SELECTING AN ARTIFICIAL LIFT METHOD

Artificial lift considerations should ideally be part of the well planning process. Future lift requirements will be based on the overall reservoir exploitation strategy, and will have a strong impact on the well design.

Initial Screening Criteria

Tables 1 and 2 below summarize some of the key factors that influence the selection of an artificial lift method.

<table>
<thead>
<tr>
<th>Table 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir and Hole Considerations in Selecting an Artificial Lift Method</td>
</tr>
<tr>
<td>(after Brown, 1980)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Characteristics:</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>IPR</strong></td>
</tr>
<tr>
<td><strong>Liquid production rate</strong></td>
</tr>
<tr>
<td><strong>Water cut</strong></td>
</tr>
<tr>
<td><strong>Gas-liquid ratio</strong></td>
</tr>
<tr>
<td><strong>Viscosity</strong></td>
</tr>
<tr>
<td><strong>Formation volume factor</strong></td>
</tr>
<tr>
<td><strong>Reservoir drive mechanism</strong></td>
</tr>
<tr>
<td><strong>Other reservoir problems</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Hole Characteristics:</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Well depth</strong></td>
</tr>
<tr>
<td><strong>Completion type</strong></td>
</tr>
<tr>
<td><strong>Casing and tubing sizes</strong></td>
</tr>
<tr>
<td><strong>Wellbore deviation</strong></td>
</tr>
</tbody>
</table>
Table 1
Reservoir and Hole Considerations in Selecting an Artificial Lift Method
(after Brown, 1980)

<table>
<thead>
<tr>
<th>Reservoir Characteristics:</th>
</tr>
</thead>
<tbody>
<tr>
<td>PCP systems because of drag, compressive forces and potential for rod and tubing wear.</td>
</tr>
</tbody>
</table>

Table 2
Surface and Field Operating Considerations in Selecting an Artificial Lift Method
(after Brown, 1980)

<table>
<thead>
<tr>
<th>Surface Characteristics:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow rates</td>
</tr>
<tr>
<td>Flowline size and length</td>
</tr>
<tr>
<td>Fluid contaminants</td>
</tr>
<tr>
<td>Power sources</td>
</tr>
<tr>
<td>Field location</td>
</tr>
<tr>
<td>Climate and Physical environment</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Field Operating Characteristics:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-range recovery plans</td>
</tr>
<tr>
<td>Pressure maintenance operations</td>
</tr>
<tr>
<td>Enhanced oil recovery projects</td>
</tr>
<tr>
<td>Field automation</td>
</tr>
<tr>
<td>Availability of operating and service personnel and support services</td>
</tr>
</tbody>
</table>

Clegg, Bucaram and Hein (1993), in a piece written for the SPE Distinguished Author Series, observe that “selecting the proper artificial lift method is critical to the long-term profitability of most producing oil and gas wells.” They list 31 attributes for comparing the eight most common artificial lift techniques (continuous...
and intermittent gas lift, beam pumping, progressing cavity pumping, hydraulic pumping, electric submersible pumping, jet pumping and plunger lift), and provide practical guidelines for assessing each method’s capabilities. These are summarized as follows:

**Design considerations and overall comparisons:**
- Capital cost
- Downhole equipment
- Efficiency
- Flexibility
- Miscellaneous [operating] problems
- Operating costs
- Reliability
- Salvage value
- System (total)
- Usage/outlook

**Normal operating considerations:**
- Casing size limits
- Depth limits
- Intake capabilities
- Noise level
- Obtrusiveness
- Prime mover flexibility
- Surveillance
- Testing
- Time cycle and pump-off controllers application

**Artificial lift considerations:**
- Corrosive/scale handling ability
- Crooked/deviated holes
- Multiple completions
- Gas-handling ability
- Offshore application
- Paraffin-handling capability
- Slim-hole completions
- Solids/sand-handling ability
- Temperature limitations
- High-viscosity fluid handling
- High-volume lift capabilities
- Low-volume lift capabilities

Finally, Table 3 (from Weatherford International Ltd., 2005) summarizes typical characteristics and applications for each form of artificial lift. These are general guidelines, which vary among manufacturers and researchers. Each application needs to be evaluated on a well-by-well basis.

<table>
<thead>
<tr>
<th>Operating Parameter(s)</th>
<th>Positive displacement pumps</th>
<th>Dynamic displacement pumps</th>
<th>Gas lift</th>
<th>Plunger lift</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rod pump</td>
<td>PCP</td>
<td>Hydraulic Piston</td>
<td>ESP</td>
</tr>
<tr>
<td>Typical Operating Depth (TVD)</td>
<td>100 to 11000 ft</td>
<td>2000 to 4500 ft</td>
<td>7500 to 10000 ft</td>
<td>5000 to 10000 ft</td>
</tr>
<tr>
<td>Maximum Operating Depth (TVD)</td>
<td>16000 ft</td>
<td>6000 ft</td>
<td>17000 ft</td>
<td>15000 ft</td>
</tr>
<tr>
<td>Typical Operating</td>
<td>5 to 1500</td>
<td>5 to 2200</td>
<td>50 - 500</td>
<td>100 to 30000</td>
</tr>
<tr>
<td>Operating Parameter</td>
<td>Positive displacement pumps</td>
<td>Dynamic displacement pumps</td>
<td>Gas lift</td>
<td>Plunger lift</td>
</tr>
<tr>
<td>---------------------</td>
<td>-----------------------------</td>
<td>---------------------------</td>
<td>----------</td>
<td>-------------</td>
</tr>
<tr>
<td></td>
<td>Rod pump</td>
<td>PCP</td>
<td>ESP</td>
<td>Hydraulic Jet</td>
</tr>
<tr>
<td>Volume</td>
<td>BFPD</td>
<td>BFPD</td>
<td>BFPD</td>
<td>BFPD</td>
</tr>
<tr>
<td>Maximum Operating Volume</td>
<td>6000 BFPD</td>
<td>4500 BFPD</td>
<td>4000 BFPD</td>
<td>40000 BFPD</td>
</tr>
<tr>
<td>Typical Operating Temperature</td>
<td>100 - 350 °F [40-177 °C]</td>
<td>75 - 150 °F [24-65 °C]</td>
<td>100 - 250 °F [40-120 °C]</td>
<td>100 - 250 °F [40-120 °C]</td>
</tr>
<tr>
<td>Typical Wellbore Deviation</td>
<td>0 - 20 deg landed pump</td>
<td>0 - 20 deg landed pump</td>
<td>0 - 20 deg hole angle</td>
<td>0 - 50 deg</td>
</tr>
<tr>
<td>Maximum Wellbore Deviation</td>
<td>0 - 90 deg landed pump</td>
<td>0 - 90 deg &lt; 15 deg/100 ft</td>
<td>0 - 90 deg &lt; 15 deg/100 ft</td>
<td>0 - 90 deg &lt; 24 deg/100 ft</td>
</tr>
<tr>
<td>Corrosion handling</td>
<td>Good to Excellent</td>
<td>Fair</td>
<td>Good</td>
<td>Excellent</td>
</tr>
<tr>
<td>Gas handling</td>
<td>Fair to good</td>
<td>Good</td>
<td>Fair</td>
<td>Good</td>
</tr>
<tr>
<td>Solids handling</td>
<td>Fair to good</td>
<td>Excellent</td>
<td>Poor</td>
<td>Good</td>
</tr>
<tr>
<td>Fluid gravity</td>
<td>&gt; 8 ° API</td>
<td>&lt; 35 ° API</td>
<td>&gt; 8 ° API</td>
<td>&gt; 10 ° API</td>
</tr>
<tr>
<td>Servicing</td>
<td>Workover or pulling rig</td>
<td>Workover or pulling rig</td>
<td>Hydraul ic or wireline</td>
<td>Workover or pulling rig</td>
</tr>
<tr>
<td></td>
<td>GLR = 300 SCF/Bbl per 1000 ft of depth</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 3: Artificial Lift Methods—Characteristics and Areas of Application (after Weatherford, 2005)

<table>
<thead>
<tr>
<th>Operating Parameters</th>
<th>Positive displacement pumps</th>
<th>Dynamic displacement pumps</th>
<th>Gas lift</th>
<th>Plunger lift</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rod pump</td>
<td>PCP</td>
<td>Hydraulic Piston</td>
<td>ESP</td>
</tr>
<tr>
<td>Prime mover</td>
<td>Gas or electric</td>
<td>Gas or electric</td>
<td>Multi-cylinder or electric</td>
<td>Electric motor</td>
</tr>
<tr>
<td>Offshore applications</td>
<td>Limited</td>
<td>Good</td>
<td>Good</td>
<td>Excellent</td>
</tr>
<tr>
<td>System efficiency</td>
<td>45% - 60%</td>
<td>40% - 70%</td>
<td>45% - 55%</td>
<td>35% - 60%</td>
</tr>
</tbody>
</table>

ECONOMICS OF ARTIFICIAL LIFT

The features, benefits and limitations of one artificial lift method are relative to those of the other methods under consideration. Each method should be evaluated from the standpoint of comparative economics. Brown (1980) lists six critical bases of comparison:

- Initial capital cost
- Monthly operating expense
- Equipment life
- Number of wells to be lifted
- Surplus equipment availability
- Expected producing life of well(s)

Capital cost considerations may favor one type of system over another, particularly when there is significant uncertainty regarding well performance characteristics or reserve volumes. Gas lift is not likely to be a good option for a one or two-well system, for example—particularly if it requires adding surface compression facilities. For multiple wells, however, it may be a very economical choice. Hydraulic pumping is likewise less costly when multiple wells are operated from a central injection facility.

Projected operating costs also figure into the selection of an artificial lift method. High gas prices will reduce the profitability of gas lift, particularly if it becomes necessary to purchase additional gas for injection. But gas lift may be an attractive option in a remote field where there is no market for produced gas. In the same way, in places where electricity is not readily available, submersible pumps will be less attractive compared to gas lift or other forms of pump-assisted lift.

System reliability and easy access to repair equipment and services must also be considered. Sometimes, the prevalence of a particular type of lift equipment in a given area will make that system more attractive.

If a well is expected to have a short producing life, capital and operating costs will play an important role in the overall field economics and will affect the choice of an artificial lift system.

It is clear that for each well or field situation, a number of factors will affect the choice of artificial lift system. Equipment manufacturers can explain important advantages and disadvantages of different systems. Each type of artificial lift method has economic and operating limitations that can make it more or less desirable.
when compared to others. Similarly, one artificial lift system will usually have at least one advantage over all others for a given set of operating conditions.

GAS LIFT SYSTEM OVERVIEW

Gas lift is a four-step process (Figure 1: Gas lift system):

1. Natural gas is compressed at the surface and routed to individual wells.
2. This "lift gas" is injected downhole and into the produced fluid stream through one or more valves set at specified depths (most commonly, the gas is injected into the production tubing from the casing-tubing annulus).
3. The lift gas and formation fluids are produced to the surface.
4. The gas and liquids are separated; the gas is then treated and sent either to compression or to sales.

In most wells, gas is injected continuously into the produced fluid stream. This continuous gas lift process reduces the backpressure on the formation by reducing the density—and therefore the hydrostatic pressure—of the produced fluid (Figure 2: Continuous gas lift).
Continuous gas lift is typically used in higher productivity wells to handle rates ranging from 100 up to 30,000 B/D. In wells with very high productivity indexes, even higher rates can be attained by injecting gas into the tubing and producing fluids through the casing-tubing annulus.

**Intermittent gas lift** employs much of the same equipment as continuous lift, but its operating principle is completely different. Rather than lowering the density of the produced fluid so that it can produce in a continuous flow stream, intermittent lift works by physically displacing “slugs” of liquid to the surface (Figure 3: Intermittent gas lift):
• When a certain volume of fluid accumulates in the wellbore, gas is injected into the tubing, where it lifts the column of fluid to the surface as a slug.
• As each liquid slug is produced, gas injection is interrupted to allow the fluid volume to build up again. Intermittent injection uses a timer or an adjustable choke located on the surface to control the gas injection. Cycling of gas injection is regulated to coincide with the accumulation of wellbore fluids.

Intermittent lift is generally used in wells with limited inflow potential (i.e., high productivity index with low average reservoir pressure or, alternatively, low productivity index with high reservoir pressure).
As is true for other artificial lift methods, gas lift offers a number of benefits, and at the same time has some inherent limitations (Brown, 1982; Takács, 2005). Advantages include:

- Flexibility in handling a wide range of production rates; can convert from continuous to intermittent lift as reservoir pressure or well productivity declines.
- Relatively good solids-handling capabilities.
- Suitability for producing high-GLR wells (unlike pump-assisted lift, where gas production is usually detrimental to system efficiency).
- Can be used in deviated wells.
- Installations can be designed for servicing with wireline units; gas lift valves can be run and retrieved without having to pull tubing string.
- Relatively low-profile surface wellhead equipment, takes up little surface space.
- Can easily manage high bottomhole temperatures or corrosive environments.
- Most installations provide full-bore tubing strings, which facilitate downhole surveys, well monitoring and workover.

Some of the main limitations and disadvantages of gas lift systems include:

- Obtaining sufficient amounts of lift gas.
- The need to provide compression and gas treatment facilities.
- Generally lower energy efficiency than other lift methods.
- Cannot reduce bottomhole pressure to the low levels attainable by pump-assisted lift.

**DOWNHOLE INSTALLATIONS**

The key subsurface components of a gas lift system are the gas lift valves that regulate the flow of injected gas into the producing fluid column. These pressure-operated devices—usually 1 or 1.5 inches in diameter and about 16 to 24 inches long—are placed in mandrels that are set at selected depths in the tubing string, most often in a conventional or side pocket configuration (Figure 1: Conventional and side pocket mandrel installations).
• In a conventional or tubing retrievable valve-mandrel configuration, the valves are run with the tubing string, and the tubing must be pulled in order to repair or replace a valve. (Figure 2) shows a valve designed for a conventional gas lift installation. (Camco conventional injection-pressure operated gas lift valves, Types J50 and J40. Courtesy of Schlumberger.)
Side pocket mandrels are designed to accommodate valves in parallel with the tubing (Figure 3: Camco KBMM Series side pocket mandrel. Courtesy of Schlumberger.). These are the most common types of mandrels in use, their main attraction being that they enable gas lift valves to be run and retrieved on wireline. This eliminates the need to pull the tubing for valve repairs or adjustments.
Installation Types

The type of downhole installation used in a gas lift well depends on whether it is to be placed on continuous or intermittent lift. This in turn depends on its present and anticipated future inflow performance. Other considerations include completion type, casing diameters and wellbore deviation. As is true for any type of downhole installation, a gas lift system should be designed with enough flexibility to minimize the number of workovers required over a well’s producing life.

Except for the annular flow installation mentioned at the end of this section, all of the downhole installations discussed here are designed for gas injection through the casing and production through the tubing string.

**Open Installation**

An open gas lift installation is one in which the tubing string is suspended in the well without a packer, and the casing and tubing are in communication. This, the oldest type of gas lift installation, has several major disadvantages:

- Only a fluid seal in the annulus prevents gas from blowing around the bottom of the tubing. This results in wasted gas, additional backpressure on the formation, and reduced production rates.
- Without a packer, the lower gas lift valves may be submerged in well fluids because the fluid rises in the annulus every time the well is shut-in. This may lead to valve corrosion.
When production resumes, the fluid must flow back through the gas lift valves, causing the valves to wear out faster.

The open installation is not normally recommended, and it is used nowadays only when a packer cannot be installed.

**Semi-Closed Installation**

A semi-closed installation has a packer installed in the tubing to seal off the tubing-casing annulus, as shown in the continuous gas lift well of (Figure 4) (Semi-closed gas lift installation).
This is the most common type of installation for continuous gas lift wells. It eliminates most of the characteristic disadvantages of the open installation—the packer keeps produced fluids from entering the annulus, and prevents the casing pressure from directly communicating with the formation.

This installation is also used in intermittent gas lift wells. It is not the best choice for wells exhibiting very low bottomhole pressures, however, because it is possible that gas injected into the tubing string may place additional backpressure on the formation when the operating valve is open.

**CLOSED INSTALLATION**

A closed installation (Figure 5) is similar to a semi-closed installation, except that a standing valve is placed in the tubing string below the bottom gas lift valve to prevent fluids from moving downward. Thus, high-pressure gas injected into the tubing from the annulus cannot increase backpressure on the formation, and any produced fluids standing in the tubing will not flow back into the formation. These features make the closed installation the option of choice for intermittent gas lift.
CHAMBER INSTALLATIONS

A chamber installation can greatly increase production rates, especially in wells with low bottomhole pressures and high productivity indexes. It is used in intermittent lift operations to increase the volume of fluids in the wellbore prior to lifting, without significantly increasing the backpressure on the formation.

One type of chamber installation consists of a lower packer and an upper, or bypass packer. This two-packer chamber installation works as follows:

- As the chamber fills with fluid, gas in the chamber passes through a bleed valve into the tubing.
- When the chamber is filled, a slug of gas is injected down the annulus to open the operating valve.
The gas in the chamber forces the fluid to enter the tubing through a perforated nipple above the bottom packer (Figure 6: Chamber installation—fluid entry).

When all the fluid in the chamber above the nipple is forced into the tubing, gas follows behind the slug and forces it to the surface (Figure 7: Chamber installation—fluid displacement).
The operating valve should close when the slug reaches the surface, at which time the filling cycle begins again.

In wells where it is not feasible to set two packers, an *insert chamber* installation may be used, in which the chamber is formed by a larger-diameter section of pipe at the bottom of the tubing string. The principles of operation are the same as for the two-packer installation. Alternative configurations may be designed for special circumstances.

**SLIM HOLE INSTALLATIONS**
Slim hole completions are often used in lower productivity wells. These normally use a string of 2-3/8 to 3-1/2-inch OD pipe as the production casing. Smaller size tubing, (e.g., 1 to 1-1/2-inches in diameter) is then run inside this casing (Figure 8: Slim hole gas lift completion).

**Figure 8**

Slim hole completions are especially useful for producing from two or more zones without commingling. Production rates for continuous gas lift will depend on the ID of the tubing, but can range from 150 B/D for 3/4-inch tubing to 900 B/D for 1 1/2-inch ID tubing. The rates for intermittent injection in slim hole wells are considerably lower.

**DUAL INSTALLATIONS**

Gas lift wells, like flowing wells, can be designed with parallel or concentric dual tubing strings (Figure 9: Dual gas lift installations). The two most common configurations are (1) parallel strings of 2 3/8-inch OD tubing inside 7-inch casing and (2) parallel strings of 3 1/2-inch OD tubing inside 9 5/8-inch casing (API RP 11V8, 2003).
Gas is supplied through the tubing-casing annulus, and injected into two separate tubing strings. The zones may be produced using the same type of lift method (i.e., both on continuous or both on intermittent lift), or the two methods may be used in combination (e.g., one zone is on intermittent lift while the other is on continuous lift). For a dual installation to work, the valves must be spaced to prevent interference between the two zones, and selected so that the desired amounts of gas are injected for each zone.

**COILED TUBING INSTALLATIONS**

Coiled tubing can be used to convert a flowing well to gas lift without having to pull the main production tubing string, simply by placing conventional gas lift mandrels at the appropriate depths on the coiled tubing string and then running it inside the production tubing. The smaller diameter of the coiled tubing restricts its use to lower-productivity wells.

**ANNULAR FLOW INSTALLATIONS**

In most gas lift operations, production is confined to the tubing because of safety issues, regulatory requirements and company operating policies. This is especially true offshore. In some areas, however—such as the Middle East, where wells produce at rates up to 80,000 B/D—operators use **annular flow gas lift**.

In this process, gas is injected down the tubing and production is from the annulus. A bull plug is placed at the bottom of the tubing to contain the injected gas. A small-bore orifice or check valve can also be used for this purpose.
Apart from regulatory prohibitions, annular flow installations are limited in their application due to concerns about casing corrosion, high injection requirements and the potential for fluid slugging as production rates decline.

**GAS LIFT VALVES**

Depending on where it is placed in the tubing string, a gas lift valve may be used as an *operating valve* or an *unloading valve*.

- The operating valve is the deepest valve in the string. It is designed and placed to ensure that the proper amount of gas is injected into the tubing at the appropriate depth to optimize well performance.
- Unloading valves are set at predetermined depths above the operating valve. They are used to progressively reduce the static fluid level in a well when it is first brought on production (or returned to production after having been killed for workover or other operations). As gas is injected into the well, each valve opens in sequence from top to bottom. The gas displaces the liquid in the well, “u-tubing” it through the unloading valve and displacing it to the surface. As the liquid level drops below the valve, that valve closes and the valve below it opens, and so on down to the operating valve. The unloading valves remain closed during normal production.

Individual valve specifications will depend on whether the well is being produced by continuous or intermittent lift.

**Valve Types**

Gas lift valves are *pressure-operated* valves, so-called because they are designed to open or close in response to gas injection pressure, fluid production pressure or both. The pressure that controls the valve operation is that which is exposed to the largest area in the valve.

The most common types of gas lift valves are described below:

- **Injection pressure-operated (IPO) valve**: Increase in gas injection pressure opens valve; decrease in gas injection pressure closes valve (*Figure 1*: Camco retrievable injection pressure operated gas lift valves, BK series and R-20-02 series. Courtesy of Schlumberger.)
• Production-pressure-operated (PPO) and Differential-pressure-operated valves: Increase in production pressure opens valve; decrease in production pressure closes valve (Figure 2: Camco retrievable production pressure operated gas lift valve, type BKF-12. Courtesy of Schlumberger).
• **Throttling valve**: Increase in gas injection pressure opens valve; decrease in gas injection pressure or production pressure closes valve.
• **Combination valves**: Increase in production pressure opens valve; decrease in gas injection pressure or production pressure closes valve.

Where injection takes place in the annulus and production takes place through the tubing, the gas injection pressure is commonly referred to as the “casing pressure” and the production pressure is referred to as the “tubing pressure.”

**Injection Pressure-Operated Valves**
An injection-pressure-operated (IPO) valve opens and closes in response to changes in gas injection pressure. One type of IPO valve, represented schematically in (Figure 3), operates as follows:
• The dome is charged to a specified pressure with nitrogen, at a controlled surface temperature.
• The bellows serve as a flexible or responsive element. Movement of the bellows causes the valve stem to rise and fall, and the ball to open and close over the port.
• When the port is open, the annulus and tubing are in communication
• Because the area of the bellows is much larger than the area of the port, and since the bellows is exposed to casing pressure, it is casing pressure that controls the operation of the valve.
• A buildup in injection pressure opens the valve, and a reduction in injection pressure closes it.

IPO valves may be classified as either unbalanced or balanced, depending on whether the production pressure plays a role in opening the valve.
A balanced valve opens only at a specified pressure and does not respond to pressure changes in the tubing. By design, tubing pressure cannot act on the port or bellows; thus, the valve is not affected by changes in tubing pressure. Only casing pressure can move the bellows and control the flow of gas from the casing into the tubing.

An unbalanced valve is one in which the (1) opening or (2) opening and closing pressure are affected by the production pressure. The valve is kept closed by a nitrogen-charged dome that loads the bellows. The bellows is attached to a stem that moves a ball and controls gas flow into the tubing. When tubing pressure is high enough, the ball moves up and the valve opens.

The valve in (Figure 1) is unbalanced, since the tubing pressure can open the port. It may also be classified as a single-element valve, since the charge pressure in the dome represents the only control on the valve’s operation. In contrast, a double-element valve has two loading elements: the pressure-charged dome and a spring. The spring provides a closing force, which ensures that if the bellows is ruptured, the valve can still close when needed. Double element valves can be used in both continuous and intermittent flow gas lift installations.

**Production Pressure-Operated Valves**

In a production pressure-operated (PPO) valve, the port is exposed to the injection pressure and the bellows is exposed to the production pressure (Figure 4: Production pressure-operated gas lift valve). Therefore, it is the production pressure that controls the operation of the valve.
PPO valves are double element valves, having both a spring and dome (that may or may not be charged) to supply the valve closing force. Most manufacturers of this valve type charge the dome only when high valve-setting pressures require a supplement to the spring force.

Another type of production pressure-operated valve is called a differential-pressure-operated valve. This valve opens and closes in response to tubing pressure relative to the casing pressure. It does not have a pressure-charged dome, but has only a spring acting against the stem and ball.

**THROTTLING VALVES**

An IPO valve closes only when the casing pressure falls below the dome pressure. If a tapered seat is used, however, then the valve’s closing becomes somewhat sensitive to tubing pressure (Figure 5: Throttling gas lift valve). The tapered seat allows the port area to “sense” the tubing pressure when the
valve is open. This type of valve, called a **throttling valve**, responds to both tubing and casing pressure, even when it is open.

![Throttling Valve Diagram](image)

If the tubing pressure is lower than the casing pressure, the throttling valve can close even before the casing pressure has dropped to the dome pressure. In fact, a throttling valve will close with a reduction in tubing pressure - even though the casing pressure is held constant. Throttling valves are also known as **proportional** valves or **continuous flow** valves.

A throttling valve, then, requires a buildup in tubing or casing pressure to open, and a reduction in tubing or casing pressure to close. During continuous gas lift, the injection gas pressure is held constant by a regulator at the surface; as a result, the valve opens and closes only in response to changes in tubing pressure.

**Pilot Valves**

A *pilot valve* is a variable-spread valve that is used to unload or “kick off” a well. It has both a small port to control the *spread* (i.e., the difference between the opening and closing pressures), and a larger port used for more efficient gas flow. This type of valve is often used for intermittent gas lift operations, which benefit from a valve with a large port size while also keeping close control over the spread ([Figure 6: Pilot Valve Operation](#)).
Dome Charge Pressure Corrections

A pressure-operated gas lift valve is charged to its specified dome pressure under controlled surface temperature conditions. Its use in a gas lift installation, however, is based on the charge pressure at its setting depth. The surface pressure therefore has to be corrected for changes in temperature and the gas compressibility factor.

Brown (Vol. 2a, 1980), Winkler and Smith (1962), Takács (2005) and others have published charts that can be used to determine the nitrogen dome charge pressure at a given downhole temperature. Winkler and Eads (1989) present the following formulas, which incorporate the effects of the deviation factor for nitrogen:

- For \( P'_d \) < 1238 psi, where \( P'_d \) = dome charge pressure at 60 °F, psia: \[
P_d = P'_d + (-0.00226 + 0.001934 \cdot P'_d + 3.054 \times 10^{-7} \cdot (P'_d)^2) \times (T_{valve} - 60)
\]

- For \( P'_d > 1238 \) psi: \[
P_d = P'_d + (-0.267 + 0.002298 \cdot P'_d + 1.84 \times 10^{-7} \cdot (P'_d)^2) \times (T_{valve} - 60)
\]

**Example:**

A gas lift valve has a dome charge pressure of 500 psia at a surface temperature of 60 °F. What is this pressure at the valve setting depth of 6000 ft, where the temperature is equal to 144 °F?

**Solution:**

\[
P'_d = 500 \text{ psia}; \quad P'_d < 1238 \text{ psi}
\]

\[
P_d = P'_d + (-0.00226 + 0.001934 \cdot P'_d + 3.054 \times 10^{-7} \cdot (P'_d)^2) \times (T_{valve} - 60)
\]

\[
P_d = 500 + (-0.00226 + 0.001934 \cdot (500) + 3.054 \times 10^{-7} \cdot (500)^2) \times (144 - 60)
\]

\[
P_d = 587 \text{ psi}
\]

**Gas Lift Valve Selection**
The type of gas lift valve used in a given installation will depend on whether the well will be placed on continuous or intermittent lift. Some types of valves are suitable for either continuous or intermittent injection; these may be worth considering if the lift method has not been determined or if well performance is marginal.

**CONTINUOUS GAS LIFT**

The ideal continuous lift installation would be one in which gas is injected in a steady stream, resulting in more-or-less constant pressures and production rates according to the original design. In reality, production rates and pressures fluctuate from the design parameters, often on a day-to-day basis. The operating valve thus needs to be sensitive to production pressure when it is in the open position. As production pressure decreases, (i.e., tubing pressure for a tubing installation) the valve should begin to throttle closed to decrease gas throughput; as it increases, the valve should open to increase gas throughput. This proportional response maintains the established flowing wellhead pressure and keeps a constant pressure inside the tubing. Therefore, the best type of operating valve to use for continuous gas flow would be a throttling valve or one with identical gas throughput characteristics.

**INTERMITTENT GAS LIFT**

Operating valves used for intermittent lift must be designed for immediate or “snap” opening and closing. Immediate opening ensures that the gas is injected as a compressed slug and not as a gradual stream that bubbles up through the liquid, while quick valve closure prevents excess gas from being injected. Because the operating valve must be able to handle a relatively large volume of gas in a short time, it has to be able to open to a large port (normally between 3/8 and 3/4 inch), and remain fully open until closing. At the same time, the valve should have a small enough spread so that the volume of gas injected can be tightly controlled. In a single-point injection system, these requirements can be met by using a pilot valve. In a multipoint system, a number of valves are installed at various depths in the tubing string. At each depth, the valve should allow sufficient gas to enter the tubing so that the fluid slug can be moved upward to the next higher valve. As the fluid slug passes by each valve, the pressure under the slug opens that valve, allowing more gas to be injected and supplementing the gas that has entered through the deeper valves. The valves normally remain open until the slug is produced to the surface.

**GAS LIFT VALVE MECHANICS**

The opening and closing characteristics of gas lift valves are important considerations in system design and operation. It is important, therefore, to know how and when a valve opens and closes, and to understand the significance of its *spread*, or difference between opening and closing pressures.

**Pressures To Operate a Valve**

Consider an unbalanced IPO single-element valve in the closed position, represented schematically in (Figure 1).
To calculate the valve’s opening and closing pressures, it is necessary to solve a force-balance equation.

- The force tending to close the valve, $F_{\text{close}}$, is

$$F_{\text{close}} = P_d A_b$$

where $P_d$ is the dome charge pressure, and $A_b$ is the bellows area.  

- The force tending to open the valve, $F_{\text{open}}$, equals

$$F_{\text{open}} = P_{\text{inj}} (A_b - A_p) + P_{\text{prod}} A_p$$

- where $P_{\text{inj}}$ is the injection pressure,
  $A_p$ is the area of the stem or port; and
If we set $F_{\text{close}} = F_{\text{open}}$ and define $R = (A_p/A_b)$, we obtain an expression for the injection pressure required to just open the valve at the valve setting depth, or $(P_{\text{inj}})_{\text{open}}$:

$$
(P_{\text{inj}})_{\text{open}} = \frac{P_d - P_{\text{prod}}R}{1 - R}
$$

(3)

**Example:**

Determine the casing (injection) pressure required to open an IPO valve under the following conditions:
Bellows area = 0.77 square inches; Port area = 0.129 square inches; Bellows pressure (corrected to valve depth) = 500 psi; Tubing pressure = 425 psi.

**Solution:**

$$
R = \frac{A_p}{A_b} = \frac{0.129}{0.77} = 0.167
$$

$$
(P_{\text{inj}})_{\text{open}} = \frac{500 - 425(0.167)}{1 - 0.167} = 515 \text{ psi}
$$

The casing pressure required to open the valve is 515 psi, or 15 psi above the bellows pressure. A higher casing pressure is required because of the effect of the lower tubing pressure on the port area.

We may also calculate the pressure required to close the valve once it is opened. Once again, equate the forces tending to keep the valve opened with those tending to close it. The force tending to close the valve is equal to:

$$
F_{\text{close}} = P_d A_b
$$

(1)

The force tending to hold the valve open is equal to:

$$
F_{\text{open}} = P_{\text{inj}}(A_p - A_b) + P_{\text{inj}} A_p
$$

(4)

Note that when the valve is open, the injection pressure has replaced the production pressure from Equation 2.

Equating these two terms yields the casing pressure required to close the valve:

$$
(P_{\text{inj}})_{\text{close}} = P_d
$$

(5)

In this example, the bellows pressure is 500 psi, and so the valve will close at this pressure.

**VALVE SPREAD**

The difference between the opening pressure and the closing pressure is the spread.

$$
\text{Spread} = (P_{\text{inj}})_{\text{open}} - (P_{\text{inj}})_{\text{close}}
$$

(6)

Thus, in the preceding example, the valve spread is $(515 - 500) = 15$ psi.

An inspection of Equations 3 and 5 shows that the spread is a function of the ratio $R$, the bellows pressure, and the tubing pressure:
For specific bellows and tubing pressures, and since $R = \frac{A_p}{A_b}$, reducing the area of the port will result in lowering the spread. Spread is a particularly important consideration in intermittent lift, because it controls the volume of gas used in each injection cycle. As the spread needed to close the operating valve increases, the amount of gas injected during the cycle also increases—this would call for a smaller spread in order to reduce gas volume requirements, and therefore a smaller port size. On the other hand, a smaller port size increases the compression horsepower requirements. Thus, there needs to be a balance between the need to conserve gas and the need to minimize power costs.

**TEST RACK OPENING PRESSURE (TRO)**

When unbalanced gas lift valves are tested at the surface, they are set in special valve testers, usually at a production pressure of zero. The injection pressure required to open the valve under these conditions is referred to as the test rack opening, or TRO pressure:

$$TRO = \frac{P_d'}{1 - R}$$

where $P_d'$ is the dome charge pressure at surface conditions.

**PRODUCTION PRESSURE EFFECT (PPE)**

The Production Pressure Effect (PPE) describes the contribution that the production pressure makes to the valve's opening injection pressure, and is equal to the difference between the opening pressure at $P_{prod} = 0$ and its actual opening pressure:

$$PPE = P_{prod} \frac{R}{1 - R}$$

For a given valve size and port diameter, $R$ is constant, and so PPE increases linearly with production pressure. The slope of this line is known as the Production Pressure Effect Factor (PPEF) and is equal to $R/(1-R)$, or

$$PPEF = \frac{R}{1 - R} = \frac{\frac{A_p}{A_b}}{1 - \frac{A_p}{A_b}}$$

Thus, as valve port sizes increase for a given bellows area, so does the PPEF.

**Flow Characteristics of a Gas Lift Valve**

A plot of flow rate versus tubing pressure provides insight into the flow characteristics of a gas lift valve. (Figure 2) illustrates the performance characteristics of a throttling valve (note that in this plot, the vertical axis represents *flow rate* and the horizontal axis represents *tubing pressure*).
At very low tubing pressure, to the left of point 1, the valve is closed. As the tubing pressure reaches point 1, the valve begins to open and gas flows from the casing to the tubing. The flow rate increases as the port continues to open. Throttling occurs from point 2 to point 3, at which time the port is fully opened and throttling ends. The maximum flow rate occurs at point 4. As the tubing pressure increases from point 4 to point 5, the tubing and casing pressures become balanced and the flow rate drops to zero. During the reverse cycle (i.e., as the tubing pressure decreases) the valve opens at point 5, throttling takes place between points 3 and 2, and the valve throttle closes between points 2 and 1.

CONTINUOUS GAS LIFT

In continuous gas lift, an uninterrupted stream of high-pressure gas is injected downhole to reduce the flowing bottomhole pressure of the producing fluid. Injection takes place at set rates and at pre-determined depths to optimize well performance and maximize system efficiency. In most wells, gas is injected down the casing-tubing annulus and into the production tubing.
Continuous gas lift works as an artificial lift method because it reduces the hydrostatic component of the bottomhole pressure. As a simple illustration, consider three shut-in wells:

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th>Well 2</th>
<th>Well 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>True vertical depth (TVD):</td>
<td>6000 ft</td>
<td>6000 ft</td>
<td>6000 ft</td>
</tr>
<tr>
<td>Average reservoir pressure:</td>
<td>2100 psi</td>
<td>2100 psi</td>
<td>2100 psi</td>
</tr>
<tr>
<td>Fluid in tubing (TVD to surface):</td>
<td>Salt water</td>
<td>Oil</td>
<td>Gas</td>
</tr>
<tr>
<td>Average fluid gradient:</td>
<td>0.465 psi/ft</td>
<td>0.346 psi/ft</td>
<td>0.069 psi/ft</td>
</tr>
<tr>
<td>Bottomhole pressure at TVD:</td>
<td>2790 psi</td>
<td>2076 psi</td>
<td>414 psi</td>
</tr>
</tbody>
</table>

Note how much lower the bottomhole pressure is in Well 3, and remember the equation that describes the Inflow Performance Relationship:

\[
q = PI(P_{avg} - P_{wf}) \tag{1}
\]

where \(q\) = flow rate, \(PI\) = productivity index, \(P_{avg}\) = average reservoir pressure and \(P_{wf}\) = flowing bottomhole pressure.

Clearly, if we have a well filled with liquid and can mix the liquid column with gas, we can significantly reduce \(P_{wf}\) and, for a given reservoir pressure, increase the inflow from the formation.

**Gas Lift versus Pump-Assisted Lift**

One of the most basic decisions in selecting an artificial lift method is the choice between gas lift and pump-assisted lift. If we are thinking about installing continuous gas lift, we first must consider the physical limit gas-liquid ratio (GLR) and the optimal GLR.

**Physical Limit GLR**

The higher the rate of lift gas injection, the more we improve well performance—up to a point. Consider the pressure traverse curves of (Figure 1). These curves were generated for a specified set of flowing well conditions at a tubing depth of 4000 ft.
We can see from this figure that:

- Adding gas to the liquid column lowers the hydrostatic pressure in the wellbore. In this case, increasing the GLR from zero to 100 SCF/Bbl reduces the bottomhole pressure by nearly 600 psi.
- Higher GLRs result in higher friction pressure losses, which offset the hydrostatic pressure drop. For example, if we again increase the GLR—this time from 100 to 200 SCF/Bbl—the bottomhole pressure decreases by only 270 psi. As we further increase the GLR, the corresponding bottomhole pressure decrease is smaller still.
- Eventually, we reach a physical limit GLR where the increase in friction pressure becomes approximately equal to the decrease in hydrostatic pressure. The net change in bottomhole pressure becomes negligible. In (Figure 1), this occurs between 800 and 1000 SCF/Bbl. At this point, injecting additional gas will not result in additional liquid production.

The bottomhole pressure corresponding to the physical limit GLR is likely to be much higher than the bottomhole pressure we could attain by installing a downhole pump. This consideration alone would tend to favor pump-assisted lift. But there are other factors to take into account. If a formation is subject to drawdown-related production problems such as water coning or sand production, for instance, then gas lift may be the preferred option.

**Optimal GLR**
The choice between gas lift and pump-assisted lift ultimately comes down to economics. Back when the costs of gas re-injection were insignificant compared with the benefits of increasing the incremental oil production rate, the physical limit GLR was considered optimal for meeting gas lift requirements.

Since that time, however, with production costs escalating and natural gas becoming valuable in its own right, this is no longer a safe assumption. The actual optimum will be the GLR above which the incremental cost of injecting additional gas exceeds the incremental revenue from increased oil production. This may be lower than the physical limit value.

General Design Considerations

Continuous gas lift design follows a systems analysis approach, in which pressures at various key points are determined for the desired production rate and different GLR values. The sequences of steps may vary, depending on which system parameters are known, and which are to be determined. The two most fundamental design issues are

- How much gas to inject?
- At what depth(s) to inject it?

To address these issues, we must be able to determine how a well is likely to perform under different operating conditions.

**Formation Deliverability**

A well’s IPR defines the rate at which the formation can deliver fluid to the wellbore under a given reservoir pressure drawdown. This relationship should be established for the current reservoir pressure and, if necessary, for anticipated future reservoir pressures. We can then use the IPR to determine what flowing bottomhole pressure is needed to maintain a desired production rate.

The flowing bottomhole pressure attainable from continuous gas lift may be constrained by the formation’s tendency toward drawdown-sensitive problems such as sand production and water or gas coning. In any case, it will be restricted to some minimum value by the physical limit GLR (or, if it is lower, the optimal GLR) as described above. The limiting GLR, in turn, will be influenced by the tubing head pressure required to deliver fluid from the wellhead to the separator, and on the pressure losses that take place in the production tubing.

As the average reservoir pressure decreases over time, so will the gas injection pressure required to produce at a given flow rate. This effect must be included in the gas lift system design. Likewise, the system must accommodate increases or decreases in GLR or water cut. If we can determine the magnitude of these changes, we must include them in our system design. If not, it may be necessary to adjust the design or rely on subsequent wireline operations to modify valve setting and placement.

**Tubing Head Pressure Requirements**

The separator typically represents the downstream end of the production system. To determine the flowing tubing pressure (FTP) needed for formation fluids and lift gas to flow to the separator, we start with the known separator pressure and calculate the pressure losses that occur in the gathering lines at the surface, between the separator and the wellhead.

**Tubing Diameter**

In most areas, safety and environmental regulations require that fluid be produced through the tubing. In some fields with high-rate producing wells, however, annular production may be an option.

(Figure 2) illustrates the difference in production performance for a specific well, based on the size of the production tubing or tubing/casing annulus. The producing GLR is 400 SCF/Bbl, the flowing tubing head pressure is fixed at 250 psi and the well's IPR has been calculated. We consider four different production tubing installations:
1. Tubular flow through 2-inch tubing
2. Tubular flow through 2 1/2-inch tubing
3. Annular flow through 2 x 4 1/2-inch tubing-casing diameters
4. Annular flow through 2 1/2 x 5 1/2-inch tubing-casing diameters

For each curve, a higher flow rate results in a higher bottomhole pressure, and the performance curves shift to the right with increases in the cross-sectional area available for flow. This means that for a given bottomhole pressure, there is a significant flow rate increase with increasing tubing diameter. The intersection of each tubing performance curve with the IPR curve specifies the maximum production rate for the given GLR and surface tubing pressure. (If the desired production rate is lower than this value, it is possible to use smaller production tubing with a performance curve that intersects the IPR curve at a higher bottomhole pressure.) In this example, the highest production rates would be attained through annular flow.

**GAS INJECTION RATE**

The gas injection rate required for continuous gas lift is estimated as follows:

\[ (q_{gas})_{inj} = 0.001 \times (GLR_2 - GLR_1)q_{liquid} \]  

where \((q_{gas})_{inj} = \) gas injection rate, MCF/D  

\[ (2) \]
GLR₂ = producing gas-liquid ratio above the point of gas injection, SCF/Bbl
GLR₁ = natural producing gas-liquid ratio (i.e., below the point of gas injection), SCF/Bbl
qₜₜₜ = desired liquid production rate, B/D

For example, assume that a well's IPR and pressure traverse relationships indicate that it can produce 850 B/D of fluid at a GLR of 1490 SCF/Bbl, and that the formation GLR is 452 SCF/Bbl. The required gas injection rate would be

\[
q_{gas/inj} = 0.001 \times (1490 - 452)850 = 882.3 \text{ MCF/D}
\]

A preliminary step in any gas lift system design is to inventory current and anticipated future gas volumes. The injection gas will probably come from field production operations (usually from a high-pressure separator). Additional "makeup" gas may be available from local gathering systems or pipelines.

**GAS INJECTION PRESSURE**

The surface gas injection pressure that the system requires will depend on the gas lift design parameters for individual wells, including the expected production rates, gas lift GLRs and the depths of the operating valves. Keep in mind that increasing the producing GLR increases flowline pressure losses and can affect separator performance.

Gas injection pressure requirements are based on the injection pressure required to open the operating valve. This pressure is greater than the surface injection pressure by an amount equal to the gas gradient times the injection depth. For a tubing installation under static conditions, we may express the pressure gradient in the tubing-casing annulus as

\[
\frac{(P_{inj})_{valve} - (P_{inj})_{surf}}{D} = \frac{0.01875 \gamma}{Z_{avg}}
\]

where \( (P_{inj})_{valve} \) is the injection pressure at the operating valve,
\( (P_{inj})_{surf} \) is the minimum operating injection pressure at surface
\( D \) is the valve depth

We may obtain this gradient using the following equation, which is based on a mechanical energy balance and the real gas law (Economides et al, 1994):

\[
(P_{inj})_{valve} = (P_{inj})_{surf} \times \frac{0.01875 \gamma}{Z_{avg}}
\]

where \( \gamma \) = gas gravity (air = 1)
\( Z_{avg} \) = compressibility factor at average temperature and pressure
\( T_{avg} \) = average temperature, \( ^\circ R = ^\circ F + 460 \)

Because the compressibility factor depends on pressure and temperature, we must use an iterative procedure to determine the unknown pressure. Where the casing pressure at the injection point is known, we may obtain \( (P_{inj})_{surf} \) by trial-and-error as follows:

1. Assume values for \( (P_{inj})_{surf} \) and \( Z_{avg} \) at an arithmetic average pressure.
2. Use this value of \( Z_{avg} \) to calculate a new \( (P_{inj})_{surf} \) value from Equation 2.
3. Repeat steps 1 and 2 until the values of \( (P_{inj})_{surf} \) and \( Z_{avg} \) remain consistent within an acceptable margin.

(This same procedure applies if \( (P_{inj})_{valve} \) is the unknown quantity and \( (P_{inj})_{surf} \) is known)

Gilbert (1954) introduced a simple approximation for Equation 3, in which he assumed \( \gamma = 0.7 \), \( Z_{avg} = 0.9 \) and \( T = 600^\circ R \), and then applied a a Taylor Series expansion:
An existing compressor, a high-pressure separator or gas from outside sources may provide sufficient pressure for gas injection. If not, then the system design will have to be based on the surface pressure that is available, or additional compression capabilities will have to be built into the system.

LOCATION AND DESIGN OF THE OPERATING VALVE

In a tubing installation, lift gas from the surface enters the production tubing through the operating valve. The operating valve is placed such that the gas injection pressure at the valve depth, minus the pressure differential across the valve, is equal to the flowing production pressure at that depth.

Depending on the gas lift GLR, we can place the operating valve at any of several depths. It requires less compression horsepower to inject gas at a high pressure and low rate than it does to inject it at a low pressure and high rate. Thus, a gas lift design operating at a low GLR requires a higher operating pressure and a lower compression horsepower. By selecting the lowest operating GLR, we can minimize the horsepower and gas volume requirements for a given production rate.

If the available gas volumes or injection pressures are limited, that limitation should be considered in the design. If, on the other hand, we are constrained only by the physical limit GLR, then our design recommendations will be governed by the above guidelines and by the economics of gas injection.

The design of the operating valve depends on the type of operation and any anticipated fluctuation in flow rate, producing GLR and water cut. To provide a constant GLR when there are varying production rates, the operating valve should exhibit the gas throughput characteristics of a throttling valve. The capability to adjust the valve through wireline operations allows modification of the design to accommodate changing conditions.

Tubing diameters should be specified to give the lowest operating GLR for the target production rate. This will minimize horsepower requirements, surface operating pressure, and the volume of injected gas.

System Design Example

Consider a well for which we want to establish a production rate of 600 B/D, and for which we have the following information:

- Depth: 5600 ft to midpoint of perforations (MPP)
- Average reservoir pressure = 1750 psi at MPP
- Target production rate = 600 B/D (32 º API oil; 20% water cut)
- Formation (current) GLR = 180 SCF/Bbl
- $P_{wf}$ required for target rate = 914 psi, based on IPR analysis
- Average reservoir temperature = 147 ºF
- Average surface temperature = 65 ºF
- Tubing size: 2 3/8 inch OD
- Required tubing head pressure: 100 psi
- Assume a pressure differential of 100 psi across the operating valve

DESIGN OBJECTIVE

We want to incorporate this well into an existing gas lift system. The injection line pressure is 800 psi, and the injection pressure available at the wellhead will be 750 psi. Our goal at this stage of the design is to determine

1. the depth of the operating valve and
(2) the required gas injection volume.

The operating valve should be placed to minimize the gas injection volumes and compression horsepower requirements. This means that we will want to inject at the maximum available pressure of 750 psi.

**DESIGN PROCEDURE**

The basic design procedure is adapted from Brown (1980, vol. 2a).

**Pressure Traverse**

Using an appropriate multi-phase vertical flow correlation—in this case, a spreadsheet-generated model based on a modified Hagedorn-Brown correlation (Economides et. al, 1994)—and starting “at bottom” with the 914 psi required to produce 600 B/D at a GLR of 180 SCF/Bbl, we establish the pressure traverse relationship for the current well conditions (Figure 3: Pressure traverse curve for example well, 600 B/D at 180 SCF/Bbl GLR).

![Continuous Gas Lift Design Example](image)

In this well, the pressure in the tubing goes to zero before it reaches the surface. In other words, the well cannot produce at the desired rate of 600 B/D under natural flowing conditions. This well is a candidate for gas lift.

**Gas Gradient and Operating Valve Depth**

Using Equation 4 and the iterative procedure described above, we can generate the gas injection gradient in the casing-tubing annulus (Figure 4: Gas injection gradient for example well, surface injection pressure of 750 psi).
The depth at which the gas injection pressure is equal to the tubing pressure is referred to as the *point of balance*. It is represented graphically by the intersection of the pressure traverse curve and the gas injection gradient; in this example, the point of balance is at 5372 ft.

To account for the 100 psi pressure differential across the operating valve, the valve needs to be set above the point of balance. The setting depth is represented graphically by the intersection of:

- the tubing pressure traverse curve for GLR = 180 SCF/Bbl, and
- a line parallel to the gas gradient curve and separated by 100 psi.

The depth at which these intersect is 4940 ft (*Figure 5: Determination of gas injection point for example well*). This is the lowest depth at which we can place the operating valve.
Alternatively, we could determine the operating valve depth by generating pressure traverse curves for a set of gas lift GLRs ranging from just above the current 180 SCF/Bbl to the physical limit GLR. For each gas lift GLR, the point of injection would be the depth at which its pressure traverse intersected the curve for the current GLR—in other words, where the tubing pressure above the injection point equals the tubing pressure below the injection point.

In this case, because our design objective is to minimize the gas injection volume and compressor horsepower requirements at a given injection pressure, we are using the gas injection gradient to define the location of the operating valve.

**Gas Injection Rate**

To determine the gas injection rate, we must find a GLR for which the pressure traverse fits these two endpoints:

- The flowing bottomhole pressure at the injection point of 4940 ft
- The flowing tubing pressure of 100 psi.

Using a spreadsheet-based, trial-and-error calculation, we determine that the optimal GLR is 500 SCF/Bbl (Figure 6: Determination of optimal gas lift GLR for example well). Thus, the GLR will be 500 SCF/Bbl above the injection point, and 180 SCF/Bbl below the injection point.
From Equation 2, we can now determine the gas injection rate as

\[(q_{gas})_{inj} = 0.001(500 - 180)600 = 192 \text{ MCF/D}\]

Again, this gas lift installation could have been designed for a higher GLR and a lower injection pressure, in which case the operating valve would have been set at a shallower depth. Selecting a lower GLR, however, fits in with our stated design objective for an established gas injection pressure.

**Production Rate Variations**

The gas lift valve, located at the injection point, must have a large enough opening to handle the required gas volume at a casing-tubing pressure differential of 100 psi. But what would happen if the flow rate dropped from 600 B/D to 300 B/D? Assuming critical flow conditions, a fixed-size orifice valve would allow the same volume of injection gas to flow for each production rate. Therefore, the GLR at the 300 B/D rate would be too high, resulting in inefficient fluid production.

Alternatively, if the production rate was to increase from 600 B/D to 900 B/D—for example, following a successful well stimulation treatment—the fixed-size orifice valve would be too small to deliver enough gas to the fluid column.

When variable production rates are possible, a gas lift valve must be able to respond to these variations while delivering sufficient gas to provide a constant GLR.

Where the inflow performance is expected to change over time, a throttling valve may be used to allow a proportional response to flow rate. If this type of valve is used, it should be dynamically performance-tested before installation, to ensure that the desired gas flow rates at the various casing and tubing pressures will actually occur. The flow testing of valves is often carried out at the manufacturer's shop under simulated operating conditions. The throttling valve, however, does have certain disadvantages:
Because throttling valves have limited gas throughput capacity, high-volume wells sometimes require an additional valve to reach the desired lift depth. Pressure adjustments are more difficult than with certain other types of gas lift valves. Since more information must be considered, throttling valve designs are more technically detailed and thus require a higher degree of accuracy.

Unloading in Continuous Gas Lift Wells

Unloading or kicking off is the process of removing a static column of liquid from a wellbore so that the well can flow. A well must be unloaded when either of two conditions occurs:

- Liquid has accumulated in the well and the fluid level has reached a static point below the surface.
- The well is full of kill fluid following completion or workover operations, and is ready to be put on production.

In either case, the well will not produce until it is unloaded. This unloading process must be part of the gas lift design.

In completion and workover operations, we typically unload wells by swabbing, injecting nitrogen or circulating a fluid of lower density than the kill fluid. In continuous gas lift, we assume that the gas injection rate and pressure used to produce the well is available for unloading (in some facilities, an additional “kick-off” pressure may be available); all that will be needed are additional valves in the tubing, spaced at appropriate depths for unloading fluids.

Because of the hydrostatic pressure that the kill fluid exerts in the tubing-casing annulus, the operating valve is open, and the fluid levels in the casing and tubing are equal prior to unloading.

Normal practice for unloading gas lift wells is to set the top unloading valve just above the static fluid level. Because most wells that produce on continuous gas lift have relatively high formation pressures, their static fluid levels tend to be at or near the surface. For design purposes, therefore, we may assume that the fluid column reaches to surface.

If the density of the wellbore fluid is known, then that value should be used to determine the unloading pressure gradient. If the fluid density is unknown, assume that its gradient is slightly higher than a fresh water gradient of 0.433 psi/ft - 0.45 psi/ft is a good value for design purposes.

**General Principles**

Unloading calculations are based on providing sufficient pressure at progressively lower valve depths to “U-tube” liquids to the surface, through each valve in succession from top to bottom.

To illustrate how the process works, consider a gas lift well with three valves in the tubing string. From top to bottom, these are

- **Valve 1** (unloading valve)
- **Valve 2** (unloading valve)
- **Valve 3** (operating valve)

Before unloading, the static fluid level is at the surface, and all valves are open. Unloading takes place according to the following sequence:

1. Gas is injected into the annulus at the unloading pressure. The gas displaces the liquid in the annulus through the open valves and into the tubing. The liquid is “u-tubed” to the surface.
2. As liquid is displaced, the fluid level in the annulus drops until **Valve 1** is uncovered.
3. Gas begins to flow into the tubing through Valve 1, reducing the liquid density in the tubing above the point of injection and decreasing the tubing pressure.

4. Because Valves 2 and 3 are still open, the annular fluid level continues to drop as gas is injected through Valve 1 and the pressure in the tubing decreases.

5. The tubing pressure drops to a stable value as the annular fluid level reaches a corresponding stable depth. If the unloading string is properly designed, this stable fluid level should be just below Valve 2.

6. Valve 1 should close just as gas begins to flow through Valve 2. This makes Valve 2 the sole point of gas injection.

7. As gas is injected through Valve 2, the density of the liquid in the tubing above Valve 2 is reduced. The tubing pressure decreases, and the liquid level in the annulus falls because Valve 3 is still open.

8. The tubing pressure drops to a stable value as the annular fluid level reaches a corresponding stable depth. If the unloading string is properly designed, this stable fluid level should be just deep enough to uncover Valve 3.

9. At this point, Valve 2 closes and Valve 3, the operating valve, becomes the sole point of gas injection.

UNLOADING DESIGN PROCEDURES

The basic objective in designing an unloading string is to progressively transfer the point of gas injection downhole, from the top to the bottom unloading valves, and finally to the operating valve. Each valve closes in turn as the next deepest valve is uncovered, and all of the valves above the operating valve remain closed during normal production.

Beyond these general considerations, design procedures vary according to the valve type and to the completeness and reliability of the design input data.

Takács (2005) describes several representative valve spacing methods developed for various types of valves. These include procedures for:

- Injection pressure-operated (IPO) valves:
  - Variable pressure drop per valve (Winkler and Smith, 1962)
  - Constant pressure drop per valve (API RP 11V6, 1999)
  - Constant surface opening pressure (U.S. Industries, 1959)
- Balanced valves
- Production pressure-operated valves
- Throttling valves

The design example that follows is based on using IPO valves with constant surface opening pressures. In this procedure, the top-to-bottom injection transfer is accomplished by increasing the production (i.e., tubing) pressures (U.S. Industries, 1959).

SYSTEM DESIGN EXAMPLE

Table 1 summarizes the design parameters that have been established for a well to be placed on continuous gas lift.

<table>
<thead>
<tr>
<th>Table 1: System Design Example — Continuous Gas Lift</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average reservoir pressure</td>
</tr>
<tr>
<td>$P_{wf}$ required for target rate</td>
</tr>
<tr>
<td>Target production rate</td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>
Average reservoir temperature | 147 °F
---|---
Average surface temperature | 65 °F
Formation GLR | 180 SCF/Bbl
Tubing: | 2 3/8 inch
Flowing tubing pressure (FTP) | 100 psi
Gas lift GLR | 500 SCF/Bbl
Gas injection rate | 192 MCF/D
Depth of operating valve | 4940 ft
Tubing pressure at operating valve depth | 744 psi
Kill fluid | Lease crude oil, kill gradient = 0.38 psi/ft; assume fluid to surface. Formation overbalance = 378 psi

As a starting point, we refer to (Figure 6). This shows the gas injection and design gradients for this well, along with the pressure traverse curve above and below the point of injection.

For design safety, and to minimize valve interference, it is typical to select a surface design pressure that is the greater of these two values:
In this example, the larger of these values is \(100 + (0.2 \times 750) = 250\) psi. Using this surface design pressure and the tubing pressure at the operating valve depth, we can generate a tubing design pressure gradient as shown in (Figure 7).

\[ D_1 = \frac{\left( P_{ki} \right) - FTP}{\gamma_{kill} - \gamma_g} \]  

where \(P_{ki}\) = gas injection pressure, psi  
FTP = flowing tubing pressure, psi  
\(\gamma_{kill}\) = kill fluid gradient, psi/ft  
\(\gamma_g\) = average gas gradient, psi/ft—in this example, the average gas gradient is estimated at 0.0183 psi/ft.

In this case,
\[ D_1 = \frac{750 - 100}{0.38 - 0.0183} = 1797 \text{ ft} \]

This result may also be obtained graphically by starting from the FTP and generating a line parallel to the kill fluid gradient. The depth at which this line intersects the gas injection pressure gradient curve corresponds to \( D_1 \). From the tubing design gradient line, we determine that the tubing design pressure at this depth is 430 psi. (Figure 8: Unloading design—location of top unloading valve.)

The tubing design pressure at \( D_1 \) represents the starting point for locating the second and subsequent valves. Again, we use the pressure gradient of the kill fluid to determine the required gas design pressure. (Figure 9) illustrates the process graphically.
For this example, five unloading valves are needed to unload the well, along with the operating valve to provide continuous gas lift operations:

<table>
<thead>
<tr>
<th>Valve No.</th>
<th>Depth</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1797 ft</td>
</tr>
<tr>
<td>2</td>
<td>2772 ft</td>
</tr>
<tr>
<td>3</td>
<td>3533 ft</td>
</tr>
<tr>
<td>4</td>
<td>4124 ft</td>
</tr>
<tr>
<td>5</td>
<td>4584 ft</td>
</tr>
</tbody>
</table>
There are a number of design options for locating the unloading valves, especially when considering the available selection of valves and the ability to specify the valve opening and closing pressures. Often, for example, a lower valve will be opened before an upper valve is closed in order to provide a smoother unloading operation.

**Continuous Gas Lift: Summary Design Procedure**

Below is a summary design procedure for a continuous gas lift installation. Depending on the design program in use, certain of these steps will be carried out automatically once the input parameters are entered. Also, the sequence of steps may vary depending on which design parameters (e.g., surface injection pressure, maximum gas volumes, etc.), if any, are already defined.

1. Collect all available input data; Table 1 provides a starting point for listing input parameters.

<table>
<thead>
<tr>
<th>Table 1: Input Data for Continuous Gas Lift Design</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well number, field, location, zone</td>
</tr>
<tr>
<td>Average reservoir pressure</td>
</tr>
<tr>
<td>Average bottomhole, surface temperatures</td>
</tr>
<tr>
<td>Anticipated pressure decline rate</td>
</tr>
<tr>
<td>Back pressure or separator pressure</td>
</tr>
<tr>
<td>Gas-oil ratio, water cut</td>
</tr>
<tr>
<td>Gas specific gravity, oil API gravity</td>
</tr>
<tr>
<td>Water specific gravity</td>
</tr>
<tr>
<td>Type of well completion</td>
</tr>
<tr>
<td>Depths of perforations</td>
</tr>
</tbody>
</table>

2.

3. Establish the well’s Inflow Performance Relationship for the current reservoir pressure and, if desired, anticipated future reservoir pressures.

4. Carry out a production system analysis to define pressure traverse curves for various combinations of producing GLR and production tubing assemblies. For each combination, generate the pressure traverse by evaluating the lift performance in the tubing string and the flowing tubing head pressure needed to move fluid from the wellhead to the production separator. For analysis purposes,
   - the range of tubing diameters is based on the diameter of the production casing and/or the type of completion (if annular flow is permitted, consider it as a design option)
   - the lower GLR limit is the formation GLR, while the upper GLR limit is the "physical limit" GLR above which additional gas injection will not increase the well’s production rate.
5. Combine these pressure traverse calculations with the IPR to establish the optimal production rate.

6. For the selected tubing or annular flow system, determine the depths at which the pressure traverse curves for various values of gas lift GLR intersect the pressure traverse curve that corresponds to the well’s natural flow. These intersections define several possible locations for the operating valve.

7. Select the depth for the operating valve, keeping in mind that the lowest GLR requires the highest operating pressure, the lowest injected gas volume and lowest compression horsepower. This would normally be the option selected.

8. Determine the injection pressure as a function of depth. At the operating valve, this pressure will be equal to the required production pressure at that depth plus the pressure corresponding to the valve spread. With this pressure as a starting point, obtain the gas gradient in a static gas column using the equation below or a suitable approximation or correlation:

\[
(P_{\text{inj, valve}}) = (P_{\text{inj, surf}}) \times \left( \frac{0.01375 \cdot h}{z_{\text{avg}} \cdot T_{\text{avg}}} \right) \exp \left( \frac{g}{z_{\text{avg}} \cdot T_{\text{avg}}} \right)
\]

where:
- \((P_{\text{inj, valve}})\) is the injection pressure at the operating valve, psia
- \((P_{\text{inj, surf}})\) is the minimum operating injection pressure at surface, psia
- \(g\) = gas gravity (air = 1)
- \(h\) = operating valve depth, feet
- \(z_{\text{avg}}\) = compressibility factor at average temperature and pressure
- \(T_{\text{avg}}\) = average temperature, °R

Note: Where the lift system is being designed “from the bottom up,” and \((P_{\text{inj, valve}})\) has been determined, this equation is used to determine the minimum required gas injection pressure at the surface. For an existing gas lift system, where \((P_{\text{inj, surf}})\) is already established, this relationship will be used to determine \((P_{\text{inj, valve}})\) for various depths.

9. Locate the unloading valves using the appropriate procedure for given valve types and operating conditions.

10. Review the manufacturer’s specifications to select the unloading and operating valves that will satisfy the system design for the life of the well. The values are set to meet the required operating conditions.

11. Before completing the system design, be sure there is sufficient gas volume and pressure to meet operating conditions and, finally, be sure that the design can be modified as inflow performance characteristics change.

A gas lift system designer must realize that the design is not static. The inflow performance, producing GLR and water cut of the well will probably change as production from the well continues. Also, a system is often designed for an entire field rather than a single well. The future performance of individual wells that collectively make up the system must be considered when developing the optimal field design.

**INTERMITTENT GAS LIFT**

Intermittent gas lift is similar to continuous gas lift in that it employs some of the same equipment and procedures, and it improves well performance through the injection of pressurized gas from the surface into the production tubing. The way in which it works, however, is very different.

- Continuous gas lift is based on introducing a constant stream of gas into the producing fluid column in order to reduce its density.
- Intermittent lift, on the other hand, is based on periodically injecting “slugs” of compressed gas below the liquid that accumulates in the production tubing. These gas slugs do not change the liquid
density; instead, they physically displace or “push” the liquid to surface. (Figure 1: Intermittent gas lift, closed installation).

Intermittent lift involves three steps, or periods (Figure 2: Intermittent gas lift cycle):
1. **Inflow or Accumulation**: Fluid from the formation flows into the wellbore and collects in the tubing above the gas lift valve. This period continues until a sufficient volume of liquid has accumulated, based on the well’s inflow performance and the system design. At this point, the hydrostatic pressure of the accumulated fluid causes the standing valve to close.

2. **Lift**: The operating valve opens, and a high-pressure slug of gas flows into the tubing, displacing the accumulated liquid up the tubing and to the surface. The lift period ends when the last of the liquid has moved into the flowline.

3. **Pressure Reduction or Afterflow**: As the liquid exits the well, the hydrostatic head in the tubing is reduced, and the pressure of the gas slug rapidly dissipates. When the pressure drops below a certain level, the operating valve closes, the standing valve opens and another inflow period begins.

Control of the intermittent lift cycle is based on regulating the frequency and duration of the lift period, along with the amount of gas injected during the lift period. The optimal system design is one that combines maximum liquid recovery with an economical volume of injected gas.

**Estimating Production Capability**

The production capability of an intermittent gas lift system depends on three factors:
Starting Load

The starting load reflects the pressure at the operating valve just as the valve opens. It is the pressure exerted on the operating valve by the column of fluid in the tubing above it.

A typical design might employ a Starting Load Factor of 50 to 75 percent—that is, fluid will be allowed to build up in the tubing until the tubing pressure is 50 to 75 percent of the available casing pressure. For a normal design situation, a smaller load factor would be used; when there is a high surface tubing pressure or a high gas delivery rate into the tubing, the Starting Load Factor would be closer to 75 percent. In either case, the excess casing pressure provides the slug velocity.

For a given starting load, we may calculate the volume of liquid in the tubing as follows:

\[ \Delta p = p_t - p_{ts} \]
\[ h = \frac{\Delta p}{G_s} \]
\[ B_e = (h)F_{tb} \]

where:
- \( \Delta p \) = pressure imposed by the fluid in the tubing above the valve.
- \( p_t \) = bottomhole tubing pressure
- \( p_{ts} \) = surface tubing pressure
- \( h \) = height of rise of fluid in the tubing. Ignoring the gas column in the tubing, it is equal to \( \Delta p \) divided by the pressure gradient of the produced liquid, \( G_s \)
- \( F_{tb} \) = tubing volume factor, volume/unit of length (e.g., Bbl/ft)
- \( B_e \) = fluid influx volume/cycle (the volume of fluid in the tubing available for lift during each cycle—e.g., Bbl/cycle).

Lift Efficiency

The next consideration is whether the entire volume of fluid inflow into the tubing is lifted during a cycle and, if not, what level of efficiency exists.

As a slug of fluid moves up the tubing during lift, some of the fluid adheres to the tubing walls and some becomes entrained as droplets in the gas phase. This lost fluid is referred to as holdup.

Field tests have shown that a holdup of five percent to seven percent of the starting load per 1000 feet of lift will exist when the starting load is within 65 to 75 percent of available casing pressure (Winkler and Smith, 1962). These conditions exist when the slug velocity is optimum and holdup is low.

For an assumed loss of 5 percent per 1000 feet of vertical lift, the efficiency of lift, \( E \), will be equal to:

\[ E = \left[ 1.0 - \frac{0.05D_v}{1000} \right] \times 100 \]

where:
- \( E \) = efficiency of lift, percent
- \( D_v \) = depth to the gas lift valve, feet.

If, for example, the gas lift valve is at a depth of 4000 feet, the efficiency of lift will be:
With this information, we may calculate $B_t$, the liquid produced per cycle:

$$B_t = \frac{E}{100} B_e = 0.8 \ B_e$$

Under these conditions, 80% of the starting load should be produced. With this information, we can calculate the volume of fluid produced per cycle.

**NUMBER OF CYCLES**

Knowing the volume of fluid produced per cycle, the next step is to calculate the number of lift cycles that are possible per day as follows:

$$N_c = \frac{\left(24 \text{ hr/D} \times 60 \text{ min/hr} \right) \times 1000 \text{ ft}}{\left(t_e \right) \times D_v} = \frac{1440000}{\left(t_e \right) \times D_v}$$

where $N_c =$ number of cycles per day

$t_e =$ minimum time per cycle, minutes per 1000 ft of depth

$D_v =$ depth of valve, ft

$N_c$ depends on the depth of lift and the length of time required for pressure reduction and inflow periods. The cycle time is usually adjusted in the field under actual operating conditions, but initial estimates may be made.

For example, given a particular range of operating conditions, a reasonable first assumption for the minimum time per cycle might be on the order of 3.0 minutes per 1000 feet of lift (Winkler and Smith, 1962). For an operating valve located at a depth of 4000 feet and a minimum cycle time factor of 3 minutes per 1000 feet of depth, then, the maximum number of cycles per day is:

$$N_c = \frac{1440 \times 1000}{3 \times 4000} = 120 \ cycles \ / \ day$$

The daily production rate is the product of $N_c$ and $B_t$. This estimate provides a good starting point for determining daily production. However, when the intermittent system is installed in the field, it may turn out that the ideal number of cycles per day, as determined through field tests, is less than this maximum.

To estimate the maximum daily production rate $q$, use the following equation:

$$q = N_c B_t = \frac{N_c E B_e}{100}$$

**Sample Problem**

Estimate the production capability of a well under the following conditions:

- Depth of the operating valve = 8000 feet
- Tubing size = 2 3/8-inches OD
- Surface tubing pressure = 100 psi
- Surface operating gas pressure = 800 psi
- Gas gravity = 0.65
- Oil gradient = 0.40 psi/ft

$$E = \left[ 1.0 - \frac{(0.05)(4000)}{1000} \right] \times 100 = 80\%$$
Calculate the *maximum daily production rate* of the well using intermittent gas lift operations.

1. First, calculate the liquid inflow per cycle.

2. Determine the gas pressure in the annulus opposite the operating valve, with a known surface pressure of 800 psi, and an estimated gas gradient of 0.02125 psi/ft. The gas pressure at the operating valve is

\[ p_c = 800 + 0.02125 \times 8000 = 970 \text{ psi}. \]

Using a 65 percent load factor, find \( \Delta p \)

\[
\Delta p = p_t - p_{ts} = 0.65 \times p_c = 0.65 \times 970 = 630 \text{ psi}
\]

\[ \Delta p = 630 - 100 = 530 \text{ psi}. \]

With this pressure, the produced fluid should rise in the tubing to a total height of:

\[ h = \frac{\Delta p}{G_i} = \frac{530}{0.40} = 1325 \text{ ft}. \]

This is equivalent to a fluid inflow volume of:

\[ F_{\text{in}} = 0.0038 \text{ bbl/ft} \text{ (from tubing tables or calculations)} \]

\[ B_e = hF_{\text{in}} = (1325) (0.0038) = 5.03 \text{ bbls}. \]

3. Next, calculate the *lift efficiency*.

   For a depth of 8000 feet and an assumed 5% holdup per 1000 ft, the efficiency, \( E \), is

\[ E = 1.0 - \frac{(0.05)(8000)}{100} \times 100 = 60\% \]

   With a lift efficiency of 60%, the fluid production per cycle is:

\[ B_t = 0.60 \times 5.03 = 3.02 \text{ bbls/cycle}. \]

4. Next, calculate the maximum number of cycles possible per day. For a gas lift operating valve located at a depth of 8000 feet, it is equal to:

\[ N_c = \frac{1440 \times 1000}{3 \times 8000} = 60 \text{ cycles/day} \]

5. Complete the calculations by combining the production per cycle and the maximum number of cycles per day to find a *maximum production rate* of:

\[ q = N_cB_t = (60)(3.02) = 180 \text{ B/D}. \]

If the inflow performance calculations for this well show that the well will sustain this rate, it is very likely a good design. However, some degree of field adjustment will probably be required.

**Valve Selection**

The primary requirement of an operating valve used in intermittent lift is to be able to handle a large volume of gas over a short time period. This is an ideal application for the pilot-operated valve. Its large port allows a large volume of gas to pass once the valve is opened. A properly designed dome-charged valve, or a fluid-operated valve, could also be used. However, because the port of a fluid-operated valve is small, a series of operating valves, opening in succession, would be required to move the slug up the tubing. Required Gas Volumes Two-phase slug flow is a complex phenomenon, and as such, it is difficult to calculate the exact gas volumes required during an intermittent cycle. For estimation purposes, we may
assume that the required volume equals the volume of gas left in the tubing at the moment that the slug reaches the surface, and that the pressure of the gas in the tubing is equal to the average of the two values of tubing pressure when the valve opens and closes. The basic gas volume required per cycle is equal to:

\[
\text{Gas volume/cycle} = \frac{p_t + p_w}{2} \times \frac{V_t}{p_a}
\]

where:
- \(p_t\) = pressure at the operating valve;
- \(p_w\) = the pressure just as the valve closes;
- \(V_t\) = the volume of tubing not occupied by fluid, and;
- \(p_a\) = atmospheric pressure (used to convert gas volume in the tubing to standard conditions), in this example, 14.73 psia.

This estimate is approximate, and does not include the effects of temperature and compressibility.) For example, continuing with the Sample Problem from above, and given the following information for this 180 b/d well,

- Valve opening pressure is 970 psi
- Valve closing pressure is 725 psi
- Tubing length is 8000 feet; capacity = 0.0217 cubic feet per foot.
- Fluid fills 1325 feet of the tubing.
- The tubing gas volume is \(V_t = (8000 - 1325) \times 0.0217 = 144.8\) cu. ft.

We can estimate the gas volume per cycle as follows (converting to standard cubic feet of gas in the tubing at the average pressure):

\[
\text{Gas volume/cycle} = \frac{970 + 725}{2} \times \frac{144.8}{14.73} = 8331\ SCF \approx 3.3\ MCF.
\]

This agrees with a common rule-of-thumb whereby the injection gas requirement can be approximated as 200-400 SCF/Bbl per 1000 ft of lift for a well on conventional intermittent lift (Winkler and Smith, 1962):

\[
\frac{8331\ SCF}{cycle} \times \frac{60\ cycle}{day} \times \frac{day}{180\ Bbl} \times \frac{1000}{3000} = 347\ SCF/Bbl
\]

This gas must be conserved and reused in subsequent cycles to create an efficient production operation.

**SURFACE CONTROL OF INJECTED GAS**

The gas lift valve controls the flow of gas from the casing to the tubing. Surface controllers, which may be actuated on a time-cycle or by a choke, complement the subsurface valve control function.

With time-cycle control, a clock drives a pilot that opens and closes a diaphragm-actuated valve on the gas supply line. The pilot can be adjusted to open and close for specific time periods.

The choke control uses the inflow performance of the well and the operating spread characteristics of the gas lift valve to control the cycle. The surface equipment consists of an adjustable choke or flow control valve on the gas supply line. The choke is adjusted to admit gas continuously into the annulus so that its pressure builds at a steady rate.
When the pressure reaches a specified level, the gas lift valve opens and the slug is displaced. When the choke is set to admit gas at a rate compatible with the well's inflow capacity, an efficient cycle frequency is established. A very important feature of choke control is that it eliminates the cyclical injection surges from the compressor and effectively isolates the cyclic surges to the casing annulus. The compressor operates more evenly and the gas circulated to the well can thus be measured more accurately.

The difference between the opening and closing pressures of the gas lift valve is called its spread. This feature of choke control allows the casing annulus to store the volume of gas needed for each intermittent lift cycle. In other words, the gas lift valve spread makes the casing annulus act as a storage chamber.

**UNLOADING INTERMITTENT GAS LIFT WELLS**

Intermittent gas lift design is similar to continuous gas lift design in that liquids are “U-tubed” to the surface from one valve to the next. Therefore, the procedures for locating the unloading valves in a continuous lift system generally apply to intermittent lift as well. The one significant difference for intermittent flow is that we must define a pressure gradient in the tubing string for times when kill fluids are unloaded as slugs. Under these conditions, the pressure gradient in the tubing is caused primarily by frictional losses that are a function of the velocity of flow and tubing size. Empirical correlations indicate that these “design gradients” range from 0.02 to 0.35 psi/ft. We may use the appropriate gradient from these correlations to generate the “design gradient” and find the optimal locations for the unloading valves.

**PRACTICAL ASPECTS OF WELL UNLOADING AND OPERATION**

The guidelines in this section are adapted primarily from API RP 11 V5 (1999), *Recommended Practice for Operations, Maintenance and Troubleshooting of Gas Lift Installations*.

**Initial Unloading**

The first step in bringing a well on production after gas lift valves have been installed is to unload the fluids from the wellbore and obtain a stabilized production rate. Normally, a well placed on continuous gas lift is unloaded continuously, and a well placed on intermittent gas lift is unloaded intermittently. Primary considerations in unloading include avoiding excessive pressures that could damage the valves, and using clean, filtered workover fluids to avoid plugging or abrasion of the valves.

Prior to unloading, a two-pen pressure recorder should be installed at the surface to monitor both the gas injection pressure and the production (tubing) pressure. These pressures should be measured as close to the wellhead as practical. In any case, the gas injection pressure should be measured downstream of the injection choke, and the production pressure should be measured upstream of any flowline choke that is present. The wellhead pressure should be bled down to the pressure of the downstream separator, and the flowline choke, if present, should be either fully open or removed.

**CONTINUOUS GAS LIFT WELLS**

With continuous gas lift, the unloading process begins when gas is injected slowly into the annulus, probably through a choke located at the surface. Pressure is incrementally raised by approximately 50 psi every eight to ten minutes until it reaches about 400 psi, and 100 psi every eight to ten minutes thereafter. The kill fluid is displaced through the standing valve, up the tubing and to the surface into a disposal tank, until gas starts coming around the first valve or oil appears in the produced fluid. A steady stream of fluid will be then unloaded. If these fluids are directed into a separator, it is important to keep the backpressure on the well as low as possible. As gas is continuously injected into the annulus, a gradual increase in casing pressure will be required to keep fluids flowing from the tubing string.

Valve 1, the uppermost valve, is the first valve to be uncovered; gas first enters the tubing string at this point. This is noted at the surface by an immediate increase in the velocity of the fluid stream coming out of the tubing. A mixture of gas and liquid is soon produced at the surface, and the casing pressure levels off at the surface operating pressure of Valve 1. As gas continues to enter the annulus, the liquid column in the annulus is lowered until Valve 2 is uncovered. As soon as this valve is uncovered, gas flows through it and enters the tubing. Casing pressure then drops to the surface operating pressure of this valve. At about
the same time, pressure in the annulus opposite Valve 1 should have been reduced to a level low enough to cause that valve to close.

Unloading continues from valve to valve until the deepest operating valve is uncovered. At this point, the bottomhole pressure has been reduced to a level that allows the formation fluid to move into the tubing, and the volume of gas injected through the operating valve is sufficient to lift the production under design conditions.

**INTERMITTENT GAS LIFT WELLS**

With intermittent gas lift, fluid is unloaded at the surface in the form of piston-like slugs. The unloading process is the same as that for continuous flow until the uppermost valve (Valve 1) is uncovered. At that point, the well is placed on intermittent control for unloading. This is accomplished with a choke or a time-cycle controller at the surface so that the well is alternately produced and shut-in. During this period, the fluid in the annular space will continue to be U-tubed into the tubing and will be produced as slugs. A good cycle for unloading is obtained with 2 to 4 minutes of gas injection every 20 to 30 minutes. This allows ample time for stabilization to take place between slugs.

When the well is unloaded down to the operating valve, the choke size or cycle time should be adjusted to suit the well’s production characteristics. Thus the unloading operation may start with a high number of cycles per day and then, in response to the well’s production behavior, the number of cycles will be adjusted downward as fewer cycles will be needed to maintain optimum production rates. If the fluid production rate begins to fall off, then the number of daily cycles is too low for optimal production. With this information, it is possible to make further refinements to the process by reducing the duration of gas injection during each cycle. The objective is to maximize production and minimize the gas volume required. A very useful monitoring procedure involves simultaneously recording the shapes of the tubing and casing pressures curves. Adjustments are made on the basis of the shapes of these two curves.

**System Adjustments**

Once a well is unloaded, the next step is to optimize its production rate and gas usage. This will require some adjustment of its operating parameters. For detailed procedures, refer to API RP 11V5 (1999).

In a continuous gas lift installation, adjustments are generally made using an adjustable choke to control the rate of gas injection (a positive choke could also be used, but this would require interrupting gas injection to change the choke size). To prevent freezing, the gas system may be equipped with a dehydrator, gas heater or heat exchanger, or methanol may be injected upstream of the choke. To adjust the gas injection rate, the choke is initially set at a diameter that is larger than required for the design rate. The diameter is reduced incrementally until the production rate begins to drop, and then readjusted to establish the optimal production rate.

Similar types of adjustments are made for intermittent gas lift installations that employ time cycle control: the controller is initially set for a duration that will exceed the design gas injection requirements, and then the number of cycles per day is reduced until the well can no longer produce at its desired rate. The controller is then reset in steps until the optimal production and gas injection rates are established. For intermittent wells operating on choke control, the choke is initially sized for the design production rate, and then adjusted in the same type of trial-and-error manner.

**Gas Lift System Monitoring**

Successful gas lift performance depends largely on the efforts of field personnel. A gas lift installation requires close supervision during the unloading process, and when injection gas is adjusted and regulated.

A common practice is to analyze the system only when a problem arises. A better approach is to analyze each well while it is operating satisfactorily to determine if the installation has been properly designed. This provides a baseline measure of performance for reference in the event of trouble, and helps to indicate needed design changes. It is important to analyze this baseline information before planning well servicing or workover operations—otherwise, the operator will not know what changes are needed.

Diagnostic tools for monitoring and troubleshooting gas lift wells include:
- Two-pen pressure recorder charts and calibrated pressure gauges installed at the well
- Acoustical and production logging surveys
- Fluid level determinations using wireline

*API RP 11V5* (1999) describes these tools and their applications in detail.

**Remote Monitoring**

Gas lift wells are a common area of application for remote monitoring and control techniques. These systems can measure the performance of a single well or an entire field using sensors and data transmitting devices that alert field personnel to changes in well performance. By comparing performance parameters over time, the operator can analyze well stability, allocate lift gas injection, and optimize the operation of the entire field. This capability leads to improved efficiency, better field operations management, and increased profitability.

A significant feature of monitoring systems is their ability to remotely control gas injection and change well settings using two-way control devices. Continuous monitoring and comparison of parameters such as injection pressure, wellhead pressure, and flow rate lets the operator identify potential problems and take preventive and corrective action from a central location. In many cases, the operator is notified automatically when sensors detect significant changes to key parameters.

Primary components of remote monitoring systems include:

- Downhole Pressure & Temperature Sensors
- Sensor Data Process System
- Well Controller
- Remote Terminal Unit (RTU)

The downhole pressure and temperature sensors communicate via a system controller to adjust gas injection through the sensor data process system. This allows the operator to control the well or the field based on changing surface or downhole conditions.

A remote terminal unit (RTU) can transmit data continuously or store well performance data for later transmission and analysis. The RTU is a two-way system, thus allowing the operator to communicate back to the well.

The monitoring and communication equipment is powered by solar cells, which are backed up by a battery system to ensure a constant power supply.

Through monitoring of gas lift injection and production systems, field efficiency can be improved and future gas lift valve design, valve placement and unloading programs can be designed on the basis of actual field operating experience.

**GAS LIFT SURFACE FACILITIES**

(*Figure 1*) shows the main elements of a surface gas lift system, beginning with production at the wellhead and ending with the injection of gas into the casing annulus or tubing.
Starting at the wellhead, produced fluids travel first to the separator. The separator gas is usually re-used as lift gas. If more gas is produced than is needed for gas lift, the excess gas is either sold or re-injected into the formation.

Moving downstream, there is a point where outside supply may be added to the system if the gas from the separator is not sufficient to meet the demand. Both the separator gas and the outside makeup gas flow through a scrubber, where impurities are removed.

The gas next moves to the compressor, where gas pressure is raised to desired levels. The compressor must provide the appropriate discharge pressure and volume needed at both average and peak rates. Some of the gas reaching the compressor is normally used as fuel.

Downstream of the compressor, gas is metered and various controls are introduced before the gas is injected into the annulus. In the case of continuous injection, the control is normally a choke in series with a pressure regulator. For intermittent gas injection, a time-cycle controller or choke is the most common form of control.

It is clear that the surface system consists of a number of individual components, each of which must be designed to provide the quantities and peak demands of gas for the gas lift system at the desired injection pressures. It is also easy to see that the ideal gas lift system, especially with respect to the compressor operation, is one that has a constant suction pressure and constant discharge pressure on the compressor. This is easy to achieve in continuous flow operations, because of the continuous supply of gas available from the separator and because of the need to continuously inject gas. Intermittent systems are more complicated with intermittent injection and production - the duration of which may vary for each well. Control is more difficult with time-cycle control than for choke control because with the choke, the annulus serves as a storage chamber between lift cycles.

Data Collection
The first step in designing surface facilities for a gas lift installation is to collect the following data:

- Number and location of wells requiring gas lift
- Gas lift valve design for each well
- Whether continuous or intermittent injection will be used
- Gas volumes needed (along with estimates of peak demand)
- Availability of gas supply from the separator or external supply
- Location of sales gas lines
- Pressure required at the point of injection into the well
- Pressure of the separator or supply gas
- Sizing of the compressor
- Auxiliary control and metering system required for the surface system.

**Calculating Compressor Horsepower**

The compressor is a major component of a gas lift system. Compressors are available in many different sizes and horsepower ratings to handle different gas lift operating conditions.

An approximation for determining a compressor’s brake horsepower (bhp), is given by the equation

\[
bhp = 1.05 \times 23 \times nQ \times \left( \frac{P_{\text{discharge}}}{P_{\text{suction}}} \right)^{\frac{1}{n}} = 24.15nQ \left( \frac{P_{\text{discharge}}}{P_{\text{suction}}} \right)^{\frac{1}{n}}
\]

(1)

where \( n \) = number of stages
\( Q \) = gas throughput capacity, MMCFD (\( 10^6 \text{SCF/D} \))
\( \left( \frac{P_{\text{discharge}}}{P_{\text{suction}}} \right) \) = overall absolute compression ratio
1.05 = correction factor for pressure drop and gas cooling between stages

(For a single-stage compressor, the correction factor reduces to 1.0)

The quantity \( \left( \frac{P_{\text{discharge}}}{P_{\text{suction}}} \right)^{\frac{1}{n}} \), which represents the absolute compression ratio per stage, should not be greater than 4.

**Example:**

Find the horsepower needed to move 2500 MCFD (2.5 MMCFD) through a 2-stage compressor with 50 psi suction pressure and 200 psi discharge pressure.

First, find the absolute compression ratio per stage:

\[
\left( \frac{P_{\text{discharge}}}{P_{\text{suction}}} \right)^{\frac{1}{n}} = \left( \frac{200}{50} \right)^{\frac{1}{2}} = 2
\]

Continue with Equation 1 as follows:

\[
bhp = 1.05 \times 23 \times 2 \times 2 \times 2.5 = 241.5 \text{ hp} \Rightarrow \text{use a 250 hp compressor}
\]

To solve the problem using a single stage compressor, the solution would be:

\[
bhp = 1.00 \times 23 \times 1 \times 2.5 = 230 \text{ hp}.
\]

**Design Safety Factors**

For the surface gas lift system to have enough capacity, it is customary to estimate a mainline pressure that is approximately 100 psi higher than is called for in the design. This additional pressure will accommodate unexpected line losses. In addition, the compressor delivery volume is usually increased by 10% to account for volume losses and the fuel needed for compression.
SUMMARY OF DESIGN PROCEDURES

We may summarize the procedure for designing a surface system for gas lift installation as follows:

1. Begin by laying out the entire surface system, including the wells, gathering lines, stock tanks, separators, and other items of equipment that materially affect gas lift operations.
2. Specify the wells that will use either continuous or intermittent gas lift. Also consider the time during which each well will use gas lift.
3. Design the gas lift system for each well, specifying the pressures, the volume, the cycles, and the expected life of the gas lift operation for that well. This is a key element of the design because it provides the pressures, volumes, and cycles to which the system must respond over time.
4. Make production estimates, including the gas volumes and pressures that will be available from the separator. These volumes and pressures serve as input for the compressor calculations.
5. Specify the gas sales and makeup volumes needed, along with their availability.
6. Design the balance of the surface system, including the gathering lines and the control system.
7. Design the system compressor. A reasonably accurate measure of the required horsepower can be calculated; however, it is advisable to discuss these estimates with the manufacturer to ensure that the final design will meet the needs of the gas lift system.
8. Finally, remember to include a volume safety factor of 10% and a pressure safety factor of 100 psi.

This procedure can be used in a preliminary design of a gas lift system. This preliminary design should be reviewed with the representatives of a gas lift equipment manufacturer. The optimized final design will be one that satisfies all the requirements of the system without being over-designed.