

Recommended Practice for Gas Lift System Design and Performance Prediction

API RECOMMENDED PRACTICE 11V8
FIRST EDITION, SEPTEMBER 2003

REAFFIRMED, MARCH 2015



AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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FOREWORD

This Recommended Practice (RP) is under the jurisdiction of the API Committee on Standardization of Production Equipment (Committee 11).

This document presents RPs for the design of gas lift systems. Other API Specifications, API RPs, and Gas Processors Suppliers Association (GPSA) documents are referenced and should be used for assistance in design and operation.

Introduction to Gas Lift System Design and Performance Prediction

API RP 11V8 *Recommended Practice for Gas Lift System Design and Performance Prediction*, provides two functions:

- A broad overview of gas lift systems and various major types of gas lift operations.
- Recommended practices for gas lift system design and for modeling methods used in performance prediction. All key system components are reviewed to provide guidance for engineers, technicians, well analysts, and operating personnel who are involved in gas lift system analysis, troubleshooting, design, and optimization.

The primary purpose of this API Recommended Practice (RP) is to emphasize gas lift as a system and to discuss methods used to predict its performance. Information must be gathered and models validated prior to a system design, which must precede wellbore gas lift mandrel and valve design. The subsurface and surface components of the system must be designed together to enhance the strengths of each and to minimize the constraints.

This recommended practice bridges and enhances the general information from the *API Gas Lift Manual* (Book 6 of the Vocational Training Series) and the technical details of other API Gas Lift RPs, each of which contain information on a specific subject or part of the overall gas lift system. The gas lift system designer or operator should have and become familiar with the full set of documents from the API (American Petroleum Institute), GPSA (Gas Processors Suppliers Association), and ISO (International Standards Organization) that relate to gas lift system components:

API Gas Lift Manual (Book 6 of the Vocational Training Series)

API Spec 11V1—*Gas Lift Equipment*

API RP 11V2—*Gas Lift Valve Performance Testing*

API RP 11V5—*Operation, Maintenance, and Troubleshooting Gas Lift Installations*

API RP 11V6—*Design of Continuous Flow Gas Lift Installations*

API RP 11V7—*Repair, Testing, and Setting Gas Lift Valves*

API Spec 12GDU—*Glycol-Type Gas Dehydration Units*

API Spec 12J—*Oil and Gas Separators*

API Std 617—*Centrifugal Compressors for General Refinery Service*

API Std 618—*Reciprocating Compressors for General Refinery Service*

API Manual of Petroleum Measurement Standards (MPMS)—Chapter 5, *Metering*;
Chapter 14, *Natural Gas Fluids Measurement*

GPSA—Engineering Data Book

ISO 17078—Gas Lift Equipment Specifications

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Suggested revisions are invited and should be submitted to API, Standards department, 1220 L Street, NW, Washington, DC 20005.

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Recommended Practice for Gas Lift System Design and Performance Prediction

1 Overview of a Gas Lift System

This section provides a broad overview of the various components of a gas lift system and how these components interact with one another.

1.1 MAJOR COMPONENTS OF A GAS LIFT SYSTEM

The components of a gas lift system can be grouped as follows:

- a. Gas compression and distribution system.
- b. Subsurface equipment.
- c. Gas and liquid gathering system.

A. Gas Compression and Distribution System

A typical gas compression and distribution system is composed of a compression and dehydration plant, manifolds, gas lines, meters, and rate control devices as depicted in Figure 1-1. The compressor station receives gas from the low pressure separator and gathering system, or from gas wells, or from the sales pipeline, and compresses it to a pressure suitable for gas lift operations. The compressor discharge pressure typically ranges from 800 psig – 2000 psig, although other pres-

ures are used as needed, based on reservoir pressure, well productivity (PI), and gas lift valve constraints.

The amount of gas required depends on a number of criteria:

- Number of wells and the depth of the injection point.
- Amount of oil and water to be produced and the water fraction.
- Amount of formation gas produced.
- Reservoir pressure.

Compressor options are based on the required gas rate:

1. Small reciprocating units can compress a few million standard cubic ft per day—sufficient for a small field with a few wells.
2. Large reciprocating units can compress from a few million to a hundred million standard cubic ft per day—for large on-shore fields with numerous wells.
3. Centrifugal compressors can compress from a few million to more than a hundred million standard cubic ft per day—for numerous wells in large oil fields, especially offshore.

Gas lift uses the same surface facilities that process formation gas, since most fields require compression, dehydration,

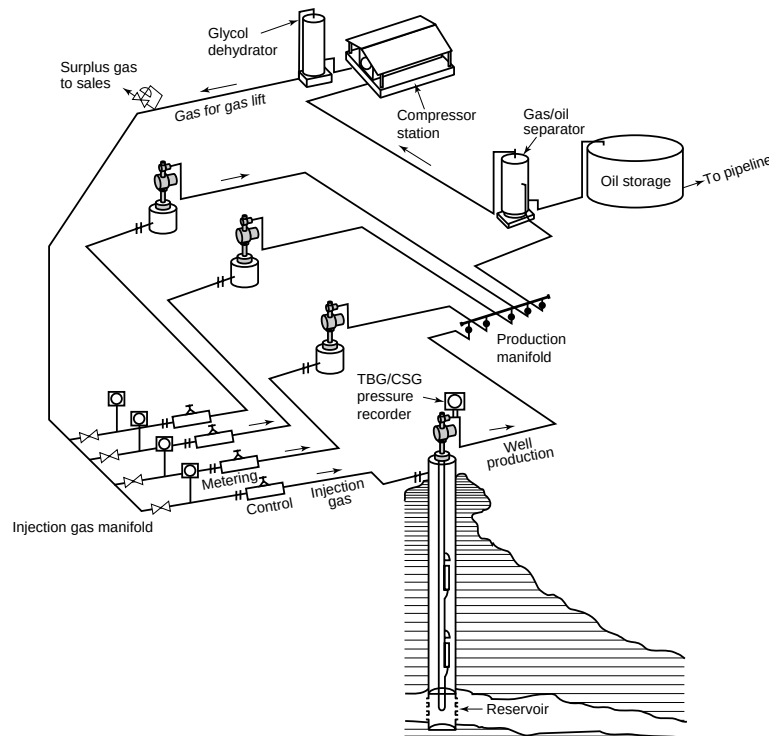


Figure 1-1—Gas Lift System

and treating to send the gas associated with the oil to sales, fuel for utilities, a natural gas liquids recovery plant, or to a re-injection plant. Lift gas is cycled in a closed loop that utilizes the existing facility, but often requires added low pressure compression capacity, and added high pressure compression capacity to raise the gas pressure to that needed by the gas lift process.

Gas lift gas distribution pipelines connect the compression plant with the wells either directly or through field injection manifolds. The working pressure rating of the piping system should equal or exceed the maximum discharge pressure of the compressors. The diameter of the pipeline depends on the flow rate, the number of wells, and the length of the pipelines. The distribution piping pattern can have different forms:

1. Random, connecting from one well to another.
2. An oval ring with individual well connections.
3. Major pipelines to field manifolds, with wells connected to the manifold.
4. Combination of methods.

Gas injection manifolds in the field can reduce the total installed pipe length and centralize operations such as gas flow measurement and control. The optimum number of manifolds to be installed will depend on the total surface area of the field and the number of wells. The number of wells per manifold may range from less than ten to more than thirty.

B. Subsurface Equipment

Tubing in a gas lift well usually has several gas lift valves and mandrels installed at different depths as depicted in Figure 1-2. The number of valves to be installed depends primarily on the:

1. Depth of the well.
2. Kill or static fluid gradient.
3. Reservoir pressure.
4. Available injection pressure.
5. Gas lift valve design method.

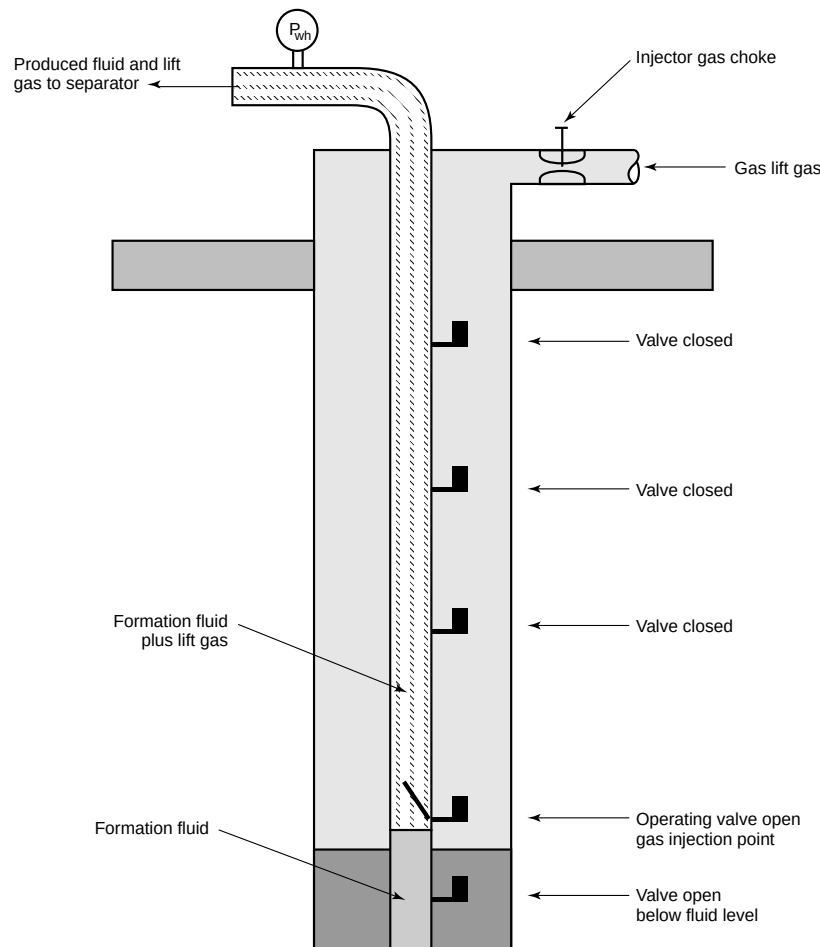


Figure 1-2—Gas Lift Valves and Mandrels

Gas lift valve installation and retrieval methods are:

- Conventional valves and mandrels installed/retrieved with the tubing.
- Wireline installed/retrieved valves set inside the pocket of a side-pocket mandrel in the tubing string.
- Special valves and mandrels installed/retrieved with coiled tubing.

Important, fundamental concepts about valves, Figure 1-3, are:

- Valves control the point of entry of the compressed gas into the production string and act as a pressure regulator.
- Valves have cross-sectional areas at the bellows (A_b) and at the stem/port (A_p) that pressure acts on:
 - nitrogen pressure (P_b) and/or a spring forces the stem/ball to close on the port seat,
 - injection gas (P_g) and fluid production (P_f) pressures provide the counter forces that act to open the valve.
- Valve port size may be a constraint to the maximum amount of injected gas, but the optimum gas rate is adjusted with the surface injection choke or controller (a choke in the valve can also be used).
- A reverse flow check valve, mounted below the port of the valve, prevents flow from the production fluid conduit back into the gas column (not shown).

An orifice can be used in lieu of a valve at the expected depth of injection. The orifice consists of the orifice (port) and the reverse flow check, but does not have a bellows and stem, so it is not a valve that can open or close.

Usually, the gas lift valve allows the injection gas to flow from the tubing-casing annular space into the production tubing. But alternatively, a gas lift valve can be installed to allow the gas to flow from the tubing into the annular space where it mixes with the production fluids coming from the reservoir. This is done when the gas and oil flow rates are high and require the annular area to minimize pressure loss. Casing corrosion due to annular flow is difficult to remedy, thus flow up the casing annulus is usually not recommended and often prohibited.

C. Gas and Liquid Gathering System

The multiphase gas-liquid flow from the well is transported either directly or through a gathering manifold to a separator station. Pipeline (flowline) sizing is dependent on the connection method:

- Directly connected flowlines—the diameter of the gas/oil/water pipeline depends on the flow rate, topography,

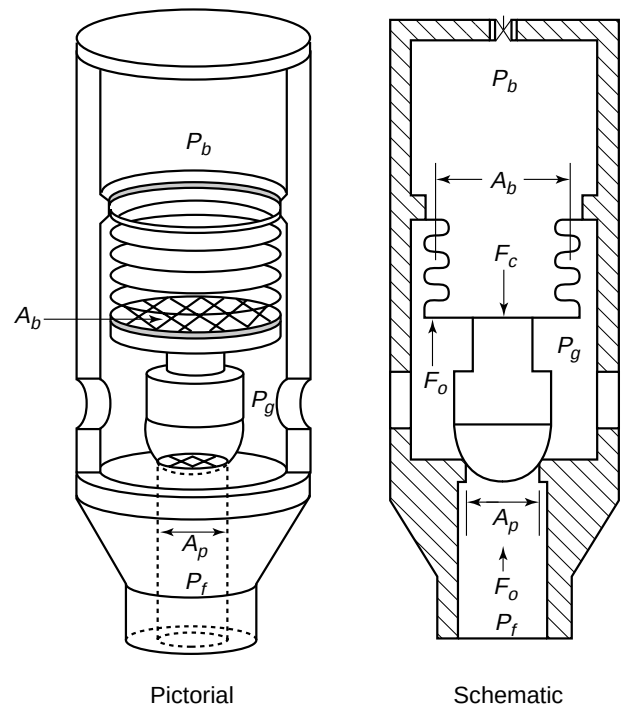


Figure 1-3—Injection Pressure Operated (IPO) Gas Lift Valve

and distance traveled, and it is usually equal to or greater than the diameter of the production tubing. Modeling of production rate vs. wellhead pressure for several flowline sizes aids in selecting an optimum size.

- Manifold connected flowlines—in large fields where the wellheads are distant from the separation plant, gathering manifolds can minimize total pipeline length. The wellhead to manifold connection is sized as stated above. From the manifold, usually two flow lines connect with the flow station. One is the production pipeline, used to transport the commingled flow from all the wells (except for the one being tested), and is sized for total flow including future water increases plus lift gas. The other is a smaller diameter test line and is used to connect only one of the wells to the test separator where its fluid and gas production is measured.
- A test separator located at the manifold is an option to avoid the need for the small test line and associated purging methods for long test lines.

From the separator flow station, the low-pressure gas is returned to the compression plant to complete the cycle.

1.2 WAYS IN WHICH SYSTEM COMPONENTS INTERACT

Each component interacts with the rest of the system in ways that can considerably affect the required gas injection

and the achievable oil production. The key objectives with all components acting as a system are:

- Deep injection of gas.
- A stable injection gas rate that:
 - reduces density in the production string,
 - lowers the flowing bottomhole pressure,
 - induces greater flow from the reservoir.

Gas compression and distribution must provide a steady, constant pressure supply of dehydrated gas at an adequate rate for all wells served:

- Low gas pressure causes the point of gas injection to be too shallow.
- High gas pressure deepens the point of lift when the unloading valve pressures are appropriately set.
- Gas rate, liquid rate, and the mixture density control the flowing bottomhole pressure.
- Injection gas rate must be matched to the liquid rate and tubing size because:
 - inadequate gas will not sufficiently reduce density,
 - the resulting low fluid velocity permits excessive liquid holdup,
 - excessive gas causes friction pressure loss to increase.
- Injection gas rate is adjusted with a surface choke or gas flow rate control valve.

Gas and liquid gathering components must be properly sized to allow maximum production:

- Well production is limited by the imposed system back-pressure created from:
 - high separation pressure,
 - a flow line with a small diameter,
 - a long flow line with diameter too small for the distance.
- Pipe sizing should be based on realistic flow rates since:
 - excessively large diameter can cause severe slug-ging,
 - too small of a diameter results in excessive friction losses.

The subsurface gas lift design is used to achieve the objective of reduced density and low flowing bottomhole pressure:

- Gas lift mandrel spacing:
 - enables the well to unload the kill fluid with the available kickoff pressure,

- must be correct between valve mandrels or the unloading stops prematurely and effective, deep lift is not attained.
- Gas lift valve pressure settings:
 - are based on a specified gas injection pressure,
 - are affected by valve type and size,
 - permit the valve to close after unloading and transferring to the next deeper valve.
- Valve port size and gas/fluid pressures influence the gas flow throughput, but primary control is by the surface choke or controller.
- An injection pressure operated valve (IPO) will react mainly to the gas injection pressure.
- A production pressure operated valve (PPO) will react primarily to the production fluid pressure.

The system can be operated with continuous injection into each well or with intermittent injection into some wells, provided the pulsing gas pressure does not adversely affect the continuous flow wells.

2 Types of Gas Lift Systems

The gas lift system type will be determined by the most effective gas lift method, continuous or intermittent. Choice is based on the well and the gas distribution system conditions:

- Producing rate and tubing diameter.
- Static bottomhole pressure (SBHP).
- PI.
- Gas piping diameter.
- Gas injection pressure and available rate.

Intermittent lift applies only when rate, SBHP, and/or PI are too low for effective continuous gas lift. The choice is related to the tubing size as well, since continuous flow might be maintained by reducing tubing diameter to increase fluid velocity.

Water or gas coning or sand production may influence selection:

- Steady continuous flow is preferred.
- Pulsating intermittent flow aggravates an existing sand production problem.
- Gas piping restrictions are greater constraints with intermittent lift.
- Surging continuous flow contributes to these same problems.

Future conditions such as water cut, SBHP, formation gas-liquid ratio (FGLR), and productivity index (PI) should be



considered in planning the installation with either type of gas lift system.

2.1 CONTINUOUS GAS LIFT

Continuous gas lift requires constant injection of high pressure gas into a flowing fluid column:

- To reduce mixture density,
- Which lowers flowing bottomhole pressure (FBHP), and
- Increases the production from the well.

RECOMMENDED PRACTICE: Continuous gas lift is best for most wells, especially for high capacity wells and for wells in which flowing bottomhole pressure pulsations must be minimized because of sand, gas, or water production, or due to reservoir gas or water coning.

Figure 2-1 shows the flowing gas lift and static fluid gradients. With the well shut-in and without gas injection, the well-

head pressure plus the static wellbore gas and liquid pressure gradients equal the SBHP.

When gas is injected into the tubing, the fluid gradient becomes lighter from the point of gas injection to the surface. This reduces the FBHP and creates the drawdown needed for a higher production rate.

The flowing bottomhole pressure (FBHP) is a function of the:

- Flowing pressure gradient above the point of gas injection.
- Formation fluid pressure gradient below the point of injection.
- Flowing wellhead backpressure.

To attain lift effectiveness at the lowest injection gas-liquid ratio (IGLR):

- The point of gas injection should be at the deepest valve.
- High distribution pipeline pressure and properly set unloading valves permit lift from the deepest valve (if the deepest point is an orifice, the operating injection pressure may decline substantially).

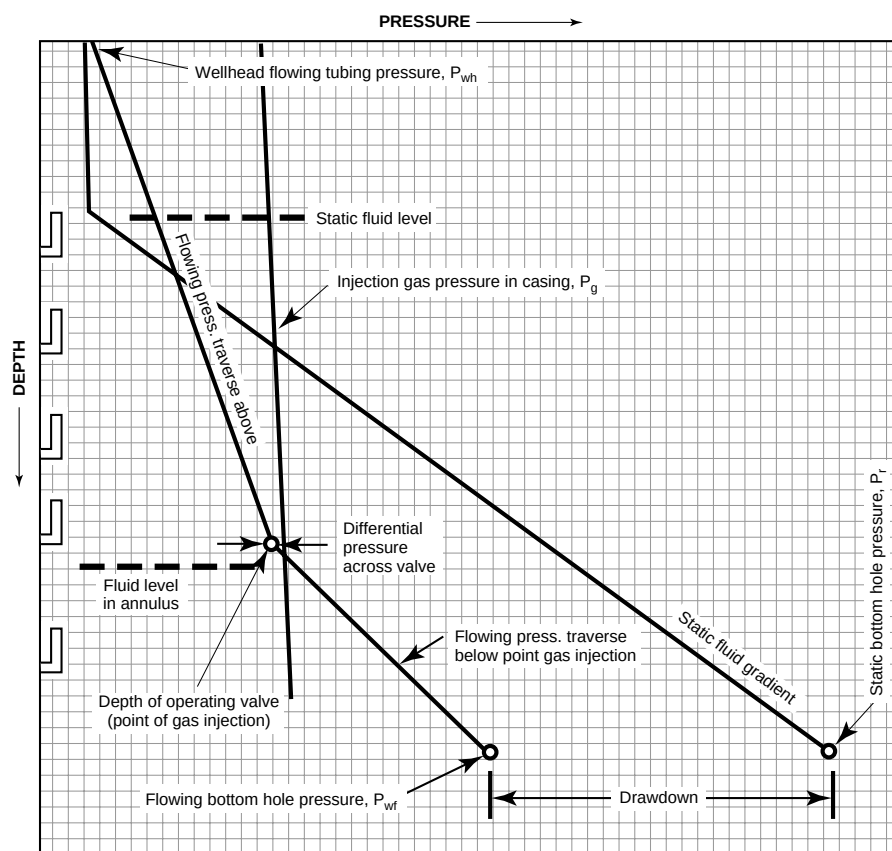


Figure 2-1—Flowing and Static Gas Lift Gradients

Continuous gas lift can only achieve a flowing gradient of approximately 0.10 psi/ft – 0.15 psi/ft, depending on the liquid flow rate. This limitation must be considered when applying the technique to wells with low SBHP.

2.2 INTERMITTENT GAS LIFT

Intermittent gas lift applies large rates of gas for a short time duration. The production cycle consists of a liquid slug followed by a gas slug, followed by tail gas until the intermittent cycle is repeated. The large rate of gas and low rate of liquid causes the flowing gradient to be approximately 0.05 psi/ft, after the slugs have surfaced, thus the method is applicable to low SBHP wells. However, the lift effectiveness is diminished and more gas is required, in terms of standard cubic ft (scf) of lift gas per stock tank barrel (bbl) of liquid produced. The injection gas can be controlled by a choke or by a control valve.

RECOMMENDED PRACTICE: Intermittent gas lift should be applied to low rate wells, caused by high SBHP but low PI, or by low SBHP but high PI. Intermittent lift should incorporate tubing flow and IPO unloading valves, with a large ported pilot operating valve.

In Figure 2-2 a complete cycle of intermittent gas lift operation is illustrated. The cycle phases are:

1. The operating valve is closed, the standing valve is open, and fluid from the formation accumulates inside the tubing above the operating valve.
2. The controller and operating valve are open, the injection gas enters into the tubing and displaces the liquid slug toward the surface. At this time, the standing valve closes, preventing high-pressure gas flow into the formation.
3. The controller closes, which stops the inflow of gas into the annular space, and the operating valve will close when the annular pressure reaches the valve closing pressure.
4. If choke control is used, then the choke constraint (choke area is smaller than the valve port area) causes the gas injection pressure to decline to the valve closing pressure. This method minimizes intermittent cycle disruption of other wells.

Intermittent gas lift is recommended for low rate wells, but defining where continuous lift should end and intermittent lift should begin varies. Important disadvantages of intermittent lift are the limited maximum production rate and its pulsating effect on the gas distribution piping which could destabilize other wells. Also, the method is not suited for deep lift through small tubing. Finally, an intermittent lift well gas slug

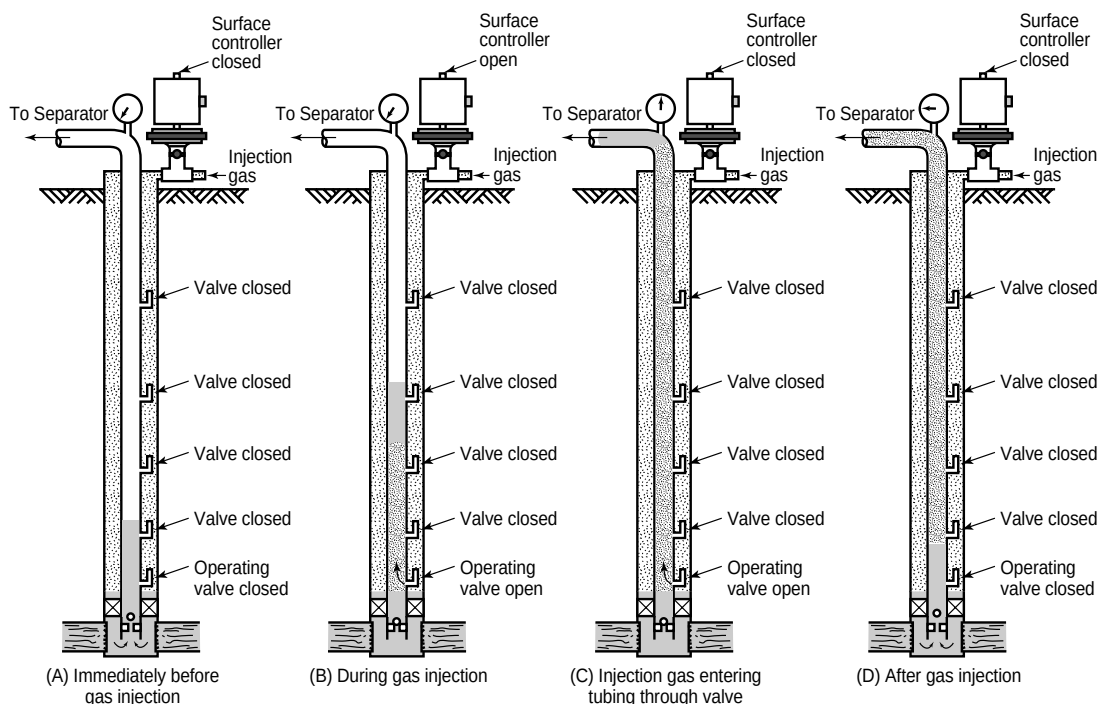


Figure 2-2—Intermittent Lift Cycle

may be difficult to handle in a small closed system, and intermittent wells could adversely affect the performance of the continuous wells due to supply pressure fluctuations. Increasing the gas storage volume using old wellbores or large diameter pipelines is beneficial.

Intermittent lift production rate strongly depends on the liquid slug volume that is lifted. Low reservoir pressure wells can use bottomhole chambers to reduce the backpressure and to allow accumulation of a large slug size.

Chambers can lift more fluid per cycle but require more time to fill the chamber, which results in fewer cycles. Also, gassy or foamy wells will have less liquid accumulation in the chamber, which affects net liquid production.

RECOMMENDED PRACTICE: The chamber type of installation should be evaluated for high PI and low BHP intermittent lift wells. A chamber allows the lowest BHP possible to be attained and produces adequate rates by using the larger volume to store fluids for lift.

A. Two-packer Chamber

A two-packer chamber, Figure 2-3, accumulates a large volume of liquid with a minimum amount of pressure on the formation. The lift process is:

1. The operating gas lift valve is closed and the reservoir fluid flows into the chamber.
2. Well fluid flows up through the open standing valve, perforated nipple, chamber space, and tubing string.
3. The bleed ports are open, allowing gas to escape from the chamber space into the tubing from a point near the top of the chamber.
4. The operating gas lift valve opens and gas is injected into the chamber.
5. The resultant extra pressure (a small choke can be used as a bleed port) closes the standing valve and bleed ports.
6. The accumulated liquid slug is u-tubed from the chamber into the tubing string and lifted to the surface.

B. Insert Chamber

The insert chamber, Figure 2-4, is often used in an open hole completion, but can be used in wells with a long casing perforated interval. Not as large as the two-packer chamber, its slug is less because of the smaller diameter required to fit inside the casing. Venting in both the outer and inner annular space is crucial for liquid accumulation in the chamber.

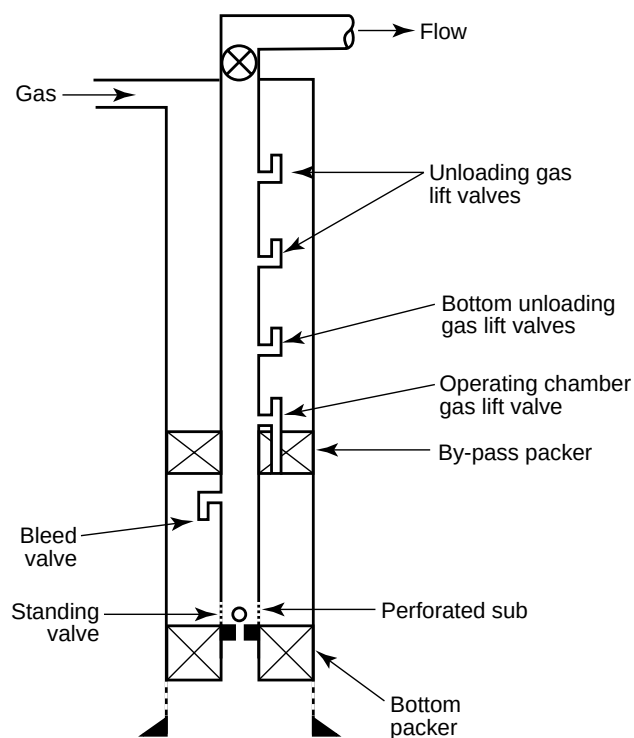


Figure 2-3—Two-packer Chamber

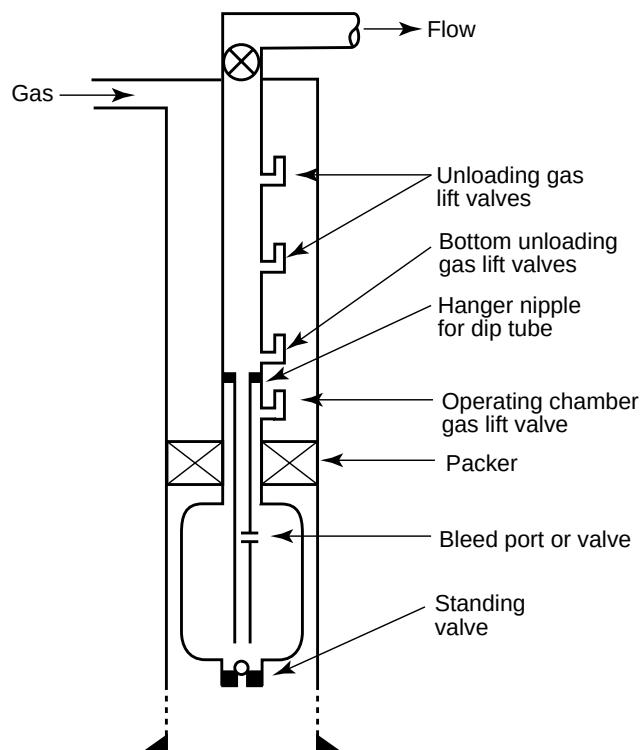


Figure 2-4—Insert Chamber

2.3 GAS LIFT WITH PLUNGER

Gas lift with a plunger can be used as intermittent lift. The piston traverses the length of the tubing string in a cyclic manner, providing an interface between the lifting gas and the produced liquid. The plunger sweeps more of the liquid film from the tubing wall, minimizing the liquid fallback. Sand or solids in the tubing could prevent the plunger from operating successfully, however, plungers are used to control paraffin deposits.

RECOMMENDED PRACTICE: Plunger lift may be used with intermittent lift to improve slug lift effectiveness or in wells whose fluid properties cause the gas to channel through the liquid column. It can also be used in low rate gas wells that are aided with lift gas.

Figure 2-5 shows a down hole plunger installation with the gas lift valve located below the plunger. The surface wellhead equipment shows the lubricator/catcher to hold the plunger for its short time at the top. Two important considerations for plunger installation are:

- Master valve type—the master valve must have a full bore equal to the tubing size to allow plunger passage. Also the valve must not be oversized more than $\frac{1}{8}$ ", since the extra clearance permits excessive gas passage, which could prevent the plunger from being lifted into the lubricator, or could cause the plunger to “hang up” at the valve.
- Tubing condition—the tubing must be gauged and broached (cleaned) before running any subsurface equipment. Damaged tubing, paraffin, scale, asphaltine, or corrosion deposits can prevent successful operation.

2.4 GAS LIFT TUBING/PACKER ALTERNATIVES

The descriptions for downhole tubing/packer arrangements are:

- Open
- Semi-closed
- Closed

A. Open

Open installations, Figure 2-6, have no packer and the tubing is hanging freely in the wellbore. Gas is transported in the casing-tubing annular space to the valve or to the end of the tubing. Constant communication exists between the casing and tubing, which is not recommended. This accelerates cor-

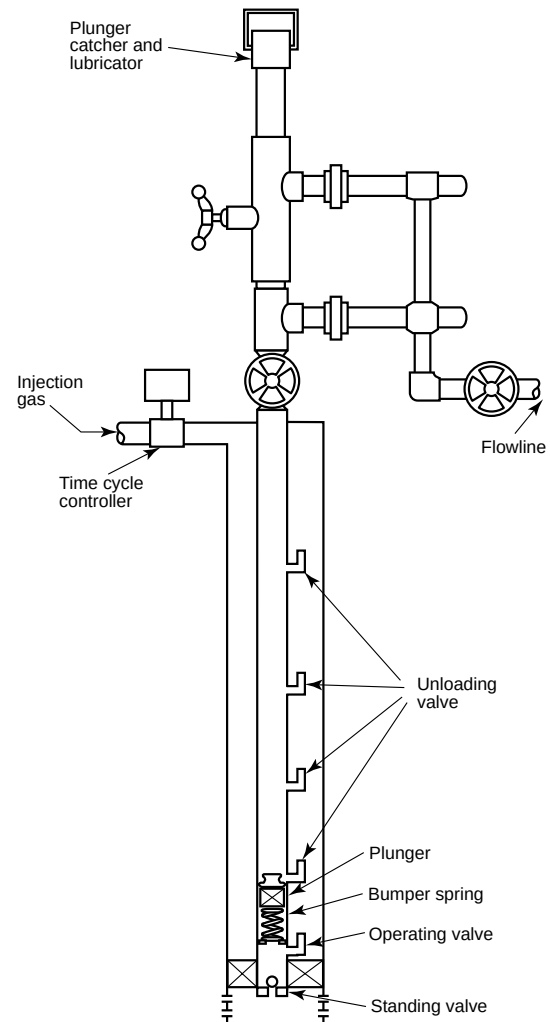


Figure 2-5—Gas Lift with Plunger

rosion, aggravates gas/liquid slugging, and requires unloading every time the well is shutdown, subjecting the valves to additional fluid erosion.

Even though open installations have serious disadvantages, this method may be required for conditions such as repaired casing resulting in a short section of reduced diameter, or deviations and hole crookedness which may prevent a packer installation. Fluid levels obtained during stable flow can be used for estimating flowing bottomhole pressure and for troubleshooting.

B. Semi-closed

Semi-closed installations, Figure 2-7, have a packer as a seal between the tubing and casing, but a standing valve (check valve) is not installed. These installations are suitable for both continuous and intermittent gas lift. Unloading is not

required with every shutdown since all the gas lift valves are provided with a reverse flow check valve.

RECOMMENDED PRACTICE: Packer and tubing, used in a semi-closed installation, is the preferred continuous flow gas lift downhole arrangement.

C. Closed

Closed installations add a standing valve (check valve to prevent reverse flow) to eliminate high pressure gas being exerted on the reservoir. Usually the standing valve is wire-line set in a landing nipple near the packer. The intermittent lift installation often uses the closed completion but continuous flow designs do not require a standing valve.

RECOMMENDED PRACTICE: A closed installation consisting of a packer, tubing, and standing valve is useful in an intermittent gas lift downhole arrangement when the SBHP is low. If sand production, or scale or paraffin deposits are a problem, then the standing valve should not be used.

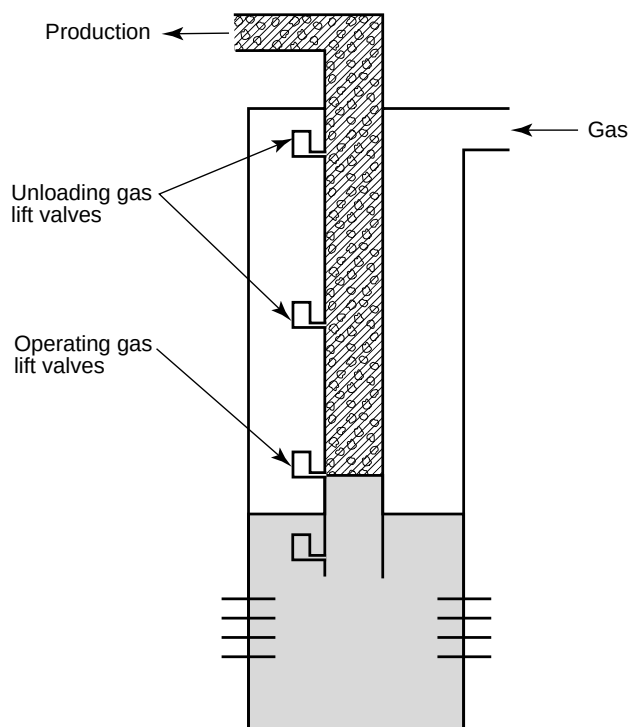


Figure 2-6—Open Installation

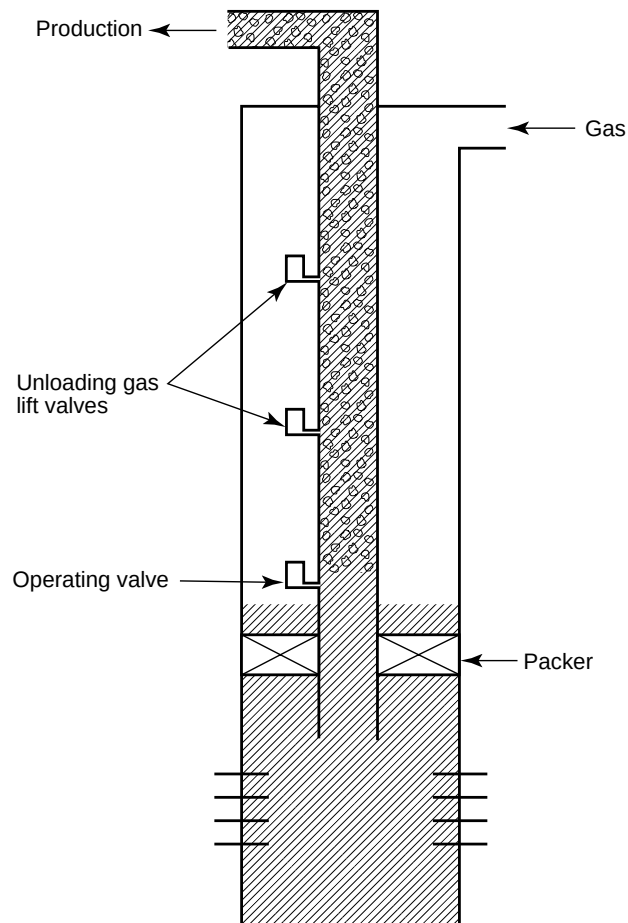


Figure 2-7—Semi-closed Installation

3 Information Required for Effective Gas Lift

Design, performance prediction, optimization, or troubleshooting of a gas lift system requires data that includes:

- Oil, gas, and water fluid properties,
- Producing pressure and temperature surveys,
- Well test production rates,
- Gas lift valve characteristics,
- Identification of constraints such as gas pressure and rate, or back-pressure against the well.

3.1 FLUID PVT (PRESSURE-VOLUME-TEMPERATURE) DATA

RECOMMENDED PRACTICE: Oil, gas, and water fluid property information based on downhole samples and laboratory analysis should be used in gas lift analysis and design work. If downhole samples are not available, then recombined samples of separator oil and gas should be used.

Correct hydrocarbon and water property data for each well will assist in improving the:

- Match of calculated to measured flowing pressure gradients
- Accuracy of computer calculations of flowing pressure gradients
- Reliability of delivery performance models of the wells

The fluid properties from the PVT reports, either by a commercial lab or the oil company lab, are the starting point. They should be based on subsurface or recombined hydrocarbon-pressurized samples obtained during exploration drilling or later during production tests.

A PVT report is generally not available for each well and its reservoir interval. The wells for which data are available must be used as a guide and other wells' data should be adjusted to match measured pressure data.

PVT reports contain two types of data:

- "Flash" data at several pressure and temperature points.
- "Differential liberation" data at various pressure points at constant reservoir temperature.

The flash data are preferred since it simulates the flow up the well to the separator (with laboratory separator pressure and temperature representing facility data). However, the differential liberation data, which is obtained at constant reservoir temperature, should also be considered.

A. PVT Data Available

The hydrocarbon fluid properties that can be obtained from flash data are:

- Gas-oil ratio (GOR) at each stage.
- Gas specific gravity (Gas $SpGr$) at each stage.
- Stock tank API gravity of the oil.

The PVT report flash data for an example oil sample are:

$P_{stg1} = 125$ psig @ 100°F	$GOR_1 = 177$ scf/stb	Gas $SpGr_1 = 0.86$
$P_{stg2} = 0$ psig @ 60°F	$GOR_2 = 67$ scf/stb	Gas $SpGr_2 = 1.39$
	$GOR_T = 244$ scf/stb	Gas $SpGr_T = 1.01$

The total gas-oil ratio, GOR_T , is calculated from:

$$GOR_T = GOR_1 + GOR_2$$

$$GOR_T = 177 + 67$$

$$GOR_T = 244 \text{ scf/stb}$$

The total gas specific gravity, Gas $SpGr_T$, is calculated from:

$$\text{Gas } SpGr_T = (GOR_1 / GOR_T) \times \text{Gas } SpGr_1 + (GOR_2 / GOR_T) \times \text{Gas } SpGr_2$$

$$\text{Gas } SpGr_T = (177/244) \times 0.86 + (67/244) \times 1.39$$

$$\text{Gas } SpGr_T = 1.01$$

The example PVT report also provides:

API oil gravity = 28°API at standard conditions,

Bubble point, P_{bp} = 1270 psig at 250°F reservoir temperature,

Volume factor, B_o = 1.19 bbl oil/stb at the P_{bp} and reservoir temperature,

Oil viscosity, μ_o = 1.25 centipoise at the P_{bp} and reservoir temperature.

Correlations to calculate bubble point pressure are based on fluid properties and temperature. The correlation equations are included in all multiphase flow computer calculations for pressure gradients or well performance models. The calculated bubble point, including any fluid property adjustments, should be compared to the PVT report measured data.

RECOMMENDED PRACTICE: The calculated bubble point pressure should match within 5% when compared to the PVT report measured data. A match is obtained by adjusting gas specific gravity, GOR , and oil API gravity.

The frequently used correlations for solution GOR and bubble point pressure will not give an exact match. However, if the correlations do not provide a reasonable match with measured data for the crude being modeled, then check the PVT reports for GOR , Gas $SpGr$, and API gravity to deter-

Table 3-1—PVT Data and Adjustment to Match Bubble Point

Well	Measured			Adj. Form. Gas $SpGr$	Calc. P_{bp} @ 250°F	GL Gas $SpGr$
	GOR scf/stb	Oil °API	Form. Gas $SpGr$			
A	235	26.1	1.01	1.03	1285	0.78
B	225	25.2	0.98	1.03	1253	0.78
C	250	27.3	1.04	1.02	1295	0.78
PVT*	244*	28.0*	1.01*		1270*	

* From PVT report

mine which item(s) may be incorrect. Review all pertinent PVT reports and select those that best represent most of the wells and their reservoir segments.

The PVT data should be adjusted to provide a suitable match between measured and calculated bubble point pressures as well as between measured flowing pressure gradient data and multiphase flow computer calculations. The items to adjust, and the order of adjustment, are:

- Gas specific gravity (Gas $SpGr_T$)
- Gas-oil ratio (GOR_T)
- Oil API gravity

This adjustment should not require a drastically different value. Reservoir gas specific gravity should be reviewed as it is often incorrectly assumed to be 0.65. Gas from an oil reservoir is usually heavier.

The three wells from different segments in the same reservoir in Table 3-1 give an example of data which, when gas specific gravity is adjusted, provide a reasonable fit to the bubble point listed. The gas specific gravity was adjusted by trial and error until the bubble point was within the 5% recommended tolerance.

B. PVT Data Not Available

With some wells, PVT data may not be available. New downhole sample gathering is not feasible because the reservoir pressure is below bubble point, or because of a high water percentage (insufficient hydrocarbon quantity in the subsurface wireline sample chamber). However, separator samples of oil and gas can be obtained and recombined on the ratio of the test GOR (separator samples from reservoirs below the bubble point would represent both solution gas and free gas).

RECOMMENDED PRACTICE: If PVT data are not available, then the fluid properties should be estimated using measured flowing pressure gradient, temperature, and rate data.

The **first step** is to obtain measured data. If the system is automated, then several items will be in the database. The required items:

- Flowing pressure and temperature data in the wellbore with wireline gauges stopped at numerous depths,
- Injection gas pressure on the casing at the wellhead (24 hr. chart),
- Gas composition and specific gravity (using chromatograph analysis) from a sample of separator gas and from a sample of injection gas,
- Oil API gravity from production test separator sample,
- Water specific gravity from production test separator sample,
- Production tests (rate, water percent, gas-liquid ratio).

The production tests will give results that typically vary 10% or more from test to test. Gas rate is the most common error since separator gas rate is not steady (total measured separator gas less measured gas lift gas gives formation gas). However, the test is adequate as a starting point for matching.

The **second step** is a comparison of the measured wellbore pressure gradient data to the multiphase flow calculated data. In a gas lift well, the wellbore must be divided into the:

- Lower section below the point of injection
- Upper section above the point of injection

The *lower section* fluid flow will have a measured pressure gradient that corresponds to reservoir PVT properties and formation water. The pressure gradient comparison should be from the bottom of the hole upward to the point of injection, as this method will eliminate error due to the injection gas. The calculation model should allow input of data for:

- Gas specific gravity
- GOR
- Water percent
- Water specific gravity



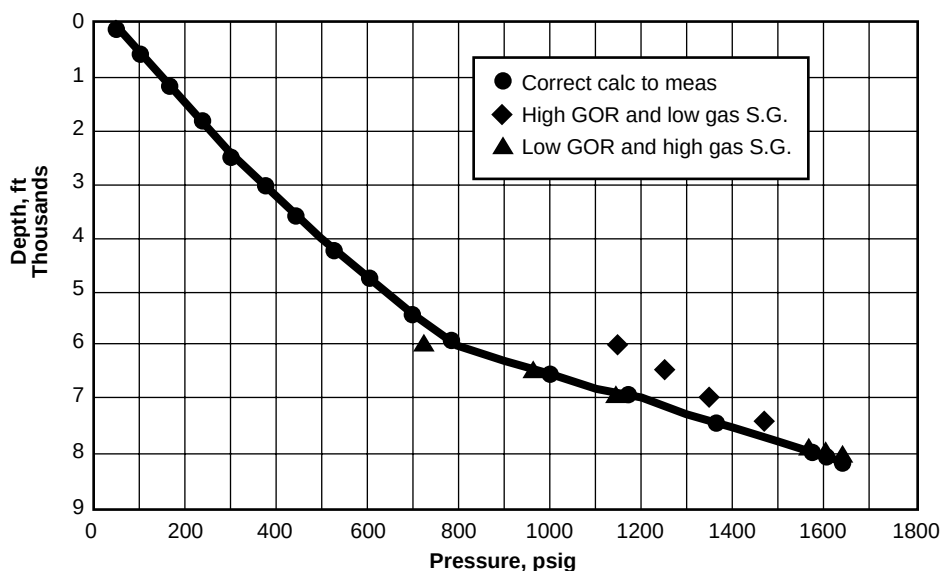


Figure 3-1—High, Low, and Correct Calculated Gradients Obtained by Adjusting Fluid Properties

The initial value of this data can be based on production tests, and then adjusted until a match of the measured to the calculated pressure profile is obtained. The matched pressures indicate that the reservoir PVT and formation water properties used in the final computer calculation are representative of the fluids flowing in the well.

Figure 3-1 illustrates the correct calculated pressure profile, as compared to measured pressure in the reservoir fluid section below the point of injection. Also shown are high and low calculated gradients, caused by different fluid properties, as defined on the graph.

The *upper* section represents fluid flow with gas lift gas added to the reservoir fluid. The additional variables that affect the fluid properties and pressure profile from the point of injection to the surface are:

- Injection gas specific gravity
- Injection gas rate (IGLR)

Injection gas specific gravity is obtained from a sample that is analyzed with the chromatograph. If data are not available, then the injection gas gravity should be estimated by comparing the calculated gas pressure at the valve (in the casing) to the measured fluid pressure in the tubing:

1. Start with the measured gas pressure on the casing (at the wellhead).
2. Calculate the gas pressure at the valve.
3. Adjust the gas specific gravity to give a casing pressure at the gas lift valve injection point that is approximately 100 psi greater than the measured pressure

inside the tubing (the 100 psi difference is based on experience).

The injection gas rate (IGLR) has a strong effect on the comparison of measured to calculated pressure in the upper section. The lift gas rate is adjusted until a Δp match (within 10%) is obtained in the pressure profile comparison from bottomhole to the wellhead.

If the production rate tests are inconsistent (not repeatable), then the liquid rate can also be adjusted to help achieve the match in the upper section.

RECOMMENDED PRACTICE: The calculated pressure difference, Δp (flowing bottomhole – flowing wellhead), should match within 10% when compared to the survey measured Δp data. The lower gradient (below the point of injection) should have a Δp match of 5%.

3.2 FLOWING PRESSURE AND TEMPERATURE SURVEYS

Gradient and deliverability models require good fluid property data for satisfactory results from the multiphase flow correlations, but the key is calibration with a flowing pressure and temperature survey.

Flowing survey objectives and procedural points are discussed in API RP 11V5 *Operation, Maintenance, and Trouble-Shooting of Gas Lift Installations*. Pressure surveys are also applied to well performance models in *Part 2* of this RP.

The pressure gradient data are used to:

- Adjust fluid properties.
- Give the flowing bottomhole pressure for a productivity index (PI) calculation or for use in the inflow performance relationship (IPR).
- Confirm the point(s) of injection or find suspected leaks.

The temperature survey data are used to:

- Detect cooling at gas expansion (injection) points.
- Obtain the temperature of the lower operating valves for applying correction factors to the test rack opening pressure calculations.
- Provide measured data for the computer multiphase flow and PVT calculations.

RECOMMENDED PRACTICE: Obtain quality pressure and temperature surveys, coupled with PVT fluid data, and repeatable production rate tests, to calibrate and to select the best multiphase flow correlations and well deliverability models.

A. Pressure Surveys

Points to improve the quality of survey data are:

- Use wireline contractors that specialize in well testing surveys, not just any company that can provide gauges.
- Query the wireline contractor on the frequency of gauge calibration. Every fifth use should be a minimum calibration frequency for mechanical gauges. Electronic gauges are calibrated with their software on every use.
- Use a dead weight tester (or calibrated test gauge) to measure the wellhead flowing pressure and injection gas pressure. This will verify the surface pressure gauges and the wireline gauges.
- If the well is heading (surging or slugging), then keep the wireline gauges at each depth for sufficient time to sense the maximum and minimum pressures. To observe the pressure swings, request chart interpretation at one min. intervals (to obtain pressure vs. time data at each depth).
- Use the recommended practices in API RP 11V5 for gauge installation, stops, and tools on the wireline string and for guidance in running and obtaining the surveys.
- Comply with manufacturer's stop times for temperature equalization when using electronic gauges. This time can be up to 5 min. depending on transducer type and the location in the gauge.
- If using electronic gauges, then obtain data going into the wellbore when the gauge heats and equalizes tem-

perature more quickly (coming out, the gauge has to cool and equalize temperature, which is slower).

Other points that improve the measured to calculated data comparison accuracy are:

- Achieve a stable well test (see 3.3) before beginning or during the survey. If the test separator is busy, then test under the same operating conditions within three days of the flowing survey.
- Obtain at least four data measurements at depths below the (expected) gas injection depth for PVT data validation (and pressure extrapolation if the gauges are not set in the perforations).
- In modeling, use the exact well completion configuration:
 - tubular internal and external diameters, including extension tubes below the packer. A safety valve can be approximated as a tubular length of 20 ft of pipe with the safety valve ID.
 - depth to the mid-point of the perforations.
 - inclination or deviation survey data for measured and true vertical depth (TVD). Define the hole deviation path with an adequate number of MD (measured depth)/TVD data pairs to properly define the deviation of the well. The data is contained in the deviation survey obtained when the well was drilled.
- Be consistent in the use of reservoir data:
 - the reservoir pressure data can come from static surveys. For accurate pressure extrapolation, at least four static stops should be made in the lower wellbore near the perforations.
 - an alternate method is to obtain reservoir pressure from pressure build-up tests. With the pressure build-up test, skin and permeability also can be determined. Permit sufficient shut-in time for the reservoir to cease afterflow and to reach radial flow equilibrium, indicated by the straight line in the build-up data.
 - for trend analysis, compare results with prior data, but only from the same test method, static or buildup.

B. Measured Temperatures

The flowing temperature survey may be conducted on the same wireline trip and the guidelines in 3.2 should be applied. The data are used to:

- Locate the point(s) of injection where gas cools with expansion

- Obtain a flowing temperature profile to serve in valve temperature estimates for the lower valves (the upper unloading valves will have a cooler, transient temperature during initial unloading).

Temperature prediction is important in the design calculations of gas lift valves with nitrogen charged bellows. It is much less important for spring loaded valves. The flowing temperature profile measured in conjunction with a pressure survey represents the producing well. The survey does not give the cooler wellbore temperatures that exist at the start of the unloading process.

- Use the flowing temperature survey for analysis by stopping at (or slightly above and below) each gas lift valve. A cooling effect indicates gas passage. A tubing hole can also be located with numerous stops through the interval of the suspected problem.
- The temperature profile can be used to set the lower valves that are subjected to hot reservoir fluid. The temperatures for the upper valves are not based on the flowing temperature survey. These upper temperatures (for the design calculations) must be estimated from unloading conditions. Section 4.1 recommends temperature models for unloading valves.

3.3 PRODUCTION TESTS

Production tests, which are also known as well tests, are essential for effective gas lift analysis and design. These tests are used to gauge or measure the oil, water, and total gas production rates. The water fraction, and coupled with measured gas injection rates, the IGLR can be calculated.

RECOMMENDED PRACTICE: Production rate tests and facilities should adhere to these guidelines for accuracy, frequency, and duration. The tests should be conducted under normal operating conditions to obtain the most representative data.

API RP 11V5 includes more detailed recommendations on test methods.

A. Test Accuracy

Test methods can range from estimates to accurate testing with a portable wellhead test skid and associated testing company crew. However, most tests are conducted through an existing field test separator and attached meters which should provide repeatability within $\pm 10\%$. Establishing greater accuracy requires use of meter provers that are not usually used for production allocation test equipment.

Conditions that promote acceptable, repeatable tests are:

- High production rate relative to the tubing and flowline size (mixture velocity is maintained at 10 ft/sec. or greater to minimize phase segregation and severe slugging).
- Steady non-slugging flow.
- Intermittent well testing should be conducted for a sufficient number of cycles to obtain a good average production rate.
- Gas, oil, and water meters (and their associated outlet control valves downstream of the meter) sized to operate at the mid-point of their full-scale range. Dual meters (and control valves) should be used when the test vessel will be used for both very high rate and very low rate tests. The piping between the separator and the meter should be short with no restrictions.
- Separator purge time, linked to the well's rate, which eliminates the initial instability and diminishes the effects of the prior well's test.
- Test flowline purge time (for wells linked to the station via a test line) that establishes new equilibrium gas, oil, and water flow regimes and liquid holdup in the pipeline.
- Test duration that permits the rate to stabilize at the test separator pressure (which should give the same flowing wellhead pressure as created by the production separator pressure).
- Shrinkage factor (reciprocal of volume factor at separator pressure and temperature) based on PVT data applied to obtain stock tank barrels.
- Meter temperature compensation (either in the meter or with the shrinkage factor).
- Gas samples and chromatograph analysis for specific gravity applied to gas measurement.

Test accuracy in low rate wells is usually poor. The biggest problem is the low rate (relative to tubular size) and slugging. The gas and liquid rates are not repeatable and the true rate is difficult to determine.

Obtaining a stable condition may require a high injection gas rate, resulting in an IGLR of 2000 scf/stb or greater. For field optimization, the well may be returned to the lower injection rate after testing.

If severe slugging cannot be controlled by injection rate variation or by adjustments on controls, then a station inlet choke may be necessary to dampen the slugs. This will raise the wellhead pressure and reduce the test production rate, but it may be the only technique that will yield repeatable tests.

Measurement inaccuracy due to surging through poorly sized meters/control valves (on the separator outlet piping) is

another problem. The control valve trim should be resized for the lower rates and meters adjusted, where possible, so that continuous and steady throughput is attained.

If the float/control valve controller is on periodic (dump) control mode, then the control valve trim should be sized for a rate that does not exceed the maximum meter range. For guidance on separator sizing and design, refer to API Spec 12J *Oil and Gas Separators*.

Meters in production service may not be able to give the $1/2\%$ — 1% accuracy obtained in the manufacturers lab with clean water. Thus a more realistic expectation is 5% — 10% accuracy since these meters are usually not proved (except when custody transfer occurs).

RECOMMENDED PRACTICE: A three phase test separator with properly sized meters, control valves, and computer data collection should be used for production testing of gas lift wells.

Test quality is related to the quality of the test facility. The cost and resulting quality can be ranked as follows:

1. Properly sized meters and frequent computer data collection, storage and averaging of results give the best tests.
2. Good meters (or tank testing for liquids) give the next best test.
3. Liquid rate estimates by timing separator fill-up are poorest.

The facility can also be rated by its ability to separate the phases:

1. A good three-phase test separator with proper metering is best.
2. A two-phase vessel can be used, but samples must be taken at the wellhead (or other highly turbulent point, such as the inlet test manifold) to estimate water fraction, which can vary from sample to sample.
3. Liquid residence time aids phase separation and metering. Time guides, from API Spec 12J, are:
 - 2 min. for two-phase separators.
 - 5 min. for three-phase separators.

B. Test Frequency

Continuous monitoring of each well is the ideal method for gas lift optimization. For periodic testing, the frequency may be based on:

- Regulatory requirements

- Company policy
- Reservoir and production management considerations.

Testing more frequently than once per month can often be justified for the following reasons:

- Rapid reservoir pressure loss is suspected and rates are used to estimate the percentage exponential decline (static 24-hr shut-in pressure or build-up testing should also be done).
- Water break-through from a waterflood or natural drive is occurring and frequent testing is used to observe the change in water fraction (water samples are important also).
- Lift gas allocation is adjusted based on the last test in an attempt to maximize oil. Gas allocation improves oil production only when measured wellbore flowing data are used to calibrate the computer model.
- Depth of injection is obtained by comparing the test separator rate to a computer model rate prediction at each mandrel (the model should be validated with a flowing gradient survey). An action response is generated if the well is found to be lifting at a shallow point.

RECOMMENDED PRACTICE: Test frequency guidelines:

1. More frequent than monthly testing if oil maximizing and gas allocation adjustments are being attempted (flowing gradient surveys should be implemented to validate a computer delivery model and the PVT fluid property data).
2. Monthly, if sufficient test separators are available.
3. Less frequent testing may be adequate if the well conditions are not changing, if gas lift gas allocation is not a priority, and if other methods of well surveillance are provided.
4. Sequentially test wells, keeping a well on test at all times.

C. Test Duration

The duration needed for a representative well test is a combination of:

- Purge time to remove the effect of the prior test.
- Time to attain rate stability.

- Test time.

Stability is dependent on the rate and productivity (permeability) of the well. The higher rate, high productivity wells stabilize quickly whereas the lower rate wells are slow to stabilize. Key items to establishing stability, and thus test duration, are:

- A wellhead pressure when flowing into the test separator that is approximately the same as flowing into the production manifold. If the test vessel must operate at a higher pressure, then the well must stabilize and a rate reduction should be expected.
- A surging well should exhibit the same slugging pattern whether in production or in test.
- The rate/hr should be steady (steady means the allowable variation is $\pm 10\%$ and not continuously declining or continuously increasing).
- The water fraction (% water cut) test sample each hr should not vary more than 10%.

If production and test conditions, such as wellhead pressure, remain constant, then the purge and rate stability time could be as quick as 2 hr. If conditions are changing, then a guide to test duration based on productivity index (stbpd/psi) is:

PI stbpd/psi	Purge hr	Test hr	Total hr	Comment
> 10	2	4	6	High PI wells stabilize quickly
> 5 – 10	4	4	8	Wellhead pressure should be steady
1 – 5	8	8	16	Rate/hr should be steady
< 1	12	12	24	Rate/hr should be steady

One field guide for purging/stabilizing time is the time needed to produce five tubing volumes. Other operators relate purge time to vessel size and production rate.

This time guide includes vessel purging in the “Purge” time column. However, it does not include purge time required when a well is located at a remote site or wellhead platform and is switched from a common production header line into a test line.

D. Flowline Purging

Purging or displacing fluids in the test line from a remote onshore or offshore well manifold requires a time that should be added to the purge time above. If two test lines connect the remote manifold to the test station, then one line can be purging while the other is in test.

Purging of the test line is more complex than a simple estimate of time based on the volume capacity of the line divided

by the estimated test rate. A preferred method to estimate the time needed for pipeline purging is:

1. Analyze the flow regime and liquid holdup based on those regimes.
2. Use a multiphase flow computer program that lists liquid holdup for the specific geometry of the test line.
3. Holdup is the liquid volume fraction of the pipe based on a computer calculation.
4. Obtain holdup for the prior test rate, gas-liquid ratio, and water fraction.
5. Repeat the analysis for the estimated current test conditions.
6. Calculate purge time from:

$$\text{Purge Time, hr} = \frac{\text{Holdup [Prior Test — Cur. Test Est.], * bbls 24 hr/d}}{\text{Estimated Current Test Rate, bbl/d}}$$

The difference in holdup (*an absolute value*) represents the filling or sweeping of liquid that must occur before the new flow patterns reach equilibrium and the well’s production rate and fluid composition are reasonably represented in the test results at the vessel.

Pipeline purge time should be added to the time guide table in 3.3.C. For most situations the time should not exceed 2 hr – 4 hr. If a suitable computer program is not available, then pipe volume divided by estimated rate can give an approximate pipeline purge time.

3.4 GAS LIFT VALVE PERFORMANCE INFORMATION

Gas lift valve performance is the *quantitative* measure of a valve’s gas flow rate response to changes in casing and/or tubing pressure for a given valve set pressure and temperature. API RP 11V2 *Gas Lift Valve Performance Testing* describes the methods by which a valve’s flow performance can be measured.

RECOMMENDED PRACTICE: Valve performance data should be utilized in gas lift design to ensure adequate gas passage when unloading or producing. The data should be requested if it is not available.

A. Types of Gas lift Valves

Two basic types of gas lift valves commonly used are:

- IPO
- PPO

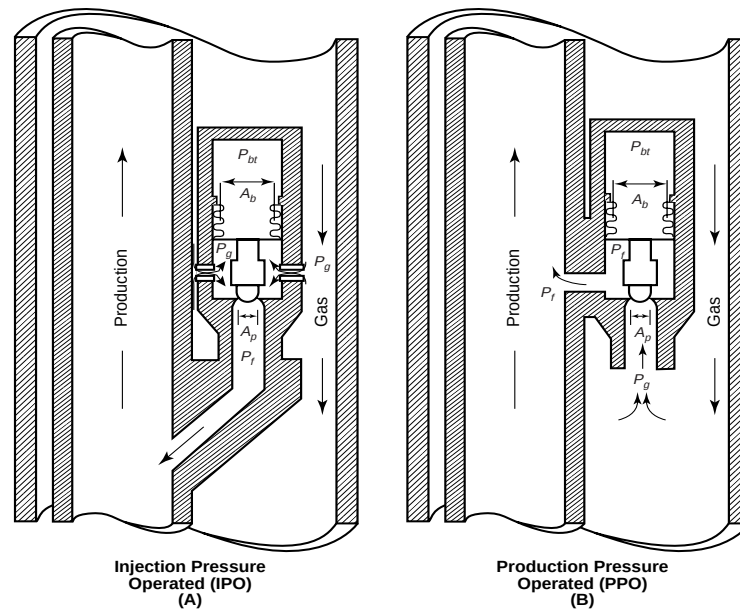


Figure 3-2—IPO and PPO Valves

Both types, Figure 3-2, utilize a bellows and apply a shop-set load (nitrogen pressure, spring, or both) to hold the valve stem/ball on the seat (port). The combination of annulus and tubing pressure acting under the stem and on the outside of the bellows pushes against this preset load and, when sufficient, will cause the stem to move away from the seat. The open port, plus pressure differential, will allow either liquid or gas to flow through the valve.

IPO valves:

- Have a large area of the outside of the bellows exposed to injection gas pressure, thus small changes in injection pressure may result in relatively large changes in stem position.
- Utilize a nitrogen charge in the bellows to provide the preset load (some valves will use a spring rather than or in addition to nitrogen).

PPO valves:

- Have a large area of the outside of the bellows exposed to production pressure and thus changes in production pressure will cause relatively large changes in stem movement.
- Have either a spring and/or a nitrogen charge to preload the bellows and hold the valve stem on the port.

B. Valve Opening

All valves (both IPO and PPO) have a *loadrate*. The loadrate is:

- A measure of the valve stem's resistance to movement and is similar to a spring rate except that loadrate is measured in psi/in.
- An indication of the amount of increase in pressure required causing the valve stem to move away from the seat.

The loadrate will vary between valves from one manufacturer and certainly between manufacturers. API Spec 11V1 *Gas Lift Equipment* and API RP 11V2 describe the methods by which loadrate is measured and terms such as stem travel.

The pressures acting on the stem and bellows generate two forces acting to open the valve:

- Injection pressure acting on the area of the bellows minus the area of the port
- Production pressure acting on the area of the port

When the combination of these two forces equals the preset dome charge times the area of the bellows, the net force holding the valve on the port is zero. An increase in either injection pressure or production pressure will then cause the valve to begin opening. The amount of movement is governed by the loadrate.

For example:

1. A 1½ in. IPO valve with ¼ in. port (area of port to area of bellows ratio, $A_p/A_b = 0.07$) has:
 - a. a valve bellows pressure (at the temperature of the valve) of 800 psig.
 - b. a loadrate of 450 psi/in.

2. If the annulus injection pressure is 820 psig and the tubing production pressure is 538 psig,
3. Then the force holding the valve stem on the port equals the forces generated by the injection pressure and production pressure.
4. For the same tubing pressure, an increase in annulus pressure of 10 psig will cause the valve to open 0.022 in.

C. Valve Gas Passage Performance

The amount of gas that will pass through a valve will depend on valve stem travel, differential pressure across the valve, temperature affecting nitrogen expansion in the bellows, and flow coefficient of the valve. Refer to API RP 11V2 for details on flow coefficients and the methods by which they are calculated.

Gas passage performance of a valve is governed by the pressure acting on the bellows. Some gas lift valves have been characterized as “throttling” valves and others as “full-open” valves. But, either valve type can “throttle” if the pressures acting on the bellows are insufficient to cause the valve stem to move far enough away from the seat to achieve a flow area equivalent to a full open port. Likewise, either valve can act as a “full-open” valve if the pressures acting on the bellows are large enough.

All valves will be full open when maximum pressure is applied during the process of U-tubing fluid (unloading) and will be throttling at lower pressure when injecting gas. The actual performance is based on the loadrate, the set pressure, the annulus and production pressures, and the flow capacity of the valve.

3.5 FIELD CONSTRAINTS

Physical and/or operational constraints often prohibit the gas lift system designer from having complete freedom to design the gas lift system for optimum operation based solely on gas lift technology. The designer must be aware of these constraints and take them fully into consideration or else the gas lift design may be doomed to failure, or at least to far less than optimum performance.

RECOMMENDED PRACTICE: The entire gas lift system should be reviewed to eliminate or minimize constraints that impair gas lift performance. Constraints that remain must be incorporated into each design.

A. Available Pressure for Injection

Pressure for injection in a gas lift system is controlled by:

- Gas compressor discharge pressure or facility and piping maximum pressure limits.

- Backpressure regulators that send excess compressed gas to the gas plant or gas transmission line.
- Gas plant processing facility, transmission line, or gas wells that provide the gas if the gas supply is not from field compression.

In all options, the *best pressure is that which permits injection near bottom of the well* because deep, efficient lift can be attained and sustained. Economic evaluation of gas circulation rate, pressure, and oil recovery can guide the choice of pressure.

Terms important in system design and in each well’s valve pressure settings are:

• Compressor Discharge Pressure

The design discharge pressure for the field compressor(s) should be based on the desired maximum kickoff pressure plus piping system pressure loss (usually not more than 100 psi). Compressor discharge pressure is limited by cylinder or case MWP (maximum working pressure), driver horsepower, or rod load (reciprocating compressors). The discharge pressure can be raised by increasing the set point of the backpressure controller that directs excess gas to the sales transmission line or gas plant, up to the limiting pressure of the safety devices. This action will also raise the field kickoff pressure.

• Kickoff Pressure

Kickoff pressure is the highest pressure available at the wellhead (casing) that can be used to start the unloading of dead completion or workover fluids in the casing and tubing. Compressor discharge pressure (or other source) less dehydration system and pipeline losses will equal the kickoff pressure at the well.

System kickoff pressure can be inadvertently lowered if one well’s choke or controller malfunctions and excessive gas is injected into one well. The kickoff gas injection pressure can be made temporarily higher for unloading by two methods:

1. Raise the compressor discharge pressure by resetting to a higher pressure the backpressure controller sending gas to the plant or sales pipeline.
2. Reduce or shut off the gas lift gas to a high rate gas consumer well that is connected to the same branch of the system (be sure that the well will return to production when the gas is restored).

These methods can be applied during the unloading time period of 24 hr – 48 hr and then normal control settings can be restored. This technique will result in the highest possible injection pressure or it can be applied to wells that are difficult to unload.

• Unloading Pressure

The unloading pressure for each valve is used in the calculation to set the test rack pressure of each. The first valve (shallowest) has an unloading pressure nearly equal to the kickoff pressure. Succeedingly lower unloading valves have unloading gas pressures reduced by a pressure difference of about 25 psi between valves (10 psi is a minimum for low pressure systems up to 50 psi for high pressure systems). Each deeper unloading valve lowers the gas pressure until the operating valve, or orifice, and operating pressure is reached.

• Operating Pressure

The gas pressure needed for continuous operation at the point of lift. The pressure depends on whether a valve or orifice is used:

- when a valve is used, the operating pressure is controlled by the valve set pressure, port size, gas rate, temperature, and fluid production pressure.
- when an orifice is used, the operating pressure is controlled by the orifice size, gas rate, and fluid production pressure.

Available operating gas pressure at the lift point is directly related to the number of unloading valves and the gas pressure difference between valves. For example, a well with a kickoff pressure of 1000 psig, six unloading valves, and 25 psi gas pressure difference between valves, would have a surface operating pressure of approximately 850 psig when lifting at the design point.

The valve design method affects the gas pressure difference that is used, which in turn affects operating pressure available at the point of lift.

Thus the **operating pressure** available for injection is a function of:

- Compressor discharge pressure.
- Kickoff pressure at the casing.
- Number of unloading valves.
- Unloading gas pressure difference between valves.

New compressor systems and new wells should be designed to provide gas pressures to accommodate the highest productivity (PI) wells, as these wells have the highest pressures needs. The lower PI wells will be easily lifted with this design approach.

Existing systems may need revisions to maximize oil:

1. The first step is to make available the highest compressor and kickoff pressure.
2. The next step is to reset (and possibly re-space) the valves to utilize this higher unloading pressure.

Thus, the highest compressor discharge pressure will yield the highest kickoff, which will result in higher operating pressure, deeper lift, and more total fluid (and hopefully more oil).

RECOMMENDED PRACTICE: The gas supply should be the highest possible compressor pressure and should be dry (processed to reduce both water and hydrocarbon). This gives the steadiest supply with the highest kickoff and operating pressure that maximizes the oil production.

B. Minimum Wellhead Pressure

Flowing wellhead pressure for a gas lifted well (no choke at the wellhead or at the inlet to the station) is dependent on:

- Reservoir pressure and productivity.
- Density and friction pressure losses in the wellbore.
- Separator pressure plus flowline pressure losses due to friction, terrain effects, and elevation changes.

High reservoir pressure plus good productivity, and low density, gaseous fluid result in the reservoir energy being transmitted to the wellhead, if tubular friction loss is not excessive. Low pressure at the inlet separator and a relatively large flowline minimize the resistance to flow (backpressure). Addition of lift gas aids wellbore delivery but adds to friction losses in the horizontal flowline, and in the tubing, if the diameters are too small.

The minimum achievable wellhead pressure is a function of the backpressure produced by:

- Separator pressure.
- Losses from terrain effects and elevation changes.
- Rate (velocity) induced flowline friction, which is caused by:
 1. Tubular pipeline internal diameter,
 2. Fluid properties,
 3. Gas-liquid ratio,
 4. Liquid flow rate.

When the wellbore tubular, flowline, and separator facility is designed, the anticipated well rate can be calculated and then reservoir withdrawal constraints (or regulatory limits) can be imposed. The tubing and flowline size to achieve the needed rate can then be selected.

During this design calculation procedure, wellhead pressure can be minimized by reducing separator pressure and by