

CONTROL VALVE SOURCEBOOK

OIL & GAS



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Printed in U.S.A.

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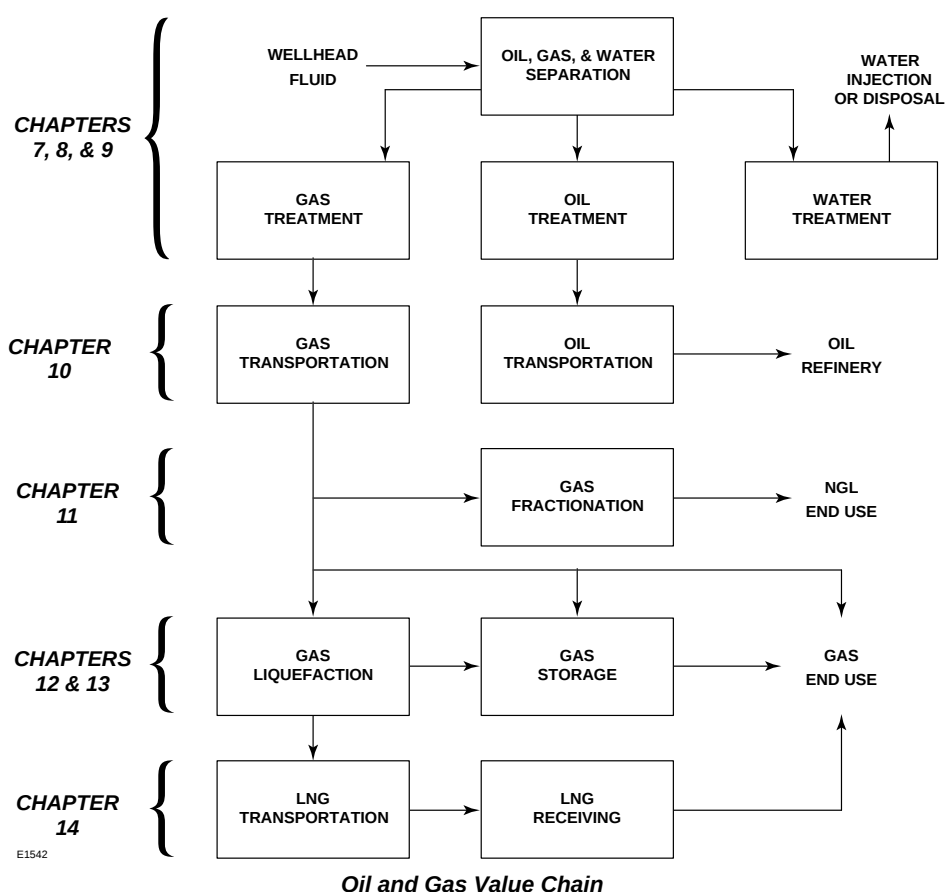
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Preface

This Oil and Gas Control Valve Sourcebook is intended to be a resource to aid in the understanding of control valve applications for the oil and gas industry. Under no circumstances should this information alone be used to select a control valve. All valve considerations should be reviewed with your Fisher® sales office or representative as part of any valve selection or specification activity.

Section I of this book covers control valve sizing

and selection basics. If not familiar with control valve terminology it is recommended that this section be reviewed before moving on to Section II. Section II covers the basics of oil and gas production and transportation processes with a focus on common control valve applications. Below is a general flow diagram of the major topics covered within this section in this edition, and where they fit within the oil and gas value chain:



Section II starts where all oil and gas starts, the wellhead. For any given well a combination of oil, water, and natural gas is produced among other minor constituents. After production the fluid needs to be processed in order to meet customer specifications. The first process is the separation of the components. Descriptions of separation processes in onshore and offshore production facilities can be found in Chapters 7 and 8. Not covered in this edition are secondary and tertiary production processes, including heavy oil and bitumen production. Look for this information in a future edition.

After separation, the oil, gas, and water streams need further processing before they are ready for sale, disposal, or reinjection into a reservoir. Chapter 9 is dedicated to gas treatment processes, including dehydration and sulfur removal. Brief oil treatment process descriptions can be found in Chapters 7 and 8. After the oil is treated it is transported to a refinery. For details on control valves for refining applications please refer to the Fisher Refining Control Valve Sourcebook. Not covered in this edition are water treatment processes. Look for this and more information on oil treatment in a future edition.

After separation, dehydration, and sulfur removal (if needed) natural gas is usually sold as is to an end user. Often, however, higher value natural gas liquids such as ethane, propane, and butane can be separated out of the natural gas and sold individually. Chapter 11 covers the natural gas fractionation process.

After treatment the oil and gas is ready for transportation. Chapter 10 covers traditional onshore transportation of both oil and gas. Because there are seasonal fluctuations in demand for natural gas, natural gas storage is required (Chapter 12). Liquefying natural gas (Chapter 13) is performed to reduce its volume ($1/600^{\text{th}}$) in order to easily transport it around the globe. Once at its end destination the LNG needs to be re-gasified before sale to an end user (Chapter 14).

The content in this sourcebook is continually a work in progress, with future editions intended to expand upon, amend, and add to existing content. For further information, or to answer any questions, please contact your local Fisher sales office or representative.

Section 1:

Control Valve Sizing and Selection

Control Valve Selection

Picking a control valve for a particular application used to be straightforward. Usually only one general type of valve was considered, a sliding-stem valve. Each manufacturer offered a product suitable for the job, and the choice among them depended upon such obvious matters as cost, delivery, vendor relationships and user preference.

Today, control valve selection is considerably more complex, especially for engineers with limited experience or those who have not kept up with changes in the control valve industry.

For many applications, an assortment of sliding-stem and rotary valve styles are available. Some are touted as “universal” valves for almost any size and service, while others are claimed to be optimum solutions for narrowly defined needs. Even the most knowledgeable user may wonder whether they are really getting the most for their money in the control valves they have been specifying.

Like most decisions, selection of a control valve involves a great number of variables. Presented here is an overview of the selection process. The discussion includes categorization of available valve types and a set of criteria to be considered in the selection process.

General Categories of Control Valves

“Control valve” in this discussion means any power-operated valve, whether used for throttling or for on-off control. Other valve varieties such as motorized gate valves, louvers, pinch valves and self-operated regulators are not considered here.



Figure 1-1. Modern control valve combines actuator, valve assembly and digital valve controller to provide maximum performance in a wide variety of control applications.

The major valve types, sliding-stem and rotary, are further divided within Table 1-2 into a total of nine subcategories according to relative performance and cost. Despite variations found within each category, such as cage-guiding versus stem-guiding, all valves within a given subcategory may be considered very much alike in the early stages of the selection process.

Selecting a valve involves narrowing down to one of these nine subcategories and then comparing specific valves in that group.



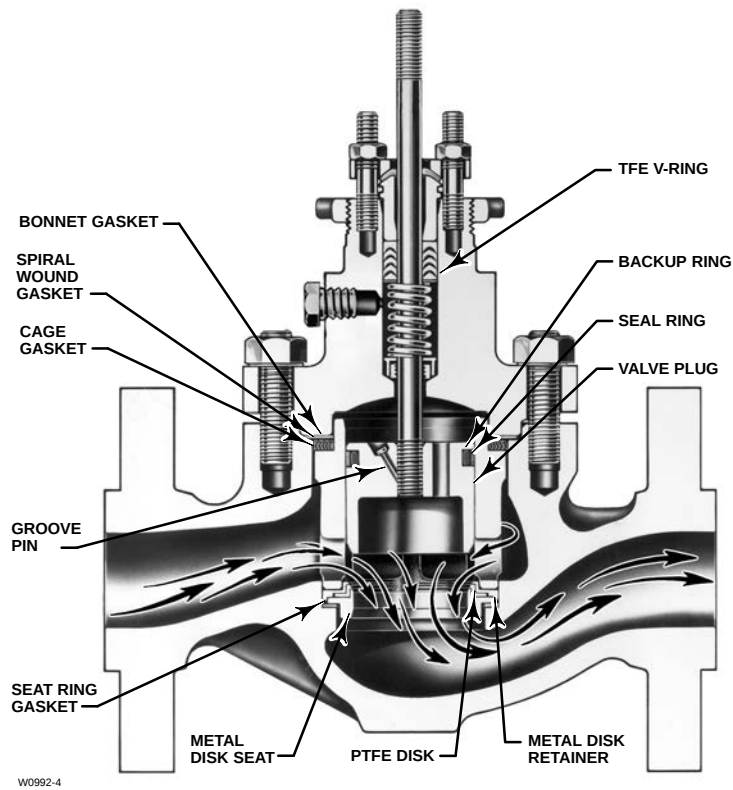


Figure 1-2. Standard globe sliding-stem valve design is typified by the ET. A broad range of sizes, materials and end connections is available. The balanced plug reduces plug force and allows use of smaller actuators. These valves are the first choice for applications less than NPS 3 size.

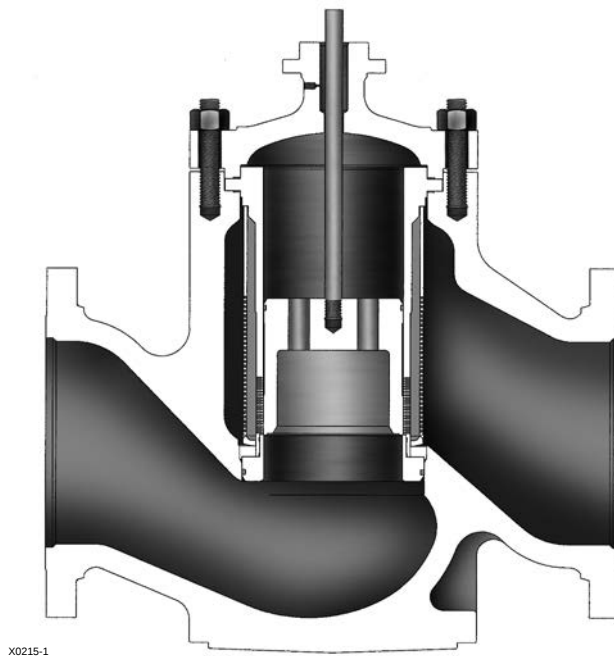


Figure 1-3. Severe service capability in globe valves demonstrated by this Large ET. The drilled hole cage provides attenuation of flow noise by splitting the flow into multiple passages. Spacing of the holes is carefully controlled to eliminate jet interaction and higher resultant noise levels.

Sliding-Stem Valves

The most versatile of control valves are the sliding-stem designs. Globe, angle, and Y-pattern valves can be purchased in sizes ranging from NPS 1/2 - 36. More choices of materials, end connections and control characteristics are included here than in any other product family.

Globe valves are available in cage-guided, post-guided and stem-guided designs, with flanged, screwed or weld ends. Economical cast iron as well as carbon steel, stainless steel and other high-performance body materials are available. Available valve body pressure ratings range to ASME CL4500 or API 10,000.

The globe valve's precise throttling capabilities, overall performance and general sturdiness make them a bargain despite their slight cost premium. With the globe valve, the buyer gets a rugged, dependable unit intended for long, trouble-free service.

Sliding-stem valves are ruggedly built to handle field conditions such as piping stress, vibration, and temperature changes. In sizes through NPS 3 - 4, incremental costs over rotary valves are low in contrast to the increments in benefits received.

For many extreme service conditions, sliding-stem valves are the only suitable choice. These situations include high pressures and temperatures, excessive noise, and the potential for cavitation. Due to process demands, these applications require the rugged construction of the sliding-stem design.

Barstock valves are small, economical sliding-stem valves featuring bodies machined from bar stock. Body sizes range from fractions of NPS 1 - 3; flow capacities generally are lower than those of general purpose valves. End connections usually are flangeless (for mounting between piping flanges) or screwed.

The main advantage of the barstock valve is that far more materials are readily available in bar form than in cast form. Consequently, these valves are often used where there are special corrosion considerations.

Also, the compactness and general high-quality construction of barstock valves make them attractive for low flow rate applications. Overall, they are an economical choice when they can be used.

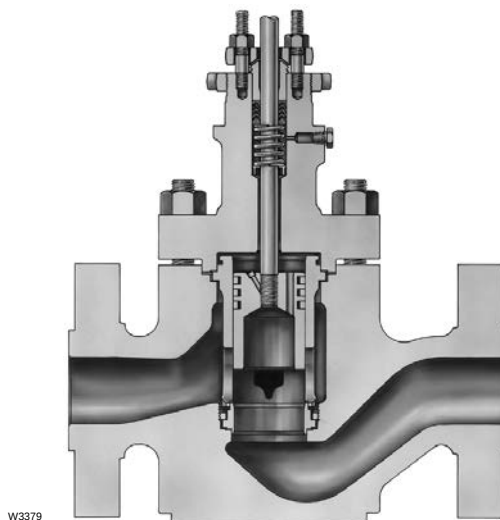


Figure 1-4. EHD is typical of high-pressure globe valves. Rated at ASME CL2500, it provides throttling control of high-pressure steam and fluids. Anti-noise and anti-cavitation trims are available to handle flow problems.



Figure 1-5. NPS 1 Baumann 24000 Little Scotty valve with a size 32 actuator and a FIELDVUE DVC6200

The third subcategory, which involves the lowest cost products among sliding-stem valves, utilizes "economy" bodies (Figure 1-5). These valves are used for low-pressure steam, air and water applications that are not demanding. Sizes available range from NPS 1/2 - 4. Body materials include bronze, cast iron, steel and SST. Pressure classes generally stop at ASME CL300. Compared to regular sliding-stem valves, these units are very simple; their actuators are smaller, and their construc-

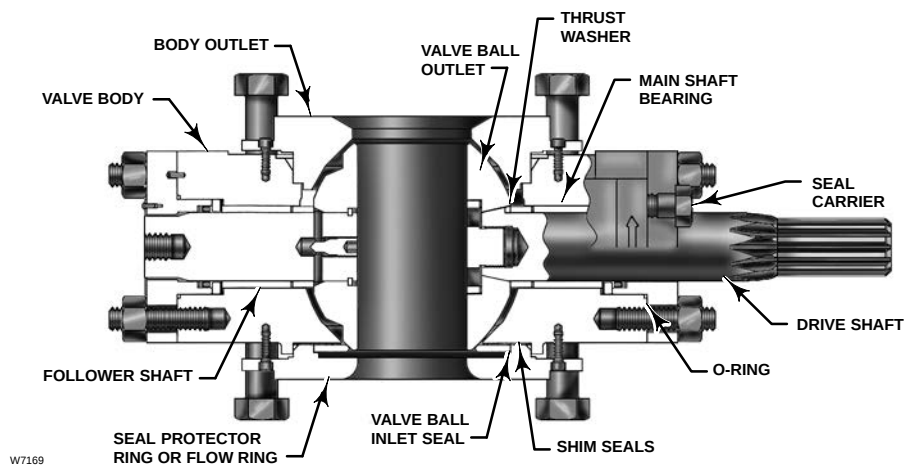


Figure 1-6. High-pressure ball valves feature heavy shafts and full ball designs. This V250 is suitable for pressure drops to 2220 psig. ASME CL600 and CL900 bodies are available—sizes range to NPS 24.

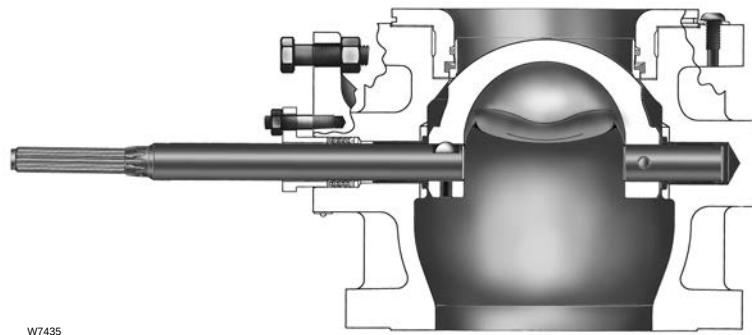


Figure 1-7. Applications to ASME CL600 can be handled by the V150/V200/V300 Vee-Ball™. This product incorporates many features to improve throttling performance and rangeability. Tight shutoff is achieved by using either heavy-duty metal seals or composition seals.

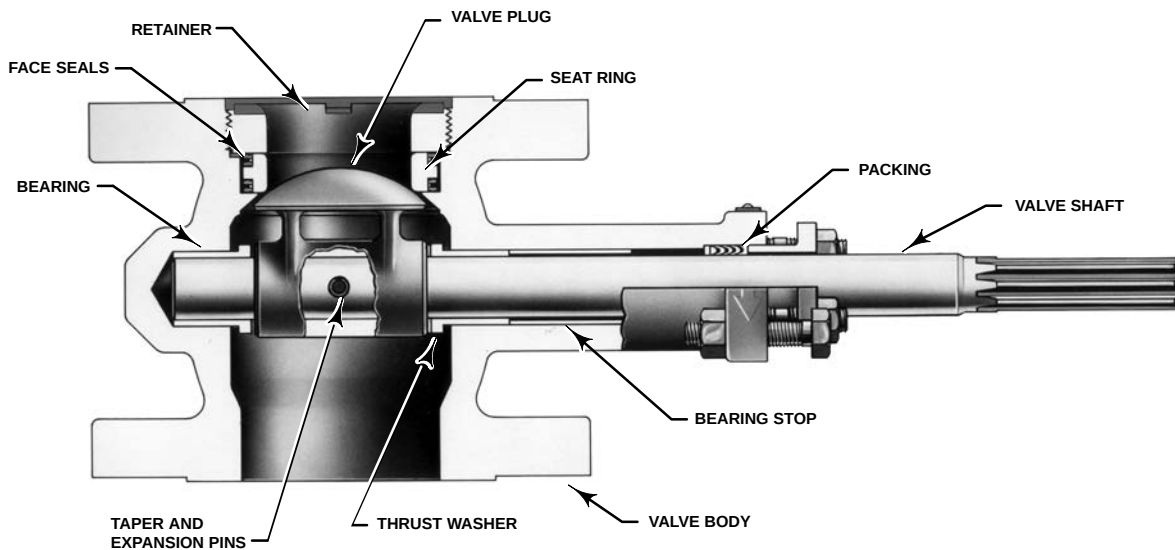
tion is economical. Severe service trims for noise and cavitation service are not available in these products.

Ball Valves

There are two subcategories of ball valves. The through-bore or full-ball type illustrated in Figure 1-6 is used typically for high pressure drop throttling and on-off applications in sizes to NPS 24. Full port designs exhibit high flow capacity and low susceptibility to wear by erosive streams. However, sluggish flow response in the first 20% of ball travel may make full-bore ball valves unsuitable for some throttling applications.

Another popular kind of ball valve is the segmented-ball style (Figure 1-7). This subcategory utilizes a reduced bore, and the edge of the ball segment has a contoured notch shape for better throttling control and higher rangeability. Intended primarily for modulating service, segmented-ball valves are generally higher in overall control performance than full-ball products.

Segmented-ball valves with their splined shaft connections are engineered to eliminate lost motion, which is detrimental to performance. The use of heavy-duty metal and fluoroplastic sealing elements allows wide temperature and fluid applicability. Their straight-through flow design achieves high capacity with sizes ranging through NPS 24 and pressure ratings to ASME CL600. Price is generally lower than that of globe valves.



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Figure 1-8. The V500 eccentric plug valve is specially designed for severe rotary applications. Since the valve plug “cams” into the seat ring upon closure, it features tight shutoff with globe valve style seating. It also offers excellent resistance to abrasive wear and flashing induced erosion.

Eccentric Plug Valves

This class of valves combines many features of sliding-stem and rotary products. Eccentric plug valves feature rotary actuation. But, unlike most rotary valves, this product utilizes a massive, rigid seat design.

Eccentric-plug valves (Figure 1-8) exhibit excellent throttling capability and resistance to erosion. Thus, many of the good aspects of both rotary and sliding-stem designs are combined.

Sizes generally range through NPS 8; pressure ratings go to ASME CL600. Both flanged and flangeless body styles are available in a variety of materials.

The requirement for zero or low leakage gave rise to new designs such as the lined and high performance butterfly valves (BFV's).

Lined butterfly valves feature an elastomer or fluoropolymer (TFE) lining that contacts the disk to provide tight shutoff. Since this valve design depends on interference between the disk and liner for shutoff, it is more limited in pressure drop. Temperature ranges typically are limited due to the elastomer disk seal.

In addition to serving as the disk seal, the liner also protects the inner bore of the valve body from the process fluid, which allows these valves to be used in many corrosive situations. Elastomer-lined BFV's are generally the lowest price products available as control valves in medium to large sizes.

Heavy shafts and discs, full-rated bodies and sophisticated seals that allow tight shutoff against high pressures characterize high performance but-

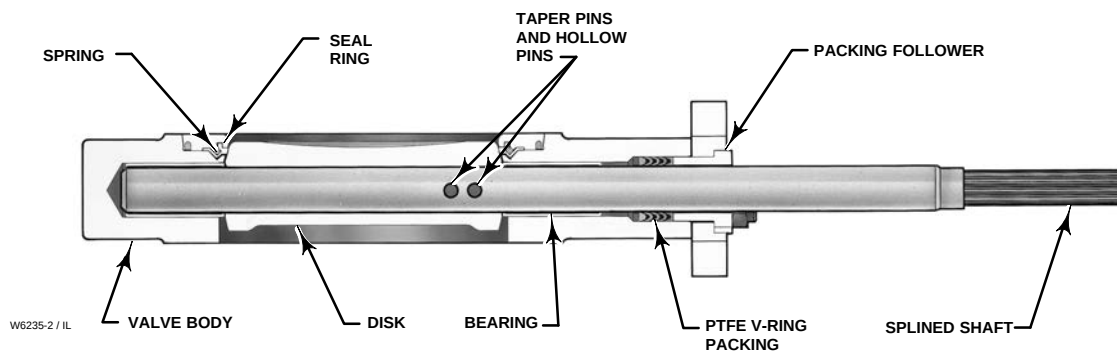


Figure 1-9. High performance butterfly valves provide excellent performance and value. High-pressure capability, tight shutoff and excellent control are featured as standard. This 8560 design is made for ASME CL150 applications.

terfly valves such as the one in Figure 1-9. These valves provide an excellent combination of performance features, lightweight and very reasonable pricing.

In offset disc designs, eccentric shaft mounting allows the valve disc to swing clear of its seal to minimize wear and torque. The offset disc allows uninterrupted sealing and a seal ring that can be replaced without removing the disc. High performance butterfly valves come in sizes from NPS 2 through NPS 72, with flangeless, lugged, double flanged connections, carbon steel or stainless steel bodies, and pressure ratings to ASME CL2500. Tight metal-to-metal seals, made possible with advanced eccentric design, provide tight shutoff in applications that are too hot for elastomer lined valves. Considering this tight shutoff capability and heavy-duty construction, high performance butterfly valves can be a suitable option to many applications where sliding-stem valves are normally specified.

General Selection Criteria

Most of the considerations that guide the selection of valve type and brand are rather basic. However, there are some matters that may be overlooked by users whose familiarity is mainly limited to just one or a few valve types. Table 1-1 below provides a checklist of important criteria; each is discussed at length following the table.

Pressure Ratings

Body pressure ratings ordinarily are considered according to ASME pressure classes—the most common ones for steel and stainless steel being

Classes 150, 300 and 600. (Source documents are ASME/ANSI Standards B16.34, “Steel Valves,” and ANSI/ASME B16.1, “Cast Iron Pipe Flanges and Flanged Fittings.”) For a given body material, each ASME Class corresponds to a prescribed profile of maximum pressures that decrease with temperature according to the strength of the material. Each material also has a minimum and maximum service temperature based on loss of ductility or loss of strength. For most applications, the required pressure rating is dictated by the application. However, since all products are not available for all ASME Classes, it is an important consideration for selection.

Table 1-1. Suggested General Criteria for Selecting Type and Brand of Control Valve

Body pressure rating
High and low temperature limits
Material compatibility and durability
Inherent flow characteristic and rangeability
Maximum pressure drop (shutoff and flowing)
Noise and cavitation
End connections
Shutoff leakage
Capacity versus cost
Nature of flowing media
Dynamic performance

Temperature Considerations

Required temperature capabilities are also a foregone conclusion, but one that is likely to narrow valve selection possibilities. The considerations include the strength or ductility of the body material as well as relative thermal expansion of various parts.

Temperature limits also may be imposed due to disintegration of soft parts at high temperatures or

loss of resiliency at low temperatures. The soft materials under consideration include various elastomers, plastics, and PTFE. They may be found in parts such as seat rings, seal or piston rings, packing, rotary shaft bearings and butterfly valve liners. Typical upper temperature limits for elastomers are in the 200-350°F (93-176°C) range, and the general limit for PTFE is 450°F (232°C).

Temperature affects valve selection by excluding certain valves that do not have high- or low-temperature options. It also may have some effect on the valve's performance. For instance, going from PTFE to metal seals for high temperatures generally increases the shutoff leakage flow. Similarly, high temperature metal bearing sleeves in rotary valves impose more friction on the shaft than do PTFE bearings, so that the shaft cannot withstand as high a pressure-drop load at shutoff. Selection of valve packing is also based largely on service temperature.

Material Selection

The third criterion in Table 1-1, *material compatibility and durability*, is a more complex consideration. At issue may be corrosion by the process fluid, erosion by abrasive material, flashing, cavitation or simply a matter of process pressure and temperature. The piping material usually indicates the body material. However, since velocity is higher in valves other factors must be considered. When these items are included, often valve and piping materials will differ. The trim materials, in turn, are usually a function of the body material, temperature range and qualities of the fluid.

Flow Characteristic

The next selection criterion, *inherent flow characteristic*, refers to the pattern in which the flow at constant pressure drop changes according to valve position.

Typical characteristics are quick-opening, linear and equal-percentage. The choice of characteristic may have a strong influence on the stability or controllability of the process (see Table 1-3), since it represents the change of valve gain relative to travel.

Most control valves are carefully "characterized" by means of contours on a plug, cage, or ball ele-

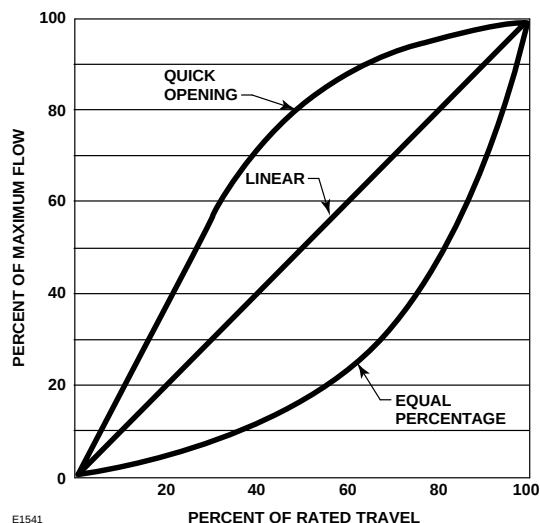


Figure 1-10. Many control valves offer a choice of characteristic. Selection to match process requirements is guided by simple rules. Adherence to these guidelines will help assure stable operation.

ment. Some valves are available in a variety of characteristics to suit the application, while others offer little or no choice. To quantitatively determine the best flow characteristic for a given application, a dynamic analysis of the control loop can be performed.

The accompanying drawing illustrates typical flow characteristic curves (Figure 1-10). The quick opening flow characteristic provides for maximum change in flow rate at low valve travels with a fairly linear relationship. Additional increases in valve travel give sharply reduced changes in flow rate, and when the valve plug nears the wide open position, the change in flow rate approaches zero. In a control valve, the quick opening valve plug is used primarily for on-off service.

The linear flow characteristic curve shows that the flow rate is directly proportional to the valve travel. This proportional relationship produces a characteristic with a constant slope so that, with constant pressure drop, the valve gain will be the same at all flows. The linear valve plug is commonly specified for liquid level control and for certain flow control applications requiring constant gain.

In the equal percentage flow characteristic, equal increments of valve travel produce equal percentage changes in the existing flow. The change in flow rate is always proportional to the flow rate just before the change in valve plug, disc, or ball position is made. When the valve plug, disc, or ball is near its seat and the flow is small, the change in

flow rate will be small; with a large flow, the change in flow rate will be large.

An equal percentage flow characteristic is used generally on pressure control applications and on other applications where a large percentage of the pressure drop is normally absorbed by the system itself with only a relatively small percentage available at the control valve. Valves with an equal percentage characteristic should also be considered where highly varying pressure drop conditions could be expected.

Rangeability

Another aspect of a valve's flow characteristic is its rangeability, which is the ratio of its maximum and minimum controllable flow rates. Exceptionally wide rangeability may be required for certain applications to handle wide load swings or a combination of start-up, normal and maximum working conditions. Generally speaking, rotary valves—especially partial ball valves—have greater rangeability than sliding-stem varieties.

Use of Positioners

A positioner is an instrument that helps improve control by accurately positioning a control valve actuator in response to a control signal. They are useful in many applications and are required with certain actuator styles in order to match actuator and instrument pressure signals or to provide operating stability. To a certain extent, a valve with one inherent flow characteristic can also be made to perform as though it had a different characteristic by using a nonlinear (i.e., characterized) positioner-actuator combination. The limitation of this approach lies in the positioner's frequency response and phase lag compared to the characteristic frequency of the process.

Although it is common practice to use a positioner on every valve application, each application should be reviewed carefully.

Pressure Drop

The maximum pressure drop a valve can tolerate at shutoff or when partially or fully open is an important selection criteria. Sliding-stem valves are generally superior in both regards because of the

rugged nature of their moving parts. Many rotary valves are limited to pressure drops well below the body pressure rating, especially under flowing conditions, due to dynamic stresses that high velocity flow imposes on the disk or ball segment.

Noise and Cavitation

Noise and cavitation are two considerations that often are grouped together because both may result from high pressure drops and large flow rates. They are treated by special modifications to standard valves. Chapter 5 discusses noise generation and abatement, while Chapter 6 discusses the cavitation phenomenon and its impact and treatment.

End Connections

The three common methods of installing control valves in pipelines are by means of screwed pipe threads, bolted flanges, and welded end connections. At some point in the selection process, the valve's end connections must be considered with the question simply being whether the desired connection style is available in the valve being considered. Maintenance, weight, size, and service conditions all contribute to what end connection is used.

In some situations, this matter can limit the selection rather narrowly. For instance, if a piping specification calls for welded connections only, the choice usually is limited to sliding-stem valves.

Screwed end connections, popular in small control valves, offer more economy than flanged ends. The threads usually specified are tapered female NPT (National Pipe Thread) on the valve body. They form a metal-to-metal seal by wedging over the mating male threads on the pipeline ends. This connection style is usually limited to valves not larger than NPS 2, and is not recommended for elevated temperature service.

Valve maintenance might be complicated by screwed end connections if it is necessary to take the body out of the pipeline. Screwed connections require breaking a flanged joint or union connection to permit unscrewing the valve body from the pipeline.

Flanged end valves are easily removed from the piping and are suitable for use through the range

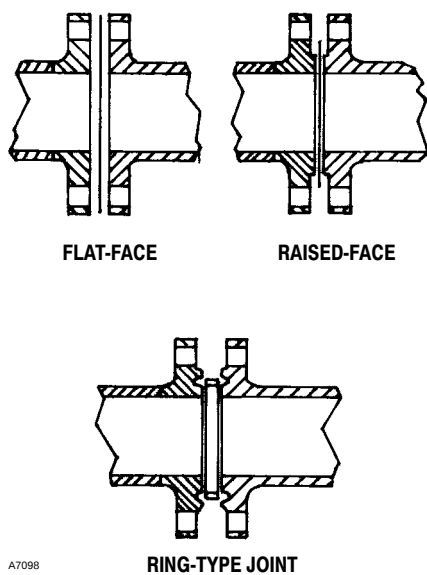


Figure 1-11. Popular varieties of bolted flange end connections.

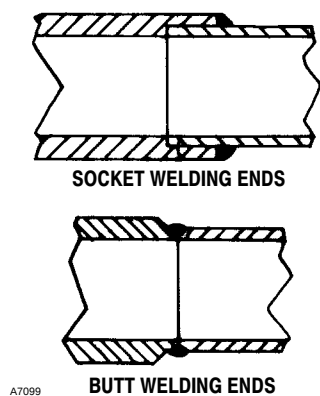


Figure 1-12. Common welded end connections.

of working pressures that most control valves are manufactured (Figure 1-11).

Flanged end connections can be used in a temperature range from absolute zero (-273°F) to approximately 1500°F (815°C). They are used on all valve sizes. The most common flanged end connections include flat face, raised face, and ring type joint.

Welded ends on control valves are leak tight at all pressures and temperatures and are economical in initial cost (Figure 1-12). Welded end valves are more difficult to remove from the line and are obviously limited to weldable materials. Welded

ends come in two styles, socket weld and butt-weld.

Shutoff Capability

Some consideration must be given to a valve's shutoff capability, which usually is rated in terms of Classes specified in ANSI/FCI70-2 (Table 1-4). In service, shutoff leakage depends on many factors, including but not limited to, pressure drop, temperature, the condition of the sealing surfaces, and actuator force.

Since shutoff ratings are based on standard test conditions that can be very different from service conditions, service leakage cannot be predicted accurately. However, the shutoff Class provides a good basis for comparison among valves of similar configuration. It is not uncommon for valve users to overestimate the shutoff class required.

Since tight shutoff valves generally cost more both in initial cost as well as in later maintenance expense, serious consideration is warranted. Tight shutoff is particularly important in high-pressure valves, considering that leakage in these applications can lead to the ultimate destruction of the trim. Special precautions in seat material selection, seat preparation and seat load are necessary to ensure success.

Flow Capacity

Finally, the criterion of capacity or size can be an overriding constraint on selection. For very large lines, sliding-stem valves are more expensive than rotary types. On the other hand, for very small flows, a suitable rotary valve may not be available.

If future plans call for significantly larger flow, then a sliding-stem valve with replaceable restricted trim may be the answer. The trim can be changed to full size trim to accommodate higher flow rates at less cost than replacing the entire valve body assembly.

Rotary style products generally have much higher maximum capacity than sliding-stem valves for a given body size. This fact makes rotary products attractive in applications where the pressure drop available is rather small. However, it is of little or no advantage in high-pressure drop applications such as pressure regulation or letdown.

Conclusion

We may simplify the process of selection as follows:

For most general applications, it makes sense both economically as well as technically to use sliding-stem valves for lower flow ranges, ball valves for intermediate capacities, and high performance butterfly valves for the very largest required flows.

For sizes less than NPS 3, general-purpose sliding-stem valves provide an exceptional value. For a minimal price premium over rotary products, they offer unparalleled performance, flexibility and service life. In NPS 3 size and larger, the premium for these devices over rotary products is warranted. For severe service applications the most frequently used and often the only available product is the sliding-stem valve.

Applications ranging from NPS 4 to NPS 6 are best served by such transitional valve styles as the eccentric plug valve or the ball valve. These products have minimal body material and therefore lower cost. They also offer higher capacity levels than globe designs.

In sizes NPS 8 and larger, applications tend to have lower pressures and pressure drops than in smaller valve sizes. This gives rise to the possibility of using high-performance butterfly valves. These valves are economical, can offer tight shut-off as well as provide good control capability, not to mention capacity benefits well beyond those of globe and high-performance rotary valves.

Special considerations may require out of the ordinary valve solutions. There are valve designs and special trims available to handle high noise applications, cavitation, high pressure, high temperature and combinations of these conditions.

After going through all the criteria for a given application, the selection process may point to several types of valves. From there on, selection becomes a matter of price versus capability as discussed here, coupled with the inevitable personal and institutional preferences. Since no single control valve package is cost-effective over the full range of applications, it is important to keep an open mind to alternative choices.

Table 1-2. Major Categories and Subcategories of Control Valves, with Typical General Characteristics

Valve Style	Main Characteristics	Typical Size Range, NPS	Typical Standard Body Materials	Typical Standard End Connection	Typical Pressure Ratings	Relative Flow Capacity	Relative Shutoff Capability
Regular Sliding-stem	Heavy Duty Versatile	1 to 24	Carbon Steel Cast Iron Stainless	ASME Flanged Welded Screwed	To ASME CL2500	Moderate	Excellent
Bar Stock	Machined from Bar Stock	½ to 3	Variety of Alloys	Flangeless Screwed	To ASME CL600	Low	Excellent
Economy Sliding-stem	Light Duty Inexpensive	½ to 2	Bronze Cast Iron Carbon Steel	Screwed	To ASME CL125	Moderate	Good
Thru-Bore Ball	On-Off Service	1 to 24	Carbon Steel Stainless	Flangeless	To ASME CL900	High	Excellent
Segmented Ball	Characterized for Throttling	1 to 24	Carbon Steel Stainless	Flangeless Flanged	To ASME CL600	High	Excellent
Eccentric Plug	Erosion Resistance	1 to 8	Carbon Steel Stainless	Flanged	To ASME CL600	Moderate	Excellent
Swing-Thru Butterfly	No Seal	2 to 96	Carbon Steel Cast Iron Stainless	Flangeless Lugged Welded	To ASME CL2500	High	Poor
Lined Butterfly	Elastomer or TFE Liner	2 to 96	Carbon Steel Cast Iron Stainless	Flangeless Lugged	To ASME CL300	High	Good
High Performance Butterfly	Offset Disk General Service	2 to 72	Carbon Steel Stainless	Flangeless Lugged	To ASME CL600	High	Excellent

Table 1-3. Control Valve Characteristic Recommendations

Liquid Level Systems

Control Valve Pressure Drop	Best Inherent Characteristic
Constant ΔP	Linear
Decreasing ΔP with increasing load, ΔP at maximum load > 20% of minimum load ΔP	Linear
Decreasing ΔP with increasing load, ΔP at maximum load < 20% of minimum load ΔP	Equal-percentage
Increasing ΔP with increasing load, ΔP at maximum load < 200% of minimum load ΔP	Linear
Increasing ΔP with increasing load, ΔP at maximum load > 200% of minimum load ΔP	Quick Opening

Pressure Control Systems

Application	Best Inherent Characteristic
Liquid Process	Equal-Percentage
Gas Process, Large Volume (Process has a receiver, Distribution System or Transmission Line Exceeding 100 ft. of Nominal Pipe Volume), Decreasing ΔP with Increasing Load, ΔP at Maximum Load > 20% of Minimum Load ΔP	Linear
Gas Process, Large Volume, Decreasing ΔP with Increasing Load, ΔP at Maximum Load < 20% of Minimum Load ΔP	Equal-Percentage
Gas Process, Small Volume, Less than 10 ft. of Pipe between Control Valve and Load Valve	Equal-Percentage

Flow Control Processes

Application		Best Inherent Characteristic	
Flow Measurement Signal to Controller	Location of Control Valve in Relation to Measuring Element	Wide Range of Flow Set Point	Small Range of Flow but Large ΔP Change at Valve with Increasing Load
Proportional to Flow	In Series	Linear	Equal-Percentage
	In Bypass*	Linear	Equal-Percentage
Proportional to Flow Squared	In Series	Linear	Equal-Percentage
	In Bypass*	Equal-Percentage	Equal-Percentage
*When control valve closes, flow rate increases in measuring element.			

Table 1-4. Control Valve Leakage Standards

ANSI / FCI 70-2 and IEC 60534-4	Maximum Leakage		Test Medium	Pressure and Temperature	
Class II	0.5% valve capacity at full travel		Air	Service ΔP or 50 psig (3.4 bar differential), whichever is lower, at 50° or 125° F (10° to 52° C)	
Class III	0.1% valve capacity at full travel		Air	Service ΔP or 50 psig (3.4 bar differential), whichever is lower, at 50° or 125° F (10° to 52° C)	
Class IV	0.01% valve capacity at full travel		Air	Service ΔP or 50 psig (3.4 bar differential), whichever is lower, at 50° or 125° F (10° to 52° C)	
Class V	5 x 10 ⁻⁴ mL/min/psig/inch port dia. (5 x 10 ⁻¹² m ³ /sec/ Δ bar/mm port dia)		Water	Service ΔP at 50° or 125° F (10° to 52° C)	
Class VI	Nominal Port Diameter	Bubbles per Minute	mL per Minute	Test Medium	Pressure & Temperature
	In	mm			
	1	25	1	0.15	Service ΔP or 50 psig (3.4 bar differential), whichever is lower, at 50° or 125° F (10° to 52° C)
	1-1/2	38	2	0.30	
	2	51	3	0.45	
	2-1/2	64	4	0.60	
	3	76	6	0.90	
	4	102	11	1.70	
	6	152	27	4.00	
	8	203	45	6.75	

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Packing Materials and Systems

This section provides information and insight to help in selection of packing systems. Application guidelines for each packing selection have been developed to aid in the packing selection process. These guidelines were developed based on test results of various packing systems conducted in Fisher's technical center. Exceeding these guidelines may result in reduced service life.

The ratings for these systems do not affect the valve pressure/temperature class rating. Traditional valve selection entails selecting a valve design based on pressure and temperature capabilities, flow characteristics, and material compatibility. An additional factor—packing selection—is now a critical factor in the valve selection process.

Proper packing selection is being driven in the United States by the Clean Air Act Amendments, subsequent Environmental Protection Agency (EPA) regulations, and our customers' increasing concern for improved packing performance (less maintenance and longer service life.)

In recent years, packing selection has been primarily based on process temperature; that is, PTFE was selected for temperatures below 450°F (232°C), and graphite was selected for temperatures above 450°F (232°C). Considerations now include the effect of packing friction on process control, hysteresis, seal quality, and cycle life.

Given the variety of process applications and installation conditions, these variables are difficult to quantify. A relative packing performance comparison can be made that provides an engineered approach to the packing selection process.

Clarification of trade names is required for proper understanding of the Table 1-5 shown in this publication. From the perspective of Fisher, ENVIRO-SEAL™ packing is defined as an advanced system using a "compact", live-load spring design. From a user perspective, ENVIRO-SEAL packing is most

typically thought of as an emission-reducing packing system; however, as shown in the following chart and graphs, it is highly useful in non-environmental applications as well.

Although other packing materials and combinations of packing materials are available, the recommendations for nearly all applications are listed in Table 1-5. Simply select the appropriate packing based on pressure, temperature, leakage requirements, service life required, etc. Use the charts for additional guidance.

The packing selection guidelines in Table 1-5 present two categories of service conditions. The first category defines those packing systems designed for environmental or fugitive emission applications where 500 parts per million volume (ppmv) seal performance is required.

The second category defines application guidelines for non-environmental services. Depending on category requirements, different pressure/temperature guidelines have been established for the packing systems.

In addition, a given packing design has certain characteristics concerning seal performance, service life, and friction. The pressure and temperature guidelines and the relative comparison of these characteristics are defined in Table 1-5 and the supporting charts.

Keep in mind that for non-environmental applications these are guidelines and are not intended as the ultimate limit. Exceeding the pressure guidelines for packing may be required; however, depending on how much the guidelines are exceeded, a reduction in total life span can be expected.

With flexible graphite packing this same logic applies to temperature. The recommended pressure / temperature limits for environmental applications using Fisher ENVIRO-SEAL packing cannot be exceeded without compromising sealing integrity.

Table 1-5. Packing Selection Guidelines for Sliding-Stem Valves

Packing System	Maximum Pressure & Temperature Limits for 500 PPM Service ⁽¹⁾		Application Guideline for Nonenvironmental Service ⁽¹⁾		Seal Performance Index	Service Life Index	Packing Friction ⁽²⁾
	Customary U.S.	Metric	Customary U.S.	Metric			
Single PTFE V-Ring	300 psig 0 to 200 °F	20.7 bar –18 to 93 °C	See figure 1-16 –50 to 450 °F	See figure 1-16 –46 to 232 °C	Better	Long	Very low
ENVIRO-SEAL PTFE	See figure 1-15 –50 to 450 °F	See figure 2 –46 to 232 °C	See figure 1-16 –50 to 450 °F	See figure 1-16 –46 to 232 °C	Superior	Very long	Low
ENVIRO-SEAL Duplex	750 psig –50 to 450 °F	51.7 bar –46 to 232 °C	See figure 1-16 –50 to 450 °F	See figure 1-16 –46 to 232 °C	Superior	Very long	Low
KALREZ® with PTFE (KVSP 400) ⁽³⁾	350 psig 40 to 400 °F	24.1 bar 4 to 204	See figure 1-16 –40 to 400 °F	See figure 1-16 –40 to 204 °C	Superior	Long	Low
ENVIRO-SEAL Graphite ULF	1500 psig 20 to 600 °F	103 bar –7 to 315 °C	3000 psig –325 to 700 °F	207 bar –198 to 371 °C	Superior	Very long	High
HIGH-SEAL Graphite with PTFE	1500 psig 20 to 600 °F	103 bar –7 to 315 °C	4200 psig ⁽⁴⁾ –325 to 700 °F	290 bar ⁽⁴⁾ –198 to 317 °C	Superior	Very long	High
HIGH-SEAL Graphite	– – – – – –	– – – – – –	4200 psig ⁽⁴⁾ –325 to 1200 °F ⁽⁵⁾	290 bar ⁽⁴⁾ –198 to 649 °C ⁽⁵⁾	Better	Very long	Very high
Braided Graphite Filament	– – – – – –	– – – – – –	1500 psig –325 to 1000 °F ⁽⁵⁾	103 bar –198 to 538 °C ⁽⁵⁾	Acceptable	Acceptable	High

1. The values shown are only guidelines. These guidelines can be exceeded, but shortened packing life or increased leakage might result. The temperature ratings apply to the actual packing temperature, not to the process temperature.
2. See Catalog 14 for actual friction values.
3. The KALREZ pressure/temperature limits referenced in this bulletin are for Fisher Controls valve applications only. DuPont may claim higher limits.
4. Except for the 3/8-inch (9.5 mm) stem, 1600 psig (110 bar).
5. Except for oxidizing service, –325 to 700 °F (–198 to 371 °C).

Packing Set Possibilities

Single PTFE V-Ring Packing (Sliding-Stem and Rotary Valves)

The single PTFE V-ring arrangement uses a coil spring, as in the easy-e™ valves, and meets the EPA 500 ppmv criteria, assuming that the pressure does not exceed 300 psig (20.7 bar) and the temperature is between 0°F and 200°F (–18 and 93°C). This packing arrangement offers very good seal performance with the lowest packing friction and usually the lowest cost.

ENVIRO-SEAL PTFE Packing (Sliding-Stem and Rotary Valves)

The ENVIRO-SEAL PTFE arrangement is suitable for environmental applications on services up to 750 psig and 450°F (51.7 bar and 233°C). The sealing capability is superior. The ENVIRO-SEAL PTFE packing system is designed to operate at a nearly constant high stress. This design approach results in an increase in stem friction. Typically, the slight increase in stem friction does not cause problems with actuator sizing or process control, such as hysteresis. It is always recommended that actuator sizing be verified whenever you select a different packing material.

Flexible Graphite Packing Material (Sliding-Stem Only)

It is important to understand some of the issues associated with the base material that is common to all high temperature graphite packing systems. The single most important issue is the potential for galvanic corrosion in valves in storage that have graphite packing system installed.

Fisher uses only the highest grades of base flexible graphite material that contain a non-metallic, inorganic, passivating inhibitor for galvanic corrosion resistance. All Fisher graphite packing systems (with the exception of nuclear applications) also include sacrificial zinc washers to prevent galvanic corrosion.

However, even with these preventive measures, under humid conditions, in the presence of chlorides, with air or oxygen present, there is potential for galvanic corrosion of the valve stem. Because there are numerous variables associated with galvanic corrosion it is near impossible to predict when it may occur.

The best policy is to remove the packing if the valve is to be stored for a long period. This, however, may create a safety issue if someone were to use the valve not realizing that there was no packing in the valve. For this exact reason all Fisher valves are supplied with the packing installed.

ENVIRO-SEAL Graphite ULF (Sliding-Stem and Rotary Valves)

ENVIRO-SEAL Graphite ULF packing is designed for environmental applications from 300 to 600°F (149 to 316°C), or for those applications where fire safety is a concern and graphite packing is desired. The ENVIRO-SEAL Graphite ULF arrangement can also be used with higher pressures up to 1500 psig (103 bar) and still maintain the 500 ppmv EPA leakage criteria.

ENVIRO-SEAL Graphite ULF packing systems were developed by utilizing the benefits of both PTFE and graphite components. These special packing systems provide the firesafe capability of graphite packing along with reduced friction advantages of PTFE packing. Thus, ENVIRO-SEAL Graphite ULF packing systems provide a lower friction, lower emission, fire-tested solution for applications with process temperatures up to 316°C (600°F). ENVIRO-SEAL Graphite ULF packing systems were tested in accordance with API Standard 589, "Fire Test Evaluation of Valve Stem Packing", second edition. See Figure 1-14 for applications guidelines for 500 ppm service. Figure 1-17 shows the ENVIRO-SEAL Graphite ULF packing system.

HIGH-SEAL™ Graphite with PTFE for Environmental Applications (Sliding-Stem Only)

The HIGH-SEAL packing system features live-loading and unique packing ring arrangements for consistent, long-term sealing performance. It is offered without PTFE washers for nuclear service where PTFE is prohibited and with PTFE washers for all other applications.

The primary advantage of the HIGH-SEAL packing system arrangement is the use of large Belleville springs, which can be calibrated with a load scale. The load scale provides a visual indication of packing load, making it easier to determine when additional torque might be required.

HIGH-SEAL packing systems have a disadvantage, from an installation perspective. This disadvantage is that the actuator cannot be removed from the valve without removing the Belleville springs.

The HIGH-SEAL graphite packing system provides a service life that is very long compared to other graphite packing arrangements.

Non-Environmental Services

For the non-environmental pressure/temperature guidelines, using ENVIRO-SEAL and HIGH-SEAL packing systems can extend service life.

As service pressures and temperatures increase, the ENVIRO-SEAL packing systems provide a significant step change in performance, compared to the traditional single PTFE V-ring or braided graphite filament arrangements. For example, an ASME CL1500 (HP valve) application at 2000 psig and 200°F (137 bar and 93°C) frequently required packing maintenance. The HIGH-SEAL packing system with PTFE washers was installed, significantly reducing maintenance requirements. This system is rated to 420 psig and 700°F (290 bar and 371°C). The ENVIRO-SEAL packing system or compact Belleville spring arrangement is rated to 3000 psig and 700°F (20.7 bar and 371°C).

Table 1-5 shows that the braided graphite filament arrangement is limited to 1500 psig (103 bar). Due to its construction, braided graphite filament cannot sustain high packing stress levels. Over time, the braided graphite filament will break down and compress, and sealing force will be lost. Due to these characteristics, braided graphite filament will not provide the required seal performance for environmental services. The braided graphite filament arrangement is also susceptible to stick-slip action, which might cause process control deviations.

Rotary Valve Considerations

The basic principles of sealing a rotary shaft are the same as sealing a sliding stem. However, experience shows that sealing the shaft on a rotary valve is less difficult than on sliding stem applications. The rotary motion does not tend to remove material from the packing box as does the sliding stem motion. Also, many of the rotary valve applications tend to be lower pressure applications than sliding stem valve services. As with sliding stem valves, the basic material recommendation for rotary valve packing is either PTFE or flexible graphite.

Single Packing Arrangements

Used in most applications for a durable, yet economical package.

Double Packing Arrangements

Where an especially tight seal is required, double packing is available. Consisting of two stacks of packing and a spacer, double packing arrangements have more packing on the actuator side if a lubricating connection is used.

Leak-Off Packing Arrangements

Certain rotary valve applications require that any leakage from the inner set of packing be detected and channeled away before it can leak through the outer set to the atmosphere. Leak-off packing arrangements are designed for this purpose.

Some standard packing arrangements, such as double PTFE V-ring, that have packing on either side of a lubricator connection can also be used for leak-off applications. However, standard packing arrangements are not specifically designed for leak-off applications and do not have a suitable ratio of packing on either side of the lubricator.

Purged Packing Arrangement

Certain rotary valve applications require that a lantern gland and a tapped pipe connection be provided inboard of the packing itself to permit purging of any accumulated deposits around the valve shaft and bushing. This arrangement is recommended for handling fluids with entrained solids and where fluids condense or solidify with loss of temperature.

Process Fluid Compatibility and Temperature Ranges

Fisher's published literature lists packing types that are used with various process fluids. However, some process fluids may not be compatible with the packing throughout the entire temperature range. If in doubt about the compatibility of Fisher's packing material with a process fluid of a specific concentration and temperature, consult your Fisher Representative sales office.

Published temperature ranges refer to temperatures in the packing box. When using any packing at low temperatures, frost allowed to form on the shaft can damage the packing. For a given process temperature, the packing box temperature depends on several factors. Contact the Fisher sales representative for information on packing box temperatures.

Conclusion

It is important to recognize that many parameters affect seal performance and service life. Even if the optimum design is selected, other factors such as stem finish, packing bore finish, and installation practices will have an effect on performance.

The knowledge gained by Fisher as a result of the ENVIRO-SEAL and HIGH-SEAL packing development program has provided an opportunity to help you "engineer" the packing selection. Proper selection has a bottom line result; that is, increased service life and reduced maintenance.

If you need a more detailed engineering discussion of the design principles affecting packing seal design, contact your Fisher sales office or sales representative.

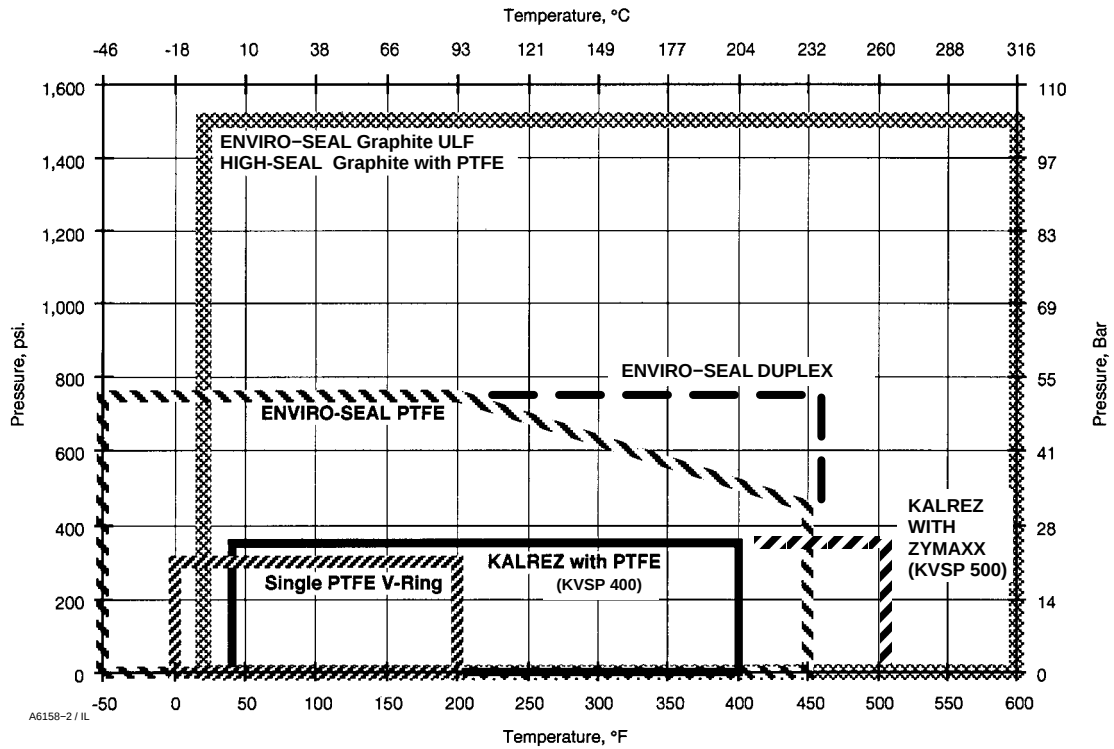


Figure 1-13. Application Guidelines Chart for 500 PPM Service

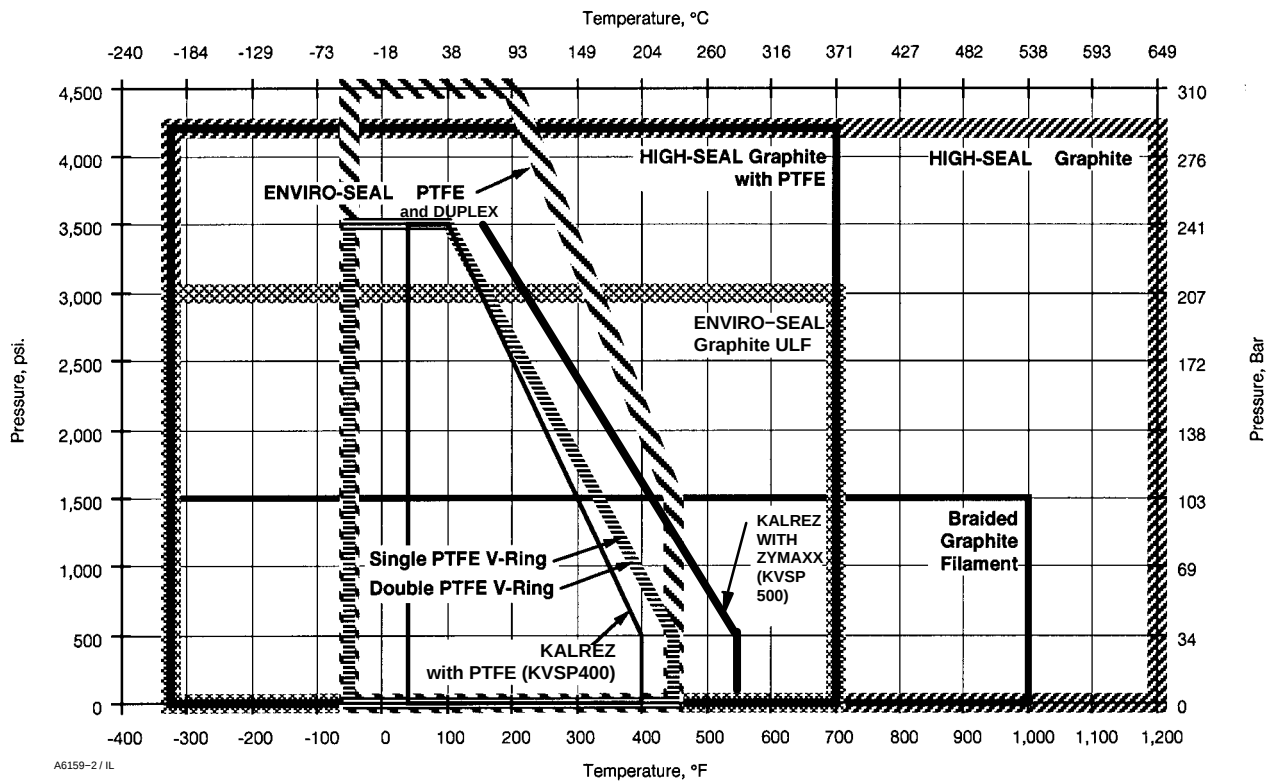
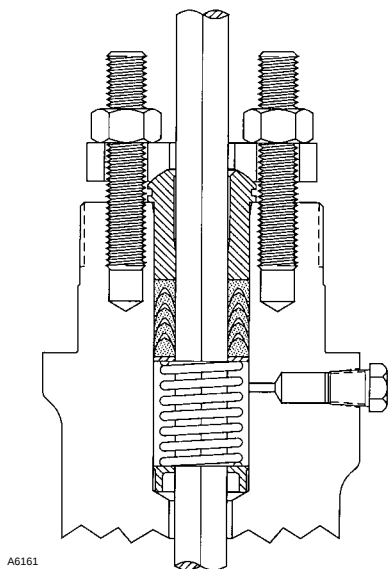
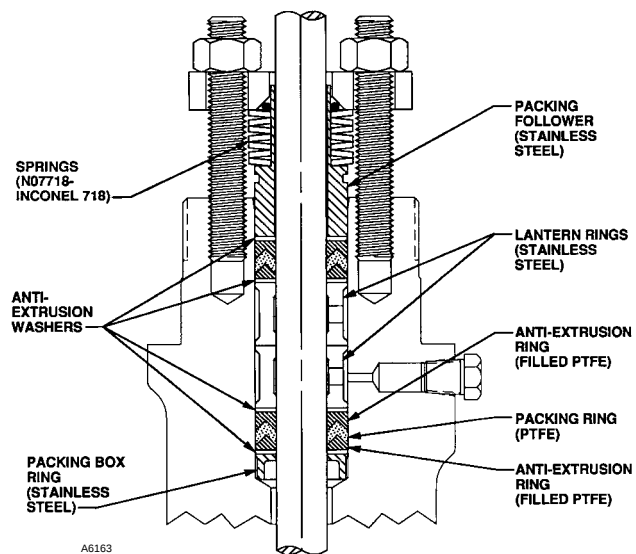


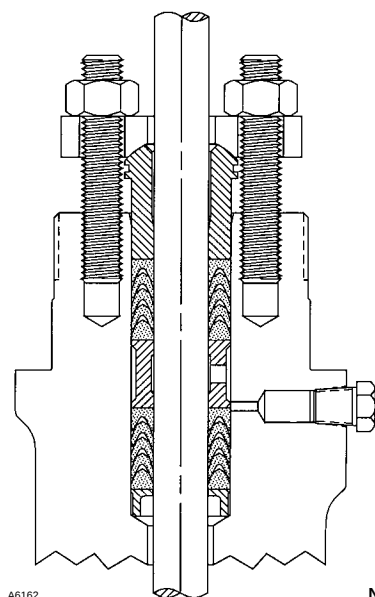
Figure 1-14. Application Guidelines Chart for Non-Environmental Service



SINGLE PTFE V-RING

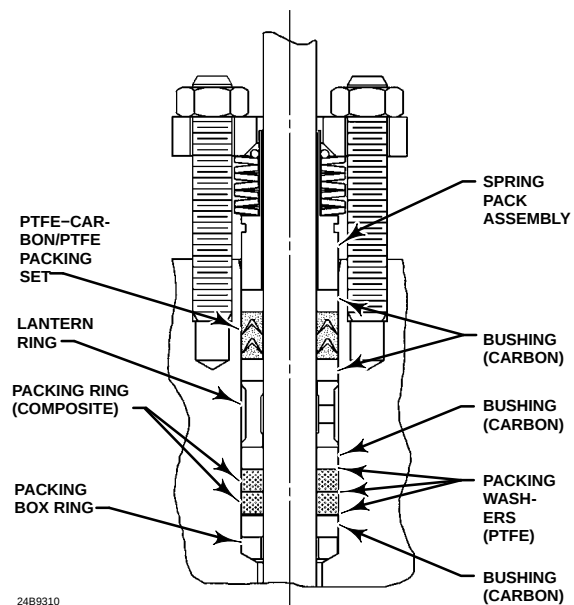


ENVIRO-SEAL PTFE



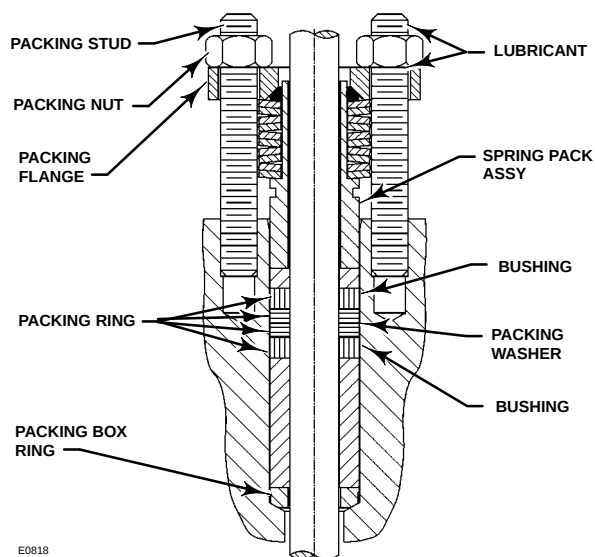
DOUBLE PTFE V-RING

NOTE: LEAD-OFF TAPPING
AND PIPE PLUG ARE OPTIONAL



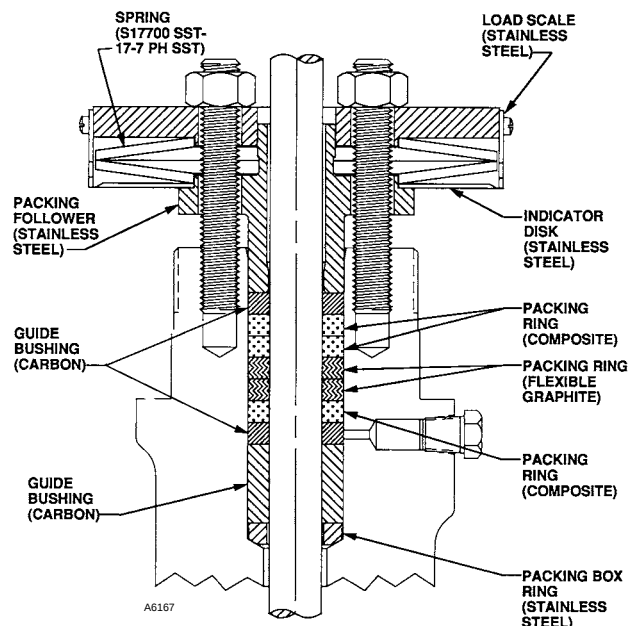
ENVIRO-SEAL DUPLEX PACKING

Figure 1-15. Typical Packing Examples for Sliding-Stem Valves



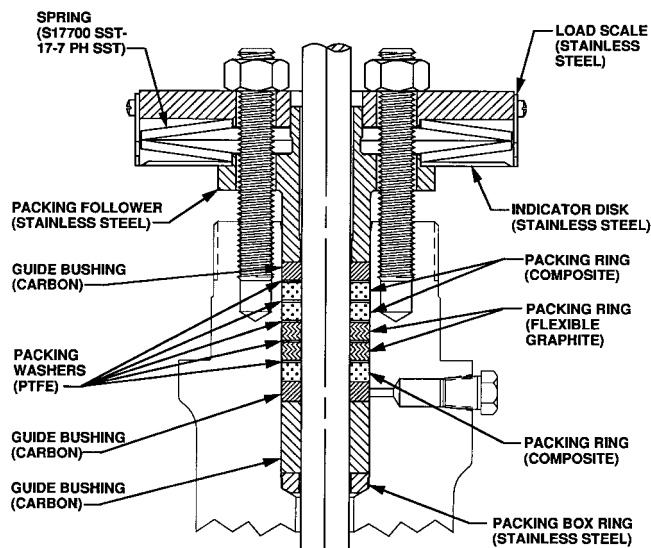
E0818

ENVIRO-SEAL GRAPHITE ULF



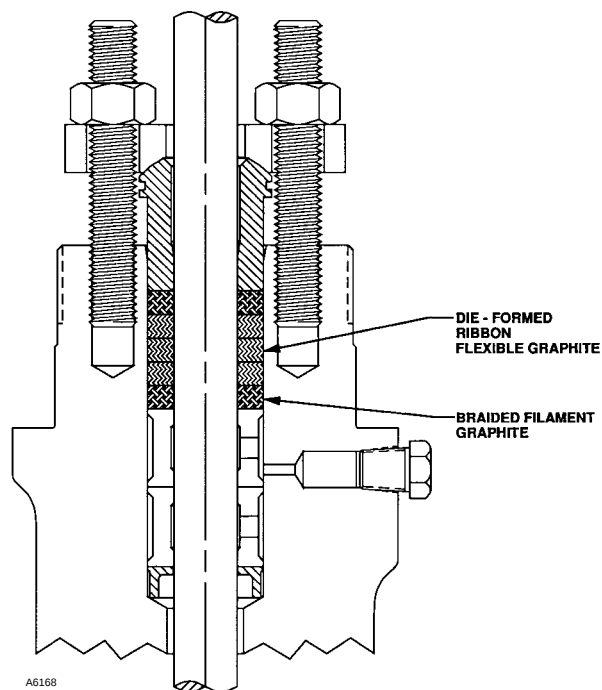
A6167

HIGH-SEAL GRAPHITE



A6166

HIGH-SEAL GRAPHITE WITH PTFE

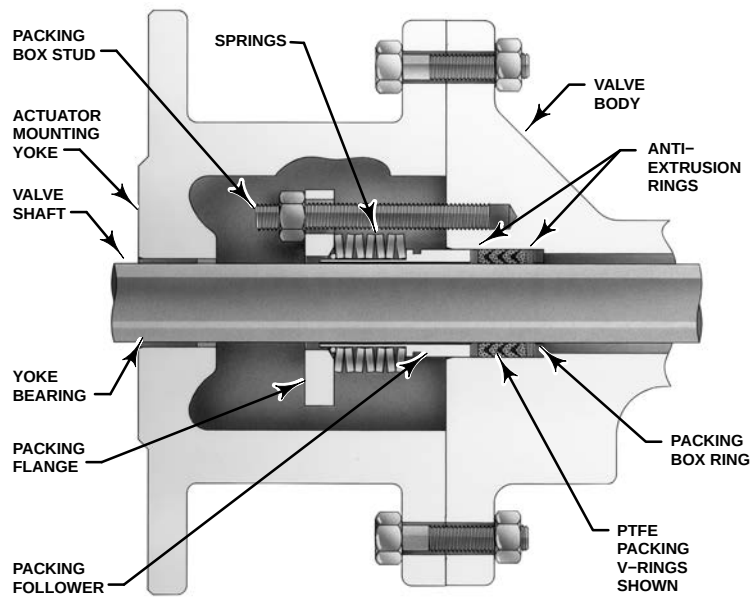


A6168

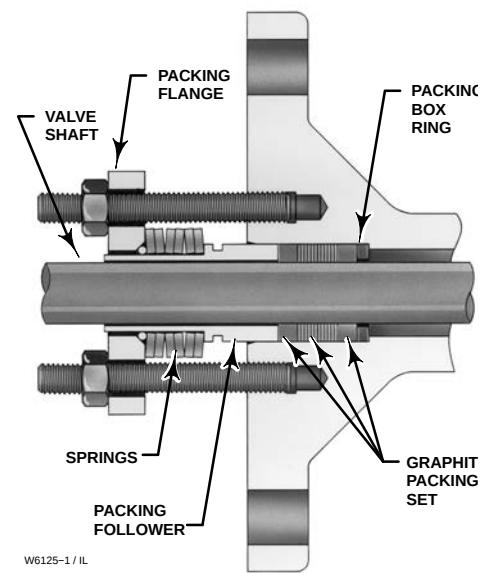
BRAIDED GRAPHITE FILAMENT

NOTE: LEAD-OFF TAPPING AND PIPE PLUG ARE OPTIONAL

Figure 1-16. Typical Packing Examples for Sliding-Stem Valves



SINGLE PTFE PACKING



GRAPHITE PACKING

Figure 1-17. Typical ENVIRO-SEAL Packing Arrangements for Rotary Valves

Actuator Selection

The actuator is the distinguishing element that differentiates control valves from other types of valves. The first actuated valves were designed in the late 19th Century. However, today they would be better described as regulators since they operated directly from the process fluid. These “automatic valves” were the mainstay of industry through the early 1930s.

It was at this time also that the first pneumatic controllers were used. Development of valve controllers and the adaptation of standardized control signals stimulated design of the first, true, control valve actuators.

The control valve industry has evolved to fill a variety of needs and desires. Actuators are available with an array of designs, power sources and capabilities. Proper selection involves process knowledge, valve knowledge and actuator knowledge.

A control valve can perform its function only as well as the actuator can handle the static and dynamic loads placed on it by the valve. Therefore, proper selection and sizing are very important. Since the actuator can represent a significant portion of the total control valve price, careful selection of actuator and accessory options can lead to significant dollar savings.

The range of actuator types and sizes on the market today is so great that it seems the selection process might be highly complex. It is not! With a few rules in mind and knowledge of fundamental needs, the selection process can be very simple.

The following parameters are key as they quickly narrow the actuator choices:

- Power Source Availability
- Fail-safe Requirements

- Torque or Thrust Requirements

- Control Functions

Power Source Availability

The power source available at the location of a valve often can point directly to what type of actuator to choose. Typically, valve actuators are powered either by compressed air or by electricity. However, pipeline pressure is often used in the natural gas transmission industry.

Fail-safe Requirements

The overall reliability of power sources is quite high. However, many loops demand specific valve action should the power source ever fail. Desired action upon a signal failure may be required for safety reasons or for protection of equipment.

Fail-safe systems store energy, either mechanically in springs, pneumatically in volume tanks, or in hydraulic accumulators. When power fails, the fail-safe systems are triggered to drive the valves to the required position and to then maintain this position until returned to normal operation. In many cases the process pressure is used to ensure or enhance this action.

Actuator designs are available which allow a choice of failure mode between failing open, failing closed, or holding in the last position. Many actuator systems incorporate failure modes at no extra cost. For example, spring-and-diaphragm types are inherently fail open or closed, while electric operators typically hold their last position.



Torque or Thrust Requirements

An actuator must have sufficient thrust or torque for the prescribed application. In some cases this requirement can dictate actuator type as well as power supply requirements.

For instance, large valves requiring a high thrust may be limited to only electric or electro-hydraulic actuators due to a lack of pneumatic actuators with sufficient thrust capability. Conversely, electro-hydraulic actuators would be a poor choice for valves with very low thrust requirements.

The matching of actuator capability with valve body requirements is best left to the control valve manufacturer as there are considerable differences in frictional and fluid forces from valve to valve.

Control Functions

Knowledge of the required actuator functions will most clearly define the options available for selection. These functions include the actuator signal (pneumatic, electric, etc.), signal range, ambient temperatures, vibration levels, operating speed, frequency, and quality of control that is required.

Generally, signal types are grouped as being either:

- Two-position (on-off) or
- Analog (throttling).
- Digital

Two-position electric, electro-pneumatic, or pneumatic switches control on-off actuators. This is the simplest type of automatic control and the least restrictive in terms of selection.

Throttling actuators have considerably higher demands put on them from both a compatibility and performance standpoint. A throttling actuator receives its input from an electronic or pneumatic instrument that measures the controlled process variable. The actuator must then move the final control element in response to the instrument signal in an accurate and timely fashion to ensure effective control. The two primary additional requirements for throttling actuators are:

- Compatibility with instrument signal
- Better static and dynamic performance to ensure loop stability.

Compatibility with instrument signals is inherent in many actuator types, or it can be obtained with add-on equipment. But, the high-performance characteristics required of a good throttling actuator cannot be bolted on; instead, low hysteresis and minimal deadband must be designed into actuators.

Stroking speed, vibration, and temperature resistance must also be considered if critical to the application. For example, on liquid loops fast-stroking speeds can be detrimental due to the possibility of water hammer.

Vibration or mounting position can be a potential problem. The actuator weight, combined with the weight of the valve, may necessitate bracing.

It is essential to determine the ambient temperature and humidity that the actuator will experience. Many actuators contain either elastomeric or electronic components that can be subject to degradation by high humidity or temperature.

Economics

Evaluation of economics in actuator selection is a combination of the following:

- Cost
- Maintenance
- Reliability

A simple actuator, such as a spring-and-diaphragm, has few moving parts and is easy to service. Initial cost is low. Maintenance personnel understand and are comfortable working with them.

An actuator made specifically for a control valve eliminates the chance for a costly performance mismatch. An actuator manufactured by the valve vendor and shipped with the valve will eliminate separate mounting charges and ensure easier coordination of spare parts procurement. Interchangeable parts among varied actuators are also important to minimize spare-parts inventory.

Actuator Designs

There are many types of actuators on the market, most of which fall into four general categories:

- Spring-and-diaphragm
- Pneumatic piston
- Electric motor
- Electro-hydraulic.

Each actuator design has weaknesses, strong points and optimum uses. Most actuator designs are available for either sliding stem or rotary valve bodies. They differ only by linkages or motion translators; the basic power sources are identical.

Most rotary actuators employ linkages, gears, or crank arms to convert direct linear motion of a diaphragm or piston into the 90-degree output rotation required by rotary valves. The most important consideration for control valve actuators is the requirement for a design that limits the amount of lost motion between internal linkage and valve coupling.

Rotary actuators are now available that employ tilting pistons or diaphragms. These designs eliminate most linkage points (and resultant lost motion) and provide a safe, accurate and enclosed package.

When considering an actuator design, it is also necessary to consider the method by which it is coupled to the drive shaft of the control valve. Slotted connectors mated to milled shaft flats generally are not satisfactory if any degree of performance is required. Pinned connections, if solidly constructed, are suitable for nominal torque applications. A splined connector that mates to a splined shaft end and then is rigidly clamped to the shaft eliminates lost motion, is easy to disassemble and is capable of high torque.

Sliding-stem actuators are rigidly fixed to valve stems by threaded and clamped connections. Since they don't have any linkage points, and their

connections are rigid, they exhibit no lost motion and have excellent inherent control characteristics.

Spring-and-Diaphragm Actuators

The most popular and widely used control valve actuator is the pneumatic spring-and-diaphragm style. These actuators are extremely simple and offer low cost and high reliability. They normally operate over the standard signal ranges of 3 to 15 psig (0.2 to 1 bar) or 6 to 30 psig (0.4 to 2.1 bar), and therefore, they are often suitable for throttling service using instrument signals directly.

Many spring-and-diaphragm designs offer either adjustable springs and/or wide spring selections to allow the actuator to be tailored to the particular application. Since they have few moving parts that may contribute to failure, they are extremely reliable. Should they ever fail, maintenance is extremely simple. Improved designs now include mechanisms to control the release of spring compression, eliminating possible personnel injury during actuator disassembly.

Use of a positioner or booster with a spring-and-diaphragm actuator can improve control, but when improperly applied, can result in very poor control. Follow the simple guidelines available for positioner applications, and look for:

- Rugged, vibration-resistant construction
- Calibration ease
- Simple, positive feedback linkages

The overwhelming advantage of the spring-and-diaphragm actuator is the inherent provision for fail-safe action. As pneumatic supply is loaded on the actuator casing, the diaphragm moves the valve and compresses the spring. The stored energy in the spring acts to move the valve back to its original position as air is released from the casing. Should there be a loss of signal pressure to the instrument or the actuator, the spring can move

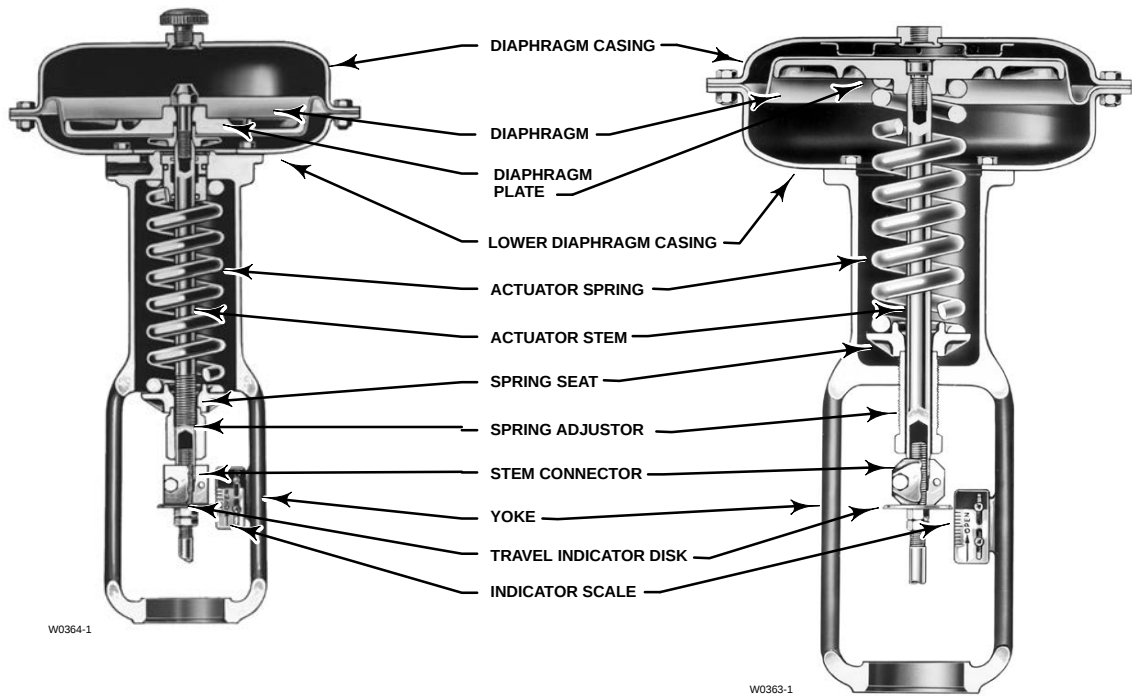


Figure 2-1. Spring-and-diaphragm actuators offer an excellent first choice for most control valves. They are inexpensive, simple and have built-in, fail-safe action. Pictured above are cutaways of the popular 667 (left) and 657 (right) actuators.

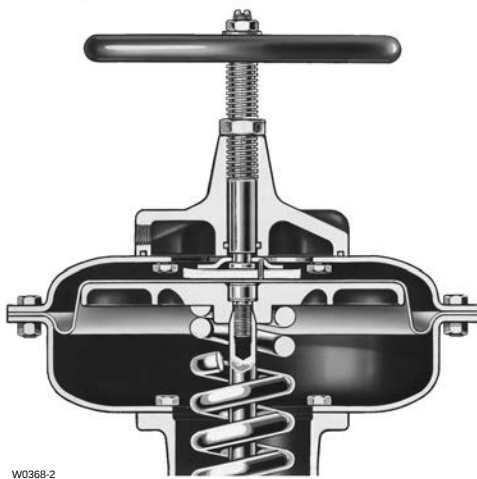


Figure 2-2. Spring-and-diaphragm actuators can be supplied with a top-mounted handwheel. The handwheel allows manual operation and also acts as a travel stop or means of emergency operation.

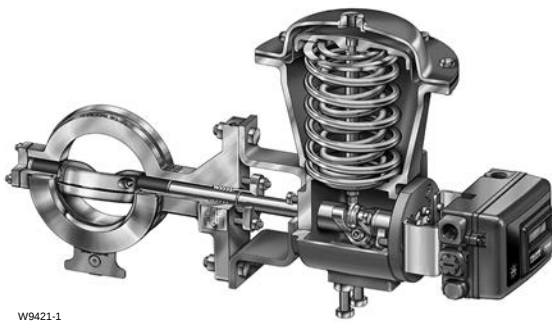
the valve to its initial (fail-safe) position. Actuators are available for either fail-open or fail-closed action. Fail-lock is also available by utilizing a pneumatic switching valve such as a Fisher 164A, piped as a lock valve.

The only real drawback to the spring-and-diaphragm actuator is a relatively limited output capability. Much of the thrust created by the diaphragm is taken up by the spring and thus does not result in output to the valve. Therefore, the spring-and-diaphragm actuator is used infrequently for high force requirements. It is not economical to build and use very large spring-and-diaphragm actuators because the size, weight and cost grow exponentially with each increase in output force capability.

Piston Actuators

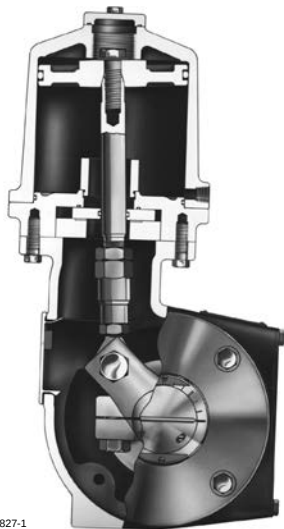
Piston actuators are generally more compact and provide higher torque or force outputs than spring-and-diaphragm actuators. Fisher piston styles normally work with supply pressures between 50 and 150 psig (3.4 and 10.3 bar) and can be equipped with spring returns (however, this construction has limited application).

Piston actuators used for throttling service must be furnished with double-acting positioners, which simultaneously load and unload opposite sides of the piston. The pressure differential created across the piston causes travel toward the lower pressure side. The positioner senses the motion, and when the required position is reached, the



W9421-1

Figure 2-3. The 2052 is a spring-and-diaphragm actuator that has many features to provide precise control. The splined actuator connection features a clamped lever and single-joint linkage to help eliminate lost motion.



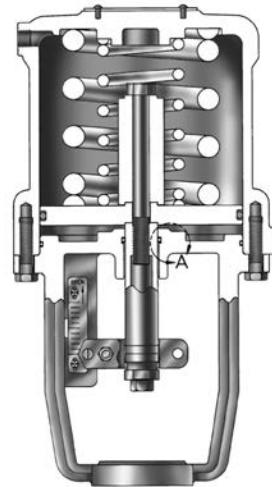
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Figure 2-4. Double-acting piston actuators such as 1061 rotary actuator are a good choice when thrust requirements exceed the capability of spring-and-diaphragm actuators. Piston actuators require a higher supply pressure, but have benefits such as high stiffness and small size.

positioner equalizes the pressure on both sides of the piston.

The pneumatic piston actuator is an excellent choice when a compact unit is required to produce high torque or force. It is also easily adapted to services where high ambient temperatures are a concern.

The main disadvantages of piston actuators are high supply pressures required for positioners



W7447

Figure 2-5. Spring fail-safe is present in this piston design. The 585C actuator is an example of a spring-bias piston actuator. Process pressure can aid fail-safe action, or the actuator can be configured for full spring-fail closure.

when used in throttling service and the lack of fail-safe systems.

There are two types of spring-return piston actuators available. The variations are subtle, but significant. It is possible to add a spring to a piston actuator and operate it much like a spring-and-diaphragm. These designs use a single-acting positioner that loads the piston chamber to move the actuator and compress the spring. As the pneumatic supply is unloaded, the spring forces the piston back. These designs use large, high output springs that are capable of overcoming the fluid forces in the valve.

The alternative design uses a much smaller spring and relies on valve fluid forces to help provide the fail-safe action. In normal operation they act like a double action piston. In a fail-safe situation the spring initiates movement and is helped by unbalance forces on the valve plug. These actuators also can be sized and set up to provide full spring closure action without process assistance.

An alternative to springs is a pneumatic trip system, which often adds complexity to the design. While a trip system is completely safe, any fail-safe requirement consideration should be given first to spring-and-diaphragm operators if they are feasible.

Special care should be given during the selection of throttling piston actuators to specify a design that has minimal hysteresis and deadband. As the number of linkage points in the actuator increases,

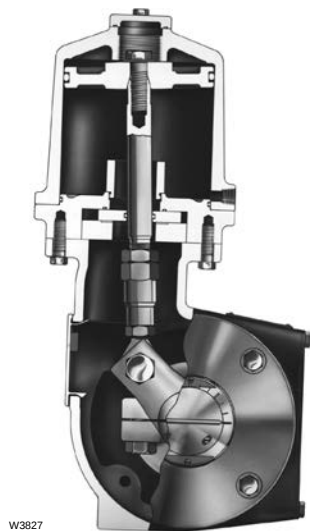


Figure 2-6. This 1061 actuator is a double-acting rotary piston actuator for throttling service.

so does the deadband. As the number of sliding parts increases, so does the hysteresis. An actuator with high hysteresis and deadband can be quite suitable for on-off service; however, caution is necessary when attempting to adapt this actuator to throttling service by merely bolting on a positioner.

The cost of a spring-and-diaphragm actuator is generally less than a comparable piston actuator. The inherent provision for fail-safe action in the spring-and-diaphragm actuator is also a consideration.

Electric Actuators

Electric actuators can be applied successfully in many situations. Most electric operators consist of motors and gear trains and are available in a wide range of torque outputs, travels and capabilities. They are suited for remote mounting where no

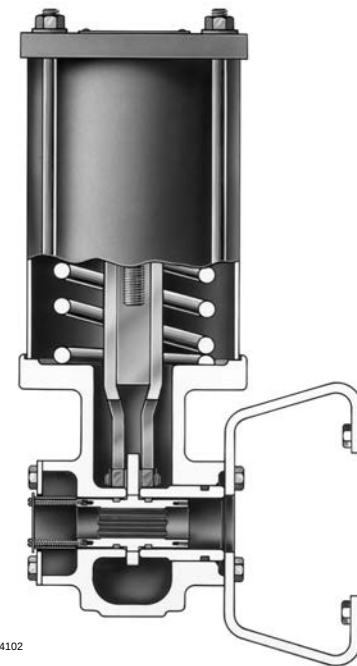


Figure 2-7. Since the requirements for accuracy and minimal lost motion are unnecessary for on-off service, cost savings can be achieved by simplifying the actuator design. The 1066SR incorporates spring-return capability.

other power source is available, for use where there are specialized thrust or stiffness requirements or when highly precise control is required.

Electric operators are economical versus pneumatic actuators for applications in small size ranges only. Larger units operate slowly and weigh considerably more than pneumatic equivalents. Available fail action is typically lock in last position.

One very important consideration in choosing an electric actuator is its capability for continuous closed-loop control. In applications where frequent changes are made in control-valve position, the electric actuator must have a suitable duty cycle. High performance electric actuators using continuous rated DC motors and ball screw output de-



W9933-2

Figure 2-8. Fisher D4 Control Valve with easy-Drive Electric Actuator

VICES are capable of precise control and 100% duty cycles.

Compared to other actuator designs, the electric actuator generally provides the highest output available within a given package size. Additionally, electric actuators are very stiff, that is, resistant to valve forces. This makes them an excellent choice for good throttling control of large, high-pressure valves.

Electro-hydraulic Actuators

An electro-hydraulic actuator internally pumps oil at high pressure to a piston, which in turn creates an output force. The electro-hydraulic actuator is an excellent choice for throttling due to its high stiffness, compatibility with analog signals, excellent frequency response and positioning accuracy.

Most electro-hydraulic actuators are capable of very high outputs, but they are handicapped by high initial cost, complexity and difficult maintenance. Fail-safe action on electro-hydraulic actuators can be accomplished by use of a return spring or a hydraulic accumulator and by shutdown systems.

Like electric actuators, the electro-hydraulic actuators are suitable for remote mounting where no other power source is available (such as pipelines).

Electro-hydraulic actuators from Fisher are available in two basic configurations: self-contained, and externally powered. The self-contained unit

includes its own motor, pump, fluid reservoir, etc. (this type of unit can be available with spring-return fail mode.) The external power supply unit requires a separate motor, pump, reservoir, hydraulic hoses and other accessories. This type requires an accumulator to achieve a fail mode.

Actuator Sizing

The last step in the selection process is to determine the required actuator size. Fundamentally, the process of sizing is to match as closely as possible the actuator capabilities to the valve requirements.

In practice, the mating of actuator and valve requires the consideration of many factors. Valve forces must be evaluated at the critical positions of valve travel (usually open and closed) and compared to actuator output. Valve force calculation varies considerably between valve styles and manufacturers. In most cases it is necessary to consider a complex summation of forces including:

- Static fluid forces
- Dynamic fluid forces and force gradients
- Friction of seals, bearings and packing
- Seat loading

Although actuator sizing is not difficult, the great variety of designs on the market and the ready availability of vendor expertise (normally at no cost) make detailed knowledge of the procedures unnecessary.

A. Unbalance Force

The unbalance force is that resulting from fluid pressure at shutoff and in the most general sense can be expressed as:

Unbalance force = net pressure differential X net unbalance area

Frequent practice is to take the maximum upstream gauge pressure as the net pressure differential unless the process design always ensures a back pressure at the maximum inlet pressure. Net unbalance area is the port area on a single seated flow up design. Unbalance area may have to take into account the stem area depending on configuration. For balanced valves there is still a small unbalance area. This data can be obtained from the manufacturer. Typical port areas for balanced

valves flow up and unbalanced valves in a flow down configuration are listed in Table 2-1.

B. Force to Provide Seat Load

Seat load, usually expressed in pounds per lineal inch or port circumference, is determined by shut-off requirements. Use the guidelines in Table 2-2 to determine the seat load required to meet the factory acceptance tests for ANSI/FCI 70-2 and IEC 534-4 leak classes II through VI.

Because of differences in the severity of service conditions, do not construe these leak classifications and corresponding leakage rates as indicators of field performance. To prolong seat life and shutoff capabilities, use a higher than recommended seat load. If tight shutoff is not a prime consideration, use a lower leak class.

C. Packing Friction

Packing friction is determined by stem size, packing type, and the amount of compressive load placed on the packing by the process or the bolting. Packing friction is not 100% repeatable in its friction characteristics. Newer live loaded packing designs can have significant friction forces especially if graphite packing is used. Table 2-3 lists typical packing friction values.

D. Additional Forces

Additional forces to consider may include bellows stiffness, unusual frictional forces resulting from seals or special seating forces for soft metal seals.

Table 2-1. Typical Unbalance Areas of Control Valves

Port Diameter, Inches	Unbalance Area Single-Seated Unbalanced Valves, In ²	Unbalance Area Balanced Valves, In ²
1/4	0.049	---
3/8	0.110	---
1/2	0.196	---
3/4	0.441	---
1	0.785	---
1-5/16	1.35	0.04
1-7/8	2.76	0.062
2-5/16	4.20	0.27
3-7/16	9.28	0.118
4-3/8	15.03	0.154
7	38.48	0.81
8	50.24	0.86

Table 2-2. Recommended Seat Load Per Leak Class for Control Valves

Class I	As required by customer specification, no factory leak test required
Class II	20 pounds per lineal inch of port circumference
Class III	40 pounds per lineal inch of port circumference
Class IV	Standard (Lower) Seat only—40 pounds per lineal inch of port circumference (up through a 4-3/8 inch diameter port) Standard (Lower) Seat only—80 pounds per lineal inch of port circumference (larger than 4-3/8 inch diameter port)
Class V	Metal Seat—determine pounds per lineal inch of port circumference from Figure 2-9

The manufacturer should either supply this information or take it into account when sizing an actuator.

Actuator Force Calculations

Pneumatic spring-and-diaphragm actuators provide a net force with the additional air pressure after compressing the spring in air-to-close, or with the net pre-compression of the spring in air-to-open. This may be calculated in pounds per square inch of pressure differential.

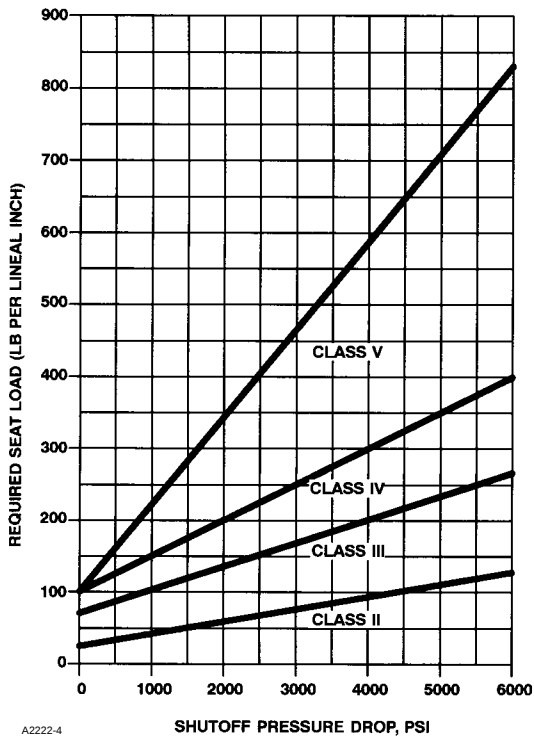


Figure 2-9. Recommended seat load.

For example: Suppose 275 lbf. is required to close the valve as calculated per the process described earlier. An air-to-open actuator with 100 square inches of diaphragm area and a bench set of 6 to 15 psig (0.4 to 1 bar) is one available option. The expected operating range is 3 to 15 psig (0.2 to 1 bar). The pre-compression can be calculated as the difference between the lower end of the bench set, 6 psig (0.4 bar) and the beginning of the operating range, 3 psig (0.2 bar). This 3 psig is used to overcome the pre-compression so the net pre-compression force must be:

$$3 \text{ psig} \times 100 \text{ sq. in.} = 300 \text{ lbf.}$$

This exceeds the force required and is an adequate selection.

Piston actuators with springs are sized in the same manner.

The thrust from piston actuators without springs can be calculated as:

$$\text{Piston Area} \times \text{Minimum Supply Pressure} = \text{Minimum Available Thrust}$$

(Be careful to maintain compatibility of units)

Table 2-3. Typical Packing Friction Values (Lb)

Stem Size (Inches)	ASME Class	PTFE Packing		Graphite Ribbon/Filament
		Single	Double	
5/16	All	20	30	---
3/8	125	38	56	---
	150			125
	250			---
	300			190
	600			250
	900			320
	1500			380
1/2	125	50	75	---
	150			180
	250			---
	300			230
	600			320
	900			410
	1500			500
	2500			590
5/8	125	63	95	---
	150			218
	250			---
	300			290
	600			400
	900			
	1500			
	2500			
3/4	125	75	112.5	---
	150			350
	250			---
	300			440
	600			660
	900			880
	1500			1100
	2500			1320
1	300	100	150	610
	600			850
	900			1060
	1500			1300
	2500			1540
1-1/4	300	120	180	800
	600			1100
	900			1400
	1500			1700
	2500			2040
2	300	200	300	1225
	600			1725
	900			2250
	1500			2750
	2500			3245

Values shown are frictional forces typically encountered when using standard packing flange bolt-torquing procedures.

In some circumstances an actuator could supply too much force and cause the stem to buckle, to bend sufficiently to cause a leak, or to damage valve internals.

The manufacturer normally takes responsibility for actuator sizing and should have methods documented to check for maximum stem loads. Manufacturers also publish data on actuator thrusts, effective diaphragm areas, and spring data.

Table 2-4. Typical Rotary Shaft Valve Torque Factors V-Notch Ball Valve with Composition Seal

Valve Size, NPS	Valve Shaft Diameter, Inches	A	B	C		Maximum T _D , Lbf•In.
		Composition Bearings		60 Degrees	70 Degrees	
2	1/2		8	0.11	0.60	515
3	3/4	0.15	280	0.15	3.80	2120
4	3/4	0.10	380	1.10	18.0	2120
6	1	0.10	500	1.10	36.0	4140
8	1-1/4		750	3.80	60.0	9820
10	1-1/4		1250	3.80	125	9820
12	1-1/2	1.80	3000	11.0	143	12,000
14	1-3/4	4.00	2400	75	413	23,525
16	2	42	2800	105	578	23,525
18	2-1/8	60	2800	105	578	55,762
20	2-1/2		5200	190	1044	55,762

Table 2-5. Typical High Performance Butterfly Torque Factors for Valve with Composition Seal

Valve Size, NPS	Shaft Diameter Inches	A	B	C			Maximum Torque, Inch-Pounds	
				60°	75°	90°	Breakout T _B	Dynamic T _D
3	1/2	0.50	136	0.8	1.8	8	280	515
4	5/8	0.91	217	3.1	4.7	25	476	225
6	3/4	1.97	403	30	24	70	965	2120
8	1	4.2	665	65	47	165	1860	4140
10	1-1/4	7.3	1012	125	90	310	3095	9820
12	1-1/2	11.4	1422	216	140	580	4670	12,000

Actuator Sizing for Rotary Valves

In selecting the most economical actuator for a rotary valve, the determining factors are the torque required to open and close the valve and the torque output of the actuator.

This method assumes the valve has been properly sized for the application and the application does not exceed pressure limitations for the valve.

Torque Equations

Rotary valve torque equals the sum of a number of torque components. To avoid confusion, a number of these have been combined, and a number of calculations have been performed in advance. Thus, the torque required for each valve type can be represented with two simple and practical equations.

Breakout Torque

$$T_B = A(\Delta P_{\text{shutoff}}) + B$$

Dynamic Torque

$$T_D = C(\Delta P_{\text{eff}})$$

Specific A, B, and C factors for example rotary valve designs are included in tables 2-4 and 2-5.

Maximum Rotation

Maximum rotation is defined as the angle of valve disk or ball in the fully open position.

Normally, maximum rotation is 90 degrees. The ball or disk rotates 90 degrees from the closed position to the wide-open position.

Some of the pneumatic spring-return piston and pneumatic spring-and-diaphragm actuators are limited to 60 or 75 degrees rotation.

For pneumatic spring-and-diaphragm actuators, limiting maximum rotation allows for higher initial spring compression, resulting in more actuator breakout torque. Additionally, the effective length of each actuator lever changes with valve rotation. Published torque values, particularly for pneumatic piston actuators, reflect this changing lever length.

The Selection Process

In choosing an actuator type, the fundamental requirement is to know your application. Control signal, operating mode, power source available, thrust/torque required, and fail-safe position can make many decisions for you. Keep in mind simplicity, maintainability and lifetime costs.

Safety is another consideration that must never be overlooked. Enclosed linkages and controlled compression springs available in some designs are very important for safety reasons. Table 2-6 below lists the pros and cons of the various actuator styles.

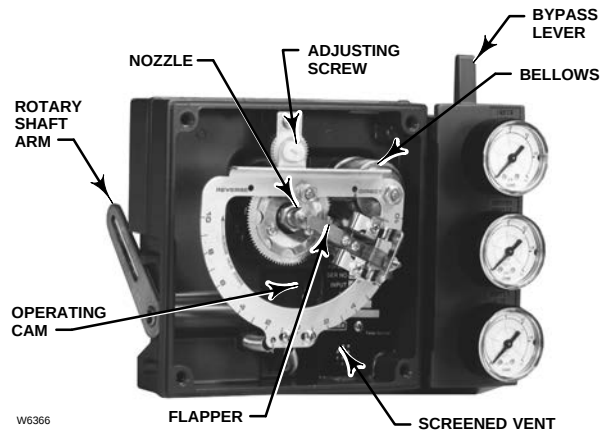
Table 2-6 Actuator Feature Comparison

Actuator Type	Advantages	Disadvantages
Spring-and-Diaphragm	Lowest cost Ability to throttle without positioner Simplicity Inherent fail-safe action Low supply pressure requirement Adjustable to varying conditions Ease of maintenance	Limited output capability Larger size and weight
Pneumatic Piston	High thrust capability Compact Lightweight Adaptable to high ambient temperatures Fast stroking speed Relatively high actuator stiffness	Higher cost Fail-safe requires accessories or addition of a spring Positioner required for throttling High supply pressure requirement
Electric Motor	Compactness Very high stiffness High output capability	High cost Lack of fail-safe action Limited duty cycle Slow stroking speed
Electro-Hydraulic	High output capability High actuator stiffness Excellent throttling ability Fast stroking speed	High cost Complexity and maintenance difficulty Large size and weight Fail-safe action only with accessories



W4920

Figure 2-10. The 3620JP is an electro-pneumatic positioner that combines the functions of transducer and positioner into one unit. The combustion unit generally is more economical but may not be as flexible as separate units.



W6366

Figure 2-11. The standard pneumatic positioner for spring-and-diaphragm actuators is Fisher 3582. This time-proven design features ease for reversal and calibration as well as availability of characterizing cams to alter its input/output relationship.

Actuator Selection Summary

- Actuator selection must be based on a balance of process requirements, valve requirements and cost.
- Simple designs such as the spring-and-diaphragm are simpler, less expensive and easier to maintain. Consider them first in most situations.
- Piston actuators offer many of the advantages of pneumatic actuators with higher thrust capability than spring-and-diaphragm styles. They are especially useful where compactness is desired or long travel is required.
- Electric and electro-hydraulic actuators provide excellent performance. They are, however, much more complex and difficult to maintain.
- Actuator sizing is not difficult, but the wide variety of actuators and valves make it difficult to master. Vendor expertise is widely available.
- Systems such as control valves are best purchased, assembled and tested by one source. Use of actuators and accessories of the same manufacture will eliminate many problems.



W8119-2

Figure 2-12. The FIELDVUE digital valve controller brings increased control accuracy and flexibility. When utilized with AMS ValveLink™ software, FIELDVUE instruments provide valuable diagnostic data that helps avoid maintenance problems.



W8710

Figure 2-13. Electro-pneumatic transducers are a common actuator accessory. They take a milliamp signal and produce a proportional pneumatic output. The i2P-100 is compact, accurate and has low air consumption.



W9262-1

Figure 2-15. Pneumatic controllers compare sensed process pressure (or differential pressure) with an operator-adjusted set point, and send a pneumatic signal to an adjacent control valve that maintains the process pressure at or near the set point. Fisher C1 controllers and transmitters continue the tradition of durable and dependable Fisher pressure instrumentation while addressing air or gas consumption concerns.



X0206

Figure 2-14. On fast control loops, a positioner may not be able to react quickly enough to be of use. In these situations, performance of spring-and-diaphragm actuators can be improved by use of pneumatic boosters such as the SS-263.



X0214-1

Figure 2-16. In the upstream oil and gas industry displacer type liquid level controllers along with on/off dump valves are used for controlling liquid level in oil and gas production separators. The controllers use a displacer sensor to detect liquid level or the interface of two liquids of different specific gravities. The output signal from the controller is either electric or pneumatic and sent to an on/off dump valve to open or close it. The L2e shown is the electric output version of this controller.



W9954-1

Figure 2-17. The FIELDVUE DLC3010 digital level controller is used with level sensors to measure liquid level, the level of the interface between two liquids, or liquid specific gravity (density). Changes in level or specific gravity exert a buoyant force on a displacer, which rotates a torque tube shaft. The digital level controller converts this rotational motion to an electronic signal that is used by a control valve to maintain the level or specific gravity set point.

Liquid Valve Sizing

Valve Sizing

Standardization activities for control valve sizing can be traced back to the early 1960s when a trade association, the Fluids Control Institute, published sizing equations for use with both compressible and incompressible fluids. The range of service conditions that could be accommodated accurately by these equations was quite narrow, and the standard did not achieve a high degree of acceptance. In 1967, the ISA established a committee to develop and publish standard equations. The efforts of this committee culminated in a valve sizing procedure that has achieved the status of American National Standard. Later, a committee of the International Electrotechnical Commission (IEC) used the ISA works as a basis to formulate international standards for sizing control valves. (Some information in this introductory material has been extracted from ANSI/ISA S75.01 standard with the permission of the publisher, the ISA.) Except for some slight differences in nomenclature and procedures, the ISA and IEC standards have been harmonized. ANSI/ISA Standard 75.01 is harmonized with IEC Standards 60534-2-1.

In the following sections, the nomenclature and procedures are explained, and sample problems are solved to illustrate their use.

Sizing Valves for Liquids

Following is a step-by-step procedure for the sizing of control valves for liquid flow using the IEC procedure. Each of these steps is important and must be considered during any valve sizing procedure. Steps 3 and 4 concern the determination of certain sizing factors that may or may not be required in the sizing equation depending on the service conditions of the sizing problem. If one, two, or all three of these sizing factors are to be included in the equation for a particular sizing prob-

lem, refer to the appropriate factor determination section(s) located in the text after the sixth step.

1. Specify the variables required to size the valve as follows:

- Desired design
- Process fluid (water, oil, etc.), and
- Appropriate service conditions q or w , P_1 , P_2 or ΔP , T_1 , G_f , P_v , P_c , and v

The ability to recognize which terms are appropriate for a specific sizing procedure can only be acquired through experience with different valve sizing problems. If any of the above terms appears to be new or unfamiliar, refer to the Abbreviations and Terminology Table 3-1 for a complete definition.

2. Determine the equation constant, N .

N is a numerical constant contained in each of the flow equations to provide a means for using different systems of units. Values for these various constants and their applicable units are given in the Equation Constants table 3-2.

Use N_1 , if sizing the valve for a flow rate in volumetric units (gpm or m^3/h).

Use N_6 if sizing the valve for a flow rate in mass units (lb/h or kg/h).



3. Determine F_p , the piping geometry factor.

F_p is a correction factor that accounts for pressure losses due to piping fittings such as reducers, elbows, or tees that might be attached directly to the inlet and outlet connections of the control valve to

be sized. If such fittings are attached to the valve, the F_p factor must be considered in the sizing procedure. If, however, no fittings are attached to the valve, F_p has a value of 1.0 and simply drops out of the sizing equation.

Table 3-1. Abbreviations and Terminology

Symbol		Symbol	
C_v	Valve sizing coefficient	P_1	Upstream absolute static pressure
d	Nominal valve size	P_2	Downstream absolute static pressure
D	Internal diameter of the piping	P_c	Absolute thermodynamic critical pressure
F_d	Valve style modifier, dimensionless	P_v	Vapor pressure absolute of liquid at inlet temperature
F_F	Liquid critical pressure ratio factor, dimensionless	ΔP	Pressure drop ($P_1 - P_2$) across the valve
F_k	Ratio of specific heats factor, dimensionless	$\Delta P_{\max(L)}$	Maximum allowable liquid sizing pressure drop
F_L	Rated liquid pressure recovery factor, dimensionless	$\Delta P_{\max(LP)}$	Maximum allowable sizing pressure drop with attached fittings
F_{LP}	Combined liquid pressure recovery factor and piping geometry factor of valve with attached fittings (when there are no attached fittings, F_{LP} equals F_L), dimensionless	q	Volume rate of flow
F_P	Piping geometry factor, dimensionless	$q_{\max}$	Maximum flow rate (choked flow conditions) at given upstream conditions
G_f	Liquid specific gravity (ratio of density of liquid at flowing temperature to density of water at 60°F), dimensionless	T_1	Absolute upstream temperature (degree K or degree R)
G_g	Gas specific gravity (ratio of density of flowing gas to density of air with both at standard conditions ⁽¹⁾ , i.e., ratio of molecular weight of gas to molecular weight of air), dimensionless	w	Mass rate of flow
k	Ratio of specific heats, dimensionless	x	Ratio of pressure drop to upstream absolute static pressure ($\Delta P/P_1$), dimensionless
K	Head loss coefficient of a device, dimensionless	x_T	Rated pressure drop ratio factor, dimensionless
M	Molecular weight, dimensionless	Y	Expansion factor (ratio of flow coefficient for a gas to that for a liquid at the same Reynolds number), dimensionless
N	Numerical constant	Z	Compressibility factor, dimensionless
		γ_1	Specific weight at inlet conditions
		ν	Kinematic viscosity, centistokes

1. Standard conditions are defined as 60°F (15.5°C) and 14.7 psia (101.3kPa).

Table 3-2. Equation Constants⁽¹⁾

		N	w	q	p ⁽²⁾	γ	T	d, D
N ₁		0.0865	---	m ³ /h	kPa	---	---	---
		0.865	---	m ³ /h	bar	---	---	---
		1.00	---	gpm	psia	---	---	---
N ₂		0.00214	---	---	---	---	---	mm
		890	---	---	---	---	---	inch
N ₅		0.00241	---	---	---	---	---	mm
		1000	---	---	---	---	---	inch
N ₆		2.73	kg/h	---	kPa	kg/m ³	---	---
		27.3	kg/h	---	bar	kg/m ³	---	---
		63.3	lb/h	---	psia	lb/ft ³	---	---
N ₇ ⁽³⁾	Normal Conditions T _N = 0°C	3.94	---	m ³ /h	kPa	---	deg K	---
		394	---	m ³ /h	bar	---	deg K	---
	Standard Conditions T _S = 15.5°C	4.17	---	m ³ /h	kPa	---	deg K	---
		417	---	m ³ /h	bar	---	deg K	---
	Standard Conditions T _S = 60°F	1360	---	scfh	psia	---	deg R	---
N ₈		0.948	kg/h	---	kPa	---	deg K	---
		94.8	kg/h	---	bar	---	deg K	---
		19.3	lb/h	---	psia	---	deg R	---
N ₉ ⁽³⁾	Normal Conditions T _N = 0°C	21.2	---	m ³ /h	kPa	---	deg K	---
		2120	---	m ³ /h	bar	---	deg K	---
	Standard Conditions T _S = 15.5°C	22.4	---	m ³ /h	kPa	---	deg K	---
		2240	---	m ³ /h	bar	---	deg K	---
	Standard Conditions T _S = 60°F	7320	---	scfh	psia	---	deg R	---

1. Many of the equations used in these sizing procedures contain a numerical constant, N, along with a numerical subscript. These numerical constants provide a means for using different units in the equations. Values for the various constants and the applicable units are given in the above table. For example, if the flow rate is given in U.S. gpm and the pressures are psia, N₁ has a value of 1.00. If the flow rate is m³/hr and the pressures are kPa, the N₁ constant becomes 0.0865.
2. All pressures are absolute.
3. Pressure base is 101.3 kPa (1.013 bar)(14.7 psia).

For rotary valves with reducers (swaged installations), and other valve designs and fitting styles, determine the F_p factors by using the procedure for Determining F_p , the Piping Geometry Factor, page 3-4.

4. Determine q_{max} (the maximum flow rate at given upstream conditions) or ΔP_{max} (the allowable sizing pressure drop).

The maximum or limiting flow rate (q_{max}), commonly called choked flow, is manifested by no additional increase in flow rate with increasing pressure differential with fixed upstream conditions. In liquids, choking occurs as a result of vaporization of the liquid when the static pressure within the valve drops below the vapor pressure of the liquid.

The IEC standard requires the calculation of an allowable sizing pressure drop (ΔP_{max}), to account for the possibility of choked flow conditions within the valve. The calculated ΔP_{max} value is compared with the actual pressure drop specified in the service conditions, and the lesser of these two values is used in the sizing equation. If it is desired to use ΔP_{max} to account for the possibility

of choked flow conditions, it can be calculated using the procedure for determining q_{max} , the Maximum Flow Rate, or ΔP_{max} , the Allowable Sizing Pressure Drop. If it can be recognized that choked flow conditions will not develop within the valve, ΔP_{max} need not be calculated.

5. Solve for required C_v , using the appropriate equation:

- For volumetric flow rate units—

$$C_v = \frac{q}{N_1 F_p \sqrt{\frac{P_1 - P_2}{G_f}}}$$

- For mass flow rate units—

$$C_v = \frac{w}{N_6 F_p \sqrt{(P_1 - P_2) \gamma}}$$

In addition to C_v , two other flow coefficients, K_v and A_v , are used, particularly outside of North America. The following relationships exist:

$$K_v = (0.865)(C_v)$$

$$A_v = (2.40 \times 10^{-5})(C_v)$$

6. Select the valve size using the appropriate flow coefficient table and the calculated C_v value.

Determining Piping Geometry Factor (F_p)

Determine an F_p factor if any fittings such as reducers, elbows, or tees will be directly attached to the inlet and outlet connections of the control valve that is to be sized. When possible, it is recommended that F_p factors be determined experimentally by using the specified valve in actual tests.

Calculate the F_p factor using the following equation.

$$F_p = \left[1 + \frac{\sum K}{N_2} \left(\frac{C_v}{d^2} \right)^2 \right]^{-1/2}$$

where,

N_2 = Numerical constant found in the Equation Constants table

d = Assumed nominal valve size

C_v = Valve sizing coefficient at 100-percent travel for the assumed valve size

In the above equation, the $\sum K$ term is the algebraic sum of the velocity head loss coefficients of all of the fittings that are attached to the control valve.

$$\sum K = K_1 + K_2 + K_{B1} - K_{B2}$$

where,

K_1 = Resistance coefficient of upstream fittings

K_2 = Resistance coefficient of downstream fittings

K_{B1} = Inlet Bernoulli coefficient

K_{B2} = Outlet Bernoulli coefficient

The Bernoulli coefficients, K_{B1} and K_{B2} , are used only when the diameter of the piping approaching the valve is different from the diameter of the piping leaving the valve, whereby:

$$K_{B1} \text{ or } K_{B2} = 1 - \left(\frac{d}{D} \right)^4$$

where,

d = Nominal valve size

D = Internal diameter of piping

If the inlet and outlet piping are of equal size, then the Bernoulli coefficients are also equal, $K_{B1} = K_{B2}$, and therefore they are dropped from the equation.

The most commonly used fitting in control valve installations is the short-length concentric reducer. The equations for this fitting are as follows:

- For an inlet reducer—

$$K_1 = 0.5 \left(1 - \frac{d^2}{D^2} \right)^2$$

- For an outlet reducer—

$$K_2 = 1.0 \left(1 - \frac{d^2}{D^2} \right)^2$$

- For a valve installed between identical reducers—

$$K_1 + K_2 = 1.5 \left(1 - \frac{d^2}{D^2} \right)^2$$

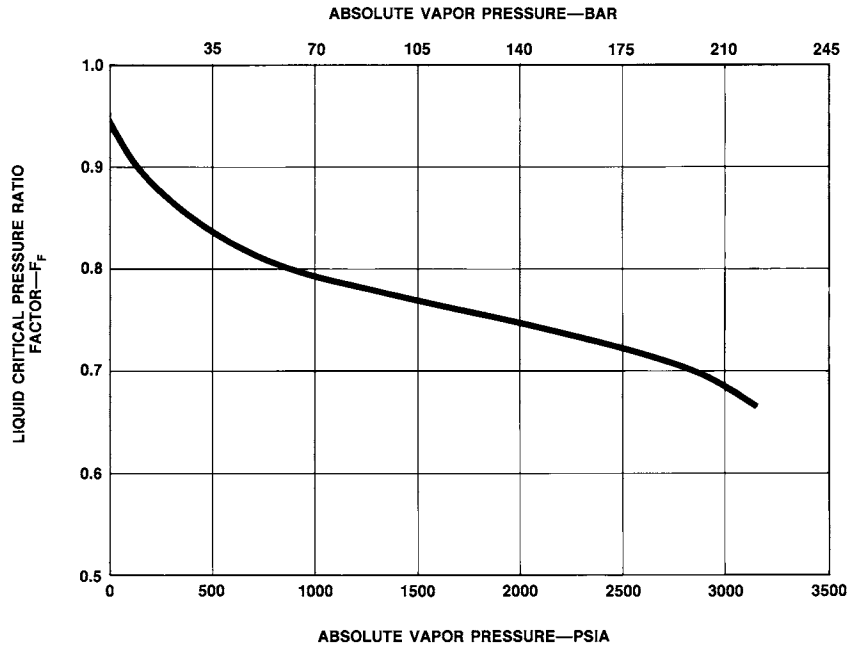
Determining Maximum Flow Rate ($q_{\max}$)

Determine either $q_{\max}$ or $\Delta P_{\max}$ if it is possible for choked flow to develop within the control valve that is to be sized. The values can be determined by using the following procedures.

$$q_{\max} = N_1 F_L C_v \sqrt{\frac{P_1 - F_F P_v}{G_f}}$$

Values for F_F , the liquid critical pressure ratio factor, can be obtained from figure 3-1, or from the following equation:

$$F_F = 0.96 - 0.28 \sqrt{\frac{P_v}{P_c}}$$



A2737-1

USE THIS CURVE FOR WATER. ENTER ON THE ABSCISSA AT THE WATER VAPOR PRESSURE AT THE VALVE INLET. PROCEED VERTICALLY TO INTERSECT THE CURVE. MOVE HORIZONTALLY TO THE LEFT TO READ THE CRITICAL PRESSURE RATIO, F_F , ON THE ORDINATE.

Figure 3-1. Liquid critical pressure ratio factor for water.

Values of F_L , the recovery factor for rotary valves installed without fittings attached, can be found in published coefficient tables. If the given valve is to be installed with fittings such as reducer attached to it, F_L in the equation must be replaced by the quotient F_{LP}/F_P , where:

$$F_{LP} = \left[\frac{K_1}{N_2} \left(\frac{C_v}{d^2} \right)^2 + \frac{1}{F_L^2} \right]^{-1/2}$$

and

$$K_1 = K_1 + K_{B1}$$

where,

K_1 = Resistance coefficient of upstream fittings

K_{B1} = Inlet Bernoulli coefficient

(See the procedure for Determining F_P , the Piping Geometry Factor, for definitions of the other constants and coefficients used in the above equations.)

Determining Allowable Sizing Pressure Drop (ΔP_{max})

ΔP_{max} (the allowable sizing pressure drop) can be determined from the following relationships:

For valves installed without fittings—

$$\Delta P_{max(L)} = F_L^2 (P_1 - F_F P_V)$$

For valves installed with fittings attached—

$$\Delta P_{max(LP)} = \left(\frac{F_{LP}}{F_P} \right)^2 (P_1 - F_F P_V)$$

where,

P_1 = Upstream absolute static pressure

P_2 = Downstream absolute static pressure

P_V = Absolute vapor pressure at inlet temperature

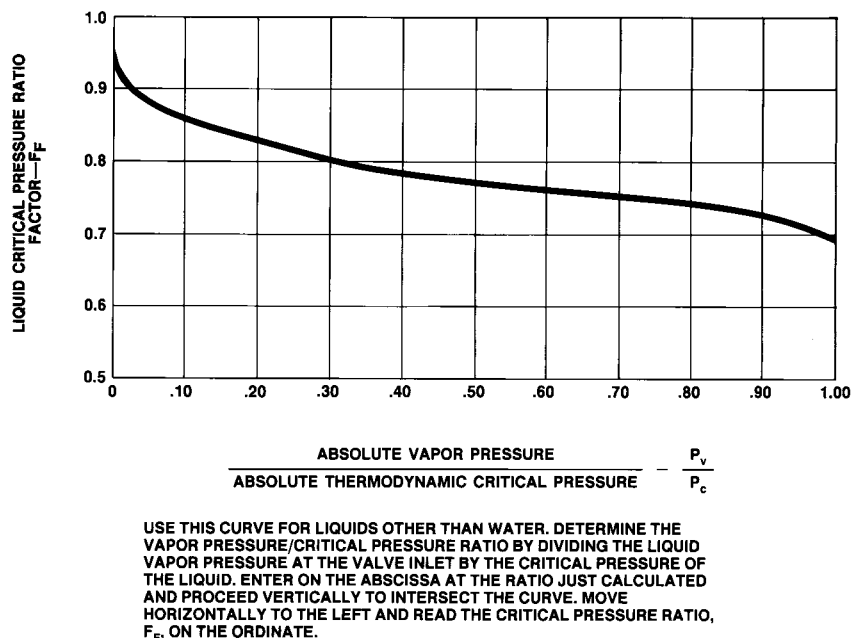


Figure 3-2. Liquid critical pressure ratio factor for liquids other than water.

Values of F_F , the liquid critical pressure ratio factor, can be obtained from figure 3-1 or from the following equation:

$$F_F = 0.96 - 0.28 \sqrt{\frac{P_v}{P_c}}$$

An explanation of how to calculate values of F_{LP} , the recovery factor for valves installed with fittings attached, is presented in the preceding procedure Determining $q_{\max}$ (the Maximum Flow Rate).

Once the $\Delta P_{\max}$ value has been obtained from the appropriate equation, it should be compared with the actual service pressure differential ($\Delta P = P_1 - P_2$). If $\Delta P_{\max}$ is less than ΔP , this is an indication that choked flow conditions will exist under the service conditions specified. If choked flow conditions do exist ($\Delta P_{\max} < P_1 - P_2$), then step 5 of the procedure for Sizing Valves for Liquids must be modified by replacing the actual service pressure differential ($P_1 - P_2$) in the appropriate valve sizing equation with the calculated $\Delta P_{\max}$ value.

Note

Once it is known that choked flow conditions will develop within the specified valve design ($\Delta P_{\max}$ is calculated to be less than ΔP), a further distinction can be made to deter-

mine whether the choked flow is caused by cavitation or flashing. The choked flow conditions are caused by flashing if the outlet pressure of the given valve is less than the vapor pressure of the flowing liquid. The choked flow conditions are caused by cavitation if the outlet pressure of the valve is greater than the vapor pressure of the flowing liquid.

Liquid Sizing Sample Problem

Assume an installation that, at initial plant start-up, will not be operating at maximum design capability. The lines are sized for the ultimate system capacity, but there is a desire to install a control valve now which is sized only for currently anticipated requirements. The line size is NPS 8, and an ASME CL300 globe valve with an equal percentage cage has been specified. Standard concentric reducers will be used to install the valve into the line. Determine the appropriate valve size.

1. Specify the necessary variables required to size the valve:

- Desired valve design—ASME CL300 globe valve with equal percentage cage and an assumed valve size of NPS 3.

- Process fluid—liquid propane
- Service conditions— $q = 800$ gpm

$$P_1 = 300 \text{ psig (21 bar)} = 314.7 \text{ psia}$$

$$P_2 = 275 \text{ psig (19 bar)} = 289.7 \text{ psia}$$

$$\Delta P = 25 \text{ psi (1.7 bar)}$$

$$T_1 = 70^\circ \text{F (21}^\circ \text{C)}$$

$$G_f = 0.50$$

$$P_v = 124.3 \text{ psia}$$

$$P_c = 616.3 \text{ psia}$$

2. Use an N_1 value of 1.0 from the Equation Constants table.

3. Determine F_p , the piping geometry factor.

Because it is proposed to install a NPS 3 valve in an NPS 8 line, it will be necessary to determine the piping geometry factor, F_p , which corrects for losses caused by fittings attached to the valve.

$$F_p = \left[1 + \frac{\sum K}{N_2} \left(\frac{C_v}{d^2} \right)^2 \right]^{-1/2}$$

where,

$$N_2 = 890, \text{ from the Equation Constants table}$$

$$d = 3 \text{ inches, from step 1}$$

$C_v = 121$, from the flow coefficient table for an ASME CL300, NPS 3 globe valve with equal percentage cage

To compute $\sum K$ for a valve installed between identical concentric reducers:

$$\sum K = K_1 + K_2$$

$$= 1.5 \left(1 - \frac{d^2}{D^2} \right)^2$$

$$= 1.5 \left(1 - \frac{(3)^2}{(8)^2} \right)^2$$

$$= 1.11$$

where,

$D = 8$ inches, the internal diameter of the piping
so,

$$F_p = \left[1 + \frac{1.11}{890} \left(\frac{121}{3^2} \right)^2 \right]^{-1/2}$$

$$= 0.90$$

4. Determine $\Delta P_{\max}$ (the Allowable Sizing Pressure Drop.)

Based on the small required pressure drop, the flow will not be choked ($\Delta P_{\max} > \Delta P$).

5. Solve for C_v , using the appropriate equation.

$$C_v = \frac{q}{N_1 F_p \frac{\sqrt{P_1 - P_2}}{G_f}}$$

$$= \frac{800}{(1.0)(0.90) \sqrt{\frac{25}{0.5}}}$$

$$= 125.7$$

6. Select the valve size using the flow coefficient table and the calculated C_v value.

The required C_v of 125.7 exceeds the capacity of the assumed valve, which has a C_v of 121. Although for this example it may be obvious that the next larger size (NPS 4) would be the correct valve size, this may not always be true, and a repeat of the above procedure should be carried out.

Assuming a NPS 4 valve, $C_v = 203$. This value was determined from the flow coefficient table for an ASME CL300, NPS 4 globe valve with an equal percentage cage.

Recalculate the required C_v using an assumed C_v value of 203 in the F_p calculation.

where,

$$\begin{aligned}\Sigma K &= K_1 + K_2 \\ &= 1.5 \left(1 - \frac{d^2}{D^2} \right)^2 \\ &= 1.5 \left(1 - \frac{16}{64} \right)^2 \\ &= 0.84\end{aligned}$$

and

$$\begin{aligned}F_p &= \left[1.0 + \frac{\Sigma K}{N_2} \left(\frac{C_v}{d^2} \right)^2 \right]^{-1/2} \\ &= \left[1.0 + \frac{0.84}{890} \left(\frac{203}{4^2} \right)^2 \right]^{-1/2} \\ &= 0.93\end{aligned}$$

and

$$\begin{aligned}C_v &= \frac{q}{N_1 F_p \sqrt{\frac{P_1 - P_2}{G_f}}} \\ &= \frac{800}{(1.0)(0.93) \sqrt{\frac{25}{0.5}}} \\ &= 121.7\end{aligned}$$

This solution indicates only that the NPS 4 valve is large enough to satisfy the service conditions given. There may be cases, however, where a more accurate prediction of the C_v is required. In such cases, the required C_v should be redetermined using a new F_p value based on the C_v value obtained above. In this example, C_v is 121.7, which leads to the following result:

$$\begin{aligned}F_p &= \left[1.0 + \frac{\Sigma K}{N_2} \left(\frac{C_v}{d^2} \right)^2 \right]^{-1/2} \\ &= \left[1.0 + \frac{0.84}{890} \left(\frac{121.7}{4^2} \right)^2 \right]^{-1/2} \\ &= 0.97\end{aligned}$$

The required C_v then becomes:

$$\begin{aligned}C_v &= \frac{q}{N_1 F_p \sqrt{\frac{P_1 - P_2}{G_f}}} \\ &= \frac{800}{(1.0)(0.97) \sqrt{\frac{25}{0.5}}} \\ &= 116.2\end{aligned}$$

Because this newly determined C_v is very close to the C_v used initially for this recalculation (116.2 versus 121.7), the valve sizing procedure is complete, and the conclusion is that a NPS 4 valve opened to about 75-percent of total travel should be adequate for the required specifications.

Gas Valve Sizing

Sizing Valves for Compressible Fluids

Following is a six-step procedure for the sizing of control valves for compressible flow using the ISA standardized procedure. Each of these steps is important and must be considered during any valve sizing procedure. Steps 3 and 4 concern the determination of certain sizing factors that may or may not be required in the sizing equation depending on the service conditions of the sizing problem. If it is necessary for one or both of these sizing factors to be included in the sizing equation for a particular sizing problem, refer to the appropriate factor determination section(s), which is referenced and located in the following text.

1. *Specify the necessary variables required to size the valve as follows:*

- Desired valve design (e.g. balanced globe with linear cage)
- Process fluid (air, natural gas, steam, etc.) and
- Appropriate service conditions— q , or w , P_1 , P_2 or ΔP , T_1 , G_g , M , k , Z , and γ_1

The ability to recognize which terms are appropriate for a specific sizing procedure can only be acquired through experience with different valve sizing problems. If any of the above terms appear to be new or unfamiliar, refer to the Abbreviations and Terminology Table 3-1 in Chapter 3 for a complete definition.

2. *Determine the equation constant, N .*

N is a numerical constant contained in each of the flow equations to provide a means for using different systems of units. Values for these various

constants and their applicable units are given in the Equation Constants Table 3-2 in Chapter 3.

Use either N_7 or N_9 if sizing the valve for a flow rate in volumetric units (scfh or m^3/h). Which of the two constants to use depends upon the specified service conditions. N_7 can be used only if the specific gravity, G_g , of the flowing gas has been specified along with the other required service conditions. N_9 can be used only if the molecular weight, M , of the gas has been specified.

Use either N_6 or N_8 if sizing the valve for a flow rate in mass units (lb/h or kg/h). Which of the two constants to use depends upon the specified service conditions. N_6 can be used only if the specific weight, γ_1 , of the flowing gas has been specified along with the other required service conditions. N_8 can be used only if the molecular weight, M , of the gas has been specified.

3. *Determine F_p , the piping geometry factor.*

F_p is a correction factor that accounts for any pressure losses due to piping fittings such as reducers, elbows, or tees that might be attached directly to the inlet and outlet connections of the control valves to be sized. If such fittings are attached to the valve, the F_p factor must be considered in the sizing procedure. If, however, no fittings are attached to the valve, F_p has a value of 1.0 and simply drops out of the sizing equation.

Also, for rotary valves with reducers and other valve designs and fitting styles, determine the F_p factors by using the procedure for Determining F_p the Piping Geometry Factor, which is located on page 3-4 in Chapter 3.



4. Determine Y , the expansion factor, as follows:

$$Y = 1 - \frac{x}{3F_k x_T}$$

where,

$F_k = k/1.4$, the ratio of specific heats factor

k = Ratio of specific heats

$x = \Delta P/P_1$, the pressure drop ratio

x_T = The pressure drop ratio factor for valves installed without attached fittings. More definitively, x_T is the pressure drop ratio required to produce critical, or maximum, flow through the valve when $F_k = 1.0$

If the control valve to be installed has fittings such as reducers or elbows attached to it, then their effect is accounted for in the expansion factor equation by replacing the x_T term with a new factor x_{TP} . A procedure for determining the x_{TP} factor is described in the following section for Determining x_{TP} , the Pressure Drop Ratio Factor.

Note

Conditions of critical pressure drop are realized when the value of x becomes equal to or exceeds the appropriate value of the product of either $F_k x_T$ or $F_k x_{TP}$ at which point:

$$y = 1 - \frac{x}{3F_k x_T} = 1 - 1/3 = 0.667$$

Although in actual service, pressure drop ratios can, and often will, exceed the indicated critical values, this is the point where critical flow conditions develop. Thus, for a constant P_1 , decreasing P_2 (i.e., increasing ΔP) will not result in an increase in the flow rate through the valve. Values of x , therefore, greater than the product of either $F_k x_T$ or $F_k x_{TP}$ must never be substituted in the expression for Y . This means that Y can never be less than 0.667. This same limit on values of x also applies to the flow equations that are introduced in the next section.

5. Solve for the required C_v using the appropriate equation:

For volumetric flow rate units—

- If the specific gravity, G_g , of the gas has been specified:

$$C_v = \frac{q}{N_7 F_p P_1 Y \sqrt{G_g \frac{x}{T_1} z}}$$

- If the molecular weight, M , of the gas has been specified:

$$C_v = \frac{q}{N_9 F_p P_1 Y \sqrt{\frac{x}{M} \frac{1}{T_1} z}}$$

For mass flow rate units—

- If the specific weight, γ_1 , of the gas has been specified:

$$C_v = \frac{w}{N_6 F_p Y \sqrt{x} P_1 \gamma_1}$$

- If the molecular weight, M , of the gas has been specified:

$$C_v = \frac{w}{N_8 F_p P_1 Y \sqrt{\frac{x}{M} \frac{1}{T_1} z}}$$

In addition to C_v , two other flow coefficients, K_v and A_v , are used, particularly outside of North America. The following relationships exist:

$$K_v = (0.865)(C_v)$$

$$A_v = (2.40 \times 10^{-5})(C_v)$$

6. Select the valve size using the appropriate flow coefficient table and the calculated C_v value.

Determining x_{TP} , the Pressure Drop Ratio Factor

If the control valve is to be installed with attached fittings such as reducers or elbows, then their effect is accounted for in the expansion factor equation by replacing the x_T term with a new factor, x_{TP} .

$$x_{TP} = \frac{x_T}{F_p^2} \left[1 + \frac{x_T K_i \left(\frac{C_v}{d^2} \right)^2}{N_5} \right]^{-1}$$

where,

N_5 = Numerical constant found in the Equation Constants table

d = Assumed nominal valve size

C_v = Valve sizing coefficient from flow coefficient table at 100 percent travel for the assumed valve size

F_p = Piping geometry factor

x_T = Pressure drop ratio for valves installed without fittings attached. x_T values are included in the flow coefficient tables

In the above equation, K_i is the inlet head loss coefficient, which is defined as:

$$K_i = K_1 + K_{B1}$$

where,

K_1 = Resistance coefficient of upstream fittings (see the procedure for Determining F_p , the Piping Geometry Factor, which is contained in the section for Sizing Valves for Liquids).

K_{B1} = Inlet Bernoulli coefficient (see the procedure for Determining F_p , the piping Geometry factor, which is contained in the section for Sizing Valves for Liquids.)

Compressible Fluid Sizing Sample Problem No. 1

Determine the size and percent opening for a Fisher V250 ball valve operating with the following service conditions. Assume that the valve and line size are equal.

1. Specify the necessary variables required to size the valve:

- Desired valve design—Fisher V250 valve
- Process fluid—Natural gas
- Service conditions—

$$P_1 = 200 \text{ psig (14 bar)} = 214.7 \text{ psia}$$

$$P_2 = 50 \text{ psig (3.4 bar)} = 64.7 \text{ psia}$$

$$\Delta P = 150 \text{ psig (10.3 bar)}$$

$$x = \Delta P/P_1 = 150/214.7 = 0.70$$

$$T_1 = 60^\circ \text{F (15.5}^\circ \text{C)} = 520^\circ \text{R}$$

$$M = 17.38$$

$$G_g = 0.60$$

$$k = 1.31$$

$$q = 6.0 \times 10^6 \text{ scfh}$$

2. Determine the appropriate equation constant, N , from the Equation Constants Table 3-2 in Chapter 3.

Because both G_g and M have been given in the service conditions, it is possible to use an equation containing either N_7 or N_9 . In either case, the end result will be the same. Assume that the equation containing G_g has been arbitrarily selected for this problem. Therefore $N_7 = 1360$.

3. Determine F_p , the piping geometry factor. Since valve and line size are assumed equal, $F_p = 1.0$.

4. Determine Y , the expansion factor.

$$\begin{aligned} F_k &= \frac{k}{1.40} \\ &= \frac{1.31}{1.40} \\ &= 0.94 \end{aligned}$$

It is assumed that an NPS 8 Vee-Ball V250 valve will be adequate for the specified service conditions. From the flow coefficient table 4-1, x_T for an NPS 8 V250 valve at 100-percent travel is 0.137.

$$x = 0.70 \text{ (This was calculated in step 1.)}$$

Since conditions of critical pressure drop are realized when the calculated value of x becomes

equal to or exceeds the appropriate value of $F_k x_T$, these values should be compared.

$$F_k x_T = (0.94) (0.137)$$

$$= 0.129$$

Because the pressure drop ratio, $x = 0.70$ exceeds the calculated critical value, $F_k x_T = 0.129$, choked flow conditions are indicated. Therefore, $Y = 0.667$, and $x = F_k x_T = 0.129$.

5. Solve for required C_v using the appropriate equation.

$$C_v = \frac{q}{N_7 F_p P_1 Y \sqrt{\frac{x}{G_g T_1 Z}}}$$

The compressibility factor, Z , can be assumed to be 1.0 for the gas pressure and temperature given and $F_p = 1$ because valve size and line size are equal.

So,

$$C_v = \frac{6.0 \times 10^6}{(1360)(1.0)(214.7)(0.667) \sqrt{\frac{0.129}{(0.6)(520)(1.0)}}} = 1515$$

6. Select the valve size using the flow coefficient table and the calculated C_v value.

The above result indicates that the valve is adequately sized (rated $C_v = 2190$). To determine the percent valve opening, note that the required C_v occurs at approximately 83 degrees for the NPS 8 V250 valve. Note also that, at 83 degrees opening, the x_T value is 0.252, which is substantially different from the rated value of 0.137 used initially in the problem. The next step is to rework the problem using the x_T value for 83 degrees travel.

The $F_k x_T$ product must now be recalculated.

$$x = F_k x_T$$

$$= (0.94) (0.252)$$

$$= 0.237$$

The required C_v now becomes:

$$C_v = \frac{q}{N_7 F_p P_1 Y \sqrt{\frac{x}{G_g T_1 Z}}}$$

$$= \frac{6.0 \times 10^6}{(1360)(1.0)(214.7)(0.667) \sqrt{\frac{0.237}{(0.6)(520)(1.0)}}}$$

$$= 1118$$

The reason that the required C_v has dropped so dramatically is attributable solely to the difference in the x_T values at rated and 83 degrees travel. A C_v of 1118 occurs between 75 and 80 degrees travel.

The appropriate flow coefficient table indicates that x_T is higher at 75 degrees travel than at 80 degrees travel. Therefore, if the problem were to be reworked using a higher x_T value, this should result in a further decline in the calculated required C_v .

Reworking the problem using the x_T value corresponding to 78 degrees travel (i.e., $x_T = 0.328$) leaves:

$$x = F_k x_T$$

$$= (0.94) (0.328)$$

$$= 0.308$$

and,

$$C_v = \frac{q}{N_7 F_p P_1 Y \sqrt{\frac{x}{G_g T_1 Z}}}$$

$$= \frac{6.0 \times 10^6}{(1360)(1.0)(214.7)(0.667) \sqrt{\frac{0.308}{(0.6)(520)(1.0)}}}$$

$$= 980$$

The above C_v of 980 is quite close to the 75 degree travel C_v . The problem could be reworked further to obtain a more precise predicted opening; however, for the service conditions given, an NPS 8 V250 valve installed in an NPS 8 line will be approximately 75 degrees open.

Compressible Fluid Sizing Sample Problem No. 2

Assume steam is to be supplied to a process designed to operate at 250 psig (17 bar). The supply source is a header maintained at 500 psig (34 bar) and 500°F (260°C). A 6-inch line from the steam main to the process is being planned. Also, make the assumption that if the required valve size is less than NPS 6, it will be installed using concentric reducers. Determine the appropriate ED valve with a linear cage.

1. Specify the necessary variables required to size the valve:

a. Desired valve design—ASME CL300 Design ED valve with a linear cage. Assume valve size is NPS 4.

b. Process fluid—superheated steam

c. Service conditions—

$$w = 125,000 \text{ lb/h}$$

$$P_1 = 500 \text{ psig (34 bar)} = 514.7 \text{ psia}$$

$$P_2 = 250 \text{ psig (17 bar)} = 264.7 \text{ psia}$$

$$\Delta P = 250 \text{ psig (17 bar)}$$

$$x = \Delta P/P_1 = 250/514.7 = 0.49$$

$$T_1 = 500^\circ\text{F (260}^\circ\text{C)}$$

$$\gamma_1 = 1.0434 \text{ lb/ft}^3 \text{ (from Properties of Saturated Steam table)}$$

$$k = 1.28 \text{ (from Properties of Saturated Steam table)}$$

2. Determine the appropriate equation constant, N , from the Equation Constants Table 3-2 in Chapter 3.

Because the specified flow rate is in mass units, (lb/h), and the specific weight of the steam is also specified, the only sizing equation that can be used is that which contains the N_6 constant. Therefore,

$$N_6 = 63.3$$

3. Determine F_p , the piping geometry factor.

$$F_p = \left[1 + \frac{\Sigma K}{N_2} \left(\frac{C_v}{d^2} \right)^2 \right]^{-1/2}$$

where,

$$N_2 = 890, \text{ determined from the Equation Constants table}$$

$$d = 4 \text{ in.}$$

$$C_v = 236, \text{ which is the value listed in the flow coefficient Table 4-2 for a NPS 4 ED valve at 100-percent total travel.}$$

and

$$\begin{aligned} \Sigma K &= K_1 + K_2 \\ &= 1.5 \left(1 - \frac{d^2}{D^2} \right)^2 \\ &= 1.5 \left(1 - \frac{4^2}{6^2} \right)^2 \\ &= 0.463 \end{aligned}$$

Finally:

$$\begin{aligned} F_p &= \left[1 + \frac{0.463}{890} \left(\frac{(1.0)(236)}{(4)^2} \right)^2 \right]^{-1/2} \\ &= 0.95 \end{aligned}$$

4. Determine Y , the expansion factor.

$$Y = 1 - \frac{x}{3F_k x_{TP}}$$

where,

$$\begin{aligned} F_k &= \frac{k}{1.40} \\ &= \frac{1.28}{1.40} \\ &= 0.91 \end{aligned}$$

$$x = 0.49 \text{ (As calculated in step 1.)}$$

Because the NPS 4 valve is to be installed in a NPS 6 line, the x_T term must be replaced by x_{TP} .

$$x_{TP} = \frac{x_T}{F_p^2} \left[1 + \frac{x_T K_i}{N_5} \left(\frac{C_v}{d^2} \right)^2 \right]^{-1}$$

where,

$$N_5 = 1000, \text{ from the Equation Constants table}$$

$$d = 4 \text{ inches}$$

$$F_p = 0.95, \text{ determined in step 3}$$

$$x_T = 0.688, \text{ a value determined from the appropriate listing in the flow coefficient table}$$

$$C_v = 236, \text{ from step 3}$$

and

$$\begin{aligned}
 K_i &= K_1 + K_{B1} \\
 &= 0.5 \left(1 - \frac{d^2}{D^2} \right)^2 + \left[1 - \left(\frac{d}{D} \right)^4 \right] \\
 &= 0.5 \left(1 - \frac{4^2}{6^2} \right)^2 + \left[1 - \left(\frac{4}{6} \right)^4 \right] \\
 &= 0.96
 \end{aligned}$$

where D = 6 inches

so:

$$X_{TP} = \frac{0.69}{0.95^2} \left[1 - \frac{(0.69)(0.96)}{1000} \left(\frac{236}{4^2} \right)^2 \right]^{-1} = 0.67$$

Finally:

$$\begin{aligned}
 Y &= 1 - \frac{X}{3 F_k X_{TP}} \\
 &= 1 - \frac{0.49}{(3) (0.91) (0.67)}
 \end{aligned}$$

$$= 0.73$$

5. Solve for required C_v using the appropriate equation.

$$C_v = \frac{W}{N_6 F_P Y \sqrt{x} P_1 \gamma_1}$$

$$\begin{aligned}
 C_v &= \frac{125,000}{(63.3)(0.95)(0.73) \sqrt{(0.49)(514.7)(1.0434)}} \\
 &= 176
 \end{aligned}$$

6. Select the valve size using flow coefficient tables and the calculated C_v value.

Refer to the flow coefficient Table 4-2 for ED valves with linear cage. Because the assumed NPS 4 valve has a C_v of 236 at 100-percent travel and the next smaller size (NPS 3) has a C_v of only 148, it can be surmised that the assumed size is correct. In the event that the calculated required C_v had been small enough to have been handled by the next smaller size, or if it had been larger than the rated C_v for the assumed size, it would have been necessary to rework the problem again using values for the new assumed size.

Table 4-1. Representative Sizing Coefficients for Rotary Shaft Valves

Valve Size (NPS)	Valve Style	Degrees of Valve Opening	C _v	F _L	X _T	F _D
1	V-Notch Ball Valve	60	15.6	0.86	0.53	
		90	34.0	0.86	0.42	
1 1/2	V-Notch Ball Valve	60	28.5	0.85	0.50	
		90	77.3	0.74	0.27	
2	V-Notch Ball Valve	60	59.2	0.81	0.53	0.49 0.70
		90	132	0.77	0.41	
	High Performance Butterfly Valve	60	58.9	0.76	0.50	
		90	80.2	0.71	0.44	
3	V-Notch Ball Valve	60	120	0.80	0.50	0.92 0.99 0.49 0.70
		90	321	0.74	0.30	
	High Performance Butterfly Valve	60	115	0.81	0.46	
		90	237	0.64	0.28	
4	V-Notch Ball Valve	60	195	0.80	0.52	0.92 0.99 0.49 0.70
		90	596	0.62	0.22	
	High Performance Butterfly Valve	60	270	0.69	0.32	
		90	499	0.53	0.19	
6	V-Notch Ball Valve	60	340	0.80	0.52	0.91 0.99 0.49 0.70
		90	1100	0.58	0.20	
	High Performance Butterfly Valve	60	664	0.66	0.33	
		90	1260	0.55	0.20	
8	V-Notch Ball Valve	60	518	0.82	0.54	0.91 0.99 0.49 0.70
		90	1820	0.54	0.18	
	High Performance Butterfly Valve	60	1160	0.66	0.31	
		90	2180	0.48	0.19	
10	V-Notch Ball Valve	60	1000	0.80	0.47	0.91 0.99 0.49 0.70
		90	3000	0.56	0.19	
	High Performance Butterfly Valve	60	1670	0.66	0.38	
		90	3600	0.48	0.17	
12	V-Notch Ball Valve	60	1530	0.78	0.49	0.92 0.99 0.49 0.70
		90	3980	0.63	0.25	
	High Performance Butterfly Valve	60	2500			
		90	5400			
16	V-Notch Ball Valve	60	2380	0.80	0.45	0.92 1.00
		90	8270	0.37	0.13	
	High Performance Butterfly Valve	60	3870	0.69	0.40	
		90	8600	0.52	0.23	

Table 4-2. Representative Sizing Coefficients for Design ED Single-Ported Globe Style Valve Bodies

Valve Size (NPS)	Valve Plug Style	Flow Characteristic	Port Dia. (in.)	Rated Travel (in.)	C _V	F _L	X _T	F _D
1/2	Post Guided	Equal Percentage	0.38	0.50	2.41	0.90	0.54	0.61
3/4	Post Guided	Equal Percentage	0.56	0.50	5.92	0.84	0.61	0.61
1	Micro Form™	Equal Percentage	3/8	3/4	3.07	0.89	0.66	0.72
			1/2	3/4	4.91	0.93	0.80	0.67
			3/4	3/4	8.84	0.97	0.92	0.62
		Cage Guided	1 5/16	3/4	20.6	0.84	0.64	0.34
1 1/2	Micro-Form™	Equal Percentage	1 5/16	3/4	17.2	0.88	0.67	0.38
			3/8	3/4	3.20	0.84	0.65	0.72
			1/2	3/4	5.18	0.91	0.71	0.67
			3/4	3/4	10.2	0.92	0.80	0.62
2	Cage Guided	Linear	1 7/8	3/4	39.2	0.82	0.66	0.34
			1 7/8	3/4	35.8	0.84	0.68	0.38
			2 5/16	1 1/8	72.9	0.77	0.64	0.33
		Equal Percentage	2 5/16	1 1/8	59.7	0.85	0.69	0.31
3	Cage Guided	Linear	3 7/16	1 1/2	148	0.82	0.62	0.30
		Equal Percentage			136	0.82	0.68	0.32
4	Cage Guided	Linear	4 3/8	2	236	0.82	0.69	0.28
		Equal Percentage			224	0.82	0.72	0.28
6	Cage Guided	Linear	7	2	433	0.84	0.74	0.28
		Equal Percentage			394	0.85	0.78	0.26
8	Cage Guided	Linear	8	3	846	0.87	0.81	0.31
		Equal Percentage			818	0.86	0.81	0.26

Control Valve Noise

Noise Control

In closed systems (not vented to atmosphere), any noise produced in the process becomes airborne only by transmission through the valves and adjacent piping that contain the flowstream. The sound field in the flowstream forces these solid boundaries to vibrate. The vibrations cause disturbances in the ambient atmosphere that propagate as sound waves.

Noise control employs either source treatment, path treatment, or both. Source treatment, preventing or attenuating noise at its source, is the most desirable approach, if economically and physically feasible.

Recommended cage-style source treatment approaches are depicted in Figure 5-1. The upper view shows a cage with many narrow parallel slots designed to minimize turbulence and provide a favorable velocity distribution in the expansion area. This economical approach to quiet valve design can provide 15 to 20 dBA noise reduction with little or no decrease in flow capacity.

The lower view in Figure 5-1 illustrates flow through a two-stage, cage-style trim designed for optimum noise attenuation where pressure drop ratios ($\Delta P/P_1$) are high.

This trim design can reduce the valve noise as much as 40 dBA by utilizing a combination of several noise reduction strategies:

- Unique passage shape that reduces the conversion of total stream power generated by the valve into noise power.
- Multistage pressure reduction that divides the stream power between stages and further reduces the acoustic conversion efficiency.

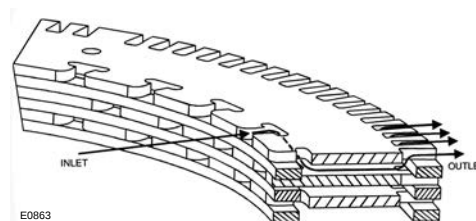


Figure 5-1. Valve Trim Designs for Reducing Aerodynamic Noise

- Frequency spectrum shifting that reduces acoustic energy in the audible range by capitalizing on the transmission loss of the piping.
- Exit jet independence that avoids noise regeneration due to jet coalescence.
- Velocity management is accomplished with expanding areas to accommodate the expanding gas.
- Complementary body designs that avoid flow impingement on the body wall and secondary noise sources.

For control valve applications operating at high pressure ratios ($\Delta P/P_1 > 0.8$) the series restriction



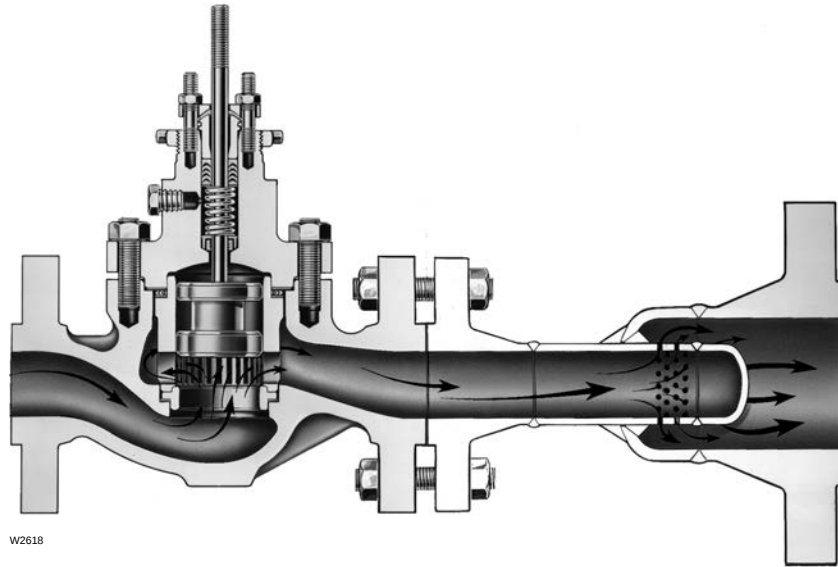


Figure 5-2. Valve and Inline Diffuser Combination

approach, splitting the total pressure drop between the control valve and a fixed restriction (diffuser) downstream of the valve can be effective in minimizing noise. To optimize the effectiveness of a diffuser, it must be designed (special shape and sizing) for each given installation so that the noise levels generated by the valve and diffuser are equal. Figure 5-2 shows a typical installation.

Control systems venting to atmosphere are generally very noisy because of the high pressure ratios and high exit velocities involved. Dividing the total pressure drop between the actual vent and an upstream control valve, by means of a vent diffuser, quiets both the valve and the vent. A properly sized vent diffuser and valve combination, such as that shown in Figure 5-3, can reduce the overall system noise level as much as 40 dBA.

Source treatment for noise problems associated with control valves handling liquid is directed primarily at eliminating or minimizing cavitation. Because flow conditions that will produce cavitation can be accurately predicted, valve noise resulting from cavitation can be eliminated by application of appropriate limits to the service conditions at the valve by use of break-down orifices, valves in series, etc. Another approach to source treatment is using special valve trim that uses the series restriction concept to eliminate cavitation as shown in Figure 5-4.

A second approach to aerodynamic noise control is that of path treatment. The fluid stream is an excellent noise transmission path. Path treatment consists of increasing the impedance of the trans-

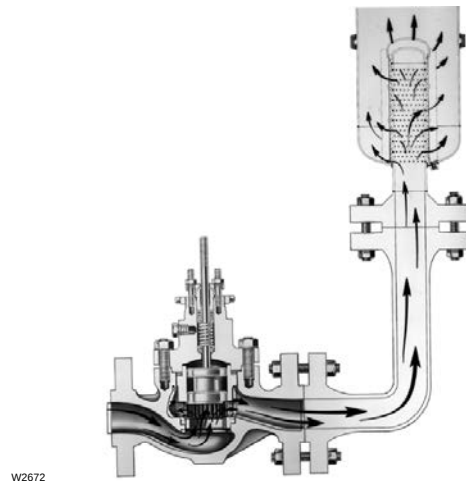


Figure 5-3. Valve and Vent Diffuser Combination

mission path to reduce the acoustic energy communicated to the receiver.

Dissipation of acoustic energy by use of acoustical absorbent materials is one of the most effective methods of path treatment. Whenever possible the acoustical material should be located in the flow stream either at or immediately downstream of the noise source. In gas systems, inline silencers effectively dissipate the noise within the fluid stream and attenuate the noise level transmitted to the solid boundaries. Where high mass flow rates and/or high pressure ratios across the valve exist, inline silencers, such as that shown in Figure 5-5, are often the most realistic and economical approach to noise control. Use of absorption-type inline silencers can provide almost any degree of attenuation desired. However, economic consider-

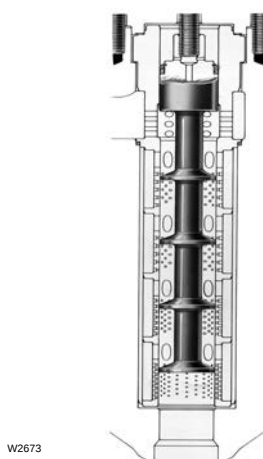


Figure 5-4. Special Valve Design to Eliminate Cavitation



Figure 5-5. Typical Inline Silencer

ations generally limit the insertion loss to approximately 25 dBA.

Noise that cannot be eliminated within the boundaries of the flow stream must be eliminated by external treatment. This approach to the abatement of control valve noise suggests the use of heavy walled piping, acoustical insulation of the exposed solid boundaries of the fluid stream, use of insulated boxes, buildings, etc., to isolate the noise source.

Path treatment such as heavy wall pipe or external acoustical insulation can be an economical and effective technique for localized noise abatement. However, noise is propagated for long distances via the fluid stream and the effectiveness of the heavy wall pipe or external insulation ends where the treatment ends.

Aerodynamic Noise Prediction

Industry leaders use the International Electrotechnical Commission standard *IEC 60534-8-3-2010: Industrial-process control valves—Part 8: Noise Considerations—Section 3: Control valve aerodynamic noise prediction* method. This method consists of a mix of thermodynamic and aerodynamic theory and some empirical information. The design of the method allows a noise prediction for a valve

based only on the measurable geometry of the valve and the service conditions applied to the valve.

The method defines five basic steps to a noise prediction:

1. Calculate the total stream power in the process at the vena contracta.

The noise of interest is generated by the valve in and downstream of the vena contracta. If the total power dissipated by throttling at the vena contracta can be calculated, then the fraction that is noise power can be determined. Since power is the time rate of energy, a form of the familiar equation for calculating kinetic energy can be used. The kinetic energy equation is $\frac{1}{2} mv^2$ where m is mass and v is velocity. If the mass flow rate is substituted for the mass term, then the equation calculates the power. The velocity is the vena contracta velocity and is calculated with the energy equation of the First Law of Thermodynamics.

2. Determine the fraction of total power that is acoustic power.

The method considers the process conditions applied across the valve to determine the particular noise generating mechanism in the valve. There are five defined regimes dependent on the relationship of the vena contracta pressure and the downstream pressure. For each of these regimes an acoustic efficiency is defined and calculated. This acoustic efficiency establishes the fraction of the total stream power, as calculated in Step 1, which is noise power. In designing a quiet valve, lower acoustic efficiency is one of the goals.

3. Convert acoustic power to sound pressure.

The final goal of the IEC prediction method is determination of the sound pressure level at a reference point outside the valve where human hearing is a concern. Step 2 delivers acoustic power, which is not directly measurable. Acoustic or sound pressure is measurable and therefore has become the default expression for noise in most situations. Converting from acoustic power to the sound pressure uses basic acoustic theory.

4. Account for the transmission loss of the pipe-wall and restate the sound pressure at the outside surface of the pipe.

Steps 1 through 3 are involved with the noise generation process inside the pipe. There are times when this is the area of interest, but the noise levels on the outside of the pipe are the prime requirement. The method must account for the change in the noise as the reference location moves from inside the pipe to outside the pipe.

The pipe wall has physical characteristics, due to its material, size, and shape, that define how well the noise will transmit through the pipe. The fluid-borne noise inside the pipe must interact with the inside pipe wall to cause the pipe wall to vibrate, then the vibration must transmit through the pipe wall to the outside pipe wall, and there the outside pipe wall must interact with the atmosphere to generate sound waves. These three steps of noise transmission are dependent on the noise frequency. The method determines the pipe transmission loss as a function of frequency. The method then compares the internal noise spectrum and the transmission-loss spectrum to determine how much the external sound pressure will be attenuated by the pipe wall.

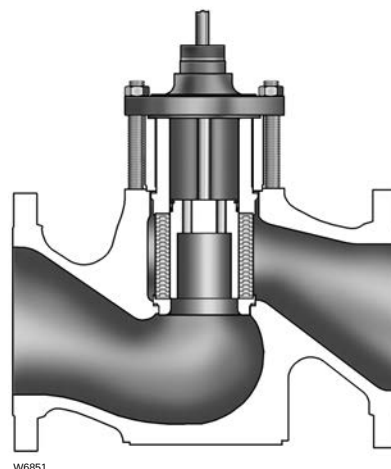
5. Account for distance and calculate the sound pressure level at the observer's location.

Step 4 delivers the external sound pressure level at the outside surface of the pipe wall. Again, basic acoustic theory is applied to calculate the sound pressure level at the observer's location. Sound power is constant for any given situation, but the associated sound pressure level varies with the area the power is spread over. As the observer moves farther away from the pipe wall, the total area the sound power is spread over increases. This causes the sound pressure level to decrease.

Hydrodynamic

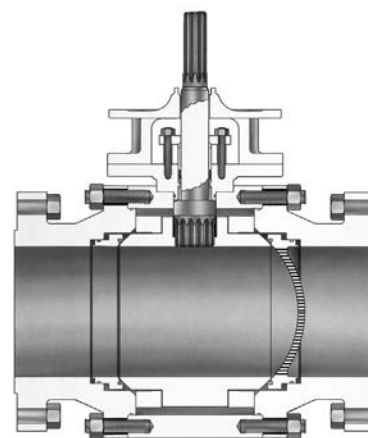
Noticeable hydrodynamic noise is usually associated with cavitation. The traditional description of the sound is as if rocks were flowing inside the pipe. This association of hydrodynamic noise with cavitation is reflected in the various prediction methods available today. The methods account for one noise characteristic for liquids in non-choked flow situations and another characteristic in choked, cavitating flow situations.

There are a variety of situations where the fluid is a two-phase mixture. These include liquid-gas two-phase fluids at the inlet of the valve, flashing fluids, and fluids that demonstrate out-gassing due to throttling. Noise prediction methods for these cases are not yet well established. Test results and field surveys of installed multi-phase systems indicate these noise levels do not contribute to overall plant noise levels or exceed worker exposure levels.



W6851

Figure 5-6. *Globe-Style Valve with Noise Abatement Cage for Aerodynamic Flow*



W6343

Figure 5-7. *Ball-Style Valve with Attenuator to Reduce Hydrodynamic Noise*

Noise Summary

The amount of noise that will be generated by a proposed control valve installation can be quickly and reasonably predicted by use of industry standard methods. These methods are available in computer software for ease of use. Such sizing and noise prediction tools help in the proper selection of noise reduction equipment such as shown in Figures 5-6 and 5-7. Process facility requirements for low environmental impact will continue to drive the need for quieter control valves. The prediction technologies and valve designs that deliver this are always being improved. For the latest in either equipment or prediction technology, contact the valve manufacturer's representative.

Control Valve Cavitation and Flashing

Cavitation and a related issue, flashing, are hydrodynamic flow phenomena that began to receive recognition as technical engineering problems in the early 1900s. At that time, observations led to the conclusion that vaporization of water in the vicinity of high-speed propellers was responsible for a decrease in their effectiveness. This liquid vaporization was defined later as cavitation.

Cavitation and flashing are a concern to the control valve industry not only because they decrease flow capability through control valves, but also because they create noise, vibration, and material damage.

This chapter will define cavitation and flashing and will discuss the negative effects of both flow phenomena. Control valves designed to prevent cavitation and flashing damage will be discussed along with other considerations in choosing control valves for cavitating and flashing services.

Cavitation and Flashing

Cavitation and flashing are purely liquid flow phenomena. Gases and vapors can neither cavitate nor flash. While there are three recognized types of cavitation, the most significant type, as applied to control valves, is vaporous cavitation.

Vaporous cavitation consists of explosive vapor cavity growth within a liquid resulting from local liquid vaporization. Cavity formation is followed by rapid cavity collapse due to vapor re-condensation. The phase change sequence is caused by local pressure fluctuations in the liquid.

To understand the conditions in a control valve that can cause cavitation or flashing, consider the simple restriction shown in Figure 6-1. In this figure the pressure of the liquid, P , is plotted as a function of the distance, x , through the simple restriction shown at the top of the figure. Figure 6-2 is a plot of the velocity, V , of the liquid versus the distance, x , as it relates to the pressure profile.

There is a point called the vena contracta where the flow area of the liquid will be at a minimum. The vena contracta will be downstream some distance of the minimum flow area. This distance will vary with pressure conditions and actual type of restriction.

Figure 6-2 shows that at the vena contracta point, the pressure will hit a minimum that will be defined as the vena contracta pressure, P_{vc} . After the vena contracta pressure occurs, the liquid pressure will recover to the downstream pressure. Note that the downstream pressure is less than the upstream pressure because some of the available energy is converted into heat.

To maintain a constant flow rate through the restriction, the flow velocity must increase to offset the effect of the decreased cross-sectional flow area. As the energy due to fluid velocity (kinetic energy) increases, other forms of fluid energy must be offset accordingly, which accounts for the pressure drop of the liquid through the restriction.



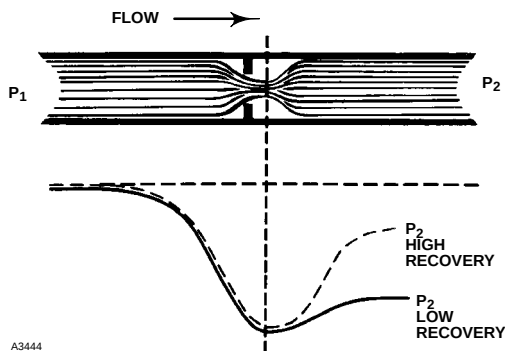


Figure 6-1. Pressure profile of flow through a restriction

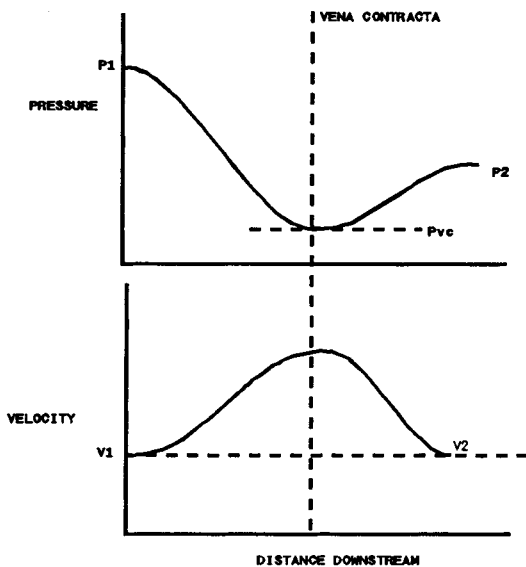


Figure 6-2. Pressure versus velocity curves illustrate that the highest flow rate occurs at the vena contracta.

This relationship can be shown in equation form by looking at Bernoulli's Equation (equation 6-1). Bernoulli's Equation between point P_1 and the vena contracta may be written as:

$$\frac{\rho V_1^2}{2g_c} + P_1 = \frac{\rho V_{vc}^2}{2g_c} + P_{vc} \quad (6-1)$$

An increase in the fluid velocity (kinetic energy) must be offset by a decrease in the static pressure.

To clearly define flashing and cavitation and also the difference between the two, it is best to look at

the pressure profile (Figure 6-1) of flow through a fixed restriction in relationship to the vapor pressure of the liquid. Figure 6-3 shows this relationship and graphically defines the difference between cavitation and flashing.

A liquid that cavitates or flashes behaves in the same manner from the inlet to the vena contracta. As the pressure falls from the inlet pressure, a point is reached where the local fluid pressure is equal to the vapor pressure. When the fluid pressure falls below the vapor pressure, the fluid becomes unstable, and it begins to turn to vapor. This phase change from a liquid to a vapor shows up as bubbles in the flow stream and is very similar to the bubbles that form in a boiling pan of water.

When the water hits a temperature (212°F, 100°C) where its vapor pressure is equal to the atmospheric pressure, bubbles will form. Boiling occurs when the vapor pressure increases to equal atmospheric pressure.

Conversely, in cavitation, the velocity change at the restriction lowers the fluid pressure to equal the vapor pressure. Cavitation is a much faster transition than boiling and produces much more vigorous results.

Flashing is another liquid phenomenon that is related to cavitation. In fact, the onset of flashing is identical to that of cavitation. It is only when the fluid passes the restriction and its pressure recovers that the two phenomena separate.

A fluid is said to flash when the downstream pressure of that fluid is less than its vapor pressure. The vapor bubbles that are formed when the pressure falls below the vapor pressure continue to grow, and eventually the liquid changes, or flashes to a vapor. It should be noted that flashing is determined by the vapor pressure of the liquid and the downstream pressure. Therefore, it is a system phenomenon, and no control valve can prevent flashing unless the system conditions (P_2 , P_v) are changed.

Cavitation occurs when the pressure downstream of the valve rises back above the vapor pressure. The bubble can no longer exist as a vapor, and it immediately turns back to a liquid. Since the vapor bubble mass had a larger volume than the equivalent liquid mass, the bubble is said to implode. Note that cavitation is a liquid-vapor-liquid phase change. Unlike flashing, a correctly chosen control valve can prevent cavitation. This will be covered in detail in the upcoming sections.

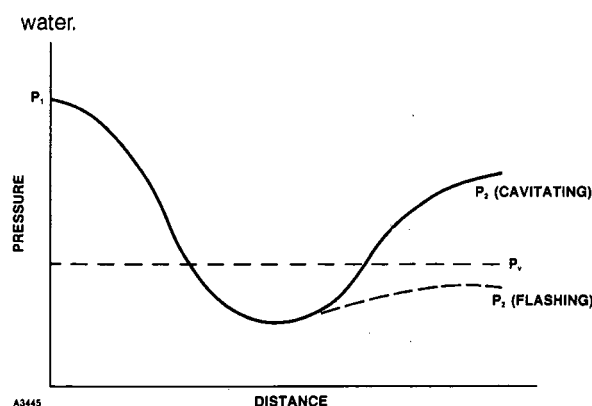


Figure 6-3. Pressure recovery above the vapor pressure of the liquid results in cavitation. Remaining below the vapor pressure incurs flashing.

Bubble Cycle

The bubble cycle refers to the phase changes from a liquid to a vapor and back to a liquid that occur when a liquid cavitates. The behavior of these bubbles has a direct bearing on the degree of the negative side effects that will result. There are four primary events in the bubble cycle: nucleation, growth, collapse, and rebound.

In order for a liquid to cavitate at or near the vapor pressure of the liquid, it is necessary to have a place for the cavity to form. Often this is a small bubble of an entrained noncondensable gas in the liquid. These nuclei must be of a certain minimum size in order to explosively grow or cavitate. This process of initiating bubble formation is known as nucleation.

Once the bubble is formed, it proceeds across the reduced pressure region and grows in response to the continually decreasing pressure and increasing liquid vaporization. This portion of the bubble cycle is known as the growth portion. Eventually, the pressure recovery halts the growth of the bubble and forces it to collapse which is the third event in the bubble cycle.

Under certain circumstances, several growth and collapse cycles can occur in a series of rebounds.

There are four primary negative side effects of cavitation: excessive noise, excessive vibration, material damage, and deterioration of flow effec-

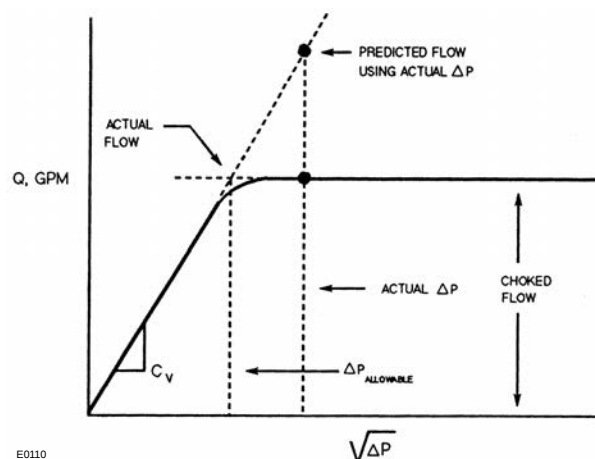


Figure 6-4. The $\Delta P_{allowable}$ equation will predict the occurrence of fully choked flow

tiveness. The flow through a restriction is normally proportional to the square root of the pressure drop. The constant of proportionality is the liquid-flow coefficient of the restriction, C_v , divided by the square root of the specific gravity, G .

Therefore,

$$Q = C_v \sqrt{\frac{P_1 - P_2}{G}} \quad (6-2)$$

This relationship suggests that increasing the pressure differential across the restriction can continually increase the flow rate. However, in practice the relationship begins to break down when a sufficient amount of the vapor phase (produced in the cavitation process) is formed. Less of a flow increase is realized for the same pressure differential increase (at a given P_1), until finally the flow remains constant despite an increase in the pressure drop. Figure 6-4 portrays this choking phenomenon graphically.

The exact mechanisms of liquid choking are not fully confirmed, although there are parallels between it and critical flow in gas applications. In gas flows, the flow chokes when the flow velocity is equal to the acoustic wave speed (sonic velocity).

For pure liquids (incompressible fluids) the acoustic wave speed is very high. In liquids that partially vaporize, however, the fluid is actually a two-phase mixture and typically has a very low acoustic wave speed (actually lower than that of a pure gas). Therefore, it is possible for the mixture ve-

locity to become equal to the sonic velocity and choke the flow.

Material Damage

Cavitation damage is usually the most troublesome negative side effect plaguing the control valve industry. It does not take many examples of such damage to fully demonstrate the destructive capabilities of cavitation.

Typically, cavitation damage is characterized by a very irregular, rough surface. The phrase “cinder-like appearance” is used frequently to describe cavitation damage. It is discernible from other types of flow damage such as erosion and flashing damage, which are usually very smooth and shiny in appearance. This next section will deal with cavitation damage, although most of the comments also can apply to flashing damage. Figure 6-6 illustrates these differences.

While the results of cavitation damage are all too familiar, the events and mechanisms of the cavitation damage process are not known or understood completely in spite of extensive study over the years. There is general agreement, however, on a number of aspects of the process and a consistency in certain observations.

Cavitation damage has been consistently observed to be associated with the collapse stage of the bubble dynamics. Furthermore, this damage consists of two primary events or phases: (1) an attack on a material surface as a result of cavitation in the liquid, and (2) the response or reaction of the material to the attack. Any factor that influences either of these events will have some sort of final effect on the overall damage characteristics.

The attack stage of the damage process has been attributed to various mechanisms, but none of them account for all the observed results. It appears that this attack involves two factors that interact in a reinforcing manner: (1) mechanical attack and (2) chemical attack.

There is evidence indicating the almost universal presence of a mechanical attack component which can occur in either of two forms:

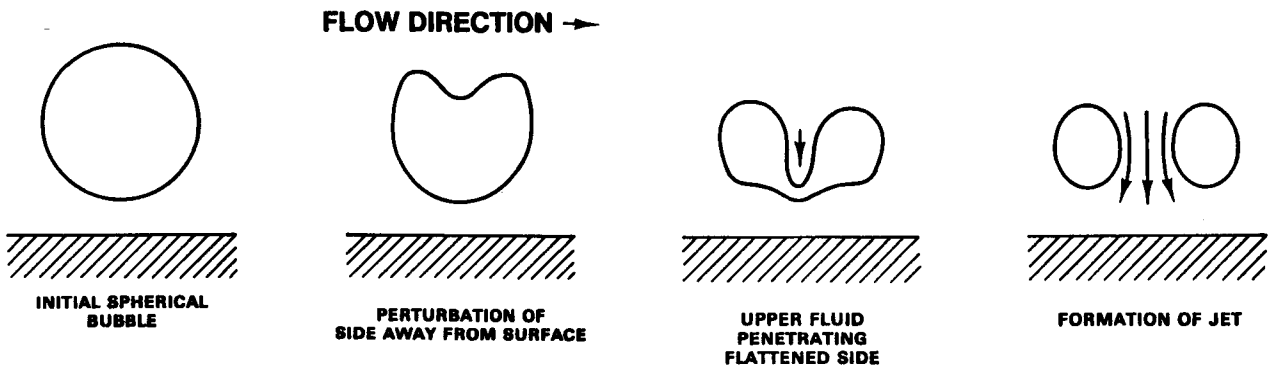
1. *Erosion resulting from high-velocity microjets impinging on the material surface.*



Figure 6-6. The top plug shows the characteristic rough texture of cavitation damage, which differs greatly from the polished appearance of damage due to flashing (lower photo). The two damage mechanisms vary greatly.

2. *Material deformation and failure resulting from shock waves impinging on the material surface.*

In the first type of mechanical attack, a small, high-velocity liquid jet is formed during the asymmetrical collapse of a vapor bubble. If orientation and proximity of the jets is proper, a damaging attack occurs on the metal surface, as shown in Figure 6-7. This is the most probable form of mechanical attack, and high-speed cinematography,



E0111

Figure 6-7. The implosion of cavitation vapor cavities is rapid, asymmetric and very energetic. The mechanics of collapse give rise to high velocity liquid jets, which impinge on metallic surfaces. Ultimately, the metal fatigues and breaks away in small pieces.

liquid drop impingement comparisons, and various analytical studies support its presence.

The second type of mechanical attack—shock wave impingement—does not appear to be as dominant. Analytical estimations of vapor bubble collapse pressures do not suggest that the shock waves are on a damaging order of magnitude—at least during the initial collapse. Experimental studies bear this out. They also reveal that resulting collapse pressures increase in magnitude with subsequent rebound collapses and become potentially damaging.

The other primary component of attack, chemical attack, is perhaps more significant since it interacts with the mechanical component, rather than acting by itself. After a period of mechanical attack many of the protective coatings of a material, (films, oxides, etc.) are physically removed, making the base material more vulnerable to chemical attack.

Just as a number of variables have an effect on the behavior of individual cavities, so too there are influences affecting the degree and extent of material damage. The principal influences include such variables as air content, pressure, velocity, and temperature.

Air content impacts cavitation damage primarily through its effect on cavity mechanics, as previously discussed. Again, two opposing trends are evident on increasing the amount of air. Adding air supplies more entrained air nuclei, which in turn produce more cavities that can increase the total damage. After a point, however, continued increases in air content disrupt the mechanical at-

tack component and effectively reduce the total damage.

Pressure effects also exhibit two opposing trends. Given a fixed inlet pressure P_1 , decreasing the backpressure P_2 tends to increase the number of cavities formed, which creates a worse situation. However, a lower backpressure also creates a lower collapse pressure differential ($P_2 - P_v$), resulting in a decrease in the intensity of the cavitation.

An additional pressure effect unrelated to the above concerns the location of damage. As the backpressure is changed, the pressure required to collapse the cavities moves upstream or downstream, depending on whether the pressure is increased or decreased, respectively. In addition to a change in the severity of the total damage, there may be an accompanying change in the physical location of the damage when pressure conditions are altered.

It should now be apparent that the cavitation and flashing damage process is a complex function of:

1. *Intensity and degree of cavitation (cavitation attack)*
2. *Material of construction (material response)*
3. *Time of exposure*

While the above-mentioned influences have been observed, they remain to be quantified. Often, experience is the best teacher when it comes to trying to quantify cavitation damage.

Noise

Although the noise associated with a cavitating liquid can be quite high, it is usually of secondary concern when compared to the material damage that can exist. Therefore, high intensity cavitation should be prevented to decrease the chance of material damage. If cavitation is prevented, the noise associated with the liquid flow will be less than 90 dBA.

For a flashing liquid, studies and experience have shown that the noise level associated with the valve will be less than 85 dBA, regardless of the pressure drop involved to create the flashing.

Hardware Choices for Flashing Applications

It was stated previously that flashing is a liquid flow phenomenon that is defined by the system, and not by the valve design. Therefore, since flashing cannot be prevented by the control valve, all that can be done is to prevent flashing damage.

There are three main factors that affect the amount of flashing damage in a control valve.

- Valve Design
- Materials of Construction
- System Design

Valve Design

While valve design has no bearing on whether flashing does or does not occur, it can have a large impact on the intensity of flashing damage. Generally, there are two valve designs that are more resistant to flashing damage than the generally accepted globe body.

An angle valve with standard trim in the flow down direction and with a downstream liner is perhaps the best solution to preventing flashing damage. Figure 6-8 shows a typical angle valve for flashing service.

The reason this construction is an excellent choice is that flashing damage occurs when high velocity vapor bubbles impinge on the surface of a valve. An angle valve reduces the impingement by directing flow into the center of the downstream pipe, not into the valve body. If damage does occur, the

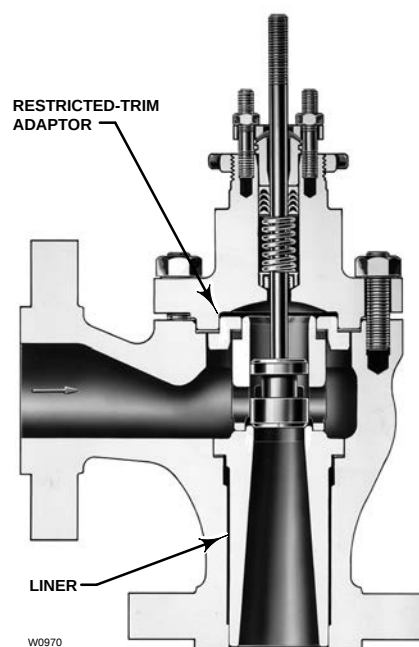


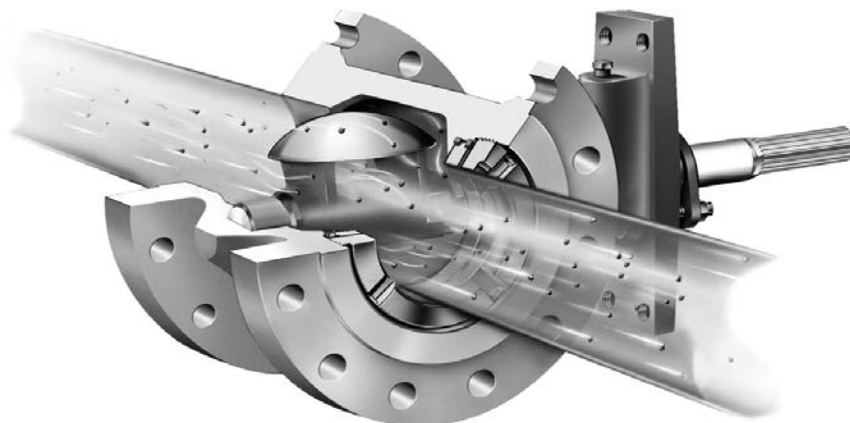
Figure 6-8. Design EAS valve with outlet liner is used for flashing service. The liner resists erosion and protects the body.

downstream liner can be replaced much more economically than the valve body.

A rotary plug style of valve is also an excellent choice for medium to low pressure flashing applications. This valve can be installed with the plug facing the downstream side of the body (Figure 6-9) so when flashing occurs, it does so downstream of the valve. In some cases, a spool piece of sacrificial pipe is used to absorb the flashing damage.

Materials of Construction

There are several factors which determine the performance of a given material in a particular flashing and/or cavitating situation, including the materials' toughness, hardness, and its corrosion-resistance in the application environment. Within a given material family (for example, the 400-series stainless steels), hardness is a fairly accurate method for ranking materials. However, when comparing materials from different families, hardness doesn't correlate with overall resistance to damage. For example, cobalt-chromium-tungsten based Alloy 6 has much more resistance to cavitation and flashing than either hardened type 410 or 17-4 stainless steels, even though



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Figure 6-9. Rotary plug valves, such as the Design V500 (reverse flow trim direction, trim level 3) have excellent erosion resistance and perform well in flashing service.

they all exhibit roughly the same hardness. In fact, Alloy 6 equals or exceeds the performance of many materials with hardnesses of 60 HRC and higher. The superior performance of Alloy 6 is attributed to a built-in “energy-absorbing” mechanism shared by a number of cobalt-base alloys. However, Alloy 6 is not without its weaknesses; in many amine-treated feedwater applications, Alloy 6 suffers accelerated attack by an erosion-corrosion mechanism (see “Alloy 6 Corrosion” in Chapter 10 for more information).

Materials commonly used for flashing and cavitating services are Alloy 6 (solid and overlays), nickel-chromium-boron alloys (solid and overlays), hardened 440C stainless steel, hardened 17-4 stainless steel, and hardened 410/416 stainless steel.

Since the standard materials used in valve bodies are relatively soft, selection for cavitation and flashing resistance must rely on factors other than hardness. In general, as the chromium and molybdenum contents increase, the resistance to damage by both cavitation and flashing increases. Thus the chromium-molybdenum alloy steels have better resistance than the carbon steels, and the stainless steels have even better resistance than the chromium-molybdenum alloy steels.

In the past, ASME SA217 grade C5 was the most commonly specified chromium-molybdenum alloy steel. However, because of the poor casting, welding, and manufacturing characteristics of C5, ASME SA217 grade WC9 has become a more

popular alternative. Experience indicates that WC9 performs on par with C5 in cavitation and flashing services despite its lower chromium content (2-1/4% vs. 5%). This is apparently because its higher molybdenum content (1% vs 1/2%) makes up for the lower chromium content.

While angle bodies are a better choice for flashing applications than globe bodies, they are also a more economical choice in most cases. The reason is that carbon steel bodies can be used in an angle valve with an optional hardened downstream liner, (17-4PH SST, Alloy 6, etc.) since only the downstream portion of the valve will experience the flashing liquid. See Figure 6-8. If a globe valve is used, it is better to use a chromium-molybdenum alloy steel body since the flashing will occur within the body itself.

Hardware Choices for Cavitating Applications

The design of a control valve greatly affects the ability of a valve to control cavitation. This section discusses the theories behind each type of trim design that is used for cavitation control and also reviews each type of trim that Fisher Controls uses to control cavitation.

The design theories or ideas behind the various trim designs include:

- Tortuous path
- Pressure drop staging

- Expanding flow area
- Drilled hole design
- Characterized cage
- Separation of seating and throttling locations
- Cavitation control in lieu of prevention

Pressure Drop Staging

This approach to damage control routes flow through several restrictions in series, as opposed to a single restriction. Each restriction dissipates a certain amount of available energy and presents a lower inlet pressure to the next stage.

A well-designed pressure-staging device will be able to take a large pressure differential, yet maintain the vena contracta pressure above the vapor pressure of the liquid, which prevents the liquid from cavitating.

For the same pressure differential then, the vena contracta pressure in conventional trim will be lower than for the staged trim, and the liquid will be more prone to cavitate.

Trims that dissipate available energy have an additional advantage. If the design pressure differential is exceeded and cavitation does occur, the intensity will be less. This is because the pressure that causes the collapse of cavities (i.e., the recovered pressure) will be less.

Expanding Flow Areas

The expanding flow area concept of damage control is closely related to the pressure drop staging concept. Figure 6-10 shows a pressure versus distance curve for flow through a series of fixed restrictions where the area of each succeeding restriction is larger than the previous. Notice that the first restriction takes the bulk of the pressure drop and the pressure drop through successive sections decreases.

In the last restriction, where cavitation is most likely to occur, the pressure drop is only a small percentage of the total drop, and the pressure recovery is substantially lowered.

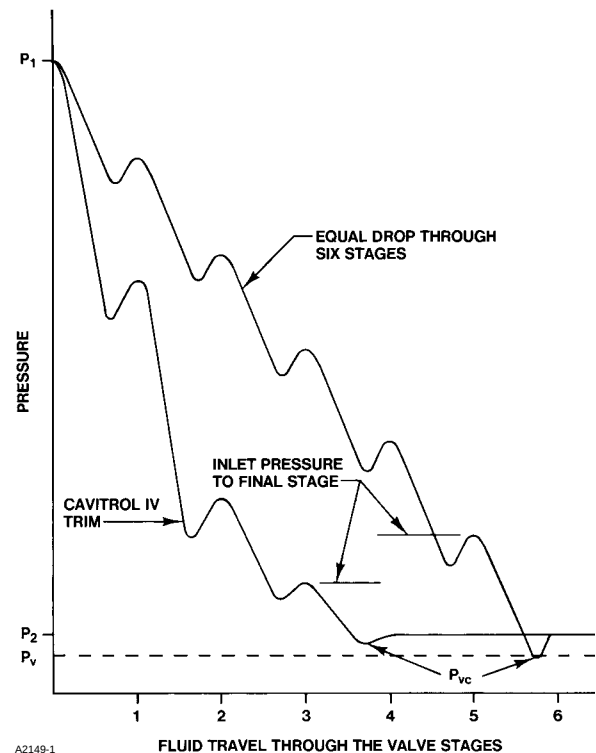


Figure 6-10. In Cavitrol™ trim, the pressure drop is staged in two or more unequal steps. Staging is accomplished by increasing the flow area from stage to stage. This stepped reduction allows full pressure drop without the vena contracta pressure falling below the vapor pressure of the liquid.

The expanding flow area concept requires fewer pressure drop stages to provide the same cavitation protection as the equal area concept. Since the pressure drop of the last stage is rather low compared to the total pressure drop, if cavitation does occur, the intensity and cavitation damage will be much less.

Drilled Hole Design

Fisher Controls uses drilled hole cages to provide a tortuous path, pressure drop staging, and expanding flow area in its Cavitrol™ line of cavitation control trims. The design of each particular drilled hole has a significant impact on the overall pressure recovery of the valve design.

Figure 6-11 shows a cross section of three types of drilled holes that could be used in a cavitation control cage. The thin plate design is a very inefficient flow device, but it does provide a high FL^2 and therefore a low pressure recovery. The thick plate design provides an efficient design, but also

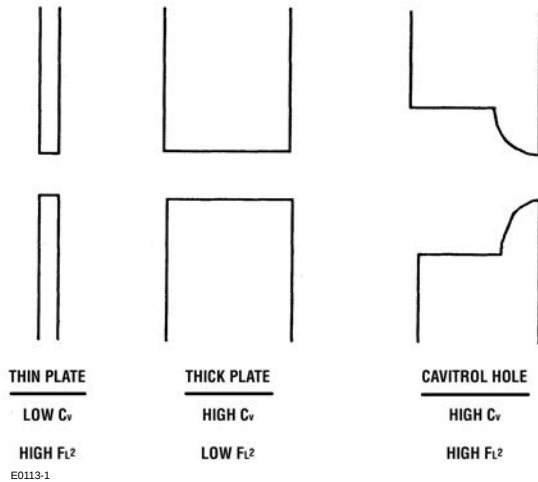


Figure 6-11. By combining the geometric effects of thick plates and thin plates, it is possible to design a flow passage that optimizes capacity and recovery coefficient values. These carefully designed passages are used exclusively in Cavitrol cages.

provides a high pressure recovery as denoted by a low F_L^2 value.

The Cavitrol trim hole design is a balance between the thick plate and the thin plate hole designs. It provides a relatively high flow efficiency while still maintaining a high F_L^2 , which results in a low pressure recovery. This design represents the optimal choice between capacity and cavitation control.

Other benefits of this type of drilled hole design is that the vena contracta point is further from the exit of the hole when compared to a straight through drilled hole. Therefore, if pressure recovery above the vapor pressure occurs (cavitation), it will do so further away from the external wall of the cage, and the amount of damage will be smaller.

One disadvantage of cavitation control trims is the potential for flow passages to become plugged. The flowing media often times contains small particulate such as sand that can plug the passages, restricting or totally stopping flow through the valve. If this potential exists, the particles must be removed from the flow stream, usually by filtration, or an alternative approach to cavitation should be taken.

An alternative is to use a trim that is designed to allow the particulate to pass, but still control cavitation. The Fisher Dirty Service Trim (DST) has been designed to allow particles up to 3/4-inch to

be passed and to control cavitation up to pressure drops of 4000 psig (275 bar).

Characterized Cages

The characterized cage design theory has evolved from the fact that “capacity is inversely related to a design’s ability to prevent cavitation.” In those applications where the pressure drop decreases as the flow rate increases, characterized cages can be used to optimize cavitation prevention and capacity.

For a Cavitrol™ III characterized trim design, as the travel increases, the cage design changes. It begins as a pressure-staging design and then to a straight-through hole design. Consequently, the cavitation control ability of this trim design is greatest at low travels and decreases with increasing valve plug travel.

Care should be taken to employ characterized cages only in applications where the pressure drop decreases as travel increases.

Separate Seating and Throttling Locations

Most cavitating applications require a control valve to not only provide cavitation control, but also provide tight shutoff. The best way to accomplish this is to separate the throttling location from the seating location as shown in Figure 6-12. The seating surface of the plug is upstream of the throttling location, and the upper cage is designed such that it takes very little pressure drop. The seating surface experiences relatively low flow velocities since velocity is inversely related to pressure. A recent technological advancement has been to implement the use of a softer seating material relative to the material of the plug. This allows for a slight deformation of the seating material, which provides much better plug/seat contact and hence greatly enhanced shutoff capability. Valves utilizing this soft seating material are capable of providing Class VI shutoff.

Cavitation Control Hardware Alternatives

The previous section dealt with the theories behind modern types of cavitation control hardware.

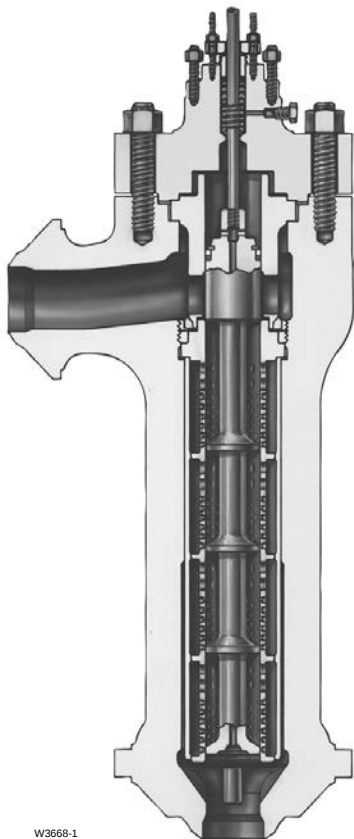


Figure 6-12. Cavtrol IV trim provides cavitation protection at pressures to 6500 psig. It uses expanding flow areas to affect a four-stage pressure drop. All significant pressure drop is taken downstream of the shutoff seating surface.

This section presents alternatives to the sometimes-costly cavitation hardware. Guidelines are also presented to help determine when cavitation control hardware is required or when other alternatives can be employed.

System Design

Correct liquid system design is the most economical way to prevent the damaging effects that are caused by cavitation without applying cavitation prevention control valves. Unfortunately, even the best system design is likely to need cavitation type control valves, but by applying certain design features, the complexity of these control valves may be simplified.

The most common and oldest method of designing a liquid flow system where large pressure

drops must occur is to use a standard trim control valve with a downstream backpressure device. Although these devices come in various sizes, shapes, and designs, they all perform the same function of lowering the pressure drop across the control valve by raising its downstream pressure.

Since the downstream pressure of the valve is increased, the vena contracta pressure is increased. If the backpressure device is sized correctly, the vena contracta pressure will not fall below the vapor pressure, and cavitation will not occur.

While this is a simple and cost effective way to prevent cavitation damage in the control valve, there are several serious considerations to look at before using a downstream backpressure device.

- A larger valve may be required to pass the required flow since the pressure drop is lowered.
- Although cavitation may not occur at the control valve, it may occur at the backpressure device.
- The backpressure device can only be sized for one condition. If other conditions exist, the backpressure provided may allow cavitation to occur.
- If the backpressure device becomes worn, the backpressure will decrease and cavitation in the valve may occur.

Another disadvantage that is rarely mentioned occurs when a valve is opened against a high upstream pressure. Until the flow reaches the backpressure device and stabilizes, the valve will experience the entire pressure drop of the system. Although this may only occur for a short period of time, a potential for damage exists.

Cavitation is an interesting but destructive phenomenon. Preventing cavitation is the most acceptable way of limiting potential for damage. Proper application of available products based on sizing equations and field experience will provide long term success.

Cavitation Control Summary

- Cavitation is a phenomenon arising from a liquid-vapor-liquid phase change. This phase change occurs when liquids are throttled through control valves.

- Cavitation must be controlled because it potentially damages valves and piping and creates noise and vibration in piping systems.

- Flashing is a related liquid phenomenon arising from similar circumstances. With flashing, however, vapor bubbles remain in the fluid stream rather than collapsing.

- Flashing is a system situation that cannot be prevented by valve selection. Use of designs and materials that resist erosion will generally solve problems related to flashing.

- Either system changes or valve hardware changes can solve cavitation. Prevention and control by use of specialized valve designs is most effective. Material substitutions are helpful, but limited in long term effectiveness.

- Valve recovery coefficients are used along with system and fluid parameters to predict the presence of cavitation and choked flow. Experience gives guidance on sizing and how to avoid problems.

Section 2:

Oil and Gas Control Valve Applications

Onshore Oil and Gas Production

Crude oil and natural gas are naturally occurring hydrocarbons found in rock formations below the earth's surface, called reservoirs. Crude oil is a liquid fossil fuel that is a mixture of many different hydrocarbon liquids. Natural gas is also a fossil fuel that is a mixture of compressible hydrocarbon gases.

Conventional onshore production simply consists of bringing trapped oil and gas located in reservoirs that can be accessed on land to the surface in order to be further processed. The natural gas produced leads to further processing in a natural gas plant (discussed in Chapter nine), and the oil produced leads to additional downstream processing in a refinery (refinery processes and application reviews can be found in the refinery sourcebook).

There are numerous production geographies, multiple recovery methods, and many processing

techniques for the production of oil and gas. This chapter, however, will solely discuss the methods used for conventional onshore production; including well head production, initial separation, gathering, and gas compression.

Also discussed are the control valve selections in conventional onshore production. Onshore production scale and scope varies widely between sites, however, the methods and equipment used at each site are very similar, so control valve selection is largely independent of site scale and scope.

Onshore Production Process

Figure 7-1 shows the general process flow typical of onshore production.

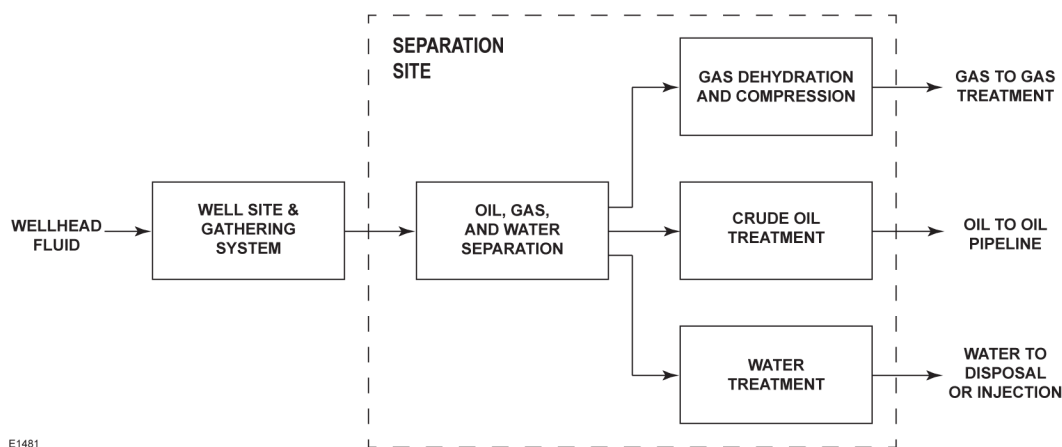


Figure 7-1. Production Process Flow Diagram

Firstly, oil and gas is removed from a reservoir via a well site. The fluid produced, called raw fluid, is comprised of oil, gas, water, and varying amounts of undesired products. The produced mixture is then gathered through a manifold system and transported to a separation site. The mixture enters the separation facility through separator vessels that use simple gravity driven technology to separate the gas, oil, and water mixture. The separated gas is commonly compressed and transported to a nearby gas plant and the crude oil is transported to a refinery. Oil and gas transportation is discussed in Chapter ten. Specific details of the entire well to pipeline process will be examined in the following sections.

Well Site and Gathering System

Production at a well site involves a pressurized well's release of fluid. A varying number of producing wells, when lumped together, form a well pad and many well pads feed the gathering and separation systems. Also known as a trunk and lateral system, this system is located relatively close to the individual well sites and is more or less used to collect the raw production into one pipeline system for advancement to the separation site.

Separation Site

The main purpose of the separation site is for the separation of the constituents in the fluid produced at the well sites. A separation site may be used for a single well or serve multiple wells. It may also be referred to as a gas oil separation plant (GOSP), among other broad terms such as gathering center, flow station, and central processing facility.

A separation site can utilize varying amounts of process equipment (type and quantity) depending on production scale, fluid behavior, fluid characteristics, and/or selection preference. Equipment can include gravity separators, emulsion heater treaters, storage tanks, and test separator units to name a few. Depending on total well recovery, customer preference, etc., a single well site may include all of the before mentioned equipment.

Despite the differences in separation sites, the final goal of each facility is very similar; to separate oil and natural gases from the raw fluid and prepare it for the distribution to oil refineries and gas processing plants respectively. This typically involves four main processes:

1. Oil, gas, and water separation

2. Crude oil treatment and preparation for distribution

3. Gas dehydration and compression

4. Water treatment and injection

Oil, Gas, and Water Separation

Separation of the fluid produced from the production wells and gathered can be accomplished by a combination of slug catchers, KO drums, scrubbers, and gravity separators. The majority of separation, however, is performed by standard gravity assisted equipment. For the purposes of this chapter, we will discuss only this type of separator.

Commonly there are two or more separators in series that allow for optimal separation of natural gas, oil, and water. The separator pressure classification for a given vessel is defined by the pressure rating capabilities of the separator. High pressure vessels are typically rated to ASME CL600, intermediate pressure vessels are typically rated to ASME CL300 and low pressure vessels are typically rated to ASME CL150. The first separator in the series will always be rated the highest, with each one thereafter typically reducing to a lower pressure rating until the fluids reach ambient pressures. The number of stages depends on the pressure of the production field, however, most will have a high, intermediate, and low pressure separator.

The inlet separator provides a significant cut in the plant's inlet pressure. This separator is ideal for smoothing out surging liquid flows. In virtually all instances, unprocessed raw production media, including its multiple unwanted components, will enter the first stage separator. The process equipment, including inlet and outlet valves must be suited for handling production that contains sand and other sediment. First stage outlet oil flow will then enter the second stage separation area.

The second stage separation will follow a similar process flow to that of the first stage separation, but will simply work from a reduced inlet pressure. Most second stage flow is via the outlet of the first stage separation process, but may also have incorporated low pressure manifold flow that has bypassed initial stage separation. The second stage process will follow similar control valve selection criteria to that of the first stage.

The final, low pressure separation stage is commonly a two phase (oil and gas) separator.

Note, test separators, in terms of conditions and valve selection, are similar to that of standard gravity separation equipment. Please reference the below separation application review for associated valve selection.

Crude Oil Treatment and Preparation

In general, the crude treatment process, or stabilization process, completes three important tasks:

1. *The removal of hydrogen sulfide*
2. *The removal of light hydrocarbons such as methane, ethane, propane, and butane*
3. *The removal of water*

The combined result is a safe, transportable crude oil at atmospheric pressure that can be transferred to a refinery via existing pipeline infrastructure. Two common methods for oil treatment are electrostatic coalescers and hydrocyclones.

Electrostatic coalescers expose the crude oil stream to a high voltage electrostatic field, causing any water to coalesce into droplets and fall free from the oil. This process also helps to remove any dissolved salts left in the stream. Once treated, the crude is routed to storage or a separate export system. Hydrocyclones use centrifugal force to remove oil droplets from oily water. Centrifugal force causes the lighter density droplets to move toward the low-pressure central core where axial reverse flow occurs. Clean water is removed through the downstream outlet. Floatation cells employ a process in which fine gas bubbles are generated and dispersed in water where they attach themselves to oil droplets or solid particles. Gas bubbles then help to lift the oil to the water surface for collection.

Gas Dehydration and Compression

In most separation sites, the separated gas stream will be dried and compressed for export to a gas processing plant.

There are a number of factors taken into account by compressor skid manufacturers to determine a package that is flexible enough to work in multiple fields with the appropriate Horse Power (Hp). The Hp of a given skid is the driving factor in the size of the equipment required. Compressor skids can have Hp ranging from 50 Hp for the smallest of packages up to 8,000 Hp for the largest of packages. These skids can have reciprocating or rotary

screw compressors that use natural gas engines or turbines, or electric motor drives. The compressor's capacity and Hp is largely determined from the following three factors:

1. *Suction pressure and temperature*
2. *Discharge pressure and temperature*
3. *Speed*

This allows the compressors to be designed to utilize the engine Hp as fully loaded and efficiently as possible for specified conditions. These conditions will change over the life of a project, which requires a suction control valve and recycle valve to allow for the required flexibility of the skids.

Compressors play a large role in the production and sale of gas. They are responsible for aiding the transmission of gas from the production well head to gathering systems, from gathering systems to midstream pipelines and from midstream infrastructure to large interstate pipelines that deliver gas to far stretching regions.

Water Treatment and Injection

Wellhead quality production normally contains significant amounts of water (free or entrained). Typical gravity separation will result in a water phase that needs to be removed from the separator system and eventually directed away from the site. The separated water may be subjected to treatment to remove dispersed gases, oil droplets, entrained solids and other undesirable constituents. In most cases, the separation site is the means by which the water is prepared for dispersal. This book will solely focus on water injection dispersal methods. An in depth discussion on water injection is presented in Chapter eight.

Application Review

The below applications discussed are intended to give an outline of the typical range of process conditions and valves applied in conventional onshore production. The pressure of each specific field will vary based on age, region, formation and depth of the field. Additionally, each field will have a unique ratio of oil, gas, and water. In either case, main process equipment will follow similar guidelines that will lead to common valve type selections. The materials noted below are found in many production fields, but given the nature of sour production areas globally, a shift to high alloy materials may be necessary. NACE MR0175/ISO 15156 metallurgical considerations are the most common user applied guidelines.

Well Site & Gathering System

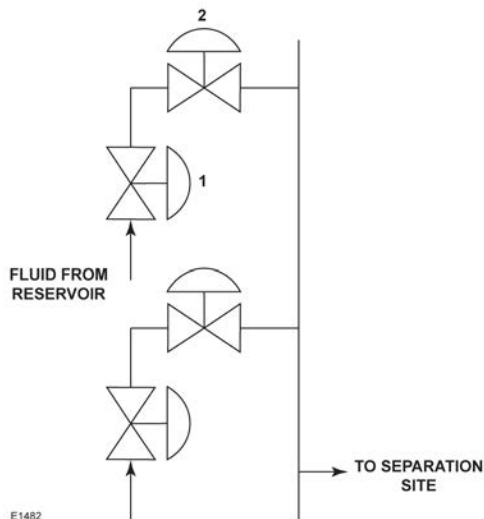


Figure 7-2. Well Site & Gathering System

1. Well Site Choke: Produced oil and gas will hit ground level entering production well tree units. Production well tree units include production header valves. These on/off choke valves are the means to maintain production rates. A typical tree



Figure 7-3. Product Catalog – High Pressure – D or DA; Oil and Gas – D or DA

choke valve needs to be reliable, while providing varying flow restriction. Production pressures can be upwards of 3000 psig (207 bar) in some producing fields. The production choke reduces the well pressure to the manifold gathering system and first stage separator pressures, which are typically 450-750 psig (31-52 bar). Angle valve selection is the primary choice in order to handle erosive, high pressure flows. A common large scale well includes sour gases and particulates, presenting possible corrosion or erosion damage. Thus, material selection is important in well site applications.

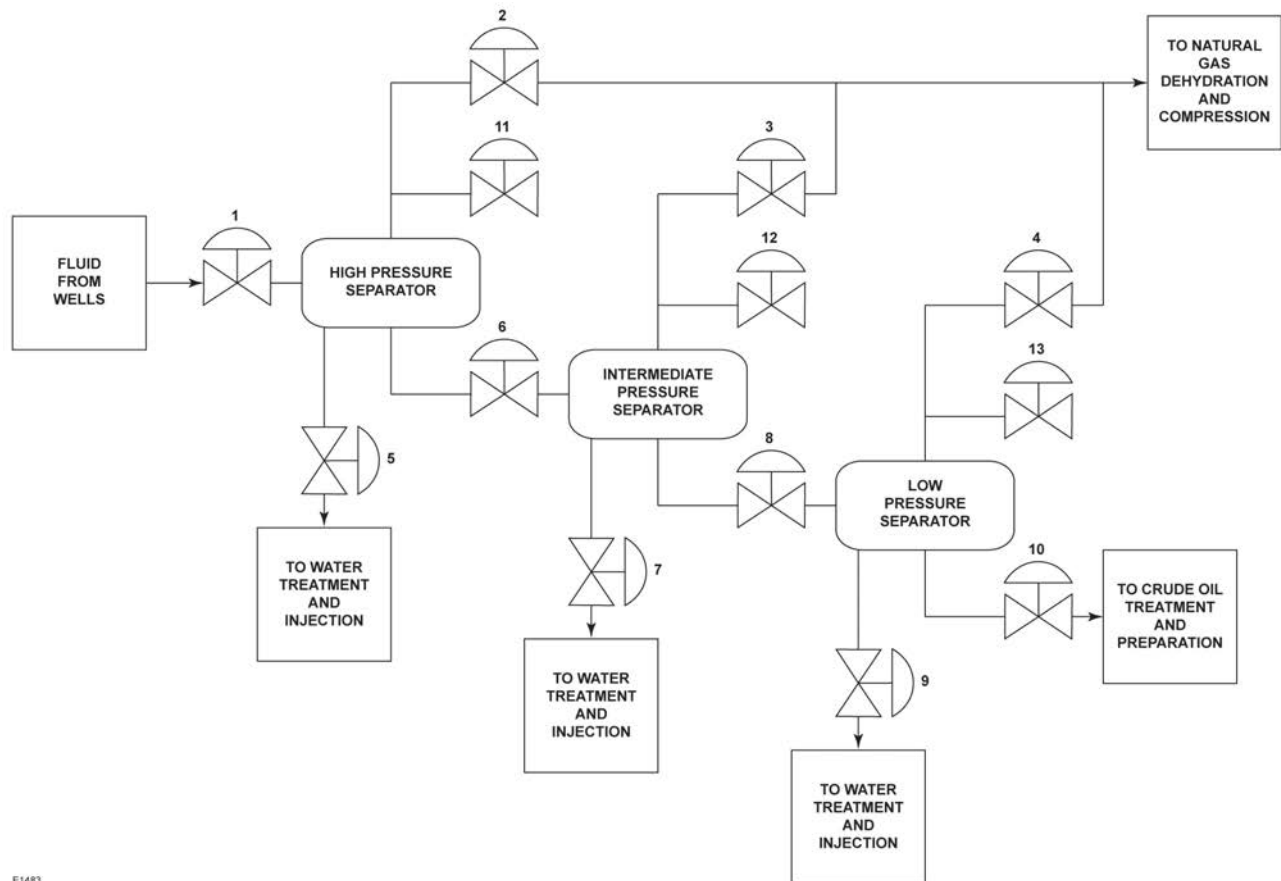
Table 7-1. Well Site Choke Valve

Parameter	Typical Value
Inlet Pressure	5 - 3000 psig (1 - 207 bar)
Pressure Drop	0 - 2500 psi (0 - 172 bar)
Inlet Temp.	100 - 190° F (38 - 88° C)
Valve Type and Pressure Class	D, DA
Valve Material and Trim Material	WCC with Hardened
Shutoff Requirement	ANSI Class V
Trim Type	Standard

2. Manifold Control: The producing wells are initially gathered to form one pad flow outlet. Well pad production flow is then gathered into a manifold type configuration, consisting of a trunk and lateral system. This system requires flow control and pressure control valves in order to adequately combine and pipe production flow. This valve controls the flow to the main line piping network. Gathering flow will include sour gases and particulates, as processing has not yet taken place, presenting possible corrosion and/or erosion valve damage. Thus, corrosion and erosion resistant materials must be selected. Erosive service valves are typical in gathering applications. A standard large scale manifold will consist of six to ten control valves.

Table 7-2. Manifold Control Valve

Parameter	Typical Value
Inlet Pressure	800 - 2400 psig (55 - 165 bar)
Pressure Drop	300 - 1000 psi (20 - 70 bar)
Inlet Temp.	100 - 190° F (38 - 88° C)
Valve Type and Pressure Class	EHT/V500, ASME CL600/900
Valve Material and Trim Material	WCC/316SST with Standard/316SST/Hardened
Shutoff Requirement	Class IV or V
Trim Type	Standard



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Figure 7-4. Process Fluid Separation System

Separation Site

Produced Fluid Separation

Separator Inlet Control

This valve is the first control valve in the high and intermediate pressure systems. This control valve provides the final pressure cut before the fluid enters the separator vessel. Many times this is a pressure control valve that can utilize the pressure drop across it to jump start the separation of the water, oil, and gas. In some systems this valve is a level control valve used to help control the fluid level in the tank. In these situations the control valve is linked to a level controller in the tank. In gas streams, where the feed gas has not received initial separation, this valve may be presented as a “slug catcher”. “Slug catchers” handle the gathered fluid, which may consist of a gas, oil and water (could form a liquid slug) and solids, coming out of the pipeline. Full bore ball valves with throttling capability are standard selections for this application. The full bore, high recovery valve will

allow slugs to pass through without restriction. The rugged trunnion mounted ball valve provides heavy and stable guiding for handling of this service.

1. Separator Inlet Control:

Table 7-3. High Pressure Separator Inlet Control Valve

Parameter	Typical Value
Inlet Pressure	600 - 1800 psig (41 - 124 bar)
Pressure Drop	10 - 300 psi (1 - 21 bar)
Inlet Temp.	100 - 190° F (38 - 88° C)
Valve Type and Pressure Class	V260C/Vee-Ball, ASME CL600/900
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

Gas Outlet Back Pressure Control

This back pressure control valve is located on the top most area of the separator. Its primary function is to control the pressure of the separator vessel by controlling the amount of gas flow out of the

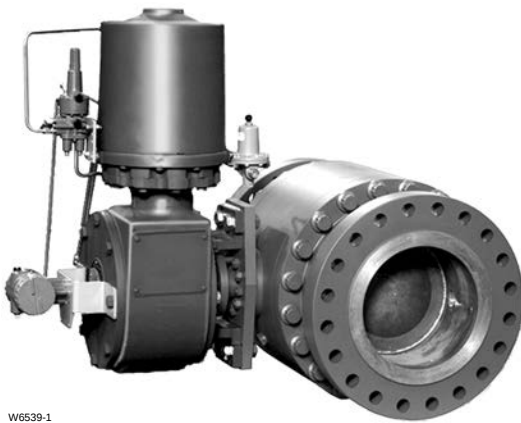


Figure 7-5. V260 Valve Exterior.

vessel. This gas stream is either sent to the compression skid or directly to export. The intent of this valve is to keep the separator operating in the optimal separation pressure range. The gas flowing through this valve will contain all of the produced gas constituents that were present at well site. Depending on location, this valve may be subject to both low and high pressure drops, resulting in the need for noise attenuating trim. The majority of solutions include globe style constructions.

2. High Pressure Separator Gas Outlet Pressure Control:

Table 7-4. High Pressure Separator Gas Outlet Control Valve

Parameter	Typical Value
Inlet Pressure	500 - 1,500 psig (35 - 103 bar)
Pressure Drop	10 - 1,150 psi (1 - 80 bar)
Inlet Temp.	150 - 190°F (65 - 88°C)
Valve Type and Pressure Class	D4/easy-Drive/e-body/Vee-Ball, ASME CL600
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard, Whisper III Trim, WhisperFlo Trim or Vee-Ball Attenuator

3. Intermediate Pressure Separator Gas Outlet Pressure Control:

Table 7-5. Intermediate Pressure Separator Gas Outlet Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 300 psig (5 - 21 bar)
Pressure Drop	0 - 200 psi (0 - 14 bar)
Inlet Temp.	150 - 190°F (65 - 88°C)
Valve Type and Pressure Class	D4/easy-Drive/e-body/Vee-Ball, ASME CL300
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

4. Low Pressure Separator Gas Outlet Pressure Control:

Table 7-6. Low Pressure Separator Gas Outlet Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 100 psig (1 - 7 bar)
Pressure Drop	0 - 80 psi (0 - 6 bar)
Inlet Temp.	150 - 190°F (65 - 88°C)
Valve Type and Pressure Class	D4/easy-Drive/e-body, ASME CL150
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

Separator Liquid Level Control

These valves are liquid level dump valves that are strategically placed based on the gravity separators design. The dump valves are controlled by a level system (controller coupled to a displacer). One valve controls the level of the water in the separator. When the level system senses a water level higher than what is desired, it sends a signal to the control valve to open, therefore lowering the water level. The separated water is then sent to water treatment and injection, which is discussed in Chapter eight. The other valve controls the level of oil in the separator. It also receives a signal from its corresponding level controller to open and reduce the level of oil in the separator. The separated oil is sent to storage tanks for holding until it is delivered for eventual shipment to a refinery for processing. Both level control valves may be subjected to conditions that result in flashing or cavitation, which may result in the need for hardened valve trim and/or Cavitrol III Trim.



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Figure 7-6. easy-Drive Actuator
on D4 Control Valve

5. High Pressure Separator Water Level Control:

Table 7-7. High Pressure Separator
Water Level Control Valve

Parameter	Typical Value
Inlet Pressure	500 - 1,500 psig (35 - 103 bar)
Pressure Drop	0 - 200 psi (0 - 14 bar)
Inlet Temp.	20 - 100°F (-7 - 38°C)
Valve Type and Pressure Class	D2/D3/D4/easy-Drive/e-body/ Vee-Ball, ASME CL600
Valve Material and Trim Material	WCC with Standard/ Hardened (flashing) (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard or Cavitrol III Trim (depending on dP)

6. High Pressure Separator Oil Level Control:

Table 7-8. High Pressure Separator
Oil Level Control Valve

Parameter	Typical Value
Inlet Pressure	500 - 1,500 psig (35 - 103 bar)
Pressure Drop	0 - 200 psi (0 - 14 bar)
Inlet Temp.	100 - 190°F (38 - 88°C)
Valve Type and Pressure Class	D2/D3/D4/easy-Drive/e-body/ Vee-Ball, ASME CL600
Valve Material and Trim Material	WCC with Standard/ Hardened (flashing) (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard or Cavitrol III Trim (depending on dP)

7. Intermediate Pressure Separator Water Level Control:

Table 7-9. Intermediate Pressure Separator
Water Level Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 300 psig (5 - 21 bar)
Pressure Drop	0 - 200 psi (0 - 14 bar)
Inlet Temp.	20 - 100°F (-7 - 38°C)
Valve Type and Pressure Class	D2/D3/D4/easy-Drive/e-body/ Vee-Ball, ASME CL300
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard or Cavitrol III Trim (depending on dP)

8. Intermediate Pressure Separator Oil Level Control:

Table 7-10. Intermediate Pressure Separator
Oil Level Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 300 psig (5 - 21 bar)
Pressure Drop	0 - 200 psi (0 - 14 bar)
Inlet Temp.	100 - 190°F (38 - 88°C)
Valve Type and Pressure Class	D2/D3/D4/easy-Drive/e-body/ Vee-Ball, ASME CL300
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard or Cavitrol III Trim (depending on dP)

9. Low Pressure Separator Water Level Control:

Table 7-11. Low Pressure Separator Water Level Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 100 psig (1 - 7 bar)
Pressure Drop	0 - 80 psi (0 - 6 bar)
Inlet Temp.	20 - 100°F (-7 - 38°C)
Valve Type and Pressure Class	D2/D3/D4/easy-Drive/e-body, ASME CL150
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

10. Low Pressure Separator Oil Level Control:

Table 7-12. Low Pressure Separator Oil Level Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 100 psig (1 - 7 bar)
Pressure Drop	0 - 80 psi (0 - 6 bar)
Inlet Temp.	100 - 190°F (38 - 88°C)
Valve Type and Pressure Class	D2/D3/D4/easy-Drive/e-body, ASME CL150
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

Separator Vent to Flare

This valve is a high pressure vent to flare header valve that is operated under emergency conditions. If the pressure in the separator increases above the set point, it's relieved to safeguard the separator. These valves are subjected to very high pressure drops, resulting in high levels of aerodynamic noise. Globe style valves with attenuating trims are commonly required to mitigate noise and potential vibration.

11. High Pressure Separator Vent to Flare:

Table 7-13. High Pressure Separator Vent to Flare Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 93 bar)
Pressure Drop	150 - 1,100 psi (10 - 76 bar)
Inlet Temp.	140 - 190°F (60 - 88°C)
Valve Type and Pressure Class	E-body, ASME CL300/600
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class V
Trim Type	Standard, Whisper Trim I, Whisper Trim III

12. Intermediate Pressure Separator Vent to Flare:

Table 7-14. Intermediate Pressure Separator Vent to Flare Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 300 psig (5 - 21 bar)
Pressure Drop	0 - 200 psi (0 - 14 bar)
Inlet Temp.	150 - 190°F (66 - 88°C)
Valve Type and Pressure Class	D4/easy-Drive/e-body/Vee-Ball, ASME CL300
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class IV
Trim Type	Standard, Whisper Trim I, Whisper Trim III

13. Low Pressure Separator Vent to Flare:

Table 7-15. Low Pressure Separator Vent to Flare Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 100 psig (1 - 7 bar)
Pressure Drop	0 - 80 psi (0 - 6 bar)
Inlet Temp.	150 - 190°F (66 - 88°C)
Valve Type and Pressure Class	D4/easy-Drive/e-body, ASME CL150
Valve Material and Trim Material	WCC with Standard (NACE)
Shutoff Requirement	ANSI Class V
Trim Type	Standard, Whisper Trim I, Whisper Trim III

Gas Compression

Compressor applications in the oil and gas industry can vary substantially depending on process location, wellhead pressures, gas properties (specific gravity), gas quality (wet or dry), temperature and vibration. Please consider that depending on the inlet and discharge pressures, a single compressor station can contain anywhere from one to three stages of compression. We will focus solely on single stage systems for the purposes of this review.

Proper sizing and selection of these four control valves is essential for allowing the compressor skid to operate as efficiently as possible. The next section will contain a review of the typical process conditions and valves used in the above applications.

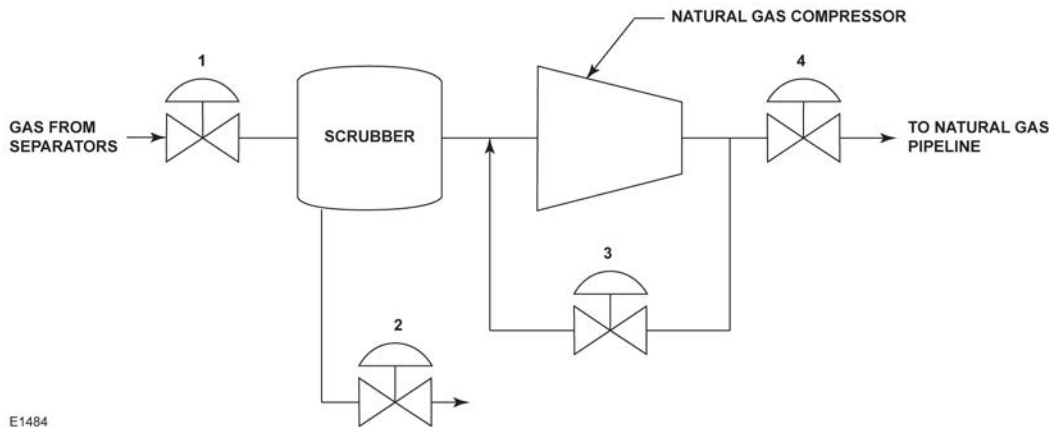


Figure 7-7. Compressor System



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Figure 7-8. 657 easy-e EZ Low Angle NPS 2 CL150 67AFR DVC6010

are between 50% open and 70% open. This is done to ensure a minimum pressure drop across the valve once upstream and downstream pressures equalize. This minimum pressure drop is desired when the pressures equalize because it takes more power to draw gas through a restrictive valve opening, which is an inefficient use of the available compressor Hp. The less energy that is required to move the gas through the compressor, the more likely the compressor will be running at the maximum Hp with best compression and fuel efficiency. Regardless of the number of stages of compression required, there is always only one suction control valve located at the inlet of the first stage scrubber. The pressure drop taken across this valve depends on the field pressure and optimal operating pressure of the compression skid.

Table 7-16. Compression Suction Throttle Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 600 psig (1 - 41 bar)
Pressure Drop	0 - 300 psi (0 - 21 bar)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	e-body/Vee-Ball, ASME CL150/300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

1. Compression Suction Throttle Control:

This valve is located on the inlet of the first stage scrubber and needs to be sized based on depleting field pressure over time. The purpose of this valve is to maintain the flow at which the compressor operates the most efficiently. In a majority of applications, the valve is sized so that under normal operating conditions, it never operates above 85% open and below 15% open. It is initially sized so that the normal operating conditions

2. Compression Suction Scrubber Level

Control: The compressor scrubber system is used to remove the unwanted particulates from the gas. The pure, dry gas leaves the top of the scrubber toward the compressor, protecting the compressor from damage caused by condensate impurities present in the separated gas stream. The purpose of the scrubber level control valve is to regulate the level of the hydrocarbon / water mixture. The level control valve is typically a dump valve that empties the water at the bottom of the scrubber. This valve is tied to a level controller that senses the water level in the vessel.

Table 7-17. Compression Suction Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 600 psig (1 - 41 bar)
Pressure Drop	Up to 500 psi (35 bar)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	D-body/e-body/Vee-Ball, ASME CL150/300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

3. Compressor Anti-surge: The purpose of this valve is to prevent the compressor from shutting down when low suction pressure or high discharge pressure is experienced. When either of these conditions occur, the recycle valve opens up until the pressures normalize, allowing the compressors to run continuously, without being damaged. The recycle valve is typically on the outlet of the discharge before the discharge check valve. It can either be coming off of the cooler section or directly off the compressor cylinders. Depending on where it is located, temperatures can result in the need for an ASME CL900 rated valve. Due to the large pressure drops across this valve it typically requires a noise abatement trim.

Anti-surge valves, also known as recycle valves, must be able to respond quickly and accurately to changes in set point with minimal travel overshoot and must be able to provide throttling capability at various travel ranges. Trip systems associated with the valve assembly are configured to respond to a trip case by opening the valve to full travel in less than one second in most cases. Performance criteria for the compressor system drive the requirements associated with this control valve. Please reference Chapter 13 for additional information on compressor surge control applications.



Figure 7-9. 12x8 EW Antisurge Valve, 585C Size 130 Actuator, DVC6200 Instrument, and 2625 Boosters

Table 7-18. Compressor Anti-surge Control Valve

Parameter	Typical Value
Inlet Pressure	100 - 1800 psig (7 - 124 bar)
Pressure Drop	Up to 1380 psi (95 bar)
Inlet Temp.	70 - 150°F (21 - 66°C)
Valve Type and Pressure Class	e-body/FB/HP, ASME CL150/300/600/900
Valve Material and Trim Material	WCC/316SST with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper Trim III or WhisperFlo Trim

4. Compressor Export Control: This valve is common to a compressor system that is directly exporting to a metering station. This valve controls the gas export flow of gas that is being compressed. This valve may be responsible for export of multiple initial compression sites. If this valve is not operating, there is no output to the pipeline system. The export valve is typically a high capacity construction to account for the large flow rates present.

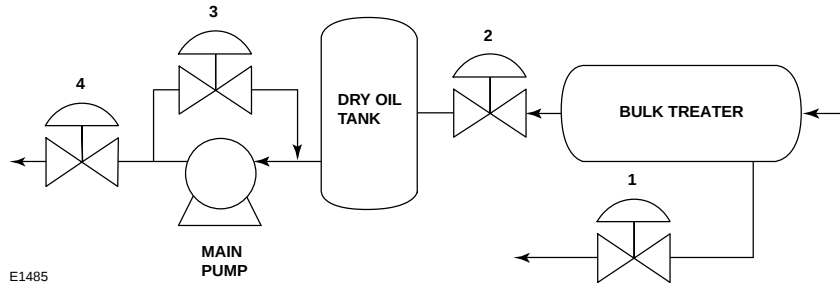


Figure 7-10. Oil Treatment System

Table 7-19. Compressor Export Control Valve

Parameter	Typical Value
Inlet Pressure	900 - 1700 psig (62 - 117 bar)
Pressure Drop	Up to 400 psi (28 bar)
Inlet Temp.	70 - 150°F (21 - 66°C)
Valve Type and Pressure Class	V250/EH, ASME CL600/900
Valve Material and Trim Material	WCC/316SST with Standard/316SST
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

Table 7-20. Bulk Treater Produced Water Valve

Parameter	Typical Value
Inlet Pressure	50 - 350 psig (3 - 24 bar)
Outlet Pressure	25 - 300 psig (2 - 21 bar)
Flow Rate	8,000 - 70,000 bpd (50 - 465 m ³ /h)
Inlet Temp.	120 - 200°F (49 - 93°C)
Valve Type and Pressure Class	NPS 6 - 10 ET/EWT, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Oil Processing

The crude oil is dehydrated utilizing a bulk treater or electrostatic coalescers. The bulk treater further separates any water from the crude oil product. The coalescer subjects the crude oil stream to a high voltage electrostatic field, causing any water to coalesce into droplets, which then fall free from the oil. This process helps to remove any dissolved salts left in the stream.

Bulk Treater

1. Bulk Treater Produced Water: This valve controls the produced water level in the bulk treater and will experience relatively low pressure drop ratios, which can be handled by a globe valve. A ball valve may be used depending upon pressure recovery characteristics of the valve.

2. Bulk Treater Oil Out: This valve controls flow of oil out of the bulk treater. The oil will then flow into the dry oil storage tank to be pumped onshore. A globe valve is the most common solution for this application.

Table 7-21. Bulk Treater Oil Out Valve

Parameter	Typical Value
Inlet Pressure	50 - 350 psig (3 - 24 bar)
Outlet Pressure	40 - 340 psig (3 - 23 bar)
Flow Rate	10,000 - 150,000 bpd (65 - 995 m ³ /h)
Inlet Temp.	140 - 200°F (60 - 93°C)
Valve Type and Pressure Class	6 - 16 ET/EWT, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Cavitrol III Trim 1 stage or Equal Percentage

3. Dry Oil Pump Recirculation Valve: This valve recycles flow around the main discharge pump to prevent the pump from cavitating. It will experience high pressure drops and the potential for damaging cavitation. A globe valve with anti-cavitation trim is typically used.

Table 7-22. Dry Oil Pump Recirculation Valve

Parameter	Typical Value
Inlet Pressure	2,500 - 3,700 psig (172 - 255 bar)
Outlet Pressure	125 - 200 psig (9 - 14 bar)
Flow Rate	5,000 - 60,000 bpd (30 - 400 m ³ /h)
Inlet Temp.	120 - 180° F (49 - 82°C)
Valve Type and Pressure Class	NPS 2 - 4 HPT, ASME CL1500
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III Trim 3 or 4 stage

4. Crude Oil Discharge Valve: Here, the flow from the platform to the pipeline network is controlled. It will be delivered to the onshore pipeline and processing network.

Table 7-23. Crude Oil Discharge Valve

Parameter	Typical Value
Inlet Pressure	2,500 - 3,700 psig (172 - 255 bar)
Outlet Pressure	125 - 3,200 psig (9 - 221 bar)
Flow Rate	30,000 - 150,000 bpd (195 - 995 m ³ /h)
Inlet Temp.	120 - 180° F (49 - 82°C)
Valve Type and Pressure Class	NPS 4 - 14 HPT/EHT, ASME CL1500
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Electrostatic Coalescer

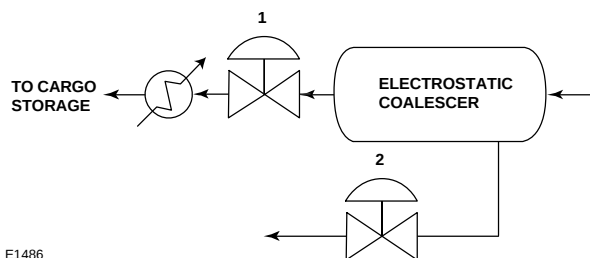


Figure 7-11. Electrostatic Coalescer Oil Treatment System

1. Electrostatic Treater Oil Out: Here, the flow of oil out of the electrostatic coalescer is controlled. This valve may be located before or after the crude pumps to storage. The conditions noted below are those with the valve placed after the crude pump. In situations where there is a valve located upstream of the pump, the conditions will be similar to those noted in the produced water level control valve. A globe valve is the most common solution for this application.

Table 7-24. Electrostatic Treater Oil Out Valve

Parameter	Typical Value
Inlet Pressure	100 - 125 psig (7 - 9 bar)
Outlet Pressure	30 - 35 psig (2 - 3 bar)
Flow Rate	5,000 - 35,000 ft ³ /hr (140 - 995 m ³ /h)
Inlet Temp.	120 - 160° F (49 - 93°C)
Valve Type and Pressure Class	NPS 6 - 8 ET, ASME CL150/300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Cavitrol III Trim 1 stage or Equal Percentage

2. Electrostatic Treater Produced Water: This valve controls the produced water level in the electrostatic coalescer, and will experience relatively low pressure drop ratios which can be handled by a globe valve. A ball valve may be used depending upon the pressure recovery characteristics of the valve.

Table 7-25. Electrostatic Treater Produced Water Valve

Parameter	Typical Value
Inlet Pressure	65 - 115 psig (4 - 8 bar)
Outlet Pressure	30 - 85 psig (2 - 6 bar)
Flow Rate	25,000 - 40,000 ft ³ /hr (705 - 1135 m ³ /h)
Inlet Temp.	120 - 250° F (49 - 121°C)
Valve Type and Pressure Class	NPS 3 - 4 ET/EWT, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Offshore Oil and Gas Production

Offshore oil and gas production, as defined in this chapter, is the production of oil and gas from reservoirs located off land. There are several offshore technologies used including:

- Fixed Leg Platforms (FLP)
- Tension Leg Platforms (TLP)
- Floating Production Storage and Offloading (FPSO) units
- Spars
- Semi-submersible units

Each type of production unit has unique characteristics that are described in detail below. The oil and gas production methods, however, are common to nearly all units. The subsequent sections will discuss the commonalities in processing and equipment in these units.

Offshore Production Units

Fixed Leg Platforms

Fixed Leg Platforms (FLP) consist of concrete and or steel legs that are anchored to the seabed that support a deck above sea level where production equipment and other facilities are located. They are some of the tallest structures in the world, producing from depths of up to 1,700 feet. The feasibility of these units depends on the depth of water, distance from the shoreline the platform will be built, and the length of time production will occur. Both oil and gas can be produced by these units,

with gas production being dependent on available distribution pipelines to shore. Fixed platforms are economically feasible for installation in water depths up to about 1,700 feet.

Tension Leg Platform

Tension leg platforms (TLP) are floating platforms tethered to the seabed in a manner that eliminates most vertical movement of the structure. TLPs are used in water depths up to about 6,000 feet. A TLP is a 4-column design and looks similar to a semi-submersible. Mini TLPs can also be used as utility, satellite, or early production platforms for larger deepwater discoveries.

Floating Production Storage and Offloading (FPSO) Units

FPSOs are essentially hull-based vessels that can be either constructed from converted crude oil carriers or from new builds. The mooring systems on modern FPSOs are built upon a geostationary turret mounted inside the hull that allows the vessel to rotate to head into prevailing weather. FPSOs typically produce only crude oil, as it is uneconomical to store and transport natural gas to land from most of these units. The natural gas produced, therefore, is either injected back into the reservoir, used for energy production on the vessel, or flared. The range of production capacity of an FPSO varies from 30,000 barrels per day to 250,000 barrels per day. The storage capacity of a typical FPSO varies between 1,000,000 and 2,000,000 barrels of crude oil, which allows for three to ten days of production before unloading is required. FPSOs can be used in depths up to 8,500 feet.



Spar

Spars are cylindrical, vertical hulls supporting a deck structure. In addition to production equipment and living quarters, spars can also feature drilling and/or workover facilities. Spars are moored to the seabed by means of a semi-taut mooring system. Spars are classified by their design and production capability.

There are three types of commonly used spar technologies. These include:

1. Conventional
2. Truss
3. Cell spars

The oil production rates of existing spars ranges from 30,000 b/d to 200,000 b/d. Unlike FPSOs, none of the spars in operation or under construction have storage capabilities. This limits their usage to areas where infrastructure already exists to bring produced oil and gas to shore. Spars can be used in depths up to 8,000 feet.

Semi-Submersible

Semi-submersible platforms are multi-legged floating structures containing a large deck. The legs are interconnected at the bottom with horizontal buoyant members called pontoons. Most units are typically square containing four columns with box or cylinder shaped pontoons connecting these columns. The range of production capacity of semi-submersibles varies from 30,000 barrels per day to 250,000 barrels per day. Semi-submersibles can be used in depths up to 8,000 feet.

Offshore Topsides

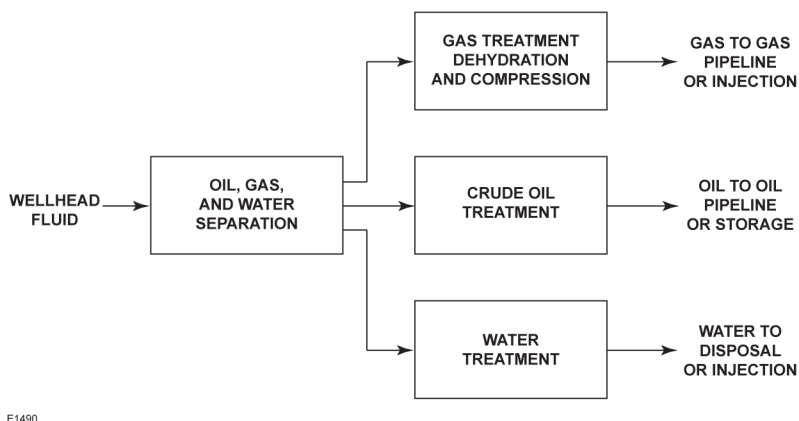
Each of the four technologies listed has an oil and/or gas production unit commonly called the “top-sides”. Upstream of the oil and gas processing equipment, each type of production unit types uses similar processing technologies, mainly for the initial separation of the oil, gas, and water in the fluid produced from the reservoir. Downstream equipment will depend on if both oil and gas are produced or just oil, and if water and/or gas injection methods are used to increase production from the reservoir. All major units that can be found in the four most common production unit types will be discussed in detail in the following sections.

Offshore Production Process

Figure 8-1 shows a general process flow diagram of the topsides of an offshore production facility.

Separation

When reservoir fluids arrive at the topsides they enter the separation train. There may be multiple trains depending upon the production capacity of the vessel. A slug catcher may also be needed to protect the separation system from variations in the production streams. Slugging is the partial separation of gas and liquid phases in a multiphase flow line. Slugging is characterized by sudden drops and surges in liquid and gas volumes. These variations can be highly problematic for topsides processing facilities. Large and rapid variations in flow can induce excessive gas flaring, reduction of operating capacity and can trigger plant shutdowns. In situations where frequent



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Figure 8-1. Process Flow Diagram of Topsides in Offshore Production

slugging problems are anticipated, a dedicated slug catcher may be installed.

After the fluids pass through the slug catcher, they will be exposed to a series of separation vessels referred to as the high and low pressure separation units. As they enter the high pressure separator, the momentum of the stream is dissipated allowing the liquids to fall free from the gas. At this point, the liquid phase is heated and undergoes additional separation to flash off the remaining gas and separate the crude oil from the produced water.

High Pressure Separation

The high pressure separation phase will be split between a test separator and a high pressure separator. In cases where a slug catcher is present, some initial separation has already occurred. It is not uncommon to have the high pressure separator sized large enough to act as both the separator and the slug catcher.

Low Pressure Separation

After the high pressure separation step, the oil product is heated and further separated in the low pressure separator. The off gas will be compressed in the low pressure compression system, if present, and move to the high pressure compression and dehydration system. The crude oil stream will be sent to the bulk oil treater, and sometimes to an electrostatic coalescer, to remove any additional water. The produced water will be sent to the free water knockout drum.

Oil Treatment

After completion of low pressure separation, the crude oil is dehydrated. Electrostatic coalescers expose the crude oil stream to a high voltage electrostatic field, causing any water to coalesce into droplets and fall free from the oil. This process also helps to remove any dissolved salts left in the stream. Once treated, the crude is routed to storage or a separate export system. Hydrocyclones use centrifugal force to remove oil droplets from oily water. Centrifugal force causes the lighter density droplets to move toward the low-pressure central core where axial reverse flow occurs. Clean water is removed through the downstream outlet. Flootation cells employ a process in which fine gas bubbles are generated and dispersed in water where they attach themselves to oil droplets

or solid particles. Gas bubbles then help to lift the oil to the water surface for collection.

Gas Compression, Treatment, and Injection

After separation, the gas produced in the vessels will be dried, compressed, potentially treated, and sent back into the formation or onshore for additional processing. If the gas is treated equipment is used to remove H_2S and CO_2 . At a minimum, this will consist of a high pressure compression unit and a dehydration package. Some gas exiting the dehydration unit will be used for fuel gas to power the vessel. On larger production vessels, there will likely be a low pressure compression system. If the vessel can be tied back to a pipeline network the gas may be compressed and sent onshore. In instances where the pipeline network is not available, the gas will be compressed and reinjected into the formation to be disposed of and to enhance oil recovery.

Low Pressure Compression

Not every floating technology will incorporate low pressure compression, and is more common on larger production vessels (150,000 b/d and greater). The low pressure compression system typically consists of a two-stage compressor used to boost the gas pressure from the secondary separators for additional compression in the high pressure compression system. If there are multiple separation trains, there will likely be multiple compression trains. After compression, the gas can be exported for additional use. Some of the gas may be injected for secondary oil recovery or involved in gas lift for tertiary oil recovery, both to improve the flow of fluids from the well to the vessel.

In some installations, there may not be a low pressure compression system though a vapor recovery system may be present. This system is designed to capture vapors off the free water knockout drum and bulk treater among a number of other vessels. These off-gasses are compressed and sent to the high pressure compression system, potentially taking the place of a low pressure compression system.

High Pressure Compression

The gas from low pressure compression, if present, combines with the gas from the test and high pressure separator prior to high pressure compression. At this point, the gas is compressed to be used for gas lift, gas injection or sent to the

pipeline network for additional processing onshore. At a minimum, the high pressure compression system will consist of two 50% capacity three or four-stage compression trains. Units operating in more shallow waters will likely utilize a three-stage compressor train while units operating in deeper water will utilize additional staging. On larger production units, there may be up to three high pressure compression trains.

Midway through high pressure gas compression, the gas is routed to dehydration to remove any remaining water in the stream. The gas is dehydrated using conventional methods employing tri-ethylene glycol (TEG) as an absorption medium. This unit is typically located upstream of the final compression stages with a separate contactor for each compression train. Some gas will be removed at the outlet of the dehydrator, compressed, and used for fuel gas to power the vessel.

Gas Injection and Gas Lift

Similar to water injection, produced gas from the well may be reinjected to raise the reservoir pressure. This is done through low and high pressure compression onboard the vessel. Even without the need to maintain well pressure, the overwhelming majority of areas in the world now limit the amount of gas flaring that can occur. It is often less costly to reinject the gas rather than to install a pipeline to transport the gas from the vessel. Nearly every FPSO will have gas compression systems specifically used for gas injection. Those that do not utilize gas injection will still have compression systems for transporting gas off the vessel. Most existing fixed and tension leg platforms, semi-submersibles, and spars are used for both oil and gas production, with both components being sent onshore for further processing.

The produced gas can be used to improve product flow up the well bore to the surface. This is referred to as gas lift. In these applications, the produced gas is compressed and routed into the outer annulus of the well bore. It enters the wellstream through a series of gas inlets in the inner production conduit. This reduces the density and the hydrostatic head of the wellstream fluids, increasing recovery. Gas lift is used where reservoir pressure is relatively low and in deepwater developments where reservoir drive pressure is countered by high hydrostatic head.

Water Treatment and Water Injection

Water Treatment

The level of produced water treatment depends upon whether it is to be disposed overboard or re-injected into the reservoir. Water disposed overboard is subjected to additional cleaning versus water injected back into the formation. It must be cleaned to an acceptable oil-in-water specification, typically below 40 ppm. This is done with hydrocyclones or floatation cells. Hydrocyclones utilize centrifugal technology while floatation cells utilize microscopic bubbles of compressed air that are forced through the contaminate water. As the bubbles rise through the liquid, they carry oil and other contaminants with them to the surface for collection and removal. The valves used in this process will not be discussed in this chapter, but can range from NPS 1-14 globe, ball, or butterfly valves. The size and type of valves vary dramatically depending upon pressure and flow constraints.

Water Injection

Water injection is often used to ensure continued reservoir productivity. In typical applications, produced water is separated and cleaned on the topsides of the vessel and then injected into the lowest portion of the reservoir via separate injection wells. This raises the level of the oil, moving it toward the producing areas. The need for water injection increases over time as the reservoir becomes depleted. This method of oil recovery, known as secondary recovery, helps improve yield rates.

Other Systems and Applications

There are a number of other systems on board these floating technologies that have similar characteristics to the applications previously noted, or may or may not be present on the vessel. Some of the systems noted below may be present based upon the infrastructure and the reservoir characteristics. Valve application details are not covered under the scope of this sourcebook at this time.

Fuel Gas System

After dehydration, some of the gas is removed from the outlet stream to be compressed and used for fuel gas on the vessel. Fuel gas is used to power the vessel and for other utility purposes including firing of boilers used to generate steam for the aforementioned processes. Main applications associated with the fuel gas system are tied to the

fuel gas compression system. The fuel gas is typically compressed using a multi-train, two-stage compression system.

Chemical Injection

Chemical treatment is the traditional method of preventing the build up of hydrates and waxes as well as other deposits such as scale in the risers. Deploying chemical treatments is costly and with it comes certain environmental issues. Methanol and glycol systems are the most common chemicals used for injection cleaning.

Acid Gas Removal Unit

If there is a pipeline network to transport the gas onshore for additional processing and fractionation, there may be an acid gas removal unit on board the vessel. The acid removal units are typically amine treatment units that utilize a lean amine in a contactor to absorb the acid gases present in the flow stream. The rich amine is then removed from the bottom of the tower and the acid gases are flashed off to flare or for additional sulfur recovery. After regeneration of the amine, it is then passed through the contactor again and the cycle is complete. For more details on this process please see Chapter 9.

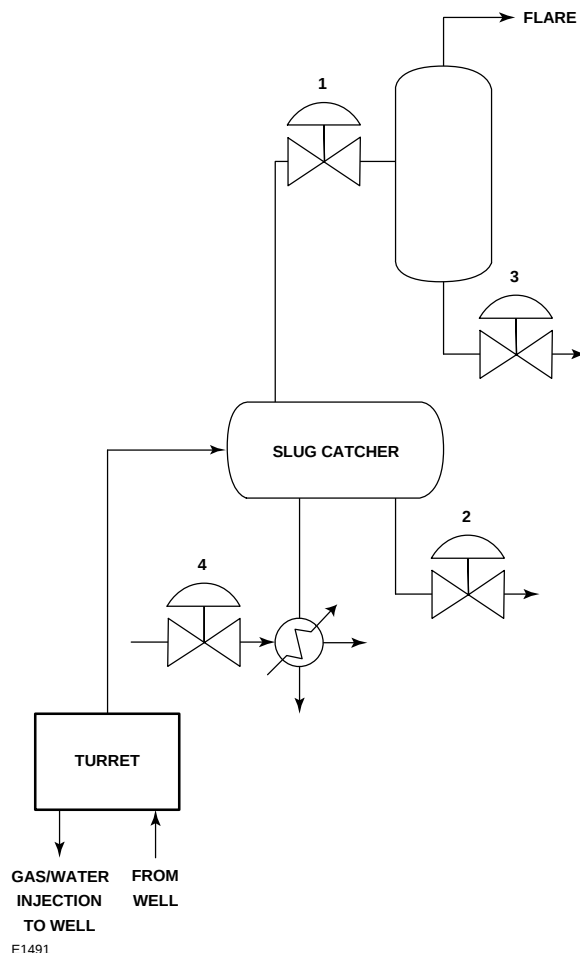


Figure 8-2. Common Slug Catcher Valves

Application Review

An application review of the control valve applications, process data, and recommended valve selection for the floating production units we discussed are broken out below. These processes include separation, oil treatment, gas treatment, water injection, gas injection, and gas lift.

Slug Catcher

In most cases slug catchers are found only in FPSO units. Figure 8-2 shows the common valves around the slug catcher.

1. Slug Catcher Gas to Flare: This valve controls the pressure in the slug catcher vessel by directing gas to the flare knockout drum. Depending upon the design of the unit, this valve may feed into the low pressure gas compression sec-

tion versus going to the flare knockout drum. As with most flare valves, noise generation is a concern. A globe valve with low noise trim is the most common solution.

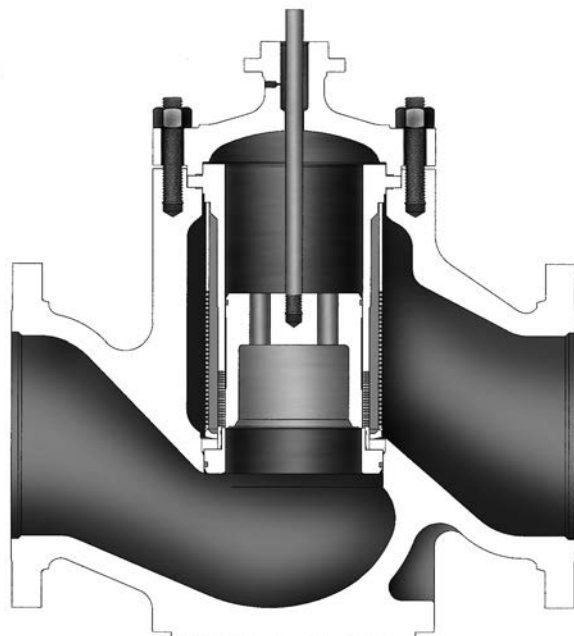


Figure 8-3. Large ET Valve with Whisper III Trim and D3 Cage and Baffle

Table 8-1. Spar Slug Catcher Gas to Flare Valve

Parameter	Typical Value
Inlet Pressure	135 - 250 psig (9 - 17 bar)
Outlet Pressure	50 - 85 psig (3 - 6 bar)
Flow Rate	60 - 120 MSCFD (65 - 135 m ³ /h)
Inlet Temp.	90 - 120° F (32 - 49° C)
Valve Type and Pressure Class	NPS 10 - 16 EWT, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper Trim III or WhisperFlo trim

2. Slug Catcher Level Control Valve: The liquid interface level in the slug catcher is controlled by this valve. Appropriate level control is necessary to prevent any drastic fluctuations in oil and gas levels going to the High Pressure Separator. This valve does not experience high pressure differentials, eliminating the need for severe service trim. A ball valve is the most common solution for this application.



Figure 8-4. Vee-Ball V150 NPS 3 with 2052 Size 1 Actuator and DVC6200

Table 8-2. Spar Slug Catcher Level Control Valve

Parameter	Typical Value
Inlet Pressure	135 - 250 psig (9 - 17 bar)
Outlet Pressure	120 - 225 psig (8 - 16 bar)
Flow Rate	35,000 - 65,000 ft ³ /h (990 - 1840 m ³ /h)
Inlet Temp.	90 - 140° F (32 - 60° C)
Valve Type and Pressure Class	NPS 10 - 16 Vee-Ball V150, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. HP Flare Scrubber: This valve controls the hydrocarbon/water stream after the flare gas has been scrubbed to remove some undesirable constituents. A globe valve is most commonly used in this application, but a ball valve would be an acceptable solution.

Table 8-3. Spar HP Flare Scrubber Valve

Parameter	Typical Value
Inlet Pressure	50 - 85 psig (3 - 7 bar)
Outlet Pressure	3 - 6 psig (1 bar)
Flow Rate	3,000 - 6,000 ft ³ /h (85 - 170 m ³ /h)
Inlet Temp.	90 - 140° F (32 - 60° C)
Valve Type and Pressure Class	NPS 3 Vee-Ball V150, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. Slug Catcher to Test Separator Heating Medium Control Valve: Here, the heating fluid used to warm the fluids to improve separation is controlled. This heating medium can be condensate or

the final oil product being cooled before going to storage. A butterfly valve is most commonly applied.



W9498

Figure 8-5. 8580 Rotary Valve with 2052 Actuator and DVC6000

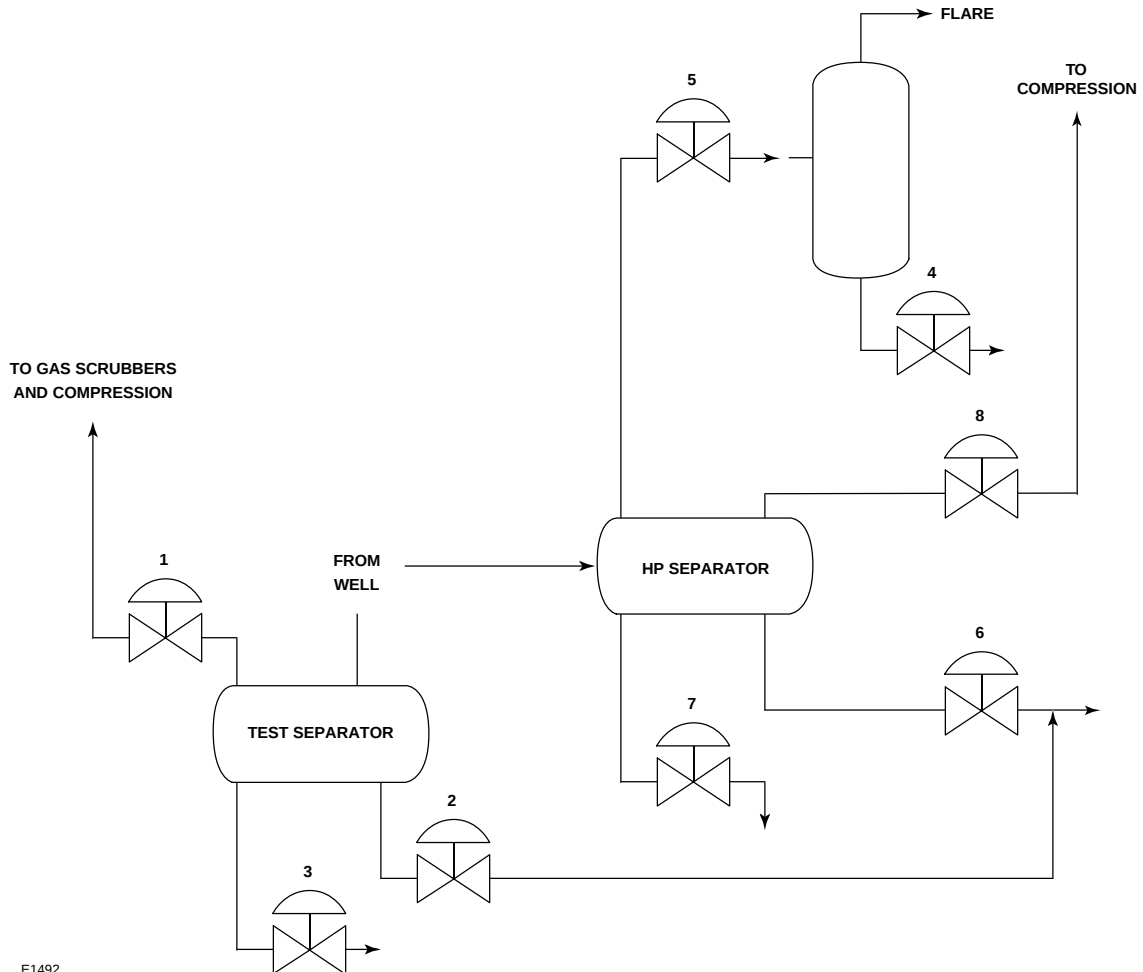
Table 8-4. Spar Slug Catcher to Test Separator Heating Medium Control Valve

Parameter	Typical Value
Inlet Pressure	120 - 150 psig (8 - 10 bar)
Outlet Pressure	100 - 120 psig (7 - 8 bar)
Flow Rate	8,000 - 12,000 ft ³ /hr (225 - 340 m ³ /h)
Inlet Temp.	225 - 275°F (107 - 135°C)
Valve Type and Pressure Class	NPS 6 - 10 8580 rotary valve, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Separation

High Pressure Separation

1. Test Separator Gas Outlet Pressure Control: This valve controls the pressure in the test



E1492

Figure 8-6. High Pressure Separation Process Diagram

separator and directs the gas to the high pressure compression section. Depending upon the design of the compression system, this valve may see relatively high pressure drops or minimal pressure drops. In applications with high pressure drops, this may be due to a lack of a low pressure compression system. When present, the low pressure gas compression system will boost the gas pressure eliminating the need for low pressures at the inlet to the high pressure compression system. In applications with low pressure drops, it is likely that there is a low pressure compression system.

Table 8-5. Test Separator Gas Outlet Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 93 bar)
Outlet Pressure	275 - 1,250 psig (19 - 86 bar)
Flow Rate	8 - 35 MSCFD (8 - 40 m ³ /h)
Inlet Temp.	150 - 190°F (66 - 88°C)
Valve Type and Pressure Class	NPS 4 - 8 EWT, ASME CL150/300/600
Valve Material and Trim Material	WCC/316 SST/Duplex SST with Standard/316 SST/Duplex SST (depending on gas quality)
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. Test Separator Oil Interface Level Control Valve: Here, the oil interface level in the test separator is controlled. Appropriate level control is necessary for proper separation of the gas, oil and water. This valve does not experience high pressure differential, eliminating the need for severe service trim. A ball valve is the most common solution for this application.

Table 8-6. Test Separator Oil Interface Level Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 93 bar)
Outlet Pressure	250 - 400 psig (17 - 28 bar)
Flow Rate	10,000 - 80,000 bpd (65 - 530 m ³ /h)
Inlet Temp.	120 - 190°F (49 - 88°C)
Valve Type and Pressure Class	NPS 2 - 4 ET/Vee-Ball V150/V200/V300, ASME CL150/300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. Test Separator Produced Water Interface Level Control Valve: This valve controls the produced water interface level in the test separator. Appropriate level control is necessary for proper separation of the gas, oil and water. This valve will experience moderately high pressure drops creating the potential for cavitation damage. Depending upon the pressure drop, Cavitrol III trim may be necessary.



Figure 8-7. Cavitrol III Trim

Table 8-7. Test Separator Produced Water Interface Level Control Valve

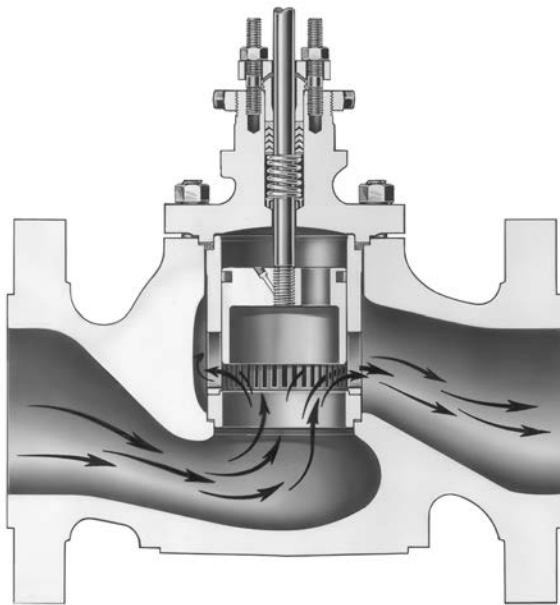
Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 93 bar)
Outlet Pressure	250 - 400 psig (17 - 28 bar)
Flow Rate	10,000 - 30,000 bpd (65 - 200 m ³ /h)
Inlet Temp.	140 - 190°F (60 - 88°C)
Valve Type and Pressure Class	NPS 2 - 6 ET, ASME CL150/300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage or Cavitrol III trim (depending on dP)

4. HP Flare Scrubber: The hydrocarbon/water stream is controlled here after the flare gas has been scrubbed to remove some of the undesirable constituents. A globe valve is most commonly used in this application, but a ball valve would be an acceptable solution.

Table 8-8. HP Flare Scrubber Valve

Parameter	Typical Value
Inlet Pressure	10 - 25 psig (1 - 2 bar)
Outlet Pressure	2 - 5 psig (1 bar)
Flow Rate	6,000 - 15,000 bpd (40 - 100 m ³ /h)
Inlet Temp.	100 - 200°F (38 - 93°C)
Valve Type and Pressure Class	NPS 2 - 4 ET/Vee-Ball V150/V300, ASME CL150/300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

5. HP Separator Vent to Flare: While it may not be present on every semi-submersible platform or spar, the HP separator vent to flare valve is intended to operate only under emergency situations. The pressure in the high pressure separator is controlled by the high pressure gas outlet pressure control valve. This valve will experience moderate pressure drops that can lead to requirements for noise attenuating trim.



W9038

Figure 8-8. EWT Metal Seat Valve with Whisper Trim I Cage

Table 8-9. HP Separator Vent to Flare Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 93 bar)
Outlet Pressure	150 - 250 psig (10 - 17 bar)
Flow Rate	10 - 20 MSCFD (10 - 25 m ³ /h)
Inlet Temp.	140 - 190°F (60 - 88°C)
Valve Type and Pressure Class	NPS 2 - 4 ET, ASME CL150/300/600
Valve Material and Trim Material	WCC/316 SST/Duplex SST with Standard/316 SST/Duplex SST (depending on gas quality)
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

6. HP Separator Oil Interface Level Control Valve: The oil interface level in the high pressure separator is controlled by this valve. The flow from this valve will go to the low pressure separator. Appropriate level control is necessary for proper separation of the gas, oil and water. This valve does not experience high pressure differentials, eliminating the need for severe service trim. A ball valve is ideal for this application.

Table 8-10. HP Separator Oil Interface Level Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 98 bar)
Outlet Pressure	290 - 350 psig (20 - 24 bar)
Flow Rate	50,000 - 210,000 bpd (330 - 1,400 m ³ /h)
Inlet Temp.	120 - 190°F (49 - 88°C)
Valve Type and Pressure Class	NPS 4 - 8 EWT, ASME CL150/300/600
Valve Material and Trim Material	WCC/316 SST/Duplex SST with Standard/316 SST/ Duplex SST
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

7. HP Separator Produced Water Interface Level Control Valve: This valve controls the produced water interface level in the HP separator. Appropriate level control is necessary for proper separation of the gas, oil, and water. This valve may experience moderate pressure drops and a globe valve may be utilized. In applications with low pressure drops, a butterfly valve is an acceptable option.

Table 8-11. HP Separator Produced Water Interface Level Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 93 bar)
Outlet Pressure	35 - 50 psig (3 - 4 bar)
Flow Rate	10,000 - 75,000 bpd (65 - 500 m ³ /h)
Inlet Temp.	120 - 190°F (49 - 88°C)
Valve Type and Pressure Class	NPS 2 - 6 ET, ASME CL150/300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage or Cavitol III 2-stage trim (depending on dP)

8. HP Separator Gas Outlet Pressure Control: This valve controls the pressure in the HP separator and directs the gas to the high pressure compression section. Depending upon the design of the compression system, this valve may see relatively high pressure drops. In applications with high pressure drops, this is likely due to a lack of a low pressure compression system. In these systems, a globe valve with noise attenuating trim is likely required. When present, the low pressure gas compression system will boost the gas pressure, eliminating the need for low pressures at the inlet to the high pressure compression system. In applications with low pressure drops, it is likely that there is a low pressure compression system. Globe valves are the most common solution, though butterfly valves are also acceptable in these situations.

Table 8-12. HP Separator Gas Outlet Pressure Control

Parameter	Typical Value
Inlet Pressure	300 - 1,350 psig (21 - 93 bar)
Outlet Pressure	150 - 300 psig (10 - 21 bar)
Flow Rate	25 - 80 MSCFD (25 - 90 m ³ /h)
Inlet Temp.	150 - 190°F (66 - 88°C)
Valve Type and Pressure Class	NPS 6 - 10 EWT, ASME CL150/300/600
Valve Material and Trim Material	WCC/316 SST/Duplex SST with Standard/316 SST/Duplex SST (depending on gas quality)
Shutoff Requirement	ANSI Class IV
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

Low Pressure Separation

1. Low Pressure (LP) Separator Vent to Flare: While it may not be present in every floating unit, the LP separator vent to flare valve is intended to operate only under emergency situations. The

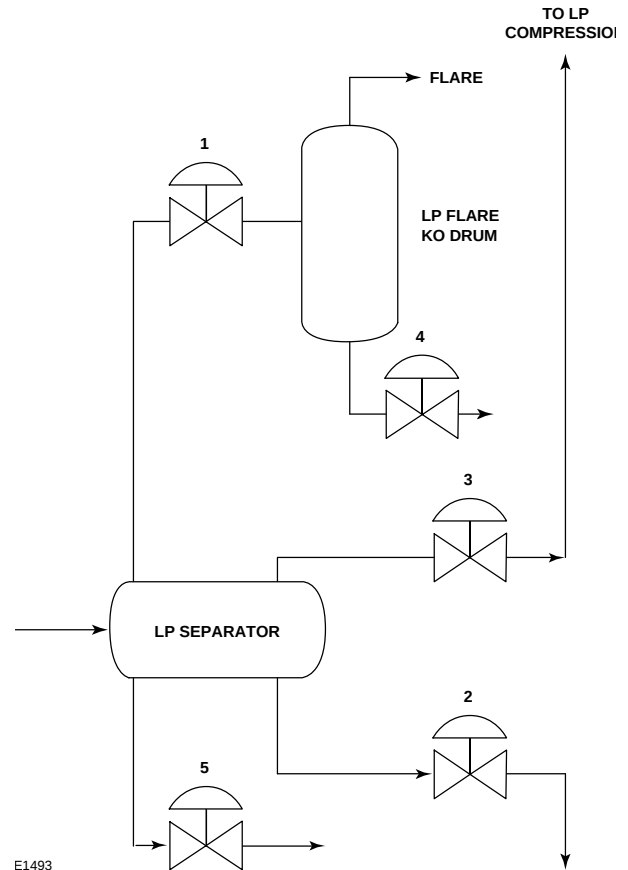


Figure 8-9. Low Pressure Separation Process Diagram

pressure in the low pressure separator is controlled by the low pressure separator gas outlet pressure control valve. This valve will experience moderate pressure drops that may lead to requirements for noise attenuating trim.

Table 8-13. Low Pressure (LP) Separator Vent to Flare Valve

Parameter	Typical Value
Inlet Pressure	45 - 250 psig (3 - 17 bar)
Outlet Pressure	20 - 25 psig (1 - 2 bar)
Flow Rate	10 - 45 MSCFD (10 - 50 m ³ /h)
Inlet Temp.	150 - 250°F (66 - 121°C)
Valve Type and Pressure Class	NPS 4 - 8 ET, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

2. LP Separator Oil Interface Level Control Valve: This valve controls the oil interface level in the low pressure separator. Appropriate level control is necessary for separation of the gas and oil. This valve does not experience high pressure dif-

ferentials, eliminating the need for severe service trim, although valves may be used because of the low pressure recovery factor.

Table 8-14. LP Separator Oil Interface Level Control Valve

Parameter	Typical Value
Inlet Pressure	40 - 250 psig (3 - 17 bar)
Outlet Pressure	5 - 20 psig (1 bar)
Flow Rate	50,000 - 180,000 bpd (330 - 1,200 m ³ /h)
Inlet Temp.	150 - 250°F (66 - 121°C)
Valve Type and Pressure Class	NPS 8 - 12 ET/EWT/Vee-Ball V150, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. LP Separator Gas Outlet Pressure Control: This valve controls the pressure in the low pressure separator and directs the gas to the low pressure compression section, if present or the high pressure compression system if no low pressure compression is present. High pressure drops are not common in this application and butterfly valves may be selected.

Table 8-15. LP Separator Gas Outlet Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	35 - 250 psig (3 - 17 bar)
Outlet Pressure	34 - 245 psig (3 - 17 bar)
Flow Rate	9 - 15 MSCFD (10 - 20 m ³ /h)
Inlet Temp.	150 - 250°F (66 - 121°C)
Valve Type and Pressure Class	NPS 6 - 10 EWT, ASME CL150
Valve Material and Trim Material	WCC/316 SST/Duplex SST with Standard/316 SST/Duplex SST (depending on gas quality)
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. LP Flare Scrubber: The hydrocarbon/water stream is controlled here after the flare gas has been scrubbed to remove some of the undesirable constituents. A globe valve is commonly used in this application, but a ball valve is also an acceptable solution.

Table 8-16. LP Flare Scrubber Valve

Parameter	Typical Value
Inlet Pressure	40 - 50 psig (3 - 4 bar)
Outlet Pressure	2 - 3 psig (1 bar)
Flow Rate	1,000 - 4,500 bpd (5 - 300 m ³ /h)
Inlet Temp.	100 - 200°F (38 - 93°C)
Valve Type and Pressure Class	NPS 1 - 3 ET/Vee-Ball V150/V300, ASME CL150/300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

5. LP Separator Produced Water Interface Level Control Valve: This valve controls the produced water interface level in the LP Separator. Appropriate level control is necessary for proper separation of the gas, oil and water. This valve may experience moderate pressure drops, which may lead to a globe valve selection. In applications with low pressure drops, a butterfly valve is an acceptable solution.

Table 8-17. LP Separator Produced Water Interface Level Control Valve

Parameter	Typical Value
Inlet Pressure	40 - 1,350 psig (3 - 93 bar)
Outlet Pressure	150 - 250 psig (10 - 17 bar)
Flow Rate	10 - 20 MSCFD (10 - 25 m ³ /h)
Inlet Temp.	140 - 190°F (60 - 88°C)
Valve Type and Pressure Class	NPS 3 - 6 ET, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Oil Treatment

Oil Treatment occurs after the low pressure stage. The crude oil is dehydrated utilizing a bulk treater or electrostatic coalescers. The bulk treater further separates any water from the crude oil product. The coalescer subjects the crude oil stream to a high voltage electrostatic field, causing any water to coalesce into droplets that then fall free from the oil. This process helps to remove any dissolved salts left in the stream.

Bulk Treater

1. Bulk Treater Produced Water: This valve controls the produced water level in the bulk treater and will experience relatively low pressure drop

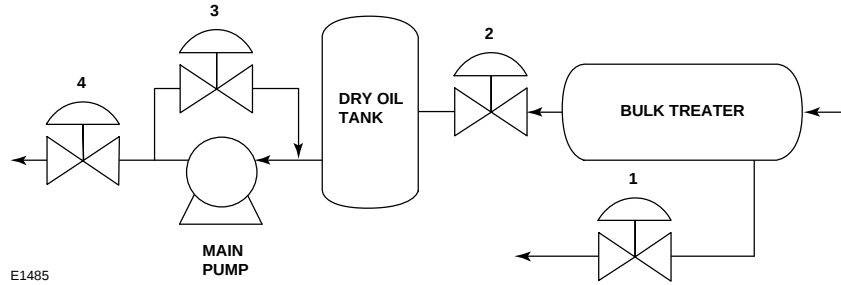


Figure 8-10. Oil Treatment System

ratios, which can be handled by a globe valve. A ball valve may be used depending upon pressure recovery characteristics of the valve.

Table 8-18. Bulk Treater Produced Water Valve

Parameter	Typical Value
Inlet Pressure	50 - 350 psig (3 - 24 bar)
Outlet Pressure	25 - 300 psig (2 - 21 bar)
Flow Rate	8,000 - 70,000 bpd (50 - 465 m ³ /h)
Inlet Temp.	120 - 200°F (49 - 93°C)
Valve Type and Pressure Class	NPS 6 - 10 ET/EWT, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. Bulk Treater Oil Out: This valve controls flow of oil out of the bulk treater. The oil will then flow into the dry oil storage tank to be pumped on-shore. A globe valve is the most common solution for this application.

Table 8-19. Bulk Treater Oil Out Valve

Parameter	Typical Value
Inlet Pressure	50 - 350 psig (3 - 24 bar)
Outlet Pressure	40 - 340 psig (3 - 24 bar)
Flow Rate	10,000 - 150,000 bpd (65 - 995 m ³ /h)
Inlet Temp.	140 - 200°F (60 - 93°C)
Valve Type and Pressure Class	NPS 6 - 16 ET/EWT, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Cavitrol III 1-stage trim or Equal Percentage

3. Dry Oil Pump Recirculation Valve: This valve recycles flow around the main discharge pump to prevent the pump from cavitating. It will experience high pressure drops and the potential for damaging cavitation. A globe valve with anti-cavitation trim is typically used.

Table 8-20. Dry Oil Pump Recirculation Valve

Parameter	Typical Value
Inlet Pressure	2,500 - 3,700 psig (172 - 255 bar)
Outlet Pressure	125 - 200 psig (9 - 14 bar)
Flow Rate	5,000 - 60,000 bpd (30 - 400 m ³ /h)
Inlet Temp.	120 - 180°F (49 - 82°C)
Valve Type and Pressure Class	NPS 2 - 4 HPT, ASME CL1500
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III 3- or 4-stage trim

4. Crude Oil Discharge Valve: Here, the flow from the platform to the pipeline network is controlled. It will be delivered to the onshore pipeline and processing network.

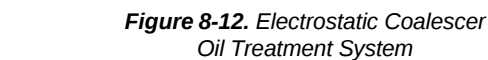


W9050

Figure 8-11. 667 HP Control Valve

Parameter	Typical Value
Inlet Pressure	2,500 - 3,700 psig (172 - 255 bar)
Outlet Pressure	125 - 3,200 psig (9 - 221 bar)
Flow Rate	30,000 - 150,000 bpd (200 - 995 m ³ /h)
Inlet Temp.	120 - 180°F (49 - 82°C)
Valve Type and Pressure Class	NPS 4 - 14 HPT/EHT, ASME CL1500
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

1. Electrostatic Treater Oil Out: Here, the flow of oil out of the electrostatic coalescer is controlled. This valve may be located before or after the crude pumps to storage. The conditions noted below are those with the valve placed after the crude pump. In situations where there is a valve located upstream of the pump, the conditions will be similar to those noted in the produced water level control valve. A globe valve is the most common solution for this application.



Parameter	Typical Value
Inlet Pressure	105 - 125 psig (7 - 9 bar)
Outlet Pressure	30 - 35 psig (2 - 3 bar)
Flow Rate	5,000 - 35,000 ft ³ /h (140 - 1,000 m ³ /h)
Inlet Temp.	120 - 160°F (49 - 71°C)
Valve Type and Pressure Class	NPS 6 - 8 ET, ASME CL150/300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Cavitrol III 1-stage trim or Equal Percentage

The diagram illustrates a distillation process. Feed enters a reboiler (1) at the bottom. The bottom product exits through valve 1. The vapor from the reboiler passes through a condenser (2) and is collected in a reflux drum. The liquid in the drum can be either returned to the condenser inlet through valve 3 or sent to a storage tank (3) through valve 4. The top product of the distillation column exits through valve 2.

trostatic coalescer, and will experience relatively low pressure drop ratios, which can be handled by a globe valve. A ball valve may be used depending upon the pressure recovery characteristics of the valve.

Parameter	Typical Value
Inlet Pressure	65 - 115 psig (4 - 8 bar)
Outlet Pressure	30 - 85 psig (2 - 6 bar)
Flow Rate	25,000 - 40,000 ft ³ /h (700 - 1,135 m ³ /h)
Inlet Temp.	120 - 250°F (49 - 121°C)
Valve Type and Pressure Class	NPS 3 - 4 ET/EWT, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

After separation takes place in each of the floating units, the produced gas streams will be compressed, dried, potentially treated, and sent back into the formation or onshore for additional processing.

Figure 8-13 shows the typical low pressure compression system and its related valves.

8-13

hydrocarbon/water mixture in the upstream scrubber is controlled. The upstream scrubber is used to separate liquids from the gas and clean the gas prior to compression. A small globe valve is the typical solution.

Table 8-24. Low Pressure Compression Suction Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	85 - 180 psig (6 - 12 bar)
Outlet Pressure	75 - 115 psig (5 - 8 bar)
Flow Rate	1,500 - 2,000 bpd (10 - 15 m ³ /h)
Inlet Temp.	150 - 180°F (66 - 82°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ/ET, ASME CL150
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. Low Pressure Compression Discharge Scrubber Level Control Valve: This valve controls the level of the hydrocarbon/water mixture in the upstream scrubber, which is used to separate liquids from the gas and clean the gas prior to compression. A small globe valve is the typical solution.

Table 8-25. Low Pressure Compression Discharge Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	250 - 325 psig (17 - 22 bar)
Outlet Pressure	150 - 175 psig (10 - 12 bar)
Flow Rate	3,000 - 4,000 bpd (20 - 25 m ³ /h)
Inlet Temp.	120 - 140°F (49 - 60°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ/ET, ASME CL300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. Low Pressure Compressor Anti-surge

Valve: This valve recycles discharge flow from the compressor to protect it from damage due to surge. Flow is recycled from the compressor discharge to the upstream scrubber/knockout drum. Depending upon the type of compressor and operator of the vessel, this may be a one or two valve solution. The typical solution is a one valve solution that protects the compressor from the effects of surge. When two valves are utilized, one will act as a control valve and the other will act as an on/off recycle valve. The latter approach minimizes the valve size while the former solution combines both functions into one valve, but increases the valve size. A globe valve with noise attenuating trim is the most common solution for the anti-surge/control solution. When a separate recycle valve is used, it may or may not have noise attenuating trim. The solution noted below assumes a single valve is utilized.

Table 8-26. Low Pressure Compressor Anti-surge Valve

Parameter	Typical Value
Inlet Pressure	100 - 325 psig (7 - 22 bar)
Outlet Pressure	60 - 120 psig (4 - 8 bar)
Flow Rate	220,000 - 290,000 lb/h (100,000 - 130,000 kg/h)
Inlet Temp.	130 - 150°F (54 - 66°C)
Valve Type and Pressure Class	NPS 4 - 6 ET, ASME CL300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper I Trim, Whisper III Trim, or WhisperFlo trim

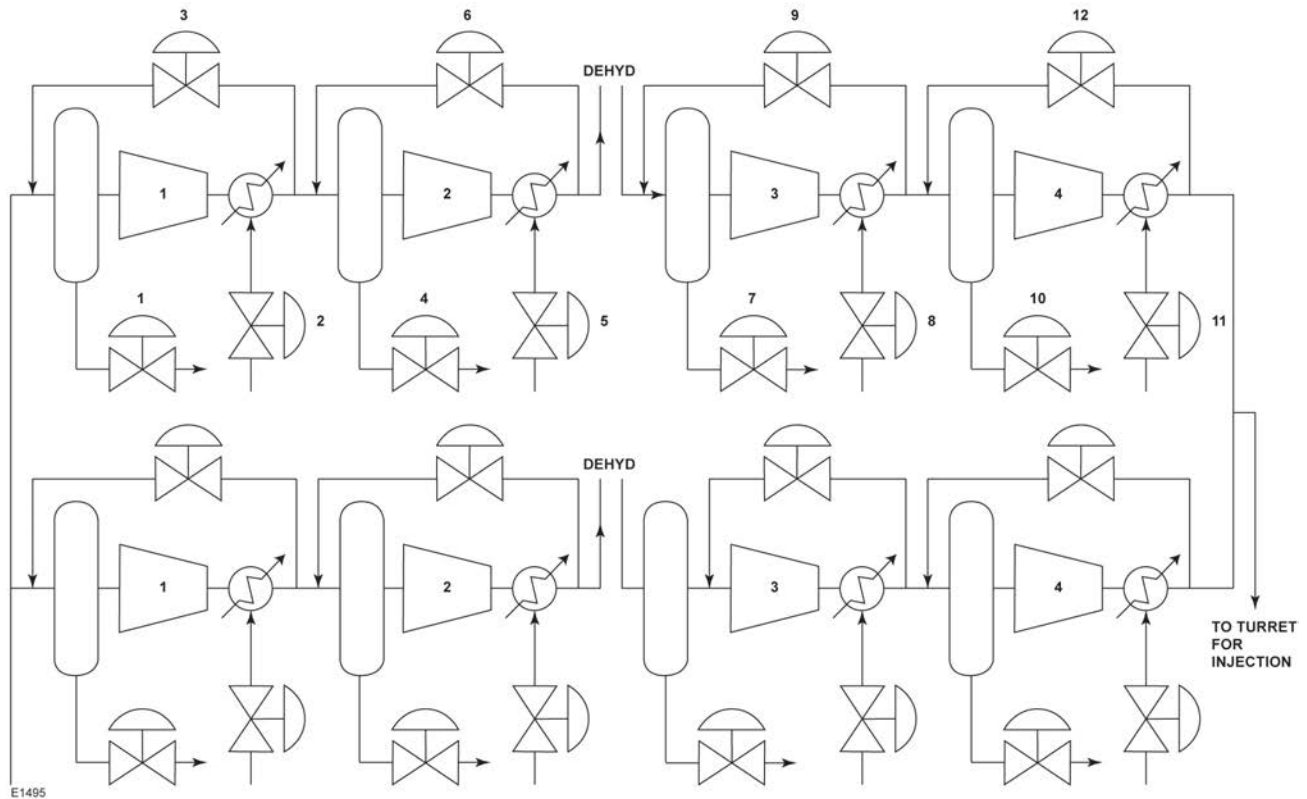


Figure 8-14. High Pressure Compression Train, Four stages

4. Low Pressure Discharge Cooling Control Valve: This valve controls the flow on cooling water to lower the temperature at the discharge of the compressor. The cooling fluid is typically seawater. Depending upon treatment of the seawater onboard, the materials of selection will vary. The most commonly used material is 316 Stainless Steel, but various grades of duplex are also used. A butterfly valve provides adequate control in this application.

Table 8-27. Low Pressure Discharge Cooling Control Valve

Parameter	Typical Value
Inlet Pressure	30 - 100 psig (2 - 7 bar)
Outlet Pressure	20 - 40 psig (1 - 3 bar)
Flow Rate	7,500 - 11,000 bpd (50 - 75 m ³ /h)
Inlet Temp.	110 - 130°F (43 - 54°C)
Valve Type and Pressure Class	NPS 3 - 4 8580 rotary valve, ASME CL150
Valve Material and Trim Material	WCC/316 SST/Duplex SST with Standard/316 SST/Duplex SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

High Pressure Compression

The gas from low pressure compression, if present, combines with the gas from the test and high pressure separator prior to high pressure compression. At this point, the gas is compressed to be used for gas lift, gas injection, or sent to the pipeline network for additional processing onshore. Figure 8-14 below shows the high pressure compression system with four stages. Refer to

Chapters 7 and 13 for additional information on compression systems.

1. First Stage Compression Suction Scrubber Level Control: This valve controls the level of hydrocarbon/water mixture in first stage scrubber, which is used to separate liquids from the gas and to clean the gas prior to compression. This need is met by using small globe or ball valves.

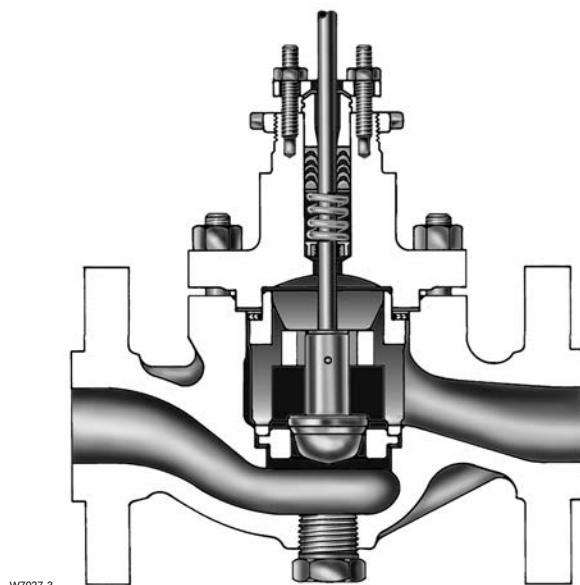


Figure 8-15. EZ Control Valve Sectional

Table 8-28. First Stage Compression Suction Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	130 - 310 psig (9 - 21 bar)
Outlet Pressure	15 - 130 psig (1 - 9 bar)
Flow Rate	50 - 80 gpm (10 - 20 m ³ /h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ/Vee-Ball V150/V300 ASME CL150/300
Valve Material and Trim Material	316 SST/317 SST Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. First Stage Discharge Cooler Temperature Control: This valve controls the cooling medium used to lower the discharge temperature of the gas exiting the compressor. The cooling medium is typically seawater, which will require varying materials depending on the chloride levels. Materi-

als ranging from carbon steel to 316 SST to aluminum bronze are the most common. Butterfly valves typically address the need of this application.

Table 8-29. First Stage Discharge Cooler Temperature Control Valve

Parameter	Typical Value
Inlet Pressure	35 - 65 psig (3 - 4 bar)
Outlet Pressure	25 - 50 psig (2 - 3 bar)
Flow Rate	12,000 - 25,000 ft ³ /h (335 - 710 m ³ /h)
Inlet Temp.	115 - 120°F (46 - 49°C)
Valve Type and Pressure Class	NPS 6 - 8 8560 rotary valve, ASME CL150
Valve Material and Trim Material	WCC, 316 SST, or Aluminum Bronze Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. First Stage Compressor Antisurge and/or Recycle: This valve recycles discharge flow from the first stage compressor to protect it from damage due to surge. Flow is recycled from the compressor discharge to the upstream scrubber/knockout drum. Depending on the type of compressor and operator of the vessel, this may be a one- or two-valve solution. The most common solution is a one-valve solution that protects the compressor from the effects of surge. When two valves are utilized, one will act as a control valve and the other will act as an on/off recycle valve. The latter approach minimizes the valve size while the former solution combines both functions into one valve, but increases the valve size. A globe valve with noise attenuating trim is the most common solution for the antisurge/control solution. When a separate recycle valve is used, it may or may not have noise attenuating trim. The two-valve arrangement is noted below.

Table 8-30. First Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	350 - 950 psig (24 - 66 bar)
Outlet Pressure	120 - 350 psig (8 - 24 bar)
Flow Rate	295,000 - 520,000 lb/h (135,000 - 235,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 6 - 10 ET/EWT, ASME CL300
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

Table 8-31. First Stage Compressor Recycle Valve

Parameter	Typical Value
Inlet Pressure	350 - 950 psig (24 - 66 bar)
Outlet Pressure	120 - 350 psig (8 - 24 bar)
Flow Rate	165,000 - 300,000 lb/h (75,000 - 135,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 6 - 10 ET/EWT or 8560 rotary valve, ASME CL300
Valve Material and Trim Material	WCC or 316SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

4. Second Stage Compression Suction Scrubber Level Control: This valve controls the level of hydrocarbon/water mixture in second stage scrubber, which is used to separate liquids from the gas and to clean the gas prior to compression. This need is met by using small globe or ball valves.

Table 8-32. Second Stage Compression Suction Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	350 - 900 psig (24 - 62 bar)
Outlet Pressure	15 - 130 psig (1 - 9 bar)
Flow Rate	50 - 80 gpm (10 - 20 m ³ /h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ/HPS, ASME CL300/600/900
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Cavitrol III 1- or 2-stage or Equal Percentage

5. Second Stage Discharge Cooler Temperature Control: This valve controls the cooling medium used to lower the discharge temperature of the gas exiting the compressor. The cooling medium is typically seawater, which will require varying materials depending on the chloride levels. Materials ranging from carbon steel to 316 SST to aluminum bronze are the most common. Butterfly valves typically address the need of this application.

Table 8-33. Second Stage Discharge Cooler Temperature Control Valve

Parameter	Typical Value
Inlet Pressure	35 - 65 psig (3 - 4 bar)
Outlet Pressure	25 - 50 psig (2 - 3 bar)
Flow Rate	10,000 - 14,000 ft ³ /h (280 - 400 m ³ /h)
Inlet Temp.	115 - 120°F (46 - 49°C)
Valve Type and Pressure Class	NPS 4 - 6 8560 rotary valve, ASME CL150
Valve Material and Trim Material	WCC, 316 SST or Aluminum Bronze Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

6. Second Stage Compressor Antisurge and/or Recycle Valve: This valve recycles discharge flow from the second stage compressor to protect it from damage due to surge. Flow is recycled from the compressor discharge to the upstream scrubber/knockout drum. Depending on the type of compressor and operator of the vessel, this may be a one- or two-valve solution. The most common solution is a one-valve solution that protects the compressor from the effects of surge. When two valves are utilized, one will act as a control valve and the other will act as an on/off recycle valve. The latter approach minimizes the valve down while the former solution combines both functions into one valve, but increases the valve size. A globe valve with noise attenuating trim is the most common solution for the anti-surge/control solution. When a separate recycle valve is used, it may or may not have noise attenuating trim. The two-valve arrangement is noted below.

Table 8-34. Second Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	950 - 2000 psig (66 - 138 bar)
Outlet Pressure	350 - 1100 psig (24 - 76 bar)
Flow Rate	220,000 - 450,000 lb/h (100,000 - 200,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 3 - 4 ET/HPT, ASME CL600/900/1500
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

Table 8-35. Second Stage Compressor Recycle Valve

Parameter	Typical Value
Inlet Pressure	950 - 2000 psig (66 - 138 bar)
Outlet Pressure	350 - 1100 psig (24 - 76 bar)
Flow Rate	110,000 - 220,000 lb/h (50,000 - 100,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 4 - 6 ET/EWT/HPS ASME CL600/900/1500
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I, Whisper Trim III, or WhisperFlo trim

7. Third Stage Compression Suction Scrubber Level Control: This valve controls the level of hydrocarbon/water mixture in third stage scrubber, which is used to separate liquids from the gas and to clean the gas prior to compression. This need is met by using small globe or ball valves.

Table 8-36. Third Stage Compression Suction Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	950 - 2100 psig (66 - 145 bar)
Outlet Pressure	15 - 1800 psig (1 - 124 bar)
Flow Rate	50 - 80 gpm (10 - 20 m ³ /h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 HPS, ASME CL1500/2500
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Cavitrol III 2-stage trim or Equal Percentage

8. Third Stage Discharge Cooler Temperature Control: This valve controls the cooling medium used to lower the discharge temperature of the gas exiting the compressor. The cooling medium is typically seawater, which will require varying materials depending on the chloride levels. Materials ranging from carbon steel to 316 SST to aluminum bronze are the most common. Butterfly valves typically address the need of this application.

Table 8-37. Third Stage Discharge Cooler Temperature Control Valve

Parameter	Typical Value
Inlet Pressure	35 - 65 psig (3 - 4 bar)
Outlet Pressure	25 - 50 psig (2 - 3 bar)
Flow Rate	10,000 - 14,000 ft ³ /h (280 - 400 m ³ /h)
Inlet Temp.	115 - 120°F (46 - 49°C)
Valve Type and Pressure Class	NPS 4 - 6 8560 rotary valve, ASME CL150
Valve Material and Trim Material	WCC, 316SST or Aluminum Bronze Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

9. Third Stage Compressor Antisurge and/or Recycle: This valve recycles discharge flow from the third stage compressor to protect it from damage due to surge. Flow is recycled from the compressor discharge to the upstream scrubber/knockout drum. Depending on the type of compressor and operator of the vessel, this may be a one- or two-valve solution. The most common solution is a one-valve solution that protects the compressor from the effects of surge. When two valves are utilized, one will act as a control valve and the other will act as an on/off recycle valve. The latter approach minimizes the valve size while the former solution combines both functions into one valve, but increases the valve size. A globe valve with noise attenuating trim is the most common solution for the antisurge/control solution. When a separate recycle valve is used, it may or may not have noise attenuating trim. The two-valve arrangement is noted below.

Table 8-38. Third Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	3,200 - 4,300 psig (221 - 296 bar)
Outlet Pressure	950 - 2,000 psig (66 - 138 bar)
Flow Rate	220,000 - 450,000 lb/h (100,000 - 200,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 3 - 4 HPT/EHT, ASME CL1500/2500
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim III

Table 8-39. Third Stage Compressor Recycle Valve

Parameter	Typical Value
Inlet Pressure	3,200 - 4,300 psig (221 - 296 bar)
Outlet Pressure	950 - 2,000 psig (66 - 138 bar)
Flow Rate	95,000 - 200,000 lb/h (45,000 - 90,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 3 - 4 HPT/EHT, ASME CL1500/2500
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim III

10. Fourth Stage Compression Suction Scrubber Level Control: This valve controls the level of hydrocarbon/water mixture in the fourth stage scrubber, which is used to separate liquids from the gas and to clean the gas prior to compression. This need is met by using small globe or ball valves.

Table 8-40. Fourth Stage Compression Suction Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	3,800 - 4,200 psig (262 - 290 bar)
Outlet Pressure	3,700 - 3,900 psig (255 - 269 bar)
Flow Rate	50 - 80 gpm (10 - 20 m ³ /h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 HPS, ASME CL2500
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

11. Fourth Stage Discharge Cooler Temperature Control: This valve controls the cooling medium used to lower the discharge temperature of the gas exiting the compressor. The cooling medium is typically seawater, which will require varying materials depending on the chloride levels. Materials ranging from carbon steel to 316 SST to aluminum bronze are the most common. Butterfly valves typically address the need of this application.

Table 8-41. Fourth Stage Discharge Cooler Temperature Control Valve

Parameter	Typical Value
Inlet Pressure	35 - 65 psig (3 - 4 bar)
Outlet Pressure	25 - 50 psig (2 - 3 bar)
Flow Rate	10,000 - 14,000 ft ³ /h (280 - 400 m ³ /h)
Inlet Temp.	115 - 120°F (46 - 49°C)
Valve Type and Pressure Class	NPS 4 - 6 8580 rotary valve, ASME CL150
Valve Material and Trim Material	WCC, 316 SST or Aluminum Bronze Body and Trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

12. Fourth Stage Compressor Antisurge and/or Recycle: This valve recycles discharge flow from the fourth stage compressor to protect it from damage due to surge. Flow is recycled from the compressor discharge to the upstream scrubber/knockout drum. Depending on the type of compressor and operator of the vessel, this may be a one- or two-valve solution. The most common solution is a one-valve solution that protects the compressor from the effects of surge. When two valves are utilized, one will act as a control valve and the other will act as an on/off recycle valve. The latter approach minimizes the valve size while the former solution combines both functions into one valve, but increases the valve size. A globe valve with noise attenuating trim is the most common solution for the antisurge/control solution. When a separate recycle valve is used, it may or may not have noise attenuating trim. The two-valve arrangement is noted below. .

Table 8-42. Fourth Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	5500 - 7000 psig (379 - 483 bar)
Outlet Pressure	3800 - 4500 psig (262 - 310 bar)
Flow Rate	220,000 - 450,000 lb/h (100,000 - 200,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 2 - 3 EHT, ASME CL2500 or API 10000
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim III

Table 8-43. Fourth Stage Compressor Recycle Valve

Parameter	Typical Value
Inlet Pressure	5500 - 7000 psig (379 - 483 bar)
Outlet Pressure	3800 - 4500 psig (262 - 310 bar)
Flow Rate	220,000 - 450,000 lb/h (100,000 - 200,000 kg/h)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	NPS 2 - 3 EHT, ASME CL2500 or API 10000
Valve Material and Trim Material	WCC or 316 SST Body and Trim
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim III

Gas Treatment

Gas Dehydration

Midway through high pressure gas compression, the gas is routed to dehydration to remove any remaining water in the stream. The gas is dehydrated using conventional methods employing tri-ethylene glycol (TEG). Please refer to Chapter 9 for additional details regarding gas treatment. Figure 8-16 shows the common valves associated with a TEG dehydration unit.

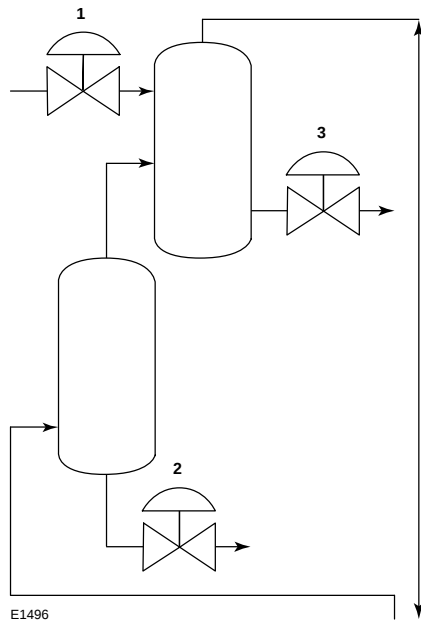


Figure 8-16. TEG Gas Dehydration Unit

1. Lean Glycol to Glycol Contactor Control Valve: The flow of lean glycol from the glycol re-generation unit to the contactor is controlled by the lean glycol to glycol contactor valve. The glycol will enter the top of the contactor and as it moves down the column will strip the water from the gas stream that is flowing up through the bottom of the column. This valve may not be present if a variable speed pump is used. A globe valve is the typical solution for this application.

Table 8-44. Lean Glycol to Glycol Contactor Control Valve

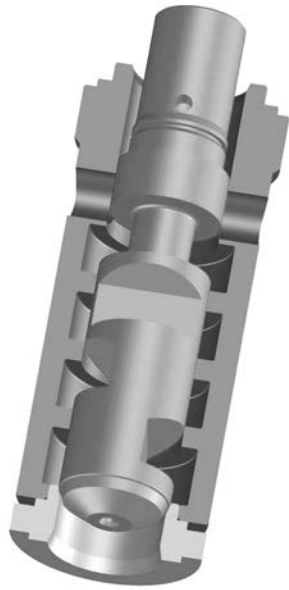
Parameter	Typical Value
Inlet Pressure	1,100 - 2,300 psig (76 - 159 bar)
Outlet Pressure	900 - 1,900 psig (62 - 131 bar)
Flow Rate	100 - 500 bpd (0 - 4 m ³ /h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 EZ/HPS, ASME CL600/900
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. Gas Dehydration Inlet Separator Level Control Valve: This valve controls the glycol-water interface level in the glycol contactor. This valve will experience a relatively high pressure drop requiring anti-cavitation trim. A globe valve with Cavitrol III 2-stage trim is typically used.

Table 8-45. Gas Dehydration Inlet Separator Level Control Valve

Parameter	Typical Value
Inlet Pressure	1,100 - 2,300 psig (76 - 159 bar)
Outlet Pressure	250 - 350 psig (17 - 24 bar)
Flow Rate	50 - 1,000 bpd (0 - 7 m ³ /h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ/ET/HPS/HPT, ASME CL300/600/900
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. Glycol Contactor Level Control Valve: The glycol-water interface level in the glycol contactor is controlled here. This valve will experience a relatively high pressure drop requiring anti-cavitation trim. A globe valve with Cavitrol III 2-stage trim is typically used.



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Figure 8-17. Notchflo DST Trim

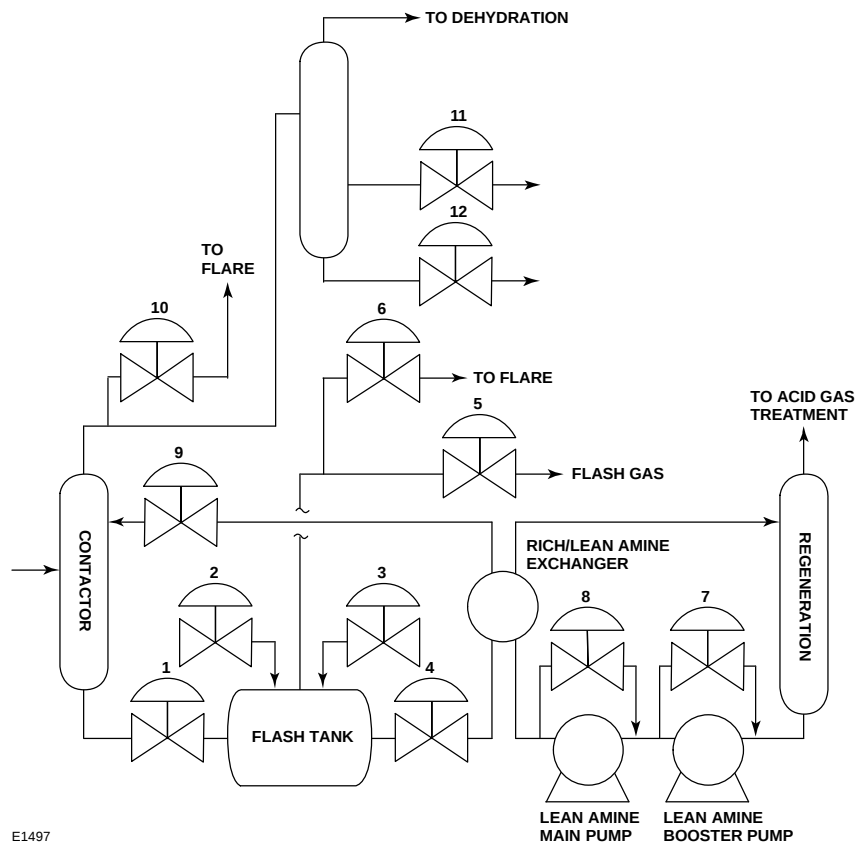
Table 8-46. Glycol Contactor Level Control Valve

Parameter	Typical Value
Inlet Pressure	1,100 - 1,600 psig (76 - 110 bar)
Outlet Pressure	30 - 200 psig (2 - 14 bar)
Flow Rate	100 - 500 gpm (20 - 115 m ³ /h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/HPS, ASME CL300/600/900
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III 2 stage trim or NotchFlo 4-stage trim

Gas Treatment

The first step in treatment of the natural gas is to remove the sour gas components. Amine absorbers are most commonly used for this process. Figure 8-18 below shows the layout of an amine treatment unit and the common control valves in the process.

1. Rich Amine Letdown Control Valve: Liquid level in the bottom of the contactor is controlled by this valve. Given the low downstream pressure needed to drive off the gases, this valve may ex-



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Figure 8-18. Amine Treatment Unit

perience severe outgassing effects. Therefore, the trim selection will vary depending upon the pressure drop and the amount of gas entrained in the solution. While the recommendation in the guide summary below is commonly seen, it is important that each application be reviewed in detail to ensure proper valve selection.

Table 8-47. Rich Amine Letdown Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1020 psig (21 - 70 bar)
Outlet Pressure	20 - 120 psig (1 - 8 bar)
Flow Rate	20,000 - 4,200,000 lb/h (9,000 - 1,905,000 kg/h)
Inlet Temp.	100 - 160°F (38 - 71°C)
Valve Type and Pressure Class	NPS 1 - 20 ET/EWT, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I, Whisper Trim III, or NotchFlo DST trim

2. Flash Drum Lean Solvent Control Valve: This valve controls the flow of lean solvent into the flash drum. The introduction of lean solvent is utilized to facilitate the removal of the acid gases entrained in the rich amine. A small globe valve is generally used.

Table 8-48. Flash Drum Lean Solvent Control Valve

Parameter	Typical Value
Inlet Pressure	40 - 165 psig (3 - 11 bar)
Outlet Pressure	30 - 135 psig (2 - 9 bar)
Flow Rate	3,000 - 55,000 lb/h (1,350 - 25,000 kg/h)
Inlet Temp.	100 - 120°F (38 - 49°C)
Valve Type and Pressure Class	NPS 1 - 3 ET/EZ, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

3. Flash Drum Water Control Valve: Here, the flow of water to the flash drum is controlled. This helps to drive off the acid gases entrained in the rich amine. A small globe valve may be used in this application.

Table 8-49. Flash Drum Water Control Valve

Parameter	Typical Value
Inlet Pressure	40 - 165 psig (3 - 11 bar)
Outlet Pressure	30 - 135 psig (2 - 9 bar)
Flow Rate	500 - 12,000 lb/h (225 - 5,500 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. Flash Drum Level Control Valve: The liquid level in the flash drum is controlled here. Similar to the rich amine letdown valve, this valve may experience varying degrees of outgassing. Therefore, it is necessary that each application is appropriately reviewed to determine the proper body and trim selection.

Table 8-50. Flash Drum Level Control Valve

Parameter	Typical Value
Inlet Pressure	40 - 165 psig (3 - 11 bar)
Outlet Pressure	30 - 135 psig (2 - 9 bar)
Flow Rate	500 - 12,000 lb/h (225 - 5,500 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

5. Flash Drum Pressure Control Valve: This valve controls pressure in the flash drum, which is critical to driving off the acid gases entrained in the rich amine. The sour gases driven off at this point may be subjected to additional treatment. A globe valve with standard trim is commonly used here.

Table 8-51. Flash Drum Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	30 - 105 psig (2 - 7 bar)
Outlet Pressure	20 - 90 psig (1 - 6 bar)
Flow Rate	500 - 11,000 lb/h (225 - 5,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 6 ET, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

6. Flash Gas to Flare Control Valve: Flash gas to the flare header is controlled here in the event of an upset in the process. This valve will normally remain closed during operation and can experience relatively high pressure drops that may lead to high noise and vibration if not properly attenuated. A globe valve with Whisper Trim may be used in this application.

Table 8-52. Flash Gas to Flare Control Valve

Parameter	Typical Value
Inlet Pressure	30 - 105 psig (2 - 7 bar)
Outlet Pressure	5 - 15 psig (1 bar)
Flow Rate	500 - 11,000 lb/h (225 - 5,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/EWT, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Whisper Trim I or Whisper Trim III

7. Lean Amine Booster Pump Recirculation Control Valve: This valve bypasses flow around the lean amine booster pump to protect the pump from cavitation damage. Because of the high pressure drop across the valve, cavitation protection is required. A globe valve with Cavitrol III anti-cavitation trim can typically be found in this application.

Table 8-53. Lean Amine Booster Pump Recirculation Control Valve

Parameter	Typical Value
Inlet Pressure	150 - 225 psig (10 - 16 bar)
Outlet Pressure	40 - 60 psig (3 - 4 bar)
Flow Rate	20,000 - 650,000 lb/h (9,000 - 300,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/EWT, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

8. Lean Amine Main Pump Recirculation Control Valve: This valve bypasses flow around the main lean amine pump to protect the pump from cavitation damage. Because of the high pressure drop across the valve, cavitation protection is required. A globe valve with Cavitrol III anti-cavitation trim is commonly used.

Table 8-54. Lean Amine Main Pump Recirculation Control Valve

Parameter	Typical Value
Inlet Pressure	400 - 1,600 psig (28 - 110 bar)
Outlet Pressure	150 - 225 psig (10 - 16 bar)
Flow Rate	20,000 - 650,000 lb/h (9,000 - 300,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/EWT/HPT, ASME CL300/600/900
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

9. Lean Amine to Contactor Control Valve: Here, flow of lean amine to the top of the contactor is controlled. Proper flow control is critical to ensure the proper ratio of amine to gas arriving in the contactor. A globe valve is typically utilized in this application.

Table 8-55. Lean Amine to Contractor Control Valve

Parameter	Typical Value
Inlet Pressure	400 - 1,600 psig (28 - 110 bar)
Outlet Pressure	350 - 1,080 psig (24 - 74 bar)
Flow Rate	20,000 - 4,200,000 lb/h (9,000 - 1,900,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 20 ET/EWT, ASME CL300/600/900
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

10. Lean Gas to Flare Control Valve: This valve controls the flow of lean gas to the flare header in the event of an upset in the process. It will remain closed during normal operation and may experience relatively high pressure drops that can lead to high noise and vibration if not properly attenuated. A globe valve with Whisper trim may be used.

Table 8-56. Lean Gas to Flare Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,020 psig (21 - 70 bar)
Outlet Pressure	30 - 45 psig (2 - 3 bar)
Flow Rate	30,000 - 1,300,000 lb/h (13,000 - 590,000 kg/h)
Inlet Temp.	110 - 155°F (43 - 68°C)
Valve Type and Pressure Class	NPS 3 - 24 ET/EWT/FBT, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I or Whisper Trim III

11. Lean Gas Separator Level Control Valve: Because the gas leaving the contactors is generally saturated, a downstream separator is used to capture any carry over liquids (hydrocarbons and water) prior to dehydration. This valve is used to control the liquid level in the separator. A small globe valve is generally used.

Table 8-57. Lean Gas Separator Level Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,200 psig (21 - 83 bar)
Outlet Pressure	45 - 405 psig (3 - 28 bar)
Flow Rate	500 - 5,500 lb/h (225 - 2,500 kg/h)
Inlet Temp.	110 - 155°F (43 - 68°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/ES, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

12. Lean Gas Separator Sour Water Letdown Control Valve: Because the gas leaving the contactors is generally saturated, a downstream separator is used to capture any carry over liquids (hydrocarbons and water) prior to dehydration. This valve is used to control the liquid level in the separator. A small globe valve is typically used.

Table 8-58. Lean Gas Separator Sour Water Letdown Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1020 psig (21 - 70 bar)
Outlet Pressure	45 - 150 psig (3 - 10 bar)
Flow Rate	500 - 5,500 lb/h (225 - 2,500 kg/h)
Inlet Temp.	110 - 155°F (43 - 68°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/ES, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

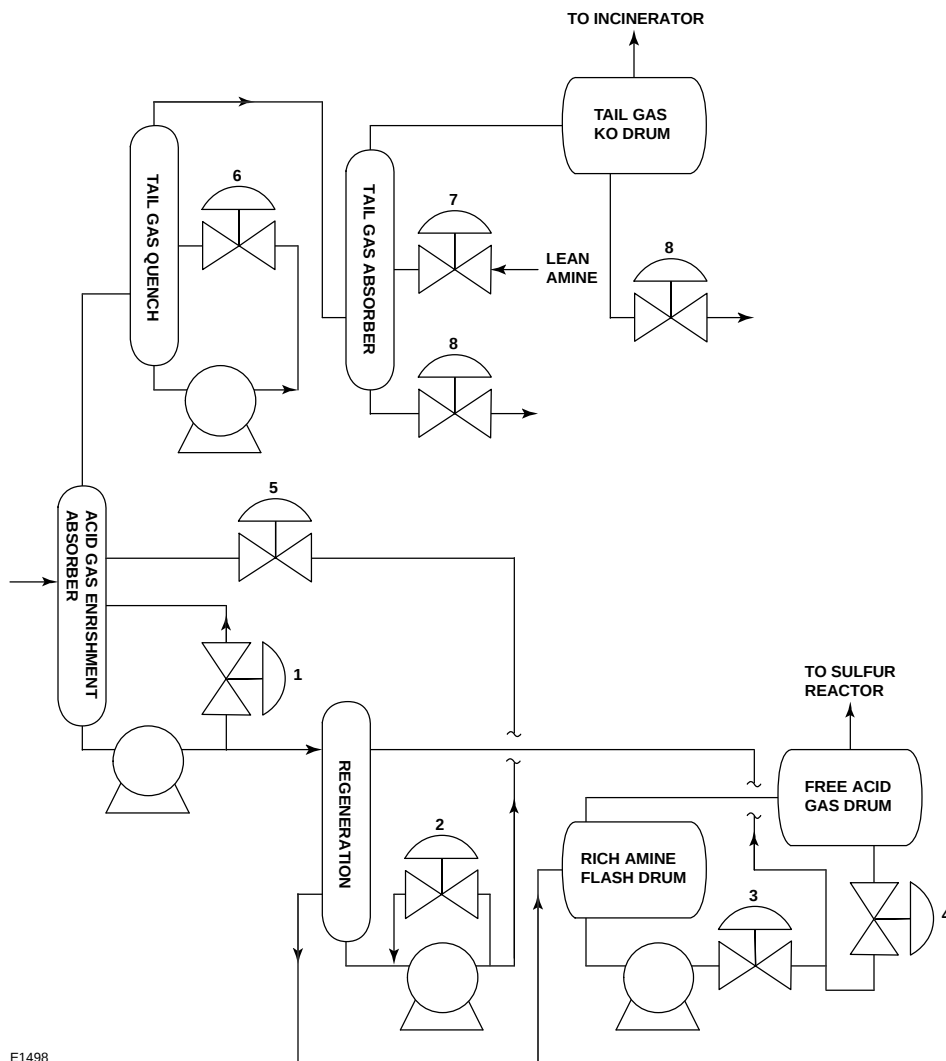
As previously noted, this process is extremely scalable and can be found in many gas treatment units of varying sizes.

The tail gas driven from the amine during regeneration must be further treated prior to sulfur recovery. The process is very similar to that previously discussed, but typically utilizes a different set of amine derivatives such as MDEA. Figure 8-19 shows the tail gas treatment process and the associated control valves.

1. Rich Amine Recirculation to Acid Gas Enrichment Control Valve: This valve is used to bypass flow around the rich amine pump to prevent the pump from the potential for cavitation. It may experience relatively high pressure drops, increasing the potential for the formation of damaging cavitation. To eliminate this potential, a globe valve with Cavitrol III trim may be used.

Table 8-59. Rich Amine Recirculation to Acid Gas Enrichment Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 135 psig (5 - 9 bar)
Outlet Pressure	20 - 30 psig (1 - 2 bar)
Flow Rate	20,000 - 1,000,000 lb/h (9,000 - 455,000 kg/h)
Inlet Temp.	100 - 140°F (38 - 60°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage



E1498

Figure 8-19. Tail Gas Treatment System

2. Regeneration Lean Amine Pump Recirculation Control Valve: This valve bypasses the lean amine from the bottom of the regeneration tower. Bypassing the flow around the pump prevents the pump from cavitating. This requires the valve to take a relatively high pressure drop, which can lead to the formation of damaging cavitation. This valve must be able to eliminate the formation of cavitation. A globe valve with anti-cavitation trim is generally used.

Table 8-60. Regeneration Lean Amine Pump Recirculation Control Valve

Parameter	Typical Value
Inlet Pressure	150 - 240 psig (10 - 17 bar)
Outlet Pressure	30 - 45 psig (2 - 3 bar)
Flow Rate	20,000 - 1,320,000 lb/h (9,000 - 600,000 kg/h)
Inlet Temp.	125 - 175°F (52 - 79°C)
Valve Type and Pressure Class	NPS 2 - 12 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

3. Rich Amine Pump Discharge to Regeneration Control Valve: Here, the flow of amine back to the regeneration tower is controlled here. Given the lower pressure drop, a globe valve with equal percentage trim may be utilized.

Table 8-61. Rich Amine Pump Discharge to Regeneration Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 105 psig (5 - 7 bar)
Outlet Pressure	60 - 75 psig (4 - 5 bar)
Flow Rate	5,000 - 135,000 lb/h (2,000 - 65,000 kg/h)
Inlet Temp.	95 - 125°F (35 - 52°C)
Valve Type and Pressure Class	NPS 1 - 4 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. Free Acid Gas Drum Level Control Valve: The level of liquid in the free acid gas drum is controlled by this valve. It will experience relatively low pressure drops and a globe valve is a commonly used solution.

Table 8-62. Free Acid Gas Drum Level Control Valve

Parameter	Typical Value
Inlet Pressure	90 - 105 psig (6 - 7 bar)
Outlet Pressure	75 - 85 psig (5 - 6 bar)
Flow Rate	5,000 - 50,000 lb/h (2,000 - 25,000 kg/h)
Inlet Temp.	95 - 125°F (35 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

5. Lean Amine Flow Control Valve: This valve controls the flow of lean amine to the acid gas enrichment absorber. Similar to other applications, this valve experiences relatively low pressure drops, but with the potential of relatively high flow rates. A globe valve is generally used in this application.

Table 8-63. Lean Amine Flow Control Valve

Parameter	Typical Value
Inlet Pressure	150 - 240 psig (10 - 17 bar)
Outlet Pressure	30 - 60 psig (2 - 4 bar)
Flow Rate	20,000 - 3,500,000 lb/h (9,000 - 1,600,000 kg/h)
Inlet Temp.	125 - 175°F (52 - 79°C)
Valve Type and Pressure Class	NPS 2 - 16 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage or Characterized Cavitrol III trim

6. Tail Gas Quench Water Control Valve: The gas leaving the acid gas enrichment absorber is subjected to a water quench prior to additional treatment. This valve controls the quench water flow to the quench tank. A globe valve is commonly used with the potential for anti-cavitation trim dependent upon the pressure drop.

Table 8-64. Tail Gas Quench Water Control Valve

Parameter	Typical Value
Inlet Pressure	50 - 140 psig (3 - 10 bar)
Outlet Pressure	30 - 45 psig (2 - 3 bar)
Flow Rate	50,000 - 1,750,000 lb/h (20,000 - 800,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 12 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

7. Lean Amine to Tail Gas Absorber Control Valve: This valve controls the flow of lean amine to the tail gas absorber in order to scrub the gas one last time prior to use as fuel or incineration. The valve and trim combination will depend upon the pressure drop, but a globe valve with linear or anti-cavitation trim is typically used.

Table 8-65. Lean Amine to Tail Gas Absorber Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 195 psig (5 - 14 bar)
Outlet Pressure	60 - 75 psig (4 - 5 bar)
Flow Rate	30,000 - 1,550,000 lb/h (13,000 - 705,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 3 - 16 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

8. Tail Gas Treater Semi-lean Amine Letdown Control Valve: Here, the level of amine in the tail gas absorber is controlled. There is potential for relatively light outgassing in this application depending upon the amount of gas entrained in the solution. A globe valve is generally used in this application.

Table 8-66. Tail Gas Treater Semi-lean Amine Letdown Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 195 psig (5 - 14 bar)
Outlet Pressure	65 - 160 psig (4 - 11 bar)
Flow Rate	30,000 - 1,550,000 lb/h (13,000 - 705,000 kg/h)
Inlet Temp.	65 - 160 psig (18 - 71 bar)
Valve Type and Pressure Class	NPS 2 - 16 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

9. Tail Gas Knockout Drum Level Control Valve: This valve controls the level of liquid in the tail gas knockout drum. A small globe valve may be used.

Table 8-67. Tail Gas Knockout Drum Level Control Valve

Parameter	Typical Value
Inlet Pressure	45 - 165 psig (3 - 11 bar)
Outlet Pressure	40 - 150 psig (3 - 10 bar)
Flow Rate	2,000 - 25,000 lb/h (900 - 12,000 kg/h)
Inlet Temp.	90 - 125°F (32 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Water Injection

Figure 8-20 below shows the most common valves associated with the water injection system. Each will be discussed in further detail below.

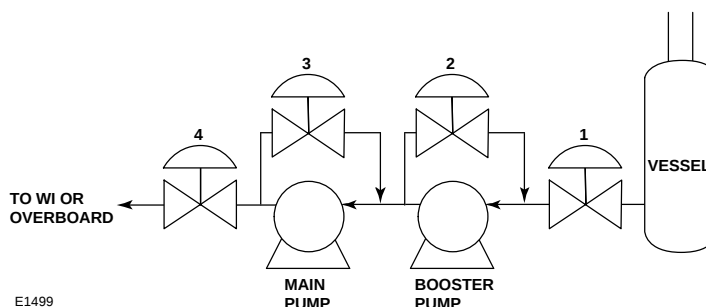


Figure 8-20. Water Injection System, FPSO Unit

These will be high pressure valves, some of which will require anti-cavitation trim due to high pressure drops.

1. Water Injection Surge Vessel Level Control Valve: This valve controls the level of produced water in the water injection surge vessel.

Table 8-68. Water Injection Surge Vessel Level Control Valve

Parameter	Typical Value
Inlet Pressure	85 - 100 psig (6 - 7 bar)
Outlet Pressure	75 - 85 psig (5 - 6 bar)
Flow Rate	20,000 - 35,000 ft ³ /hr (550 - 1,000 m ³ /h)
Inlet Temp.	80 - 100°F (27 - 38°C)
Valve Type and Pressure Class	NPS 6 - 8 ET, ASME CL150/300
Valve Material and Trim Material	316 SST/Duplex SST with 316 SST/Duplex SST
Shutoff Requirement	ANSI Class IV or V
Trim Type	Cavitrol III 1 stage trim or Equal Percentage

2. Booster Pump Recirculation Valve: Not every unit will have a booster pump. This is done in certain situations to minimize the size of the main injection pump. This valve will experience high pressure differentials requiring a globe valve with the appropriate level of anti-cavitation trim.

Table 8-69. Booster Pump Recirculation Valve

Parameter	Typical Value
Inlet Pressure	85 - 250 psig (6 - 17 bar)
Outlet Pressure	1 - 10 psig (1 bar)
Flow Rate	17,000 - 25,000 ft ³ /hr (480 - 710 m ³ /h)
Inlet Temp.	80 - 120°F (27 - 49°C)
Valve Type and Pressure Class	NPS 4 - 6 ET, ASME CL150
Valve Material and Trim Material	316 SST/Duplex SST with 316 SST/Duplex SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. Water Injection Pump Recirculation Valve: Some units will use produced water for injection purposes while others will use seawater. Regardless of the media, this valve will be exposed to extremely high pressure differentials, which will depend upon the reservoir characteristics. The flow will also vary depending upon the characteristic of the reservoir. Globe or angle valves with Cavitrol III trim, Cavitrol IV trim, or DST trim are typically required. It should be noted that the pressures below are based upon past experience. Higher pressures can be expected with deeper operating water depths.



W6787

Figure 8-21. DST Trim

Table 8-70. Water Injection Pump Recirculation Valve

Parameter	Typical Value
Inlet Pressure	2,000 - 8,000 psig (138 - 552 bar)
Outlet Pressure	10 - 150 psig (1 - 10 bar)
Flow Rate	10,000 - 30,000 ft ³ /hr (280 - 850 m ³ /h)
Inlet Temp.	80 - 120°F (27 - 49°C)
Valve Type and Pressure Class	NPS 3 - 6 EHT/EHAT, ASME CL2500 or API 10000
Valve Material and Trim Material	316 SST/Duplex SST with 316 SST/Duplex SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim, Cavitrol IV trim, or NotchFlo DST or DST trim

4. Water Injection Discharge Pressure Control Valve: Not all units will incorporate the use of a pressure discharge control valve. It is intended to control the pressure of the water injected into the reservoir. Depending upon the need, the pressures may vary to enhance oil recovery. NPS 4 - 12 high pressure globe or angle valve with Cavitrol trim or DST trim is the typical solution.



W9983-2

Figure 8-22. Cavitrol IV Trim

Table 8-71. Water Injection Discharge Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	2,000 - 8,000 psig (138 - 552 bar)
Outlet Pressure	Minimal (dependant on reservoir requirements)
Flow Rate	10,000 - 30,000 ft ³ /hr (280 - 850 m ³ /h)
Inlet Temp.	80 - 120° F (27 - 49° C)
Valve Type and Pressure Class	NPS 4 - 12 EHT/EHAT, ASME CL2500 or API 10000
Valve Material and Trim Material	316 SST/Duplex SST with 316 SST/Duplex SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim, Cavitrol IV trim, NotchFlo DST or DST trim

Natural Gas Treatment

Most natural gas contains contaminants that must be removed before it can be safely delivered to its intended source. Its pressures, BTU content, or water content can also cause operational problems with downstream units or pipeline deterioration and potential failure. Natural gas treatment plants are used to remove the contaminants and water and ensure proper pressures and BTU content.

Natural gas treatment facilities consist of a number of different units, but all will typically contain a receiving area, a treatment area, a unit to remove water from the treated natural gas, a sulfur recovery unit, and a discharge compression unit. Though not discussed further in this chapter, natural gas treatment units may also be combined with gas fractionation units used to separate natural gas liquids.

The capacity of a natural gas treatment facility varies in North America between 50 MMSCFD and 500 MMSCFD. Where large reserves of natural gas are located, like the Middle East, it is common to find facilities that can handle between 800 MMSCFD and 1 BSCFD.

Natural Gas Treatment Process

Figure 9-1 is a process flow diagram of a common natural gas treatment plant:

Inlet Separation

Depending upon plant design, an initial separator or slug catcher will be present at the inlet of the plant. The separator is designed to allow any condensate to fall out prior to further treatment. No matter the type, the upstream separator is critical to operation of the plant as it prevents the introduction of liquids in the downstream treatment process. A compressor may be utilized after initial separation to boost the gas pressure to the appropriate level for treatment. In most cases, however, the gas is compressed before arriving at the plant.

Gas Treatment

Gas treatment involves the reduction or elimination of acid gases in the flowstream, the most common of which are hydrogen sulfide (H_2S) and carbon dioxide (CO_2). Others include Nitrogen and Helium. It is necessary to remove these components as they can damage downstream piping and equipment, especially in the presence of water. If water is introduced into the system, weak acids can form and may corrode piping systems and treatment equipment.

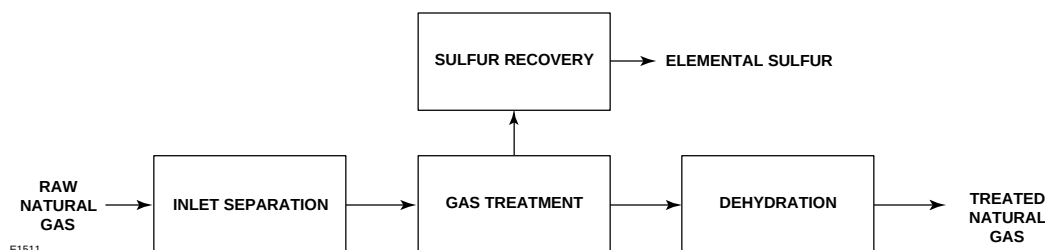


Figure 9-1. Natural Gas Treatment Process Flow Diagram



There are a number of different means of removing acid gases from the flow stream. Solvent absorption is typically utilized and involves a combination of both chemical and physical absorption methods. Other viable techniques include solid absorption, membrane, direct conversion, and cryogenic fractionation. Because it is more commonly used, this chapter will place focus on solvent absorption techniques utilizing amines.

Amines used in gas treatment include monoethanolamine (MEA), diethanolamine (DEA) and methyl-diethanolamine (MDEA). Each can be used to meet different natural gas quality specifications. For example, MEA is generally used when complete removal of H_2S and CO_2 is required. DEA is slightly less reactive than MEA, but can operate at higher acid gas loadings. MDEA can selectively remove H_2S to pipeline specifications, while not capturing all of the CO_2 .

In an amine absorber, called a contactor, sour gas enters the bottom of the unit where it flows countercurrent to a “lean” amine (amine absent of sour components) that enters at the top. The treated gas will then leave as a saturated gas (gas with water still present) at the top of the unit to be dehydrated, while the “rich” amine (amine plus sour components) leaves the bottom of the unit.

After the rich amine leaves the bottom of the absorber unit the acid gases must be separated from the amine. Initial separation begins when the rich amine enters a flash tank where the pressure is reduced to remove, or flash off, any dissolved hydrocarbons. The hydrocarbons removed can be used for fuel gas or subjected to additional treatment to further remove any impurities. The additional treatment process will be a smaller scale version of that previously discussed.

After the flash tank the rich amine passes through a heat exchanger and enters a solvent stripper. The solvent stripper utilizes low pressure steam to “strip” the acid gases away from the rich amine to return it to its “lean” amine state. The lean amine at the bottom of the stripper is then cooled in and flows to the top of the amine absorber, or contactor, where the process will begin again.

The acid gas that is driven from the amine during regeneration in the “stripper” must be further treated prior to sulfur recovery. The process is similar to that previously discussed, but typically utilizes a different set of amine derivatives such as MDEA.

Dehydration

The treated gas stream leaving the contactor must be dried to meet either pipeline or other production specifications. There are a number of approaches to removing any water from the gas, which will vary depending upon the downstream uses of the treated natural gas. The two methods of removal involve absorption or adsorption techniques.

The most commonly used method is absorption, in which the natural gas stream is contacted with a liquid that absorbs water vapor. Ethylene glycol, diethylene glycol, and triethylene glycol are the most commonly used liquids, with triethylene glycol (TEG) being the most popular. The use of TEG typically provides a natural gas product with less than 10 ppm of water vapor.

The adsorption approach utilizes molecular sieves that use solids with a high surface contact area that attract water molecules. This approach, while more costly, does yield a greater degree of dehydration than can be achieved with absorbents. This process is typically seen in LNG and other cryogenic processes. While there are control valves used with molecular sieves (regeneration process), this section will focus on the absorption technology.

In the glycol absorption process, the wet gas will pass through an inlet scrubber to remove any solids and free liquids from the process. Afterwards the gas enters the bottom of the glycol contactor where the gas flows countercurrent to the lean glycol that flows down through the contactor. The lean glycol absorbs the water and leaves at the bottom of the tower while the dry gas exits at the top of the tower.

The rich glycol solution is warmed and then flows into a flash tank where the dissolved gases (water) are flashed and removed. The solution is then further heated in a boiler to remove any residual water vapor. Lean glycol is removed from the bottom of the boiler, cooled, and pumped back to the contactor to repeat the process.

Sulfur Recovery

After removal from the natural gas in the gas treatment unit the H_2S must be properly disposed. Two methods frequently utilized include injection into underground formations, which enhances product recovery by maintaining well pressure, and conversion to elemental sulfur. The majority of elemental sulfur produced is used in the production of sulfuric acid. This section will place focus on the

recovery of elemental sulfur, as this method is more commonly used in many large treatment units.

The Claus process, or a modification of such, is the most common method of conversion of H_2S to elemental sulfur. There are several variations of the process, but all Claus units involve an initial combustion step in a furnace. The combustion products then pass through a series of catalytic converters. At the exit of the converters, the gas is condensed to remove the sulfur that is formed. The vapor leaving the condenser is at the sulfur dew point requiring reheating before passing to additional converters that may be present.

Discharge Compression

After treatment, the natural gas will be compressed and injected into a high pressure gas distribution network at pressures ranging from 1,200 to 1,700 psig. The gas will then be used for industrial or residential purposes.

Application Review

Depending upon the treatment capacity of the plant, the number of control valves will vary between 50 for a smaller plant (100 MMCFD) and up to 300 for larger units (1000 MMCFD). The majority of the valves utilized will be CL600 and less, but the sizes will vary from small to large constructions based upon the throughput capacity of the unit. The materials noted below are found in many plants, but given the greater emphasis on the development of sour gas fields globally, there is a shift to high nickel alloy materials. Below is a summary of each of the key areas of the plant and the critical valves associated with each area. The typical service conditions and valve selections will be outlined.

Inlet Separation

From the wellhead and gathering systems, the raw natural gas will flow into the natural gas treatment plant. Prior to treatment of the natural gas, any liquids and solids in the flow stream must be removed. This is accomplished via a large inlet separator or slug catcher. Figure 9-2 shows the key valves associated with the inlet separation system and will be discussed in the following text.

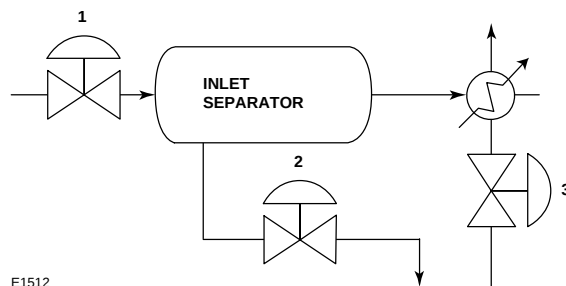


Figure 9-2. Inlet Separation System



Figure 9-3. A11 with 2052 Actuator and FIELDVUE DVC6000

1. Feed Gas Inlet Pressure Control Valve: Inlet pressure of the gas into the inlet separator is controlled here. Pressure drop across the valve will be minimal, but the flow may be high depending on the capacity of the plant. A high performance butterfly valve may be used in this application.

Table 9-1. Feed Gas Inlet Pressure Control Valve

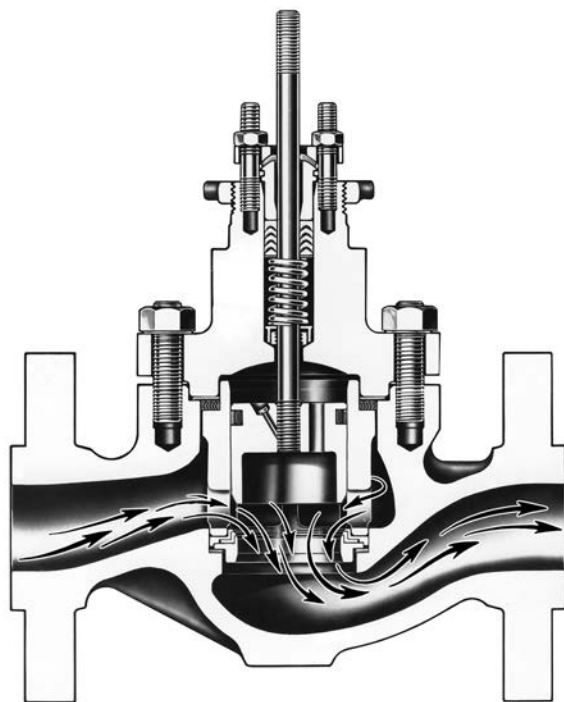
Parameter	Typical Value
Inlet Pressure	300 - 1,050 psig (21 - 72 bar)
Outlet Pressure	285 - 1,035 psig (20 - 71 bar)
Flow Rate	500,000 - 4,000,000 lb/h (225,000 - 1,900,000 kg/h)
Inlet Temp.	20 - 100°F (-7 - 38°C)
Valve Type and Pressure Class	NPS 10 - 30 8532/8580 rotary valve/A31A/A11 HPBV, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV or V
Trim Type	Equal Percentage

2. Inlet Separator Level Control Valve: Here, the liquid level in the inlet separator is controlled. Depending upon the inlet pressure to the facility, this valve may experience high pressure drops. It is common to find multiple level valves on a given separator. A globe or angle valve with anti-cavitation trim is typically used in this application.

Table 9-2. Inlet Separator Level Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,050 psig (21 - 72 bar)
Outlet Pressure	50 - 400 psig (3 - 28 bar)
Flow Rate	50 - 2,000 lb/h (20 - 910 kg/h)
Inlet Temp.	20 - 100°F (-7 - 38°C)
Valve Type and Pressure Class	NPS 1 - 2 ET, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

3. Heat Exchanger Temperature Control Valve: This valve controls the flow of steam to the inlet heat exchanger, thus controlling outlet temperature of the feed gas. There is not a tremendous amount of heat added to the system, thus valve sizes are not typically large. A globe valve is a suitable solution for this application.



W3162-3

Figure 9-4. NPS 1-6 Design ET with Plug Open for Dynamic Action

Table 9-3. Heat Exchanger Temperature Control Valve

Parameter	Typical Value
Inlet Pressure	100 - 225 psig (7 - 16 bar)
Outlet Pressure	90 - 215 psig (6 - 15 bar)
Flow Rate	2,000 - 25,000 lb/h (900 - 12,000 kg/h)
Inlet Temp.	250 - 350°F (121 - 177°C)
Valve Type and Pressure Class	NPS 2 - 6 ET, AMSE CL150/300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Linear

Gas Treatment

The first step in treatment of the natural gas is to remove the sour gas components. Amine absorbers are most commonly used for this process. Figure 9-5 shows the layout of an amine treatment unit and the common control valves in the process.

1. Rich Amine Letdown Control Valve: Liquid level in the bottom of the contactor is controlled by this valve. Given the low downstream pressure needed to drive off the gases, this valve may experience severe outgassing effects. Therefore, the trim selection will vary depending upon the pressure drop and the amount of gas entrained in the solution. While the recommendation in the guide summary below is commonly seen, it is important that each application be reviewed in detail to ensure proper valve selection.

Table 9-4. Rich Amine Letdown Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1020 psig (21 - 70 bar)
Outlet Pressure	20 - 120 psig (1 - 8 bar)
Flow Rate	20,000 - 4,200,000 lb/h (9,000 - 1,910,000 kg/h)
Inlet Temp.	100 - 160°F (38 - 71°C)
Valve Type and Pressure Class	NPS 1 - 20 ET/EWT, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class or V
Trim Type	Whisper Trim I, Whisper Trim III, or NotchFlo DST trim

2. Flash Drum Lean Solvent Control Valve: This valve controls the flow of lean solvent into the flash drum. The introduction of lean solvent is utilized to facilitate the removal of the acid gases entrained in the rich amine. A small globe valve is generally used.

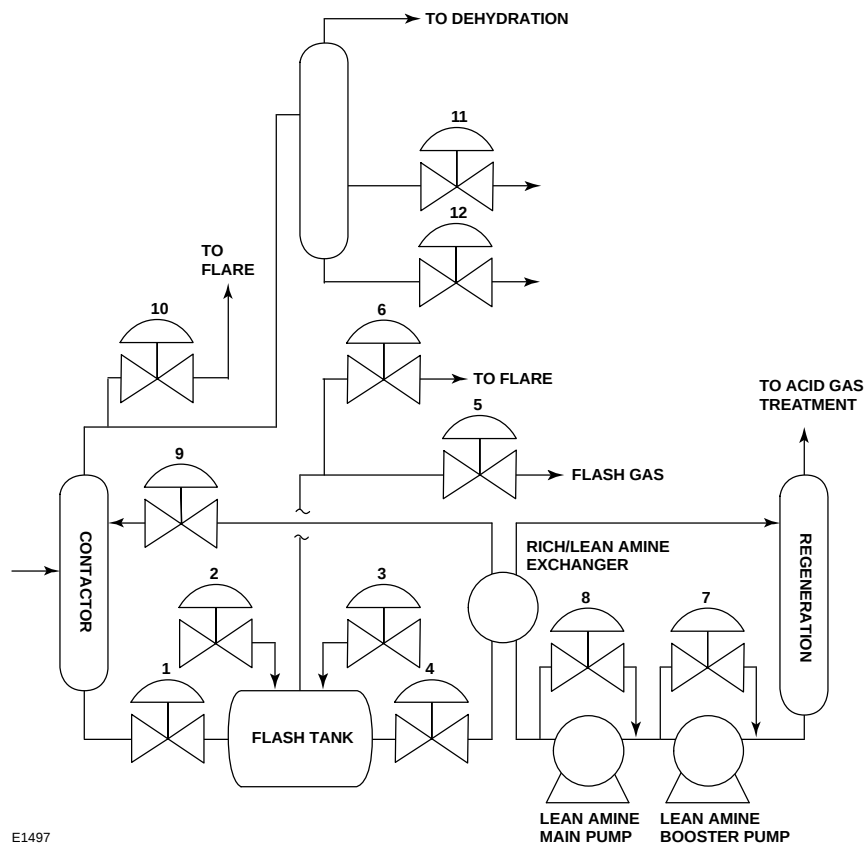


Figure 9-5. Amine Treatment Unit

Table 9-5. Flash Drum Lean Solvent Control Valve

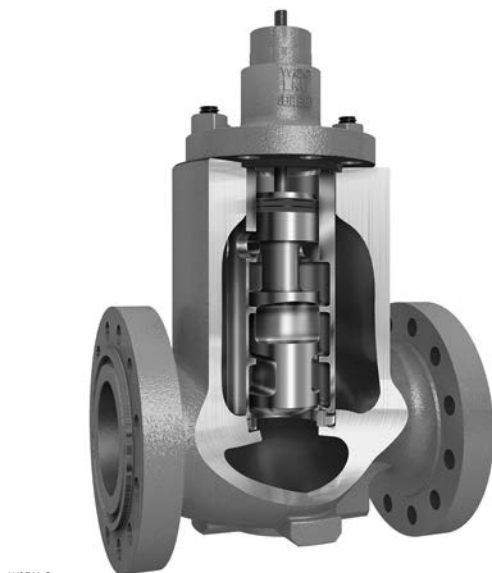
Parameter	Typical Value
Inlet Pressure	40 - 165 psig (3 - 11 bar)
Outlet Pressure	30 - 135 psig (2- 9 bar)
Flow Rate	3,000 - 55,000 lb/h (1,000 - 25,000 kg/h)
Inlet Temp.	100 - 120°F (38 - 49°C)
Valve Type and Pressure Class	NPS 1 - 3 ET/EZ, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

3. Flash Drum Water Control Valve: Here, the flow of water to the flash drum is controlled. This helps to drive off the acid gases entrained in the rich amine. A small globe valve may be used in this application.

Table 9-6. Flash Drum Water Control Valve

Parameter	Typical Value
Inlet Pressure	40 - 165 psig (3 - 11 bar)
Outlet Pressure	30 - 135 psig (2 - 9 bar)
Flow Rate	500 - 12,000 lb/h (225 - 5,500 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. Flash Drum Level Control Valve: The liquid level in the flash drum is controlled here. Similar to the rich amine letdown valve, this valve may experience varying degrees of outgassing. Therefore, it is necessary that each application is appropriately reviewed to determine the proper body and trim selection.



W9711-2

Figure 9-6. NPS 6 Class 600 NotchFlo Cast Globe Body

Table 9-7. Flash Drum Level Control Valve

Parameter	Typical Value
Inlet Pressure	40 - 165 psig (3 - 11 bar)
Outlet Pressure	30 - 135 psig (2 - 9 bar)
Flow Rate	500 - 12,000 lb/h (225 - 5,500 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

5. Flash Drum Pressure Control Valve: This valve controls pressure in the flash drum, which is critical to driving off the acid gases entrained in the rich amine. The sour gases driven off at this point may be subjected to additional treatment. A globe valve with standard trim is commonly used here.

Table 9-8. Flash Drum Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	30 - 105 psig (2 - 7 bar)
Outlet Pressure	20 - 90 psig (1 - 6 bar)
Flow Rate	500 - 11,000 lb/h (225 - 5,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 6 ET, AMSE CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

6. Flash Gas to Flare Control Valve: Flash gas to the flare header is controlled here in the event of an upset in the process. This valve will normally remain closed during operation and can experience relatively high pressure drops that may lead to high noise and vibration if not properly attenuated. A globe valve with Whisper Trim may be used in this application.



W2629

Figure 9-7. Whisper Trim III

Table 9-9. Flash Gas to Flare Control Valve

Parameter	Typical Value
Inlet Pressure	30 - 105 psig (2 - 7 bar)
Outlet Pressure	5 - 15 psig (1 bar)
Flow Rate	500 - 11,000 lb/h (225 - 5,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/EWT, ASME CL150/300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class IV
Trim Type	Whisper Trim I or Whisper Trim III

7. Lean Amine Booster Pump Recirculation Control Valve: This valve bypasses flow around the lean amine booster pump to protect the pump from cavitation damage. Because of the high pressure drop across the valve, cavitation protection is required. A globe valve with Cavitrol III anti-cavitation trim can typically be found in this application.

Table 9-10. Lean Amine Booster Pump Recirculation Control Valve

Parameter	Typical Value
Inlet Pressure	150 - 225 psig (10 - 16 bar)
Outlet Pressure	40 - 60 psig (3 - 4 bar)
Flow Rate	20,000 - 650,000 lb/h (9,000 - 300,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/EWT, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

8. Lean Amine Main Pump Recirculation Control Valve: This valve bypasses flow around the main lean amine pump to protect the pump from cavitation damage. Because of the high pressure drop across the valve, cavitation protection is required. A globe valve with Cavitrol III anti-cavitation trim is commonly used.

Table 9-11. Lean Amine Main Pump Recirculation Control Valve

Parameter	Typical Value
Inlet Pressure	400 - 1,600 psig (28 - 110 bar)
Outlet Pressure	150 - 225 psig (10 - 16 bar)
Flow Rate	20,000 - 650,000 lb/h (9,000 - 300,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/EWT/HPT, ASME CL300/600/900
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

9. Lean Amine to Contactor Control Valve: Here, flow of lean amine to the top of the contactor is controlled. Proper flow control is critical to ensure the proper ratio of amine to gas arriving in the contactor. A globe valve is typically utilized in this application.

Table 9-12. Lean Amine to Contractor Control Valve

Parameter	Typical Value
Inlet Pressure	400 - 1,600 psig (28 - 110 bar)
Outlet Pressure	350 - 1,080 psig (24 - 74 bar)
Flow Rate	20,000 - 4,200,000 lb/h (9,000 - 1,900,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 20 ET/EWT, ASME CL300/600/900
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

10. Lean Gas to Flare Control Valve: This valve controls the flow of lean gas to the flare header in the event of an upset in the process. It will remain closed during normal operation and may experience relatively high pressure drops that can lead to high noise and vibration if not properly attenuated. A globe valve with Whisper Trim may be used.

Table 9-13. Lean Gas to Flare Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1020 psig (21 - 70 bar)
Outlet Pressure	30 - 45 psig (2 - 3 bar)
Flow Rate	30,000 - 1,300,000 lb/h (13,000 - 590,000 kg/h)
Inlet Temp.	110 - 155°F (43 - 68°C)
Valve Type and Pressure Class	NPS 3 - 24 ET/EWT/EBT, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class V
Trim Type	Whisper Trim I or Whisper Trim III

11. Lean Gas Separator Level Control Valve: Because the gas leaving the contactors is generally saturated, a downstream separator is used to capture any carry over liquids (hydrocarbons and water) prior to dehydration. This valve is used to control the liquid level in the separator. A small globe valve is generally used.

Table 9-14. Lean Gas Separator Level Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1,200 psig (21 - 83 bar)
Outlet Pressure	45 - 405 psig (3 - 28 bar)
Flow Rate	500 - 5,500 lb/h (225 - 2,500 kg/h)
Inlet Temp.	110 - 155°F (43 - 68°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/ES, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

12. Lean Gas Separator Sour Water Letdown Control Valve: Because the gas leaving the contactors is generally saturated, a downstream separator is used to capture any carry over liquids (hydrocarbons and water) prior to dehydration. This valve is used to control the liquid level in the separator. A small globe valve is typically used.

Table 9-15. Lean Gas Separator Sour Water Letdown Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 1020 psig (21 - 70 bar)
Outlet Pressure	45 - 150 psig (3 - 10 bar)
Flow Rate	500 - 5,500 lb/h (225 - 2,500 kg/h)
Inlet Temp.	110 - 155°F (43 - 68°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/ES, ASME CL300/600
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

As previously noted, this process is extremely scalable and can be found in many gas treatment units of varying sizes.

The tail gas driven from the amine during regeneration must be further treated prior to sulfur recovery. The process is very similar to that previously discussed, but typically utilizes a different set of amine derivatives such as MDEA. Figure 9-8 shows the tail gas treatment process and the associated control valves.

1. Rich Amine Recirculation to Acid Gas Enrichment Control Valve: This valve is used to bypass flow around the rich amine pump to prevent the pump from the potential for cavitation. It may experience relatively high pressure drops, increasing the potential for the formation of damaging cavitation. To eliminate this potential, a globe valve with Cavitrol III trim may be used.

Table 9-16. Rich Amine Recirculation to Acid Gas Enrichment Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 135 psig (5 - 9 bar)
Outlet Pressure	20 - 30 psig (1 - 2 bar)
Flow Rate	20,000 - 1,000,000 lb/h (9,000 - 460,000 kg/h)
Inlet Temp.	100 - 140°F (38 - 60°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316SST
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage

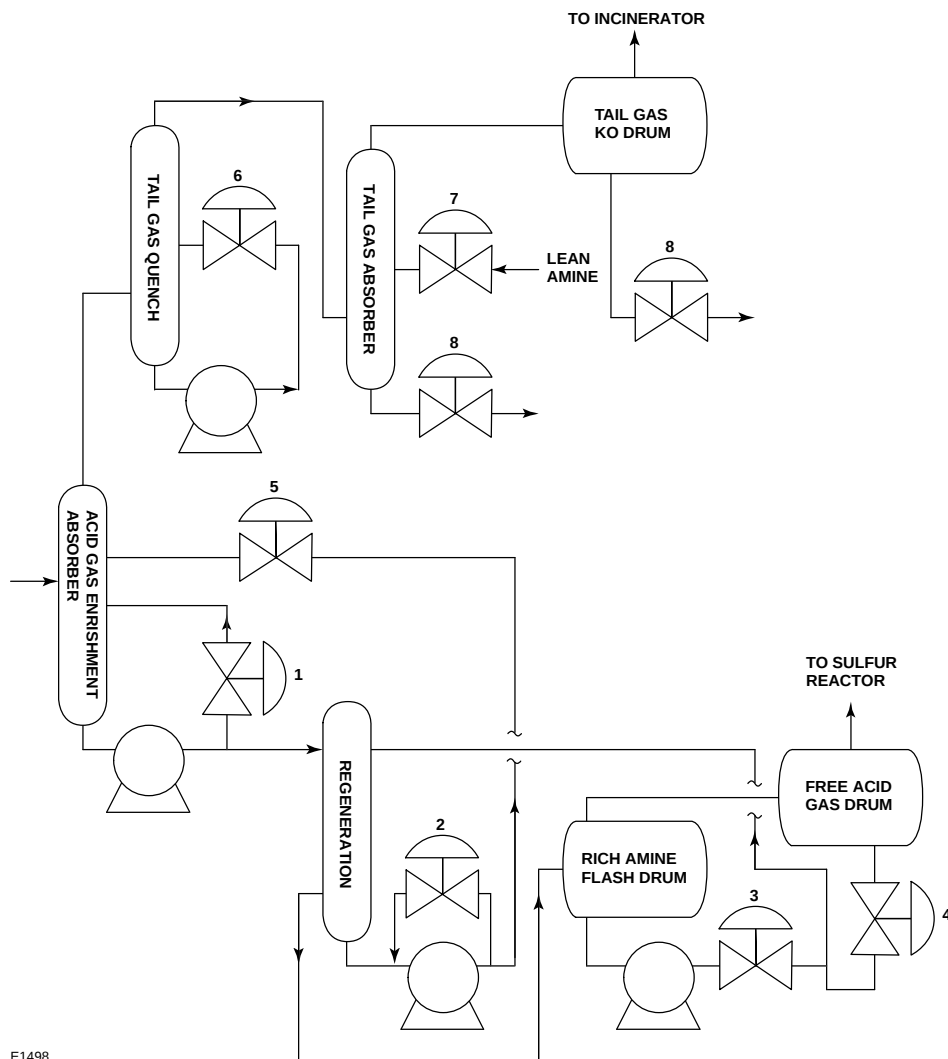


Figure 9-8. Tail Gas Treatment System

2. Regeneration Lean Amine Pump Recirculation Control Valve: This valve bypasses the lean amine from the bottom of the regeneration tower. Bypassing the flow around the pump prevents the pump from cavitating. This requires the valve to take a relatively high pressure drop, which can lead to the formation of damaging cavitation. This valve must be able to eliminate the formation of cavitation. A globe valve with anti-cavitation trim is generally used.

Table 9-17. Regeneration Lean Amine Pump Recirculation Control Valve

Parameter	Typical Value
Inlet Pressure	150 - 240 psig (10 - 17 bar)
Outlet Pressure	30 - 45 psig (2 - 3 bar)
Flow Rate	20,000 - 1,320,000 lb/h (9,000 - 600,000 kg/h)
Inlet Temp.	125 - 175°F (52 - 79°C)
Valve Type and Pressure Class	NPS 2 - 12 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

3. Rich Amine Pump Discharge to Regeneration Control Valve: Here, the flow of amine back to the regeneration tower is controlled here. Given the lower pressure drop, a globe valve with equal percentage trim may be utilized.

Table 9-18. Rich Amine Pump Discharge to Regeneration Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 105 psig (5 - 7 bar)
Outlet Pressure	60 - 75 psig (4 - 5 bar)
Flow Rate	5,000 - 135,000 lb/h (2,000 - 62,000 kg/h)
Inlet Temp.	95 - 125°F (35 - 52°C)
Valve Type and Pressure Class	NPS 1 - 4 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. Free Acid Gas Drum Level Control Valve: The level of liquid in the free acid gas drum is controlled by this valve. It will experience relatively low pressure drops and a globe valve is a commonly used solution.

Table 9-19. Free Acid Gas Drum Level Control Valve

Parameter	Typical Value
Inlet Pressure	90 - 105 psig (6 - 7 bar)
Outlet Pressure	75 - 85 psig (5 - 6 bar)
Flow Rate	5,000 - 50,000 lb/h (2,000 - 25,000 kg/h)
Inlet Temp.	95 - 125°F (35 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

5. Lean Amine Flow Control Valve: This valve controls the flow of lean amine to the acid gas enrichment absorber. Similar to other applications, this valve experiences relatively low pressure drops, but with the potential of relatively high flow rates. A globe valve is generally used in this application.

Table 9-20. Lean Amine Flow Control Valve

Parameter	Typical Value
Inlet Pressure	150 - 240 psig (10 - 17 bar)
Outlet Pressure	30 - 60 psig (2 - 4 bar)
Flow Rate	20,000 - 3,500,000 lb/h (9,000 - 1,600,000 kg/h)
Inlet Temp.	125 - 175°F (52 - 79°C)
Valve Type and Pressure Class	NPS 2 - 16 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage or Characterized Cavitrol III trim

6. Tail Gas Quench Water Control Valve: The gas leaving the acid gas enrichment absorber is subjected to a water quench prior to additional treatment. This valve controls the quench water flow to the quench tank. A globe valve is commonly used with the potential for anti-cavitation trim dependent upon the pressure drop.

Table 9-21. Tail Gas Quench Water Control Valve

Parameter	Typical Value
Inlet Pressure	50 - 140 psig (3 - 10 bar)
Outlet Pressure	30 - 45 psig (2 - 3 bar)
Flow Rate	50,000 - 1,750,000 lb/h (20,000 - 800,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 2 - 12 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

7. Lean Amine to Tail Gas Absorber Control Valve: This valve controls the flow of lean amine to the tail gas absorber in order to scrub the gas one last time prior to use as fuel or incineration. The valve and trim combination will depend upon the pressure drop, but a globe valve with linear or anti-cavitation trim is typically used.

Table 9-22. Lean Amine to Tail Gas Absorber Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 195 psig (5 - 13 bar)
Outlet Pressure	60 - 75 psig (4 - 5 bar)
Flow Rate	30,000 - 1,550,000 lb/h (13,000 - 705,000 kg/h)
Inlet Temp.	90 - 120°F (32 - 49°C)
Valve Type and Pressure Class	NPS 3 - 16 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Cavitrol III trim

8. Tail Gas Treater Semi-lean Amine Letdown Control Valve: Here, the level of amine in the tail gas absorber is controlled. There is potential for relatively light outgassing in this application depending upon the amount of gas entrained in the solution. A globe valve is generally used in this application.

Table 9-23. Tail Gas Treater Semi-lean Amine Letdown Control Valve

Parameter	Typical Value
Inlet Pressure	75 - 195 psig (5 - 13 bar)
Outlet Pressure	65 - 160 psig (4 - 11 bar)
Flow Rate	30,000 - 1,550,000 lb/h (13,000 - 705,000 kg/h)
Inlet Temp.	100 - 130°F (38 - 54°C)
Valve Type and Pressure Class	NPS 2 - 16 ET/EWT, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

9. Tail Gas Knockout Drum Level Control

Valve: This valve controls the level of liquid in the tail gas knockout drum. A small globe valve may be used.

Table 9-24. Tail Gas Knockout Drum Level Control Valve

Parameter	Typical Value
Inlet Pressure	45 - 165 psig (3 - 11 bar)
Outlet Pressure	40 - 150 psig (3 - 10 bar)
Flow Rate	2,000 - 25,000 lb/h (900 - 12,000 kg/h)
Inlet Temp.	90 - 125°F (32 - 52°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Dehydration

After the initial treatment step, the gas needs to be dehydrated. As previously mentioned, the method of dehydration depends upon the type of plant and any additional treatment that may occur. Figure 9-9 below shows the conventional method of employing tri-ethylene glycol (TEG). The primary valves associated with the system are those controlling the glycol solution into and out of the dehydration unit.

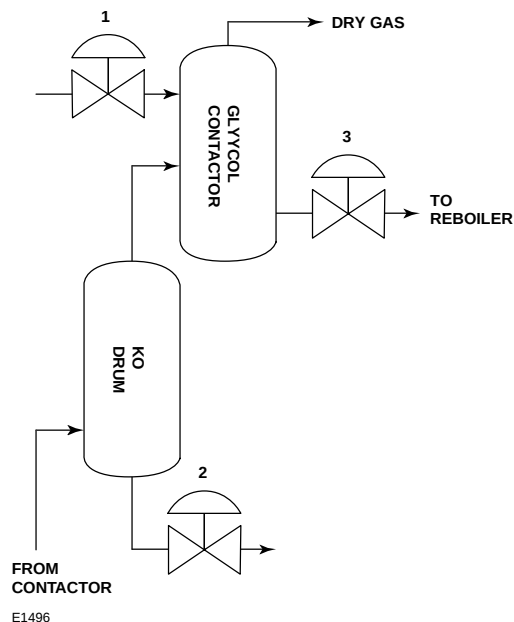


Figure 9-9. TEG Gas Dehydration Unit

1. Lean Glycol to Glycol Contactor Control

Valve: Here, the flow of lean glycol from the glycol regeneration unit to the contactor is controlled. The glycol will enter the top of the contactor and as it moves down the column will strip the water from the gas stream flowing up through the bottom of the column. This valve may not be present if a variable speed pump is used. A globe valve is the typical solution for this application.

Table 9-25. Lean Glycol to Glycol Control Valve

Parameter	Typical Value
Inlet Pressure	600 - 1100 psig (41 - 76 bar)
Outlet Pressure	500 - 900 psig (35 - 62 bar)
Flow Rate	10 - 250 lb/h (4 - 115 kg/h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 3 EZ/ET, ASME CL300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. Gas Dehydration Inlet Separator Level Control

Valve: The inlet separator valve is utilized to remove as much water and other liquids as possible prior to glycol dehydration. It controls the liquid level in the separator. A globe valve is the most common solution.

Table 9-26. Gas Dehydration Inlet Separator Level Control Valve

Parameter	Typical Value
Inlet Pressure	600 - 1100 psig (41 - 76 bar)
Outlet Pressure	150 - 350 psig (10 - 24 bar)
Flow Rate	100 - 750 lb/h (45 - 340 kg/h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 3 EZ/ET, ASME CL300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Table 9-27. Glycol Contactor Level Control Valve

Parameter	Typical Value
Inlet Pressure	30 - 1050 psig (2 - 72 bar)
Outlet Pressure	30 - 200 psig (2 - 14 bar)
Flow Rate	100 - 750 lb/h (45 - 340 kg/h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 1 - 3 ET, ASME CL300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Cavitrol III trim

3. Glycol Contactor Level Control Valve: This valve controls the glycol-water interface level in the glycol contactor. It will experience relatively high pressure drops requiring anti-cavitation trim. A globe valve with Cavitrol III 2-stage trim is generally used.

Sulfur Recovery

Figure 9-10 below shows a common Claus process that is used to produce elemental sulfur from the H₂S produced in the gas treatment section, and the associated control valves.

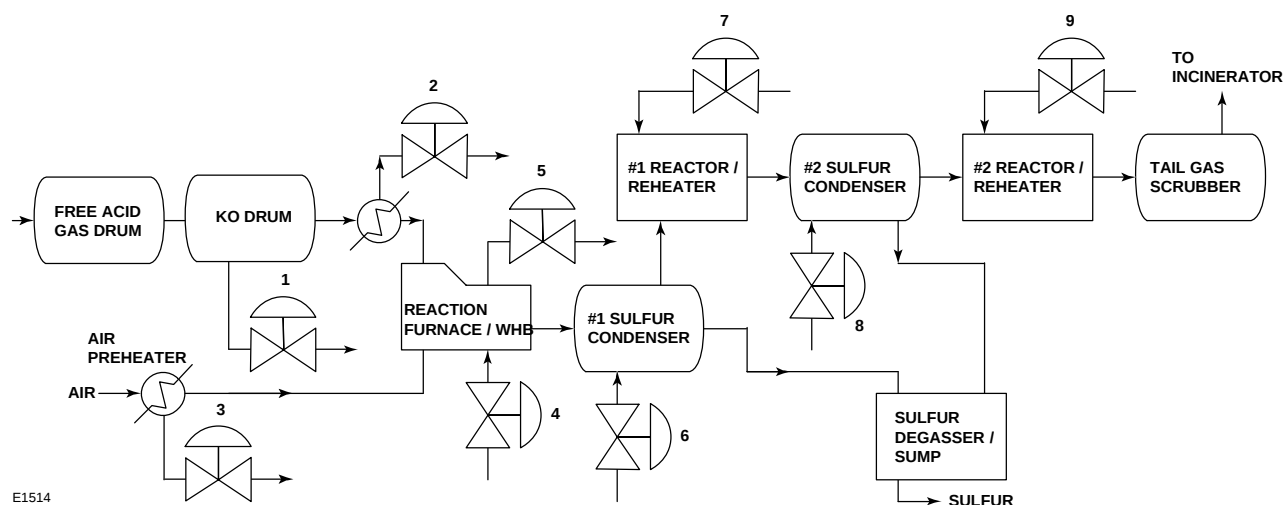


Figure 9-10. Sulfur Recovery System

1. Acid Gas Knockout Drum Level Control Valve: Here, the liquid level in the upstream knockout drum is controlled. A globe valve with standard trim is typically used in this application.

Table 9-28. Acid Gas Knockout Drum Level Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 30 psig (1 - 2 bar)
Outlet Pressure	15 - 18 psig (1 bar)
Flow Rate	5,000 - 55,000 lb/h (2,000 - 25,000 kg/h)
Inlet Temp.	100 - 125°F (38 - 52°C)
Valve Type and Pressure Class	NPS 2 EZ, ASME CL150/300
Valve Material and Trim Material	WCC-HT/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage

2. Acid Gas Preheater Temperature Control Valve: This valve controls the flow of steam to in turn control the discharge temperature of the acid gas leaving the preheater. Flow rates are commonly low, but inlet pressures may be high depending upon the source of steam in the plant. A small globe valve is generally used.

Table 9-29. Acid Gas Preheater Temperature Control Valve

Parameter	Typical Value
Inlet Pressure	450 - 675 psig (31 - 47 bar)
Outlet Pressure	50 - 125 psig (3 - 9 bar)
Flow Rate	1,000 - 16,500 lb/h (450 - 7,500 kg/h)
Inlet Temp.	400 - 500°F (204 - 260°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. Air Preheater Temperature Control Valve: This valve controls the flow of steam, which in turn controls the discharge temperature of the combustion air leaving the preheater. Flow rates are typically low, but inlet pressures may be high depending upon the source of steam in the plant. A small globe valve is commonly used.

Table 9-30. Air Preheater Temperature Control Valve

Parameter	Typical Value
Inlet Pressure	450 - 675 psig (31 - 47 bar)
Outlet Pressure	50 - 125 psig (3 - 9 bar)
Flow Rate	1,000 - 16,500 lb/h (450 - 7,500 kg/h)
Inlet Temp.	400 - 500°F (204 - 260°C)
Valve Type and Pressure Class	NPS 1 - 2 EZ, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. Waste Heat Boiler (WHB) Boiler Feedwater Level Control Valve: Drum level in the waste heat boiler downstream of the reaction furnace is controlled by this valve. Depending upon startup conditions, a globe valve with equal percentage or characterized anti-cavitation trim is used.

Table 9-31. Waste Heat Boiler (WHB) Feedwater Level Control Valve

Parameter	Typical Value
Inlet Pressure	550 - 1,000 psig (38 - 69 bar)
Outlet Pressure	475 - 675 psig (33 - 47 bar)
Flow Rate	20,000 - 200,000 lb/h (9,000 - 91,000 kg/h)
Inlet Temp.	225 - 275°F (107 - 135°C)
Valve Type and Pressure Class	NPS 2 - 4 ET, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage or Cavitrol III trim

5. Reaction Furnace Waste Heat Boiler Steam Pressure Control Valve: Here, the steam pressure in the WHB is controlled. The valve selection will depend upon the intended use of the steam, but a globe valve is typically used.

Table 9-32. Reaction Furnace Waste Heat Boiler Steam Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	475 - 675 psig (33 - 47 bar)
Outlet Pressure	150 - 240 psig (10 - 17 bar)
Flow Rate	20,000 - 200,000 lb/h (9,000 - 91,000 kg/h)
Inlet Temp.	400 - 500°F (204 - 260°C)
Valve Type and Pressure Class	NPS 2 - 8 ET, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Linear or Whisper III Trim

6. Sulfur Condenser Boiler Feedwater Control Valve #1: This valve controls boiler feedwater flow to the sulfur heat exchanger/condenser to facilitate fallout of sulfur from the flowstream. This is the same boiler feedwater used in the WHB, but typically experiences much higher pressure drops creating the need for anti-cavitation trim.

Table 9-33. Sulfur Condenser Boiler Feedwater Control Valve #1

Parameter	Typical Value
Inlet Pressure	550 - 1,000 psig (38 - 69 bar)
Outlet Pressure	50 - 75 psig (3 - 5 bar)
Flow Rate	2,000 - 35,000 lb/h (900 - 16,000 kg/h)
Inlet Temp.	225 - 275°F (107 - 135°C)
Valve Type and Pressure Class	NPS 2 - 3 ET, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

7. Reactor/Reheater Steam Temperature Control Valve #1: Because the gas leaving the #1 sulfur condenser is at its dew point, it must be reheated for further sulfur separation. This valve controls the flow of steam to control discharge temperature from the reheater. A globe valve is commonly used in this application.

Table 9-34. Reactor/Reheater Steam Temperature Control Valve #1

Parameter	Typical Value
Inlet Pressure	475 - 675 psig (33 - 47 bar)
Outlet Pressure	400 - 650 psig (28 - 45 bar)
Flow Rate	1,000 - 15,000 lb/h (450 - 7,000 kg/h)
Inlet Temp.	400 - 500°F (204 - 260°C)
Valve Type and Pressure Class	NPS 2 - 6 ET, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

8. Sulfur Condenser Boiler Feedwater Control Valve #2: This valve controls boiler feedwater flow to the sulfur heat exchanger/condenser to facilitate fallout of sulfur from the flowstream. This is the same boiler feedwater used in the WHB, but typically experiences much higher pressure drops creating the need for anti-cavitation trim.

Table 9-35. Sulfur Condenser Boiler Feedwater Control Valve #2

Parameter	Typical Value
Inlet Pressure	550 - 1,000 psig (38 - 69 bar)
Outlet Pressure	50 - 75 psig (3 - 5 bar)
Flow Rate	2,000 - 35,000 lb/h (900 - 16,000 kg/h)
Inlet Temp.	225 - 275°F (107 - 135°C)
Valve Type and Pressure Class	NPS 2 - 3 ET, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

9. Reactor/Reheater Steam Temperature Control Valve #2: Since the gas leaving the #2 sulfur condenser is at its dew point, it must be reheated for further sulfur separation. This valve controls the flow of steam to control discharge temperature from the reheater. A globe valve is generally used in this application.

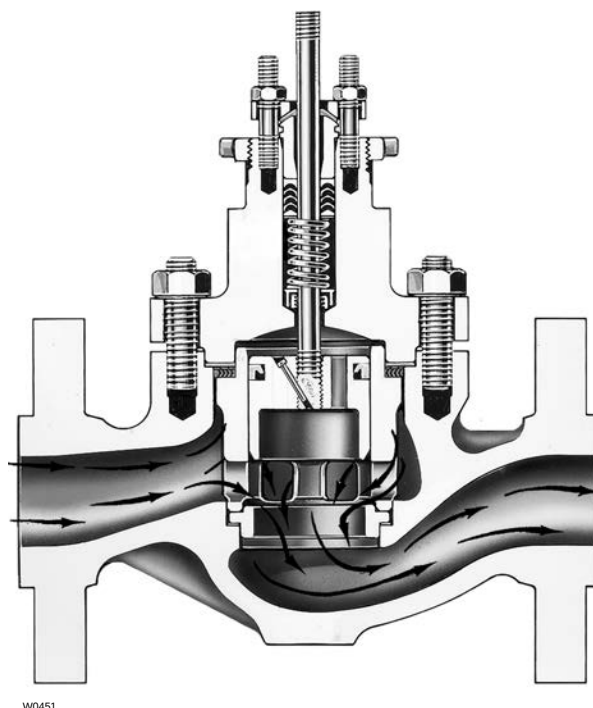


Figure 9-11. Design ED

Table 9-36. Reactor/Reheater Steam Temperature Control Valve #2

Parameter	Typical Value
Inlet Pressure	475 - 675 psig (33 - 47 bar)
Outlet Pressure	400 - 650 psig (28 - 45 bar)
Flow Rate	1,000 - 15,000 lb/h (450 - 7,000 kg/h)
Inlet Temp.	400 - 500°F (204 - 260°C)
Valve Type and Pressure Class	NPS 2 - 6 ED, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Linear

Oil and Gas Transportation

To move a fluid through a pipe, whether it is a gas or liquid, one needs simply to increase the fluid's pressure above that of the final destination of where it is going to. For gases, a compressor is used to perform this task; for liquids, a pump. In the upstream oil and gas industry, pumps and compressors are used to move oil and natural gas, respectively, through pipelines.

Natural gas transportation, as defined in this chapter, will be the transportation of gas through a pipeline between a natural gas processing plant and to and from interconnects, where natural gas is metered and distributed to end users through local utility lines. Compressor stations along the pipeline are used to move the gas between these points.

Crude oil transportation, as defined in this chapter, will be the transportation of crude oil through pipelines between production wells, oil terminals, and oil refineries. Pump stations along these pipelines are used to move the oil to and from these points.

Gas Transportation Process

Figure 10-1 shows a general process flow diagram of a gas transportation network.

Compressor Station:

The compressor station is the engine that powers a gas pipeline. As the name implies, the compressor station compresses the natural gas (increases its pressure) thereby providing energy to move the gas through the pipeline. Pipeline companies install compressor stations along a pipeline typically every 40 to 100 miles. The size

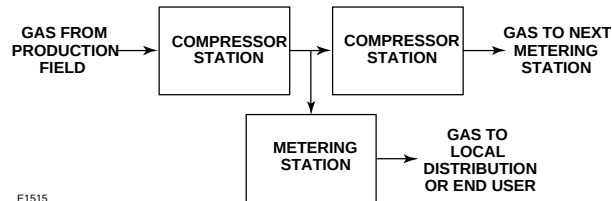


Figure 10-1. Gas Transportation Process Flow Diagram

of the station and the number of compressors varies, and is dependent on the diameter of the pipe and the volume of gas to be moved. Nevertheless, the basic components of a station are similar.

Gas Filters:

As the pipeline enters the compressor station the natural gas passes through a unit that removes any free liquids or dirt particles from the gas before it enters the compressors. This may also be called the liquid separators, scrubbers, or strainers. Though the pipeline is carrying dry gas, some water and hydrocarbon liquids may condense out of the gas stream as the gas cools and moves through the pipeline. Any liquids that may be produced by these units are collected and stored for sale or disposal.

Compressors and Drivers:

There are three typical compressor styles:

1. *Centrifugal*
2. *Reciprocating*
3. *Screw compressors.*

Each style can be driven with either an electric motor, a gas engine, or turbine. Centrifugal compressors typically don't provide high



compression ratios, but can move large volumes of gas. As such they are typically used on large capacity mainline compression. Reciprocating compressors have a limited compression ratio, typically 2:1 or 3:1 per stage, but can use as many as four stages on a single engine. They are typically used on production lines from the wellhead to processing plant. Finally, a third style is the screw compressor. They have traditionally been smaller compressors, but are getting to be as large as capacities of 18 MMSCFD. They can produce extremely high compression ratios as high as 100:1.

Metering Stations:

For a pipeline company to manage its gas pipeline system efficiently, it must know how much gas is in the system at all times. This can be a daunting task, as pipeline systems often extend over thousands of miles. To accomplish this, pipeline companies use metering stations to measure all natural gas entering or exiting the pipeline system. Metering stations found at any point in the pipeline where gas is removed for local distribution are called an interconnect.

Oil Transportation Process

Figure 10-2 shows a general process flow diagram of an oil transportation network.

Pump Station:

Like the compressor station for a gas pipeline, the pump station is the engine that powers an oil pipeline. As the name implies, the pump station increases the pressure of the oil thereby providing energy to move the oil through the pipeline. Pipeline companies install pump stations along a pipeline typically every 25 to 50 miles. The size of the station and the number of pumps varies, and is dependent on the diameter of the pipe and the volume of oil to be moved. Nevertheless, the basic components of a station are similar.

There are two types of pumps commonly used for pump stations, centrifugal or reciprocating, with centrifugal being the most common. They are most commonly electricity driven, and sometimes include a variable speed drive (VSD) to throttle the outlet pressure. In this case a “control” valve is not needed to control the outlet pressure during

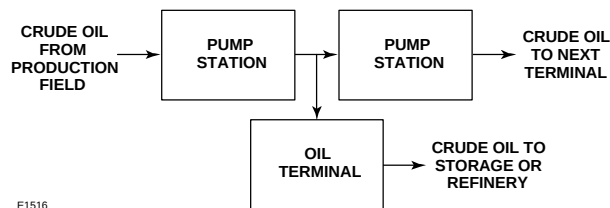


Figure 10-2. Oil Transportation Process Flow Diagram

normal operation of the station; however, one is typically specified to control the outlet pressure when the outlet pressure required is outside the control range of the VSD.

Oil Terminal:

At the end of each oil pipeline exists a breakout station where personnel can perform final metering and distribute products to various storage tanks, redirect them to a different pipeline, or load them directly to truck transports or vessels for additional transport to points of use. These are typically located within or adjacent to oil terminals.

Gas Transportation Application Review

Metering Station:

1. Worker Valve: This is a flow control valve. There is a high pressure drop that often requires noise attenuating trim.

Table 10-1. Worker Valve

Parameter	Typical Value
Inlet Pressure	200 - 1500 psig (14 - 103 bar)
Outlet Pressure	1 - 150 psig (1 - 10 bar)
Inlet Temp.	60°F (16°C)
Valve Type and Pressure Class	Globe, ASME CL600
Valve Material and Trim Material	WCC/416 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage or Whisper Trim III

2. Monitor Valve: This valve is normally wide open until worker is in fail mode. When operating, it is under the same conditions as the worker. Typically noise isn't a concern because these valves will operate only when the worker is in fail mode.

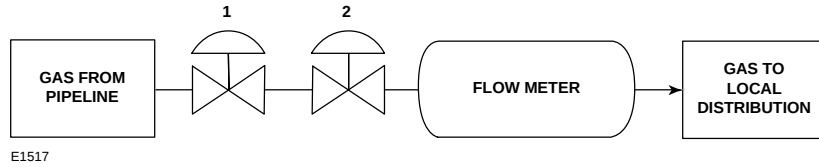


Figure 10-3. Metering Station Control Valve Diagram

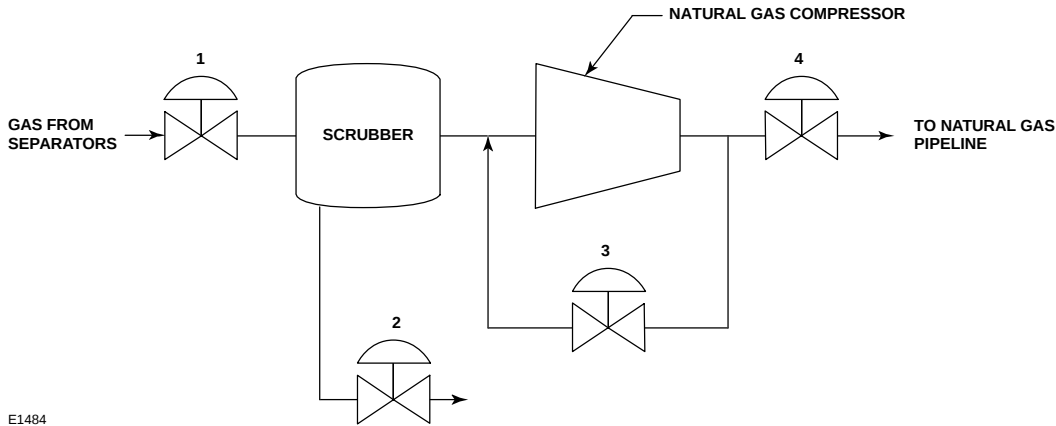


Figure 10-4. Compressor System

Table 10-2. Monitor Valve

Parameter	Typical Value
Inlet Pressure	200 - 1500 psig (17 - 103 bar)
Outlet Pressure	1 - 150 psi (1 - 10 bar)
Inlet Temp.	60°F (16°C)
Valve Type and Pressure Class	Globe, ASME CL600
Valve Material and Trim Material	WCC/416 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

pressures equalize because it takes more power to draw gas through a restrictive valve opening which is an inefficient use of the available compressor Hp. The less energy that is required to move the gas through the compressor, the more likely the compressor will be running at the maximum Hp with best compression and fuel efficiency. Regardless of the number of stages of compression required, there is always only one suction control valve located at the inlet of the first stage scrubber.

Compressor Station:

Depending on the inlet and discharge pressures, a single compressor station can contain anywhere from one to three stages of compression. We will focus solely on single stage systems for the purposes of this review.

1. Compression Suction Throttle Control: The purpose of this valve is to maintain the flow at which the compressor operates the most efficiently. In a majority of applications, the valve is sized so that under normal operating conditions, it never operates above 85% open and below 15% open. It is initially sized so that the normal operating conditions are between 50% open and 70% open. This is done to ensure a minimum pressure drop across the valve once upstream and downstream pressures equalize. This minimum pressure drop is desired when the

Table 10-3. Compression Suction Throttle Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 600 psig (1 - 41 bar)
Pressure Drop	0 - 300 psi (0 - 21 bar)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	E-body/Vee-Ball, ASME CL150/300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

2. Compression Suction Scrubber Level Control: The compressor scrubber system is used to remove the unwanted particulates and or liquids from the gas to protect the compressor. The purpose of the scrubber level control valve is to regulate the level of the liquid mixture. The level control valve is typically a dump valve that empties the water at the bottom of the scrubber. This valve

is tied to a level controller that senses the water level in the vessel.

Table 10-4. Compression Suction Scrubber Level Control Valve

Parameter	Typical Value
Inlet Pressure	20 - 600 psig (1 - 41 bar)
Pressure Drop	Up to 500 psi (35 bar)
Inlet Temp.	100 - 150°F (38 - 66°C)
Valve Type and Pressure Class	D-body/E-body/Vee-Ball, ASME CL150/300/600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

3. Compressor Anti-surge: The purpose of this valve is to prevent the compressor from shutting down when low suction pressure or high discharge pressure is experienced. When either of these conditions occur, the recycle valve opens up until the pressures normalize, allowing the compressors to run continuously, without being damaged. The recycle valve is typically on the outlet of the discharge before the discharge check valve. It can either be coming off of the cooler section or directly off the compressor cylinders. Depending on where it is located, temperatures can result in the need for an ASME CL900 rated valve. Due to the large pressure drops across this valve it typically requires a noise abatement trim.

Anti-surge valves, also known as recycle valves, must be able to respond quickly and accurately to changes in set point with minimal travel overshoot and must be able to provide throttling capability at various travel ranges. Trip systems associated with the valve assembly are configured to respond to a trip case by opening the valve to full travel in less than one second in most cases. Performance criteria for the compressor system drive the requirements associated with this control valve. Please reference Chapter 13 for additional information on compressor surge control applications.

Table 10-5. Compressor Anti-surge Control Valve

Parameter	Typical Value
Inlet Pressure	100 - 1800 psig (7 - 124 bar)
Pressure Drop	Up to 1380 psi (95 bar)
Inlet Temp.	70 - 150°F (21 - 66°C)
Valve Type and Pressure Class	E-body/FB/HP, ASME CL150/300/600/900
Valve Material and Trim Material	WCC/316 SST with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper Trim III or WhisperFlo trim



Figure 10-5. ET Class 300 with WhisperFlo trim and Spoked Plug

4. Compressor Export Control: This valve controls the gas export flow of gas that is being compressed. It is typically a high capacity construction to account for the large flow rates present.

Table 10-6. Compressor Anti-surge Control Valve

Parameter	Typical Value
Inlet Pressure	900 - 1700 psig (62 - 117 bar)
Pressure Drop	Up to 400 psi (28 bar)
Inlet Temp.	70 - 150°F (21 - 66°C)
Valve Type and Pressure Class	V250/EH, ASME CL600/900
Valve Material and Trim Material	WCC/316 SST with Standard/316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Standard

Oil Transportation Application Review

Pump Station:

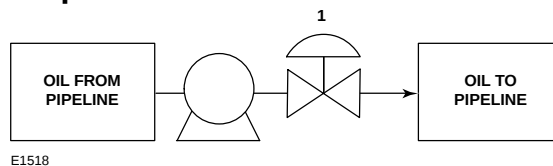
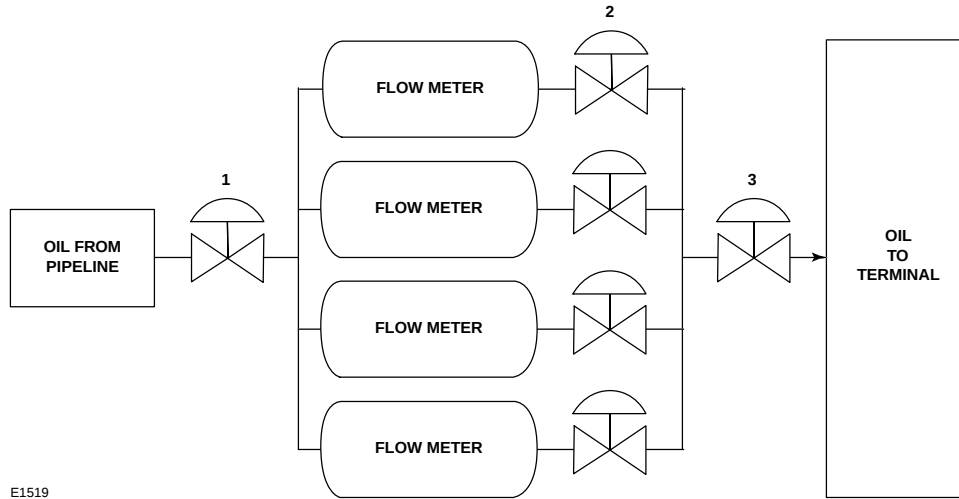


Figure 10-6. Pump Station Control Valve Diagram

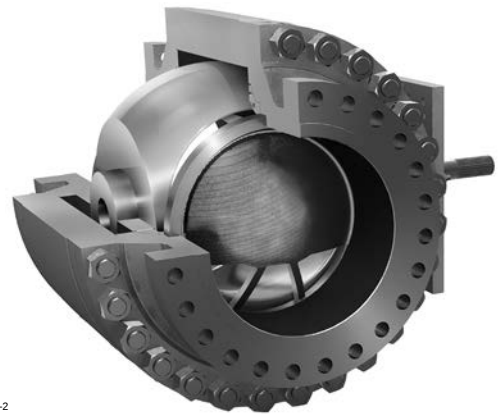
1. Pump Discharge Valve: A pump station may have multiple pumps in series and/or parallel, but



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Figure 10-7. Oil Terminal Receiving Unit Control Valve Diagram

usually only has one discharge valve. This valve is held wide open during normal operating conditions in order to minimize the amount of energy lost across the valve. This minimizes the energy spent by the pumps in order to maintain appropriate pressure in the pipeline. During startup, however, this valve is used to maintain a constant back pressure on the pump while the pipeline downstream builds pressure. During these startup conditions cavitation of the fluid may be present. While not seen as an issue from an erosion standpoint, the resultant noise and vibration may be damaging to components in the pipeline. Hydrodynamic noise attenuating trims such as hydrodomes may be used to minimize or eliminate the cavitation and the resultant noise and vibration.



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Figure 10-8. V260B with Hydrodome Attenuator

Table 10-7. Pump Discharge Valve

Parameter	Typical Value
Inlet Pressure	720 - 1480 psig (50 - 102 bar)
Outlet Pressure	10 - 150 psig (1 - 10 bar)
Inlet Temp.	40 - 100°F (4 - 38°C)
Valve Type and Pressure Class	NPS 12 - 24 V250 or V260, ASME CL600
Valve Material and Trim Material	LCC
Shutoff Requirement	None
Trim Type	Standard Flow Ring/Full Bore or Hydrodome

this valve will often cause cavitation that is not damaging to the valve, but may cause excessive noise and vibration. A full port ball valve with hydrodynamic noise attenuating hydrodome trim is typically required.

Table 10-8. Delivery Valve

Parameter	Typical Value
Inlet Pressure	150 - 400 psig (10 - 28 bar)
Outlet Pressure	80 psig (6 bar)
Inlet Temp.	40 - 100°F (4 - 38°C)
Valve Type and Pressure Class	NPS 8 - 20 V260, ASME CL600
Valve Material and Trim Material	LCC or WCC
Shutoff Requirement	Class IV
Trim Type	Hydrodome

Oil Terminal:

1. Delivery: This valve takes the initial pressure cut from the pipeline. The pressure drops seen for

2. **Flow Balancing:** These valves are used to ensure each flow meter has approximately the same flow rate.

Table 10-9. Inlet Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	70 psig (5 bar)
Outlet Pressure	60 psig (4 bar)
Inlet Temp.	40 - 100°F (4 - 38°C)
Valve Type and Pressure Class	Line size A81, NPS 6 - 8, ASME CL150
Valve Material and Trim Material	LCC or WCC
Shutoff Requirement	None
Trim Type	Standard

3. **Meter Backpressure:** This valve is used to maintain the appropriate pressure needed within the flow meter.

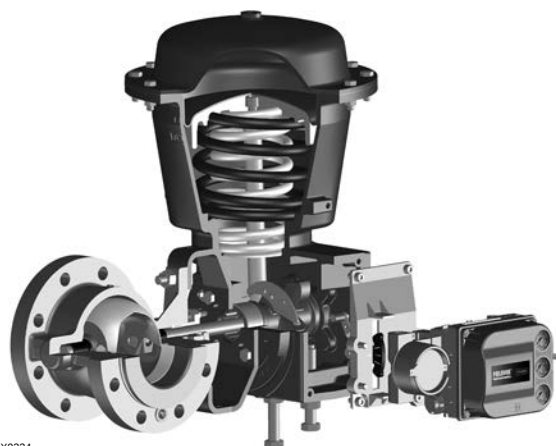


Figure 10-9. Cutaway of Vee-Ball V150/2052 Size 3 Actuator and DVC6200

Table 10-10. Outlet Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	60 psig (4 bar)
Outlet Pressure	35 - 55 psig (3 - 4 bar)
Inlet Temp.	40 - 100°F (4 - 38°C)
Valve Type and Pressure Class	Vee-Ball V150, ASME CL150
Valve Material and Trim Material	LCC or WCC
Shutoff Requirement	None
Trim Type	Attenuator

Fractionation

Natural gas at the wellhead is primarily composed of four hydrocarbon constituents; Methane (C1), Ethane (2), Propane (C3), and Butane (C4). Though composition will vary by reservoir, methane commonly accounts for 80% or more of the raw stream that is produced from a gas-producing well. Fields that produce gas that are high in C2+⁽¹⁾ constituents are described as “high BTU” or “liquids-rich” fields.

(1) For a list of the makeup of hydrocarbons, please refer to the chart below:

	Name	Chemical Formula
C1	Methane	CH ₄
C2	Ethane	C ₂ H ₆
C3	Propane	C ₃ H ₈
C4	Butane	C ₄ H ₁₀
C5	Pentane	C ₅ H ₁₂
C6	Hexane	C ₆ H ₁₄
C7	Heptane	C ₇ H ₁₆
C8	Octane	C ₈ H ₁₈
C9	Nonane	C ₉ H ₂₀
C10	Decane	C ₁₀ H ₂₂
C11	Undecane	C ₁₁ H ₂₄
C12	Dodecane	C ₁₂ H ₂₆

Traditionally, fields have been developed to monetize the methane present in the reservoir by delivering it to a local gas treatment plant for processing and injection into the local natural gas grid. If the BTU content of the produced gas stream was under sales pipeline specifications, the C2+ hydrocarbons would commonly be left in the gas as it flowed into the grid. If the BTU content exceeded specifications, a portion of the heavier hydrocarbons would be separated from the methane in the gas treatment plant through a low temperature NGL recovery process. This process produces a mixed stream of C2+ hydrocarbons, commonly referred to as “y-grade” or “raw mix”. With the widening oil-to-gas price spread,

the economics of recovering NGLs at the gas treatment facility have improved significantly in recent years, and production has increased.

While the composition of mixed NGL streams can vary significantly depending on the reservoir, a typical breakdown of hydrocarbon fractions has been established for marketing purposes. This typical NGL stream consists of 45% ethane, 30% propane, 10% butane, and 15% C5+ hydrocarbons.

Fractionation Process

This process overview is based on a typical fractionation facility that is designed to separate and recover ethane, propane, butane, and gas condensates. As such, it will encompass the deethanizer, depropanizer, and debutanizer towers (see Figure 11-1 below for a simplified block diagram of this process). The number of towers that an actual plant will have is dependent on the products that it is designed to recover. Regional demand and economics will dictate which hydrocarbons are recovered at each particular fractionation plant.

Initial gas treatment and NGL recovery occur upstream of the fractionation process, and will not be covered in this process overview. Gas treatment plants located upstream of a fractionation unit remove impurities such as moisture, H₂S, and CO₂, in addition to recovering C2+ hydrocarbons from the natural gas stream. Stand-alone fractionation facilities receive this mixed NGL stream consisting of C2+.

The fractionation process operates based on the varying boiling points of the different hydrocarbon constituents present in the mixed NGL stream. Each stage in the fractionation process separates out one hydrocarbon constituent by boiling it off



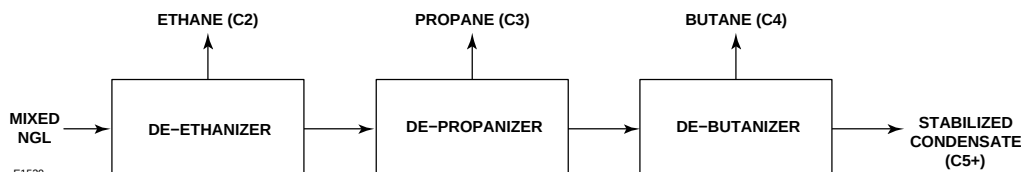


Figure 11-1. Typical Fractionation Process Recovering C2, C3, and C4

from the mixed stream and then recovering the pure product stream via an overhead condenser. These stages are named purposefully for the constituent that is boiled off. Hence, the first stage of the process is the deethanizer, followed by the depropanizer and debutanizer. The fluid leaving the debutanizer primarily consists of pentanes and other heavier hydrocarbons, and is commonly referred to as stabilized gas condensate or natural gasoline.

Deethanizer

The deethanizer separates ethane from the heavier components in the NGL mixture. The resulting product stream is typically 95% ethane or greater. The deethanizer tower is typically a trayed design that increases residence time of the NGL stream and promotes higher overall ethane recovery. The NGL mixture typically enters the deethanizer at ambient temperature ($<100^{\circ}\text{F}$ or 38°C) and a pressure of 200 - 300 psig (14 - 21 bar).

The ethane vapor boiling off overhead is sent to an overhead condenser to lower the temperature of the vapor and force the ethane to condense into its liquid form. The condenser lowers the temperature of the vapor down to nearly 0°F (-18°C). As the condensing temperature of ethane is relatively low ($20 - 50^{\circ}\text{F}$ or $-7 - -10^{\circ}\text{C}$), a deethanizer typically requires a refrigerant chiller to achieve condensation. This change in temperature forces the ethane component to condense as it enters the reflux accumulator, where the liquid product is drawn off and pumped to metering or storage. Any heavier hydrocarbons are pumped back to the top tray of the deethanizer.

The remaining NGL liquid reaching the bottom tray of the deethanizer tower goes to the deethanizer reboiler. The reboiler utilizes a hot oil supply to boil off ethane vapor from the liquid, which rises up through the tower and promotes additional boiloff by increasing the liquid temperature as it passes upward to the overhead. Net liquid from the reboiler compartment overflows into the column net bottoms compartment, and ultimately flows downstream to the depropanizer.

Depropanizer

The remaining C3+ NGL stream is fed into the top of the depropanizer tower. The process stream's pressure and temperature is typically at about 200 psig (14 bar) and 170°F (77°C) as it enters. As it serves the same function of boiling off a single hydrocarbon from the stream, the depropanizer shares a number of characteristics with the deethanizer previously described. It is a trayed tower that feeds vapor to an overhead condenser and liquid to a bottom reboiler. However, it is also common for a heat pump compressor to be used overhead to boost the pressure of the propane vapor exiting the depropanizer. Since the propane vapor undergoes adiabatic heating as it passes through the compressor, it must be cooled before it will condense into the reflux accumulator. As such, it is passed through one of two heat exchangers located in either the deethanizer or in the depropanizer side reboiler. The propane vapor gives up heat and ultimately condenses down into its liquid form in the reflux accumulator before it is pumped to propane product storage. The waste heat given up increases the efficiency of the deethanizer and/or depropanizer towers. In plants where butane will be separated out, the net C4+ liquid stream from the depropanizer bottoms flows to a debutanizer tower.

Debutanizer

The debutanizer functions in a nearly identical manner to the deethanizer. The bottom reboiler drives heated butane vapor up through the tower and the overhead condenser produces liquid butane that is recovered in the reflux accumulator. The liquid product is comprised of isobutane and normal butane. Typically, a mixed butane product contains 97% of butanes with small amounts of propane and heavier components. Hot oil enters the debutanizer reboiler at about 325°F (163°C). Net liquid leaving the debutanizer bottoms (C5+) is cooled through a condensate cooler, and then pumped to storage. This product stream is commonly referred to as stabilized condensate or natural gasoline.

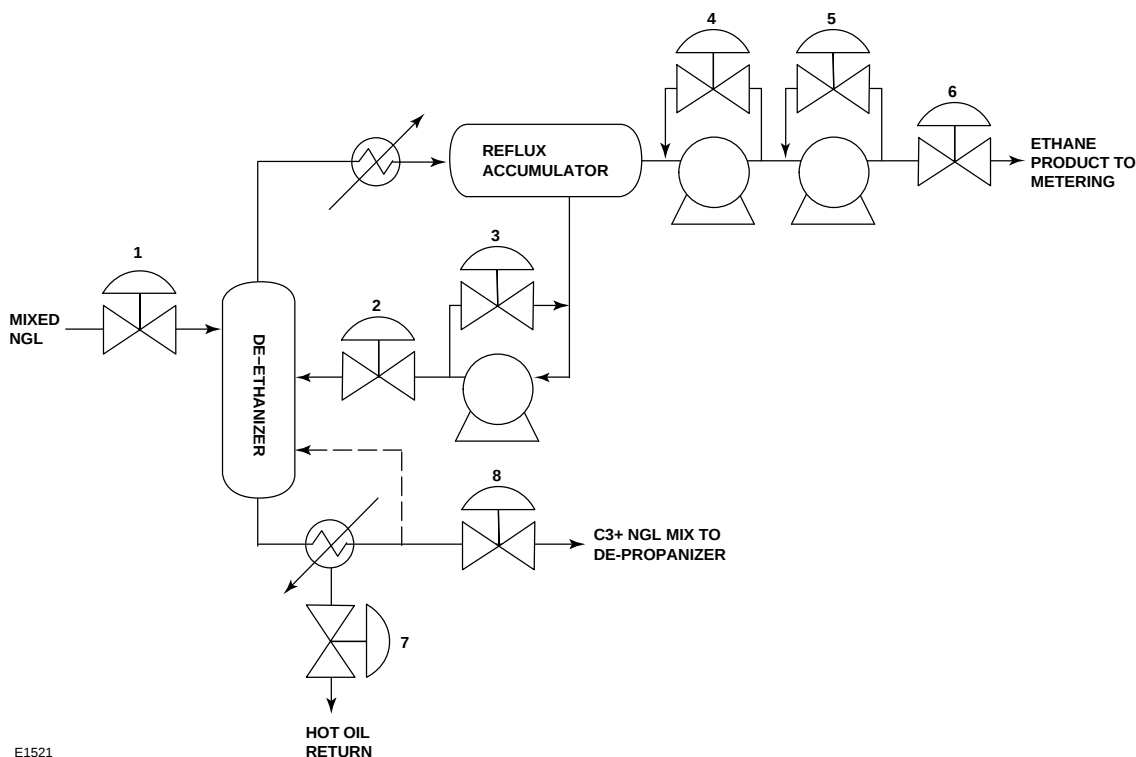


Figure 11-2. Process Diagram of Typical Deethanizer Unit

Though the process outlined here is typical for a plant recovering ethane, propane, and butane, the design of each plant will vary depending on numerous factors. In certain cases, an ethane and propane mix is the primary product, so only one tower is required. Some plants will require sulfur removal from the propane product. Others will require an additional butane splitter to produce separate streams of isobutane and normal butane.

Fractionation Application Review

At some sites, fractionation units will be integrated into a gas treatment plant that is capable of recovering NGLs from the natural gas supply. However, most large-scale fractionation units are standalone and receive their NGL stream from other gas treatment plants that recover NGL from produced natural gas and pipe it offsite for fractionating. The following application review is based on fractionators with a rated capacity of 50,000 to

100,000 bbl/d, which encompasses the vast majority of units in operation today.

Deethanizer

A typical deethanizer is featured in Figure 11-2. As the lightest component in the mixed NGL stream, ethane is the first hydrocarbon to be boiled off. Ethane vapor boiled off into the deethanizer overhead is cooled, condensed, and captured in the reflux accumulator. The remaining liquid hydrocarbons in the deethanizer tower are heated through the bottom reboiler to boil off any residual ethane, and then flow to the depropanizer.

1. Deethanizer Inlet Control: This valve controls the flow of mixed NGL into the deethanizer tower. Accurate control is required to maintain the proper volume of mixed NGL feeding into the tower and optimize ethane recovery. CoCr-A hardfacing is required on the trim, as this valve may experience mild to moderate flashing depending on the pressure drop. Use of an angle body with hardened liner is suggested if flashing is expected to be severe.

Table 11-1. Deethanizer Inlet Control Valve

Parameter	Typical Value
Inlet Pressure	400 - 500 psig (28 - 35 bar)
Outlet Pressure	200 - 300 psig (14 - 21 bar)
Inlet Temp.	80 - 100°F (27 - 38°C)
Flow Rate	20,000 - 100,000 bpd (130 - 665 m ³ /h)
Valve Type and Pressure Class	NPS 4 - 8 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST / CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. Deethanizer Reflux Pump to Deethanizer Control: This valve controls discharge flow of liquid ethane from the deethanizer reflux pump back to the deethanizer tower. A segmented ball valve is used to provide accurate flow control and rangeability with minimal pressure drop across the valve. Low temperature carbon steel (LCC) body may be required if excursions below -20 °F (-29 °C) are expected.

Table 11-2. Deethanizer Reflux Pump to Deethanizer Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 320 psig (21 - 22 bar)
Outlet Pressure	280 - 300 psig (19 - 21 bar)
Inlet Temp.	0 - 10°F (-18 - -12°C)
Flow Rate	10,000 - 45,000 bpd (65 - 300 m ³ /h)
Valve Type and Pressure Class	NPS 4 - 10 Vee-Ball V300, ASME CL300
Valve Material and Trim Material	WCC/LCC body, 317 SST / CrPI ball
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. Deethanizer Reflux Pump Recycle Control: This valve recycles flow through the deethanizer reflux pump when needed to prevent cavitation. It is used most commonly in commissioning and startup as the unit is brought up to full capacity. Due to the small pressure drop across this valve, a globe with standard trim is usually sufficient. Low temperature carbon steel (LCC) body may be required if excursions below -20 °F (-29 °C) are expected.

Table 11-3. Deethanizer Reflux Pump Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 320 psig (21 - 22 bar)
Outlet Pressure	250 psig (17 bar)
Inlet Temp.	0 - 10°F (-18 - -12°C)
Flow Rate	5,000 - 20,000 bpd (30 - 135 m ³ /h)
Valve Type and Pressure Class	NPS 2 - 6 ET, ASME CL300
Valve Material and Trim Material	WCC or LCC body, 316 SST / CoCr-A trim
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage

4. Ethane Booster Pump Recycle Control: This valve recycles flow through the ethane booster pump when needed to prevent cavitation. It is used most commonly in commissioning and startup as the unit is brought up to full capacity. A globe body with standard or anti-cavitation trim is most common in this application.

Table 11-4. Ethane Booster Pump Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	600 - 700 psig (41 - 48 bar)
Outlet Pressure	250 - 300 psig (17 - 21 bar)
Inlet Temp.	10 - 20°F (-12 - -7°C)
Flow Rate	4,000 - 30,000 bpd (25 - 200 m ³ /h)
Valve Type and Pressure Class	NPS 1 - 4 ET, ASME CL600
Valve Material and Trim Material	WCC or LCC body, 316 SST / CoCr-A trim
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage/Cavitrol III trim

5. Ethane Pump Recycle Control: This valve recycles flow through the primary ethane pump when needed to prevent cavitation. It is used most commonly in commissioning and startup as the unit is brought up to full capacity. Anti-cavitation trim is nearly always required due to the elevated pressure drop across the primary pump. Micro-Trim may be required as well to address low flow requirements.

Table 11-5. Ethane Pump Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	1600 - 1800 psig (110 - 124 bar)
Outlet Pressure	1100 - 1250 psig (76 - 86 bar)
Inlet Temp.	60 - 80°F (16 - 27°C)
Flow Rate	4,000 - 30,000 bpd (25 - 200 m ³ /h)
Valve Type and Pressure Class	NPS 1 - 3 HPT, ASME CL900
Valve Material and Trim Material	WCC body, 17-4 SST trim
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim



Figure 11-3. NPS 4 EH or HP Control Valve and 657 Actuator Size 80 with DVC6010

6. Ethane to Product Meter Control: This valve controls the flow of ethane from the pump discharge to metering. The pressure drop across this valve is intended to be minimal. A globe with standard trim is the most common selection.

Table 11-6. Ethane to Product Meter Control Valve

Parameter	Typical Value
Inlet Pressure	1600 - 1800 psig (110 - 124 bar)
Outlet Pressure	1580 - 1780 psig (109 - 123 bar)
Inlet Temp.	80 - 100°F (27 - 38°C)
Flow Rate	15,000 - 50,000 bpd (95 - 335 m ³ /h)
Valve Type and Pressure Class	NPS 4 - 8 HPT/EHT, ASME CL900
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

7. Deethanizer Reboiler Hot Oil Return Control: This valve controls the flow of hot oil from the bottom reboiler heat exchanger back to the hot oil heater.

Table 11-7. Deethanizer Reboiler Hot Oil Return Control Valve

Parameter	Typical Value
Inlet Pressure	60 psig (4 bar)
Outlet Pressure	25 - 35 psig (2 - 3 bar)
Inlet Temp.	200 - 250°F (93 - 121°C)
Flow Rate	250 - 300 gpm (55 - 70 m ³ /h)
Valve Type and Pressure Class	NPS 2 - 4 Vee-Ball V300, ASME CL300
Valve Material and Trim Material	WCC body, 317 SST/CrPI ball
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

8. Deethanizer Reboiler to Depropanizer Control: This valve controls the flow of liquid C3+ mixed NGL from the deethanizer bottom reboiler to the depropanizer. Accurate control is required to maintain the proper volume of NGL feeding into the depropanizer to ensure optimal propane recovery.

Table 11-8. Deethanizer Reboiler to Depropanizer Control Valve

Parameter	Typical Value
Inlet Pressure	260 psig (18 bar)
Outlet Pressure	180 - 210 psig (12 - 14 bar)
Inlet Temp.	170°F (77°C)
Flow Rate	20,000 - 75,000 bpd (130 - 500 m ³ /h)
Valve Type and Pressure Class	NPS 3 - 8 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Depropanizer

Figure 11-4 features a typical depropanizer. Propane vapor boiled off into the depropanizer overhead is cooled, condensed, and captured in the reflux accumulator. A heat pump compressor is utilized to boost the pressure of the propane vapor. Heat input from the compression process is recovered via two heat exchangers, which allow the propane to cool and condense into the reflux accumulator. The remaining liquid hydrocarbons in the depropanizer tower are heated through the bottom reboiler to boil off any residual propane, and then flow to the debutanizer.

1. Depropanizer Heat Pump Compressor Recycle Control: This valve is used to recycle the flow of propane gas back through the heat pump

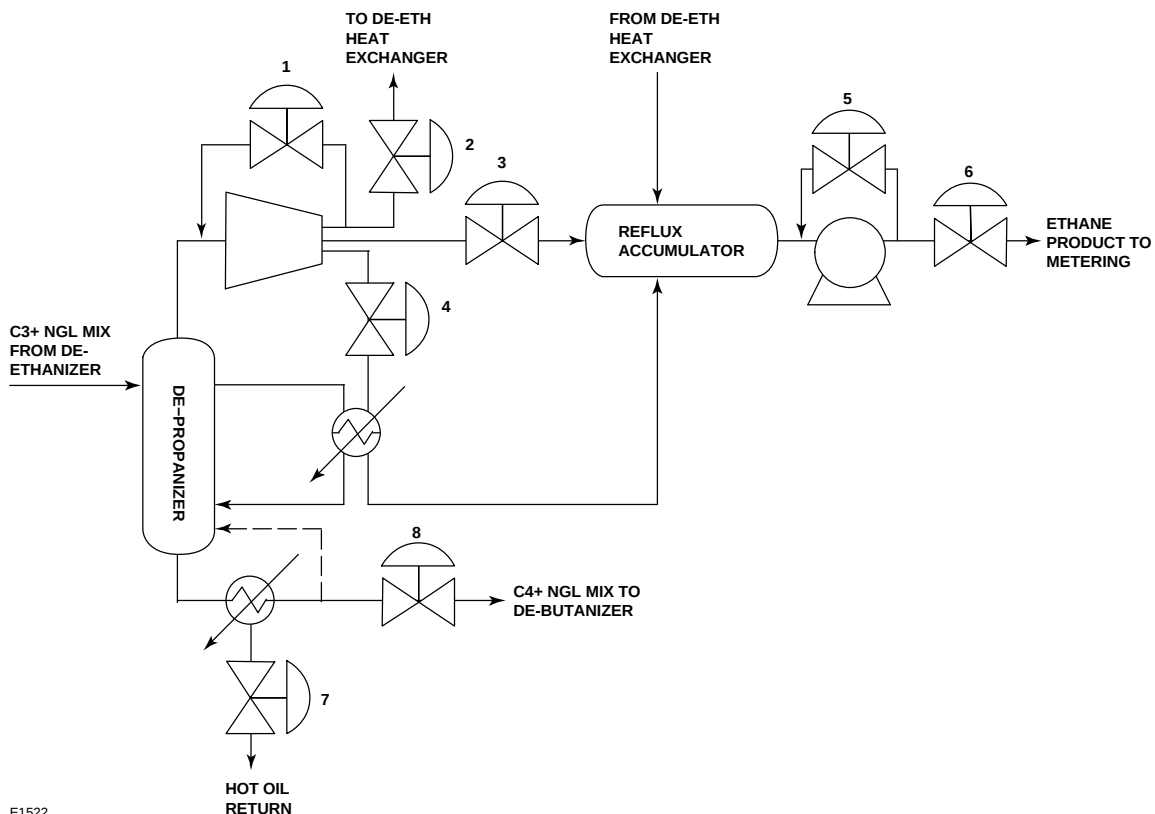


Figure 11-4. Process Diagram of Typical Depropanizer Unit

compressor. It is most commonly used in startup and commissioning to bring the compressor up to capacity. Fast stroking requirements common when this valve is used in anti-surge service. Quote the Fisher Optimized Digital Valve (ODV) on larger valves when needed to meet stroke speed and throttling requirements.

Table 11-9. Depropanizer Heat Pump Compressor Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	500 - 600 psig (35 - 41 bar)
Outlet Pressure	180 - 200 psig (12 - 14 bar)
Inlet Temp.	200 - 225°F (93 - 107°C)
Flow Rate	12,000 - 108,000 MSCFD (13,000 - 120,000 m ³ /h)
Valve Type and Pressure Class	NPS 6 - 12 ET/EWT, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

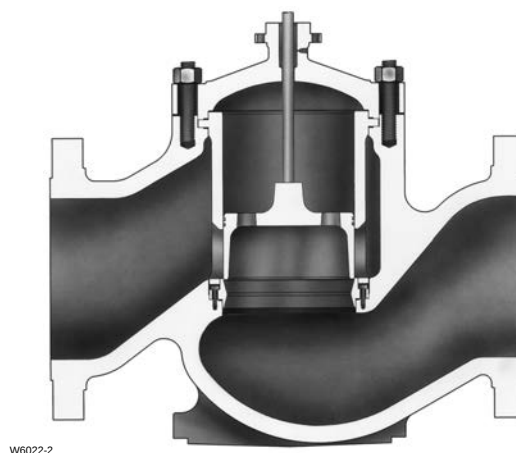


Figure 11-5. NPS 10-24 EWT or EWD

2. Depropanizer Heat Pump Compressor to Deethanizer Control: This valve controls the flow of compressed propane vapor back to the deethanizer heat exchanger. This valve typically takes a minimal pressure drop and a butterfly valve is usu-



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Figure 11-6. 8580 Valve with 2052 Actuator and DVC6000

ally sufficient. Tight shutoff will be specified in some cases.

Table 11-10. Depropanizer Heat Pump Compressor to Deethanizer Control Valve

Parameter	Typical Value
Inlet Pressure	500 - 600 psig (35 - 41 bar)
Outlet Pressure	480 - 580 psig (33 - 40 bar)
Inlet Temp.	200 - 225°F (93 - 107°C)
Flow Rate	28,000 - 58,000 MSCFD (32,000 - 65,000 m ³ /h)
Valve Type and Pressure Class	NPS 6 - 12 8580, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CrPI disc, PTFE seal
Shutoff Requirement	ANSI Class VI
Trim Type	Linear

3. Depropanizer Heat Pump Compressor to Reflux Accumulator Control: This valve controls the flow of compressed propane vapor directly into the reflux accumulator. Pressure drop across this valve is minimal, and a segmented ball valve is typically used to provide rangeability and accurate control.

Table 11-11. Depropanizer Heat Pump Compressor to Reflux Accumulator Control Valve

Parameter	Typical Value
Inlet Pressure	500 - 600 psig (36 - 41 bar)
Outlet Pressure	480 - 580 psig (33 - 40 bar)
Inlet Temp.	200 - 225°F (93 - 107°C)
Flow Rate	12,000 - 24,000 MSCFD (13,000 - 25,000 m ³ /h)
Valve Type and Pressure Class	NPS 4 - 12 Vee-Ball V300, ASME CL300
Valve Material and Trim Material	WCC body, 317 SST/CrPI ball
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

4. Depropanizer Heat Pump Compressor to Depropanizer Side Reboiler: This valve controls the flow of compressed propane vapor to the side reboiler heat exchanger. Pressure drop is minimal and a butterfly valve is typically used. Tight shutoff will be required in some cases.

Table 11-12. Depropanizer Heat Pump Compressor to Depropanizer Side Reboiler Valve

Parameter	Typical Value
Inlet Pressure	500 - 600 psig (35 - 41 bar)
Outlet Pressure	480 - 580 psig (33 - 40 bar)
Inlet Temp.	200 - 225°F (93 - 107°C)
Flow Rate	24,000 - 48,000 MSCFD (25,000 - 55,000 m ³ /h)
Valve Type and Pressure Class	NPS 6 - 14 8580/8532, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CrPI disc, PTFE seal
Shutoff Requirement	ANSI Class VI
Trim Type	Linear

5. Propane Pump Recycle Control: This valve recycles flow through the primary propane pump, when needed, to prevent cavitation. It is used most commonly in commissioning and startup as the unit is brought up to full capacity. Anti-cavitation trim is nearly always required due to the elevated pressure drop across the primary pump. Micro-Trim may be required, as well, to address low-flow requirements.

Table 11-13. Propane Pump Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	1400 - 1600 psig (97 - 110 bar)
Outlet Pressure	400 - 500 psig (28 - 35 bar)
Inlet Temp.	80 - 100°F (27 - 38°C)
Flow Rate	5000 - 12,000 bpd (30 - 80 m ³ /h)
Valve Type and Pressure Class	NPS 1 - 3 HPT, ASME CL900
Valve Material and Trim Material	WCC body, 17-4 SST trim
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim

6. Propane to Product Meter Control: This valve controls the flow of propane from the pump discharge to metering. The pressure drop across this valve is intended to be minimal. A globe with standard trim is the most common selection.

Table 11-14. Propane to Product Meter Control Valve

Parameter	Typical Value
Inlet Pressure	1400 - 1600 psig (97 - 110 bar)
Outlet Pressure	1380 - 1580 psig (95 - 109 bar)
Inlet Temp.	80 - 100°F (27 - 38°C)
Flow Rate	10,000 - 35,000 bpd (65 - 235 m ³ /h)
Valve Type and Pressure Class	NPS 3 - 6 HPT, ASME CL900
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

7. Depropanizer Bottom Reboiler Hot Oil Return Control: This valve controls the flow of hot oil from the bottom reboiler heat exchanger back to the hot oil heater.

Table 11-15. Depropanizer Bottom Reboiler Hot Oil Return Control Valve

Parameter	Typical Value
Inlet Pressure	60 psig (4 bar)
Outlet Pressure	45 - 50 psig (3 bar)
Inlet Temp.	250 - 275°F (121 - 135°C)
Flow Rate	900 - 2,000 gpm (200 - 455 m ³ /h)
Valve Type and Pressure Class	NPS 4 - 8 Vee-Ball V300, ASME CL300
Valve Material and Trim Material	WCC body, 317 SST/CrPl ball
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

8. Depropanizer Bottom Reboiler to Debutanizer Control: This valve controls the flow of liquid C4+ mixed NGL from the depropanizer bottom reboiler to the debutanizer. Accurate control is required to maintain the proper volume of NGL feed-

ing into the debutanizer to ensure optimal recovery of butanes.

Table 11-16. Depropanizer Bottom Reboiler to Debutanizer Control Valve

Parameter	Typical Value
Inlet Pressure	190 psig (13 bar)
Outlet Pressure	150 - 170 psig (10 - 12 bar)
Inlet Temp.	230°F (110°C)
Flow Rate	15,000 - 50,000 bpd (95 - 335 m ³ /h)
Valve Type and Pressure Class	NPS 3 - 8 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Debutanizer

The debutanizer operates in a similar manner as the deethanizer and depropanizer, but produces butane product. With the lighter products already removed (ethane and propane), the remaining liquid C4+ mixed NGL stream enters the debutanizer tower. Butane product boils off to the overhead, is condensed, and collected in the reflux accumulator. The remaining C5+ liquid condensate at the tower bottom is reboiled to recover any residual butane, and then eventually cooled through the condensate cooler and piped to storage.

1. Debutanizer Reflux Pump to Debutanizer Control: This valve controls discharge flow of liquid butane from the debutanizer reflux pump back to the debutanizer tower. A segmented ball valve is used to provide accurate flow control and rangeability with minimal pressure drop across the valve.

Table 11-17. Debutanizer Reflux Pump to Debutanizer Control Valve

Parameter	Typical Value
Inlet Pressure	180 psig (12 bar)
Outlet Pressure	150 - 170 psig (10 - 12 bar)
Inlet Temp.	160 - 180°F (71 - 82°C)
Flow Rate	15,000 - 35,000 bpd (100 - 230 m ³ /h)
Valve Type and Pressure Class	NPS 3 - 8 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

2. Debutanizer Reflux Pump Recycle Control: This valve recycles flow through the debutanizer reflux pump when needed to prevent cavitation. It

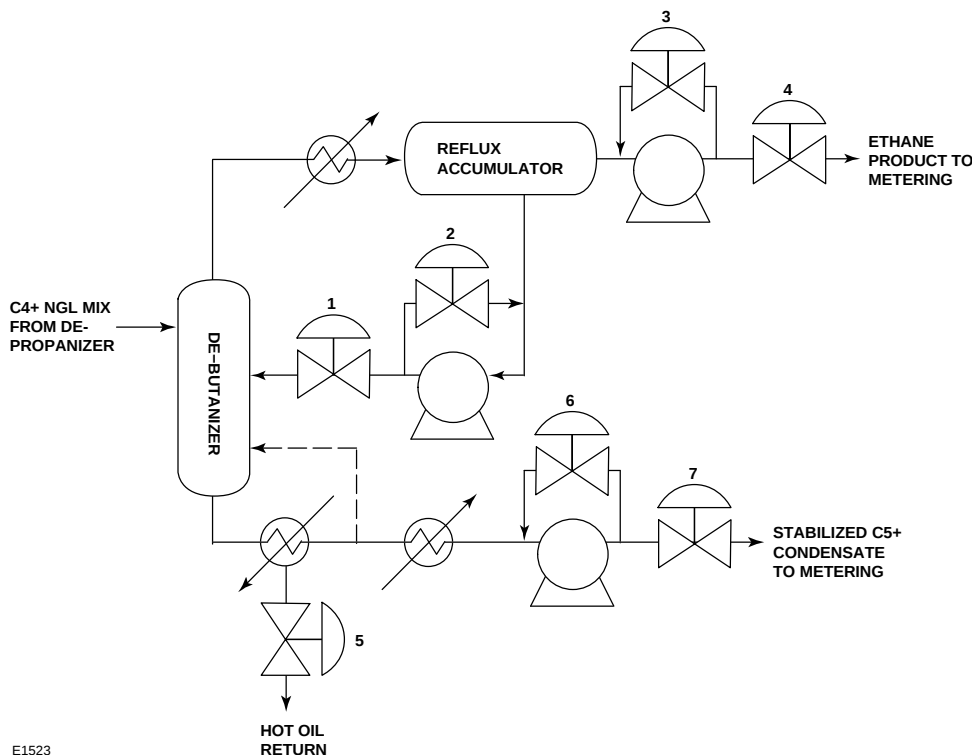


Figure 11-7. Process Diagram of Typical Debutanizer Unit

is used most commonly in commissioning and startup as the unit is brought up to full capacity. Due to the small pressure drop across this valve, a globe with standard trim is usually sufficient.

commonly in commissioning and startup as the unit is brought up to full capacity. Pressure drop is relatively low across this valve and standard trim is usually sufficient.

Table 11-18. Debutanizer Reflux Pump to Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	180 psig (12 bar)
Outlet Pressure	160 psig (11 bar)
Inlet Temp.	160 - 180°F (71 - 82°C)
Flow Rate	4000 - 12,000 bpd (25 - 80 m ³ /h)
Valve Type and Pressure Class	NPS 1 - 3 ET, ASME CL300
Valve Material and Trim Material	WCC or LCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage

3. Butane Pump Recycle Control: This valve recycles flow through the primary butane pump when needed to prevent cavitation. It is used most

Table 11-19. Butane Pump Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 350 psig (21 - 24 bar)
Outlet Pressure	100 - 150 psig (7 - 10 bar)
Inlet Temp.	100 - 120°F (38 - 49°C)
Flow Rate	6,000 - 10,000 bpd (40 - 70 m ³ /h)
Valve Type and Pressure Class	NPS 1 - 3 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class V
Trim Type	Standard

4. Butane to Product Meter Control: This valve controls the flow of butane from the pump discharge to metering. The pressure drop across this valve is intended to be minimal. A globe with standard trim is the most common selection.



X0187

Figure 11-8. Vee-Ball V150 NPS 3 with 2052 Size 1 Actuator and DVC6200

Table 11-20. Butane to Product Meter Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 350 psig (21 - 24 bar)
Outlet Pressure	280 - 330 psig (19 - 23 bar)
Inlet Temp.	80 - 100°F (27 - 38°C)
Flow Rate	6,000 - 20,000 bpd (40 - 135 m ³ /h)
Valve Type and Pressure Class	NPS 3 - 6 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

5. Debutanizer Reboiler Hot Oil Return Control: This valve controls the flow of hot oil from the bottom reboiler heat exchanger back to the hot oil heater.

Table 11-21. Debutanizer Reboiler Hot Oil Return Control Valve

Parameter	Typical Value
Inlet Pressure	60 psig (4 bar)
Outlet Pressure	45 - 50 psig (3 bar)
Inlet Temp.	325°F (163°C)
Flow Rate	1,400 - 3,200 gpm (300 - 725 m ³ /h)
Valve Type and Pressure Class	NPS 6 - 12 Vee-Ball V150, ASME CL150
Valve Material and Trim Material	WCC body, 317 SST/CrPI ball
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

6. Debutanizer Bottoms Pump Recycle Control: This valve recycles flow through the bottoms pump when needed to prevent cavitation. It is used most commonly in commissioning and start-up as the unit is brought up to full capacity. Pressure drop is relatively low across this valve and standard trim is usually sufficient.

Table 11-22. Debutanizer Bottoms Pump Recycle Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 350 psig (21 - 24 bar)
Outlet Pressure	100 - 150 psig (7 - 10 bar)
Inlet Temp.	80 - 100°F (27 - 38°C)
Flow Rate	1,000 - 8,000 bpd (5 - 55 m ³ /h)
Valve Type and Pressure Class	NPS 1 - 3 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class V
Trim Type	Standard

7. Condensate Product Meter Control: This valve controls the flow of stabilized C5+ condensate from the pump discharge to metering. The pressure drop across this valve is intended to be minimal. A globe with standard trim is the most common selection.

Table 11-23. Condensate Product Meter Control Valve

Parameter	Typical Value
Inlet Pressure	300 - 350 psig (21 - 24 bar)
Outlet Pressure	280 - 330 psig (19 - 23 bar)
Inlet Temp.	80 - 100°F (25 - 40°C)
Flow Rate	5,000 - 15,000 bpd (27 - 38 m ³ /h)
Valve Type and Pressure Class	NPS 3 - 6 ET, ASME CL300
Valve Material and Trim Material	WCC body, 316 SST/CoCr-A trim
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Natural Gas Storage

In regions that utilize natural gas for residential and commercial heating, gas storage facilities are required to accommodate the seasonal surge in demand during the winter months. Excess gas produced during the summer months is put into storage as demand is relatively low during this time. Storage facilities also serve as a buffer to supply gas during interruptions brought about by accidents, natural disasters, or other unforeseen causes.

The total gas in storage at such a facility is divided into two categories; base gas and working gas. Base gas, also called “cushion gas”, is the volume of gas that is required to maintain a minimum well-head pressure. In order to properly operate the facility, this volume can never leave the formation. Working gas is the volume of gas that can be extracted in the normal operation of the reservoir. Smaller peak load facilities may only have 0.1 Bcf of working gas volume, with larger base load facilities up to 100 Bcf.

There are three types of formations that are used for underground gas storage:

1. Depleted reservoirs
2. Aquifers
3. Salt caverns

Most existing storage facilities make use of depleted natural gas or oil reservoirs. These locations provide the benefit of existing wells and gas transportation infrastructure. Another primary benefit is that depleted reservoirs typically have much larger storage volumes than other types of storage facilities.

Despite their relatively low storage capacities, salt caverns have grown in popularity due to their higher relative injection and withdrawal rates. Naturally

occurring domes within salt formations are not often large enough to provide sufficient storage capacity. Nearly all caverns used for storage require a solution mining process upfront to remove additional salt from the formation and create sufficient storage volume. This process is commonly referred to as leaching.

Naturally occurring aquifers are the least common type of storage facility due to the relatively high base gas requirements and low permeability inherent to these formations.

Natural Gas Storage Process

Underground Storage Process

While the type of formation used for storage may vary, the basic processes employed at underground storage facilities are common to nearly all sites. All facilities will contain two straightforward processes; gas injection, and gas withdrawal and export. In addition, salt dome formations will commonly require that a brine plant be employed upfront to leach out additional storage volume before the facility will begin gas storage operations. Figure 12-1 shows a process flow diagram of this process.

Water Injection and Brine Disposal

The brine plant facilitates the leaching process, which creates salt caverns of sufficient storage volume. This is a relatively straightforward process. Fresh water injected into the existing salt dome removes solid salt from the formation as it dissolves. This process results in a salt-laden brine solution that flows to the surface through an extraction well. Depending on the location of the site, this brine is either injected into a different



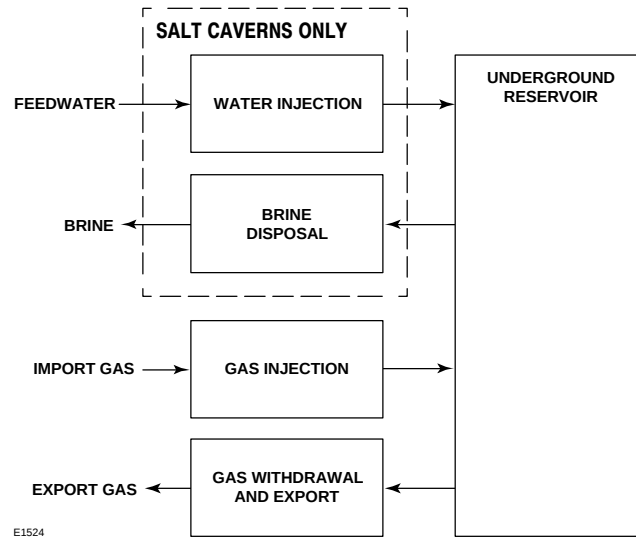


Figure 12-1. Underground Storage Process

formation nearby for disposal or sold to a chemical facility for use as a feedstock.

Depending on the size of the salt cavern required, the leaching process will take anywhere from six months to three years to remove a sufficient volume of salt from the formation. The leaching process is not required when other types of formations are used for storage, as they already have enough storage volume to be considered economically feasible.

Gas Injection

Gas injection facilities are used to fill the storage facility with gas. This gas will be metered at an interconnect exiting the pipeline and piped directly to the injection sites. The pressure of gas entering this unit will depend on the operating pressure of the nearby pipeline from which it is sourced. In most facilities, additional compression is required to boost the pressure of the gas before injection. Since the gas has already been processed to pipeline specifications, no further processing is required prior to injection into the storage formation.

The number and capacity of each gas injection well will vary depending on the physical footprint of

the storage formation, and the injection capacity of the facility. Injection wells are commonly spread out over a large footprint and operated remotely. It is common for gas injection wells to be designed for bi-directional flow for withdrawal.

Gas Withdrawal and Export

The gas withdrawal and export facilities extract gas from the formation and export it back to the pipeline system for distribution, and ultimate consumption. Due to changes in the gas that can occur while it resides in storage there is typically a need for processing to remove contaminants, and restore the gas to pipeline specifications before export.

Gas that is extracted from the storage formation will first enter a separator vessel where any free liquids or solids that have exited with the gas will fall out. Liquids from this vessel are injected into a disposal formation or pumped to a nearby holding tank. The gas exiting the withdrawal separator will require additional dehydration to remove moisture before export to the pipeline. Dehydration processes utilizing glycol absorbents to remove the remaining moisture are most common in storage facilities. See Chapter nine for more details on this process.

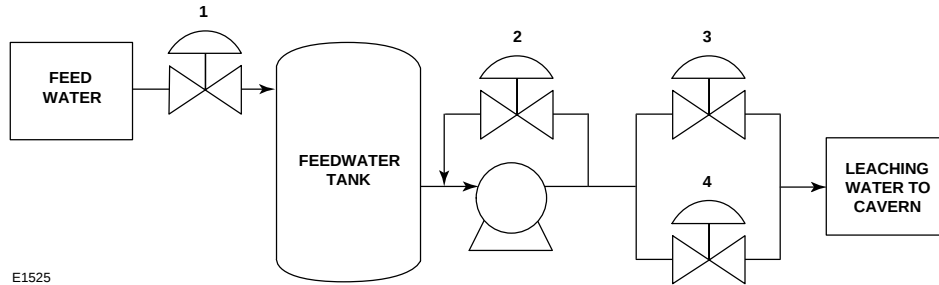


Figure 12-2. Water Injection System Valve Diagram

Natural Gas Storage Application Review

Underground Storage

Water Injection and Brine Disposal

1. **Water Injection System Control:** Entrained solids are possible, but not common in this application.

Table 12-1. Water Injection System Control Valve

Parameter	Typical Value
Fluid	Fresh Well Water
Inlet Pressure	35 - 110 psig (3 - 8 bar)
Outlet Pressure	25 - 100 psig (2 - 7 bar)
Flow Rate	500 - 1,500 gpm (110 - 340 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 6 - 8 Vee-Ball V150, ASME CL150
Valve Material and Trim Material	WCC with 316 SST

2. **Water Injection Pump Minimum Flow Recirculation Control:** Recycles flow during startup to control dP across pump. Cavitrol 2-stage trim is typically required to prevent cavitation damage in this high-dP service.

Table 12-2. Feedwater Injection Pump Minimum Flow Recirculation Control Valve

Parameter	Typical Value
Fluid	Fresh Well Water
Inlet Pressure	200 - 750 psig (14 - 52 bar)
Outlet Pressure	180 - 730 psig (12 - 50 bar)
Flow Rate	180 gpm (40 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 1 - 4 ET, ASME CL600
Valve Material and Trim Material	WCC with Standard
Trim Type	Cavitrol III trim

3. **Feedwater Injection Pump Discharge Minimum Flow Control:** This valve provides flow control of leaching water into the cavern. It is used during startup and process upsets to control low flow, high dP conditions. Cavitrol 2-stage trim is typically required to prevent cavitation damage from high dP service.

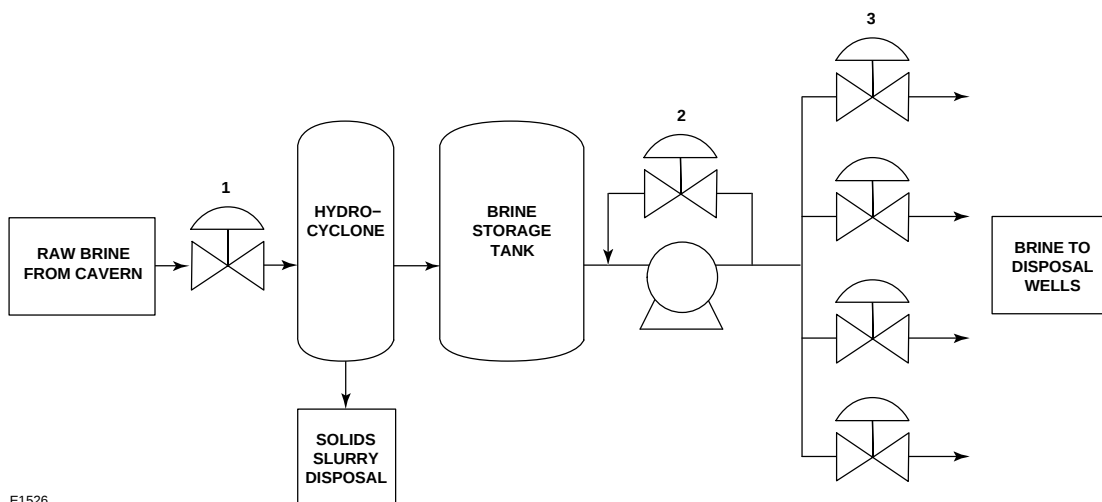
Table 12-3. Feedwater Injection Pump Discharge Minimum Flow Control Valve

Parameter	Typical Value
Fluid	Fresh Well Water
Inlet Pressure	200 - 750 psig (14 - 52 bar)
Outlet Pressure	10 psig (1 bar)
Flow Rate	200 - 350 gpm (45 - 80 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 1 - 4 ET, ASME CL600
Valve Material and Trim Material	WCC with Standard
Trim Type	Cavitrol III trim

4. **Feedwater Injection Pump Discharge Maximum Flow Control:** This valve provides flow control of leaching water into the cavern. It is used in normal operating conditions for high flow, low dP service and operates in tandem with minimum flow injection valve. When minimum flow injection valve is not present, a Vee-Ball V200 with rotary attenuator or a V260B is required to mitigate startup cavitation.

Table 12-4. Feedwater Injection Pump Discharge Maximum Flow Control Valve

Parameter	Typical Value
Fluid	Fresh Well Water
Inlet Pressure	200 - 750 psig (14 - 52 bar)
Outlet Pressure	190 - 740 psig (13 - 51 bar)
Flow Rate	300 - 1,500 gpm (65 - 340 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 6 - 8 Vee-Ball V200, ASME CL600
Valve Material and Trim Material	WCC with Standard



E1526

Figure 12-4. Brine Disposal System Valve Diagram



X0188

Figure 12-3. Vee-Ball V200 NPS 3 with a 2052 Size 1 Actuator and DVC6200

1. Brine Storage Tank Level Control: Brine enters this valve directly from the cavern and entrained solids are likely. A rotary solution is required here due to high capacity, low dP conditions. A Vee-Ball V500 valve is recommended when solids erosion is possible. The WCC body will suffer general corrosion, but this is typically acceptable due to the relatively short service life of the brine plant.

Table 12-5. Brine Storage Tank Level Control Valve

Parameter	Typical Value
Fluid	Raw Brine from Cavern
Inlet Pressure	20 - 110 psig (1 - 8 bar)
Outlet Pressure	5 - 30 psig (1 - 2 bar)
Flow Rate	800 - 4,000 gpm (180 - 910 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 6 - 10 Vee-Ball V250/V500, ASME CL600
Valve Material and Trim Material	WCC with Standard/316 SST Ball

2. Brine Injection Pump Min Flow Recirculation Control: This valve is used during pump startup and normal operation to maintain appropriate upstream and downstream pressure. Solids and particulate may be present in some installations. Cavitrol III trim is recommended if clean and NotchFlo Trim if significant solids are present. Full stroke requirements of one to two seconds are typical for this valve. The WCC body will suffer general corrosion, but this is typically acceptable due to the relatively short service life of the brine plant.



W8433

Figure 12-5. NotchFlo DST Trim

Table 12-6. Brine Injection Pump Min Flow Recirculation Control Valve

Parameter	Typical Value
Fluid	Brine
Inlet Pressure	1000 - 1200 psig (69 - 83 bar)
Outlet Pressure	50 psig (3 bar)
Flow Rate	600 - 1,000 gpm (135 - 230 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 2 - 6 ET/HPT, ASME CL600/900
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Cavitrol III trim or NotchFlo Trim

3. Brine Disposal Flow Control: Potential for cavitation damage exists depending on the duration of high dP operation. Solids and particulate are present in some installations. Cavitrol trim is recommended if clean and NotchFlo Trim if significant solids are present. The WCC body will suffer general corrosion, but this is typically acceptable due to the relatively short service life of the brine plant. Electric actuators may be specified in some instances due to the remote location of disposal wells. In this instance, it is recommended that EIM is quoted.

Table 12-7. Brine Disposal Flow Control Valve

Parameter	Typical Value
Fluid	Brine
Inlet Pressure	650 - 1550 psig (45 - 107 bar)
Outlet Pressure	10 - 1450 psig (1 - 100 bar)
Flow Rate	900 - 1,200 gpm (200 - 275 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 4 - 6 ET/HPT, ASME CL600/900
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Equal Percentage, Cavitrol III trim or NotchFlo Trim

Gas Injection System

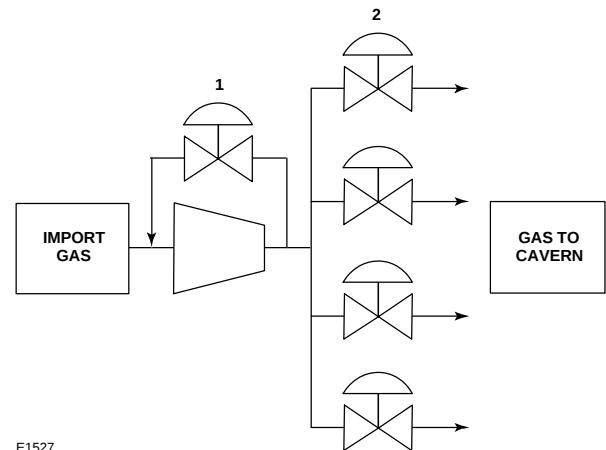


Figure 12-6. Gas Injection System Valve Diagram

1. Injection Compressor Anti-surge Control: An anti-surge valve is used during compressor startup and during normal operation to prevent damaging surge event. Full open stroke requirements of less than one second are common to recycle flow and prevent surge event. Ball valves will be specified by the compressor vendor in some instances.

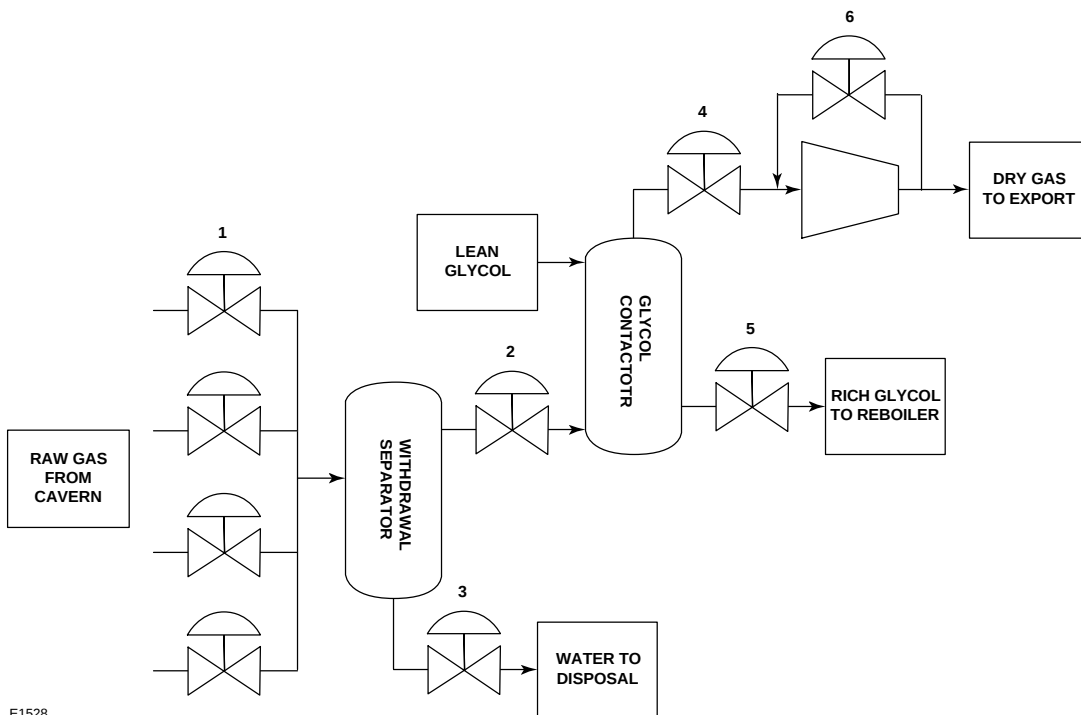


Figure 12-8. Gas Withdrawal & Export System Valve Diagram

Table 12-8. Injection Compressor Anti-surge Control Valve

Parameter	Typical Value
Fluid	Natural Gas
Inlet Pressure	1000 - 2000 psig (69 - 138 bar)
Outlet Pressure	250 - 1000 psig (17 - 69 bar)
Flow Rate	50,000 - 300,000 MSCFD (56,000 - 335,000 m ³ /h)
Inlet Temp.	60 - 100°F (16 - 38°C)
Valve Type and Pressure Class	NPS 4 - 6 ET/HPT, ASME CL600/900
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Whisper III Trim or WhisperFlo Trim

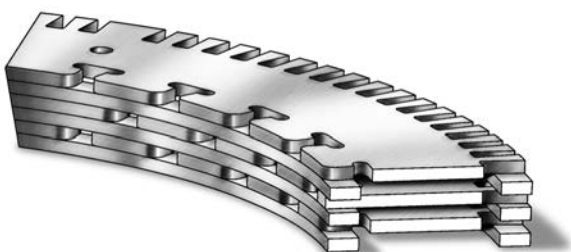


Figure 12-7. WhisperFlo Trim

2. Cavern Injection Control: This valve controls the flow of gas into the storage cavern. Capacity requirements will vary greatly based on the num-

ber of wells and rated injection capacity of the facility. This valve is commonly used for gas withdrawal, as well. In those cases, bi-directional flow capability is required. When bi-directional use is required for withdrawal, turndown requirements can be extreme. Low dP drives high C_v requirements during injection. High dP drives low C_v requirement during withdrawal. A specially characterized cage is commonly required.

Table 12-9. Cavern Injection Control Valve

Parameter	Typical Value
Fluid	Natural Gas
Inlet Pressure	1000 - 3000 psig (69 - 207 bar)
Outlet Pressure	700 - 2000 psig (48 - 138 bar)
Flow Rate	5,000 - 250,000 MSCFD (5,500 - 280,000 m ³ /h)
Inlet Temp.	80 - 150°F (27 - 66°C)
Valve Type and Pressure Class	NPS 6 - 20 ET/HPT, ASME CL600/900/1500
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Whisper III Trim or WhisperFlo Trim

Gas Withdrawal and Export

1. Cavern Withdrawal Control: This valve controls the flow of gas out of the storage cavern. Capacity requirement will vary greatly based on the number of wells and rated delivery capacity of the facility. This valve is commonly used for gas injec-

tion as well. In those cases, bi-directional flow capability is required. When bi-directional use is required for injection or withdrawal, turndown requirements can be extreme. A low dP drives high C_v requirements during injection. A high dP drives low C_v requirements during withdrawal. A specially characterized cage is commonly required. This valve will be specified as a full-bore ball valve in some instances. Quote a Vee-Ball V250/260 as needed. Sand content in withdrawn gas will vary by site. Confirm the presence of sand before providing drilled-hole trim.

Table 12-10. Cavern Withdrawal Control Valve

Parameter	Typical Value
Fluid	Natural Gas
Inlet Pressure	500 - 2500 psig (35 - 172 bar)
Outlet Pressure	300 - 1500 psig (21 - 103 bar)
Flow Rate	5,000 - 250,000 MSCFD (5,500 - 280,000 m ³ /h)
Inlet Temp.	40 - 150°F (4 - 66°C)
Valve Type and Pressure Class	NPS 6 - 20 ET/EHT, ASME CL600/900/1500
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Whisper III Trim or WhisperFlo Trim

2. Separator Pressure Control: This valve controls the flow of gas out of the withdrawal separator and maintains vessel pressure. A D4 can be quoted to improve competitiveness where possible. Two-stage separation is common in higher pressure facilities. HP and LP separator vessels will be present. Applications are similar other than pressure of the vessel.

Table 12-11. Separator Pressure Control Valve

Parameter	Typical Value
Fluid	Natural Gas
Inlet Pressure	300 - 1500 psig (21 - 103 bar)
Outlet Pressure	200 - 1200 psig (14 - 83 bar)
Flow Rate	50,000 - 500,000 MSCFD (56,000 - 560,000 m ³ /h)
Inlet Temp.	40 - 150°F (4 - 66°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/ED/EHT, ASME CL600/900/1500
Valve Material and Trim Material	WCC with 316 SST

3. Separator Level Control: This valve maintains water level in the withdrawal separator. Particulate will typically fall out with the liquids. Erosion can be a concern in this application. A D2, D3, or D4 may be used when possible to improve competitiveness.

Table 12-12. Separator Level Control Valve

Parameter	Typical Value
Fluid	Water
Inlet Pressure	300 - 1500 psig (21 - 103 bar)
Outlet Pressure	50 - 75 psig (3 - 5 bar)
Flow Rate	5 - 50 gpm (1 - 12 m ³ /h)
Inlet Temp.	40 - 150°F (4 - 66°C)
Valve Type and Pressure Class	NPS 1 - 3 ET/ED/EHT, ASME CL600/900
Valve Material and Trim Material	WCC with 316 SST

4. Glycol Contactor Pressure Control:

Table 12-13. Glycol Contactor Pressure Control Valve

Parameter	Typical Value
Fluid	Dry Natural Gas
Inlet Pressure	500 - 1200 psig (35 - 83 bar)
Outlet Pressure	300 - 500 psig (21 - 35 bar)
Flow Rate	50,000 - 500,000 MSCFD (56,000 - 560,000 m ³ /h)
Inlet Temp.	40 - 150°F (4 - 66°C)
Valve Type and Pressure Class	NPS 2 - 8 ET/HPT, ASME CL600/900
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Equal Percentage or Whisper III Trim

5. Glycol Contactor Level Control Valve: Controls the level of rich glycol in the glycol contactor. Cavitrol III trim is typically required due to high pressure drops. NotchFlo Trim may be required if any sand carryover from separator or particulate due to glycol degeneration is present.

Table 12-14. Glycol Contactor Level Control Valve

Parameter	Typical Value
Fluid	Rich Glycol
Inlet Pressure	500 - 1200 psig (35 - 83 bar)
Outlet Pressure	50 - 200 psig (3 - 14 bar)
Flow Rate	10 - 250 gpm (2 - 60 m ³ /h)
Inlet Temp.	40 - 150°F (4 - 66°C)
Valve Type and Pressure Class	NPS 1 - 4 ET/HPT, ASME CL600/900
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Cavitrol III Trim

6. Export Compressor Anti-Surge Control: The compressor boosts gas pressure for export to pipeline interconnect and metering. An anti-surge valve should be used during compressor startup and during normal operation to prevent damaging surge events. Full open stroke requirements of less than one second are common to recycle flow and prevent a surge event. Ball valves will be specified by the compressor vendor in some instances.

Table 12-15. Export Compressor Anti-Surge Control Valve

Parameter	Typical Value
Fluid	Natural Gas
Inlet Pressure	1000 - 2000 psig (69 - 138 bar)
Outlet Pressure	300 - 500 psig (21 - 35 bar)
Flow Rate	50,000 - 300,000 MSCFD (56,000 - 335,000 m ³ /h)
Inlet Temp.	100 - 200°F (38 - 93°C)
Valve Type and Pressure Class	NPS 4 - 12 ET/EHT, ASME CL600/900/1500
Valve Material and Trim Material	WCC with 316 SST
Trim Type	Whisper III Trim or WhisperFlo Trim

LNG Liquefaction

Liquefied Natural Gas (LNG) is a mixture of light hydrocarbons (86-99% methane) that is in a liquid state at cryogenic temperatures ($-258^{\circ}\text{F}/-161^{\circ}\text{C}$). LNG occupies approximately 1/600 of the volume of natural gas at atmospheric pressure. This drastic reduction in volume is the primary benefit of the LNG process. When natural gas reserves exist in remote locations and pipelines are not feasible, LNG production becomes an option.

Because LNG is composed mainly of liquid methane, it is made from natural gas feedstock. This natural gas originates from a number of sources. It may come from offshore platforms, onshore gas wells or a combination of both. The natural gas is bulk separated from the hydrocarbon liquids at these production sites and then compressed to high pressures (1000-1400 psig/69-97 bar) and transported through a large bore pipeline(s) to the LNG plant. When the gas arrives at the plant, it enters the slug catchers where condensates are removed. These condensates are sometimes sold as light end crude oil if there is a large enough volume. LNG plants recover around 50,000 bpd of condensates. These oils are light and low in sulfur and may have a high market value. As a result, this can be one of the more profitable by-products of the plant.

Today, there are a number of different commercially patented LNG technologies. The majority of the plants in the world use Air Products' liquefaction technology. This is commonly referred to as the Air Products Mixed Refrigerant (APCI - MR) process. There are other technologies used to a lesser extent, including the Phillips Optimized Cascade Process and the Shell Double Mixed Refrigerant (DMR) process. These processes use the same basic philosophies to make LNG, i.e. gas production, treating, dehydration, heavy ends removal, liquefaction, and storage for shipment. The

differences in the process are primarily in the refrigerant cycle, or in the type of heat exchangers used in the cryogenic section. In this chapter, the APCI-MR will be discussed in detail as it currently represents the largest percentage of worldwide installed base load LNG production capacity.

LNG Process Overview

Figure 13-1 shows a general process flow diagram of an LNG facility. The front end of an LNG facility will have almost identical processing units as those seen in Chapters nine and eleven. Please refer to those chapters for information on these units. After dehydration, the natural gas is cooled to ($-40^{\circ}\text{F}/-40^{\circ}\text{C}$) using propane as a refrigerant, and then moves to a scrub column. Once scrubbed of heavy hydrocarbons, the light gas from the overhead is then further cooled and fed to the main heat exchanger (MHE). The liquid bottoms of the scrub column are further cooled and fed to demethanizer, depropanizer, and debutanizer fractionation columns. These remove NGLs that are used for refrigerant and possible sale. This chapter will focus only on the refrigerant cycles and liquefaction units as they are found in the APCI-MR process. Figure 13-2 shows a process flow diagram of these processes.

One thing to note is that the dehydration section of the plant removes water from the natural gas by the application of molecular sieves instead of traditional glycol absorbers. Molecular sieves remove more water than glycol absorbers, which is critical in protecting downstream cryogenic equipment from ice buildup. The dehydration section of the plant will not be discussed in this chapter, as the majority of the valves used for this process are on/off valves.



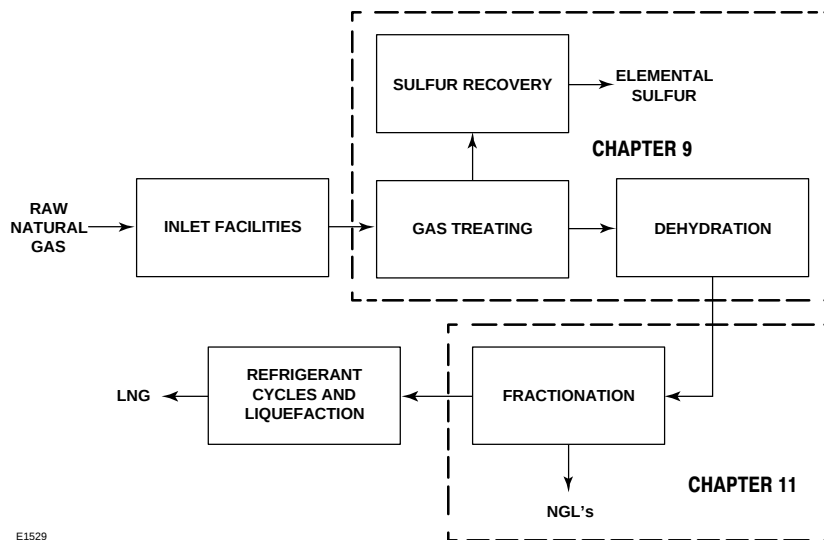


Figure 13-1. LNG Process Flow Diagram

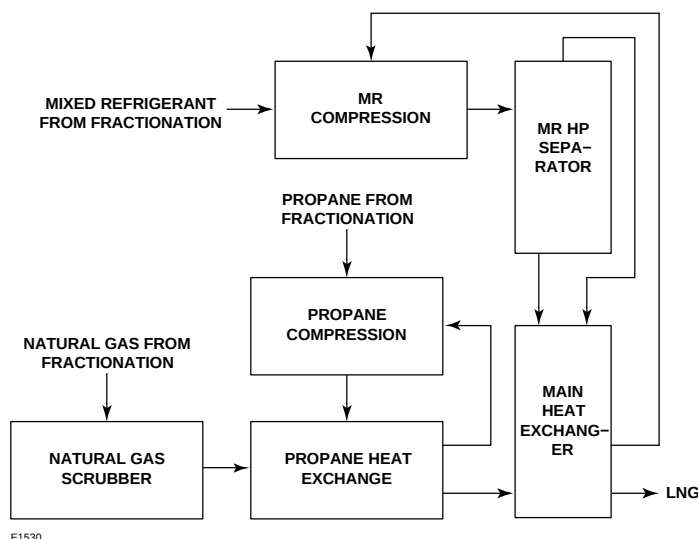


Figure 13-2. Refrigerant Cycles and Liquefaction

Inlet Facilities

When the gas arrives at the plant, it enters the slug catchers where condensates are removed. These condensates are sometimes sold as light end crude oil if there is a large enough volume. LNG plants recover around 50,000 bpd of condensates. These oils are light and low in sulfur and may have a high market value. As a result, this can be one of the more profitable by-products of the plant. The gas that comes off the top of the slug catcher is reduced in pressure by the main plant/pipeline pressure letdown valves that supply gas to the inlet of each train in the LNG plant.

Refrigerant Cycles

Propane Cycle

The propane refrigerant cycle is a closed loop system that is periodically fed propane produced from the fractionation columns. Starting at the outlet of the compressor(s) the propane discharge is condensed with cooling water. It then passes through evaporators throughout the process to provide cooling, although it is not used in the MHE. In the evaporators, heat from the feed natural gas and gaseous mixed refrigerant is transferred to the propane, which is vaporized. Once the propane is vapor, it returns to flash drums where any liquids

are separated and sent back to the evaporators for further heat transfer. The gaseous portion of the propane removed from the flash drums is sent to the propane compressor for recompression.

Mixed Refrigerant Cycle

The refrigerant used in the MHE to liquefy the natural gas is called mixed refrigerant (MR). This is a mixture of N₂, methane, ethane, and propane. The mixed refrigerant cycle is a closed loop process, and refrigerants are supplied by the fractionation columns as needed. Starting at the outlet of the compressor(s) cooling water and propane from the propane cycle cools and partially condenses the MR. The partially condensed MR is separated into MR vapor and MR liquid in a separator. Both MR liquid from the bottom of the separator and MR gas from the top of the separator pass through the tube side of the MHE for further cooling. Its pressure is then reduced by passing it through Joule-Thomson valves or expanders, which partially vaporizes the mixture and further cools it via the Joule Thomson effect. The partially vaporized MR then enters the shell side of the MHE and contacts the tubes that contain natural gas and MR. This contact provides enough heat exchange to liquefy the natural gas feed to -231°F (-146°C). The MR vapor from the shell side of the MHE is then returned to the MR compressors suction for recycle.

Liquefaction

Liquefaction and sub-cooling of the natural gas takes place in the MHE. The overhead vapor from the scrub column, which contains mostly methane at -112°F (-80°C), is the feed to the MHE. By the time the feed gas gets to the top of the MHE it is at approximately -240°F (-151°C) and is a high percentage of pure LNG. The LNG exiting the MHE passed through a valve to reduce its pressure and enters the product/N₂ rejection drum. The expansion through the valve reduces the liquid to the storage temperature of -250°F to -260°F (-157°C to -161°C) and boils off the light end gasses. These are usually nitrogen and light hydrocarbons and only represent about one to three percent of the total mass flow exiting the valve. The flash gasses from the N₂ rejection drum are then sent to the fuel gas compressor.

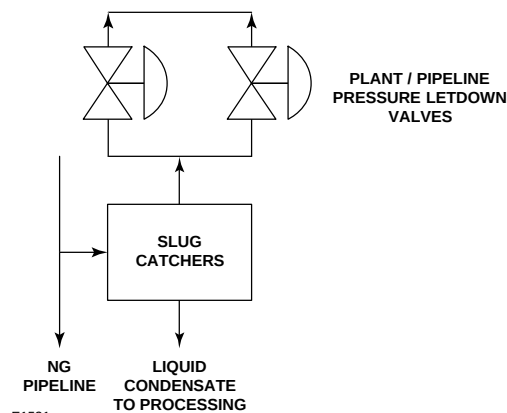


Figure 13-3. Feed Gas Pressure Letdown Valves

LNG Application Review

Inlet Facilities

When the gas arrives at the plant, it enters the slug catchers where condensates are removed. The gas that comes off the top of the slug catcher is reduced in pressure by the main plant/pipeline pressure letdown valves. This valve(s) supplies gas at about 1000 psig (69 bar) to the inlet of each train in the LNG plant.

Feed Gas Inlet Pressure Letdown: The feed gas inlet letdown valves provide the first substantial pressure reduction of the feed gas when it enters the plant inlet receiving facilities.

There are two valves at the inlet to the plant reducing station, providing 100% operational redundancy. The inlet piping to the plant may be NPS 24 to 48 piping and hundreds of millions of standard cubic feet of gas will flow each day to meet the total LNG plant demand. This, coupled with at least a 218 psig (15 bar) differential pressure drop across the inlet letdown valves, can result in high noise and vibration generation. Noise attenuation trim is a requirement. Because of the line size, the flow, and the trim, the valve size may be anywhere from NPS 16 to 24 and rated at ASME CL600 or CL900. It will almost always be a fail-close valve.

In addition to having stringent noise attenuation requirements, inlet letdown valve reliability is critical to the operation of the plant. These valves supply the feedstock to the entire LNG plant. If one of the valves in the LNG trains fails, then the train is shutdown. The plant can try to make up the LNG production with other trains. However, if the plant

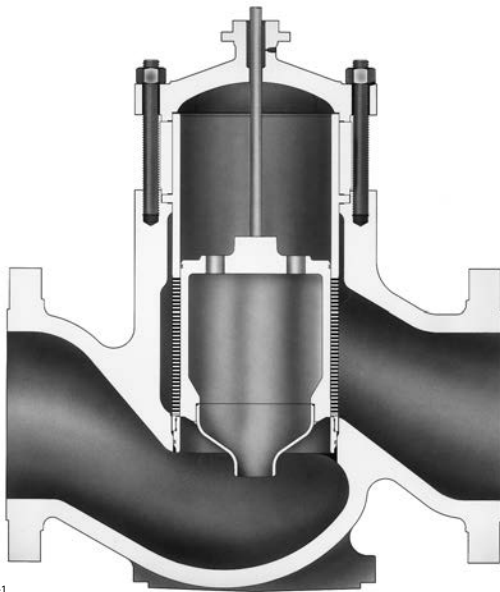


Figure 13-4. EWT with Whisper Trim III Cage

inlet valve fails, the whole plant must shut down. This can jeopardize the plant's abilities to make their quota of LNG to meet the requirements of long-term contracts.

Controllability of the inlet valve is also critical. It is a true throttling control valve that throttles based upon the pressure downstream of the valve. It is usually controlled by the DCS with pressure readings from transmitters in a triple voting configuration. If the valve cannot accurately maintain the inlet pressure to the plant, the pressure swings can cause cycling of the whole plant. This process instability can reduce the amount of throughput of LNG and affect the ability for the plant to meet its quota. Additionally, cycling can cause excessive trips throughout the plant. This can reduce the life of the mechanical equipment due to frequent starting and stopping. Consequently, the sizing and application of these control valves is critical to the whole plant. These valves are configured in the plant ESD systems.

Table 13-1. Feed Gas Pressure Letdown Valve

Parameter	Typical Value
Inlet Pressure	1200 - 1305 psig (83 - 90 bar)
Pressure Drop	220 - 435 psi (15 - 30 bar)
Inlet Temp.	110°F (43°C)
Valve Type and Pressure Class	NPS 16 - 20 EWT-2 or EUT-2, ASME CL600 / 900
Valve Material and Trim Material	WCC with 316 SST / Alloy 6 (NACE)
Shutoff Requirement	ANSI Class IV or V
Trim Type	WhisperFlo Trim or Whisper III Trim

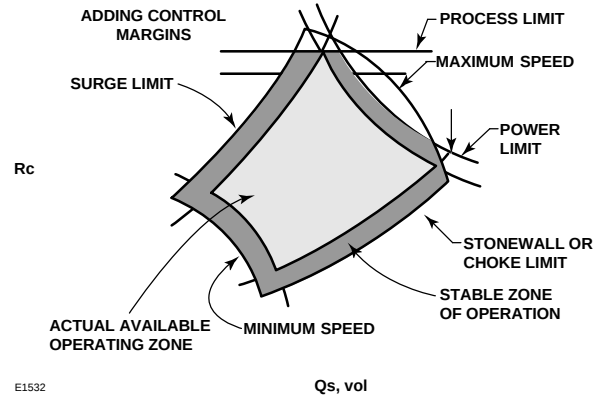


Figure 13-5. Typical Compressor Map

Refrigerant Cycles

For both the propane and MR cycles, only the anti-surge valves protecting the refrigerant compressors are the most critical applications. The compressor can be the most expensive and critical component of a process system; capital costs of a single refrigerant compressor in an LNG facility can be upwards of \$50 million. One of the more prevalent concerns of compressor operators are the damaging effects of the surge cycle. Surge cycles typically occur very fast and pose serious risk of damage to compressor components.

Compressor surge occurs when the compressor reaches a point where it can no longer produce enough pressure head to overcome the downstream resistance. This is due to either a lack of suction flow to the inlet of the compressor or a sudden reduction in process demand, both of which result in greater discharge pressure downstream of the unit. Once surge conditions have been met, process will flow backwards through the compressor up until enough pressure head is developed to initiate forward flow. This change in direction puts stress on the thrust bearings and other components inside the compressor causing excessive wear and eventually damage. Compressor surge is a cyclic process that will occur as long as the aforementioned conditions are met.

Figure 13-5 shows the relationship between discharge pressure head and suction flow through a compressor. The surge line is the point where surge occurs and the stonewall, or "choke" line is the point where there is not enough pressure head to force process through the compressor at a given suction flow. As seen from the figure compressors should be operated at conditions representative with operation between the surge and stonewall lines. Operation as close as possible to

the surge line is desired to obtain peak efficiency. Today's control systems and antisurge valve technology allow for this operation to take place in a safe and effective way.

To allow this type of operation to take place anti-surge valves must act in a throttling mode more than the on/off mode that was required in the past when stroke time was the only specification. Today antisurge valves are required to not only provide fast stroke times, but are also required to effectively throttle the process and respond accurately to small step changes.

Fisher Optimized Digital Valve (ODV) packages meet the stringent performance requirements of antisurge applications by providing a complete packaged solution. These packages are subjected to rigorous factory testing per Factory Acceptance Test FGS4L11 to ensure the necessary performance requirements are met before the assembly is shipped. In retrofit cases where the valve body is not present at the time of testing the Site Acceptance Test FGS4L12 can be performed at the customer's location in select locations by our highly trained Instrument & Valve Services technicians. These tests are only a starting point though, if necessary, additional testing and engineering can and has been performed in the past to meet specific customer specifications.

Every antisurge control valve includes an ODV package, which provides the necessary components to ensure fast, stable operation of the control valve. These packages are only available with double acting piston actuators, including the Fisher 585C and 585CLS, which are capable of providing travels of up to 24 inches in bore diameters of up to 18 inches. If more thrust or longer travel is required an ATI actuator can be used.

The ODV package provides the following components as shown below; depending on the application some components may not be applicable or required such as dump valves, solenoid valves, or volume tanks.



X0210

Figure 13-6. ODV Package with FB NPS 16x20, 585CLS Actuator, DVC6200, and SS-263 Booster

Table 13-2. Antisurge Valve Components

Package Component	Description
Regulator:	Controls system air pressure.
Filter:	Ensures air supply is clean and free of debris that could clog ports or cause other problems.
Trip Valve:	Provides a pneumatically controlled fail mode in the event of a loss of plant air pressure.
Volume Booster:	Amplifies DVC instrument air output and exhausts air from the actuator providing for fast stroking.
Dump Valve (ASCO valve model 8290):	Quickly exhausts air from the actuator upon solenoid trip ensuring fast stroke to the required fail mode.
Solenoid Valve:	Provides an electronically controlled fail mode that can be controlled by the control system or be configured to trip on a loss of voltage.
Volume Tank:	Prevents pressure droop ensuring all pneumatic devices have an adequate supply of air. In the event of the loss of plant air, the volume tank supplies the necessary volume of air required to move the valve to the fail mode.
ODV Tiered DVC6200:	Includes all of the features with the PD tier plus several specialized control and tuning algorithms not available in the other tiers including: Endpoint Pressure Control Lead/Lag Filtering Stabilize/Optimize Tuning
Double Acting Piston Actuator:	Provides thrust required to quickly and accurately stroke the valve.

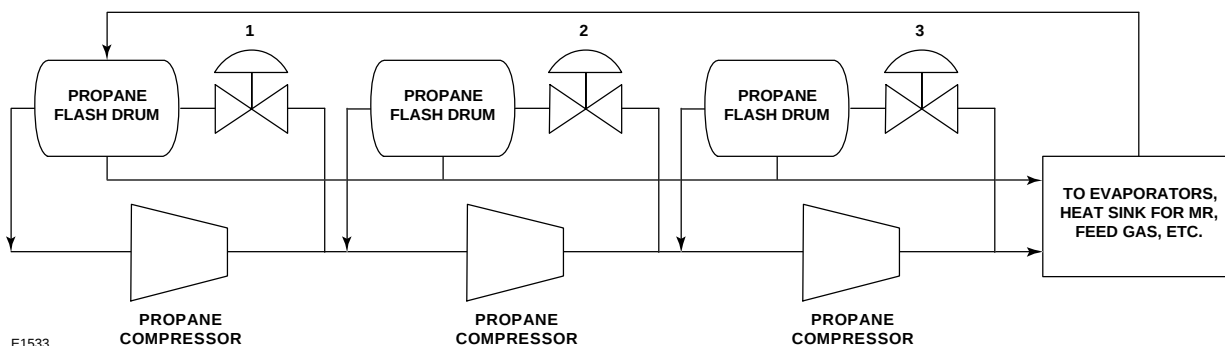


Figure 13-8. Propane Compressor



Figure 13-7. DVC6200 Instrument for ODV Package

Propane Cycle

The propane antisurge valves are located at the discharge of the compressor or its stages. These valves provide a path for the compressed gas to be returned back to the suction side of the compressor.

1. 1st Stage Propane Compressor Antisurge Valve: This valve encounters high pressure drops. Noise abatement trim is necessary to reduce noise and associated vibration. The Optimized Antisurge System is also recommended.

Table 13-3. C3 1st Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	20 - 200 psig (1 - 14 bar)
Pressure Drop	Up to 100 psi (7 bar)
Inlet Temp.	140°F (60°C)
Valve Type and Pressure Class	NPS 16 - 36 FB, ASME CL300 / 600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim or WhisperFlo Trim
Actuation	Optimized Antisurge System

2. 2nd Stage Propane Compressor Antisurge Valve: This valve encounters high pressure drops. Noise abatement trim is necessary to reduce noise and associated vibration. The Optimized Antisurge System is also recommended.

Table 13-4. C3 2nd Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	50 - 200 psig (3 - 14 bar)
Pressure Drop	Up to 150 psi (10 bar)
Inlet Temp.	140°F (60°C)
Valve Type and Pressure Class	NPS 16 - 36 FB, ASME CL300 / 600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim or WhisperFlo Trim
Actuation	Optimized Antisurge System

3. 3rd Stage Propane Compressor Antisurge Valve: This valve encounters high pressure drops. Noise abatement trim is necessary to reduce noise and associated vibration. The Optimized Antisurge System is also recommended.

Table 13-5. C3 3rd Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	100 - 200 psig (7 - 14 bar)
Pressure Drop	Up to 185 psi (13 bar)
Inlet Temp.	140°F (60°C)
Valve Type and Pressure Class	NPS 16 - 24 FB, ASME CL300 / 600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim or WhisperFlo Trim
Actuation	Optimized Antisurge System

Mixed Refrigerant Cycle: Individual Stage Compression

The MR antisurge valves are located at the discharge of the compressor or its stages. These

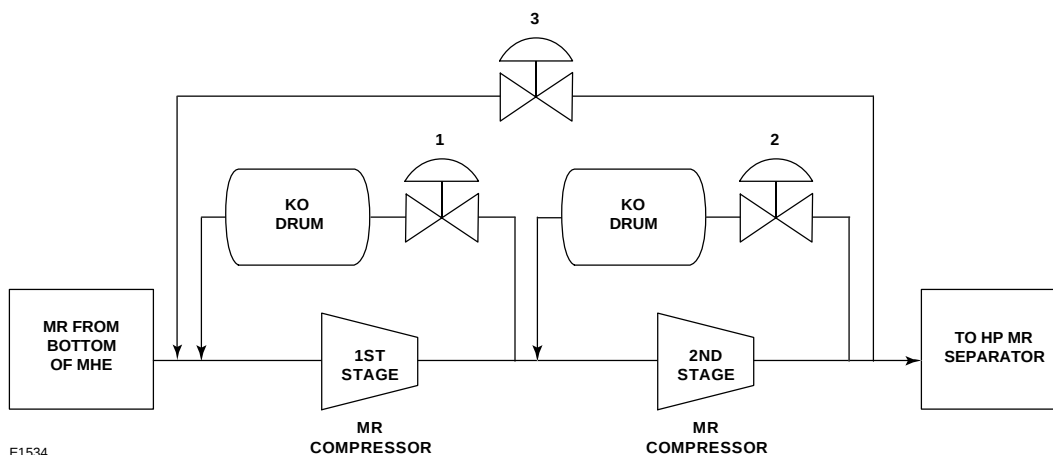


Figure 13-9. Mixed Refrigerant Compressor

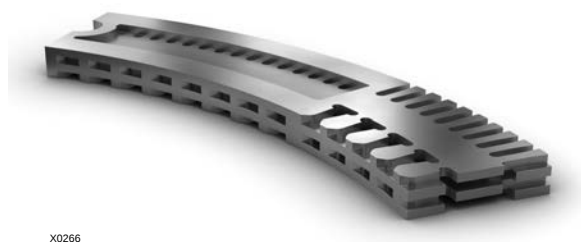


Figure 13-10. WhisperFlo Trim Disk Stack

valves provide a path for the compressed gas to be returned back to the suction side of the compressor.

1. 1st Stage Mixed Refrigerant Compressor Antisurge Valve: This valve encounters high pressure drops. Noise abatement trim is necessary to reduce noise and associated vibration. Fisher's Optimized Antisurge System is also recommended.

Table 13-6. MR 1st Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	195 psig (13 bar)
Pressure Drop	150 psi (10 bar)
Inlet Temp.	90°F (32°C)
Valve Type and Pressure Class	NPS 16 - 30 FB, ASME CL300 / 600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim or WhisperFlo Trim
Actuation	Optimized Antisurge System

2. 2nd Stage Mixed Refrigerant Compressor Antisurge Valve: This valve encounters high pressure drops. Noise abatement trim is neces-

sary to reduce noise and associated vibration. The Optimized Antisurge System is also recommended.

Table 13-7. MR 2nd Stage Compressor Antisurge Valve

Parameter	Typical Value
Inlet Pressure	650 psig (45 bar)
Pressure Drop	450 psi (31 bar)
Inlet Temp.	250°F (121°C)
Valve Type and Pressure Class	NPS 16 - 24 FB, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim or WhisperFlo Trim
Actuation	Optimized Antisurge System

Mixed Refrigerant Cycle: Hot Gas Bypass

In order to provide additional protection for the compressors, some installations will utilize a hot gas bypass system. This bypass recycles gas around the entire group of compressors, not just the single stage. It is not always a design feature in every LNG plant. This is intended to operate when there is a shut down of the whole refrigeration unit and all the flow has to be recycled around the compressors so that they don't shut down. This is only built into a plant if the individual recycle loops and valves were not designed to handle the entire load in a major shut-in.

3. Hot Gas Bypass Valve: Due to the normal capacity requirements of the compressors, the hot gas bypass valves need to be very large to accommodate the flow. Typically valves are NPS 20-24. However, sizes could be up to NPS 48 and larger. These valves have the same requirements and solutions as the propane and MR antisurge

valves with respect to quick opening times with minimal to no throttling service being required. The Optimized Antisurge System is also recommended.

Table 13-8. Hot Gas Bypass Valve

Parameter	Typical Value
Inlet Pressure	650 psig (45 bar)
Pressure Drop	600 psi (41 bar)
Inlet Temp.	250°F (121°C)
Valve Type and Pressure Class	NPS 20 - 48 FB, ASME CL600
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim or WhisperFlo Trim
Actuation	Optimized Antisurge System

Liquefaction

There are three critical valves that will be discussed in this section:

1. Warm Joule-Thomson valves
2. Cold Joule-Thomson valves
3. LNG temperature valve

The LNG temperature valve controls the temperature of the LNG coming out of the MHE as well as reduces the pressure of the LNG so light end products bubble out of the solution. The primary function of the Joule-Thomson valves are to spray MR coolant onto the heat exchanger bundles that carry the feed gas and the MR liquid and vapor from the MR separator. The drop through the valves lowers the temperature of the MR via the Joule-Thompson effect. This refers to the cooling of a fluid by a pressure drop and expansion of that fluid. It is important to have both a reliable and accurate throttling control valve to maintain efficient cooling of the feed gas and MR.

Note that in some process designs, expanders are used as the main pressure drop mechanism rather than the JT and LNG temperature valves. In this design, the energy of the high pressure fluid can be recovered and generate auxiliary power. The expanders are also more efficient at expanding the fluid and have a greater cooling effect than a

valve. If the expander is used in the process, the JT valve will be in a bypass/backup role. If the expander must shut down, the valve has to take over and throttle the fluid. It is beneficial to have a C_V with this valve similar to the expander C_V for smooth transitions from the expander to the valve.

1. Warm Joule-Thomson Valve: When the MR moves up the tubes between the inlet to the MHE and the warm JT valve, it loses its heat to the colder MR fluids moving countercurrent through the shell. Therefore, when the MR reaches the inlet to the warm JT valve in the lower section of the MHE, it is typically at cryogenic temperatures, around -200°F (-130°C). The MR fluid that flows through the valve may turn into a liquid and vapor mix as it exits the valve. The proper trim must be selected. Balanced cryogenic valves are preferred. If a large percentage of refrigerant by volume is converted to a vapor when the valve takes its pressure drop to spray the bundles, then the drilled-hole or slotted trim in a flow up direction is used to eliminate flashing related noise, vibration and erosion.

Table 13-9. Warm Joule-Thomson Valve

Parameter	Typical Value
Inlet Pressure	500 psig (35 bar)
Pressure Drop	450 psi (31 bar)
Inlet Temp.	-200°F (-129°C)
Valve Type and Pressure Class	NPS 6 - 12 EW-C and E-C, ASME CL600
Valve Material and Trim Material	316 SST with 315 SST / Alloy 6
Shutoff Requirement	150 ml/min/NPS at 7 bar
Trim Type	Drilled-hole flow up

2. Cold Joule-Thomson Valve: The inlet temperature of the MR entering the cold JT valve is lower than the temperature of the MR entering the warm JT valve, approximately -240°F (-150°C). This is due to the longer pass through the heat exchanger. The MR fluid that flows through the valve may turn into a liquid/vapor mix as it exits the valve. The proper trim must be selected. Balanced cryogenic valves are preferred. If a large percentage of refrigerant by volume is converted to a vapor when the valve takes its pressure drop to spray the bundles, then the drilled-hole or slotted trim in a flow up direction is used to eliminate flashing related noise, vibration, and erosion.

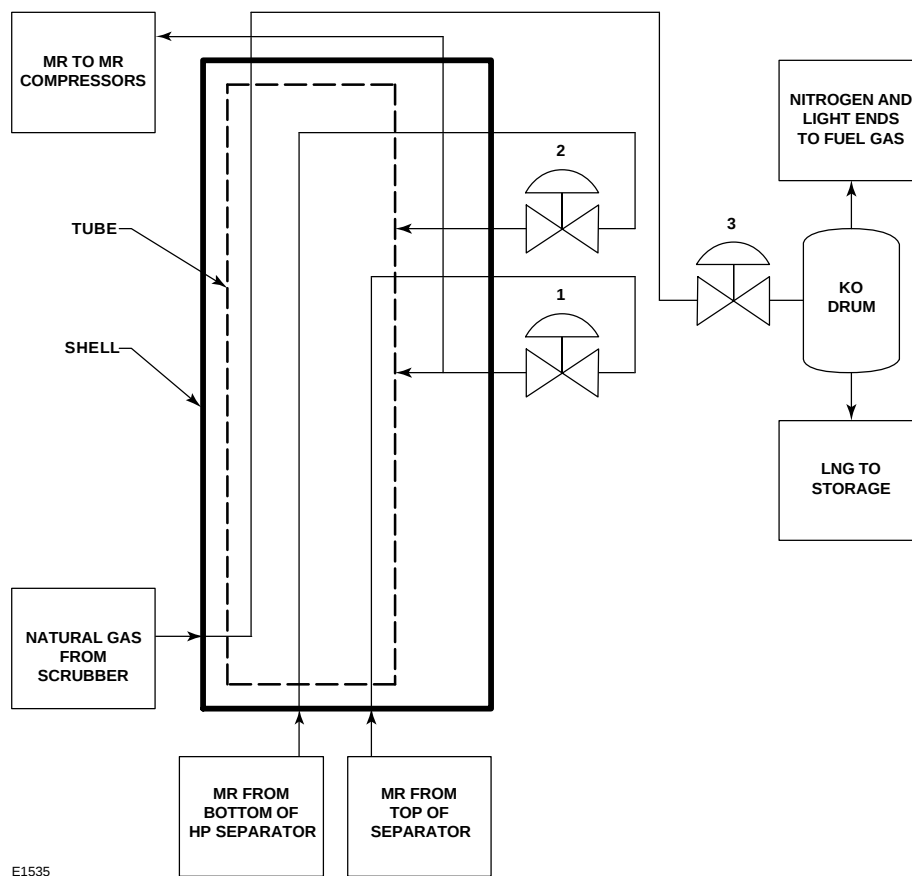


Figure 13-11. Common Valves Associated with the MHE

Table 13-10. Cold Joule-Thomson Valve

Parameter	Typical Value
Inlet Pressure	450 psig (31 bar)
Pressure Drop	400 psi (28 bar)
Inlet Temp.	-230°F (-146°C)
Valve Type and Pressure Class	NPS 6 - 12 EW-C and E-C, ASME CL600
Valve Material and Trim Material	316 SST, Alloy 6
Shutoff Requirement	150 ml/min/NPS at 7 bar
Trim Type	Drilled-hole flow up

3. LNG Temperature Valve: Temperatures for this valve are full cryogenic and require 316 SST body and bonnet, extension bonnets, and 316/Alloy 6 trim. When the pressure of the LNG fluid drops across the valve, the lighter gases, such as N₂, bubble out of the LNG liquid. With these small amounts of vapor downstream, the majority of the LNG may cavitate but not flash. In these cases, it is best to use a Cavitrol trim to eliminate cavit-

tion, vibration and noise. If there is a large percentage of N₂ or other light end gasses in the feed gas stream of a particular plant, or if there is a smaller pressure drop across the valve, then the majority of the damage and vibration can be attributed to flashing. A drilled-hole trim or slotted trim should be used in the flow up direction in this case.

Table 13-11. LNG Temperature Valve

Parameter	Typical Value
Inlet Pressure	400 - 800 psig (28 - 55 bar)
Pressure Drop	300 - 770 psi (21 - 53 bar)
Inlet Temp.	-230°F (-146°C)
Valve Type and Pressure Class	NPS 6 - 12 EW-C and E-C, ASME CL600
Valve Material and Trim Material	316 SST with 316 SST / Alloy 6 or 17-4 H1150
Shutoff Requirement	150 ml/min/NPS at 7 bar
Trim Type	Cavitrol trim, drilled-hole if large quantities of N ₂ rejection or small dP

LNG Receiving Terminals

A Liquefied Natural Gas (LNG) receiving terminal is one link in the LNG chain between the gas field and the residential or industrial customer. The sole purpose of this unit is to receive LNG from ocean-going cargo vessels, store it, and convert its state from the liquid phase back to the gaseous phase for injection into the local natural gas grid.

An LNG terminal consists of a deepwater port that is used to berth and unload LNG tanks. The terminal has holding tanks designed to keep the LNG at -256°F (124°C). These non-pressurized tanks use an insulated concrete and steel structure to keep the LNG at the desired temperature. A vaporization system is used to return the LNG to a gaseous state prior to distribution in a natural gas pipeline system.

The terminal is designed to deliver a specified gas rate into the distribution pipeline and to maintain a reserve capacity of LNG. The amount of reserve depends upon expected shipping delays, seasonal variations in supply, demand, and strategic reserve requirements.

Depending upon the regasification capacity of the terminal, the number of control valves will vary between 75 for an average size unit (1 BCFD) and 150 for larger units (two BCFD). The number of valves can be directly correlated to the number of storage tanks and the vaporization technology employed. As the storage and send out rates increase, additional tanks and vaporizers are required.

The majority of the valves utilized will be cryogenic constructions. Nearly half of the control valves utilized will be medium to large sized butterfly valves. The other half will consist of small to medium sized globe valves.

LNG Receiving Process

Figure 14-1 shows the general process flow diagram of an LNG receiving terminal.

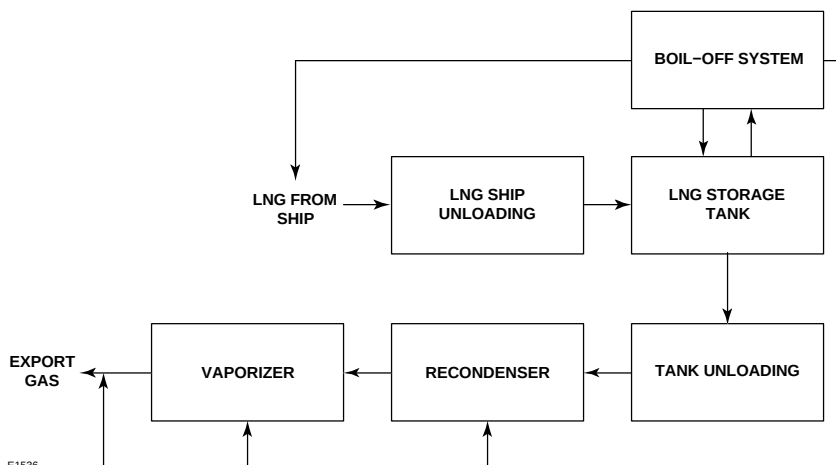


Figure 14-1. LNG Receiving Terminal Process Flow Diagram

LNG Ship Unloading

Following the berthing of the LNG vessel and cool down of the unloading arms, LNG is transferred to the onshore LNG tanks by the ship's pumps. It may take up to fourteen hours to unload the vessel. From the vessel, LNG flows through the unloading arms and unloading lines into the storage tank(s). The loading lines are typically parallel pipe runs, but may be a single line run in specific situations.

During ship unloading, some of the vapor boiloff generated in the storage tank is returned to the vessel's tanks via a vapor return line in order to maintain positive pressure in the vessel's tanks. Because of the potential for a low pressure differential between the storage tank(s) and the vessel's tanks, vapor return blowers may be necessary. LNG terminals usually have three unloading arms and one vapor return arm.

LNG Storage

Usually two above ground tanks are installed for receiving and storing LNG, although some terminals have been designed using only one tank. To reduce cost, designers try to minimize the number of tanks and maximize the amount of storage per tank.

Several low-head pumps are normally installed in each LNG storage tank. These pumps are fully submerged in LNG and are located within pump wells or columns. The pump wells also serve as the discharge piping from the pumps and are connected to the tank-top piping.

These pumps usually have a discharge pressure of approximately 165 psig. There are usually two pumps per tank in an effort to minimize cost by selecting fewer, larger pumps. Each pump will have a recirculation valve to prevent the pump from low flow damage. It is also common to have a discharge pressure control valve from each pump feeding into a header. These may not be present if variable speed drives are used, but most LNG terminals utilize constant speed pumps with control valves to minimize costs.

Boil-off System and Recondenser

During normal operation, boil-off vapor is produced in the storage tanks and in LNG lines by heat transfer from the surroundings. This vapor is collected in a header that ties into a compressor suction drum. Vapor can also be routed to the

boil-off gas blowers, if present, for return to the ship. Boil-off vapors are compressed and liquefied in a recondenser. This process helps to avoid flaring for most operating conditions, and also provides fuel gas to the vaporizers if needed. The recondenser houses a packed bed that creates a large surface area for vapor-liquid contact. LNG is also pumped to the recondenser from the storage tanks before it is pumped to the vaporizers.

LNG Vaporizers

Send-out gas from the facility is usually injected into a high pressure gas distribution system at pressures ranging from 1200 to 1700 psig. To achieve this pressure, multi-staged send-out pumps are required from the recondenser to the vaporizers. There will be from two to four high pressure send-out pumps per tank. This is dependent upon the design of the plant, but regardless of the design, there will be a bank of pumps, several acting in standby mode.

LNG terminals have multiple operating vaporizers with several spare units. There are several common vaporizers utilized including:

- Submerged Combustion Vaporizers (SCV)
- Open Rack Vaporizers (ORV)
- Shell and Tube Vaporizers

The selection of vaporizer depends heavily on initial capital cost, operating cost, and environmental impacts.

Submerged Combustion Vaporizers

Submerged combustion vaporizers (SCV) use a tube bundle submerged in a water bath to vaporize the LNG. The water temperature is maintained by burning natural gas. Combustion products are bubbled through a distribution tube into the water bath, creating a two-phase frothing action. Heat is transferred from the water bath to the LNG fluid flowing inside the tube bundle. Combustion products, after disengaging from the gas and water mixture, are discharged to the atmosphere through a short stack.

Open Rack Vaporizers

In this method, seawater is used as the heat source to vaporize the LNG. The seawater flows over a series of panel coils to vaporize the LNG flowing countercurrent with the panels. These pan-

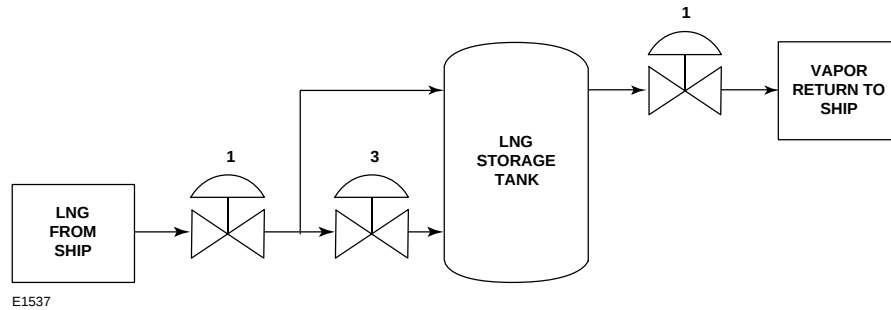


Figure 14-2. LNG Ship Unloading and Vapor Return Lines

els are made up of multiple LNG tubes with integral fins. Seawater lift pumps raise the seawater to the top of the ORV to flow down the outside of the panels as a falling film. LNG flowing upward through the tubes is vaporized and warmed to approximately 40°F (4°C).

Seawater flows through intake screens to remove debris and marine life prior to being pumped to the ORV. Intake screens are designed and operated with inlet velocities set to minimize impingement and entrain marine organisms. The treated seawater is pumped to distribution troughs located on top of the ORV panels. The seawater flows downward next to the vertical panels and is collected in a concrete basin beneath the ORV. The cooled seawater is gravity fed into a trench and routed to the seawater outfall.

This type of vaporizer will not be covered in the valve application section. The main valves associated with this process are seawater intake control valves and bypass valves around each of the main seawater pumps. Both of these application needs are met by using large butterfly valves, mainly NPS 24 to 36 sizes.

Shell and Tube Vaporizers

Shell and Tube vaporizers are specially designed heat exchangers that utilize a variety of heating mediums as a heat source for vaporization. The heating mediums may be seawater, freshwater or a glycol and water mixture. A fired heater can be used to heat the circulating heating medium loop. This consumes 1.5% to 2.0% of the send out gas and results in high operating costs.

After vaporization, the natural gas is ready for distribution to the pipeline network. Some of the natural gas at this point is taken off for high pressure fuel gas, which is common for facilities that utilize some type of combustion-based vaporization or if

there are onsite utilities such as boilers or combustion turbines.

LNG Receiving Application Review

LNG Ship Unloading

Figure 14-2 shows the typical valves associated with the unloading system.

1. LNG Unloading Control: This valve controls the discharge flow from the LNG tanker into the storage tanks. There are generally three of these valves per LNG terminal, but there may be more depending upon the number of storage tanks. This application is typically handled by a butterfly valve with cryogenic capabilities.

Table 14-1. LNG Unloading Control Valve

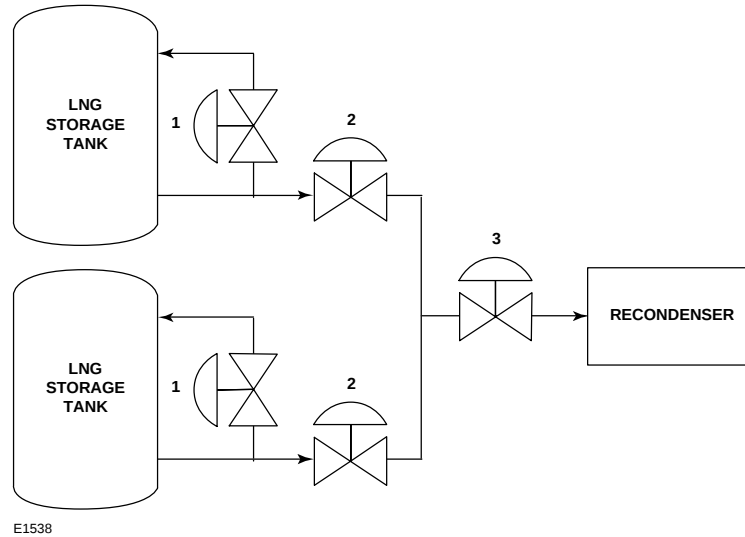
Parameter	Typical Value
Inlet Pressure	4 - 70 psig (1 - 5 bar)
Outlet Pressure	3 - 69 psig (1 - 5 bar)
Flow Rate	3,000,000 - 7,500,000 lb/h (1,360,000 - 3,500,000 kg/h)
Inlet Temp.	-260 - -250°F (-162 - -157°C)
Valve Type and Pressure Class	NPS 20 - 30 A11-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class V or VI
Trim Type	Equal Percentage

2. Vapor Return Line Control: In order to help facilitate unloading of the tanker during off-loading, boil-off vapors generated in the storage tanks during filling can be routed to the tanker to maintain the appropriate pressure differential between the tanker and the storage tanks. The inlet pressure will depend on whether there is an upstream vapor blower (common when the distance between the



W7449

Figure 14-3. A31A Cryogenic Valve



E1538

Figure 14-4. LNG Storage Send-Out System

tanks and the tanker is extensive), but it will not cause a change in the pressure class.

Table 14-2. Vapor Return Line Valve

Parameter	Typical Value
Inlet Pressure	2 - 6 psig (0.14 - 0.4 bar)
Outlet Pressure	1 - 4 psig (0.07 - 0.3 bar)
Flow Rate	40,000 - 60,000 lb/h (18,000 - 30,000 kg/h)
Inlet Temp.	-180 - -250°F (-118 - -157°C)
Valve Type and Pressure Class	NPS 12 - 18 A31A-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class V or VI
Trim Type	Equal Percentage

3. Tank Fill Control: To minimize large temperature differences in the tank during filling operations, the tank is filled from the top and bottom. This valve controls the flow of LNG from the tanker into the lower portion of the storage tank. This is typically a small, cryogenic globe valve.

Table 14-3. Tank Fill Control Valve

Parameter	Typical Value
Inlet Pressure	4 - 6 psig (0.3 - 0.4 bar)
Outlet Pressure	2 - 4 psig (0.14 - 0.3 bar)
Flow Rate	50,000 - 80,000 lb/h (20,000 - 40,000 kg/h)
Inlet Temp.	-260 - -250°F (-162 - -157°C)
Valve Type and Pressure Class	NPS 3 ET-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

LNG Storage

Figure 14-4 shows the valves commonly associated with LNG storage and the low pressure pumping system.

1. First Stage LNG Pump Recirculation: This valve is responsible for recirculating a small amount of flow to the pump intake to prevent the pump from overheating and potentially cavitating. As previously noted, there are typically two pumps per tank with a recycle valve around each pump.

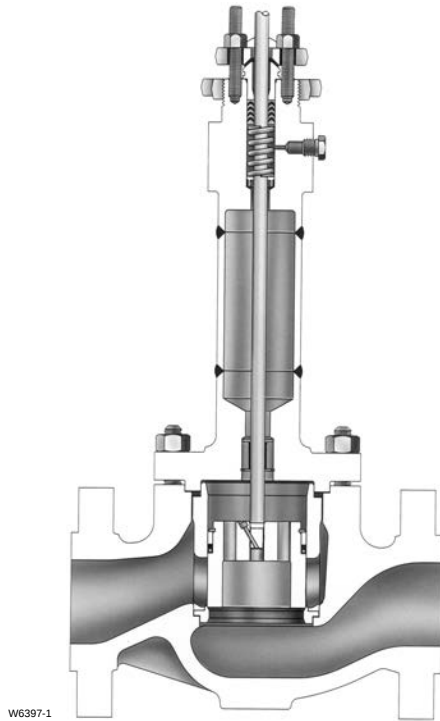


Figure 14-5. Design ET-C

This valve will experience a high pressure drop ratio with low overall pressure drop. Anti-cavitation trim is generally not required in these applications.

Table 14-4. First Stage LNG Pump Recirculation Valve

Parameter	Typical Value
Inlet Pressure	60 - 150 psig (4 - 10 bar)
Outlet Pressure	10 - 50 psig (1 - 3 bar)
Flow Rate	300,000 - 750,000 lb/h (135,000 - 340,000 kg/h)
Inlet Temp.	-260 - -250°F (-162 - -157°C)
Valve Type and Pressure Class	NPS 4 - 6 ET-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Linear

2. First Stage LNG Pump Discharge Pressure Control: *This valve is used to control discharge flow into the main LNG header destined for the reconder. There is one valve associated with each in-tank pump. Given that there are typically two pumps per storage tank, there will be two discharge pressure control valves per storage tank. A butterfly valve is generally used in this application.*

Table 14-5. First Stage LNG Pump Discharge Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	60 - 150 psig (4 - 10 bar)
Outlet Pressure	58 - 140 psig (4 - 10 bar)
Flow Rate	300,000 - 750,000 lb/h (135,000 - 340,000 kg/h)
Inlet Temp.	-260 - -250°F (-162 - -157°C)
Valve Type and Pressure Class	NPS 8 - 10 A31A-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

3. Recondenser Inlet Control: *This valve is used to control the flow of LNG into the reconder, which cools the boil-off gas. This valve may operate at varying positions depending upon the required outlet capacity of the facility.*

Table 14-6. Recondenser Inlet Control Valve

Parameter	Typical Value
Inlet Pressure	60 - 150 psig (4 - 10 bar)
Outlet Pressure	58 - 149 psig (4 - 10 bar)
Flow Rate	750,000 - 2,000,000 lb/h (340,000 - 910,000 kg/h)
Inlet Temp.	-260 - -250°F (-162 - -157°C)
Valve Type and Pressure Class	NPS 16 - 20 A31A-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Vapor Handling

Figure 14-6 shows the layout of the vapor handling and boil-off gas system assuming a pipeline compressor is being used.

1. Boil-off Gas Compressor Anti-surge: *Depending upon the design of the system, this may be a one- or two- valve solution. The one valve system combines both antisurge and recycle valve functions into one valve. The two valve system utilizes an antisurge valve in combination with a high capacity recycle valve.*

They must be of cryogenic constructions due to the temperature of the boil-off gas. Potential for high pressure drop will require the use of low noise trim. A globe valve with Whisper Trim I or Whisper Trim III is the most common solution for this application.

If a two valve system is utilized, there will be a smaller anti-surge valve with Whisper trim installed

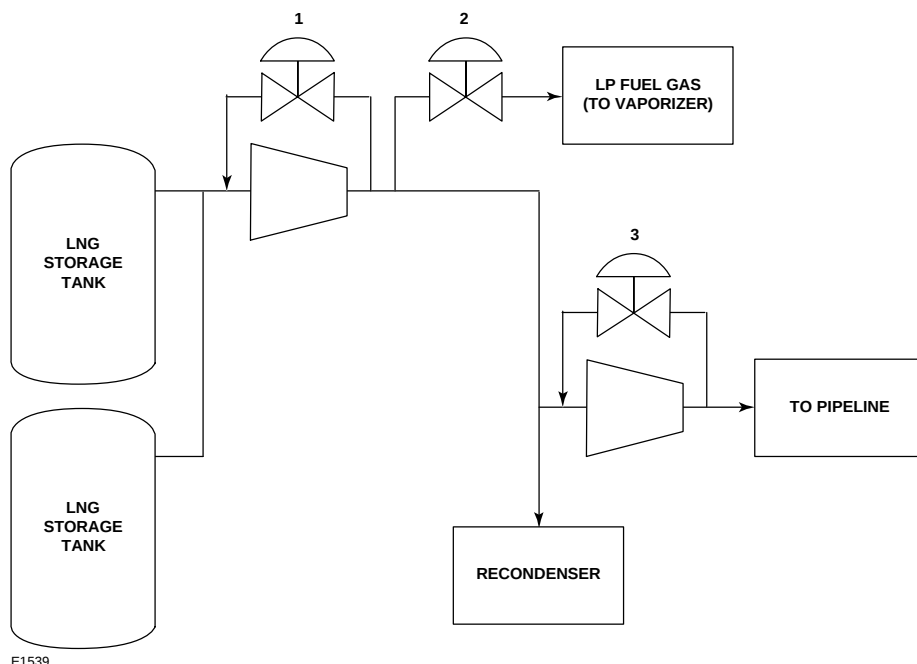


Figure 14-6. Boil Off Gas and Pipeline Compression System

in combination with another valve with little to no noise attenuation capabilities.

Table 14-7. Boil-off Gas Compressor Anti-surge Valve

Parameter	Typical Value
Inlet Pressure	60 - 150 psig (4 - 10 bar)
Outlet Pressure	10 - 40 psig (1 - 3 bar)
Flow Rate	20,000 - 40,000 lb/h (9,000 - 20,000 kg/h)
Inlet Temp.	-150 - -95°F (-101 - -71°C)
Valve Type and Pressure Class	NPS 4 - 6 ET-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim A1 / A3

2. Low Pressure Fuel Gas Control: Depending upon the type of vaporizer and the need for low pressure fuel gas, there may be a pressure control valve used to maintain low pressure fuel gas header pressure. Valve selection will depend directly upon the type and number of vaporizers, as well as any onsite utilities. A globe valve is used for this application.

Table 14-8. Low Pressure Fuel Gas Control Valve

Parameter	Typical Value
Inlet Pressure	60 - 150 psig (4 - 10 bar)
Outlet Pressure	50 - 140 psig (3 - 10 bar)
Flow Rate	20,000 - 80,000 lb/h (9,000 - 40,000 kg/h)
Inlet Temp.	-150 - -95°F (-101 - -71°C)
Valve Type and Pressure Class	NPS 2 - 6 ET-C, ASME CL150
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear

3. Pipeline Compressor Anti-surge: A pipeline compressor may or may not be present in the system. They are present when there is not enough LNG to absorb the boil-off gases generated in the tanks. This compressor compresses the boil-off gas to pipeline pressures for transmission purposes. The anti-surge valve will see higher pressures than in the boil-off gas compressors, but will still be satisfied by a globe valve with Whisper Trim.

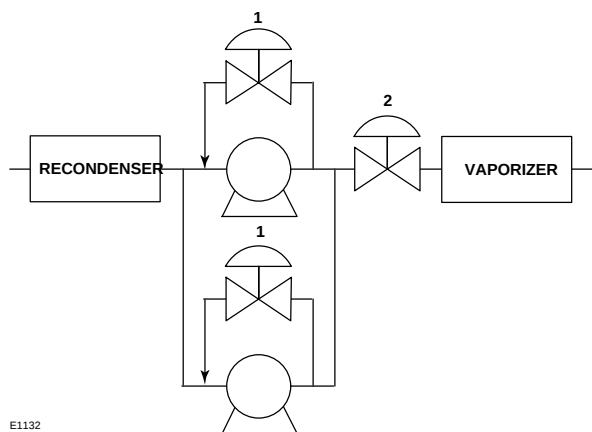


Figure 14-7. High Pressure Pump System

Table 14-9. Pipeline Compressor Anti-surge Valve

Parameter	Typical Value
Inlet Pressure	1300 - 1700 psig (90 - 117 bar)
Outlet Pressure	50 - 140 psig (3 - 10 bar)
Flow Rate	20,000 - 80,000 lb/h (9,000 - 40,000 kg/h)
Inlet Temp.	-95 - -50°F (-71 - -46°C)
Valve Type and Pressure Class	NPS 2 - 6 ET-C / HPT-C, ASME CL600 / 900
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV or V
Trim Type	Whisper III Trim

Second Stage LNG Send-Out Pumps

Figure 14-7 shows the layout of the high pressure pump system.

1. Send-out Pump Recirculation: This valve recirculates a minimum flow around the pump to protect the pump from overheating and potentially cavitating. It will experience relatively high pressure drops requiring the use of anti-cavitation trim to protect the valve from damage. A globe valve with Cavitrol III trim is the commonly used solution in this application.

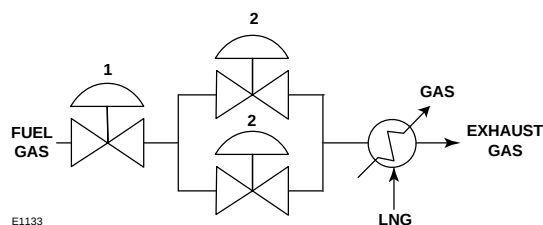


Figure 14-8. High Pressure Pump System

Table 14-10. Send-out Pump Recirculation Valve

Parameter	Typical Value
Inlet Pressure	1500 - 1900 psig (103 - 131 bar)
Outlet Pressure	10 - 60 psig (1 - 4 bar)
Flow Rate	30,000 - 400,000 lb/h (13,000 - 185,000 kg/h)
Inlet Temp.	-240 - -225°F (-151 - -143°C)
Valve Type and Pressure Class	NPS 2 - 6 HPT-C, ASME CL900 / 1500
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class V
Trim Type	Cavitrol III trim 2-stage

2. Vaporizer Inlet Flow Control: This valve controls the flow of LNG into the separate vaporizers. The number of valves in a plant will depend directly upon the number of vaporizers being utilized. These are medium sized globe valves that take minimal pressure drops.

Table 14-11. Vaporizer Inlet Flow Control Valve

Parameter	Typical Value
Inlet Pressure	1500 - 1900 psig (103 - 131 bar)
Outlet Pressure	800 - 1500 psig (55 - 103 bar)
Flow Rate	300,000 - 575,000 lb/h (135,000 - 265,000 kg/h)
Inlet Temp.	-240 - -225°F (-151 - -143°C)
Valve Type and Pressure Class	NPS 4 - 6 HPT-C, ASME CL900 / 1500
Valve Material and Trim Material	316 SST with 316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Linear or Equal Percentage

LNG Vaporizers

Submerged Combustion Vaporizer

Figure 14-8 shows the typical valves associate with an SCV.

1. High Pressure Fuel Gas Pressure Control: This valve may or may not be present in a facility.

It is found in plants where there is not a separate low pressure fuel gas take-off line. A globe valve will be utilized to control downstream pressure. Because of the high pressure drops, it is likely that noise attenuating trim will be required.

Table 14-12. High Pressure Fuel Gas Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	1300 - 1600 psig (90 - 110 bar)
Outlet Pressure	100 - 250 psig (7 - 17 bar)
Flow Rate	20,000 - 60,000 lb/h (9,000 - 30,000 kg/h)
Inlet Temp.	80 - 150°F (27 - 66°C)
Valve Type and Pressure Class	NPS 2 - 4 HPT, ASME CL900 / 1500
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Whisper III Trim

2. Fuel Gas Pressure Control: Fuel gas control may be split among two valves or combined into one. This depends upon turndown of the SCV and required flow rates. The conditions noted below assume the flow is split between two valves.

Table 14-13. Fuel Gas Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	100 - 250 psig (7 - 17 bar)
Outlet Pressure	50 - 190 psig (3 - 13 bar)
Flow Rate	4,000 - 30,000 lb/h (1,800 - 15,000 kg/h)
Inlet Temp.	80 - 150°F (27 - 66°C)
Valve Type and Pressure Class	NPS 2 - 4 ET, ASME CL150 / 300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage

Shell and Tube Vaporizers

Figure 14-9 shows the typical valves used in a shell and tube vaporizer.

1. High Pressure Fuel Gas Pressure Control: This valve may or may not be present in a given facility. It is commonly found in plants where there is not a separate low pressure fuel gas take-off line. This will be a globe valve controlling downstream pressure. Because of the high pressure drops, it is likely that noise attenuating trim will be required.

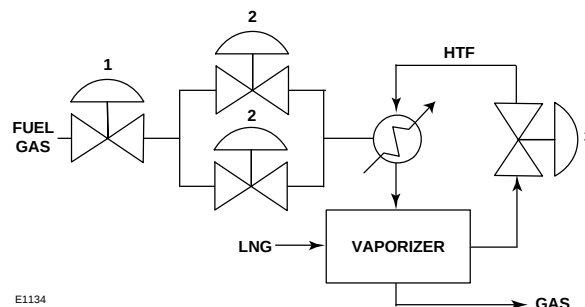


Figure 14-9. Shell and Tube Vaporizer and Associated Valves

Table 14-14. High Pressure Fuel Gas Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	1300 - 1600 psig (90 - 110 bar)
Outlet Pressure	100 - 250 psig (7 - 17 bar)
Flow Rate	20,000 - 60,000 lb/h (9,000 - 30,000 kg/h)
Inlet Temp.	80 - 150°F (27 - 66°C)
Valve Type and Pressure Class	NPS 2 - 4 HPT, ASME CL900 / 1500
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Whisper III Trim

2. Fuel Gas Pressure Control: The fuel gas control may be split among two valves or combined into one. The conditions noted below assume the flow is split between two valves.

Table 14-15. Fuel Gas Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	100 - 250 psig (7 - 17 bar)
Outlet Pressure	50 - 190 psig (3 - 13 bar)
Flow Rate	4,000 - 30,000 lb/h (1,800 - 15,000 kg/h)
Inlet Temp.	80 - 150°F (27 - 66°C)
Valve Type and Pressure Class	NPS 2 - 4 ET, ASME CL150 / 300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Equal Percentage

3. Heat Transfer Fluid Inlet to Heater: This valve is used to control the flow of the heat transfer fluid to the heater to warm the fluid prior to vaporization. This application is typically handled by a butterfly valve.

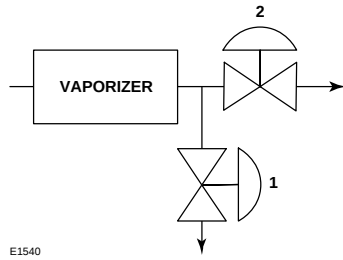


Figure 14-10. Plant Discharge Valves

Table 14-16. Heat Transfer Fluid Inlet to Heater Valve

Parameter	Typical Value
Inlet Pressure	150 - 250 psig (10 - 17 bar)
Outlet Pressure	140 - 240 psig (10 - 17 bar)
Flow Rate	1,000,000 - 4,000,000 lb/h (450,000 - 1,815,000 kg/h)
Inlet Temp.	150 - 210°F (66 - 99°C)
Valve Type and Pressure Class	NPS 16 - 18 A31A, ASME CL300
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

Send-out System

Figure 14-10 shows the valves found at the end of the terminal.

1. High Pressure Fuel Gas Pressure Control: This valve may or may not be present in a facility or may be supplied as part of a combustion type vaporization system. In systems with low pressure fuel gas, the high pressure fuel gas system is used for onsite utilities or combustion turbines. In these situations, there may be two to four valves.

Table 14-17. High Pressure Fuel Gas Pressure Control Valve

Parameter	Typical Value
Inlet Pressure	800 - 1600 psig (55 - 110 bar)
Outlet Pressure	350 - 500 psig (24 - 35 bar)
Flow Rate	20,000 - 80,000 lb/h (9,000 - 40,000 kg/h)
Inlet Temp.	80 - 150°F (27 - 66°C)
Valve Type and Pressure Class	NPS 2 - 4 HPT, ASME CL900 / 1500
Valve Material and Trim Material	WCC with Standard
Shutoff Requirement	ANSI Class V
Trim Type	Whisper III Trim

2. System Outlet Control: Here, the final discharge pressure to the pipeline network is controlled. Depending upon the plant's designers, this valve may be of a cryogenic design in the event the upstream vaporizers fail. In this case, the valve could experience cryogenic conditions. Regardless of materials use for construction or design criteria, this will be a butterfly valve.

Table 14-18. System Outlet Control Valve

Parameter	Typical Value
Inlet Pressure	1000 - 1600 psig (67 - 110 bar)
Outlet Pressure	900 - 1400 psig (62 - 97 bar)
Flow Rate	750,000 - 5,000,000 lb/h (340,000 - 2,300,000 kg/h)
Inlet Temp.	80 - 150°F (27 - 66°C)
Valve Type and Pressure Class	NPS 20 - 30 A11 / A11-C, ASME CL900
Valve Material and Trim Material	WCC / 316 SST with Standard / 316 SST
Shutoff Requirement	ANSI Class IV
Trim Type	Equal Percentage

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