

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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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	<i>PI</i> —use of chamber lift installations and accumulators	If the <i>PI</i> is high, a chamber lift installation is recommended to increase the liquid production. If the <i>PI</i> is low, chambers are recommended for wells with low formation GLR to reduce the injection GLRs. Wells with high <i>PI</i> 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 <i>PI</i> .

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 M³/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."

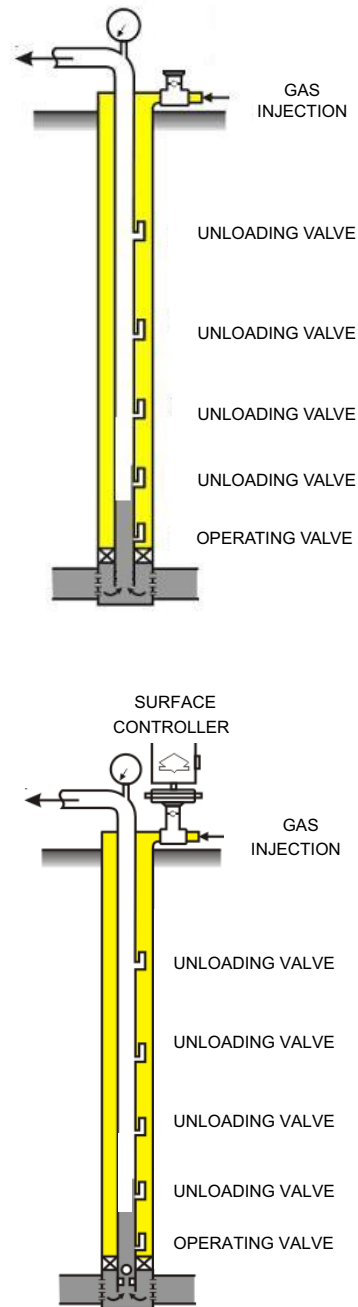


Figure 1.1—Simple Completion (Closed Installation)

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.

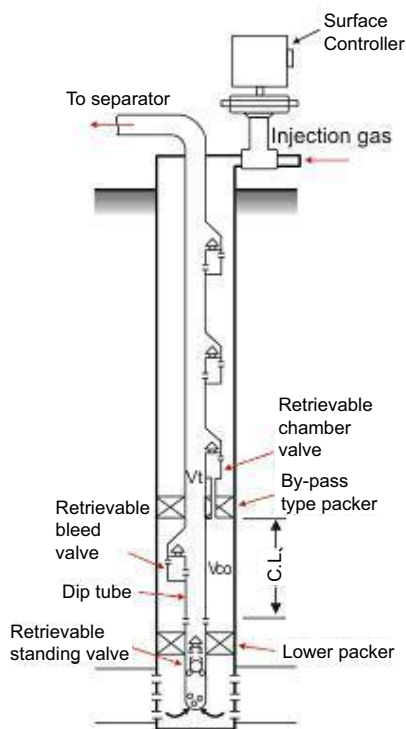


Figure 1.2—Double Packer Chamber

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 m³/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.

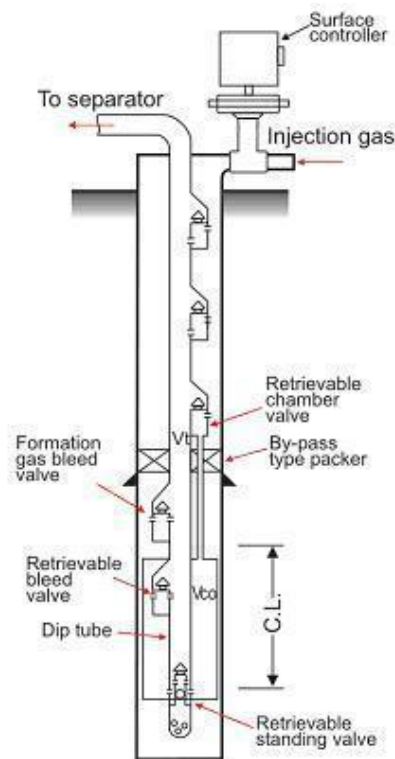


Figure 1.3—Insert Chamber

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.

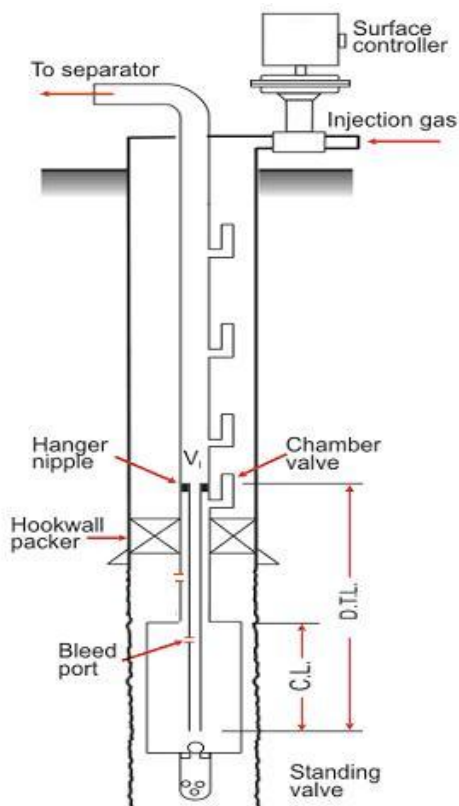


Figure 1.4—Insert Chamber with Hanger Nipple for “Stripper”-type Wells

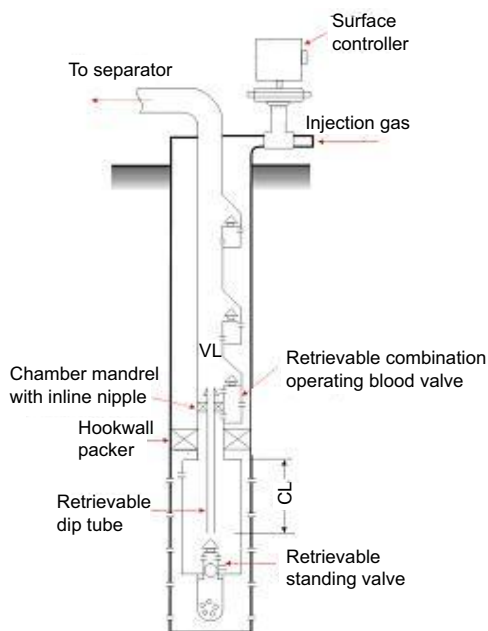


Figure 1.5—Insert Chamber with Combination Operating-bleed Valve

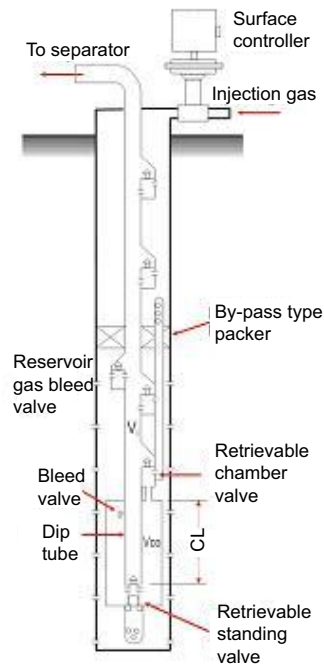


Figure 1.6—Extremely Long Insert Chamber

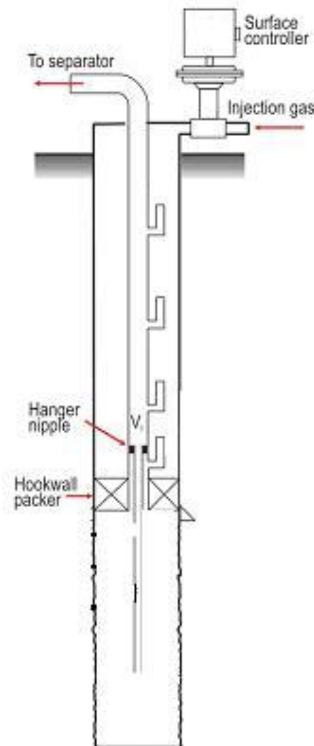


Figure 1.7—Insert Chamber for Tight Formations

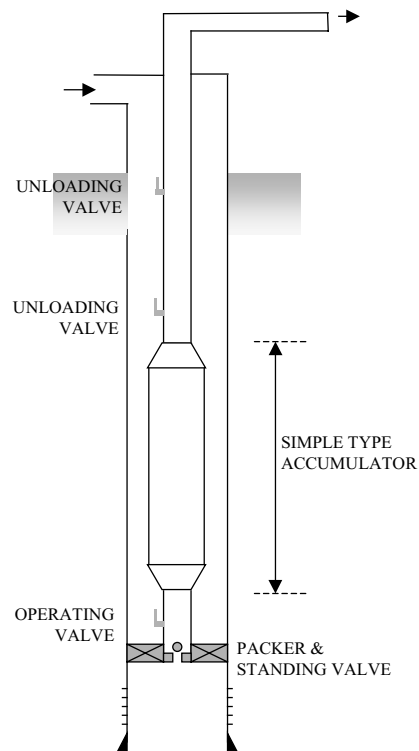


Figure 1.8—Simple Type Accumulator (Not to Scale)

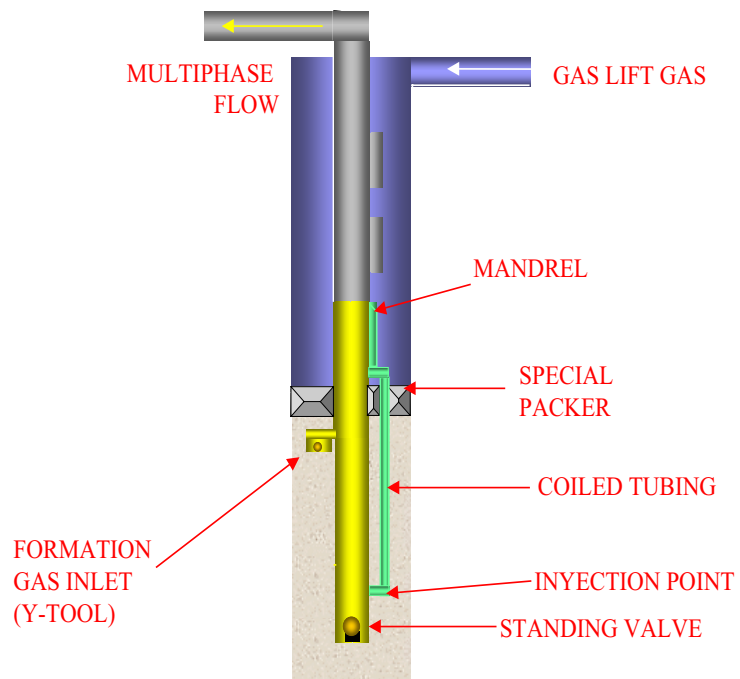


Figure 1.9—Insert Accumulator

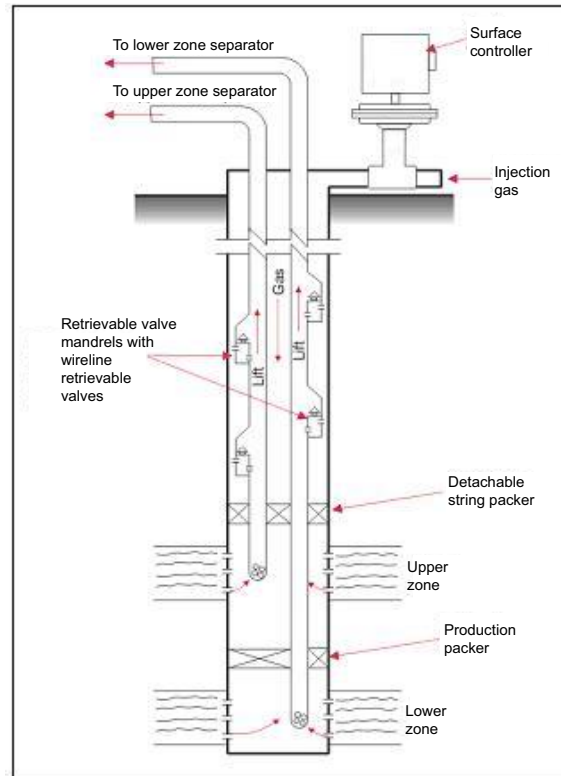


Figure 1.10—Parallel String Dual Completion

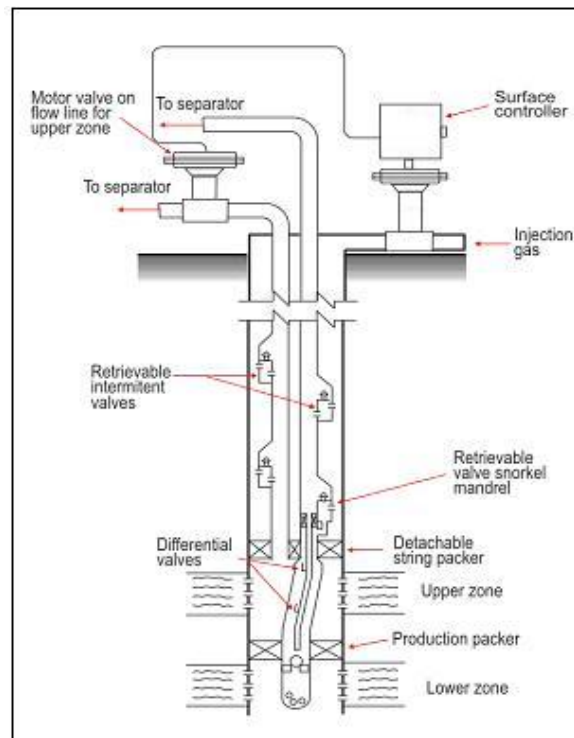


Figure 1.11—Completion for Zones That are Too Far Apart

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.

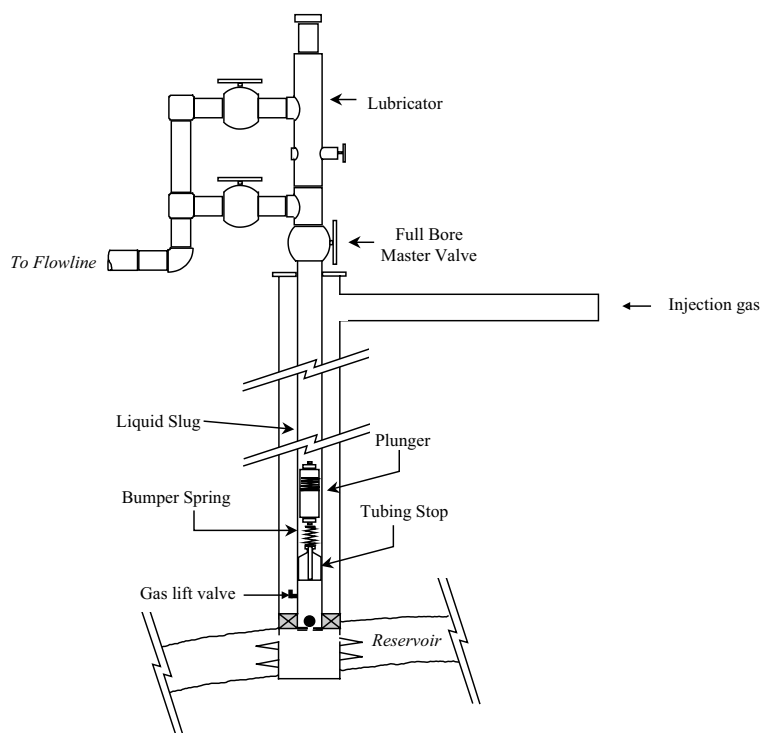


Figure 1.12—Completion for Intermittent Gas-lift with Plungers

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:

- 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.

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 <i>PI</i> 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 <i>PI</i> . 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 ($< 50 \text{ ft}^3/\text{bbl}$) ($8.93 \text{ m}^3/\text{m}^3$) 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 <i>PI</i> . 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 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 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 it 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, <i>International standard for flow control devices</i> .
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 A_v/A_b ratio for the operating gas-lift valve when choke control is used	Once a valve with a particular A_v/A_b 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 A_v/A_b 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 A_v/A_b 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 valve 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 A_v/A_b 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.

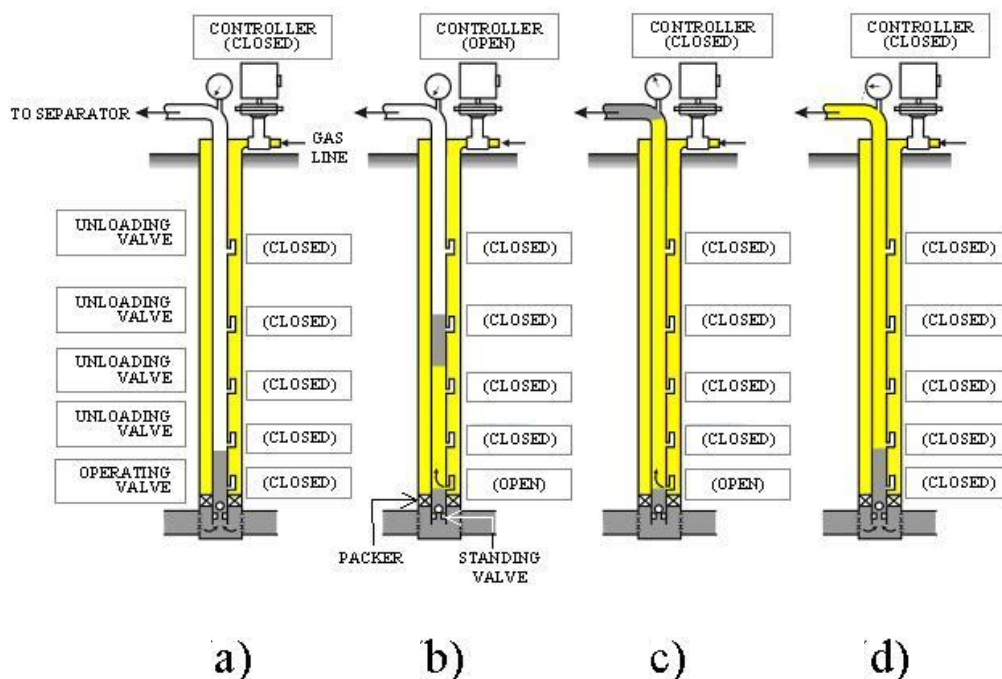


Figure 2.1—Intermittent Gas-lift Cycle

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 Continuous 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.

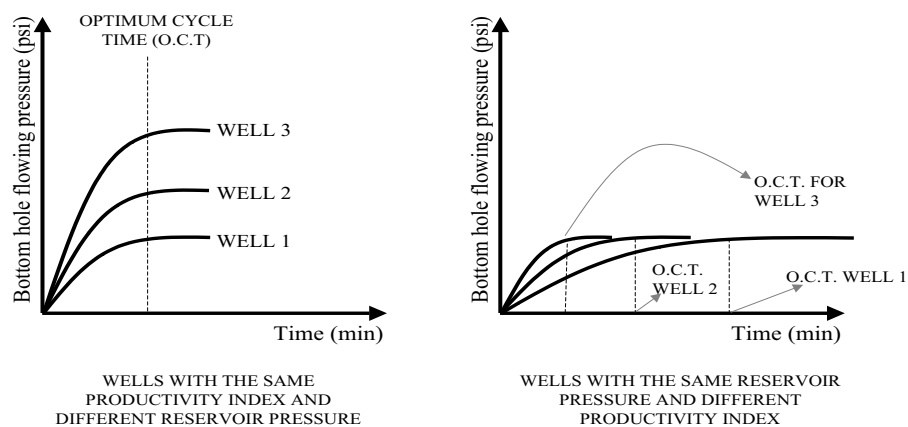


Figure 2.2—Effect of Reservoir Pressure and *PI* on Optimum Cycle Time

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, V_{gs} , can be roughly estimated in m^3 in SI Units and ft^3 in Field Units.

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

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.

$$V_{gs} = A_t \times L_v \times \frac{P_t}{14.7} \text{ in Field Units} \quad (1)$$

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:

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

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

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

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 $\text{ft}^3/\text{barrel}$, is given by:

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

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

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 $356.2 \text{ m}^3/\text{m}^3$ ($2000 \text{ ft}^3/\text{barrel}$), 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