Recommended Practices for Design and Operation of Intermittent and Chamber Gas-lift Wells and Systems

API RECOMMENDED PRACTICE 11V10
FIRST EDITION, JUNE 2008

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Upstream Segment

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Contents

Page

Figures

Page

Tables

Recommended Practices for Design and Operation of Intermittent and Chamber Gas-lift Wells and Systems

1 Introduction and Organization of This Document

This API document presents guidelines and recommended practices for the design and operation of intermittent, chamber, and plunger gas-lift systems.

1.1 Overview of Section 1

Section 1 presents a summary of the primary guidelines and recommended practices for these methods of artificial lift. This summary section is sub-divided into nine subsections as outlined below. Then following this, there are the corresponding sections or annexes with detailed information on each section.

Section 1 is designed to provide a complete set of guidelines and recommended practices for use by practicing engineers and field operators. Sections 2 to Sections 7 are designed to provide more detailed information, including theoretical background for many of the guidelines and recommended practices. These sections are available for anyone, but are specifically intended for those who wish to gain a comprehensive understanding of the theory and practice of intermittent gas-lift.

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 Units Calculator and SI Units Calculator. These are two spreadsheets that are part of this RP.

The nine sections of this section, and the corresponding detailed sections and annexes are:

Subsection in Section 1	Associated Detailed Section	Topic That is Covered for Intermittent, Chamber, and Plunger Gas-lift
1.1	Section 1	Introduction of Guidelines and Recommended Practices
1.2	Section 2	Understanding Intermittent, Chamber, and Plunger Gas-lift
1.3	Section 3	Deciding When Each Method is Applicable. Choosing Candidate Wells (Includes a Table for Comparing Pros and Cons of Each Method)
1.4	Section 4	Selecting the Most Appropriate Control Method(s)
1.5	Section 5	Designing These Types of Gas-lift Wells and Systems
1.6	Section 6	Troubleshooting These Types of Gas-lift Wells and Systems
1.7	Section 7	Operational Considerations for Individual Gas-lift Wells and Systems
1.8	Annex A	Derivation of Important Intermittent Gas-lift Equations
1.9	Annex B	Detailed Example of an Intermittent Gas-lift Design
	Annex C	Use of Field Units and SI Units Calculators

The specific titles of each of the detailed sections and the two annexes are:

Section, Annex	Title
Section 2	Definition of the Intermittent Gas-lift Method and General Guidelines for its Application
Section 3	Types of Intermittent Gas-lift Installations (General Description and Operation)
Section 4	Types of Gas Injection Control
Section 5	Design of Intermittent Gas-lift Installations
Section 6	Troubleshooting Techniques for Intermittent Gas-lift

Section, Annex	Title
Section 7	Operational Considerations for Intermittent Gas-lift Systems and Wells
Annex A	Analytical Derivation of Optimum Cycle Time
Annex B	Intermittent Gas-lift Design—A Detailed Example
Annex C	Use of Field Units and SI Units Calculators

1.2 Understanding Intermittent, Chamber, and Plunger Gas-lift

This section presents a summary of the guidelines and recommended practices for understanding intermittent, chamber, and plunger gas-lift, and gaining an appreciation for how and when it can/should be applied. For more detailed information on this subject, please refer to Section 2, "Definition of the Intermittent Gas-lift Method and General Guidelines for its Application."

1.2.1 Summary of Recommended Practices in Section 2

The following table contains a summary of the recommended practices in Section 2 of this document.

No.	Subsection	Topic	Recommended Practice
2.1	**Definition of the Intermittent Gas-lift Method**		
1	2.1	Definition of the intermittent gas-lift method	Intermittent gas-lift is an artificial lift method in which high-pressure gas is intermittently 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) possible. The gas enters the tubing through a single point of injection located as deep as possible in the well. The liquid slug that has previously accumulated inside the tubing and above the point of injection is lifted to the surface by the work done by the gas entering the tubing as it expands to the surface.
2.2	**General Guidelines for Intermittent Gas-lift Installations**		
1	2.2.1	Guidelines for intermittent gas-lift oil wells	This section describes the reservoir and well conditions that are best suited for the application of intermittent gas-lift.
2	2.2.1.1	Reservoir pressure	As reservoir pressure or well productivity declines, the injection GLR required for gas-lift increases.
3	2.2.1.2	When to convert from continuous to intermittent gas-lift	Before shifting from continuous to intermittent gas-lift, it is recommended to explore the possibility of installing smaller diameter tubing using a nodal analysis approach.
4	2.2.1.3	PI—use of chamber lift installations and accumulators	If the PI is high, a chamber lift installation is recommended to increase the liquid production. If the PI is low, chambers are recommended for wells with low formation GLR to reduce the injection GLRs. Wells with high PI and high formation gas oil ratio are good candidates for accumulator type of completions as explained in Section 3.
5	2.2.1.4	Crude API gravity	Liquid fallback increases exponentially as the API gravity decreases below 23 °API.
6	2.2.1.5	Effect of water	When the percentage of water (water cut) is above 60 %, the intermittent lift is more efficient than it is for lower water cuts.
7	2.2.1.6	Depth of point of injection	The deeper the point of injection, the greater the required injection GLR becomes for a given reservoir pressure and PI.

No.	Subsection	Topic	Recommended Practice
8	2.2.1.7 a	Production tubing	The production tubing diameter should not be too large because large tubing diameters require high volumes of gas per cycle and it might be difficult to provide a gas injection rate high enough to keep the liquid slug velocity around 1000 ft/min (304.8 m/min) to maintain the fallback losses at a low value. As a rough estimate of the needed instantaneous gas flow rate, the required volume of gas per cycle, calculated using the equation given in Section 5, is divided by the time that would take the slug to travel to the surface at 1000 ft/min (304.8 m/min).
9	2.2.1.7 b	Injection annulus	A large annulus volume is recommended when the gas-lift system compression capacity is limited. In this case, the gas stored in the annulus provides the volume of gas injected per cycle and the gas injection is controlled by a surface choke.
10	2.2.1.7 c	The flowline	The flowline should be as large, or larger, than the production tubing.
11	2.2.1.7 d	The injection line	The injection line should not provide a large pressure drop when using time cycle controller because a steep increase in the casing pressure is required once the controller opens.
12	2.2.1.8	Use of standing valve	Standing valves prevent the reservoir from being exposed to high injection pressure when the operating valve opens. They are highly recommended for wells with low reservoir pressure and high PI. They should always be used in chamber type installations. Standing valves are recommended for the following reasons. — To prevent the injection gas from pushing the fluids back into the formation. — To prevent wasting injection gas energy in compressing the liquids with high formation gas content located from just below the operating valve to the perforations. For this reason, the standing valve should be located as closed to the operating valve as possible.
13	2.2.1.9	Wellhead arrangement	A well on intermittent gas-lift producing liquid slugs that travel at 304.8 M/min (1000 ft/min) in a 7.30-cm (2 $^7/_8$-in.) tubing is equivalent to a well on continuous gas-lift instantaneously producing over 1,271.9 M^3/D (8,000 Br/D). At this velocity, any restriction at the wellhead can cause severe fallback losses due to gas breakthrough. All unnecessary ells, tees, bends, etc., near the wellhead should be eliminated. If possible, a well should be streamlined always making sure that the wellhead allows wire line operations.
14	2.2.1.10	Surface chokes	If an intermittent installation must be choked to reduce the rate of gas entry into a low-pressure gathering system, the choke should not be placed at or near the wellhead, but should be located as far from the well as possible, preferably near the gathering manifold. This allows the slug to leave the production tubing and accumulate in the flowline.

No.	Subsection	Topic	Recommended Practice
15	2.2.1.11	Single element vs. pilot valves	Single element valves are recommended in a few cases only. Surface intermitters are recommended when using single element valves. The advantages of using single element valves are: — they are less expensive than pilot valves; — they have longer operation life in the well. Pilot valves are always recommended for any type of intermittent gas-lift operation except when severe operational conditions limit their use. The disadvantages of using pilot valves are as follows: — they are more expensive; — their failure rate is higher; — salt deposition can plug the bleed port in a pilot valve, which results in the main valve remaining open after the pilot section closes. The advantages of pilot valves are as follows: — The main orifice diameter is very large, which allows a high instantaneous gas flow rate. The spread of the valve can be adjusted without affecting its flow capacity. This allows a pilot valve to pass a large or small total volume of gas per cycle but always at a high flow rate.
16	2.2.2	Guidelines for gas-lift systems with intermittent gas-lift wells	This section presents guidelines for implementing the gas-lift systems that support intermittent gas-lift installations.
17	2.2.2	Use of closed “rotative” gas-lift systems	The design of closed rotative gas-lift systems is more difficult for intermittent gas-lift installations than for continuous gas-lift. The smaller the total number of wells, the harder the design becomes for intermittent lift. As the number of wells in the system increases, the smoother the operation becomes and the easier it is to design.
18	2.2.2	System pressure	To maintain a fixed compressor horsepower, the suction pressure must be maintained as constant as possible.
19	2.2.2	Type of intermittent gas-lift injection control	A gas-lift system with very few wells will perform better if the wells are on choke control because the casing annulus can be used as a high-pressure gas storage volume. As the number of wells increases, time cycle controllers are recommended so that control can be provided over the maximum number of wells intermitting at the same time.
20	2.2.2	Gas-lift compressors	A system with several smaller units permits the service or repair of a single unit with no loss of oil production. However, many small units increase detail attention, maintenance cost and final cost of the compressor station.
21	2.2.2	Gas-lift injection pressure	For surface injection pressures above 700 psig (4828 kPa), the injection pressure does not affect the liquid fallback for wells handling liquid slugs between 200 ft (60.96 m) and 800 ft (243.84 m) in length. The gas-lift efficiency decreases for surface injection pressures below 700 psig (4828 kPa). The system available injection pressure should consider the pressure drops taken per valve and the pressure drop across the operating valve itself.
22	2.2.2	Compressor inlet pressure	The compressor suction pressure needs to be as low as possible to lower the back pressured exerted on the intermittent gas-lift wells.

No.	Subsection	Topic	Recommended Practice
23	2.2.2	Inlet volume chambers	For small systems handling intermittent gas-lift wells, it is recommended to design low-pressure volume chambers to avoid excessive surges on the separator.
24	2.2.2.1	Separator Design	The production separator should be sized to handle the maximum number of wells intermitting at the same time plus the wells on continuous flow in the system. Restrictions such as unnecessary valves downstream of the gas outlet of the separator should be avoided. A safety relief pressure valve, set at higher pressure than the low-pressure controller, should be installed
25	2.2.2.2	Well tests and guidelines	It is not practical to have a continuous liquid meter at the test separator liquid outlet combined with a constant separator liquid-level control for testing wells on intermittent gas-lift. It is better to continuously monitor the liquid level in the separator from which the average volume of liquid per cycle can be calculated. See API 11V5 for general guidelines on well testing.

1.3 Deciding When Each Method is Applicable and Choosing Candidate Wells (Includes a Table for Comparing Pros and Cons of Each Method)

This section presents a summary of the guidelines and recommended practices for deciding when intermittent, chamber, or plunger gas-lift is the most applicable means of artificial lift, and for choosing wells that will be good candidates for this technique. This section contains a table for comparing the pros and cons of each method of artificial lift. For more detailed information on this subject, please refer to Section 3, "Types of Intermittent Gas-lift Installations (General Description and Operation)."

1.3.1 Types of Intermittent Gas-lift Installations

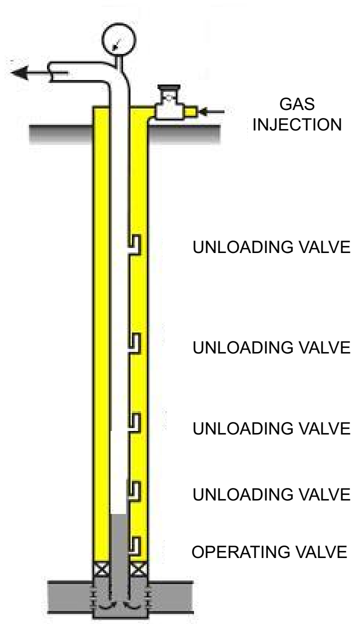
There are different types of intermittent gas-lift installations, each of which is recommended for a particular operational condition. This section shows the most common types of installations, their descriptions and applications.

There are more types of completions than the examples given in this section, but most of them follow the same principles outlined here.

1.3.1.1 Simple Completion

A simple completion is presented in Figure 1.1. 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. This is the most common type of intermittent lift installation as most of the wells on intermittent lift are wells that were initially on continuous gas-lift and were shifted to intermittent lift to reduce the injection GLR. Many continuous gas-lift wells will "self intermit" when the production rate falls below the rate that can be sustained on continuous gas-lift. Self-intermitting may be (is usually) much less efficient and effective than a properly designed intermittent operation because there is no standing valve, and the type of injection valve is not designed for intermittent operation. It will tend to throttle the injection gas rather than allow rapid injection of the gas “slug” beneath the liquid column in the well.

The completion in Figure 1.1 is called a “closed completion” because a packer and a standing valve are used. If the standing valve is not installed, the completion is called a “semi-closed installation.” A completion without a packer and a standing valve is called “open installation.”



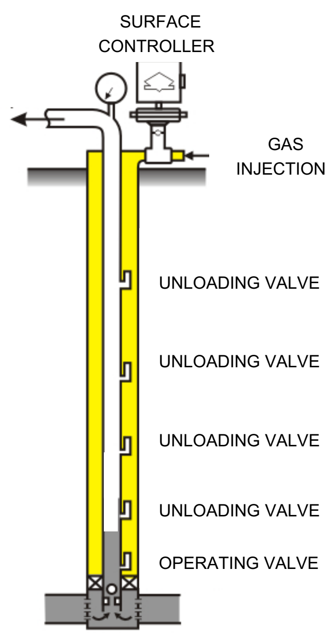


Figure 1.1—Simple Completion (Closed Installation)

1.3.1.2 Chamber Installations

1.3.1.2.1 Double Packer Chambers

Figure 1.2 shows a double packer chamber installation. The fluids from the reservoir enter the chamber annulus through the perforated nipple located right above the lower packer in the dip tube. As the liquid level rises in the annulus, the gas above it is vented to the tubing through a bleed valve located below the upper packer. When the chamber annulus and the dip tube are completely filled, the gas-lift valve located just above the upper packer opens and the gas in the high-pressure injection annulus is injected to the upper part of the chamber annulus. The liquids are forced downwards closing the standing valve and rising through the dip tube and the production tubing and are finally produced to the surface as a continuous liquid slug.

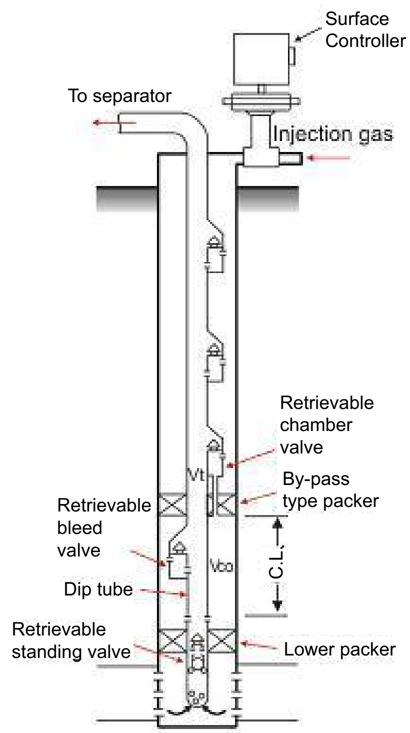


Figure 1.2—Double Packer Chamber

1.3.1.2.2 Insert Chamber

Figure 1.3 shows an example of an insert chamber installation: when the chamber valve opens, high-pressure gas enters the chamber through the by-pass packer forcing the liquids downward and closing the standing valve. The liquids rise through the dip tube to the production tubing until they are produced to the surface.

Figure 1.4 shows a completion recommended for wells in the “stripper” category. Stripper wells are normally defined as low *PI*, low-SBHP wells. In some cases, there are defined as wells that produce less than 100 bpd (15.9 m^3/day).

Figure 1.5 shows a chamber with an operating valve that acts as a bleed valve that allows communication from the chamber annulus to the tubing when it is not open. When the valve opens high pressure gas is injected into the chamber annulus.

Figure 1.6 shows a completion suitable for extremely long perforations.

Figure 1.7 shows a completion that can be used for tight formations. The gas forces the liquid downward and into the entrance of the dip tube. Some liquids might enter the formation, but for tight formations most liquids will be produced to the surface. This type of chamber is usually referred to as “open hole chamber.” Wells in hard-rock formations or with low *PI* which produce sand are good candidates for open hole chambers.

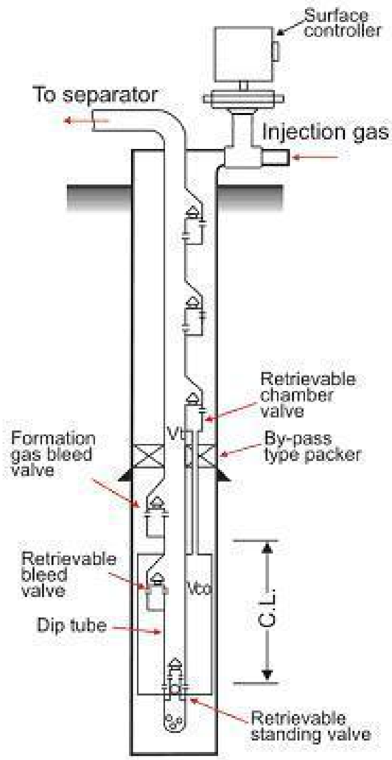


Figure 1.3—Insert Chamber

1.3.1.2.3 Accumulators

An accumulator is a section of the tubing located at the lower end of the tubing string with a diameter greater than the rest of the tubing.

1.3.1.2.4 Simple Type Accumulators

A simple type accumulator is shown in Figure 1.8. The accumulator combines the effect of liquid accumulation of a chamber installation with the ability of simple type completion to handle high formation GLRs. The small diameter tubing from the accumulator to the surface decreases the volume of gas required per cycle.

1.3.1.2.5 Insert Accumulators

Figure 1.9 shows an insert type accumulator.

1.3.1.2.6 Dual Completions

Figure 1.10 shows a typical parallel string dual completion.

In a dual completion with top of lower zone too far from upper packer if the lower zone is too far below the upper packer, intermittent gas-lift cannot be implemented if the top of the liquid column cannot reach the upper packer depth. A completion such as the one shown in Figure 1.11 is needed in this case.

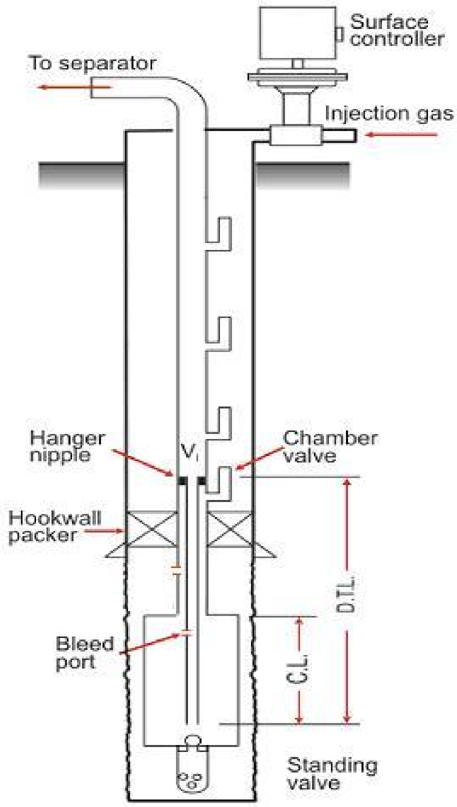


Figure 1.4—Insert Chamber with Hanger Nipple for "Stripper"-type Wells

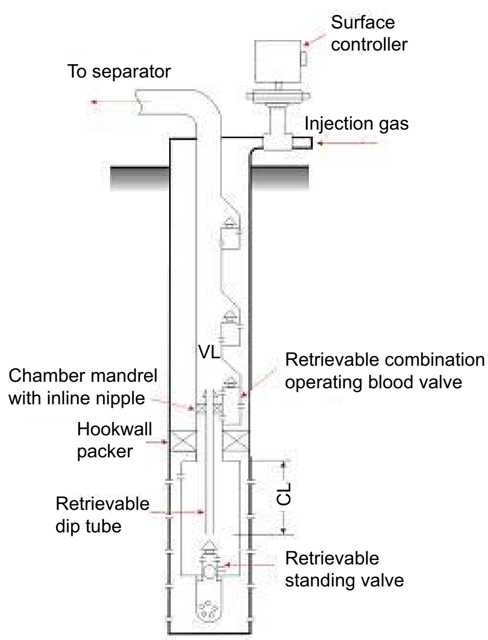


Figure 1.5—Insert Chamber with Combination Operating-bleed Valve

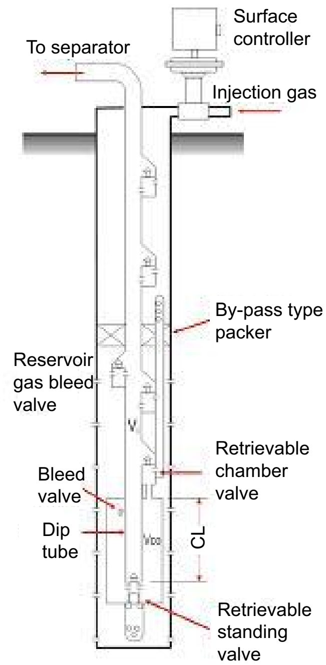


Figure 1.6—Extremely Long Insert Chamber

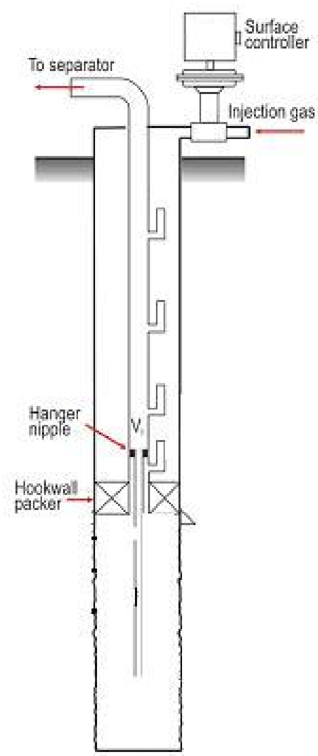


Figure 1.7—Insert Chamber for Tight Formations

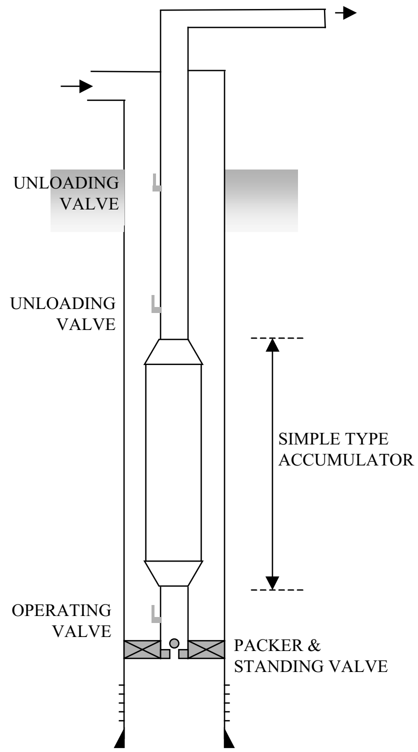


Figure 1.8—Simple Type Accumulator (Not to Scale)

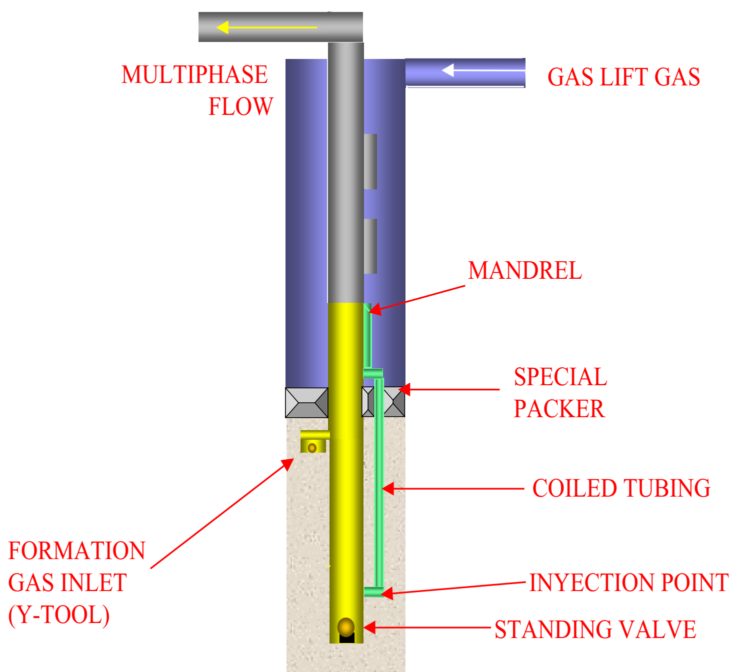


Figure 1.9—Insert Accumulator

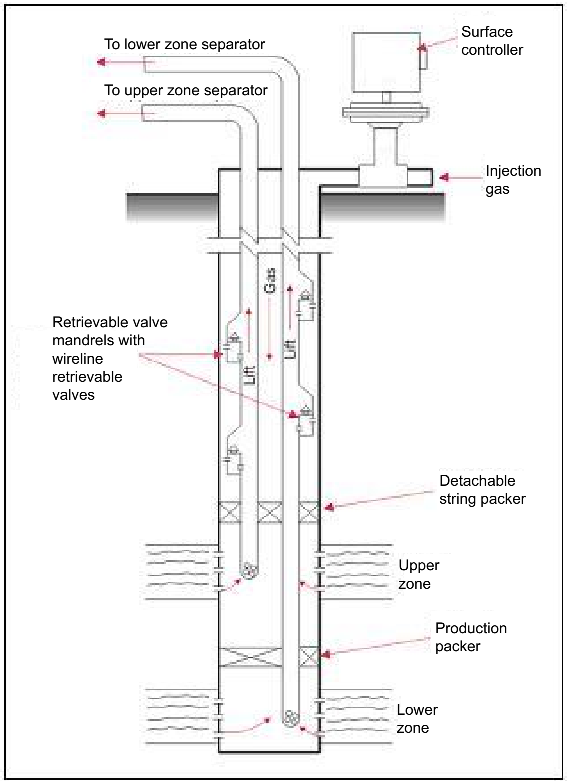


Figure 1.10—Parallel String Dual Completion

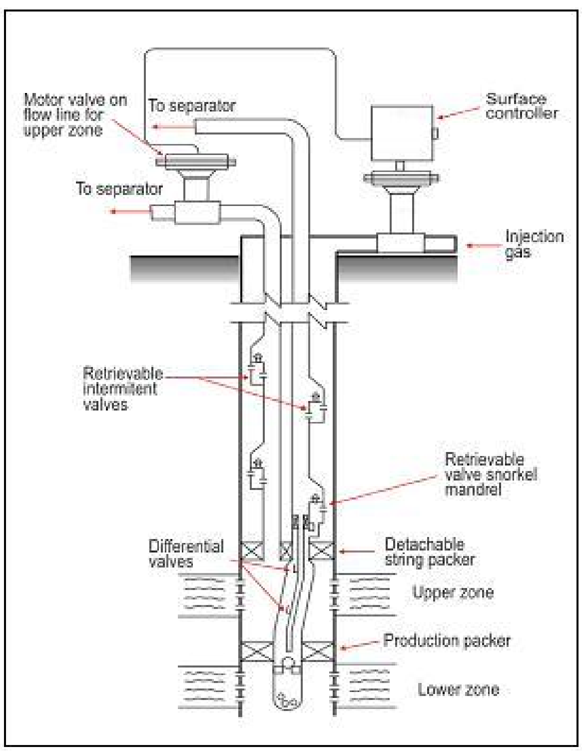


Figure 1.11—Completion for Zones That are Too Far Apart

1.3.1.2.7 Gas-lift with Plungers

A recommended completion for intermittent gas-lift with a plunger is presented in Figure 1.12. It is important to be sure intermittent gas-lift is working properly before considering use of a plunger. And, there are different types of plungers—constant OD, variable OD, "pacemaker" hollow plunger with ball, etc.

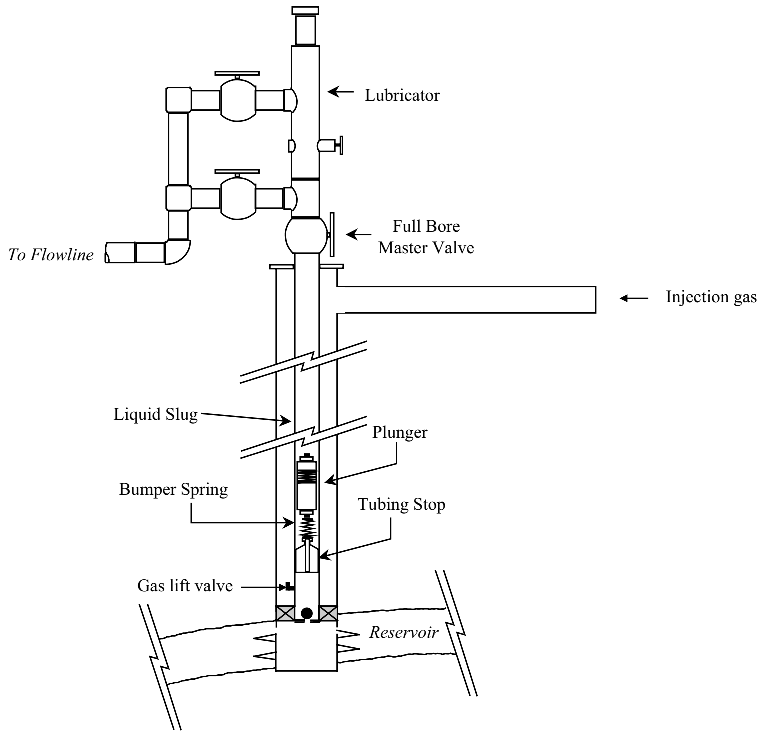


Figure 1.12—Completion for Intermittent Gas-lift with Plungers

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 happen:

a) if the lubricator is set to catch and retain the plunger, then the plunger stays in the lubricator and it can be pulled out (retrieved) by simply closing the master valve;

b) if the lubricator is not set to catch the plunger, it will fallback to the bottom of the well as soon as the force exerted by the injection gas on the plunger diminishes to a value below the weight of the plunger.

1.3.2 Advantages and Disadvantages of Each Type of Completions

The following table contains a summary of the advantages and disadvantages of each type of completion.

Primary Advantages	Primary Disadvantages
Simple Completions	
The completion is simpler than any other type of installation; there is less downhole equipment. This reduces the risk of any production inefficiency due to completion failure.	The volumetric capacity of a simple completion, as compared to chamber installations, might limit the maximum daily production of the well and increase the injection gas liquid ratio.
In a closed completion, the packer and the standing valve prevent the reservoir from being exposed to the high injection pressure.	Sand may prevent access to the standing valve.

Primary Advantages	Primary Disadvantages
In a semi-closed completion, it is not necessary to purchase, install, or maintain a standing valve.	In semi-closed installations, the reservoir is exposed to high injection pressure, which might inhibit production, cause sand problems, and other types of damages.
In an open completion, it is not necessary to purchase, install, or maintain a standing valve and a packer.	In open installations, the reservoir is exposed to high injection pressure, which might inhibit production, cause sand problems, and other types of damages. This completion may require unloading each time it must be re-started.
Chamber Installations	
If the PI of the well is high enough, it could be possible to increase the liquid production if a chamber type completion is installed instead of a simple completion. The increase in liquid production is obtained due to the fact that more liquid can be accumulated for a given flowing bottom hole pressure. This is also true for low PI well, but in this case, the time required to fill the chamber will be considerably longer with the end result of increasing the daily liquid production by a small percentage only.	The completion is more complex. This increases the risk of any production inefficiency due to completion failure.
A chamber installation will always reduce the injection gas liquid ratio.	It can not handle wells with high formation gas liquid ratios. Chamber installations are not recommended for gassy wells because the chamber annulus will fill with liquids with high gas content, reducing the ability of the installation to accumulate high volume of liquids per cycle. In gassy wells, the liquid level in the annulus will always tend to be much lower than in the dip tube and because the gas content of the liquid that does enter the annulus is so high, the annulus is mostly filled with gas.
For deep wells with low PI, installing a chamber might be the only way to have an economically suitable injection gas liquid ratio. Chamber installations can be considered the method for ultimate depletion of low static pressure wells by gas-lift.	Severe sand problems limit the use of a chamber installation due to the difficulty in pulling a chamber installation and performing wire-line operations.
Double packer chamber installations offer greater annular capacity than any other type of chamber installations.	
Insert chambers can significantly increase the draw-down in wells with extremely long perforations or open-hole completions.	
Insert open hole chambers can be easily implemented in tight formation wells. (see Figure 1.7)	
Accumulators	
Accumulators, rather than chambers, are recommended for gassy wells with high PI, since they can handle formation gas better than any type of chamber installation. With accumulators the free gas is always being (produced or percolated) vented to the wellhead.	The volumetric capacity of an accumulator is typically small as compared to a chamber installation.
The simple design of an accumulator makes it a better completion to handle high volumes of gas from the formation.	Compared to a chamber installation, the required injection gas liquid ratio is greater for accumulators and a small increase in liquid fallback is expected.
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.	
An accumulator completion is not as complex as the one for chamber installations, thereby reducing the risk of completion failure.	
The accumulator combines the effect of liquid accumulation of a chamber installation with the ability of simple type completion to handle high formation gas liquid ratios.	

Primary Advantages	Primary Disadvantages
Compared to simple type completions, the injection gas liquid ratios for accumulators is lower.	
Wells that would otherwise be good candidates for insert chambers but with high formation gas liquid ratio or with small diameter casings, are excellent candidates for insert accumulators since they handle formation gas better.	
Dual Completions	
Dual completions allow the production of two different zones using only one well. This implies a potential savings in completion equipment and gas injection piping costs.	The design of parallel string dual intermittent gas-lift installations with a common injection gas source is difficult. For all cases, the designs of both zones are related. One of the strings is designed to meet the exact production requirements of its particular production zone, while the other string design is limited by the design constraints imposed by the first string.
	Dual completions are difficult to operate and troubleshoot.
	The complexity of the completion increases the risk of completion failure.
	May be very labor intensive to keep a dual well operating.
Gas-lift with Plungers	
Plungers can reduce the liquid fallback losses.	Plungers require extra care and they cause an increase in maintenance costs.
This may be pertinent when the instantaneous gas flow rate cannot make the liquid slug travel at values as high as 1000 ft/min (304.8 m/min), or when the injection point is too deep.	At liquid velocity around 1000 ft/min (304.8 m/min) , plungers do not provide a significant advantage.
They may help overcome operational problems like paraffin formation along the tubing, or low viscosity emulsion problems.	Plungers can not handle viscous fluid, deformed or highly deviated tubing, or tubing with sections of different inside diameters.
Low liquid slug velocities are found in places where: a) the gas-lift system can not provide a high instantaneous gas flow rate into the tubing. Sometimes this happens because the available maximum pressure or the gas flow rate that the compressor can deliver is too low; b) a gas-lift system has a low high-pressure storage capacity; c) the gas-lift mandrel already installed in the well accepts small diameter gas-lift valves, which limit the gas flow rate into the well; and d) single element valves are used.	

1.3.3 Summary of Recommended Practices in Section 3

The following table contains a summary of the recommended practices in Section 3 of this document.

No.	Subsection	Topic	Recommended Practice
3.1	**Simple Completions**		
1	3.1	Location of the operating valve	The operating valve should be located as close as feasible to the perforations. For a long perforated interval, the possibility of using insert type completions should be contemplated.
2	3.1	Function of the unloading valves	The unloading valves should remain closed during the normal operating cycle and should only be used for unloading the well.
3	3.1	Open installations	"Open installations" are limited to wells with high reservoir pressures and should only be installed if a packer cannot be used. Open installations should be avoided if possible.
4	3.1	Tubing diameter	The production tubing diameter should be sized to keep the designed liquid slug velocity around 304.8 M/min (1000 ft/min) to maintain the fallback losses at a minimum. A tubing OD of less than 6.03 cm (2 $^3/_8$ in.) is not recommended due to potential well servicing difficulties.
5	3.1	Standing valve	Standing valves should be installed in most intermittent lift installations, unless they are low PI or produce sand.
6	3.1	Wellhead	All unnecessary elbows, tees, bends, etc., near the wellhead should be eliminated. If possible, a well should be streamlined always making sure that the wellhead allows wire line operations.
3.2	**Chamber Installations**		
1	3.2	Type of well	Chamber type installations are especially recommended for wells with low formation GLR, low bottom hole pressure, and high PI. Wells with severe sand production problems should be avoided.
2	3.2.1	Unloading valve spacing and design	The unloading valve spacing calculations for chamber installations are the same as those for conventional intermittent installations. An unloading valve is needed one or two joints above the operating valve, so that when unloading the well, the operating valve only needs to displace the fluids in the chamber. The opening pressure of the unloading valves should be set at a value as high as feasible so that they will not open due to the hydrostatic pressure caused by the long liquid slugs produced from the chamber.
3	3.2.1	Size of the dip tube for double packer chambers	A good practice is to have the same size for the dip tube and for the tubing string, this permits the use of a wire-line retrievable standing valve and bleed valve.
4	3.2.1	Operating valve calculation	When calculating the operating valve opening pressure, the tubing production pressure acting on the valve is only due to the wellhead pressure plus the weight of the gas column from the wellhead to the bleed valve. This is because the operating valve should be above the liquid level.
5	3.2.1	Gas injection pressure for double packer chambers	The gas injection pressure in the annulus, at the valve depth, is equal to the sum of the following pressures: the wellhead injection gas pressure, the gas pressure gradient to the depth of the valve, the pressure drop across the gas-lift valve, and the length of the chamber times the liquid gradient times one plus the volume capacity ratio of the chamber annulus to tubing above the chamber.
6	3.2.1	Chamber length	The calculations for the optimum cycle time are identical to the ones for a simple completion, but using the volumetric capacity of the chamber annulus plus the dip tube and not that of the producing tubing. The size of the chamber is equal to the liquid column length calculated at the optimum cycle time, but correcting its value with the true liquid gradient. It is important that the top of the chamber is not too far above the liquid level so that no injection gas is wasted.
7	3.2.1	Before installing the chamber	A downhole pressure survey should be run with the well on intermittent lift before installing the chamber to determine the true liquid gradient. If the true liquid gradient is too low, a chamber should not be installed.

No.	Subsection	Topic	Recommended Practice
8	3.2.1	Bleeding the gas in the chamber annulus	It is important to provide ample bleeding capacity at the upper part of the annulus chamber. A 0.32-cm ($^1/_8$-in.) diameter bleed hole in an upper collar of the dip tube is recommended for low capacity wells with a low (< 50 ft^3/bbl) (8.93 m^3/m^3) formation GLR. If a differential valve is employed as a bleed valve, a differential spring setting of at least 517.1 kPa to 689.5 kPa (75 psi to 100 psi) is recommended and the maximum size of the orifices employed is limited by the valve port size. For wells with extremely high formation GLRs and/or high injection gas cycle frequencies, a casing pressure operated chamber valve with a large built-in bleed port is recommended.
9	3.2.1	Standing valve	The standing valve must be installed in a way that will prevent it from being dislodged from its seating nipple. Care must also be used if the well has a tendency for scaling, sanding, etc.
10	3.2.2	Types of wells recommended for insert chambers	Insert chambers are recommended for wells with one or several of the following conditions: long perforated intervals, low reservoir pressure, damaged casing, or open hole completion.
11	3.2.2	Special design considerations for insert chambers	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 special considerations are required for the design of insert chambers. a) The calculation of the daily liquid production is completely different. It is not possible to calculate the daily liquid production potential that the well will have with an insert chamber before installing it, but a good estimate can be made if a downhole survey can be run before the installation of the chamber and if the well is on intermittent gas-lift. Refer to Annex A for a practical approximation of the liquid daily production that can be expected from a well with an insert chamber installed. b) Provisions must be made to bleed the formation gas.
12	3.2.2	Insert chamber with parallel gas injection tubing	For this type of completion it is important to take into account the pressure drop that takes place along the injection tubing below the by-pass packer. If this pressure drop is high, the valve will close at a lower pressure than the one existing in the casing annulus, so the effective spread will provide less gas than initially calculated.
13	3.2.2	Open hole chamber	Use this type of chamber (see Figure 1.7) for tight formations.
3.3 Accumulators			
1	3.3	Type of wells suitable for accumulators	Accumulators are recommended for gassy wells with a high PI. Wells that would otherwise be good candidates for insert chambers but with high formation GLR or with small diameter casings, are excellent candidates for insert accumulators.
2	3.3.1	Accumulator tubing diameter	The diameter of the accumulator should be larger than the production tubing connecting the accumulator to the wellhead but, it is important to consider the fact that large diameter tubing increases the liquid fallback.
3	3.3.1	Production tubing diameter	The production tubing diameter should not be too small, especially for long accumulators, as the injection pressure needed to overcome the hydrostatic pressure, once the liquids have been displaced entirely to the tubing, might be too high.

No.	Subsection	Topic	Recommended Practice
4	3.3.2	Design considerations	The length of the accumulator is equal to the liquid slug length calculated for the optimum cycle time as shown in Annex A for simple completions, but it must be corrected for true liquid gradient. The extra volume of the accumulator should be accounted for when calculating the theoretical gas required per cycle using the procedure given in Annex A. The same major considerations for double packer chambers and insert chambers apply for insert accumulators. The procedure given in Annex A for estimating the daily liquid production of insert chambers can be used for insert accumulators as well. And, as for insert chambers, it is also expected to have most of the liquid filling the accumulator coming from the valve intended to serve as a bleed valve for the formation gas, so this valve needs to be designed for two-phase flow rather than for gas flow only.
3.4	**Dual Completions**		
1	3.4	Gas source	For dual completions, the best recommendation is not to try to produce both strings by gas-lift using a common gas source or injection annulus. It is better to use a coil tubing type of installation to isolate the gas-lift gas going to one well from the gas going to the other well. If possible, it is also recommended to use other types of lift method in one or both strings.
2	3.4	Types of completion	Use only parallel dual completion. Concentric dual completion (one zone producing through an outer annulus and the other through a macaroni tubing inside the production tubing) should not be lifted with intermittent gas-lift because of the following. a) The fallback losses and the volume of gas needed to lift intermittently through an annulus are too high and should never be attempted. b) The volume of liquid that can be accumulated per cycle in macaroni type tubing is very low. Unless the reservoir pressure is very low, macaroni tubing are recommended for continues gas-lift. Parallel string completions offer better possibilities for intermittent lift even though the casing may limit the size of the parallel strings. For 13.97-cm (5 $^{3}/_{4}$-in.) casing, tubing diameters are limited to around 4.44-cm (1 $^{3}/_{4}$-in.), in which case continuous gas-lift will usually be more efficient.
3	3.4	General design considerations	The design of parallel string dual intermittent gas-lift installations with a common injection gas source is difficult, but it can be done if general rules are followed. For all cases, the designs of both zones are related.
4	3.4.1.1	Design consideration for: one zone continuous gas-lift and the other intermittent (both strings with pressure operated valves installed)	Surface control can be attained using pressure operated valves in both strings. The surface closing pressure of the operating valve for the intermittent flow zone should be higher than the surface pressure required for the operation of the continuous flow zone. The operating valve for the continuous flow zone should be choked and its orifice size should be calculated from the gas flow rate required for continuous lift, its tubing pressure at valve depth and an operation pressure below the closing pressure of the operating valve for the intermittent flow zone. In this way the injection gas flow rate fluctuations in the continuous string will not be appreciably affected by the fluctuations in the injection pressure for the intermittent lift operation. Control of the casing pressure can be attained by a pressure reducing regulator, choke or metering valve installed on a by-pass around a time cycle operated controller.

No.	Subsection	Topic	Recommended Practice
5	3.4.1.2	Design considerations for one zone on continuous gas-lift and the other on intermittent gas-lift (one string with pressure operated valves and the other with fluid operated valves)	This arrangement can be implemented with fluid operated valves for the intermittent string as long as these valves can close without a significant decrease in the casing pressure. The fluid opening pressure of the fluid operated valve should be based on the operating pressure for the continuous flow zone. A pressure-reducing regulator is used to control the casing pressure. In this way, the injection pressure will not decrease when the fluid valve opens. The surface operation is easier than using pressure operated valves for both zones but there is no surface control of the cycle time for the intermittent zone.
6	3.4.2.1	Both zones on intermittent gas-lift (one string with pressure operated valves and the other with fluid operated valves)	The casing pressure is fixed according to the fluid pressure operated valve, which should be used to lift the lower capacity zone. The higher capacity zone is lifted with a pressure operated valve so that the cycle frequency can be controlled from the surface to obtain the maximum production rate from that zone. If the fluid operated valve can close without a decrease in casing pressure, a time cycle controller with a minimum casing pressure control can be used. If the fluid valve requires a decrease in casing pressure before closing, a “time opening” with ”pressure closing” controller is needed for the pressure operated gas-lift valve and a by-pass around this controller with a pressure reducing regulator and choke or metering valve is needed for the fluid operated zone. This last arrangement reduces the risk of the pressure operated valve skipping one or several cycles.
7	3.4.2.2	Both zones on intermittent gas-lift (both strings with pressure operated valves)	Using pressure operated valves for both zones is only recommended if the reservoir pressures of both zones are not high enough to trigger fluid operated valves. The opening pressure of the pressure operated gas-lift valve used for the higher cycle frequency zone is lower than the opening pressure of the lower cycle frequency zone. The high frequency valve opens several times without opening the lower frequency valve, which is set to open at a higher pressure. When the signal is sent to open the low frequency valve, the controller remains open for a longer time and both operating gas-lift valve open, but at the same time a signal is sent to a motor valve that shuts in the high frequency well. In this way, both zones can be lifted with pressure operated valves but the maximum production capacity is limited due to lifting only one zone at a time and some injection gas is wasted by pressuring up the tubing of the zone shut in by the motor valve.
8	3.4.2.3	Both zones on intermittent gas-lift (both strings with fluid operated valves)	The fluid opening pressure of both fluid operated valves are set at the same operating casing pressure. Surface control is easy if the valves can close with full line pressure in the casing. In this case a choke or a metering valve is the only control needed. If the fluid valves require a significant casing pressure reduction before closing, a combination tubing pressure cutoff and a casing pressure reducing regulator can be used. When the tubing pressure cutoff senses an increase in tubing pressure, a signal is sent to the controller ordering it to close. The controller opens again when the tubing pressure has decreased and the gas-lift valve has closed.
9	3.4.3	Top of lower zone too far from upper packer	The point of gas injection for the lower zone is the lower end of the dip tube located opposite this zone. The operating valve for the lower zone is set to have a higher opening pressure in the well than that for the upper zone (see Figure 1.11).
3.5 Gas-lift with Plungers			
1	3.5	Gas-lift with plungers	Plungers originally 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 can not make the liquid slug to travel at values as high as 1000 ft/min, or to overcome operational problems like paraffin formation along the tubing, or the injection point is too deep.

No.	Subsection	Topic	Recommended Practice
2	3.5.3	Not recommended	Plungers are not recommended when: a) the fluids being lifted are too viscous because the falling speed of the plunger in the liquid might be too low; b) the tubing is deformed or highly deviated; c) the tubing string is composed of sections with different inside diameters; and d) the liquid slug velocity that can be attained is around 304.8 M/min (1000 ft/min), because in this case the liquid fallback losses and the gas required per cycle are about the same for installations with and without plungers. Any small increase in efficiency will be overcome by extra maintenance costs associated with the use of plungers.
3	3.5.4	Type of plungers	Conventional plungers need only be modified to make them longer so that they can be used in installations with gas-lift mandrels for wireline retrieval valves. There are different types of plungers and the ones that have experimentally shown to have the lowest instantaneous fallback loss rate, in bbls/day (m^3/day), for a given plunger velocity are dual turbulent seal and expandable blade. The ones with the highest instantaneous fallback loss rate are brush plungers and capillary type plungers. It is interesting to know that it has been found that a plunger with a hole through its longitudinal axis is more efficient than one without it.
4	3.5.5	Design considerations	As a reasonable approximation, most of the calculations required for conventional intermittent gas-lift can be used for gas-lift with plunger applications. In this way, the procedures given in Annex A for optimum cycle time, theoretical gas required per cycle and the gas mass balance to find the valve closing pressure can be used for gas-lift with plunger. For the theoretical calculation of the gas required per cycle, the weight of the plunger must be added to the weight of the liquid slug in the energy balance equation. This addition must also be observed in the momentum equations when using numerical models to design gas-lift with plunger installations. The major difference in designing gas-lift with plunger installations is the way in which the liquid fallback losses are calculated. Instantaneous liquid fallback losses can be estimated from published experimental plunger rise data relating instantaneous plunger velocity to instantaneous liquid fallback loss rate.

1.4 Selecting the Most Appropriate Control Method(s)

This section presents a summary of the guidelines and recommended practices for choosing and designing the most appropriate method(s) for controlling an intermittent gas-lift system and its associated wells. For more detailed information on this subject, please refer to Section 4, "Types of Gas Injection Control."

The intended method or type of intermittent gas-lift control must be chosen before it is possible to design the gas-lift valves to be used for intermittent gas-lift. Furthermore, this choice can be profoundly important for the long-term success of the intermittent gas-lift system.

1.4.1 Types of Intermittent Gas-lift Control

There are three primary types of gas injection control for intermittent gas-lift: choke control, time cycle control, and control by production automation.

1.4.1.1 Choke Control

The gas injection rate into each well is controlled on the surface by use of a surface choke or control valve. Gas is injected continuously into the well's annulus. The downhole operating gas-lift valve opens when the casing pressure builds high enough to cause the valve to open. The valve closes due to a drop in casing pressure as gas is injected from the casing annulus into the tubing. The injection frequency (the frequency with which the operating gas-lift valve opens) is a function of the gas injection rate, and therefore the rate of pressure rise in the annulus. However, the amount of gas injected per cycle is based on the design of the operating gas-lift valve; it cannot be controlled from the surface.

1.4.1.2 Time Cycle Control

The gas injection volume into the well is controlled by time-cycle-controlled intermitters or open/close control valves. Gas is injected when the intermitter or control valve is open. The injection of gas causes the casing pressure to rise. This causes the operating gas-lift valve to open. The gas-lift valve can be held open for a longer or shorter period of time, depending on the time that the intermitter or control valve on the surface is held open. This can result in the injection of a higher or lower volume of gas per cycle. Both the injection frequency and the amount of gas injected per cycle can be controlled from the surface.

1.4.1.3 Control by Production Automation

Control by production automation may be based either on choke control or time-cycle control. That is, the automation system can continuously inject gas as in choke control, or it can intermittently inject gas as in time cycle control. The difference between control by production automation and normal or conventional choke or time cycle control is that the entire process of data acquisition and control is automated. This permits the gas-lift Operator to remotely (or automatically) adjust the various injection parameters.

Automatic control also opens the possibility of using a combination of choke and time cycle control on the same wells at the same time. This can permit the advantages of both methods to be gained. This is discussed further in Section 4.

1.4.2 Importance of Choosing the Best Method for Intermittent Gas-lift Control

The type of intermittent gas-lift control has a profound impact on the cost and the effectiveness of the operation. Once candidate wells have been selected for intermittent, chamber, or plunger lift, choice of the most effective control method may be the most important decision to be made in implementation of the system. The type of control that is chosen will affect the following items.

1.4.2.1 Capital Cost of the Intermittent Gas-lift Installation

Capital expenditures are required for all surface and downhole equipment. Some intermittent gas-lift systems require more surface equipment than others. For example, with time cycle control, some form of surface timer or intermitter must be added to the system. Also, the type of control system will have an impact on the type and cost of the operating gas-lift valves.

1.4.2.2 Operating Cost

Systems with more equipment require more operation. For example, with a time cycle control system, operators must set both the timing and the duration of each injection cycle. Moreover, these must be frequently adjusted as well conditions change.

1.4.2.3 Maintenance Cost

More equipment requires more maintenance. Thus, time cycle control systems, and automated control systems, which use more equipment, are likely to have higher maintenance costs.

1.4.2.4 Number of Staff Required to Successfully Operate the System

Intermittent gas-lift wells with choke control are operated very much like continuous gas-lift wells. The difference is that the injection rate and the operating gas-lift valve are designed for intermittent lift. Time cycle control requires much more attention to continuously review and update the injection timing and parameters for each well.

1.4.2.5 Amount of Training These People Will Need

Effective intermittent gas-lift is a very specialized field, and very specialized training is required. Since time cycle control requires more human interaction to optimize each injection cycle, more training is required to fine-tune this process.

1.4.2.6 Effectiveness of the System

Because more can be done to optimize a time cycle control system, it can be made more effective *if* there are a sufficient number of trained staff. On the other hand, if there is not a sufficient number of trained staff, this form of intermittent lift can become less effective than the "more conventional" choke control method.

1.4.2.7 Overall Production That Can Be Achieved

Here as well, because a time cycle control system can be more effectively optimized, it can be used to enhance production and obtain greater oil production, *if* it is properly optimized and operated. However, if it is not properly optimized, it may actually lead to less overall production due to inefficiency.

1.4.2.8 Ability to Handle Both Continuous and Intermittent Gas-lift Wells in the Same Gas-lift System

It is often the case in a producing oil field that some wells can be better produced by continuous gas-lift and some by intermittent. In some cases, there have been too many difficulties in trying to mix both continuous and intermittent gas-lift wells in the same system, so all of the wells have been "forced" to use one method or the other, often to the detriment of both types of wells. Time cycle control makes is particularly difficult to mix continuous and intermittent gas-lift wells in the same system, due to the frequent fluctuations in surface injection pressure. This mixing is much easier to accommodate when choke control is used.

1.4.2.9 Impact of Production Automation

Production automation does not bring a "new" method of control. Gas injection is still controlled continuously (choke control) or in cycles. However, with a production automation system, the overall intermittent control process can be continuously monitored and changed, if necessary, to obtain optimum performance. Also, this opens the possibility of using both choke (continuous injection on the surface) and time-cycle (intermittent injection) gas-lift at the same time. Additional information on this subject is in Section 4.

1.4.3 Advantages and Disadvantages of the Types of Intermittent Gas-lift Control

The primary advantages and disadvantages of each intermittent gas-lift control method are given in the following table.

NOTE The lists of advantages and disadvantages are independent from each other.

Primary Advantages	Primary Disadvantages
Choke Control	
The well's annulus is used as a gas storage volume. This is important in systems with limited compression capacity.	Once a particular operating gas-lift valve is installed in a well, the volume of injection gas per cycle cannot be changed. The injection frequency can be changed, but not the volume per cycle. Thus, it is not possible to fully optimize the gas-lift operation. This can be partially overcome if the valve can be easily changed by wireline means.
Smaller, less expensive gas injection lines can be used.	Small surface chokes can result in freezing problems unless dry gas or a dehydration system is used.
Less surface equipment is required. This reduces surface operating and maintenance costs.	If liquids are present in the injection system, the intermittent injection process can be interrupted while the liquid "slug" passes through the surface choke.
Interference between wells is essentially non-existent.	If the well's required injection frequency is low, the required choke size may be too small to be practical. That is, they may plug with “foreign” material.
Both continuous and intermittent gas-lift wells can be mixed on the same gas-lift system. This can be significant if some wells must be lifted continuously and some must be intermitted.	If the well's required injection frequency is high, the required choke size may be too large to allow effective control of the injection cycle frequency.
	Use of choke control makes it difficult to control the time of each injection cycle. This can lead to multiple wells injecting and being produced at the same time, which can overload a small production separator.
Time Cycle Control	
The frequency of injection cycles can be controlled from the surface.	More surface equipment must be installed, operated, and maintained. This increases capital, operating, and maintenance costs.
The volume of gas injected per cycle can be controlled from the surface. This makes it possible to "fine tune" or optimize the liquid recovery per slug.	Since gas injection is alternately stopped and started, pressures in the gas injection system can fluctuate.
Injection cycles into different intermittent gas-lift wells can be staggered to avoid having several wells take injection cycles and produce slugs at the same time.	More people, and more highly trained and skilled people, are required to successfully operate a time cycle control system.
Control by Production Automation	
By continuous monitoring and control, a production automation system can help the gas-lift operator to optimize each gas-lift well and keep it optimized all of the time.	A challenge of many production automation systems is cost. In addition to the costs of instrumentation and controls, which are required in one form or another for any intermittent gas-lift system anyway, there are the costs of electronic communication systems, telecommunication systems, computer hardware and software, and the people who are trained to operate these systems. The good news is that these costs are dropping with time. And, new software systems and training programs are being developed to allow more gas-lift operators to effectively understand and use these systems.
A production automation system can also help to optimize the performance of an entire gas-lift system. For example, by automatically coordinating injection cycles, it can reduce the occurrence of system upsets that may occur when two or more wells are injected at the same time.	
A production automation system can also help to keep a gas-lift system stable when a system upset occurs. Such upsets may result from a compressor trip or restart, a production station trip or restart, or the trip or restart of large wells on the system.	

Primary Advantages	Primary Disadvantages
A production automation system continuously monitors all wells and the system to provide surveillance and troubleshooting information to the gas-lift operators.	
A production automation system can coordinate gas-lift activities with other related production activities such as well tests, production station shut-downs, etc.	
A production automation system can permit continuous and intermittent gas-lift wells to be operated on the same gas-lift system. Some wells are much better suited for continuous lift, while others are better suited for intermittent lift.	

1.4.4 Guidelines for Choosing the Method of Intermittent Gas-lift Control

This section contains guidelines for making the choice of which control method to use for an intermittent gas-lift system in a particular field.

Choose the choke control method if:

— the gas-lift system must serve both continuous and intermittent gas-lift wells;

— there is a need to minimize the capital, operating, and maintenance costs of the system;

— there are a limited number of trained staff who are very familiar with intermittent gas-lift operation and optimization.

Choose the time cycle control method if:

— the gas-lift system is only required to serve intermittent gas-lift wells;

— the primary goal is to optimize the performance of each intermittent gas-lift well, to optimize the amount of gas injected per cycle, and to optimize the amount of oil production;

— there are a sufficient number of trained and skilled staff to effectively operate and optimize the system.

Choose an automated intermittent gas-lift control system:

— The goal is to optimize both cost and performance;

— There is already an "automation culture" in the production operation, i.e. production automation is already being used, or being considered for use, for other purposes such as operation of other types of wells, well testing, monitoring and control of production facilities, monitoring and control of secondary or tertiary recovery injection systems, etc.;

— There is a limited number of staff so it is necessary to leverage their capabilities by providing automation of gas-lift monitoring, control, and surveillance/troubleshooting operations;

— There is a desire to obtain the benefits of both choke control and time cycle control on the same wells at the same time.

1.4.5 Recommended Practices for Using Each Method of Intermittent Gas-lift Control

Once the desired method of control has been selected, the following recommended practices should be considered:

No.	Subsection	Topic	Recommended Practice
4.1	**Choke Control**		
1	4.1	Location of choke	The intermittent gas-lift choke may be placed, in the injection line, either at the injection manifold or at the wellhead. Normally, placement at the manifold is recommended, to facilitate centralized measurement and control, and to allow the gas injection line to be used for extra gas storage. If the required gas injection volume per cycle is less than the amount that can be allowed by the minimum spread of the gas-lift valve, the choke must be placed at the wellhead.
2	4.1	Small gas-lift systems	Be wary of choke control in gas-lift systems with a small number of wells, or with a small production separator. With choke control, it is difficult to control the timing of injection cycles, and too high concurrent liquid and gas production volumes may overload too-small separators or the suction of too-small gas compressors.
4.2	**Surface Time Cycle Control**		
1	4.2	Types of gas-lift valves	Pilot gas-lift valves should be used for the operating gas-lift valve. These valves allow the desired gas injection from the annulus to the tubing to occur rapidly, without throttling.
2	4.2	Location of time cycle controller	Place the time cycle controller, or open/close control valve at the wellhead. This permits more rapid casing pressure rise and more effective intermittent gas-lift operation.
4.3	**Controlling the Gas Injection While Unloading Intermittent Gas-lift Wells**		
1	4.3.1	Before unloading	If the annulus is loaded with mud, it should be circulated clean before running the gas-lift valves and starting the gas-lift unloading process. Carefully check all surface facilities, valves, etc. to assure that all are in proper working order and ready for intermittent gas-lift.
2	4.3.2	During unloading	Unload the well very slowly to avoid the possibility of damaging an unloading gas-lift valve. If an unloading valve is damaged, it may never be possible to unload below this depth.
3	4.3.3	Unloading valve design	Consider the use of downstream chokes in the unloading gas-lift valves. This can prevent too-high gas injection volumes through the unloading valves. Too high volumes can cause overloading of the production separator.
4	4.3.4	Injection control during loading	Always use choke (continuous) gas-lift injection control during unloading, even if time cycle control is going to be used once the well is unloaded. The process of unloading (removing liquid from the annulus) is a continuous process.
5	4.3.5	Optimizing injection	Once the well is unloaded, the injection process can be optimized. Section 5.2 describes the way to optimize the injection cycle time and 5.3 describes the way to optimize the volume of gas per injection cycle.
6	4.3.6	Unloading if the system pressure is too low	If the gas-lift system pressure is low, some operators use gas to pressure up on the tubing to force some liquid back into the formation to make the unloading process easier. This procedure is known as "rocking" the well. It is recommended that this process only be undertaken with extreme caution. There must be no standing valve in the well for this to work. And, this may risk damage to the production formation and/or the sand control system if there is one in the well.
7	4.3.7	After unloading a well with large tubing	The following operational problem has been observed in the field when using choke control in wells with 4 $^{3}/_{4}$-in. ID tubing. After the well is unloaded, the spread that is seen on the pressure chart is very small. This is because the liquid column above the operating valve may be large. The valve might have been sized correctly, but due to high fallback losses, it opens at a lower injection pressure (causing a small spread). To observe this phenomenon, go to the injection manifold and open the choke completely until the spread appears normal. When the injection rate is choked back to the value at which the well should operate, the well may begin to load up again. In this case the well should be produced with the help of a surface controller or a pilot valve with a larger area ratio should be installed.

No.	Subsection	Topic	Recommended Practice
4.4 Variations in Time Cycle and Choke Control of Injection Gas			
1	4.4.1	Variable injection system pressure	If the injection pressure varies significantly, it is recommended to use time cycle control to open the injection valve, but to close it based on casing pressure. This maintains a desired injection frequency and assures that there is sufficient pressure in the annulus to support effective intermittent gas-lift.
2	4.4.2	Time cycle control with a pressure limit	If a well has a very small casing annulus, the maximum injection pressure should be limited to prevent upper unloading gas-lift valves from being opened during the injection cycle.
3	4.4.3	Using an injection choke on a time cycle control installation	If the injection system pressure is much higher than the well's casing pressure, a choke may be used to limit the rate of pressure increase in the annulus.
4	4.4.4	Choke control with pressure reducing regulators	If a low capacity well requires a small choke (high-pressure drop) that may have freezing problems, this approach may be used. The pressure regulator controls the maximum pressure between cycles. Once this maximum pressure is obtained, the regulator closes until the pressure begins to fall during the next gas injection period, when the gas-lift valve opens. This type of control is recommended for low capacity wells that would require an extremely small choke. Small chokes increase the possibility of freezing and can plug very easily. This approach removes the requirement for using a small choke.
4.5 Automatic Control with a Production Automation System			
1	4.5.1.1	Optimizing intermittent gas-lift well performance	Focus on optimizing the oil production from each intermittent gas-lift well, not necessarily on maximizing production. The real goal is to optimize profitability which requires that gas injection, oil production, and all capital, operating, and maintenance costs be optimized.
2	4.5.1.2	Optimizing intermittent gas-lift system performance	In addition, it is necessary to focus on the gas-lift system. It is not sufficient to optimize the performance of each well, while ignoring the system and its performance. Sometimes, some wells must be operated at less than optimum to obtain the overall optimum performance from the entire system.
3	4.5.1.3	Focus on intermittent gas-lift surveillance	Gas-lift surveillance must be a continuous process. To optimize profitability, the gas-lift system and all of its wells must be maintained at optimum overall performance all of the time through continuous, effective surveillance.
4	4.5.1.4	Coordinate intermittent gas-lift with other related production activities	A focus must be placed on coordination and integration of intermittent gas-lift with other pertinent production activities including: — coordinate with other forms of artificial lift, especially with continuous gas-lift where this is appropriate; — coordinate with well testing; — coordinate with production facility operations.
5	4.5.2.1	Measure gas-lift system information	Provide the necessary measurement system(s) to accurately measure: — overall gas injection rate that is available to all of the wells in the system; — gas-lift system pressure. These are required to permit continuous optimization of the gas-lift system and all of the wells that are served by the system.

No.	Subsection	Topic	Recommended Practice
6	4.5.2.2	Measure gas-lift well information	Provide the necessary measurement system(s) to accurately measure: — gas-lift injection rate (and volume) into each well, on both a per cycle and a daily basis; — gas-lift injection pressure; — production pressure; — production rate, if possible. These are required to permit effective monitoring and control of each intermittent gas-lift well. The injection and production pressures must be measured at the wellhead, if possible. For intermittent wells, these values should be measured every few seconds, if possible. Infrequent measurements (e.g. once each 5 to 10 minutes) are of very limited value for an intermittent gas-lift well.
7	4.5.2.4	Well test information	While it may not be essential, a recommended practice is to provide full (or at least partial) automation of the well test process. This helps to assure that timely, accurate well test information is collected on a frequent basis to help evaluate intermittent gas-lift performance.
8	4.5.3.1	Gas-lift system control	Effective control of all of the wells in an intermittent gas-lift system can help to: — assure system stability when a system upset occurs, such as a compressor trip or restart; — assure system stability when both continuous and intermittent gas-lift wells are mixed in the same system. This coordinated (system) control can help to optimize the overall performance of the system and all of the wells in the system.
9	4.5.3.2	Gas-lift well control	A production automation system can allow each well to be controlled in the way that is optimum for that well. Some wells can be controlled by "choke" (continuous) control, some by intermittent (time-cycle) control, and some by a combination of the two methods on the same wells at the same time. Please review 4.5.3 for more discussion of this option.
10	4.5.3.3	Dynamic intermittent gas-lift well control	Consider the possibility of "dynamic" intermittent gas-lift control to provide "real time" optimization. It may be possible to optimize the frequency of gas-lift injection cycles and the injection volume per cycle based on "real time" measurements of production rate and pressure.
11	4.5.4	Enhanced intermittent gas-lift surveillance	Use a production automation system to enhance intermittent gas-lift surveillance. Use "real time" information to: — detect problems as soon as they occur; — provide timely surveillance information to the gas-lift team at the location where they work; — help analyze the causes of problems; — automate the response to some problems such as "freezing" problems.

1.5 Designing These Types of Gas-lift Wells and Systems

This section presents a summary of the guidelines and recommended practices for designing intermittent, chamber, and plunger lift wells, including mandrel spacing, valve selection, valve design, etc. For more detailed information on this subject, please refer to Section 5, "Design of Intermittent Gas-lift Installations."

1.5.1 Summary of Recommended Practices in Section 5

The following table contains a summary of the recommended practices in Section 5 of this document.

No.	Subsection	Topic	Recommended Practice
5.1 Mandrel Spacing			
1	5.1	Mandrel spacing	Intermittent gas-lift wells produce from reservoirs that have low static pressure. Nevertheless, unloading valves need to be installed to be able to unload the well in case it has been loaded up for any operational reason such as a chemical treatment or a work over. It is a good practice to assume that the well is filled with fluid all the way to the top, but if the mandrel spacing is going to be based on the actual static liquid level that can be sustained by the reservoir pressure, then the top valve should be placed at the static fluid level.
2	5.1.1	Graphical procedure for spacing unloading mandrels/ valves for intermittent installations	The graphical procedure presented in this section is recommended for training new staff. Once the procedure is understood, a computer program can be used for spacing.
3	5.1.2	Analytical procedure for spacing unloading valves	The analytical procedure, which can be programmed in a computer, is recommended once the process is fully understood.
4	5.1.3	Choosing the unloading valves	For economical and operational reasons, it is recommended to use single element valves instead of pilot valves as the unloading valves. Furthermore, the unloading valves should be injection pressure operated gas-lift valves set to open at high pressure so that they will stay closed when the bottom of the liquid slug reaches each valve. Designing installations with production pressure operated unloading valves is difficult and will not provide any operational advantage. See ISO 17078.2, *International standard for flow control devices*.
5	5.1.4	Choosing the operating valve	Choosing the operating valve is the most important step in designing an intermittent gas-lift installation, especially if surface intermitters will not be used. This is because the complete operation of the installation depends upon three parameters that the operating valve has to control in intermittent lift which have a profound effect on the efficiency of the method: — gas injection pressure; — total volume of gas injected per cycle; — instantaneous gas flow rate.
5.2 Optimum Cycle Time			
1	5.2	Optimum cycle time	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 potential of the well. If the cycle time is too long, the injection GLR will be low but the liquid production could be considerably lower than the maximum production that can be obtained from the well. There is a trade off between column height and accumulation time. The bigger the column the longer the accumulation time, the lower the number of cycles per day.
5.3 Volume of Gas Required Per Cycle			
1	5.3	Volume of gas to be injected per intermittent gas-lift cycle	The fallback losses drastically increase if the volume of gas is injected below the required volume of gas per cycle. On the other hand, not much is gained by injecting more gas than the required volume of gas per cycle. So it is important to know the volume of gas needed to be injected. This section helps to define this amount.

No.	Subsection	Topic	Recommended Practice
5.4	**Valve Area Ratio Calculation for Choke Control**		
1	5.4	Determine the Av/Ab ratio for the operating gas-lift valve when choke control is used	Once a valve with a particular Av/Ab area ratio is installed in the well, the volume of gas injected per cycle is fixed for choke-controlled intermittent gas-lift if the cycle is not allowed to change from the optimum cycle time. So, it is very important to be able to calculate the area ratio of the valve if surface time cycle controllers will not be used. This section shows how to determine the correct Av/Ab ratio for the operating gas-lift valve.
5.5	**Valve Area Ratio Calculation When Surface Time Cycle Controllers are Used**		
1	5.5	Determine the Av/Ab ratio for the operating gas-lift valve when time cycle control is used	The use of time cycle controllers is recommended to be able to change the volume of gas per cycle to values above that which the spread of the valve alone can allow. Refer to 4.2 for guidance on the use of time cycle controllers.
5.6	**Use of Mechanistic Models for Intermittent Gas-lift Design Calculations**		
1	5.6	Use of mechanistic models for intermittent gas-lift design	The use of mathematical models (a.k.a. mechanistic models), based on the physics of the intermittent lift process, is becoming increasingly popular among gas-lift designers. These models provide detailed information of the process, as a function of time, which will otherwise be impossible to obtain. Refer to Annex A for a general description of two different types of approaches.

1.6 Troubleshooting These Types of Gas-lift Wells and Systems

This section presents a summary of the guidelines and recommended practices for troubleshooting intermittent gas-lift systems and wells. For more detailed information on this subject, please refer to Section 6, "Troubleshooting Techniques for Intermittent Gas-lift."

1.6.1 Summary of Recommended Practices in Section 6

The following table contains a summary of the recommended practices in Section 6 of this document.

No.	Subsection	Topic	Recommended Practice
6.1	**Required Data**		
1	6.1	Information required for troubleshooting	The reliability of a troubleshooting analysis depends on the quality and quantity of the data available to the field operator, well analyst, or engineer. The first step in trying to troubleshoot the operation of the well is to gather as much good quality and reliable information as possible. The necessary data is listed below.
2	6.1.1	Injection and tubing pressure values and fluctuations vs. time	This is the most important information to be collected, as it is not possible to do a troubleshoot analysis on intermittent lift without knowing how the injection pressure and the production pressure at the wellhead change with time. From this information it is possible to know the values of the surface opening and closing pressure, the cycle time, the gas injection and liquid accumulation time, and possibly, the slug average velocity.
3	6.1.2	Liquid and total gas production	Information from one well test, at the current intermittent gas-lift cycle time, must be available. Refer to Section 2 for guidance on well test recommended procedure for wells on intermittent gas-lift.

No.	Subsection	Topic	Recommended Practice
4	6.1.3	Fluid and gas properties	To perform a troubleshooting analysis, the following information is required: — crude API gravity; — formation GLR; — bubble point pressure; — injection and formation gas gravity; — water cut. Means to obtain a liquid sample at the wellhead should be available. A flow-line bleeder valve can be used to find out if the well is producing liquids or gas.
5	6.1.4	Reservoir data	It is important to know the inflow capability of the well to determine how close the current liquid production is to the well's potential. The important reservoir parameters are: — static reservoir pressure; — effective PI, which is defined as the average PI within the operational range of the IPR curve for intermittent lift in which the flowing bottom hole pressure goes from separator pressure to 40 % to 50 % of the static pressure.
6	6.1.5	Completion data, including gas-lift valve settings	The following completion information is needed: — production casing inside diameter; — tubing inside and outside diameter; — tubing inclination; — valves, packer, and perforations depths; — type of operating gas-lift valve; — valve area ratio; — valve orifice diameter; — test rack opening or closing pressure; — injection line inside diameter and length; — flowline inside diameter and length; — wellhead conditions.
7	6.1.6	Data from diagnostic tools	The use of specialized equipment discussed in the following section can be of assistance in gas-lift evaluation. These tools can be expensive or can involve risk, so their application needs to be carefully considered.
6.2 Diagnostic Tools Available for Troubleshooting Intermittent Gas-lift Installations			
1	6.2	Diagnostic tools	Several tools can be used to provide information on the efficiency of the intermittent-lift method. The most important ones are discussed in this section.

No.	Subsection	Topic	Recommended Practice
2	6.2.1	Determine gas-lift valve performance from two-pen chart recorders or from SCADA information	Two-pen recorder charts can provide valuable information on the performance of a well, but without proper analysis a wrong conclusion may be reached. Refer to 6.3 for information on troubleshooting analysis for wells on intermittent lift. If a two-pen chart recorded is used, its calibration must be checked periodically. If the information comes from a SCADA system, the scan rate should be one measurement every 3 seconds. Refer to API 11V5 for recommendations on the installation of wellhead pressure recorders. This section provides typical pressure recordings that indicate specific intermittent gas-lift problems.
3	6.2.2	Acoustical surveys	Well sounding devices can be used to determine a variety of diagnostic information, the most important being the depth of the liquid level in the annulus. For general description of this type of tool and its applications and limitations, refer to API 11V5.
4	6.2.3	Flowing pressure and/or temperature surveys	General recommendations for running flowing bottom-hole pressures/ temperature surveys and for plotting survey results are presented in API 11V5. Following these recommendations, it is possible to determine the operating valve for a well on intermittent lift
6.3 Troubleshooting Analysis			
1	6.3.1	Analyzing multiple injection points	The fact that a pressure recorder chart indicates a normal choke control intermittent lift operation does not imply that there is only one point of injection. There might be one valve acting intermittently and another valve continuously open. If time cycle controllers are used, this situation is easily verified from the two-pen recorder charts, as their injection pressures will look like Figure 6.6 i) or Figure 6.6 j) in Section 6.
2	6.3.2	Troubleshooting analysis for simple completions and single points of injection	Each gas-lift valve in the well should be analyzed to determine if it corresponds to the operating valve or if several valves could be open at current conditions. Recommended calculations required per valve to troubleshoot the well as provided in this section.
3	6.3.3	Troubleshooting analysis for chamber installations	The unloading valves of a chamber installation can be analyzed using the same procedure described in 6.3.2. The operating valve, on the other hand, needs special treatment as discussed in this section.
4	6.3.4	Analysis of pressure and temperature surveys	Using the equations given in this section, the information gathered following the procedure described in 6.2.3 can be used to find: — true liquid gradient; — tubing opening pressure and temperature at valve depth; — valve performance; — liquid fallback; — PI; — optimum cycle time.

1.7 Operational Considerations for Individual Gas-lift Wells and Systems

This section presents a summary of the guidelines and recommended practices for operating intermittent gas-lift systems and wells. For more detailed information on this subject, please refer to Section 7, "Operational Considerations for Individual Gas-lift Systems and Wells."

1.7.1 Summary of Recommended Practices in Section 7

The following table contains a summary of the recommended practices in Section 7.

No.	Subsection	Topic	Recommended Practice
7.1 Staffing Requirements			
1	7.1.1	Job responsibilities	Define job responsibilities for operators, well analysts, production engineers, facility engineers, well services, and others.
2	7.1.2	Training requirements	Seek and provide intermittent gas-lift training, especially to operators, well analysts, and production engineers who are or will be involved in intermittent gas-lift operations.
3	7.1.3	Working as a team	Supervisors who are responsible for a field where intermittent gas-lift is used must build and maintain a team with proven skills for intermittent gas-lift design, installation, operation, surveillance, troubleshooting, diagnostic, and optimization.
7.2 Understanding the Design Philosophy			
1	7.2.1	System design	Understand the following components of the intermittent gas-lift system, and how these components affect and/or interact with one another: — system gas volume; — other uses of gas; — system pressure; — number of wells; — effects of interference.
2	7.2.2	Control strategy	Understand the control strategy(ies) that the system is designed to support. These may include: — time cycle control; — choke control; — computer control; — special control, e.g. for plungers. If an attempt is made to use a control strategy that the system is not designed to support, it may operate inefficiently.
3	7.2.3	Well design	Understand how the intermittent gas-lift well is designed, the components that are used to implement this design, and the impact of this design on how the well must be operated. The components to be understood include: — surface control; — mandrel spacing; — unloading gas-lift valves; — operating gas-lift valve; — standing valve; — plunger.
7.3 System/Well Monitoring			
1	7.3.1	System—when/what to monitor	The following items are the most important "system" parameters to monitor: — total system gas rate; — system gas pressure; — compressor availability; — water vapor content.

No.	Subsection	Topic	Recommended Practice
2	7.3.2	Wells—what/when to monitor	The recommended practice in well monitoring is to monitor/measure those variables that are necessary to optimize intermittent gas-lift well action. The following items are the most important "well" parameters to monitor: — injection rate; — injection cycle; — injection pressure; — production pressure; — production rate, if possible; — well test data.
7.4 Control			
1	7.4.1	Control of the system	The primary recommendation for control of the gas-lift distribution system is to control it such that the system pressure remains relatively constant. Gas-lift wells are designed based on a design operating pressure. If the pressure in the distribution system is allowed to become too high or too low, gas may be lost from the system, wells may become inefficient, and other problems may arise.
2	7.4.2	Control of individual wells	If it is possible, the recommended method to control injection into individual intermittent gas-lift wells is with computer control of the injection rate and/or frequency at the surface. This has advantages over other means of control. The primary methods of control are: — computer control; — time cycle control; — choke control; — combination control (where control can be a combination of choke and time cycle control performed by a computer control system).
3	7.4.3	Other types of wells in the system	If a gas-lift system must serve both intermittent and continuous gas-lift wells, the priorities of the wells must be understood. It is often the case that the continuous wells are higher producers. If this is the case, it may be especially important to keep the system pressure stable. This may argue in favor of using some form of choke control, or combination control, rather than conventional time cycle control.
7.5 Analysis/Problem Detection/Troubleshooting			
1	7.5.1	Analytical tools and techniques	The recommended practice is to use a computer monitoring and control system (sometimes referred to as a SCADA system) to continuously monitor the gas-lift system and each well. A modern computer system can provide: — alarm information; — reports; — trend plots; — analysis of system and well performance.
2	7.5.2	Detection tools and techniques	There are several problem detection tools and techniques.

No.	Subsection	Topic	Recommended Practice
3	7.5.3	Performance indicators	Performance indicators can be useful in spotting wells that need attention. For example, an intermittent gas-lift performance indicator might be defined as in 7.5.3. This is one example; there can be others. The important thing is that the SCADA system be able to automatically compute the performance indicators on a daily basis. The actual numbers are measured by the system. The optimum values are calculated by the intermittent gas-lift model.
4	7.5.4	Troubleshooting and root cause analysis	It is not enough to monitor intermittent gas-lift wells and detect problems. The main benefit comes when troubleshooting is used to determine the cause of problems and to “drill down” to determine the root causes of problems. If the root causes can be found, corrective actions can be taken to solve the source(s) of the problems and hopefully prevent their reoccurrence.
7.6	**Maintenance**		
1	7.6.1	System maintenance	The recommended practice in maintenance of the gas-lift system is to keep the system in good working order so it can deliver the desired amount of gas at the desired pressure, all of the time. The key maintenance items are the gas-lift compressors, the gas-lift distribution system, and the piping in the distribution system. See API 11V5 for recommended practices on maintaining these system components.
2	7.6.2	Individual well maintenance	The recommended practice in maintenance of the intermittent gas-lift wells is to keep each well producing at its optimum rate at all times. The key maintenance items are the wellhead and flowline, the wellhead control system, the wellhead injection control choke or valve, the unloading gas-lift valves, and the operating gas-lift valve. See API 11V5 for recommended practices on maintaining these system components.
7.7	**Optimization**		
1	7.7.1	System optimization—allocation, coordination	There are at least two aspects in intermittent gas-lift system optimization: — optimize allocation of gas to the wells; — optimize coordination of intermittent gas-lift injection cycles.
2	7.7.2	Well optimization—optimum cycle frequency and gas volume per cycle	Optimization of intermittent gas-lift wells basically consists of two related things: optimizing the cycle frequency and optimizing the volume of gas per cycle.

1.8 Derivation of Important Intermittent Gas-lift Equations

This section presents a summary of the guidelines and recommended practices that are presented along with the derivation of the important intermittent gas-lift equations. For more detailed information on this subject, please refer to Annex A, "Analytical Derivation of Optimum Cycle Time."

1.8.1 Summary of Recommended Practices in Annex A

The following table contains a summary of the recommended practices in Annex A of this document.

No.	Subsection	Topic	Recommended Practice
A.1	**Analytical Derivation of the Optimum Cycle Time**		
1	A.1	Optimum cycle time	This method can be used to calculate and know the optimum cycle time for each intermittent gas-lift operation.
A.2	**Numerical Procedure for the Optimum Cycle Time**		
1	A.2	Computer program to calculate optimum cycle time	The procedure given in this section may be used to calculate the optimum cycle time described in A.1.

No.	Subsection	Topic	Recommended Practice
A.3	**Calculation of the Total Volume of Gas Required Per Cycle Based on an Energy Balance**		
1	A.3	Volume of gas required per cycle	This method can be used in association with the optimum cycle time to determine the optimum amount of gas to be injected during each intermittent gas-lift cycle.
A.4	**Gas Mass Balance Used to Calculate the Valve Closing Pressure for Pressure Operated Gas-lift Valves**		
1	A.4	Closing pressure of operating gas-lift valve	This method can be used to determine the closing pressure of the operating gas-lift value when the optimum cycle time and volume of gas per cycle are used.
A.5	**Example of Numerical Models for Intermittent Gas-lift Design**		
1	A.5	Instructive use of a numerical model	This section provides information on how a numerical model using momentum and mass balance can be used for intermittent gas-lift design.
A.6	**Estimation of Daily Liquid Flow Rate of an Insert Chamber or Accumulator from a Downhole Pressure Survey**		
1	A.6	Estimate daily production rate	This method can be used to estimate the daily production rate when using an insert chamber or accumulator as part of an intermittent gas-lift system.
A.7	**General Mandrel Spacing Procedure**		
1	A.7.1	Analytical design for top valve at the static fluid level	This is an analytical method that can be used to determine the appropriate depth of the top mandrel when the well will not stand fluid to the surface.
2	A.7.2	Graphical design with the well full of fluid	This is a graphical method that can be used to determine the appropriate depth of the top mandrel when the well will stand fluid to the surface.

1.9 Detailed Example of an Intermittent Gas-lift Design

This section presents a summary of the guidelines and recommended practices that are presented along with the derivation of the important intermittent gas-lift equations. For more detailed information on this subject, please refer to Annex B, "Intermittent Gas-lift Design—A Detailed Example."

1.9.1 Summary of Recommended Practices in Annex B

The following table contains a summary of the recommended practices in Annex B of this document.

No.	Subsection	Topic	Recommended Practice
B.1	**API 11V10 Overall Example of a Design**		
1	B.1.1	Well data	Carefully select the well data needed to make an intermittent gas-lift design. Methods to gather and evaluate input data are discussed in Annex B.
2	B.1.2	Mandrel spacing	Follow the recommended procedures in this section to determine the mandrel spacing for: — the first valve; — the second valve; — the third valve; — subsequent valves—repeat the procedure defined for the third valve.

No.	Subsection	Topic	Recommended Practice
3	B.1.3	Operating Valve design	Follow the recommended procedures in this section for designing the operating gas-lift valve. NOTE No example is given for designing the unloading gas-lift valves. They can be designed using the procedures defined in API 11V6. This design for the operating gas-lift valve is based on a spring-loaded pilot valve.
4	B.1.4	First approximation of the optimum cycle time	Follow the recommended procedures in this section to determine the optimum cycle time. This also gives a recommendation for the amount of gas to be injected per cycle. Finally, a recommendation is given for the Av/Ab ratio of the operating gas-lift valve.

2 Definition of the Intermittent Gas-lift Method and General Guidelines for its Application

This section provides a detailed definition of intermittent gas-lift and guidelines for the most effective and efficient application of this method of artificial lift.

2.1 Definition of the Intermittent Gas-lift Method

Intermittent gas-lift is an artificial lift method in which high pressure gas is intermittently 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 GLR possible. The gas enters the tubing through a single point of injection located as deep as possible in the well. The liquid slug that has previously accumulated inside the tubing and above the point of injection is lifted to the surface due to the work done by the gas entering the tubing as it expands to the surface.

Figure 2.1 shows a complete cycle of an intermittent gas-lift operation.

In Figure 2.1 a), the liquid slug is accumulating above the operating valve. In Figure 2.1 b), the surface controller and operating gas-lift valve are open, the gas is entering the tubing and the liquid slug is rising towards the surface. In Figure 2.1 c), the liquid slug has surfaced, the surface controller has closed and the gas-lift valve remains open until the pressures in the tubing and annulus allow it to close. In Figure 2.1 d), the controller and gas-lift valve are closed and the liquids are entering from the reservoir to form a new slug.

2.2 General Guidelines for Intermittent Gas-lift Installations

The following guidelines are intended to help identify the main characteristics that oil producing wells and gas-lift systems should have for efficient intermittent gas-lift operation.

2.2.1 Guidelines for Intermittent Gas-lift Oil Wells

This section describes the reservoir and well conditions that are best suited for the application of intermittent gas-lift.

2.2.1.1 Reservoir Pressure

As the reservoir pressure and/or well productivity declines, the injection GLR that is required for gas-lift increases for wells on continuous or intermittent gas-lift. There is less energy available from the well so more energy in the form of injected gas must be used. From another perspective, much more gas is required to attempt to continuously lift a well with a low operating bottom-hole pressure than is needed to operate the same well with an effective intermittent design.

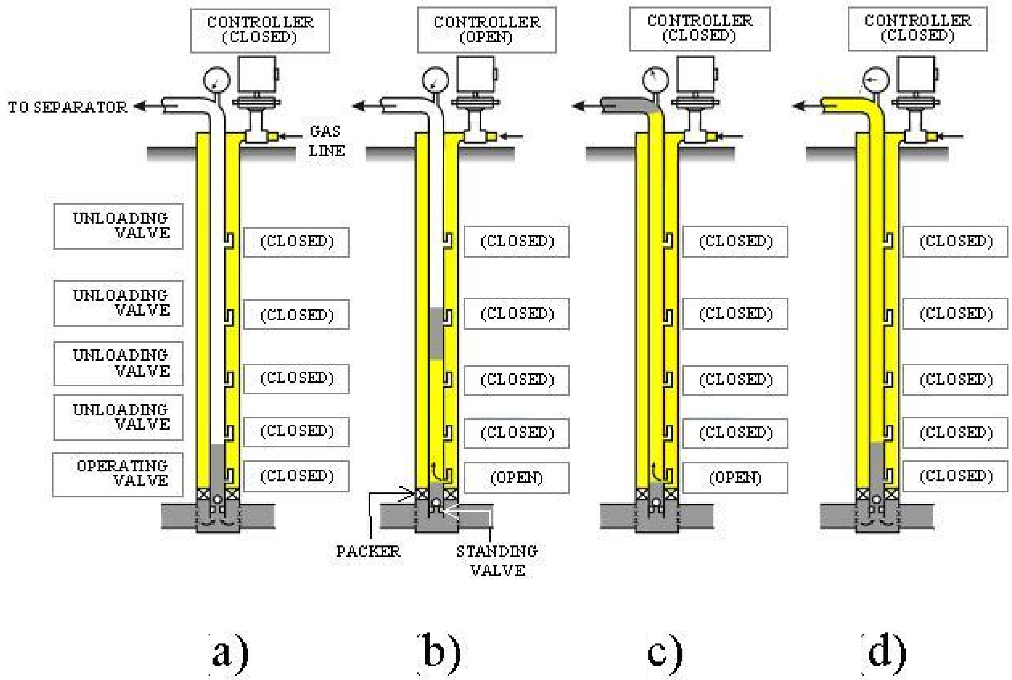


Figure 2.1—Intermittent Gas-lift Cycle

For low reservoir pressure wells, the injection GLR is lower if they produce on intermittent gas-lift rather than on continuous gas-lift. The opposite is true for wells with high reservoir pressure. So the main reason for shifting from continuous to intermittent gas-lift, when the reservoir pressure has declined, is not to produce more oil but to save on compression requirements.

2.2.1.2 Converting from Continuos to Intermittent Gas-lift

Before converting from continuous to intermittent gas-lift, it is recommended to explore the possibility of installing smaller diameter tubing using a nodal analysis approach. A change in tubing size might help keep the well on continuous lift operation. Wells that perform equally well with either method should be placed on continuous flow for more efficient compressor operation and less equipment and maintenance cost.

There are many factors affecting the GLR beside the reservoir pressure, so it is not possible to give a general rule for deciding when to shift from continuous to intermittent gas-lift based on reservoir pressure alone. For wells on intermittent lift, the injection GLR depends on many factors, the most important ones being the depth of point of injection, liquid viscosity (only for API gravity below 23 °) and initial liquid slug length at the optimum cycle time, which is really a function of the reservoir pressure. The cycle time that would yield maximum liquid production is defined as the "optimum cycle time." Refer to Annex A for a procedure that can be used to find the optimum cycle time analytically. It is shown in Annex A that the optimum cycle time is only a function of the PI. Then, for a given PI, the initial slug length is only a function of the reservoir pressure if the cycle time is kept constant at its optimum value. For a given reservoir pressure, the PI affects the daily production but not the GLR for a well producing at its maximum production capacity.

As the reservoir pressure declines, the initial liquid slug becomes smaller and the injection GLR increases, eventually reaching a maximum value beyond which it is not economically feasible to produce the well. This maximum injection GLR can be maintained for a while by intermitting the well at cycle times longer than the optimum cycle time, but the well would not be producing at its maximum potential and, at this time, it might be recommended to shift to chamber lift or, if it is already a chamber installation, to sucker rod pumping or progressing cavity pumping, etc.

2.2.1.3 *PI*—Use of Chamber Lift Installations and Accumulator

Inflow performance relationship (IPR) equations, such as Vogel or Fetkovich, were developed for wells producing at a constant flowing bottom-hole pressure. So, it is not quite correct to apply these equations for wells on intermittent gas-lift. They can only be used to get an approximation of the production potential of the well. Even if these inflow equations were used, the PI would not be a constant value such as the ones used for wells producing at under-saturation conditions. But it has been demonstrated by downhole pressure surveys, that a constant PI value can be used to model analytically the pressure increase during the slug formation period, as long as the flowing bottom hole pressure is kept below 40 % to 50 % of the static reservoir pressure, which is precisely the practical range for intermittent gas-lift. Refer to Annex A for more details on how to find an approximate PI that can be used to calculate the optimum cycle time.

As it was mentioned in the previous section, it can be analytically shown that the optimum cycle time depends on the PI and not on the reservoir pressure. Figure 2.2 shows a consequence of this fact.

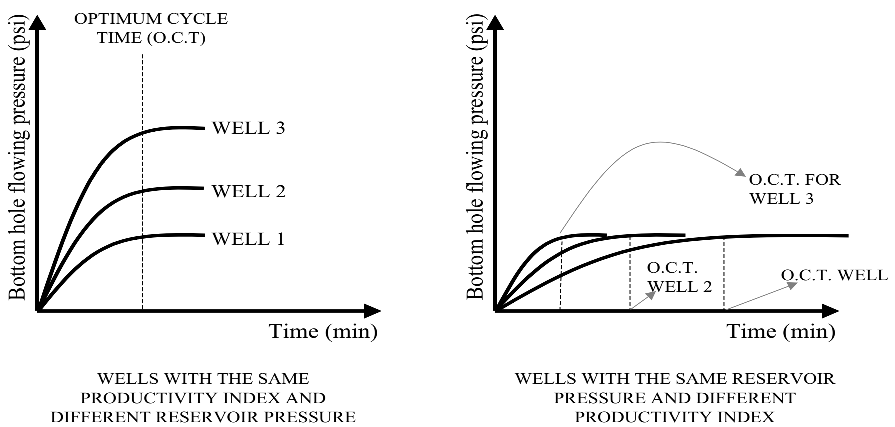


Figure 2.2—Effect of Reservoir Pressure and *PI* on Optimum Cycle Time

In the example shown in Figure 2.2, Well 3 has the greatest reservoir pressure for the first case (left graph) and the greatest PI for the second case (right graph).

Intermittent gas-lift wells can have low or high PI. If the PI is high, a chamber lift installation is recommended to increase the liquid production. If the PI is low, chambers are recommended for wells with low formation GLR to reduce the injection GLRs. Wells with high PI and high formation gas oil ratio are good candidates for accumulator type of completions as explained in Section 2.

2.2.1.4 Crude API Gravity

For oil above 23 ° API gravity, the effect of viscosity on the liquid fallback, which is the portion of the initial liquid slug that is not produced to the surface, is negligible. On the other hand, field test measurements indicate that the liquid fallback increases exponentially as the API gravity decreases below 23 ° API. This increase in liquid fallback represents an increase in the injection GLR. For this reason, low API gravity oil might not be effectively gas-lifted by intermittent gas-lift.

2.2.1.5 Effect of Water Production

Based on field experience and logic, the efficiency of intermittent gas-lift is impacted based on the amount (percentage) of water production. This has not been confirmed by actual tests, but the following effects have been observed. Often, when the percentage of water (water cut) is above approximately 60 %, intermittent lift is more efficient than it is for lower water cuts. This may have to do with water becoming the continuous phase at a higher fraction of the total fluid.

2.2.1.6 Depth of Point of Injection

As is the case for continuous gas-lift, for intermittent gas-lift the deeper the point of injection is, the greater the required injection GLR becomes, for a given reservoir pressure and *PI*. The combination of having to fill more tubing volume with injection gas behind the slug and having more fallback losses as the depth of injection increases can make intermittent gas-lift not economically feasible even for relatively high reservoir pressures. The increase in the required volume of gas per cycle changes linearly with depth; but the injection GLR changes exponentially due to the increased in liquid fallback.

The required injection GLR can be reduced by properly installing chamber type installations as the ones described in Section 3.

An operational guideline that combines the effect of reservoir pressure and depth is to shift from continuous to intermittent lift when the height of the static column is around 30 % the depth of the point of injection. This guideline is too general and more analysis is required for each particular case, but it is a good indicator and its foundation is found as follows:

The volume of gas per cycle, Vgs, can be roughly estimated in m^3 in SI Units and ft^3 in Field Units.

$$Vgs = A_t \times L_v \times \frac{P_t}{101.35} \times 0.0001 \quad \text{in SI Units}$$

where

A_t is the area of the tubing in cm^2;

L_v is the point of injection depth in m;

P_t is the average tubing pressure when the slug reaches the surface in kPa.

$$Vgs = A_t \times L_v \times \frac{P_t}{14.7} \qquad \text{in Field Units} \tag{1}$$

where

A_t is the area of the tubing in ft^2;

L_v is the point of injection depth in ft;

P_t is the average tubing pressure when the slug reaches the surface in psia, and 14.7 is the base pressure in psia.

NOTE All of the equations identified throughout this document are shown in US Customary and SI Unit equivalents in Annex C. In Annex C, the user can evaluate the results of each equation by using his/her own variables.

On the other hand, the liquid produced per cycle, Q_L, in m^3, assuming a fallback factor of 6 % of the initial slug length per 304.8 m of point of injection, is:

$$Q_L = L_{\text{slug}} \times A_t \times \left[1 - \left(\frac{FBF}{304.8}\right) \times L_v\right] \times 0.0001 \quad \text{in SI Units}$$

In Field Units, the liquid produced per cycle, Q_L, in barrels (bbl), assuming a fallback factor of 6 % of the initial slug length per thousand ft of point of injection, is

$$Q_L = L_{\text{slug}} \times A_t \times \left[1 - \left(\frac{FBF}{1000}\right) \times L_v\right] \times \frac{1}{5.61} \quad \text{in Field Units} \tag{2}$$

where

L_{slug} is the initial slug length in m (ft);

FBF is the fallback factor which ranges from 0.03 – 0.04 for good operation with low viscosity crude to a high of 0.10 – 0.12 for high viscosity crude. In this example, FBF is taken as 0.06.

So the injection GLR, RGL, in SI Units is m^3 per m^3 and in Field Units is standard ft^3/barrel, is given by:

$$RGL = \frac{L_v}{L_{\text{slug}}}(P_t)\left[\frac{0.0098}{(1 - 0.0001968 \times L_v)}\right] \quad \text{in SI Units}$$

$$RGL = \frac{L_v}{L_{\text{slug}}}(P_t)\left[\frac{0.38}{(1 - 0.00006 \times L_v)}\right] \quad \text{in Field Units} \tag{3}$$

This last equation shows that the area of the tubing does not play a major role in the injection GLR. This is true as long as the gas-lift system can maintain a gas flow rate high enough to keep the liquid slug velocity around 304.8 m/min (1000 ft/min), which is a recommended velocity to keep the fallback losses at a minimum value. Usually, for large diameter tubing, the slug velocity is low and the fallback factor is higher than 6 % of the initial slug per thousand ft (304.8 m) of point of injection depth.

The initial slug length can be taken as half the static slug length as a reasonable approximation for maximum daily production. Then, for a depth of injection of 1,524 m (5000 ft), a tubing pressure of 4,137 kPa (600 psia), and a GLR of 356.2 m^3/m^3 (2000 ft^3/barrel), the ratio L_{slug}/L_v is equal to 0.16, so the static slug length divided by the depth of the point of injection is twice that value or 0.32.

2.2.1.7 Production Tubing, Injection Annulus, Flow-line and Injection Line Size

a) *Production tubing*. The production tubing diameter should not be too large because large tubing diameters require high volumes of gas per cycle and it might be difficult to provide a gas injection rate high enough to keep the liquid slug velocity around 304.8 m/min (1000 ft/min) to maintain the fallback losses at a low value. As a rough estimate of the needed instantaneous gas flow rate, the required volume of gas per cycle, calculated using the equation given in the previous section, is divided by the time that would take the slug to travel to the surface at 304.8 m/min (1000 ft/min).

   On the other hand, using small tubing diameters would limit the daily liquid production, especially for high cycle frequency wells. This is because the volume of liquid that can accumulate per cycle is very low for small diameter tubing.

   For general guidelines on effective tubing string, refer to API 11V5.

b) *Injection annulus*. Large annulus volume is recommended when the gas-lift system compression capacity is limited. In this case, the gas stored in the annulus provides the volume of gas injected per cycle and the gas injection is controlled by a surface choke. Refer to Section 4 for detail information on choke control intermittent gas-lift. If the annulus volume is too large, the required spread of the valve (defined as the difference between the valve's opening and closing pressure) might be too small to pass the required volume of gas per cycle. In this case the surface choke needs to be installed at the wellhead and not at the manifold and the gas-lift valve-opening pressure should be set at a lower value. If the latter action introduces freezing problems at the choke, a time cycle controller should control the gas injection into the well.

If the annulus volume is too small, the spread of the valve should be high enough to provide the volume of gas needed per cycle. Unloading a well on choke control with a very small annulus might be difficult or impossible. If this is the case, a time cycle controller should be used to unload the well.

For general guidelines on effective casing annulus, refer to API 11V5.

c) *Flowline*. The flowline should be as large, or larger, than the production tubing. The time required for the wellhead pressure to decrease to separator pressure after a slug surfaces is a primary factor in the maximum producing rate from an installation that requires a high cycle frequency. A small diameter flowline can cause high wellhead pressure for a long time after the slug surfaces.

   It is not recommended to have a common flowline for several wells. If several wells intermit at the same time into a common flowline, excessive backpressure will result.

   The flowline should be kept clean of paraffin and other deposition to prevent excessive backpressure.

   For general guidelines on flowline considerations, refer to API 11V5.

d) *Injection line*. The injection line should not provide a large pressure drop when using time cycle controller because a steep increase in the casing pressure is required once the controller opens. For this reason, the diameter of the injection line needs to be calculated for a minimum pressure drop at a maximum instantaneous gas flow rate expected. If the installed injection line is too small, it is recommended to place the controller as close as possible to the wellhead so that the gas in the injection line is at a high pressure making its velocity lower for a given flow rate. Looping and tying the ends of these lines is recommended for many installations to reduce pressure loss and permit isolating parts of the system with valves without a complete shutdown.

   If the compression capacity of the gas-lift system is limited, large diameter injection lines are beneficial to provide high-pressure gas storage volume for intermittent lift operations.

   Gas injection lines should periodically be blown clean of debris because they can plug gas-lift pilot valves used for intermittent lift operations. This is a common problem in old or large gas-lift field or in recently installed lines.

   If using time cycle controllers, it is not recommended to install chokes in the injection line to decrease the gas flow rate so that the compressor can meet the instantaneous peak demand. This might cause high liquid fallback losses. High-pressure volume chambers should provide the necessary peak demand if the compressor cannot supply it.

   Refer to API 11V5 for guidance on gas-lift distribution system in general.

2.2.1.8 Use of Standing Valves

Standing valves prevent the reservoir from being exposed to high injection pressure when the operating valve opens. They are highly recommended for wells with low reservoir pressure and high PI. They should always be used in chamber type installations (described in Section 3).

Standing valves are recommended for the following reasons:

— To prevent the injection gas from pushing the fluids back into the formation;

— To prevent wasting injection gas energy in compressing the liquids with high formation gas content located from just below the operating valve to the perforations. For this reason, the standing valve should be located as closed to the operating valve as possible.

In chamber installations that produce sand, an extended standing valve should be used, refer to Figure 2.3. The extended standing valve allows it to be washed clean each cycle.

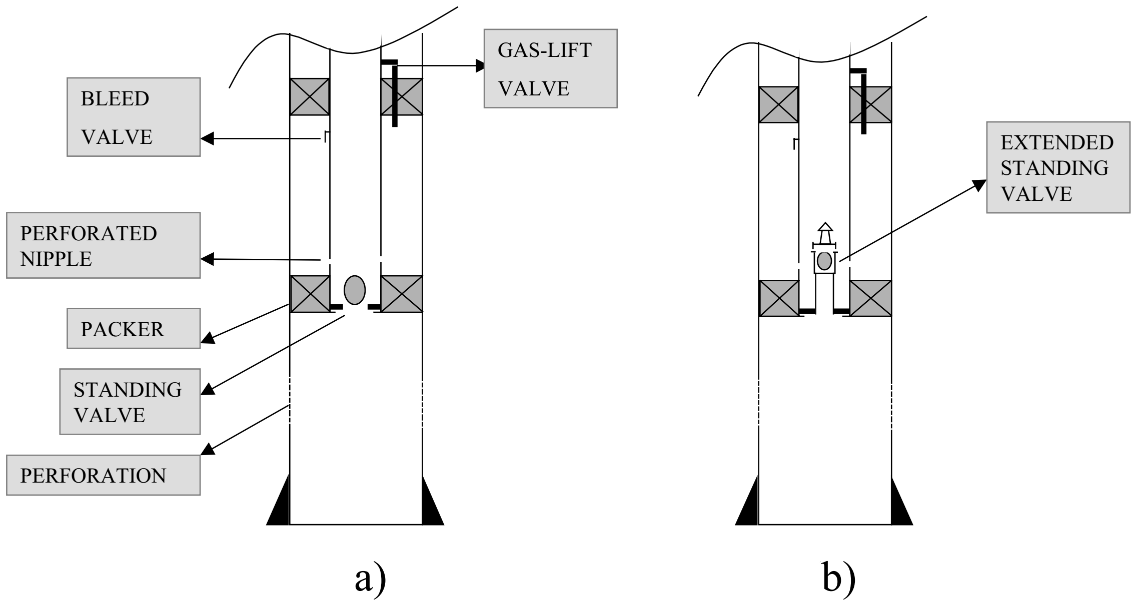


Figure 2.3—Chamber Type Completions: a) with Normal Sanding Valve; b) with Extended Standing Valve

2.2.1.9 Wellhead Arrangement

A well on intermittent gas-lift producing liquid slugs that travel at 304.8 m/min (1000 ft/min) in a 7.3-cm (2 $^7/_8$-in.) tubing is equivalent to a well on continuous gas-lift instantaneously producing over 1,272 m^3/day (8,000 bbl/day). At this velocity, any restriction at the wellhead can cause severe fallback losses due to gas breakthrough. All unnecessary ells, tees, bends, etc., near the wellhead should be eliminated. If possible, a well should be streamlined always making sure that the wellhead allows wire line operations.

Maximum wellhead pressure should occur following the surfacing of the liquid slug. If restrictions near the wellhead are causing the tubing pressure to reach its maximum value before the liquid slug has surfaced, the liquid velocity will decrease causing high liquid fallback.

For general guidelines on wellhead, refer to API 11V5.

2.2.1.10 Surface Chokes

If an intermittent installation must be choked to reduce the rate of gas entry into a low pressure gathering system, the choke should not be placed at or near the wellhead, but should be located as far from the well as possible, preferably near the gathering manifold. This allows the slug to leave the production tubing and accumulate in the flowline.

The maximum inside diameter of some choke assemblies that have been installed in the wellhead for several years can cause high fallback losses even if no choke is installed inside these assemblies.

2.2.1.11 Single Element Valves vs. Pilot Valves

Single element valves are recommended in a few cases only. Surface intermitters are recommended when using single element valves.

The advantages of using single element valves are as follows:

— they are less expensive than pilot valves;

— they have longer operation life in the well.

The disadvantage of using single element valves is that the spread of these valves depends on the diameter of the seat through which all the injection gas must pass. Even the largest seat available for a single element valve could still be too small to provide a high flow rate, which is essential in intermittent lift to have an efficient operation. Installing a valve with a large seat diameter will provide a large spread that might be only necessary if the injection annulus volume is small. If the total volume of gas needed per cycle is small, then a small area ratio valve is required, which in turn will cause a restriction on the flow rate.

Pilot valves are always recommended for any type of intermittent gas-lift operation except when severe operational conditions limit their use.

The disadvantages of using pilot valves are as follows:

— They are more expensive;

— Their failure rate is higher. If the injection gas carries dirt and debris, which is common in big and old gas-lift fields or new injection gas lines, pilot valve can usually fail open because the piston bleed orifice of the main section gets plugged. This can be corrected by injecting gas at line pressure to both, the tubing and the casing, and then blowing the gas in the tubing to the separator, or preferable to the atmosphere, at a rate as high as possible. This procedure might unplug the gas-lift valve without having to pull it out;

— Salt deposition can plug the bleed port in a pilot valve, which results in the main valve remaining open after the pilot section closes. Salt deposition can be removed by pumping fresh water into the casing.

The advantages of pilot valves are as follows:

— The main orifice diameter is very large, which guarantees a high instantaneous gas flow rate;

— The spread of the valve can be adjusted without affecting its flow capacity. This allows a pilot valve to pass a large or small total volume of gas per cycle but always at a high flow rate.

2.2.2 Guidelines for Gas-lift Systems with Intermittent Lift Wells

This section presents guidelines for implementing the gas-lift systems that support intermittent gas-lift installations.

Closed recirculation (rotative) gas-lift system design considerations for handling intermittent gas-lift wells.

The design of a closed rotative gas-lift system is more difficult for intermittent gas-lift installations than for continuous gas-lift. The smaller the total number of wells, the harder the design becomes for intermittent lift. The gas-lift system for only one intermittent lift well is the most difficult one to design. As the number of wells in the system increases, the smoother the operation becomes and the easier it is to design. Figure 2.4 shows a typical configuration of a closed rotative gas-lift system.

To maintain a fixed compressor horsepower, the suction pressure must be maintained as constant as possible. This can be very difficult for systems with intermittent gas-lift wells if proper low-pressure storage facilities are not considered. Good operation can be expected by installing large low-pressure volume chambers; nevertheless, the compressor sizing must consider a variable suction pressure.

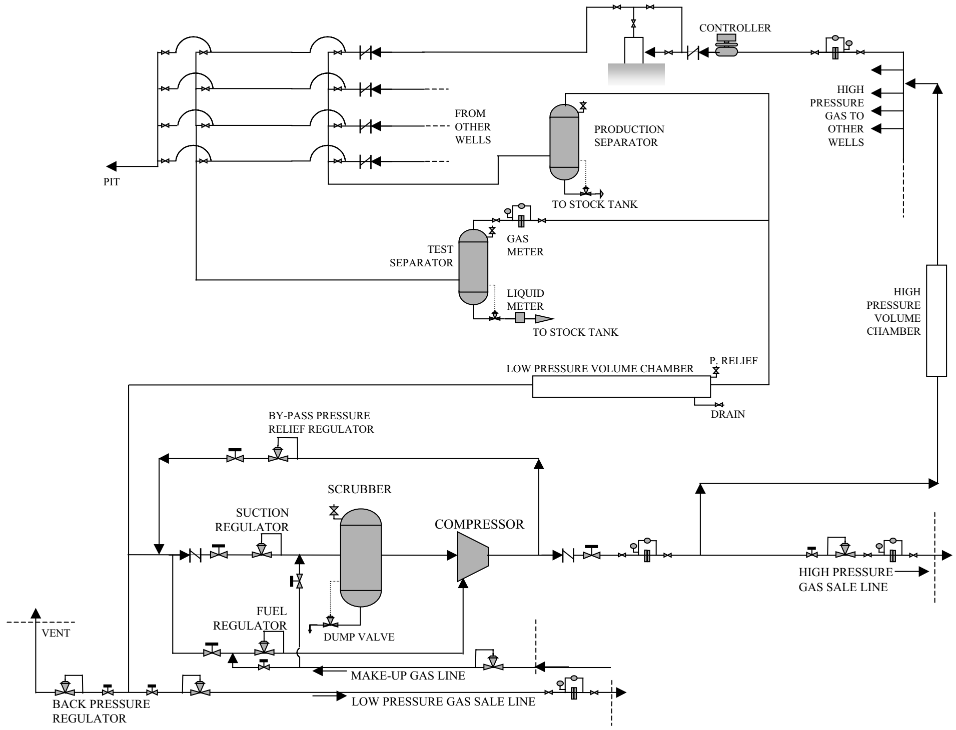


Figure 2.4—Closed Rotative Gas-lift System

A gas-lift system with very few wells will perform better if the wells are on choke control because the casing annulus can be used as a high-pressure gas storage volume. As the number of wells increases, time cycle controllers are recommended to have control over the maximum number of wells intermitting at the same time, which can cause trouble for low-pressure volume storage. If several wells intermit at the same time, the compressor could not handle all the suction gas and a large amount of gas might be flared. This increases the demand for make-up gas. For very large gas-lift systems, the type of gas injection control has very little effect on the performance of the system. Refer to Section 4 for detail information on choke control, time cycle controllers, and control by a production automation system.

To design a gas-lift system capable of handling intermittent gas-lift wells, the location of the compressor should be carefully studied. A compressor centrally located causes minimum friction pressure drops in long lines. If friction pressure drops are minimal, other factors such as high-pressure storage volume might be considered in the location of the compressor as gas injection lines can be used to store high or low pressure gas.

The number of independent compression units should be determined. A system with several smaller units permits the service or repair of a single unit with no loss of oil production. However, many small units increase detail attention, maintenance cost and final cost of the compressor station.

To size the compressor, the peak flow rate demand for gas and the compressor discharge pressure must be determined. The required compressor gas flow rate is determined from the following factors:

— Total gas flow rate required for continuous gas-lift wells;

— Instantaneous gas flow rate required for wells intermitting at the same time (refer to Section 5 for details on the required total volume of gas per cycle). This volume of gas should be injected at a high enough rate so as to maintain a liquid slug velocity of around 304.8 m/min (1000 ft/min). Experimental evidence has shown that a liquid slug velocity of 304.8 m/min (1000 ft/min) (± 15 % approximately) is recommended. This means that 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 100s of m (1000s of ft) of the operating valve is multiplied by a factor of 1.15 to pass the total volume of gas required;

— The high-pressure storage volume, including the volume of gas injection lines and casing annulus of wells on choke control: the storage volume can be built from large pipes or the casing annulus of abandoned wells. Adequate capacity in the high pressure system is necessary to decrease the compressor requirement for intermittent installations using time cycle controllers. The injection gas demand rate is high during the time that the controller is open and no injection gas is required for the long period of time the compressor is closed. The high pressure storage provides the difference in gas volume between the compressor output and the high demand rate. Storage can be obtained for less cost than additional compressor horsepower. The smaller the system, the more important this volume becomes. The controller should be located as close as possible to the well in order to use the injection gas line as a storage volume;

— The difference between the compressor discharge pressure and the valve opening pressure. If the discharge pressure is high enough, high-pressure volume chambers can be smaller or even unnecessary;

— The formation GLR; formation gas can be very important in helping to supply the compressor suction.

The compressor should be selected for 10 % to 20 % excess gas to handle any variation not considered in the initial sizing. For general guidelines on compression facility, refer to API 11V5.

The injection pressure needed to open the valves also determines the compressor discharge pressure. The higher the injection pressure needed, the higher the discharge pressure of the compressor, thereby increasing the compressor horsepower requirements for the same volume of gas at constant suction pressure. Even for low static pressure wells, very low injection pressure are not recommended for several reasons as follows:

— The lower the valve opening pressure, the lower the difference between the opening and closing pressure, which is known as the spread of the valve. This might limit choke control applications, as the spread of the valve might not be sufficient to pass the volume of gas required per cycle even for the largest available valve area ratio;

— Low injection pressure causes high initial fallback even if cycle controllers are used.

It has been shown that for surface injection pressures above 4,826 kPa (700 psig), the injection pressure does not affect the liquid fallback for wells handling liquid slugs between 61 m and 244 m in length (200 ft and 800 ft). The gas-lift efficiency decreases for surface injection pressures below 4,826 kPa (700 psig). The system available injection pressure should consider the pressure drops taken per valve and the pressure drop across the operating valve itself.

The compressor should be designed to discharge 5 % to 15 % higher gas volume than calculated for actual gas-lift requirements to take care of line losses, temperature reductions, or increased fluid volumes at a later date.

The higher the discharge pressure, the more likely the formation of hydrates is if no appropriate precautions are taken. The formation of hydrates can occur well above the freezing point of water; it is caused by a combination of water and hydrocarbon vapors. The higher the gas pressure, the higher the temperature at which hydrates may be expected to form. One or several of the following solutions can be taken to minimize hydrate formation and the best-suited solution will depend on the severity of the problem:

— Eliminate dips and sags in the distribution line where hydrates can accumulate;

— Install bleed-off valves at low spots. This might be the only precaution needed if the problem is not severe;

— Lower the temperature at which hydrates might form by injecting alcohol, glycol, ammonia, or methanol in the injection line. This can be done only during the months were hydrates are expected to form;

— Remove water by installing a dehydrator. Dehydrators can be expensive and are recommended for severe hydrate problems;

— Install a heater to heat the gas above the temperature at which hydrates form. A heater can be used only during the winter if that is all that is needed;

— Eliminate any places where unnecessary pressure drops occur.

The suction pressure needs to be as low as possible to lower the back pressured exerted on the sand face. Excessive surface back pressure can cause severe reduction in liquid production of low reservoir pressure wells with high *PI*. But the low suction pressure must be balanced against compressor horsepower: the lower the suction pressure, the higher the compressor horsepower required for a given discharge pressure and required gas flow rate. Also, there must be enough pressure for the production and well test separators to function correctly.

For intermittent lift, it is important to provide a good design for the gathering system to eliminate the use of make-up gas. The design of the gathering system for handling peak volumes of gas into the suction side of the system should consider all flowlines from the wells (after the check valve near the gathering manifold), separators, scrubbers, lines from the separators to the compressor, lines to the low pressure sale regulator and to the back pressure regulators and any low pressure volume chamber that is installed. The sale pressure and back-pressure regulators should be installed as far as possible from the compressor to increase the capacity of the low pressure system. Where several intermittent wells are supplying 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 do if the wells are on choke control. Although the use of surface controllers offers problems to the high-pressure side of the system for not using the casing annulus as high-pressure gas storage volume, they allow staggering of intermittent slug production.

For small systems handling intermittent lift wells, it is always recommended to design low-pressure volume chambers to avoid excessive surges on the separator. Additionally, installing a choke far form the wellhead so as not to cause an increase in fallback losses can slow the slugs and tail gas into the low-pressure side of the system. Abandoned wells are additional sources of low-pressure capacity. It is recommended to include in the gathering system as many wells as possible, it does not matter if these wells are not on gas-lift.

The required high and low-pressure storage volumes can be estimated from very simple equations. In SI Units, the high-pressure storage volume, V_h in m^3, is found from:

$$V_h = \frac{(N \times Qgia - Qgic)(101.325 \times T)}{Pd - Pc} \text{ in SI Units}$$

where

N	is the maximum number of wells injecting gas simultaneously;
$Qgia$	is the average per-well injection rate in m^3/min;
$Qgic$	is the maximum compressor output in m^3/min;
T	is the average injection time in min/cycle;
Pd	is the discharge pressure in kPa;
Pc	is the maximum required well surface injection pressure in kPa. As can be seen, increasing the discharge pressure or increasing the compressor output can reduce the storage volume.

In Field Units the high-pressure storage volume, V_h in ft^3, can be found from

$$V_h = \frac{(N \times Qgia - Qgic)(14.7 \times T)}{Pd - Pc} \text{ in Field Units} \quad (4)$$

where

N is the maximum number of wells injecting gas simultaneously;

$Qgia$ is the average per-well injection rate in ft^3/min;

$Qgic$ is the maximum compressor output in ft^3/min;

14.7 is the base pressure;

T is the average injection time in min/cycle;

Pd is the discharge pressure in psig;

Pc is the maximum required well surface injection pressure in psig.

The low-pressure storage volume, V_L in m^3 (ft^3), is found from

$$V_L = \frac{(N \times Qgia \times T - Qgic \times t)(101.325)}{Pl - Pci} \text{ in SI Units}$$

$$V_L = \frac{(N \times Qgia \times T - Qgic \times t)(14.7)}{Pl - Pci} \text{ in Field Units} \quad (5)$$

where

t is the time in minutes it takes for the gas to pass the separator;

Pl is the low-pressure or suction storage pressure in kPa (psig);

Pci is the compressor intake pressure in kPa (psig).

The gas-lift system design should consider the availability of make-up gas. Make up gas is essential to charge a system originally, unless gas from flowing wells in the system can be used. It is recommended that the make-up gas enter the system as close as possible to the suction side of the compressor. The regulator controlling the make-up gas should be set to allow entry only after the low-pressure volume chamber has been depleted to its minimum low pressure. If the daily produced formation gas is greater than the fuel requirement for the compressor and the unaccountable gas loss for the system (estimated as 4 % of volume of gas compressed daily), then no make-up gas is required.

High- and low-pressure gas sales lines are always desirable to have since the gas possibly lost from the separator because of surges or any other pressure fluctuation can be redeemed by placing it into a gas sales line.

2.2.2.1 Separator Design

The production separator should be sized to handle the maximum number of wells intermitting at the same time plus the wells on continuous flow in the system. Restrictions such as unnecessary valves downstream of the gas outlet of the separator should be avoided. A safety relief pressure valve, set at higher pressure than the low-pressure controller, should be installed.

The well test separator should be able to handle all wells in the system individually. If the total gas from the well is measured using an orifice plate, the size of the orifice should be properly sized to avoid the separator pressure increasing above the set pressure of the pressure relief valve.

Separator pressure should be maintained as low as possible. The lower the flowing bottom hole pressure, the more important minimum separator pressure becomes. High separator pressure reduces the starting slug length and production per cycle.

2.2.2.2 Most Effective Way(s) to Conduct Well Tests on Intermittent Gas-lift Wells

It is not practical to have a continuous liquid meter at the test separator liquid outlet combined with a constant separator liquid-level control for testing wells on intermittent gas-lift. It is better to continuously monitor the liquid level in the separator from which the average volume of liquid per cycle can be calculated. Figure 2.5 shows a typical chart or data-acquisition system output of the liquid level inside the separator as a function of time.

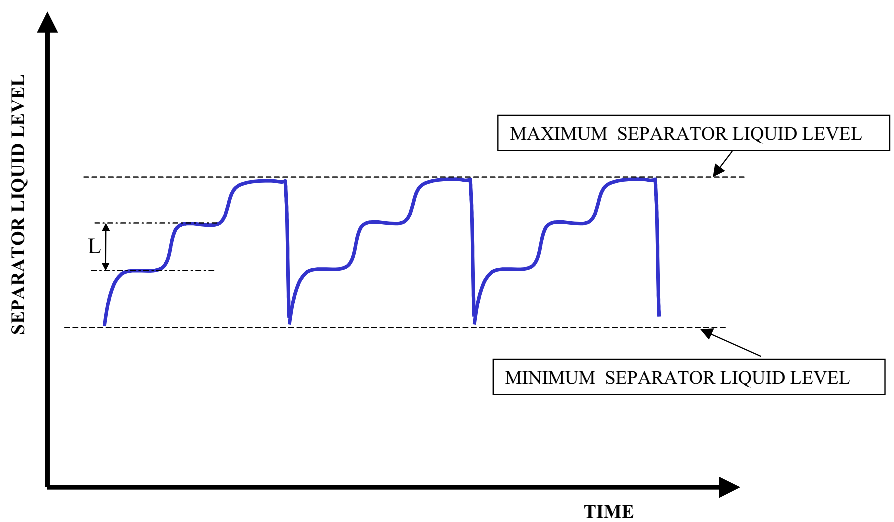


Figure 2.5—Separator Liquid Level vs. Time

Every time a liquid slug is produced from the well, the liquid level inside the separator increases by a distance "L." When the liquid level inside the separator reaches a maximum value, the valve located at the liquid outlet of the test separator opens and the separator is emptied of fluids from the separator to a minimum level.

As the test proceeds, the level difference "L" and the time needed to fill the separator will reach constant values. For the first few slugs, the level difference "L" might be higher or lower than the final approaching value because of the liquid left in the flowline from the previous well being tested.

As soon as a constant value of the level difference is reached, the test can begin. If the separator has been calibrated with a "volume vs. height" curve, the test can end as soon as a few stable readings of "L" and the cycle time are taken. If only the total volume of the separator between its maximum and minimum level is known, it will be necessary to measure the time for an even number of separator liquid discharges.

If the test separator is a two-phase separator, the procedure used for measuring the liquid level should be carefully examined as the water cut might be changing, giving the wrong measurement if a differential pressure transducer is used for determining the liquid level. This problem is not present if a three-phase separator is used.

During the test, the wellhead pressure must be the same as the one during normal operation. This might imply having a higher pressure at the test separator than in the production separator. This is very important for low-bottom-hole pressure wells with high PI.

For general guidelines on well production rate testing, refer to API 11V5.

3 Types of Intermittent Gas-lift Installations (General Description and Operation)

There are different types of intermittent gas-lift installations, each of which is recommended for a particular operational condition. The following sections show the most common types of installations, their descriptions and applications.

There are more types of completions than the examples given in this section, but most of them follow the same principles outlined here.

3.1 Simple Completions

A simple completion is presented in Figure 3.1. 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 and they should only be used for unloading the well. This is the most common type of intermittent lift installations as most of the wells on intermittent lift are wells that were initially on continuous gas-lift and were shifted to intermittent lift to reduce the injection GLR.

Additionally many continuous gas-lift wells will "self intermit" when the production rate falls below the rate that can be sustained on continuous gas-lift. And, self-intermitting is much less efficient and effective than a properly designed intermittent operation. There is no standing valve and the type of injection valve is not designed for intermittent use.

The completion in Figure 3.1 is called a “closed completion” because the packer and the standing valve prevent the reservoir from being exposed to the high injection pressure.

If the standing valve is not installed, the completion is called a “semi-closed installation.” Refer to Section 1 for guidance on using standing valves.

A completion without a packer and a standing valve is called an “open installation.” In these types of installations, enough tail pipe is run below the bottom valve to form a fluid seal and to prevent U-tubing around bottom, so that the annulus gas pressure is not lost during each cycle which would result 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.

When shifting from continuous to intermittent lift using the same completion, the following points must be considered:

— The tubing diameter must be adequate for intermittent gas-lift operation. Refer to Section 2 for guidance on production tubing diameter;

— For intermittent lift wells, it is important for the operating valve to be as close to the perforations as possible. Usually, existing completions were adequate for continuous lift and maybe, due to the tubing outside diameter, the deepest mandrel could not be lowered close to the perforations. For a long perforated interval, the possibility of using insert type completions should be contemplated;

— Standing valves should be installed in most intermittent lift installations. Refer to Section 2 for guidance on standing valve installations;

— The wellhead should be suitable for intermittent lift. Refer to Section 2 for guidance on wellhead arrangement.

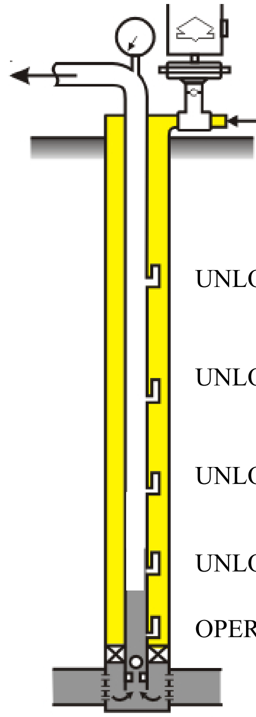


Figure 3.1—Simple Completion (Closed Installation)

3.2 Chamber Installations

Chamber type installations are especially recommended for wells with low bottom hole pressure but with a high *PI*, for in this case the liquid production of the wells can be increased with a chamber type completion. For low *PI* wells, the liquid production might not increase but the injection GLR can be reduced. For deep wells with low *PI*, installing a chamber might be the only way to have an economically suitable injection GLR. Chamber installations can be considered the method for ultimate depletion of low static pressure wells by gas-lift.

If the reservoir pressure of the well is low and the *PI* is high, it may be possible to increase the liquid production if a chamber type completion is installed. In any case, a chamber installation will always reduce the injection GLR relative to "conventional" intermittent gas-lift, but will complicate the completion and their use must be analyzed on a cost/benefit basis.

The increase in liquid production is obtained due to the fact that more liquid can be accumulated for a given flowing bottom-hole pressure. This is also true for low *PI* well, but in this case, the time required to fill the chamber will be considerably longer with the end result of increasing the daily liquid production by a small percentage only.

Chamber installations are not recommended for gassy wells because the chamber annulus will fill with liquids with a high gas content, reducing the ability of the installation to accumulate high volume of liquids per cycle. Severe sand problems limit the use of a chamber installation due to the difficulty in pulling a chamber installation and performing wireline operations. Various types of chamber installations are described in the following sections.

3.2.1 Double Packer Chambers

Figure 3.2 shows a double packer chamber installation. The fluids from the reservoir enter the chamber annulus through the perforated nipple located right above the lower packer in the dip tube. As the liquid level rises in the annulus, the gas above it is vented to the tubing through a bleed valve located below the upper packer. When the chamber annulus and the dip tube are completely filled, the gas-lift valve located just above the upper packer opens and the gas in the high-pressure injection annulus is injected to the upper part of the chamber annulus. The liquids are forced downwards closing the standing valve and rising through the dip tube and the production tubing and are finally produced to the surface as a continuous liquid slug.

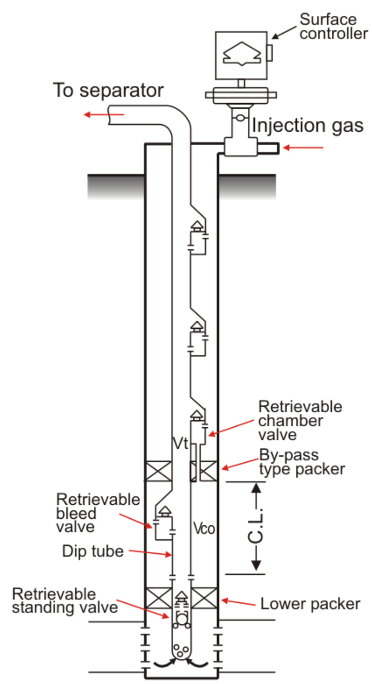


Figure 3.2—Double Packer Chamber

Double packer chamber installations offer maximum annular capacity, more than any other type of chamber installations.

The unloading valve spacing calculations for chamber installations are the same as those for conventional intermittent installations. Refer to Section 5 for guidance on valve spacing and unloading sequence.

The important things to consider when designing a chamber installation are below:

— The dip tube diameter should not be too small, especially for long chambers, as the injection pressure needed to overcome the hydrostatic pressure, once the liquids have been displaced entirely to the dip tube and the tubing, might be too high. On the other hand, a large dip tube diameter will increase the fallback losses. Even with this fact in mind, an unloading valve is needed one or two joints above the operating valve, so that when unloading the well, the operating valve only needs to displace the fluids in the chamber. A good practice is to have the same size for the dip tube and for the tubing string, this permits use of a wireline retrievable standing valve and bleed valve. The gas injection pressure at depth should be equal to the sum of the wellhead pressure at depth, the pressure drop across the gas-lift valve, and the length of the chamber times the liquid gradient times one plus the volume capacity ratio of the chamber annulus to tubing above the chamber;

— The opening pressure of the unloading valves should be set at a high value as possible so that they will not open due to the hydrostatic pressure caused by the long liquid slugs produced from the chamber;

— When doing the calculations for setting the operating valve opening pressure, the tubing production pressure acting on the valve is only due to the wellhead pressure plus the weight of the gas column from the wellhead to the bleed valve. This is because the operating valve is above the liquid level;

— The calculations for the optimum cycle time are identical to the ones shown in Annex A, but using the volumetric capacity of the chamber annulus plus the dip tub and not that of the producing tubing. The size of the chamber is equal to the liquid column length calculated at the optimum cycle time following the equations given in Annex A, but correcting its value with the true liquid gradient. It is important that the top of the chamber is not too far above the liquid level so that no injection gas is wasted. A downhole pressure survey should be run with the well on intermittent lift before installing the chamber to determine the true liquid gradient. If the true liquid gradient is too low a chamber must not be installed. Refer to Section 6 for guidance on running and analyzing downhole pressure surveys;

— The volume of the chamber should be accounted for when doing the calculations for the theoretical gas required per cycle using the procedure given in Annex A;

— It is important to provide ample bleeding capacity at the upper part of the annulus chamber. A diagram of the pressure along the dip tube and the chamber annulus is presented in Figure 3.3. If the pressure drop across the bleed valve is considerable, the liquid level in the dip tube is above the one in the annulus. Once the liquid in the dip tube reaches the bleed valve, bleeding the gas to the tubing will be more difficult and gas will be trapped in the chamber annulus well before it could be completely filled. For the same pressure drop across the dip tube, this situation is worst if the true liquid gradient is very low, as seen in Figure 3.4. Notice that the gradient in the annulus is always heavier than in the dip tube due to the gas separation that might occur when the liquid enters the annulus through the perforated nipple;

— A 0.32-cm ($^1/_8$-in.) diameter bleed hole in an upper collar of the dip tube is recommended for low capacity wells with no formation GLR. If a differential valve is employed as a bleed valve, a differential spring setting of at least 517.1 kPa to 689.5 kPa (75 psi to 100 psi) is recommended and the maximum size of the orifices employed is limited by the valve port size. For wells with extremely high formation GLRs and/or high injection gas cycle frequencies, a casing pressure operated chamber valve with a large built-in bleed port is recommended;

— The standing valve must be installed in a way that will prevent it from being dislodged from its seating nipple. High-pressure differentials can exist across a standing valve just after the slug surfaces.

Gassy wells are not good candidates for chamber installations because the liquid level in the annulus will always tend to be much lower than in the dip tube and because the gas content of the liquid that does enter the annulus is so high that the annulus is mostly fill with gas. Accumulators, rather than chambers, are recommended for gassy wells with high PI, since they can handle formation gas better than any type of chamber installation. Refer to 3.3 for information on accumulators.

3.2.2 Insert Chamber

Insert chambers are recommended for wells with one or several of the following conditions: long perforated intervals, low reservoir pressure, damaged casing or open hole completion. By properly inserting a chamber installation below the perforations, the economic life of a low liquid production well can be considerably extended. Figure 3.5 shows an insert chamber installation: when the chamber valve opens, high-pressure gas enters the chamber through the by-pass packer forcing the liquids downwards and closing the standing valve. The liquids rise through the dip tube to the production tubing until they are produced to the surface.

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 the ones for double packer chambers. But two major special considerations are required for the design of insert chambers: the calculation of the daily liquid production is completely different and provisions must be made to bleed the formation gas.

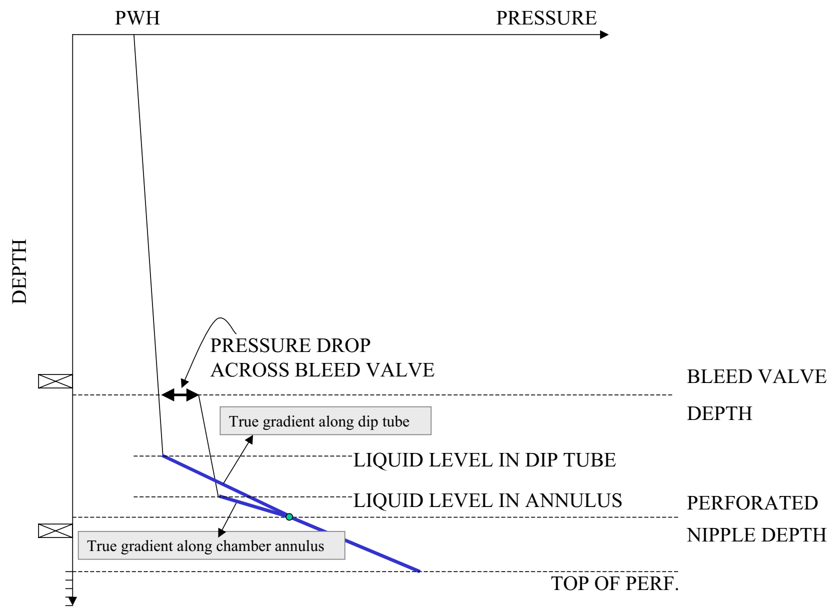


Figure 3.3—Pressure Diagram in Dip Tube and Chamber Annulus (for High True Liquid Gradient)

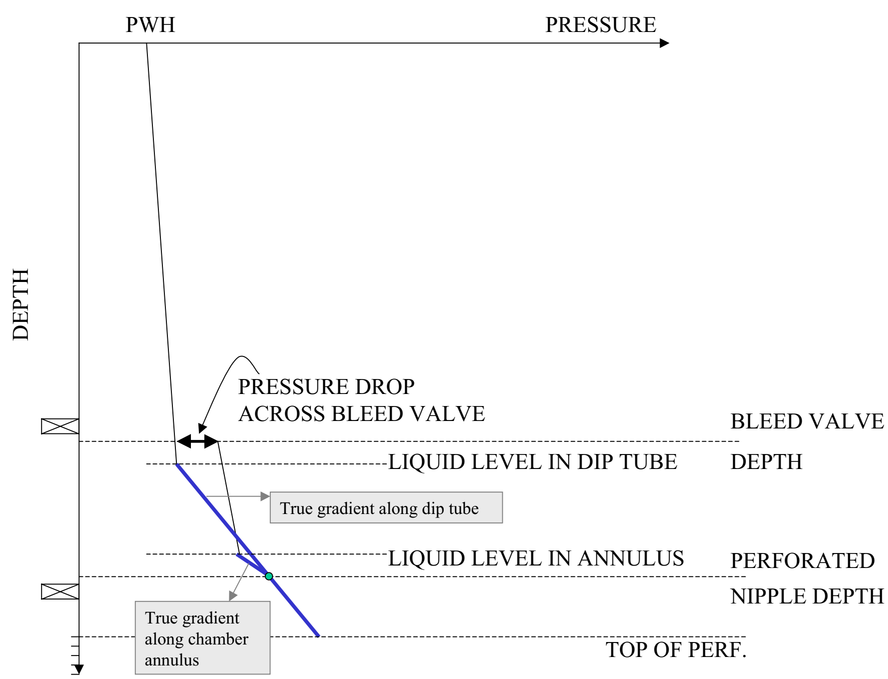


Figure 3.4—Pressure Diagram in Dip Tube and Chamber Annulus (for High True Liquid Gradient)

It is not possible to calculate the daily liquid production potential that the well will have with an insert chamber before installing it, but a good estimate can be made if a downhole survey can be run before the installation of the chamber and if the well is on intermittent gas-lift. Refer to Annex A for a practical approximation of the liquid daily production that can be expected from a well with an insert chamber installed.

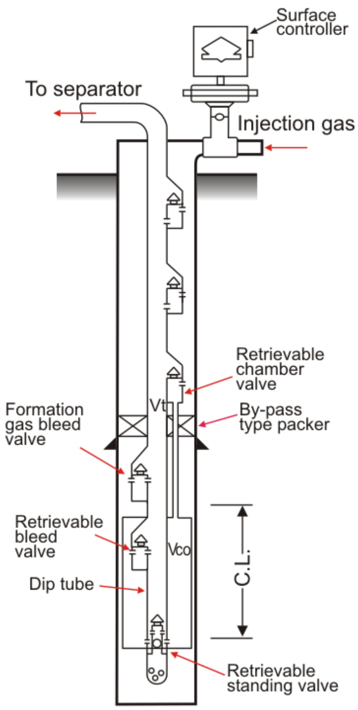


Figure 3.5—Insert Chamber

A major point that must be considered when installing an insert type of completion is to provide adequate means to bleed the formation gas even if the formation GLR is very low. Figure 3.6 and Figure 3.7 show pressure diagrams for the same well with:

a) intermittent gas-lift with a simple type completion;

b) insert chamber without bleeding the formation gas; and

c) insert chamber with the means to bleed the formation gas.

For a simple completion, the minimum pressure along the perforation is higher than any other type of insert completion. The minimum pressure along the completion for an insert chamber without a formation gas bleed valve is lower than a simple type completion, but due to the gas that accumulates in the outer annulus (along the perforations) below the packer, the minimum pressure obtained at the entrance of the chamber is transmitted directly to the upper part of the perforations, thereby blocking the liquid inflow from the reservoir. This gas accumulation will also take place for wells with low formation GLRs. For an insert chamber with the means to vent the formation gas, the pressure along the formation is reduced uniformly providing a larger drawdown. For the latter case, the minimum pressure at the entrance of the chamber and at the formation gas bleed valve is equal for both, the formation and the inside of the chamber.

Towards the end of the cycle, the pressures along the formation and inside the chamber behave as shown in Figure 3.7:

— For a simple type completion, the pressure is high toward the bottom of the perforations but, due to the effect of the gas from the formation being constantly vented to the tubing, the pressure in the upper part of the

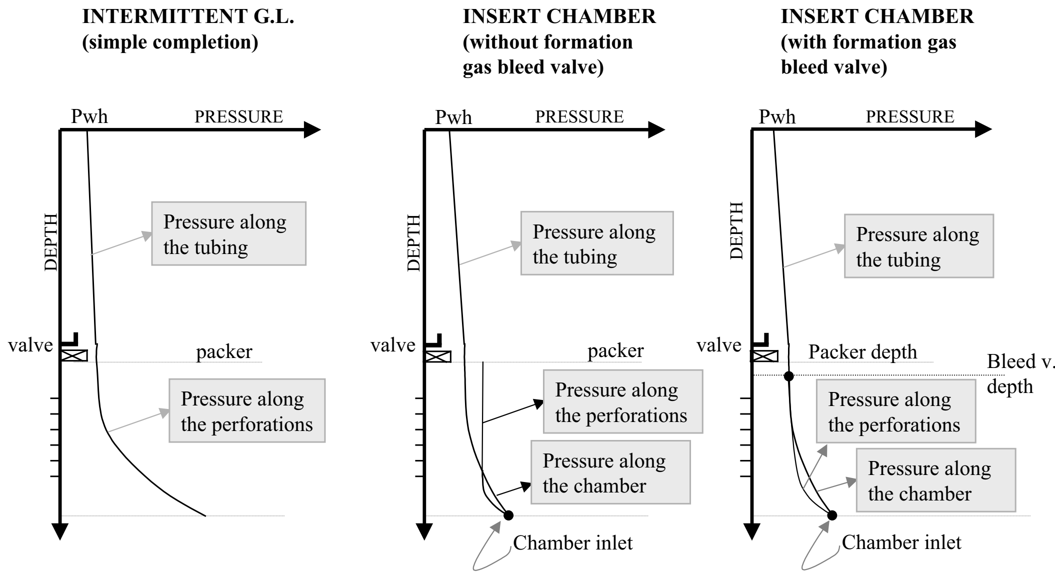


Figure 3.6—Pressure-depth Diagrams for the Same Well and Three Different Types of Completions (Beginning of Liquid Accumulation Period)

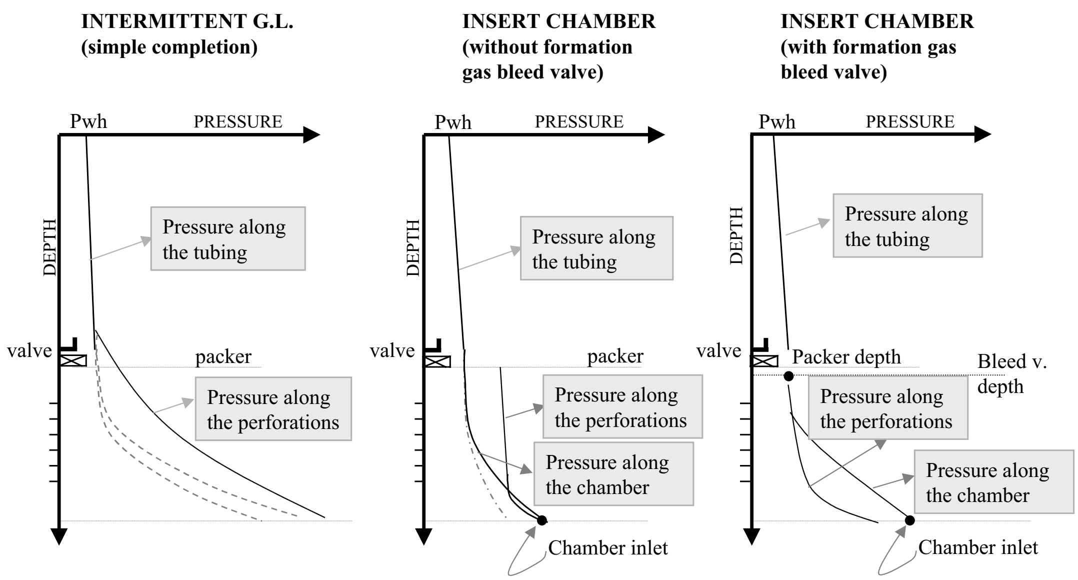


Figure 3.7—Pressure-depth Diagrams for the Same Well and Three Different Types of Completions (Just Before Chamber Valve Opens)

perforations is low. In conventional intermittent gas-lift the formation gas is constantly being vented to the wellhead and no gas accumulation can occur;

— For insert chambers without the means to vent the gas from the formation, the pressure along the perforation is high. Whatever 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 that has been accumulated below the packer along the perforations. This limits the daily production of the insert chamber to values comparable to what can be obtained with a simple completion, only that more volume of gas per cycle is needed for the insert installation. If the gradient in the annulus between the chamber and the perforations is very low, the hydraulic pressure created by a small liquid slug at the bottom of the chamber is transmitted directly to the upper zones. If the reservoir pressure is very low, this sort of gas lock will occur even if the formation GLR is low, because the formation gas will gradually accumulate at the top of the outer annulus (between the perforations and the chamber) eventually blocking the liquid production;

— For insert chambers with formation gas bleed valves, a complex two-phase flow process takes place along the perforations, with free gas moving upwards and being vented to the chamber and from there to the tubing, while the liquids with low gas content are entering the lower intake of the chamber. Early on 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. But the chamber can continue to fill with liquids if the upper entrance, so far called the formation gas bleed valve, has being designed to handle two-phase flow. The end result is that the pressure along the perforations stays very low throughout the cycle as long as the liquid level inside the chamber is below the upper entrance of the chamber.

Figure 3.8 shows a completion recommended for wells in the stripper category.

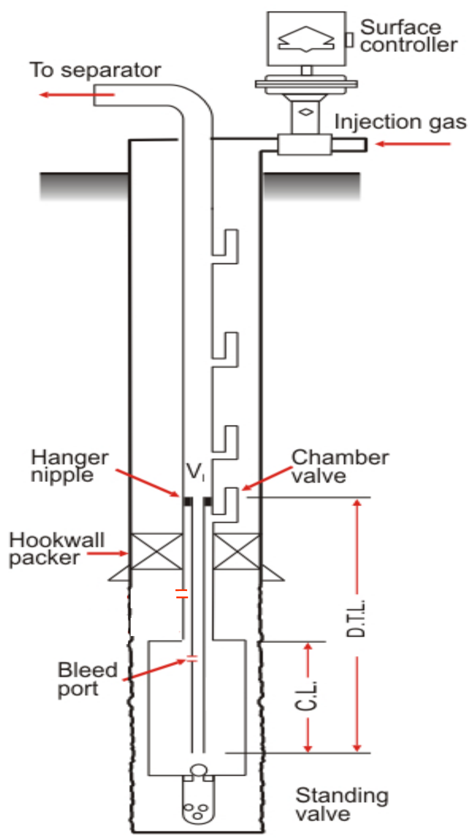


Figure 3.8—Insert Chamber with Hanger Nipple

Figure 3.9 shows a chamber with an operating valve that acts as a bleed valve that allows communication from the chamber annulus to the tubing when it is not open. When the valve opens, high-pressure gas is injected into the chamber annulus.

Figure 3.10 shows a completion suitable for extremely long perforations. For this type of completion it is important to take into account the pressure drop that takes place along the injection tubing below the by-pass packer. If this pressure drop is high, the valve will close at a lower pressure than the one existing in the casing annulus, so the effective spread will provide less gas than initially calculated.

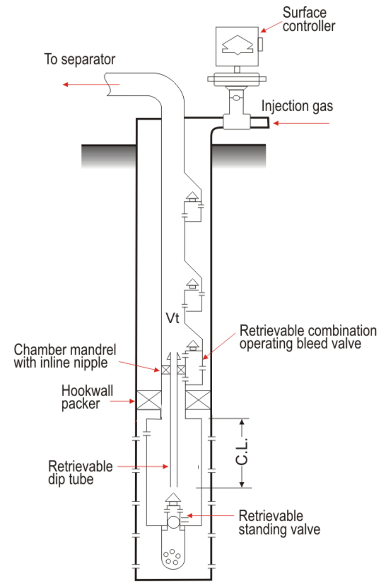


Figure 3.9—Insert Chamber with Combination Operating-bleed Valve

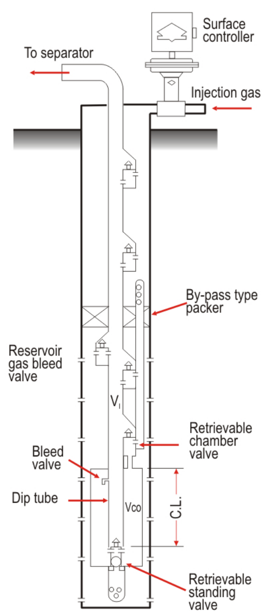


Figure 3.10—Extremely Long Insert Chamber

Figure 3.11 shows a completion that can be used for tight formations. The gas forces the liquid downwards and into the entrance of the dip tube. Some liquids might enter the formation, but for tight formations most liquids will be produced to the surface. This type of chamber is usually referred to as “open hole chamber.” Wells in hard-rock formations or with low PI which produce sand are good candidates for open-hole chambers.

3.3 Accumulators

An accumulator is a section of the tubing located at the lower end of the tubing string with a diameter greater than the rest of the tubing. Accumulators are recommended for gassy wells with high PI. With accumulators the free gas is

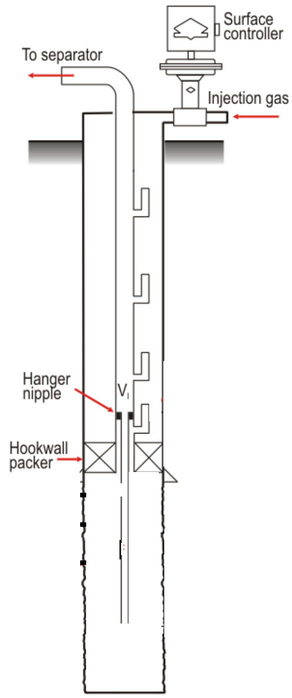


Figure 3.11—Insert Chamber for Tight Formations

always being vented to the wellhead and even 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.

3.3.1 Simple Type Accumulators

A simple type accumulator is shown in Figure 3.12. The accumulator combines the effect of liquid accumulation of a chamber installation with the ability of simple type completion to handle high formation GLRs. The small diameter tubing from the accumulator to the surface decreases the volume of gas required per cycle.

The diameter of the accumulator should not be too large to avoid high fallback losses. The length of the accumulator is equal to the liquid slug length calculated for the optimum cycle time as shown in Annex A for simple completions, but it must be corrected for true liquid gradient. The diameter of the tubing above the accumulator should not be too small to avoid having to overcome high hydrostatic pressures due to the length of the liquid slug once inside the tubing. The extra volume of the accumulator should be accounted for when calculating the theoretical gas required per cycle using the procedure given in Annex A.

3.3.2 Insert Accumulators

Wells that would otherwise be good candidates for insert chambers but with high formation GLR or with small diameter casing, are excellent candidates for insert accumulators. The simple design of an accumulator makes it a better completion to handle high volumes of gas from the formation. The same major considerations for double packer chambers and insert chambers apply for insert accumulators. Figure 3.13 shows an insert type accumulator.

The procedure given in Annex A for estimating the daily liquid production of insert chambers can be used for insert accumulators as well. And, as for insert chambers, it is also expected to have most of the liquid filling the accumulator coming from the valve intended to serve as a bleed valve for the formation gas, so this valve needs to be designed for two-phase flow rather than for gas flow only.

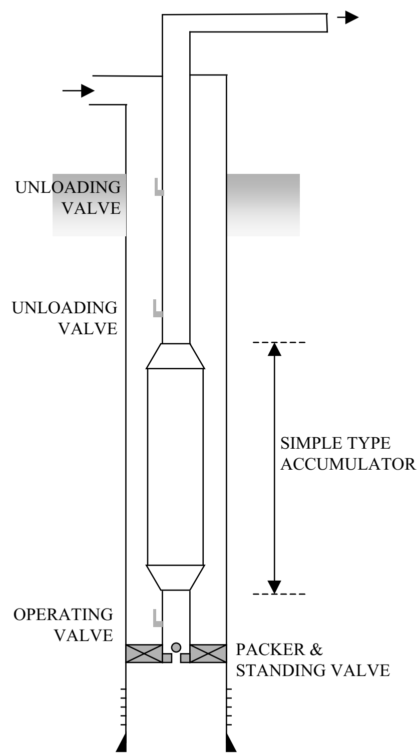


Figure 3.12—Simple Type Accumulator (Not to Scale)

3.4 Dual Completions

For dual completions, the best recommendation is not to try to produce both strings by gas-lift using a common gas source or injection annulus. It is better to use a coil tubing type of installation to isolate the gas-lift gas going to one well from the gas going to the other well. If possible, it is also recommended to use other types of lift method in one or both strings. The following recommendations are given for situations in which no other alternatives can be used but to lift both strings from a common injection annulus (see API 11V9, in development, for dual gas lift completions).

Dual completions can be either concentric or parallel string installations. In concentric completions, fluids from the upper zone are usually produced continuously up the casing tubing annulus and fluids from the lower zone are produced through a small tubing (macaroni type) installed inside the production tubing. In either case, intermittent gas-lift is not recommended because of the following:

— The fallback losses and the volume of gas needed to lift intermittently through an annulus are too high and should never be attempted;

— The volume of liquid that can be accumulated per cycle in macaroni type tubing is very low. Unless the reservoir pressure is very low, macaroni tubing are recommended for continuous gas-lift.

Parallel string completions offer better possibilities for intermittent lift even though the casing may limit the size of the parallel strings. For 13.97-cm (5 $^1/_2$-in.) casing, tubing diameters are limited to around 4.44 cm (1 $^3/_4$ in.), in which case continuous gas-lift will usually be more efficient. Figure 3.14 shows a typical parallel string dual completion.

The design of parallel string dual intermittent gas-lift installations with a common injection gas source is difficult, but it can be done if general rules are followed. For all cases, the designs of both zones are related.

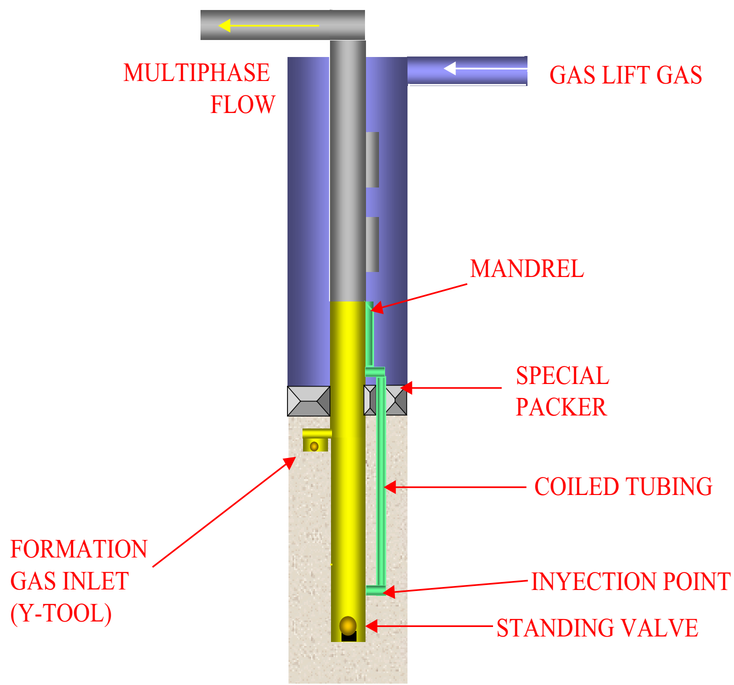


Figure 3.13—Insert Accumulator

3.4.1 One Zone on Continuous Gas-lift and the Other on Intermittent Gas-lift

This section discusses the case where a dual gas-lift well may have one side on continuous gas-lift and the other side on intermittent gas-lift.

3.4.1.1 Both Strings with Pressure Operated Valves Installed

Surface control can be attained using pressure operated valves in both strings. The surface closing pressure of the operating valve for the intermittent flow zone should be higher than the surface pressure required for the operation of the continuous flow zone. The operating valve for the continuous flow zone should be choked and its orifice size should be calculated from the gas flow rate required for continuous lift, its tubing pressure at valve depth and an operation pressure below the closing pressure of the operating valve for the intermittent flow zone. In this way the injection gas flow rate fluctuations in the continuous string will not be appreciably affected by the fluctuations in the injection pressure for the intermittent lift operation. The casing pressure recording from a dual installation with one zone on continuous gas-lift and the other on time cycle control intermittent lift looks like the one shown in Figure 6.5 j) in Section 6. Control of the casing pressure can be attained by a pressure reducing regulator, choke or metering valve installed on a by-pass around a time cycle operated controller.

3.4.1.2 One String with Pressure Operated Valves and the Other with Fluid Operated Valves

This arrangement can be implemented with fluid operated valves for the intermittent string as long as these valves can close without a significant decrease in the casing pressure. The fluid opening pressure of the fluid operated valve should be based on the operating pressure for the continuous flow zone. A pressure-reducing regulator is used to control the casing pressure. In this way, the injection pressure will not decrease when the fluid valve opens. The surface operation is easier than using pressure operated valves for both zones but there is no surface control of the cycle time for the intermittent zone.

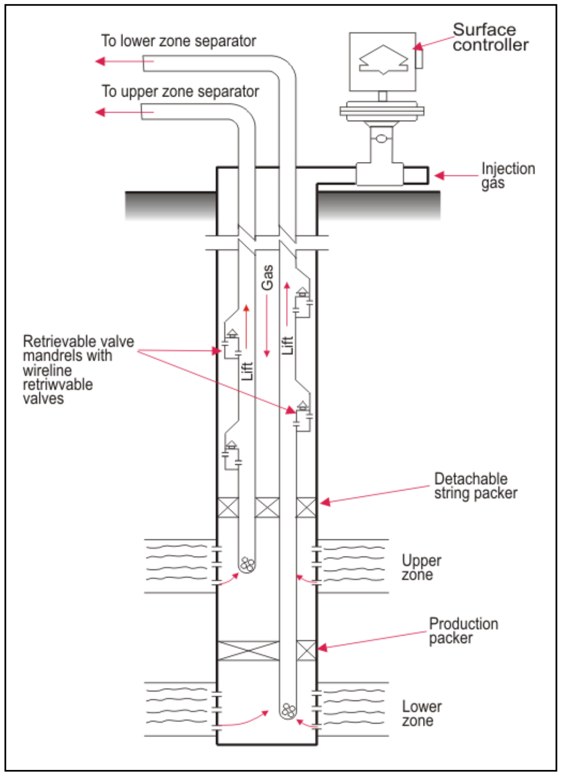


Figure 3.14—Parallel String Dual Completion

3.4.2 Both Zones on Intermittent Gas-lift

3.4.2.1 One String with Pressure Operated Valves and the Other with Fluid Operated Valves

The casing pressure is fixed according to the fluid pressure operated valve, which should be used to lift the lower capacity zone. The higher capacity zone is lifted with a pressure operated valve so that the cycle frequency can be controlled from the surface to obtain the maximum production rate from that zone. If the fluid operated valve can close without a decrease in casing pressure, a time cycle controller with a minimum casing pressure control can be used. If the fluid valve requires a decrease in casing pressure before closing, a “time opening” with ”pressure closing” controller is needed for the pressure operated gas-lift valve and a by-pass around this controller with a pressure reducing regulator and choke or metering valve is needed for the fluid operated zone. This last arrangement reduces the risk of the pressure operated valve skipping one or several cycles.

3.4.2.2 Both Strings with Pressure Operated Valves

Using pressure operated valves for both zones is only recommended if the reservoir pressures of both zones are not high enough to trigger fluid operated valves. The opening pressure of the pressure operated gas-lift valve used for the higher cycle frequency zone is lower than the opening pressure of the lower cycle frequency zone. The high frequency valve opens several times without opening the lower frequency valve, which is set to open at a higher pressure. When the signal is sent to open the low frequency valve, the controller remains open for a longer time and both operating gas-lift valves open, but at the same time a signal is sent to a motor valve that shuts in the high frequency well. In this way, both zones can be lifted with pressure operated valves but the maximum production capacity is limited due to lifting only one zone at a time and some injection gas is wasted by pressuring up the tubing of the zone shut in by the motor valve.

3.4.2.3 Both Strings with Fluid Operated Valves

The fluid opening pressures of both fluid operated valves are set at the same operating casing pressure. Surface control is easy if the valves can close with full line pressure in the casing. In this case a choke or a metering valve is the only control needed. If the fluid valves require a significant casing pressure reduction before closing, a combination tubing pressure cutoff and a casing pressure reducing regulator can be used. When the tubing pressure cutoff senses an increase in tubing pressure, a signal is sent to the controller ordering it to close. The controller opens again when the tubing pressure has decreased and the gas-lift valve has closed.

3.4.3 Top of Lower Zone Too Far from Upper Packer

If the lower zone is too far below the upper packer, intermittent gas-lift cannot be implemented if the top of the liquid column cannot reach the upper packer depth. A completion such as the one shown in Figure 3.15 is needed in this case. The point of gas injection for the lower zone is the lower end of the dip tube located opposite this zone. The operating valve for the lower zone is set to have a higher opening pressure in the well than that for the upper zone.

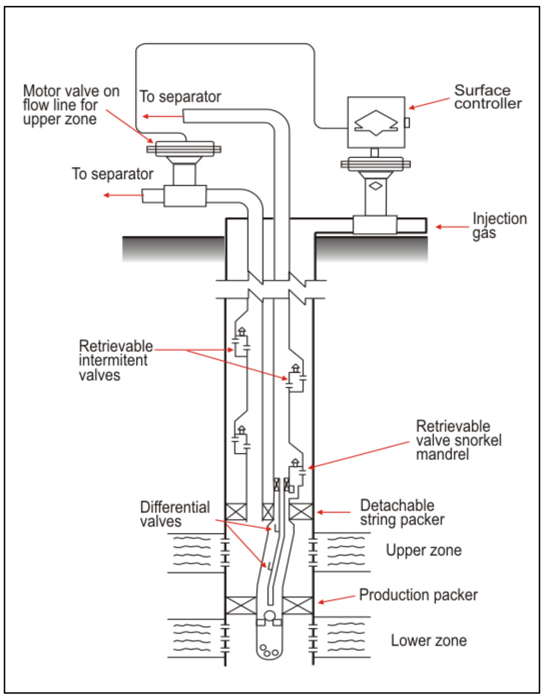


Figure 3.15—Completion for Zones That are Too Far Apart

3.5 Gas-lift with Plungers

Plungers originally 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 can not make the liquid slug to travel at values as high as 304.8 m/min or 5.08 m/s (1000 ft/min or 16.67 ft/s), or to overcome operational problems like paraffin formation along the tubing, or the injection point is too deep. Conventional plungers are only modified to make them longer so that they can be used in installation with gas-lift mandrels for wireline retrieval valves.

3.5.1 Low Liquid Slug Velocities

Low liquid slug velocities are found in places as follows:

— The gas-lift system can not provide a high instantaneous gas flow rate into the tubing. Sometimes this happens because the available maximum pressure or the gas flow rate that the compressor can deliver is too low. But it can also be due to a gas-lift system with low high-pressure storage capacity;

— The gas-lift mandrel already installed in the well accepts small diameter gas-lift valves, which limit the gas flow rate into the well.

3.5.2 Single Element Valves

Single element valves are used as follows:

— For the situations just described above, using plungers can be beneficial. But it is recommended to try to fix the problem whenever possible, for in the long run, plungers require extra care and they cause an increase in maintenance costs. At low liquid velocities, the fallback without plungers is very high, while for gas-lift with plunger at low velocities the losses are very low. As the velocity increases, the fallback is reduced if plungers are not being used while the opposite is true if plungers are used. At high velocities, the losses are about the same with or without plungers. The important thing is that the losses with plungers at low velocities compared to the losses without plunger 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 having a longer cycle time;

— For cases where the point of injection is too deep or there are paraffin depositions or emulsion problems, using plungers might be the only way to economically produce the well.

3.5.3 Plunger Use not Recommended

Plungers are not recommended when as follows:

— The fluids being lifted are too viscous because the falling speed of the plunger in the liquid might be too low;

— The tubing is deformed or highly deviated;

— The tubing string is composed of sections with different inside diameters;

— The liquid slug velocity that can be attained is around 304.8 m/min or 5.08 m/s (1000 ft/min or 16.67 ft/s) because in this case the liquid fallback losses and the gas required per cycle are about the same for installations with and without plungers. Any small increase in efficiency will be overcome by extra maintenance costs associated with the use of plungers.

A recommended completion for intermittent gas-lift with plunger is presented in Figure 3.16.

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 happen:

— if the lubricator is set to catch and retain the plunger, then the plunger stays in the lubricator and it can be pulled out (retrieved) by simply closing the master valve;

— if the lubricator is not set to catch the plunger, it will fallback to the bottom of the well as soon as the force exerted by the injection gas on the plunger diminishes to a value below the weight of the plunger.

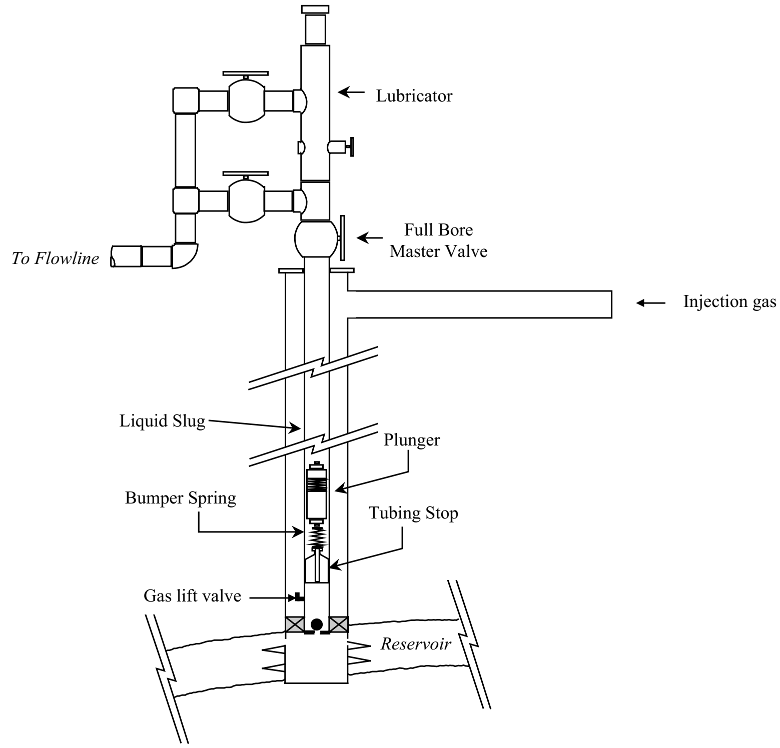


Figure 3.16—Completion for Intermittent Gas-lift with Plungers

3.5.4 Types of Plungers

There are different types of plungers and the ones that have experimentally shown to have the lowest instantaneous fallback loss rate, in m^3/s (bbl/s), for a given plunger velocity are the dual turbulent seal and expandable blade types.

The ones with the highest instantaneous fallback loss rate are brush plungers and capillary type plungers. It is interesting to know that it has been found that a plunger with a hole through its longitudinal axis is more efficient than one without it. The internal hole does not significantly increase fallback but it does make it easier for the plunger to fallback to the bottom of the well after a cycle.

3.5.5 Design Considerations

As a reasonable approximation, most of the calculations required for conventional intermittent gas-lift can be used for gas-lift with plunger applications. In this way, the procedures given in Annex A for optimum cycle time, theoretical gas required per cycle and the gas mass balance to find the valve closing pressure can be used for gas-lift with plunger. For the theoretical calculation of the gas required per cycle, the weight of the plunger must be added to the weight of the liquid slug in the energy balance equation. This addition must also be observed in the momentum equations when using numerical models to design gas-lift with plunger installations.

The major difference in designing gas-lift with plunger installations is the way in which the liquid fallback losses are calculated. Instantaneous liquid fallback losses can be estimated from published experimental plunger rise data relating instantaneous plunger velocity to instantaneous liquid fallback loss rate. It has been found that the rate of liquid fallback is a linear function of the average plunger rise velocity. This is a fact that has been used in numerical methods as presented in Annex A to sum, in time increments, the liquid fallback while the plunger is rising to the surface. However, this procedure does not take into account the liquid that is produced with the tail gas, which makes the final fallback lower than just adding up the fallback as the plunger travels along the tubing. Finding the volume of liquid produced with the tail gas is a much more difficult problem for which no experimental data has been published.

In simple equations, the fallback rate F_B for a given plunger type in m^3/s (Br/s), can be related to the plunger velocity Vpl, in m/s (ft/s), by the following equation:

$$F_B = (V_{pl} - s_1)s_2 \quad \text{in SI Units}$$

$$F_B = 0.0238(V_{pl} - s_1)s_2 \quad \text{in Field Units} \tag{6}$$

where

s_1 is the experimentally found V_{pl} -axis intercept for a particular plunger type;

s_2 is the experimentally found slope in (m^3/s)/(m/s) in SI Units and (gal/s)/(ft/s) in Field Units.

A typical experimental plot relating the fallback rate with the plunger velocity is presented in Figure 3.17.

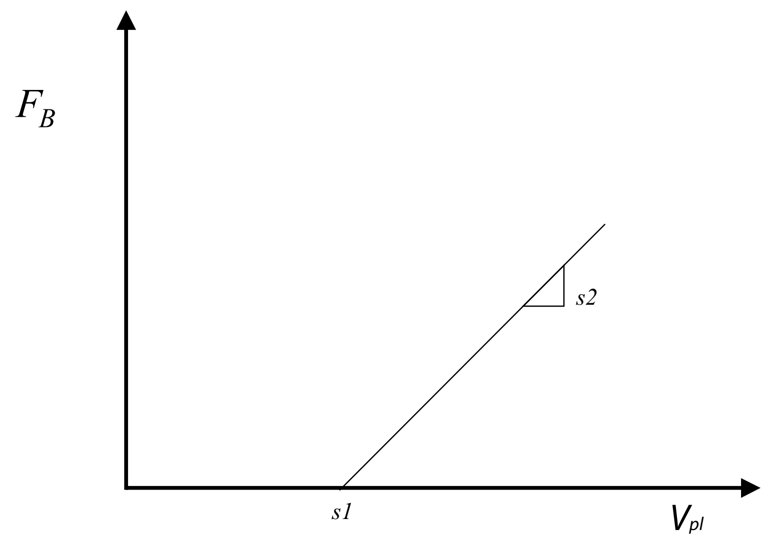


Figure 3.17—Typical Experimental Fallback vs. Plunger Velocity

Any velocity below s_1 will yield a zero fallback loss rate.

The fallback loss ΔF_B in a given time increment Δt as the plunger travels along the tubing is:

$$\Delta F_B = F_B \times \Delta t \ \text{m}^3 \text{ (barrels)} \tag{7}$$

This amount of lost liquid is removed from the total slug length by updating the length of the slug L.

$$L_{t+\Delta t} = L_t - \frac{\Delta F_B}{B_t} \tag{8}$$

where

B_t is the volumetric capacity of the tubing in m^3 per meter (barrels/ft);

L is the length of the liquid slug in m (ft).

Numerical models such as the ones presented in Annex A are very well suited for this type of calculations.

4 Types of Gas Injection Control

The design of an intermittent gas-lift installation will depend on how the gas injection per cycle to the well is going to be controlled. There are three major types of the gas injection control: “choke control,” “time cycle control,” and control by a production automation system.

4.1 Choke Control

When the well is on “choke control” the gas is allowed to pass continuously to the casing annulus at a low flow rate, which is controlled by a surface choke or a control valve. The surface choke can be in the gas injection line at the wellhead or at the gas injection manifold. The pressure in the casing annulus is continuously rising until the combined gas injection and tubing pressures cause the operating gas-lift valve to open. When the valve opens, the flow rate through it is much greater than the surface gas flow rate, allowing the casing pressure to rapidly decrease to the gas-lift valve closing pressure. Refer to Figure 6.3 for a typical choke control pressure recorder chart.

The advantages of choke control are as follows:

— The well annulus is used as a storage volume from which most of the gas injected per cycle comes. This is important for a gas-lift system with limited compression capability such as small rotative systems where it is better to have a constant injection gas demand rate;

— Smaller gas lines can be used and the surface equipment is less expensive;

— Many wells receiving gas from the same manifold can be simultaneously producing on intermittent lift without affecting the manifold pressure;

— Less surface equipment, minimum attention by field personnel, and lower maintenance costs are needed for choke controlled installations;

— This method allows both continuous and intermittent gas-lift to be "mixed" on the same gas-lift distribution system.

The disadvantage of choke control intermittent gas-lift is its inability to change the gas injected per cycle once a particular operating gas-lift valve is installed in the well. Changing the gas flow rate injected through the surface choke would mostly change the cycle frequency, but the total volume of gas injected per cycle would not change considerably if it is desired to stay around the optimum cycle time. The volume of gas injected per cycle is then fixed by the spread of the valve, which depends on the valve’s area ratio and to a minor degree, on the tubing pressure (unless the gas-lift valve is highly sensitive to tubing pressure and the cycle time is drastically changed from the optimum cycle time).

If the size or flow capacity of the operating valve does not support efficient lift, and if it can be changed by wireline, a recommended practice is to determine the correct valve design and change out the inappropriate valve.

Small surface chokes in places with injection gas with high water content can cause severe operational problem due to freezing. Dry injection gas is essential for efficient choke control. If the injection gas is wet, a dehydration unit should be considered. Other solutions might be to install a gas heater or by-passing the compressor after cooler, or locating the choke near the outlet of the compressor.

Besides freezing, liquids can cause regular gas injection interruptions since a long period of time might be required for an appreciable volume of liquid to pass through a small choke.

For low producing rates, the choke size becomes too small for practical applications; and for high producing rates, such as the ones encountered in chamber completions, choke control limits the cycle frequency.

The surface choke is recommended to be at the manifold to facilitate centralized measurement and control operations and, additionally, to use the line volume for extra storage capacity. For wells with a large casing annulus volume, it might be impossible, even with the lowest valve's area ratio available, to pass the required gas volume per cycle when it is less than the spread of the valve can supply. In these cases, it is recommended to install a surface choke in the gas injection line at the wellhead. If the latter action does not correct the problem, the well should be put on time cycle control.

Finally, choke control makes it difficult to control the precise time for each well to intermit and for small gas-lift systems, if many wells intermit at the same time, the compressor might not be able to handle all the suction gas and a large amount of gas would be flared. This will increase the demand for make-up gas.

4.2 Surface Time Cycle Control

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 the gas-lift valve stay 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 in the casing annulus rises very rapidly until the gas-lift valve opens. Once the gas-lift valve opens, for a well designed installation, the injection pressure should continue to rise, sometimes making it hard to detect when the gas-lift valve has opened. This means that the gas flow rate into the casing should be greater than the gas flow rate leaving it. If both rates are equal or close in value, the required injection time might be too long affecting the efficiency of the process, especially for high frequency wells. 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 is an undesired operation as it might damage the gas-lift valve and the gas injection into the tubing is interrupted causing high fallback losses. Refer to Figure 6.6 for typical examples of inefficient gas injection operations.

One of the major advantages of using time cycle controllers is their ability to adjust the volume of gas per cycle to what is precisely needed. With time cycle control, the cycle time and the volume of gas injected per cycle can be independently changed. Refer to 5.3 for information on a practical procedure to find the precise volume of gas required per cycle.

Where several intermittent wells are supplying 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 do if the wells are on choke control. Although the use of surface controllers offers problems to the high-pressure side of the system for not using the casing annulus as high-pressure gas storage volume, they allow staggering of intermittent slug production.

The disadvantages of using surface controllers are as follows:

— Greater maintenance costs;

— The manifold pressure can drop if too many wells intermit at the same time, which might cause a well to skip one or several cycles, as the flow rate into it might not be sufficient to reach the gas-lift valve's opening pressure. The manifold pressure can drop either because of lack of compression capacity or lack of high-pressure storage volume available in the gas-lift system. To overcome a pressure drop at the manifold, a synchronized gas injection control is recommended at the manifold. Refer to 4.5 for automation control.

It is recommended to use gas-lift pilot valves for intermittent lift installations, even when using time cycle controllers. Single element valves require a large area ratio to attain high gas flow rates. This might limit one of the main advantages of using time cycle controllers, which is their ability to change the volume of gas injected per cycle within a broad range of values. The area ratio of the valve should be 30 % lower than the one calculated for choke control, to have effective control of the gas needed per cycle in case it is less than the calculated value.

For most intermittent installations, the controller 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 line to the well must be filled to increase the casing pressure, causing the injection pressure to rise at a lower rate which can result in a less efficient operation. The injection gas line cannot be included as part of the high-pressure storage unless the controller is at the well.

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

This section discusses considerations for controlling gas injection while unloading an intermittent gas-lift well.

4.3.1 Before Unloading

If the well is loaded with mud, it should be circulated clean of mud to the perforations prior to running gas-lift valves. Abrasive materials in the well fluids can damage the gas-lift valve seats or may result in valve malfunction. If the injection gas line is new, it should be blown clean of scale, welding slag, etc. before being connected to a well.

The surface facilities should be checked prior to unloading the well: valves between the wellhead and the flow station, separator capacity, and specially all safety release valves for the gas gathering system should be carefully inspected.

4.3.2 During Unloading

It is recommended to unload the well very slowly, especially before the top valve is uncovered. During this time, fluid form 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 that is approximately equal to this line pressure will occur across each valve in the installation and high liquid velocities can damage the seats of the valves. After the top valve is uncovered, this condition cannot re-occur because the top valve will always open before a high pressure differential could exist across valves below the fluid level (see API 11V5).

4.3.3 Unloading Valve Design

The first injection gas head immediately after the top valve is uncovered can overload the surface facilities, especially if the valve area ratio is large. In those cases, the gas into the flowline should be restricted during the first head. One way to do this is by installing a choke downstream of the port in the unloading valve. This will limit the injection rate to the desired design value.

4.3.4 Injection Control During Unloading

During U-tubing, the time cycle controller should be set at 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 than that required for normal operation. As depth of lift increases, the duration of gas injection should be lengthened to assure ample gas volume for filling the increased tubing length and the injection gas cycle frequency should be decreased to allow the unloading valve to close between cycles. In practice, wells are always unloaded using “continuous” injection. If the well is designed for time cycle control, this may require “control” of the injection rate by pinching back the manual surface valve on the injection line.

Not all intermittent installations can be unloaded or operated with choke control. The type of gas-lift valve and the ratio of casing annulus capacity to tubing capacity must 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. Unloading a well in choke control takes more time than when cycle controllers are used. When the valve is first uncovered, the tubing pressure is high and the valve opening pressure is low. At this time, the initial slug is large and maximum gas volume is needed, but usually this gas volume is not met because the spread of the valve is very small due to high tubing pressure. Furthermore, for the first valves, the available annular space is small since it is mostly filled with fluids. 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 and so 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 larger slugs.

4.3.5 Optimization of Injection

After an installation is unloaded, the time cycle controller should be adjusted for optimum cycle time (which will maximize daily liquid production), and minimum injection GLR. A procedure to find the optimum cycle time is given in 5.2 and a practical way of finding the required volume of gas per cycle is described in 5.3. If the well is going to be operating on choke control, the final selection of the choke or opening through a metering valve is determined by a trial-and-error procedure. If the choke size is too large, the valve will open at a higher casing pressure than required for adequate injection gas storage in the casing. In this case, the tubing pressure will not reach a value that will result in the lower casing pressure needed for minimum injection gas requirement. This is because the choke control operations require unbalanced pressure operated valves that respond to casing and tubing pressure. By decreasing the choke size, the well has a longer time in which to deliver fluid into the tubing which, in turn, increases the tubing pressure at valve depth and reduces the casing pressure required to open the valve.

4.3.6 Unloading if the System Pressure is Low

When not enough pressure is available to unload the well, a procedure is to apply gas injection pressure to the tubing while also keeping the casing at line pressure. If a standing valve is not present, this will force some of the liquid in the tubing and the casing into the formation. This will uncover the top valve and allow the unloading process to continue. For fluid operated valves, this operation will open an upper valve and permit resumption of the unloading operation. This process should be used with care if there is a possibility of sand production. It can work if the well is producing from a carbonate reservoir.

4.3.7 After Unloading a Well with Large Tubing

The following operational problem has been observed in the field when using choke control in wells with 4 $^{3}/_{4}$-in. (12.06 cm) ID tubing. After the well is unloaded, the spread that is seen on the pressure chart is very small. This is because the liquid column above the operating valve may be large. The valve might have been sized correctly, but due to high fallback losses, it opens at a lower injection pressure (causing a small spread). To observe this phenomenon, go to the injection manifold and open the choke completely until the spread appears normal. When the injection rate is choked back to the value at which the well should operate, the well may begin to load up again. In this case the well should be produced with the help of a surface controller or a pilot valve with a larger area ratio should be installed.

4.4 Variations in Time Cycle and Choke Control of Injection Gas

This section discusses various options and considerations for designing time cycle and choke control of intermittent gas-lift wells.

4.4.1 TIme Opening and Set-pressure Closing Controller

When the injection gas line pressure varies significantly, it is recommended to open the controller on time and close it after a predetermined set pressure is reached. In this way, the cycle frequency will remain constant and the controller remains open until the maximum desired casing pressure is reached regardless of time required for this increase. This operation requires a pressure signal sent to the controller, which in turn, is programmed to analyze the information and send a command to open or close a valve in the injection line.

4.4.2 Time Cycle Controller with Maximum Pressure Control

In this application the controller is opened and closed on time, but the maximum pressure is controlled during the gas injection period so that it never increases above a certain level. This maximum pressure is maintained until the timing device closes the controller.

This type of control is recommended for intermittent installations with small casing, where the casing pressure increase may be excessive and open upper valves.

4.4.3 Time Cycle Controller with a Choke in the Injection Line

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. But for most installations, the use of a choke for reducing the time rate of increase of the casing pressure should be avoided, because this will increase the injection GLR and might decrease the daily fluid production.

4.4.4 Pressure Reducing Regulator and Choke Control

The pressure regulator controls the maximum pressure between cycles. Once this maximum pressure is obtain, the regulator closes until the pressure begins to fall during the next gas injection period, when the gas-lift valve opens. This type of control is recommended for low capacity wells that would require an extremely small choke. Small chokes increase the possibility of freezing and can plug very easily.

4.5 Automatic Control with a Production Automation System

Optimization of an intermittent gas-lift system is a challenging process. It is challenging enough to optimize the injection cycle frequency, injection volume per cycle, and production volume of individual intermittent gas-lift wells. It is much more difficult to optimize the production from a group of intermittent gas-lift wells. It can be daunting to optimize production from a field that may contain a mixture of wells on natural flow and various forms of artificial lift including continuous gas-lift, intermittent gas-lift, and one or more forms of pumping.

In modern times of limited staffing resources, perhaps the only effective way to truly optimize a complex oil field with many wells is with the proper application and use of a production automation system. Production automation systems have been successfully deployed for all forms of oil field production including intermittent gas-lift. The purpose of this section of this RP is to describe the important objectives and components of production automation as it is applied for intermittent gas-lift.

4.5.1 Objectives of Production Automation of Intermittent Gas-lift

The primary objectives of production automation of intermittent gas-lift are as follows.

4.5.1.1 Optimize Oil Production and Gas Usage for Individual Intermittent Gas-lift Wells

Clearly, the primary goal is to optimize (not necessarily to maximize) the oil production from each intermittent gas-lift well. The word "optimize" is important (rather than maximize) as it might be possible to produce more oil than the "optimum" amount, but at an unacceptable cost in terms of excess gas usage. Optimum oil production occurs when the profitability (income minus all costs) of the intermittent gas-lift operation is maximized.

A production automation system can help to optimize oil production from each intermittent gas-lift well by helping the gas-lift staff to optimize the intermittent gas-lift injection cycle frequency and the volume of gas injected per cycle. Additional information is found throughout this recommended practice concerning these topics.

4.5.1.2 Optimize Performance of the Intermittent Gas-lift System

It is not sufficient to focus only on individual intermittent gas-lift wells. What happens in one well can affect what happens in other wells that are part of the same gas-lift distribution system. For example, if gas is injected into two neighboring wells at the same time, both wells may experience an ineffective injection cycle. Moreover, if two wells are produced at the same time, the production slugs from the two wells may temporarily overload the production separator, causing liquid carryover into the gas gathering system. Therefore, an important objective of a production automation system can be to coordinate injection cycles into neighboring wells to prevent inter-well interference.

Another "system" performance issue arises when there is a system upset of some form or other. 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 in the system is temporarily less than normal, it may be necessary to temporarily defer injection cycles in some wells to prevent having ineffective injection cycles into all of the wells, or to prevent starving continuous gas-lift wells that may be connected to the same gas-lift distribution system. When the supply of lift gas is returned to normal, the injection process must again be adjusted to keep from over pressuring the system and causing over injection into some wells, or some gas to be flared.

4.5.1.3 Provide Information for Effective Intermittent Gas-lift Surveillance

Gas-lift wells and systems frequently change; inflow performance changes, gas-lift equipment wears, the mix of wells in the system changes. It is never sufficient to optimize a gas-lift system and its wells one time. This must be an on-going process. An important function of a production automation system is to continuously collect, analyze, and present information that can be used by the gas-lift staff for effective surveillance. The first steps in solving problems are to be aware of the problems and to collect the information required to understand the causes (not just the symptoms) of the problems. The only way that gas-lift personnel can keep up-to-date on the "state of health" of a complex production system and its wells is with an effective production automation system to "keep watch" on the system and wells on a continuous basis.

4.5.1.4 Coordinate Intermittent Gas-lift Activities with Other Related Production Activities

Intermittent gas-lift is never the only production function in a field. Often there are other types of wells that must be produced in the same field. Almost always there is a well test system. There are production gathering and processing systems. There is a gas compression and distribution system. There may be a pressure maintenance or secondary recovery injection system. All of these systems and processes must be effectively coordinated for overall optimum operation. Below are a few examples:

4.5.1.4.1 *Coordinating different forms of artificial lift*. 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. While it may be infrequent to find all of these forms of artificial lift in one field, it is common that both continuous and intermittent gas-lift operations are (or at least should be) mixed in one common system.

Continuous and intermittent gas-lift share many similarities and they have some important differences. Often these differences have caused production operators to avoid mixing the two forms of gas-lift in the same field. However, this can be lead to significant inefficiencies if, on the one hand, wells that should be intermitted are "forced" to use continuous gas-lift, or on the other hand, wells that should use continuous gas-lift are intermitted, for the sake of avoiding mixing the two types in one system.

With a modern production automation system, and with its ability to control the operation of each well in the system, there is no reason to avoid mixing continuous and intermittent gas-lift when this would be most beneficial for the wells involved.

4.5.1.4.2 *Coordinating with well testing*. The purpose of well testing is to obtain information on the production (oil, water, and gas) of a well. To do this effectively, the well production process must be coordinated with the well test process.

For example, when a well is being tested, it should be produced in a "normal" manner and should not be subject to having its operation "adjusted" to meet system upsets. If a system upset occurs, other wells should be adjusted as needed to address the upset situation, without affecting the well on test.

As another example, when an intermittent gas-lift well is tested, the test period should cover an equal number of injection cycles. This requires that both the well and the well test process be monitored and coordinated together.

4.5.1.4.3 *Coordinating with production facility operations*. It is frequently important to coordinate gas-lift operations with the operation of production facilities. Below are two examples:

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

b) If a field uses water or some other form of injection for reservoir pressure maintenance or secondary recovery, it is often important to coordinate the operation of the injection system with the operation of offsetting wells in the same injection pattern. This coordination may include matching production with injection into a pattern to maintain effective reservoir performance.

4.5.2 Measurements from Production Automation Systems

There are several categories of items that must be measured by the production automation system for an effective automated intermittent gas-lift system.

4.5.2.1 Gas-lift System Information

Normally, it is sufficient to measure this information on a frequency of once each minute. However, for an intermittent gas-lift system a higher frequency of once each 15 seconds may be required. The following gas-lift system information must be measured on a continuous basis:

a) *Gas-lift system rate that is available for injection*. It is necessary to continuously measure the rate of gas-lift gas that is available for injection into the gas-lift wells (both continuous and intermittent) that are served by the system. This may require use of several individual measurement points to measure the net gas in the system. That is, in some gas-lift systems, there may be more than one source of gas and there may be more than one "demand" or "customer" for this gas. For example, gas may be provided by more than one compressor and/or high pressure gas well, and gas may be delivered or used for fuel, sales, flare, and/or other uses, in addition to use for gas-lift. Sufficient measurements must be made to continuously determine the net amount (current rate) of gas available for gas-lift injection.

b) *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 a stable (as nearly constant as possible) 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. Major upsets can occur when a compressor trips or restarts. In each of these situations, the gas-lift automation system can keep the system pressure essentially constant, thus providing a stable pressure for operation of all of the wells that are served by the system.

4.5.2.2 Intermittent Gas-lift Well Information

As with the system information, it is normally sufficient to measure this information once each minute. However, for an intermittent gas-lift system where the performance of each injection cycle must be closely monitored and controlled, a higher frequency of once each 15 seconds may be required. The following information must be measured on each intermittent gas-lift well, on a continuous basis:

4.5.2.2.1 Gas-lift Injection Rate

For an intermittent gas-lift well, the volume of gas that is injected per cycle must be known. This is determined by measuring the rate of gas injection and by integrating this over the time of the injection cycle.

If the intermittent gas-lift well is on choke control, the gas injection into the well's casing annulus is continuous. The volume of gas injected per cycle is determined by calculating the volume of gas between two consecutive injection cycles. Moreover, it can 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.

4.5.2.2.2 Gas-lift Injection Pressure

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 such as more than one open valve, valve interference, premature valve opening, etc.

4.5.2.2.3 Production Pressure

For intermittent gas-lift wells, it is necessary to measure the production pressure so the arrival and duration of each production slug can be determined and problems with the slug production can be evaluated.

4.5.2.2.4 Production Rate

Normally, production rate is not 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 greatly assist in evaluating the effectiveness of the production slugs and in troubleshooting problems with the production process. Once such technique is the "differential pressure" method whereby a small pressure drop is taken across an orifice plate or a choke body and the differential pressure is measured. This differential pressure, in combination with the measured production pressure and the measured gas injection rate, can be used to provide a reasonable accurate estimate of the total liquid production rate. The method must be "calibrated" to an accurate well test.

4.5.2.3 Production System Information

While it is not required as part of the intermittent gas-lift operation, it can be very useful to measure the pressure in the production manifold. It is stated elsewhere in this RP that the wellhead backpressure must be kept as low as possible for effective intermittent gas-lift. If the pressure drop between the wellhead and the production manifold is too high, this may signify possible line blockage due to sand, paraffin, scale, etc.

4.5.2.4 Well Test Information

While it is also not directly a part of the intermittent gas-lift automation, it is very worthwhile to also automate the well test process. This will permit the well test process to be fully coordinated with well operations. Furthermore, if the differential pressure method is used to estimate the well's production rate on a continuous basis, the well test information is required to calibrate this process.

Well test information is discussed elsewhere in this document and in API 11V5. It is recommended to monitor the level in the well test separator as it changes with each intermittent gas-lift cycle. This may be a more accurate method to determine the actual production volume per cycle. The production automation system can directly assist with this process and can directly calculate the liquid volume produced per cycle. Otherwise, this can be a time consuming manual process.

4.5.3 What to Control

There are two primary levels of control to be addressed by an intermittent gas-lift automation system. A third possible future option is discussed.

4.5.3.1 Gas-lift System Control

The primary purpose of the gas-lift system is to provide a reliable, stable source of high pressure gas for injection into the gas-lift wells (potentially both continuous and intermittent) that are served by the system. With this in mind, the automation system can provide several services.

4.5.3.1.1 Assure System Stability When There are System Upsets

If a compressor trips or comes back on line, or if a production station trips or comes back on line, a major upset can occur in the gas-lift distribution system. This can adversely affect all gas-lift wells that are served by the system, both continuous and intermittent.

The role of the automation system in this case is to keep the demand for gas (the injection into all of the wells served by the system) in balance with the supply of gas into the system. In times of low supply (e.g. after a compressor trip), this may mean turning off the gas to some lower priority continuous gas-lift producers, reducing (slowing down) the injection rate into intermittent gas-lift wells that are on "choke" control, or deferring the injection cycles into some lower priority intermittent gas-lift producers that are on time cycle control. In times of high supply (where supply exceeds demand), this may mean restoring injection to some of the poorer continuous wells and/or restoring the injection rate or desired injection cycle frequency into the intermittent wells.

4.5.3.1.2 Assure System Stability When a Number of Wells are on Time Cycle Control

If there are a number of wells in a system on time cycle control, it can be important to coordinate (schedule) the injection cycles to avoid conflicts. If injection cycles occur into too many wells at the same time, this may have the effect of temporarily upsetting the system and causing ineffective injection into the wells. It can also cause problems on the production side if too may wells produce liquid slugs to the production separator at the same time.

The role of the automation system in this case is to coordinate (schedule) the injection cycles into the wells to avoid conflicts.

4.5.3.2 Gas-lift Well Control

There are three primary means for controlling the injection into intermittent gas-lift wells. The three are choke control, time cycle control, and a combination of these two. All can be effectively implemented with a production automation system. The pluses and minuses of choke control are discussed in 4.1. The pluses and minuses of time cycle control are discussed in 4.2.

4.5.3.2.1 Choke Control

In choke control, the gas-lift injection rate into the well's casing annulus is kept constant. 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 into the annulus, and thus the rate of pressure buildup in the annulus.

From a production automation perspective, this form of control is ideal since any impact of the injection cycles on the system and the other wells is minimized, since the injection rate into the well is held constant. With this form of intermittent control, it is easy for the production automation system to perform the system control service.

4.5.3.2.2 Time Cycle Control

In time cycle control, the surface injection valve is kept closed until time for the injection cycle. Then it is opened to allow a high injection rate into the 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. However, from a production automation perspective, this form of control does lead to more system instability.

In this case, the production automation system must 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.

4.5.3.2.3 Combined Choke and Time Cycle Control

A production automation system provides a third option for intermittent gas-lift control. It is to combine the features of both choke control and time cycle control into one process. Injection into the well's casing annulus is controlled on a continuous basis like in choke control. However, the injection is stopped just before the casing pressure rises high enough to cause the intermittent gas-lift operating valve to open. When it is time for the actual 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 cause the gas-lift valve to close but enough to allow the gas injection into the casing to continue.

The advantages of this approach are:

— the impact on the gas-lift system is minimized since most of the gas injection into the well occurs on a continuous basis, and not just when an injection cycle is required;

— but, the timing of each injection cycle is controlled, and the amount of gas injected per cycle is controlled, thus providing the advantages of time cycle control, without its downside of causing system instability.

4.5.3.3 Dynamic Well Control

As described elsewhere in this RP, the goal of intermittent gas-lift is to optimize oil production by optimizing both the timing and the size of each production slug. To do 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 be inefficient from a unit of gas injected per unit of oil produced perspective.

With a production automation system, the possibility exists to dynamically measure the production pressure and the production rate vs. time (see 4.5.2). With this "real time" information, it may be possible to optimize the duration of the injection cycle in real time, i.e. to stop the injection cycle at precisely the optimum time to assure maximum liquid recovery per cycle, without over injecting.

4.5.4 Using the Automation System for Intermittent Gas-lift Surveillance

Surveillance and troubleshooting of intermittent gas-lift wells is discussed in Section 6. The first step for effective gas-lift surveillance is to be aware of problems as soon as they occur. The second step is to have access to the information needed to evaluate, understand, and diagnose the cause of the problem, not just the symptoms. The third step is to have access to and to use the tools necessary to actually evaluate the information, diagnose the cause(s) of the problems, and determine the most effective solutions.

4.5.4.1 Awareness of Problems

The production automation system directly addresses the first step by continuously monitoring the important intermittent gas-lift parameters of system rate and pressure and individual well injection rate, injection pressure, production pressure, and (in some cases) production rate. It can use this information to detect problems, if these problems can be defined. For example, it can readily detect such problems as: too frequent or too infrequent injection cycles, too little or too much gas per injection cycle, too little or too much production pressure response, etc.

4.5.4.2 Access to Surveillance Information

An effective production automation system can collect, store, transmit, and present this information in ways to assist gas-lift staff in quickly finding problem wells, while not spending time reviewing wells that are functioning properly. The information can be presented in the form of alarms, reports, graphs, exception reports, etc. This can be "tailored" to meet the needs of the particular gas-lift personnel. When appropriate, the information can be shared with multiple people in the production organization—operations, engineering, etc.—so that the surveillance process can be effectively conducted by a team.

4.5.4.3 Analysis of Causes of Problems (Troubleshooting)

Once the information on the gas-lift system and wells has been collected, processed, stored, etc. it can be analyzed if the necessary tools are available. For example, if there is an effective model of the intermittent gas-lift process, the "system" can detect if more than one gas-lift valve is opening, if the standing valve is leaking, if too little or too much gas is being injected per cycle, etc. This analysis can greatly assist in the surveillance process. If the analysis process must be performed manually, this analysis often is not done. If it can be automated to the point that the gas-lift staff can spend their time responding to identified and defined problems, rather than trying to determine the causes of the problems, then the overall surveillance process can be far more effective.

4.5.4.4 Automatic Responses to Some Problems

There are some things that the production automation system can do by itself to address problems. Actions by the system to address system upsets have already been discussed. Another example occurs when freezing occurs across the surface injection control valve. If an intermittent gas-lift well is on choke control, there may be a relatively high pressure drop across the control valve. If there is too high water vapor content in the gas, this can cause freezing problems. If the automation system detects a potential freezing problem, it can often address this problem by momentarily fully opening the surface control valve, thus allowing the hydrate particles to be flushed down the casing.

5 Design of Intermittent Gas-lift Installations

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 would maximize daily production.

5.1 Mandrel Spacing

Intermittent gas-lift wells produce from reservoirs that have low static pressure. Nevertheless, unloading valves need to be installed to unload the well in case it has been loaded up for any operational reason such as a chemical treatment or a work over.

It is a good practice to assume that the well is filled with fluid all the way to the top, but if the mandrel spacing is going to be based on actual static liquid level that can be sustained by the reservoir pressure, then the top valve should be placed at the static fluid level.

The following sections describe one of the different procedures available for mandrel spacing for wells on intermittent gas-lift. This procedure is well suited for unloading the well by intermittent injection using pressure operated unloading valves. A general spacing procedure giving in Annex A can be used to unload the well with most types of gas-lift valves.

5.1.1 Graphical Procedure for Spacing Unloading Mandrels/Valves for Intermittent Installations

A graphical procedure for spacing unloading mandrels and valves in wells on intermittent gas-lift is presented in Figure 5.1. Also, refer to API 11V6 for a recommended gas-lift design. The recommended steps according to this particular procedure are as follows:

— In a pressure-depth diagram, trace a vertical line from the expected wellhead pressure (Pwh) 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 might be needed to install;

— From the available surface gas injection pressure ($Pio1$), trace a line to the top of the perforations using a suitable gas pressure gradient;

— From the wellhead pressure (Pwh) 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 instead of the operating gas injection pressure, the maximum available injection pressure, or kick off pressure, is used. In any case, the operating pressure should be at least 689.48 kPa (100 psi) less than the line pressure to assure ample gas entry;

— To find the depth of the second unloading valve, the following steps must be followed;

  — Subtract from kPa 172.37 to 344.74 kPa (25 psi to 50 psi) from injection pressure $Pio1$. This defines the surface injection pressure for the second valve ($Pio2$). Taking a drop in injection pressure is recommended for injection pressure operated valves and it provides excellent surface information for troubleshooting analysis. If production pressure operated valves are used, mandrel spacing can be based on the same opening or closing surface pressure. However, use of production pressure operated valves is not recommended for intermittent gas-lift wells unless there is some compelling reason to do so. See discussion in 5.1.4;

  — Trace a line from $Pio2$ 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 to 0.06, times the depth of the point of injection (in 1000 ft or 304.8 m) 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 SI Units by $0.05 \times (D1/304.8) \times D1$ with $D1$ expressed in m and, in Field Units, by $0.05 \times (D1/1000) \times D1$ with $D1$ expressed in ft;

— From point "$i2$" trace a line with a kill fluid gradient until it intercepts the gas injection pressure (point $i3$). The depth of this interception corresponds to the depth of the second valve;

— To find the depth of the third unloading valve, the following steps must be followed;

  — Subtract from 172.37 kPa to 344.74 kPa (25 psi to 50 psi) from injection pressure $Pio2$. This defines the surface injection pressure for the third valve ($Pio3$);

  — Trace a line from $Pio3$ 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 SI Units by $0.05 \times (D2/304.8) \times (D2 - D1)$ with $D1$ expressed in meters and, in Field Units, by $0.05 \times (D2/1000) \times (D2 - D1)$ with $D1$ expressed in ft;

— From point "*i*4" trace a line with a kill fluid gradient until it intercepts the gas injection pressure (point *i*5). The depth of this interception corresponds to the depths of the third valve.

— This procedure is continued until a valve depth falls below the packer. In this case all valve's depths need to be corrected by a procedure given in 5.1.2.

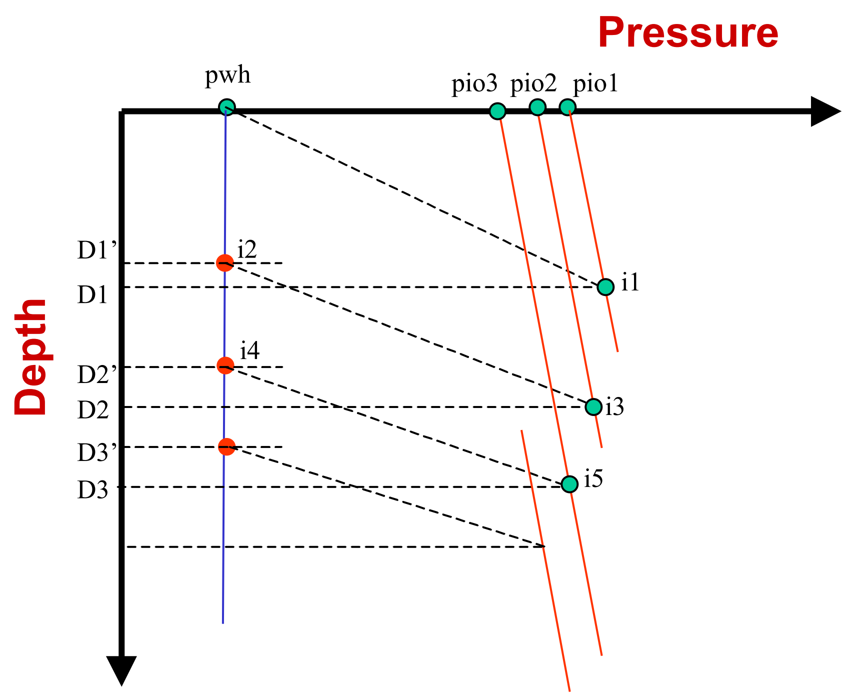


Figure 5.1—Graphical Procedure for Spacing Unloading Valves

5.1.2 Analytical Procedure for Spacing Unloading Valves

To derive an analytical expression that will describe the procedure presented in 5.1.1 for mandrel spacing, it is necessary to have an expression for the downhole injection pressure in terms of the surface injection pressure and the depth of the point of injection. The following expression had been found to be within 5 % accuracy when compared with field measurements in situations where losses due to friction can be neglected:

$$Piod = FGL \times (Pio) \tag{9}$$

where

$Piod$ is the injection pressure at depth;

Pio is the surface injection pressure and FGL is given by

$$FGL = 1 + BGL \times (Di) \tag{10}$$

where

Di is the depth of the point of injection expressed in 1000s of ft if Field Units are used.

If SI Units are used, Di is expressed in the actual depth in meters divided by 304.8. And

$$BGL = BLA + BLB \times (PO) + BLC \times (PO2) \tag{11}$$

where

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

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

$$BLB = (0.57508 - 1.8442 \times SGi + 1.5754 \times SGi^{\,2}) \times 10^{-4} \text{ in.} \quad \text{Field Units} \tag{13}$$

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

$$BLC = (7.1615 \times SGi - 2.3070 - 5.7763 \times SGi^{\,2}) \times 10^{-8} \quad \text{in Field Units} \tag{14}$$

with

$PO = Pio + 101.35$ in SI Units

$PO = Pio + 14.7$ in Field Units and SGi is the gas specific gravity. (15)

The analytical expression for each valve depth, Di, is found from a pressure balance equation: the gas injection pressure at depth must be greater than or equal to the pressure inside the tubing. For the depth of the first valve, $D1$, the pressure balance equation is

$$PWH + D1 \times g_s = FGL \times Pio \tag{16}$$

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 meters of true vertical depth if SI Units are used.

Since $FGL = 1 + BGL \times (D1)$, the depth of the first valve, $D1$, will be

$$D1 = (Pio - Pwh)/(g_s - BGL \times Pio) \tag{17}$$

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

$$Dn = \frac{(Pko - (n-1)S) + (1 + (D_{n-2} - D_{n-1})FF)g_s D_{n-1} - Pwh}{g_s - (Pko - (n-1)S)BGL} \tag{18}$$

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;

Pko 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 9.14 m to 18.29 m (30 ft or 60 ft), and all upper valve's depths are corrected according to

$$Dn' = Dn - n\,(DEL) \tag{19}$$

Where DEL is given by

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

where

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

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

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

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

where

n is the valve number.

5.1.3 Choosing the Unloading Valves

For economical and operational reasons, it is recommended to use single element valves instead of pilot valves as the unloading valves. Furthermore, the unloading valves should be injection pressure operated gas-lift valves set to open at high pressure so that they will stay closed when the bottom of the liquid slug reaches each valve. Designing installations with production pressure operated unloading valves is difficult and will not provide any operational advantage (see ISO 17078-2, *Petroleum and natural gas industries—drilling and production equipment—Part 2*: *flow control devices for side-pocket mandrels*).

5.1.4 Choosing the Operating Valve

Choosing the operating valve is the most important step in designing an intermittent gas-lift installation, especially if surface intermitters will not be used. This is because the complete operation of the installation depends upon three parameters that the operating valve has to control in intermittent lift which have a profound effect on the efficiency of the method:

— gas injection pressure;

— total volume injected per cycle;

— instantaneous gas flow rate.

Setting the valve to open at a particular injection and fluid pressure can be handled by any type of valves available and does not represent a problem in intermittent gas-lift.

It has been shown that for surface injection pressures above 4826.33 kPa (700 psig), the injection pressure does not affect the liquid fallback for wells handling liquid slugs between 60.96 m to 243.84 m (200 ft to 800 ft) in length. The gas-lift efficiency decreases for surface injection pressures below 4826.33 kPa (700 psig). The system available injection pressure should consider the pressure drops taken per valve and the pressure drop across the operating valve itself.

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 choke control operations, it is very important to install a valve with the right area ratio since the volume of gas injected per cycle will be fixed once a particular area ratio is selected if the cycle time is going to remain constant and around its optimum value. For choke control intermittent gas-lift, increasing the gas flow rate at the surface will only increase the cycle frequency but it will have very little effect on the total volume of gas injected per cycle, unless the valve is highly sensitive to tubing pressure and the cycle time is considerably change from the optimum cycle time. Guidance for area ratio calculation is provided in 5.4.

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 the liquid fallback losses. On the other hand, if the velocity is too low, the gas tends to bubble through the liquid, also increasing the liquid fallback losses. Experimental evidence has shown that a liquid slug velocity of 304.8 m/min (1000 ft/min) (± 15 % approximately) is recommended. This means that 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 three hundreds of meters in SI or thousands of ft in Field Units) 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 represents a problem for single element valves for which the spread of the valve is related to the diameter of the seat. If a small spread is required then a small seat diameter has to be installed which will not provide a high instantaneous flow rate, even though it will probably be able to pass the correct total volume of gas per cycle but in a very inefficient way. Guidance for selecting single element or pilot valves is provided in 2.2.1.

To have a flexible control over the operation of the well, injection pressure operated valves are preferred over production pressure operated valves. A production pressure operated valve will respond mainly to the pressure inside the tubing and unless precise information of the optimum liquid slug length is given, production pressure operated valves are not recommended. Furthermore, if production pressure operated valves are used, provisions must be made to account for inflow changes over time. Production pressure valves are not used for chamber installations, as they are always located above the fluid level. But in dual completions, using fluid valves may be beneficial. Refer to Section 3 for recommendations for dual installations. Fluid tripped valves with casing pressure closing action offer a good choice for compressor operation in very small gas-lift systems.

Finally, it is better to have 3.81-cm (1 $^1/_2$-in.) valves in operation rather than 2.54-cm (1-in.) valves. The reasons for this are:

— 3.81-cm (1 $^1/_2$-in.) valves have larger main port diameters, which will provide high flow rates across the valve, required for efficient intermittent lift;

— the minimum area ratio for a 2.54-cm (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 casings);

— for single element valves, the bellows;

— for pilot operating valves, the 3.81-cm (1 $^1/_2$-in.) pilot valve is more robust and historically gives a longer operating life than 2.54-cm (1-in.) pilots.

5.2 Optimum Cycle Time

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 potential of the well. If the cycle time is too long, the injection GLR will be low but the liquid production could be considerably lower than the maximum production that can be obtained from the well. There is a trade off between column height and accumulation time. The bigger the column the longer the accumulation time 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 bottom hole pressure. An analytical expression, derived in Annex A, provides a way to calculate the optimum cycle.

A practical way of knowing the optimum cycle time is to test the well several times for different cycle frequencies (refer to Section 2 for guidance on ways to conduct well tests on intermittent gas-lift). For this practical 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 a two pen pressure chart or by inspection at the wellhead. Refer to 5.3 for guidance on the required total volume of gas injected per cycle. It is recommended to follow this practical procedure even if the optimum cycle time has been determined analytically using the algorithm given in Annex A.

5.3 Volume of Gas 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 5.2. 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.

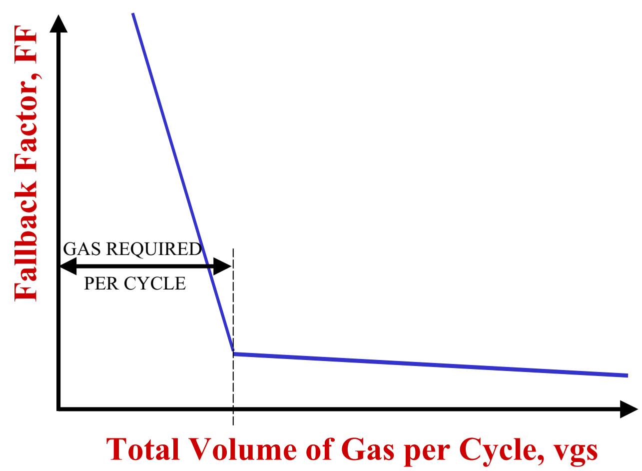


Figure 5.2—Fallback Factor as a Function of the Total Volume of Gas Per Cycle

Figure 5.2 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).

The fallback losses drastically increase if the volume of gas is injected below the required volume of gas per cycle. On the other hand, not much is gained by injecting more gas than the required volume of gas per cycle as seen in Figure 5.2. So it is important to know precisely the volume of gas needed to be injected.

It has been found that the required total volume of gas per cycle is a function primarily 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 extend). Between columns of 60.96 m to 243.84 m (200 ft to 800 ft), the liquid column length does not play a major role on the required gas per cycle.

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

— Using an analytical procedure described in Annex A, find the theoretical gas required per cycle. This will provide a starting point 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 three days to provide for stabilization and then test the well following the procedure suggested in Section 2;

— While keeping the total cycle time constant, decrease the volume of gas injected per cycle by 10 % of the previous volume. After at least three 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:

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

where

Q is the volume of gas per cycle in m^3;

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 m^3/m.

$$Q = \frac{Ppd \times Dv \times Bt}{14.7} \quad \text{in Field Units} \tag{24}$$

where

Q is the volume of gas per cycle in ft^3;

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 ft^3/ft.

5.4 Valve Area Ratio Calculation for Choke Control

Once a valve with a particular 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 is not allowed to change from the optimum cycle time. So, it is very 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 a pressure operated valve opens, the area ratio can be calculated as;

$$R = \frac{Piod - Pvcd}{Piod - Ppod} \tag{25}$$

The injection opening pressure at valve depth, $Piod$, is usually known as soon as the valve spacing has been found. $Pvcd$ is the valve closing pressure at depth and $Piod$ is the production pressure in the tubing when the valve opens. It represents no operational problem as long as the general recommendations given in Section 2 are followed.

The tubing opening pressure in kPa (psi), $Ppod$, is found from:

$$Ppod = Pwh \times fg + Q \times \rho_f \qquad \text{in SI Units}$$

fg is the gas pressure correction factor used to calculate the gas pressure at depth, Pwh is the wellhead pressure in kPa, ρ_f is the liquid gradient in kPa/m, and 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 5.2 and Annex A to find the optimum cycle time.

$$Ppod = Pwh \times fg + Q \times \rho_f \qquad \text{in Field Units} \tag{26}$$

where

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

Pwh is the wellhead pressure in psi;

ρ_f is the liquid gradient in psi/ft;

Q is the liquid column length in ft.

The value of Q can be found as soon as the optimum cycle time has been calculated. Refer to 5.2 and Annex A 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, $Pvcd$. This is done by a mass balance of the gas injected into the tubing and the gas provided by the gas-lift system:

$$vgs = vga + vgl + vge \tag{27}$$

The volume of gas injected into the tubing, vgs, is equal to the volume provided by the annulus, vga, plus the volume provided by the injection line from the choke to the wellhead, vgl, plus the volume of gas that passes through the surface choke while the gas-lift valve is open, vge.

The volume of gas injected into the tubing, vgs, can be calculated following the procedure given in Annex A. vge is a function of vgs and the cycle time, while vga and vgl are functions of $Piod$ and $Pvcd$. So the only unknown in the mass balance equation is $Pvcd$. Refer to Annex A for calculation details.

Once $Pvcd$ is found from the procedure given in Annex A, all the parameters needed to find the value of R are known.

For spring loaded pressure operated valves, $Pvcd$ 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, pressure operated valves, $Pvcd$ 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.

5.5 Valve Area Ratio Calculation When Surface Time Cycle Controllers are Used

The use of time cycle controllers is recommended to be able to change at will the volume of gas per cycle to values above that which the spread of the valve alone can allow. Refer to 4.2 for guidance on the use of time cycle controllers.

Due to the flexibility in the total volume of gas per cycle that the use of time cycle controllers can offer, the calculation of the area ratio of the gas-lift valve is not as critical as it is for choke control intermittent lift. Nevertheless, there are steps that must be considered to provide an efficient operation:

— The valve opening pressure should not be set at values close to the available pressure at the manifold. Following this recommendation 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 since this will cause an increase in the gas injection time required to inject the volume of gas needed, but more importantly, the area ratio cannot be too large as this will limit the volume of gas per cycle to high values only. In the latter case, 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;

— It is recommended to calculate the area ratio of the valve as if the well will operate on choke control, following the procedures given in 5.4, and then use an area ratio 30 % to 40 % less than the calculated value.

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

The use of mathematical models (a.k.a mechanistic model), based on the physics of the intermittent lift process, is becoming increasingly popular among gas-lift designers. These models provide detail information of the process as a function of time that will otherwise be impossible to obtain. Refer to Annex A for the general description of two different types of approaches.

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 complicated, 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 phenomenon are extremely difficult to model and they are not taken into consideration by current mechanistic models. That is the reason why the classical engineering approach is always a good first choice for design and the more refined mechanistic models available today should be used as a refinement and check and balance procedure.

In conclusion, mechanistic models can be used for design purposes as long as they have been properly calibrated against actual measurements for a variety of operational conditions expected to be present in a particular field.

6 Troubleshooting Techniques for Intermittent Gas-lift

This section provides guidelines and recommended practices for troubleshooting intermittent gas-lift systems and wells.

6.1 Information Required for Troubleshooting

The reliability of a troubleshooting analysis depends on the quality and quantity of the data available to the field operator, well analyst, or engineer. The first step in trying to troubleshoot the operation of the well is to gather as much good quality and reliable information as possible. The following is a list of necessary data required to start a troubleshooting process.

6.1.1 Injection and Tubing Pressure Values and Fluctuations with Respect to Time

This is the most important information to be collected, as it is not possible to do a troubleshooting analysis on intermittent lift without knowing how the injection pressure and the production pressure at the wellhead change with time. From this information it is possible to know the values of the surface opening and closing pressure, the cycle time, the gas injection and liquid accumulation time, and possibly, the slug average velocity.

Knowing the injection and tubing surface pressure is necessary but not sufficient to troubleshoot the well when previous analysis have not been done, for in this case, a complete analysis must always be done to ascertain the efficiency of the intermittent lift method.

6.1.2 Liquid and Total Gas Production

Information provided by at least one well test, at the current cycle time, must be available. Refer to Section 2 for guidance on well test recommended procedures for wells on intermittent gas-lift.

The changes in separator liquid level and in total gas flow rate with time are as important as the total daily production. The surface injection pressure might give the impression that the gas is being injected intermittently, but there exists the possibility that one valve is continuously open while another is opening and closing at constant intervals due to valve interference. This is analytically determined by a gas mass balance performed as suggested in 6.3 and it is clearly identified if the liquid level at the separator increases constantly and especially if the total gas flow rate out of the separator is always considerably greater than zero.

An integrating device that uses the static and differential pressure across an orifice plate usually measures the total gas flow rate out of the separator. For intermittent lift wells, these pressures change erratically and it is usually difficult to determine the total gas flow rate accurately. Alternatively, it is usually not economically justified for wells on intermittent lift to install sophisticated turbine flow meters that can electronically integrate the daily total gas flow. Nevertheless, it is recommended to always use some kind of gas flow rate measuring device as it provides useful qualitative information and, to a certain degree, the total gas flow rate can be estimated.

6.1.3 Fluid and Gas Properties

To perform a troubleshooting analysis, the following information is required: crude API gravity, formation GLR, bubble point pressure, injection and formation gas gravity and water cut. Means to obtain a liquid sample at the wellhead should be available. A flow-line bleeder valve can be used to find out if the well is producing liquids or gas.

The injection gas specific gravity is required to calculate the injection pressure at depth. The liquid content of the gas is also important information because liquids can cause problems such as freezing at the injection choke or gas injection interruptions. Dirt and debris in the gas can also cause problems by plugging the main sections of most types of pilot valves.

6.1.4 Reservoir Data

It is important to know the inflow capability of the well to determine how close the current liquid production is to the well's potential.

The important reservoir parameters to be determined are the static reservoir pressure and the effective PI, which is defined as the average PI within the practical operational range of the IPR curve for intermittent lift in which the flowing bottom hole pressure goes form separator pressure to 40 % to 50 % of the static pressure.

The reservoir engineers usually provide the static reservoir pressure and it is recommended to have an updated estimate of its value. The effective PI, on the other hand, can be determined by the field operator in two ways:

a) by a downhole pressure survey (refer to 6.2.3 and 6.3.4); or

b) by an analytical procedure given in 6.3.2 which can only be applied when the liquid fallback can be estimated within an approximate value.

Once the static reservoir pressure and the effective PI are known, the optimum cycle time, and therefore the well's production potential, can be calculated using the equations given in Annex A.

6.1.5 Completion Data Including Gas-lift Valve Settings

The following information is needed and should be readily available to field personnel:

— production casing inside diameter;

— tubing inside and outside diameter;

— tubing inclination;

— valves, packer and perforations depths;

— type of gas-lift valve;

— valve area ratio;

— valve orifice diameter;

— test rack opening or closing pressure;

— injection line inside diameter and length;

— flowline inside diameter and length;

— wellhead conditions.

6.1.6 Data from Diagnostic Tools

The use of specialized equipment discussed in the following section can be of great assistance in gas-lift evaluation. These tools can be expensive to use or involve some type of mechanical risk so their application needs to be carefully considered.

6.2 Diagnostic Tools Available for Troubleshooting Intermittent Gas-lift Installation

There are several tools that can be used to gain information on the actual efficiency of the intermittent-lift method. The most important ones are discussed in this section.

6.2.1 Valve Performance from Two-pen Chart Recorder or from a SCADA Report

Two-pen recorder charts provide valuable information on the performance of the well, but without proper analysis a wrong conclusion might be reached. Refer to 6.3 for information on troubleshooting analysis for wells on intermittent lift. If a two-pen chart recorder is used, its calibration must be checked periodically and if the information comes from a SCADA report, it is important to have a scan rate no less than one measurement every 20 seconds. Refer to API 11V5 for recommendations on the installation of wellhead pressure recorders.

The pressure element in a pressure recorder should be compatible with the pressures being measured. Usually, a 1000 psig (6996 kPa) or 1500 psig (10443 kPa) pressure element is used for the casing pressure and a 500 psig (3549 kPa) or 1000 psig (6996 kPa) element for the tubing pressure recording. A 24-hour chart rotation clock is the most widely used. A combination 24-hour, 24-minute clock is ideal for a test pressure recorder. A 24-minute rotation chart is used to study an individual gas-injection cycle. Seven-day rotation charts are not recommended.

6.2.1.1 Tubing Pressure Recording

Tubing pressure recording gives the first indication of the efficiency of the intermittent-lift method or the well capacity to produce liquids. The values of the maximum pressure and the time required for the wellhead pressure to descend to separator pressure are valuable pieces of information that must be available to the operator.

The maximum wellhead pressure is a function of several variables, the most important being the liquid slug length and its velocity, continuity of the liquid slug and any restriction downstream of the wellhead (especially near the wellhead). Even thought it provides a great deal of information, a statement on the efficiency of the actual operation of the well cannot be made based only on the observation of the wellhead pressure recording.

Maximum wellhead pressure should occur following the surfacing of the liquid slug. If restrictions near the wellhead are causing the tubing pressure to reach its maximum value before the liquid slug has surfaced, the liquid velocity will decrease causing high liquid fallback. Restrictions away from the wellhead might cause the tubing pressure to decrease to separator pressure after a long period of time. This limits the maximum cycle frequency and producing capacity of higher liquid producing wells, but it is not too important for lower producing wells.

Examples of typical tubing pressure recordings are shown in Figure 6.1.

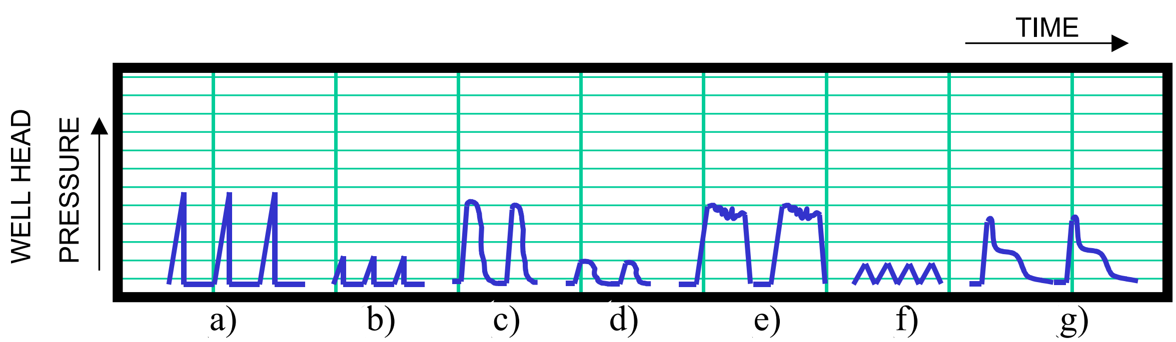


Figure 6.1—Typical Wellhead Pressure Recordings

Figure 6.1 a) indicates a good intermittent operation with a continuous slug being produced and a fast pressure reduction indicating no restriction at the wellhead or flowline.

Figure 6.1 b) indicates that the initial liquid slug is shorter because of low reservoir pressure or because the cycle frequency is high, but it can also be due to a low liquid velocity.

Figure 6.1 c) indicates a restriction away from the wellhead such as a smashed flowline; paraffin deposition; long and small flowline; etc. A restriction near the wellhead like a choke or numerous bends near the wellhead will look more like Figure 6.1 a) with a higher than normal maximum pressure, just like the ones expected of a chamber installation.

A small but wide kick like the ones shown in Figure 6.1 d) indicates one, or several, of the following possibilities: smaller initial slugs with gas break through; emulsions; or not enough gas per cycle.

A long, gas-cut slug will produce spikes like the ones in Figure 6.1 e).

If the cycle frequency is high, the wellhead pressure will look like Figure 6.1 f), and in this case the minimum pressure can be higher than the minimum attainable separation pressure as seen in Figure 6.2. An engineering analysis will indicate if the loss of efficiency caused by a higher average wellhead pressure is overcome by a high cycle frequency.

Figure 6.1 g) is a clear indication of excessive tail gas or a severe restriction at the separator.

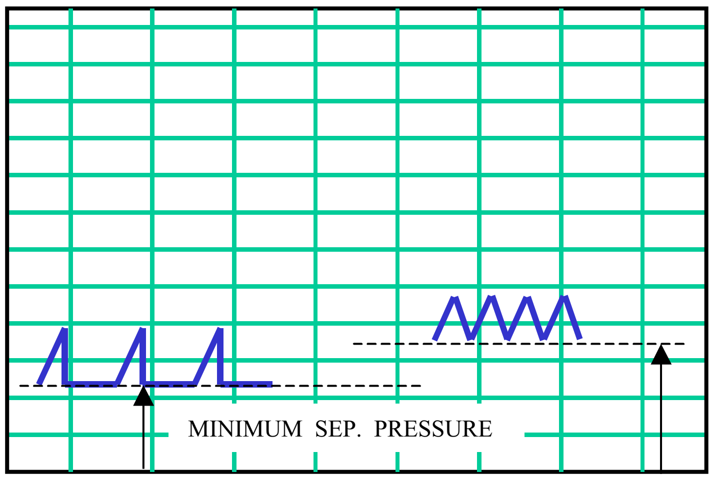


Figure 6.2—Cycle Frequency Effect on Minimum Wellhead Pressure

Careless field operations can induce data errors:

— a clock set for 7 days using a 24-hour chart gives the impression of a high cycle frequency;

— a constant wellhead pressure in an intermittent well might be due to a closed valve connecting the wellhead to the recorder or undetected plugged tubing used to send the pressure signal from the wellhead;

— bad instrument calibration can give the impression of extremely high or low separation pressure;

— a recorder mounted in the tubing can vibrate during slug production and cause the pen to move giving the wrong impression of wild pressure fluctuations that do not exist;

— one pen can be pushing the other if not mounted properly in the recorder.

6.2.1.2 Casing Pressure Recording

Casing pressure recording provides an important piece of information from which the gas-lift system, the gas-lift valve and the time cycle controller performance can be inferred. Just as for tubing pressure recording, statements on the performance of the gas-lift system and equipment cannot be made based only on observation of the casing pressure recording and without engineering analysis.

The casing pressure is measured downstream of the injection gas controller or surface choke. Casing pressure, not line pressure, is required to analyze a gas-lift installation. Sometimes three-pen chart recorders are used: one for the casing pressure, one for the tubing pressure and the other for the differential pressure across an orifice plate install in the gas injection line.

a) *Choke control*. The normal behavior of the injection pressure for choke control operation is as shown in Figure 6.3.

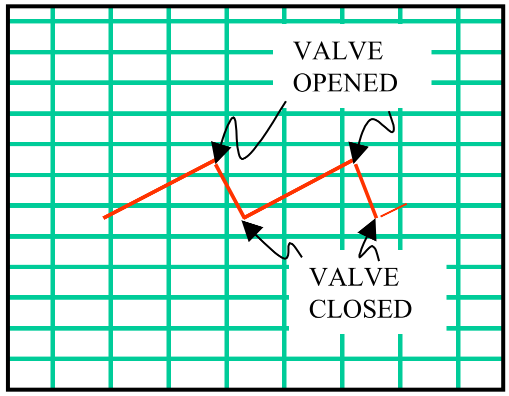


Figure 6.3—Surface Injection Pressure Recording (Choke Control)

Examples of typical gas injection pressure recordings are shown in Figure 6.4.

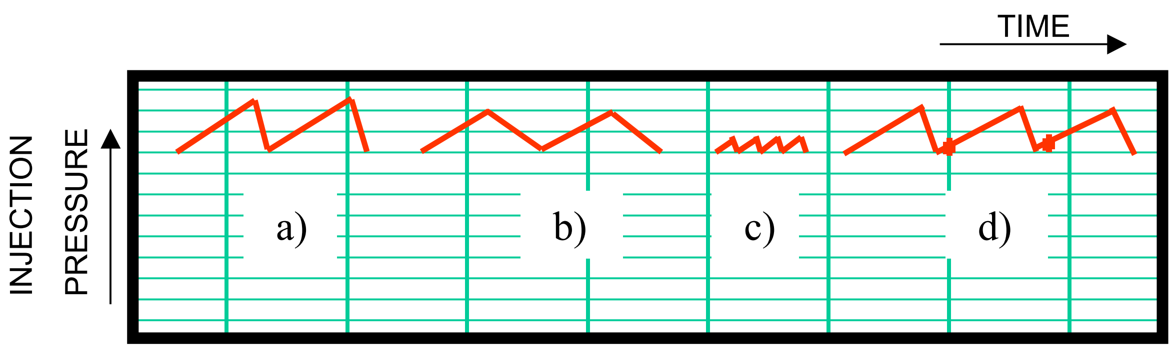


Figure 6.4—Typical Gas Injection Pressure Recordings

Figure 6.4 a) shows good valve action, with a fast decrease in gas injection pressure once the valve opens, indicating a high gas flow rate into the tubing, but it can also indicate that the casing-tubing annulus is very small or the operating valve depth is very shallow. A simple analysis will indicate if the instantaneous gas flow rate is or is not adequate.

Figure 6.4 b), on the other hand, shows a slow decrease of gas injection pressure once the valve opens, indicating a low gas flow rate into the tubing due to a plugged valve or a small orifice diameter valve, but it can also indicate one, or several, of the following: a deep operating valve; a large casing-tubing annulus or a long and large diameter injection line.

Figure 5.4 c) shows a small valve spread due to a valve with a small area ratio, but it can also indicate a high tubing pressure that causes the valve to open at a lower pressure. Only an engineering analysis will determine if the spread, and therefore the valve area ratio, is sufficient to inject the total volume of gas required per cycle and if the cycle frequency is adequate.

Figure 6.4 d) shows signs of vibration of the recorder once the slug reaches the surface.

b) *Time cycle control*. The normal behavior of the injection pressure for time cycle control operation is as shown in Figure 6.5.

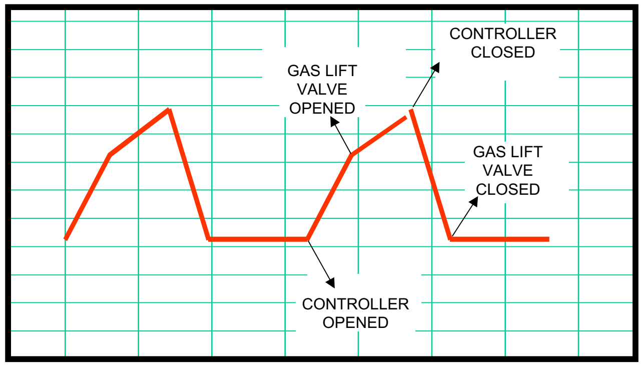


Figure 6.5—Surface Injection Pressure Recording (Time Cycle Control)

Examples of gas injection pressure recordings that reflect inefficient operations are shown in Figure 6.6.

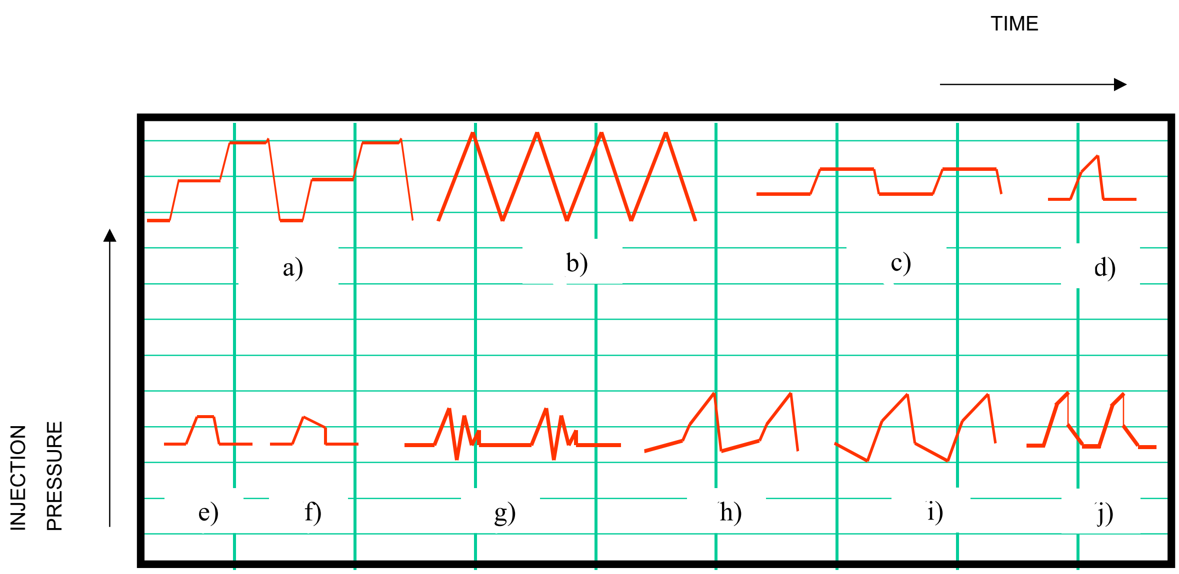


Figure 6.6—Examples of Inefficient Gas Injection Operation

Figure 6.6 a) shows a case where the gas volume per cycle is not sufficient to raise the casing pressure to open the gas-lift valve.

If the controller is working properly and the injection pressure looks like Figure 6.6 b) then there exist two possibilities: if the injection pressure is low, the gas-lift valve has failed in the open position or there is a large leak from the annulus to the tubing, but if the injection pressure is high it means that the gas flow rate into the annulus is so high that the gas-lift valve never closes.

In Figure 6.6 c), the gas enters the tubing at the same rate that the gas enters the casing, so the injection pressure, while the gas-lift valve is open, remains constant. This might require a long gas injection period which is undesirable and it might be due to a restriction in the manifold, or the gas-lift system not being able to supply a high flow rate, or the opening pressure of the gas-lift valve has been set too close to the available pressure at the gas injection manifold.

Figure 6.6 d) shows a good operation while Figure 6.6 e) shows the same problem presented in Figure 6.6 c) only that the required injection time is shorter.

If the gas flow rate out of the annulus is greater than the gas flow rate provided by the gas-lift system, the pressure in the casing will decrease as shown in Figure 6.6 f), and can even make the gas-lift valve to close prematurely as shown in Figure 6.6 g) where the gas-lift valve opens and closes several times while the surface controller is open.

Figure 6.6 h) shows that the controller is leaking gas to the annulus if the completion is a closed type completion, but it could be a normal operation for an open type of completion.

Figure 6.6 i) indicates a small leak from the annulus to the tubing. If the controller is purposely kept closed and the pressure drops to the separator pressure, the leak is above the tubing liquid level, but if the pressure drops to a higher pressure, the leak should be below the tubing liquid level. But Figure 6.6 i) can also indicate that the gas-lift valve is opening between injection cycles due to high tubing pressure, this is easily verified by looking at the tubing pressure change between injection cycles.

Figure 6.6 j) shows the case where more than one gas-lift valve opens during the cycle, but it is a sign of good operation in case of a dual completion in which one zone is producing continuously while the other is on intermittent gas-lift.

6.2.1.3 Examples of Intermittent Gas-lift Malfunctions

Refer to API 11V5 for examples of two-pen charts showing typical intermittent gas-lift malfunctions.

6.2.2 Acoustical Surveys

Well sounding devices can be used to determine a variety of diagnostic information, the most important being the depth of the liquid level in the annulus. For general description of this type of tool, its applications and limitations, refer to API 11V5.

The fluid level in the casing does not always indicate the depth of the opening valve. Most intermittent installations have a packer and the valves have reverse checks. If they do not leak, the maximum depressed fluid level in the casing annulus will not change when a well is shut in. Although the fluid level in the casing can be lower than the operating valve, the deepest point of gas injection cannot be below this fluid level.

Acoustical surveys provide valuable information when trying to troubleshoot a well on intermittent gas-lift with an open type completion or an intermittent well in which a gas-lift valve with a faulted internal check valve or an open communication between the tubing and the casing is suspected. In these cases, the liquid level in the annulus is constantly changing and sounding the well at key times during the cycle might indicate very quickly the depth of the communication. The liquid level should be determined at the moment the maximum injection pressure is reached, which should coincide with the gas uncovering the point of communication, and two or three times during the liquid accumulation period. If the survey can identify the packer, then it is not holding and gas is blowing around it.

6.2.3 Flowing Pressure and/or Temperature Surveys

General recommendations, procedural points to remember, plotting survey results and a procedure for running flowing bottom-hole pressures/temperature surveys are presented in API 11V5. Following these recommendations it is possible to determine the operating valve for a well on intermittent lift.

Conducting a survey in an intermittent lift installation with small tubing is dangerous. It is recommended to station below the bottom valve in the string and obtain a flowing bottom-hole pressure survey. If a well has a standing valve, the pressure element can only be run to the depth of the valve.

A temperature survey is specially recommended for detecting the leaking valves or the operating valve. The response time of a temperature sensor is slower than that of a pressure instrument.

If the operating valve has been identified, the following survey procedure can be used to perform a more detailed analysis on the well's inflow performance:

— The well should be tested during the survey or one or two days before as long as the cycle time and the wellhead pressure remain unchanged from normal operation conditions. The test duration needs to be long enough to accurately determine the well's production. See API 11V5 and API 11V8 for discussions of well test frequency, duration, and accuracy;

— Use electronic sensors with a sample rate of at least one measurement every 20 seconds;

— Do not shut in the well during the survey. Communication between the production tubing and the separator must be kept at all times;

— Install new casing and tubing pressure recorder charts and verify the pressure measurement with a calibrated manometer. Set the recorder clock for 12 or 24 hours and verify it is working properly. Use a dead weight tester or calibrated gauge;

— Wait for at least 1 cycle to check the cycle frequency;

— The first trip should be made to verify the tubing condition, the actual well's total depth, and specially the exact depth of the operating valve, as it will be needed as precisely as possible for the survey;

— The first stop should be at the lubricator once it is connected to the tubing. This stop can be no longer than 5 minutes and serves the purpose of checking the calibration of the pressure instruments;

— Always use the recommendations provided in API 11V5 to reduce the chances of the tools being blown up the hole;

— The second stop should be 4.6 m (15 ft) below the operating valve and for a time period no less than three complete cycles;

— If there is a standing valve installed in the well, it is recommended to pull it out before the survey. Pulling the valve may change the conditions of the well a little, but this is less important than being able to measure the flowing pressure at the top of the perforations and to determine the flowing gradient below the point of gas injection;

— If the standing valve cannot be pulled out for any reason, the survey should be completed as follows:

    — Staying at 4.6m (15 ft) below the operating valve, stop the gas injection to the well by closing the gas injection valves at the well and in the manifold. To prevent the operating gas-lift valve from opening during the last stages of the survey, lower the casing annulus pressure by 344.7 kPa (50 psi). For high frequency wells, wait for at least three hours before changing the position of the sensors. For wells with long cycle time, wait for at least the equivalent of three complete cycles. The tubing should be open into the flowline. If there is a leak in the tubing string and the well is shut in, the pressure curve is not a true indication of reservoir derivability.

  - For the last stop, move the instruments up the hole by a distance equal to the produced liquid slug length, calculated from the liquid production per cycle and the volumetric capacity of the tubing. The effect of the free gas present in the liquid slug and the fact that the liquid fallback is not taken into consideration when calculating the produced slug length, assures that the instrument will still be located below the liquid level during this last stop which will enable the calculation of the true liquid gradient. This last stop should only last 5 to 10 minutes.

- If no standing valve is installed or it has been pulled out, the survey should be completed as follows:

  - Staying at 4.6 m (15 ft) below the operating valve, stop the gas injection to the well by closing the gas injection valves at the well and in the manifold. To prevent the operating gas-lift valve from opening during the last stages of the survey, reduce the casing annulus pressure by 344.7 kPa (50 psi);

  - Lower the instruments to the top of the perforations and, for high frequency wells, wait for at least three hours before changing the position of the sensors. For wells with long cycle time, wait for at least the equivalent of three complete cycles;

  - The last stop should be at 4.6 m (15 ft) below the operating valve and for a period of time no longer than 10 minutes.

If the survey is run in a chamber installation, the pressure and temperature sensors should be placed right above the standing valve during two or three complete cycles, provided that the sensors can be run inside the dip tube. Then, the sensors can be placed right above the top of the chamber for two or more cycles. The flowing pressure recorded at this station indicates whether the chamber is overfilling and may be used to calculate the true liquid gradient in the dip tube. Take precaution to reduce the chances of the tools being blown up the hole.

Using the equations given in 6.3.3, the information gathered following this procedure can be used to find the true liquid gradient, tubing opening pressure and temperature at valve depth, valve performance, liquid fallback, PI and the optimum cycle time. The pressure survey is not intended for reservoir analysis.

6.3 Troubleshooting Analysis

This section discusses various methods for troubleshooting intermittent gas-lift wells.

6.3.1 Analyzing Multiple Injection Points

The fact that a pressure recorder chart indicates a normal choke control intermittent lift operation does not imply that there is only one point of injection. There might be one valve acting intermittently and another valve continuously open. If time cycle controllers are used, this situation is easily verified from the two-pen recorder charts, as their injection pressures will look like Figure 6.6 i) or Figure 6.6 j).

Unintentional multiple gas injection usually occurs when:

- an unloading valve with a small port diameter fails open, allowing it to pass a gas flow rate lower than the gas flow rate through the surface injection choke;

- over injection of a well designed for continuous gas-lift.

The analysis of wells with multiple points of injection is extremely difficult. But multiple injection can be detected in several ways as follows:

- continuous liquid production;

- high and continuous gas production and injection;

— the force balance equations discussed in the following sections indicate that more than one valve could be open;

— the volume of gas injected per cycle, as calculated from the spread of the valve, is below the volume of gas per cycle calculated from the daily gas flow rate through the surface injection choke and the number of cycles per day;

— a downhole temperature survey.

The calculations required for multiple injection points (gas injection mass balance and valve force balance) are described in the following sections.

6.3.2 Troubleshooting Analysis for Simple Completions and Single Injection Point

Each gas-lift valve installed in the well should be analyzed to determine if it corresponds to the operating valve or if there are several valves able to open at current conditions. The following is a list of recommended calculations required per valve to troubleshoot the well.

The first step is to calculate the static reservoir fluid level, which can be approximately found from the following equation

$$Dsl = Dpt - \frac{Psbh - Pwh}{\rho_f} \tag{28}$$

where

Dsl is the static liquid level;

Dpt is the depth of the top of the perforations;

$Psbh$ is the bottom hole pressure;

Pwh is the wellhead pressure and ρ_f is the liquid gradient calculated in kPa/m by:

$$\rho_f = (1-w)\frac{141.5}{131.5 + °\mathrm{API}}(9.79) + w(9.79) \tag{29}$$

and

$$\rho_f = (1-w)\frac{141.5}{131.5 + °\mathrm{API}}(0.433) + w(0.433) \qquad \text{in psi/ft} \tag{30}$$

where

w is the water cut of the produced liquids.

For a closed completion, a valve above the static level can be the operating valve if the liquid accumulated in the annulus each cycle is being forced into the tubing through a lower annulus-tubing communication point and:

— the force balance equation will predict that the valve can open with the current surface opening pressure; or

— the valve has failed open.

So, as remote as the possibility of a valve above the static liquid level being the operating valve might be, almost all calculations required for valves below the static liquid level can be, and should be, made for the ones above this level. Only the calculation of the PI, and therefore the optimum cycle time, cannot be performed for valves above the static liquid level using the analytical procedure given in this section.

The next step is to calculate the initial liquid column length, which can be found in SI Units by:

$$Q = \frac{T(q_f)}{0.1129(Dt^2)\left(1 - FF \times \frac{Dov}{1000}\right)} \qquad \text{in SI Units}$$

where

Q	is the initial column length in m;
T	is the cycle time in minutes;
q_f	is the production in m^3/D;
Dt	is the tubing inside diameter in cm;
FF	is the liquid fallback factor;
Dov	is the valve depth in m.

The fallback factor is usually taken to be between 0.098 and 0.196 (which represent a loss of 9.8 % to 19.6 % of the initial liquid slug per 1000 m of the injection point depth).

$$Q = \frac{T(qf)}{1.399(Dt^2)\left(1 - FF \times \frac{Dov}{1000}\right)} \qquad \text{in Field Units} \tag{31}$$

where

Q	is the initial column length in ft;
T	is the cycle time in minutes;
qf	is the production in Br/D;
Dt	is the tubing inside diameter in in.
FF	is the liquid fallback factor;
Dov	is the valve depth in ft.

The fallback factor is usually taken to be between 0.03 and 0.06 (which represent a loss of 3 % to 6 % of the initial liquid slug per thousand ft of the injection point depth), which is a good approximation only if the volume of gas per cycle is greater than or equal to the required gas per cycle as calculated in Annex A. Otherwise, an estimate of the initial column length must be made from the force balance equation just when the valve opens. In any case, the value of Q calculated above does not take into account that formation gas tends to make the column longer. This is not important when using the force balance equation or the PI equation, as long as the true liquid column does not reach the surface. A correction factor used to estimate the true liquid column length is found from the analysis of a downhole pressure survey, as presented in 5.3.3.

The volume of gas injected per cycle is calculated from:

$$Vg = 1000 \times Qgi \times T\frac{1}{1440} \tag{32}$$

where

Vg is in m/cycle (scft/cycle);

Qgi is the daily gas flow rate in Mm^3/D (Mscf /D);

T is the cycle time in minutes.

Once the true initial column length is estimated, a series of tests should be performed to determine if the PI could be calculated as follows.

— If the top of the liquid column is below the static level, all calculations are made.

— If the top of the liquid column is above the static liquid level but below the surface, production from this valve is only possible if liquid from the casing annulus is being produced. The PI cannot be calculated in this case.

— If the initial liquid column is greater than the depth of the valve, production from this valve is only possible if liquid from the casing annulus is being produced, the PI cannot be calculated and the initial column length is assigned the value of the valve depth to perform the valve force balance calculations.

To apply the valve opening force balance equation, it is necessary to find first the tubing opening pressure at valve depth, $Ppod$, the injection opening pressure at valve depth, $Piod$, and the dynamic temperature of the valve if the valve is nitrogen charged. The tubing opening pressure is found by:

$$Ppod = fg \times Pwh + \rho_f \times Q \qquad (33)$$

where

Pwh is the wellhead pressure in kPa (psi);

ρ_f is the fluid gradient in kPa/m (psi/ft);

Q is the initial column length in m (ft);

fg is used to correct the wellhead pressure due to the gas column above the liquid, a good approximation of which is given by:

$$fg = \left(1 + \frac{Dov - Q}{16459.2}\right)^{1.5240}$$ if Dov and Q are expressed in m.

$$fg = \left(1 + \frac{Dov - Q}{54000}\right)^{1.5240}$$ if Dov and Q are expressed in ft. (34)

The opening injection pressure at valve depth can be found using a factor similar to, but more accurate than, the factor fg given above. The factor FGL given in 5.1.2 is recommended.

The dynamic temperature of the valve is very difficult, if not impossible, to find and, for wire line retrievable valves, it is better to use a dynamic temperature calculated as if the well were producing continuously than to use the geothermal temperature, which is only acceptable for tubing retrievable valves. Refer to the annex of API 11V6 for dynamic temperature calculations.

The opening tubing pressure, as calculated above, divided by the gas factor FGL, will give the valve surface opening injection pressure in case the valve has failed open but its internal check valve is working properly. So, in this case $Ppod/FGL$ should be close to the actual surface opening injection pressure. If the valve has failed open and its internal check valve is not working (which is the same as having a constant communication in the tubing), there is liquid accumulation in the annulus and when the gas uncovers the valve (or communication occurs) the liquid slug in the tubing has already an upward velocity, so the maximum injection pressure should be close to, but greater than, $Ppod/FGL$ to account for losses due to friction. Very low surface opening pressure, as compared to the valve set opening pressure, is a good indication of a valve that failed open but with an undamaged internal check valve. A large spread with a long cycle time, as compared to that which is expected from the valve set pressures, together with an high liquid production per cycle are good indications of an open communication between the tubing and the casing.

If the valve is working properly, a force balance equation based on the valve test rack pressure, should give a surface opening pressure close to the actual surface opening pressure.

For a spring loaded, pressured operated gas-lift valve, with a given test rack closing pressure, $Ptrc$, and an area ratio, R, the force balance equation gives the surface opening injection pressure as:

$$Pio(\mathrm{calc}) = \left(\frac{Ptrc - Ppod \times R}{1 - R}\right) / (FGL) \tag{35}$$

For a spring loaded, pressured operated gas-lift valve, with a given test rack opening pressure, $Ptro$, and an area ratio, R, the force balance equation gives the surface opening injection pressure as:

$$Pio(\mathrm{calc}) = \left(\frac{Ptro \times (1 - R) - Ppod \times R}{1 - R}\right) / (FGL) \tag{36}$$

For a nitrogen charged, pressure operated gas-lift valve, with a given test rack opening pressure, $Ptro$, an area ratio, R, and a spring equivalent pressure (caused by spring tension and assumed to be acting on the bellows effective area minus the port area) St, the force balance equation gives the surface opening injection pressure as:

$$Pio(cal\dot{c}) = \left(\frac{Pbt + St \times (1 - R) - Ppod \times R}{1 - R}\right) / (FGL) \tag{37}$$

Pbt is the bellows pressure at operating conditions, which can be calculated from the knowledge of the operating temperature of the valve and the test rack bellows pressure, Pb, which in turn is calculated from:

$$Pb = (Ptro - St) \times (1 - R) \tag{38}$$

To get Pbt from Pb, refer to API 11V6.

Based on the theory presented in Annex A, the average PI in m^3/D/kPa (Br/D/psi) for the practical range of intermittent lift downhole flowing pressure, can be calculated using the following equation:

$$PI = \frac{1.44 \times (0.07849 \times Dt^2) \times (Alff)}{(t) \times \rho_f} \qquad \text{in SI Units}$$

$$PI = \frac{1.44 \times (0.9713 \times Dt^2) \times (Alff)}{(t) \times \rho_f} \qquad \text{in Field Units} \tag{39}$$

where

t is the liquid accumulation time in minutes;

ρ_f is the liquid gradient in kPa/m (psi/ft);

Dt is the tubing inside diameter in cm (in.)

$$Alff = \ln\left(\frac{As - FF \times (Dov/1000) \times Q \times \rho_r}{As - Q \times \rho_r}\right) \tag{40}$$

where

Dov	is the depth of the operating valve in m (ft);
FF	is the fallback factor;
Q	is the initial column length in m (ft).

$$As = Psbh + (Dov - Dpt)\rho_T - Pwh \times fg \tag{41}$$

where

$Psbh$	is the static reservoir pressure in kPa (psig);
Dpt	is the depth of the top of the perforations in m (ft);
ρ_T	is the true liquid gradient (found from downhole surveys) in kPa/m (psi/ft);
fg	is the gas pressure factor as calculated above in this section.

Finally, once the PI has been estimated, the optimum cycle time can be calculated using the theory presented in Annex A. If the cycle time needs to be changed, it can be accomplished by changing the gas flow rate at the manifold in the case of a choke control installation, or by adjusting the settings of the surface controller in case of a time cycle control intermittent-lift facility.

6.3.3 Troubleshooting Analysis for Chamber Installations

The unloading valves of a chamber installation can be analyzed using the same procedure described in 6.3.2 The operating valve, on the other hand, needs special treatment as discussed below. Figure 6.7 shows a double packer chamber: Dov is the depth of the operating valve in m (ft), Dch is the depth of the lower packer in m (ft) and Ch is the length of the double packer chamber in m (ft).

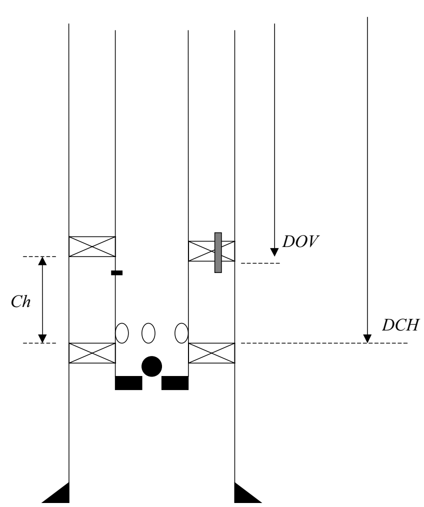


Figure 6.7—Double Packer Chamber

Based on the fluid production q_f in m^3/D (Br/D), the cycle time T in minutes, the liquid gradient ρf in kPa/m (psi/ft) calculated from the water cut and the crude API gravity, the volumetric capacity of the chamber Bch in m^3/1000 m (Br/

1000-ft), the liquid fallback factor FF, and the true liquid gradient ρT in kPa/m (psi/ft), the initial liquid slug in m (ft) calculated as if the liquid does not reach the upper packer is given by:

$$Qc = \frac{q_f \times T \times \rho_f}{1.44 \times Bch \times (1 - FF \times Dch/1000) \times \rho_T} \quad (42)$$

The value of Qc as calculated using the above equation is only reliable if the volume of gas per cycle is greater than or equal to the theoretical volume calculated using the procedure given in Annex A. If the actual volume of gas injected is lower than the theoretical volume, the fallback factor FF can be much higher than 0.196 in SI Units (0.06 in Field Units) and it is extremely difficult to estimate its value from the valve force balance equation for chamber installations.

Qc may or may not be greater than Ch. Figure 6.8 shows the case in which the liquids have filled the chamber completely and the liquid level is above the upper packer when the valve located at the upper packer opens.

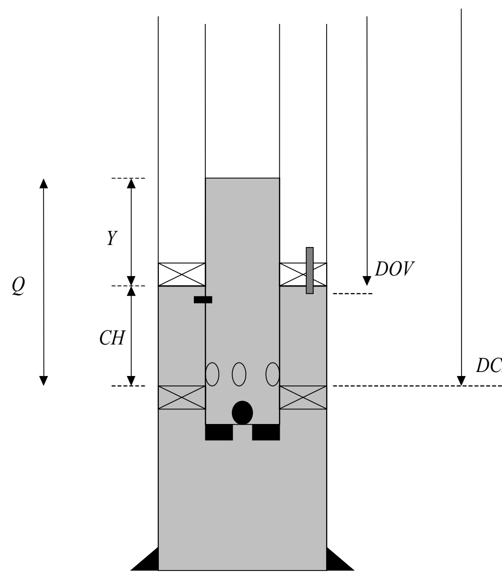


Figure 6.8—Double Packer Chamber (Initial Liquid Level Above Upper Packer)

Q is the initial liquid column length and Y is the liquid column length above the upper packer. If the calculated liquid column Qc is greater than Ch, Y can be found from:

$$Y = \frac{(Qc - Ch)Bch}{Bt} \quad (43)$$

where

Bt is the volumetric capacity of the production tubing above the upper packer in m^3/1000 m (Br/1000 ft).

In this case, the production pressure used in the valve force balance equation is found from:

$$Ppod = \rho_T \times Y + Pwh \times fg \quad (44)$$

If Qc is less than Ch, the tubing opening pressure at valve depth is only the wellhead pressure plus the pressure due to the weight of the gas above the valve:

$$Ppod = Pwh \times fg \quad (45)$$

With this production pressure, and if the operating valve is assumed to be working properly, the surface injection pressure, Pio, can be calculated using the same equations given in 6.3.2. But if the operating valve has failed open, then the maximum injection pressure should be close to, but higher than, the pressure given by:

$$Pio(\max) = \frac{L \times \rho_T + Pwh \times fg}{FGL} \tag{46}$$

L is the liquid slug length once all the liquid has entered the tubing and is equal to $Qc \times Bch/Bt$, fg is used to correct the wellhead pressure due to the gas column above the liquid, a good approximation of which is given in 6.3.2 as:

$$fg = \left(1 + \frac{Dov - Q}{16459.2}\right)^{1.5240} \quad \text{if } Dov \text{ and } Q \text{ are expressed in m}$$

$$fg = \left(1 + \frac{Dov - Q}{54000}\right)^{1.5240} \quad \text{if } Dov \text{ and } Q \text{ are expressed in ft} \tag{47}$$

FGL is a factor similar to, but more accurate than, fg. The factor FGL given in 5.1.2 is recommended.

If the volume of gas injected per cycle is high enough so that a reasonable approximate value of the liquid fallback factor can be used, and the liquid level is equal to or lower than the upper packer, the PI can be found from the following equation

$$PI = \frac{1.44 \times (Bch) \times (Alff)}{(t) \times \rho_T} \tag{48}$$

where

t	is the liquid accumulation time in minutes;
ρ_T	is the true liquid gradient in kPa/m (psi/ft);
Bch	is the chamber volumetric capacity in m^3/1000 m (Br/1000 ft).

$$Alff = \ln\left(\frac{As - FF \times (Dch/1000) \times \rho_T}{As - Qc \times \rho_T}\right) \tag{49}$$

where

Dch	is the depth of the perforated nipple in m (ft);
FF	is the fallback factor (usually given a value between 0.03 and 0.06, which represents 3 % to 6 % loss of initial liquid slug length per 1000 ft of point of injection depth taken as Dch or 9.8 % to 19.68 % loss per 1000 m);
Qc	is the initial column length in m (ft).

$$As = Psbh + (Dch - Dpt)\rho_T - Pwh \times fg \tag{50}$$

where

$Psbh$	is the static reservoir pressure;
Dpt	is the depth of the top of the perforations;
ρ_T	is the true liquid gradient (found from downhole surveys);
fg	is the gas pressure factor as calculated above.

Finally, once the PI has been estimated, the optimum cycle time can be calculated using the theory presented in Annex A. If the cycle time needs to be changed, it can be accomplished by changing the gas flow rate at the manifold in case of a choke control installation, or by adjusting the settings of the surface controller in case of a time cycle control intermittent lift facility.

6.3.4 Analysis of Pressure and Temperature Surveys

Using the equations given in this section, the information gathered following the procedure described in 6.2.3 can be used to find the true liquid gradient, tubing opening pressure and temperature at valve depth, valve performance, liquid fallback, PI and the optimum cycle time.

Figure 6.9 shows a typical output of a pressure survey and the relevant pressure measurements for each of the four stops.

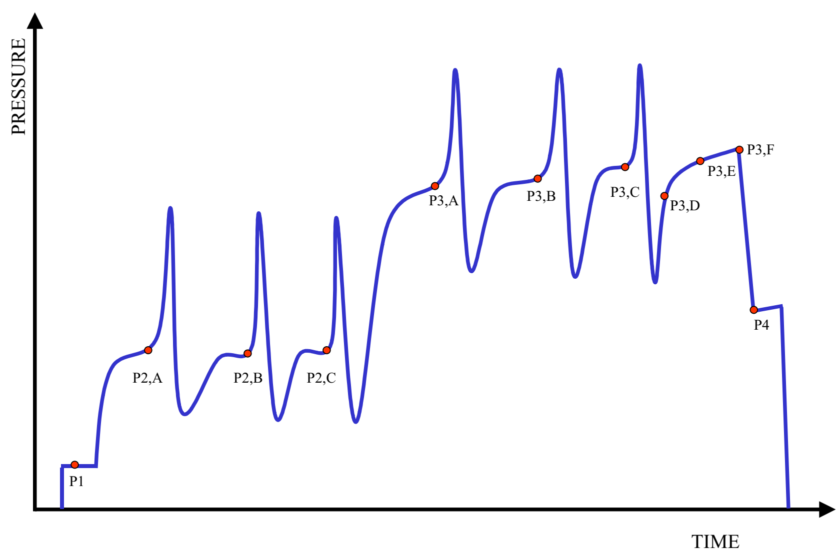


Figure 6.9—Downhole Pressure Survey Output
(1st Stop at Wellhead, 2nd Stop at Valve Depth, 3rd Stop at Top of Perforations, 4th Stop at Valve Depth)

The minimum tubing pressure does not provide practical information for quantitative analysis. Figure 6.10 shows the three components of the pressure that are registered by the sensors at the beginning of the liquid slug formation period. It is not possible to identify each component separately from a simple pressure and temperature survey. This can only be approximately determined by using, simultaneously, a flow meter below the valve, two pressure sensors at two different locations below the valve and one above the liquid level. The practicality and cost of such a procedure can only be justified for research purposes and field wide calibration studies.

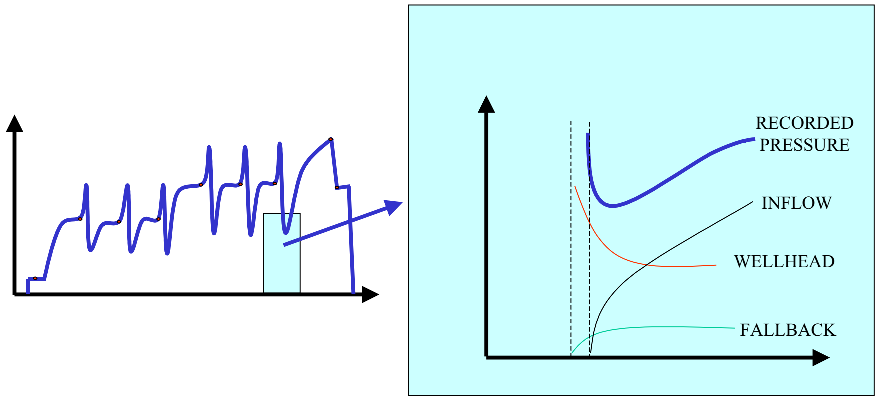


Figure 6.10—Minimum Pressure Components

The true liquid gradient is usually lower than the liquid gradient calculated from the water cut and the crude's API gravity. It is not uncommon to find the value of the true liquid gradient to be only 30 % to 60 % of the liquid gradient calculated from the liquid's properties alone. This difference is caused by the free gas present in the liquids as the liquid slug forms above the operating valve. Knowing the true liquid gradient is not important when using the force balance equations to get an idea of the valve's performance, since the effect of the free gas on the tubing opening pressure is negligible. But it is important to know the true liquid gradient for estimating the *PI* of the well and the optimum cycle time, or when troubleshooting chamber installations.

The best estimate of the true liquid gradient, ρT, is obtained if a standing valve is not installed in the well and using the following equation

$$\rho_T = \frac{P_{3,\,\mathrm{avg}} - P_{2,\,\mathrm{avg}}}{D_{3-2}} \tag{51}$$

$P_{3,\mathrm{avg}}$ and $P_{2,\mathrm{avg}}$ are the average pressures at the third and second stop respectively, D_{3-2} is the distance between the third and the second stop. If there is a standing valve present, the liquid gradient needs to be estimated from the last two stops recommended for that case, which is not too accurate as it does not really represent the dynamic flowing condition during normal operation.

Once the true liquid gradient is known, the opening production pressure at valve depth can be found from:

$$Ppod = P_{2,\,\mathrm{avg}} - \Delta H \times \rho_T \tag{52}$$

where

ΔH is the distance between the pressure instruments and the operating valve during the second stop.

It is convenient to have a temperature sensor if nitrogen charged gas-lift valves are used, as it is extremely difficult to predict the temperature near the valves when they open.

Once the opening production temperature and pressure at valve depth are known, the valve opening performance can be investigated from the force balance equation if the injection pressure at depth, $Piod$, has been calculated:

$$R = \frac{Piod - Pbt}{Piod - Ppod} \tag{53}$$

where

R is the valve's area ratio; and

Pbt is the test rack closing pressure in case the valve is spring loaded; or

Pbt is the dome pressure at the operating opening temperature if the valve is nitrogen charged.

The fallback factor, FF, can also be determined from a survey using the following equation:

$$FF = \frac{\frac{Qini - Qp}{Qini}}{(Dov)/1000} \tag{54}$$

where

FF represents the percentage of the initial apparent column length, $Qini$, that is not produced to the surface per thousand m (ft) of depth of the injection point, Dov; and

Qp is the produced liquid column given in m (ft) by:

$$Qp = \frac{q \times T}{1440 \times Bt} \tag{55}$$

where

q is the daily production in m^3/D (Br/D);

T is the cycle time in minutes;

Bt is the volumetric capacity of the production tubing in m^3/m (Br/ft). $Qini$ is calculated from:

$$Qini = \left[\frac{Ppod - Pwh \times fg}{\rho_f}\right] \tag{56}$$

where

Pwh is the wellhead pressure when the valve opens;

fg is used to correct the wellhead pressure due to the gas column above the liquid, a good approximation of which is given 6.3.2;

ρ_f is the apparent liquid gradient in kPa/m (psi/ft) calculated from the liquid water cut and crude oil's API gravity and neglecting the free gas present in the liquid since it is compared to the produced liquid column calculated from the well test outcome:

$$\rho_f = (1 - w)\frac{141.5}{131.5 + °\text{API}}(9.79) + w(9.79) \qquad \text{in kPa/m}$$

and

$$\rho_f = (1 - w)\frac{141.5}{131.5 + °\text{API}}(0.433) + w(0.433) \qquad \text{in psi/ft} \tag{57}$$

where

w is the water cut.

If, when analyzing a survey from a chamber installation, the calculated fallback is high but sufficient gas is being injected per cycle, then the value of FF so calculated is in error and the chamber annulus is just not being filled with liquids.

The information of the last part of the third stop, after the gas injection to the well has been stopped, can be used in the following two ways.

a) To find the optimum cycle time by inspection: it can be usually readily found by inspection alone if the well is being over-injected or the cycle time is too long. Referring to Figure 6.9, it can be seen that the pressure increases at a high rate during the first stages of the slug accumulation period and then there is a flat portion of the curve in which the pressure increases very slowly. The well should be gas-lifted when the steeper portion of the curve ends.

b) Using the pressure at two different times, like $P_{3,D}$ and $P_{3,E}$ in Figure 6.9, the PI and the optimum cycle time can be found analytically by the method described below. It is recommended that $P_{3,D}$ be taken after the separator pressure has stabilized and ample time has been allowed so that the liquid fallback accumulation has diminished.

If there is a standing valve installed, the PI can be calculated using the following equation:

$$PI = \frac{1440(Bt)}{\Delta t(\rho_a)} \ln\left[\frac{A - Qini \times \rho_f}{A - Qfin \times \rho_f}\right] \tag{58}$$

where

Δt is the time elapsed between the two pressure measurements in minutes;

Bt is the volumetric capacity of the production tubing in m^3/m (Br/ft);

ρ_f is the apparent liquid gradient in kPa/m (psi/ft) and A, $Qini$ and $Qfin$ are given by:

$$A = Psbh - (Dpt - Dov)\rho_T - Pwh \times fg \tag{59}$$

$$Qini = (P_{3,D} - Pwh \times fg - \Delta H \times \rho_T)(\rho_f) \tag{60}$$

$$Qfin = (P_{3,E} - Pwh \times fg - \Delta H \times \rho_T)(\rho_f) \tag{61}$$

where

$P_{3,D}$ and $P_{3,E}$ are in this case the pressures at 4.6 m (15 ft) below the operating valve which correspond to the second stop depth if there is a standing valve in the well;

$Psbh$ is the static reservoir pressure;

Dpt is the depth of the perforations;

Dov is the depth of the operating valve;

ρ_T is the true liquid gradient;

Pwh is the wellhead pressure;

fg is the pressure correction factor given above;

ΔH is the distance between the pressure instruments and the operating valve during the second stop.

If no standing valve is installed in the well, the PI is found from:

$$PI = \frac{1440(Bt)}{\Delta t(\rho_f)} \ln\left[\frac{Psbh - P_{3,D}}{Psbh - P_{3,E}}\right] \tag{62}$$

Once the PI has been found, the optimum cycle time can be calculated using the procedure given in Annex A.

7 Operational Considerations for Intermittent Gas-lift Systems and Wells

This section provides guidelines and recommended practices that should be considered in operating an intermittent gas-lift system and wells.

7.1 Staffing Requirements

Operating an intermittent gas-lift system and its wells is not the same as operating a continuous gas-lift system and its wells. Different knowledge and skills are required. Operating intermittent gas-lift is not just the responsibility of operators. Well analysts, engineers, well services staff, and others must be involved.

7.1.1 Job Responsibilities

Recommendation: Consider the following job responsibilities:

— *Operators*. In many companies, operators do not have much, if anything, to do with intermittent gas-lift, other than possibly changing charts. They primarily focus on operating well test systems, gas compressors and dehydration systems, and other production equipment. This is generally a mistake; operators are in the field. They are in a position to be on the front line to detect and address problems. Therefore, operators should be given the responsibility to not only change carts, but to also check injection cycles, check the amount of gas being injected per cycle, and track oil and water production per day and per cycle. If they spot problems, they should immediately notify others;

— *Well analysts*. Some companies call these people well analysts; some call them well technicians; some artificial lift technicians. In some companies, production engineers or junior engineers fulfill this role. These people typically work in or close to the field. They typically have an in-depth understanding of artificial lift in general and intermittent gas-lift in particular. They typically monitor the production automation system to keep very current on the operation of the intermittent gas-lift systems and wells. They make the routine, day-by-day decisions on how the system and wells should be operated;

— *Production engineers*. In most companies, design of the system is performed by production engineers. Some companies call them production technologists. They space the unloading mandrels, design the operating gas-lift valves and standing valves, design the plungers if plungers are used and design the surface control systems. They must take particular care for interference between different intermittent gas-lift wells, and between intermittent gas-lift wells and other types of wells in the overall system. They must evaluate the effectiveness of intermittent gas-lift vs. other types of artificial lift that could potentially be used to optimize overall production and recovery from the reservoir;

— *Facility engineers*. In some cases, operating intermittent gas-lift systems and wells can have a substantial impact on the production facilities, due to slugging in both the injection system and the production system. The facilities engineers must understand the impact that intermittent gas-lift may have on the flowlines and facilities and design these systems accordingly;

— *Well services*. Some special equipment may be required for intermittent gas-lift. This may include a standing valve, special mandrels if plungers are used, and special features if chamber gas-lift is used. Well services staff must understand how this equipment is to be installed, used, and serviced;

— *Others*. Others have a responsibility too. These include corrosion engineers, safety engineers, and production accountants.

7.1.2 Training Requirements

Training staff in intermittent gas-lift is a challenge. There are not many training courses, or qualified trainers. One source of training material is this RP. It can and should be used as the basis and core of training programs for intermittent gas-lift. In addition, some service/supply companies can provide training for intermittent gas-lift. And there are a few consultants that can offer this service.

Recommendation: Seek and provide intermittent gas-lift training, especially to operators, well analysts, and production engineers who are or will be involved in intermittent gas-lift operations.

7.1.3 Working as a Team

As with any form of artificial lift, no individual can successfully design, install, operate, monitor, troubleshoot, diagnose, and optimize an intermittent gas-lift system and its wells alone. This requires teamwork between the operating company and the service/supply company, and between the key staff members in both companies.

Recommendation: Supervisors who are responsible for a field where intermittent gas-lift is used must build and maintain a team with proven skills for intermittent gas-lift design, installation, operation, surveillance, troubleshooting, diagnostic, and optimization.

7.2 Understanding the Design Philosophy

In many and perhaps most cases, different people are responsible for designing an intermittent gas-lift system and its wells than those who are responsible for operating it. Often the two are in different departments, are located in different offices, and may not have much opportunity to talk with one another. However, it is essential that operators fully understand the philosophy and thinking that went into design of the system. It can be difficult and perhaps impossible to operate a system properly if different rates, pressures, and cycles are used than those that were intended in the design of the system.

7.2.1 System Design

The intermittent gas-lift system consists of the source(s) of gas, the equipment to compress and dehydrate the gas, and the lines to distribute the gas to the wells.

Recommendation: Understand the following components of the intermittent gas-lift system, and how these components affect and/or interact with one another.

— *System gas volume*. How much gas is the system designed to deliver for intermittent gas-lift. What is the expected variability in this volume?

— *Other uses of gas*. What other uses of gas are intended? Will the system also serve continuous flow gas-lift wells? Must it also provide fuel for various types of production equipment? If the system must serve multiple types of uses, what is the priority of each use? In other words, are continuous gas-lift wells to be given higher priority than intermittent gas-lift wells when the overall volume of gas is not sufficient to meet all of the needs?

— *System pressure*. What is the design delivery pressure? What is the expected variability in this pressure? What pressure can be delivered at the wellheads of the wells that are served by the system?

— *Number of wells*. How many intermittent gas-lift wells is the system designed to accommodate?

— *Effect of interference*. How is the system designed to deal with interference if gas is injected into two or more intermittent gas-lift wells at the same time? Must steps be taken to avoid this interference?

7.2.2 Control Strategy

Intermittent gas-lift systems can be designed to support one or more control strategies, such as: time cycle control, choke control, computer control, special control (e.g. when plungers are used).

Recommendation: Understand the control strategy(ies) that the system is designed to support. If an attempt is made to use a control strategy that the system is not designed to support, it may operate inefficiently.

— *Time cycle control*. If the system is designed for time cycle control, it may be important to coordinate the injection cycles so no two cycles occur at the same time as this could cause a pressure dip in the system.

— *Choke control*. If the system is designed for choke control, the system may depend on maintaining a relatively stable pressure. In "choke control" the injection rate into the intermittent gas-lift well is essentially constant and the intermittent cycles are controlled by the opening and closing of the operating gas-lift valve.

This could be the case if the system must also serve continuous gas-lift wells. If the system is designed for choke control, use of time cycle control on some of the wells in the system may be disruptive to the operation of the system.

— *Computer control*. With some forms of computer control, it may be possible to optimize the control of each well, where some may perform better with time cycle control and some better with choke control. If computer control is provided and if it is to be used to maximum advantage, special training must be provided to those who configure the control logic for each well.

— *Special control*. Some forms of intermittent gas-lift require special control strategies. An example is some forms of plunger lift used in association with intermittent gas-lift. Clearly here special training is required.

7.2.3 Well Design

There are many different options for design of intermittent gas-lift wells. These include options on the method to control gas injection into the well, the spacing of the gas-lift mandrels, the design of the unloading gas-lift valves, selection and design of the operating gas-lift valve, choice and design of the standing valve, selection of a plunger, if one is used, and other aspects.

Recommendation: Understand how the intermittent gas-lift well is designed, the components that are used to implement this design, and the impact of this design on how the well must be operated.

— *Surface control*. As discussed elsewhere in this RP, the recommended method of surface control is by use of a computer-controlled control valve. With this, various methods of well control are possible, including time cycle control, choke control, combined time-cycle/choke control, and plunger control. If computer control is not provided, the well must be designed for time cycle control or choke control. These operate very different so the actual method of control must be understood.

— *Mandel spacing*. Typically, mandrel spacing is the same for continuous and intermittent gas-lift. The importance of understanding the spacing is to understand it in conjunction with the well's current static bottom-hole pressure. The well may no longer stand a column of liquid to the surface, so it may not be necessary to use all of the mandrels for unloading the well.

— *Unloading gas-lift valves*. There are two issues here: the spacing of the valves and the type of valves. If the mandrel spacing was designed for continuous gas-lift, it was probably designed assuming that injection pressure operated gas-lift valves would be used. So, they should be used to unload the well for intermittent gas-lift. Also, if the well won't stand a column of liquid to the surface, the top unloading valve can be placed at or below the static liquid level. It may not be necessary to install valves in all of the mandrels. And, if the mandrel spacing was designed for a high bottom-hole pressure, high PI well, it may not be necessary to install unloading valves in all of the mandrels; it may be possible to skip some of them and leave dummies in the mandrels that are not needed for unloading.

— *Operating gas-lift valve*. For effective intermittent gas-lift the recommended practice is to use an operating gas-lift valve that will move to full open very quickly to rapidly inject a "slug" of gas beneath the liquid column. Most gas-lift valves throttle open. That is, they open relatively slowly as the opening pressure increases.

Therefore, the recommended practice for intermittent gas-lift is to use a "pilot" valve. The pilot section causes the valve to open when the opening pressure is reached. The valve then very quickly moves to the full open position to allow maximum gas flow from the annulus into the tubing. Then, when the casing pressure decreases to the closing pressure, the valve closes. This avoids wasting unnecessary gas.

— *Standing valve*. In most cases, intermittent gas-lift is used when the reservoir pressure is low and the liquid inflow rate is too low to sustain continuous gas-lift. In such cases, use of a standing valve is recommended to prevent liquid from being pushed back into the formation when the pressure of the gas injection slug enters the tubing and acts to lift the liquid slug to the surface. The goal is to focus all of the gas pressure on lifting the liquid slug, and to not allow part of it to focus on injecting liquid back into the formation.

— *Plunger*. In many intermittent gas-lift operations, there is some liquid fallback as the "slug" of gas tries to lift the much heavier "slug" of liquid to the surface. Some operators like to use a plunger to provide a barrier between the gas and liquid and to minimize fallback. There are significant issues in using a plunger, including control of the plunger fall, timing of the gas injection cycle beneath the plunger, and design of the plunger to pass through the gas-lift mandrels without excessive gas slippage past the plunger. If a plunger is to be used, it is recommended to use a good plunger design program.

7.3 System/Well Monitoring

In many companies, people other than operators and well analysts are responsible for designing and implementing the system(s) use to monitor the intermittent gas-lift system and its wells. However, this system is or should be one of the primary tools used by operators and well analysts for routine monitoring, surveillance, troubleshooting, and optimization of the intermittent gas-lift system and wells. So, operators and well analysts must have direct input into how the monitoring system is designed, implemented, and used.

7.3.1 System—What/When to Monitor

Recommendation: The following items are the most important "system" parameters to monitor:

— *Gas rate*. It very important to know the rate of gas-lift gas entering the gas-lift distribution system. It is recommended to measure this on a continuous basis if possible. As recommended in the next section, the best way to keep the gas-lift system in balance is to control the overall rate of gas that is leaving the system and being injected into the gas-lift wells, and to keep this rate in balance with the rate of gas entering the system;

— *Gas pressure*. It is important to know the pressure of the gas-lift system. First, gas-lift valves are designed to operate at a given pressure. Second, it can be difficult to keep a gas-lift system perfectly in balance by controlling the injection rate into a number of wells. Some injection meters may not be accurate. If the injection rates are not all accurate, the system pressure will tend to be too high or too low. The injection rates can be fine tuned to keep the system pressure at the desired level;

— *Compressor availability*. In most gas-lift systems, the source of gas is from one or more compressors. Typically, the rate of gas entering the system will be measured at the discharge from the compressor(s). The benefit of monitoring the individual compressors is to know the compressor performance. If one compressor is frequently down or under performing, it may be time to schedule compressor maintenance;

— *Water content*. Ineffective gas dehydration can be cause of the most troublesome operating problems. Too high water vapor in the gas can lead to freezing problems, problems with gas measurement, problems with gas-lift valve operation, etc. The benefit of monitoring the water content or dew point of the gas is to know when the dehydration system requires maintenance.

7.3.2 Wells—What/When to Monitor

Recommendation: The recommended practice in well monitoring is to monitor/measure those variables that are necessary to optimize intermittent gas-lift well action. These include the injection rate, the injection cycle, and production parameters. The following items are the most important “well” parameters to monitor:

— *Injection rate*. Measurement of the injection rate depends on the method of intermittent gas-lift control. If some form of time cycle control is used, it is important to know the volume of gas per cycle and the total volume of gas injected per day, since the volume per cycle may vary somewhat from cycle to cycle. If some form of choke control is used, it is important to know the average injection rate and the injection volume per day. If a combination control (part choke control and part time-cycle), it is necessary to know the average injection rate, the volume per cycle, and the volume per day;

— *Injection cycle*. Regardless of whether intermittent gas-lift control is by time-cycle or choke control, the intermittent gas-lift well will be cycling. It is important to know the frequency of cycles, and the period of each cycle. A primary optimization objective will be to optimize the volume of liquid production per injection cycle;

— *Injection pressure*. Injection pressure is an important variable since both the unloading gas-lift valves and the operating gas-lift valve are designed based on pressure. If the injection pressure changes from the design value, it may be necessary to redesign the gas-lift valves to maintain proper operation;

— *Production pressure*. The primary reason to monitor production pressure is to detect any situations where it is higher than desired. This may be caused by a blockage in the flowline or a problem in the production separator. If the production pressure is too high, this can adversely affect the lifting of intermittent gas-lift slugs;

— *Production rate*. If possible, it is recommended to measure or at least accurately estimate the liquid production rate on a continuous basis. The primary reason is for production optimization. If the volume of liquid produced per slug can be known, this can be used to optimize the timing and size of each intermittent gas-lift cycle;

— *Well test data*. If liquid production rate can not be measured or estimated on a continuous basis, it is necessary to obtain accurate well test data. It is necessary to not only determine the volume of oil, gas, and water during the test time, but to also measure the number of injection cycles during the well test so the average liquid production per cycle can be determined.

7.4 Control

As discussed in Section 4, deciding how to control an intermittent gas-lift system and its wells depends on many factors. And, the “best” form of control may not be the same for all wells in the system. Operators must understand the pros and cons of the different control strategies and must influence how, when, and where these methods are used.

7.4.1 Control of the System

Recommendation: The primary recommendation for control of the gas-lift distribution system is to control it such that the system pressure remains relatively constant. Gas-lift wells are designed based on a design operating pressure. If the pressure in the distribution system is allowed to become too high or too low, gas may be lost from the system, wells may become inefficient, and other problems may arise.

In general, the pressure of the system can not be controlled directly. It must be controlled by keeping gas flow out of the system essentially equal to (in balance with) the gas inflow into the system. In most cases, the gas inflow comes from the compressors or from other sources. There may not be much opportunity to control the inflow. Therefore, the primary way to keep the inflow and outflow in balance is to control the outflow to keep it approximately equal to the inflow. This can be done by controlling the injection rates into the gas-lift wells. In an intermittent gas-lift system, they may mean some combination of controlling the injection rates into the wells and/or controlling the frequency of gas injection cycles into the wells.

If the supply (inflow) of gas into the system is temporarily below the target value due to a compressor outage or other problem, it is necessary to reduce the outflow of gas below its target value. This means that some of the wells may not be operated at optimum values. But, this is normally preferable to allowing the system pressure to fall and adversely affecting all of the wells in the system.

7.4.2 Control of Individual Wells

As discussed in Section 4, there are several ways to control intermittent gas-lift wells. The “best” way depends on the characteristics of the individual wells, but in some cases system considerations may override individual well considerations.

Recommendation: If it is possible, the recommended method to control injection into individual intermittent gas-lift wells is with computer control of the injection rate and/or frequency at the surface. This has advantages over other means of control. Comments on each of the control strategies are given below.

Computer Control: Computer control is preferable to time cycle control because the frequency and duration of injection cycles can be controlled when needed without needing to change the time cycle controller at each well. This can permit the frequency and duration of the injection cycles to be optimized on an on-going basis.

Computer control is preferable to choke control for similar reasons. The concept of choke control can be implemented by computer, but the injection rate can be changed without needing to change the surface choke or fixed control valve.

Computer control is also compatible with the use of plungers. The plunger cycles can be controlled and optimized by the computer control system.

The challenge with computer control is that it must be properly designed and configured for each well, and the operator or well analyst must understand how to use it.

Time Cycle Control: As indicated, time cycle control can be implemented by computer control. If there is no computer control, time cycle control is normally preferable to choke control since the frequency and duration of injection cycles can be controlled from the surface.

The challenge with time cycle control occurs if there is no effective way to control when the cycles occur and there is a risk of having injection cycles into several wells occur simultaneously. This can lead to a "boom or bust" situation where the pressure in the distribution system can go too low when injection occurs into several wells and too high when no wells are being injected.

Choke Control: As indicated, choke control can be implemented by computer control. If there is no computer control, choke control is normally preferred if it is difficult to coordinate injection cycles and it is important to maintain relatively stable system pressure.

The challenge with choke control, where the injection rate into the well is maintained at a relatively constant rate and the intermittent injection cycles are controlled by the operating gas-lift valve, is that change of the intermittent action requires that the downhole operating gas-lift valve be changed.

Combination Control: When there is computer control in use, the possibility exists to obtain the benefits of choke and time cycle control at the same time. The computer system can control of gas injection into the well at a constant rate. This will provide the advantage of maintaining a relatively stable injection system pressure. Then, when the pressure in the well's annulus has built close to the value needed to open the operating gas-lift valve, the computer can fully open the surface control valve, momentarily increase the rate and pressure in the annulus, and force the operating valve to "snap" open as it would with normal time cycle control. This will provide the advantage of controlled injection cycle frequency and duration.

7.4.3 Other Types of Wells in the System

If a gas-lift system must serve both intermittent and continuous gas-lift wells, the priorities of the wells must be understood. It is often the case that the continuous wells are higher producers. If this is the case, it may be especially important to keep the system pressure stable. This may argue in favor of using some form of choke control, or combination control, rather than conventional time cycle control.

7.5 Analysis/Problem Detection/Troubleshooting

Intermittent gas-lift requires careful monitoring of gas injection pressure, injection rates, injection cycles, wellhead pressure, etc. There are many opportunities for things to go wrong; and if they do, this can significantly affect the performance of the system and wells.

7.5.1 Analytical Tools and Techniques

The recommended practice is to use a computer monitoring and control system (sometimes referred to as a SCADA system) to continuously monitor the gas-lift system and each well. A modern computer system can provide the following:

Alarm Information: At least three levels of alarms should be considered.

— *Category 1*: These are simple alarms based on comparing a measured variable with an alarm limit, such as injection pressure too high, injection pressure too low, etc. These alarms can be useful in spotting problems but care must be used in setting the alarm limits or too many "nuisance" alarms can be generated. These alarms are not specifically related to gas-lift but can be generated for any measured variables. All automation (SCADA) systems can generate these types of alarms.

— *Category 2*: These are alarms that are specifically configured for gas-lift and are normally based on a combination of two or more measured variables. For example, an injection gas frozen alarm can be generated if the injection line pressure is normal or high, the injection rate is low, and the wellhead injection pressure is low.

These alarms can be useful in spotting typical gas-lift problems. Automation (SCADA) systems do not natively provide these types of alarms; they must be configured by the system support personnel.

— *Category 3*: These are alarms that are determined by comparing actual performance with the predicted or ideal performance as determined by a model of the gas-lift operation. For example, injection cycle too frequent can be generated if the actual gas-lift injection cycle frequency is shorter than the frequency that is predicted or recommended by the intermittent gas-lift model.

Reports: Many forms of reports can be provided.

— *Daily reports*. Daily reports are sometimes referred to as "gauge off" reports since they are automatically produced at night or early in the morning to reflect a summary of the previous day's operations. They contain a summary of how the system and each well has performed during the previous production day.

— *Current reports*. Current reports can be produced manually or automatically. They contain current information on how the system and each well is performing.

— *Historical reports*. Historical reports are usually produced manually when they are needed to provide historical information on how the system or wells have performed over a period of time, e.g. the last week, month, or year.

— *Alarm reports*. A variety of alarm reports can be produced. Some are produced automatically when alarms occur or at specified times of day. Some are produced manually to permit research into the occurrences or causes of certain alarm conditions.

— *Specialized reports*. There can be a wide variety of specialized reports to provide information on well performance, well test results, etc.

Trends: Plots of operating variables vs. time can be very useful.

— *Manual plots*. Plots can be produced manually at any time to help evaluate the performance of a system, a well, or a group of wells. Plots can show short term behavior such as might be used to evaluate individual intermittent gas-lift injection cycles. They can show long term behavior such as injection rate vs. time over longer periods of time.

— *Automatic plots*. Plots can be automatically generated either on a time schedule or on the occurrence of an event. For example, if certain alarm conditions occur, such as cycle too long or too short, a trend plot can be automatically generated to help diagnose the cause and effect of the problem

Analysis of System and Well Performance: It is not enough for the SCADA system to produce alarms, reports, and plots of data. If this is all there is, it is left to people to analyze all of the data and diagnose the causes of well problems, poor well performance, etc.

So, the system should analyze the performance of each well and the gas-lift system. It should produce a priority listing of wells that are not performing as desired. It should recommend actions to improve the performance. The operator can use or ignore the recommendations, but if they are well formed, they can be of significant value to operators who may not have enough time to carefully monitor each well on their own.

7.5.2 Problem Detection Tools and Techniques

There are several problem detection tools and techniques. One recommended practice is configured for use with intermittent gas-lift, and works as follows:

— plots of injection pressure, injection rate, and other pertinent variables are collected on intermittent gas-lift wells;

— the conditions of selected wells, including any problem(s) they may have, are analyzed;

— the plots and a description of the conditions or problems are stored in a "library" of plots;

— comparable plots are obtained on individual intermittent gas-lift wells on a routine basis;

— the current plots are compared with the cases in the library and the most likely matches are found;

— the Operator is informed of the most likely condition or problem associated with each well;

— the "report" of these problems can be sorted so the highest priority problems, or the ones that require immediate action, are listed first.

7.5.3 Performance Indicators

Performance indicators can be useful in spotting wells that need attention. For example, an intermittent gas-lift performance indicator might be defined as shown below. This is one example; there can be others. The important thing is that the SCADA system be able to automatically compute the performance indicators on a daily basis. The actual numbers are measured by the system. The optimum values are calculated by the intermittent gas-lift model.

The intermittent gas-lift performance indicator is a function of the ratio of the:

a) actual to optimum daily gas injection volume;

b) actual to optimum number of cycles per day;

c) actual to optimum daily volume of oil production.

Since the actual volumes or cycles can be larger or smaller than the optimum values, the ratio is always constructed such that it is less than or equal to 1.0.

$$IGLPI = SQRT\ ((Q_i / Q_{io}) \times (C / C_o) \times (Q / Q_o)) \tag{63}$$

where

$IGLPI$ is the intermittent gas-lift performance indicator;

Q_i is the actual injection gas volume in units per day;

Q_{io} is the optimum injection gas volume in units per day;

C is the actual number of injection cycles per day;

C_o is the optimum number of injection cycles per day;

Q is the actual oil production volume in units per day;

Q_o is the optimum oil production volume in units per day.

Performance indicators can be used in various ways to compare the performance of the following:

— *One well vs. a target value*. For example, produce an alarm or "poor performance" report is a well's performance indicator is less than 0.75;

— *One well over time*. For example, produce a trend plot of a well's performance indicator over time;

— *One well vs. other wells*. For example, produce a performance report where wells are sorted according to their performance indicators;

— *A group of wells vs. another group of wells*. Since performance indicators are non-dimensional, and are all ratios between 0.0 and 1.0, they can be combined by multiplying them together. So, the performance of a group of wells can be calculated by multiplying the performance indicators of the wells in the group. In this way, the performance of wells in one part of a field, or wells operated by one operator, can be compared with wells in another part of the field or operated by another operator.

7.5.4 Troubleshooting and Root Cause Analysis

It is not enough to monitor intermittent gas-lift wells and detect problems. The main benefit comes when troubleshooting is used to determine the cause of problems and to "drill down" to determine the root causes of problems. If the root causes can be found, corrective actions can be taken to solve the source(s) of the problems and hopefully prevent their reoccurrence. The troubleshooting techniques described in Section 6 can be implemented in a computer system.

7.6 Maintenance

For intermittent gas-lift to work well, a number of components must be well maintained and in good operating condition. This includes the source of gas-lift gas, the surface controllers, unloading gas-lift valves, the operating gas-lift valve, the wellhead, the flowline, the separator, etc.

7.6.1 System Maintenance

The recommended practice in maintenance of the gas-lift system is to keep the system in good working order so it can deliver the desired amount of gas at the desired pressure, all of the time. The key maintenance items are the gas-lift compressors, the gas-lift distribution system, and the piping in the distribution system. See API 11V5 for recommended practices on maintaining these system components.

7.6.2 Individual Well Maintenance

The recommended practice in maintenance of the intermittent gas-lift wells is to keep each well producing at its optimum rate at all times. The key maintenance items are the wellhead and flowline, the wellhead control system, the wellhead injection control choke or valve, the unloading gas-lift valves, and the operating gas-lift valve. See API 11V5 for recommended practices on maintaining these system components.

7.7 Optimization

Optimization of intermittent gas-lift is not a one time affair. Since equipment, system conditions, and well conditions can change, the system must be continuously optimized.

7.7.1 System Optimization—Allocation, Coordination

There are at least two aspects in intermittent gas-lift system optimization as follows:

— *Optimize allocation of gas to the wells*. The volume of gas available from the gas-lift system is (almost) never equal to the sum of the optimum injection rates into all of the wells served by the system. So, to keep a balance between the gas rate into and out of the system it is necessary to allocate gas from the system to the wells in an optimum manner. This is a relatively easy thing to do for continuous gas-lift and is also straight-forward when intermittent gas-lift wells are being controlled by choke control. See API 11V5 and API 11V8 for recommendations on how to do this;

— *Optimize coordination of intermittent injection cycles*. When intermittent gas-lift wells are operated by time cycle control, system optimization is a little trickier. There are two issues involved:

  — First, to keep the distribution system in balance and keep the system pressure (relatively) stable, it may be necessary to schedule some cycles closer together, if the volume of gas entering the distribution system is greater than that leaving the system, or schedule some of them to be farther apart if the volume of gas leaving the system is greater than that entering the system;

  — Second, when wells are on time cycle control, it is important to schedule the injection cycles so that not too many of them occur simultaneously. Periods of injection into too many wells, followed by periods of no injection, can cause system pressure fluctuations that can upset the wells being served by the system.

7.7.2 Well Optimization—Optimum Cycle Frequency and Gas Volume Per Cycle

Optimization of intermittent gas-lift wells basically consists of three things: optimizing the cycle frequency, optimizing the volume of gas per cycle and optimizing the instantaneous gas flow rate into the tubing. These three things are related:

— *Optimum cycle frequency*. The optimum cycle frequency is required to optimize overall liquid production. If the cycle frequency is too fast, not enough liquid will have entered the wellbore since the last injection cycle and gas will be wasted. If the cycle is too slow, total liquid production will be reduced because the longer inflow time between cycles will result in a higher liquid column in the wellbore. This higher column will exert more backpressure on the formation, which will inhibit inflow.

  Cycle frequency can best be optimized by accurately measuring the total liquid production per cycle, if possible, or per day and adjusting the cycle frequency (up and down) until the daily volume is maximized.

— *Optimum gas volume per cycle*. The optimum volume of gas per injection cycle is that amount of gas that best produces the liquid slug to the surface. If the volume is too small, not all of the liquid will reach the surface, some will fallback to the bottom of the wellbore. If the volume is too large, more gas than is needed to lift the liquid slug to the surface will have been injected.

  The volume of gas per cycle can best be optimized by very closely monitoring each cycle to see when the slug of liquid reaches the surface and when it has been produced from the wellbore into the production flowline.

— *Optimum instantaneous gas flow rate*. The volume of gas per cycle might be correct, but if it is injected into the well at a rate that would not be able to sustain a liquid slug velocity around 1000 ft/min (304.8 m/min), then the liquid fallback might be too high. Low liquid velocity is avoided by adjusting the valve opening pressure at a value that will guarantee a high gas flow rate into the well.

Annex A

Analytical Derivation of Optimum Cycle Time

A.1 Analytical Derivation of the Optimum Cycle Time

The equation that relates the flowing bottom-hole pressure with the liquid flow rate is given by:

$$q_f = PI(Psbh - Pwf) \quad \text{in SI Units} \tag{A.1}$$

$$q_f = PI(Psbh - Pwf) \quad \text{in Field Units}$$

In Equation (A.1), qf is the liquid production in m^3/day (bbl/day), PI is in m^3/(day/kPa) (bbl/day/psi), $Psbh$ is the bottom hole static pressure in kPa (psi) and Pwf is the bottom hole flowing pressure in kPa (psi). The PI used in this equation is an average PI obtained for values of the bottom hole pressure below 40 % to 50 % of the static pressure, which is the practical range of operation for intermittent gas-lift operation. For these values, assuming a constant PI is acceptable, refer to Figure A.1. Note that some operators define a value called "true" PI, rather than "average" PI, where "true" PI is the slope of the IPR curve at some specific Pwf and q_f. For the purposes here, the definition of "average" PI is recommended.

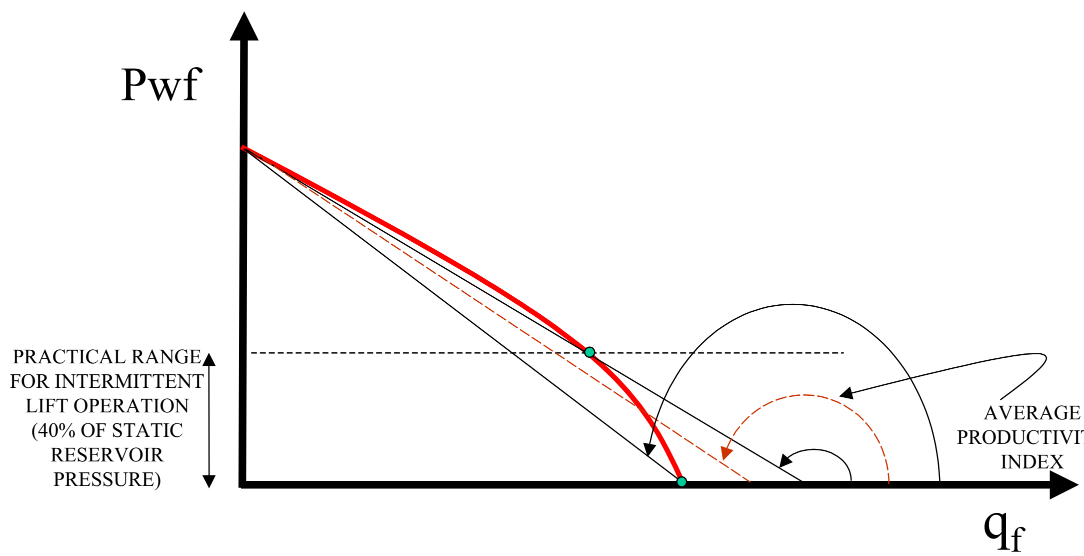


Figure A.1—Practical Range for Intermittent Lift Operation

If Bt is the volumetric capacity of the tubing in m^3/304.8 m (bbl/1000 ft), the daily production can be expressed as:

$$q_f = Bt\left(\frac{dQ}{dt}\right) \quad \text{in SI Units}$$

$$q_f = Bt\left(\frac{dQ}{dt}\right) \quad \text{in Field Units} \tag{A.2}$$

where

Q is the liquid column length above the point of gas injection in 304.8 m (1000 ft).

If A is the maximum drawdown at the perforation just after the liquid slug has been produced in kPa (psi), the drawdown at any time afterwards can be expressed as:

$$Psbh - Pwf = (A - Q \times \rho_f \times 304.8) \quad \text{in SI Units}$$

$$Psbh - Pwf = (A - Q \times \rho_f \times 1000) \quad \text{in Field Units} \tag{A.3}$$

A can be calculated from the following equation:

$$A = Psbh - (Dpt - Dov)\rho_T - Pwh \times fg \tag{A.4}$$

where

Dpt is the mean depth of the perforations in m (ft);

Dov is the depth of the operating valve in m (ft);

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

In Equation (A.3), ρ_f is the fluid gradient in the tubing in kPa/m (psi/ft) calculated from the water cut and the crude API. In Equation (A.4), ρ_f is the true liquid gradient in kPa/m (psi/ft) which takes into account the free gas present in the liquid and can be determined from a downhole pressure survey. Introducing Equations (A.3) and (A.2) in Equation (A.1), the following expression is obtained:

$$\frac{dQ}{dt} = \alpha'(A - Q\rho_f 304.8) \quad \text{in SI Units}$$

$$\frac{dQ}{dt} = \alpha'(A - Q\rho_f 1000) \quad \text{in Field Units} \tag{A.5}$$

In Equation (A.5), α' is equal to $PI/(1440 \times Bt)$ since dQ/dt is given in 304.8 m/min (1000 ft/min). Equation (A.5) can be integrated in the following way. α' equation is same for both SI and Field Units.

$$\int_{Q_a}^{Q} \frac{dQ}{A - Q\rho_f 304.8} = \int_0^t \alpha' dt \quad \text{in SI Units}$$

$$\int_{Q_a}^{Q} \frac{dQ}{A - Q\rho_f 1000} = \int_0^t \alpha' dt \quad \text{in Field Units} \tag{A.6}$$

Q_a is the liquid column that forms due to fallback losses from the previous cycle, which for calculation purposes is assumed to accumulate completely at the beginning of the cycle. Q_a is given by:

$$Q = FF \times (Dov \times Q)/304.8 \quad \text{in SI Units}$$

$$Q = FF \times (Dov \times Q)/1000 \quad \text{in Field Units} \tag{A.7}$$

where

Dov is the depth of the point of injection in m (ft);

Q is the liquid column length just before the gas-lift valve opens in 304.8 m (1000 ft);

FF is the fallback factor, which is usually equal to 0.06.

Integrating Equation (A.6), an expression is found for Q as a function of time t:

$$Q = \frac{A\left(e^{\alpha\rho_f t} - 1\right)}{304.8\rho_f\left(e^{\alpha\rho_f t} - cm\right)} \quad \text{in SI Units}$$

$$Q = \frac{A\left(e^{\alpha\rho_f t} - 1\right)}{304.8\rho_f\left(e^{\alpha\rho_f t} - cm\right)} \quad \text{in Field Units} \tag{A.8}$$

where

α is equal to 304.8 α' in SI Units (1000 α' in Field Units); and

cm is $FF \times Dov/304.8$ in SI Units ($FF \times Dov/1000$ in Field Units).

If the gas injection time is approximated as the depth of the valve in m (ft) divided by the liquid slug velocity, vat in m/min (ft/min), the total cycle time is given by:

$$T = t + (Dov)/(vat) \quad \text{in SI Units}$$

$$T = t + (Dov)/(vat) \quad \text{in Field Units} \tag{A.9}$$

The daily production in 1000 m^3/day (1000 bbl/day) can be calculated for a given cycle time T as (for the last equation, the term 1000 has to do with 1000 bbl/day and not with depth):

$$q_f = Q(1 - cm)Bt\frac{1440}{T}\frac{1}{1000} \quad \text{in SI Units}$$

$$q_f = Q(1 - cm)Bt\frac{1440}{T}\frac{1}{1000} \quad \text{in Field Units} \tag{A.10}$$

If $C3$ is defined as to 1.44Bt (1 cm) for convenience, then qf is equal to $C3 \times Q/T$. Using Equations (A.8) and (A.9), Equation (A.10) for q_f can be expressed as:

$$q_f = \frac{C3 \times A\left(\dfrac{e^{\alpha\rho_f T}}{e^{\alpha\rho_f (Dov)/(vat)}} - 1\right)}{T304.8\rho_f\left(\dfrac{e^{\alpha\rho_f T}}{e^{\alpha\rho_f (Dov)/(vat)}} - cm\right)} \quad \text{in SI Units}$$

$$q_f = \frac{C3 \times A\left(\dfrac{e^{\alpha\rho_f T}}{e^{\alpha\rho_f (Dov)/(vat)}} - 1\right)}{T1000\rho_f\left(\dfrac{e^{\alpha\rho_f T}}{e^{\alpha\rho_f (Dov)/(vat)}} - cm\right)} \quad \text{in Field Units} \tag{A.11}$$

To maximize qf, Equation (A.11) must be differentiated with respect to T and set it equal to zero.

$$\frac{dq_f}{dT} = 0 \tag{A.12}$$

Which yields the desired expression for the optimum cycle time T:

$$T = \frac{(e^{\gamma T} - C4)(e^{\gamma T} - cm \times C4)}{\gamma e^{\gamma T} C2 \times C4} \quad \text{in SI Units}$$

$$T = \frac{(e^{\gamma T} - C4)(e^{\gamma T} - cm \times C4)}{\gamma e^{\gamma T} C2 \times C4} \quad \text{in Field Units} \tag{A.13}$$

where

$$C2 = 1 - cm$$

$$\gamma = \alpha\rho_f \quad \text{for both SI and Field Units systems}$$

$$C4 = e^{\gamma \frac{Dov}{vat}}$$

This value can be found using the Newton-Raphson algorithm, as shown in the next section. Once the value of T has been found, Q can be calculated using Equations (A.8) and (A.9) and the tubing opening pressure is given by:

$$Pto = Pwh \times fg + Q1000\rho_f \quad \text{in SI Units}$$

$$Pto = Pwh \times fg + Q1000\rho_f \quad \text{in Field Units} \tag{A.14}$$

A.2 Numerical Procedure for the Optimum Cycle Time

The following procedure can be used to find the optimum cycle time described in the previous section:

Equation (A.13) can be expressed as

$$T - \frac{(e^{\gamma T} - C4)(e^{\gamma T} - cm \times C4)}{\gamma e^{\gamma T} C2 \times C4} = 0 \tag{A.15}$$

The problem is then reduced to finding the value of T for which Equation (A.13) is satisfied. This can be easily done by setting the left hand side of Equation (A.13) equal to a function F of T and then use an iterative procedure such as Newton's method to find its root.

If F is the left hand side of Equation (A.13) and dF/dT is the derivative of F with respect to T, then a first guess of T, $T1$, is used to find a new value of $T2$, which, if Newton's method is used, can be found by

$$T2 = T1 - F/\,(dF/dT) \tag{A.16}$$

If the absolute value of ($T2 - T1$) is greater than, say, 0.01 min, then $T1$ takes the value of $T2$ and a new value of $T2$ is found using Equation (A.13). This process is repeated until $T2$ and $T1$ are approximately equal. The final value of $T2$ is the optimum cycle time.

A.3 Calculation of the Total Volume of Gas Required Per Cycle Based on an Energy Balance

The theoretical volume of gas that has entered the tubing as the tip of the liquid slug reaches the surface can be calculated using:

a) the equation of state for real gasses;

b) the pressure drop calculation of the liquid slug;

c) the first law of thermodynamics for control volumes of variable boundaries.

First, according to the equation of state, the volume of gas per cycle vgs will be given by:

$$vgs = \frac{288.55 \times Bg \times (Dov - Q) \times P_{ga}}{101.35 \times Za \times Ta} \quad \text{in SI Units}$$

$$vgs = \frac{520 \times Bg \times (Dov - Q) \times P_{ga}}{14.7 \times Za \times Ta} \quad \text{in Field Units} \tag{A.17}$$

where

Bg	is the tubing volumetric factor in m^3/304.8 m (SCF/1000 ft);
Dov	is the depth of the operating valve in 304.8 m (1000 ft);
Q	is the initial column length also in 304.8 m (1000 ft);
P_{ga} and Ta	are the average pressure and temperature of the gas inside the tubing between the operating valve and the lower end of the liquid slug, which is just beginning to be produced to the surface at a velocity of about 304.8 m/min (1000 ft/min). For normal liquid slug lengths, it is assumed that the gas injected until the tip of the liquid slug reaches the surface will be sufficient to produce the entire slug to the surface. P_{ga} can be found using pressure drop calculations for single-phase flow as indicated below;
Ta	is the average temperature of the gas that has entered the tubing and it can be found using the first law of thermodynamics. Za is the compressibility factor for the gas inside the tubing at P_{ga} and Tga.

To find the volume of gas per cycle, vgs, the pressure P_{ga} is calculated first and then the temperature and the compressibility factor Za are found simultaneously in an iterative procedure.

P_{ga} is given by:

$$P_{ga} = \frac{P_{gu} + Ptm}{2} + 101.35 \text{ in SI Units}$$

$$P_{ga} = \frac{P_{gu} + Ptm}{2} + 14.7 \text{ in Field Units} \tag{A.18}$$

P_{gu} is the pressure underneath the liquid slug and Ptm is the pressure at the operating valve. Pgu is given by:

$$P_{gu} = Pwh + Q(1 - FF \times Dov)304.8\rho_f C_f \quad \text{in SI Units}$$

$$P_{gu} = Pwh + Q(1 - FF \times Dov)1000\rho_f C_f \quad \text{in Field Units} \tag{A.19}$$

where

FF is the fallback factor (usually taken as 0.06);

ρ_f is the fluid gradient in the tubing in kPa/m (psi/ft) calculated from the water cut and the crude API;

Pwh is the wellhead pressure in psi;

Q is the initial liquid column length in 304.8 m (1000 ft);

Dov is the depth of the operating valve in 304.8 m (1000 ft);

Cf is a coefficient that takes into account both, the friction and hydrostatic pressure drop and is given by:

$$C_f = \frac{207.23f(vat)^2}{dt} + 1 \quad \text{(A.20)}$$

where

vat is the slug velocity in 304.8 m/min (1000 ft/min);

dt is the tubing inside diameter in in.;

f is the friction factor obtained from the Moody diagram as a function of the liquid Reynolds's number and the relative roughness of the pipe. For design purposes, vat can be assumed equal to 1.

Ptm is then found by adding the pressure due to the weight of the column of gas behind the slug to Pgu. This is done by multiplying the depth pressure factor, fg, times Pgu:

$$Ptm = P_{gu} \times fg \quad \text{in SI Units}$$

$$Ptm = P_{gu} \times fg \quad \text{in Field Units} \quad \text{(A.21)}$$

The next step is to find the average temperature of the gas inside the tubing. This can be done by using the first law of thermodynamics for control volumes of variable boundaries. The control volume is the bubble of gas below the liquid slug. An energy balance equation for the process is given by:

$$\int h_i dm_i = m_t u_t + \Delta P.E._{ls} \quad \text{(A.22)}$$

The integral of the initial enthalpy of the gas in the casing, h_i, is equal to the internal energy of the gas injected into the tubing plus the gain in potential energy of the liquid slug $\Delta P.E._{ls}$. The kinetic energy of the liquid and gas can be neglected. If the injection mass flow rate is constant, the energy balance equation can be integrated:

$$h_i m_i = m_t u_t + \Delta P.E._{ls} \quad \text{(A.23)}$$

The continuity equation indicates that $m_i = m_t$ and m_i is precisely the mass that occupies a volume vgs at standard conditions and can be expressed as:

$$m_i = \frac{5.12 \times vgs(101.35)}{R(520)} \quad \text{in SI Units}$$

$$m_i = \frac{vgs(14.7)}{R(520)} \quad \text{in Field Units} \quad \text{(A.24)}$$

R is the universal gas constant divided by the molecular weight. The universal constant is 8.315 kPa m^3/(Kg-mol °K) or 10.73 ft^3 × psi × °R^{-1} lbm-mol^{-1}.

The gain in potential energy of the liquid slug is given by:

$$\Delta P.E._{ls} = C\rho_f Q(1 - FF \times Dov)(Dov - (1 - FF \times Dov)Q)(g)(Bg) \quad \text{in SI Units}$$

$$\Delta P.E._{ls} = C\rho_f Q(1 - FF \times Dov)(Dov - (1 - FF \times Dov)Q)(g)(Bg) \quad \text{in Field Units} \tag{A.25}$$

where

C is a constant that takes care of the units used in SI or Field Units systems;

g is the acceleration due to gravity. The energy balance equation can be expressed as:

$$h_i = u_t + 0.1875\frac{\Delta P.E._{ls}}{vgs}R \quad \text{in SI Units}$$

$$h_i = u_t + \frac{\Delta P.E._{ls}}{vgs}\frac{R(520)}{(14.7)} \quad \text{in Field Units} \tag{A.26}$$

The initial enthalpy can be calculated since the pressure and temperatures in the casing are known. The increase in potential energy can also be calculated, so the unknowns are the internal energy and vgs, which are both functions of the average temperature Ta in the tubing. The following represents an iterative algorithm used to find Ta, Za and vgs simultaneously.

1) Calculate h_i and the gain in potential energy.

2) Assume a temperature Ta.

3) With P_{ga} and Ta calculate Za and then vgs using Equation (A.14).

4) Use the energy equation to find ut.

5) With P_{ga} and ut, look up the temperature of the gas, which will be named Tac, from thermodynamic tables or compute it from equations relating u, T and P.

6) Compare Tac with Ta, if they are within a given tolerance stop the calculations and Ta has been found. If Tac and Ta are too far apart, assign the value of Tac to Ta and redo calculations from step 3.

In this way, the theoretical volume of gas required per cycle is found.

A.4 Gas Mass Balance Used to Calculate the Valve Closing Pressure for Pressure Operated Gas-lift Valves

The following procedure can be used to find the operating valve closing pressure based on a gas injection mass balance once the valve opening pressure and the gas required per cycle are known. The valve closing pressure at depth, $Pvcd$, can be found by a mass balance of the gas injected into the tubing and the gas provided by the system:

$$vgs = vga + vgl + vge \quad \text{in SI Units}$$

$$vgs = vga + vgl + vge \quad \text{in Field Units} \tag{A.27}$$

The volume of gas injected into the tubing, vgs, in m^3 (ft^3) is equal to the volume provided by the annulus, vga, in m^3 (ft^3) plus the volume provided by the injection line from the choke to the wellhead, vgl, in m^3 (ft^3) plus the volume of gas that passes through the surfaces choke while the gas-lift valve is open, vge, in m^3 (ft^3).

The volume of gas injected into the tubing, vgs, can be calculated following the procedure given in the last section.

vga at standard conditions is equal to the volume of gas at standard conditions in the casing annulus just before the valve opens, minus the volume of gas at standard condition in the casing annulus just after the valve closes.

The number of moles of natural gas in the annulus just before the valve opens is given by:

$$n = \frac{P_{ga,\,\mathrm{open}} \times V_{\mathrm{annulus}}}{Z_{ga}(\mathrm{open}) \times R \times Ta,\,\mathrm{geoth}} = \frac{101.35 \times vsc}{(1) \times R \times (288.55)} \quad \text{in SI Units}$$

$$n = \frac{P_{ga,\,\mathrm{open}} \times V_{\mathrm{annulus}}}{Z_{ga}(\mathrm{open}) \times R \times Ta,\,\mathrm{geoth}} = \frac{(14.7) \times vsc}{(1) \times R \times (520)} \quad \text{in Field Units} \qquad \text{(A.28)}$$

where

vsa is the volume that the gas in the casing annulus just when the valve opens would occupy at standard conditions in m^3 (ft^3);

V_{annulus} is the actual volume of the casing annulus in m^3 (ft^3);

Ta,geoth is the average geothermal temperature °K (°R);

Zga and $P_{ga,\mathrm{open}}$ are the average compressibility factor and the average pressure of the gas in kPa (psi) in the annulus when the valve opens. P_{ga}, open is given by:

$$P_{ga,\,\mathrm{open}} = \frac{Pio + Piod}{2} \quad \text{in SI Units}$$

$$P_{ga,\,\mathrm{open}} = \frac{Pio + Piod}{2} \quad \text{in Field Units} \qquad \text{(A.29)}$$

where

Pio is the surface opening pressure;

$Piod$ is the valve opening pressure at depth in kPa (psi).

vsa can be calculated from Equation (A.28).

Using the same equations, the number of moles in the casing annulus just after the valve closes is:

$$n = \frac{P_{ga,\,\mathrm{open}} \times V_{\mathrm{annulus}}}{Z_{ga}(\mathrm{open}) \times R \times Ta,\,\mathrm{geoth}} = \frac{101.35 \times vsc}{(1) \times R \times (288.55)} \quad \text{in SI Units}$$

$$n = \frac{P_{ga,\,\mathrm{open}} \times V_{\mathrm{annulus}}}{Z_{ga}(\mathrm{open}) \times R \times Ta,\,\mathrm{geoth}} = \frac{(14.7) \times vsc}{(1) \times R \times (520)} \quad \text{in Field Units} \qquad \text{(A.30)}$$

where

vsc is the volume that the gas in the casing annulus just when the valve closes would occupy at standard conditions in m^3 (ft^3);

$P_{ga,\text{close}}$ is the average pressure in the annulus when the valve closes in kPa (psi) and can be found by:

$$P_{ga,\text{ close}} = \frac{Pvc + Pvcd}{2} \quad \text{(A.31)}$$

where

Pvc is the closing pressure at the surface an $Pvcd$ is the closing pressure at depth.

The volume of gas supplied by the casing annulus in m^3 (ft^3) is then given by:

$$vga = vsa - vsc \quad \text{in SI Units}$$

$$vga = vsa - vsc \quad \text{in Field Units} \quad \text{(A.32)}$$

The average geothermal temperature is given by:

$$T_{a,\text{ geoth}} = \frac{T_s + T_{dov}}{2} + 273.15 \quad \text{in SI Units}$$

$$T_{a,\text{ geoth}} = \frac{T_s + T_{dov}}{2} + 460 \quad \text{in Field Units} \quad \text{(A.33)}$$

where

T_s is the surface temperature in °C (°F);

T_{dov} is the geothermal temperature at valve depth in °F.

If Ba is the volumetric capacity of the annulus in m^3/304.8 m (ft^3/1000 ft), Dov is the depth of the operating valve in 304.8 m (1000 ft), then V_{annulus} is:

$$V_{\text{annulus}} = Dov \times Ba \quad \text{in SI Units}$$

$$V_{\text{annulus}} = Dov \times Ba \quad \text{in Field Units} \quad \text{(A.34)}$$

Using Equations (A.28), (A.30), (A.33) and (A.34) and assuming a surface temperature of 29.44 °C (85 °F) expressions for vsa and vsc are found:

$$vsa = 2.84706\frac{Ba \times Dov \times (Pio + Piod)}{(575.74 + Tdov) \times Zga,\text{ open}} \quad \text{in SI Units}$$

$$vsa = 35.37\frac{Ba \times Dov \times (Pio + Piod)}{(1005 + Tdov) \times Zga,\text{ open}} \quad \text{in Field Units} \quad \text{(A.35)}$$

$$vsc = 2.84706\frac{Ba \times Dov \times (Pvc + Pvcd)}{(575.74 + Tdov) \times Zga,\text{ close}} \quad \text{in SI Units}$$

$$vsc = 35.37\frac{Ba \times Dov \times (Pvc + Pvcd)}{(1005 + Tdov) \times Zga,\text{ close}} \quad \text{in Field Units} \quad \text{(A.36)}$$

Using Equations (A.32), (A.35) and (A.36) gives an expression is found for vga where the only unknowns are the closing pressures at depth and at the surface:

$$vga = 2.84706 \times k1 \times (Pio + Piod - Pvc - Pvcd) \quad \text{in SI Units}$$

$$vga = 35.37(k1) \times (Pio + Piod - Pvc - Pvcd) \quad \text{in Field Units} \tag{A.37}$$

$K1$ is given by:

$$K1 = \frac{Ba \times Dov}{(575.74 + Tdov) \times Zga, prom \times 12.42} \quad \text{in SI Units}$$

$$K1 = \frac{Ba \times Dov}{(1005 + Tdov) \times Zga, prom \times 12.42} \quad \text{in Field Units} \tag{A.38}$$

Following the steps described above, expressions can be found for the volume of gas in the injection line when the valve opens and when it closes:

$$vsa = 2.84706\frac{Bl \times L \times Pio}{(302.6)Zgl} \quad \text{in SI Units}$$

$$vsa = 35.37\frac{Bl \times L \times Pio}{(545)Zgl} \quad \text{in Field Units} \tag{A.39}$$

$$vsc = 2.84706\frac{Bl \times L \times Pvc}{(302.6)Zgl} \quad \text{in SI Units}$$

$$vsc = 35.37\frac{Bl \times L \times Pvc}{(545)Zgl} \quad \text{in Field Units} \tag{A.40}$$

Bl is the volumetric capacity of the injection line in m^3/304.8 m (ft^3/1000 ft), and L is its length in 304.8 m (1000 ft). vgl is then found by:

$$vgl = vsa - vsc \quad \text{in SI Units}$$

$$vgl = vsa - vsc \quad \text{in Field Units} \tag{A.41}$$

Combining Equations (A.39), (A.40) and (A.41):

$$vgl = 2.84706 \times k2 \times (Pio - Pvc) \quad \text{in SI Units}$$

$$vgl = 35.37 \times k2 \times (Pio - Pvc) \quad \text{in Field Units} \tag{A.42}$$

$k2$ is given by:

$$k2 = 302.6\frac{Bl \times L}{Zgl} \quad \text{in SI Units}$$

$$k2 = \frac{Bl \times L}{545 \times Zgl} \quad \text{in Field Units} \tag{A.43}$$

The gas flow rate that goes through the surface choke in m^3/min (scft/min), VPM, is equal to the daily injection rate in 1000 m^3/day (1000 scf/day), Qgi, divided by 1.44.

$$VPM = Qgi[1000\mathrm{m}^3/(\mathrm{day})]\frac{1}{1440\left[\frac{\min}{\mathrm{day}}\right]}1000\left[\frac{m^3}{1000\ \mathrm{m}^3}\right] = (Qgi)/(1.440) \quad \text{in SI Units}$$

$$VPM = Qgi[1000\mathrm{ft}^3/(\mathrm{day})]\frac{1}{1440\left[\frac{\min}{\mathrm{day}}\right]}1000\left[\frac{ft^3}{1000\ \mathrm{ft}^3}\right] = (Qgi)/(1.440) \quad \text{in Field Units} \qquad \text{(A.44)}$$

Qgi in 1000 m^3/day (1000 scf/day) can be easily computed once the volume injected per cycle, vgs, and the cycle time T are found, and is equal to $vgs \times (1440/T)/1000$ for both SI and Field Units.

The time in minutes that the gas-lift valve remains open can be approximated as:

$$Tinj. = \frac{Dov}{vat} \quad \text{in SI Units}$$

$$Tinj. = \frac{Dov}{vat} \quad \text{in Field Units} \qquad \text{(A.45)}$$

vat is the velocity of the slug in m/min (ft/min). Then vge is given by:

$$vge = \frac{Qgi \times Dov}{1.44 \times vat} = 2.84706\frac{Qgi \times Dov}{4.09976 \times vat} \quad \text{in SI Units}$$

$$vge = \frac{Qgi \times Dov}{1.44 \times vat} = 35.37\frac{Qgi \times Dov}{50.94 \times vat} \quad \text{in Field Units} \qquad \text{(A.46)}$$

With $k4$ as:

$$k4 = \frac{Qgi \times Dov}{50.94 \times vat} \quad \text{in SI Units}$$

$$k4 = \frac{Qgi \times Dov}{50.94 \times vat} \quad \text{in Field Units} \qquad \text{(A.47)}$$

vge can be expressed as:

$$vge = 35.37 \times k4 \quad \text{in SI Units}$$

$$vge = 35.37 \times k4 \quad \text{in Field Units} \qquad \text{(A.48)}$$

Introducing the expressions found for vge, vga and vgl in the general mass balance equation, the valve closing pressure is found as:

$$Pvcd = \frac{\left[Pio(k1 \times k3 + k2) + k4 - \dfrac{vgs}{2.8470}\right]fg}{k1 \times k3 + k2} \quad \text{in SI Units}$$

$$Pvcd = \frac{\left[Pio(k1 \times k3 + k2) + k4 - \dfrac{vgs}{35,374}\right]fg}{k1 \times k3 + k2} \quad \text{in Field Units} \tag{A.49}$$

where

$k3 = 1 + fg$

$Pvcd = Pvc \times fg$

$Piod = Pio \times fg$

where

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

A.5 Example of Numerical Models for Intermittent Gas-lift Design

This section provides an example showing how numerical models can be used for intermittent gas-lift design.

A.5.1 Model Based on Momentum and Mass Balance

This approach is based on the simultaneous solution of the momentum and mass balance equations to determine the operational conditions at time $t + \Delta t$, from the conditions that existed at a previous time t.

A.5.1.1 Model Stages

The intermittent gas-lift cycle is divided into five distinct stages. Each stage has its own particular operational conditions that distinguish it from the others. Applying momentum and mass balance equations for each stage will result in a set of ordinary, first order equations that must be solved simultaneously.

The stages are as follows.

— *Liquid slug rise*. During this stage, the gas-lift valve is open and gas from the annulus enters the production tubing pushing the liquid upwards. At the same time, gas from the manifold is injected into the well injection annulus.

— *Liquid production to the surface*. This stage begins as soon as the tip of the liquid slug reaches the surface and ends when the entire liquid slug has been produced to the flowline.

— *Full slug in the flowline*: this stage begins when the entire slug has reached the surface and ends when all the liquid has reached the separator or when the liquid velocity becomes negligible.

— *Gas venting stage*. This stage takes place only if the operating gas-lift valve is still open when the entire liquid slug has reached the separator or it has completely stopped in the flowline. During this stage gas is being injected from the manifold to the well annulus and from the annulus into the tubing. The stage will end as soon as the operating gas-lift valve closes.

— *Pressure build up*. This stage begins when the operating gas-lift valve closes. Gas injection into the annulus continues during this stage. A new liquid slug begins to form above the gas-lift valve with fluids from the reservoir and from the fallback losses from the previous cycle. The stage ends when the pressures in the annulus and in the tubing are sufficiently high to open the operating gas-lift valve.

A.5.2 Equations That Model Each Stage

The most important variables considered by the model are presented in Figure 6.1. At each stage, momentum and continuity equations are applied separately to the following control volumes:

a) the injection annulus;

b) the gas bubble that forms behind the liquid slug; and

c) the liquid slug itself.

From this, a set of ordinary differential equations is obtained that describes the dynamic behavior of the following variables:

— annular pressure;

— tubing pressure;

— liquid slug velocity;

— gas flow rate into the annulus;

— gas flow rate out of the annulus;

— liquid flow from the reservoir;

— liquid slug length;

— liquid fallback.

First Stage: liquid slug rise.

Conservation of mass for the annular space gives

$$\frac{Ytc}{2}\left[\frac{d\rho_{TC1}}{dt}+\frac{d\rho_{TC2}}{dt}\right] = -m1+m2 \text{ in SI Units}$$

$$\frac{Ytc}{2}\left[\frac{d\rho_{TC1}}{dt}+\frac{d\rho_{TC2}}{dt}\right] = -m1+m2 \text{ in Field Units} \quad \text{(A.50)}$$

where

Ytc is the annular space volume;

$m1$ is the mass flow rate out to the production tubing;

$m2$ is the mass flow rate into the annulus.

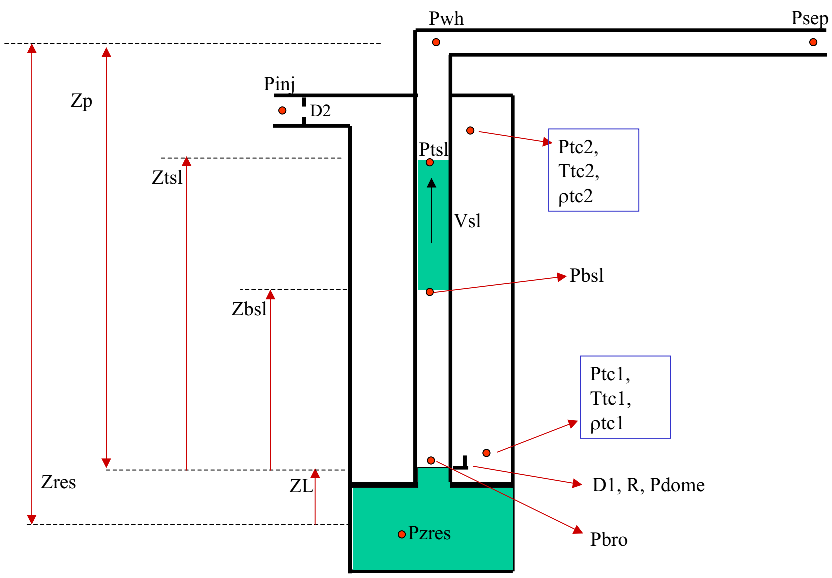


Figure A.2—Variables Considered by the Model

In Equation (A.50) the gas density in the annular space is the average of the density at the surface, $\rho TC2$, and at valve's depth, $\rho TC1$.

The equation of state is defined as:

$$\rho = P\frac{M}{zRT} \quad \text{in SI Units (kPa)}$$

$$\rho = P\frac{M}{zRT} \quad \text{in Field Units (psi)} \tag{A.51}$$

where

M is the molecular weight;

z is the compressibility factor;

R is the universal gas constant;

T is the absolute temperature. Introducing Equation (A.51) in Equation (A.50) the following equation is derived:

$$\frac{Ytc}{2}\left(\frac{M}{R}\right)\left[\left(\frac{1}{zT}\right)_{TC1}\frac{dp_{TC1}}{dt} + \left(\frac{1}{zT}\right)_{TC2}\frac{dp_{TC2}}{dt}\right] = -m1 + m2 \quad \text{in SI Units}$$

$$\frac{Ytc}{2}\left(\frac{M}{R}\right)\left[\left(\frac{1}{zT}\right)_{TC1}\frac{dp_{TC1}}{dt} + \left(\frac{1}{zT}\right)_{TC2}\frac{dp_{TC2}}{dt}\right] = -m1 + m2 \quad \text{in Field Units} \tag{A.52}$$

If losses due to friction are neglected, the gas injection pressure at depth can be expressed in terms of the surface injection pressure as follows:

$$PTC1 = PTC2 \times e^{\left[\frac{0.06151 \times zp \times Gg}{(zT)_{\text{average}}}\right]} \quad \text{in SI Units}$$

$$PTC1 = PTC2 \times e^{\left[\frac{0.01875 \times zp \times Gg}{(zT)_{\text{average}}}\right]} \quad \text{in Field Units} \qquad \text{(A.53)}$$

where

Gg is the gas specific gravity;

zp is the depth of the gas-lift valve;

z and T are the average compressibility and temperature of the gas in the annular space.

From Equations (A.53) and (A.52):

$$\frac{Ytc}{2}\left(\frac{M}{R}\right)\left[\left(\frac{1}{zT}\right)_{TC1} + \left(\frac{1}{zT}\right)_{TC2} \times e^{\left[\frac{0.06151 \times zp \times Gg}{(zT)_{\text{average}}}\right]}\right]\frac{dp_{TC1}}{dt} = -m1 + m2 \quad \text{in SI Units}$$

$$\frac{Ytc}{2}\left(\frac{M}{R}\right)\left[\left(\frac{1}{zT}\right)_{TC1} + \left(\frac{1}{zT}\right)_{TC2} \times e^{\left[\frac{0.01875 \times zp \times Gg}{(zT)_{\text{average}}}\right]}\right]\frac{dp_{TC1}}{dt} = -m1 + m2 \quad \text{in Field Units} \qquad \text{(A.54)}$$

$m1$ and $m2$ can be calculated using the Thornhill-Craver equation from the upstream and downstream pressures at the surface choke and at the gas-lift valve.

If the gas bubble in the tubing rises at an assumed velocity equal to the liquid velocity, the mass balance of the gas inside the gas bubble can be expressed as:

$$Yb\frac{d\rho\rho}{dt} = m1 - \rho bsl \times At \times Vpl \quad \text{in SI Units}$$

$$Yb\frac{d\rho\rho}{dt} = m1 - \rho bsl \times At \times Vpl \quad \text{in Field Units} \qquad \text{(A.55)}$$

where

Yb is the volume of the gas bubble m^3 (ft^3);

ρb is the average gas density inside the bubble in kg/m^3 (lbm/ft^3);

ρbsl is the density of the gas inside the bubble just underneath the liquid slug;

At is the tubing area;

Vpl is the velocity of the liquid slug.

The density ρb can be expressed as:

$$\rho b = \frac{\rho bsl + \rho bro}{2} \quad \text{in SI Units}$$

$$\rho b = \frac{\rho bsl + \rho bro}{2} \quad \text{in Field Units} \tag{A.56}$$

where

ρbro is the gas density inside the gas bubble and at valve depth.

Equation (A.55) be expressed as:

$$At \times zbsl \times \left[\frac{dPbsl}{dt} + \frac{(zT)_{bsl}}{(zT)_{bro}}\frac{dPbro}{dt}\right] = \frac{2 \times m1 \times R}{M}(zT)_{bsl} - 2 \times Pbsl \times At \times Vpl \quad \text{in SI Units}$$

$$At \times zbsl \times \left[\frac{dPbsl}{dt} + \frac{(zT)_{bsl}}{(zT)_{bro}}\frac{dPbro}{dt}\right] = \frac{2 \times m1 \times R}{M}(zT)_{bsl} - 2 \times Pbsl \times At \times Vpl \quad \text{in Field Units} \tag{A.57}$$

where

$zbsl$ is the bubble length.

Losses due to friction are important in the gas bubble and are given by:

$$Pbsl - Pbro = -fb\frac{\rho b \times |Vpl| \times Vpl \times zbsl}{2 \times Dt} \quad \text{in SI Units}$$

$$Pbsl - Pbro = -fb\frac{\rho b \times |Vpl| \times Vpl \times zbsl}{2 \times g_c \times Dt} \quad \text{in Field Units} \tag{A.58}$$

where

fb is the friction factor obtained from the Moody diagram;

gc is the gravity proportionality constant;

Dt is the tubing inside diameter;

Vpl is the velocity of the gas in the bubble, which is assumed to be equal to the lower interface of the liquid slug.

Differentiating Equation (A.58) with respect to time, the following equation is found:

$$\frac{dPbsl}{dt} - \frac{dPbro}{dt} + fb\frac{|Vpl| \times Vpl \times zbsl}{2 \times Dt}\left(\frac{d\rho\rho}{dt}\right) + \frac{fb}{dt}|Vpl| \times \rho b \times zbsl\left(\frac{dVpl}{dt}\right) = \frac{-fb|Vpl|Vpl \times \rho b \times Vpl}{2 \times Dt} \quad \text{in SI Units}$$

$$\frac{dPbsl}{dt} - \frac{dPbro}{dt} + fb\frac{|Vpl| \times Vpl \times zbsl}{2 \times g_c \times Dt}\left(\frac{d\rho\rho}{dt}\right) + \frac{fb}{g_c dt}|Vpl| \times \rho b \times zbsl\left(\frac{dVpl}{dt}\right) = \frac{-fb|Vpl|Vpl \times \rho b \times Vpl}{2 \times g_c \times Dt} \quad \text{in Field Units} \tag{A.59}$$

Differentiating Equation (A.56) with respect to time:

$$\frac{d\rho\rho}{dt} = \frac{M}{2R(zT)_{bsl}}\left[\frac{dPbsl}{dt} + \frac{(zT)_{bsl}}{(zT)_{bro}}\frac{dPbro}{dt}\right] \text{ in SI Units}$$

$$\frac{d\rho\rho}{dt} = \frac{M}{2R(zT)_{bsl}}\left[\frac{dPbsl}{dt} + \frac{(zT)_{bsl}}{(zT)_{bro}}\frac{dPbro}{dt}\right] \text{ in Field Units} \quad \text{(A.60)}$$

Introducing Equation (A.60) in (A.59):

$$A\frac{dPbsl}{dt} + B\frac{dPbro}{dt} + \frac{fb}{12 \times Dt}|Vpl| \times \rho b \times zbsl \times \frac{dVpl}{dt} = \frac{-fb \times |Vpl| \times |Vpl| \times \rho b \times Vpl}{24 \times Dt} \quad \text{in SI Units}$$

$$A\frac{dPbsl}{dt} + B\frac{dPbro}{dt} + \frac{fb}{12g_c \times Dt}|Vpl| \times \rho b \times zbsl \times \frac{dVpl}{dt} = \frac{-fb \times |Vpl| \times |Vpl| \times \rho b \times Vpl}{24g_c \times Dt} \quad \text{in Field Units} \quad \text{(A.61)}$$

where in SI Units

$$A = \left[1 + \frac{M}{2R(zT)_{bsl}}\frac{fb}{24 \times Dt}|Vpl|Vpl(zbsl)\right]$$

$$B = \left[1 - \frac{M}{2R(zT)_{bro}}\frac{fb}{24 \times Dt}|Vpl|Vpl(zbsl)\right]$$

And in Field Units

$$A = \left[1 + \frac{M}{2R(zT)_{bsl}}\frac{fb}{24g_c \times Dt}|Vpl|Vpl(zbsl)\right]$$

$$B = \left[1 - \frac{M}{2R(zT)_{bro}}\frac{fb}{24g_c \times Dt}|Vpl|Vpl(zbsl)\right]$$

$$\rho b = \left[\frac{pbsl}{(zT)_{bsl}} + \frac{Pbro}{(zT)_{bro}}\right]\frac{M}{2R}$$

For SI or Field Units use the appropriate units. The momentum balance equation for the liquid slug is as follows:

$$\rho_L At(ztsl - zbsl)\frac{dVsl}{dt} = -144At \times (Ptsl - Pbsl) - \frac{fl \times |Vsl| \times Vsl \times (ztsl - zbsl)\rho_L}{2Dt} - \rho_L \times g \times At \times (ztsl - zbsl)$$

in SI Units

$$\rho_L At(ztsl - zbsl)\frac{dVsl}{dt} = -144At \times g_c \times (Ptsl - Pbsl) - \frac{fl \times |Vsl| \times Vsl \times (ztsl - zbsl)\rho_L}{2Dt} - \rho_L \times g \times At \times (ztsl - zbsl)$$

in Field Units (A.62)

where

ρ_L is the liquid density;

Vsl is the liquid velocity;

fl is the friction factor for the liquid in the tubing found using the Moody diagram;

g is the acceleration due to gravity.

The pressure on top of the liquid column, $Ptsl$, can be calculated from the wellhead pressure, Pwh, using the following equation:

$$Ptsl = Pwh \times e^{\left[\frac{0.06151 \times (zp - ztsl) \times Gg}{(zT)_{\text{average}}}\right]} \quad \text{in SI Units}$$

$$Ptsl = Pwh \times e^{\left[\frac{0.01875 \times (zp - ztsl) \times Gg}{(zT)_{\text{average}}}\right]} \quad \text{in Field Units} \tag{A.63}$$

The slug length is continuously decreasing in time due to fallback losses FB, so the slug length at $t+\Delta t$ can be calculated from the slug length at time t using:

$$(ztsl - zbsl)_{t + \Delta t} = (ztsl - zbsl)_t - FB_{t + \Delta t} \quad \text{in SI Units}$$

$$(ztsl - zbsl)_{t + \Delta t} = (ztsl - zbsl)_t - FB_{t + \Delta t} \quad \text{in Field Units} \tag{A.64}$$

The model assumes that if, at any time, the flowing pressure, $Pzres$ in kPa (psi), is lower than the reservoir pressure, $Pres$ in kPa (psi), the liquid from the reservoir is accumulated in the bottom and it will be taken into account during the pressure build up stage. The liquid level increment, dzl/dt, is given by the Vogel's inflow equation:

$$\frac{dzl}{dt} = \frac{1}{At \times 86400} \times Q\max \times \left(1 - 0.2 \times \frac{Pzres}{Pres} - 0.8 \times \left(\frac{Pzres}{Pres}\right)^2\right) \quad \text{in SI Units}$$

$$\frac{dzl}{dt} = \frac{5.615}{At \times 86400} \times Q\max \times \left(1 - 0.2 \times \frac{Pzres}{Pres} - 0.8 \times \left(\frac{Pzres}{Pres}\right)^2\right) \quad \text{in Field Units} \tag{A.65}$$

where

At is the area of tubing in cm^2 (ft^2);

$Q\max$ is the maximum production that the well could produce if the bottom-hole pressure were zero in m^3/day (bbl/day).

The bottom hole pressure can be calculated from:

$$Pzres = Pbro + \rho_L (zres - zp)/144 \quad \text{in SI Units}$$

$$Pzres = Pbro + \rho_L (zres - zp)/144 \quad \text{in Field Units} \tag{A.66}$$

The liquid level increment in the tubing is given by:

$$zl_{t + \Delta t} = zl_t + \frac{dzl}{dt}_{t + \Delta t} \times \Delta t + (\text{fallback}) \quad \text{in SI Units}$$

$$zl_{t + \Delta t} = zl_t + \frac{dzl}{dt}_{t + \Delta t} \times \Delta t + (\text{fallback}) \quad \text{in Field Units} \tag{A.67}$$

Finally, a numerical solution is found for the first stage: Equations (A.54), (A.57), (A.61) and (A.62) represent a set of four ordinary differential equations with the following variables as the unknowns:

$$\frac{dPtc1}{dt}, \frac{dPbro}{dt}, \frac{dPbsl}{dt}, \frac{dVpl}{dt}$$

These equations can be solved for the unknowns at each time $t = n \times \Delta t$, n = 1,2,3...Once found for a given time t, the values of these variables are used, following Euler's procedure, to find the conditions at $t + \Delta t$. For example, to calculate the value of Vpl at $t + \Delta t$, the following equation is used once the value of $dVpl/dt$ is found at $t + \Delta t$:

$$Vpl_{t+\Delta t} = Vpl_t + \frac{dVpl}{dt} \times \Delta t \qquad \text{in SI Units}$$

$$Vpl_{t+\Delta t} = Vpl_t + \frac{dVpl}{dt} \times \Delta t \qquad \text{in Field Units} \tag{A.68}$$

This calculation procedure is continued until the liquid slug reaches the wellhead.

Second stage: Liquid production.

This stage begins when the tip or the slug reaches the surface and ends when the entire slug has been produced to the surface. All the equations developed for the previous stage are valid with the exception of the momentum balance for the liquid slug, Equation (A.62), and the fact that the wellhead pressure is not a constant for this stage. If the losses through the wellhead are taken into account in Equation (A.62), and substituting the pressure at the top of the liquid column, $Ptsl$, by the variable wellhead pressure, Pwh, and the top of the liquid column, $ztsl$, by zp, Equation (A.62) is changed to:

In the next equation, please eliminate g_c (there is no need for it in SI Units!)

$$\rho_L At(zp - zbsl)\frac{dVsl}{dt} =$$

$$-144At \times g_c \times (Pwh - Pbsl) - \frac{fl \times |Vsl| \times Vsl \times At \times (zp - zbsl)\rho_L}{2Dt} - \rho_L \times g \times At \times (zp - zbsl) - 0,6 \times Vsl \times |VSL| \times \rho_L \times At$$

in SI Units

$$\rho_L At(zp - zbsl)\frac{dVsl}{dt} =$$

$$-144At \times g_c \times (Pwh - Pbsl) - \frac{fl \times |Vsl| \times Vsl \times At \times (zp - zbsl)\rho_L}{2Dt} - \rho_L \times g \times At \times (zp - zbsl) - 0,6 \times Vsl \times |VSL| \times \rho_L \times At$$

in Field Units (A.69)

The wellhead pressure can be calculated if the velocity and acceleration of the liquid that has entered the flowline are known. Applying the continuity equation for the flowline and the production tubing, the following equation can be used to find the velocity in the flowline:

$$\rho_L \times Vsl \times At = \rho_L \times Vh \times Ah \qquad \text{in SI Units}$$

$$\rho_L \times Vsl \times At = \rho_L \times Vh \times Ah \qquad \text{in Field Units} \tag{A.70}$$

where

Ah is the area of the flowline;

Vh is the velocity of the liquid in the flowline in m/s (ft/s).

From Equation (A.70), the velocity in the flowline is found to be:

$$Vh = Vsl\frac{At}{Ah} \quad \text{in SI Units}$$

$$Vh = Vsl\frac{At}{Ah} \quad \text{in Field Units} \tag{A.71}$$

The acceleration of the liquid in the flowline, a_H, is found by differentiating the previous equation with respect to time:

$$a_H = \frac{At}{Ah}\frac{dVsl}{dt} \quad \text{in SI Units}$$

$$a_H = \frac{At}{Ah}\frac{dVsl}{dt} \quad \text{in Field Units} \tag{A.72}$$

The wellhead pressure is now the sum of the pressure at the separator plus the pressure drops due to friction and acceleration in the flowline which are negative values in kPa (psi):

$$Pwh = Psep + \Delta Pfh + \Delta Pah \quad \text{in SI Units}$$

$$Pwh = Psep + \Delta Pfh + \Delta Pah \quad \text{in Field Units} \tag{A.73}$$

But this equation can be expressed as:

$$Pwh = Psep + \frac{\rho_L}{2000}fh\frac{L_H \times V_H^2}{Dh} + \frac{\rho_L L_H ah}{1000} \quad \text{in SI Units}$$

$$Pwh = Psep + \frac{\rho_L}{288}fh\frac{L_H \times V_H^2}{g_c \times Dh} + \frac{\rho_L L_H}{144}\frac{a_H}{g_c} \quad \text{in Field Units} \tag{A.74}$$

where

L_H is the length of the liquid slug in the flowline;

Dh is the inside diameter of the flowline.

At each time step, a force balance equation is used to determine if the gas-lift valve has closed.

Third stage: Full slug in the flowline.

This stage begins when the entire slug has reached the surface and ends when all the liquid has reached the separator or when the liquid velocity of the slug becomes negligible.

The equations for this stage are the same as the ones derived for the previous one, but with the following changes:

— the hydrostatic pressure is not taken into account in the momentum equation for the liquid slug since it has been entirely produced to the surface;

— the mass balance equation for the gas bubbles must take into consideration the gas in the tubing as well as the gas behind the liquid slug in the flowline.

Fourth stage: Gas venting to the separator.

This stage takes place only if the gas-lift valve is still open when the entire liquid slug has reached the separator or it has completely stop in the flowline. During this stage, gas is being injected from the manifold to the well annulus and from the annulus into the tubing. The stage will end as soon as the gas-lift valve closes.

The model assumes that no liquid is produced to the surface during this stage, nevertheless, as for all the other stages, if the flowing bottom hole pressure gets smaller than the reservoir pressure, the accumulated liquid that could be produced is added at the beginning of the following liquid slug regeneration stage. The force balance equation is used continuously to determine if the gas-lift valve has closed.

The mass and momentum balance equations for the annular space are the same as the ones for the first two stages.

The mass balance equation for the gas in the tubing is as follows:

$$m1 - \rho_{gwh} \times V_{gwh} \times At = At \times zp \times \frac{d\rho_{g-\text{average}}}{dt} \qquad \text{in SI Units}$$

$$m1 - \rho_{gwh} \times V_{gwh} \times At = At \times zp \times \frac{d\rho_{g-\text{average}}}{dt} \qquad \text{in Field Units} \tag{A.75}$$

where

ρ_{gwh} is the gas density at the wellhead;

V_{gwh} is the gas velocity at the wellhead;

$\rho_{g\text{-average}}$ is the average gas density in the entire production tubing.

From the real gas equation, the derivative of the average density is found by:

$$\frac{d\rho_{g-\text{average}}}{dt} = \frac{1}{2}\frac{M}{R}\frac{d}{dt}\left[\frac{Pwh}{(zT)_{wh}} + \frac{Pbro}{(zT)_{bro}}\right] \qquad \text{in SI Units}$$

$$\frac{d\rho_{g-\text{average}}}{dt} = \frac{1}{2}\frac{M}{R}\frac{d}{dt}\left[\frac{Pwh}{(zT)_{wh}} + \frac{Pbro}{(zT)_{bro}}\right] \qquad \text{in Field Units} \tag{A.76}$$

wh stands for conditions at the wellhead and bro for conditions at valve depth.

Introducing Equation (A.76) into (A.75) and assuming the wellhead pressure to be constant for this stage, the following equation is found for the time rate of change of the pressure at valve depth:

$$\frac{dPbro}{dt} = 2\left[\frac{(zT)_{bro}}{At \times zp}\frac{R}{M}m1 - \frac{(zT)_{bro}Pwh}{(zT)_{wh}}\frac{Vgwh}{zp}\right] \text{ in SI Units}$$

$$\frac{dPbro}{dt} = 2\left[\frac{(zT)_{bro}}{At \times zp}\frac{R}{M}m1 - \frac{(zT)_{bro}Pwh}{(zT)_{wh}}\frac{Vgwh}{zp}\right] \text{ in Field Units} \tag{A.77}$$

The momentum equation for the gas in the tubing can be expressed as:

$$Pwh - Pbro = -fb\frac{\rho_{g-\text{average}} \times (V_{g-\text{average}})^2 \times zp}{7.46 \times g_c Dt} \qquad \text{in SI Units}$$

$$Pwh - Pbro = -fb\frac{\rho_{g-\text{average}} \times (V_{g-\text{average}})^2 \times zp}{288(7.46) \times g_c Dt} \qquad \text{in Field Units} \tag{A.78}$$

where

fb is the friction factor for the gas in the tubing;

$V_{g\text{-prom}}$ is the gas average velocity in the tubing in m/s (ft/s), which can be calculated as follows:

$$V_{g\text{-prom}} = 0.5\left[Vgwh + \frac{m1}{At}\frac{R}{M}\frac{(zT)_{bro}}{Pbro}\right] \text{ in SI Units}$$

$$V_{g\text{-prom}} = 0.5\left[Vgwh + \frac{m1}{At}\frac{R}{M}\frac{(zT)_{bro}}{Pbro}\right] \text{ in Field Units} \quad (A.79)$$

The average density of the gas in the tubing in kg/m^3 (lbm/ft^3) is given by:

$$\rho_{g\text{-average}} = \frac{1}{2}\frac{M}{R}\left[\frac{Pwh}{(zT)_{wh}} + \frac{Pbro}{(zT)_{bro}}\right] \text{ in SI Units}$$

$$\rho_{g\text{-average}} = \frac{1}{2}\frac{M}{R}\left[\frac{Pwh}{(zT)_{wh}} + \frac{Pbro}{(zT)_{bro}}\right] \text{ in Field Units} \quad (A.80)$$

Introducing Equations (A.80) and (A.79) in Equation (A.78) an expression to calculate the gas velocity in m/s (ft/s) at the wellhead is found as:

In the next equation, please replace $14.92g_c$ by 4000:

$$Vgwh = 2\left[\frac{14.92g_cDt}{fb \times zp}\left(\frac{R}{M}\right)\left(\frac{Pbro - Pwh}{\frac{Pbro}{(zT)_{bro}} + \frac{Pwh}{(zT)_{wh}}}\right)\right]^{\frac{1}{2}} - \frac{m1}{At}\frac{R}{M}\frac{(zT)_{bro}}{Prbo} \quad \text{in SI Units}$$

$$Vgwh = 2\left[\frac{576g_cDt}{fb \times zp}\left(\frac{R}{M}\right)\left(\frac{Pbro - Pwh}{\frac{Pbro}{(zT)_{bro}} + \frac{Pwh}{(zT)_{wh}}}\right)\right]^{\frac{1}{2}} - \frac{m1}{At}\frac{R}{M}\frac{(zT)_{bro}}{Prbo} \quad \text{in Field Units} \quad (A.81)$$

The final values from the previous stage of $Pbro$, $Ptc1$ and $Ptc2$ are used as initial conditions for this stage. Equations (A.77) and (A.54) are solved simultaneously to find $dPtc1/dt$ and $dPbro/dt$. Variables such as Ptc, $m1$, $m2$, $Vgwh$, $Pbro$, $Ptc1$, $Pzres$ and zL can be calculated using Euler's numerical procedure. For example, the value of $Pbro$ at $t + \Delta t$ is found from:

$$Pbro_{t+\Delta t} = Pbro_t + \left[\frac{dPbro}{dt}_{t+\Delta t} \times \Delta t\right] \quad \text{in SI Units}$$

$$Pbro_{t+\Delta t} = Pbro_t + \left[\frac{dPbro}{dt}_{t+\Delta t} \times \Delta t\right] \quad \text{in Field Units} \quad (A.82)$$

Fifth stage: Pressure build up or liquid column formation stage.

The gas-lift valve is closed during this stage and gas is continuously injected to the annulus. At the same time, fluids from the reservoir are being accumulated above the gas-lift valve.

The mass balance equation in the annulus is:

$$\frac{Ytc}{2}\left[\frac{d\rho_{TC1}}{dt}+\frac{d\rho_{TC2}}{dt}\right] = m2 \qquad \text{in SI Units}$$

$$\frac{Ytc}{2}\left[\frac{d\rho_{TC1}}{dt}+\frac{d\rho_{TC2}}{dt}\right] = m2 \qquad \text{in Field Units} \tag{A.83}$$

Following the same steps presented for the first stage, an expression is found for the time rate of change of the pressure in the annular space:

$$\frac{dp_{TC1}}{dt} = \frac{m2}{\frac{YTC}{2}\left(\frac{M}{R}\right)\left[\left(\frac{1}{zT}\right)_{TC1}+\left(\frac{1}{zT}\right)_{TC2}\times e^{\left[\frac{0.06151\times zp\times Gg}{(zT)\text{average}}\right]}\right]} \qquad \text{in SI Units}$$

$$\frac{dp_{TC1}}{dt} = \frac{m2}{\frac{YTC}{2}\left(\frac{M}{R}\right)\left[\left(\frac{1}{zT}\right)_{TC1}+\left(\frac{1}{zT}\right)_{TC2}\times e^{\left[\frac{0.01875\times zp\times Gg}{(zT)\text{average}}\right]}\right]} \qquad \text{in Field Units} \tag{A.84}$$

Equation (A.65) can be used to calculate the time rate of change of the liquid column length. Equations (A.84) and (A.65) are solved to find $dPtc1/dt$ and dzL/dt. These values are then used to find $Pbro$ and $Ptc1$. At each time increment, a force balance equation is used to determine if the gas-lift valve opens. This stage ends the moment the gas-lift valve opens.

A.6 Estimation of Daily Liquid Flow Rate of an Insert Chamber or Accumulator from a Downhole Pressure Survey

It is not possible to know the production capability of the lower zones of a well before the installation of the insert chamber. Even with the sophisticated surveys that are available today, it is not possible to know the real production capability of the lower zones at low pressure because to do that, the flowing pressure would have to be reduced first, and that is not feasible without changing the completion.

The following paragraphs provide an approximate way of predicting the production of a well in which an insert chamber is going to be installed. It is only an approximation for two reasons.

a) It is only based on the maximum production rate that a well on conventional intermittent gas-lift can attain at the beginning of the liquid slug accumulation period.

b) It says nothing about the possible gas coning that an insert installation might cause. With the installation of an insert type of completion in a well producing from a gas cap reservoir, an increase in formation GLR is expected. A careful look at this is recommended before proceeding with the installation of an insert chamber or accumulator.

A very simple procedure to estimate the liquid flow rate of insert type of completion is given here. To apply this procedure, the well has to be producing on conventional intermittent lift and a downhole survey must be run. Refer to Section 6 for guidance on running and analyzing a downhole surveys for intermittent gas-lift.

As mentioned above, an exact calculation of the increase of liquid production, when shifting from conventional intermittent lift to the use of insert chambers or accumulators, is not possible. This is because the lower producing zones will be exposed to a much lower flowing pressure, impossible to attain without changing the completion. This fact eliminates the possibility of using any kind of IPR curve analysis. But it is possible to have a good estimate of the increase in liquid production if a survey is run before the insert accumulator is installed.

From a pressure survey output, like the one shown in Figure A.3, it is possible to obtain the maximum flow rate for wells on conventional intermittent lift. This maximum flow rate is proportional to the angle shown in the figure.

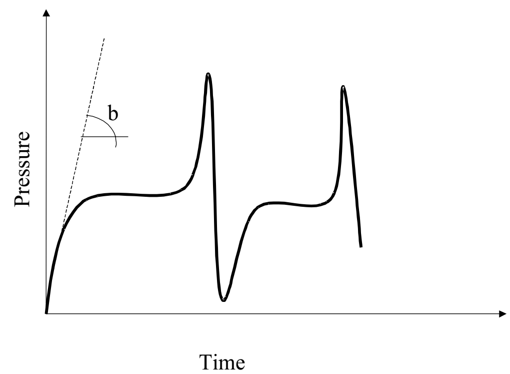


Figure A.3—Downhole Pressure Survey in a Conventional Intermittent Lift Installation

The pressure plotted is the downhole pressure minus the wellhead pressure, which will approximately give the pressure due only to the liquid column. The maximum derivative of the downhole pressure with respect to time, kPa/day (psi/day), is given by the tangent of the maximum angle. The maximum flow rate is then given by:

$$q\max\left(\frac{M^3}{D}\right) = \frac{\tan(b)\left(\frac{kPa}{D}\right) \times Bt\left(\frac{M^3}{M}\right)}{gl\left(\frac{kPa}{M}\right)} \qquad \text{in SI Units}$$

$$q\max\left(\frac{Br}{D}\right) = \frac{\tan(b)\left(\frac{psi}{D}\right) \times Bt\left(\frac{Br}{ft}\right)}{gl\left(\frac{psi}{ft}\right)} \qquad \text{in Field Units} \tag{A.85}$$

Here, Bt is the volumetric capacity of the accumulator or chamber in m^3/m (bbl/ft), and gl is the liquid gradient in kPa/m (psi/ft) as obtained from the water cut and API of the oil. The fallback must be subtracted from $q$max to give a more realistic maximum flow rate because the initial increase in pressure is due to both the liquid feed in and the liquid fallback. The value of the fallback is estimated from the same survey following the procedure given in Section 6. This corrected value of $q\max$ is a conservative approximation of the rate at which the accumulator will fill, since this rate is equal to the liquid rate when the formation is exposed to a minimum pressure in a conventional intermittent lift installation which is higher than the minimum pressure expected of an insert installation. In any case, the true liquid rate will be some how higher than $q$max.

The net liquid volume that will fill the accumulator or chamber is obtained by multiplying the total volume of the accumulator by the ratio of the true liquid gradient (obtained from the survey) divided by the liquid gradient obtained from the water cut and oil API gravity. Knowing $q\max$ and the net liquid volume in the accumulator, the liquid feed in time is easily calculated by

$$T_{\text{feedin}} = \frac{\text{netvolume}}{q\max} \quad \text{in SI Units}$$

$$T_{\text{feedin}} = \frac{\text{netvolume}}{q\max} \quad \text{in Field Units} \tag{A.86}$$

To obtain the total cycle time, the gas injection time must be added to the feed in time. The gas injection time depends on the spread and type of valve used and the injection annular volume of the well. 4.44-cm (1 3/4-in.) spring loaded pilot valves are recommended because they show less injection time to pass a certain volume of gas. A good rule of thumb to get the gas injection time in minutes, for wells having a casing of 14.6 cm (5 3/4 in.) and a spread not greater than 482.63 kPa (70 psi), is to multiply the depth of the point of injection in 304.8 m (1000 ft) by 1.2 if 4.44-cm (1 3/4-in.) spring loaded pilot valves are used and times 2.0 if 2.54-cm (1-in.) spring pilot valves are used.

With the total cycle time, the number of cycles per day can be found and the liquid production is obtained by multiplying the number of cycles per day times the net volume of liquid per cycle. A 6 % of this production must be subtracted per 304.8 m (1000 ft) of depth of the effective point of injection (not equal to the depth of the operating valve), to account for liquid fallback losses.

A.7 General Mandrel Spacing Procedure

The method presented here can be used with most types of gas-lift valves.

A.7.1 Analytical Design for Top Valve at the Static Fluid Level

The static fluid level, SFL in m (ft), is calculated from:

$$SFL = TD - (Psbh)/\rho_f \quad \text{in SI Units}$$

$$SFL = TD - (Psbh)/\rho_f \quad \text{in Field Units} \tag{A.87}$$

where

TD is the total depth in m (ft);

$Psbh$ is the bottom hole static pressure in kPa (psi);

ρ_f is the liquid gradient calculated from the oil API gravity and its water cut in kPa/m (psi/ft).

The first valve is placed at the static fluid level. To calculate the second valve depth, the weight of the gas column in the injection annulus is disregarded and the following equation is used to find the valve spacing S_v in m (ft):

$$S_v = \frac{(P_{io} - n \times S) - P_{WH} - D_{va} \times F}{\rho_f} \quad \text{in SI Units}$$

$$S_v = \frac{(P_{io} - n \times S) - P_{WH} - D_{va} \times F}{\rho_f} \quad \text{in Field Units} \tag{A.88}$$

where

Pio is the surface gas pressure;

n	is the number of valves above the current valve;
S	is the injection pressure drop per valve;
Pwh	is the wellhead pressure;
Dva	is the depth from surface to the valve above;
F	is the unloading gradient, which is the average pressure gradient in kPa/m (psi/ft) that exists from the surface to the valve above and is usually taken as 0.9 kPa/m (0.04 psi/ft).

Higher unloading gradients can be used for tubing smaller than 3.81 cm (1 $^3/_4$ in.) or depths in excess of 1828.8 m (6000 ft) and producing rates in excess of 23.85 m^3/day (150 bbl/day).

A.7.2 Graphical Design with the Well Full of Fluid

This graphical procedure takes into account the weight of the gas column in the casing and the valves are set at the same surface operating pressure, which is 689.48 kPa (100 psi) less than the available kick off pressure. Refer to Figure A.4 for the graphical design procedure:

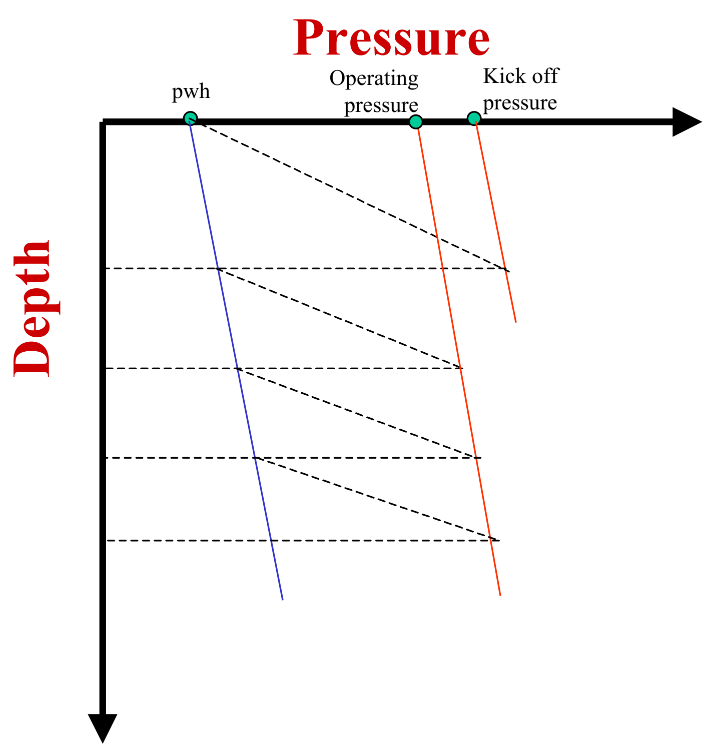


Figure A.4—Graphical Valve Spacing with Well Full of Fluid

— plot the depth of the well as the ordinate axis and the pressure as abscissa axis;

— plot the tubing pressure, the kick-off pressure and the operating pressure at zero depth;

— extend the kick-off pressure to depth by accounting for the gas column weight;

— extend the operating pressure to depth by accounting for the gas column weight;

— extend the wellhead tubing pressure to depth using the appropriate unloading gradient;

— extend the kill fluid gradient line from the wellhead surface pressure to the intersection with the kick-off pressure line, which is the location of the first valve;

— bring a horizontal line from the point located in the last step back to the unloading gradient line as extended from the tubing;

— from the point found in the previous step, draw a kill fluid gradient line until it intercepts the operating casing pressure line, which locates the depth of the second valve;

— repeat this procedure to total spacing depth.

Annex B

Intermittent Gas-lift Design—A Detailed Example

The following examples in Annex B are merely examples for illustration purposes only (each company should develop its own approach). They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

Where applicable, authorities having jurisdiction should be consulted.

B.1 API 11V10 Overall Example of a Design

This annex shows an example of a complete intermittent gas-lift design.

B.1.1 Well Data

— Dc (casing diameter 7 in. × 23 lbm/ft) = 6.366 in. = 16.1 cm;

— Dt (tubing diameter 2 $^7/_8$ in.) = 2.441 in. = 6.2 cm;

— Dpt (top of perforations depth) = 6000 ft = 1828.8 m;

— P_{SBH} (reservoir pressure) = 1250 psi = 8618.45 kPa;

— P_{WH} (wellhead pressure) = 60 psi = 413.68 kPa;

— W (water cut) = 10 %;

— API: 25 °;

— Gf (fluid gradient) = 0.396 psi/ft = 8.95 kPa/m (0.396 × (6.89475/0.3048) = 8.95);

— Gk (kill fluid gradient) = 0.45 psi/ft = 10.18 kPa/m;

— Available surface pressure: 1000 psi = 6894.76 kPa (missing);

— Gg (specific gravity of injection gas) = 0.7;

— Surface pressure drop per valve: 30 psi = 206.84 kPa (missing);

— FF (fallback factor) = 0.05;

— PI = 0.5 bbl /(psi × day) = 0.01152 m^3/(kPa × day);

— L (length of gas injection pipe from the manifold or choke to the wellhead) = 3000 ft = 914.4 m;

— Dl (inside diameter of gas injection pipe) = 2.067 in. = 5.25 cm.

B.1.2 Mandrel Spacing

B.1.2.1 Fist Valve

For the first valve the pressure balance equation is given by:

$P_{WH} + D_1 \times Gk = Pio_1 \times Gg$ in SI Units

$P_{WH} + D_1 \times Gk = Pio_1 \times Gg$ in Field Units (B.1)

where

P_{WH} is the wellhead pressure;

D_1 is the depth of the first valve;

Gk is the kill fluid gradient;

Pio_1 is the surface opening pressure of the first valve;

fg is the depth pressure factor which, as a first approximation, it can be taken equal to 1.

Using the well data given above:

$413.68 + D_1 \times 10.18 = 6894.76$ in SI Units

$60 + D_1 \times 0.45 = 1000 \times 1.057$ in Field Units

For which D_1 is equal to 636.69 m (2088.89 ft). At that depth and with a surface injection pressure of 6894.76 kPa (1000 psi) the value of fg, calculated using any available method, is equal to 1.057. A second approximation is then given by:

$413.68 + D_1 \times 10.18 = 7287.76$ in SI Units

$60 + D_1 \times 0.45 = 1000 \times 1.057$ in Field Units

For which D_1 is equal to 675.3 m (2215.55 ft), giving a new value of fg equal to 1.063. The new iteration is the:

$413.68 + D_1 \times 10.18 = 7329.13$ in SI Units

$60 + D_1 \times 0.45 = 1000 \times 1.063$ in Field Units

For which D_1 is equal to 679.1 m (2228 ft), giving a new value of fg equal to 1.064. The new iteration is giving by:

$413.68 + D_1 \times 10.18 = 7336.03$ in SI Units

$60 + D_1 \times 0.45 = 1000 \times 1.064$ in Field Units

For which D_1 is equal to 680 m (2231 ft), for which fg is again equal to 1.064 and the iteration is terminated. The depth of the first valve is then equal to 680 m (2231 ft).

B.1.2.2 Second Valve

For the second valve, the fallback left by the first valve should be taken into account. The fallback losses are calculated using the following equation:

$\text{Losses} = Dov \times FF \times Q$ in SI Units

$\text{Losses} = Dov \times FF \times Q$ in Field Units (B.2)

where

Dov is the depth of the first valve in 304.8 m (1000 ft);

FF is the fallback factor (usually taken equal to 16.4 % of the initial liquid slug per 1 Km of depth of point of injection or 5 % per 1000 ft in Field Units);

Q is the length of the liquid slug lifted from the first valve, which in this case it is equal to D_1.

The fallback losses are then calculated as:

$\text{Losses} = 0.680\ \text{Km} \times 16.4\ (\%/100)\ /\ \text{Km} \times 680\ \text{m} = 75.85\ \text{m}$ in SI Units

$\text{Losses} = 2.231\ \text{Mft} \times 0.05 \times 2231 = 248.86\ \text{ft}$ in Field Units

The pressure balance is then given by:

$P_{WH} + \text{losses} \times Gk + D_2 \times Gk = (6894.76 - 206.84) \times fg$ in SI Units

$P_{WH} + \text{losses} \times Gk + D_2 \times Gk = (1000 - 30) \times fg$ in Field Units

D_2 is the distance between the first and the second valve and 206.84 kPa (30 psi) are dropped from the available pressure of 6894.76 kPa (1000 psi). For the first iteration, fg is equal to 1 and D_2 is calculated from:

$413.68 + 75.85 \times 10.18 + D_2 \times 10.18 = 6687.92 \times 1$ in SI Units

$60 + 248.86 \times 0.45 + D_2 \times 0.45 = 970 \times 1$ in Field Units

From which D_2 is equal to 540.5 m (1773.36 ft). The second valve depth is then equal to $D_1 + D_2$= 1220.5 m (4004.36 ft). At that depth and with a surface injection pressure of 6687.9 kPa (970 psi), the value of fg is equal to 1.1127. The second iteration is given by:

$413.68 + 75.85 \times 10.18 + D_2 \times 10.18 = 6687.92 \times 1.1127$ in SI Units

$60 + 248.86 \times 0.45 + D_2 \times 0.45 = 970 \times 1.1127$ in Field Units

For which the new value of D_2 is 614.59 m (2016.36 ft). The new depth of the second valve is 1294.6 m (4247.36 ft). This new depth and with a surface injection pressure of 6687.9 kPa (970 psi), the value of fg is 1.1195. The third iteration is given by:

$413.68 + 75.85 \times 10.18 + D_2 \times 10.18 = 6687.92 \times 1.1195$ in SI Units

$60 + 248.86 \times 0.45 + D_2 \times 0.45 = 970 \times 1.1195$ in Field Units

D_2 is now equal to 618.97 m (2030.74 ft) for which the new valve depth is now 1298.98 m (4261.73 ft) and fg is 1.1198 which is very close to the last calculated value and the iteration can be terminated. The depth of the second valve is then 1298.98 m (4261.73 ft).

B.1.2.3 Third Valve

The fallback losses from the second valve need to be considered for the third valve. These losses are calculated as:

$$\text{Losses} = 4.26 \times 0.05 \times (1298.98 - 680 + 75.85) = 148 \quad \text{in SI Units}$$

$$\text{Losses} = 4.26 \times 0.05 \times (4261.73 - 2231 + 248.86) = 486 \quad \text{in Field Units}$$

Since the initial liquid slug is $1298.97\text{ m} - 680\text{ m} + 75.86\text{ m}$ $(4261.72\text{ ft} - 2231\text{ ft} + 248.80\text{ ft})$.

The pressure balance for the first iteration (fg = 1) is then given by:

$$413.68 + 148 \times 10.18 + D_3 \times 10.18 = 6481.07 \times 1 \quad \text{in SI Units}$$

$$60 + 486 \times 0.45 + D_3 \times 0.45 = 940 \times 1 \quad \text{in Field Units}$$

D_3 is 447.92 m (1469.55 ft) and the depth of the third valve is 1746.89 m (5731.28 ft). At that depth and for a surface injection pressure of 6481.07 kPa (940 psi), fg is 1.1592. The second iteration with this new value of fg is:

$$413.68 + 148 \times 10.18 + D_3 \times 10.18 = 6481.07 \times 1.1592 \quad \text{in SI Units}$$

$$60 + 486 \times 0.45 + D_3 \times 0.45 = 940 \times 1.1592 \quad \text{in Field Units}$$

This gives a new value of D^3 of 549.3 m (1802.15 ft). The new depth of the third valve is 1848.27 m (6063.88 ft) for which fg is 1.168 and the third iteration is given by:

$$413.68 + 148 \times 10.18 + D_3 \times 10.18 = 6481.07 \times 1.168 \quad \text{in SI Units}$$

$$60 + 486 \times 0.45 + D_3 \times 0.45 = 940 \times 1.168 \quad \text{in Field Units}$$

D_3 is now 554.74 m (1820 ft) and the depth of the valve is 1853.79 m (6082 ft). The new value of fg is 1.165 which is very close to the last calculated value and the iteration is terminated. Since the depth of the top of the perforation is 1828.8 m (6000 ft), the depth of the third valve is taken 18.29 m (60 ft) above the perforation (Dov = 1810.5 m or 5940 ft). At this depth and with a surface injection pressure of 6481.07 kPa (940 psi), the injection pressure at depth is 7549.48 kPa (1094.96 psi). For the calculations of the following section, the value of Dov is given in Km (Mft), 1.81 Km (5.94 Mft).

B.1.3 Valve Design

The operating valve selected is a spring-loaded pilot valve. The area ratio and the test rack closing pressure need to be calculated. The area ratio is given by the following equation:

$$Ap/Ab = \frac{Piod - Picd}{Piod - Pto} \tag{B.3}$$

where

Ap	is the port area;
Ab	is the bellows area;
$Piod$	is the gas injection opening pressure at depth;
$Picd$	is the gas injection closing pressure at depth;
Pto	is the production opening pressure.

$Piod$ has already been calculated in the previous section and it is equal to 7549.48 kPa (1094.96 psi). The first step to calculate the area ratio is to calculate the tubing pressure at the time the valve opens. This corresponds to the pressure exerted by the liquid column above the valve plus the wellhead pressure. Once the tubing pressure is calculated, the volume of gas needed to produce the liquid slug to the surface is calculated and this in turn will determine the injection closing pressure.

B.1.3.1 Tubing Pressure *Pto*

The tubing opening pressure is the one that corresponds to the optimum cycle time. The following calculations are based on the information given in the Annex A.2. The gas injection time (=FACTOR) for a slug velocity of 304.8 m/min (1000 ft/min) is equal to 6 min.

Volumetric capacity (Bt)

[2.441 in. is not equal to 6.02 cm, and also 0.5017 × $(6.02)^2$ is not equal to 3.03]
$Bt = 0.07849 \times Dt^2 = 0.07849 \times (6.2)^2 = 3.02$ in SI Units

$Bt = 0.97143 \times Dt^2 = 0.97143 \times (2.441)^2 = 5.7882$ in Field Units

Oil specific gravity (SGO)

$SGO = 141.5/(131.5 + 25) = 0.9041$

Liquid gradient ($DENSF$)

$DENSF = 0.433 \times (0.1 + (1 - 0.1) \times 0.9041) = 0.3956$ psi/ft $= 8.9487$ kPa/m

$ALFA \times DENSF$
$ALFA \times DENSF = DENSF \times PI/(1.44 \times Bt) = 0.3956 \times 0.5/(1.44 \times 5.7882) = 0.0237\ \mathrm{min}(^{-1})$

CM

$CM = FF \times Dov = 0.05 \times 5.9400 = 0.297$

$C4$

$C4 = \exp(ALFA \times DENSF \times FACTOR) = \exp(0.0237 \times 6) = 1.1528$
($C4$ is dimensionless)

KA

$KA = CM \times C4^2 = 0.3947$

KB

$KB = ALFA \times DENSF \times C4 \times (1 - CM) = 0.0237 \times 1.1528 \times (1 - 0.297) = 0.0192 \text{ min } (^{-1})$

KC

$KC = C4 \times (1 + CM) = 1.1528 \times (1 + 0.297) = 1.49518$

B.1.4 First Approximation of the Optimum Cycle Time: $T = 3 \times \text{FACTOR} = 18$ min

Exp ($ALFA \times T$)	7.2.4	7.2.5
1.5320	15.34	22.64
1.7116	23.22	21.94
1.6833	21.95	21.95

Optimum cycle time = 21.94 min

For the optimum cycle time, the liquid slug generation time is equal to the cycle time minus the gas injection time. t = 21.94 – 6 = 15.94 min. The liquid slug length can then be calculated by:

$$Q = \frac{A(\exp(ALFA \times DENSF \times t) - 1)}{DENSF(\exp(ALFA \times DENSF \times t) - CM)} \quad \text{(B.4)}$$

$$A = P_{SBH} - (Dpt - Dov) \times DENSF - P_{WH} \times fg$$

$$= 8618.45 - (1828.8 - 1810.5) \times 8.95 - 413.68 \times 1.133 = 7984 \text{ KPA} \quad \text{in SI Units}$$

$$= 1250 - (6000 - 5940) \times 0.3956 - 60 \times 1.133 = 1158 \text{ psi} \quad \text{in Field Units}$$

fg is calculated based on a wellhead pressure of 413.68 kPa (60 psi) and the depth of the operating valve.

Then the value of Q is:

$$Q = \frac{7984.13(\exp(0.0237 \times 15.94) - 1)}{8.949(\exp(0.0237 \times 15.94) - 0.297)} = 352.45 \text{ m} \quad \text{in SI units}$$

$$Q = \frac{1158(\exp(0.0237 \times 15.94) - 1)}{0.3956(\exp(0.0237 \times 15.94) - 0.297)} = 1156.32 \text{ ft} \quad \text{in Field Units}$$

The value of Pto is calculated by:

$$Pto = Pwh \times fg + Q \times DENSF$$

$$= 413.68 \times 1.133 + 352.45 \times 8.949 = 3622.77 \text{ kPa} \quad \text{in SI Units}$$

$$= 60 \times 1.133 + 1156.32 \times 0.3956 = 525.42 \text{ psi} \quad \text{in Field Units}$$

The fluid production is then:

$$\text{Production} = (\text{number of cycles/day}) \times (Q/1000) \times Bt \times (1 - ff \times Dov \times 3.28) \quad \text{in SI Units (m}^3\text{/day)}$$

$$\text{Production} = (\text{number of cycles/day}) \times (Q/1000) \times Bt \times 1 - ff \times Dov \quad \text{in Field Units (bbl/day)} \quad \text{(B.5)}$$

where

Bt is the volumetric capacity of the tubing in m^3/304.8 m (bbl/1000ft);

ff is the fallback factor and Dov is the valve depth.

The daily production is then:

$$\text{Production} = (1440/21.94) \times (352.45/1000) \times 3.019 \times (1 - 0.05 \times 1.\dot{8}1 \times 3.28) = 49 \text{ m}^3 \quad \text{in SI Units}$$

$$\text{Production} = (1440/21.94) \times (1156.32/1000) \times 5.7882 \times (1 - 0.05 \times 5.94) = 308.8(49) \text{ bbl} \quad \text{in Field Units}$$

B.1.4.1 Volume of Gas Per Cycle

The volume of gas per cycle, Vgs, in m^3 (ft^3) is given by:

$$Vgs = \frac{288.55}{101.35}\frac{Pga}{Ta \times Za}Bg(Dov - Q) \quad \text{in SI Units}$$

$$Vgs = \frac{520}{14.7}\frac{Pga}{Ta \times Za}Bg(Dov - Q) \quad \text{in Field Units} \quad (B.6)$$

P_{ga}, Ta and Za are the average pressure, temperature and average compressibility of the gas underneath the liquid slug when its tip reaches the wellhead. Bg is the volumetric capacity of the tubing in m^3/m (ft^3/ft) and can be calculated as:

$$Bg = (5.45415/1000) \times Dt^2 = 0.03249 \text{ ft}^3/\text{ft} = 0.003 \text{ m}^3/\text{m}$$

Average pressure P_{ga}

The average pressure P_{ga} in kPa (psi) is given by:

$$Pga = \frac{Pgu + Ptm}{2} + 101.35 \text{ kPa} \quad \text{in SI Units}$$

$$Pga = \frac{Pgu + Ptm}{2} + 14.7 \text{ psia} \quad \text{in Field Units} \quad (B.7)$$

Pgu is the pressure just underneath the liquid slug in kPa (psi) and Ptm is the pressure at valve depth.

Pgu is calculated from:

$$Pgu = Pwh + Q(1 - CM) \times DENSF \times CF \text{ kPa} \quad \text{in SI Units}$$

$$Pgu = Pwh + Q(1 - CM) \times DENSF \times CF \text{ psig} \quad \text{in Field Units} \quad (B.8)$$

Where CF is the friction factor that takes into account the friction and hydrostatic pressure drop and is given by:

$$CF = 207.23 \times f \times Vat^2/(Dt) + 1 \quad (B.9)$$

where

Vat is the liquid slug velocity and it is assumed to be equal to 304.8 m/min (1 1000ft/min);

f is the friction factor from the Moody diagram.

To find the friction factor from the Moody diagram, it is necessary to find the Reynolds number, which is given by:

$$Re = 12.4340 \times Dt \times Densf \times \frac{Vat}{\mu_0} \tag{B.10}$$

μ_o is the fluid viscosity that, for the reservoir temperature, it can be approximated as 53.85×10^{-6} cp. The Reynolds's number is then equal to 2.2718×10^5 for which the friction factor from the Moody diagram is equal to 0.0159.

CF is then found to be

$$CF = 207.23 \times 0.0159 \times Vat^2 / Dt + 1 = 2.3498$$

And Pgu is then:

$$Pgu = P_{WH} + Q(1-(Dov/1000) \times ff)DENSF \times CF$$

$$= 413.68 + 352.45(1-5.94 \times 0.05) \times 8.9487 \times 2.3498 = 5623.75 \text{ kPa} \qquad \text{in SI Units}$$

$$= 60 + 1156.32(1-5.94 \times 0.05) \times 0.3956 \times 2.3498 = 815.65 \text{ psi} \qquad \text{in Field Units}$$

With 5623.75 kPa (815.65 psi), at valve depth the depth pressure factor is equal to 1.158 and $Ptm = 1.158 \times 815.65 = 944.52$ psi = 6512.25 kPa and $P_{ga} = (815.65 + 944.53)/2 + 14.7 = 894.7$ psi = 6169.39 kPa.

Average Temperature Ta:

An energy balance can be used to approximate the average temperature of the gas inside the tubing. A good approximation is the following energy conservation equation:

$H = HC$ – (Potential energy gain by the liquid slug)

where

H is the final enthalpy of the gas that has entered the tubing;

HC is the enthalpy of the gas in the casing just before the operating valve opens.

H and HC are functions of the pressure and temperature of the gas and for methane their values can be approximated in kJ/kg (Btu/lbm) by the following correlation:

$$T = Ao + Bo \times H + (C2 \times H^2 + A2 - B2 \times H) \times P + 273.15 \qquad \text{in SI Units}$$

$$T = Ao + Bo \times H + (C2 \times H^2 + A2 - B2 \times H) \times P + 460 \qquad \text{in Field Units}$$

where

P is the absolute pressure in kPa (psi);

T is the absolute temperature in °K (°R) and the following correlation factors are given by:

$Ao = 152.46 \times Gg - 207.85$

$Bo = 0.78946 \times Gg + 1.3223$

$A2 = 0.11038 \times Gg + 0.013944$

$B2 = (2.5757 \times Gg^2 - 2.9663 \times Gg + 1.3437) \times 10^{-3}$

$C2 = (6.866 \times Gg - 7.561 \times Gg + 2.934) \times 10^{-6}$

Using this correlation, the value of HC can be calculated based on the pressure and temperature of the gas in the casing just before the operating valve opens.

The potential energy gained by the liquid slug, Hw, in kPa m (psi ft) is found by:

$$Hw = \frac{5637.52 \times DENSF \times Q \times ((1 - ff \times Dov)(Dov - (1 - ff \times Dov)) \times Q) \times Bg}{Gg \times Vgs} \quad \text{KJ/Kg}$$

$$Hw = \frac{2423.7 \times DENSF \times Q \times ((1 - ff \times Dov)(Dov - (1 - ff \times Dov)) \times Q) \times Bg}{Gg \times Vgs} \quad \text{Btu/ Lbm} \qquad \text{(B.11)}$$

Where Vgs is the volume of gas that enter the tubing in m^3 (ft^3) and, as indicated above, is calculated by the following equation:

$$Vgs = \frac{288.55}{101.35} \frac{P_{ga}}{Ta \times Za} Bg(Dov - Q)\text{m}^3 \quad \text{in SI Units}$$

$$Vgs = \frac{520}{14.7} \frac{P_{ga}}{Ta \times Za} Bg(Dov - Q)\text{scft} \quad \text{in Field Units}$$

In which the only variable that needs to be determined is Ta and it can be done by the following iteration.

A first value of Ta is assumed.

With this assumed value of Ta, the compressibility factor of the gas, Za, is calculated.

With the value of P_{ga}, Ta and Za, the first value of Vgs is calculated.

With Vgs, Hw is calculated.

Using the energy balance equation, the first value of H is found.

Using the enthalpy correlation and the value of H just found, a new value of Ta is calculated.

If the calculated value of Ta is closed to the assumed value then the iteration is terminated. On the contrary, all these steps are repeated with the assumed value now equal to the calculated value.

Using the above, the following values are found:

H = 107.15 Btu/lbm = 249.24 kJ/kg

HC = 126.91 Btu/lbm = 295.21 kJ/kg

Hw = 19.759 Btu/lbm = 45.96 kJ/kg

Vgs = 9389.26 SCF/Cycle = 265.82 m^3/cycle

Ta = 576.54 °R = 320.3 °K

Za = 0.871

The daily gas injection, Qgi is then:

$$Qgi = \frac{1440\text{min/day}}{21.94\text{min/cycle}} 9389.26\text{Scft/cycle} = 616.41\ \text{MScft/day} = 17.44\ \text{Mm}^3/\text{d}$$

Closing pressure at depth $Picd$:

The following procedure can be used to find the operating valve closing pressure based on a gas injection mass balance once the valve opening pressure and the gas required per cycle are known.

The valve closing pressure at depth, $Picd$, can be found by a mass balance of the gas injected into the tubing and the gas provided by the system:

$vgs = vga + vgl + vge$ in SI Units

$vgs = vga + vgl + vge$ in Field Units (B.12)

The volume of gas injected into the tubing, vgs, in m^3 (ft^3) is equal to the volume provided by the annulus, vga, plus the volume provided by the injection line from the choke to the wellhead, vgl, plus the volume of gas that passes through the surfaces choke while the gas-lift valve is open, vge.

vga at standard conditions is equal to the volume of gas at standard conditions in the casing annulus just before the valve opens, minus the volume of gas at standard condition in the casing annulus just after the valve closes.

The number of moles of natural gas in the annulus just before the valve opens is given by:

$$n = \frac{P_{ga,\,\text{open}} \times V_{\text{annulus}}}{Zga,\,\text{open} \times R \times Ta,\,\text{geoth}} = \frac{101.35 \times vsa}{1 \times R \times 288.55} \quad \text{in SI Units}$$

$$n = \frac{P_{ga,\,\text{open}} \times V_{\text{annulus}}}{Zga,\,\text{open} \times R \times Ta,\,\text{geoth}} = \frac{(14.7) \times vsa}{(1) \times R \times (520)} \quad \text{in Field Units} \tag{B.13}$$

where

vsa is the volume that the gas in the casing annulus just when the valve opens would occupy at standard conditions;

V_{annulus} is the actual volume of the casing annulus;

$T_{a,\text{geoth}}$ is the average geothermal temperature;

Zga and $P_{ga,\text{open}}$ are the average compressibility factor and the average pressure of the gas in the annulus when the valve opens.

$P_{ga,\text{open}}$ in kPa (psi) is given by

$$P_{ga,\,\text{open}} = \frac{Pio + Piod}{2} \quad \text{in SI Units}$$

$$P_{ga,\,\text{open}} = \frac{Pio + Piod}{2} \quad \text{in Field Units} \tag{B.14}$$

where

Pio is the surface opening pressure;

$Piod$ is the valve opening pressure at depth.

Using the same equations, the number of moles in the casing annulus just after the valve closes is:

$$n = \frac{P_{ga,\,close} \times V_{annulus}}{Zga,\,close \times R \times Ta,\,geoth} = \frac{101.35 \times vsc}{1 \times R \times 288.55} \quad \text{in SI Units}$$

$$n = \frac{P_{ga,\,close} \times V_{annulus}}{Zga,\,close \times R \times Ta,\,geoth} = \frac{(14.7) \times vsc}{(1) \times R \times (520)} \quad \text{in Field Units} \qquad (B.15)$$

where

vsc is the volume that the gas in the casing annulus just when the valve closes would occupy at standard conditions;

$P_{ga,close}$ is the average pressure in the annulus in kPa (psi) when the valve closes and can be found by:

$$P_{ga,\,close} = \frac{Pic + Picd}{2} \quad \text{in SI Units}$$

$$P_{ga,\,close} = \frac{Pic + Picd}{2} \quad \text{in Field Units} \qquad (B.16)$$

where

Pic is the closing pressure at the surface;

$Picd$ is the closing pressure at depth.

The volume of gas supplied by the casing annulus in m^3 (ft^3) is then given by:

$$vga = vsa - vsc \quad \text{in SI Units}$$

$$vga = vsa - vsc \quad \text{in Field Units} \qquad (B.17)$$

The average geothermal temperature is given by:

$$T_{a,\,geoth} = \frac{T_S + T_{dov}}{2} + 273.15 \quad \text{in SI Units}$$

$$T_{a,\,geoth} = \frac{T_S + T_{dov}}{2} + 460 \quad \text{in Field Units} \qquad (B.18)$$

Ts is the surface temperature in °C (°F), T_{dov} is the geothermal temperature at valve depth in °C (°F).

If Ba is the volumetric capacity of the annulus in m^3/304.8 m (ft^3/1000 ft), Dov is the depth of the operating valve in 304.8 m (1000 ft), then $V_{annulus}$ is:

$$V_{annulus} = Dov \times Ba \quad \text{in SI Units}$$

$$V_{annulus} = Dov \times Ba \quad \text{in Field Units} \qquad (B.19)$$

Combining the equations above and assuming a surface temperature of 29.44 °C (85 °F) for this particular example, expressions for vsa and vsc in m^3 (ft^3) are found:

$$vsa = 2.84706\frac{Ba \times Dov \times (Pio + Piod)}{(575.74 + Tdov) \times Zga, \text{open}}$$ in SI Units

$$vsa = 35.37\frac{Ba \times Dov \times (Pio + Piod)}{(1005 + Tdov) \times Zga, \text{open}}$$ in Field Units (B.20)

$$vsc = 2.84706\frac{Ba \times Dov \times (Pic + Picd)}{(575.74 + Tdov) \times Zga, \text{close}}$$ in SI Units

$$vsa = 35.37\frac{Ba \times Dov \times (Pic + Picd)}{(1005 + Tdov) \times Zga, \text{close}}$$ in Field Units (B.21)

As an approximation, Zga, close is equal to Zga, open.

Then an expression is found for vga where the only unknowns are the closing pressures at depth and at the surface:

$$vga = 2.8476 \times K1_{\text{in SI units}} \times (Pio + Piod - Pic - Picd)$$ in SI Units

$$vga = 35.37 \times K1_{\text{in field units}} \times (Pio + Piod - Pic - Picd)$$ in Field Units (B.22)

$K1$ is given by m^3/kPa (ft^3/psi) because 35.37 comes from dividing 520 °R/14.7 psi)

$$K1 = \frac{Ba \times Dov}{(575.74 + Tdov) \times Zga, \text{open}}$$ in SI Units

$$K1 = \frac{Ba \times Dov}{(1005 + Tdov) \times Zga, \text{open}}$$ in Field Units (B.23)

(this $K1$ value has to be checked same as the Annex A)

Following the steps described above, expressions can be found for the volume of gas in the injection line when the valve opens and when it closes:

$$vsa = \frac{2.84706 \times Bl \times L \times Pio}{(302.6) \times Zgl}$$ in SI Units

$$vsa = 35.37\frac{Bl \times L \times Pio}{(545) \times Zgl}$$ in Field Units (B.24)

$$vsc = \frac{2.84706 \times Bl \times L \times Pic}{(302.6) \times Zgl}$$ in SI Units

$$vsc = 35.37\frac{Bl \times L \times Pic}{(545) \times Zgl}$$ in Field Units (B.25)

where

Bl is the volumetric capacity of the injection line in ft^3/1000 ft;

L is its length in 1000 ft.

vgl is then found by

$$vgl = vsa - vsc \quad \text{in SI Units}$$

$$vgl = vsa - vsc \quad \text{in Field Units} \tag{B.26}$$

Combining the equations above:

$$vgl = 35.37 \times k2 \times (Pio - Pic) \quad \text{in SI Units}$$

$$vgl = 35.37 \times k2 \times (Pio - Pic) \quad \text{in Field Units} \tag{B.27}$$

$k2$ in m^3/kPa (ft^3/psi) is given by

$$k2 = 0.006\frac{Bl \times L}{Zgl} \quad \text{in SI Units}$$

$$k2 = \frac{Bl \times L}{545 \times Zgl} \quad \text{in Field Units} \tag{B.28}$$

The gas flow rate that goes through the surface choke in m^3/min (scft/min), VPM, is equal to the daily injection rate in 304.8 m/day (1000 scft/day), Qgi, divided by 1.44.

$$VPM = Qgi[1000\text{m}^3/\text{day}]\frac{1}{1\left[\frac{\text{min}}{\text{day}}\right]}1000\left[\frac{\text{m}^3}{1000\text{m}^3}\right] = Qgi/(1.44) \quad \text{in SI Units}$$

$$VPM = Qgi[1000\text{ft}^3/\text{day}]\frac{1}{1\left[\frac{\text{min}}{\text{day}}\right]}1000\left[\frac{\text{ft}^3}{1000\text{ft}^3}\right] = Qgi/(1.44) \quad \text{in Field Units} \tag{B.29}$$

Qgi in 1000 m^3/day (1000 scft/day) can be easily computed once the volume injected per cycle, vgs, and the cycle time T are found, and is equal to $vgs \times (1440/T)/1000$.

The time in minutes that the gas-lift valve remains open can be approximated as:

$$Tinj. = \frac{Dov}{vat} \quad \text{in SI Units}$$

$$Tinj. = \frac{Dov}{vat} \quad \text{in Field Units} \tag{B.30}$$

vat is the velocity of the slug in m/min (ft/min). Then vge in m^3 (ft^3)is given by:

$$vge = \frac{Qgi \times Dov}{1.44 \times vat} = 2.84706\frac{Qgi \times Dov}{4.09976 \times vat} \quad \text{in SI Units}$$

$$vge = \frac{Qgi \times Dov}{1.44 \times vat} = 35.37\frac{Qgi \times Dov}{50.94 \times vat} \quad \text{in Field Units} \tag{B.31}$$

With $k4$ in m^3 (ft^3) as:

$$k4 = \frac{Qgi \times Dov}{4.09976 \times vat}$$ in SI Units

$$k4 = \frac{Qgi \times Dov}{50.94 \times vat}$$ in Field Units (B.32)

vge in m^3 (ft^3) can be expressed as:

$$vge = 2.84706 \times k4$$ in SI Units

$$vge = 35.37 \times k4$$ in Field Units (B.33)

Introducing the expressions found for vge, vga and vgl in the general mass balance equation, the valve closing pressure in kPa (psi) is found as:

$$Picd = \frac{\left[Pio(k1 \times k3 + k2) + k4 - \frac{vgs}{2.84706}\right]fg}{k1 \times k3 + k2}$$ in SI Units

$$Picd = \frac{\left[Pio(k1 \times k3 + k2) + k4 - \frac{vgs}{35.374}\right]fg}{k1 \times k3 + k2}$$ in Field Units (B.34)

where

$$k3 = 1 + fg$$

$$Picd = Pic \times fg$$

$$Piod = Pio \times fg$$ in both SI and Field Units

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

The numerical values for the present example are:

Pio = 940; psi = 6481.07 kPa

Vgs = 9389.26; SCF/Cycle = 265.82 m^3/cycle

fg = 1.1650

$Ba = 5.45415(Dc^2 - Dt^2) = 5.45415(6.366^2 - 2.875^2)$ = 175.95 ft^3/1000 ft = 16.3385 m^3/1000 m

Dov = 5.940 (1000 ft) = 1.8105 (1000 m)

Temperature at valve depth = 181.46 °F = 83 °C

Zga (average annulus compressibility factor) = 0.828

Bl (volumetric capacity of the gas injection line) = 5.45415(2.067)^2 = 23.3 ft^3/1000 ft = 2.1653 m^3/1000 m

L (length of gas injection line) = 3 (1000 ft) = 0.91 (1000 m)

Zgl (correlation for compressibility factor in gas line) = 1 – 1.9385 ×10^{-4} ($Piod$ + 14.7) = 0.8149

$$K1 = \frac{Ba \times Dov}{(575.74 + Tdov) \times Zga\text{, open}} = \frac{16.338 \times 1.8105}{(575.74 + 83.03)(8.828)} = 0.0542$$ in SI Units

$$K1 = \frac{Ba \times Dov}{(1005 + Tdov) \times Zga\text{, open}} = \frac{178.95 \times 5.94}{(1005 + 181.46)(0.828)} = 1.0638$$ in Field Units

$$K2 = \frac{Bl \times L}{302.6 \times Zgl} = \frac{2.1653 \times 0.914}{302.6 \times 0.8149} = 0.008025$$ in SI Units

$$K2 = \frac{Bl \times L}{545 \times Zgl} = \frac{23.3 \times 3}{545 \times 0.8149} = 0.15738$$ in Field Units

$$K3 = 1 + fg = 1 + 1.1659 = 2.1650$$

$$K4 = \frac{Qgi \times Dov}{4.0997 \times vat} = \frac{17.44 \times 1.81}{4.0997 \times 0.3048} = 25.26$$ in SI Units

$$K4 = \frac{Qgi \times Dov}{50.94 \times vat} = \frac{616.41 \times 5.94}{50.939 \times 1} = 71.879$$ in Field Units

Then,

$$Picd = \frac{\left[Pio(k1 \times k3 + k2) + k4 - \frac{vgs}{35.374}\right]fg}{k1 \times k3 + k2} = \frac{\left[6481.07(0.0542 \times 2.165 + 0.008025) + 25.26 - \frac{265.82}{2.84706}\right]1.165}{0.0542 \times 2.165 + 0.008025}$$ in SI Units

$$Picd = \frac{\left[Pio(k1 \times k3 + k2) + k4 - \frac{vgs}{35.374}\right]fg}{k1 \times k3 + k2} = \frac{\left[940(1.0638 \times 2.165 + 0.15738) + 71.8796 - \frac{9389.26}{35.374}\right]1.165}{1.0638 \times 2.165 + 0.15738}$$ in Field Units

$$Picd = 6917.55 \text{ kPa}$$

$$Picd = 1003.4586 \text{ psig}$$

For a spring loaded pilot valve, the value of $Picd$ is equal to the test rack closing pressure. For a nitrogen charged pilot valve, the test rack open pressure can be calculated from $Picd$ along with the following:

B.1.4.2 Area Ratio

Finally, the value of the area ratio is:

$$Ap/Ab = \frac{Piod - Picd}{Piod - Pto} = \frac{7549.48 - 6917.55}{7549.48 - 3622.639} = 0.16$$ in SI Units

$$Ap/Ab = \frac{Piod - Picd}{Piod - Pto} = \frac{1094.96 - 1003.4586}{1094.96 - 525.42} = 0.16$$ in Field Units

Annex C

Use of Field Units and SI Units Calculators

Users of instructions should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

Where applicable, authorities having jurisdiction should be consulted.

Work sites and equipment operations may differ. Users are solely responsible for assessing their specific equipment and premises in determining the appropriateness of applying the instructions. At all times users should employ sound business, scientific, engineering, and judgment safety when using these instructions.

All equations defined in API 11V10 have been implemented in two spreadsheets, one for field (American) units and one for SI Units. Each spreadsheet consists of several individual worksheets as follows:

1) There is a worksheet for each of the equations in each section. The worksheets are referred to as “Input Ch 2,” “Input Ch 3,” etc.

2) There is a worksheet that lists all of the equations in API 11V10. This worksheet is referred to as “Field Units Calculator” or “SI Units Calculator.”

3) There is a worksheet that lists the conversion factors from one set of units to the other. This worksheet is referred to as “Units Conversion Factors.”

These worksheets have been developed in both Field (American) and SI unit systems separately. Both the field and SI unit versions are structurally the same. The difference is that the equations have been set up in the specific field or SI unit systems, so one can use either depending on the desired unit systems.

There are two major parts in each unit system work space:

1) input datasheets;

2) units calculators.

C.1 Input Datasheets

Input datasheets are designed for fast calculation of all the equations in each section at one time. Each input sheet starts with the first defined equation in the section and ends with the last defined equation in the section.

In input data worksheets, boxes in light yellow are for input of each variable and boxes in light blue color are the calculated results (answer) of each equation, based on the entered values of the variables.

All the variables in each input sheet (for each section) are referenced to the first definition of that specific variable in the input sheet. Therefore, it is only necessary to enter a value for each variable at the first definition of it, not for all the locations where it is repeated. If a variable is used 10 times in different equations in a section, it is only necessary to input a value for that variable in the location (equation) where it is used the first time. All the values for this variable afterward in other locations in the input sheet for this section will be automatically changed to the new value and the equations will be updated automatically with this new value.

For example, in either the Field or SI unit versions (they are structurally the same), on the input data sheet for Section 2, the variable “area of the tubing” (At) is used in two equations: Equation (1) and Equation (2). If a new value is entered in Equation (1), in the light yellow box, the value in Equation (2) will automatically change to the new value and both Equations (1) and (2) will be updated and calculated automatically with this new value. Since At has been defined for the first time in Equation (1), it will be defined here as the reference value for everywhere in the input sheet for Section 2. But if a value for At is entered in Equation (2), it will not update the value for At in Equation (1), because it is the second time that At has been used or defined.

Another example is the “point of injection depth” (Lv) that has been defined three times in the input sheet for Section 2, in Equations (1), (2) and (3). One only needs to enter a value for Lv in Equation (1), all the other locations will be updated to this reference location and the equations will be calculated and updated automatically.

A different value for Lv can be entered in the second or third definition, but doing so will break the link between the location and the first definition of the variable in the input sheet. If a value is changed in a location after the first definition of a variable in the yellow input boxes, it will not be updated again, because the link has been broken.

This process for input datasheets for each section allows a fast calculation for all the variables in that section and waives the need for entering all the values for all the variables in each equation.

C.2 Units Calculator

Each spreadsheet has its own Field or SI Unit Calculator, in which all the equations in API 11V10 are listed individually in the desired units system. Equations are labeled by their number in each section. For each equation, there is an abbreviated name and definition of the equation, a list of the variables and their units used in the equation, and a listing of the actual equation. The equivalent value and units of each variable in the other unit system are also defined in front of each variable. At the end of each equation is the calculated value (answer) of that equation in the desired units system with the calculated equivalent value in the other unit system.

Equations in these calculators, unlike the input sheets, are not connected to each other. Therefore, each equation can be investigated with different values for the purpose of any study or research. The values in the orange boxes for each variable are entered and the equivalent values in the other units system are displayed automatically. Also the calculated values (answers) for the equation are shown in both unit systems in the yellow boxes. Finally, a direct conversion of the answer in the primary units system is converted to the other units system for comparison with the calculated values.

C.3 Unit Conversions

Many conversion factors are used in the worksheets. When there is a need to convert one unit to another, it is necessary to multiply the value with the appropriate conversion factor. These conversion factors are listed in worksheet “Units Conversion Factors” at the end of each spreadsheet in SI or Field Units. Table C.1 shows these conversion factors.The format to use these conversion factors in excel worksheets is to multiply your variable with the appropriate factor. For example if you want to change 10 ft to meters you need to multiply 10 ft by the conversion factor for changing ft to meters which is “*fttom*” as follows:

$= 10 \times fttom$

The new result would be 3.048 m. The same rules apply to all the conversions.

Table C.1—Conversion Factors

Conversion	From	Factor	To
psi to p	psi	6894.757	pascal
psi to kp	psi	6.894757	kPa
kp to psi	kPa	0.145037744	psi
ft to m	ft	0.3048	m
sqft to sqm	ft^2	0.09290304	m^2
cft to cm	ft^3	0.028316847	m^3
cft to bbl	ft^3	0.178253119	barrel
bbl to cft	barrel	5.61	ft^3
bbl to l	barrel	158.9873	liter
bbl to cm	barrel	0.1589873	m^3
m to ft	m	3.280839895	ft
sqm to sqft	m^2	10.76391042	ft^2
cm to cft	m^3	35.31466672	ft^3
cm to bbl	m^3	6.28981057	barrel
cm to g	m^3	264.1721	gallon
sqcm to sqft	cm^2	0.001076391	ft^2
sqft to sqcm	ft^2	929.030436	cm^2
g to cft	gallon	0.1336806	ft^3
g to bbl	gallon	0.023828984	Barrel
g to cm	gallon	0.003785411	m^3
day to min	day	1440	min
ft to in	ft	12	in.
in to ft	in.	0.083333333	ft
lb to kg	lb	0.4535924	kg
kg to lb	kg	2.204622476	lb
lb to gr	lb	453.5924	gr
lb to kg	lb-mol	0.4535924	kg-mol

Bibliography

[1] API RP 11V5, *Recommended Practices for Operation, Maintenance, Surveillance and Troubleshooting of Gas-lift Installations*

[2] API RP 11V6, *Design of Continuos Flow Gas Lift Installations Using Injection Pressure Operated Valves*

[3] API RP 11V8, *Recommended Practice for Gas Lift System Design and Performance Prediction*

[4] API RP 11V9, Recommended Practice for Design, Operation, and Troubleshooting of Dual Gas-lift Wells

[5] ISO 17078-2[1], *Petroleum and natural gas industries—drilling and production equipment—Part 2: flow control devices for side-pocket mandrels*

[1]International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211, Geneva 20, Switzerland, www.iso.org.

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