circular mil
E = voltage, V
E_g = generator voltage, V
E_m = transformer voltage, kV
E_t = motor voltage, kV
f = frequency, Hz
F_p = power factor, cos θ
H = horsepower [Eq. 12.17]
I = current, A
L = length of conductor, ft
N = rotor speed, rev/min
N_m = motor speed, rev/min
N_s = synchronous speed, rev/min
P = number of poles
P_a = active power, kW
P_{ap} = apparent power, kVA
P_g = generator kVA
P_m = motor-starting kVA

P_r = reactive power, kVAR
P_t = transformer-rated kVA
R = resistance, Ω
S = slip, %
T = torque, lbf-ft
X = cable three-phase reactance, Ω
X_g = generator reactance, Ω
X_m = motor reactance during starting, Ω
X_d' = transient reactance of the generator, %
Z = transformer impedance, Ω
Z_c = the three-phase impedance of the cable between the transformer and the motor, Ω
Z_m = motor-starting impedance, Ω
Z_t = total impedance, Ω
Z_{tr} = transformer impedance, %
ΔE = voltage drop, V
θ = power factor angle
ρ = resistivity of conductor, Ω-circular mil/ft

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SI Metric Conversion Factors

A	×	1.0*	E + 00	= A
circular mil	×	5.067 075	E – 10	= m^2
cycles/s	×	1.0*	E + 00	= Hz
°F		(°F – 32)/1.8		= °C
ft	×	3.048*	E – 01	= m
hp	×	7.460 43	E – 01	= kW
in.	×	2.54*	E + 00	= cm
$in.^2$	×	6.451 6*	E + 00	= cm^2
lbf-ft	×	1.355 818	E + 00	= N·m
mile	×	1.609 344*	E + 00	= km
rev/min	×	1.666 667	E – 02	= rev/s
V	×	1.0*	E + 00	= V

*Conversion factor is exact.

Chapter 13
Oil Storage

George H. Stilt, CB&I

Production, refining, and distribution of petroleum products require many different types and sizes of storage tanks. Small bolted or welded tanks might be ideal for production fields while larger, welded storage tanks are used in distribution terminals and refineries throughout the world.

Product operating conditions, storage capacities, and specific design issues can affect the tank selection process. This chapter discusses the types of storage tanks most commonly used with emphasis on welded construction. General guidelines are provided that aid in the selection of the correct tank.

References to various codes, standards, and recommended practices supplement the material provided in this chapter. Owners and operators should contact manufacturers directly for questions on specific design or operating issues for a particular type of storage tank.

13.1 Storage Tanks

13.1.1 Types of Storage Tanks. Storage tanks come in all sizes and shapes. Special applications might require tanks to be rectangular, in the form of horizontal cylinders, or even spherical in shape. Horizontal cylinders and spheres are generally used for full pressure storage of hydrocarbon or chemical products. For the purpose of this chapter, we focus on the atmospheric or low-pressure storage tank widely used from the production fields to the refinery.

The most common shape used is the vertical, cylindrical storage tank. Gross capacities can range from 100 bbl to over 1.5 MMbbl in a single storage tank. Corresponding tank sizes range from approximately 10 ft in diameter to over 412 ft in diameter for some of the largest floating-roof tanks ever constructed.

Fig. 13.1 shows a 312-ft diameter floating-roof storage tank for crude oil storage at a large refinery. The photograph was taken during construction and shows the single deck, pontoon-style external floating roof.

Production Tanks—Construction Practices. The type of construction selected for a storage tank depends on the size of tank required and might be dependent on the type of product being stored, the location and space available for storage, prevailing weather or site-specific conditions, and local safety or environmental considerations.

Riveted, Bolted, and Shop-Welded Tanks. Although the earliest storage tanks used by the petroleum industry were constructed from various types of wood, we will concern ourselves

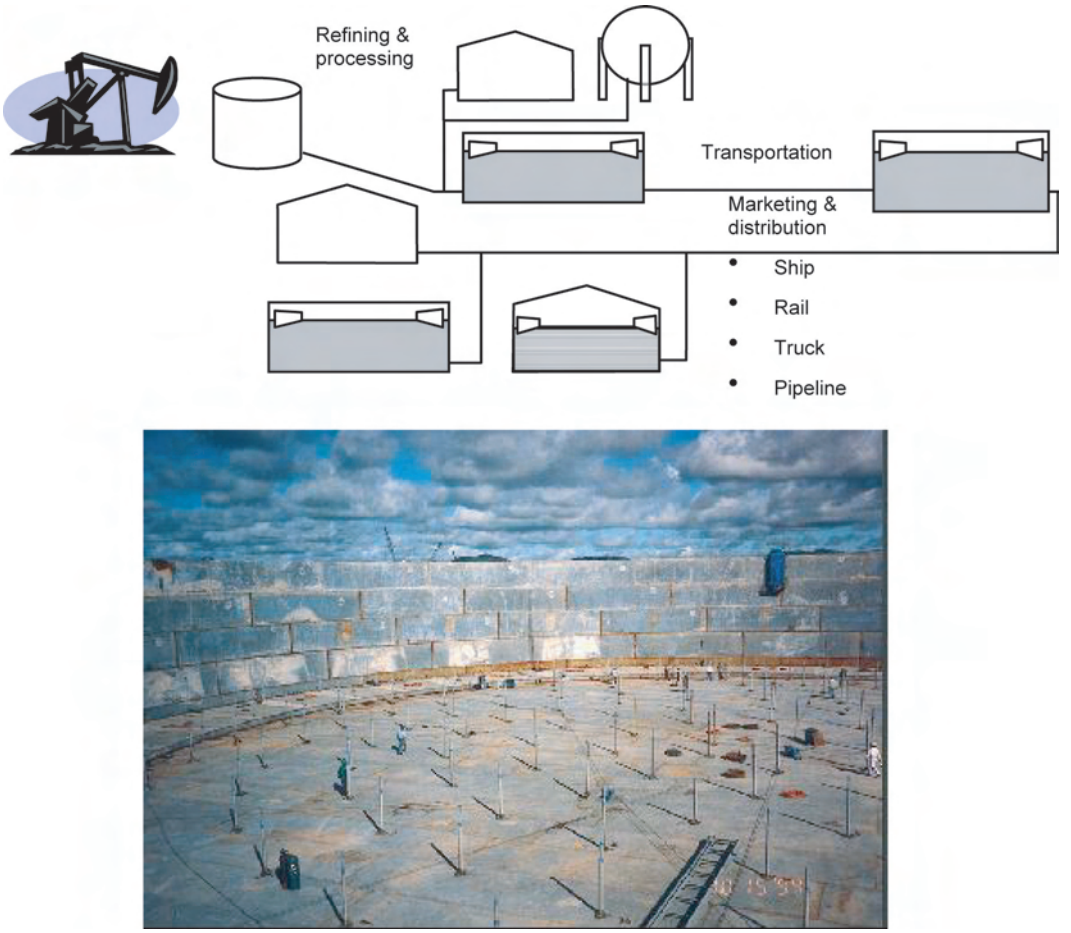


Fig. 13.1—312-ft diameter floating-roof tank.

with tanks fabricated from steel or optional nonmetallic materials. Before the development and perfection of welding processes, petroleum storage tanks used either bolted or riveted construction techniques. The tanks would be designed and supplied as segmental elements for final assembly on site.

Riveted tanks dating back to the early 1900s can still be found around the world—many still in service. It is safe to say, however, that recurring maintenance costs and increased environmental and safety concerns dictate that older riveted tanks be replaced with new, state-of-the-art storage tanks.

However, bolted tanks are still used, especially in the smaller sizes typical of produced liquid storage. The fourteenth edition of American Petroleum Institute (API) *Spec. 12B, Bolted Tanks for Storage of Production Liquids* provides standard designs for capacities from 100 bbl to 10,000 bbl. Current suppliers of bolted tanks can provide capacities up to 40,000 bbl or more depending on the storage application.

Generally, bolted tanks are fabricated either from 12- or 10-gauge steel or several nonmetallic materials. If not galvanized or furnished with a protective coating for corrosion protection, bolted steel construction might not have the expected service life provided by welded-steel tanks. Welded-steel tanks are constructed of thicker plate materials that can be designed to provide some corrosion allowance.

TABLE 13.1—PARTIAL API SPECIFICATIONS FOR SHOP-WELDED TANKS (API *SPEC. 12F*)

Nominal Capacity, bbl	Design Pressure, oz./sq in.		Approximate Working Capacity*, bbl	OD, ft-in.	Height, ft
	Pressure	Vacuum			
90	16	.5	72	7'-11"	10
100	16	.5	79	9'-6"	8
150	16	.5	129	9'-6"	12
200	16	.5	166	12'-0"	10
210	16	.5	200	10'-0"	15
250	16	.5	224	11'-0"	15
300	16	.5	266	12'-0"	15
400	16	.5	366	12'-0"	20
500	8	.5	479	15'-6"	16

*Working capacities shown apply to flat-bottom tanks.

One alternative to bolted construction is the shop welded storage tank. The size and capacities of this type of tank are limited primarily by the method of transportation used to transfer the shop built tank to the final production site. The eleventh edition of API *Spec. 12F, Shop Welded Tanks for Storage of Production Liquids* provides standard designs for capacities of 90 to 500 bbl. **Table 13.1** presents a partial listing of the standard sizes specified in API *Spec. 12F*. In this table, "working capacity" refers to the maximum amount of oil that can be stored between the oil outlet and the overflow connection.

Shop-welded storage tanks provide the production industry with tanks of adequate safety and reasonable economy for use in the storage of crude petroleum and other liquids commonly handled by the production segment of the industry. A shop-fabricated tank is tested for leaks in the shop, so it is ready for use once it arrives on site. Tanks are transferred from the truck to the final location on site; completed piping connections and the tank is then ready to be brought on line.

A second alternative for bolted construction is the shop fabricated or field assembled nonmetallic storage tank. Nonmetallic tanks customarily are constructed from plastic materials. These have the advantage of being noncorroding, durable, low-cost, and lightweight. Probably the most common type used is the fiberglass reinforced plastic (FRP) tank. FRP tanks are suitable for outdoor as well as indoor applications. Refer to API *Spec. 12P, Fiberglass Reinforced Plastic Tanks* for minimum requirements for the design, fabrication, and testing of fiberglass reinforced plastic tanks.

The temperature limits of plastic tanks are approximately 40 to 150°F. Because plastic tanks are considered to degrade more quickly than metal tanks when exposed to fire, some operators prohibit the use of plastic tanks in hydrocarbon service.

Color must be added to the outer liner for protection against ultraviolet radiation. The inner liner must be selected for compatibility with the product stored. Protection from mechanical abuse such as impact loads is necessary. Good planning dictates that plastic storage should not be located next to flammable storage tanks. Special attention should be given to local codes, ordinances, and provisions for insurance relative to storing a flammable product in a flammable container.

Field-Welded Storage Tanks. Field-welded storage tanks easily meet industry needs for increased storage capacity whether at a remote production site, at the refinery, or at the marketing terminal. As noted, earlier single-tank capacities have exceeded 1.5 MMbbl of storage with tank diameters of 412 ft and shell heights exceeding 72 ft.

TABLE 13.2—NOMINAL CAPACITY OF WELDED STORAGE TANKS

Diameter, ft	Height, 20 ft [6.1 m] Capacity		Height, 30 ft [9.1 m] Capacity		Height, 40 ft [12.2 m] Capacity		Height 50 ft [15.2 m] Capacity		Height 60 ft [18.3 m] Capacity		Diameter, m
	Mbbl*	m^{3**}	Mbbl*	m^{3**}	Mbbl*	m^{3**}	Mbbl*	m^{3*}	Mbbl*	m^{3*}	
20	1.1	178	1.7	267	2.2	356	2.8	445	3.4	534	6.1
25	1.7	278	2.6	417	3.5	556	4.4	695	5.2	834	7.6
30	2.5	400	3.8	600	5.0	801	6.3	1,001	7.6	1,201	9.1
35	3.4	545	5.1	817	6.9	1,090	8.6	1,362	10.3	1,635	10.7
40	4.5	712	6.7	1,067	9.0	1,423	11.2	1,779	13.4	2,135	12.2
45	5.7	901	8.5	1,351	11.3	1,801	14.2	2,252	17.0	2,702	13.7
50	7.0	1,112	10.5	1,668	14.0	2,224	17.5	2,780	21.0	3,336	15.2
55	8.5	1,345	12.7	2,018	16.9	2,691	21.2	3,364	25.4	4,036	16.8
60	10.1	1,601	15.1	2,402	20.1	3,202	25.2	4,003	30.2	4,804	18.3
65	11.8	1,879	17.7	2,819	23.6	3,758	29.6	4,698	35.5	5,638	19.8
70	13.7	2,179	20.6	3,269	27.4	4,359	34.3	5,449	41.1	6,538	21.3
80	19.7	2,847	26.9	4,270	35.8	5,693	44.8	7,117	53.7	8,540	24.4
90	22.7	3,603	34.0	5,404	45.3	7,206	56.7	9,007	68.0	10,808	27.4
100	28.0	4,448	42.0	6,672	56.0	8,896	69.9	11,120	83.9	13,344	30.5
110	33.9	5,382	50.8	8,073	67.7	10,764	84.6	13,455	101.6	16,146	33.5
120	40.3	6,405	60.4	9,607	80.6	12,810	100.7	16,012	120.9	19,215	36.6
130	47.3	7,517	70.9	11,275	94.6	15,034	118.2	18,792	141.8	22,551	39.6
140	54.8	8,718	82.3	13,077	109.7	17,436	137.1	21,795	164.5	26,153	42.7
150	62.9	10,008	94.4	15,012	125.9	20,015	157.4	25,019	188.8	30,023	45.7
160	71.6	11,387	107.4	17,080	143.2	22,773	179.1	28,466	214.9	34,160	48.8
180	90.6	14,411	136.0	21,617	181.3	28,822	226.6	36,028	271.9	43,233	54.9
200	111.9	17,791	167.9	26,687	223.8	35,583	279.8	44,479	335.7	53,374	61.0
220	135.4	21,528	203.1	32,291	270.8	43,055	338.5	53,819	406.2	64,583	67.1
240	161.1	25,620	241.7	38,430	322.3	51,239	402.9	64,049	483.4	76,859	73.2
260	189.1	30,068	283.7	45,101	378.2	60,135	472.8	75,169	567.4	90,203	79.3
280	219.3	34,871	329.0	52,307	438.7	69,742	548.4	87,178	658.0	104,614	85.4
300	251.8	40,031	377.7	60,046	503.6	80,062	629.5	100,077	755.4	120,092	91.5

*Mbbl = 1,000 API bbl, **m^3 = cubic meters, API bbl = 42 gal, 1 m^3 = 6.29 bbl

As with the smaller bolted storage tanks, API standards have been developed and improved over the years to ensure the tanks meet the safety and operating needs of the petroleum industry. The tenth edition of API *Spec. 12D, Field Welded Tanks for Storage of Production Liquids* provides standard sizes with nominal capacities from 500 to 10,000 bbl for the production sector.

When larger tanks are required, the industry can refer to the tenth edition of API *Standard 650, Welded Steel Tanks for Oil Storage* for material, design, fabrication, erection, and testing requirements. The standard covers open-top or fixed-roof storage tanks that generally operate at atmospheric pressures. Design pressures above atmospheric and design temperatures exceeding 200°F may be permitted when additional requirements are met. **Table 13.2** shows the capacity of welded storage tanks as a function of diameter and height.

13.1.2 Current Storage Options. The petroleum industry has experienced significant changes in the types of products used to feed the refineries around the world. The increased use of petroleum products has prompted the industry to turn to other sources for supply. Changes in product, physical, and chemical properties impose new challenges to the storage tank industry. Environmental and safety requirements continue to be a significant factor in the selection and design of the storage tanks used by the petroleum industry.

The general types of atmospheric storage tanks (AST) in use may be open top tanks (OTT), fixed-roof tanks (FRT), external floating-roof tanks (EFRT), or internal floating-roof tanks (IFRT). Depending on the product, a closed floating-roof tank (CFRT) may even be selected.

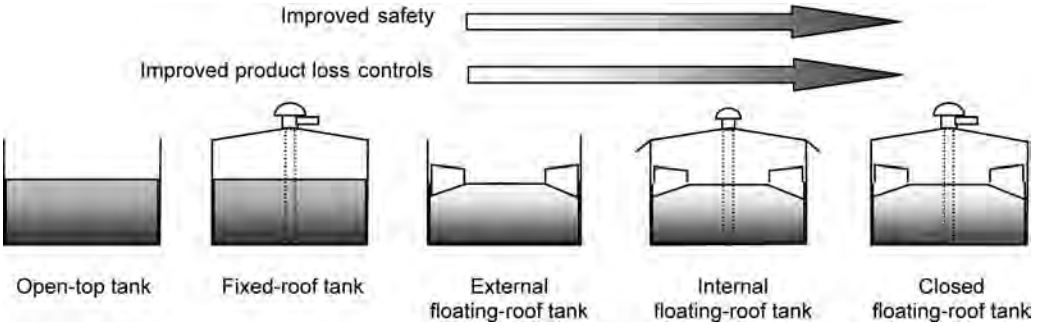


Fig. 13.2—Atmospheric storage tank improvements.

The aboveground storage tank has evolved with time. Fig. 13.2 illustrates this trend, which has emphasized improved safety and improved product loss control. Production facilities generally rely on either open-top tanks or fixed-roof tanks operating at or slightly above atmospheric pressure.

Open-Top Tanks. The OTT was one of the first tanks used to store petroleum products. While it provides liquid containment, direct exposure of the liquid surface to the atmosphere assures high evaporative losses, product odors, and increased potential for fires. The OTT has only limited use, primarily for collection of contaminated run-off or wash water and wastewater processes.

Fixed-Roof Tanks. The FRT provides improved containment of product vapors and reduces the potential for fires. The FRT still exposes the liquid surface to the tank vapor space, producing significant product evaporative losses. This increases the possibility of forming a combustible gas mixture in the vapor space for certain more volatile petroleum products. For this reason fixed-roof tanks in refineries are generally used for products with vapor pressures less than 1.5 psia.

Fixed-roof tanks are common in production facilities to store hydrocarbons with vapor pressures close to atmospheric pressure. In this use, they should be equipped with pressure-vacuum valves and purged with natural gas to eliminate air intake into the vapor space. Product evaporative losses can be high especially when crude is added to the tank and vapors are expelled through the pressure vent valve.

In crude oil terminals and pumping stations, internal floating roofs may be added to the fixed-roof tank to reduce product vapor losses if the crude oil has been stabilized to vapor pressures less than 11 psia. Examples of fixed-roof tanks are shown in Fig. 13.3.

The most common fixed-roof design contains a shallow cone roof utilizing a single center column plus internal (or external) framing to support the roof plates. Intermediate columns are used for diameters greater than 120 ft. Designs may include a frangible roof joint for added protection in the event of a sudden increase in internal pressure. In this case the design pressure is limited to the equivalent pressure of the dead weight of the roof plates including structural rafters. Other fixed-roof designs such as the self-supporting dome roof or umbrella roof may be used if storage pressures exceed the capabilities of the cone roof design. Depending on the size (diameter) of the tank, API *Standard 650,* Appendix F designs can permit internal pressures up to 2.5 psig. If operating pressures exceed 2.5 psig, API *Standard 620, Design and Construction of Large, Low-Pressure Storage Tanks* provides design procedures for internal pressures up to 15 psig.

13.1.3 Pressure-Vacuum Valves. The evolution of hydrocarbon vapors is dependent on the product's physical characteristics, the operating pressure of upstream equipment, tank storage



Fig. 13.3—Typical fixed-roof tanks.

conditions, and tank operations. In production operations, the fluid entering a tank often comes from a higher-pressure source (separator, treater, or other production vessel). As the fluid enters the tank, a portion of the fluid will "flash" to vapor. Depending on tank design, vapors may be directed through pressure vent valves directly to a vent or lighted flare. Alternatively, a vapor recovery compressor (or blower) may be installed to direct vapors vented from storage to downstream compressors for sales or injection. Vacuum relief valves are needed to keep a vacuum from occurring because of tank breathing and pumping operations. If a vacuum develops, the tank roof will collapse. Typically, both pressure and vacuum relief are combined in a single pressure-vacuum relief valve such as that shown in **Fig. 13.4**.

13.1.4 Gauge Hatches. Fixed-roof tanks should have a quick opening gauge hatch in the roof, which allows the operator access to the tank to "gauge" the tank, determine if water is present, measure the height of the oil/water interface, and take samples of the crude oil. The gauge hatch can be weighted in such a way as to work as a backup pressure or pressure-vacuum relief device to the primary pressure-vacuum valve.

Standards for manual gauging of petroleum and petroleum products are given in the API *Manual of Petroleum Measurement Standards,* Chap. 3.1 A. "Gauging" includes measuring the amount of liquid contained in the tank as well as determining the temperature of the liquid and obtaining representative samples.

13.1.5 Tank Breathing. When a volatile product is stored in a freely ventilated fixed-roof tank, the concentration of volatile vapors in the vapor space can vary depending on the tank operating conditions. During holding periods, when no liquid is added or removed from the tank, the vapor space comes to equilibrium conditions based on product temperature and vapor pressure.

Emissions during holding are generated by the vapor space breathing process. As a result of daily ambient heating and cooling processes or changes in barometric pressure, the air/vapor mixture in the vapor space expands and contracts. During the daily heating process, some of the air/vapor mixture is expelled from the tank, resulting in evaporative emissions. During product cooling, air is drawn into the vapor space and becomes saturated with product vapor from natural evaporation. The air becomes saturated with product vapors. Note that this can result in a combustible gas mixture in the vapor space, increasing the fire risk.

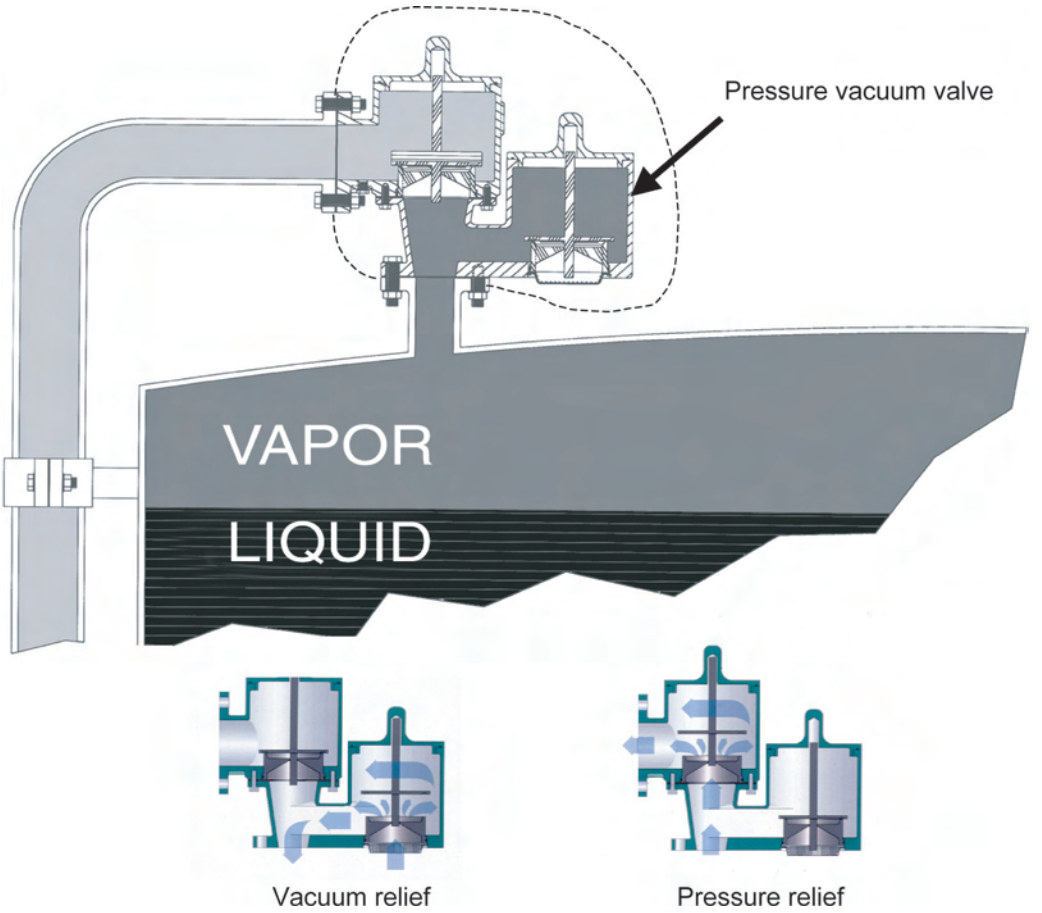


Fig. 13.4—Pressure vacuum valve operator.

13.1.6 Filling/Pumping Operations. Normal tank filling and pumping operations also affect the vapor space of a fixed-roof tank. When product is removed from the tank, air is drawn into the vapor space as liquid is removed, creating a hazard. During the holding period before the next tank filling operation, evaporative breathing losses increase because of the increased volume of the vapor space. When product is added to the tank, the increasing liquid volume displaces the air/vapor mixture through the tank vent, resulting in significant evaporative emissions.

13.1.7 Gas Blanketing Systems. As long as the product vapor pressure is low (below 1.5 psia), it is considered safe practice to use a freely ventilated fixed-roof tank. For production tanks or other applications in which vapor pressure of the incoming liquid normally exceeds atmospheric pressure at normal ambient temperatures, a gas blanketing system is required to maintain a positive tank pressure and minimize the chance of air being drawn into the tank vapor space. During periods of no inflow, the tank breathing process alone could cause air to flow into the tank through the pressure-vacuum valve and form an explosive mixture.

A gas blanketing system includes a suitable supply of natural gas and a pressure regulator that operates as needed to maintain the tank pressure at a predetermined level. During the heat of the day, as pressure increases, the regulator closes. If pressure continues to rise, the pressure vent opens to relieve tank internal pressure by venting vapors (blanket gas + product vapor) to

atmosphere or some downstream vapor recovery process. Note that a vacuum relief still must be used to protect the tank against vacuum should the gas blanketing system fail.

13.1.8 Fire Exposure. Out breathing, resulting from fire exposure, may exceed the design venting rate based on normal operating conditions. In such cases, the construction details of the tank determine whether additional venting is required.

On fixed-roof tanks, where the roof-to-shell attachment is constructed in accordance with API *Standard 650,* Sec. 3.10.2.5.1, the roof-to-shell joint may be considered frangible, and in the event of excessive internal pressure may fail before failure occurs in the tank-shell joints or the shell-to-bottom joint. In tanks built in this manner, consideration need not be given to any additional requirements for emergency venting if the tank is isolated from other equipment and loss of the roof during emergency conditions is acceptable.

On tanks that do not follow the frangible joint details, design procedures are provided in the API *Standard 2000* for calculating the required venting capacity for fire exposure.

13.1.9 Vent System Design. Safety should be a primary concern when selecting a storage tank vent system for a specific application. In production operations, this normally means that a safe way of handling vapors that evolve from the liquid must be designed into the system, and air must be excluded from entering the tank and mixing with hydrocarbon in the vapor space. Fixed-roof tanks should be configured to operate with a suitable gas blanketing system that maintains the tank at positive pressures under all operating conditions. Specially designed pressure/vacuum vent valves should be provided to protect the tank against overpressure or vacuum conditions.

Tank vent piping should include flame arrestors such as that shown in **Fig. 13.5**, which protect the tank against ignition of the vent gases owing to lightning strike or a discharge of static electricity at the vent location. Where the vent piping is routed to a lit flare system, a constant bleed of purge gas into the vent is required in addition to a flame arrestor. More complex flow devices, such as fluidic seals and molecular seals, are available from several manufacturers to minimize the amount of purge gas needed to assure the flame is not sucked back into the vapor space.

Fixed-roof tanks will fail if exposed to excessive internal pressure or extreme vacuum conditions. Regular maintenance of pressure/vacuum vent valves and flame arrestors is critical to the safe operation of any fixed-roof tank. In oil fields, crude oil service flame arrestors can become plugged. A separate pressure/vacuum valve (or specially weighted gauge hatch) set at higher pressures and vacuums than the primary should be installed without a flame arrestor. In the event the flame arrestor becomes plugged, it is better to operate without a flame arrestor then to blow off the roof of the tank.

Many design and operating conditions must be considered when designing a vent piping system. Larger vents may be required on tanks storing heated products or tanks that receive products from a source subject to a surge in pressure or flow. The pressure drop owing to flame arrestors or other vent restrictions must be considered to assure that under design vent conditions the pressure in the tank remains less than the tank design pressure.

Design recommendations can be found in the fifth edition of API *Standard 2000*, *Venting Atmospheric and Low-Pressure Storage Tanks* covering nonrefrigerated and refrigerated storage. The standard presents design guidelines for the determination of venting requirements and types of vents that may be used under normal tank operations and possible emergency conditions (fire exposure).

When provided, tank vents should be sized to protect the tank against unusually high internal pressures (venting required) or low pressure vacuum conditions (in breathing or vapor makeup required). Normal operating conditions include:

• In breathing (vacuum) resulting from maximum outflow of product from the tank.

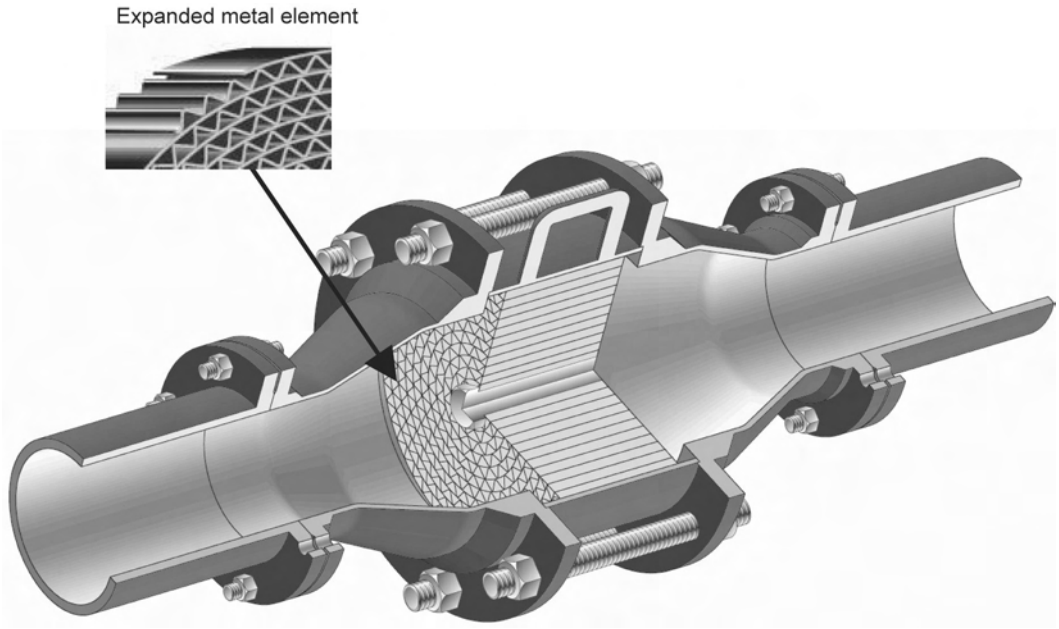


Fig. 13.5—Flame arrestor.

• In breathing (vacuum) resulting from contraction of vapors caused by a maximum decrease in atmospheric temperature.

• Out breathing (pressure) resulting from flashing of hydrocarbons as liquid flows from a higher pressure source into the tank. In production operations this can be the largest source of vent vapors. The flow rate is process specific and not addressed in the API *Standard 2000.*

• Out breathing (pressure) resulting from maximum inflow of product into the tank, hydrocarbon flash vapors, and maximum product evaporation caused by the inflow.

• Out breathing (pressure) resulting from expansion and evaporation caused by a maximum increase in atmospheric temperature.

• Out breathing (pressure) resulting from fire exposure.

13.1.10 Floating-Roof Tanks. Although not normally used in production operations, floating-roof tanks are often used in pump stations or terminals where the crude oil has been stabilized to a vapor pressure of less than 11.1 psia.

13.1.11 Product Loss Management and Safety Considerations for Floating-Roof Tanks. When product vapor pressure is greater than 0.5 psia (more in some states) but less than 11.1 psia, the U.S. Environmental Protection Agency permits the use of a floating-roof as the primary means of vapor control from the storage tank. Floating-roof tanks are not intended for all products. In general, they are not suitable for applications in which the products have not been stabilized (vapors removed). The goal with all floating-roof tanks is to provide safe, efficient storage of volatile products with minimum vapor loss to the environment.

Design requirements for external floating roofs are provided in Appendix C of the API *Standard 650.* The external floating roof floats on the surface of the liquid product and rises or falls as product is added or withdrawn from the tank.

The internal floating roof tank (IFRT) was developed in the mid-1950s to provide protection of the floating roof from the elements, including lightning strikes to the floating roof. The tank vapor space located above the floating roof and below the fixed-roof includes circulation

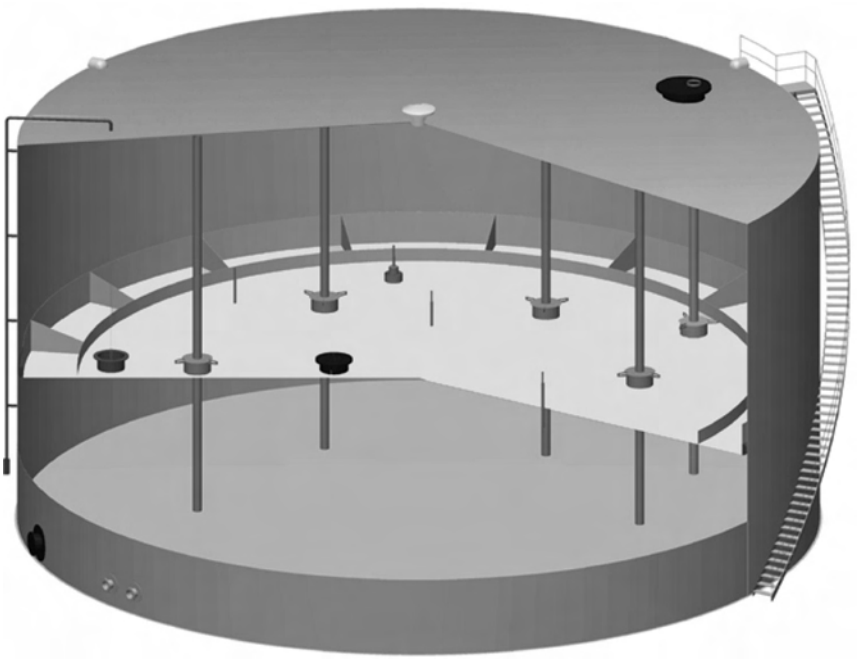


Fig. 13.6—Internal pan floating-roof tank.

vents to allow natural ventilation of the vapor space reducing the accumulation of product vapors and possible formation of a combustible mixture. **Fig. 13.6** shows a typical internal floating-roof tank.

The closed floating roof tank (CFRT) is similar to an IFRT. It uses an internal floating roof but eliminates natural ventilation of the tank vapor space. Instead, the CFRT is equipped with a pressure-vacuum (PV) vent and may even include a gas blanketing system such as that used with fixed-roof tanks. Emissions from a CFRT are virtually the same as those from an IFRT, however, can be easily collected for further treatment if necessary. One such closed roof tank for benzene storage with associated vapor recovery equipment is shown in **Fig. 13.7**.

13.1.12 Floating-Roof Tank Net-Working Capacity. Determining what tank size is required for the desired net storage capacity must consider several factors. Internal or external floating-roof tank shell height must account for the space required by the floating roof as shown in **Fig. 13.8**.

The tank working capacity is obtained by operating a floating-roof tank between the maximum high gauge and recommended low landing position for the specific floating-roof tank design. A floating roof should be landed only if the tank is to be removed from service for routine inspection or maintenance activities. Landing the floating roof during normal tank operations should be avoided. Product losses increase whenever the roof is not in complete contact with the liquid surface.

In general, floating-roof tanks have been used only at terminal or refinery locations where larger storage capacities are needed. Increased emphasis on the control of evaporative emissions from storage tanks might change the roll of floating-roof tanks in the future with the increased use in smaller tanks. Internal floating roofs have been used in tanks as small as 15 ft in diameter to minimize product losses.



Fig. 13.7—CFRT with vapor recovery.

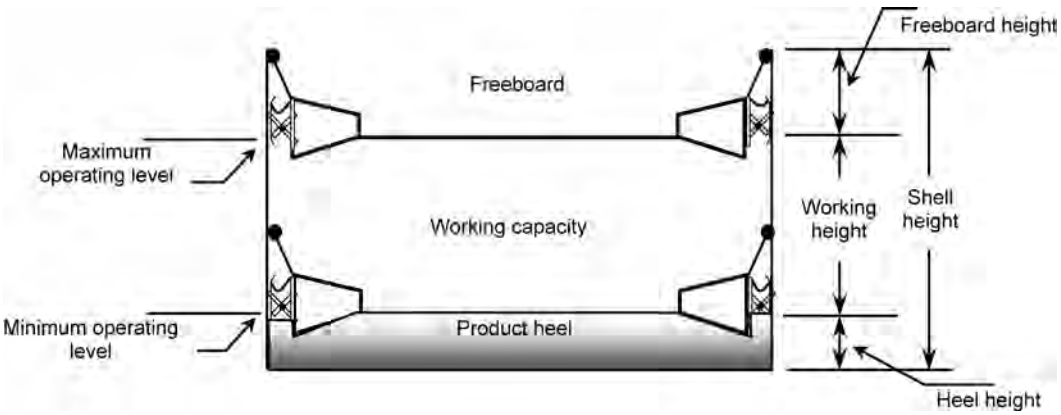


Fig. 13.8—Tank working capacity.

13.1.13 Product Vapor Control With Floating-Roof Tanks. In general, the floating roof covers the entire liquid surface except for a small perimeter rim space. Under normal floating conditions, the roof floats essentially flat and is centered within the tank shell. There should be no vapor space underneath a welded-steel floating roof. Under normal conditions, the amount of product vapor that might become trapped beneath the floating roof should be insignificant. However, if large quantities of flash vapor or other noncondensable vapors become trapped, the floatation stability of the roof can be affected. These conditions should be avoided if possible.

It is important to understand how a floating roof works and why details are so important in the design of a floating-roof storage tank. The study of evaporative emissions from storage tanks and possible methods to control or eliminate these emissions has been the focus of an extensive series of analytical studies, field, and laboratory testing programs sponsored by the American Petroleum Institute.

API *Publications 2517 (EFRT), 2518 (FRT),* and *2519 (IFRT)* summarized methods for calculating evaporative losses from the storage and handling of petroleum liquids. These were

first published in 1962 and then updated in 1991. Most recently, *Publications 2517* and *2519* were consolidated in April 1997 in "Evaporative Loss From Floating-Roof Tanks," Chap. 19.2 of the API *Manual of Petroleum Measurement Standards.*

The new publication updates the evaporative loss estimation procedures for EFRTs, IFRTs, and CFRTs. The results continue to be used as the basis for the U.S. Environmental Protection Agency (U.S. EPA) publication on air pollution emission factors.

It has been demonstrated that evaporative emissions from a fixed-roof tank can be reduced by over 98% through the use of a properly designed and maintained external floating roof tank, assuming the same product and ambient conditions.

Evaporative emissions, although greatly reduced, cannot be entirely eliminated. Normal practice is to use floating-roof tanks only to store products that are considered "stabilized" such that large quantities of vapor will not be introduced underneath the floating roof. In cases when the product entering the tank is at a condition that produces flashing conditions, vapors produced will be captured underneath the floating roof. Evaporation and associated product losses still occur from the rim space, standard roof deck fittings, product that remains on the tank shell, and tank operations that require the tank to be emptied and the floating roof landed on its supports.

13.1.14 Tank Appurtenances. Tanks may include a variety of appurtenances depending on the storage application, owner requirements, and applicable design codes. In addition to normal product fill and withdrawal connections, access man-ways and various instrument or gauging connections, a tank can include shell-mounted mixers, internal heaters, platforms, ladders, and pressure/vacuum relief vents.

Floating-roof tanks require special attention to details because many can affect safe operation of the floating roof. In external floating-roof tanks, be sure that the rim seals, rolling ladder, and roof drain(s) are designed to minimize any unbalanced loads in the floating roof structure. Each floating roof should include a single antirotation device designed to limit the rotation of the floating roof while it is free to move up or down within the tank shell.

Some features are required for safe operation of the floating roof while others may be optional based on specific storage requirements. Many of these features affect the low operating levels of the floating roof. Optional details are available to address many of these interference issues, enabling a qualified designer to minimize the product heel while maximizing the working capacity of a floating-roof tank. **Figs. 13.9 and 13.10** identify several features that must be considered when designing the floating-roof tank.

13.1.15 Controlling Liquid Leaks From Tanks. Liquid loss from a storage tank is generally caused by localized material failure in the form of localized corrosion. Tank bottom leaks can be a result of improper foundation design or operating a tank outside the recommended design pressure or temperature boundaries. Product liquid leakage remains a significant environmental concern. Any tank used to contain a hydrocarbon product can be prone to develop leaks sometime during the service life. Tank design options that reduce the risk of a leak can be considered, or in the event of a leak, any product that escapes is contained and detected in a realistic time frame.

Design options are generic with respect to the type of storage tank. Similar details are used on fixed-roof and floating-roof tanks alike. Options considered by most tank owners include internal and external corrosion protection and bottom cathodic protection systems. Secondary containment and detection systems are also considered an essential part of a tank installation.

Tank Corrosion Protection—Coatings. A primary method used to protect metal surfaces against surface corrosion is to apply a suitable coating. Exterior surfaces generally require protection only from the elements, although in some chemical production plants, chemical vapors can be prevalent in the atmosphere and might impact selection of the coating material. Apply-

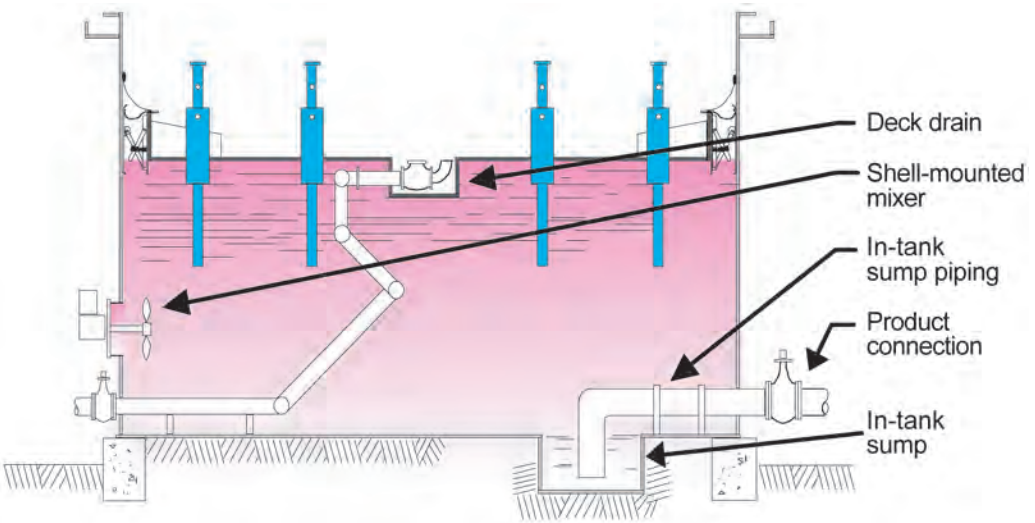


Fig. 13.9—Floating-roof tank appurtenances, Example A.

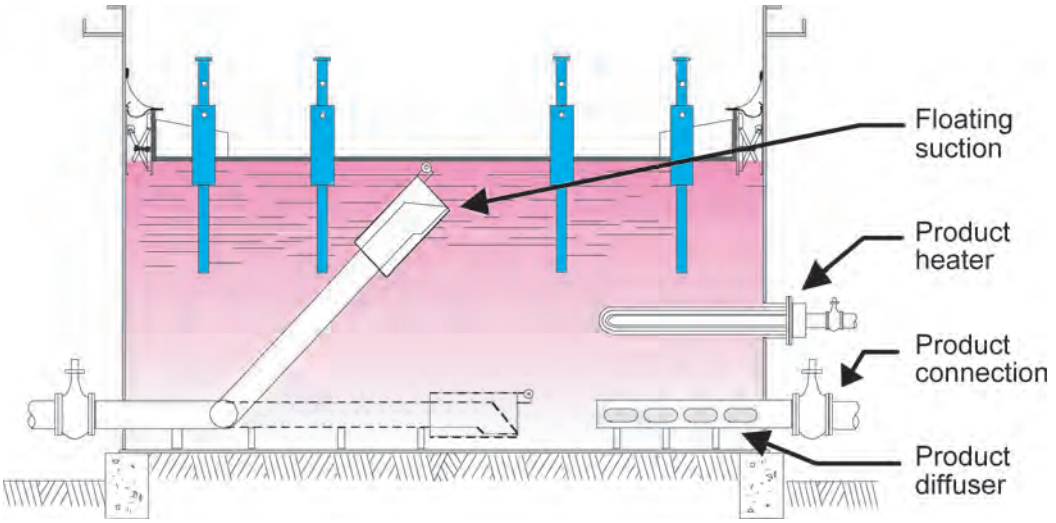


Fig. 13.10—Floating-roof tank appurtenances, Example B.

ing a suitable primer and topcoat per manufacturer's recommendations normally provides adequate protection of the external tank surfaces at onshore locations. More elaborate multicoat epoxy-based paint systems are used at offshore locations.

Internal surfaces can be more problematic. Water and other corrosive products naturally collect on the bottom. In many cases, only the bottom and 18 to 24 in. of the shell are coated.

Various types of coatings are used depending on the service requirements stipulated in the coating specification. Some of the more common coatings that remain in use in petroleum storage are coal tar, various two-part epoxy paints, and conventional fiberglass coatings. Internal flexible liners may be used for the most severe product applications.

For tanks in petroleum service, internal cathodic protection in conjunction with coatings has not gained widespread use. Under certain conditions, it can be effective in protecting against

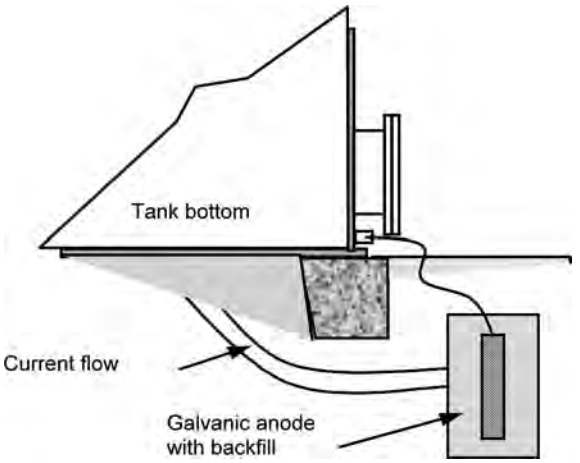


Fig. 13.11—Galvanic cathodic protection.

corrosion at holidays in the coating. More detailed information on internal cathodic protection is available in the National Association of Corrosion Engineers (NACE) *RP05-75* and *RP03-88.*

External Corrosion Control With Cathodic Protection. Corrosion of the steel tank bottom may be reduced or eliminated with proper application of cathodic protection. Systems may be used in new tank construction or may be added to an existing structure when the original bottom is replaced.

With cathodic protection systems, the entire bottom surface acts as the cathode of an electrochemical cell. Two methods currently used to protect the underbottom surfaces against corrosion are the impressed current system or the galvanic/sacrificial anode system. Each is described in some detail in the second edition of the API *RP651, Cathodic Protection of Aboveground Petroleum Storage Tanks.*

A typical galvanic system, shown in **Fig. 13.11**, uses a metal more active than the structure to be protected to supply the current required to limit or stop corrosion. The more active metal is called the anode, commonly referred to as the galvanic anode or a sacrificial anode. A galvanic corrosion cell develops, and the active metal anode corrodes (is sacrificed) while the metal bottom (cathode) is protected. Metals commonly used as the anodes are magnesium and zinc in either cast or ribbon form.

Impressed current systems use an external power source through a rectifier to provide direct current (DC) to the anode and then on to the tank bottom, as shown in **Fig. 13.12**.

The operation of any cathodic protection system can be affected by the tank foundation design, the use of secondary containment liners, and general site conditions. The system designer should complete a thorough review of all tank details.

Secondary Containment/Leak Detection. Appendix I, "Under-Tank Leak Detection and Subgrade Protection" in the API *Standard 650,* provides acceptable construction details that may be used to detect and contain leakage from aboveground storage tanks. It is noted that the API supports a general position that owners consider the installation of release prevention barriers (RPB) under new tanks during initial construction.

Acceptable RPB includes second steel bottoms, impermeable clay materials, or synthetic materials such as high density polyethylene (HDPE) materials. The API *Standard 650,* Appendix I provides several different construction details for consideration; however, the tank owner must determine whether the undertank area is to include leak detection. If required, the owner must then select the method or methods to be used.

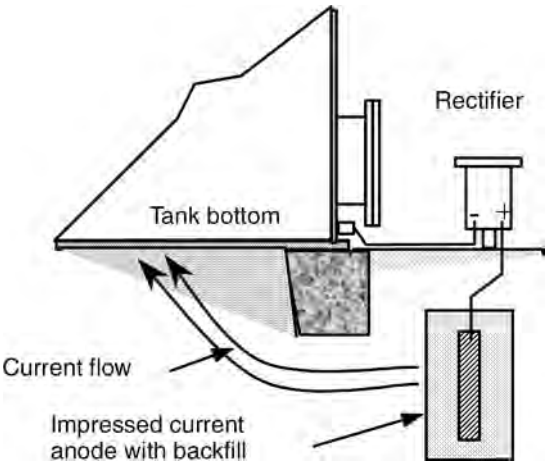


Fig. 13.12—Impressed current galvanic cathodic protection.

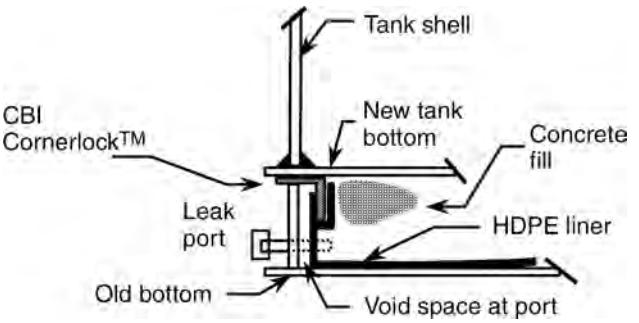


Fig. 13.13—CB&I Endolock™ lining system, Example A.

Whenever a new bottom is going to be added to an existing tank, the owner should consider adding some type of RPB. In many cases, a new bottom is only added after the original bottom has corroded through and product has leaked through to the foundation. This is covered in the second edition of API *Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction.*

Examples of typical RPB systems that are used are shown in **Figs. 13.13 and 13.14**. Each of these uses a synthetic liner fabricated from sheets of HDPE material (60–90 mil thick) welded together to form a continuous barrier. Fig. 13.13 shows a detail of a system used primarily for new tank construction on earthen birm or a concrete ring wall when leak detection is required.

The example in Fig. 13.14 is specifically used when a new bottom is to be added to an existing tank using the slotted shell method of construction. The Endolock™ system also relies on a synthetic HDPE liner as the barrier. This system also includes leak detection and can be used either with granular fill or concrete between the old and new bottom. The systems shown in Figs. 13.13 and 13.14 are patented by CB&I. Other potential systems are available, as well as systems that use adhesives or nails to secure the liner at the ringwall or inner tank shell surfaces.

Cathodic protection systems may be incorporated into each design. In most cases, an impressed current system is installed with the ribbon anodes installed between the flexible liner and the new bottom.

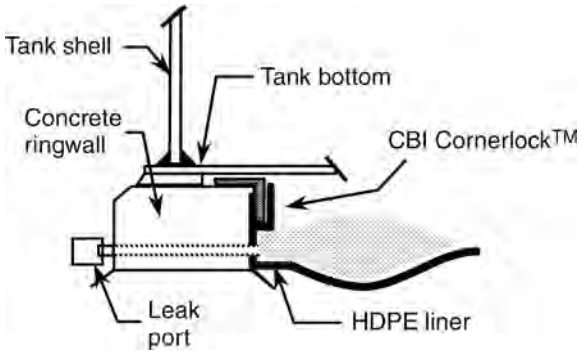


Fig. 13.14—CB&I Endolock™ lining system, Example B.

13.1.16 Site Considerations for Production Tanks. API *RP12R1, Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service* provides information on new battery installations and can serve as a guide for revamping existing batteries if required. A typical tank battery contains two or more tanks and usually has a capacity equal to four days production. Tanks should be level with each other and have a minimum spacing of 3 ft between tanks, unless increased spacing is required by local code.

Selecting the proper location for a storage tank is of prime importance. The tank foundation or grade should be slightly elevated, level, and somewhat larger in diameter than the tank itself, with the surrounding area graded to provide good drainage away from the tank(s). The best grade is one made of small gravel, crushed rock, etc. This type of grade allows no water to stand underneath the tank and provides air circulation. If the tank is to be set directly on the ground, felt tarpaper may be applied to the grade first and the tank set on this. If concrete is used for the grade, it should be slightly larger in diameter than the tank and might have shallow grooves on the surface for improved air circulation. Numerous codes, standards, and specifications may regulate the location, design, and installation of storage tanks dependent on their end use. Selection of the proper specification and providing adequate fire protection for the installation may lower insurance rates over the life of the installation.

Dikes are generally provided to contain the volume of a certain portion of the tanks enclosed depending on the tank contents. Dikes are used to protect surrounding property from tank spills or fires. In general, the net volume of the enclosed area should be the volume of the largest tank enclosed (single-failure concept). The dike walls may be earth, steel, concrete, or solid masonry designed to be watertight with a full hydrostatic head behind them. Local codes might require provisions for secondary containment of the area to limit environmental risks, should a tank leak develop. If more than one tank is within the area, curbs or, preferably, drainage channels can be provided to subdivide the area to protect the adjacent tanks from possible spills.

13.1.17 Tank-Battery Connections and Operations. The suggested setting and connection plan for a typical tank battery is shown in **Figs. 13.15 and 13.16**. The pipeline connection in the tank should be located directly below the thief hatch and a minimum of 12 in. above the tank bottom. It should be equipped with a valve and sealing device immediately adjacent to the tank. Pipeline valves should be checked frequently for leaks.

Inlet connections, preferably, should be located in the deck of the tank and should have a valve located near the inlet and capable of closing off against pressure.

Drain connections should be located immediately above the tank bottom in the side of the tank or in the tank bottom immediately adjacent to the side. They should be equipped with a

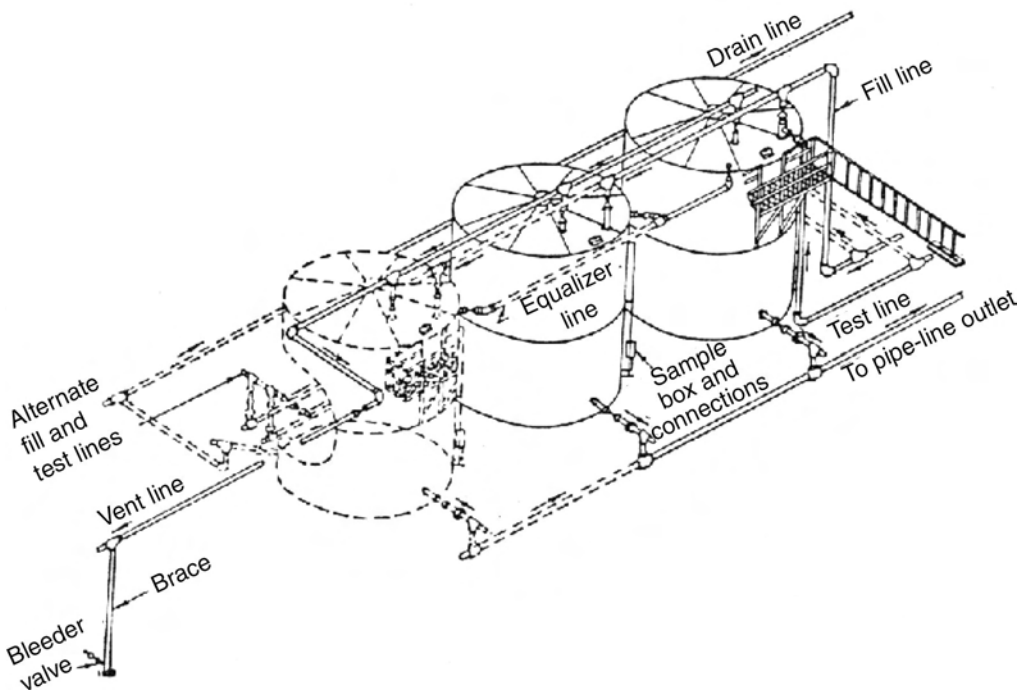


Fig. 13.15—Plan view for lease tank battery installation, Example A.

valve and sealing device located next to the tank. Drains from all the tanks in a battery should be connected together and piped well away from the tanks.

Tank batteries are operated by flowing into a single tank that is "equalized" to another. The "equalizer line" allows flow from the primary tank to overflow to a secondary tank when the primary tank is full. The operator then equalizes the second tank to another empty tank so that there is a new primary and new secondary tank.

The original primary tank is then ready to be run to sales. Before the tank is accepted by the crude purchaser, the water should be drained from the tank if necessary and the water valve sealed closed. All other valves should be sealed, except the vent or vapor-recovery line. The pipeline valve is then unsealed and opened for delivery to the purchaser. When a closing gauge is taken, and before the tank is filled again, the pipeline valve should be sealed, the drain valve checked to ensure that it is closed, and the seal removed. The seal from the equalizer-line valve can then be removed, and the tank is ready to be put in service as an equalizing tank.

Equalizer connections should be installed below the deck in the tank shell. A valve and sealing device should be installed immediately adjacent to the tank if more than two tanks are in the battery and should be connected in such a manner that any two tanks can be equalized together.

Vent connections should be installed in the center of the tank deck and all tanks connected to a common line. The line should have a pressure-vacuum valve installed in the line or on the end of it. The line should be sloped to prevent accumulation of liquids in it or in the valve. The use of gas to roll stored products is usually considered poor practice and should be restricted to temporary or emergency use. If a roller line is used, it should enter the tank through the deck and be equipped with a valve next to the tank.

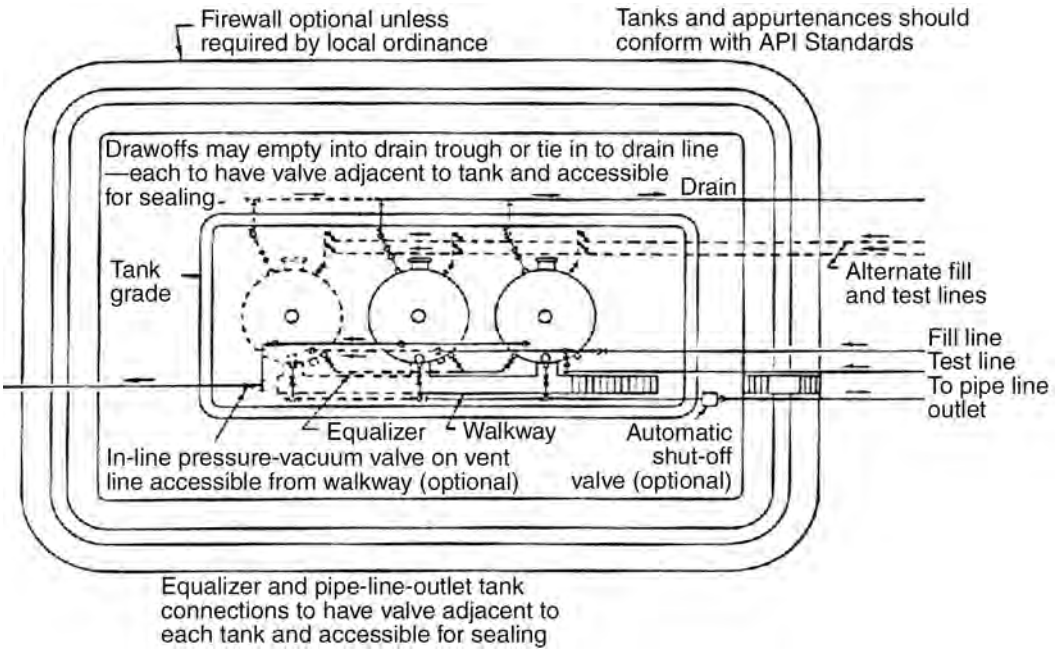


Fig. 13.16—Plan view for lease tank battery installation, Example B.

13.1.18 Tank Battery for Hydrogen Sulfide Crude Storage. Constant attention should be given to the hazardous condition created by iron sulfide deposits. These occur most frequently within the vapor space and particularly on the underneath exposed side of the deck. These iron sulfide deposits generate severe corrosion that can go unnoticed when deck conditions are observed from the topside only. When sour crude is stored, all openings on the tanks should be kept closed because hydrogen sulfide is poisonous. This can be accomplished by equipping the tanks with some type of ground-level gauging and by locating thermometers in the tank shell. Gauges and temperatures then can be read from the ground without the tank being opened. These gauging devices usually require approval by the crude purchaser. Grounding-level sampling also can be accomplished by installing pipes that extend into the tank at any desired level and to any desired distance. Valves are located at a convenient level to permit sampling on the ground without the tanks being opened. If available, a small amount of sweet gas should be fed into the top of the tank continuously to establish a "gas sweep." This ensures positive pressure within the tank at all times and prohibits air from entering the tank, thereby greatly reducing corrosion. It is advisable to extend the tank vent line well beyond the tank battery and to use a back pressure valve and flame arrester in the vent line. The vapors should be flared and not vented.

13.1.19 Maintenance of Tank Batteries. Storage tanks that are properly designed, constructed, and maintained can provide 30 to 50 years of service.

Steel tanks should be kept clean and free from spilled oil or other material. They should be kept painted and all water or accumulated dirt should be removed from around the bottom edge of the tanks. Thief hatches and vent-line valves should be kept closed and inspected periodically for proper operation and gasket condition. Should any leaks occur, they may be repaired temporarily with lead sealing plugs or toggle bolts. These leaks should be repaired permanently as soon as possible.

General References

"Evaporative Loss Measurement," *Manual of Petroleum Measurement Standards,* API, Washington, DC (April 1997) Chap. 19, Sec. 2-E.

RP12R1, Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service, fifth edition, API, Washington, DC (August 1997).

RP575, Inspection of Atmospheric and Low-Pressure Storage Tanks, first edition, API, Washington, DC (November 1995).

RP651, Cathodic Protection of Aboveground Petroleum Storage Tanks, second edition, API, Washington, DC (December 1997).

RP652, Lining of Aboveground Petroleum Storage Tank Bottoms, first edition, API, Washington, DC (April 1991).

RP2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents, fifth edition, API, Washington, DC (1991).

Spec. 12B, Bolted Tanks for Storage of Production Liquids, fourteenth edition, API, Washington, DC (February 1995).

Spec. 12D, Field-Welded Tanks for Storage of Production Liquids, tenth edition, API, Washington, DC (November 1994).

Spec. 12F, Shop-Welded Tanks for Storage of Production Liquids, eleventh edition, API, Washington, DC (November 1994).

Standard 650, Welded Steel Tanks for Oil Storage, tenth edition, API, Washington, DC (November 1998).

Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, second edition, API, Washington, DC (December 1995).

Standard 2000, Venting Atmospheric and Low-Pressure Storage Tanks (Nonrefrigerated and Refrigerated), fifth edition, API, Washington, DC (April 1998).

Standard 620, Design and Construction of Large, Low-Pressure Storage Tanks, tenth edition, API, Washington, DC (February 2002).

SI Metric Conversion Factors

°API	141.5/131.5 + °API		= g/cm^3
bbl ×	1.589 873	E – 01	= m^3
°F	(°F – 32)/1.8		= °C
ft ×	3.048*	E – 01	= m
gal ×	3.785 412	E – 03	= m^3
in. ×	2.54*	E + 00	= cm
in.^{3} ×	1.638 706	E + 01	= cm^3
psi ×	6.894 757	E + 00	= kPa

*Conversion factor is exact.

Chapter 14
Offshore and Subsea Facilities

Patrick O'Connor, BP America**, Justin Bucknell,** MSL Services Corp., and **Minaz Lalani,** MSL Engineering Ltd.

14.1 Introduction

At the present time, more than 9,000 offshore platforms are in service worldwide, operating in water depths ranging from 10 ft to greater than 5,000 ft. Topside payloads range from 5 to 50,000 tons, producing oil, gas, or both. A vast array of production systems is available today (see **Fig. 14.1**).

The concepts range from fixed platforms to subsea compliant and floating systems. This chapter presents an overview of offshore facility concepts including subsea systems and flow-assurance concepts.

14.2 Historical Review

14.2.1 Supporting Structures. In 1859, Col. Edwin Drake drilled and completed the first known oil well near a small town in Pennsylvania, U.S.A. This well, which was drilled with cable tools, started the modern petroleum industry. In 1897, near Summerland, California, U.S.A., H.L. Williams extended an offshore oil field into the Santa Barbara Channel by drilling a submarine well from a pier. This first offshore well was drilled just 38 years after Col. Drake's well. Five years later, more than 150 offshore wells were producing oil. Production from the California piers continues today.

In the late 1920s, steel production piers, which extended ¼ mile into the ocean at Rincon and Elwood, California, were built, and new high-producing wells stimulated exploration activity. In 1932, a small company called Indian Petroleum Corp. determined that there was a likely prospect about ½ mile from shore. Instead of building a monumentally long pier, they decided to build a portion of a pier with steel piles and cross-members. Adding a deck and barging in a derrick completed the installation. By September 1932, the 60 × 90-ft "steel island" was completed in 38 ft of water. This was the first open-seas offshore platform and supported a standard 122-ft steel derrick and associated rotary drilling equipment. In January 1940, a Pacific storm destroyed the steel island. During the subsequent cleanup, divers were used for the first time to remove well casing and set abandonment plugs.

Meanwhile, the first offshore field was discovered in the Gulf of Mexico in 1938. A well was drilled to 9,000 ft off the coast of Texas in 1941. With the start of World War II, howev-

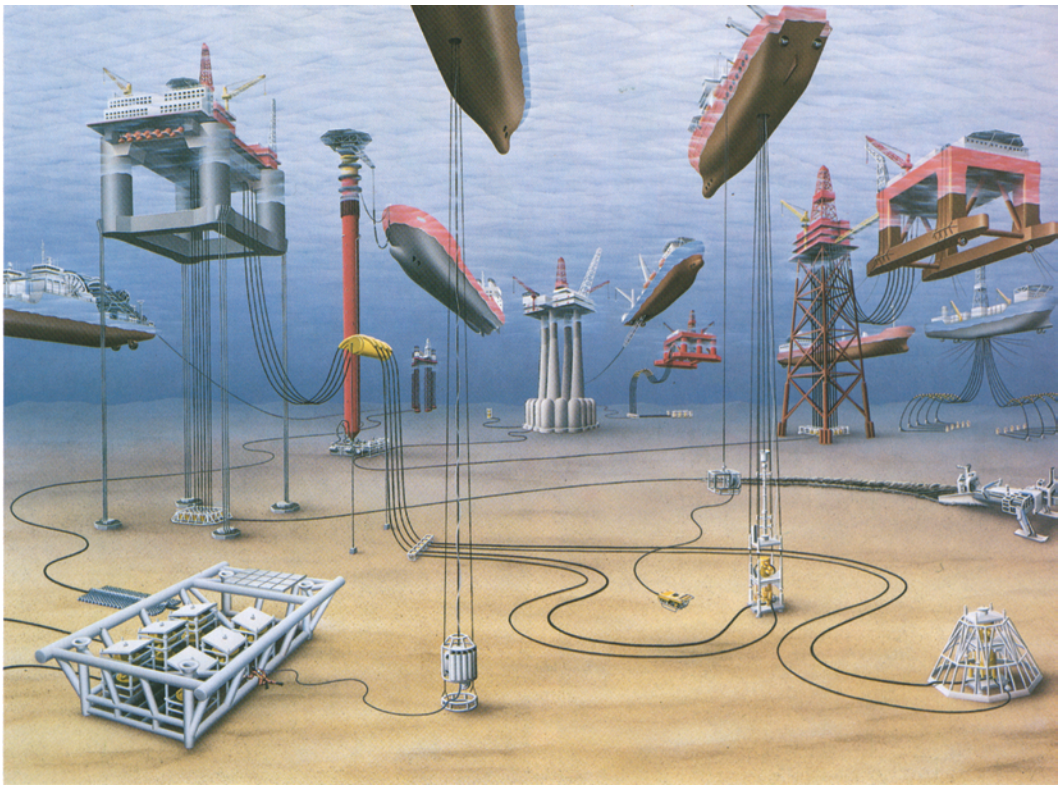


Fig. 14.1—Alternative hydrocarbon production systems [OPL Subsea Production Wallchart, Oilfield Publications Ltd. (OPL), Houston].

er, offshore activities came to a halt. Activity did not resume until 1945, when the state of Louisiana held its first offshore lease sale. In 1947, the first platform "out of sight of the land" was built off the coast of Louisiana in 20 ft of water.

Between 1947 to the mid-1990s, approximately 10,000 offshore platforms of different types, configurations, and sizes were installed worldwide.[1] In the post-World War II era, the growth of drilling in the Gulf of Mexico intensified. As platforms were placed in deeper water, their functional requirements and structural configurations became more complex. For steel-jacket structures, the offshore engineering community delivered significant technology advances to permit jacket structures to be deployed in ever-increasing water depths and hostile environments (see **Fig. 14.2**).

In the late 1960s, the development of the offshore fields in the North Sea commenced, leading to a step change with the advent of huge payload requirements in a hostile environment that did not permit intervention for de-manning in the event of a predicted storm event. Although steel-jacket structures dominated the development of North Sea fields, concrete gravity structures competed, for the first time, with their steel counterparts. In 1973, the first concrete structure was installed in the North Sea in the Ekofisk field.[1] Twenty concrete platforms later, in 1995, the Troll field was developed using a concrete substructure sitting in 985 ft of water, weighing 1 million tons. The Troll structure, shown in **Fig. 14.3**, is being towed to site.

While North Sea developments progressed rapidly from 1970 to 1990, exploration in U.S. waters ventured into deep water in the Santa Barbara Channel and the Gulf of Mexico. A num-

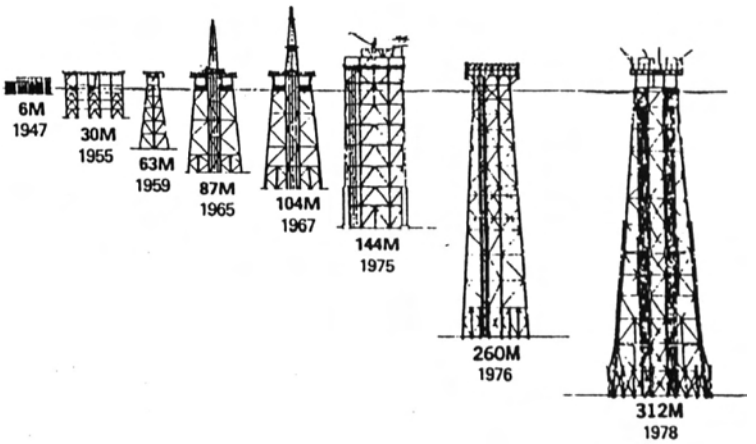


Fig. 14.2—Water depth milestones for conventional jacket structures [Website Source Figure, Minerals Management Service (MMS), U.S. Dept. of the Interior, Washington, DC].



Fig. 14.3—Troll platform being towed to site (Photographic Services, Shell Intl., London).

ber of water-depth records were set for steel-jacket structures. In 1976, the Hondo platform was installed as a two-piece jacket in 850 ft of water off the coast of California. Two years later, the Cognac platform was installed in three pieces in 1,025 ft of water in the Gulf of Mexico. As fabrication, transportation, and installation technology advanced, it became possible to install single-piece structures in deep water. In the early 1990s, the Harmony and Heritage platforms were installed single-piece in 1,200 ft of water off the coast of California. However,



Fig. 14.4—Bullwinkle platform in service in U.S. Gulf of Mexico (Photographic Services, Shell Intl., London).

the record for the largest single-piece jacket ever installed rests with the Bullwinkle platform, installed in 1,350 ft of water in 1988. Fig. 14.4 shows the Bullwinkle platform in service in the Gulf of Mexico. The platform deck gives little clue as to the size of the substructure below (see Fig. 14.5).

At the other extreme of the jacket/topsides payload milestones, the industry recognized that marginal fields could economically be exploited, provided the topsides structure was restricted to containing only the minimum facilities required for production, and a minimum substructure configuration was adopted to meet the functional specification and robustness requirements. In the Gulf of Mexico, a large number of minimum facility platform designs were adopted in the 1970s and 1980s to exploit marginal fields. As the North Sea industry matured in the 1990s, minimum facility platforms gained favor as flow assurance improved and as the need to minimize capital expense (CAPEX) for marginal fields was acknowledged. The Davy/Bessemer platforms installed in the mid-1990s and the Skiff/Brigantine platforms installed in the late 1990s demonstrated that minimum-facility platforms could be designed for service in the North Sea environment.

It became clear in the 1980s that the water depth limit for fixed platforms, from a functional and an economic perspective, was restricted to 1,500 ft. Exploration drilling was progressing in water depths beyond this limit, and offshore engineers began developing platform designs that circumvented the problems associated with fixed platforms beyond 1,500 ft. The Lena compliant guyed tower was developed and was installed in 1,000 ft of water in the Gulf of Mexico in 1982. This tower was designed to be more flexible than fixed jacket structures and, therefore, more "compliant" to the environment. The guys provided vertical and lateral stability for the structure. In 1998, the Baldpate and Petronius compliant towers were installed in 1,648 and 1,754 ft of water, respectively, in the Gulf of Mexico; Baldpate is illustrated in Fig. 14.6.

In the 1970s and 1980s, for discoveries remote from existing infrastructure, ship-shaped floating production, storage, and offloading systems (FPSOs) provided a solution to economic development as they offered oil-storage capability. In 1977, off the coast of Spain, oil was drawn from a subsea well in 370 ft of water into a tanker moored to an oscillating mooring



Fig. 14.5—Transportation of the Bullwinkle steel substructure (jacket) (Photographic Services, Shell Intl., London).

tower. Other similar developments followed (e.g., the Nilde field offshore Italy in 1982). Because of the motions of the FPSO vessel, the concept required that the wellheads be located on the seabed, known as wet or subsea wellheads. A variant to this approach was the use of dry wellheads, located on a fixed steel platform, in combination with an FPSO [e.g., Hondo offshore California in 1981 and the Tazerka offshore Tunisia in 1982 (see **Fig. 14.7**)].

The Tazerka FPSO, at 210,000 deadweight tons, was the largest FPSO deployed until 1985. Up to 1986, FPSOs were based on conversion of existing tankers. In 1986, Golar Nor demonstrated that a purpose-built FPSO, with oil, gas, and water separation, was economically feasible for production in the harsh North Sea environment. The development of FPSOs continued around the world, including offshore Australia and in the South China Sea, using a range of mooring designs. In 1993, the Gryphon FPSO was the first to be placed permanently in the North Sea; by 1998, the number operating in the North Sea had increased to sixteen.

An alternative concept in regions with an economically accessible infrastructure was the semisubmersible floating production system (FPS). This system consists of a buoyant floating facility moored to the seabed. The system offers reduced motions compared to an FPSO. In 1975, a production semi-submersible was used in the Argyll field in the North Sea in 254 ft of water. Two years later, the first production semisubmersible was placed offshore Brazil in the Enchova field. From that time, the use of production semisubmersibles gained increasing popularity, particularly offshore Brazil in water depths up to 6,000 ft. **Fig. 14.8** shows a semi-FPS being transported to its final location in deep water offshore Brazil. **Fig. 14.9a** shows the global fleet of an installed/sanctioned semisubmersible-based FPS.

In the Gulf of Mexico, the pioneering application of a semisubmersible was at a Green Canyon field for extended well testing in 1,500 ft of water from 1988 to 1990. However, ini-

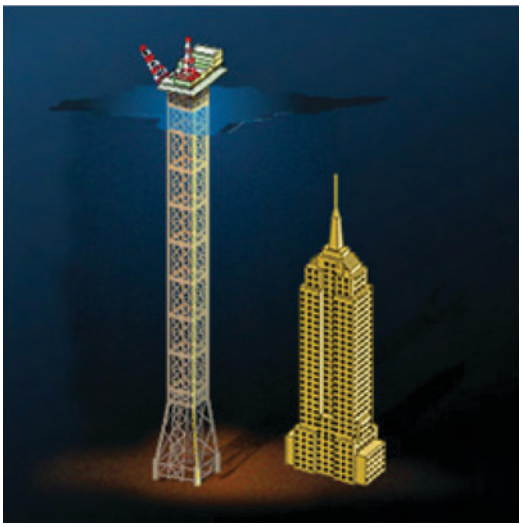


Fig. 14.6—The Baldpate Compliant Tower is one of the tallest free-standing structures in the world—Empire State Building (right) for comparison (Web Photograph, Amerada Hess Corp., New York City).



Fig. 14.7—FPSO and jacket structure at the Tazerka Field, Tunisia [Single Buoy Moorings Inc. (SBM), Marly, Switzerland].

tial deepwater production from floating systems in the Gulf of Mexico was dominated by an alternative concept known as the tension leg platform (TLP). A TLP is a vertically moored, buoyant structure anchored to the seabed with vertical taut steel tendons. The system relies on the tension in the tendons for its stability. The advantage of the TLP is reduced motion compared to FPSOs or conventional FPS facilities. The reduced motions permit the use of dry wellheads. As with an FPS, a TLP has no storage capacity and, therefore, requires a separate storage tanker or a pipeline or shuttle tanker for export. Following large-scale TLP model test-



Fig. 14.8—Sea transportation of the Petrobras P40 semisubmersible FPS (courtesy of Petrobras Image Bank, Petrobras, Rio de Janeiro).

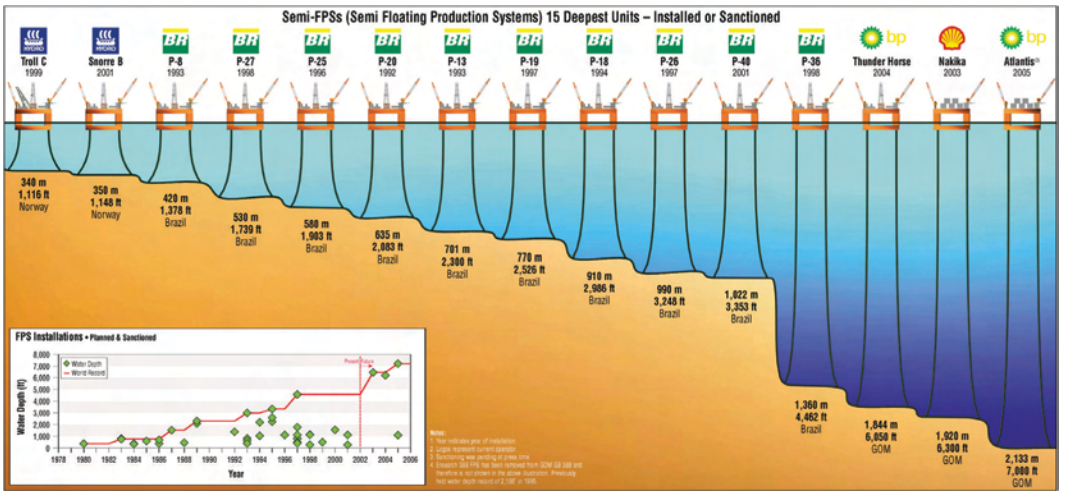


Fig. 14.9a—Worldwide fleet of installed and sanctioned semisubmersible FPS (courtesy of BP).

ing offshore California in 1974 and 1975, the concept was adopted for the first time in the Hutton field in the North Sea in 1984. Located in 500 ft of water, the Hutton field could have been developed using a conventional steel-jacket structure, but the harsh North Sea environment was judged to provide the ideal test bed for the TLP design prior to venturing into deeper waters. Since 1989, a number of TLPs have been installed in deep water in the North Sea, Gulf of Mexico, and offshore Indonesia in water depths ranging from 1,000 to almost 4,000 ft. **Fig. 14.9b** shows the global fleet of installed/sanctioned TLP facilities.

With the focus in the late 1980s and throughout the 1990s firmly on the development of deepwater production technology, a number of new concepts, or variants of established concepts, have emerged. Of these, the most widely used has been the deep draught caisson vessel (DDCV) or spar concept. The spar is a floating system comprising a deep draught cylindrical hull (caisson), which supports a topsides structure, and is moored using a system of mooring lines from the hull that are anchored to the seabed. Spars, like TLPs, reduce vessel motions compared to FPSO and FPS options, permitting the use of dry wellheads. Spars have proved a

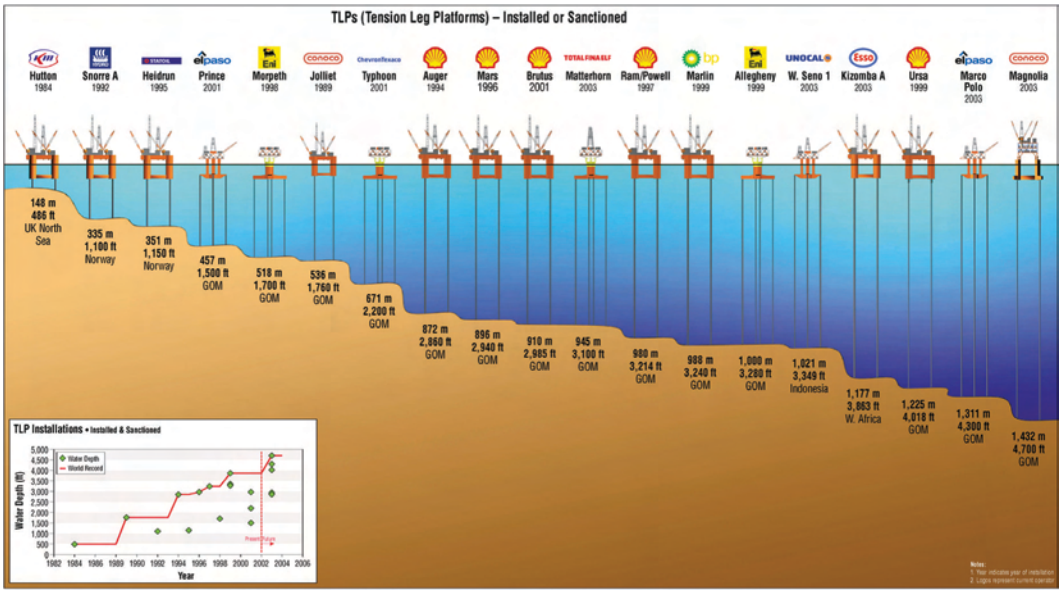


Fig. 14.9b—Worldwide fleet of installed and sanctioned TLPs (courtesy of BP).

popular development choice in the Gulf of Mexico, where three classic spars and six truss-spars have been installed or sanctioned for installation as of 2002 in water depths up to 5,610 ft; see **Fig. 14.9c**.

Other recent technology development efforts have focused on a variant of the semisubmersible FPS concept. This concept extends the draught of the hull structure of a conventional FPS to reduce motions. These systems also can be designed to be self-installing. Engineering is under way for a production semisubmersible for the development of the Thunder Horse field in the Gulf of Mexico in 6,000 ft of water, with a topsides weight in excess of 50,000 tons; see **Fig. 14.10**.

In summary, the industry has achieved enormous success and shown admirable innovation to meet the challenges of producing oil and gas in the hostile deepwater environment. A variety of proven dry-tree and wet-tree solutions exists for water depths up to 6,000 ft; see **Fig. 14.11**.

Many other special, and often one-off, structures have been installed offshore. The commercial fields in the arctic offshore continental shelves of the U.S. and Canada have led to the development of production facilities that are able to resist ice loads. By 1968, 14 platforms were installed in the Cook Inlet of Alaska. In the early 1990s, the Hibernia field, off the east coast of Canada, was developed using a gravity-based concrete substructure capable of resisting ice-driven environmental forces. An alternative to this concept was adopted for the Terra Nova field off Newfoundland. In 2001, a purpose-built FPSO with a detachable turret was installed. If ice attack is predicted, the system is designed to permit the turret to detach and fall to the seabed. The FPSO can then be maneuvered away from the path of the ice. Once the danger has passed, the FPSO is returned to site, and the turret is re-attached to allow production to continue. Other special structures include a steel gravity oil-storage structure placed in the Gulf of Mexico in 1966 and the Maureen platform in the North Sea that was a steel gravity structure (as opposed to a concrete structure) with oil-storage capacity. The Maureen platform was successfully decommissioned in 2001.

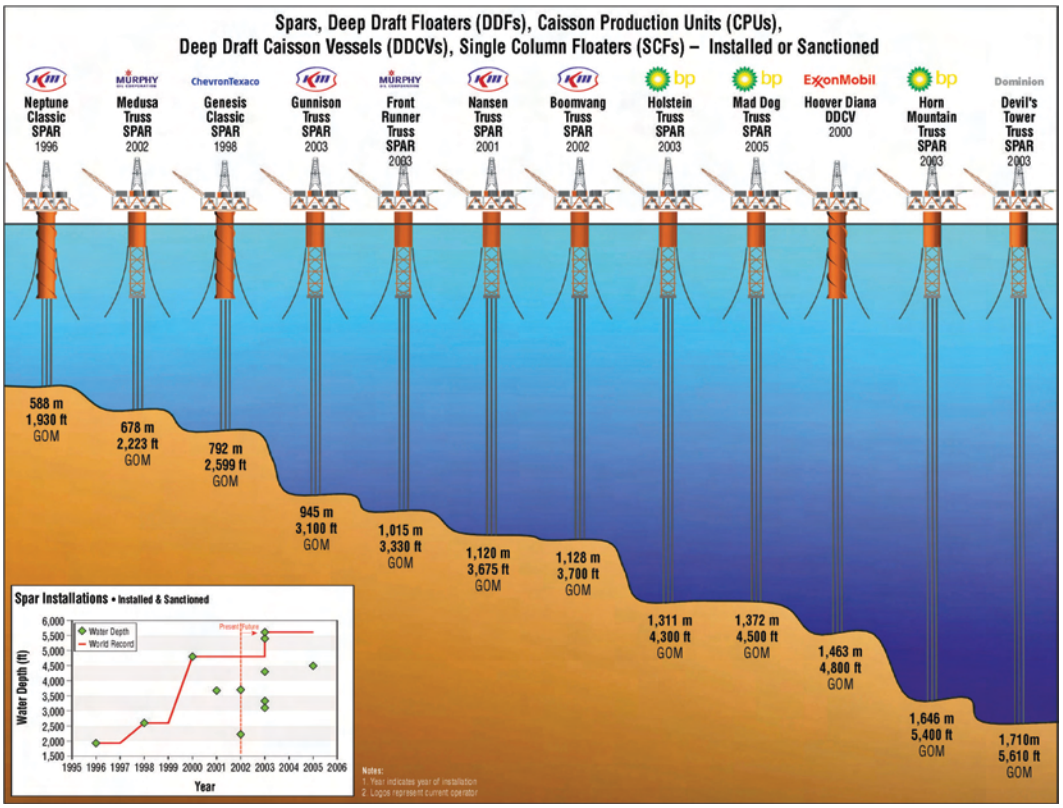


Fig. 14.9c—Worldwide fleet of installed and sanctioned spars (courtesy of BP).

In summary, the offshore industry, for the past 55 years, has come a long way since the first offshore platform was installed in 1947. Although most of the offshore structures constructed to date have withstood the test of time, there have been several failures that led to loss of life, loss of facility, and/or pollution. The industry has embraced the lessons learned from these failures, and the assurance of health and safety and the protection of the environment are of primary importance in the design of offshore structures.

As exploration and production encroaches into deeper water and harsher environments, the challenges of structural design increase. Environmental load predictions, transportation analyses, and installation procedures are as important to understand as the more obvious structural-frame analysis. Seldom is a designer afforded the luxury of optimizing a structure on the basis of in-place stress analysis; more often, the transportation and installation (lasting a few weeks out of perhaps a 20-year structure life) will dictate the major framing patterns.

14.2.2 Subsea Systems. Subsea production wells have been around for more than 40 years. A subsea well consists essentially of a wellhead assembly and Christmas tree (sometimes referred to as a wet tree), which is basically identical in operation to its surface counterpart, with the primary exception of reliability refinements, to permit operation at the seabed. Subsea wells have been used in support of fixed installations as an alternative to satellite or minimum-facility platforms for recovering reserves located beyond the reach of the drillstring or used in conjunction with floating systems such as FPSOs and FPSs. **Fig. 14.12** shows an example of subsea production trees used in conjunction with a host fixed jacket structure.



Fig. 14.10—Semisubmersible FPS planned for the Thunder Horse field (courtesy of BP).

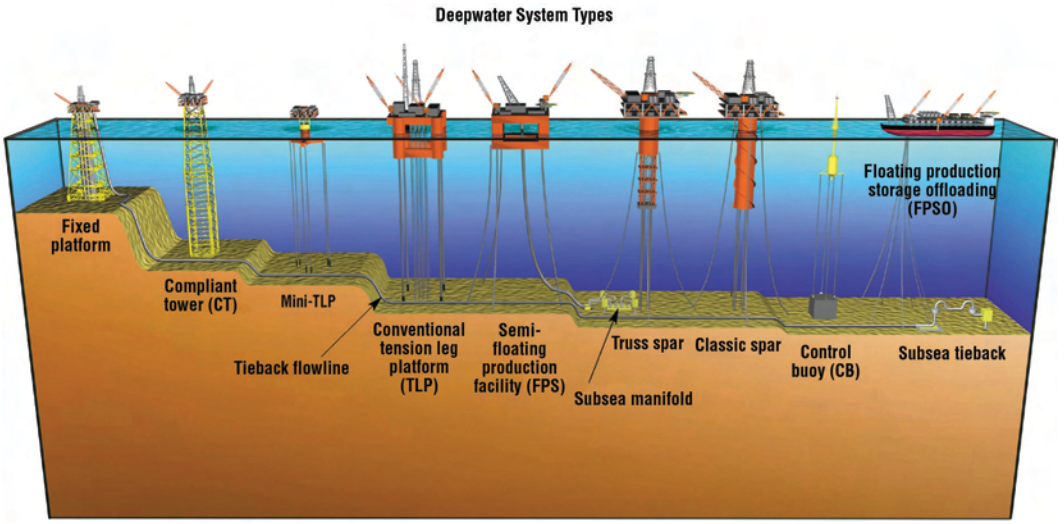


Fig. 14.11—Alternative proven technology field development options (courtesy of BP).

The first subsea completion system was installed in the Gulf of Mexico in 1961 for the West Cameron field in a water depth of 55 ft. Since that time, hundreds of subsea systems have been deployed and are in operation. Complex multiwell subsea systems have been installed, and ROV intervention has become an integral part of the subsea completion system. The 1997 Mensa subsea development (see **Fig. 14.13**) holds the longest tie-in record of 63 miles in 5,400 ft of water in the Gulf of Mexico. The current water depth record of 6,000 ft was set offshore Brazil in 1998.

14.3 Fixed Steel and Concrete Gravity Base Structures

As indicated in the historical review, many types of offshore structures are in service. Some are better suited to certain environmental and operational criteria; some are limited by availabil-

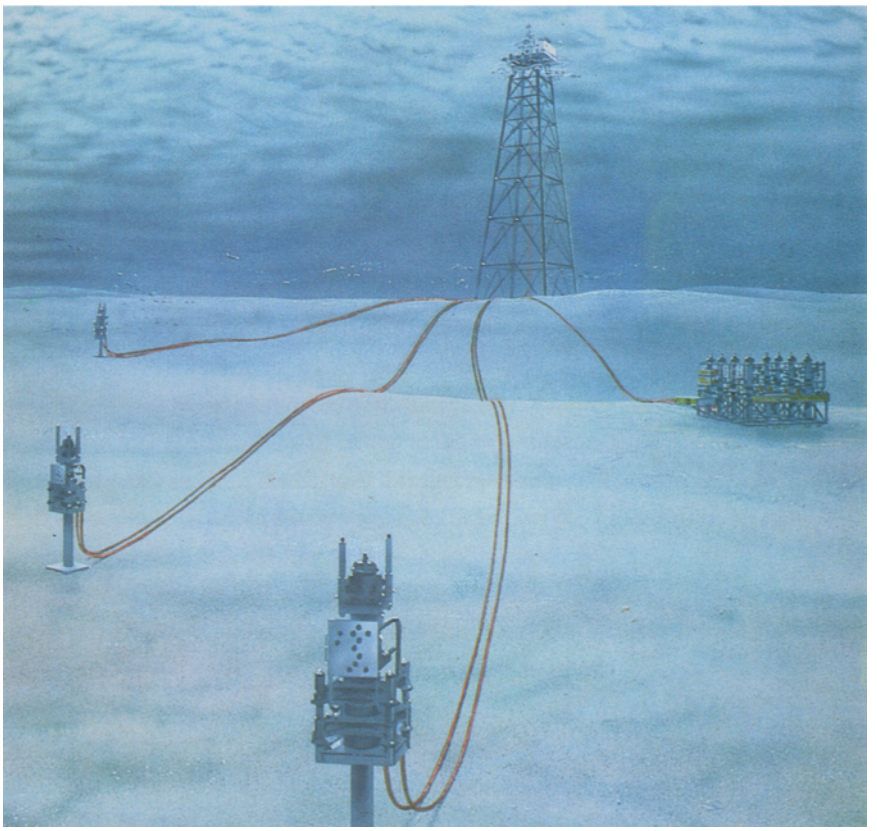


Fig. 14.12—Subsea production trees used in conjunction with a fixed jacket structure (Intec Engineering, Houston).

ity of construction sites; and some are chosen simply by subjective preference of an owner/operator. Selecting a structure type is the first major structural design task after environmental and operational criteria have been defined and will sometimes require preliminary design of several concepts before a choice is made.

14.3.1 Fixed Steel Structures. The most common type of offshore structure in service today is the jacket (or template) structure, as illustrated in Fig. 14.14. The template was derived from the function of the first offshore structures to serve as a guide for the piles. The piles, after being driven, are cut off above the templates, and the deck is placed on top of the piles. The template is prevented from settling by being welded to the piles' tops with a series of rings and gussets. Hence, the template carries no load from the deck but merely hangs from the top of the piles and provides lateral support to them.

Some companies prefer to place packers in the bottom of each template leg and to grout the annular space between the leg and pile from bottom to top. The structure and pile share the axial load from the deck and the compressive and tensile loads from the overturning moment produced by lateral wave loads. The grouted pile also provides additional strength to the tubular joints where horizontal and diagonal bracing is welded to the legs. Drawbacks to this system are the difficulty in ensuring that the grout is adequately placed and of sufficient strength to be counted in the analysis and the additional difficulty in platform removal.

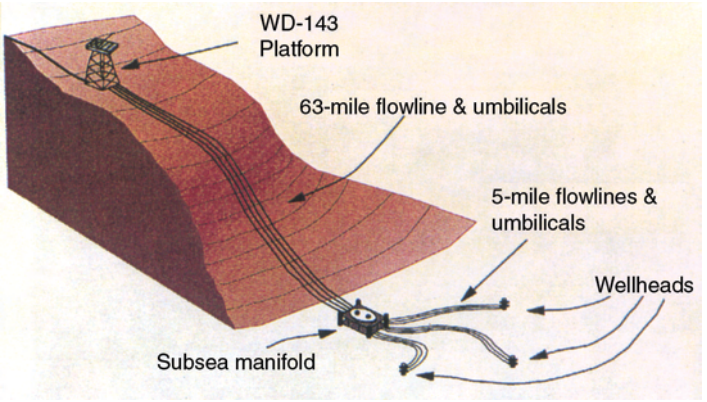


Fig. 14.13—Mensa subsea development: world's longest subsea tieback in 1997 (Shell U.S.).

Although both top-hung and grouted structures are loosely called templates, some prefer to call the latter a jacket to distinguish the difference in load path. This path is substantially different for the overturning moment as well as axial loads. The top-hung template requires that moment from lateral wave loads be transmitted up the structure to be resolved into axial pile loads. The grouted jacket has a direct downward load path for shear and moments. The novice designer would do well to learn this distinction early in his career.

When steel structures are designed for deeper water (in excess of 250 ft), pile-leg grouting is prevalent. Lateral wave loads that produce high base shear and overturning moments heavily influence deepwater jacket designs. Piles placed through the legs of the jacket are not always sufficient to transfer these loads to the soil; so "skirt piles" are added, normally in clusters around the corner legs. This adds a new dimension to the installation procedure. Pile guides are required up to water level, and a removable "follower" must be used during pile-driving operations. Grouting procedures for the skirt sleeve-to-pile must recognize that grout placement and inspection will be done remotely.

The template or jacket structure is a steel space frame that supports, above water, a superstructure comprising one or more decks for production equipment and facilities needed to support and maintain production. The production tasks may include separation of oil, gas, water, and sand; treatment and measurement of oil and/or gas for sales; and treatment of water and/or solids for disposal.

The facilities include utilities (i.e., electricity, fuel, instrument gas, power gas, water, and sewage); cranes; accommodations for personnel; workshops; control rooms; and safety systems for hazard detection, protection, and escape. Further, a helideck is usually provided. Often, a drilling derrick forms part of the equipment for drilling and maintenance of the wells. Sometimes, a flare boom is necessary for gas flaring. The accommodation/helideck facilities are situated as far from the potentially dangerous hydrocarbon process area as is physically possible. The production equipment and facilities are often called the topsides. To simplify installation and hookup at sea, the equipment and facilities are often placed in modules, which may weigh several hundreds to many thousands of tons. The modules are completely prefabricated and tested onshore prior to transportation and lifting onto the jacket deck(s) by offshore crane vessels.

The offshore structure shown in Fig. 14.14 is a modern example of a jacket structure designed for operation in 350 ft of water. The jacket structure is first placed on the seabed, and the foundation piles are driven through the pile sleeves (often called skirt piles) and grouted to form the support system for the structure. Often, it is only necessary to provide piles through

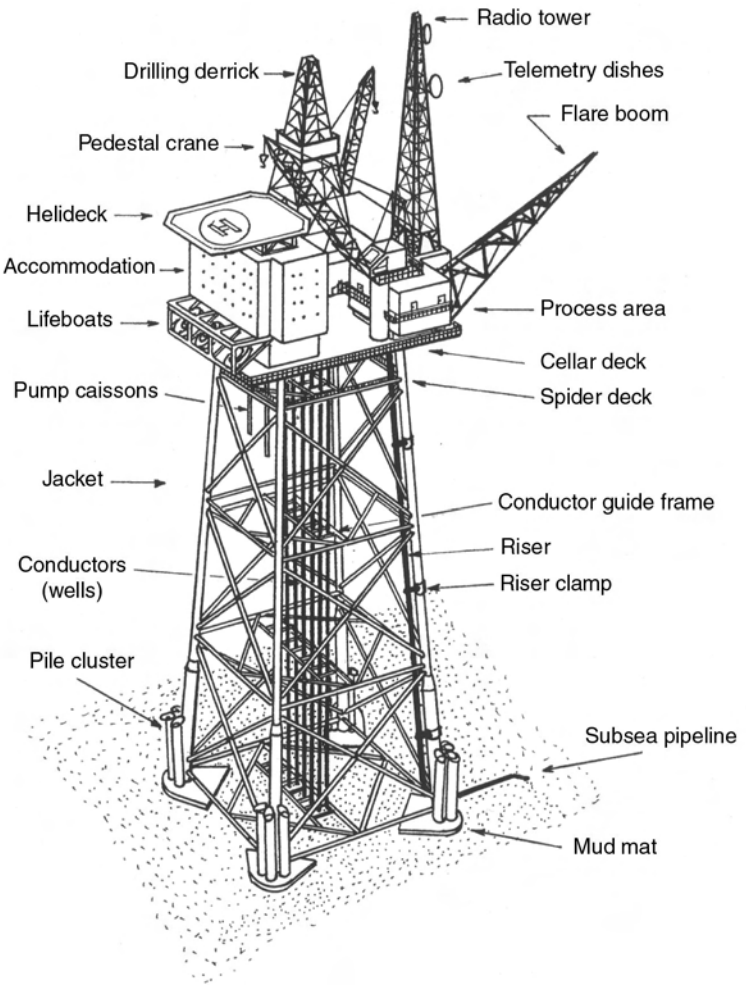


Fig. 14.14—Conventional fixed steel-jacket structure.

the legs, depending on the environment and soil characteristics. In these cases, the piles are either grouted or welded to connect the piles to the jacket and permit the topside and jacket loads to be transmitted to the piles and into the soil.

The design of a jacket structure is a matter of determining overall dimensions based on water depth and functional requirements, evaluating hydrodynamic loads caused by waves and currents; evaluating topsides and wind loads; sizing of the structure to meet the state requirements for strength, fatigue, and serviceability; and sizing of the appurtenances. Design forces on jacket structures, shown as arrows in **Fig. 14.15**, can be calculated with specialized computer software available to the industry. The horizontal force from waves consists of drag forces from the kinetic energy of the water and inertia forces from the water-particle accelerations. An appropriate wave theory is used to calculate the water-particle velocities and accelerations. The total horizontal force is calculated by multiplying the projected area of the structural members with the water pressure. Jacket design is an iterative process because a number of design cycles are gone through before achieving the optimal sizing for a particular member to bear these horizontal forces. Most of the horizontal loads are directly related to the diameter of the tubular members and their locations within the structure.

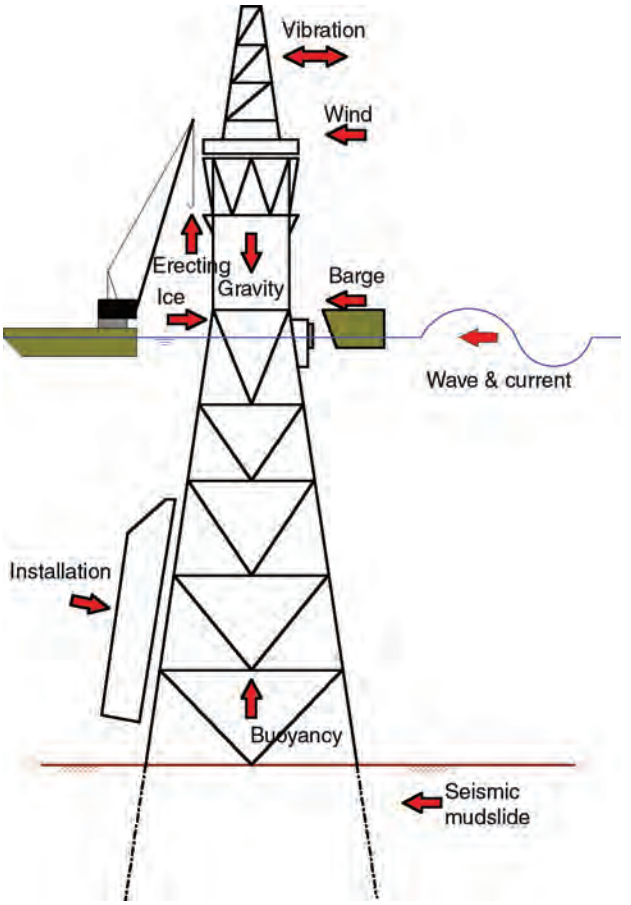


Fig. 14.15—Typical design forces on conventional-jacket structures (courtesy of MSL Engineering).

The design of the foundation piles is also critical. There is significant interaction between the response characteristics of the jacket structure, its foundation piles, and the soil, such that pile-soil-structure interaction is explicitly catered for in the design recipe for jacket structures. Over the decades, the piles have grown in size (number, diameter, and length) in line with the jacket structures. Therefore, pile weight is an important part of total structural weight. For example, the Bullwinkle jacket structure weighed 44,800 tons, and the pile weight was 9,500 tons (i.e., the pile weights are a significant portion of the jacket weight, in this case, nearly a quarter of the structure weight).[2] For small structures in shallow water, the pile weight may approach the weight of the jacket structure. The need for heavy hammers to drive large jacket piles has contributed to the development of semisubmersible heavy lift crane barges. Hydraulic hammers that operate underwater have superseded the early steam-driven hammers. A modern, high-energy hammer for 8-ft-diameter piles typically weighs around 160 tons.

Because the cost of piling is substantial, an alternative concept that has been developed is the suction pile, or bucket foundation, because its visual appearance is one of an inverted bucket. The suction pile is forced into the soil by the pressure difference over the bottom of the bucket as water is pumped out from within the bucket. While suction piles were originally developed to provide anchor points for single-point moorings, their use for jacket structures offshore Norway (Europipe 16/11E and Sleipner Vest) has encouraged their wider acceptance. The suction pile essentially comprises a plate, usually circular, and is surrounded and rein-

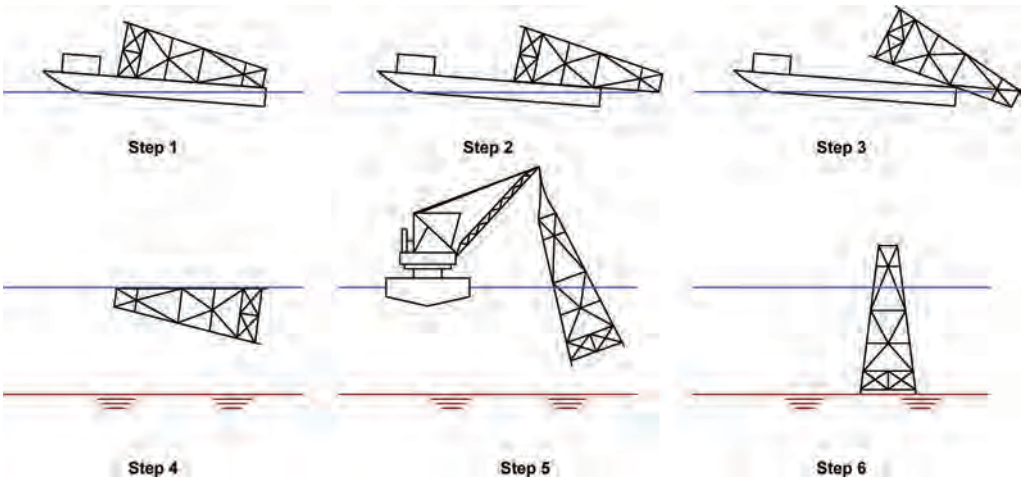


Fig. 14.16—Sequence for jacket installation by launching (courtesy of MSL Engineering).

forced by a skirt. The Sleipner suction pile, for example, has a 45-ft-diameter plate with a 16-ft skirt depth.

Without exception, the construction and installation of a jacket structure plays a central role in its design. Steel jacket structures are prefabricated onshore prior to transportation to site by a barge. Although jacket structures can be, and have been, designed as self-floating for transportation (with subsequent systematic flooding for installation), the most popular installation methods are lifting or launching. Small jackets may be lifted in place by a floating crane vessel. Larger jackets may require flotation devices to assist in their installation. The flotation devices are subsequently flooded to enable the jacket to sink slowly into its final resting place.

A typical sequence of steps involved in the installation of a jacket structure by launching is shown in **Fig. 14.16**. A jacket structure being launched is shown in **Fig. 14.17** and is consistent with Step 3 in Fig. 14.16. The jacket structure is placed horizontally on a flat-topped barge and towed to site. At location, the jacket is launched off the barge, uprighted using a crane vessel, and allowed to sink vertically to the seabed. Once located on the seabed, foundation piles secure the structure. An examination of the steps in Fig. 14.16 reveals that a number of critical factors must be considered as part of the jacket-design process:

- The weight of the jacket structure has to be less than the safe lift capacity at the construction facility if the jacket is lifted onto the barge rather than skidded.
- The jacket weight cannot exceed the capacity of the tow-out barge.
- The jacket has to be designed to withstand the loads involved during tow-out, transportation, and launching.
- The jacket has to be designed to float unassisted in the water following launch.
- The jacket is designed to be uprighted by a crane vessel, then sunk to the seabed with systematic flooding.

An alternative to launching the structure is to lift it in position. Today, vessels with a lift capacity up to 14,000 tons exist, allowing most jacket structures to be lift-installed in a cost-effective manner. Use of twin cranes on a single vessel or use of two crane vessels is often deployed to provide the required lifting capability. **Fig. 14.18** shows a jacket structure being lift-installed using two crane vessels. Once the jacket is secured with its foundation system, the topsides structure can be installed as separate modules or as a single integrated unit; see **Fig. 14.19**.

The benchmark design guidelines and standard for fixed steel structures is the American Petroleum Institute (API) *RP2A,* which was first published in 1969. In 2000, the 21st edition

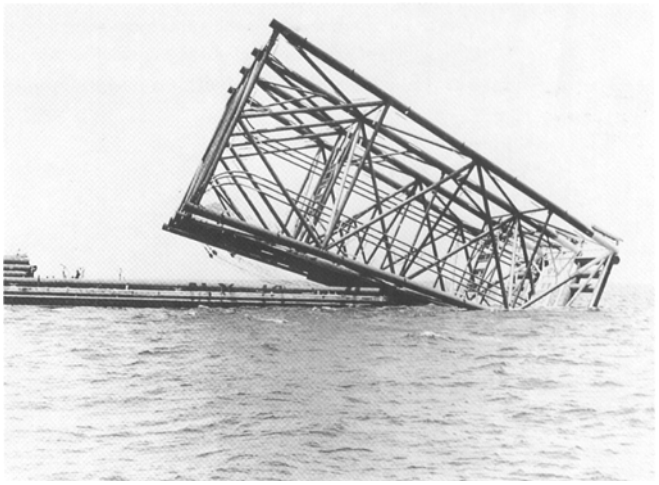


Fig. 14.17—Jacket structure being launched (Photographic Services, Shell Intl., London).

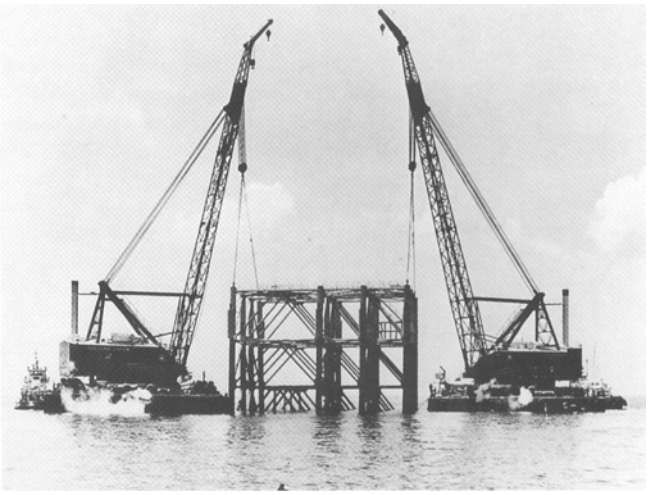


Fig. 14.18—Jacket structure being lift-installed (Photographic Services, Shell Intl., London).

of API *RP2A* was released.[3] This edition reflects good engineering practice, knowledge, and experience gained by the industry over the past five decades. Equivalent practices exist in other countries such as the U.K. and Norway. In following the development of the technology related to fixed steel structures and the historic achievements, two additional observations are worthy of note.

The first observation relates to the industry's ability to manage and maintain the structural integrity of existing installations during the service life of the platforms. In this regard, in the 1980s, Amoco pioneered the "assessment engineering" approach for its fleet of platforms in the U.K. sector of the North Sea. Today, this approach is embraced by the industry worldwide and is reflected in recommended practices, design codes, and standards. The assessment engineering approach is integral to the integrity management of offshore installations. The process, illustrated in **Fig. 14.20**, ensures the cost-effective life-cycle management of offshore structures.



Fig. 14.19—Topsides modules being lift-installed (courtesy of BP).

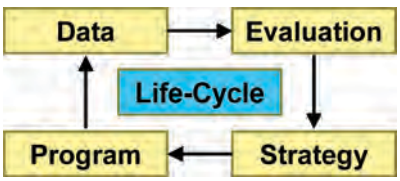


Fig. 14.20—Structural integrity management (SIM) process (courtesy of MSL Engineering).

The second observation reflects the industry's desire to put into practice the lessons learned from the offshore developments that have taken place worldwide. In the 1990s in particular, the industry undertook a "self-assessment," particularly in light of the large number of undeveloped marginal fields in existence worldwide. This led to the concept of minimum facility platforms (MFPs), which aim to restrict the equipment and facilities on topside structures to the minimum required for production, minimize or eliminate the need for manned installations in light of improved flow-assurance technology, and minimize substructure arrangements without compromising robustness or safety.[4]

A large number of novel and innovative MFP concepts exists at the present time, and sophisticated platform selection tools have been created to permit the most appropriate development options to be considered.[5] Shell's Skiff and Brigantine structures in the southern North Sea, for example, were designed to be installed using a jack-up rig with conductors placed through the legs and exploited as part of the foundation system.[6] These platforms were also designed for sea access rather than helicopter access, thereby reducing the topsides facilities.

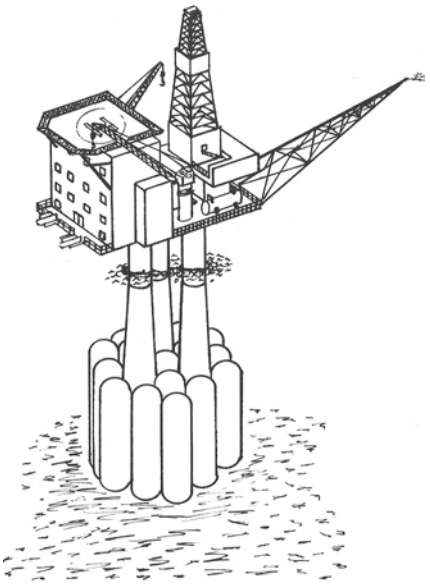


Fig. 14.21—Concrete gravity-based structure.

The use of MFPs is set to grow over the next decade.[7] The big prize for the industry is to develop MFPs that are self-installable, thereby removing the need for installation vessels.

14.3.2 Concrete Gravity-Based Structures. While the vast majority of fixed offshore structures utilize steel-jacket substructures to support the topsides facilities, a number of offshore installations utilize a substructure manufactured from reinforced concrete. As the name implies, concrete gravity-based structures rely on their own weight to resist the lateral environmental loads. These types of structures were pioneered by Norway, consistent with their design expertise, construction facilities, and construction skills that leaned heavily toward concrete rather than steel. Norway's fjords provided the ideal sites to permit construction of these large substructures. Further, these substructures provide the advantageous option of using the gravity base for oil storage.

Fig. 14.21 shows an illustration of a concrete gravity-based structure (GBS). The topsides structure is similar to that for steel-jacket structures (i.e., it is either an integrated steel-deck configuration or is of modular construction with a module support frame). GBSs are constructed with reinforced concrete and consist of a cellular base surrounding several unbraced columns that extend upward from the base to support the topsides superstructure above the water surface.

The construction and installation of GBSs is entirely different from that employed for jacket structures. **Fig. 14.22** shows a typical set of construction and installation steps for a GBS. As illustrated, the concrete bottom structure is constructed in dry dock. Once constructed, this is floated out and moored in a deepwater protected harbor. Completion by slip-forming of all the cellular base walls is undertaken in the harbor, followed by slip-forming of the towers in a continuous process; see **Fig. 14.23**. Once the towers are constructed and topped off, the whole structure is ballasted down to receive the topsides deck and modules. The completed platform is de-ballasted to a minimum draft for towing and is towed using tug boats to its final location and ballasted onto the seabed. The ballasting permits the skirts to penetrate into the seabed. Grouting is undertaken to fill any voids under the base. It can be observed that offshore

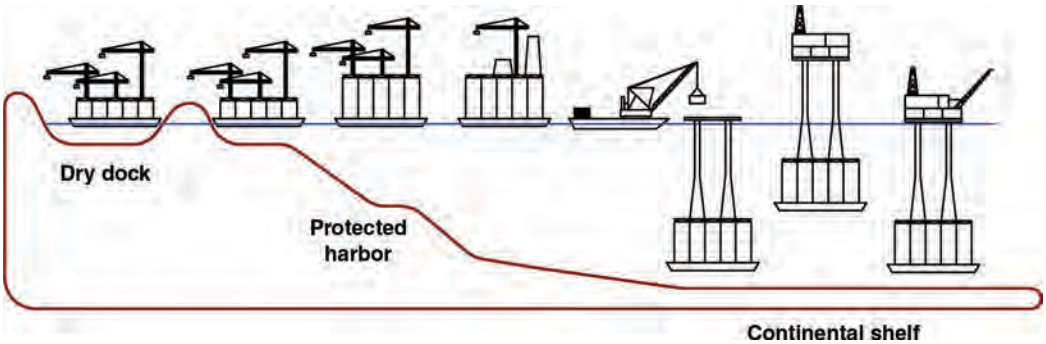


Fig. 14.22—Concrete platform construction and installation (courtesy of MSL Engineering).



Fig. 14.23—Construction of the Troll platform (Photographic Services, Shell Intl., London).

hookup is minimized because most of the topsides equipment and facilities are commissioned onshore prior to placement on the deck.

An offshore GBS is large. Its size, and the large environmental forces, can cause design problems. The structural design requirements include the categories of material quality, strength, and serviceability. Most GBSs are designed for several functions, namely combined drilling, production, and oil storage. The design is targeted to offer least resistance to environmental loads while providing adequate support for the topsides structure. Typically, using a range of standards, the structure is designed to meet the criteria laid down for the ultimate progressive collapse, fatigue, and serviceability limit states. Prestressed concrete, as used for GBSs, provides good resistance to fatigue and corrosion. Prestressing is essential because it permits the concrete to act in compression at all times. Temporary loading conditions may very well govern the structural design. These temporary cases include construction in dry dock, construction in protected harbor, ballasting for deck installation, towing, and installation. Often, the cellular base walls are not pressurized; consequently, they must be designed to resist the

substantial hydrostatic pressure imposed during immersion. Coincidentally, the ballasting of the GBS for deck installation prior to towing to site is often regarded as an effective, full-scale, inshore pressure test prior to offshore installation.

From a geotechnical standpoint, the parameters considered in foundation design include the type/extent of contact between platform base and seabed; stability against overturning and sliding; skirt penetration and grouting, to provide lateral sliding resistance and protection from scour; settlement; effects of cyclic loading on the soil; and soil-structure interaction.

The foundation aspects are considered individually and collectively as part of the design process for a GBS. The design and construction of the huge concrete gravity base structures represent a remarkable achievement by the offshore industry. However, the development of fields in the future using this technology may be limited, primarily in light of the trend toward subsea wells with long tie-backs and floating production systems.

14.4 Compliant and Floating Systems

As previously discussed, the majority of offshore fields have been developed with conventional fixed steel platforms. One common feature of fixed steel structures is that it is essentially "fixed" (i.e., it acts as a cantilever fixed at the seabed). This forces the natural period to be less than that of the damaging significant wave energy, which lies in the 8- to 20-second band. As the water depth increases, these structures begin to become more flexible, and the natural period increases and approaches that of the waves. The consequence of this is that the structure becomes dynamically responsive, and fatigue becomes a paramount consideration. Additional steelwork is required to stiffen the structure. From an engineering and economic perspective, cost-effective steel-jacket structures are extremely difficult, if not impossible, to design beyond 1,500 ft.

To circumvent this problem for water depths beyond 1,500 ft, the industry has developed concepts that work on the other side of the damaging significant wave energy (i.e., structures that have natural periods of greater than 20 seconds). These concepts include the following compliant towers for water depths up to 3,000 ft; tension leg platforms (TLPs) for water depths up to 5,000 ft with the potential for application to 7,000 ft following further development effort; floating production systems for water depths up to 7,000 ft; and deep draft floaters for water depths up to 10,000 ft.

14.4.1 Compliant Towers. Compliant towers are three-dimensional (3D) steel truss arrangements, which are slender and have a seabed footprint substantially less than an equivalent steel-jacket structure; see Figs. 14.6 and 14.24.

The guyed tower concept (**Fig. 14.24**, adopted for the Lena platform in the Gulf of Mexico) and the freestanding compliant tower concept (Fig. 14.6, adopted for the Petronius platform in the Gulf of Mexico) are sized on the principle of "compliance" to wave attack. Vertical and lateral stability is assured through the use of either guys (Fig. 14.24) or flotation devices (Fig. 14.6). The dynamic response of a compliant tower is crucial, and dynamic analyses form part of the design process for this structure. Another design and engineering focus relates to the foundation pile design. As the structure deflects, significant tension-compression coupling forces are introduced in the piles. Locating the piles near the center of the tower, limiting the maximum tower deflections, and selecting piles of sufficient length to absorb the imposed loads can limit the resulting stresses in the piles. Compliant towers can be constructed using techniques that have evolved for steel-jacket structures. A two-piece construction and installation can be adopted, as was used for the Petronius platform installation.

14.4.2 Tension Leg Platforms. **Fig. 14.25** illustrates the TLP concept. The topsides equipment and facilities are not dissimilar to those usually deployed for fixed steel structures. The platform comprises a deck structure and a buoyant hull that is composed of a series of vertical

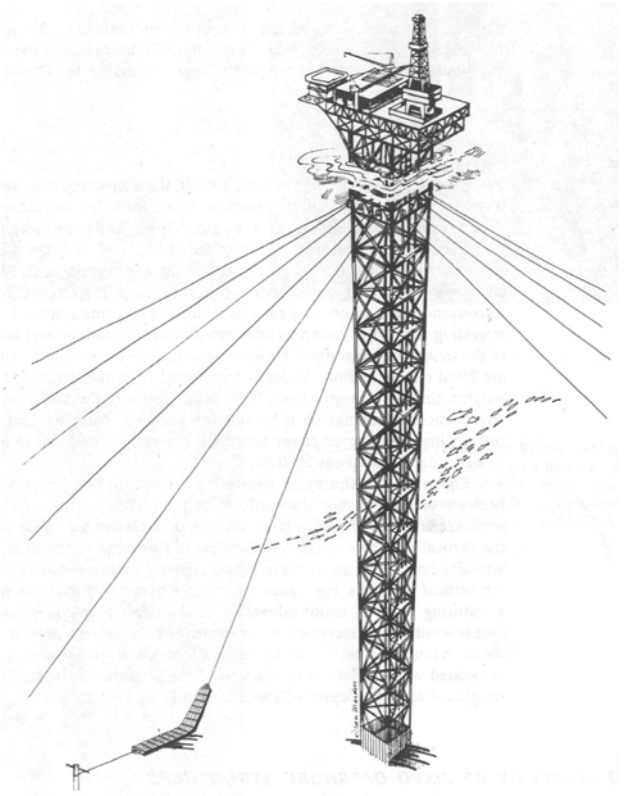


Fig. 14.24—Guyed tower concept (Photographic Archives, ExxonMobil).

cylindrical columns, horizontal submerged pontoons, and, in some instances, tubular member bracing. The platform is tethered to the seabed by a number of tendons that are kept in tension at all times by the excess buoyancy in the hull. These tendons suppress the heave motions, and the tension ensures that the platform remains virtually horizontal even at lateral excursions of up to 10% of the water depth. Lateral excursions are controlled because the tendons develop a restoring force as lateral movements take place.

The tendons are secured in a foundation template piled into the seabed. The foundation system is subjected to cyclic loads superimposed on a high-tension load. Therefore, care is required in the analysis and design of the foundation system. Nevertheless, while the foundation system may appear elaborate, the advantages are considerable. The restriction on vertical movement permits the use of fixed-steel-platform-type wellhead equipment and rigid steel riser conductor assemblies.

The production risers may suffer from vortex-induced vibrations (VIV) caused by the current, especially in high-current regions such as the Gulf of Mexico and the West of Shetlands. Riser spacing design is therefore of prime importance; see **Fig. 14.26**. If the design principle were for no contact between the risers, a cost penalty in ultra-deep water would be expected. If contact between risers is the accepted design principle, then it is important during design to predict their dynamic behavior, predict the impact energy during contact, and define acceptance criteria.

The TLP is not dissimilar to a semisubmersible, and construction techniques developed for semisubmersibles can be deployed for TLPs. However, the buoyancy requirements for a TLP may be two to five times that of a semisubmersible, and, therefore, construction facilities used

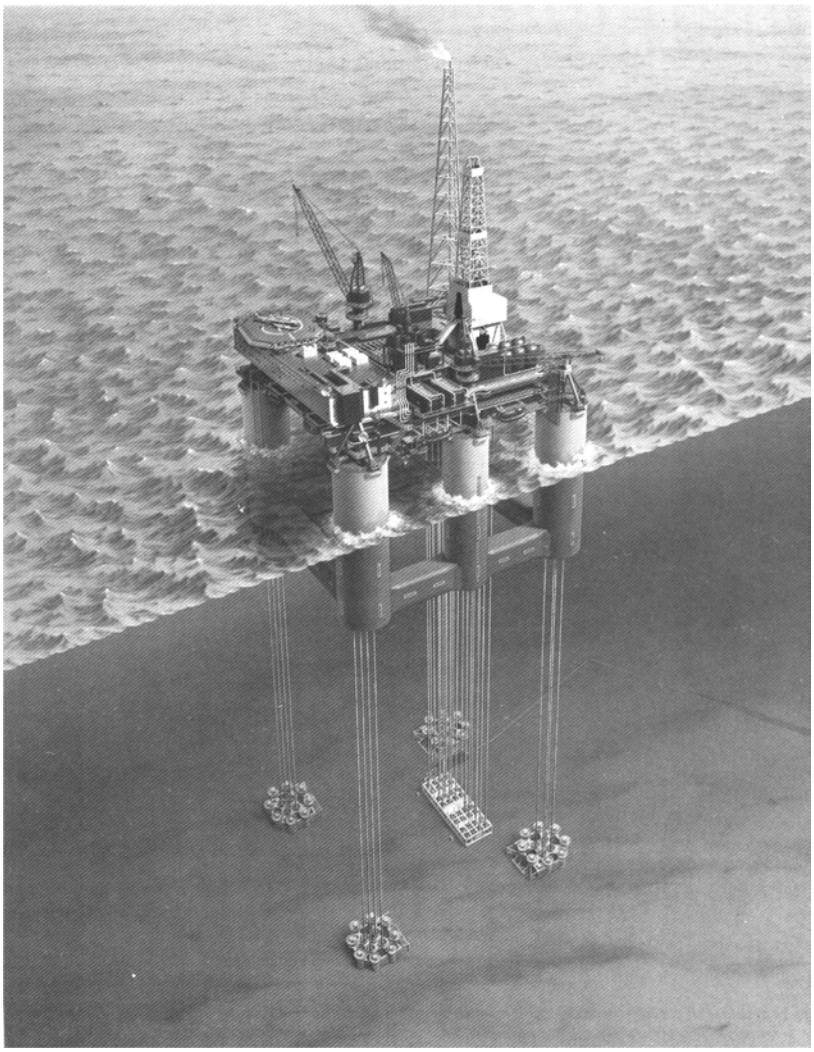


Fig. 14.25—TLP concept (Photographic Services, Shell Intl., London).

for semisubmersibles may be too small for TLP fabrication. A TLP deck may be fabricated separately from the hull and mated in a manner similar to that adopted for concrete gravity base platforms. The benefit here is reduced construction time. Alternatively, a single-piece construction can be adopted for the deck and hull with equipment and facilities placed on the completed platform. In this instance, intermediate structural bracing can be accommodated because barge clearance is not required.

A number of options exist for the placement of the template(s) and piling. A single template for the foundation and well system can be adopted, or separate templates can be specified. Tendons may be attached to the template or directly to the piles. The advantages and disadvantages for each option are considered at the design stage from both engineering (redundancy, robustness, etc.) and economic standpoints.

14.4.3 Deep-Draft Floaters. A deep-draft floater is a floating system that is provided with a deep-draft hull designed to minimize heave motions. An example of a deep-draft facility de-

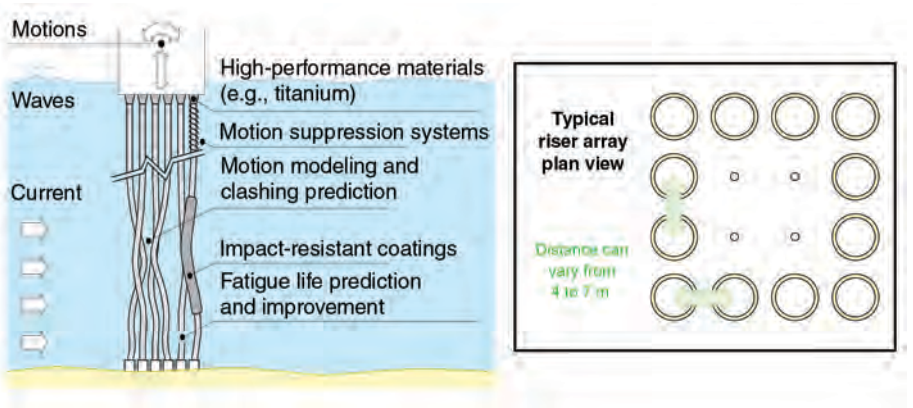


Fig. 14.26—Riser spacing and contact considerations (courtesy of BP).



Fig. 14.27—A typical truss spar (courtesy of BP).

signed by CSO Aker is shown in **Fig. 14.27**. This particular concept is more commonly known as a truss spar. Other forms of deep-draft floaters include deep-draft semisubmersibles and hull arrangements other than the arrangement shown in Fig. 14.27.

The concept shown in Fig. 14.27 has successfully been deployed for the Horn Mountain field and has been chosen for the Holstein field, both in the Gulf of Mexico. The upper section of the hull is a conventional cylindrical shell and provides the required buoyancy for the platform. A center well within the cylinder protects the production risers and their tensioning

system. The lower section is a braced truss system with heave plates to achieve the desired heave motion characteristics. In common with all spars, the vertical risers support the dry trees at the topsides, thereby providing continuous access to the wells for re-entry. A keel section at the base of the truss is specified for buoyancy during towing and contains fixed ballast.

Mooring is achieved using a taut system of mooring lines composed of chain and wire or polyester. The lines are moored to the seabed using a vertically loaded anchor. The mooring system is designed to accommodate a platform offset of several hundred feet for drilling or workover purposes.

Typical fixed platform design practices are applicable for the topside configurations with the exception that, because the spar is a floating system, lateral accelerations are higher. A payload of up to 50,000 tons can be accommodated, including drilling or workover rig and full production equipment.

Deep-draft floaters, either of the cylindrical arrangement (such as spars) or of the semisubmersible configuration, are likely to find increasing favor in deepwater applications in the future. The systems can be designed for storage capability as well. The choice between these two and other floating production systems depends on the fundamental decision on the need for dry-trees or wet-trees, as discussed next.

14.4.4 Wet vs. Dry Trees. All the concepts discussed and described allow for the wellheads and Christmas tree valve systems to be above the waterline (i.e., in the dry). Dry trees allow direct and continuous access to the wells for maintenance and re-entry. The alternative is "wet trees," so-called because the wellheads and Christmas trees are placed on the seabed. These are sometimes referred to as subsea completions.

The size and type of reservoir and the anticipated extent and cost of well intervention often dictate the selection of dry vs. wet trees. The type of field development concept utilized, in particular the choice between wet and dry trees, significantly affects all aspects of the development, from the appraisal strategy and development concept to reservoir and field management.

A number of offshore platform concepts exist that meet the dry tree requirement. These include conventional jackets, spars, and TLPs. For wet trees, possible development concepts include all of these plus ship-shaped floating production systems and semisubmersible production systems.

14.4.5 Floating Production Systems. A floating production system (FPS) is effectively a floating rig. It contains all the equipment associated with a fixed platform and is used in conjunction with subsea wellheads to exploit moderate to deepwater fields, particularly where the installation of a fixed platform is neither practical nor cost-effective. For all floating systems, a range of stability criteria is followed to ensure system stability in calm waters with sufficient safety margins to allow for the dynamic conditions of stormy seas. The primary considerations for stability revolve around the location of the center of gravity and the relative location of the center of buoyancy; see **Fig. 14.28**. As the floating structure heels, it gives rise to a restoring moment, which stabilizes the system.

A conventional FPS typically uses either a semisubmersible to accommodate the equipment and utilities or a ship-shaped monohull, the latter often built from converted oil tankers. A spread of mooring lines is used for station keeping during production, and flexible flow lines are adopted, which permit wave-induced vessel motions to be absorbed.

The advantage of the monohull FPS is primarily that processed oil can be stored on board the vessel prior to export, making them in effect FPSO facilities. The main drawback for semisubmersibles is the lack of storage capacity to prevent shutdowns when offloading operations are disrupted.

As water depths increase, the length and, hence, weight of conventional wire and chain mooring systems increase. Floating structures must increase in size to provide the necessary

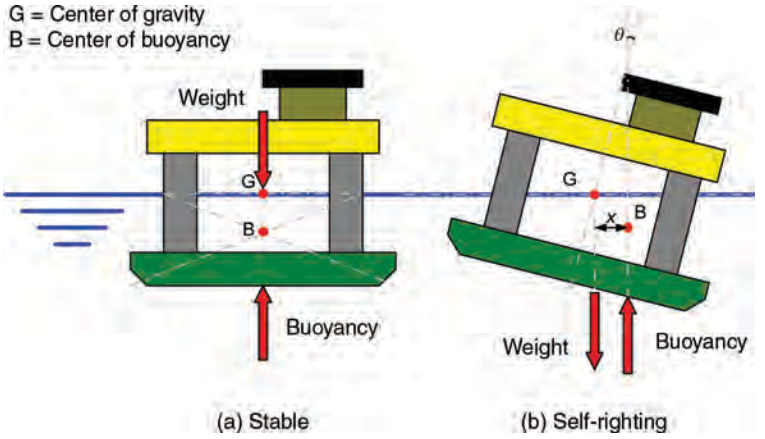


Fig. 14.28—Stability of floating systems (courtesy of MSL Engineering).

buoyancy to carry the extra weight, which adds incremental cost to the development. Further, many of the conventional mooring systems are deployed in the catenary configuration, giving low stiffness, which allows considerable offsets and poor response. This is undesirable for operational reasons and often requires use of flexible riser systems to compensate for the movement.

To overcome the weight problems associated with wire/chain moorings, synthetic materials, such as polyester, are being evaluated and have been applied as a replacement for conventional steel ropes and chain mooring systems. They have less weight and, in the taut configuration, provide lower vessel movement and a reduced footprint on the seabed.

The interaction between risers and moorings is self-evident. One of the functions of the moorings is to guarantee the integrity of the risers, but moorings are subject to practical limits regarding their numbers and strength. Assessments for the risk of mooring failure should therefore reflect this unavoidable interaction between the adopted riser and mooring systems.

Deepwater riser systems have been acknowledged by the industry as representing critical technology for current planned and future field developments. Drilling and production risers can be of the top-tensioned arrangement. Load and fatigue limitations for these risers are a significant challenge. VIV can significantly reduce the fatigue life of both the riser and the wellhead. The matter of riser contact and clashing has been covered earlier in the TLP subsection. It should be recognized that the prediction of response for an array of top-tensioned risers is nontrivial, given the hydrodynamic interaction.

Flexible risers and steel catenary risers (SCR) are other systems available to the engineer. These systems are equally complex in design and in response predictions. Nevertheless, these systems add to the range of options available to develop deepwater fields.

One other noteworthy riser system is shown in **Figs. 14.29a and 14.29b**. This system has been deployed for the Girassol FPSO in West Africa in 4,500 ft of water. Riser towers allow multiple flow lines to be installed in a small area without interference with mooring lines and each other. They can be designed with very low heat loss coefficients to minimize flow assurance problems.

For FPSs, it is perhaps revealing to consider the approach adopted by BP in its currently ongoing field development evaluations for the deepwater Thunder Horse field in the Gulf of Mexico. A unique combination of characteristics is at play in the Thunder Horse field, dictating the facilities for the project. Located in water around 6,000 ft of water depth, the field's reserves are contained within eight adjacent offshore license blocks, making it impossible to reach all reserves from a single drilling center. The reservoir itself lies deep below the seabed—

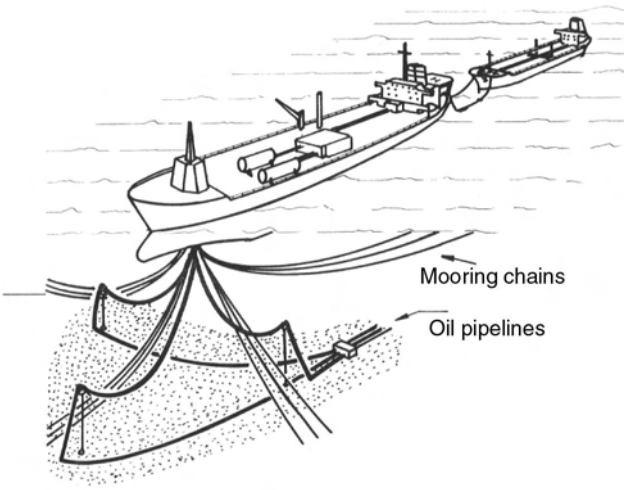


Fig. 14.29a—Schematic of FPSO.



Fig. 14.29b—Terra Nova FPSO (Photographic Archives, Petro-Canada/Terra Nova).

some zones are more than 3.7 miles down; others lie below salt formations, requiring costly and time-consuming wells. Hydrocarbon fluids from the reservoir have extremely high temperatures and pressures, around 15,000 psi and 250°F. These are among the highest yet to be handled in the offshore industry. To maximize production, seawater must be injected into the reservoir from the outset. While this is standard industry practice, it has never before been executed at the injection rates and pressures needed for Thunder Horse. These and other factors have resulted in the selection of a semisubmersible production unit (see Fig. 14.9a), which will serve as a processing, drilling, and quarters platform for the field, supporting up to 40 production and injection wells. All wells, some local to the platform, others as far as 6 miles away, will be completed as subsea wells with wellhead control trees located on the seabed, tied back by flowlines and risers to the platform.

Several proven types of platform were initially considered, among them ship-shaped vessels, semisubmersibles, TLPs, and spars. Ship-shaped production vessels, although used exten-

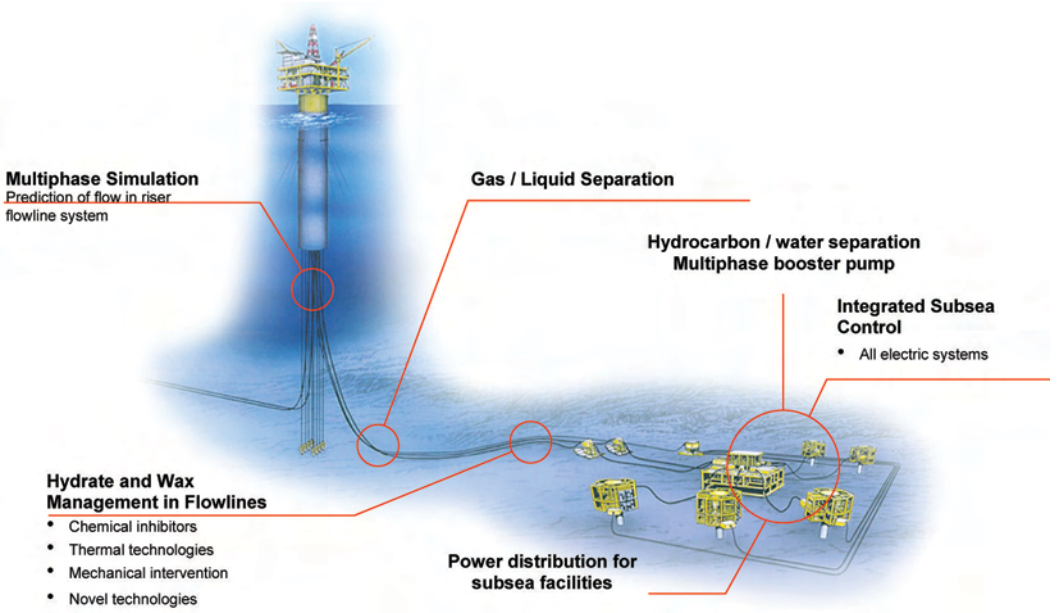


Fig. 14.30—Subsea field development.

sively around the world, were ruled out because of riser load and the technical infeasibility of bringing fluids at high temperatures and pressures onto a weathervaning vessel using the industry's standard solution of a moving swivel. TLPs carry the disadvantage that in water this deep, their rigid steel tendons anchoring the floating hull to the seabed become too heavy and costly. Spar platforms were looked at closely. Spars supporting the weight of the dry-tree steel risers and keeping these in tension becomes a critical factor. The high-pressure/high-temperature conditions on Thunder Horse also demand that the risers be heavy walled, adding to the weight problem. Another hurdle to overcome is at the top of the riser where the well fluids are transferred to the processing deck. On a spar platform, the relative movement between risers and floating platform is pronounced. The influence of this and other factors, notably the very large topsides load and the requirement for multiple well centers to access the entire reservoir, finally led to selection of a semisubmersible, but one with a difference—its scale. The Thunder Horse concept will be the largest production semisubmersible ever built, having a two-level deck measuring about 455 ft long and 360 ft wide, mounted on a four-column hull. The hull and deck, together with drilling facilities and quarters, will weigh more than 50,000 tons. The platform will be held on station by 16 mooring lines made of chain and steel wire rope. Each line will be anchored to the seabed by suction piles, giving the semisubmersible the ability to survive the Gulf of Mexico's hurricanes.

14.5 Subsea Systems

Many hundreds of subsea wells are currently in service worldwide. Subsea characteristics include wellhead (see **Fig. 14.30**), and trees are installed on the seabed; well drilling or intervention requires vessels such as jack-up rigs or semisubmersibles; reservoir fluids are generally tied back to a host facility for processing and export; and utilities, control, and chemicals are supplied from the host facility via umbilicals.

Subsea wells may be installed individually, in clusters, or on a template where the reservoir fluids from all the wells are channeled to a manifold that is tied back to a host platform. A simple template arrangement is shown in **Fig. 14.31**.

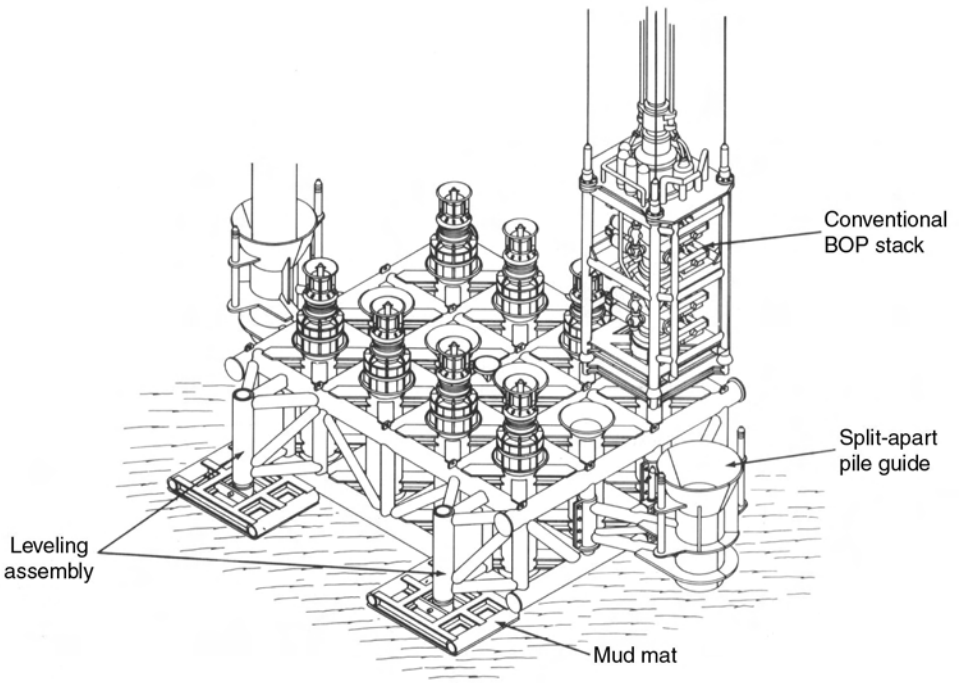


Fig. 14.31—Subsea template.

Often wellheads and wet trees are designed as "diverless" and more recently "guidelineless" because they can be installed, maintained, and repaired either by remote control using equipment that does not need guidelines or tools that are wire guided from a vessel. **Fig. 14.32** shows a single-well diverless subsea production system.

The wellhead sits on a guide base on the seabed and acts as a location device for the Christmas tree. Attachment of the tree to the wellhead and flowline is by remote control. While referred to as new technology, the diverless wellhead has proven to be reliable. It has permitted the development of fields in water depths beyond the saturation diving limits and competes with diver-assist subsea wells in moderate water depths because of potential cost savings.

For multiwell templates, some cost savings can be realized during drilling because the vessel does not have to be relocated for each well. Further, major savings may be possible by transferring the reservoir fluids through one large flowline rather than individual flowlines. Well testing is accomplished by installing a separate flowline with a valve manifold for switching wells. Potential further cost savings may be possible for the control systems and piping for gas lift and water injection. However, one of the major hazards that must be considered at the design stage is dropped objects during drilling and the risks associated with producing from completed wells while the other wells in the template are drilled. If production from completed wells is not possible until all wells have been drilled, the potential cost savings may be negated through cash-flow considerations. One technique that has been adopted for combining some of the advantages of single and multiwell subsea systems is to produce moderately spaced satellite wells to a central manifold unit on the seabed. The manifold permits the reservoir fluids from the wells to be mixed and wells to be tested, and cost savings may be significant if the host facility is located miles away. Conventional welded steel pipe is used for most flowlines. The steel is protected against external corrosion by coatings, anodes, or both. An alternative for steel flowlines is the use of flexible piping that comprises laminations of steel wires and other

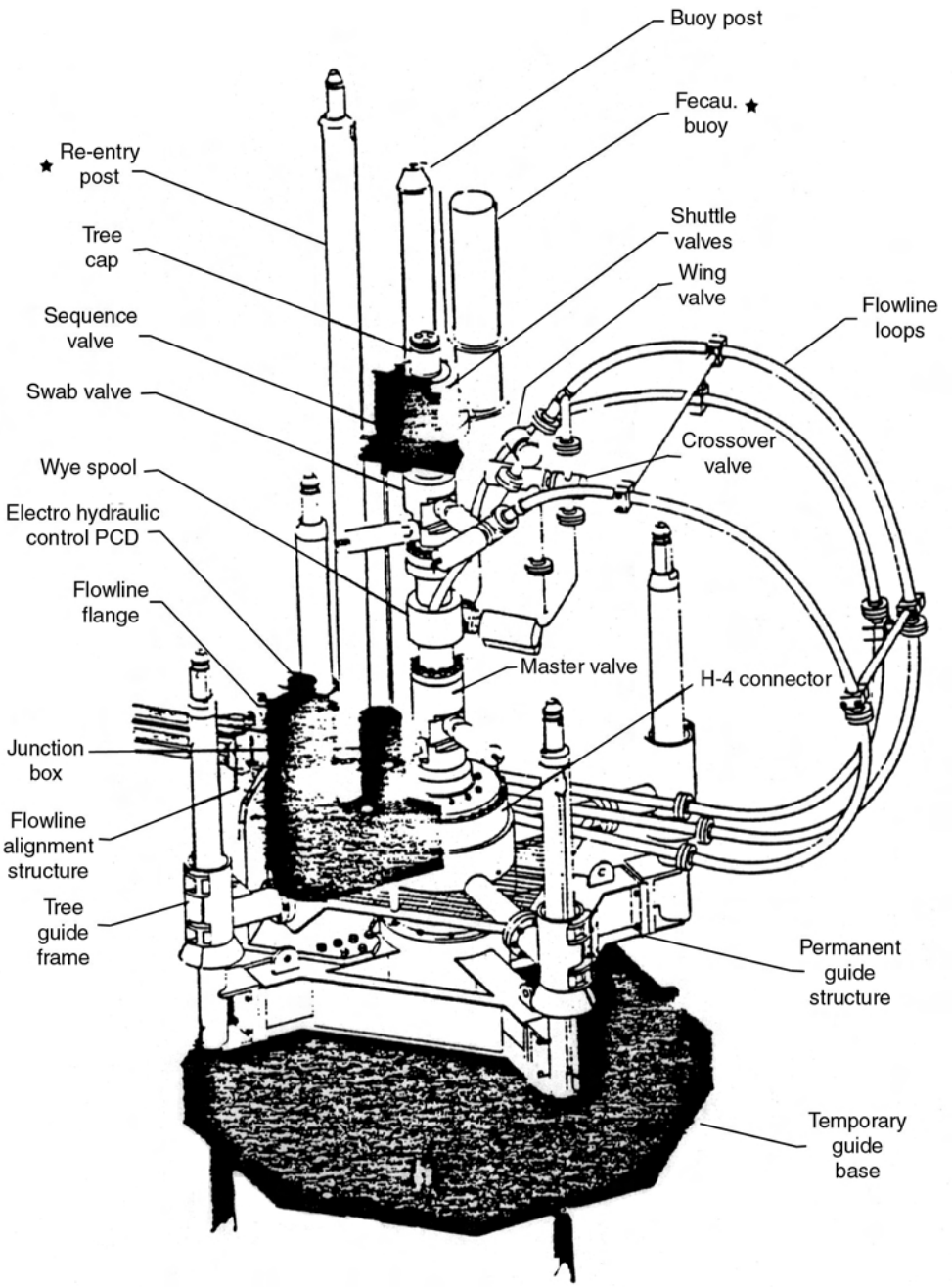


Fig. 14.32—Diverless subsea production system.

materials. Although expensive in comparison with steel pipe, the costs may be offset by savings in installation cost. Flexible pipe, through use of large-diameter reels, can be installed relatively quickly and does not need a separate external coating. For further discussion, see the chapter on Piping and Pipelines in this volume of the *Handbook*.

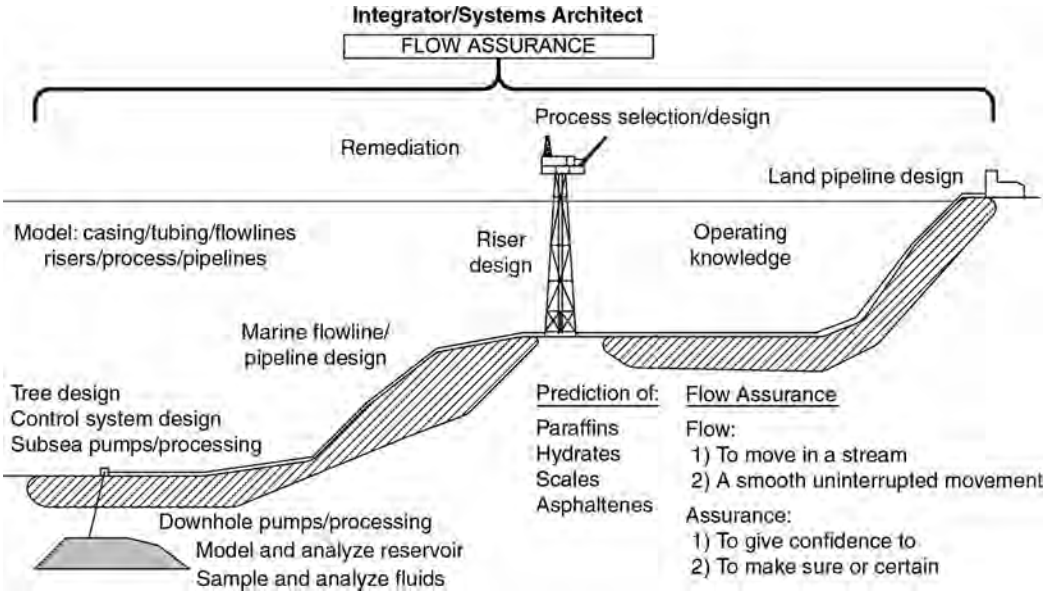


Fig. 14.33—Full scope of flow assurance (courtesy of MSL Engineering).

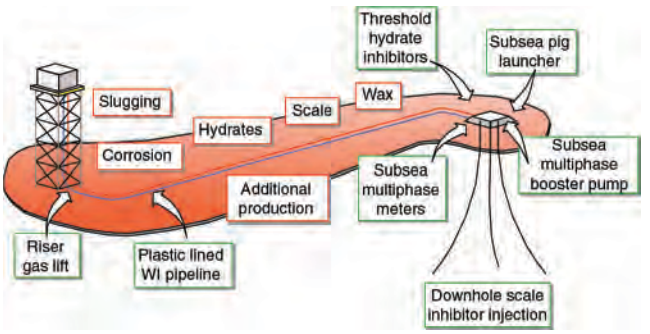


Fig. 14.34—Flow assurance matters for subsea tieback systems (courtesy of BP).

14.6 Flow Assurance

The full scope of flow assurance is shown in **Fig. 14.33**. Flow assurance matters specific to subsea tieback systems are shown in **Fig. 14.34**. Flow assurance, by definition, focuses on the whole engineering and production life cycle from the reservoir through refining, to ensure with high confidence that the reservoir fluids can be moved from the reservoir to the refinery smoothly and without interruption.

Flow assurance is sometimes referred to as "cash assurance" because breakdown in flow assurance anywhere in the entire cycle would be expected to lead to monetary losses. A few specific flow assurance issues are discussed next.

It is necessary for sufficient pressure to be available to transport the hydrocarbons at the required flow rates from the reservoir to the processing unit. Matters that require consideration in this regard include pressure loss in flowlines, separator pressure setpoint, pressure loss in wells, artificial lift method selection, remote multiphase boosting, drag reduction, slugging in horizontal wells, gas lift system stability, and interaction with reservoir performance.

Components and systems should be designed and operated to ensure that flowrate targets are achieved and that flow is continuous. Issues to be taken into account include hydrate formation, wax deposition, asphaltenes, sand and solids transport, corrosion, erosion, scale deposition, interaction of slugging and pipe fittings, interaction of slugging and risers, relief and blowdown, pigging, liquid inventory management, and well shut-in pressure.

For multiphase flowlines, it is necessary for the process to be able to handle the fluid delivery, and consideration should be given to a number of issues including interaction with facilities performance, slugging (steady state), slugging (transient), slug-catcher design, severe slugging prevention, effect of flow rate change, temperature loss prediction, piping layout, remote multiphase metering, gas and dense phase export, oil and condensate export, and separator performance.

The need for well testing and overall production system optimization contributes to flow assurance issues. Significant advances have been made in this field. Flow assurance will continue to remain critical technology as deepwater developments progress and as longer tiebacks from subsea wellhead systems are considered.

14.7 Offshore Production Operations

Offshore production operations can be either very similar to or radically different from land-based installations.

14.7.1 Well Completions. Except for a few innovative installations, wellheads and Christmas trees on platforms are basically the same as for land wells (see **Fig 14.35**). Control valves, safety valves, and piping outlets are configured the same and use the same or similar components. Some of the valves probably will have pneumatic or hydraulic actuators to facilitate remote and rapid closure in an emergency. Also, some Christmas trees may have composite block valves instead of individual valves flanged together.

The major difference, however, between land and platform well completions is the economics incentive on platforms to reduce equipment weight wherever possible and to minimize space requirements. Simply put, lighter, smaller equipment and more compact installations result in less expensive platforms. A good example is the use of composite block valves to reduce Christmas-tree size and weight. Another example is the spacing of wellheads, as close together as drilling operations will permit, with just enough room for safe and efficient operations of the tree valves, control valves, and well-workover equipment. Typically, this means centerline distances of 6 to 10 ft between wellheads.

Where only one drilling rig is on a platform, all the wellheads usually are located in one bay. Larger platforms that are designed to accommodate two drilling rigs may have two well bays (one for each rig) with two or more rows of wells in each bay.

14.7.2 Process Equipment. The primary function of process equipment, whether on a platform or on land, is to stabilize produced fluids and prepare them for shipping or disposal. Well production is separated into components of oil, gas, and water (and sometimes condensate). The separated fluids are measured and then either shipped, injected back into the reservoir, or flared.

Differences between the process equipment (oil and gas separators, free-water knockouts, gas scrubbers, pumps, compressors, etc.) installed on a platform and those installed on land are minor (see **Fig. 14.36**). Where possible, consideration is given to using vessels and machinery that are compact and lightweight (e.g., electric motors are commonly used instead of gas engines for driving pumps and compressors). Vertical clearance between decks may impose height limitations and dictate, for example, the use of horizontal instead of vertical separators.

There is a major difference, however, in the way equipment is packaged. If it is to be installed offshore after placement of the platform jacket and decks, process equipment usually is

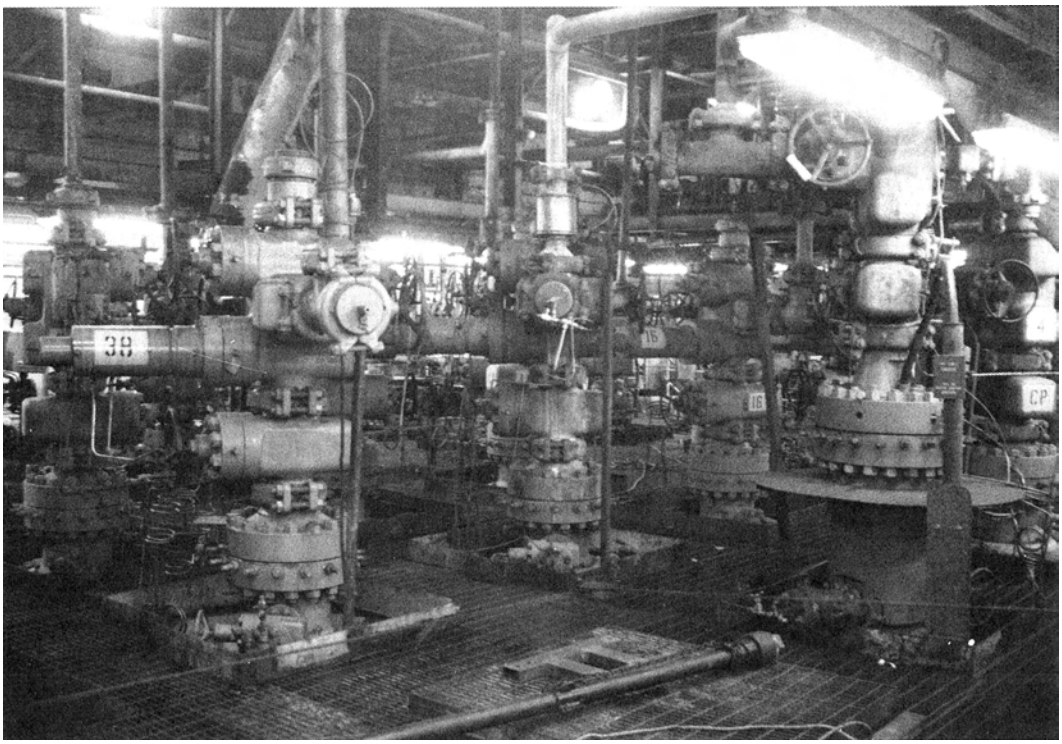


Fig. 14.35—Platform well bay.

built in modules at a land site. The module assemblies then are barged offshore, lifted onto the platform, and hooked up. This significantly reduces expensive offshore installation and hookup time. In any event, the equipment and its piping, wiring, and controls are installed as compactly as possible. The extra engineering and fabrication cost needed to reduce deck area to an absolute minimum are more than offset by savings in platform structure cost.

14.7.3 Well Servicing and Well Workover. On relatively small platforms with no more than 5 to 10 wells, it is common practice in some areas to drill all the wells before any of them are placed on production. The drilling rig is removed after the last well is drilled, and future well workover is performed with a portable workover rig well pulling unit. Downhole work that does not require pulling tubing (e.g., replacing safety valves, gas lift valves, or standing valves) normally is accomplished with a wire-line unit.

On larger platforms with more wells, drilling and production operations generally are carried on concurrently. In this case, the drilling rig performs well workover if it is still on the platform.

14.7.4 Crude-Oil Disposal. In the great majority of cases, crude-oil production is transported from platforms by subsea pipelines. Because most offshore producing areas involve multiple platforms and more than one operating company, the pipelines are generally common carriers.

Depending on pipe diameter, length, need for burial, need for coatings and cathodic protection, water depth, and various construction considerations, an offshore pipeline can be the single most expensive element of an offshore installation, sometimes far exceeding the cost of one or more platforms. In the great majority of cases, however, piping is still the safest, most economical way to transport crude-oil production to a land site.

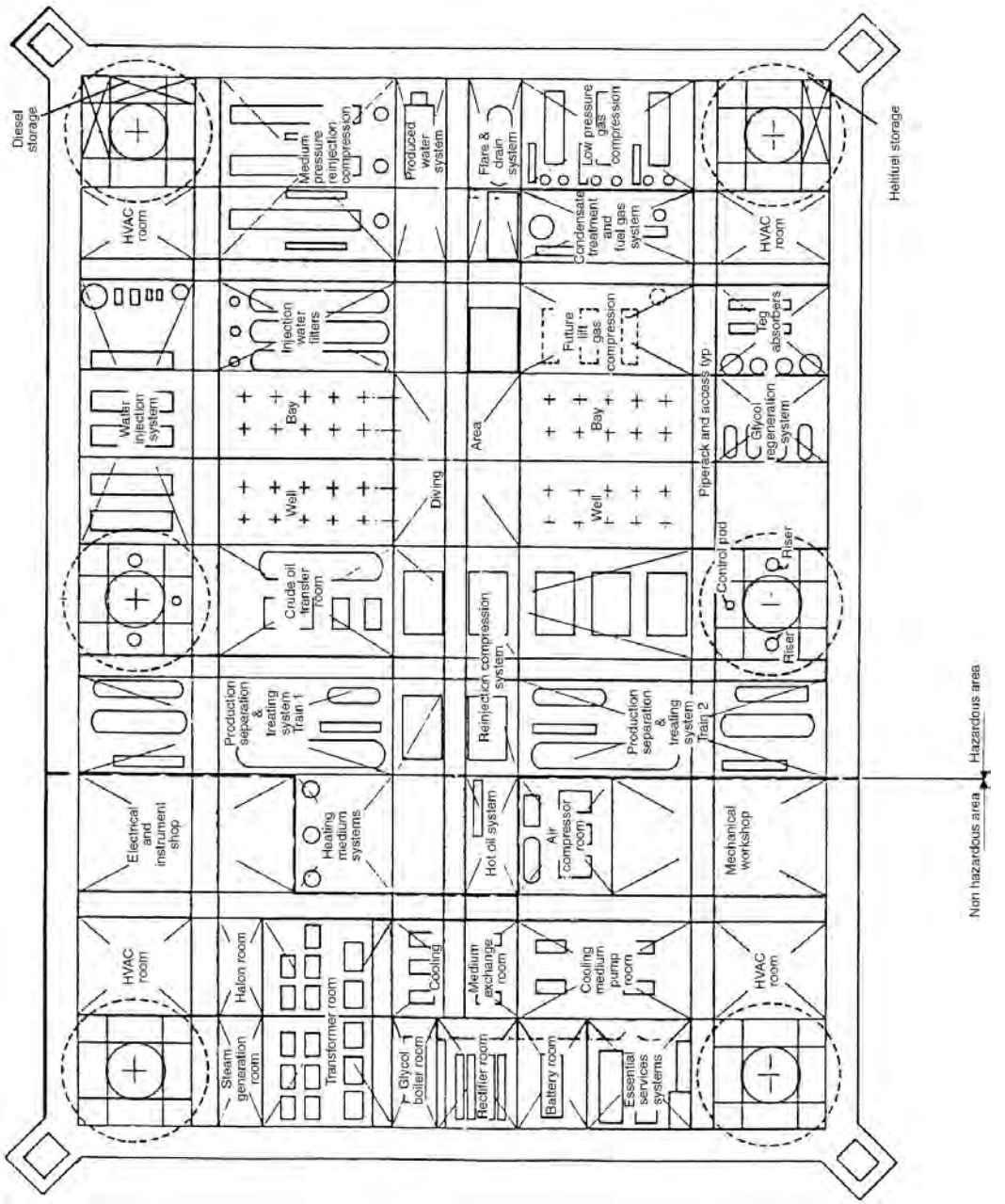


Fig. 14.36—Platform deck layout for process facilities.

Occasionally, an offshore oil field is too remote, production rates are too low, or the field is too short-lived to justify a pipeline economically. The alternative is to transport the oil using tankers. This usually requires some type of loading system installed 1 to 2 miles from the platform, such as a moored buoy or articulated loading tower. A seafloor pipeline connects the loading facility during the transfer of oil.

The two most important drawbacks of tanker-loading operations are sensitivity to weather and the need for separate oil storage. Tanker loading is best suited to mild weather areas to

minimize downtime from storms. Oil storage requirements will depend on total field producing rates and reservoir characteristics (i.e., whether the wells can be shut in for short periods without lost productivity) as well as tanker downtime. This has led to the development of permanently moored storage tankers.

14.7.5 Gas Disposal. Disposal of gas from an offshore production site will depend on a combination of reservoir and economic factors. If well production is primarily oil, the gas may be handled as a byproduct and be disposed of in the most economical way. Piping the gas to a land site for sale and use as a fuel is generally preferred if it can be done economically. Injection back into the producing formation is a common alternative. This helps maintain reservoir pressure and conserves the gas for possible future sale. In some areas, gas flaring is still acceptable, but many countries now forbid it except for the short test periods and for the disposal of small amounts of residual waste gas.

14.7.6 Water Disposal. Produced water is normally cleaned so that it may be either discharged offshore in accordance with governmental regulations or re-injected into the reservoir. In either case, a combination of mechanical and chemical methods may be used to condition the produced water before disposal. Tankage and filtration are used to remove oil and other contaminants from the water. Chemical treatment is common to control bacteria and corrosion in injection wells.

14.8 Arctic

Production operations in the offshore artic regions are within the reach of existing technology. Procedures used onshore and offshore in less hostile regions, however, must be modified to meet the challenges of the harsh climatic conditions in the remote locations.

In the last decade, the major area of industry interest has been the offshore region of Alaska and Canada. The environmental conditions vary significantly in each of these regions. Major factors that affect normal offshore operations are the extremely cold temperatures, fog, gusty winds, short open-water season, permafrost, and the persistence of ice. The specific production system that is selected must be tailored to each unique combination of these factors to ensure safe oilfield development.

14.8.1 Environmental Conditions. Sea ice is the principal environmental factor in all of the offshore artic areas. The most abundant type of sea ice encountered offshore is less than 1 year old. This first-year ice begins to form during fall and grows to a thickness of 4 to 8 ft during the winter. Sheets of ice close to shore become landfast and remain locked in place throughout the winter. Beyond the landfast zone, the ice is kept in constant motion by wind, currents and, in some areas, the influence of the arctic polar pack. This dynamic movement causes shearing impacting between ice features that produce ridges of ice several miles in length. Ice ridges formed in this manner are called pressure ridges. Localized ridging around a grounded ice feature, the shoreline, or a structure is considered a rubble pile. In areas of extremely cold winter temperatures, the ice blocks within a ridge or rubble pile begin to refreeze into a contiguous feature. Depending on the conditions, the refrozen consolidated thickness could become several times larger than the first-year ice thickness.

The other major type of ice is not formed from the seawater but is freshwater ice from the glaciers of northern Canada. In the Arctic Ocean, the glacial fragments are called ice islands. These tabular-shaped features are several thousand feet in diameter and more than 200 ft deep.

Ice usually exerts the predominant forces on arctic offshore structures. Extensive laboratory and field tests have been conducted on small-and large-scale specimens to determine in-situ strength characteristics for design. From the results of these tests, the mechanical properties of ice are predicted. They consider salinity, temperature, crystallographic structure, and loading rate.

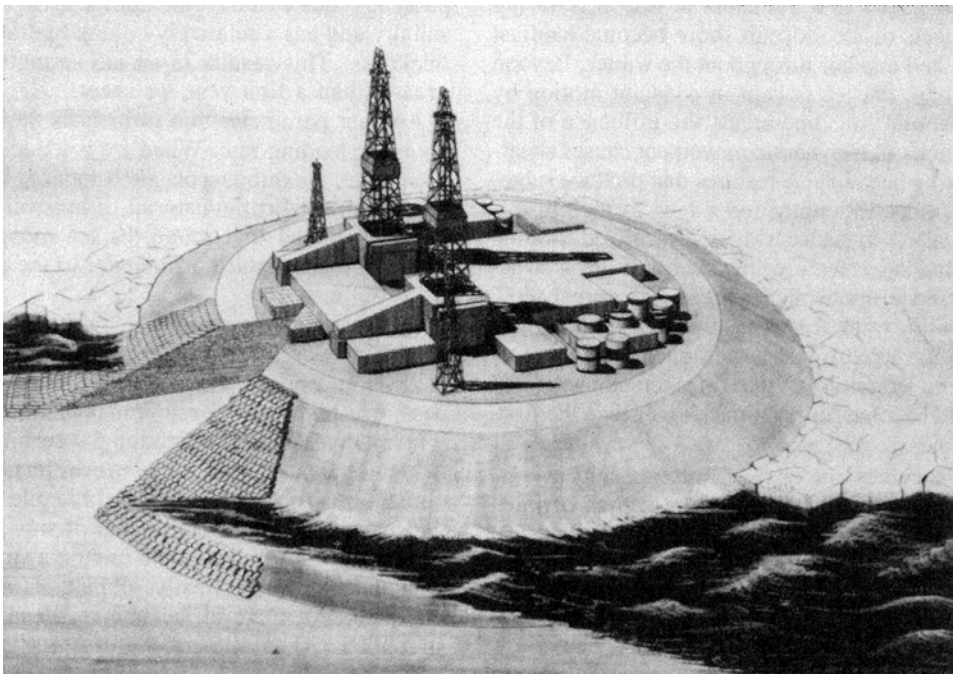


Fig. 14.37a—Protected slope production island (Sandwell Engineering Inc., Vancouver).

When ice is loaded at a very slow strain rate, it exhibits a plastic behavior. Loaded rapidly, it behaves as a brittle material. Empirical equations have been developed that relate the ice movement rate and shape of the structure or indenter to the strain in the ice feature.

The shape of the structure is also a primary factor in producing a crushing, buckling, or flexural failure of the ice feature. For narrow structures relative to the ice thickness, crushing is the predominant failure mode. As the width increases, a combination of crushing and buckling of the ice field around the platform results in the development of a rubble pile. The rubble pile will then shield the structure from direct impact of subsequent ice floes and ensure failure of the ice mantle away from the production facility. Sloping sided structures normally force a flexural ice failure. Because ice flexural strength is 20 to 40% of the crushing strength, an appreciable reduction in ice forces can be achieved when a bending failure is induced.

The wave conditions in the arctic are similar to other offshore areas, and the design of structures against wave loading is well established. Near-shore sea states can be defined by determination of the open-water area along the storm route or fetch and the water depth. In the Arctic Ocean, the presence of the sea ice and the polar pack limits the open-water fetch for storms to generate and consequently reduces the design wave height.

Permafrost is soil at a temperature below 32°F with partially or completely frozen pore water. Drilling and production operations in areas with permafrost have been well defined from experience of the Prudhoe Bay field. In most near shore areas of the artic, permafrost has been found at or near the mudline. These soils are very stiff and can make excavation for pipelines or driving of piling nearly impossible. Permafrost normally is soil bonded by ice and is very susceptible to change in temperature. This can result in significant changes in the soil characteristics and must be considered in the design.

Production Structures. *Artificial Islands.* Artificial islands already are used in many shallow-water areas throughout the world for permanent drilling and producing facilities. The islands that are currently being used for drilling in the arctic consist of either unretained or retained

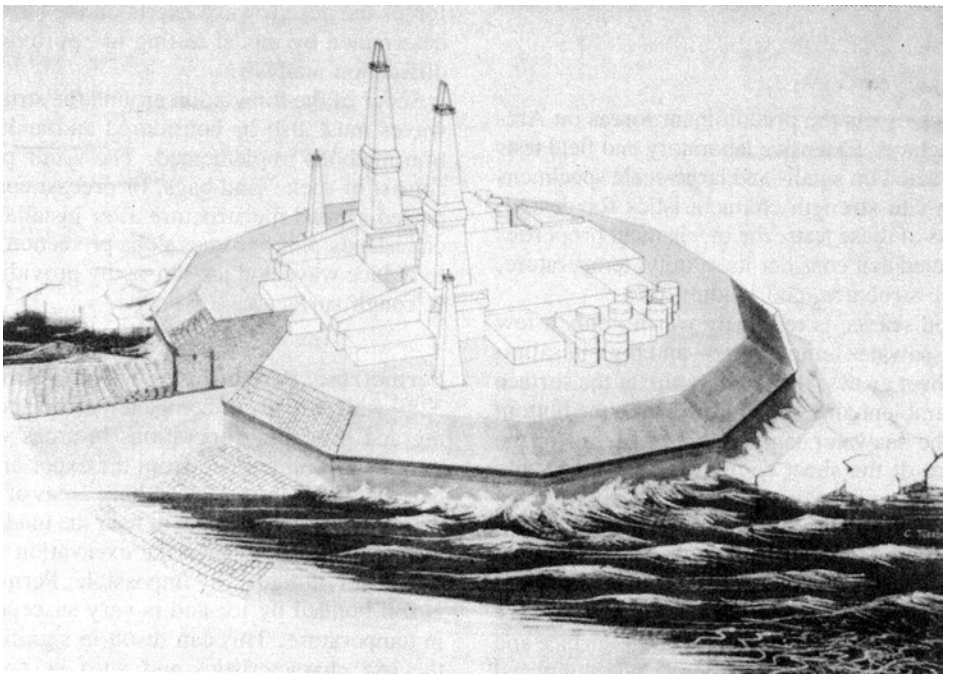


Fig. 14.37b—Caisson-retained production island (Sandwell Engineering Inc., Vancouver).

beach slope systems, as shown in **Figs. 14.37a and 14.37b**. Because of the short summer construction season and, in some areas, the lack of island fill material, the quantity of fill required for the island should be minimized. The minimum island working surface is determined by the area required for drilling and production operations. To reduce the quantity of island fill, the steepest side slopes that the mode of construction and fill material will allow should be provided. The minimum side slopes of unretained islands depend on whether the island is constructed by summer dredging or winter transport of onshore borrow material over the ice to the desired location. The side slopes for summer dredging are approximately 1:20 (vertical to horizontal), and for winter construction are 1:3. On completion, sandbags or concrete mats are placed on the exposed slopes of the island to prevent ice and wave erosion. Sandbags, stiffer soils for embankments, or caisson units are used on retained islands during construction to reduce the required volume of fill. The caisson units typically consist of vertical walled concrete or steel units. The caisson also provides easy access to the island as a dock for resupply and could be used for storage of consumables or oil.

Artificial islands must be designed to withstand the horizontal forces exerted by ice. The potential failure modes of the island consist of slope instability, bearing failure, or horizontal shearing of the island near the waterline. Each of these failure modes can be predicted by classic geotechnical analysis. The only variable in the analysis is the properties of the island fill material. During winter construction, the fill is delivered to the site at the cold ambient temperature and dumped into the sea. Ice forms on the granular material and inhibits consolidations. As the island surface thaws, considerable settlement may take place. To minimize the effects of thaw settlements, thermal analysis of freezing and thawing interface should be conducted to determine the proper graduations of fill material.

The design of production facilities placed on an island is similar to that on land. Equipment foundations must be designed and insulated to reduce the potential for frost heaving, pile jacking, and thaw settlements from seasonal thawing and freezing of the island surfaces and, in

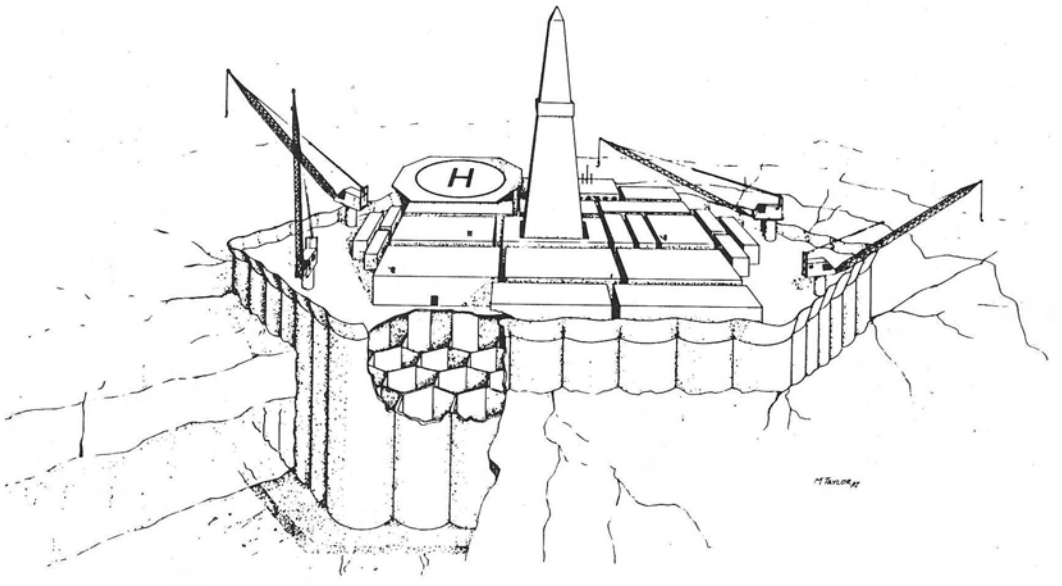


Fig. 14.38—Vertical-sided structure (Brian Watt Assocs., Houston).

some areas, subsea permafrost. To prevent thaw settlement, an artificial refrigeration system for the fill material could be installed. Placement of equipment and accommodation modules should account for predominant wind, ice movement, and wave directions to ensure safe year-round operations.

Gravity Structures. Various types of gravity structures are being proposed for use in the arctic. Many of the conventional gravity structures that are used in the North Sea are being adapted for the deepwater and moderate-ice-concentration areas. In the more hostile areas of the high arctic, vertical- and sloping-sided gravity structures are being proposed. These structures provide the large deck load and space requirements, protection of the wells within tower shafts, and storage of oil. Because of the extreme winter ice conditions in many areas, the production facilities will have to operate nine months without major resupply.

The vertical-sided structures (**Fig. 14.38**) are proposed for the shallow, near-shore areas in the arctic. These structures typically are rectangular or hexagonal and are capable of being installed directly on the seabed or subsea berm. Production equipment can be placed directly on the working surface of the top slab or integrated into the hull of the structure. Wells are drilled and produced directly from the deck of the structure. Because of the large width of this concept, the structural integrity of the system is not sensitive to local discontinuities in the seabed from ice gouges or settlements in the foundation from local degradation of permafrost.

Conical, sloping-sided structures (**Fig. 14.39**) are being proposed for the deeper-water, dynamic-ice-movement areas. This geometry induces flexural failure of the ice features and is relatively transparent to pack-ice movements. The deck is fully outfitted with processing equipment before it is mated with the structure. Wells are confined to a central moon-pool area in the cylindrical throat. Consumables and oil can be stored in the base.

Piled Structures. Piled steel structures have been developed primarily for the Bering Sea area of offshore Alaska. These structures are similar to conventional template or jacket concepts but must be modified to resist annual sheet-ice loading. A typical geometry is shown in **Fig. 14.40**. The platform concept consists of four or eight main pile legs with intermediate bracing of the legs omitted in the ice-loading zone near the waterline. Well conductors and oil-

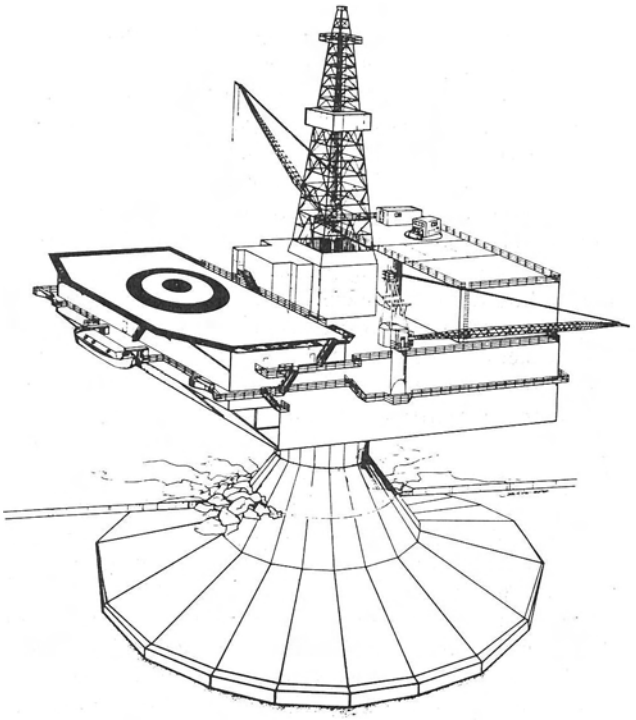


Fig. 14.39—Arctic mobile drilling structure—sloping-sided structure.

transport lines are positioned within the legs of the platform for protection from ice loading. This requires close spacing of the wells and, in some cases, completion of the wells at different levels of the deck. Diver access tubes may also be located in the legs to facilitate the repair and inspection of subsea components of the platform during complete ice coverage.

In most other arctic areas, pile structures are not practical. Subsea permafrost makes pile installation nearly impossible. The short construction season also does not accommodate the installation, pile driving, and placement of the topsides modules in one season. Also, the hookup and commissioning of the production equipment modules would be very expensive in these remote areas.

14.9 Future Technology Requirements

In the next decade, it is expected that the industry will increasingly focus on deepwater and ultradeepwater developments, with water depths up to 10,000 ft and beyond. As water depth increases, many technical challenges emerge, the solutions for which will drive the decision-making process for sanctioning new developments. Fig. 14.38 describes some of the deepwater facilities and subsea technology issues.

A number of technology development targets are being, and will continue to be, pursued. Some of these targets are listed next.

- Development of project-ready subsea systems and floating production platform concepts with storage capability for water depths up to 10,000 ft.
- Mooring system concepts and options, including polyester and composite moorings.
- Minimum-facility, dry-tree platform concepts for deepwater marginal fields.
- Steel catenary riser capabilities, including large-diameter risers.

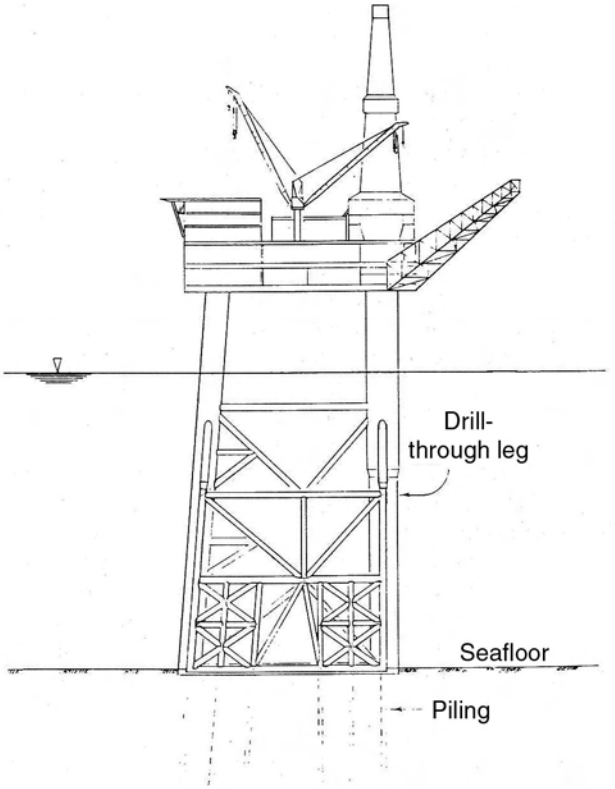


Fig. 14.40—Piled structure.

• Advances in large-diameter top-tensioned dry-tree riser arrays, including designs that permit riser contact and clashing.
• Long-term integrity assurance for intact and damaged flexible risers.
• Novel riser systems and arrays, including use of hybrid and composite risers.
• Long-distance tiebacks for subsea systems.
• Seabed-processing technology.
• Topsides reliability and optimization.
• Float-over of complete topsides for deepwater concepts, to avoid heavy offshore lift and offshore hookup and commissioning.
• Metocean data capture and assessment for deepwater sites.
• Development of self-installing minimum facility jacket structures.
• Development of self-installing deepwater development concepts.
• Flow assurance at ultradeepwater depths.

Much has changed in the industry since the first steel-jacket structure was placed offshore in 1947. The industry today is truly international, quality-conscious, and highly professional. Offshore technology challenges have been met over the past decades; much in the same manner will the challenges be met in future years with new innovations and breakthroughs.

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SI Metric Conversion Factors

ft	×	3.048*	E – 01	= m
°F		(°F–32)/1.8		= °C
mile	×	1.609 344*	E +00	= km
psi	×	6.894 757	E +00	= kPa
ton	×	9.071 847	E – 01	= Mg

*Conversion factor is exact.

Chapter 15
Project Management of Surface Facilities

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15.1 Introduction

Project management is quite different from engineering. An engineer is normally responsible only for his or her own work product and generally deals with the reactions of inanimate substances that follow the laws of physics. A project manager is required to be responsible for the quantity, quality, and timeliness of work products that generally do not follow any physical laws.

To succeed as a project manager, the most important thing is to ensure good communication within the project team. Communication can be accomplished in many forms (verbal, written, formal, and informal), but one size does not fit all, and the project manager is responsible for communications concerning the project and its execution. The communicator, not the listener, is responsible for ensuring that the message has been received and understood.

It is also important to understand that the final cost of a project is affected more by its design than by its execution. The decisions made in developing a concept have a much greater impact on cost than those made later on, as indicated in **Fig. 15.1**.

For our purposes, a project is defined as the group of tasks necessary to reach a given goal in the required timeframe. The project manager is the person responsible for getting those tasks accomplished and achieving that goal. The focus of this chapter is on project management of surface facilities; many of the details of this section are aimed at that type of facility. However, the concepts of this section may be used on any type of project.

15.2 Definitions

Before we discuss how to do a project, we will define some of the basic terms used in that discussion.

• Lease agreement—The agreement that defines the relationship (royalties, damages, rental, etc.) between the minerals owner(s) and the operating company.

• Joint operating agreement (JOA)—The agreement that defines the relationship (expenditure approval, audit rights, operator rights, etc.) between the companies of a group that have joined together to share the monetary risk and rewards of developing a property.

• Project formats—The various methods of contracting out parts of a project. The two basic project formats shown in **Table 15.1** are the following:

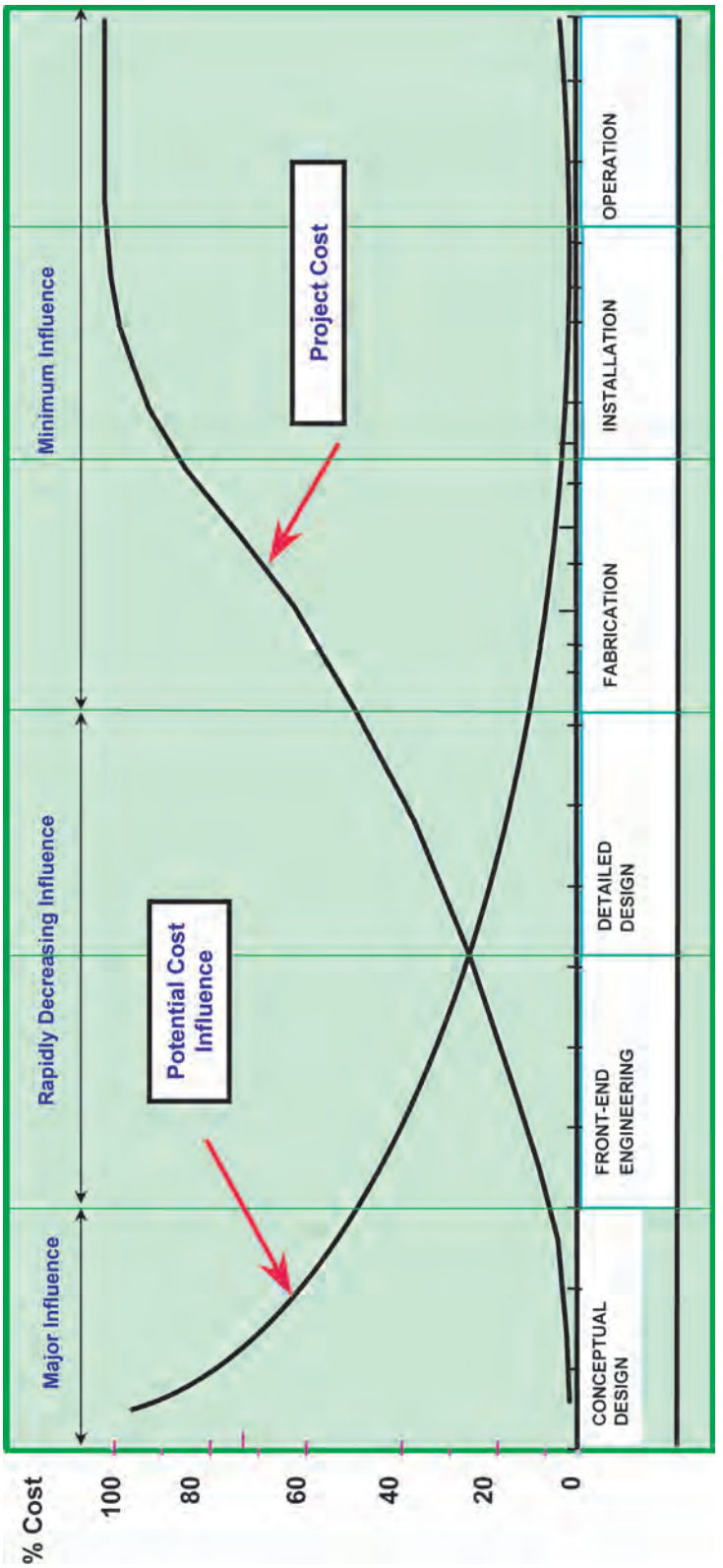


Fig. 15.1—Ability to influence project costs vs. project life cycle.

TABLE 15.1—PROJECT FORMATS

Engineer Procure Construct (EPC) (Contractor Prime)

- The operating company or an engineering company performs front-end engineering design (FEED), which is used to bid and award an EPC contract. FEED includes conceptual studies and definition engineering.
- Lump-sum bid EPC: detail engineering, procurement, and construction with one contractor.
- Contractor controls project work, with operating company monitoring quality and adherence to operating company specifications and standards.
- Sometimes operating company purchases long-delivery or very expensive items before EPC award.

Engineer, Procure, Construction Management (EPCM) (Owner Prime)

- Engineering company performs design—conceptual, project definition, design engineering, detailed engineering—under supervision of operating company.
- Engineering company coordinates and handles procurement services for operating company and develops bid packages, receives and analyzes bids, and makes recommendations.
- Operating company issues POs for bids.
- Engineering company manages procurement, inspection, expediting, shipping, and field construction and verifies invoices under supervision of operating company.
- Operating company processes and pays invoices.

• Engineer Procure Construct (EPC)—One contractor is given the responsibility and control to perform the entire project, usually for a fixed price. This method is also called "turnkey," and the responsible contractor is known as the "prime contractor."

• Engineer, Procure, and Construction-Management (EPCM)—The operating company retains project responsibility and controls the project by direct management of several smaller contracts to perform the project work. This method is also called "owner prime," and the operating company is the project's "prime contractor."

• General Services Contract (GSC)—A contract governing the relationship between the operator and a contractor that defines the basic framework (insurance requirements, invoicing instructions, rates, markups for contractor-supplied materials, payment terms, etc.) for future contracting of work between the companies. The required work is then directly requested with a form (callout form) defined in the GSC without the necessity of further, time-consuming, legal review. The GSC is normally in force for a fixed period of time (several years) and will ordinarily be used for many different callouts on many projects. The GSC is normally used to contract professional services, labor, and construction support equipment, usually on a rates basis.

• Purchase Order (PO)—A contract governing the relationship between the operator and a supplier for the purchase of an item rather than services. The terms and conditions (Ts&Cs) section of the PO defines the basic legal framework (insurance requirements, invoicing instruction, rates, payment terms, etc.) between the companies. This relationship is usually less stringent than the GSC in that most of the work to produce the purchased item is usually on the premises of the contractor, not the company, as can happen in a GSC arrangement.

• Project Specifications—Industry and/or company standards describing the quality levels, tolerances, and inspection levels necessary to obtain acceptable process, environmental, and safety risk levels in the completed project. Example project specifications and construction practices are shown in **Table 15.2**.

• Process Flow Diagrams (PFDs)—Schematic drawings that define the process and serve as a baseline for comparison with alternate processes. The drawings normally show all major equipment items—main piping with flow arrows, process control scheme, flow rate, operating conditions (pressure and temperature), fluid properties, etc.—for all major lines. Equipment sizing is optional but helpful. **Fig. 15.2** shows the primary elements of an example PFD. **Table 15.3** lists the items that are normally specified.

• Process and Instrumentation Diagram (P&IDs)—Schematic drawings that show and identify each equipment item—pipe, valve, instrument, etc.—in the project process and utility systems. These drawings are sometimes referred to as mechanical flow diagrams (MFDs). They form the basis for the detailed engineering drawings and are used in the procurement process to identify each instrument, valve, and specialty item that must be purchased. P&IDs are also used for operational and safety analysis, maintenance planning, and training of the facility operators. **Fig. 15.3** shows the primary elements of an example P&ID. **Table 15.4** describes in more detail rules for developing a P&ID.

• Facility layout—A scaled plan (view from above) that shows the relative locations and sizes of all major process equipment and civil items. **Fig. 15.4** is an example onshore facility layout.

• Detailed engineering—The conversion of the conceptual and schematic documents to drawings suitable for field construction by the contractor.

• Equipment and task list—A listing of all the items that must be purchased and tasks that must be undertaken to complete the project. The level of detail of this list depends on the scope of the project. The equipment and task list becomes the basis for cost estimating and project cost control, as well as forming a framework to develop a project schedule. **Table 15.5** is an example equipment and task list for a simple onshore facility. On more complex projects, it is often beneficial to break down the engineering and project management tasks, costs, and schedules in much more detail.

• Project schedule—A pictorial presentation of the chronological order of the items shown in the equipment and task list showing each item's time duration and the mutual dependency of the items. **Fig. 15.5** shows an example project schedule for a simple project. The level of detail depends on the complexity of the project. Most large facilities projects require a computer-based scheduling system to properly control and monitor the progress on the project. **Figs. 15.6 and 15.7** show portions of a more complex project schedule.

• Procurement and contracting plan—A matrix of the planned acquisition method (firm bid, rates bid, direct award, etc.) and contracting technique (PO, GSC, firm price contract, etc.) for each item or task shown on the equipment and task list. The matrix should also show a simple procurement scope for each item describing owner-furnished items and planned contractor supply. **Table 15.6** shows an example procurement and contracting plan.

• Cost estimate—An estimate of the project costs. The estimate is usually a matrix roll-up of the individual cost estimates of the items shown on the procurement and contracting plan. **Table 15.7** shows an example cost estimate. Developing equipment and tasks lists, project schedules, procurement and contracting plans, and cost estimates for a specific project is an iterative and integrated effort. For example, although a first iteration is normally done in the order described above, resource-loading considerations or market conditions that become evident in the procurement and contracting plan may cause task and schedule changes to meet the project's overall directives.

TABLE 15.2—EXAMPLES OF TECHNICAL SPECIFICATIONS AND CONSTRUCTION PRACTICES

Technical Specifications
- Air-cooled heat exchangers
- Concrete
- Design and construction of buildings
- Electrical system design
- Engine- or gas-turbine-driven centrifugal pump package
- Gas measurement packages
- Indirect fired heater design
- Instruments and controls
- Insulation
- Lease automatic custody transfer units
- Packaged air compressors
- Packaged gas compressors
- Packaged glycol dehydration equipment
- Packaged vapor recovery compressors
- Pipe, valves, and fittings
- Shell-and-tube and double-pipe exchangers
- Structural steel design

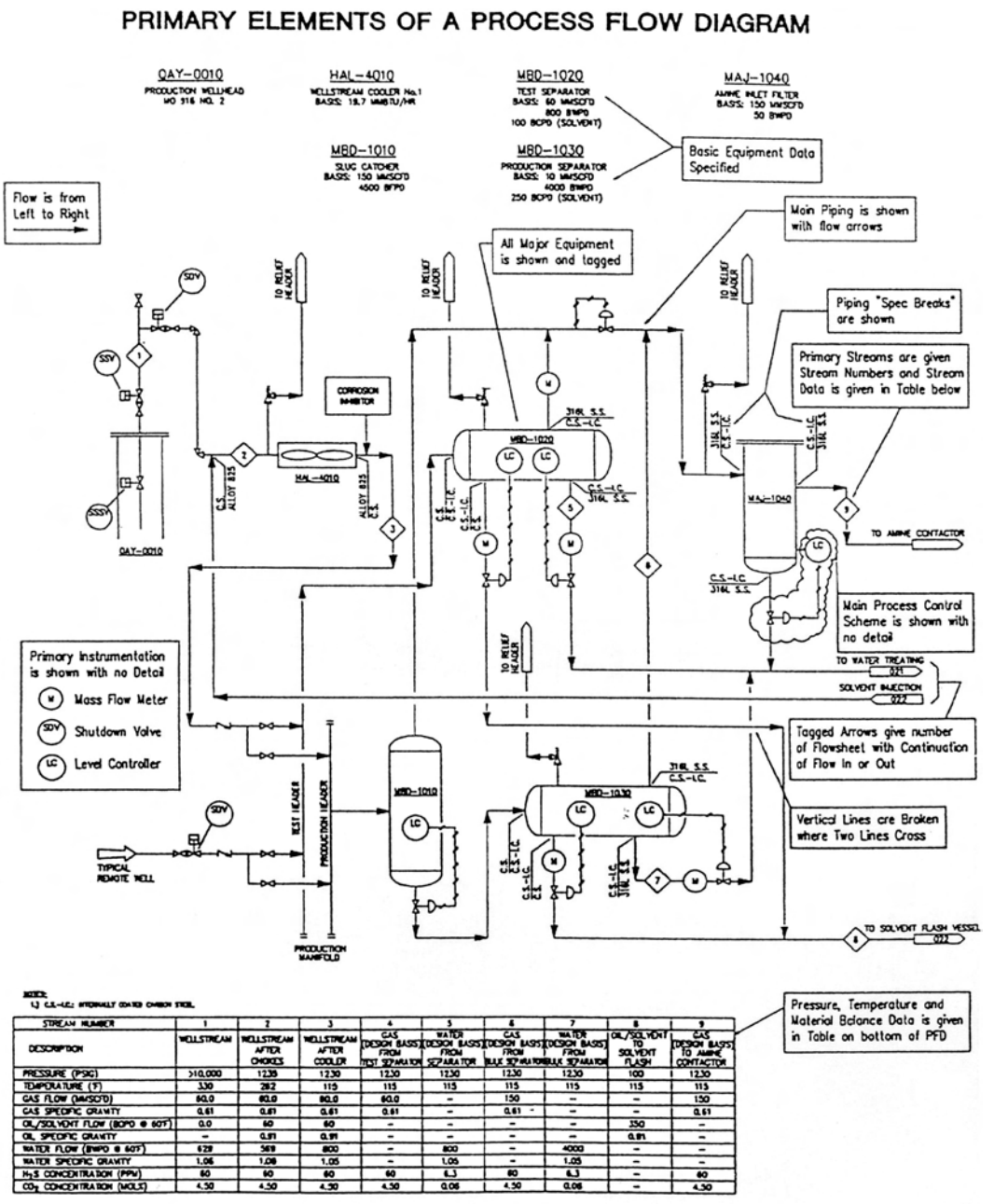
Construction Practices
- Above-ground painting
- Below-ground painting
- Cathodic protection for pipelines
- Chain-link fence standards
- Concrete-weight coating for pipeline
- Concrete work practices
- Earthwork
- External coating of field-joints damage repair
- Glass-reinforced cold-cured plastic internal tank coatings
- Internal coating of vessels, tanks, and pipe in brine service
- Marine pipe coating
- Painting, general procedures
- Pipeline construction practices
- Structural steel fabrication and erection practices
- Thin-film epoxy pipe coating

• Authorization for expenditure—Summarizes the project scope, estimated cost, and schedule to obtain formal management and partner approval.

15.3 Project Execution

15.3.1 Project Initiation. Immediately after notification of your appointment as project manager, you should quickly determine whether your company has any previous experience in this type of project. If so, you should review the project files and determine whether that effort was considered a success or failure and the reasons for that assessment. Remember, those who ignore history are bound to repeat it.

You should also copy and review the lease and JOA that affect the project. The lease agreement defines your relationship with the leaseholder; the JOA defines your relationships with other working-interest owners for whom you are the operator. Both documents may have sections that are different from your company's normal operational procedures and may affect the project accounting, procurement, facility, and pipeline options. It is important that you understand these documents and any reference in them that would affect the execution or final configuration of your project. For our purpose, we will refer to other working-interest owners



STREAM NUMBER	1	2	3	4	5	6	7	8	9
DESCRIPTION	WELLSTREAM	WELLSTREAM AFTER CHOKES	WELLSTREAM AFTER COOLER	GAS [DESIGN BASIS] FROM TEST SEPARATOR	WATER [DESIGN BASIS] FROM SEPARATOR	GAS [DESIGN BASIS] FROM BULK SEPARATOR	WATER [DESIGN BASIS] FROM BULK SEPARATOR	OIL/SOLVENT TO SOLVENT FLASH	GAS [DESIGN BASIS] TO AMINE CONTACTOR
PRESSURE (PSIG)	>10,000	1235	1230	1230	1230	1230	1230	100	1230
TEMPERATURE (F)	330	282	115	115	115	115	115	115	115
GAS FLOW (MMSCFD)	80.0	80.0	80.0	80.0	–	150	–	–	150
GAS SPECIFIC GRAVITY	0.61	0.61	0.61	0.61	–	0.61	–	–	0.61
OIL/SOLVENT FLOW (BOPD @ 60°F)	0.0	60	60	–	–	–	–	350	–
OIL SPECIFIC GRAVITY	–	0.81	0.81	–	–	–	–	0.81	–
WATER FLOW (BWPD @ 60°F)	629	569	800	–	800	–	4000	–	–
WATER SPECIFIC GRAVITY	1.06	1.08	1.05	–	1.05	–	1.05	–	–
H_2S CONCENTRATION (PPM)	80	80	80	80	6.3	80	6.3	–	80
CO_2 CONCENTRATION (MOLE)	4.50	4.50	4.30	4.50	0.06	4.50	0.06	–	4.50

Fig. 15.2—Primary elements of a process flow diagram.

as "partners," although in the United States and other jurisdictions, there may be a legal distinction between a "partner" and "working-interest owner."

The first two things to do before you actually begin the project execution are to confirm the project scope, including schedule, and to establish the contracting strategy you will follow to accomplish the task assigned. Confusion on either of these points will cause many problems

TABLE 15.3—ITEMS NORMALLY SPECIFIED ON A PFD

Purpose:

- Defines the process and aids in selecting alternatives processes.
- Provides basis for sizing major equipment items.

Items shown:

- All major equipment in process.
- Main piping with flow arrows.
- Process control scheme.
- Flow rate, operating pressure, temperature, fluid specific gravities, etc., for every major line.
- Size of major equipment (optional).

Equipment data usually specified on flowsheet:

- Pressure vessels and atmospheric tanks.
  - Equipment number.
  - Name.
  - Size.
  - Capacity.
  - Design pressure and temperature.
  - Material.
- Pumps.
  - Equipment number.
  - Name.
  - Design capacity (gal/min or bbl/D).
  - Suction and discharge pressure or design pressure differential (psi).
  - Pumping temperature.
  - Specific gravity of fluids pumped.
  - Drive horsepower (approximate).
  - Type.
- Compressors and blocks.
  - Equipment number.
  - Name.
  - Design suction and discharge pressure.
  - Design suction and discharge temperature.
  - Design capacity (MMscf/D).
  - Drive horsepower (approximate).
  - Type.
- Heat exchangers.
  - Equipment number.
  - Name.
  - Heat transfer area (sq ft).
  - Heat duty and material balance conditions (Btu/hr)
  - Design pressures and temperatures.
  - Type.
  - Materials.
- Columns.
  - Equipment number.
  - Name.
  - Internal diameter and height.
  - Design pressure and temperature.
  - Number of trays or packing material.
  - Materials.

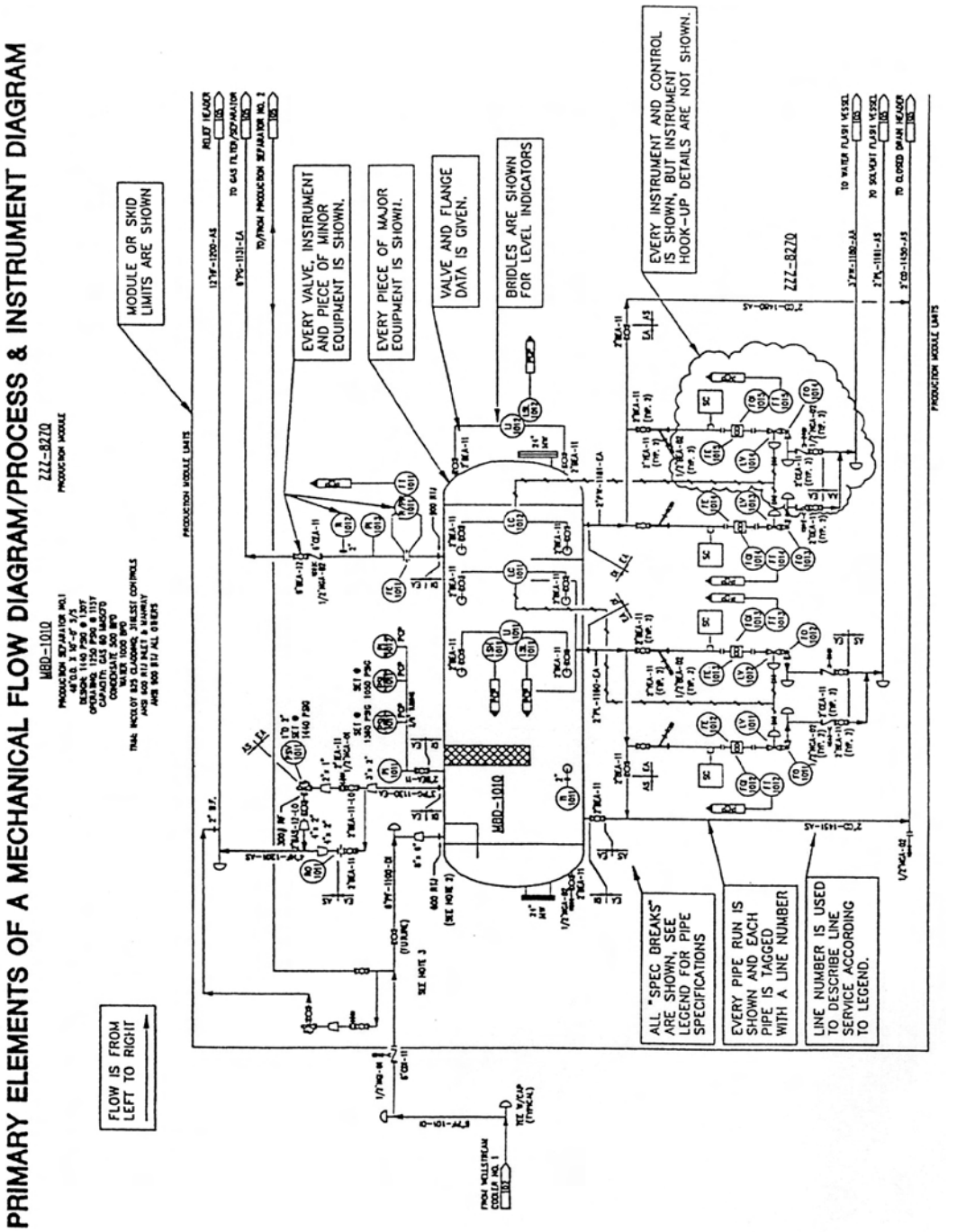


Fig. 15.3—Primary elements of a mechanical flow diagram/process and instrument diagram.

later as you try to execute the project tasks. These understandings should be formalized in a project memo and communicated to all personnel working on the project.

TABLE 15.4—RULES FOR DEVELOPING PROCESS AND INSTRUMENTATION DIAGRAMS

Purpose:

- Locates each equipment item, pipe, valve, instrument, etc., schematically in the process to form a basis for the detailed engineering drawing.
- Identifies each equipment item, pipe, valve, instrument, etc., so that it can be referenced to a specification and/or PO.
- Indicates the interrelationship of all these items so that operability and safety analysis can be performed.
- Provides a permanent record of the facility to aid in construction, operation, maintenance, training of personnel, and future modification of the facility.

Items Shown:

- All equipment items.
- Every pipe run.
- Every valve and piping specialty item.
- Every instrument and control.

Items Not Shown:

- Actual layout of equipment.
- Ells, bends, flanges, etc.
- Instrument hookup details.

Some Typical Abbreviations:

A.C.	Air to close	MWL	Mean water level
A.O.	Air to open	MX	Mixer
ASH	Gas detector	NC	Normally closed
B.F.	Blind flange	NLL	Normal liquid level
BSL	Burner flame detector	NO	Normally open
CPLG	Coupling	NOL	Normal oil level
ECC.	Eccentric	NWL	Normal water level
FO	Full opening	PP	Personnel protection
FAL	Low flow alarm	PAH	High-pressure alarm
FC	Flow controller	PAL	Low-pressure alarm
FCV	Flow control valve (choke)	PC	Pressure controller
FE	Flow element (orifice)	PCV	Pressure control valve
FI	Flow indicator (rotameter)	PDI	Differential pressure indicator
FIC	Flow indicator control	PDS	Differential pressure switch
FO	Fixed orifice	PI	Pressure indicator
FPR	Flow/pressure recorder	PR	Pressure recorder
FQI	Flowmeter/quantity indicator	PS	Pressure switch
FR	Flow recorder	PSE	Pressure safety element (rupture disk)
FSL	Low-flow shutdown	PSH	High-pressure shutdown
FT	Flow transmitter (turbine meter)	PSHL	High-/low-pressure shutdown
FTR	Flow/temperature recorder	PSL	Low-pressure shutdown
FV	Flow damper (desurger)	PSV	Pressure safety valve (relief)
FX	Strainer	PTR	Pressure/temperature recorder
FY	Flow rate relay	RO	Reduced opening
HP	High pressure	SDV	Shutdown valve
HCV	Hand control valve	SP	Sand probe
IP	Intermediate pressure	TA	Temperature alarm
LACT	Lease automatic custody transfer	TC	Temperature controller
LC	Locked closed	TCV	Temperature control valve
LO	Locked open	TI	Temperature indicator
LP	Low pressure	TIC	Temperature indicator controller
LAH	High level alarm	TR	Temperature recorder
LAL	Low level alarm	TSH	High-temperature shutdown
LC	Level controller	TW	Thermowell
LCV	Level control valve	TY	Temperature relay
LG	Level gauge	VE	Gas eliminator (vapor)
LS	Level switch	VSH	Vibration switch (high)
LSH	High-level shutdown	XE	Flame arrestor
LSL	Low-level shutdown	XFORM	Transformer
LY	Level relay	XXS	Double extra strong
MW	Man way	ZY	Position relay

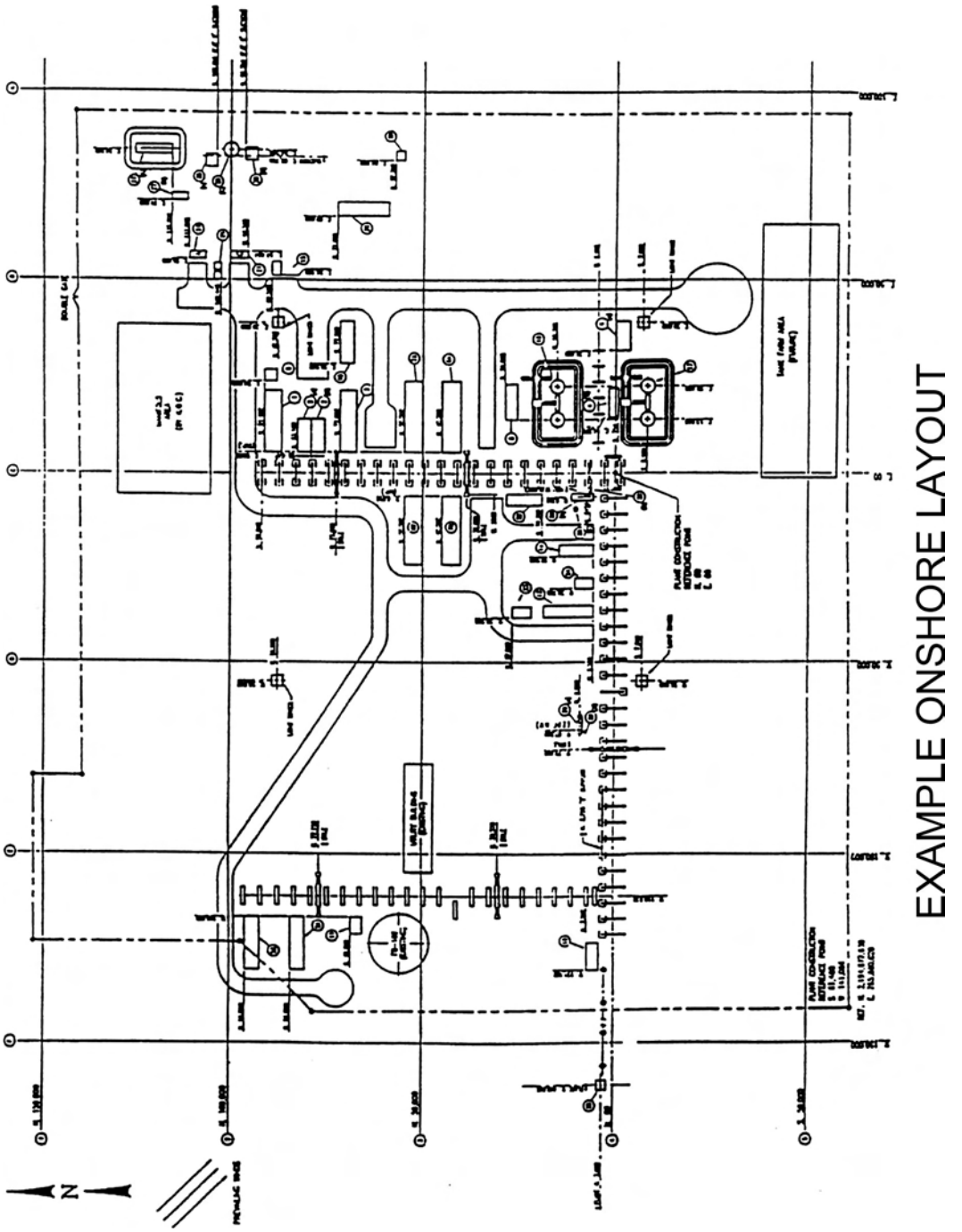


Fig. 15.4—Example onshore layout.

The first part of the memo should cover the project scope and any schedule or operational constraints imposed on the project by your management or forces outside the company such as government, landowners, working interest owners, and various other interested groups. You

TABLE 15.5—EXAMPLE EQUIPMENT AND TASK LIST

Project name: Remote Field

Equipment and Tasks	AFE Cost Code
Production skids	
Test separator	XXXXXX
High-pressure separator	XXXXXX
Low-pressure separator	XXXXXX
Heater treater	XXXXXX
Dehydration system	XXXXXX
Production liquid flash vessel	XXXXXX
Vent scrubber	XXXXXX
Fuel gas system	XXXXXX
Compressor	XXXXXX
Miscellaneous equipment	
Inlet manifold	XXXXXX
MCC building	XXXXXX
Bad-oil tank	XXXXXX
Storage tank	XXXXXX
Process valves and meters	XXXXXX
Fire-fighting/safety	XXXXXX
Generators and switch gear	XXXXXX
Motor control breakers	XXXXXX
LACT	XXXXXX
Freight and miscellaneous	XXXXXX
Instrumentation	
Main panel	XXXXXX
Installation	XXXXXX
Field installation	
Mob/demob/transport	XXXXXX
Foundations	XXXXXX
Piping	XXXXXX
Electrical	XXXXXX
Site survey	XXXXXX
Commissioning/startup	XXXXXX
Pipelines	
Line pipe	XXXXXX
P/L construction	XXXXXX
Design engineering	
Engineering	XXXXXX
Drafting	XXXXXX
Travel and miscellaneous expenses	XXXXXX
Construction management and inspection	
Personnel	XXXXXX
Travel and lodging	XXXXXX
Miscellaneous expenses	XXXXXX

will use this memo for future personal reference and to clearly communicate the project scope with your project team and other groups within your company who will support project actions. You will be surprised how easy it is to forget the objective and how other groups within your company may misunderstand the project objectives and limitations (we are just going to hook up the new well, not revamp the entire field).

The scope of the project should be clearly stated. Any available data, such as flow rate, fluid properties, formation properties, potential market standards, and environmental conditions, should be referenced and attached. Currently known schedule or operational constraints, such as lease expiration, market price spikes, and competitive leases, should be addressed. As an example, many gas projects schedule completion to take advantage of higher winter pricing and are

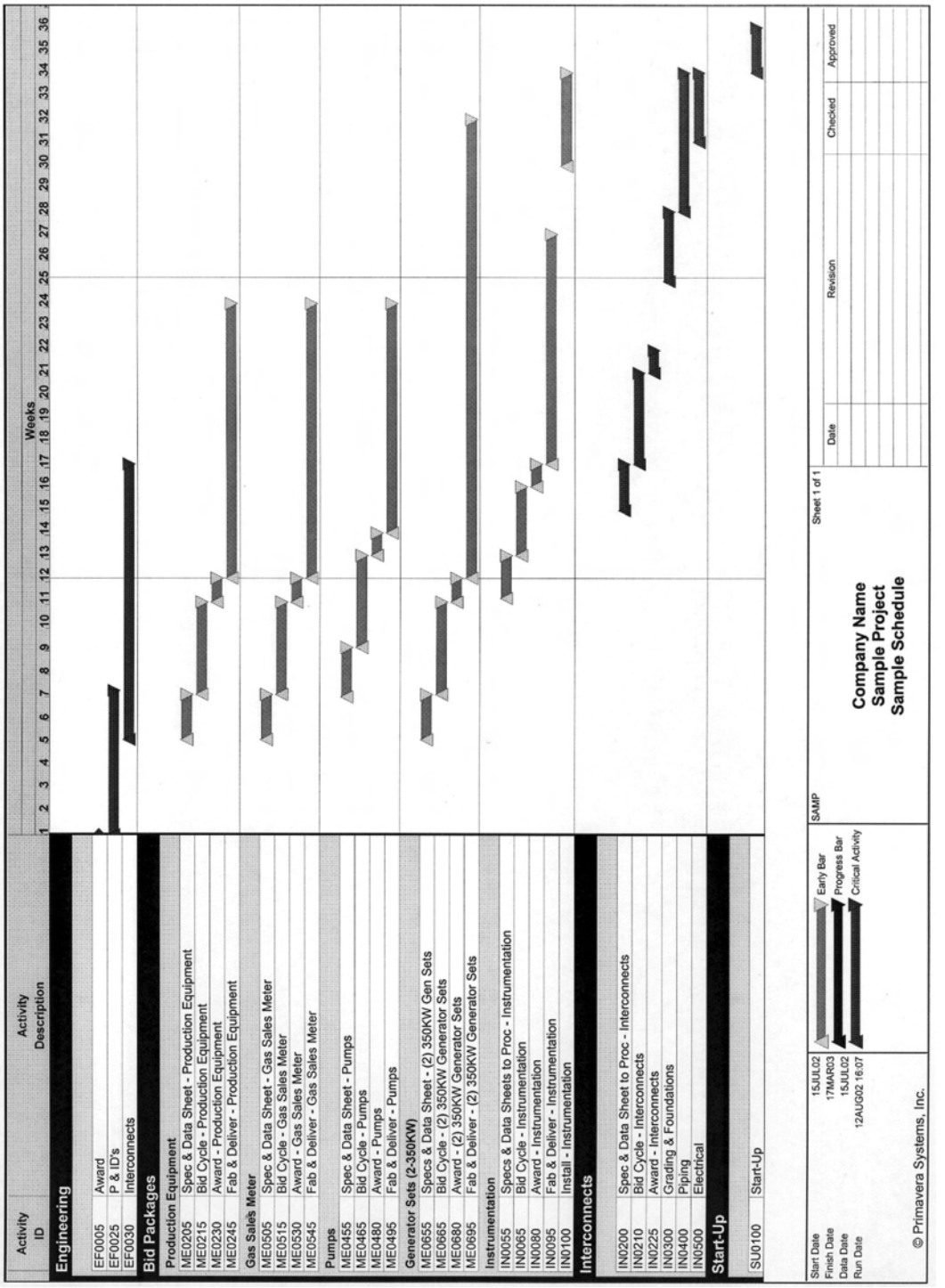
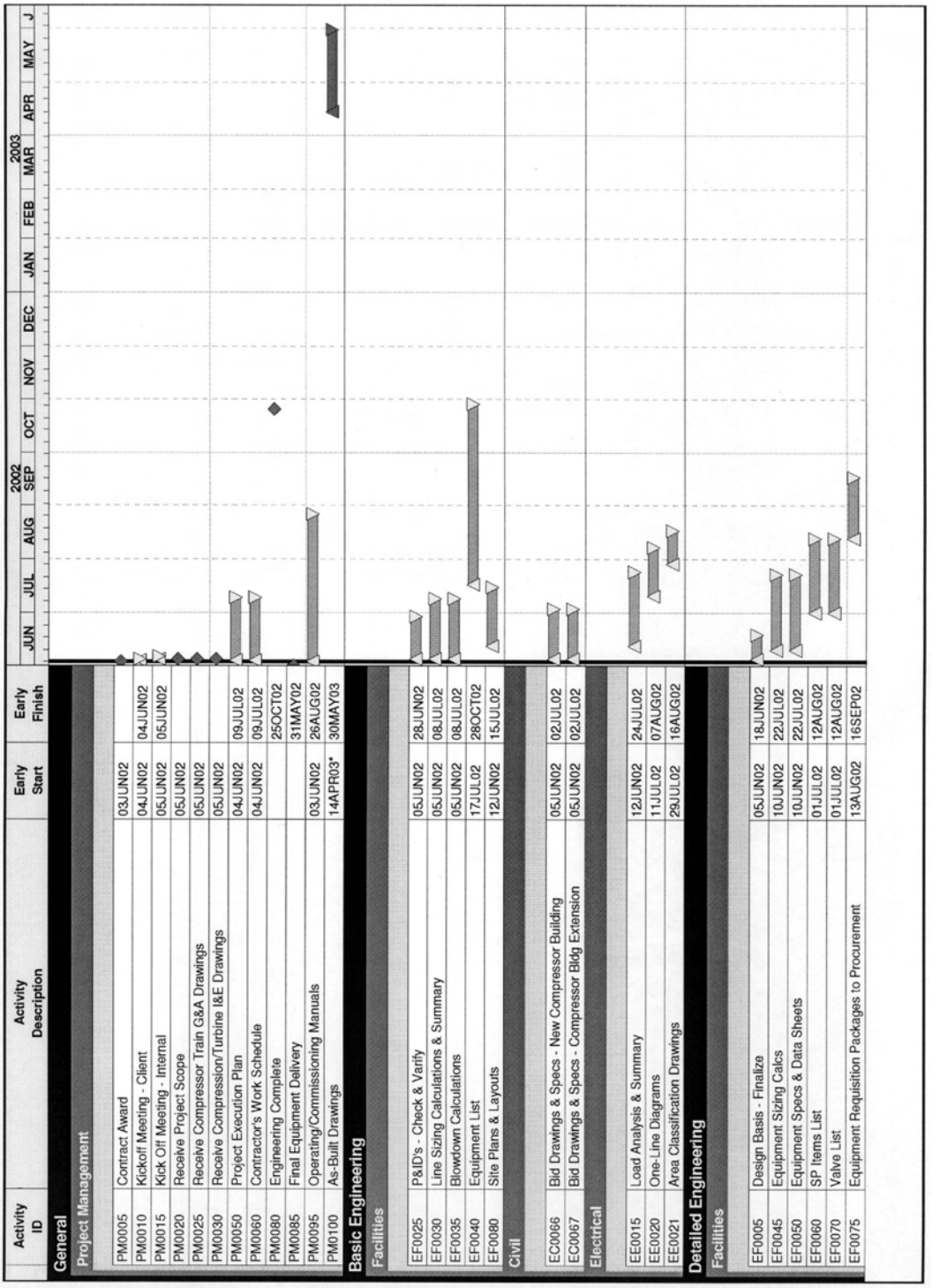


Fig. 15.5—Example project schedule for a simple project.

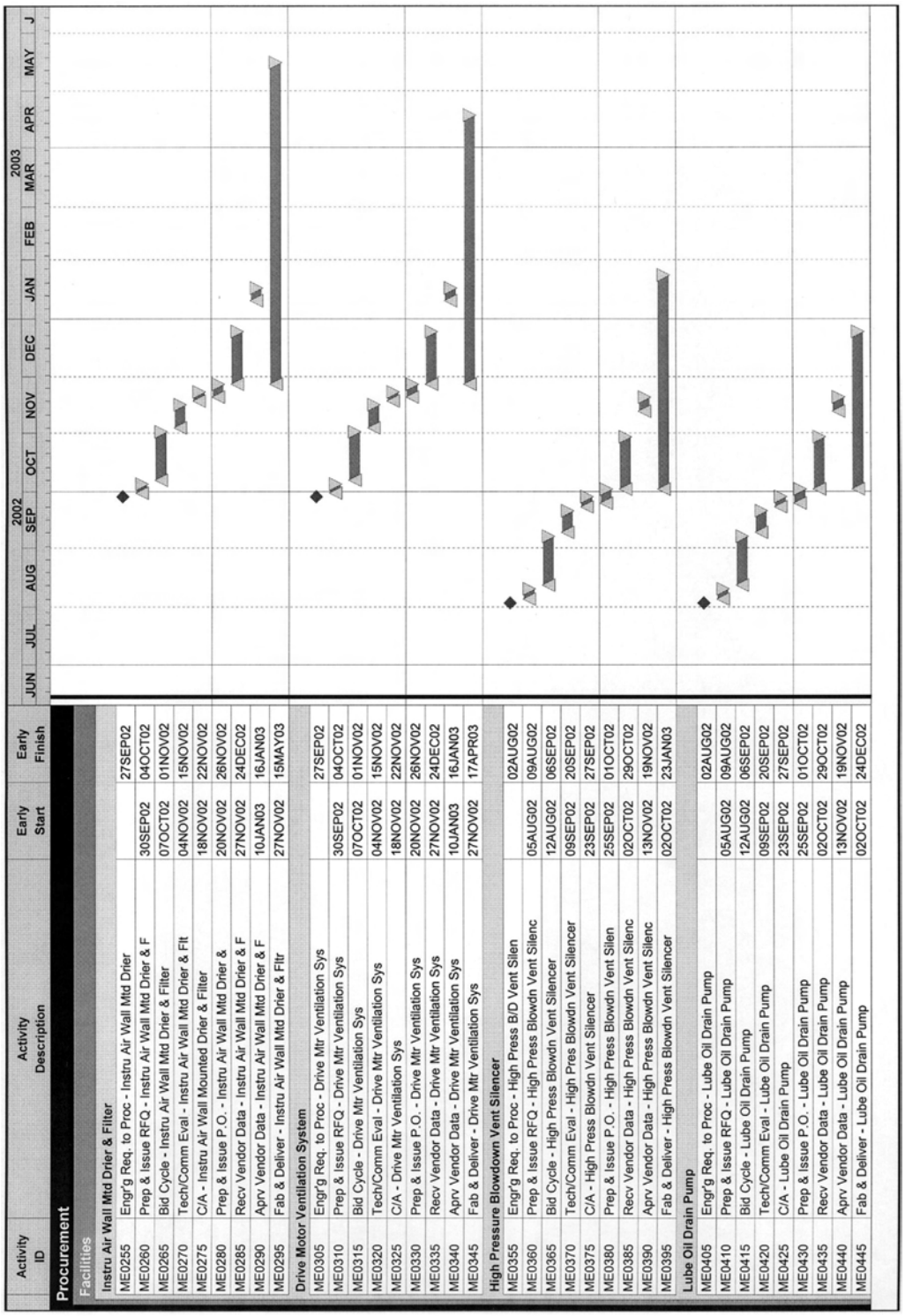
willing to bear higher total project costs to meet that goal. Any drainage by a competitive lease could result in lost revenue and should be considered when a project schedule is developed.



Activity ID	Activity Description	Early Start	Early Finish
General			
Project Management			
PM0005	Contract Award	03JUN02	
PM0010	Kickoff Meeting - Client	04JUN02	04JUN02
PM0015	Kick Off Meeting - Internal	05JUN02	05JUN02
PM0020	Receive Project Scope	05JUN02	
PM0025	Receive Compressor Train G&A Drawings	05JUN02	
PM0030	Receive Compression/Turbine I&E Drawings	05JUN02	
PM0050	Project Execution Plan	04JUN02	09JUL02
PM0060	Contractor's Work Schedule	04JUN02	09JUL02
PM0080	Engineering Complete		25OCT02
PM0085	Final Equipment Delivery		31MAY02
PM0095	Operating/Commissioning Manuals	03JUN02	26AUG02
PM0100	As-Built Drawings	14APR03*	30MAY03
Basic Engineering			
Facilities			
EF0025	P&ID's - Check & Varify	05JUN02	28JUN02
EF0030	Line Sizing Calculations & Summary	05JUN02	08JUL02
EF0035	Blowdown Calculations	05JUN02	08JUL02
EF0040	Equipment List	17JUL02	28OCT02
EF0080	Site Plans & Layouts	12JUN02	15JUL02
Civil			
EC0066	Bid Drawings & Specs - New Compressor Building	05JUN02	02JUL02
EC0067	Bid Drawings & Specs - Compressor Bldg Extension	05JUN02	02JUL02
Electrical			
EE0015	Load Analysis & Summary	12JUN02	24JUL02
EE0020	One-Line Diagrams	11JUL02	07AUG02
EE0021	Area Classification Drawings	29JUL02	16AUG02
Detailed Engineering			
Facilities			
EF0005	Design Basis - Finalize	05JUN02	18JUN02
EF0045	Equipment Sizing Calcs	10JUN02	22JUL02
EF0050	Equipment Specs & Data Sheets	10JUN02	22JUL02
EF0060	SP Items List	01JUL02	12AUG02
EF0070	Valve List	01JUL02	12AUG02
EF0075	Equipment Requisition Packages to Procurement	13AUG02	16SEP02

Fig. 15.6—Portion of the project management and engineering schedule for a complex project.

The second part of this memo should discuss the project execution strategy. This section should include the rules that determine how the project will contract with various outside com-



Activity ID	Activity Description	Early Start	Early Finish
Procurement			
Facilities			
Instru Air Wall Mtd Drier & Filter			
ME0255	Engr'g Req. to Proc - Instru Air Wall Mtd Drier		27SEP02
ME0260	Prep & Issue RFQ - Instru Air Wall Mtd Drier & F	30SEP02	04OCT02
ME0265	Bid Cycle - Instru Air Wall Mtd Drier & Filter	07OCT02	01NOV02
ME0270	Tech/Comm Eval - Instru Air Wall Mtd Drier & Flt	04NOV02	15NOV02
ME0275	C/A - Instru Air Wall Mounted Drier & Filter	18NOV02	22NOV02
ME0280	Prep & Issue P.O. - Instru Air Wall Mtd Drier &	20NOV02	26NOV02
ME0285	Recv Vendor Data - Instru Air Wall Mtd Drier & F	27NOV02	24DEC02
ME0290	Aprv Vendor Data - Instru Air Wall Mtd Drier & F	10JAN03	16JAN03
ME0295	Fab & Deliver - Instru Air Wall Mtd Drier & Fltr	27NOV02	15MAY03
Drive Motor Ventilation System			
ME0305	Engr'g Req. to Proc - Drive Mtr Ventilation Sys		27SEP02
ME0310	Prep & Issue RFQ - Drive Mtr Ventilation Sys	30SEP02	04OCT02
ME0315	Bid Cycle - Drive Mtr Ventilation Sys	07OCT02	01NOV02
ME0320	Tech/Comm Eval - Drive Mtr Ventilation Sys	04NOV02	15NOV02
ME0325	C/A - Drive Mtr Ventilation Sys	18NOV02	22NOV02
ME0330	Prep & Issue P.O. - Drive Mtr Ventilation Sys	20NOV02	26NOV02
ME0335	Recv Vendor Data - Drive Mtr Ventilation Sys	27NOV02	24DEC02
ME0340	Aprv Vendor Data - Drive Mtr Ventilation Sys	10JAN03	16JAN03
ME0345	Fab & Deliver - Drive Mtr Ventilation Sys	27NOV02	17APR03
High Pressure Blowdown Vent Silencer			
ME0355	Engr'g Req. to Proc - High Press B/D Vent Silen		02AUG02
ME0360	Prep & Issue RFQ - High Press Blowdn Vent Silenc	05AUG02	09AUG02
ME0365	Bid Cycle - High Press Blowdn Vent Silencer	12AUG02	06SEP02
ME0370	Tech/Comm Eval - High Pres Blowdn Vent Silencer	09SEP02	20SEP02
ME0375	C/A - High Press Blowdn Vent Silencer	23SEP02	27SEP02
ME0380	Prep & Issue P.O. - High Press Blowdn Vent Silen	25SEP02	01OCT02
ME0385	Recv Vendor Data - High Press Blowdn Vent Silenc	02OCT02	29OCT02
ME0390	Aprv Vendor Data - High Press Blowdn Vent Silenc	13NOV02	19NOV02
ME0395	Fab & Deliver - High Press Blowdn Vent Silencer	02OCT02	23JAN03
Lube Oil Drain Pump			
ME0405	Engr'g Req. to Proc - Lube Oil Drain Pump		02AUG02
ME0410	Prep & Issue RFQ - Lube Oil Drain Pump	05AUG02	09AUG02
ME0415	Bid Cycle - Lube Oil Drain Pump	12AUG02	06SEP02
ME0420	Tech/Comm Eval - Lube Oil Drain Pump	09SEP02	20SEP02
ME0425	C/A - Lube Oil Drain Pump	23SEP02	27SEP02
ME0430	Prep & Issue P.O. - Lube Oil Drain Pump	25SEP02	01OCT02
ME0435	Recv Vendor Data - Lube Oil Drain Pump	02OCT02	29OCT02
ME0440	Aprv Vendor Data - Lube Oil Drain Pump	13NOV02	19NOV02
ME0445	Fab & Deliver - Lube Oil Drain Pump	02OCT02	24DEC02

Fig. 15.7—Portion of the procurement schedule for a complex project.

TABLE 15.6—EXAMPLE PROCUREMENT AND CONTRACTING PLAN

Project name: Remote Field	Procurement and Contracting Plan			
Equipment and Tasks	AFE Cost Code	Acquisition Type	Contract Type	Comments
Production skids				
Test separator	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
High-pressure separator	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
Low-pressure separator	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
Heater treater	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
Dehydration system	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
Production liquid flash vessel	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
Vent scrubber	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
Fuel gas system	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager
Compressor	XXXXXX	Vendor bids	PO, firm price	All by compressor package
Miscellaneous equipment				
Inlet manifold	XXXXXX	Vendor bids	PO, firm price	P&S valves to packager
MCC building	XXXXXX	Vendor bids	PO, firm price	P&S MCC breakers to packager
Bad-oil tank	XXXXXX	Vendor bids	PO, firm price	All by vendor
Storage tank	XXXXXX	Vendor bids	PO, firm price	All by vendor
Process valves and meters	XXXXXX	Vendor bids	PO, firm price	All by vendor
Fire-fighting/safety	XXXXXX	Vendor bids	PO, firm price	All by vendor
Generators and switch gear	XXXXXX	Vendor bids	PO, firm price	All by vendor
Motor control breakers	XXXXXX	Vendor bids	PO, firm price	All by vendor
LACT	XXXXXX	Vendor bids	PO, firm price	P&S valves and meters to packager
Freight and miscellaneous	XXXXXX	Vendor bids	PO, firm price	By owner—LO&TD by item supplier
Instrumentation				
Main panel	XXXXXX	Vendor bids	PO, firm price	All by packager
Installation	XXXXXX	Vendor bids	PO, firm price	All by packager
Field installation				
Mob/demob/transport	XXXXXX	Direct award	GSC, rates	By owner—LO&TD by item supplier
Foundations	XXXXXX	Vendor rates bids	GSC, rates	All by contractor
Piping	XXXXXX	Vendor rates bids	GSC, rates	P&S Valves to contractor
Electrical	XXXXXX	Vendor rates bids	GSC, rates	All by contractor
Site survey	XXXXXX	Vendor rates bids	GSC, rates	All by contractor
Commissioning/startup	XXXXXX	Vendor rates bids	GSC, rates	All by contractor
Pipelines				
Line pipe	XXXXXX	Vendor bids	PO, firm price	Coating and joint treatment by vendor
P/L construction	XXXXXX	Vendor bids	GSC, firm price	P&S valves to contractor
Design engineering				
Engineering	XXXXXX	Vendor rates bids	GSC, rates	All by contractor
Drafting	XXXXXX	(Included above)	(Included above)	(Included above)
Travel and miscellaneous Expense	XXXXXX	(Included above)	(Included above)	(Included above)
Construction management and inspection				
Personnel	XXXXXX	Vendor rates bids	GSC, rates	All by contractor
Travel and lodging	XXXXXX	(Included above)	(Included above)	(Included above)
Miscellaneous expenses	XXXXXX	(Included above)	(Included above)	(Included above)

P&S indicates purchase and supply; LO&TD, load out and tie down

panies for work. The two basic types of project formats were presented in Table 15.1. There are many variations of these two basic types. The correct choice of project execution strategy depends on project goals, available competition, company policies, and other commercial con-

TABLE 15.7—EXAMPLE COST ESTIMATE

Project name: Remote Field

	Procurement and Contracting Plan				
Equipment and Tasks	AFE Cost Code	Acquisition Type	Contract Type	Comments	Cost Estimate, U.S. $
Production skids					
Test separator	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	32,000
High-pressure separator	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	30,000
Low-pressure separator	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	30,000
Heater treater	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	80,000
Dehydration system	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	110,000
Production liquid flash vessel	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	15,000
Vent scrubber	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	10,000
Fuel gas system	XXXXXX	Vendor bids	PO, firm price	Code vessel by packager	10,000
Compressor	XXXXXX	Vendor bids	PO, firm price	All by compressor package	410,000
					727,000
Miscellaneous equipment					
Inlet manifold	XXXXXX	Vendor bids	PO, firm price	P&S valves to packager	55,000
MCC building	XXXXXX	Vendor bids	PO, firm price	P&S MCC breakers to packager	25,000
Bad-oil tank	XXXXXX	Vendor bids	PO, firm price	All by vendor	5,000
Storage tank	XXXXXX	Vendor bids	PO, firm price	All by vendor	150,000
Process valves and meters	XXXXXX	Vendor bids	PO, firm price	All by vendor	60,000
Fire-fighting/safety	XXXXXX	Vendor bids	PO, firm price	All by vendor	10,000
Generators and switch gear	XXXXXX	Vendor bids	PO, firm price	All by vendor	45,000
Motor control breakers	XXXXXX	Vendor bids	PO, firm price	All by vendor	30,000
LACT	XXXXXX	Vendor bids	PO, firm price	P&S valves and meters to packager	80,000
Freight and miscellaneous	XXXXXX	Vendor bids	PO, firm price	By owner—LO&TD by item supplier	10,000
					470,000
Instrumentation					
Main panel	XXXXXX	Vendor bids	PO, firm price	All by packager	37,500
Installation	XXXXXX	Vendor bids	PO, firm price	All by packager	40,000
					77,500
Field installation					
Mob/demob/transport	XXXXXX	Direct award	GSC, rates	By owner—LO&TD by item supplier	80,000
Foundations	XXXXXX	Vendor rates bids	GSC, rates	All by contractor	50,000
Piping	XXXXXX	Vendor rates bids	GSC, rates	P&S Valves to contractor	350,000
Electrical	XXXXXX	Vendor rates bids	GSC, rates	All by contractor	40,000
Site survey	XXXXXX	Vendor rates bids	GSC, rates	All by contractor	12,000
Commissioning/startup	XXXXXX	Vendor rates bids	GSC, rates	All by contractor	25,000
					557,000
Pipelines					
Line pipe	XXXXXX	Vendor bids	PO, firm price	Coating and joint treatment by vendor	460,000
P/L construction	XXXXXX	Vendor bids	GSC, firm price	P&S valves to contractor	185,000
					645,000
Design engineering					
Engineering	XXXXXX	Vendor rates bids	GSC, rates	All by contractor	100,000
Drafting	XXXXXX	(Included above)	(Included above)	(Included above)	100,000
Travel and miscellaneous expenses	XXXXXX	(Included above)	(Included above)	(Included above)	10,000
					210,000
Construction management and inspection					
Personnel	XXXXXX	Vendor rates bids	GSC, rates	All by contractor	50,000
Travel and lodging	XXXXXX	(Included above)	(Included above)	(Included above)	20,000
Miscellaneous expenses	XXXXXX	(Included above)	(Included above)	(Included above)	60,000
					130,000
Total					2,816,500

P&S indicates purchase and supply; LO&TD, load out and tie down

straints. The remainder of this discussion concentrates on the second type, EPCM, which gives the operating company maximum control over project execution.

Even if your company does not have strict rules concerning procurement, such rules may be implied by requirements in the JOA that will govern your project's implementation. If your company or the JOA has set rules for contractor or supplier selection, then you must comply with them. In the absence of rules, an industry standard practice is that professional services are generally contracted and paid for on a rate (hourly or daily) basis, and definable materials, equipment, and fabrication and construction services are contracted and paid for on a lump-sum basis. Examples of professional services are land and legal, permitting, site inspection, and engineering and procurement services. Examples of definable materials, equipment, and fabrication and construction services are line pipe, production vessels, hookup materials, field hookup labor (if well defined), and site and road preparation. Typically, professional services are contracted with a GSC. The procurement of materials and manufactured items is normally contracted with a PO (with its attached Ts&Cs). Fabrication and construction services contracts are normally longer and project specific because of the potential safety risks and environmental liabilities involved in this work. Review the GSC and PO to determine how their wording will affect project execution.

You should also resolve how project invoices will be processed and coded. The invoices for all products, materials, and services for your project should come to you for review and initial approval. Although it is tempting to "just let accounting handle it," you will be losing your most valuable project control tools–the power of the purse and timely project financial information. It is not critical that the project manager have monetary approval authority; however, it is important that the project manager have the authority to review all invoices and disapprove those with which he or she disagrees. Invoicing approval should always follow the "two review rule." The invoice must first be agreed to by the team member directly responsible for the work before it is approved for payment by the individual with monetary approval authority. Depending on the level of the invoice, several members of the project team may be required to approve the invoice for payment. In no case should there be fewer than two signatures. This will make things easier on everyone at the end of the project if the joint-interest auditors show up to review project expenditures.

15.3.2 Choosing a Project Team. It is now time to start choosing the project team. Functions to be handled by the project team include operations, drilling, land and legal, insurance, marketing, environmental, engineering, purchasing, inspection, construction, and commissioning.

A project manager's job is much like that of an orchestra conductor. It requires first the communication of a basic plan (the music), constant monitoring (listening to the individual playing), and any immediate correction of the players if they stray from the plan. On all except the simplest of projects, the project manager is not there to play himself but to guide the others to accomplish their individual tasks in a complementary manner. The other thing to note in this comparison is that in both instances all tasks are being done simultaneously.

Invite representatives of each of your company's groups who are responsible for one or more or these functions to an internal project kickoff meeting to determine what parts they can play on the project team and what data they will need to start and complete their tasks. The actual size of this group varies from company to company; you may find that some of these services are performed by outside contractors. It is important that this meeting be held quickly. Any task that cannot be performed in house must be contracted to outside sources. This process must start early so as not to hinder the smooth startup of the project team. Remember that these people will also be glad to share their past experiences on this type of project with you if take the opportunity to ask every chance you get.

How much of the project work will done by personnel within your company will depend on its size, organization, past experience in this type of project, and current workload. Of these

factors, the only function that could have a large negative impact on your company is legal matters. It is important that your company counsel be involved in all legal matters concerning contracts, purchase terms and conditions, and any other situation that may lead to court action. The other functions can be contracted out to firms that specialize in the field. In most cases, this is a preferred option to minimize impact on your company's normal workloads.

The JOA may also provide a good reason to contract out these functions. Many times, the partners will not be obligated to directly pay for company labor working on the project. The JOA may make reference to "construction overhead" as a percent of total authorization for expenditure (AFE) cost. This amount is to cover all company labor working on the project not employed directly on site. With this in mind and because the partners are obligated to pay their share of any contract let for outside labor, it would seem that the cost of outside contracting for company noncritical labor may be more cost-effective than it would seem at first.

At this point it may be necessary to modify the project execution strategy to reflect the impact of these investigations.

15.3.3 Selecting an Engineering Company. Assuming you are following an EPCM project format and you do not have the engineering capabilities in house, soon after the internal kick-off meeting, you should choose an engineering company for the project. If your company has not already established a relationship with one engineering company, you should interview at least three companies at their places of business. You should describe the project scope to each company (use the memo), asking for examples of their experience with this type of work, and meet the person who would be the engineering manager for your project. Note the attitudes of the employees whom you meet and personally contact the job performance references supplied by the engineering company. If your company has already established a relationship with one or two engineering companies, this process can be shortened. However, make sure your company has a procedure in place to audit results and to ensure that value is received from this ongoing relationship.

If your company does not have equipment and material specifications that will fit the proposed work, discuss this problem with each engineering company and ask for a recommended solution and its cost. All quality engineering companies have their own specifications and construction practices that cover this type of work, and most will make them available to you for a nominal fee or even for free, depending on the competitive climate.

After furnishing the engineering company with a blank copy of the Services Contract, you should ask for a rough cost estimate and time frame for the completion of preliminary versions of the PFD, P&IDs, a facility layout, a preliminary project schedule, and a preliminary cost estimate of the project. The cost estimate should clearly note the total engineering cost for the job, along with the individual hourly rates of the personnel employed to complete the work. Using the data collected from these visits, make a recommendation to your boss, and have the company's legal organization contract the successful company with a rates basis services contract.

15.4.4 AFE and Initial Cost Estimate. Your next task will be to obtain internal project financing with an AFE. This will consist of doing a project cost estimate and schedule for the total internal and external project expenditures and presenting it to management and partners for approval of these future expenditures. Depending on the data available to you from previous similar projects and your skill and confidence levels, you can do this estimate yourself or ask your chosen engineering contractor to help. You should review your company's standard forms and conditions for AFEs. You should also review the JOA on this subject because its requirements may be different from your company's requirements.

If you choose to do the AFE estimate yourself, you should consult the equipment and service vendors in your area that will eventually be supplying the project equipment and services for help in both these areas. These vendors are happy to give these types of cost and schedule

estimates because it gives them additional market insight and the chance to meet and educate you about their company and its business. It is usually considered fair play to include those companies that supplied estimates on the final bid lists for those items. Do not forget to include intercompany services that may be directly charged to the project under the JOA.

A more standard industry solution is to use the engineering company to assist in the preparation of the AFE estimate. It is always advantageous to have the project engineering contractor involved in the AFE estimating process because doing so would allow the preliminary PFDs, P&IDs, schedule, and layout to be completed for presentation with the AFE or at the partners' meeting called to discuss the project and AFE. By using these more complete documents to do the AFE estimate, you will obtain a much more accurate project cost and schedule. This is usually well worth the extra money and time spent to obtain it. However, this expenditure will occur before approval of the AFE, and you should get management approval before following this course of action. For smaller projects, one way out of this problem is to obtain permission to charge this cost to the well drilling or completion AFE. This solution will generally correctly charge the partners' accounts.

Although you should use your company's standard AFE form for formal approval, it may be lacking in detail. The accounting system is geared to its cost codes, and form changes will be difficult in this short time frame. Be sure that the project estimate is detailed enough to allow effective job control and that it is at least based on the initial project execution plan. The AFE cost codes should be noted on the project estimate as appropriate, and the project estimate should show how the estimate's cost details roll into the AFE cost code amounts.

It is good to remember that even though these are only estimates, many people (especially management and the partners) will want to believe that these are firm prices not to be exceeded for any reason. Although most of these types of estimates are reasonably accurate, they are based on certain assumptions of conditions known at the time of the estimate. As these conditions become better defined, the final cost of the project will change. For these and other good reasons, it is always important to include a 10% to 15% general contingency in your estimate to account for these unknowns.

15.5.5 Partners' Approval. A summary to this point in the project would show that you have reviewed the company's past experience with this type of project; reviewed the lease and JOAs for possible conflicts with your company's normal practices; published the project scope and contracting strategy memo; started multiple federal, state and local permit processes; discussed marketing opportunities with the company marketing group; resolved the issue of early project charges; hired the engineering company; and issued the AFE and initial schedule to the partners for their approval using the preliminary P&ID and layout as an estimating basis. With luck, the partners sign off on the AFE, and you move on to actually doing the real work of the project. However, that seldom happens today, and a partners meeting will be called to discuss the AFE cost, project schedule, project execution, marketing options (if any), and future plans in the area.

The partners meeting is very important because it is your opportunity to present the project for outside, sometimes critical, review. Plan on this being a team presentation by the engineering company manager and you, and be sure he or she is allowed to attend the meeting. Remember, your job is to manage the overall project, not discuss the heat transfer coefficients used in the heater design or any other technical detail on which you do not feel qualified to comment. That type of question will be answered by the engineering company manager or company personnel. Be sure to have a practice session with your boss and the engineering company manager at least 3 days before the meeting so that he or she can be confident in the presentation and you can make any necessary changes in time for the actual meeting.

You should present the project as represented by the AFE in a simple manner with high-quality overheads. Be sure that you hand out a copy of every overhead you present and that

TABLE 15.8—EXAMPLE INSTRUCTION FOR PREPARING BID PACKAGES

Arrangement:

Cover sheet
Table of Contents
Section I—General Requirements
Section II—Scope of Work or Equipment Description
Section III—Technical Standards
Section IV—Bid Form
Section V—Drawings

The numbering of these sections will depend on the specific bid package. For example, some bids packages will require a contract, some may have both a Scope of Work and Equipment Description, and others may not need a bid form or drawing section.

The basic content in the each of these sections is as described below.

1. Section I of all bid packages will be the General Requirements. This section defines the basic commercial terms and conditions that must be adhered to by all bidders.

2. Section II of all bid packages will be either Scope of Work or Equipment Description. Scope of Work should be used when field work such as interconnecting piping, electrical hookup, and site work is performed. This section will be used to describe all items particular to the job site and the work to be performed. Equipment Description should be used when equipment such as cranes, production skids, and compressor packages is provided. This section will be used to describe all features particular to this item. In some instances, such as when the bid is actually made up of individual components of work (e.g., equipment skids), which can be awarded separately, both Scope of Work outlining what is required of a contractor awarded any of the separate packages and a separate Equipment Description describing each package in detail may be needed.

3. Section III of all bid packages will be Technical Standards. These standards will not change for a particular project and will be modified only slightly from project to project. It is important that all engineers read the standards incorporated into the bid package to ensure that they are consistent with the drawings and the rest of the sections.

4. Section IV, the Bid Form, will vary for each specification but as a minimum should include the information indicated. A more detailed breakdown of cost or schedule could be considered for a specific reason.

5. Section V is Drawings.

you have enough sets of handouts for everyone at the meeting. It is best if you personally present at the podium and the engineering company manager remains seated in the audience to handle any technical answers that might be outside your comfort zone.

Your presentation should include a project location map showing area pipelines and possible tie-ins (coordinated with marketing); excerpts from the scope and contracting memo covering those topics (especially note which project tasks are planned to be bid out and contracted on a firm price basis and which are to be contracted at day or hourly rates); the AFE; the P&ID, detailed cost estimate, schedule (pointing out the critical path items), and layout; a listing of the permits being procured; and short comments concerning any changes in any phases of the project that may have occurred since the AFE was originally presented to the partners. Be prepared for lengthy discussions on some of these topics. It would be very advantageous, but is not a requirement, to present for comment preliminary bid lists for the major project items (production equipment, hookup materials, site work, pipelines, etc.). Be prepared to consider modifications to this list or any other parts of the project on the basis of the partners' past experiences in this type of project.

After the meeting, review the partners' comments with the engineering company manager and your boss to determine whether any changes in your plan and the AFE are required. If any are needed, modify the appropriate documents and reissue as required.

Now that the partners meeting is behind you and the project is funded, you can proceed with the actual implementation of the project. You should confirm that the engineering company manager has the latest versions of all the required data and release him or her to finalize the drawings and documents necessary to define the project to the various contractors who will implement the work. In addition to completing the documents already generated, you must also complete the project team with experienced personnel to perform other project tasks besides engineering. It is important that these newcomers to the team be thoroughly briefed and furnished copies of all documents previously generated by the project.

15.3.6 Procurement. Although we have a contracting strategy, we do not yet have a detailed procurement plan, and everyone knows that "the devil is in the details." The first step in procurement is to review the procurement and contracting plan and modify it as required by any change in concept or new information.

The procurement process involves preparation of a technical description of the item and the appropriate contracting terms called a "bid package" (see **Table 15.8** for an example of instructions for preparing a bid package); presenting the description to the vendors for pricing (invitation to bid); resolving any questions from vendors concerning the description supplied (bid clarifications); requiring the reply to meet a standardized format to facilitate comparisons (bid reply form); comparing technical compliance, price, and contractual responses (bid tabulation); awarding the supply to the successful vendor on the basis of bid price and agreed-upon contracting terms (PO or contract); monitoring vendor progress and work quality (expediting and inspecting); approving final product (final acceptance report); and transporting to site (final shipping report). Obviously, no one individual can expertly monitor all of these activities, and how they are divided is a major challenge of project management.

Although many permutations are possible, one proven solution is as follows:

Technical description	Engineering
Contracting terms	Legal and purchasing
Present to Vendors	Purchasing and project manager
Resolve vendor questions	Engineering and legal
Bid Technical Compliance	Engineering
Bid Contractual Compliance	Legal
Bid Price Comparison	Project manager
Award work to vendor	Project manager
Expedite vendor	Purchasing
Quality inspect vendor	Purchasing and engineering
Final acceptance	Purchasing and engineering
Final shipping	Purchasing

Considering the above discussion on contracting work, it would seem that all but the legal requirements for the above work could be contracted out with minimum impact on the company. Another reason to contract these functions is to improve project control. People who work only for the project are more likely to view its priorities with a higher sense of urgency than people who have other, equally important competing interests. Company procurement people

typically must give first priority to operational concerns. In addition, although they may be skilled in procurement of standard items needed to drill wells (tubulars, mud, etc.) and to support operations (valves, parts, etc.), they may not be skilled in procuring such engineered items as compressors, pump packages, and fabricated modules.

The simplest project solution that generally is most cost-effective for the company and project is to increase the engineering company's scope to include most of the purchasing functions. This will make communication and interface control simpler and increase project efficiency. If this is your plan, then you must consider and evaluate the engineering company's procurement and especially its material tracking capabilities in the step of selecting an engineering company.

15.3.7 Monitoring and Reporting Progress and Cost. The project team is now fully assembled, and it is time to start the physical project work with all members becoming involved in the engineering, purchasing, and contracting effort. These accomplishments must be measured and reported to determine the efficiency of the work and the true financial impact of the project.

Real progress on a job is determined by a counting of such things as the number of documents delivered vs. the total number or the number of welds made vs. the total number required. Progress is not measured by comparing the money spent vs. the money allocated. The requirement for real progress monitoring increases as the job grows in size and complexity. How to account for and measure real progress is a topic not discussed here because of its complexity and the cost of accomplishing it, but your engineering contractor can assist you with this task if necessary.

During this period, you need to quickly establish a project cost monitoring method. The word "monitoring" is used by choice because "cost control" is accomplished by timely and effective project execution and procurement methods. As shown in Fig. 15.1, the optimum time to affect the cost of a project is in the concept and front-end engineering phases, not by itemizing what you have already spent or committed in the detailed design and following execution phases. See **Table 15.9** for a listing of some items that are helpful to keep in mind during project execution.

It is very important that a project manager not fool himself or herself by thinking that "we will save enough money tomorrow to cover today's overexpenditure." Cost monitoring will allow you to determine quickly the quality of your AFE estimate and indicate trouble spots that require your personal attention. If an item costs significantly more than the original estimate, the project manager should determine the reason for the difference and assess any other potential project impacts that may be caused by similar reasoning.

An example cost status summary is shown in **Table 15.10**. This is based on the original cost estimate that is maintained for comparison. Columns for "committed" (signed PO amounts), "invoiced to date," and "estimated final costs" (accounting for prospective changes) are added. It is important from a presentation standpoint that the cost monitoring report be an extension of the original project cost estimate and that it be updated weekly or monthly. Note that, as new information becomes available, the updated estimated final cost of each item is inserted, and these are summed to determine the new estimated total project cost. The cost monitoring report should also clearly note any project equipment or services not considered in the original estimate as a new line item. Any estimated overexpenditure outside AFE tolerances should be reported to management immediately with a short explanation of the reason for the overexpenditure.

Table 15.11 shows an example project status report format. The centerpiece of this report is the cost control report. The project status report is the vehicle that you will use to formally communicate project progress to your management and the partners. It should cover the necessary topics (cost and schedule) simply but completely. Problems, their solutions, and any cost or schedule impacts should be presented in a clear, concise manner as soon as they are recog-

TABLE 15.9—ITEMS TO CONSIDER IN CONTROLLING COSTS

- Cost control is, to a large extent, beyond the scope of the project manager once design engineering is complete and plan of execution is set.
- Select appropriate plan of execution.
- Engineering decisions:
  1. Design philosophy.
     - In line with chosen project format.
     - In line with contractor technical level.
  2. Technical specification details.
     - Do not overspecify or be too technical (this is an oil field, not the space shuttle).
     - Tailor to project size and location.
  3. Choosing acceptable bidders.
     - If a bidder loses money on a project, quality and schedule suffer and claims for extra work increase.
     - Consider not awarding to low bidder if the bid is too low.
     - Check financial capability. Project schedule will suffer if a vendor goes into bankruptcy.
  4. Identify true low bidder.
  5. Extra work policing.
     - Any complex fabrication project requires a small amount of extra work.
     - Good engineering and well-defined bid packages reduce extra work.
     - Inspectors must ensure that perceived extra work really is not covered in contract documents.
  6. Bonus/penalty clauses.
     - Penalty clauses become bonus clauses because contractors will normally increase bid amount by maximum exposure to penalty.
     - If delivery is important:
       1. Award work quickly.
       2. Respond to questions quickly.
       3. Expedite. Your presence shows concern and can nip many problems in the bud.
       4. Consider a meaningful bonus (one that can be shared with workers).
  7. Inspection and expediting.
     - Inspection.
       1. Ensure quality.
       2. Witness tests.
       3. Review dimensions.
     - Expediting.
       1. Review schedule and progress toward schedule.
       2. Interface with subcontractors.
       3. Early intervention.
- Account for costs vs. estimate. Original cost estimate must be in accordance with plan of execution.

nized. If a problem and its solution require more explanation than can be discussed in several sentences, attach a short discussion to the back of the report explaining the issue.

15.3.8 Managing Personnel. With your project team in place and actively working on the project tasks and your cost monitoring and reporting functioning, you should now concentrate on personnel management techniques. It is important that you have face-to-face conversations

TABLE 15.10—EXAMPLE COST STATUS SUMMARY

Project name: Remote Field Equipment and Tasks	Cost Estimate U.S. $	Committed U.S. $	Invoiced to Date, U.S. $	Estimated Final Cost U.S. $
Production skids				
Test separator	32,000	33,240	33,240	33,240
High-pressure separator	30,000	30,978	30,978	30,978
Low-pressure separator	30,000	33,250	33,250	33,250
Heater treater	80,000	82,650	82,650	82,650
Dehydration system	110,000	114,906	112,226	114,906
Production liquid flash vessel	15,000	17,360	16,827	17,360
Vent scrubber	10,000	9,951	9,951	9,951
Fuel gas system	10,000	8,785	8,785	8,785
Compressor	410,000	410,829	410,829	410,829
	727,000	741,949	738,736	741,949
Miscellaneous equipment				
Inlet manifold	55,000	57,163	57,163	57,163
MCC building	25,000	22,850	22,850	22,850
Bad-oil tank	5,000	3,818	3,818	3,818
Storage tank	150,000	145,000	145,000	150,000
Process valves and meters	60,000	55,829	55,829	55,829
Fire-fighting/safety	10,000	14,590	12,059	14,600
Generators and switch gear	45,000	42,408	42,408	42,048
Motor control breakers	30,000			
LACT	80,000	69,888	69,488	70,000
Freight and miscellaneous	10,000	9,839	9,839	9,839
	470,000	421,385	418,454	426,308
Instrumentation				
Main panel	37,500	42,673	41,788	43,000
Installation	40,000	28,970	20,695	34,500
	77,500	71,643	62,483	77,500
Field installation				
Mob/demob/transport	80,000	46,000	28,678	60,000
Foundations	50,000	65,000	50,000	65,000
Piping	350,000	227,000	124,200	350,000
Electrical	40,000	42,250	29,403	43,000
Site survey	12,000	10,000	10,000	10,000
Commissioning/startup	25,000	0	0	25,000
	557,000	390,250	242,281	553,000
Pipelines				
Line pipe	460,000	428,000	428,000	428,000
P/L construction	185,000	201,000	100,000	235,000
	645,000	629,000	528,000	663,000
Design engineering				
Engineering	100,000	97,742	39,355	97,742
Drafting	100,000	92,297	26,292	92,297
Travel and miscellaneous expenses	10,000	9,022	2,568	9,022
	210,000	199,061	68,215	199,061
Construction management and inspection				
Personnel	50,000	39,466	39,466	48,000
Travel and lodging	20,000	10,758	10,758	12,000
Miscellaneous expenses	60,000	48,743	48,743	55,000
	130,000	98,967	98,967	115,000

with the project team supervisors every week to discuss the project progress in more detail than can be handled with e-mails and phone conversations. The formality of this meeting is up to you, but at the least, an action item list noting the required action, the person responsible for handling the action, and the completion date should be compiled and circulated to the attendees and project team supervisors.

One thing to remember now that the project is in the execution phase is that one of the best ways to stop project momentum and efficiency is to allow change for change's sake. Un-

TABLE 15.11—EXAMPLE PROJECT STATUS REPORT FORMAT

Project Status Report No. _____

For period _____ through _____

I. Summary: Summarize individual task status, percent completion, and major accomplishments achieved during reporting period.

II. Costs: Project cost control report.

III. Activities planned: bid equipment, award pipeline material.

IV. Problem areas.

V. Appendices: overall progress, bar chart schedule.

less you find that part of your plan is wrong and will not work as planned, do not change. You will constantly be shown "better and cheaper ways" to do things that are already in progress. You should review each proposal carefully and be very resistive to any change. Any change will disrupt more plans and have greater schedule impact than you initially can identify and can lead to errors in engineering, which result in costly change orders and lengthy schedule impacts that are not immediately evident.

It is important that a project manager visits the engineering contractor and vendors often. During these visits it is important for you to determine that everyone on the project is working to the same goals and is "playing off the same sheet of music." Ask the fabricators and equipment suppliers what documents and drawings they are using for their work and assure yourself that these are the correct versions. Do not approve scope and execution plan changes without discussion with your boss and engineering company manager to assure that you see the full picture. Do not change the project equipment for a "better way" unless the original equipment was incorrect or would not function correctly. Changing project scope or equipment on the fly is one of the better ways to assure project failure. Do not be afraid to say, "I don't know, but I will find out quickly," and keep your promise. Pay attention and ask questions that will increase your knowledge of this type of work and try to understand how the contractors operate and what generates their cash flow and profits. Good people to talk to are the engineering contractor's engineering manager, operations people, and the shop and field inspectors. This is the time to learn how the system is supposed to work as the final exam is on the horizon.

15.3.9 Commissioning and Startup. In the course (not necessarily a smooth course) of the project, the POs will be turned into fabricated equipment and purchased materials and shipped to the site. Working under service contracts, field labor will clear the site and pipeline right-of-way and install the various pieces according to plans furnished by the engineering company. Now comes the final test—how to make it work. This part of the project is known as commissioning and startup and is the payoff for all the previous work. It is important enough that it should be considered in all phases of the project design and that a full-time instrument engineer or technician should be assigned to help accomplish the task.

Commissioning is the site checking of all equipment installed on site to ensure final compliance with the design and specification standards to which it was fabricated, purchased, and installed. Shop inspections and factory acceptance tests are considered precommissioning by this definition. The commissioning manager's job is to confirm that the equipment is installed

as per the design, is correctly tested, and is safe for the introduction of hydrocarbons. This includes all piping, electrical, instrumentation, and safety equipment.

Planning, executing, and writing the startup and operating manual is a full-time job over the last half of the project schedule and maybe even longer if the installation is complex. All commissioning and startup documentation should be reviewed by the appropriate project team members before work begins. The commissioning manager is assisted by the site installation contractor's personnel. It is very important that the installation operator be involved in this part of the project. This is his or her chance to do a final check and plan the operation program.

When the commissioning manager has completed his or her work, the installation operator confirms that it is done and begins the startup procedures. The installation operator will be in charge of the installation startup and has final approval over the commissioning manager's work. When the installation operator is satisfied that the commissioning is complete, he or she will start up the facility. This is the final test of the project. The installation operator is assisted by members of the project commissioning team for the initial startup.

15.3.10 Project Closeout. After successful installation startup, the project manager turns the startup and operating manual over to the installation operator and supervises the storage of project files. The closeout accounting and financial documentation could take 2 months or more to complete, depending on the complexity of the project, the final cost, and the possible requirement for a supplemental AFE to cover any significant cost overrun.

AUTHOR INDEX

A
Arnold, K.E., 395–438

B
Bucknell, J., 525–564

C
Chin, R.W., 13–59

D
Darby, R., 59

G
Green, D.W., 59
Griffith, P., 332
Grimley, T., 456

J
Juniel, K., 124–183

K
Kreider, G.J., 566–590

L
Lacy, W.N., 198
Lalani, M., 525–564
Lange, J., 301–316

M
May, D., 317–394
McKetta, J.J., 198–199

O
O'Connor, P., 525–564
Olds, R.H., 198–199

P
Patel, D., 461–504
Perry, R.H., 58–59

R
Rawlins, C.H., 124–183

S
Sage, B.H., 198
Stevens, R.S., III, 317–394
Stewart, M.I., Jr., 231–259, 395–438
Stilt, G.H., 505–523
Strawn, J., 301–316

T
Taylor, R.A., 261–300
Thro, M., 1–11

W
Warren, K.W., 61–122
Wehe, A.H., 198–199
Wichert, E., 185–229

Y
Yaitel, D., 334

Z
Zanker, K.J., 456

SUBJECT INDEX

A

above-NEMA motors
  altitude and ambient temperature for, 500
  enclosures for (*See* above-NEMA motors, enclosures for)
  sizes of, 500
  torque and, 500
above-NEMA motors, enclosures for
  horizontal drip-proof weather-protected type I, 501
  horizontal drip-proof weather-protected type II, 501
  OPD, 501
  TEFC for above-NEMA motors, 501
  totally enclosed, air-to-air cooled (TEAAC), 501
  totally enclosed, fan-cooled, explosion-proof, 501
  totally enclosed, water-to-air cooled (TEWAC), 501
acceleration head and pumps, 237
AC/DC coalescer, 99–100
AC/DC dehydrator, 99
acid gases, 187
AC motor drives
  constant horsepower load and, 494–495
  constant torque load and, 494
  distance between drive and motor, 496
  motor selection, 496
  reduced voltage and frequency starting, 495–496
  service factor on AC drives, 496
  volts per hertz ratio, 493–494
AC motors to load, matching
  centrifugal pump, 496–497
  load-characteristics tables, 496
  load torque calculation, 496
  screw-down actuator, 497–498
AC treaters, 96
adiabatic compression. *See* isentropic compression
adiabatic efficiency. *See* isentropic efficiency
agitation, 71
air-cooled systems, 297
aircraft turbine engines, 311
air/fuel ratio control, 306
air properties and hydrostatics, 233
aldehydes (CHO) pollutants, 306
alternating-current (AC) field, 73–74
alternating-current (AC) motors, 479–480
  induction motors, 480–481
  rotor rotation, 481–484
  synchronous motors, 484–485
American Petroleum Institute (API) *RP2A,* 539–540
American Petroleum Institute (API) standards, 262, 265, 439, 442, 510
  for distance piece, 284
  field-welded storage tanks and, 508
  floating-roof tanks and, 513, 515–516
  shop-welded tanks and, 506–507
  tank leak detection and, 518–519
  vent system design and, 512–513
American Petroleum Institute's (API's) *Recommended Practice (RP) 14C* approach, 398
  abnormal operating conditions and, 400
  blowdown/vent system and, 402–403
  effects of hydrocarbon releases and, 400–401
  emergency suport systems (ESS) and, 401
  ignition-prevention measures and, 405
  normal operating ranges and, 399–400
  pneumatic supply system and, 402
  process components and, 399
  process variables and, 399
  production-facility safety analysis and, 407–408
  production-process safety systems and, 401–404
  safety analysis and, 406–407
  safety analysis checklists (SAC) and, 406
annular combustor. *See* radial combustor
ANSI/ASME Standard B31.3 code, 343, 345–346, 353
ANSI/ASME Standard B31.4 code, 343, 346, 353
ANSI/ASME Standard B31.8 code, 343, 346–353
antifoams, 176–177
antisurge valves, 281
API *RP 500,* 477
API *RP 14C,* 16, 113
API separator, 128
Arctic, environmental conditions in, 558–559
AST. *See* atmospheric storage tank
atmospheric corrosion and pipelines, 370
atmospheric storage tank (AST), 508
Authorization for expenditure (AFE), 569, 582–587, 590
  initial project cost estimate and, 582–583
axial flow cyclones, 29
axial-flow impellers, 242

B

backpressure valves, 245
ballistic model, 39
basic sediment and water (BS&W), 2
bearings and reciprocating compressors, 286
Bernoulli's equation, 237, 318–320
best-efficiency point (BEP), 241
biocide testing, 176
  bacteriostatic test, 176
  planktonic time kill test, 176
  sessile bacteria time kill test, 176
blowdown valves
  centrifugal compressors and, 281
  and reciprocating compressors, 294
bolting materials standards and pipeline systems, 357
booster compressors, 262
branch connections standards and pipeline systems, 359
bridge-supported flares, 428
BS&W measurements, 81
bubblepoint, 2
burners and fire tubes, 113–114
burn pits and flare stacks, 434

C

can combustors, 312
capacity
  control and centrifugal compressors, 280–281
  reciprocating compressor and, 287–288
  reciprocating pumps and, 255
carbon filters, 208
carbon monoxide (CO)
  gas turbine engines and, 315
  reciprocating engines and, 306–307
cartridge filters, 164–165
casinghead compressors, 262
centrifugal compressors, 261, 263–265
  antisurge valves and, 281
  blowdown valves of, 281
  capacity control and, 280–281
  components of, 272–278
  discharge check valves of, 281

discharge coolers and, 282
flare valves of, 281
installation processes of, 279–282
maintenance of, 282
mezzanine-mounted installations of, 279–280
multistage, 272
performance characteristic of, 278
purge valves of, 281–282
relief valves of, 281
safety and monitoring devices of, 282
shutdown valves of, 281
single-stage, 272
speed control and, 280
stonewall (choke) limit of, 279
suction scrubbers and, 282
suction throttle valves and, 280
surge limit of, 278–279
variable inlet guide vanes and, 280–281
vent valves and, 282
vibration monitoring and, 282
centrifugal pumps, 231, 496–497
affinity laws and performance of, 247
backpressure valves and, 245
check valves and, 249–250
classifications, 240
considerations and hydrostatics, 233–234
flow rate regulation and, 244
impeller axial loading and, 241
impeller radial loading and, 241
impeller types and, 240–241
installation considerations, 248–250
minimum-flow recirculation valve and, 245
multistage, 241
number of impeller and, 241
parallel operation of, 241–242
pump-performance curves and, 242–243
pump priming and, 247–248
pump specific speed and, 241–242
series operation of, 242
single-stage, 241
speed change and, 245–246
system head curve and, 243–244
variable-speed control and, 246–247
centrifugation, 77
centrifuges, 137, 144
chemical demulsifiers, 68–69
chemical effect mechanisms
crystal modifiers, 173
dispersion, 173
sequestering, 173
threshold effects, 173
chlorine, 175–176
clearance volume, 289
double-acting cylinder (head-end and crank-end clearance), 291
of single-acting cylinder (crank-end clearance), 290
of single-acting cylinder (head-end clearance), 289
closed floating-roof tank (CFRT), 508
closed impellers, 240–241
coalescense, 125
coalescers, 30
coalescing plates, 71–72
coarse strainers, 161–163
commissioning, 589–590
compact deoxygenation, 167–168
compliant and floating systems
compliant towers, 544
deep-draft floaters, 546–548
floating production systems, 548–551
tension leg platforms, 544–546
wet vs. dry trees, 548
composite plate electrodes, 107
compressibility factor, 268–269
compression ratio, 270
compression theory
actual (inlet) volume flow and, 269–270
compressibility factor and, 268–269
compression stages and, 271–272
head and, 267–268
intercooling and, 270
isentropic compression, 265–266
isentropic efficiency and, 268
mass (weight) flow and, 269
polytropic compression, 266–267
polytropic efficiency and, 268
standard volume flow and, 269
compressors
booster, 262
capacity (flow) of, 269–270
casinghead, 262
centrifugal (*See* centrifugal compressors)
classification and types, 262–265
dynamic compressors, 262
flash gas, 261
gas lift, 261
integral, 263
positive displacement compressors, 262–263
power requirements and, 270
reciprocating, 262–263
reinjection, 261–262
rotary positive displacement compressors, 263
screw, 263
selection of, 270–271
separable, 262–263
vane, 263
vapor recovery, 262
concentric ring valves, 287
condensable vapors, 17
copper-ion displacement test, 174
CO_2 removal, membrane processing for, 225–227
coriolis flowmeters, 457
advantages and disadvantages, 459
CPU and, 443
flow velocity and, 443
ISO standard and, 457–458
LACT units and, 448
operational theory of, 443, 459
overview of, 458–459
sensor considerations and, 443
sizing of, 459
transmitter considerations and, 443–444
corrosion, 173
coupons, 175
protection, 173–175 (*See also* corrosion prevention)
corrosion, emulsion-treating equipment
cathodic protection, 114
corrosion inhibitors, 114
exclusion of oxygen, 114
internal coating, 115
metallurgy, 115
corrosion prevention
of offshore pipelines, 380
of onshore pipelines, 368–370
Splashtron and, 380
corrosivity and pumps, 236
counterflow-desalter, 105
crank pin bearings, 286

crude oil, 2, 15–16
viscosity/temperature relationships for, 67
crude-oil emulsions, economics of treating, 115–117
crude-oil emulsions, sampling and analyzing, 64
coalescence (flocculation), 65
destabilization (coagulation), 65
gravity separation (sedimentation), 65
cylinder(s)
cooling, 296–297
piston displacement and, 288–289
reciprocating compressors and, 283–284

D

deep draught caisson vessel (DDCV), 531
deepwater and ultradeepwater developments, future technology, 562–563
dehydration of natural gas, 198
deliquescing, 217
desiccants, 215
delta-delta connection, 467–468
delta-wye connection, 468
demineralization, 147, 150
demisters, 26
demisting cyclones, types of, 29
demulsifier, 70
deoilers, 135
depressurization, stages of, 13–14
derating factors
altitude and temperature, 493
frequency, 492–493
voltage variation, 492
derrick-supported flares, 428
derrick-supported stacks, 427
desalting
analytical methods, 81–82
dilution water, 78–79
effluent-water quality, 80
mixing efficiency, 78
water recycle, 79–80
water solubility in crude oil, 80–81
desanders, 142
desanding hydrocyclones, 142–144
desiccant dehydration process, 216
dry, 214–215
design
elevated flare stacks, 427
of flare and vent disposal systems, 424
flare stacks, 429–436
flow rate, 232
for piping and pipeline systems, 318–335
pressure, 10
for pumps, 232–233
vent stacks, 435–436
detailed engineering, 568
diaphragm pumps, 253–255
diesel engines, 303–305
diethanolamine (DEA), 191
diglycolamine (DGA), 190
diisopropanolamine (DIPA), 191
dikes, 520
dipolar attractive force, 95
direct current (DC) field, 73
discharge check valves, 281
discharge coolers, 282
discharge head, 238
discharge piping
centrifugal pump installation and, 249–250
positive-displacement pump installation and, 256
relief systems and, 421–422
discharge pressure and reciprocating compressor performance, 293
dispersed-gas units, 133–135
dissolved gases, 236
dissolved-gas units, 133
distance piece, 284–285
distillation, 77–78
distribution transformers, 466
double-acting compressor cylinders
clearance volume of, 291
piston displacement of, 288–289
rod loads of, 293
double hot AC, 96
droplet settling theory, 39
dry sweetening processes, 197
dynamic compressors, 262. *See also* centrifugal compressors
polytropic compression and, 266–267
dynamic scale-inhibition test, 173

E

eccentric reducers, 249
electrical-distribution systems
primary distribution system and voltages, 465–466
secondary electrical system, 466–469
electrical grounding, 469–471
electrical probes, 173, 175
electrical systems
above-NEMA motors (*See* above-NEMA motors)
AC motor drives (*See* AC motor drives)
alternating-current (AC) motors (*See* alternating-current (AC) motors)
derating factors (*See* derating factors)
electrical codes and standards, 461
electrical-distribution systems (*See* electrical-distribution systems)
electrical grounding, 469–471
enclosures (*See* electrical systems, enclosures)
hazardous-area classification (*See* hazardous-area classification, electrical systems)
matching AC motors to load (*See* AC motors to load, matching)
motor specifications, 485–489
motor starting, methods of (*See* motor starting, methods of)
mounting, NEMA dimensions, 500
NEMA motor characteristics, 489–490
power factor and use of capacitors, 473–475
power sources, 461–463
power supply, sizing and selection of, 463–465
voltage drop in (*See* voltage drop in electrical systems)
electrical systems, enclosures
explosion-proof (XP), 499
open drip-proof (ODP), 498–499
totally enclosed, fan-cooled (TEFC), 499
totally enclosed nonventilated (TENV), 499
electric motors. *See also* electrical systems
pump drivers and, 257
electrified oil field, 466
electrodes, 106–107
electrostatic coalescence, 72–74, 107
electrostatic coalescing treaters, 95–104
elevated flare stacks, 427
elevation head and pumps, 237
emergency-shutdown (ESD) systems, 389–390
emergency suport systems (ESS), 401. *See* also emergency-shutdown systems
emission pollutants
gas turbines and, 314–315
reciprocating engines and, 305–307

emulsifying agents, 63
emulsion(s)
  definition of, 62
  effect of, on fluid viscosity, 64
  emulsifying agents, 63
  external phase, 62
  filtering and, 75
  formation of crude, 62–63
  prevention of, 63
  sampling and analyzing, 64–65
  stability of, 63–64
emulsion(s), operational consideration of
  burners and fire tubes, 113–114
  corrosion, 114–115
  treating emulsions from enhanced oil recovery (EOR) projects, 112–113
  water calcification, 113
emulsion-heating equipment, 109
emulsion-treating equipment, 82–83
electrostatic coalescing treaters, 95–104
  FWKOs, 83–84
  horizontal emulsion treaters, 93–95
  operational parameters, 104–105
  settling tanks, 85–91
  storage tanks, 84–85
  vertical emulsion treaters, 91–93
emulsion-treating methods, 65
  agitation, 71
  centrifugation, 77
  chemical demulsifiers, 68–71
  coalescing plates, 71–72
  distillation, 77–78
  electrostatic coalescence, 72–74
  fibrous packing, 75–76
  filtering, 75
  gravity settling, 76
  heating, 66–68
  retention time, 76–77
  water recycle, 74–75
  water washing, 74–75
emulsion-treating vessels, 74–75
Endolock™ system, 519
engineer, procure, and construction-management (EPCM), 567, 581–582
engineer procure construct (EPC), 567
engine fuels
  for gas turbine engines, 315–316
  for reciprocating engines, 308
entrainment removal, mechanisms of, 26
epoxy-based paint system, 517
equations, mathematical
  Bernoulli equation, 318–320
  for equivalent lengths, 341
  for flow coefficient, 336–341
  Hazen-Williams equation, 323, 327
  Panhandle equation, 329–330
  for pipe wall thickness, 341, 343
  for resistance coefficient, 336–341
  Spitzglass equation, 330
  Weymouth equation, 327, 329–330
equipment grounding, 470
erosional velocity, and pipes, 354
exhaust emissions
  air/fuel ratio control and, 306
  catalyst reduction for control, 306
  gas turbine engines and, 314–315
  lean-burn engines and, 306–307
  reciprocating engines and, 305–307
  rich-burn engines and, 306–307
exhaust silencers, 314
expansion turbines, 257–258
expansion vessels, 14
explosion-proof (XP), 499
external corrosion and pipelines, 369–370
external floating-roof tank (EFRT), 508
external-gear pumps, 251

F

ferric sulfate, 171–172
fiber-bed
  filter cartridges, 32
  mist eliminators, 30
fiberglass reinforced plastic (FRP), 507
fiber-reinforced plastic (FRP), 179
fibrous packing, 75–76
field-welded storage tanks, 507–508
  API standards and, 508
film-forming inhibitors, 173
filters, 15
  coalescence, 31
fire tubes
  burners and, 113–114
  and hazards, 396
fixed-roof tank (FRT), 508–509
  vent system design and, 512
fixed steel and concrete gravity base structures, 534–544
flanges, 356–357
flare and vent disposal systems
  design of, 424
  flame arrestors and, 427
  flare stacks and, 427–436
  flashback protection and, 425
  fluidic seals and, 427
  knockout drums in, 424–425
  molecular drums in, 426–427
  seal drums in, 425–426
flare stacks
  burn pits and, 434
  design of, 429–436
  elevated, 427
  exit gas velocity and, 429–430
  flame distortion and, 433
  flare-tip diameter and, 429–430
  gas dispersion limitations and, 433
  height, 431–433
  offshore flare-support structures and, 427–429
  pressure drops and, 430–431
  purge gas and, 434
  radiation considerations and, 433
flare valves and centrifugal compressors, 281
flash chamber, 14
flash gas compressors, 261
floating production, storage, and offloading (FPSO)
  systems, 35, 528–533, 548–550
  vessels, 34
floating production system (FPS), 529–532, 548–549
floating-roof tanks
  API standards and, 513, 515–514
  CFRT, 514, 516
  IFRT, 513–514, 516
  net-working capacity and, 514–515
  product loss management and safety considerations for, 513–514
  product vapor control with, 515–514
  PV and, 514
  tank appurtenances and, 516
flow assurance, 554–555
flow capacity. *See* capacity

flowmeters. *See* liquid meters
fluid principles and hydraulics
  fluids types and, 231
  pumping-system design and, 232–233
  pump types and, 231
foaming oil, 30–31
foundation design
  centrifugal pumps installation and, 248–249
  positive-displacement pumps installation and, 256
  of reciprocating compressors, 296
four-stroke cycle engines, 303
free gas, 17
free-water knockout (FWKO), 83–85
  vessel, 68
FRP. *See* fiberglass reinforced plastic; fiber-reinforced plastic
FRT. *See* fixed-roof tank

G

gas blanketing system
  natural gas and, 511
  pressure regulator and, 511
  vent system design and, 512
gas blowby, 418–419
gas facility, blocks of
  compression, 8
  cooling, 6–7
  gas dehydration, 7–8
  gas processing, 8
  gas treating, 7
  heating, 6
  separation, 6
  stabilization, 8
gas flotation units, 132–133
  dispersed-gas units, 133–135
  dissolved-gas units, 133
gasket materials standards and pipeline systems, 357
gas lift compressors, 261
gas meters, 449
  coriolis, 457–459
  orifice, 450–452
  turbine, 452–455
  ultrasonic, 455–457
gas plants
  processes, 186
  refrigeration process in, 219
gas scrubber, 15
gas stripping, 166–167
gas treating and processing
  contactor design considerations, 211–212
  contactor or absorber, function of, 202–203
  dehydration of natural gas, 198
  dehydration with deliquescing desiccants, 215–218
  dehydration with glycol, 198–200
  dewpoint control by refrigeration, 219–221
  dry desiccant dehydration, 214–215
  dry sweetening processes, 197–198
  environmental concerns, 213
  glycol circulating system, components of, 207–209
  glycol dehydrator BTEX and VOC emission control, 213–214
  glycol purity enhancement methods, 206–207
  glycol regeneration, 206
  hybrid process, 194–195
  IFPEXOL process, 221–222
  inlet separator, function of, 200–202
  instrumentation and controls, 209–211
  Joule-Thomson expansion, 224–225
  membrane processing for CO_2 removal, 225–227
  NGL extraction methods, 222–223
  nonregenerative chemical solvent (scavenger) processes, 196–197
  objectives, 185
  operation checklist, normal, 212
  physical solvents, 194
  process description, 200
  reboiler, function of, 203–204
  reduction/oxidation (redox) process, 195–196
  sales-gas specifications, 185–187
  screening program for optimum process selection, 198
  sour gas sweetening and (*See* sour gas sweetening)
  trouble diagnosis, 212–213
  turbo-expander process, 223–224
  typical process equipment, 215
  water dewpoint and hydrocarbon dewpoint control, 218–219
  water dewpoint depression, 204–206
  water dewpoint determination, 212
gas turbine engines
  airflow in, 309
  air inlet system and, 313–314
  Brayton cycle and, 308
  combustor types and, 311–312
  degree of packaging and, 313
  efficiency for, 310
  exhaust emissions and, 314–315
  exhaust heat and, 316
  exhaust silencer of, 314
  fuels for, 315–316
  heavy industrial, 311
  inlet air filtration and, 313
  inlet air temperature and, 310
  inlet silencer and, 314
  light industrial, 311
  noise attenuation and, 313
  oil coolers and, 314
  pressure drop and, 313
  as prime movers, 308–316
  pump drivers and, 258
  rating point and, 310
  shaft design and, 312
  site rating and, 310
  speed limitations for, 309–310
  temperature limitations for, 310
  turbine inlet temperature (TIT) and, 309
  types of, 310–313
  types of duty and, 311
gas turbine meter
  advantages and disadvantages, 454
  ISO standard and, 452
  K factor and, 454
  operation theory of, 453–454
  overview of, 452–453
  sizing of, 454–455
gas velocity, 354
gathering pipelines, 317, 364–365
gauge hatches, 510
general services contract (GSC), 567–568, 581
glass wool, 75–76
GLYCalc™, 214
glycol circulating system, components of, 207–209
  filters, 208
  glycol circulating pump, 207–208
  glycol flash tank, 209
  glycol piping, 209
  heat exchange, 208
  strainer, 208–209
  surge drum, 208

glycol dehydration system, 8,16

glycol dehydrators, trouble diagnosis of
  corrosion, 213
  foaming, 212–213
  not meeting water dewpoint, 213
glycol purity enhancement methods, 206–207
glycol regeneration, 206
granular-media filters, 163–164
gravity-separation devices, 125–126
  API separator, 128
  plate coalescers, 128–131
  skim piles, 131–132
  skim tanks and vessels, 126–128
gravity settling, 76, 141–142
gun-barrel tanks, 90–91
guy-wire supported stacks, 427

H

hardness leak, 148–149
haulage, 145
hazards
  analysis, 398
  excess temperature and, 396, 398
hazardous-area classification, electrical systems
  International Electrotechnical Commission (IEC) Standards, 477–479
  North American Standards, 475–477
hazard tree, 396–398
Hazen-Williams equation, 323, 327
head(s)
  compression and, 267–268
  losses and pumps, 237
  pumps hydrostatics and, 233–234
heavy industrial gas turbine engines, 311
high density polyethylene (HDPE), 518– 519
high-velocity AC, 96
horizontal-directional-drilling (HDD) methods, 372
horizontal emulsion treaters, 93–95
hot- and warm-lime softening, 150–153
hot potassium carbonate (K_2CO_3) (Hot Pot), 191
hydrates, 2, 6, 186, 219, 221, 224
hydraulic motor, 439
hydraulic principles and pumps, 233–240
hydraulic turbines and pump drivers, 257–258
hydrocarbon dewpoint, 2
hydrocarbons (HC), 2
  reciprocating engines and, 306
  releases and *RP 14C* approach, 400–401
hydrocarbons separation from water
  coalescence, 125
  dispersion, 124–125
  gravity separation, 124
  theory, 124
hydrocyclones, 6, 13, 113, 135–137, 142, 160, 163, 171
hydrodynamics and pumps, 237–240
hydrostatics
  centrifugal pumps considerations and, 233–234
  positive-displacement pumps considerations and, 234–236
  pumps and, 233–236
hydrostatic testing and pipelines, 387, 389

I

IFPEXOL process, 221–222
impeller(s)
  axial loading and centrifugal pumps, 241
  closed impellers, 240–241
  with high specific speeds, 242
  with low specific speeds, 242
  with median specific speeds, 242
  multistage centrifugal pumps and, 241
  open impellers, 240
  partially open impellers, 240
  radial loading and centrifugal pumps, 241
  single-stage centrifugal pumps and, 241
  types and centrifugal pumps, 240–241
indirect-fired heater, 89
induction motors, 480–481
inlet air filtration system, 313–314
inlet cyclones, 19–23
inlet separator, function of, 200–202
inspection and pipelines, 389
instability limit, 96
installation guidelines
  of centrifugal compressors, 279–282
  centrifugal pumps and, 248–250
  positive-displacement pumps and, 255–257
  of reciprocating compressors, 293–295
  relief systems and, 421
instrumentation and controls, gas treating and processing
  gas flow control, 209
  lean glycol circulation rate, 209–210
  liquid level controls, 210–211
  pressure and temperature indicators, 211
  reboiler temperature, 210
Instrument Soc. of America (ISA), 401
insulators, 106, 369
integral compressors, 263
  frame and, 283
interconnecting piping, 317
intercooling, 270
interface-sludge drains, 109
intermediate pressure (IP) separator, 4
internal-combustion engines, 258
internal floating roof tank (IFRT), 508, 513–514
internal-gear pumps, 252
International Electrotechnical Commission (IEC) Standards, 477–479
ion exchange, 147–150
isentropic compression, 265–266
isentropic efficiency, 268
isolation (block) valves, 422–423
ISO standards, 450. *See also* American Petroleum Institute (API) standards
  coriolis flowmeters and, 457–458
  gas turbine meter and, 452
  orifice meters and, 450
  ultrasonic meters and, 455

J–K

joint operating agreement (JOA), 565, 569, 581–583
Joule-Thomson expansion, 224–225
K-factor, 443, 454
kinetic-energy pumps, 231. *See also* centrifugal pumps
knockout drums, 424–425

L

LACT. *See* lease automated custody transfer
LACT units, 447
  considerations, 448–449
  coriolis meter and, 448
  positive-displacement meters and, 448
  sediment and water (S&W) monitors, 448–449
  turbine meter and, 448
laminar flow, 24–25
leak detection, 518–520
  API standards and, 518–519
  HDPE and, 518–519

RPB and, 518–519
leaks and hazards, 396, 398
lean-burn engines, 306–307
lease agreement, 565
lease automated custody transfer (LACT) system, 439
level controllers and gauges, 112
light industrial gas turbine engines, 311
liquefied petroleum gas (LPG), 8, 446
liquid distribution systems, 107–108
liquid knockout, 14
liquid leaks control and tanks
API standards and, 518–519
cathodic protection and external corrosion, 518
corrosion protection, coatings, 516–518
secondary containment and, 518–520
liquid meters
coriolis flowmeters, 443–444
flow calculations and, 449
flowmeter performance and, 445–446
flowmeter selection and, 446–447
LACT units and, 447–449
linearity and, 445
metering system design, 444–445
positive displacement, 439–441
proving and, 447
repeatability and, 445
resolution and, 445
turbine flowmeters, 441–443
turndown and, 445
liquid velocity, 353
load-characteristics tables, 496
load torque calculation, 496
lobe pumps, 252–253
low-shear pumps, 137

M

mass (weight) flow, 269
mathematical equations
Bernoulli equation, 318–320
for equivalent lengths, 341
for flow coefficient, 336–341
Hazen-Williams equation, 323, 327
Panhandle equation, 329–330
for pipe wall thickness, 341, 343
for resistance coefficient, 336–341
Spitzglass equation, 330
Weymouth equation, 327, 329–330
maximum allowable working pressure (MAWP), 10, 406
cylinders and, 283
relief systems and, 408, 416–417, 424
mechanical flow diagrams (MFDs), 568
primary elements of, 572
mesh, 26–27
meter factor, 447
metering system design
bulk swirl and, 444–445
dowel pinning and, 444–445
methyldiethanolamine (MDEA), 191
mezzanine-mounted installations, 279–280
minimum facility platforms (MFPs), 541–542
mixed-flow impellers, 242
mixing devices, 111–112
molecular drums and disposal systems, 426–427
monitoring devices. *See* safety devices
monoethanolamine (MEA), 190
Moody friction factor, 320–323
motor starting, methods of
autotransformer starting, 490–491
full-voltage starting, 490
part-winding starting, 492
soft starting, 492
wye-delta starting, 491
multiphase flow regimes, 331–335
multiple-screw pumps, 253
multistage centrifugal compressors, 272
multistage centrifugal pumps, 241
multitube cyclone inline separator, 38–39
multitubular cyclone separator, 29–30

N

NACE Standard MR0175, 187
National Association of Corrosion Engineers (NACE), 187, 518
National Electrical Manufacturers Association (NEMA), 479–480, 487, 493
natural gas, 17
dehydration of, 198
natural-gas liquids (NGL), 8
naturally aspirated engines, 305
NEMA MG 127, 496
NEMA motor characteristics, 489–490
accelerating torque and breakdown torque, 489
full-load torque, 489
special design motors, 490
speed/torque curve, 489
standard motor designs, 489
starting current and full-load current, 489–490
starting torque, 489
net positive suction head (NPSH), 238
available (NPSHA), 238–239
margin, 239
required (NPSHR), 238
NGL extraction methods, 222–223
nondestructive testing and pipelines, 389
nonregenerative chemical solvent (scavenger) processes, 196–197
North American Standards, 475–477

O

offshore flare-support structures, 427–429
offshore pipelines
construction of, 375–379
corrosion prevention of, 380
design of, 372–375
Splashtron and, 380
offshore production operations
crude-oil disposal, 556–558
gas disposal, 558
process equipment, 555–556
water disposal, 558
well completions, 555
well servicing and well workover, 556
oil and gas processing, 1–2
design safety of, primary and secondary protection, 9–10
example oil facility of, 3–6
function of facility and, 2–3
gas facility and, 6–8
process control of, 9
oil facility, functions of
auxiliary systems, 3
main process, 2–3
secondary process, 3
oil facility, steps of
oil treating, 5
produced-water treating, 6
separation, 3–5
oilfield facility, 1–2
oil/gas separator

advantages and disadvantages of, 18
components of, 17–18
examples of, 36–39
functions of, 13–14
general, 13–15
internals, 18–30
problems (*See* oil/gas separator, problems)
separation performance, 18
separator orientation, 18
separator sizing (*See* separator sizing)
well fluids and characteristics (*See* oil/gas separator, well fluids and characteristics)
oil/gas separator, problems
corrosion, 34
foaming, 30–33
paraffin, 33
sloshing, 34–35
solids and salt, 33–34
stable control, 35–36
oil/gas separator, well fluids and characteristics
condensable vapors, 17
condensate, 16
crude oil, 15–16
free gas, 17
impurities and extraneous materials, 17
natural gas, 17
solution gas, 17
water, 17
oil seller, 5
oil-wet solids, 63
onshore pipelines, 366
construction process in, 371–372
corrosion prevention of, 368–370
horizontal-directional-drilling (HDD) methods and, 372
material selection of, 367
permits and special considerations of, 368
pipe selection and wall thickness of, 367
right-of-way (ROW) and, 367–368
route selection and survey of, 367
welding and pipe joining of, 370–371
open-delta, 468–469
open drip-proof (ODP), 498–499
open impellers, 240
open top tank (OTT), 508–509
operational parameters, 104–105
orifice meters
advantages and disadvantages, 453
Daniel Senior Fitting and, 450
ISO standard and, 450
operational theory of, 451
overview of, 450
sizing of, 451
vena contracta and, 450
OTT. *See* open top tank
overpressure
hazards and, 396
relief systems and, 414–415
owner prime, 567
oxides of nitrogen (NOx)
gas turbine engines and, 315
reciprocating engines and, 306–307
oxides of sulfur (SOx)
gas turbines and, 315
reciprocating engines and, 306
oxygen scavengers, 166, 176

P

Panhandle equation, 329–330
parallel plate interceptors (PPI), 128
partially open impellers, 240
particulate matter (PM) emission
gas turbines and, 315
reciprocating engines and, 306–307
perfect gas equation, 268–269
performance
of centrifugal pumps and affinity laws, 247
characteristic of centrifugal compressors, 278
curves of centrifugal pumps, 242–243
of flowmeter, 445–446
maps and reciprocating compressors, 293
of reciprocating compressors, 287–293
reciprocating-pump performance considerations, 255
physical solvents and gas treating and processing
Fluor solvent process, 194
Purisol, 194
Selexol process, 194
pigs and pipelines, 380–383
launchers and receivers of, 383–386
selection of, 386
slug catchers and, 386–387
pilot-operated valves, 415–416
pipe expansion, 362–363
pipe fittings standards and piping and pipeline systems, 358
pipelines
atmospheric corrosion and, 370
cathodic protection system and, 369–370
emergency-shutdown (ESD) systems and, 389–390
external corrosion and, 369–370
galvanic corrosion and, 370
gathering, 364–365
hydrostatic testing and, 387, 389
inspection and, 389
internal corrosion and, 368–369
nondestructive testing and, 389
offshore, 372–380
onshore, 366–372
pigs and, 380–387
supervisory-control-and-data acquisition (SCADA) control system and, 389–390
transmission, 365–366
welding and, 370–371
pipe-support spacing, 363–364
pipe wall thickness selection, 341
location classes for design and construction, 350–353
materials for, 343–345
piping codes and, 343–353
piping and pipeline systems
Bernoulli equation and, 318–320
Hazen-Williams equation and, 323, 327
Moody friction factor and, 320–323
multiphase flow regimes and, 331–335
Panhandle equation and, 329–330
pipe expansion and, 362–363
pipelines and (*See* pipelines)
pipe-support spacing, 363–364
pipe wall thickness selection and (*See* pipe wall thickness selection)
pressure breaks specification and, 361–362
pressure drop by valves and fittings in, 335–341
pressure-drop formulas and, 318–335
Reynolds number and, 320–323
simplified gas formula and, 327, 330
Spitzglass equation and, 330
valve, fitting, and flange pressure standards for, 355–361
velocity considerations and, 353–353
Weymouth equation and, 327, 329–330
piping codes, 343
ANSI/ASME Standard B31.3 code, 345–346

ANSI/ASME Standard B31.4 code, 346
ANSI/ASME Standard B31.8 code, 346–353
comparison of, 353
piping design
centrifugal pumps installation and, 249–250
positive-displacement pumps installation and, 256
piping systems, 177. *See also* piping and pipeline systems
piping vibration of reciprocating compressors, 296
piston displacement, 288
of double-acting cylinder, 288–289
of single-acting cylinder (head-end or crank-end displacement), 288
piston pumps, 253
plate coalescers, 128–131
plunger pumps, 253
pneumatic supply systems, 402
pollutants. *See* emission pollutants
polyelectrolites, 171–172
polytropic compression, 266–267
efficiency of, 268
head and, 267–268
polytropic efficiency, 268
positive displacement compressors, 262–263
positive displacement (PD) meters
design considerations for, 441
hydraulic motor and, 439
LACT units and, 448
operational theory of, 439–441
packing gland and, 440
positive-displacement pumps, 231
anchor-bolt-sleeve installation and, 256
considerations and hydrostatics, 234–236
grouting and, 256
installation guidelines, 255–257
metal-shim adjustments and, 256
reciprocating-pump performance considerations and, 255
reciprocating pumps and, 231, 253–255
rotary pumps and, 231, 250–253
types of, 250
power factor and use of capacitors, 473–475
power requirements
compressors and, 263, 265, 270
pumps and, 239
pressure breaks specification, 361–362
pressure drop
elevation changes and, 335
flare stacks design and, 430–431
gas turbine engines and, 313
in two-phase flow, 332–335
by valves and fittings, 335–341
pressure drop equations
for gas flow, 323, 325, 327–331
for liquid flow, 323
pressure-relief/safety devices, 360–361
pressure-relief valves. *See* relief valves
pressure safety valves (PSV), 9, 214
pressure-vacuum (PV), 514
valves, 509–510
pressurized cooling systems, 297
pressurized lubrication system, 297–298
prestressed concrete, 543
prime contractor, 567
prime movers
gas turbine engines as, 308–316
reciprocating engines as, 301–308
process and instrumentation diagram (P&IDs), 568, 582–584
rules for developing, 573
process flow diagrams (PFDs), 568, 582
items specified on, 571
procurement and contracting plan, 568
produced water, 123
treating, 6
produced-water discharge or steam injection
centrifuges, disc-stack, 137
deoiling hydrocyclones, 135–137
gas flotation units, 132–135
gravity-separation devices, 125–132
removing dissolved hydrocarbons from water, 138–141
removing dissolved solids from water, 146–154
separating free hydrocarbons from water, 124–125
separating suspended solids from produced water, 141–144
solids handling, 144–146
steam production, 154–159
walnut-shell filters, 137–138
production facility
fire/explosion and, 396
hazards analysis and, 398
hazard sources and, 396, 398
hazard tree and, 396–398
injury and, 396
oil pollution and, 396
primary defense and, 398
protection concepts and, 395–396
protection devices and, 398
production-facility safety system, 396
production-process safety systems, 401–404
production tanks, 505
API standards and, 520
dikes and, 520
site considerations for, 520
project execution
AFE and initial cost estimate, 582–583
choosing a project team, 581–582
commissioning and startup, 589–590
managing personnel, 587–589
monitoring and reporting progress and cost, 586–587
partners' approval, 583–585
procurement, 585–586
project closeout, 590
project initiation, 569–581
selecting an engineering company, 582
project formats, 567
project management of surface facilities
authorization for expenditure, 569
cost estimate, 568
detailed engineering, 568
engineer, procure, and construction-management (EPCM), 567
engineer procure construct (EPC), 567
equipment and task list, 568
facility layout, 568
general services contract (GSC), 567
joint operating agreement (JOA), 565
lease agreement, 565
mechanical flow diagrams (MFDs), 568
owner prime, 567
process and instrumentation diagram (P&IDs), 568
process flow diagrams (PFDs), 568
procurement and contracting plan, 568
project formats, 567
project schedule, 568
purchase order (PO), 567
pump(s)
centrifugal pumps (*See* centrifugal pumps)
corrosivity and, 236
design for, 232–233
drivers, 257–258

fluid principles and, 231–233
fluids types and, 231
hydraulic principles and, 233–240
hydrodynamics and, 237–240
hydrostatics and, 233–236
kinetic-energy pumps, 231
mechanical design and, 232–233
positive-displacement pumps
(*See* positive-displacement pumps)
power requirements and, 239
process design and, 232
specific speed, 241–242
suction head and, 237–238
types of, 231
for upstream production operations, 232
vendor selection and, 233
pump drivers
electric motors and, 257
expansion turbines and, 257–258
gas turbines and, 258
hydraulic turbines and, 257–258
internal-combustion engines and, 258
steam turbines and, 257
purchase order (PO), 567
purge gas and flare stacks, 434
purge valves, 281–282
Purisol, 194

R

radioactive tracers, 410
radial combustor, 312
radial-flow impellers, 242
rapid cycling, 422
reboilers
function of, 203–204
temperature, 210
reciprocating compressors, 262–263
bearings and, 286
clearance volume of, 289–291
components in, 282–287
compressor capacity of, 287–288
concentric ring valves and, 287
connecting rod and, 285
cooling systems for, 297
crankshaft and, 285–286
cylinder and packing lubrication for, 298
cylinder cooling of, 296–297
cylinders and, 283–284
distance piece and, 284–285
foundation design of, 296
frame of, 283
installation of, 293–295
lubrication systems for, 297–298
performance maps and, 293
performance of, 287–293
of piping vibration, 296
piston displacement of, 288–289
piston rod and, 285
piston rod packing in, 286
pistons and, 285–286
plate valves, 286–287
poppet-style valves and, 287
pressurized lubrication system for, 297–298
pulsations and, 295–296
rod loads of, 292–293
specific heat ratio and performance of, 293
speed and performance of, 293
splash lubrication systems for, 297
suction pressure and performance of, 293
suction temperature and performance of, 293
valves in, 286–287
vibration considerations of, 296
volumetric efficiency of, 287–288, 291–292
reciprocating engines
catalyst reduction and, 306
diesel cycle, 303–305
exhaust emissions and, 305–307
four-stroke cycle, 303
fuels for, 308
interchangeability and, 307–308
naturally aspirated, 305
as prime movers, 301–308
turbocharged, 305
two-stroke cycle, 301–303
reciprocating pumps, 231
capacity and, 255
diaphragm pumps and, 253–255
performance considerations and, 255
piston pumps and, 253
plunger pumps and, 253
speed and, 255
recuperative cycle, 310
reduced-voltage autotransformer (RVAT), 490–491
reduction/oxidation (redox) process, 195–196
refrigeration process in gas plants, 219
reid vapor pressure, 2
reinjection compressors, 261–262
reject valve, 169
release prevention barrier (RPB), 518–519
relief valves, 415
blocked discharge and, 418
centrifugal compressors and, 281
configurations, 423–424
dual, 417
gas blowby and, 418–419
multiple, 417–418
pilot-operated, 415–416
reactive forces and, 422
and reciprocating compressors, 295
spring-loaded, 415
relief valves and relief systems, 408–412
backpressure and, 417
considerations for, 415–418
discharge piping and, 421–422
fire/thermal expansion and, 420–421
inlet piping and, 421
installation and, 421
isolation (block) valves and, 422–423
liquid-discharge considerations and, 424
rapid cycling and, 422
relief-valve configurations and, 423–424
relief valves and, 415
resonant chatter and, 422
rupture-disk devices and, 415
selection of, 412–415
sizing of, 418–421
tailpipes considerations and, 422
remote flares, 428–429
resonant chatter, 422
reverse osmosis (RO), 146–147
Reynolds number, 24–25, 141, 320–323
rich-burn engines, 306–307
right-of-way (ROW) and onshore pipelines, 367–368
riveted, bolted, and shop-welded tanks, 505–507
API standards and, 506–507
RO. *See* reverse osmosis
roof-to-shell joint, 512
rotary positive displacement compressors, 263

rotary pumps, 231, 250
external gear and, 251
flexible vane design and, 250–251
internal-gear pumps and, 252
lobe pumps and, 252–253
screw pumps and, 253
sliding-vane design and, 250
rotor, 479
rotation, 481–484

S

safety analysis and *RP 14C*
production-facility, 407–408
safety analysis checklists (SAC) and, 406
safety-analysis function-evaluation charts (SAFE) and, 406–407
safety analysis tables (SAT) and, 406
safety devices and, 401
surface safety systems (SSS) and, 401
undesirable events and, 405–406
safety devices
of centrifugal compressors, 282
RP 14C and, 401
safety grounding floats, 108
sales pipelines. *See* gathering pipelines
salt analysis by conductivity, 81
sand filters, 163
sand pan, 110–111
screw compressors, 263
screw-down actuator, 497–499
screw pumps, 253
seal drums and disposal systems, 425–426
Selexol process, 194
self-priming pumps, 247–248
self-supported stacks, 427
separable compressors, 262–263
frame and, 283
separator sizing, 39
demister sizing, 45–47
examples of, 49–56
nozzle sizing, 49
retention time, 44–45
seam-to-seam length, 47–49
settling theory, 39–44
settling tanks, 85–91
settling theory of separator sizing
drop/bubble sizes, 43–44
horizontal separators, 39–41
vertical vessels, 41–43
shutdown valves and centrifugal compressors, 281
shut-in, 395–396
silica gel, 215
single-acting compressor cylinders
clearance volume of, 289–290
piston displacement of, 288
rod loads of, 292–293
single hot AC, 96
single-phase motor, 486
single-screw pumps, 253
single-stage centrifugal compressors, 272
single-stage centrifugal pumps, 241
single-stage desalter, 79
skim-pile flow pattern, 132
skim piles, 131–132
skim tanks and vessels, 126–128
sliding-vane design, 250
slip, 250, 255, 483
slug catchers and pipeline pigs, 386–387
solid/liquid hydrocyclones, 160–161, 163
solids-removal systems, 109–111
solution gas, 17
sour gas, 7, 187
sour gas sweetening
computer simulation of, 191
CO_2 removal, 187
diethanolamine (DEA), 191
diglycolamine (DGA), 190
diisopropanolamine (DIPA), 191
hot potassium carbonate (K_2CO_3) (Hot Pot), 191
methyldiethanolamine (MDEA), 191
monoethanolamine (MEA), 190
operating problems, 192–194
overview of, 187–188
process equipment for sweetening sour gas with a regenerative solvent, 188–189
proprietary amine solvent formulations, 191
regenerative chemical solvents, 189–190
solution circulation rate estimation, 191–192
sour gas, definition of, 187
sulfur compounds, 187
sweetening solvents, 189
triethanolamine (TEA), 191
spar concept. *See* deep draught caisson vessel
speed
reciprocating compressor performance and, 293
reciprocating pumps and, 255
Spitzglass equation, 330
splash lubrication systems, 297
Splashtron and offshore pipeline, 380
spring-loaded-relief-valves, 415
squirrel-cage rotor, 480–482
standards, for piping and pipeline systems
bolting materials and, 357
branch connections and, 359
control valves and pressure-relief/safety devices and, 360–361
corrosion protection, 368
flanges, 356–357
gasket materials and, 357
minimum wall thickness and, 358–359
pipe fittings and, 358
pressure ratings, 355–356
valves, 359–360
standard volume flow, 269
stator, 479–480
-coil arrangement, 480
steamflood, 123, 154
steam injectors, 158–159
steam production
quality of water for, 155–156
steam generators, 156–158
water-treating processes for, 154–155
stirred autoclave test, 174
Stokes' law, 76, 124, 141
stonewall (choke) limit, 279
storage tanks, 84–85
appurtenances, 516
batteries maintenance, 522
battery connections and operations, 520–522
breathing, 510
controlling liquid leaks and, 516–520
current storage options and, 508–509
field-welded, 507–508
filling/pumping operations and, 511
fire exposure and, 512
floating-roof, 513–516
gas blanketing systems, 511–512
gauge hatches and, 510

hydrogen sulfide crude storage, 522
net-working capacity and, 514–515
pressure-vacuum valves and, 509–510
production, 505
product vapor control and, 515–516
riveted, bolted, and shop-welded, 505–507
site considerations, 520
types of, 505–508
vent system design and, 512– 513
structural integrity management (SIM) process, 541
subsea completions, 548
subsea systems, 533–534, 551–553
subsystems, emulsions
electrodes, 106–107
instrumentation and safety systems, 108–109
insulators, 106
level controllers and gauges, 112
liquid distribution systems, 107–108
mixing devices, 111–112
power supplies, 105–106
solids-removal systems, 109–111
water-in-oil detectors, 112
suction lift, 235
suction piping
centrifugal pump installation and, 249
positive-displacement pump installation and, 256
suction pressure, 293
suction scrubbers
centrifugal compressors and, 282
and reciprocating compressors, 294–295
suction temperature, 293
Sulferox process for gas treating and processing, 195
Sulfinol process for gas treating and processing, 194–195
supervisory-control-and-data acquisition (SCADA) control system, 389–390
supporting structures, historical review, 525–533
surface safety systems (SSS), 401
surface water, 123
surface-water treatment for injection, 159–160
biological control, 168
dissolved-gas removal (oxygen), 165–168
separating suspended solids from injection water, 160–165
sulfate removal, 168–170
surfactants, 176–177
surge limit
of centrifugal compressors, 278–279
of variable speed compressors, 281
sweetening, 7, 187–189, 191, 197–198
synchronous motors, 484–485
system grounding, 470
system head curves
and centrifugal pumps, 243–244
flow rate regulation and, 244

T

tank appurtenances, 516
tank battery
connections and operations, 520–521
for hydrogen sulfide crude storage, 522
maintenance of, 522
tank breathing, 510–511
tension leg platforms (TLP), 34–35, 530–531, 544–546, 548–551
theoretical lift and pumps, 234–235
thermal-stability test, 172
thermosiphons, 297
three-phase motor, 486
total dynamic head (TDH), 237
calculation, 238
totally enclosed, fan-cooled (TEFC), 499, 501
totally enclosed nonventilated (TENV), 499
transformers for AC treating, 97
transmission pipelines, 318, 365–366
treating emulsions from enhanced oil recovery (EOR) projects, 112–113
triethylene glycol, 8, 200, 205
triple hot AC, 96
true vapor pressure. *See* bubblepoint
truss spar, 547
turbine flowmeters, 441
aeronautical applications and, 442
API standards and, 442
K-factor of, 443
LACT units and, 448
operational theory of, 442–443
turbocharged engines, 305
turbo-expander process, 223–224
turndown and flowmeter, 445–446
turnkey, 567
two-phase flow and pressure drop, 332–335
two-phase separator, 34
two review rule, 581
two-stroke cycle engines, 301–303

U

ultrasonic meters (USM)
advantages and disadvantages, 456–457
ISO standard and, 455
operational theory of, 456
overview of, 455–456
sizing of, 456–457
unburned hydrocarbons (UHC) and gas turbine engines, 315
U.S. Army Corps of Engineers (COE), 368

V

vacuum deaeration, 167
valves. *See also* specific valves
standards and piping and pipeline systems, 359–360
valves and fittings
equivalent lengths of, 341
flow coefficients of, 336–341
pressure drop by, 335–341
resistance coefficients of, 336
vane compressors, 263
vane inlet, 23–24
vane-type mist extractors, 27–28
vapor pressure, of liquid pumps and, 236
vapor recovery compressors, 262
variable frequency drives (VFD), 493–494
velocity
in gas lines, 354
in liquid lines, 353
in multiphase systems, 354–355
velocity head, 237
vena contracta, 450
vendor selection and pump design, 233
vent stacks, 435–436
vent system design
API standards and, 512–513
FRT and, 512
gas blanketing system and, 512
vent piping and, 512
vertical emulsion treaters, 91–93
vessel fabrication, 177–178
voltage drop in electrical systems, 471–472
motor-starting voltage drop (off a generator), 472–473
motor-starting voltage drop (off a transformer), 472
vortex-induced vibrations (VIV), 545

W

water
  calcification, 113, 171–172
  flood, 123
  jets, 110
  leg, 87
  recycle and emulsions, 74–75
  softening, 147
washing and emulsion treatment, 74–75
water dewpoint
  depression, 204–206
  determination, 212
water-in-oil detectors, 112
water-treating chemicals, 170–171
  antifoam, 176–177
  bacteria control, 175–176
  biocide testing, 176
  chemical effect mechanisms, 173
  chemical types, 172
  corrosion protection, 173–175
  oxygen scavenger, 176
  scale inhibition, 172
  selection methods, 172–173
  surfactants, 176–177
  water clarification (flocculants), 171–172
water-treating equipment, material selection for
  erosion protection, materials for, 178–179
  material produced-water systems, 177
  normal service materials, 177–178
  seawater systems, materials for, 179
  severe service environments, materials for, 178
  steam systems, materials for, 180
water-treating processes for steam production, 154–155
wax precipitation, 81
welding and pipelines, 370–371
well flowline, 317
Weymouth equation, 327, 329–330
wheel test, 173–174
working capacity, 507
  of floating-roof tank, 514–515
wrist pin bearings, 286
wye-delta, 466–477