

# **OIL AND GAS SEPARATION DESIGN MANUAL**

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## OIL AND GAS SEPARATION - DESIGN MANUAL

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## OIL AND GAS SEPARATION DESIGN AND SIZING

### INTRODUCTION:

Hydrocarbon streams as produced at the wellhead are composed of a mixture of gas, liquid hydrocarbons and sometimes free water. In most cases it is desirable to separate these phases as soon as possible after bringing them to the surface and handle or transport the two or three phases separately. This separation of the liquids from the gas phase is accomplished by passing the well stream through an oil-gas or oil-gas-water separator.

Different design criteria must be used in sizing and selecting a separator for a hydrocarbon stream based on the composition of the fluid mixture. In the case of low pressure oil wells, the liquid phase will be large in volume as compared to the gas phase. In the case of high pressure gas-distillate wells the gas volume will be higher as compared to the liquid volume. The liquid produced with high pressure gas is generally a high API gravity hydrocarbon, usually referred to as distillate or condensate. However, both low pressure oil wells and high pressure gas-distillate wells may contain free water.

Separators are used in many other locations other than wellhead production batteries, such as gasoline plants, upstream and downstream of compressors, and liquid traps in gas transmission lines. They are also found on inlets to dehydration units, gas sweetening units, et cetera. At some of these locations separators are referred to as knockouts, free liquid knockouts, and traps. Sometimes these vessels are called scrubbers. Caution should be used when referring to a vessel required for gas/liquid separation as a scrubber. Within the gas industry there is another type of vessel often called a scrubber. This is one that is designed to handle a gas stream with only trace amounts of free liquid present in the gas. They are not designed using the same criteria as is used for gas/liquid separation where appreciable amounts of liquid are present or where liquid slugging maybe encountered.

However, all of the vessels mentioned above that are designed to separate gas and free liquids serve the same primary purpose. This technical paper is concerned primarily with the use of separators in field installations. The theory and basic design criteria will be the same no matter where they are located or their basic use.

### INTERNAL CONSTRUCTION OF SEPARATORS:

The principal items of construction that should be present in a good liquid-gas separator are the same regardless of the overall shape or configuration of the vessel. Some of these features are itemized as follows:

1. A centrifugal inlet device where the primary separation of the liquid and gas is made;
2. A large settling section of sufficient length or height to allow liquid droplets to settle out of the gas stream with adequate surge room for slugs of liquid;
3. A mist extractor or eliminator near the gas outlet that will coalesce small particles of liquid that will not settle out by gravity;
4. Adequate controls consisting of level controller, liquid dump valve, gas back pressure valve, safety relief valve, pressure gauge, level gauge, instrument gas regulator and piping.

It has been found that the bulk of gas-liquid separation takes place in the inlet centrifugal separating section.

Here the incoming stream is spun around the walls of a small cylinder or usually the walls of the vessel in the case of a vertical or spherical separator. This subjects the fluids to a centrifugal force up to five hundred times the force of gravity. This action stops the horizontal motion of the free liquid entrained in the gas stream and forces the liquid droplets together, where they will fall to the bottom of the separator in the settling section.

The settling section is necessary to allow the turbulence of the fluid stream to subside and allow the liquid droplets to fall to the bottom of the vessel, due to the difference in the gravity between the liquid and gas phases. A large open space in the vessel has been found adequate for this purpose. Introduction of special quieting plates or baffles with narrow openings only complicates the internal construction of the separator and provides places for sand, sludge, paraffin, et cetera, to collect and eventually plug up the vessel and stop the flow. It has been found that the separation of liquid and gas using the centrifugal inlet feature and a large open settling section will produce a more stable liquid product, which can be obtained in atmospheric or low pressure storage tanks. Minute scrubbing of the gas phase by use of internal baffling or plates may produce more liquid to be discharged from the separator, but it will not be a stable product, since the light ends will be entrained in it, and therefore more vapor losses will be incurred from the storage system.

Sufficient surge room should be allowed in the settling section to handle slugs of liquid without carry over to the gas outlet. This can be accomplished to some extent by the placement of the liquid level controller in the separator, which in turn determines the liquid level. The amount of surge room required is often difficult, if not impossible, to determine based on well test or flowing data. In most cases the separator size used for a particular application is often a compromise between initial cost and possible surging requirements.

Another major item required to effect good and complete liquid-gas separation is a mist eliminator or extractor near the gas outlet. Small liquid droplets that will not settle out of the gas stream, due to the little or no gravity difference between them and the gas phase, will be entrained and pass out of the separator with the gas. This can be almost eliminated by passing the gas through a mist eliminator near the gas outlet which has a large surface impingement area. The small liquid droplets will hit the surfaces, coalesce and collect to form larger droplets which will then drain by gravity back to the liquid section in the bottom of the vessel. It is believed that the stainless steel woven wire mist eliminator is the most efficient type, and has been proven by removing up to 99.9% or more of the entrained liquids from the gas stream. This type offers the greatest surface area for the collection of liquid droplets per unit volume as compared to vane types, ceramic packing or other configurations. The vane type mist eliminators do have application in areas where there is entrained solid material in the gas phase that may collect and plug a wire mesh type mist eliminator.

#### SEPARATOR TYPES:

There are four major types or basic configurations of separators generally available from manufacturers which are as follows:

1. Vertical;
2. Horizontal Single Tube;
3. Horizontal Double Tube;
4. Spherical.

A typical vertical low pressure oil-gas separator with mechanical controls and the features as previously described is illustrated in Figure 8. Figure 9 illustrates a typical vertical high pressure or low pressure oil-gas separator with pneumatic controls. The vertical separator has the advantage that it will handle greater slugs of liquid without carry over to the gas outlet, and the action of the liquid level control is not quite as critical. Due to the greater vertical distance between the liquid level and the gas outlet there is less tendency to re-vaporize the liquid into the gas phase. Some disadvantages are that it is more difficult and expensive to fabricate and ship this type of separator in skid mounted assemblies, and it takes a larger diameter separator for a given gas capacity than a horizontal vessel. From this it can be seen that this type of separator is most often used on fluid streams with low gas-oil ratios; in other words, handling considerably more liquid than gas.

Spherical separators offer an inexpensive and compact vessel arrangement. Figure 13 illustrates a typical low pressure model with mechanical controls. Figure 14 illustrates a similar high pressure spherical oil-gas

separator with pneumatic controls. However, this type of vessel has very limited surge space and liquid settling section. The placement and action of the liquid level control in this type of vessel is also very critical.

The horizontal separator has several different advantages particular to this type of construction. Figure 10 illustrates a typical horizontal high or low pressure oil-gas separator with pneumatic controls. The horizontal high pressure double tube separator is illustrated by a typical example shown in Figure 15. The horizontal separator in both the double tube and single tube configuration has several advantages over the vertical separator as it is easier to skid mount, less piping is required for field connections, and a smaller diameter is required for a given gas capacity. This type of vessel also has a larger interface area between the liquid and gas phases which aids in separation. When gas capacity is a design criterion, the horizontal vessel is more economical in high pressure separators, due the increased wall thickness required with larger diameters. However, the liquid level control placement is more critical than in a vertical separator and the surge space is somewhat limited.

The double tube separator offers a slight advantage over a single tube in that the liquid section is separated from the gas space, and there is less chance for disturbance of the liquid and re-entrainment of any liquids into the gas phase. But, the double tube configuration is more expensive

Three phase, or oil-gas-water separation, can be easily accomplished in any type of separator by installing either a special internal baffling to construct a water leg or water siphon arrangement, or by use of an interface liquid level control. A three phase feature is difficult to install in a spherical due to the limited internal space available. With three phase operation two liquid level controls and two liquid dump valves are required. Figure 11 illustrates a typical high or low pressure separator equipped for oil-gas-water three phase operation. Figure 12 is an illustration of a typical horizontal high pressure or low pressure oil-gas-water separator.

From an evaluation of the advantages and disadvantages of the various types of separators, the horizontal single tube separator has emerged as the one that gives the most efficient operation for initial investment costs for high pressure gas distillate wells with high gas-oil ratios. For high liquid loadings, either low pressure or high pressure, vertical type separators should be considered.

#### FACTORS AFFECTING SEPARATION:

There are several basic factors which will affect the operation and separation between the liquid and gas phases in a separator.<sup>1</sup>

1. Separator operating pressure;
2. Separator operating temperature;
3. Fluid stream composition.

Changes in any one of these factors on a given fluid well stream will change the amount of gas and liquid leaving the separator. In most applications the well stream composition is a fact of nature and cannot be controlled by the operator. Only in plants or where several streams are mixed can the fluid stream composition can be varied, affecting the oil and gas separation. Generally speaking, an increase in operating pressure or decrease in operating temperature will increase the liquid recovered in a separator. However, there are optimum points in both cases beyond which further changes will not aid in liquid recovery. In fact, storage system vapor losses may become too great before these points can be reached.

In the case of wellhead separation equipment an operator generally wants to determine the optimum conditions for a separator to produce the maximum income. Again, generally speaking, the liquid recovered is worth more than the gas. So high liquid recovery is a desirable feature, providing it can be held in the available storage system. Also, pipeline requirements for the BTU content of the gas may be another factor affecting the separator operation. Without the addition of expensive mechanical refrigeration equipment it is often not feasible to try to affect the operating temperature of a separator. However, on most high pressure wells an indirect heater is used to heat the gas prior to pressure reduction in a choke to pipeline pressure. By careful operation of this indirect heater the operator can prevent overheating of the gas stream prior to choking, more than what is required, and therefore affect the temperature of the separator downstream from the indirect heater.

The operator can also control the operating pressure to some extent with the use of back pressure valves within the limitation of the flowing characteristics of the well against a set pressure head and the transmission line pressure requirements. As previously mentioned, higher operating pressure will generally result in higher liquid recovery.

An analysis can be made using the well stream composition to find the optimum temperature and pressure at which a separator should operate to give the maximum liquid and/or gas phase recovery. These calculations, known as "Flash Vaporization Calculations," require a trial-and-error solution and are more generally adapted to solution by a programmed computer. However, an operator can also make trial settings within the limitations of the equipment to find the best operating conditions to result in the maximum amount of gas or liquids that are desired. In the case where separators are used as scrubbers or knockouts ahead of other treating equipment or compressors, it is generally desired to remove the maximum amount of liquid from the gas stream to prevent operational damage to the equipment downstream from the scrubber.<sup>2</sup>

SEPARATOR DESIGN – GAS CAPACITY:

The gas capacity of oil-gas separators has been calculated for many years from the following empirical relationship proposed by Souders-Brown:

$$v = K \left[ \frac{\rho_L - \rho_g}{\rho_g} \right]^{1/2}$$

Then

$$A = \frac{q}{v}$$

Where

- v = Superficial gas velocity based on the cross-sectional area of the vessel available for vapor flow, ft/sec
- A = Cross-sectional area of the separator available for vapor flow, ft<sup>2</sup>
- q = Gas flow rate at operating conditions, ft<sup>3</sup>/sec
- ρ<sub>L</sub> = Density of liquid at operating conditions, lb/ft<sup>3</sup>
- ρ<sub>g</sub> = Density of gas at operating conditions, lb/ft<sup>3</sup>
- K = Empirical factor

K Factors for Separators

Vertical Separator	5' high	K = 0.12 to 0.24, avg. 0.18
Vertical Separator	10' high	K = 0.18 to 0.35, avg. 0.265
Horizontal Separator	10' long	K = 0.40 to 0.50, avg. 0.45
Horizontal Separator	Other lengths "L" in ft.	$K = 0.45 \left[ \frac{L}{10} \right]^{0.56}$
Spherical Separator		K = 0.2 to 0.35, avg. 0.275
Vertical Scrubbers		K = 0.35

K Factors for Columns

Bubble Cap Tray Columns	24" spacing	K = 0.16
Bubble Cap Tray Columns	18" spacing	K = 0.12
Valve Tray Columns	24" spacing	K = 0.18
Valve Tray Columns	18" spacing	K = 0.11

K Factors for Mist Eliminators<sup>3</sup>

Mesh Pad	Generally, the lower capacities correspond to the mesh pad designs with the highest droplet removal efficiencies.	K = 0.22 to 0.39
Vane Pack	Horizontal Flow	K = 0.9 to 1.0
Vane Pack	Vertical Up-flow The higher capacities are generally associated with pocketed vane designs.	K = 0.4 to 0.5

As given in the Engineering Data Book<sup>3</sup> published by the Gas Processors Suppliers Association, the K capacity factor for mesh mist extractors is often derated as given in the following table for higher pressure operation to compensate for the reduction in surface tension of the liquids that occurs with increasing pressure.

Adjustment of K Factor for Pressure

Pressure, psig	Percent of Design Value
Atmospheric	100
150	90
300	85
600	80
1150	75

The above relationship is based on a superficial vapor velocity through a vessel; and the vapor or gas capacity is then in relationship to the diameter of the vessel. The formula is also used for other designs, such as trayed towers in dehydration or gas sweetening units and for the sizing of mist eliminators. Therefore, the "K" factor for these is presented above, along with the factors for vertical and horizontal separators, so that the relationship one bears with the other can be seen.

$$Q = \frac{2.40(D)^2(K)(P)}{Z(T + 460)} \left[ \frac{\rho_L - \rho_g}{\rho_g} \right]^{1/2}$$

Where: Q = Gas capacity at std. conditions, MMSCFD

D = Internal diameter of the vessel, ft.

P = Operating pressure, psia

T = Operating Temperature, °F

Z = Compressibility factor

All other items as defined above

\*

For Horizontal single tube separators partially full of liquid, an equivalent I.D. must be determined for the vapor area available or the gas capacity must be reduced by multiplying by the ratio of the actual cross sectional area available for vapor flow to the cross sectional area of the vessel.

Since the above equation is empirical, perhaps a better determination of separator capacity should be made from actual manufacturers' field test data. Figures 1 through 4, 6 and 7 are gas capacity charts for various standard size separators based on operating pressure. These actual manufacturers' gas capacity charts take into consideration height differences in horizontal separators which add to the gas capacity of the separators. As can be seen, height and length differences are not taken into account in the above Souders-Brown equation. But, field experience has proven that additional gas capacity can be obtained by an increase in the height of vertical separators and correspondingly, the additional length of horizontal separators.

As can be seen on the sizing charts for horizontal separators, a correction must be made for the amount of



liquid in the bottom of the separator. This is for single tube horizontal vessels. One-half full of liquid is more or less standard for most manufacturers for single tube horizontal separators. However, the gas capacity can be increased by lowering the liquid level to increase the available gas space within the vessel. Gas capacities of horizontal separators with liquid sections one-half full, one-third full, or one-quarter full can be determined from the gas capacity charts.

**SEPARATOR DESIGN - LIQUID CAPACITY:**

The liquid capacity of a separator is primarily dependent upon the retention time of the liquid within the vessel. Good separation requires sufficient time to obtain an equilibrium condition between the liquid and gas phases at the temperature and pressure of separation. The liquid capacity of a separator or the settling volume required based on retention can be determined from the following equation.

$$W = \frac{1440(V)}{t} \quad \text{or} \quad t = \frac{1440(V)}{W} \quad \text{or} \quad V = \frac{W(t)}{1440}$$

Where: W = Liquid capacity, bbl/day  
 V = Liquid settling volume, bbl  
 t = Retention time, min

Basic design criteria for liquid retention times in separators have been determined by numerous field tests. These are as follows:

Oil-gas separation	1 min.
High pressure oil-gas –water separation	2 to 5 minutes
Low pressure oil-gas-water separation	5 to 10 minutes @ 100°F and up
	10 to 15 minutes @ 90°F
	15 to 20 minutes @ 80°F
	20 to 25 minutes @ 70°F
	25 to 30 minutes @ 60°F

Figures 5A and 5B are sizing charts for liquid capacity of horizontal single tube high pressure separators. These are based on the parameters of the separator working pressure, size and the depth of liquid used in the settling section. Tables 1 through 5 list the standard specifications of typical oil-gas separators available, along with the liquid settling volumes with the conventional placement of liquid level controls. The settling volumes may be used in the above equations to determine the liquid capacity of a particular vessel. For proper sizing both the liquid capacity and gas capacity required should be determined. It may be noted that on most high pressure gas distillate wells, the gas-oil ratio is high and the gas capacity of a separator is usually the controlling factor. However, the reverse may be true for low pressure separators used on well streams with low gas-oil ratios. The liquid discharge or dump valve on the separator should be sized based upon the pressure drop available and the liquid flow rate

**OTHER TYPES OF SEPARATION EQUIPMENT:**

There are several types of separation equipment which employ some of the basic features as discussed for oil and gas separation along with additional items. These types of equipment are discussed in more complete detail in other technical bulletins. Filter separators employing dry gas filters in combination with oil and gas separation are discussed in Technical Bulletin No. 162 “Filter Separators”.

Low temperature separation units are another type of equipment employed for gas – condensate separation of high pressure gas streams for maximum liquid recovery. The details and application of these units are discussed in Technical Bulletin No. 163 “Low Temperature Separation Units”.

Where only trace or small amounts of free liquid are found in the gas stream, it may be possible to use a vertical gas scrubber to remove the liquid from the gas. This type of vessel is discussed more completely in Technical Bulletin No. 177, “Vertical Gas Scrubbers”. Caution should be used in the application of these vessels in place of a conventionally designed gas/liquid separator. Scrubbers should only be used where no

appreciable amounts of free liquid are present in the gas stream or no liquid slugging is to be encountered.

CONCLUSION:

The above described sizing procedures and accompanying charts and tables offer an accurate procedure for sizing standard oilfield oil-gas separators for high pressure gas condensate well streams or low pressure oil streams. Of course, these charts and tables can be used in any reverse manner for evaluating and determining the capacity or performance of existing equipment. The following examples are presented to further illustrate the use of the charts and tables and methods to be used in sizing oil-gas separation equipment.

## EXAMPLE PROBLEMS

**Example 1:** Size a standard oil-gas separator both vertical and horizontal for the following conditions:

Gas Flow Rate: 5.0 MMSCFD  
Operating Pressure: 800 psig  
Condensate Flow Rate: 20 bbl/MMSCF

Total Liquid Capacity = 20 (5.0) = 100 bbl/day

From Figure 2A, at 800 psig operating pressure, a 20" x 7'-6" vertical separator will handle 5.4 MMSCFD.

From Table 2B, a 20" x 7'-6" separator will handle the following liquid capacity.

$$W = \frac{1440 (v)}{t} = \frac{1440 (0.65)}{1.0} = 936 \text{ bbl/day}$$

From Figure 4A, at 800 psig operating pressure and ½ full of liquid, a 16" x 5' horizontal separator will handle 5.1 MMSCFD.

From Table 4B, a 16" x 5' separator will handle:

$$W = \frac{1440 (v)}{t} = \frac{1440 (0.61)}{1.0} = 878 \text{ bbl/day}$$

Therefore, a smaller horizontal separator would be required and would be more economical. For the operating pressure involved, at least a 1,000 psig working pressure separator should be used.

**Example 2:** Size a standard vertical oil-gas separator for the following conditions:

Oil Flow Rate: 2,500 bbl/day  
Gas-Oil Ratio: 1,000  
Operating Pressure: 50 psig

Gas flow rate = 100 (2500) = 2,500,000 cu ft/day = 1.5 MMSCFD

From Figure 1, at 50 psig operating pressure, a 36" x 5' vertical separator will handle 2.9 MMSCFD.

From Table 1B, a 36" x 5' separator will handle:

$$W = \frac{1440 (v)}{t} = \frac{1440 (1.61)}{1.0} = 2318 \text{ bbl/day}$$

Therefore, a larger separator will be required to handle the liquid load. A 30" x 10' separator will handle:

$$W = \frac{1440(2.06)}{1.0} = 2966 \text{ bbl/day}$$

The gas capacity of a 30" x 10' separator is 3.75 MMSCFD. In fact, the diameter of a separator generally controls the price and a 30" x 10' separator will probably be cheaper than a 36" x 5'.

**Example 3:** A 20" x 10', 100 psig W.P. horizontal separator is operated at ½ full of liquid. It can be used on a well with the following conditions:

Gas Flow Rate: 9.0 MMSCFD  
Line Pressure: 500 psig

From Figure 4A, a 20" x 10' separator will handle only 8.1 MMSCFD at 500 psig.

But, if a gas back pressure valve were put on the separator and held at 800 psig, the separator will handle 10.2 MMSCFD. This is accepted procedure providing the well will flow the desired rate at 800 psig.

**Example 4:** Size a horizontal high pressure separator for the following conditions:

Gas Flow Rate:	10.0 MMSCFD
Operating Pressure:	800 psig
Condensate Load:	500 bbl/day
Water Load:	100 bbl/day

From Figure 4A, at 800 psig operating pressure, a 20" x 10' horizontal separator will handle 10.2 MMSCFD operating ½ full of liquid. Where three phase operation is required in a horizontal separator, the liquid section should be ½ full, otherwise the level control action becomes too critical.

From Table 4B, the liquid capacity will be:

$$W = \frac{1440 (v)}{t} = \frac{1440 (1.80)}{5.0} = 518 \text{ bbl/day}$$

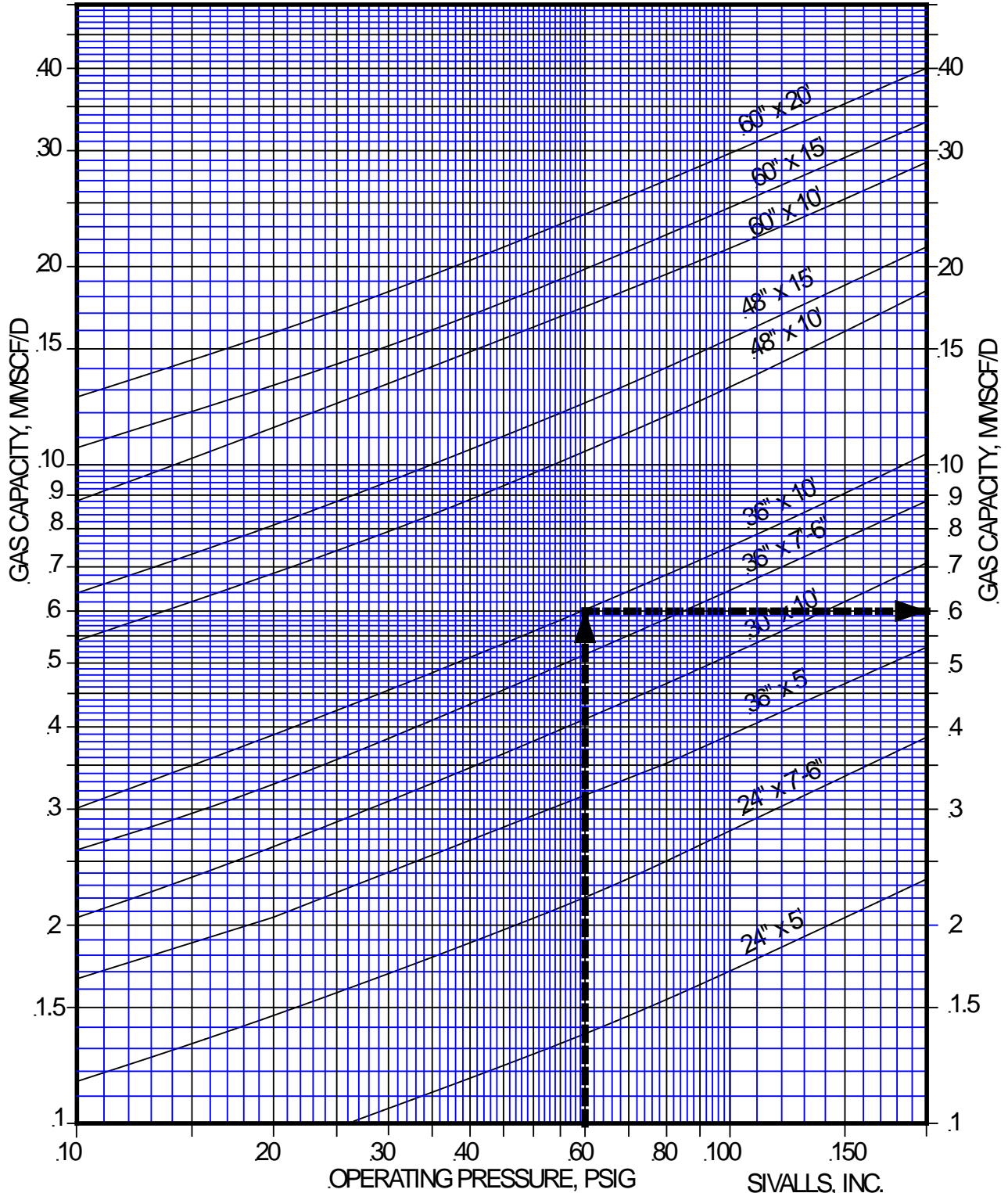
Therefore, the 20" x 10' separator will not handle the combined liquid load of 500 + 100 = 600 bbl/day. Five minute retention time is used as a conservative figure without any additional information.

From Table 4B, a separator with more settling volume is a 24" x 10'. Its liquid capacity is:

$$W = \frac{1440 (2.63)}{5.0} = 757 \text{ bbl/day}$$

The gas capacity of a 24" x 10' separator at 800 psig is 15.0 MMSCFD.

# FIGURE 1 GAS CAPACITY OF VERTICAL LOW PRESSURE SEPARATORS



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FIGURE 2A  
 GAS CAPACITY OF VERTICAL  
 HIGH PRESSURE SEPARATORS

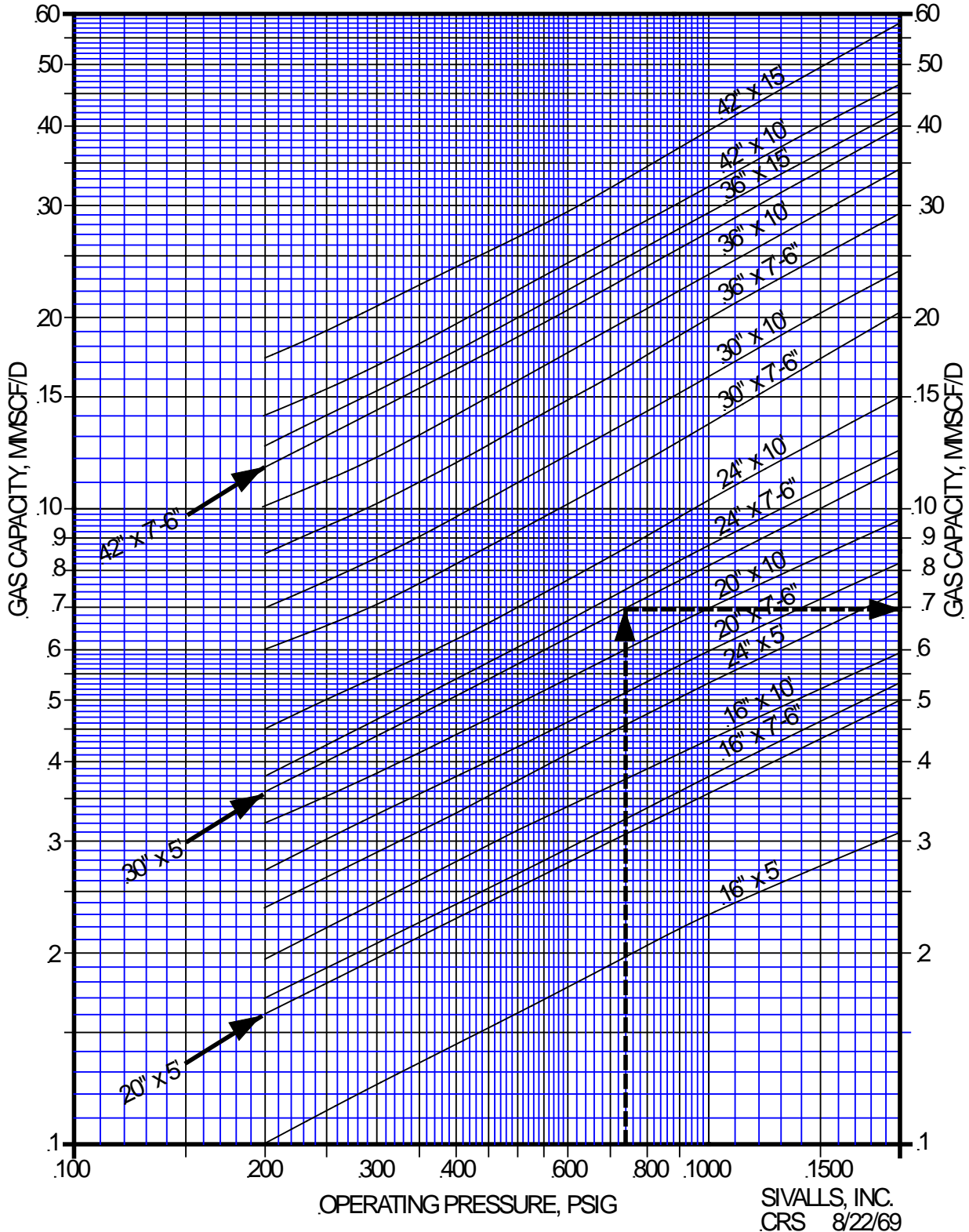
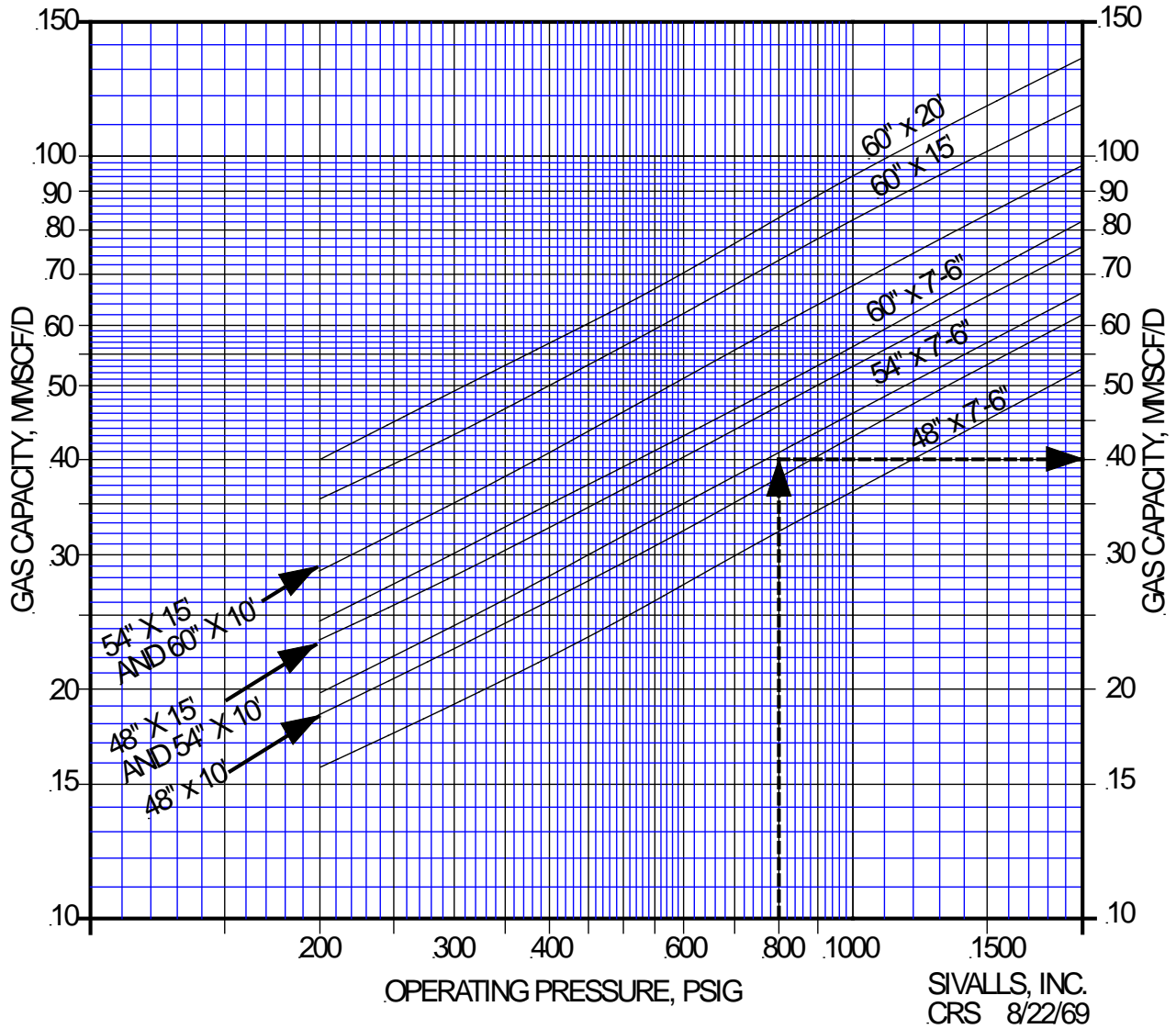


FIGURE 2B  
 GAS CAPACITY OF VERTICAL  
 HIGH PRESSURE SEPARATORS



**FIGURE 3  
GAS CAPACITY OF HORIZONTAL  
LOW PRESSURE SEPARATORS**

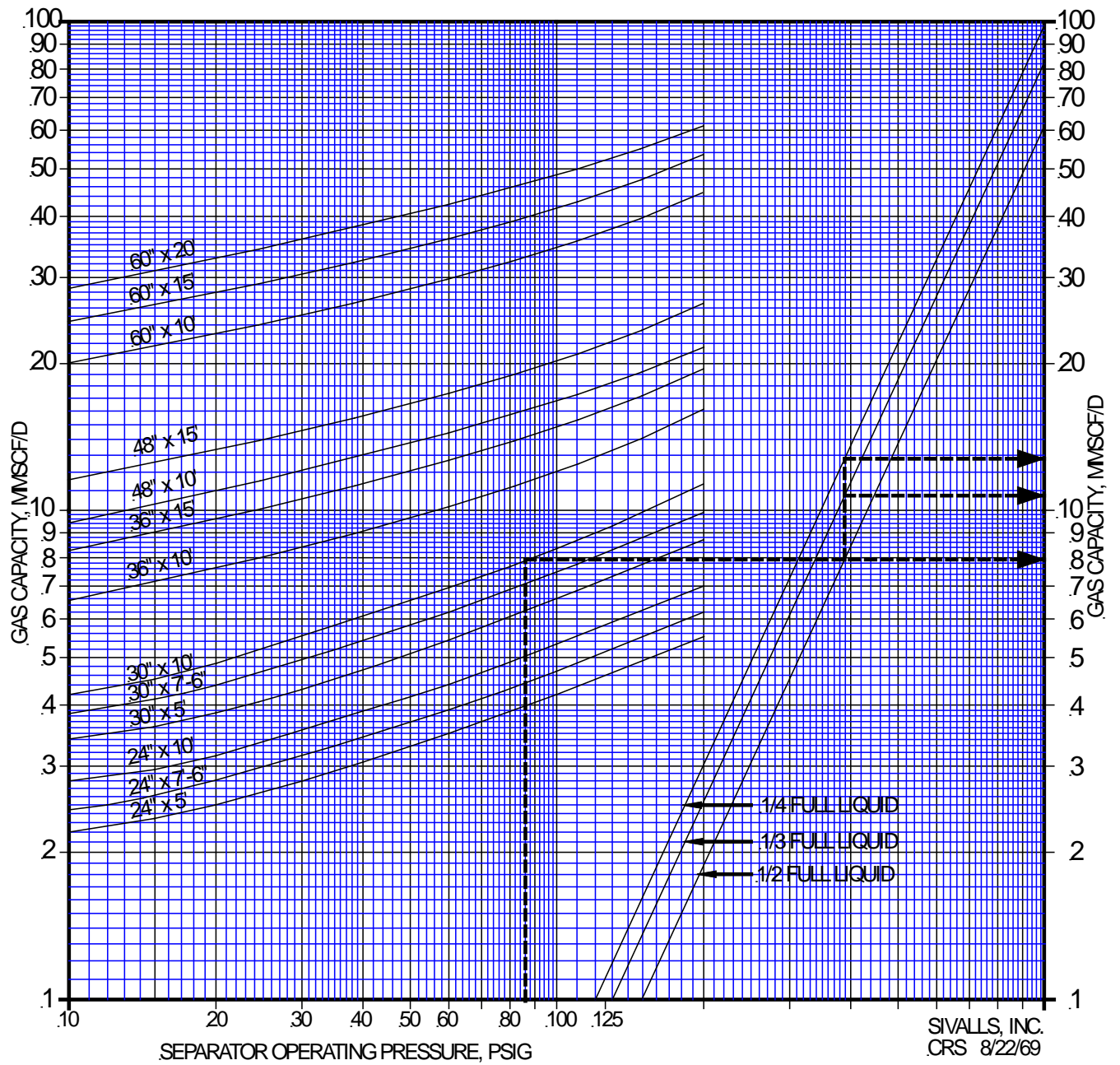




FIGURE 4A  
 GAS CAPACITY OF HORIZONTAL  
 HIGH PRESSURE SEPARATORS

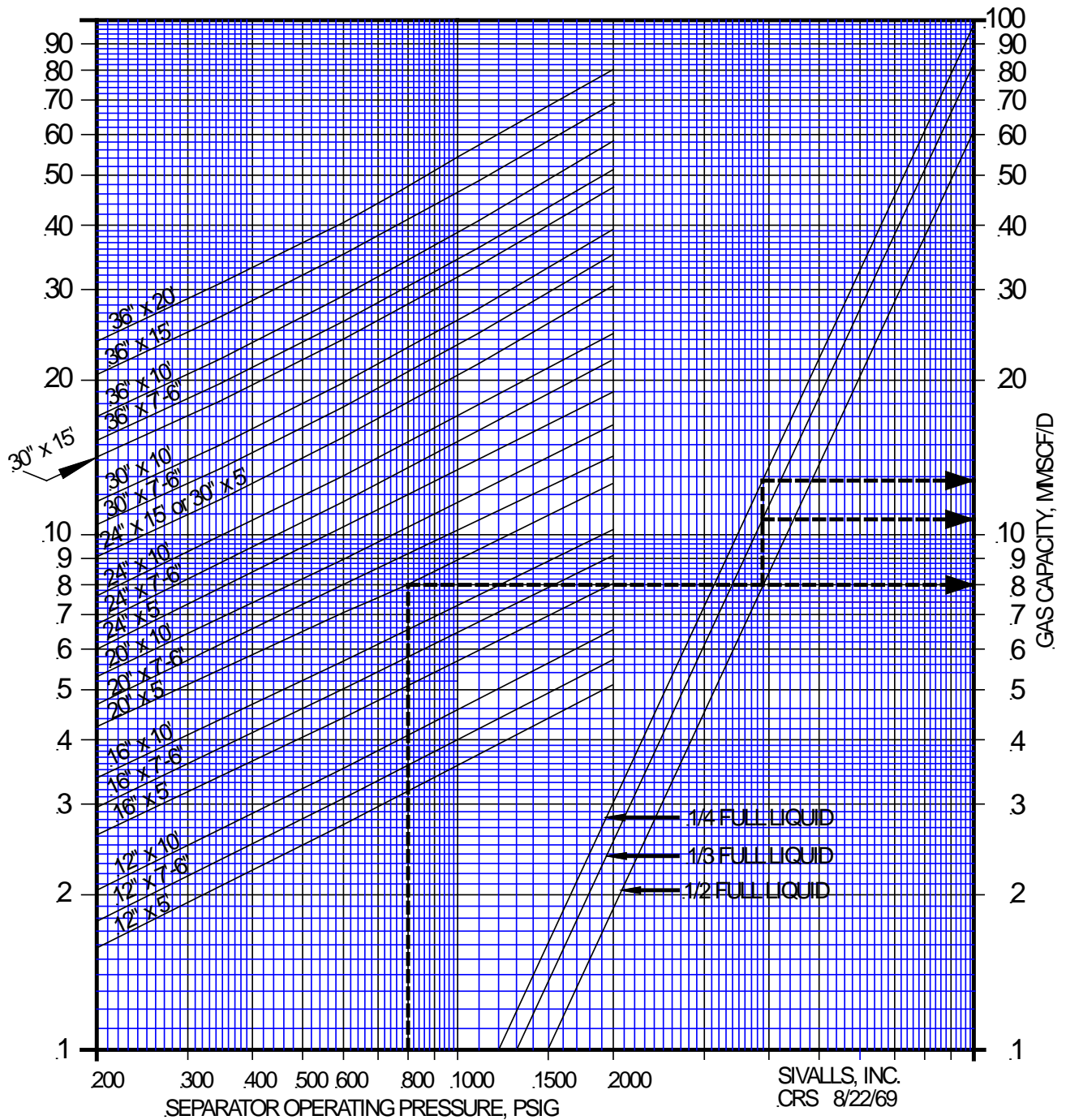
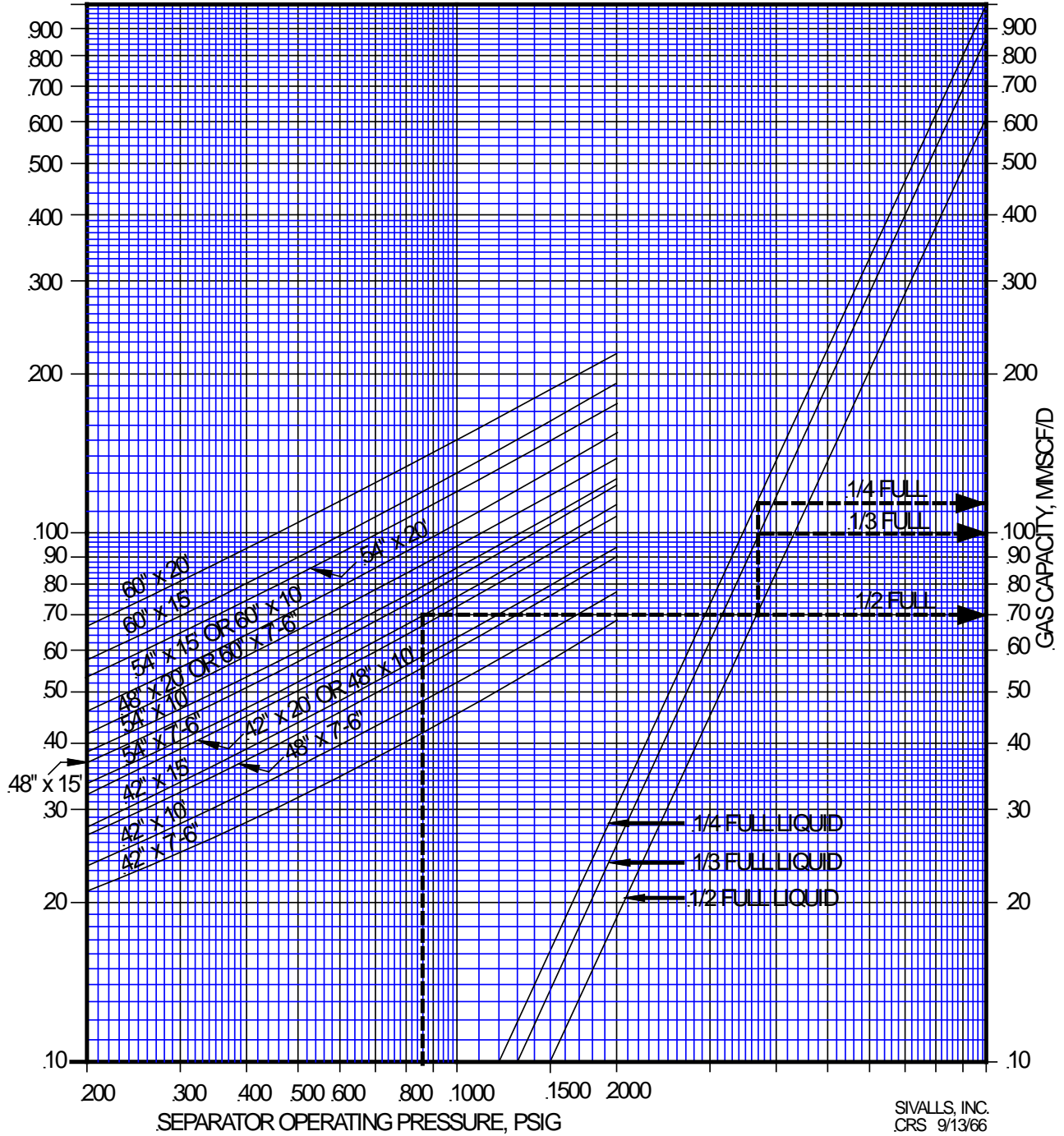


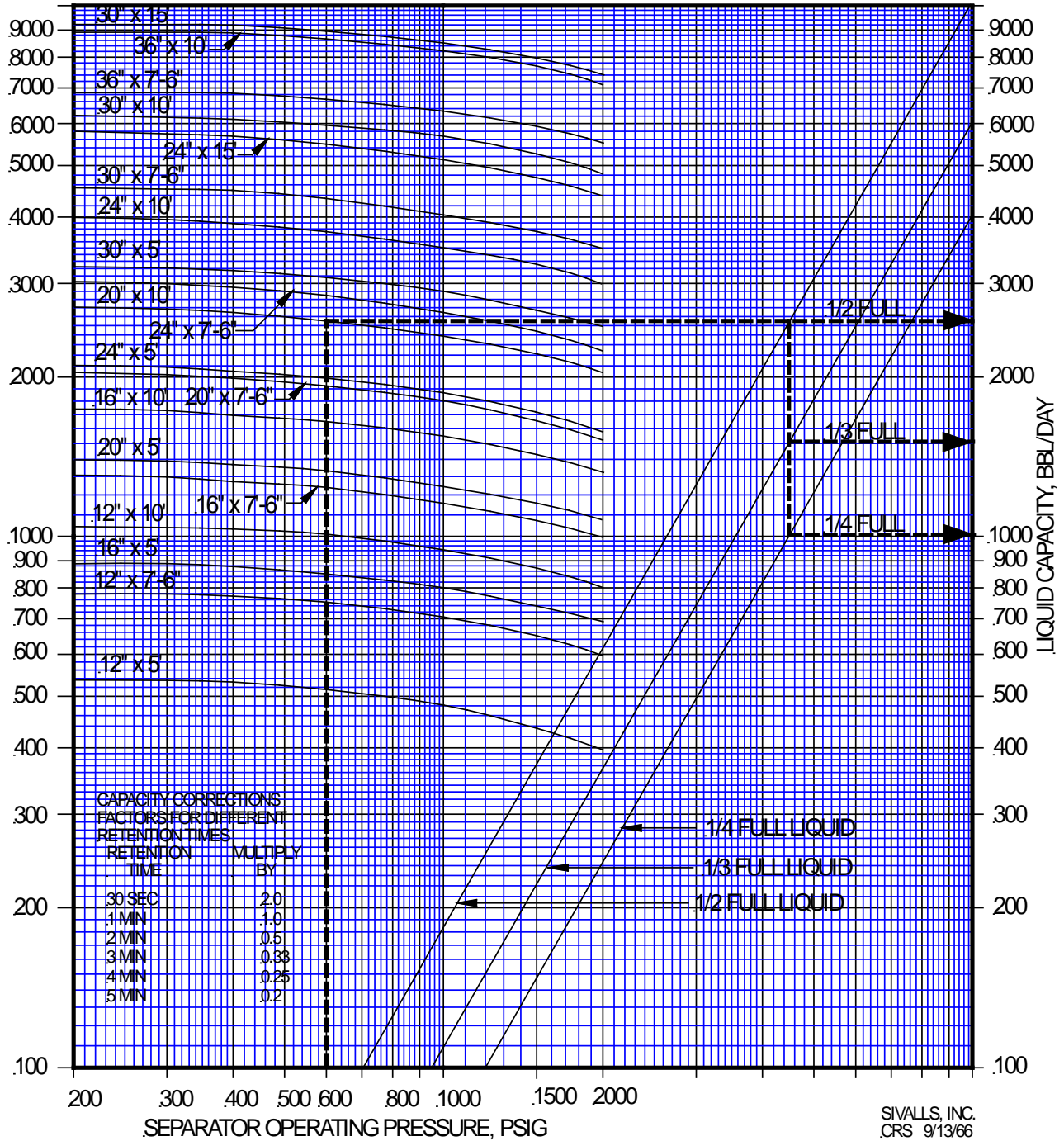
FIGURE 4B  
GAS CAPACITY OF HORIZONTAL  
HIGH PRESSURE SEPARATORS



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# FIGURE 5A LIQUID CAPACITY OF HORIZONTAL SINGLE TUBE HIGH PRESSURE SEPARATORS

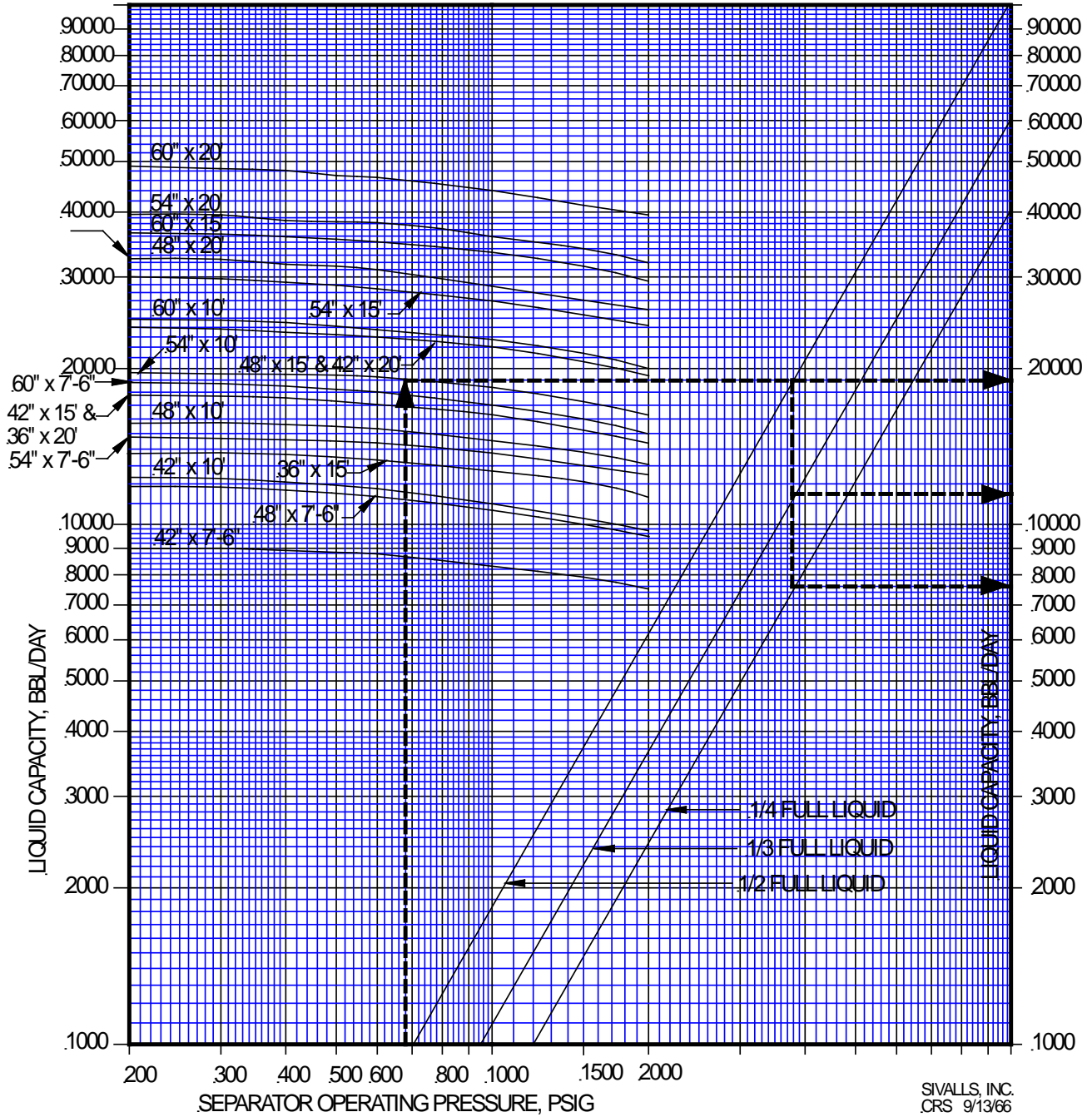
BASED ON ONE MINUTE RETENTION



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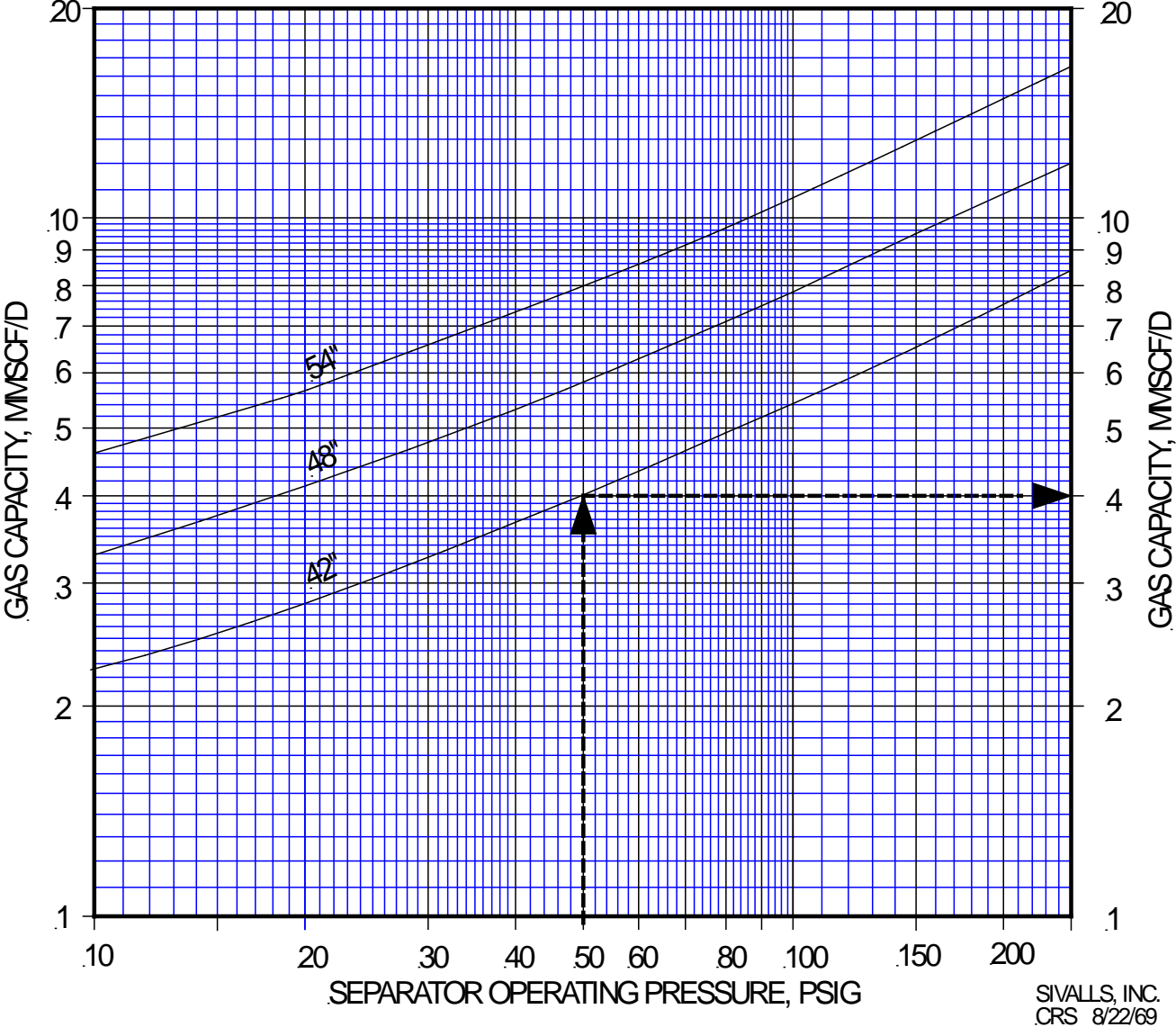
# FIGURE 5B LIQUID CAPACITY OF HORIZONTAL SINGLE TUBE HIGH PRESSURE SEPARATORS

BASED ON ONE MINUTE RETENTION



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# FIGURE 6 GAS CAPACITY OF SPHERICAL LOW PRESSURE SEPARATORS



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FIGURE 7  
 GAS CAPACITY OF SPHERICAL  
 HIGH PRESSURE SEPARATORS

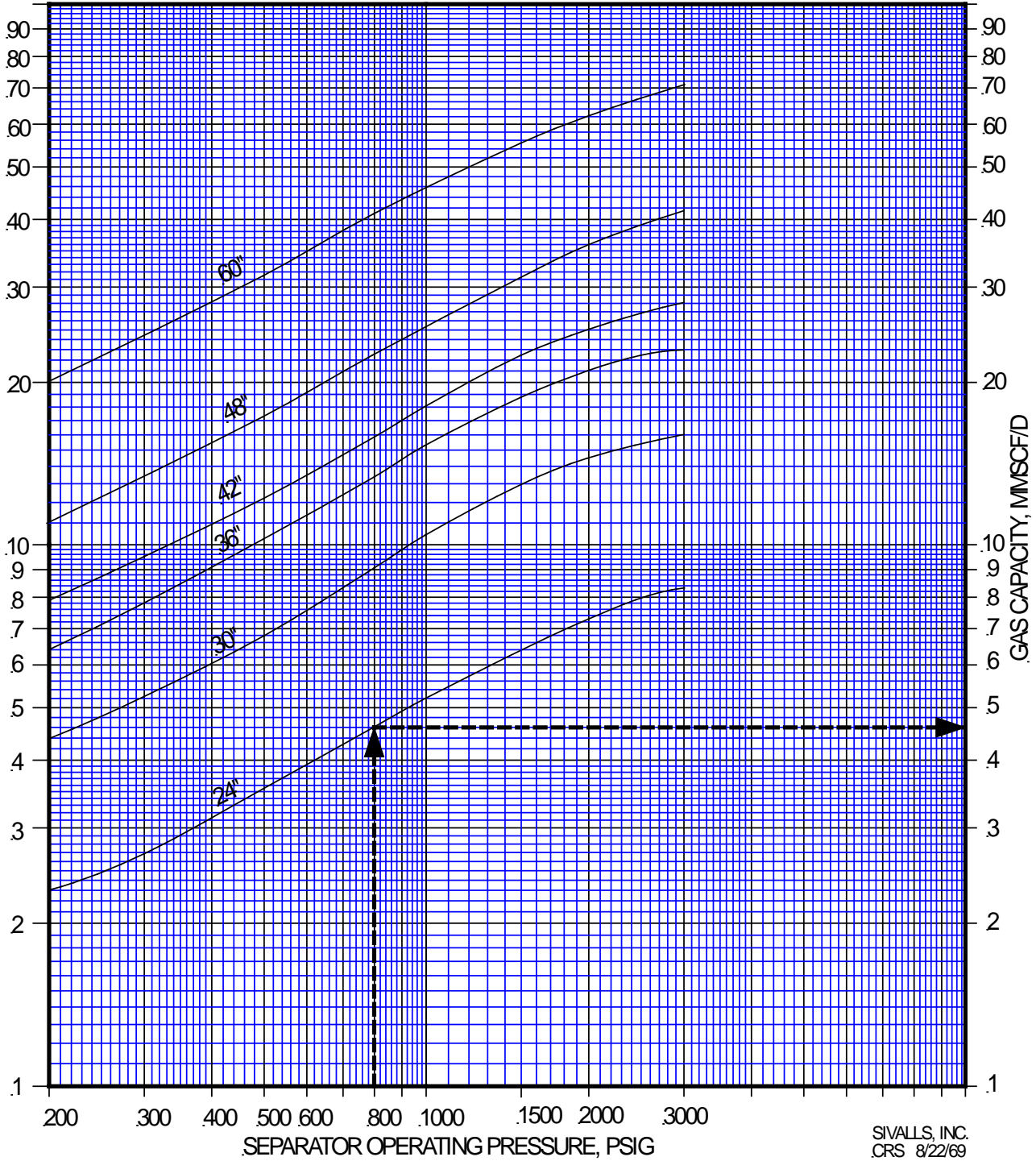


FIGURE 8  
VERTICAL LOW PRESSURE OIL AND GAS SEPARATOR  
MECHANICAL CONTROLS

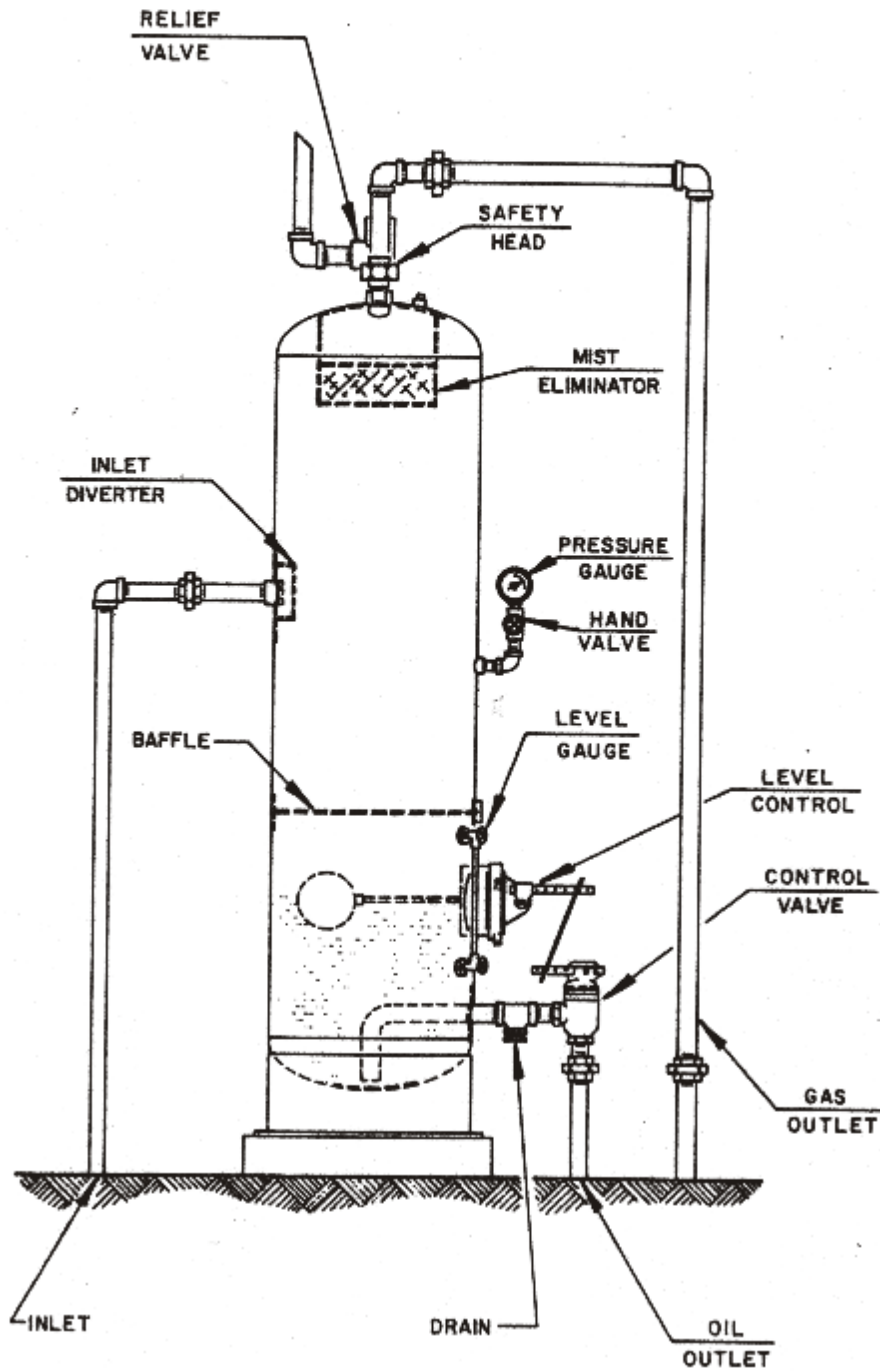


FIGURE 9  
VERTICAL HP OR LP OIL AND GAS SEPARATOR  
PNEUMATIC CONTROLS

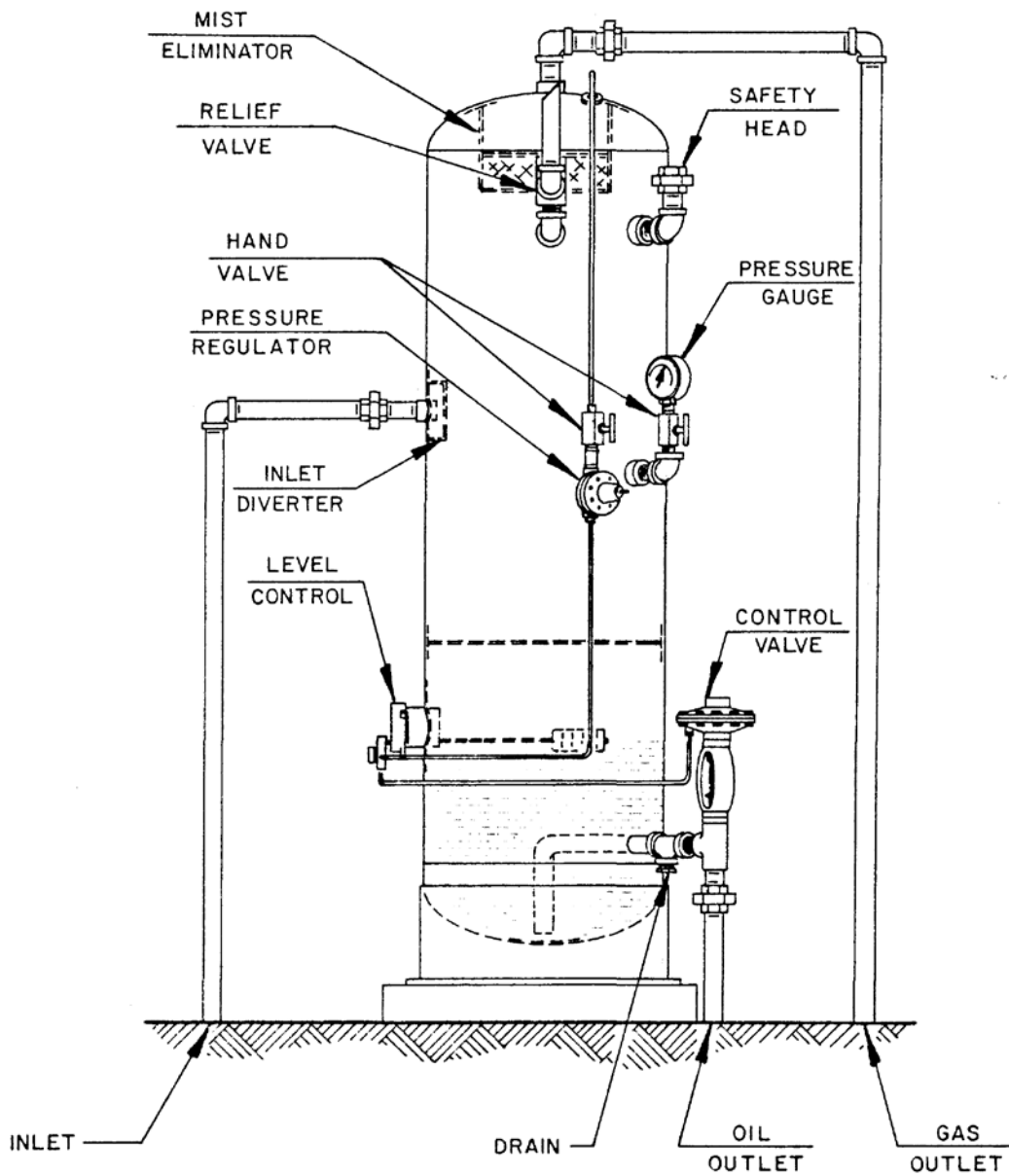




FIGURE 10  
HORIZONTAL HP OR LP OIL AND GAS SEPARATOR  
PNEUMATIC CONTROLS

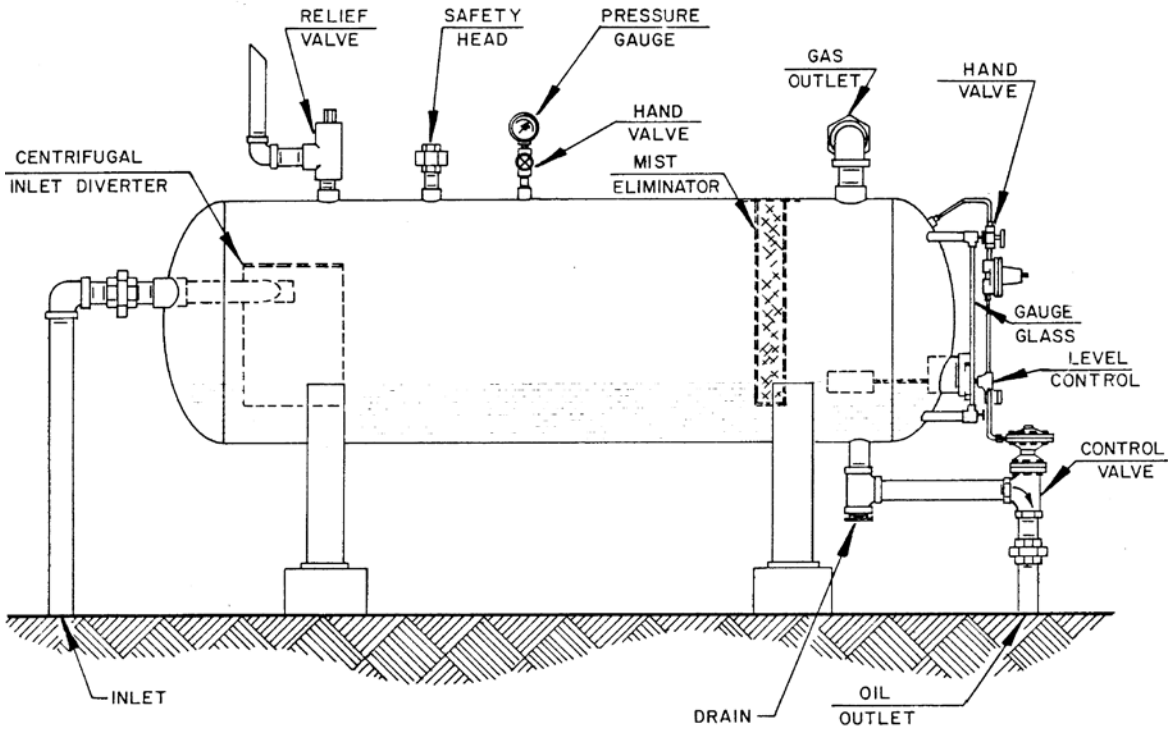


FIGURE II  
 VERTICAL HP OR LP OIL-GAS-WATER SEPARATOR  
 PNEUMATIC CONTROLS

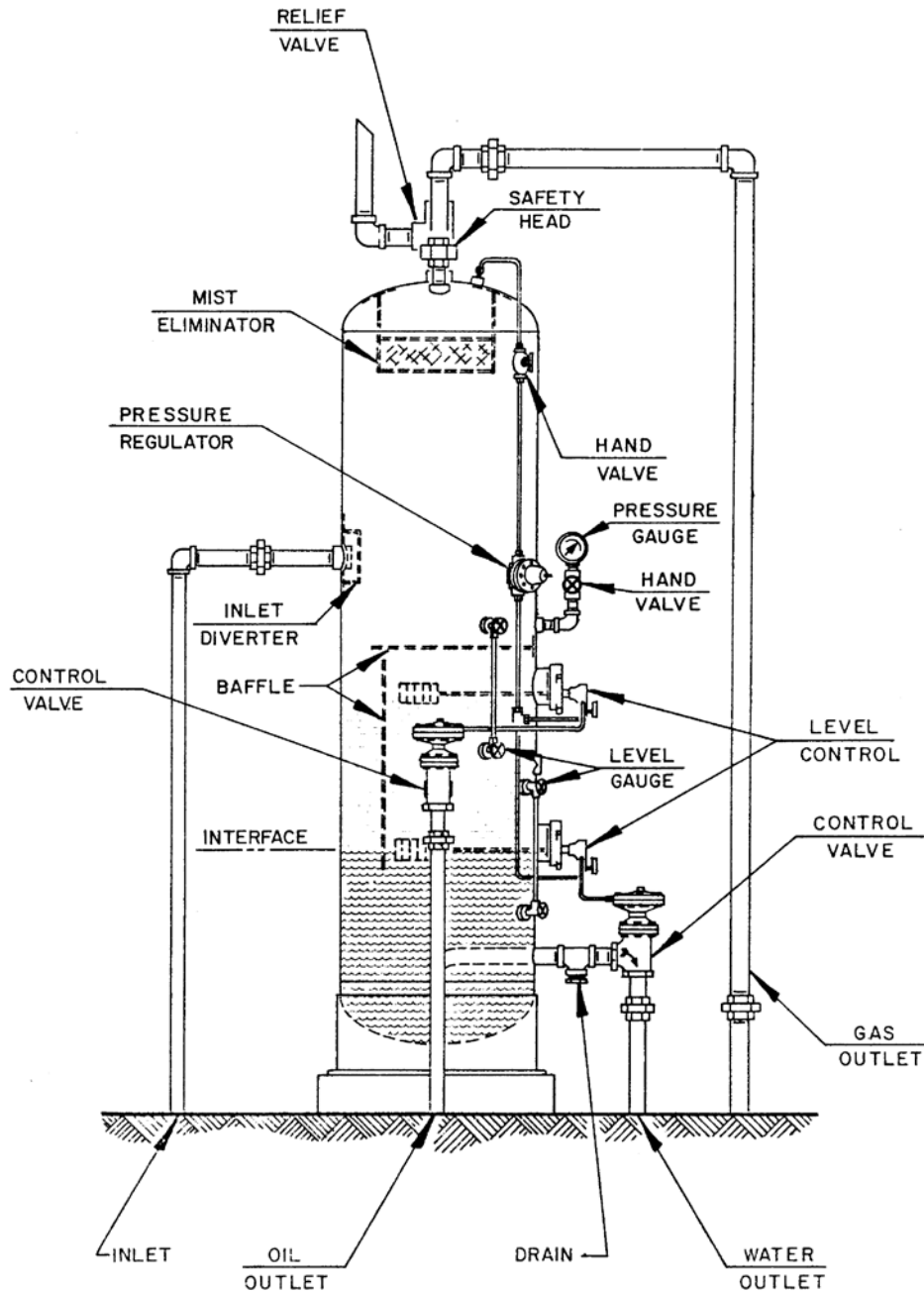
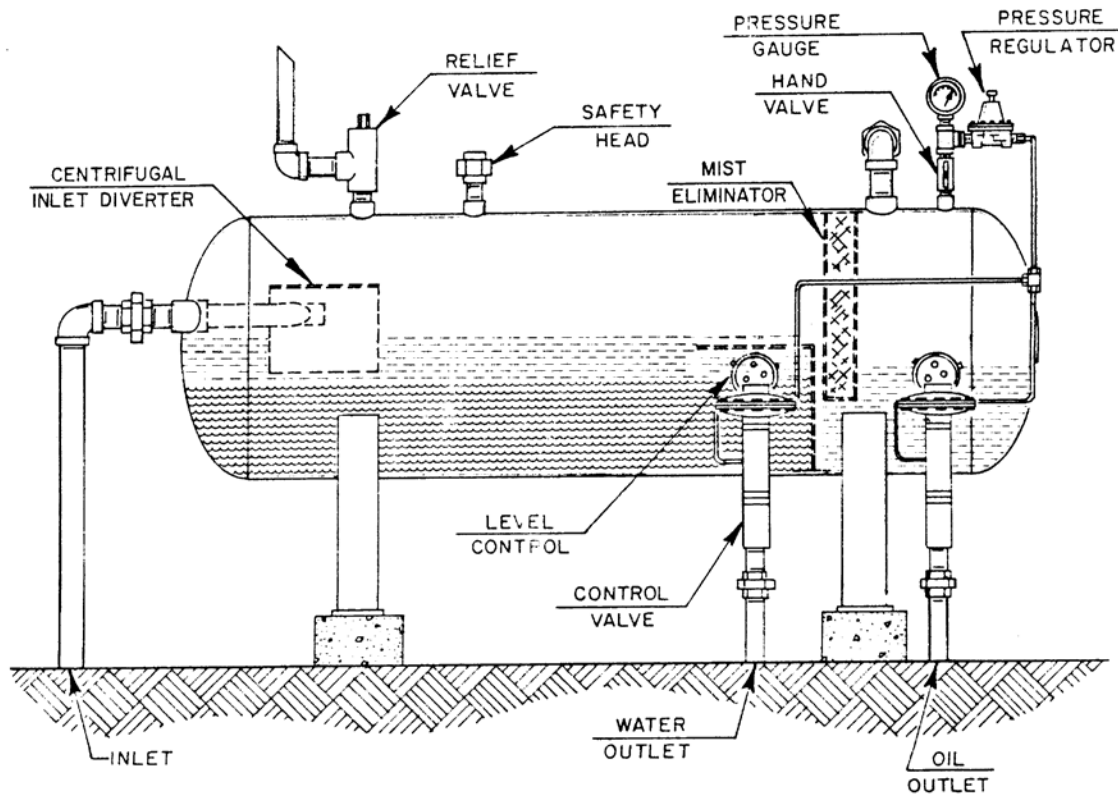


FIGURE 12  
HORIZONTAL HP OR LP OIL-GAS-WATER SEPARATOR  
PNEUMATIC CONTROLS



# SPHERICAL SEPARATORS

FIGURE 13 - LOW PRESSURE  
MECHANICAL CONTROLS

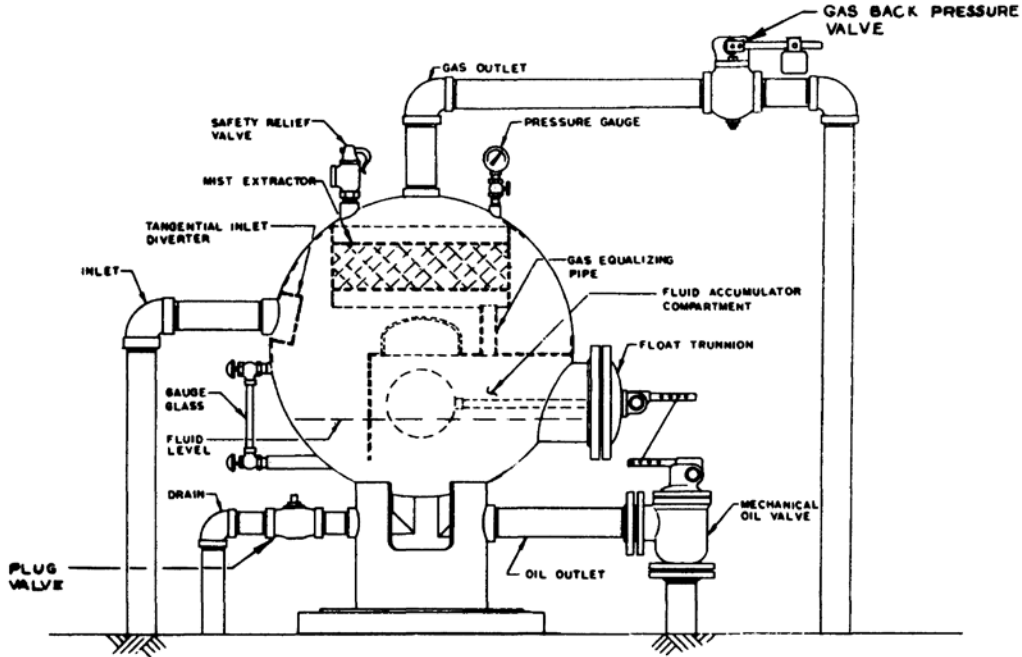


FIGURE 14 - HIGH PRESSURE  
PNEUMATIC CONTROLS

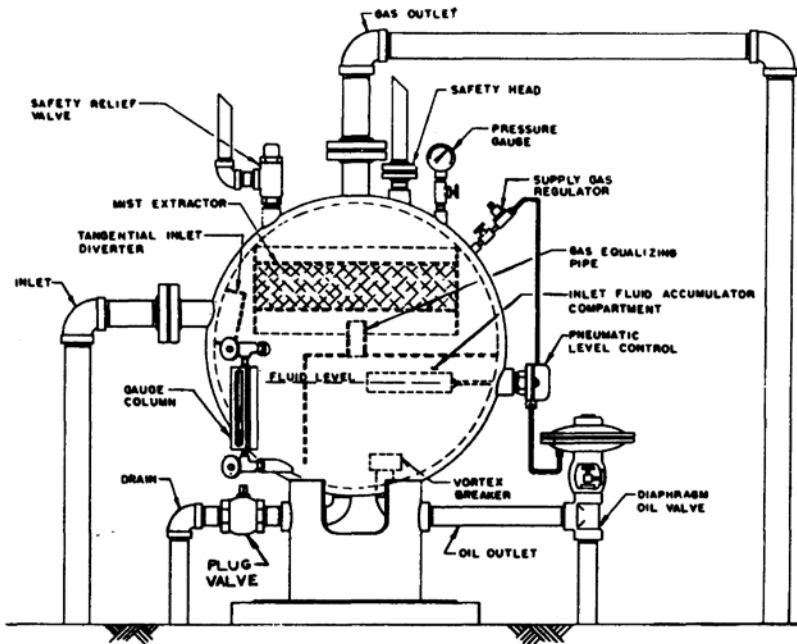


FIGURE 15  
HORIZONTAL HIGH PRESSURE  
DOUBLE TUBE SEPARATOR  
PNEUMATIC CONTROLS

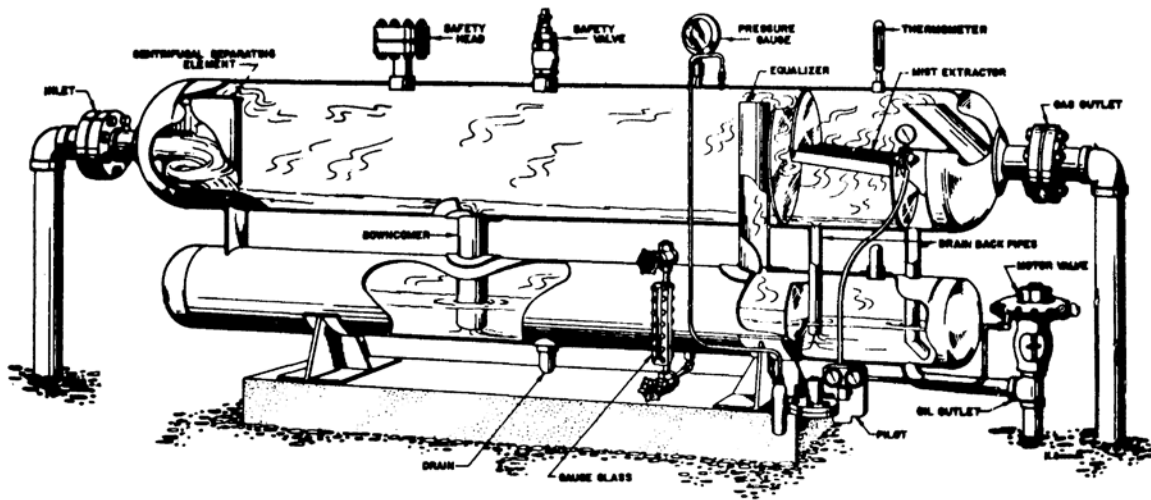


TABLE 1A  
SPECIFICATIONS OF STANDARD VERTICAL LOW PRESSURE SEPARATORS

Model No.	Size Dia. x Ht.	Working Pressure psi	Inlet & Gas Outlet Conn.	Oil Outlet Conn.	Standard Valves		Shipping Weight lb
					Oil or Oil & Water	Gas	
V-245	24" x 5'	125	2" Thd	2" Thd	2"	2"	950
V-2475	24" x 7 ½'	125	2" Thd	2" Thd	2"	2"	1,150
V-3010	30" x 10'	125	3" Thd	3" Thd	2"	2"	2,000
V-365	36" x 5'	125	4" Thd	3" Thd	2"	2"	2,000
V-3675	36" x 7 ½'	125	4" Thd	3" Thd	2"	2"	2,350
V-3610	36" x 10'	125	4" Thd	4" Thd	2"	2"	2,700
V-4810	48" x 10'	125	6" Flg	4" Thd	2"	2"	3,400
V-4815	48" x 15'	125	6" Flg	4" Thd	2"	2"	4,500
V-6010	60" x 10'	125	6" Flg	4" Thd	3"	3"	5,200
V-6015	60" x 15'	125	6" Flg	4" Thd	3"	3"	6,400
V-6020	60" x 20'	125	6" Flg	4" Thd	3"	3"	7,600

TABLE 1B  
SETTLING VOLUMES OF STANDARD VERTICAL LOW PRESSURE SEPARATORS, 125 psi W.P.

Size Dia. x Ht	Settling Volume, bbl	
	Oil-Gas Separators	Oil-Gas-Water Separators*
24" x 5'	0.65	1.10
24" x 7 ½'	1.01	1.82
30" x 10'	2.06	3.75
36" x 5'	1.61	2.63
36" x 7 ½'	2.43	4.26
36" x 10'	3.04	5.48
48" x 10'	5.67	10.06
48" x 15'	7.86	14.44
60" x 10'	9.23	16.08
60" x 15'	12.65	12.93
60" x 20'	15.51	18.64

\*Total settling volume is usually split evenly between oil and water.

TABLE 2A  
SPECIFICATIONS OF STANDARD VERTICAL HIGH PRESSURE SEPARATORS

Model No.**	Size Dia. x Ht.	Working Pressure psig*	Inlet & Gas Outlet Conn.	Standard Liquid Valve	Shipping Weight lb.
V-165-10	16" x 5'	1,000	2" Thd	1"	1,100
V-1675-10	16" x 7 ½'		2" Thd	1"	1,200
V-1610-10	16" x 10'		2" Thd	1"	1,500
V-205-10	20" x 5'	1,000	3" Flg	1"	1,600
V-2075-10	20" x 7 ½'		3" Flg	1"	1,900
V-2010-10	20" x 10'		3" Flg	1"	2,200
V-245-10	24" x 5'	1,000	3" Flg	1"	2,500
V-2475-10	24" x 7 ½'		3" Flg	1"	2,850
V-2410-10	24" x 10'		3" Flg	1"	3,300
V-305-10	30" x 5'	1,000	4" Flg	1"	3,200
V-3075-10	30" x 7 ½'		4" Flg	1"	3,650
V-3010-10	30" x 10'		4" Flg	1"	4,200
V-3675-10	36" x 7 ½'	1,000	4" Flg	1"	5,400
V-3610-10	36" x 10'		4" Flg	1"	6,400
V-3615-10	36" x 15'		4" Flg	1"	8,700
V-4275-10	42" x 7 ½'	1,000	6" Flg	2"	7,700
V-4210-10	42" x 10'		6" Flg	2"	9,100
V-4215-10	42" x 15'		6" Flg	2"	12,000
V-4875-10	48" x 7 ½'	1,000	6" Flg	2"	10,400
V-4810-10	48" x 10'		6" Flg	2"	12,400
V-4815-10	48" x 15'		6" Flg	2"	16,400
V-5475-10	54" x 7 ½'	1,000	6" Flg	2"	12,300
V-5410-10	54" x 10'		6" Flg	2"	14,900
V-5415-10	54" x 15'		6" Flg	2"	20,400
V-6075-10	60" x 7 ½'	1,000	6" Flg	2"	17,500
V-6010-10	60" x 10'		6" Flg	2"	20,500
V-6015-10	60" x 15'		6" Flg	2"	26,500
V-6020-10	60" x 20'		6" Flg	2"	32,500

\*Other standard working pressures available are 230, 500, 600, 1200, 1440, 1500, and 2000 psig.

\*\*Last two digits of model number would change for other working pressures, i.e. 1440 psig (-14), 600 psig (-6).

TABLE 2B  
 SETTLING VOLUMES OF STANDARD VERTICAL HIGH PRESSURE  
 SEPARATORS, 230 PSIG THROUGH 2000 PSIG W.P.\*\*\*

Size Dia. x Ht.	Settling Volume, bbl*	
	Oil-Gas Separators	Oil-Gas-Water Separators **
16" x 5'	0.27	0.44
16" x 7 ½'	0.41	0.72
16" x 10'	0.51	0.94
20" x 5'	0.44	0.71
20" x 7 ½'	0.65	1.15
20" x 10'	0.82	1.48
24" x 5'	0.66	1.05
24" x 7 ½'	0.97	1.68
24" x 10'	1.21	2.15
30" x 5'	1.13	1.76
30" x 7 ½'	1.64	2.78
30" x 10'	2.02	3.54
36" x 7 ½'	2.47	4.13
36" x 10'	3.02	5.24
36" x 15'	4.13	7.45
42" x 7 ½'	3.53	5.80
42" x 10'	4.29	7.32
42" x 15'	5.80	10.36
48" x 7 ½'	4.81	7.79
48" x 10'	5.80	9.78
48" x 15'	7.79	13.76
54" x 7 ½'	6.33	10.12
54" x 10'	7.60	12.65
54" x 15'	10.12	17.70
60" x 7 ½'	8.08	12.73
60" x 10'	9.63	15.83
60" x 15'	12.73	22.03
60" x 20'	15.31	27.20

\*Based on 1,000 psig W.P. Separators.

\*\*Total settling volume is usually split even between oil and water.

\*\*\*Standard working pressures available are 230, 500, 1000, 1200, 1440, 1500, and 2000 psig.



TABLE 3A  
SPECIFICATIONS OF STANDARD HORIZONTAL LOW PRESSURE SEPARATORS

Model No.	Size Dia. x Ht.	Working Pressure psig	Inlet & Gas Outlet Conn.	Oil Outlet Conn.	Standard Valves		Shipping Weight lb
					Oil or Oil & Water	Gas	
H-245	24" x 5'	125	2" Thd	2" Thd	2"	2"	1,000
H-2475	24" x 7½'	125	2" Thd	2" Thd	2"	2"	1,200
H-2410	24" x 10'	125	3" Thd	2" Thd	2"	2"	1,600
H-305	30" x 5'	125	3" Thd	3" Thd	2"	2"	1,200
H-3075	30" x 7½'	125	3" Thd	3" Thd	2"	2"	1,600
H-3010	30" x 10'	125	4" Thd	4" Thd	2"	2"	2,100
H-3610	36" x 10'	125	4" Thd	4" Thd	2"	2"	2,900
H-3615	36" x 15'	125	4" Thd	4" Thd	2"	2"	3,800
H-4810	48" x 10'	125	6" Flg	4" Thd	2"	2"	3,500
H-4815	48" x 15'	125	6" Flg	4" Thd	3"	3"	4,600
H-6010	60" x 10'	125	6" Flg	4" Thd	3"	3"	6,200
H-6015	60" x 15'	125	6" Flg	4" Thd	3"	3"	8,100
H-6020	60" x 20'	125	6" Flg	4" Thd	4"	4"	10,000

TABLE 3B  
SETTLING VOLUMES OF STANDARD HORIZONTAL LOW PRESSURE SEPARATORS, 125 PSIG W.P.

Size Dia. x Len.	Settling Volume, bbl		
	½ Full	1/3 Full	¼ Full
24" x 5'	1.55	0.89	0.59
24" x 7½'	2.22	1.28	0.86
24" x 10'	2.89	1.67	1.12
30" x 5'	2.48	1.43	0.94
30" x 7½'	3.54	2.04	1.36
30" x 10'	4.59	2.66	1.77
36" x 10'	6.71	3.88	2.59
36" x 15'	9.76	5.66	3.79
48" x 10'	12.24	7.07	4.71
48" x 15'	17.72	10.26	6.85
60" x 10'	19.50	11.24	7.47
60" x 15'	28.06	16.23	10.82
60" x 20'	36.63	21.21	14.16

TABLE 4A  
SPECIFICATIONS OF STANDARD HORIZONTAL HIGH PRESSURE SEPARATORS

Model No.**	Size Dia. x Ht.	Working Pressure psig*	Inlet & Gas Outlet Conn.	Standard Liquid Valve	Shipping Weight lb
H-125-10	12 ¾" x 5'	1000	2" Thd	1"	1,100
H-1275-10	12 ¾" x 7 ½'		2" Thd	1"	1,200
H-1210-10	12 ¾" x 10'		2" Thd	1"	1,300
H-165-10	16" x 5'	1000	2" Thd	1"	1,400
H-1675-10	16" x 7 ½'		2" Thd	1"	1,750
H-1610-10	16" x 10'		2" Thd	1"	2,100
H-205-10	20" x 5'	1000	3" Flg	1"	1,800
H-2075-10	20" x 7 ½'		3" Flg	1"	2,300
H-2010-10	20" x 10'		3" Flg	1"	2,900
H-245-10	24" x 5'	1000	4" Flg	1"	2,200
H-2475-10	24" x 7 ½'		4" Flg	1"	3,000
H-2410-10	24" x 10'		4" Flg	1"	3,800
H-2415-10	24" x 15'		4" Flg	1"	5,400
H-305-10	30" x 5'	1000	4" Flg	1"	3,200
H-3075-10	30" x 7 ½'		4" Flg	1"	4,300
H-3010-10	30" x 10'		4" Flg	1"	5,500
H-3015-10	30" x 15'		4" Flg	2"	7,800
H-3675-10	36" x 7 ½'	1000	6" Flg	2"	6,100
H-3610-10	36" x 10'		6" Flg	2"	7,500
H-3615-10	36" x 15'		6" Flg	2"	10,200
H-3620-10	36" x 20'		6" Flg	2"	12,000
H-4275-10	42" x 7 ½'	1000	6" Flg	2"	8,200
H-4210-10	42" x 10'		6" Flg	2"	9,900
H-4215-10	42" x 15'		6" Flg	2"	13,400
H-4220-10	42" x 20'		6" Flg	2"	16,900
H-4875-10	48" x 7 ½'	1000	8" Flg	2"	10,900
H-4810-10	48" x 10'		8" Flg	2"	12,700
H-4815-10	48" x 15'		8" Flg	2"	17,500
H-4820-10	48" x 20'		8" Flg	2"	22,100
H-5475-10	54" x 7 ½'	1000	8" Flg	2"	13,400
H-5410-10	54" x 10'		8" Flg	2"	16,000
H-5415-10	54" x 15'		8" Flg	2"	21,200
H-5420-10	54" x 20'		8" Flg	2"	26,400
H-6075-10	60" x 7 ½'	1000	8" Flg	2"	16,700
H-6010-10	60" x 10'		8" Flg	2"	19,900
H-6015-10	60" x 15'		8" Flg	2"	26,400
H-6020-10	60" x 20'		8" Flg	2"	32,900

\*Other standard working pressures available are 230, 500, 600, 1200, 1440, 1500, and 200 psig.

\*\*Last two digits of model number would change for other working pressures, i.e. 600 psig (-6), 1440 psig (-14).

TABLE 4B  
 SETTLING VOLUMES OF STANDARD HORIZONTAL HIGH PRESSURE  
 SEPARATORS, 230 PSIG THROUGH 2000 PSIG W.P. \*\*

Size Dia. x Length	Settling Volume, bbl*		
	½ Full	1/3 Full	¼ Full
12 ¾" x 5'	0.38	0.22	0.15
12 ¾" x 7 ½'	0.55	0.32	0.21
12 ¾" x 10'	0.72	0.42	0.28
16" x 5'	0.61	0.35	0.24
16" x 7 ½'	0.88	0.50	0.34
16" x 10'	1.14	0.66	0.44
20" x 5'	0.98	0.55	0.38
20" x 7 ½'	1.39	0.79	0.54
20" x 10'	1.80	1.03	0.70
24" x 5'	1.45	0.83	0.55
24" x 7 ½'	2.04	1.18	0.78
24" x 10'	2.63	1.52	1.01
24" x 15'	3.81	2.21	1.47
30" x 5'	2.43	1.39	0.91
30" x 7 ½'	3.40	1.96	1.29
30" x 10'	4.37	2.52	1.67
30" x 15'	6.30	3.65	2.42
36" x 7 ½'	4.99	2.87	1.90
36" x 10'	6.38	3.68	2.45
36" x 15'	9.17	5.30	3.54
36" x 20'	11.96	6.92	4.63
42" x 7 ½'	6.93	3.98	2.61
42" x 10'	8.83	5.09	3.35
42" x 15'	12.62	7.30	4.83
42" x 20'	16.41	9.51	6.32
48" x 7 ½'	9.28	5.32	3.51
48" x 10'	11.77	6.77	4.49
48" x 15'	16.74	9.67	6.43
48" x 20'	21.71	12.57	8.38
54" x 7 ½'	12.02	6.87	4.49
54" x 10'	15.17	8.71	5.73
54" x 15'	12.49	12.40	8.20
54" x 20'	27.81	16.08	10.68
60" x 7 ½'	15.05	8.60	5.66
60" x 10'	18.93	10.86	7.17
60" x 15'	26.68	15.38	10.21
60" x 20'	34.44	19.90	13.24

\*Based on 1000 psig W.P. Separator.

\*\*Standard working pressures available are 230, 500, 600, 1000, 1200, 1440, 1500, and 2000 psig.

TABLE 5A  
SPECIFICATIONS OF STANDARD SPHERICAL SEPARATORS

Model No.***	Diameter	Working Pressure psig	Inlet & Gas Outlet Conn.	Standard Liquid Valve	Shipping Weight lb
S-41F	41"	125	4" Thd	2"	1,000
S-46F	46"		4" Thd	3"	1,300
S-54F	54"		4" Thd	4"	1,700
S-342	42"	250	3" Flg	2"	1,100
S-348	48"		4" Flg	2"	1,400
S-360	60"		6" Flg	2"	3,400
S-1024	24"	1000*	2" Flg	1"	1,300
S-1030	30"		2" Flg	1"	1,400
S-1036	36"		3" Flg	1"	1,800
S-1042	42"	1000**	4" Flg	2"	2,800
S-1048	48"		4" Flg	2"	3,700
S-1060	60"		6" Flg	2"	4,300

\*Other standard working pressures available are 500, 600, 1200, 1440, 2000, and 3000 psig.

\*\*Other standard working pressures available are 500, 600, 1200 and 1440 psig.

\*\*\*First two digits of model number on high pressure units change for other working pressures, i.e. 600 psig (S-6--), 1440 psig (S-14--).

TABLE 5B  
 SETTLING VOLUMES OF STANDARD SPHERICAL LOW PRESSURE  
 SEPARATORS, 125 PSIG W.P.

Size O.D.	Settling Volume bbl
41"	0.77
46"	1.02
54"	1.60

TABLE 5C  
 SETTLING VOLUMES OF STANDARD SPHERICAL HIGH PRESSURE  
 SEPARATORS, 230 PSIG THROUGH 3000 PSIG W.P.\*\*

Size O.D.	Settling Volume bbl*
24"	0.15
30"	0.30
36"	0.54
42"	0.88
48"	1.33
60"	2.20

\*Based on 1000 psig W.P. Separator

\*\*Standard working pressures available  
 are 230, 500, 600, 1000, 1200, 1440,  
 1500, 2000, and 3000 psig.

#### REFERENCES

1. Campbell, John M., "Elements of Field Processing", The Oil & Gas Journal, pp. 6-12.
2. Perry, John, "Chemical Engineer's Handbook", 4<sup>th</sup> Ed., McGraw-Hill, 1963, pp. 18-6.
3. Engineering Data Book published by the Gas Processors Suppliers Association, 12<sup>th</sup> Ed., GPSA, 2004, Section 7



SECTION: 300  
TECHNICAL BULLETIN  
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## TWO STAGE SEPARATION SYSTEMS

### INTRODUCTION:

When natural gas was worth approximately \$.16 per MCF at the wellhead and oil or hydrocarbon condensate was worth \$3.00 per barrel, it was very hard to justify the economics of the additional equipment required for two stage separation of high pressure gas streams. As prices of gas and condensate increase, the economic payout of additional equipment changes quite rapidly. This Technical Bulletin presents charts which may be used to make a rapid estimation of the additional recoveries that may be expected from two stage versus single stage separation. The economics of these additional recoveries can be quickly determined in order to evaluate the payout of additional equipment required as described below.

### TWO STAGE SEPARATION:

In high pressure gas-condensate separation systems, it is generally accepted that a step-wise reduction of the pressure on the liquid condensate will appreciably increase the recovery of stock tank liquids. The calculation of the actual performance of the various separators in a multi-stage separation system can be made, using the initial well stream composition and the operating temperatures and pressures of the various stages. However, in the absence of a computer to perform a complete set of flash vaporization calculations, general guidelines can be furnished to estimate the anticipated performance of multi-stage separation units.

Although theoretically three to four stages of separation would increase the liquid recovery over two stage, the net increase over two stage separation will rarely pay out the cost of the second and/or third separators. Therefore, it has been generally accepted that two stages of separation, plus the stock tank, are the optimum for consideration. The actual increase in liquid recovery for two stage separation over single stage may vary from 3 to 15%, depending on the well stream composition, operating pressures and temperatures. However, in some cases, as high as 20 to 25% increase in recoveries has been reported.

The optimum high stage or first separator operating pressure is generally governed by the gas transmission line pressure and operating characteristics of the well. This will generally range in pressure from 600 to 1200 psig. If the transmission line pressure is at least 600 psig, operators will generally let the first stage separator ride the line or operate at the transmission line pressure. For each high or first stage pressure there is an optimum low stage separation pressure which will afford the maximum liquid recovery. This operating pressure can be determined from an equation based on equal pressure ratios between the stages:

$$R = \left[ \frac{P_1}{P_s} \right]^{\frac{1}{n}}$$

$$\text{or: } P_2 = \frac{P_1}{R} = P_s (R)^{n-1}$$

Where: R = Pressure Ratio  
 n = Number of stages – 1  
 P<sub>1</sub> = First stage or high pressure separator pressure, psia  
 P<sub>2</sub> = Second stage or low pressure separator pressure, psia  
 P<sub>s</sub> = Stock tank pressure, psia

#### DESCRIPTION OF PROCESS:

Figure 1 illustrates a schematic flow diagram of a typical high pressure well production equipment installation. The basic equipment is illustrated for two stage separation of the high pressure stream. From the wellhead, the high pressure well stream flows through a high pressure separator and indirect heater gas production unit. In this unit the inlet stream is heated prior to choking to reduce the well stream pressure to sales line pressure. This is done to prevent the formation of hydrates in the choke or downstream of the choke in the separator or sales line. From the indirect heater the well stream passes to the high pressure separator where the initial separation of the high pressure gas stream and produced well fluids occurs.

From the high pressure separator the gas flows through an orifice meter and to the sales line. The liquid from the high pressure separator passes through a diaphragm motor valve where the pressure is reduced, and it is discharged to a low pressure flash separator. In the low pressure flash separator which would operate at approximately 100 psig, a second separation occurs between the liquids and the lighter hydrocarbons in the liquids. The gas released from the low pressure flash separator is returned back to the high pressure unit where it may be used for both instrument and fuel gas for the indirect heater. As illustrated in Figure 1, a secondary makeup line is shown from the high pressure separator, which would provide additional makeup gas for the instrument gas and fuel gas, if not enough gas was released from the low pressure separator. Typically though, more gas is released than is required and the additional low pressure gas may be sold in a low pressure gas gathering system and/or used for other utility purposes, such as fuel for compressor engines or other fired equipment in the area. This may be for reboilers for dehydrators or acid gas sweetening units, etc. From the low pressure flash separator the liquid is discharged through another diaphragm motor valve into a storage tank which is generally operated at atmospheric pressure.

The additional feature shown here which is different from a typical single stage installation is the addition of the low pressure flash separator between the liquid discharge from the high pressure gas production unit and the storage tank. This provides for two stages of separation rather than one. This also provides a source of low pressure gas which may be used for utility purposes with any excess sold, and increases the stabilization of the liquid product, which in effect, produces more liquid in the storage tank to be sold.

#### GAS AND LIQUID INCREASE:

Flash vaporization calculations were performed on a typical high pressure gas stream to determine the increased recoveries that would be seen in both the low pressure flash gas as well as increased liquid recoveries in the storage tank. The typical well stream used was a high pressure gas stream with a specific gravity of 0.67, and the flash calculations were performed at various high pressure separator pressures from 500 to 1000 psig. The temperature was held constant at 70°F for these calculations. This would be a typical year round average for most locations. The low pressure separator flash calculations were also held at 70°F and 14.7 psia. The gas stream selected was a fairly lean stream producing only about 5 to 7 barrels per MMCF stock tank liquid recovery. This is a fairly lean stream and richer streams would produce more dramatic results in payout using two stage separation. The results indicated herein are considered very conservative for typical well streams.

Figure 2 illustrates the gas produced from the low pressure flash separator for the above described well

stream at various high pressure operating pressures (line pressure). The gas produced from the low pressure flash separator in MCF per year may be read from Figure 2, based on a high pressure gas stream flow rate in MMSCFD and the high pressure separator operating pressure.

Figure 3 illustrates the increase in stock tank liquid recovery that would be achieved by using the low pressure flash separator. This chart is also based on the high pressure gas flow rate in MMSCFD and the high pressure separator operating pressure. The increase in stock tank liquid recovery may be read from the chart in bbl/year.

ECONOMICS:

The economics, or increase in dollar revenue, that can be achieved with two stage separation can be rapidly determined based on the results from Figures 2 and 3 using the following formula:

Low Pressure Flash Gas	= (MCF/yr) (Price \$/MCF) =	\$/yr
Additional Stock Tank Liquid	= (bbl/yr) (Price \$/bbl) =	\$/yr
Total Increased Revenue	=	\$/yr

Using an example of a 2.0 MMSCFD gas well operating at a line pressure 700 psi that would normally make about 5 to 6 bbl/MMCF of condensate with single stage separation, the following additional dollar revenue would be achieved using a two stage separation.

Based on gas at \$7.00/MCF and condensate at \$75.00/bbl:

Low Pressure Flash Gas	= (2650 MCF/yr)(\$7.00/MCF)	= \$ 18,550
Additional Condensate	= (650 bbl/yr)(\$75.00/bbl)	= <u>\$ 48,750</u>
Total Increased Revenue	=	\$ 67,300 / yr

SUMMARY:

As can be seen from the above results the payout that could be achieved on the use of two stage separation is quite dramatic. The cost required for the addition of a small low pressure flash separator to provide for two stage separation is quite small compared to the additional recovery that could be achieved. This additional recovery not only produces dollars of revenue, but prevents the unneeded waste of precious hydrocarbon energy that would normally be vented out the stock tank using only single stage separation.



FIGURE 1  
 SCHEMATIC FLOW DIAGRAM  
 OF  
 TWO STAGE SEPARATION SYSTEM

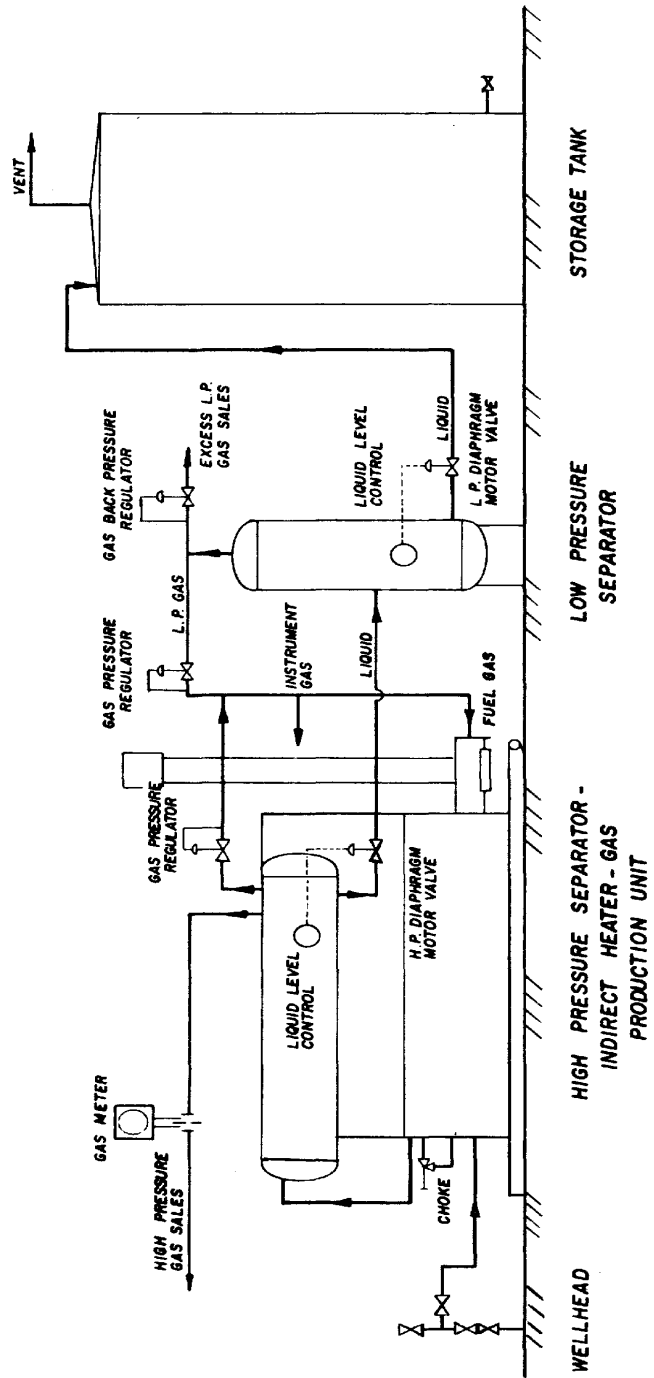


FIGURE 2  
LOW PRESSURE GAS FROM  
FLASH SEPARATOR

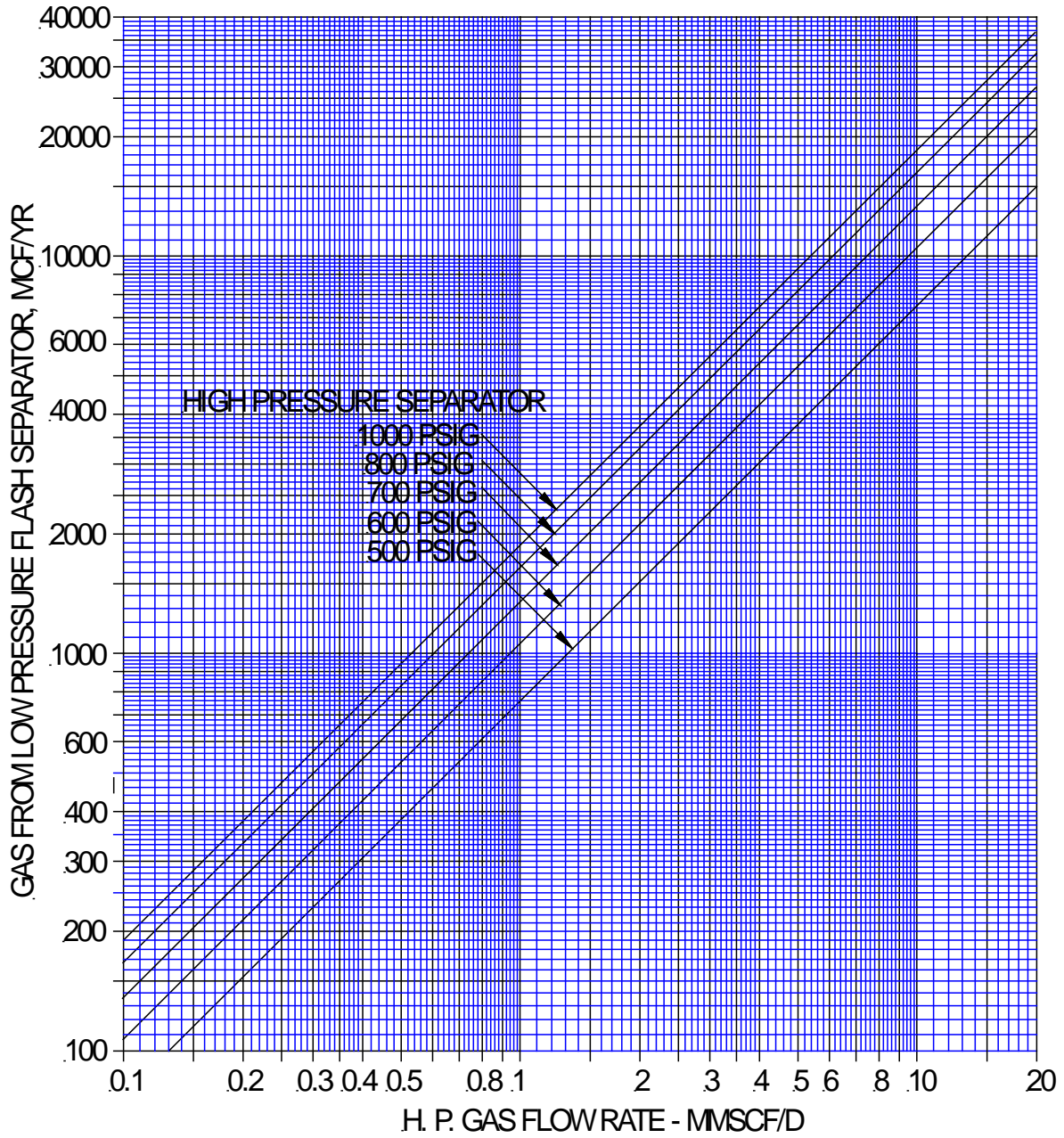
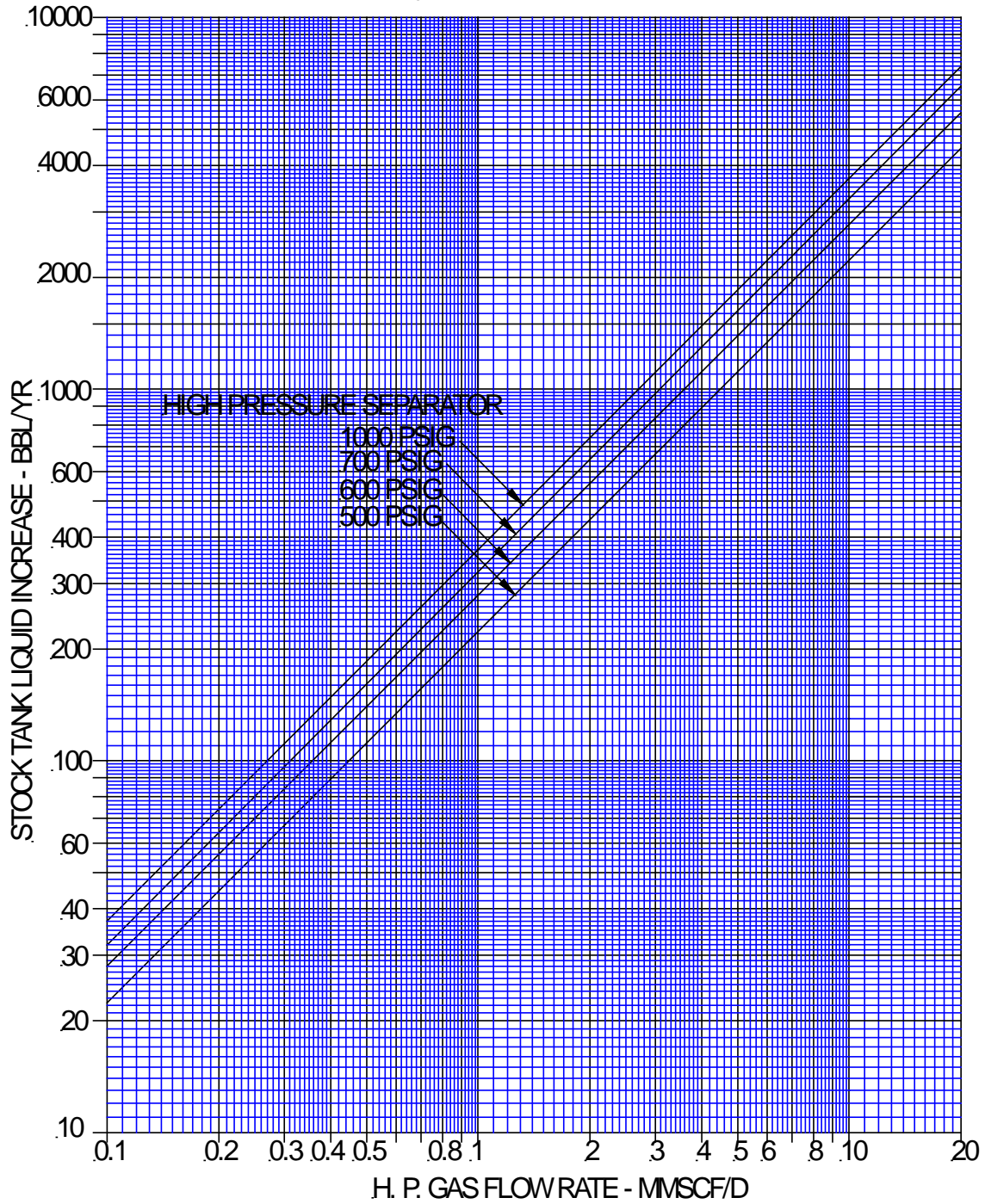


FIGURE 3  
 STOCK TANK LIQUID INCREASE  
 WITH FLASH SEPARATOR





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## **FILTER SEPARATORS**

### GENERAL:

Filter separators are combination units which incorporate the features of a dry gas filter with filter elements in conjunction with the features of a liquid-gas separation unit. They are used primarily ahead of processing equipment where it is desirable to remove any solid foreign particle elements as well as liquid from the gas stream. They are used ahead of compressors, dry desiccant processing equipment, and gas processing equipment where contamination of a liquid circulated in the system would be undesirable.

### PROCESS DESCRIPTION:

Filter separators, whether constructed in a horizontal or vertical configuration, are basically two stage vessels. The first stage is an area which is filled with multiple sock type filter elements for removing foreign solid particle contamination from the gas stream. The filter elements also aid in coalescing very small particles of liquid into larger droplets, where they will drain by gravity into the liquid settling section of the vessel. The gas flow is from the outside of the filter elements to the inside, and through a perforated mandrill located inside each element, to the next stage of the vessel. The inlet section also acts as a slug catcher for receiving surges of liquid where they may be trapped and passed into the liquid settling section of the vessel.

The second stage of the vessel consists of an open separator section which contains a mist eliminator for removing small entrained droplets from the gas stream before it passes out of the vessel. This mist eliminator may be either a vane type configuration or a stainless wire mesh type.

The liquid separated from the gas in either the first stage or second stage of the vessel passes to a liquid settling section where it is discharged from the vessel.

### HORIZONTAL FILTER SEPARATORS:

Figure 5 illustrates a typical horizontal filter separator which is normally constructed in a two-barrel separator configuration. The gas passes through the upper barrel or tube of the vessel. The gas enters through the inlet connection on the top of the vessel and passes through the first stage, or filter element section. On the end of this section is a quick opening closure for filter element access. Next, the gas proceeds through a small settling section and a mist eliminator before discharging from the vessel at the opposite end. The lower barrel or tube of the separator is the liquid accumulator or settling section which has drain-back pipes connecting the various portions of the upper barrel of the vessel. The liquid settling section is divided into two compartments so that there is no gas bypass through this section from the first stage of the vessel to the second stage. Each compartment in the liquid settling section is equipped with a high pressure liquid level control and diaphragm operated motor valve to discharge the liquid accumulated from the vessel. Table 3 lists the typical specifications of horizontal high pressure filter separators.

### VERTICAL FILTER SEPARATORS:

Vertical Filter Separators are illustrated in Figure 6 and are normally constructed in a single vessel configuration. The upper section of the vessel is the first stage of the unit which houses the filter elements. The top of the vessel is equipped with a quick opening closure for removal and changing of the filter elements. The gas inlet is on the side of the first stage of the units and the gas passes in and through the filter elements section. After passing through the filter elements the gas flow passes

downward into the lower stage or second stage of the vessel, which houses a settling section and the mist eliminator. The gas passes through this section out through the mist eliminator and leaves the vessel through a gas outlet connection on the lower side of the vessel. The upper stage of the vessel is equipped with a liquid level control and liquid discharge motor valve to discharge any liquid accumulated in this portion of the unit. The lower stage of the vessel is also equipped with a liquid level control and diaphragm motor valve to discharge liquid separated in the settling section and removed by the mist eliminator. It is also necessary to have two level controls and two discharge motor valves in this type of vessel to prevent any bypassing of gas around the filter elements or mist eliminator. Table 4 lists the typical specifications of vertical high pressure filter separators.

**FILTER SEPARATOR SIZING:**

The gas capacity of filter separators may be determined from the rapid sizing charts contained in Figures 1 through 4. The gas capacities of small horizontal filter separators are shown in Figure 1. The larger models are illustrated in Figure 2. The gas capacities of small vertical filter separators are shown in Figure 3 and the larger ones in Figure 4. These gas capacities are based on a gas specific gravity of 0.68 and an operating temperature of 60°F. For different operating conditions, use the correction factors contained in Tables 1 and 2 with the following equation:

$$Q_f = Q_s \times C_g \times C_t$$

- Where:
- $Q_f$  = Gas capacity at operating conditions, MMSCFD
  - $Q_s$  = Gas capacity of Filter/Separator at operating pressure from charts, MMSCFD
  - $C_g$  = Specific gravity correction factor
  - $C_t$  = Temperature correction factor

TABLE 1

SPECIFIC GRAVITY CORRECTION FACTORS

Gas Specific Gravity	$C_g$ Correction Factor
0.55	1.11
0.60	1.06
0.65	1.02
0.68	1.00
0.70	0.98
0.75	0.95
0.80	0.93
0.85	0.89
0.90	0.87

TABLE 2

TEMPERATURE CORRECTION FACTORS

Gas Temperature °F	$C_t$ Correction Factor
50	1.01
60	1.00
70	0.99
80	0.98
90	0.97
100	0.96
110	0.955
120	0.95
130	0.94

**CONCLUSION:**

The gas and liquid capacities of either horizontal or vertical high pressure filter separators will differ from those of conventional oil-gas separators. Caution should be observed in the design of either type of vessel to provide one with the proper capacity that is required.

FIGURE 1  
 GAS CAPACITY OF HORIZONTAL HIGH  
 PRESSURE FILTER / SEPARATOR

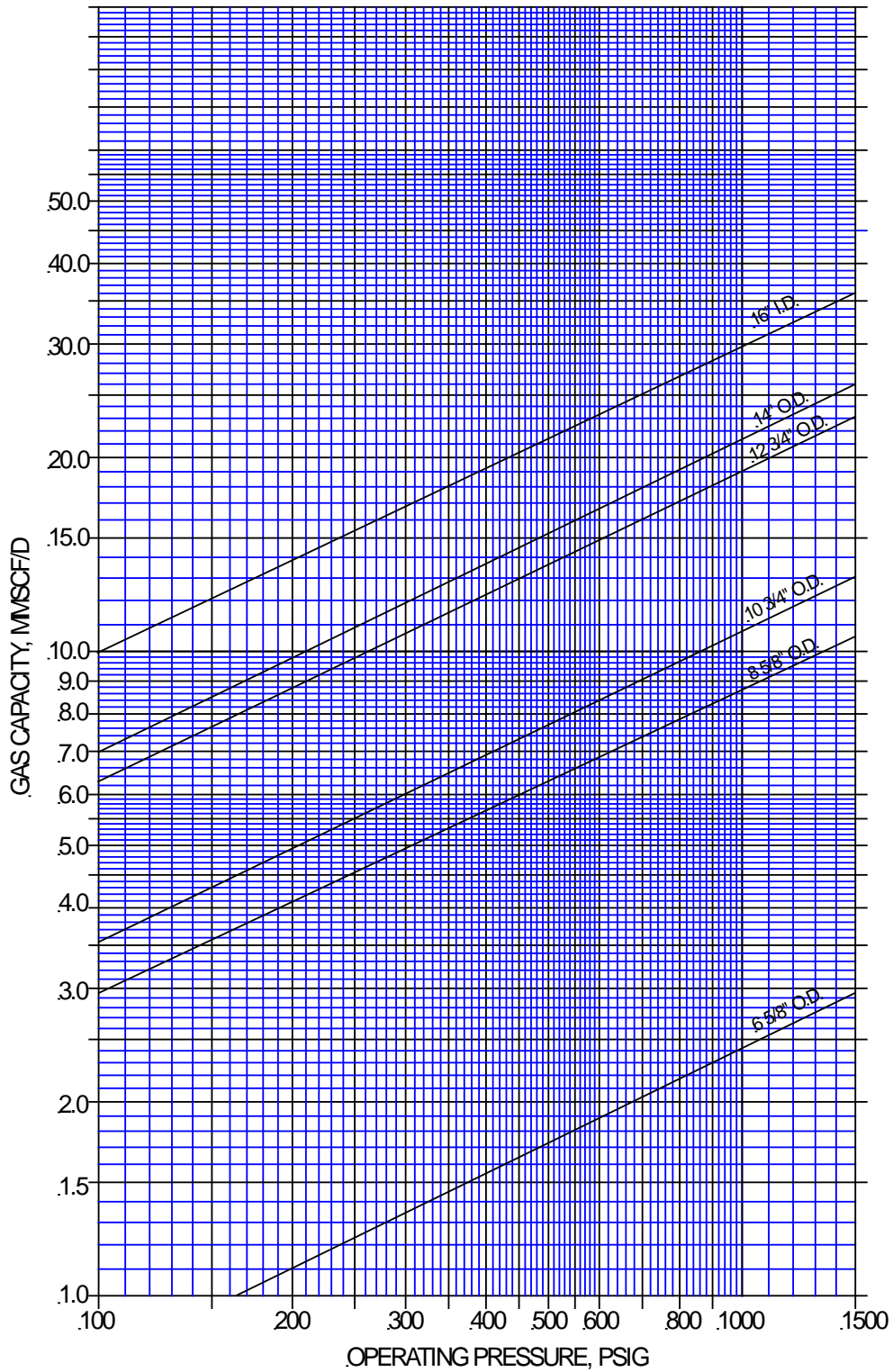


FIGURE 2  
 GAS CAPACITY OF HORIZONTAL HIGH  
 PRESSURE FILTER / SEPARATOR

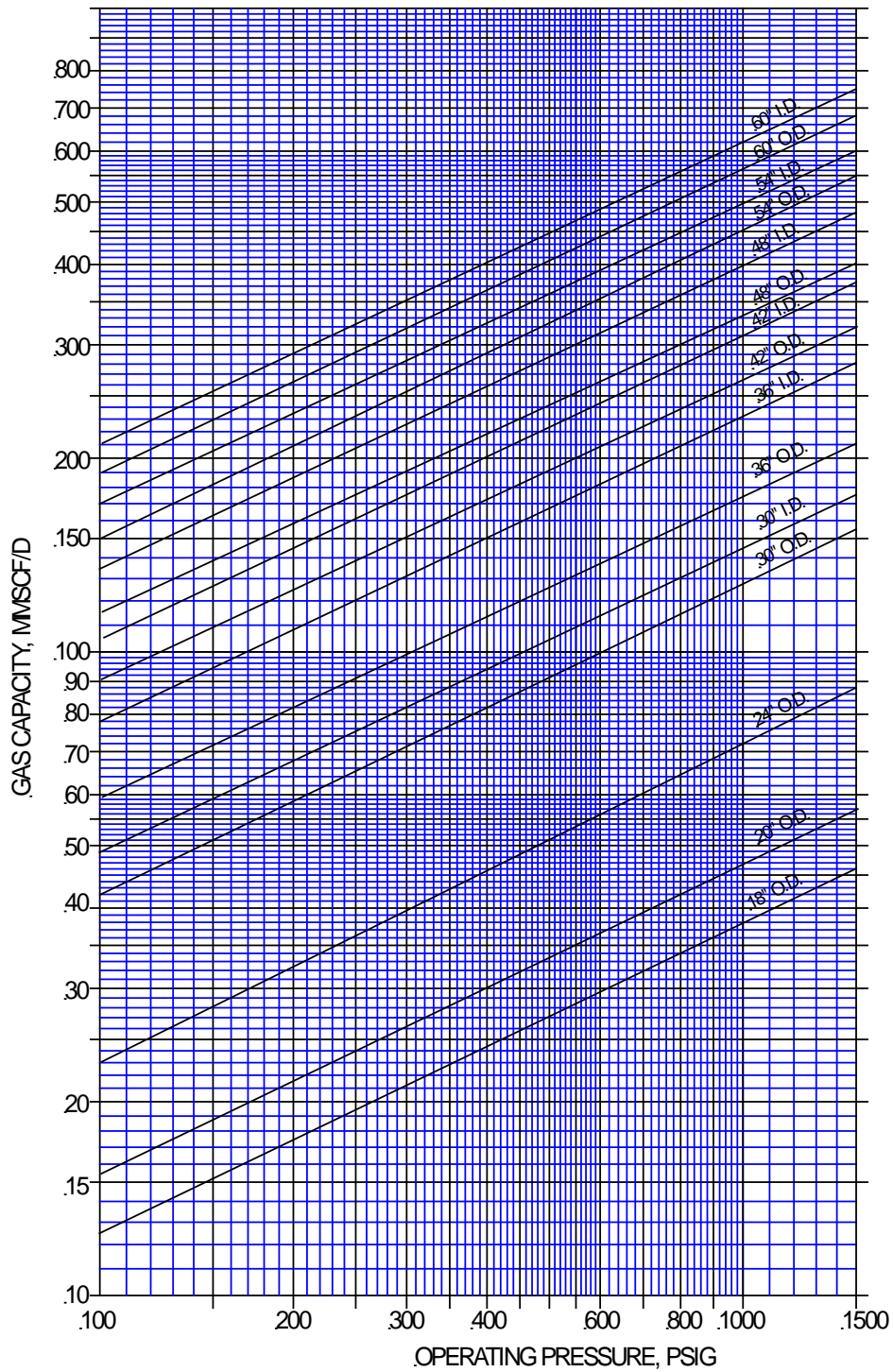
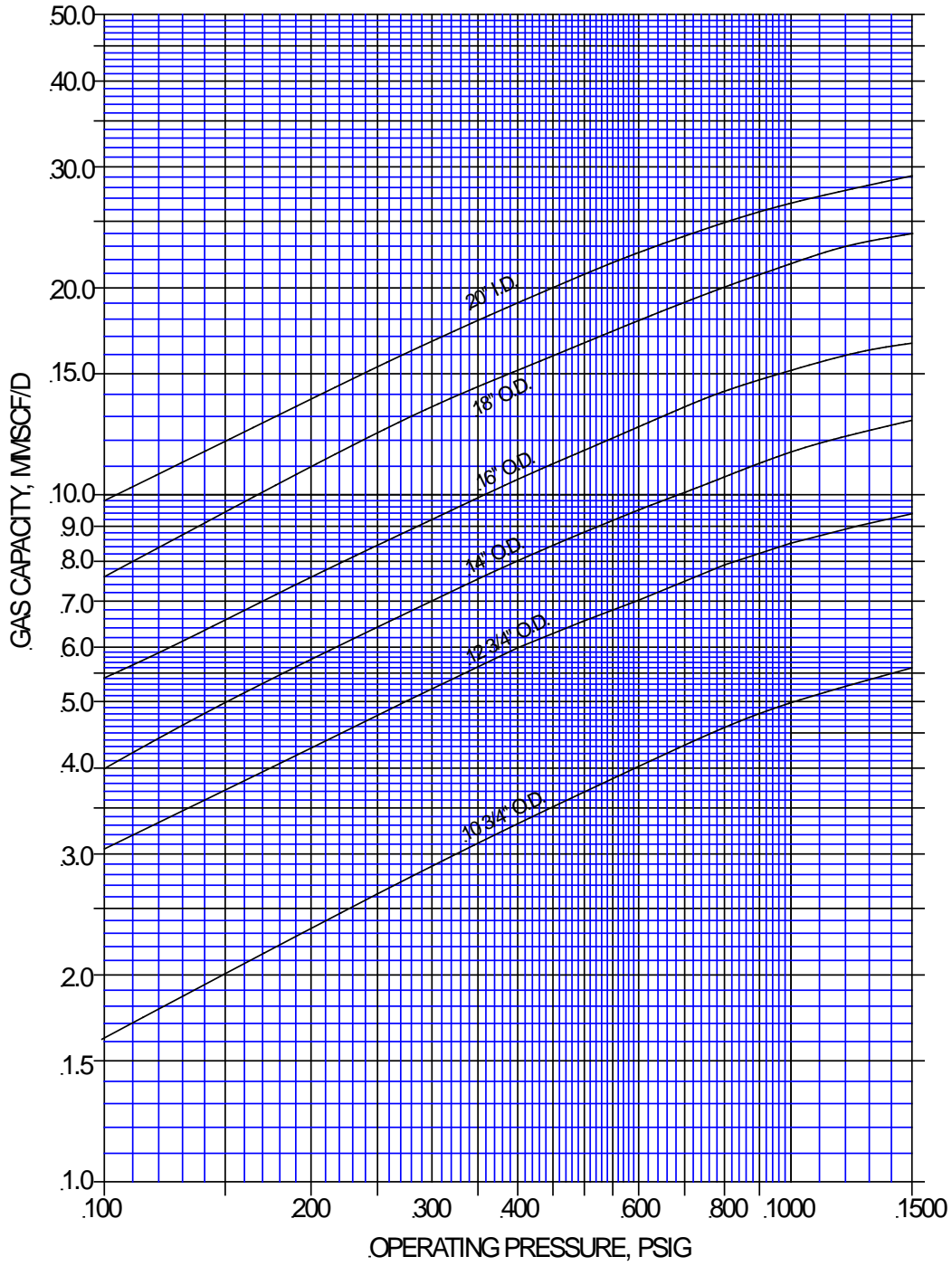
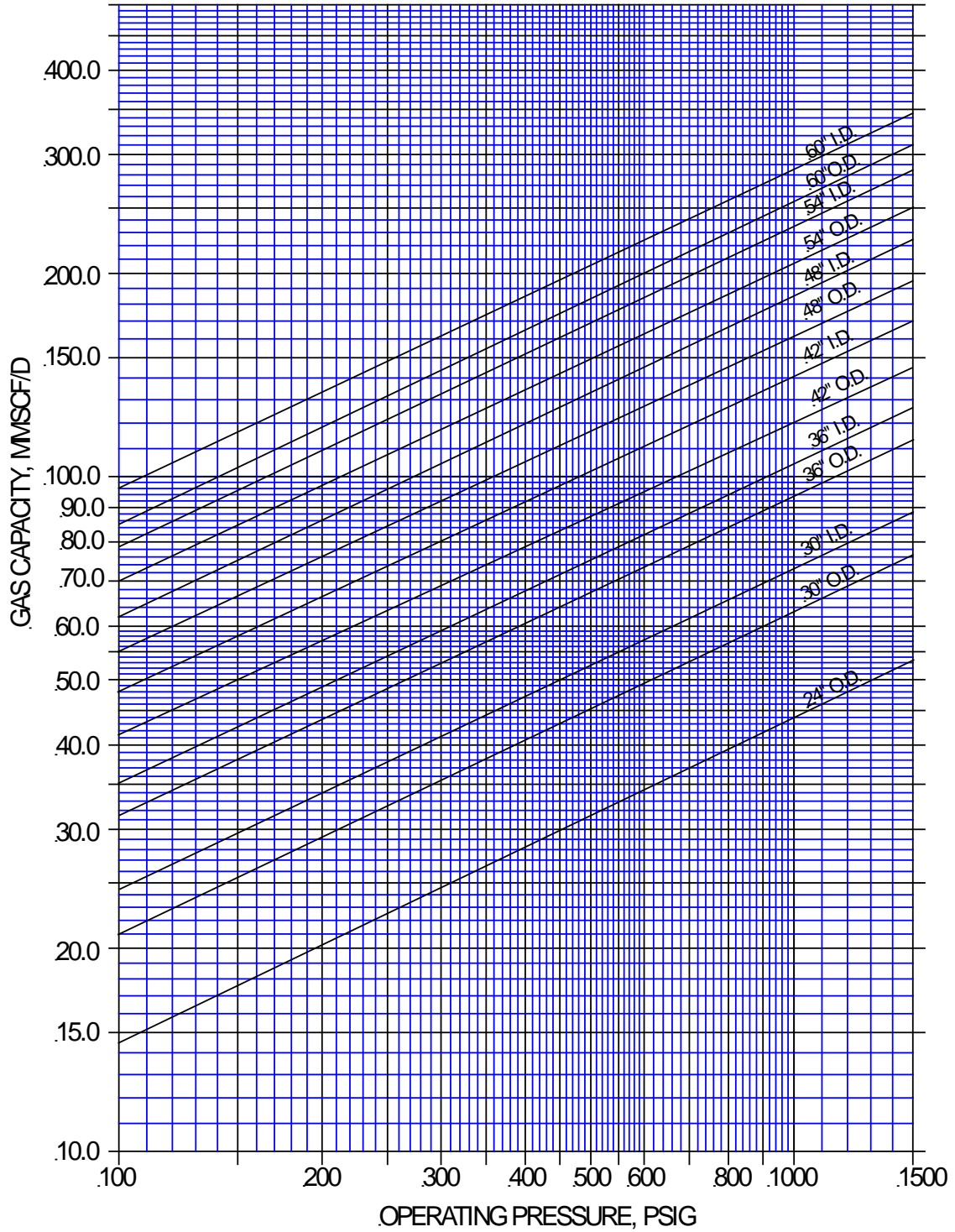


FIGURE 3  
 GAS CAPACITY OF VERTICAL HIGH  
 PRESSURE FILTER / SEPARATOR





**FIGURE 4**  
**GAS CAPACITY OF VERTICAL HIGH**  
**PRESSURE FILTER / SEPARATORS**



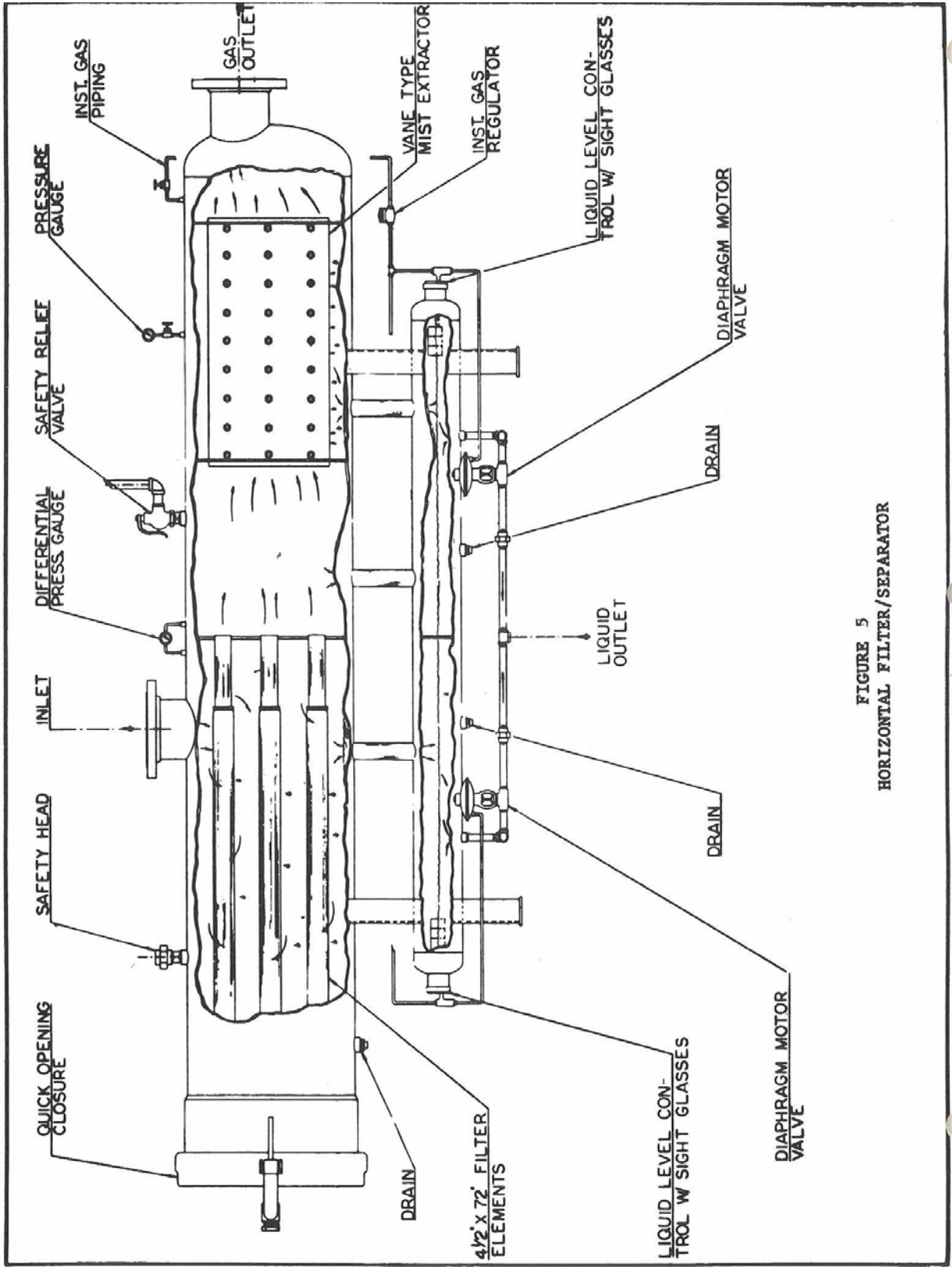
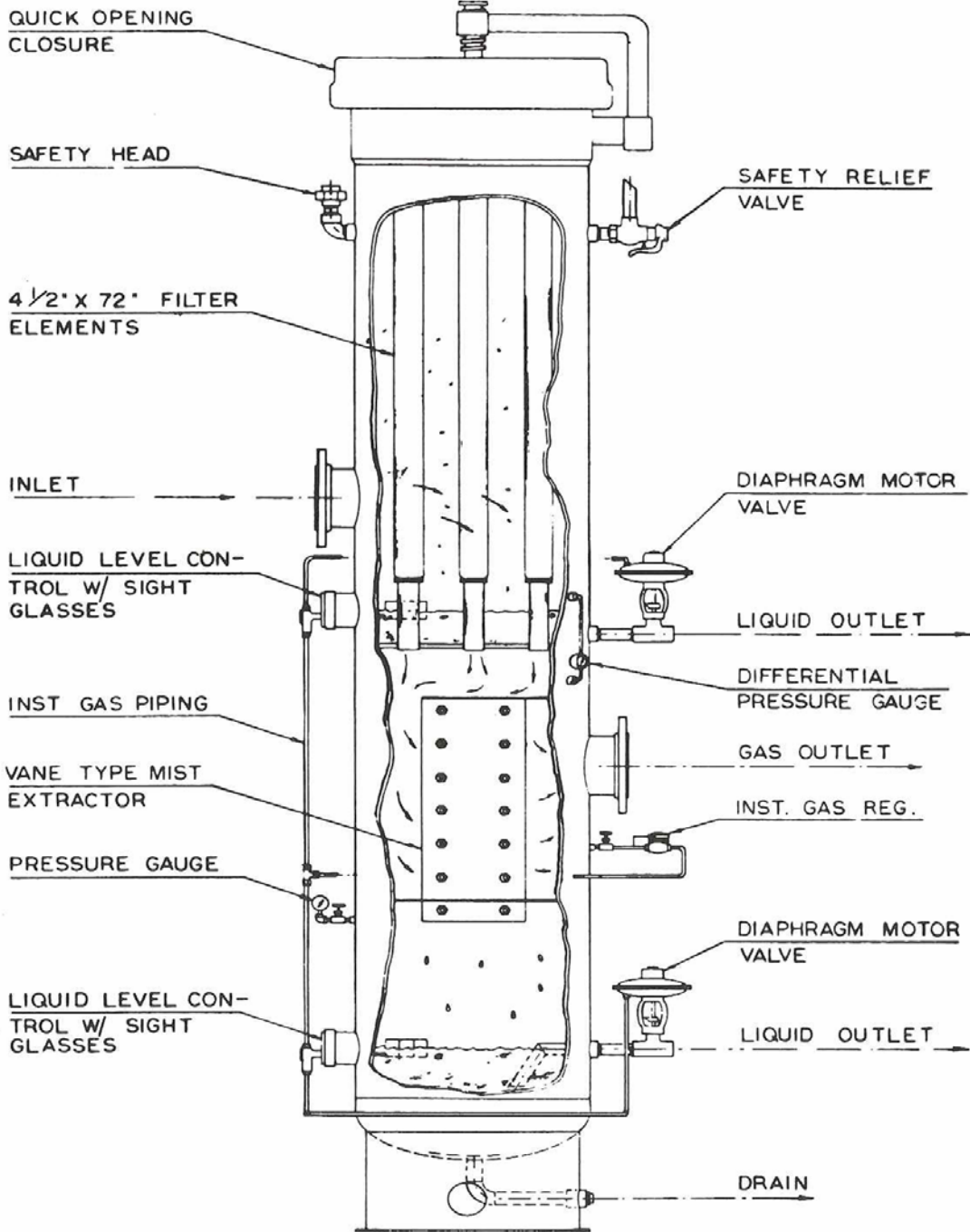


FIGURE 5  
HORIZONTAL FILTER/SEPARATOR

FIGURE 6  
VERTICAL FILTER SEPARATOR



ELEVATION

**TABLE 3  
HORIZONTAL HIGH PRESSURE FILTER/SEPARATORS  
SPECIFICATIONS**

Model No. <sup>1</sup>	Upper Tube Size OD x Length	Nominal W. P. <sup>2</sup> psig	Lower Tube Size OD x Length	Inlet & Outlet Gas Conn.	Std. Oil Valves	Nominal Gas Capacity <sup>3</sup> MMSCFD
HES-610-10	6 5/8" x 10'	1000	6 5/8" x 7'	2"	1"	2.4
HES-810-10	8 5/8" x 10'		6 5/8" x 7'	2"	1"	8.7
HES-1010-10	10 3/4" x 10'		6 5/8" x 7'	3"	1"	10.8
HES-1210-10	12 3/4" x 10'		6 5/8" x 7'	4"	1"	19.0
HES-1410-10	14" x 10'		6 5/8" x 7'	4"	1"	21.0
HES-1610-10	16" x 10'		6 5/8" x 7'	4"	1"	29.5
HES-1812-10	18" x 12'		8 5/8" x 8'	6"	1"	38
HES-2012-10	20" x 12'		8 5/8" x 8'	6"	1"	47
HES-2414-10	24" x 14'		10 3/4" x 9'	8"	1"	72
HES-3016-10	30" x 16'		10 3/4" x 11'	10"	1"	127
HES-3616-10	36" x 16'		10 3/4" x 11'	12"	1"	172
HES-4218-10	42" x 18'		14" x 12'	14"	1"	265
HES-4818-10	48" x 18'		14" x 12'	16"	1"	330
HES-5420-10	54" x 20'		16" x 13'	18"	2"	450
HES-6020-10	60" x 20'		18" x 13'	20"	2"	560

**TABLE 4  
VERTICAL HIGH PRESSURE FILTER/SEPARATORS  
SPECIFICATIONS**

Model No. <sup>1</sup>	Upper Tube Size OD x Length	Nominal W. P. <sup>2</sup> psig	Inlet & Outlet Gas Conn.	Std. Oil Valves	Nominal Gas Capacity <sup>3</sup> MMSCFD
HES-1010-10	10 3/4" x 10'	1000	2"	1"	5.0
HES-1210-10	12 3/4" x 10'		2"	1"	8.5
HES-1410-10	14" x 10'		3"	1"	11.5
HES-1610-10	16" x 10'		4"	1"	15.5
HES-1812-10	18" x 12'		4"	1"	22
HES-2012-10	20" x 12'		6"	1"	27
HES-2414-10	24" x 14'		6"	1"	43
HES-3014-10	30" x 14'		8"	1"	63
HES-3614-10	36" x 14'		10"	1"	93
HES-4216-10	42" x 16'		10"	1"	122
HES-4816-10	48" x 16'		12"	1"	160
HES-5416-10	54" x 16'		14"	2"	210
HES-6016-10	60" x 16'		16"	2"	255

1. Last two digits of model number would change for different working pressure units.
2. Other working pressures available are 230, 500, 1200, 1440 psig.
3. Gas capacity is at design working pressure for 0.69 sp. gr. natural gas at 60°F.



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## LOW TEMPERATURE GAS SEPARATION UNITS

### GENERAL:

Low temperature gas separation equipment is specifically designed to increase the recovery of liquid distillate from high-pressure gas condensate wells, over that which could be expected by conventional separation methods. Each well stream must be examined with regards to the analysis of the stream composition, as well as operating characteristics of the well, such as flowing pressures and temperatures, to determine if it would be economically feasible to install a low temperature gas separation unit. Sivalls, Inc. low temperature gas separation units are each custom designed to meet the specific well stream characteristics and operating conditions. In looking at the feasibility of installing a low temperature gas separation unit, the operator should also consider the type of liquid storage equipment available, or to be installed, as well as the transportation costs of the recovered liquid product.

### PROCESS APPLICATION:

It is well known that lowering the operating temperature of a separator will increase the liquid recovery. When the pressure is reduced on a high-pressure gas condensate stream by use of a pressure-reducing choke, there is also an accompanying decrease in the fluid temperature. This is what is known as the Joule-Thompson, or throttling effect, which is an irreversible adiabatic process where the heat content of the gas remains the same across the choke, but the pressure and temperature of the gas stream is reduced.<sup>1</sup>

It is also well known that a reduction of gas stream temperature will bring about the problem of hydrate formation in the lines and equipment. This occurrence and the handling of hydrates and gas streams are discussed more completely in other technical publications.<sup>2, 3</sup> However, in brief, the hydrates are solid particles and masses formed in gas streams consisting of water and liquid hydrocarbons. These hydrates will form at specific conditions of temperature and pressure for each gas stream which is generally above 32° F for most high pressure gas streams.

The low temperature effect is used to advantage in low temperature units to increase the liquid recovery. The lower the operating temperature of the separator, the higher the liquid recovery will be. However, the maximum flowing pressure from the well at a given flow rate and the transmission line pressure will limit the maximum amount of pressure drop available across the choke. Enthalpy curves on natural gas can be used to determine the temperature drop that can be expected based on the available pressure drop. In general, at least 2500 to 3000 psi pressure drop should be available from wellhead flowing pressure to pipeline pressure before a low temperature separation unit will pay out in increased liquid recovery. The lowest operating temperature recommended for low temperature units is usually around -20° F. Carbon steel embrittlement occurs below this temperature and high alloy steels for lower temperatures are usually not economical for most oilfield installations. Generally, low temperature separation units are operated in the range of 0° F to 20° F. The liquid recovered from the high pressure separator on low temperature units should be passed through at least one low pressure separator to help in stabilizing the liquid product before it is put in storage tanks. Since this cold liquid will contain many light hydrocarbons, severe agitation and flashing will occur if it is put directly into a stock tank.

### EQUIPMENT DESCRIPTION:

A general schematic drawing of a low temperature separation unit is illustrated in Figure 1. The inlet well stream first passes through a multiple tube heat exchanger. In the first section of the heat exchanger, the

inlet well stream is either cooled down by using the colder liquid from the high pressure-low temperature separator or heated using low pressure steam. Either method may be used depending upon the flowing temperature of the inlet well stream. In the remaining sections of the heat exchanger the inlet well stream is cooled down by exchanging heat with the cold gas from the low temperature separator. The heat exchangers are employed to raise the temperature of the cold gas from the separator to a temperature suitable for entering the pipeline, as well as lowering the inlet well stream temperature to just above the hydrate point before entering the choke.

The inlet well stream then passes through a pressure reducing choke mounted directly on the inlet of a high pressure-low temperature separator. In the choke, the pressure as well as the temperature of the inlet well stream is substantially reduced to give an outlet gas temperature in the separator of approximately 10° to 20° F. The distillate and any water produced with the well stream are collected in the high pressure-low temperature separator. More distillate is recovered than would be recovered by conventional separation due to the extremely low temperature within the vessel. The cold outlet gas from the separator passes through the shell side of the exchanger as described above and to the pipeline. A three way, throttling motor valve is installed on the cold gas line at the inlet of the heat exchanger to control the temperature within the heat exchanger section.

The distillate and water from the high pressure separator are discharged to a low pressure three phase flash separator, where the distillate is further stabilized before it is discharged to the storage equipment. If the liquid-to-gas heat exchange equipment is used as described above, the liquid passes from the high pressure separator through this heat exchanger and then to the low pressure flash separator. The water from the low-pressure separator is discharged separately to water disposal equipment.

A 15 psig (maximum 250° F) low pressure steam generator is employed to provide a heating medium for the first section of the inlet well stream heat exchanger (if required) as well as for the heating coils in the liquid section of the low temperature separator and the low pressure flash separator. Steam jackets are provided around the inlet well stream choke, the inlet centrifugal drum in the low temperature separator, and the liquid discharge line from the high pressure-low temperature separator, to prevent collection of hydrates and plugging of the lines. Since a gas-liquid interface is an extremely good insulation blanket, it is possible to maintain the liquid in the bottom of the low temperature separator at approximately 70° to 80° to prevent formation of hydrates while the gas in the separator is maintained at a much lower temperature.

A high pressure free liquid knockout is not normally used ahead of the choke and the low temperature separator. The free distillate is allowed to flow through the choke along with the gas. Any free distillate and water in the inlet well stream will pass through the choke and remain essentially at the same temperature as it entered. It is conceded that this free distillate entering the separator will give up some heat and slightly raise the temperature of the gas within the separator. Any free water accompanying the gas and distillate through the choke will act in the same manner. However, according to flash vaporization calculations and field tests, the free distillate will act as an absorption oil and actually absorb more of the gasoline and the butane fraction from the high pressure gas stream. Therefore, more distillate can be recovered at a higher operating temperature than would be possible at a lower operating temperature, if the distillate were removed ahead of the choke and discharged into the separator separately. Free water will have a more adverse effect upon the gas temperature within the separator, since it has a higher specific heat than the distillate. Generally, the water has to be produced in quantities of at least 10 barrels per MMCF, before the heat given up by water to the gas in the separator will raise the gas temperature enough to cause any adverse affects upon the distillate recovery. If this were the case, then a freewater knockout ahead of the separator and choke would be recommended. This is shown on a schematic drawing as an optional item. However, the gas and free distillate from the fluid knockout would pass directly through the choke and into the separator as described above to obtain the absorption characteristics of the free distillate.

The process for low temperature separation has been thoroughly investigated with respect to liquid recovery by both flash calculations and field tests. Sivalls, Inc. is convinced that it has merit over other processes that are now available on the market. Sivalls low temperature separation units are able to

operate at high temperatures (10 to 20° F in the low temperature separator rather than 0-10° F) which will give the operator less operational problems while maintaining high distillate recoveries.

#### ESTIMATED RECOVERIES:

A recovery chart is illustrated in Figure 2 by which it is possible to determine the effect of the lower separation temperature on liquid recovery. This will assist in feasibility studies to determine if low temperature separation equipment will pay out on a given well stream. The purpose of this chart is to estimate the liquid recovery by a low temperature separation unit, knowing the liquid recovery or gas/oil ratio that can be obtained by conventional separation units.

As illustrated by the dotted lines on the chart, first locate a point of intersection of known GOR or barrels per MMCF recovery, and the temperature at which the conventional separation test was made. Follow parallel to the slanting lines from this point to the intersection of the proposed low temperature separator temperature. Read vertically from this corner to determine the predicted distillate recovery in barrels per MMCF or the GOR. In the example shown, if it is known that 20 barrels per MMCF can be recovered at a separation temperature of 80° F, then approximately 25.0 barrels per MMCF can be recovered at a separation temperature of 20° F. On most Sivalls, Inc. low temperature separation units it would be possible to maintain the same recovery at a separation temperature of 10° F higher, or approximately 30° F.

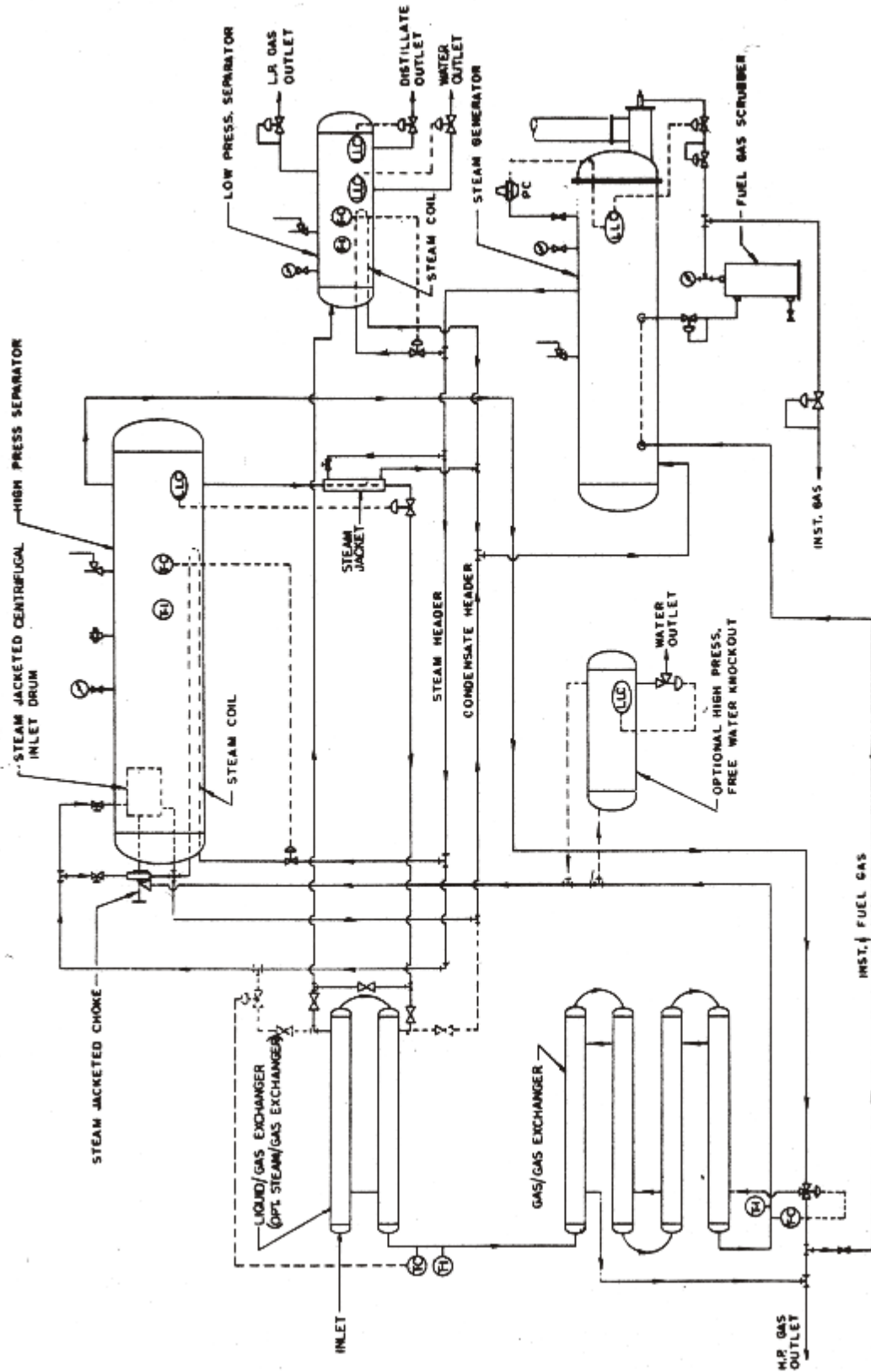
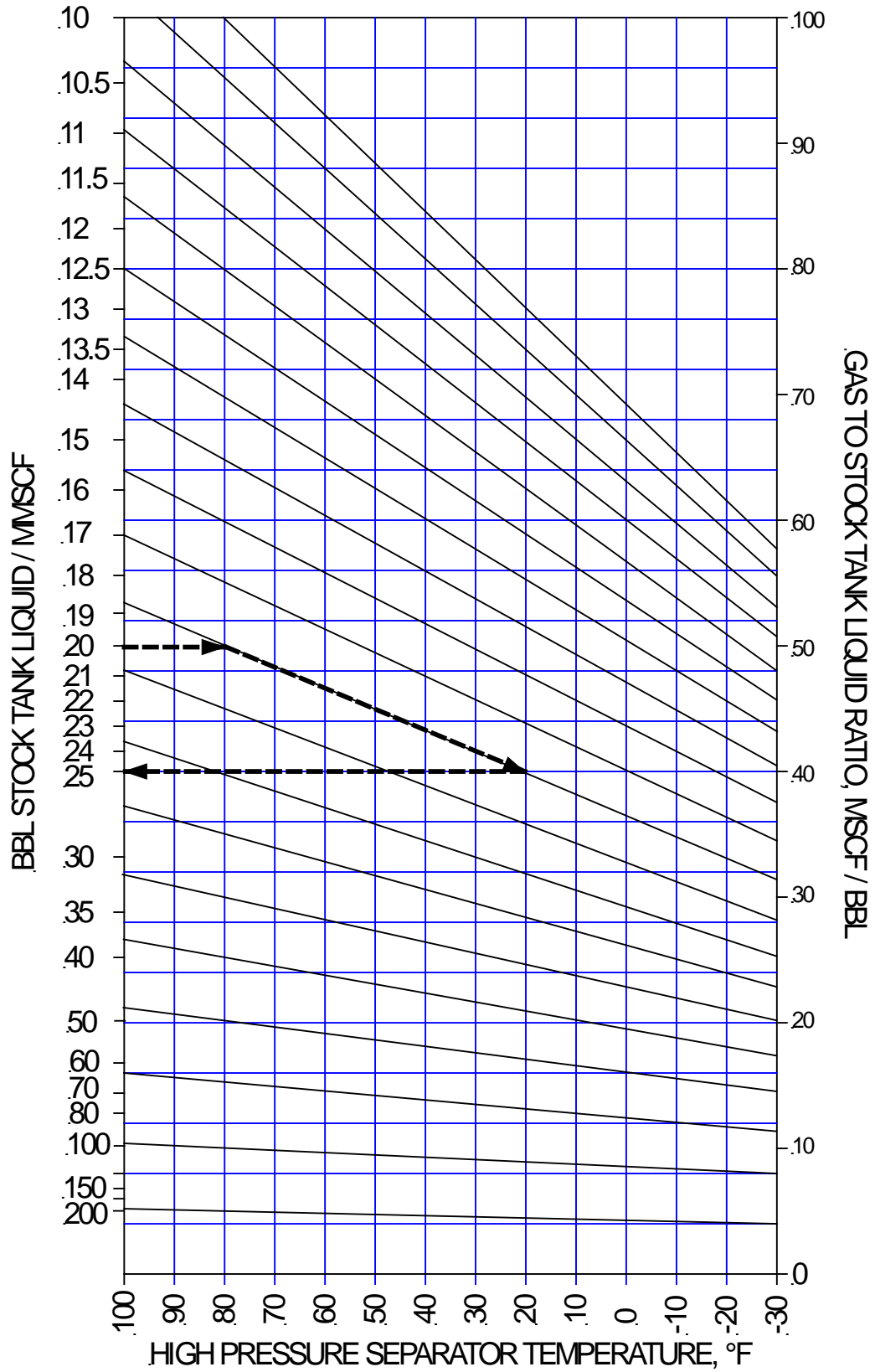


FIGURE 1  
SCHEMATIC FLOW DIAGRAM LOW TEMPERATURE SEPARATION UNIT



FIGURE 2

EFFECT OF SEPARATION TEMPERATURE ON LIQUID RECOVERY



References:

1. Katz, Donald L., et al, "Handbook of Natural Gas Engineering", McGraw-Hill, 1959, pp. 135.
2. Sivalls, C. Richard, "Indirect Heaters, Design and Sizing", Technical Bulletin No. 113, Sivalls, Inc.
3. Sivalls, C. Richard, "Glycol Dehydration Design Manual", Gas Conditioning Conference, University of Oklahoma, 1974.



SECTION 300  
TECHNICAL BULLETIN  
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## VERTICAL GAS SCRUBBERS

### INTRODUCTION:

Where only small or trace amounts of free liquid are known to be present in a gas stream, vertical gas scrubbers may be designed and sized using the gas capacity of the mist eliminator only. This will result in a considerably smaller vessel for a given gas flow rate. Or, a given size vessel will handle considerably more gas than it would under conventional vertical separator sizing procedures. The vessel would be equipped with a conventional liquid level control and liquid discharge valve and, of course, would have a settling section in the bottom of the vessel for accumulating liquid drained out of the mist eliminator. However, surge room would be limited and there would be no settling section for separation of the liquid and gas by gravity.

The major function of the vessel is to house the mist eliminator section which would remove entrained liquid mist from the gas stream strictly due to the action of the mist eliminator. This type of vessel might be used ahead of compressors where other separation equipment has already removed all of the free liquids, or downstream of process vessels where only entrained liquids or slight amounts of mist carryovers would be expected in the gas stream.

### CONSTRUCTION:

A vertical gas scrubber would normally be constructed identically to a small two phase vertical gas separator. It would have a tangential inlet diverter, a liquid level control and discharge valve, and full diameter wire mesh mist eliminator in the top of the vessel. Other usual separator devices would be furnished such as a safety head, pressure relief valve, level gauge, etc. Normally, these vessels would be built in only 5' to 7 ½' heights, depending on the diameter of the vessel. These would not be equipped for three phase operation, since there would be not enough surge room for a conventional settling section in the bottom of the vessel for proper separation of free water and distillate. See Table 2 for typical specifications of standard size vertical gas scrubbers. Normally, the gas scrubbers would have larger inlet and outlet gas connections than would conventional separators of the same physical size, because these vessels would be handling considerably more volumes of gas than would a conventional separator.

### SCRUBBER DESIGN:

The gas capacity of vertical gas scrubbers may be calculated from the following empirical relationship proposed by Souders-Brown. This is the same equation used for conventional separator sizing with only a change in the empirical K factor:

$$v = K \left[ \frac{\rho_L - \rho_g}{\rho_g} \right]^{1/2}$$

Then:  $A = \frac{q}{v}$

Or: 
$$G = \frac{2.40(D^2)(K)(P)}{(T + 460)(Z)} \left[ \frac{\rho_L - \rho_g}{\rho_g} \right]^{1/2}$$

Where:

- $v$  = Superficial gas velocity based on total cross-sectional area of vessel, ft/sec
- $A$  = Cross-sectional area of vessel, sq ft.
- $q$  = Gas flow rate at operating conditions, cu ft/sec
- $\rho_L$  = Density of liquid at operating conditions, lb/cu ft.
- $\rho_g$  = Density of gas at operating conditions, lb/cu ft.
- $K$  = Empirical factor = 0.35
- $G$  = Gas capacity at standard conditions, MMSCFD
- $D$  = Internal diameter of vessel, ft.
- $P$  = Operating pressure, psia
- $T$  = Operating temperature.
- $Z$  = Compressibility factor

For rapid sizing of vertical gas scrubbers the above equations have been plotted on Figure 1 based on a gas specific gravity of 0.69 and an operating temperature of 60°F. For other operating temperatures the correction factors may be used as listed in Table 1. The corrected gas capacity for other temperatures would then be expressed as follows:

$$G_c = G_s (C_t)$$

Where:  $G_c$  = Corrected gas capacity, MMSCFD  
 $G_s$  = Standard gas capacity from Figure 1, MMSCFD  
 $C_t$  = Temperature correction factor, Table 1

Variations in normal gas specific gravities encountered need not be considered in using the sizing chart as it will not affect the gas capacity by a great amount. However, a more accurate design can be made using the equations described in the first part of this section.

#### CONCLUSION:

As stated above, the vertical gas scrubbers are not designed to handle any appreciable amounts of free liquid or normal liquid/gas settling as is found in conventional oil-gas separators. Therefore, no liquid capacity sizing is necessary. If any liquid flow rates are known then conventional oil-gas separators should be used and vertical gas scrubbers should not be used for this application. Liquid discharge valves and liquid level controls are provided on the vessels only for discharging the small amounts of liquids coalesced and drained from the mist eliminator portion of the vessels.

TABLE 1

Operating Temperature, °F	Correction Factor, Ct
40	1.04
50	1.02
60	1.00
70	0.98
80	0.96
90	0.95
100	0.93
110	0.91
120	0.90

TABLE 2  
SPECIFICATIONS  
VERTICAL GAS SCRUBBERS

Model No. **	Size O.D., In.	Shell Height ft	Working Pressure, Psig*	Gas Connections Inlet & Outlet	Standard Liquid Valve	Shipping Weight, Lb.
VGS-1610	16"	5'	1000	3"	1"	1200
VGS-2010	20"	5'	1000	4"	1"	1700
VGS-2410	24"	5'	1000	4"	1"	2600
VGS-3010	30"	5'	1000	6"	1"	3400
VGS-3610	36"	7 ½'	1000	6"	1"	5600
VGS-4210	42"	7 ½'	1000	8"	1"	7900
VGS-4810	48"	7 ½'	1000	8"	1"	10600
VGS-5410	54"	7 ½'	1000	10"	1"	12700
VGS-6010	60"	7 ½'	1000	10"	1"	17900

\*Other standard working pressures available are 230, 500, 600, 1200, 1440, 2000 psig.

\*\*Last two digits of model number would change for other working pressures, i.e. 1440 psig (14), 600 psig (6).

FIGURE 1  
GAS CAPACITY  
VERTICAL GAS SCRUBBERS

GAS SPECIFIC GRAVITY: 0.69  
GAS TEMPERATURE: 60°F

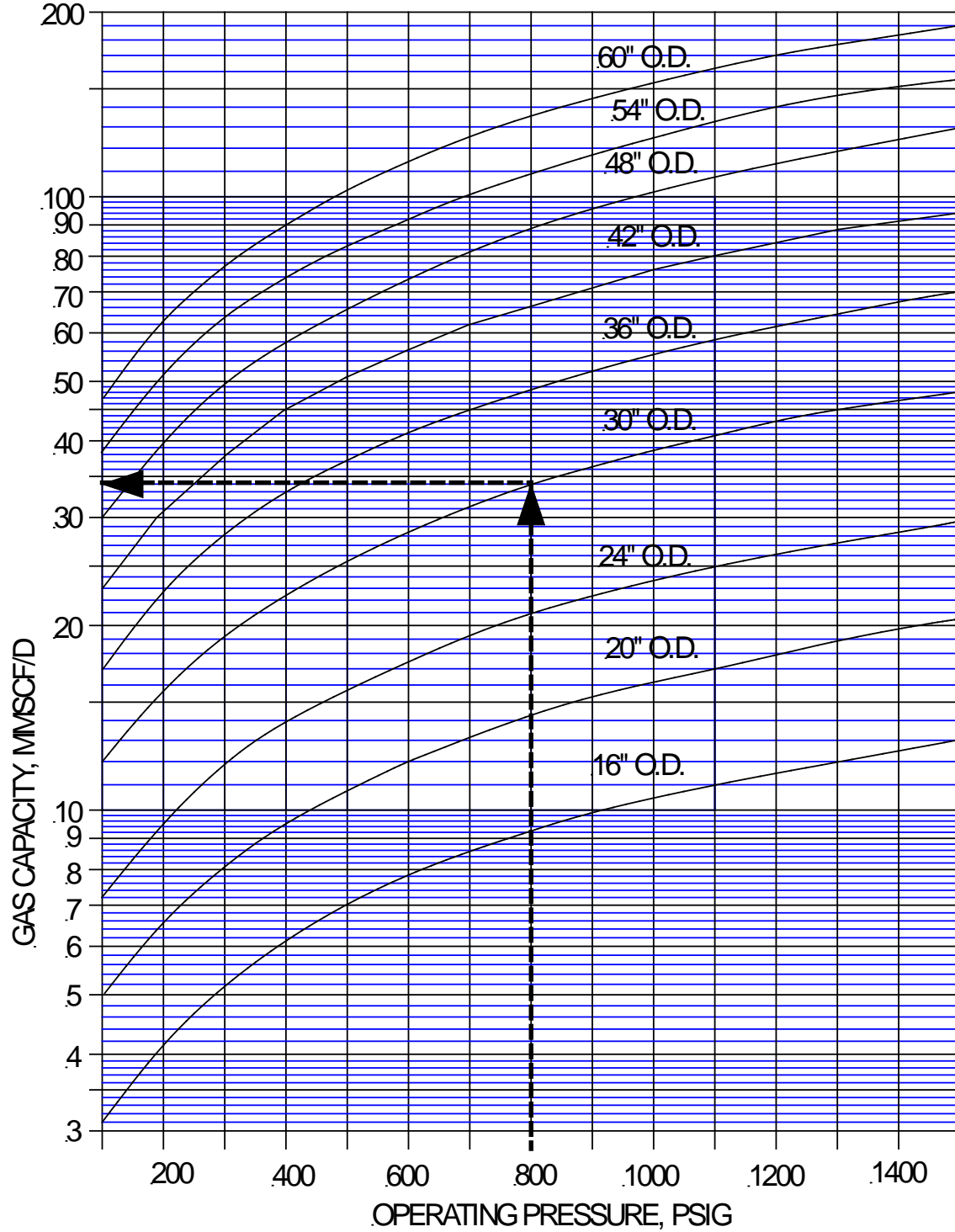


FIGURE 2  
VERTICAL GAS SCRUBBER

