

Design and Operation of Intermittent Gas-lift Systems

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Design and Operation of Intermittent Gas-lift Systems

1 Scope

This API recommended practice provides guidelines and considerations for the design and operation of intermittent gas-lift systems including designs with chamber and plunger lift equipment. Included are the background and theory of each of these systems as well as considerations for system design and operation. This information is intended for well engineers who seek to gain a general understanding of the theory and practices of intermittent gas-lift systems.

Not addressed in this recommended practice are absolutes in the development of an intermittent gas-lift system design or operation because of the range of variables for each well and field combination.

This document also contains three annexes. Annex A contains mathematical derivations and models of some of the most pertinent intermittent gas-lift calculations. Annex B contains a comprehensive example of an intermittent gas-lift design. Annex C describes how to use the Field (U.S. Customary) Units Calculator and SI Units Calculator.

The calculations described within the recommended practice are separately provided within excel spreadsheets to allow the effective use of this information by users of this document. They are referenced within text boxes inserted into the text prior to the details of the formulas. The spreadsheets can be downloaded at <http://alrdc.com>.

2 Terms and Definitions

For the purposes of this document, the terms and definitions provided in [API Q1](#) and the following apply.

2.1

chamber gas-lift

An artificial lift method that uses a downhole accumulation area that allows for the capture of more fluid than can be achieved with tubing alone and increases the volume of liquid produced with each intermittent lift cycle.

2.2

functionality

Capability of the equipment to conform to defined properties, characteristics, and limits.

2.3

mechanistic models

Mathematical models that describe the multiphase flow mechanisms (including related fluid properties and physical relationships) using physical flow equations for each of the phases within the system as opposed to empirical models that are based solely on observation rather than theory.

2.4

open installation

A completion without a packer or standing valve.

2.5

PI

productivity index

The ratio of liquid production rate, in barrels per day, to the difference between static and flowing bottomhole pressures, in pounds per square inch.

2.6**plunger lift**

A lift method wherein a reciprocating plunger is used to move liquids from producing wells, such as water, sand, oil, and wax, to help enhance the production of hydrocarbons.

2.7**standing valve**

A ball check flow-control valve that seats in a landing nipple at the bottom of the production tubing and prevents reverse flow into the formation; typically placed below the operating gas-lift valve.

2.8**test pressure**

Pressure, based upon all relevant design criteria, at which the equipment is tested.

NOTE Each test pressure has a related test temperature, as specified by the pertinent test procedure.

2.9**test temperature**

Temperature, based upon all relevant design criteria, at which the equipment is tested.

2.10**time cycle control**

Intermittent gas-lift control scheme in which the cyclic operation is determined by the programmed opening and closing of the surface gas injection line using a surface time cycle controller in conjunction with an automated control valve installed in the gas injection line near the wellhead.

2.11**unloading**

Refers to the process of displacing initial annular and/or tubing fluids in the well when gas-lift injection gas is started.

2.12**U-tubing**

Displacement of liquids from annulus to tubing using high-pressure gas during initial unloading process.

2.13**valve area ratio**

Ratio of the valve's effective port area to its bellows area.

3 General Description of Intermittent Gas-lift**3.1 General**

Intermittent gas-lift is an artificial lift method where high-pressure gas is injected into the well's production tubing at predetermined cycle times and volumes, or at a predetermined pressure, to produce the maximum amount of liquids with the minimum injection gas-to-liquid ratio (GLR). Intermittent gas-lift is typically utilized in wells where formation pressures have decreased, causing continuous flow interruptions, or in low-production wells with high formation pressures. For low-reservoir-pressure wells, the injection GLR is lower on intermittent gas-lift than on continuous gas-lift. The opposite is true for wells with high reservoir pressure. The main reason for shifting from continuous gas-lift to intermittent gas-lift is typically to improve injection gas compression/processing efficiency.

With intermittent gas-lift systems, the lift gas is designed to enter the tubing through a single point of injection located as deep as possible in the well. The liquid slug that has accumulated in the tubing above the point of injection is lifted to the surface by the gas entering the tubing. As the reservoir pressure and/or well productivity declines, the required injection GLR increases for wells either on continuous or intermittent gas-lift. More gas is

required to continuously lift a well with a low operating bottomhole pressure than to operate the same well with an effective intermittent design.

3.2 Overview of Contents

This section contains considerations for changing from continuous to intermittent gas-lift and the types of intermittent gas-lift installations: simple completion gas-lift designs, chamber completion designs, chamber designs utilizing double packers, insert chamber designs, and simple accumulator designs.

3.3 Considerations for Changing from Continuous to Intermittent Gas-lift

When shifting from continuous to intermittent gas-lift in the same completion, the following practices are recommended for consideration.

- The operating valve should be as close to the perforations as possible. Existing completion designs can be adequate for continuous lift. However, due to the tubing diameter, the deepest mandrel may not be as close to the perforations as would be ideal. The production tubing diameter should be sized to keep the designed liquid slug velocity at approximately 304.8 m/min (1000 ft/min) to keep fallback losses at a minimum. A tubing of less than 2³/₈ in. is not recommended as it will limit access for well servicing.
- For a long perforated interval, the use of insert type completions can be considered to increase the system effectiveness and to reduce system costs.
- Intermittent lift operating valve set pressures should allow the unloading valves to remain closed during normal operating cycle, and their operation should be limited to the unloading of the well.
- “Open installations” are limited to wells with high reservoir pressures and should only be installed if a packer cannot be used.
- Standing valves should be installed in intermittent lift installations unless they are low *PI* or produce sand that could damage the standing valve.
- The wellhead should be made suitable for intermittent lift by the removal of unnecessary elbows, tees, bends, etc., near the wellhead. The well access should be streamlined to allow effective wireline operations.

In the simplest completion designs, the static pressure is higher toward the bottom of the perforations, but the effect of the formation gas being constantly vented to the tubing causes low pressure in the upper part of the perforations. In conventional intermittent gas-lift, the formation gas is constantly vented to the wellhead to prevent gas accumulations.

3.4 Types of Intermittent Gas-lift Installations

3.4.1 General

Different types of installations are recommended for specific operational conditions. Some systems require more surface equipment than others, resulting in increased technical and operational complexity.

- Simple completion systems are the most common type of intermittent designs as they generally include less downhole equipment.
- Chamber systems are recommended for wells with low bottomhole pressure and a high *PI*. The downhole accumulation chamber provides greater capacity than the nominal tubing string.
- Accumulators combine the effect of the liquid accumulation of a chamber installation with the ability of a simple completion to handle high formation GLRs.

- Plunger systems are used to reduce gas breakthrough and liquid fallback, making them an efficient method of intermittent gas-lift production enhancement.
- Dual completion systems are used when two formations are being produced simultaneously, but independent of each other.

3.4.2 Simple Completion Gas-lift Designs

A simple completion is the most common type of intermittent lift system. Most wells on intermittent lift were initially operated on continuous gas-lift. They are typically shifted to intermittent lift to reduce the injection GLR. Simple completions use less downhole equipment, reducing the risk of production inefficiency. Many continuous gas-lift wells will “self-intermit” when the target production rate cannot be sustained. Self-intermitting is less efficient than a properly designed intermittent operation since the injection valve is not designed for intermittent use.

The operating valve should be located as close as possible to the perforations. The liquid slug accumulates above the operating valve. When the gas-lift valve opens, a high gas flow rate enters the tubing, pushing the liquid slug to the surface. The unloading valves should remain closed during the entire cycle.

Such an installation may be classified as either open, semi-closed, or closed, depending on the completion configuration.

- *Open*: a completion without a packer and standing valve is an “open installation.” In these installations, enough tail pipe is run below the bottom valve to form a liquid seal and prevent U-tubing around the bottom, which prevents loss of annulus gas pressure during each cycle. Loss of pressure results in excessively high gas-fluid ratios. “Open installations” are limited to wells with high reservoir pressures and should only be installed if a packer cannot be used.
- *Semi-closed*: a completion with a packer and no standing valve.
- *Closed*: a packer and standing valve, preventing the reservoir from being exposed to high injection pressure.

3.4.3 Chamber Completion Designs

3.4.3.1 General

Chamber systems increase the cycle volume by allowing accumulation of fluids in a downhole chamber that has a greater capacity than the tubing string. Chamber systems are considered the method for ultimate depletion of low-static-pressure wells by gas-lift. Inserting a chamber system can be the only way to obtain cost-effective injection GLRs in deep wells with low PI . They are also recommended in wells with low bottomhole pressure combined with a high PI to increase the liquid production and for deep wells with low PI to reduce the injection GLR. Chamber systems are not recommended for gassy wells. The chamber annulus will fill with gas, reducing the volume of liquids per cycle. Wells with significant to severe sand accumulations limit the use of a chamber system due to the difficulty in pulling a chamber installation and performing wireline operations for cleanouts. There are various types of chamber systems that can be utilized, depending on the well completion type, casing size, condition, and production rate of the well.

3.4.3.2 Chamber Designs Utilizing Double Packers

Double packer chamber systems offer maximum annular capacity. Figure 1 illustrates one such system. In this system design, the accumulation chamber is located in the tubing space between two packers, where the upper packer contains a bypass for gas injection. Double packer chamber systems allow fluids from the reservoir to enter the chamber annulus through the perforated nipple above the lower packer. As the liquid level rises, the gas above it is vented to the tubing through a bleed valve below the upper packer. When the chamber annulus and dip tube are filled, the gas-lift valve above the upper packer opens, allowing the gas to enter the upper part

of the chamber annulus. The liquids are forced downwards, closing the standing valve, then rising through the dip tube and production tubing to be produced to the surface as a continuous liquid slug. The unloading valve spacing calculations for chamber systems are the same as for conventional intermittent systems.

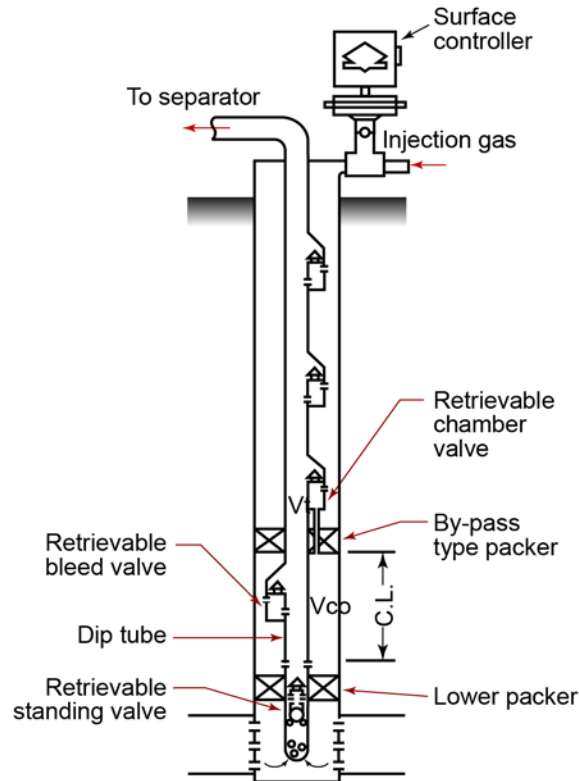


Figure 1—Double Packer Chamber System

3.4.4 Insert Chamber Designs

Insert chamber designs can extend the economic life of a low liquid production well. This design is recommended for wells with one or more of the following conditions: long perforated intervals, low reservoir pressure, damaged casing, or open-hole completions. Figure 2 illustrates one such system. When the chamber valve opens, high-pressure gas enters through the bypass packer forcing the liquids downward, closing the standing valve. The liquids then rise through the dip tube into the production tubing until they are produced to the surface.

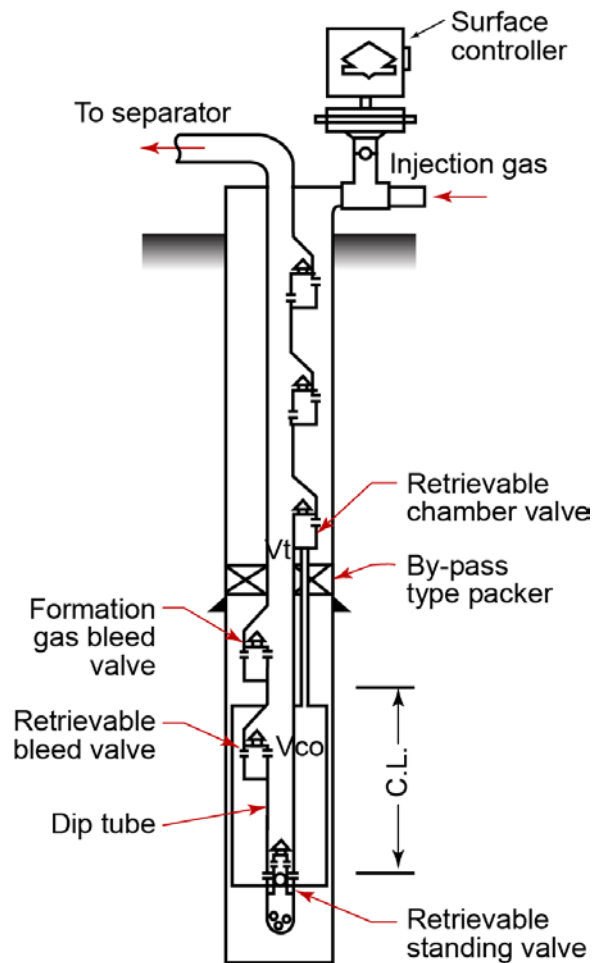


Figure 2—Insert Chamber Design

Considerations regarding dip tube diameter, opening pressures of unloading valves, setting the chamber valve, and calculating the theoretical gas injection volume per cycle are the same as for double packer chambers. Two major considerations are required for insert chamber designs:

- 1) calculation of daily liquid production can only be estimated, and
- 2) provisions should be made to bleed the formation gas.

An estimation of the daily liquid production can be made using data from a downhole survey performed before their installation. Refer to A.6 for a practical approximation of the liquid daily production expected from a well with an insert chamber design system.

The minimum pressure along the completion for an insert chamber without a formation gas bleed valve is lower than that of a simple completion. The gas accumulation in the outer annulus (along the perforations) below the packer causes pressure at the entrance of the chamber to be transmitted to the upper part of the perforations blocking the liquid inflow from the reservoir. This gas accumulation will also occur in wells with low formation GLRs.

An insert chamber with a vent for formation gas reduces the pressure along the formation uniformly, providing a larger drawdown. The minimum pressure at the entrance of the chamber and the formation gas bleed valve is equal for both the formation and inside the chamber.

For insert chambers without the means to vent the gas, pressure along the perforation is likely high. The pressure exerted by the liquid accumulating in the chamber is transmitted directly to the upper parts of the perforations due to the low gradient of the gas accumulated below the packer. This limits the production of the insert chamber to values comparable to those obtained with a simple completion, except a higher volume of gas per cycle is necessary for the insert installation. If the gradient in the annulus between the chamber and the perforations is low, the hydraulic pressure created by a small liquid slug at the bottom of the chamber is transmitted to the upper zones. If the reservoir pressure is low, a gas lock will occur even if the formation GLR is low. The formation gas will gradually accumulate at the top of the outer annulus (between the perforations and the chamber) effectively blocking the liquid production.

For insert chambers with formation gas bleed valves, a complex two-phase flow process occurs along the perforations. Free gas moves upwards, to be vented to the chamber and tubing, while the liquids with low gas content enter the lower intake of the chamber. Early in the liquid accumulation period, the pressure in the lower part of the chamber becomes greater than the pressure in the lower part of the perforations, blocking the lower entrance of the liquids to the chamber. The chamber can continue to fill with liquids if the formation gas bleed valve has been designed to handle two-phase flow. The end result is that the pressure along the perforations stays low throughout the cycle as long as the liquid level inside the chamber is below the upper entrance of the chamber. See Figures 3 through 6.

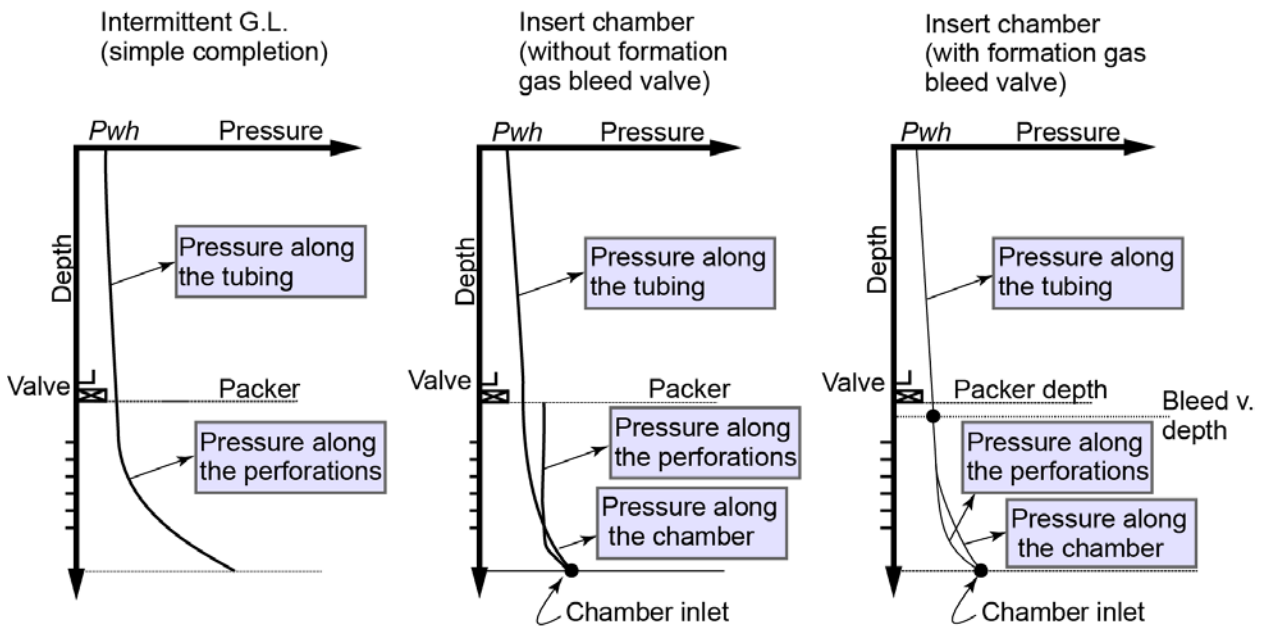


Figure 3—Pressure-depth Diagrams for the Same Well with Three Types of Completions (Beginning of Liquid Accumulation Period)

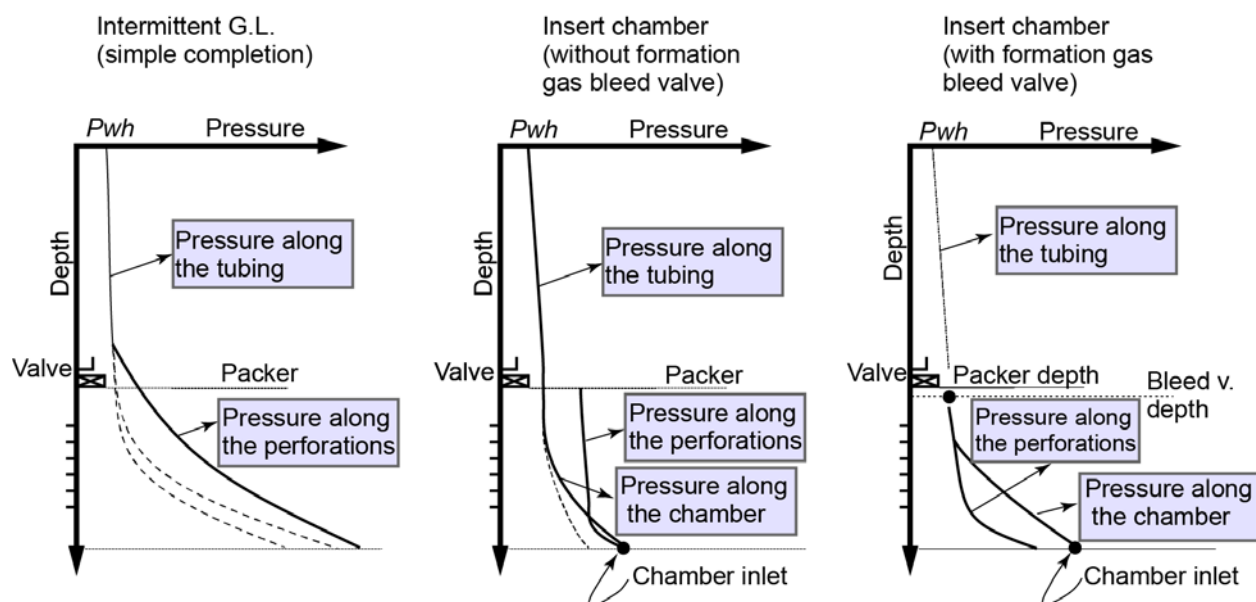


Figure 4—Pressure-depth Diagrams for the Same Well with Three Types of Completions (Just Before Chamber Valve Opens)

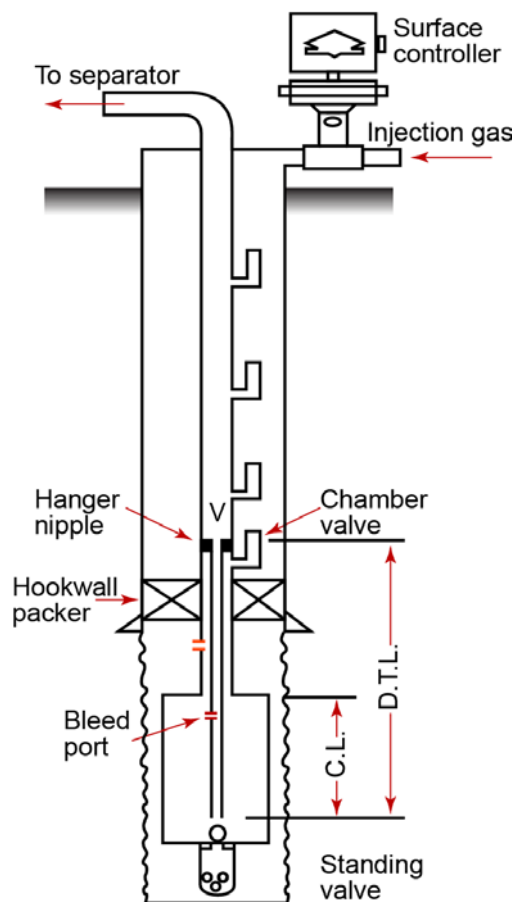


Figure 5—Insert Chamber with Hanger Nipple

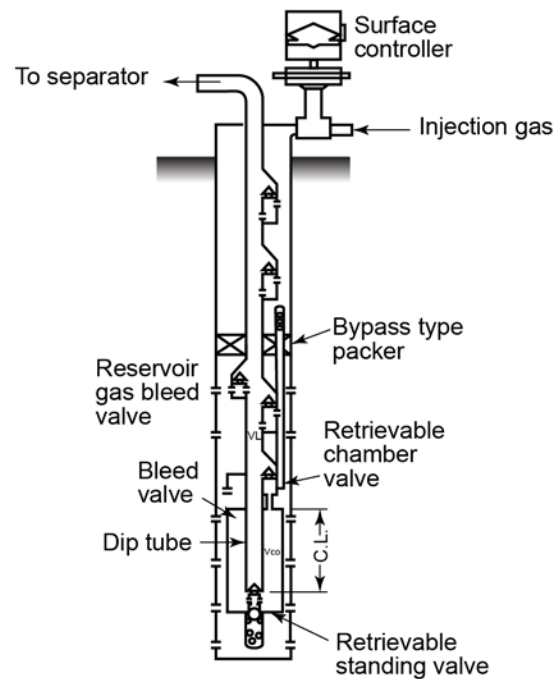
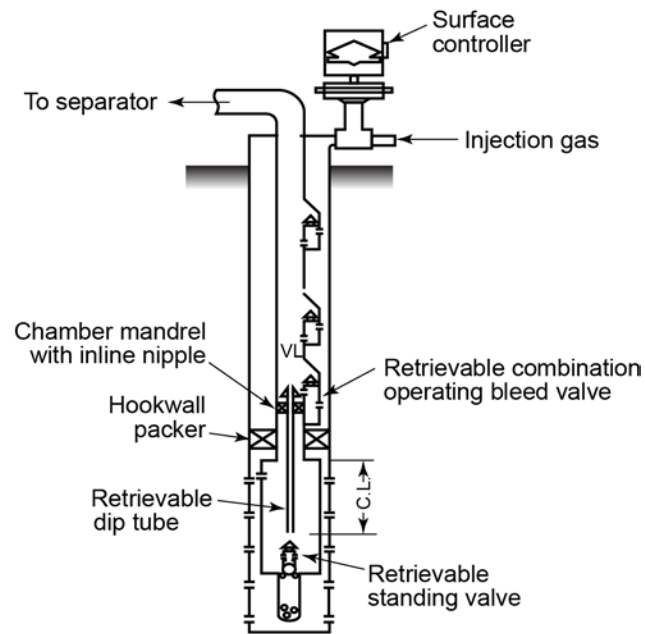


Figure 6—Extremely Long Insert Chamber Accumulator Systems

3.4.5 Simple Accumulator Systems

3.4.5.1 General

An accumulator is a section located at the lower end of the tubing string with a diameter greater than the rest of the tubing. Accumulators handle formation gas better than chamber systems and are recommended for gassy wells with high PI . Any free gas is always being vented (produced or percolated) to the wellhead. The required injection GLR is greater than a chamber system, and a small increase in liquid fallback is expected. The volumetric capacity of an accumulator is typically smaller than in a chamber system. If the liquid slugs are long due to small bubbles trapped in the liquid, the pressure exerted by the liquids on the formation is proportional only to the net volume of liquid in the tubing.

Accumulators combine the effect of a chamber installation with the ability of simple type completions to handle high formation GLRs. The small-diameter tubing from the accumulator to the surface decreases the volume of gas required per cycle. High fallback losses can result if the accumulator diameter is too large. The accumulator length is equal to the liquid slug length calculated for the optimum cycle time as shown in Annex A for simple completions, except, it is corrected for true liquid gradient. The diameter of the tubing above the accumulator should be large enough to overcome the hydrostatic pressures caused by the length of the liquid slug. See Figure 7. The extra volume of the accumulator should be accounted for when calculating the theoretical gas required per cycle by using the procedure provided in A.3.

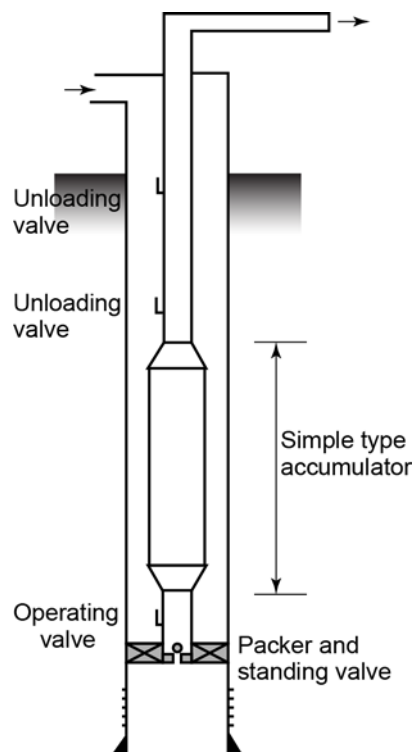


Figure 7—Simple Type Accumulator

3.4.5.2 Insert Accumulators

Wells that would otherwise be good candidates for insert chambers, but with high formation GLR or small-diameter casings, are candidates for insert accumulators. The insert accumulator design allows it to handle high volumes of formation gas. The same considerations for double packer chambers and insert chambers apply for insert accumulators. The procedure provided in Annex A for estimating the daily liquid production of insert chambers can also be used for insert accumulators. The formation gas inlet (Y-tool) is expected to be exposed to both formation gas and formation liquids that will be filling the accumulator. As a result, the formation inlet should be designed for two-phase flow. See Figure 8.

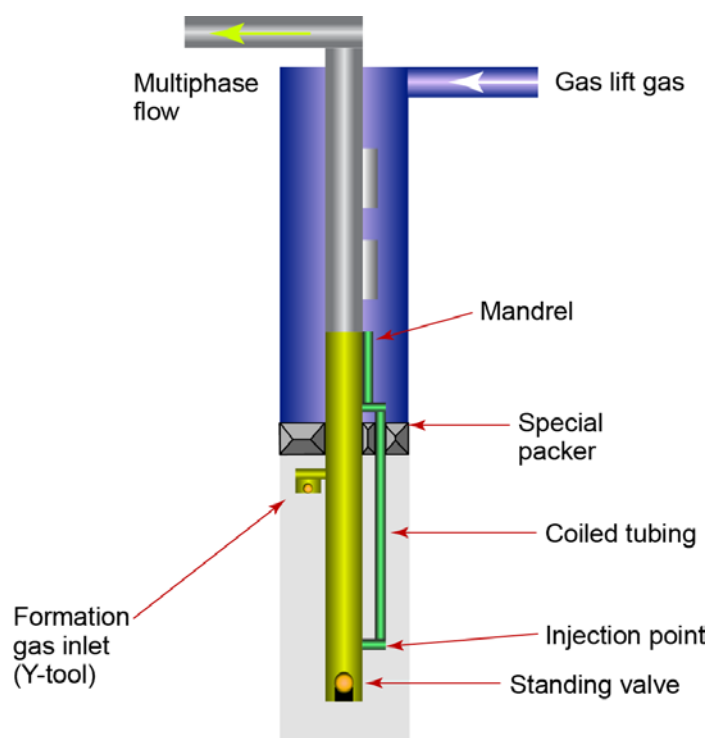


Figure 8—Insert Accumulator

3.4.6 Dual Completion Designs

Dual completion systems are utilized for production from a single well with multiple formations having independent operating tubing strings. It is not recommended to attempt to produce both strings by gas-lift using a common source or injection annulus. It is suggested that a coiled tubing installation is used for isolation of the gas-lift gas going to the different producing strings. The following recommendations are for situations where lifting both strings from a common injection annulus is the only option (see API 19G9 for dual gas-lift completion information). See Figures 9 and 10.

Dual completions can be concentric or parallel string installations. In concentric completions, fluids from the upper zone are produced continuously up the casing tubing annulus and fluids from the lower zone are produced through macaroni-type tubing installed inside the production tubing. Intermittent gas-lift is not recommended in concentric completions due to the following.

- The fallback losses and the volume of gas needed to lift intermittently through an annulus are potentially excessive.
- The volume of liquid accumulated per cycle in small-diameter capillary (“macaroni”) type tubing is low. Unless the reservoir pressure is low, macaroni tubing is recommended only for continuous gas-lift systems. Parallel string completions offer better results for intermittent lift, even though the casing can limit the size of the parallel strings. For 5.5-in. casing, tubing diameters are limited to around 1.75 in., making continuous gas-lift more efficient. The design of parallel string dual intermittent gas-lift installations with a common injection gas source can be accomplished if general rules are followed. For all cases, the designs of both zones are interrelated.

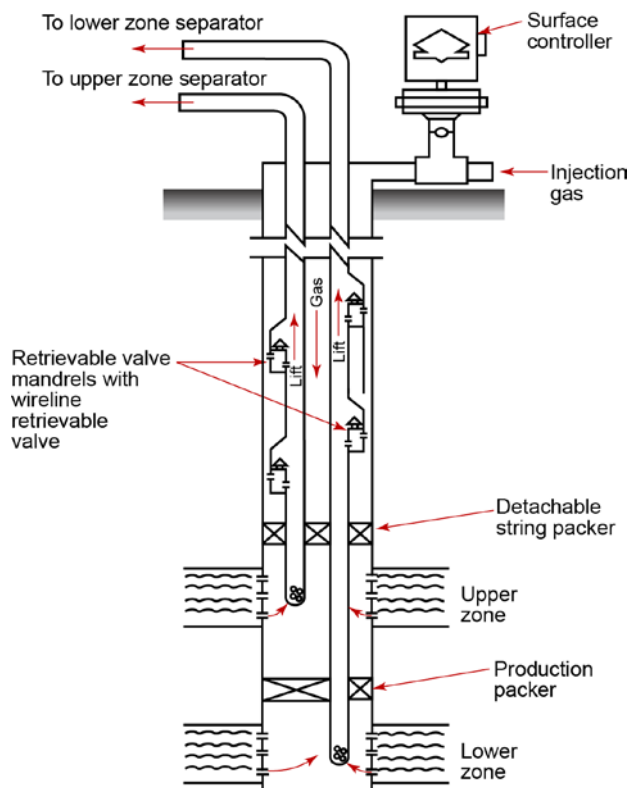


Figure 9—Parallel String Dual Completion

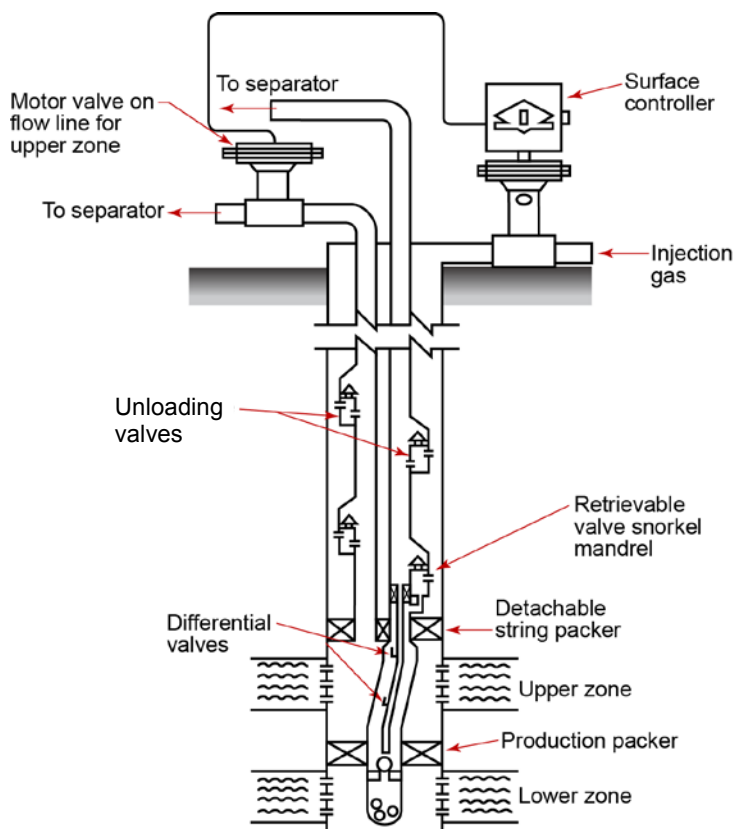


Figure 10—Completion for Zones That Are Too Far Apart

3.4.7 Plunger Systems with Gas-lift

3.4.7.1 General

Plungers designed to unload gas wells can be used in combination with gas-lift to reduce the liquid fallback losses when the instantaneous gas flow rate cannot make the liquid slug travel at 304.8 m/min or 5.1 m/s (1000 ft/min or 16.67 ft/s). They can also be used to overcome operational concerns such as paraffin formation along the tubing.

Conventional plungers are modified for use in installations with gas-lift mandrels for wireline-retrievable valves. A plunger, with a hole through its longitudinal axis, is typically more efficient than one without it. The internal hole does not significantly increase fallback, but does make it easier for the plunger to fall back to the bottom of the well after a cycle.

3.4.7.2 Slug Velocities in Plunger Systems

The primary difference between plunger lift systems and conventional gas-lift applications is the amount of liquid fallback. The amount of liquid fallback is substantively reduced using the plunger system design. Where high cycle life is desired, plungers with a bypass valve may be preferred because of the restricted low flow velocity of their integral check valve system.

During the produced fluid slug's upward travel, gas breakthrough and liquid fallback are nearly eliminated by the action of an effective plunger system. Slug acceleration lasts only a few seconds as it achieves its maximum velocity. When the liquid reaches the wellhead, its velocity slows as the drive gas is redirected and it moves into the production tubing.

Low liquid slug velocities are found where:

- the gas-lift system cannot provide a high instantaneous gas flow rate into the tubing. This occurs if the available maximum pressure or gas flow rate delivered by the compressor is inadequate, or if the gas-lift systems pressure storage capacity does not meet the flow requirements;
- the installed gas-lift mandrel accepts only small-diameter gas-lift valves, thereby limiting the gas flow rate.

Plunger systems can be beneficial, but require extra care and increase maintenance requirements. At low liquid velocities, high fallback occurs without plungers. As velocity increases, fallback is reduced when plungers are not used. The opposite is true if plungers are used. At high velocities, fallback losses are about the same with or without plungers. The loss differences with plungers at low velocities vs losses without plungers at high velocities, are not that far apart. A gain in production per cycle using plungers at low velocity is obtained at the expense of a longer cycle time. For wells where the point of injection is too deep or where paraffin deposits or emulsion problems are present, using plungers can be the only means to economically produce the well. See Figure 11.

3.4.7.3 Applications Where Plunger Systems Are Not Recommended

Plungers are not recommended where:

- the tubing is deformed or has excessive deviation or dogleg severity preventing a plunger from descending to its bottomhole bumper spring;
- the tubing string is composed of sections with different inside diameters;
- the liquid slug velocity attained is approximately 304.8 m/min or 5.1 m/s (1000 ft/min or 16.67 ft/s) as the liquid fallback losses and the gas required per cycle are about the same for installations with or without plungers. Any small increase in efficiency will be offset by the added maintenance requirements;

- the maximum production is limited by the fall time required for a plunger to descend to the bottom bumper spring, especially in high-cycle-frequency intermittent gas-lift installations.

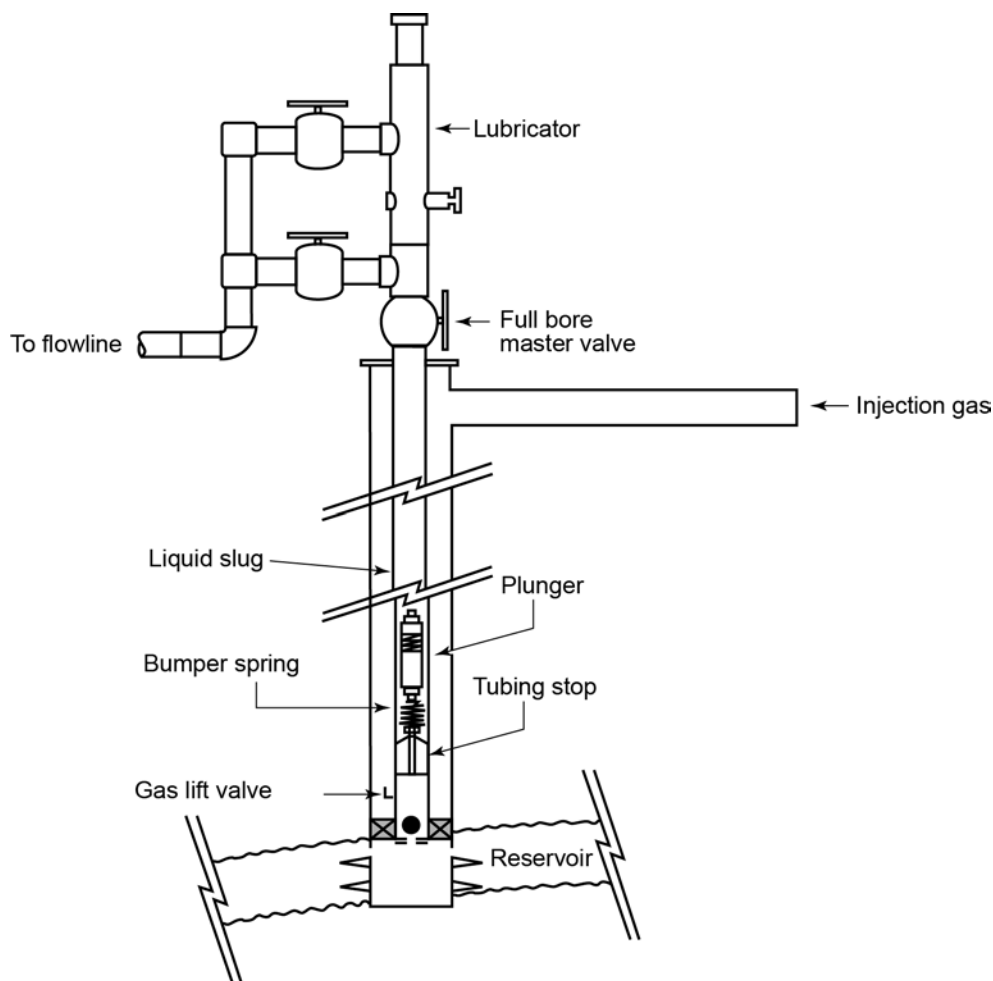


Figure 11—Design for Intermittent Gas-lift with Plungers

During the liquid slug formation period, the plunger sits on a bumper spring above the operating valve. When the gas-lift valve opens, the plunger and the liquids are pushed to the surface. When the plunger reaches the surface, two things can occur:

- if the lubricator is set to catch and retain the plunger, it stays in the lubricator and can be retrieved by closing the master valve;
- if the lubricator is not set to catch the plunger, it will fall back to the bottom of the well as soon as the force exerted by the injection gas on the plunger diminishes below the weight and friction of the plunger.

3.5 Control Methods for Intermittent Gas-lift Wells

3.5.1 General

There are three primary means for controlling the injection into intermittent gas-lift wells: choke control, time cycle control, and a combination of the two. All can be effectively implemented with a production automation system. The primary purpose of the gas-lift system is to provide a reliable, stable source of high-pressure gas for injection into intermittent gas-lift wells to enhance production.

3.5.2 Choke Control Systems

The gas injection rate into the well's tubing-casing annulus is controlled with a surface choke or control valve, often in conjunction with a pressure regulator. Gas is injected continuously into the annulus. When the pressure in the annulus builds high enough, the intermittent gas-lift operating valve opens and an injection cycle occurs. The frequency of the injection cycles is controlled by the rate of injection and pressure buildup in the annulus. From a production automation perspective, this form of control is ideal as any impact of the injection cycles on the system and other wells is minimized when the injection rate is constant.

In certain cases, a surface pressure regulator may be needed in order to allow the use of a larger sized choke in the injection line. In such cases, the pressure regulator maintains a constant maximum valve opening pressure between valve operating cycles. Once the maximum pressure is reached, the regulator closes until the pressure begins to fall during the next gas injection cycle. This type of control is recommended for low capacity wells that would require an extremely small choke. Limitations of this control method include a reduced maximum slug size that can be lifted per cycle and increased risk of freezing and plugging in installations with small chokes.

3.5.3 Time Cycle Control Systems

3.5.3.1 General

In time cycle control systems, the surface injection valve is kept closed until time for the injection cycle, when it is opened to allow a high injection rate into the tubing-casing annulus. This process allows for improved control of the injection process since both the frequency and the volume of gas per cycle can be controlled. In this case, the production automation system shall control both the opening and the closing of the surface injection valve to achieve the desired injection frequency and the desired volume of gas per cycle.

The control valve should be placed at the wellhead, rather than at the injection manifold, to assure the most efficient operation. When the controller is far from the well, both casing and injection lines to the well shall be filled to increase the casing pressure, causing the injection pressure to rise at a lower rate.

3.5.3.2 Surface Time Cycle Controls

When the well is on "time cycle control," a surface controller controls the gas injection per cycle. The operator can change the settings of the surface controller to modify the time it remains open or closed. During the liquid slug formation period, the surface controller and gas-lift valve remain closed, so the pressure in the annulus is constant. After a predetermined period of time, the controller opens allowing a high gas flow rate to flow into the annulus. The pressure rises rapidly until the gas-lift valve opens and the injection pressure continues to rise, making gas flow rate into the casing greater than the gas inflow rate. If both rates are equal, or close in value, the required injection duration is too long, decreasing the efficiency of the process. If the flow rate leaving the annulus is greater than the gas flow rate entering it, the casing pressure falls and the gas-lift valve might open and close several times while the surface controller is open. This interrupts gas injection into the tubing, causing high fallback losses, and can damage the gas-lift valve.

One advantage of utilizing time cycle controllers is their ability to adjust the volume of gas per cycle and the capability to independently change the cycle time and volume of gas injected per cycle. Where several intermittent wells are supplied by one compressor, the production slugs from each well should be staggered to avoid overloading the separator with tail gas behind the slug and vent gas that should go to the compressor. This is difficult to achieve if the wells are on choke control. The use of surface controllers can create problems to the high-pressure side of the system by not utilizing the tubing-casing annulus as high-pressure gas storage, as they allow staggering of intermittent production.

Disadvantages of using surface controllers include increased well maintenance requirements as more equipment will need to be installed, operated, and maintained. Pressures in the gas injection system can fluctuate as gas injection is alternately stopped and started. When several wells intermit at the same time, the manifold pressure decrease can cause a well to skip one or more cycles as the flow rate might not be

sufficient. The manifold pressure can drop either due to lack of compression capacity or lack of available high-pressure storage volume gas-lift system. To overcome a pressure drop at the manifold, a synchronized gas injection control at the manifold is recommended.

3.5.4 Combined Choke and Time Cycle Controls

3.5.4.1 General

A production automation system can combine the features of both choke control and time cycle control into one process. Injection into the well's tubing-casing annulus is controlled on a continuous basis similar to choke control. However, the injection is stopped just before the casing pressure increases enough to cause the intermittent gas-lift operating valve to open. When it is time for the injection cycle to occur, the automation system fully opens the surface injection valve. When the cycle is complete, the automation system partially closes the surface valve enough to close the gas-lift valve and allow the gas injection. This approach minimizes the impact on the gas-lift system as gas injection occurs on a continuous basis rather than just when an injection cycle is required. The timing of each injection cycle and amount of injected gas is controlled, providing the advantages of time cycle control and minimizing system instability.

NOTE This arrangement is only recommended when the injection gas line pressure greatly exceeds the operating casing pressure and when the capacity of the annulus is extremely small. For most installations, the use of a choke for reducing the time rate of increase of the casing pressure should be avoided, as it will increase the injection GLR and can decrease the daily fluid production.

3.5.4.2 Setting Pressure Closing Controls

When the injection gas line pressure varies significantly, it is recommended to open the controller on time and close it after a predetermined pressure is reached, allowing the cycle frequency to remain constant, also keeping the controller open, until the desired casing pressure is reached. This operation requires a pressure signal sent to the controller, which is programmed to analyze the information and send a command to open or close the injection line valve.

3.5.4.3 Time Cycle Control with Maximum Pressure Controls

In this application, the controller is opened and closed based on time, but the maximum pressure is controlled during the gas injection period, preventing it from increasing above a predetermined level. This maximum pressure is maintained until the timing device closes the controller. This type of control is recommended for intermittent installations with small casings, where the casing pressure increase can abruptly become excessive and open the upper valves.

3.6 Dynamic Well Control Methods

3.6.1 General

The goal of intermittent gas-lift is to optimize oil production by optimizing both the timing and the size of each production slug. To achieve this, it is necessary to optimize the frequency of each injection cycle, and the volume of gas injected per cycle. If too little gas is injected, there will be too much liquid fallback and too little production per cycle. If too much gas is injected, the process will also be inefficient. With a production automation system, the possibility exists to dynamically measure the production pressure and the production rate vs time. With this "real-time" information, it is possible to optimize the duration of the injection cycle in real time, i.e. stop the injection cycle at the optimum time to assure maximum liquid recovery per cycle, without overinjecting.

3.6.2 Controlling the Gas Injection While Unloading an Intermittent Gas-lift Well

3.6.2.1 General

This section discusses considerations for controlling gas injection while unloading an intermittent gas-lift well. Included are actions before unloading, unloading valve limitations, injection control during well unloading, unloading if the system pressure is low, and after unloading a well with large tubing.

3.6.2.2 Actions Before Unloading

If the well is loaded with mud, it should be circulated to clean the perforations and tubing ID prior to running gas-lift valves. Abrasive materials in the well fluids will damage the gas-lift valve seats, resulting in valve malfunctions. The injection gas line should be blown clean of scale, welding slag, and all particulates before being connected to a well. Valves between the wellhead and the flow station, separator capacity, and all safety release valves for the gas gathering system should be carefully inspected and operated to ensure applicable functionality.

3.6.2.3 Injection Control During Well Unloading

In the unloading process, when the tubing-casing annular liquid level reaches the uppermost unloading valve, a large head of liquids is produced to the surface at a high rate as the initial surge of lift gas through the valve displaces the liquids standing in the production tubing. This initial head of liquids can exceed surface facility capacity and should therefore be managed carefully. The well should be unloaded very slowly, especially before the top valve is uncovered. During unloading, fluid from the casing is transferred to the tubing through open gas-lift valves. The casing pressure should be increased gradually to maintain a low fluid velocity through the open gas-lift valves. If full line pressure is exerted on top of the fluid column in the casing, a pressure differential, approximately equal to the line pressure, will occur across each valve in the installation, potentially damaging the valves. After the top valve is uncovered, this condition will not occur as the top valve will begin to pass gas before a high pressure differential can exist across the valves below the liquid level. See API 19G5 for detailed procedures for safely unloading intermittent gas-lift wells.

During U-tubing, the time cycle controller should be set at a high injection gas cycle frequency with a short period of time to permit gradual increase in casing pressure. After the first valve is uncovered, the injection gas volume per cycle should be slightly greater (~+20 %) than required for normal operation. As the depth of lift increases, the duration of gas injection should be lengthened to assure ample gas volume and the injection gas cycle frequency should be decreased. In practice, wells are always unloaded using "continuous" injection. If the well is designed for time cycle control, it may be necessary to "control" the injection rate by partially closing the manual surface valve on the injection line during unloading.

Not all intermittent installations can be unloaded or operated with choke control. The type of gas-lift valve and the ratio of tubing-casing annulus capacity to tubing capacity shall be suited for this type of operation. The choke size should be small enough so the casing pressure can decrease when the gas-lift valve opens. Before the first valve is uncovered, the gas flow rate into the casing should be very low (<50 % of design daily injection rate).

Unloading a well in choke control takes more time than cycle controllers. When the uppermost unloading valve is first uncovered, the tubing pressure is high and the valve opening pressure is low. The initial slug is large requiring maximum gas volume, but this gas volume is difficult to achieve as high tubing pressure limits the spread of the valve. Furthermore, for the first valves, the available annular space is small since it is mostly filled with liquids. As a result of the limited volume of gas per cycle, the well will produce a series of small liquid slugs for a period of time. But as the unloading operation proceeds, the valve spread increases as does the available annular space. With time cycle control, the opening pressure of the unloading valve can be overrun and adequate injection gas volume injected to efficiently lift the incrementally larger slugs.

3.6.2.4 Unloading if the System Pressure Is Low

When not enough pressure is available to unload the well, apply gas injection pressure to the tubing while keeping the casing at line pressure. If a standing valve is not present, this will force some of the liquid from the tubing and casing into the formation, uncovering the top valve and allowing the unloading process to continue. For production-pressure-operated (PPO) valves, this procedure will open an upper valve, permitting the unloading operation to resume. This process should be used with care if there is a possibility of increased sand production. This process will incur less risk for solids production from a carbonate reservoir than from a sandstone reservoir.

3.6.2.5 After Unloading a Well with Large Tubing

Operational problems have been observed in the field where choke control is used in wells with large-diameter (i.e. 4³/₄-in. ID) tubing. After the well is unloaded, the spread seen on the pressure chart is very small, as the liquid column above the operating valve can be large. The valve may have been sized correctly, but high fallback losses cause it to open at a lower injection pressure (causing a small spread). To observe this situation, open the choke at the injection manifold completely until the spread appears normal. When the injection rate is choked, the well can begin to load up again. If this occurs, the well can be improved with the assistance of a surface controller, or a pilot valve, with a larger ratio of effective port area to bellows area.

3.7 Production Automation of Intermittent Gas-lift Wells

3.7.1 General

An effective means of optimizing a complex oil field with multiple wells is to use a production automation system. The primary goal is to optimize the oil production from each intermittent gas-lift well. A production automation system allows the gas-lift staff to optimize the intermittent gas-lift injection cycle frequency and volume of gas injected per cycle.

A production automation system can be used to coordinate injection cycles between wells to prevent inter-well interference. One well can affect other wells that are part of the same gas-lift distribution system. Performance issues arise when a system upset occurs. If a compressor temporarily trips, or comes back on line, or if a production station temporarily trips, or comes back on line, there will be a temporary upset in the system. When the supply of injection gas is temporarily decreased, it may be necessary to defer injection cycles in some wells to prevent ineffective injection cycles in all of the wells. When the supply of lift gas is returned to normal, the injection process shall be adjusted to prevent over-pressuring the system and causing over-injection.

3.7.2 Information for Effective Automation System Use

Normally, it is sufficient to measure system information once each minute. An intermittent gas-lift system can require measurement once each 15 seconds. Some gas-lift system information is best measured on a continuous basis, such as the following.

- *Gas-lift system rate that is available for injection:* It is necessary to continuously measure the rate of gas-lift gas available for injection into the gas-lift wells (both continuous and intermittent) served by the system. This requires use of several individual measurement points to measure the net gas in the system. Some gas-lift systems can have more than one source of gas, and there can be more than one “demand” for this gas.
- *Gas-lift system pressure:* It is necessary to know the pressure of the gas-lift system. One of the primary objectives of the gas-lift automation system is to maintain stable system pressure, even when there are minor or major upsets to the system. Minor upsets can occur when an injection cycle is conducted on an intermittent gas-lift well.

The following process variables require measurement on each intermittent gas-lift well, on a continuous basis.

3.7.3 Injection Rate Controls

The volume of gas injected per cycle shall be determined by measuring the rate of gas injection and integrating it over the time of the injection cycle. If the intermittent gas-lift well is on choke control, the gas injection into the well's tubing-casing annulus is continuous. The volume of gas injected per cycle is determined by calculating the volume of gas between two consecutive injection cycles. It may also be determined by calculating the volume of gas injected per day and dividing by the number of injection cycles in the day. If the well is on time cycle control, the volume injected per cycle is determined by calculating the volume of gas injected during the injection cycle.

3.7.4 Injection Pressure Measurements

For intermittent gas-lift wells, the gas-lift injection (casing) pressure will vary throughout the injection process. It is necessary to know the pressure at all stages in the process to correctly evaluate the effectiveness of the process and to troubleshoot any problems.

3.7.5 Production System Data Collection

It can be useful to measure the pressure in the production manifold. If the pressure drop between the wellhead and the production manifold is too high, it can signify possible line blockage due to sand, paraffin, scale, etc. Measuring the production pressure is necessary to determine the arrival and duration of each production slug and to help evaluate production problems.

Production rate is not normally measured on a continuous basis. However, there are inexpensive techniques available that can provide a relatively accurate estimate of production rate (of total liquid) on a continuous basis. This can assist in evaluating the effectiveness of the production slugs and troubleshooting problems in the production process. One technique is the "differential pressure" method whereby a small pressure drop is taken across an orifice plate or a choke body and measured. This differential pressure, in combination with the measured production pressure and the measured gas injection rate, can be used to provide a reasonably accurate estimate of the total liquid production rate. The method shall be "calibrated" by an accurate well test.

3.7.6 Coordination of Production Controls with Gas-lift Systems

Intermittent gas-lift is never the only production function in a field. Fields usually have a well test system, production gathering and processing systems, and a gas compression and distribution system. There may be a pressure maintenance or secondary recovery injection system in the field. All of these systems and processes require effective coordination for optimum operations.

It is normal that some wells can be produced more effectively by continuous gas-lift, some by intermittent (or chamber) gas-lift, and some by pumping. It is common that both continuous and intermittent gas-lift operations are connected to a common gas supply system. A production automation system is able to control the operation of each well in the system, allowing both continuous and intermittent gas-lift wells to produce at optimum efficiency.

If a production station trips or has some form of upset, it may be necessary to immediately stop production from the wells under production. This can be done by automatically closing an emergency shutdown (ESD) valve and relying on pressure buildup in the flowlines to stop the wells. A better approach is to automatically intervene and stop the production process before an emergency "shutdown" occurs.

3.7.7 Optimization of Injection

After an installation is unloaded, the time cycle controller should be adjusted for optimum cycle time and minimum injection GLR. If the well is to be operating on choke control, the final selection of the choke or opening through a metering valve is determined by a selection procedure. Choke control operations require unbalanced injection-pressure-operated (IPO) valves that respond to casing and tubing pressures. By

decreasing the choke size, the well has a longer time to deliver fluid into the tubing, increasing the tubing pressure at valve depth and reducing the casing pressure required to open the valve.

With choke control it is difficult to control the precise time for each well to intermit in small gas-lift systems. If many wells intermit at the same time, the compressor may not be able to handle all the suction gas and a large amount of gas would be flared. This increases the demand for additional makeup gas.

4 Design Considerations for Intermittent Gas-lift Installations

4.1 General

An intermittent gas-lift installation should be tailored to fit the well and reservoir conditions of the specific well. The flexibility of gas-lift permits the installation designed to meet various conditions in the oil field. The type of gas-lift valves, installation, valve pressure settings, mandrel spacing, tubing size, and surface equipment can vary to meet specific production and well requirements.

The design of an intermittent gas-lift installation has the following goals.

- Unload the well satisfactorily.
- Inject the proper volume of gas per cycle at an adequate flow rate and pressure, and at a cycle frequency that will maximize daily production.

4.2 Mandrel Spacing

4.2.1 General

Intermittent gas-lift wells produce from reservoirs with low static pressure; however, unloading valves should be installed to unload the well when it has been loaded for operational maintenance.

It is good practice to assume the well is filled with liquid, but if the mandrel spacing is based on actual static liquid level sustainable by the reservoir pressure, the top valve should be placed at the static liquid level. The following sections describe one procedure available for mandrel spacing for wells on intermittent gas-lift. This procedure is well suited for unloading the well by intermittent injection using IPO unloading valves. See Figure 12.

4.2.2 Graphic Procedure for Spacing Unloading Mandrels/Valves

NOTE This procedure assumes the use of IPO gas-lift valves. Use of PPO valves is not recommended for intermittent gas-lift wells. See 5.3.1.

The recommended procedure for installation design for unloading mandrels and valves in intermittent gas-lift wells is as follows.

- In a pressure-depth diagram, trace a vertical line from the expected wellhead pressure (P_{wh}) to the top of the perforations. If the well can be unloaded to atmospheric pressure instead of wellhead pressure (well unloaded to a pit), the spacing distance can be increased and fewer mandrels may be necessary.
- From the available surface gas injection pressure (P_{io1}), trace a line to the top of the perforations using a suitable gas pressure gradient.
- From the wellhead pressure (P_{wh}), trace a line with a kill fluid gradient until it intercepts the gas injection pressure (point $i1$). This defines the depth of the first unloading valve ($D1$). In locating the first valve, a deeper depth can be obtained if the maximum available injection pressure, or kickoff pressure, is used. The operating pressure should be at least 100 psi (689.48 kPa) less than the line pressure to assure ample gas entry.

To find the depth of the second unloading valve:

- subtract from 25 psi to 50 psi (172.37 kPa to 344.74 kPa) from injection pressure P_{io1} . This defines the surface injection pressure for the second valve (P_{io2}). Taking a drop in injection pressure is recommended for IPO valves and provides excellent surface information for troubleshooting analysis;
- trace a line from P_{io2} to the top of the perforation using a suitable gas pressure gradient;
- find a depth $D1'$ by subtracting the liquid fallback from the depth of the first valve. The fallback is calculated by multiplying a fallback factor, which is usually taken between 0.03 and 0.06, times the depth of the point of injection (in 304.8 m or 1000 ft) times the length of the liquid column to be lifted. For the first valve and using a fallback factor of 0.05, the fallback is calculated in field units, by $0.05 \times (D1/1000) \times D1$ with $D1$ expressed in feet, and in SI units by $0.05 \times (D1/304.8) \times D1$ with $D1$ expressed in meters;
- from point “ $i2$,” trace a line with a kill fluid gradient until it intercepts the gas injection pressure (point $i3$). The depth of this intersection corresponds to the depth of the second valve.

To obtain the depth of the third unloading valve:

- subtract from 172.37 kPa to 344.74 kPa (25 psi to 50 psi) from injection pressure P_{io2} to define the surface injection pressure (P_{io3});
- trace a line from P_{io3} to the top of the perforation using a suitable gas pressure gradient;
- find a depth $D2'$ by subtracting the liquid fallback from the depth of the second valve. The fallback is calculated in field units, by $0.05 \times (D2/1000) \times (D2 - D1)$ with $D1$ expressed in feet, and in SI units by $0.05 \times (D2/304.8) \times (D2 - D1)$ with $D1$ expressed in meters;
- from point “ $i4$,” trace a line with a kill fluid gradient until it intercepts the gas injection pressure (point $i5$). The depth of this interception corresponds to the depths of the third valve.

This procedure is continued until a valve depth falls below the maximum allowable design depth. In this case all valves' depths shall be corrected by the procedure in 5.2.3.

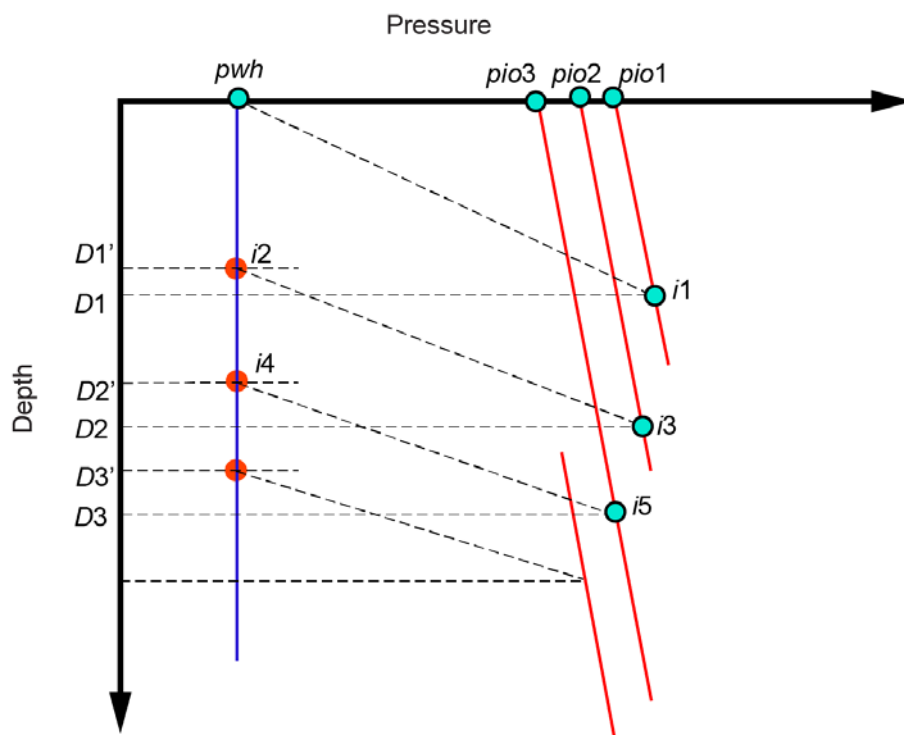


Figure 12—Graphical Procedure for Spacing Unloading Valves

4.2.3 Analytical Procedure for Spacing Unloading Valves

To derive an analytical expression that will describe the procedure for mandrel spacing, it is necessary to have an equation for the downhole injection pressure in terms of the surface injection pressure and the depth of the point of injection. The following equation may be used in cases where losses due to friction are negligible.

$$P_{iod} = FGL \times (P_{io}) \quad (9)$$

where

P_{iod} is the injection pressure at depth;

P_{io} is the surface injection pressure and FGL is given by:

$$FGL = 1 + BGL \times (D_i) \quad (10)$$

where

D_i is the depth of the point of injection expressed in thousands of feet if field units are used. If SI units are used, D_i is expressed in the actual depth in meters divided by 304.8. And

$$BGL = BLA + BLB \times (PO) + BLC \times (PO^2) \quad (11)$$

where

$$BLA = (3.6433 \times SGi - 0.2117) \times 10^{-2} \quad (12)$$

$$BLB = [(0.57508 - 1.8442 \times SGi + 1.5754 \times SGi^2) \times 10^{-4}] / 6.89 \quad \text{in SI units}$$

$$BLB = (0.57508 - 1.8442 \times SGi + 1.5754 \times SGi^2) \times 10^{-4} \text{ in.} \quad \text{field units}$$

(13)



$$BLC = [(7.1615 \times SGi - 2.3070 - 5.7763 \times SGi^2) \times 10^{-8}] / 47.53 \quad \text{in SI units}$$

$$BLC = (7.1615 \times SGi - 2.3070 - 5.7763 \times SGi^2) \times 10^{-8} \quad \text{in field units} \quad (14)$$

with

$$PO = P_{io} + 101.35 \quad \text{in SI units}$$

$$PO = P_{io} + 14.7 \quad \text{in field units and } SGi \text{ is the gas specific gravity.} \quad (15)$$

The analytical expression for each valve depth, D_i , is found from a pressure balance equation: the gas injection pressure at depth shall be greater than or equal to the pressure inside the tubing. For the depth of the first valve, D_1 , the pressure balance equation is

$$P_{wh} + D_1 \times g_s = FGL \times P_{io} \quad (16)$$

where

g_s is the gradient of the kill fluid in psi/1000 ft of true vertical depth if field units are used, or in kPa per 304.8 m of true vertical depth if SI units are used.

Since $FGL = 1 + BGL \times (D_1)$, the depth of the first valve, D_1 , will be

$$D_1 = (P_{io} - P_{wh}) / (g_s - BGL \times P_{io}) \quad (17)$$

The general equation for each valve depth, D_n , is then

$$D_n = \frac{(P_{ko} - (n-1)S) + (1 + (D_{n-2} - D_{n-1})FF)g_s D_{n-1} - P_{wh}}{g_s - (P_{ko} - (n-1)S)BGL} \quad (18)$$

where

FF is the fallback factor, which is usually a number from 0.03 to 0.06;

S is the pressure drop in surface injection pressure taken per valve as the unloading operation proceeds;

P_{ko} is the kickoff gas injection pressure at the surface.

If the depth of the last valve falls below the packer depth, then it is reassigned to be at the depth of the packer minus 9.1 m or 18.3 m (30 ft or 60 ft), and all upper valves' depths are corrected according to

$$D_n' = D_n - n (DEL) \quad (19)$$

Where DEL is given by

$$DEL = \frac{FGL_{n\psi 1} + g_s (D_{n-1} - D_n + \Psi_2) - \Psi_3}{(N)(g_s)} \quad (20)$$

where

N is the total number of valves and Ψ_1 , Ψ_2 , and Ψ_3 are

$$\Psi_1 = Pko - \frac{(N-2)S}{FGL_{n-1}} \quad (21)$$

$$\Psi_2 = (D_{n-2} - D_{n-1})FF(D_{n-1}) \quad (22)$$

$$\Psi_3 = Pwh(FGL_{n-1}) \quad (23)$$

where

n is the valve number.

4.3 Gas-lift Valve Selection

4.3.1 Choosing Unloading Valves

For economical and operational reasons, it is recommended to use single-element IPO gas-lift valves as unloading valves. The unloading valves should be set to open at high pressure so they will stay closed when the bottom of the liquid slug reaches each valve. Designing installations with PPO unloading valves is difficult and will not provide an operational advantage.

4.3.2 Choosing Operating Valves

Choosing the operating valve is the most important step in designing an intermittent gas-lift installation, if surface intermitters are not used, the operating valve shall control the following parameters that affect efficiency:

- gas injection pressure;
- total volume injected per cycle;
- instantaneous gas flow rate.

Setting the valve to open at a particular injection and production pressure is not problematic and can be handled by most commercially available valves.

The injection pressure does not affect the liquid fallback for wells handling liquid slugs between 61 m (200 ft) and 244 m (800 ft) in length, when surface injection pressures are above 4.83 MPa (700 psig). Gas-lift efficiency decreases for surface injection pressures below 4.83 MPa (700 psig). The system available injection pressure should consider the pressure drops taken per valve and the pressure drop across the system operating valve.

The total gas volume injected per cycle will depend on the spread of the valve (difference between the valve's opening and closing pressure), which in turn depends on the area ratio (area of the seat divided by the effective area of the bellows). For the cycle time to remain constant and near optimum value in choke control operations, installation of a valve with the correct area ratio is required. Area ratio determines the volume of gas injected per cycle. Increasing the gas flow rate at the surface will increase cycle frequency, but will have little effect on the total volume of gas injected per cycle, unless the valve is highly sensitive to tubing pressure, or cycle time is altered significantly.

The instantaneous gas flow rate is the parameter that clearly differentiates a gas-lift valve for intermittent operation. A high gas flow rate is required to pass through the valve once it opens to maintain a high liquid slug velocity. If the slug velocity is too high, the gas breaks through the liquid, increasing liquid fallback losses. If slug velocity is too low, the gas tends to bubble through the liquid, also increasing liquid fallback losses. Experimental evidence has shown that a liquid slug velocity of 304.8 m/min (1000 ft/min) (+15 %)

approximately) is recommended. A valve should not stay open for a period of time (in minutes) much longer than the numerical value obtained when the depth (measured in thousands of feet) of the operating valve is multiplied by a factor of 1.15 to pass the total volume of gas required.

High instantaneous gas flow rates require a large valve orifice diameter. This is problematic for single-element valves where the spread of the valve is related to the diameter of the seat. If a small spread is required, a small seat diameter shall be installed. This will not provide a high instantaneous flow rate, even though it will probably be able to pass the correct volume of gas per cycle.

To facilitate flexible control over the operation/production of the well, IPO valves are preferred over PPO valves. A PPO valve will respond mainly to the pressure inside the tubing. Therefore, precise details of the optimum liquid slug length are required for PPO valves and provisions shall be made to account for inflow changes. PPO valves are not used for chamber installations, as they are located above the liquid level. Fluid tripped valves with casing pressure closing action offer a good choice for compressor operated systems in very small gas-lift systems.

Gas-lift pilot valves are recommended for intermittent lift installations. Intermittent gas-lift requires the rapid injection of a substantial volume of gas into the tubing for short periods to displace a slug of fluid from the point of injection towards the surface production equipment. This is provided by a pilot valve design. The selection of the correct pilot valve design requires design knowledge and proper calibration to achieve the desired performance. Within the pilot valve, the size of the injection orifice together with the injection pressure determines the velocity of the liquid slug's production.

The pilot portion of these valves controls the opening and closing pressures. The difference between these pressures is identified as the "spread." The differential pressure between the injection gas pressure and the production fluid pressure working on the annulus area of the power section overcomes the integral spring/bellows force of the power section. This allows the injection gas to flow through the reverse flow checks into the production conduit.

The use of 1½-in. valves in operation are preferred, rather than 1-in. valves, because:

- 1½-in. valves have larger main port diameters, providing higher flow rates across the valve, required for efficient intermittent lift;
- the minimum area ratio for a 1-in. valve might not be as small as required for cases where the ratio of the injection annulus volume to the tubing volume is high (i.e. small tubing inside large casing);
- for pilot operating valves, the 1½-in. pilot valve is more robust and historically gives a longer operating life than 1-in. pilot valves.

The cycle time for which the daily fluid production is maximized is defined as the optimum cycle time. If the cycle time is too short, the injection GLR will be high and the liquid production will be below the well potential. If the cycle time is too long, the injection GLR will be low and the liquid production can be lower than the maximum production from the well. There is a trade-off between column height and accumulation time. The bigger the column, the longer the accumulation time, and the lower the number of cycles per day.

The optimum cycle time depends on the well *PI* at maximum drawdown, and not on the static bottomhole pressure. Testing the well several times for different cycle frequencies is one method of determining the optimum cycle time. For this procedure, it is necessary to have an injection GLR 10 % to 20 % greater than the recommended injection GLR and to inject the gas at an instantaneous flow rate that will enable the liquid slug velocity to be close to 304.8 m/min (1000 ft/min). A rough estimate of the liquid slug velocity can be obtained from evaluation of casing and tubing pressure trend data or by inspection at the wellhead. It is recommended to follow this procedure even if the optimum cycle time has been determined analytically using the algorithm provided in A.1.

4.4 Gas Volume Required per Cycle

Field scale tests have shown that the volume of gas per cycle and the liquid fallback factor, FF , are related as indicated in Figure 13. The liquid fallback factor is the percentage of the initial column length, per 300 m (1000 ft) or of point of injection depth, which will not be produced to the surface.

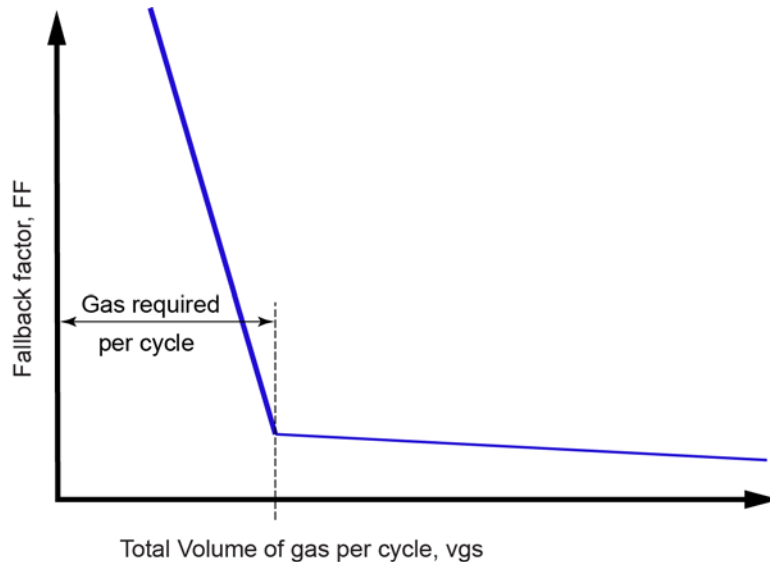


Figure 13—Fallback Factor as a Function of the Total Volume of Gas per Cycle

Figure 13 is valid only when the instantaneous gas flow rate into the tubing is kept at a rate high enough to maintain the liquid velocity around 304.8 m/min (1000 ft/min). Fallback losses increase if the volume of injection gas is below the required volume of gas per cycle. However, not much is gained by injecting more than the required volume of gas per cycle as seen in Figure 13. The precise volume of gas necessary is required to reach maximum efficiency.

The required total volume of gas per cycle is a function of the following.

- The tubing inside diameter.
- The API Gravity of the oil. The required gas per cycle will increase exponentially as the API is decreased. Above 23° API, the gravity of the oil does not play a major role on the gas injected per cycle.
- The depth of the point of injection: the required gas per cycle increases linearly with depth.
- Initial column length (to a minor extent). Columns between 60.96 m and 243.84 m (200 ft and 800 ft) do not play a major role in the required gas per cycle.

A practical way of finding the required volume of gas per cycle is as follows.

- Using an analytical procedure, find the theoretical gas required per cycle for a starting point for use in the field.
- Inject 30 % to 40 % above the theoretical volume of gas per cycle. A surface intermitter or time cycle controller is required.
- Keep this injection rate for at least 3 days to provide for stabilization and then test the well following the procedure suggested in 4.7.6. See API 19G5 and [API 11V8](#) for discussions of well test frequency, duration, and accuracy.

- While keeping the total cycle time constant, decrease the volume of gas injected per cycle by 10 % of the previous volume. After at least 3 days, test the well again.
- Follow the last step until the liquid production begins to decrease. This will indicate that the minimum gas volume per cycle has been reached.

The results of the procedure described above can be used for other wells in the same field as long as the API Gravity and the tubing diameter are about the same. Only a linear correction is needed for the depth of the point of injection in this case.

If only a rough estimate of the volume of gas per cycle is needed, the following formula can be used.

NOTE Boxed text titles are inserted immediately above the calculations that are included in the electronic files for this document, to facilitate automated calculations. Accuracy is the responsibility of the user.

Volume of gas per cycle

$$Q = \frac{Ppd \times Dv \times Bt}{14.7} \quad \text{in field units} \quad (24)$$

where

- Q is the volume of gas per cycle in ft³;
- Ppd is the tubing pressure at valve depth when the valve opens in psia;
- Dv is the depth of the valve in ft;
- Bt is the volumetric capacity of the tubing in ft³/ft.

$$Q = \frac{Ppd \times Dv \times Bt}{101.35} \quad \text{in SI units}$$

where

- Q is the volume of gas per cycle in m³;
- Ppd is the tubing pressure at valve depth when the valve opens in kPa;
- Dv is the depth of the valve in m;
- Bt is the volumetric capacity of the tubing in m³/m.

4.5 Valve Port/Bellows Area Ratio Calculation

4.5.1 Valve Port/Bellows Area Ratio Calculation for Choke Control

Once a valve with a particular port/bellows area ratio is installed in the well, the volume of gas injected per cycle is fixed for choke control intermittent gas-lift if the cycle remains at optimum cycle time. It is important to be able to calculate the area ratio of the valve, if surface time cycle controllers will not be used.

From a force balance equation just before an IPO valve opens, the area ratio can be calculated as follows.

Valve port/bellows area ratio

NOTE The boxed text indicates the name of the file within the related excel spreadsheets that facilitates efficient running of these calculations.

$$R = \frac{P_{iod} - P_{vcd}}{P_{iod} - P_{pod}} \quad (25)$$

The injection opening pressure at valve depth, P_{iod} , is usually known as soon as the valve spacing has been found. P_{vcd} is the valve closing pressure at depth and P_{pod} is the production pressure in the tubing when the valve opens.

Tubing opening pressure

The tubing opening pressure in psi (kPa), P_{pod} , is found from:

$$P_{pod} = P_{wh} \times fg + Q \times \rho_f \quad \text{in field units} \quad (26)$$

where

fg is the gas pressure correction factor used to calculate the gas pressure at depth;

P_{wh} is the wellhead pressure in psi;

ρ_f is the liquid gradient in psi/ft;

Q is the liquid column length in ft.

$$P_{pod} = P_{wh} \times fg + Q \times \rho_f \quad \text{in SI units}$$

fg is the gas pressure correction factor used to calculate the gas pressure at depth;

P_{wh} is the wellhead pressure in kPa;

ρ_f is the liquid gradient in kPa/m;

Q is the liquid column length in m.

The value of Q can be found as soon as the optimum cycle time has been calculated. Refer to A.1 to find the optimum cycle time.

The only parameter that remains to be found to compute the area ratio is the valve closing pressure at depth, P_{vcd} . This is done by a mass balance of the gas injected into the tubing and the gas provided by the gas-lift system:

$$v_{gs} = v_{ga} + v_{gl} + v_{ge} \quad (27)$$

The volume of gas injected into the tubing, v_{gs} , is equal to the volume provided by the annulus, v_{ga} , plus the volume provided by the injection line from the choke to the wellhead, v_{gl} , plus the volume of gas that passes through the surface choke while the gas-lift valve is open, v_{ge} .

The volume of gas injected into the tubing, v_{gs} , can be calculated following the procedure given in Annex A. The volume of gas that passes through the surface choke while the gas-lift valve is open (v_{ge}) is a function of v_{gs} and the cycle time, while v_{ga} and v_{gl} are functions of P_{iod} and P_{vcd} . So the only unknown in the mass

balance equation is P_{vcd} . Refer to Annex A for calculation details. Once P_{vcd} is found from the procedure given in Annex A, all the parameters needed to find the value of R are known.

For spring-loaded, IPO valves, P_{vcd} is equal to the test rack closing pressure. For this type of valve, it is recommended to use an area ratio size higher than the one calculated following the procedure presented in this section since spring-loaded valves tend to close at a higher pressure.

For nitrogen-charged, IPO valves, P_{vcd} is equal to the dome pressure at depth. For this type of valve, it is recommended to use an area ratio size lower than the one calculated following the procedure presented in this section since these valves tend to close at a lower pressure.

4.5.2 Valve Area Ratio Calculations with Surface Time Cycle Controllers

The use of time cycle controllers is recommended to allow controlled changes in the volume of gas per cycle above those allowable by the spread of the valve alone. Time cycle controllers offer more flexibility in the total volume of gas per cycle, so calculation of the area ratio of the gas-lift valve is not as critical as it is for choke control intermittent lift. However, there are steps to consider that can provide an efficient operation, such as the following.

- The valve opening pressure should not be set at values close to the available pressure at the manifold. This will provide a flow rate at the surface greater than the flow rate through the gas-lift valve, keeping the annular pressure high and avoiding a premature closure of the gas-lift valve.
- The area ratio of the valve cannot be very small as it will cause an increase in the gas injection time required to inject the required volume of gas, but it cannot be too large as it will limit the volume of gas per cycle to high values only. If the volume of gas per cycle needed is less than the spread of the valve alone supplies, the operator will not be able to decrease the volume of gas per cycle.
- Calculate the area ratio of the valve as if the well will operate on choke control, then use an area ratio 30 % to 40 % less than the calculated value.

4.6 Use of Mechanistic Models for Intermittent Gas-lift Design Calculations

The use of mathematical models based on the physics of the intermittent lift process is increasingly popular among gas-lift designers. These models provide detail information of the process as a function of time that would otherwise be impossible to obtain.

If the liquid slug could behave as an indivisible unit and the liquid fallback could stay adhered to the wall of the production pipe, the intermittent lift process would be a very simple lift method to model mathematically. But in reality, the process can be highly complex, with gas break through and liquid slug regeneration taking place behind the main body of the liquid slug as it travels along the pipe. These transient two-phase flow conditions are difficult to model and are not considered by classic mechanistic models. The classical engineering approach is a good first choice for design and the more refined mechanistic models can be used as a refinement and check and balance procedure.

5 Operational Considerations for Intermittent Gas-lift Systems

5.1 General

This section provides guidelines and recommended practices for consideration in operating an intermittent gas-lift system.

In most cases, the people responsible for designing an intermittent gas-lift system and its wells are in different departments, located in different offices, from those who are responsible for its operation. However, it is essential that operators fully understand the design philosophy of the system. It can be impossible to operate