UNIQUE APPLICATIONS OF GAS LIFT SYSTEMS

Herald W. Winkler
Consultant

INTRODUCTION

Gas lift is a flexible and forgiving form of artificial lift. Gas lift is so flexible that many installations for offshore platform wells are designed and the retrievable gas lift valve mandrels are installed during initial well completion. Efficient gas lift operations can be anticipated from installation designs based on limited well performance data by avoiding excessive distance between valve depths. The daily production rate from most gas lift installations depends upon the well deliverability and the available injection gas pressure and rate.

The gas lift designs and systems described in this paper are not typical installations that are discussed in gas lift textbooks. The design concepts are not original and most of the information has been published in years past. The same innovative ideas reappear in cycles and will seem new to the engineer who has recently entered the petroleum industry. This paper brings together the description of several unusual gas lift applications into a single publication. Hopefully, one of these special installation designs will be a solution to a present artificial lift problem. Modification of an installation design tailored to a particular well or field is left to the reader.

GAS CHAMBER PUMPS

A gas chamber pump (GCP) will lift any fluid which can be displaced through the production conduit. A concentric GCP installation is illustrated in Figure 1. The GCP operates on the simple U-tubing principle; that is, the well production is U-tubed to the surface without injection gas entering the production conduit. The production conduit is the annulus between the larger tubing string and the small concentric tubing string that is packed off in the top of the chamber. The small concentric tubing is a combination injection gas and vent string. Two motor valves on the combination injection gas and vent string at the surface are controlled by a single pilot control system. This pilot control system is the heart of the GCP operation. One motor valve is on the high pressure injection gas line, and the other motor valve is on the vent line which would be connected to the flowline in most installations. In a closed rotative gas lift system the vent line discharges into the low pressure suction side of the compressor station. A typical operating cycle can be described by referring to the GCP installation in Figure 1.

At the beginning of a cycle the injection gas motor valve is closed and the vent motor valve is open. The gas pressure above the chamber is vented through the concentric tubing into the flowline while the chamber is filling. The check valve in the bottom of the chamber is open as the chamber fills. This check valve is analogous to the intake valve on a pump or a standing valve in a sucker rod pumping installation. The check valve in the dip tube is closed to trap the hydrostatic fluid column in the production conduit and allow the chamber to fill with the well fluid. This check valve is analogous to the discharge valve in a pump or a traveling valve in a sucker rod pump. After the chamber fills, the vent motor valve closes and the injection gas motor valve opens. When injection gas is applied to the top of the fluid column in the chamber, the intake check valve closes. When this injection gas pressure exceeds the hydrostatic pressure of the fluid column in the production conduit, the discharge check valve in the dip tube opens and fluid from the chamber is displaced into the production conduit. The surface pilot control system is adjusted to close the injection gas motor valve and open the vent motor valve at the instant before the U-tubed fluid production in the chamber reaches the lower end of the dip tube; therefore, injection gas is prevented from entering the production conduit. The injection gas in the small concentric tubing string is vented into the flowline. This completes one injection gas cycle of operation.

There are numerous advantages to this lift system and several are as follows:

1) the simplicity of the subsurface equipment because the heart of the GCP operation is the surface pilot control system,

2) the minimum possible flowing bottomhole pressure can be achieved if the casing annulus can be vented to the atmosphere,

3) temperature has no effect on the mechanical subsurface operation which makes the system applicable to steam injection projects,

4) ideal for lifting heavy viscous crude with or without entrained sand,

5) the creation of an emulsion from gas lift operations is eliminated because injection gas does not enter the production conduit,

6) the problems encountered lifting sand laden production are minimized, and

7) daily injection gas volume is less than for any other gas lift method required to attain a minimum possible flowing bottomhole pressure in a low reservoir pressure well.

Any artificial lift system with these advantages must have disadvantages. The only major disadvantage can be the injection gas pressure required to U-tube the produced well fluid from the lower end of the dip tube in the chamber to the surface for a deep well. The required pressure is based on the true vertical depth and not the measured depth. The GCP is an ideal method for lifting shallow heavy oil wells with an extremely low reservoir pressure.

A technical paper on the calculations related to the design and operation of GCP installations for lifting heavy oil wells in California was presented in 1981 at the SPE California Regional Meeting in Bakersfield[1]. There are several other papers on GCP installations referenced in this SPE paper. Beginning around 1967 many GCP installations were installed for lifting heavy oil from shallow wells in Eastern Venezuela. Huff-puff steam injection was required to produce oil from this reservoir. The water with sand and heavy oil were lifted efficiently by the GCP installations. Extensive testing of the GCP system in the Cold Lake Field in Canada revealed several advantages of the GCP as compared to other artificial lift methods. Additional successful GCP installations have been run in Texas and other areas.

There are numerous modifications possible in the design of a GCP installation. The combination injection gas and vent string could be run parallel to the production tubing. For very low reservoir pressure the casing annulus and the vent string could be exposed to atmospheric pressure during the filling cycle. A two-packer chamber rather than an insert chamber may be installed. The installation illustrated in Figure 1 is the least expensive type of design which can be fabricated by the operator. The length of the chamber is based on the working fluid level since the top of the chamber should not be above this fluid level to minimize the daily injection gas requirement.

SMALL CONDUIT INTERMITTENT GAS LIFT INSTALLATION DESIGN

Gas lift offers an inexpensive and efficient method for lifting low production rate wells through small diameter concentric macaroni tubing in a larger tubing string or small casing. The injection gas rate required from the high pressure system is low for this gas lift system. Conventional tubing retrievable gas lift valves and the ease of running and pulling a small macaroni tubing string ensure low initial installation and workover costs.

An actual intermittent gas lift installation[2] for a tubingless completion (2-7/8-inch OD casing) is illustrated in Figure 2. A similar design could be used to lift liquids from a gas well if the gas production is produced through the casing annulus and a 2-3/8- or 2-7/8-inch tubing string had been run to remove the associated liquid production. This type of installation is applicable for lifting a very low productivity zone in a dual zone completion being produced through two tubing strings. The dual installation becomes two single completions in terms of gas lift operations if both zones must be gas lifted.

The volume of injection gas stored in a conduit between two pressures is a function of the physical capacity of the conduit and the pressure difference. Since there is little capacity in a small tubing annulus, the pressure difference becomes the important consideration. A design controlled pressure difference for displacing a liquid slug through a macaroni tubing string is possible by employing production-pressure-(fluid)-operated and injection-pressure-operated gas lift valves. The unloading valves are the production-pressure-operated valves with a test rack set opening pressure for the needed pressure decrease in the small tubing annulus to ensure the volume of injection gas required to displace the liquid slug to the surface. The injection-pressure-operated pilot valve (or a differential pressure opening and constant injection pressure closing valve could be used) is the deepest operating gas lift valve in the installation. The bottom operating gas lift valve should have a large port and the production pressure operated valves should have a small port.

An installation is designed whereby the volume of gas stored in the macaroni tubing annulus between the maximum and minimum annular pressures are equal to the volume of gas required to displace the liquid slug in the macaroni tubing string to the surface. The opening pressure of the bottom operating pilot gas lift valve is the maximum annular pressure. The minimum annular pressure is controlled by the test rack opening pressure of the production-pressure-(fluid)-operated valves which are set to remain open until the liquid slug surfaces.

These installations are designed for choke control rather than time cycle control of the injection gas into the well. The advantage of choke control is the low and constant rate of injection gas removal from the high pressure system. A two-pen pressure recorder chart from the installation in Figure 2 is shown in Figure 3. The well was producing a total of 41 barrels of fluid per day (17 barrels of water) from 6320 feet when this chart was taken.

INSERT GAS CHAMBER INSTALLATION FOR SHALLOW STRIPPER WELLS

There are many problems associated with gas lifting a low daily production rate from old stripper wells. Conditions which can eliminate or prevent efficient gas lift operations in these wells are:

1) old corroded oil strings,

2) long perforated interval or open hole,

3) large casing ID oil strings,

4) low reservoir pressure,

5) very low daily production rates, and

6) limited permissible expenditure for initial installation, workover and operating costs.

A special insert chamber installation was designed and run in about 300 wells in Peru[3]. The installation in Figure 4 does not require removal of the 2-3/8-inch OD tubing to replace the gas lift valves or standing valve. The lower end of the macaroni tubing string immediately above the chamber dip tube has a pack-off assembly which lands in a sucker rod pump seating nipple. The standing valve was modified by removing the no-go shoulder in order that the standing valve would pass through the seating nipple for the pack-off assembly. The combination pack-off assembly and crossover concave valve mandrel for the 1-inch OD injection-pressure-operated gas lift valve was fabricated in Peru.

The wells in Peru were converted from sucker rod pumping to gas lift chambers because the subsurface pumps needed to be replaced on an average of every 30 days as the result of excessive wear from sand in the well production. One year after installation of the gas lift chambers, the overall daily field production rate was 16 percent higher than predicted from the decline production curve for the previous pumping installations.

The combination pack-off and crossover concave valve mandrel in Figure 4 can be replaced with an off-shelf conventional production-pressure-(fluid)-operated valve mandrel which allows a 1- or 1-1/2-inch OD valve to be used as the operating chamber gas lift valve. The disadvantage of this type of chamber mandrel is that the 2-3/8-inch OD tubing must be pulled in order to repair or replace the operating chamber gas lift valve and the standing valve.

The primary advantages of these small macaroni tubing chamber installations for gas lifting low production rate stripper wells are:

1) the backpressure against the formation can be eliminated by venting the casing annulus to the atmosphere,

2) the point of gas injection is at the lower end of the chamber dip tube which can be below the perforated interval in some wells,

3) the wells with a low working fluid level are efficiently gas lifted because each foot of fluid in the chamber annulus is converted to several feet of liquid slug in the macaroni production tubing before injection gas enters the lower end of the dip tube,

4) an expensive hookwall casing packer is eliminated which reduces the initial and workover costs,

5) the casing is not subjected to the injection gas pressure,

6) the small tubing annulus for injection gas storage decreases the probability of excessive injection gas/liquid ratios associated with intermittent gas lift operations for low rate wells when the injection gas is in large casing,

7) the injection gas rate for a required increase in the injection gas pressure is much less in a small annulus,

8) the pulling costs for the installation in Figure 4 are a fraction of the cost to pull a tubing string in an installation with a hookwall casing packer, and

9) the operating costs and manpower requirements are low for these gas lift chamber installations.

The insert chamber installations in Peru had 2-3/8-inch OD tubing with a 1-inch nominal macaroni production tubing string. Since many of the wells had 5-1/2-inch OD casing, 3-1/2-inch OD line pipe with an ID of 3.068 inches and a coupling OD of 4.000 inches (3-inch nominal line pipe) was used to construct the insert chambers for most wells. The well depths varied from 1200 to 3800 feet, and the maximum available injection gas pressure at the wellsite was near 400 psig. Daily production rates of less than 6 to nearly 45 barrels per day were gas lifted from these wells. The injection gas cycle frequency for setting the time-cycle controllers ranged from injecting gas every 20 minutes to once every two hours. The period of injection varied from 2 minutes to over 4 minutes depending upon the depth of lift and well deliverability.

ONE-WELL CLOSED ROTATIVE GAS LIFT SYSTEM

A one-well closed rotative gas lift system is not considered by many operators as a viable method for lifting most wells. Generally, closed rotative gas lift systems are designed to lift a group of wells, or field, and are classified in the category of a central power type of artificial lift system.

The problem of lifting high gas/liquid ratio deep wells with extremely low permeability reservoirs created an application for the small one-well gas lift system. Other artificial lift methods fail to lift these wells economically. Pumping deep high gas/liquid ratio wells is inefficient and costly. The minimum daily total gas rate required through a given tubing size to prevent severe heading at low liquid production rates depends upon tubing size, wellhead pressure and depth of lift. Smaller tubing sizes require less total daily gas rates than larger size production conduits. The cost of replacing a larger tubing string with a smaller size tubing is difficult to justify from an economic standpoint in very low rate wells. One solution to this problem is to select a compressor with an injection gas deliverability that equals or exceeds the minimum injection gas rate to prevent severe heading conditions for the existing tubing string in the well. Generally, a 40 to 50 brake horsepower compressor will ensure the injection gas rate required for 2-3/8- and 2-7/8-inch OD tubing strings and less horsepower is needed for smaller tubing sizes.

The proper design of a one-well closed rotative gas lift system is essential - particularly when makeup gas must be purchased. The purpose of the design modifications is to retain the injection gas volume within the small closed system when the compressor goes down. Wells being gas lifted with injection gas supplied from a large compressor station are not subjected to the possible frequent compressor shut-down interruptions of an individual well being gas lifted by a small skid-mounted single compressor unit. The basic flow diagram for the low and high pressure systems for a large compressor station or a small single compressor unit are the same with the exceptions of the modifications recommended to trap the injection gas for the single compressor unit when a shutdown occurs. A typical simplified flow diagram of a one-well system[4] is shown in Figure 5.

A reliable check valve should be installed in the injection gas line near the wellhead to prevent reverse gas flow from the casing annulus back into the high pressure system when the compressor goes down. An orifice-check valve is not recommended at the depth of gas injection for most wells. An injection pressure operated gas lift valve at the depth of gas injection prevents an excessive decrease in the casing annulus pressure if gas injection ceases from a compressor shutdown. The operating gas lift valve closes and traps the injection gas in the casing annulus. The operating gas lift valve should have a small port size based on the injection gas requirement to reduce or eliminate heading in the production tubing string.

Another feature unique to the one-well gas lift operations is the installation of a large ported spring closing diaphragm valve on the flowline. The motor valve remains open when the compressor is running by supply gas controlled by an oil pressure switch. When the compressor quits running, the decrease in oil pressure is sensed by the switch which bleeds off the supply gas and allows the motor valve to shut in the flowline. Another method to control the status of the diaphragm valve on the flowline is by using a casing pressure sensitive pilot. The high-low pressure pilot monitors the casing pressure and closes the flowline motor valve when the injection gas pressure in the casing annulus reaches a minimum set pressure. This completes the isolation of the injection gas volume within the casing annulus and tubing of a one-well gas lift system. Since most of these one-well gas lift installations are installed in very low permeability wells, the choking effect of the motor valve port on the flowing wellhead pressure is negligible because of the low daily maximum production rates from these wells.

Another consideration for many one-well installations is a backpressure regulator on the discharge side of the compressor to stabilize the compressor discharge pressure. The injection gas to the well is connected into the discharge line upstream of the regulator. This assures excellent control of the injection gas rate to the well and a constant compressor load and output.

Low rate wells producing from the Austin Chalk, Edwards, Glen Rose and other similar formations have been successfully gas lifted with the one-well closed rotative gas lift systems. Average flowing pressure gradients between 0.02 and 0.04 psi/ft have been measured for total daily liquid rates from 10 to 50 barrels per day through 2-3/8- and 2-7/8-inch OD tubing. The depth of lift varied between 7500 and 9500 feet in these low permeability wells. Extremely low flowing bottomhole pressures can be attained for low rate wells by continuous flow gas lift on the basis of the above measured flowing pressure gradients.

One-well gas lift systems are not limited to extremely low rate wells. Many of these systems are installed to lift several hundred barrels per day. For example, gas lift can be the most efficient interim method for lifting wells in a waterflood during fillup when the gas/liquid ratio is high. The cost of the subsurface gas lift valves and valve mandels is low. Since the skid-mounted compressor can be leased with a maintenance service contract, a gas lift system can be replaced after formation gas production ceases without any appreciable capital cost for the more efficient interim lift method.

CLOSING REMARKS

The basic design concepts for several unique gas lift installations have been described in this paper. These gas lift installations do not begin to exhaust the many unusual applications for lifting a well by this artificial lift method. Other examples include gas lifting wells with carbon dioxide in a reservoir in which carbon dioxide is being injected and gas lifting with nitrogen in an area where a nitrogen producing formation exits.

The detailed design calculations requiring the equations for gas lift valve spacing and test rack valve opening pressures for different types of gas lift valves are beyond the scope of this presentation. Several of these installation designs require a knowledge of gas lift valve mechanics and specifications to ensure successful operation. A gas lift specialist should be consulted regarding the equipment selection and design calculations prior to installing a gas lift system if an operator is not familiar with gas lift fundamentals and technology.

REFERENCES

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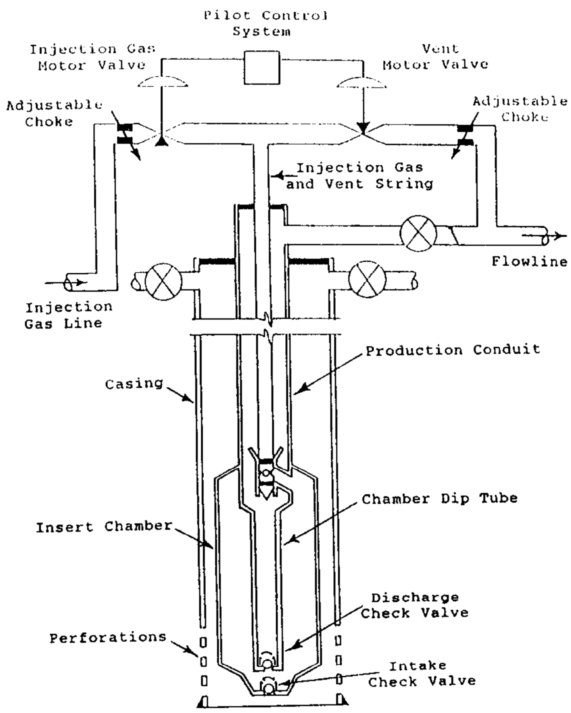

Figure 1 — Concentric type gas chamber pump

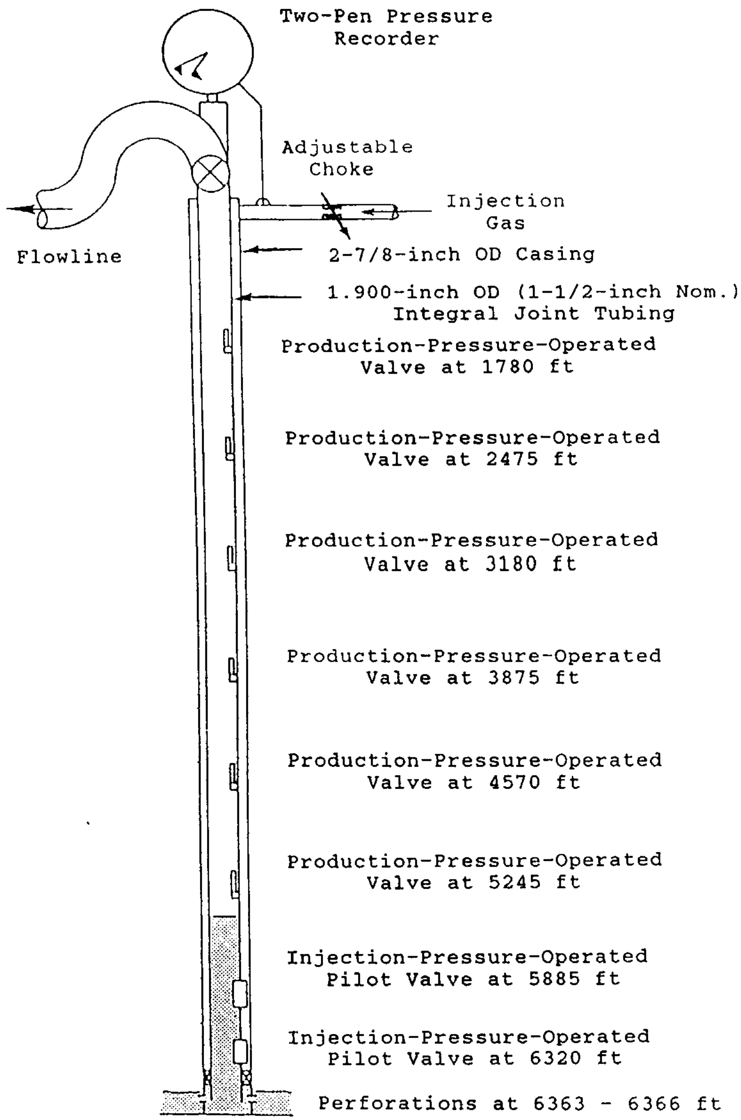

Figure 2 — Small conduit intermittent gas lift installation using combination production-pressure-operated and injection-pressure-operated gas lift valves

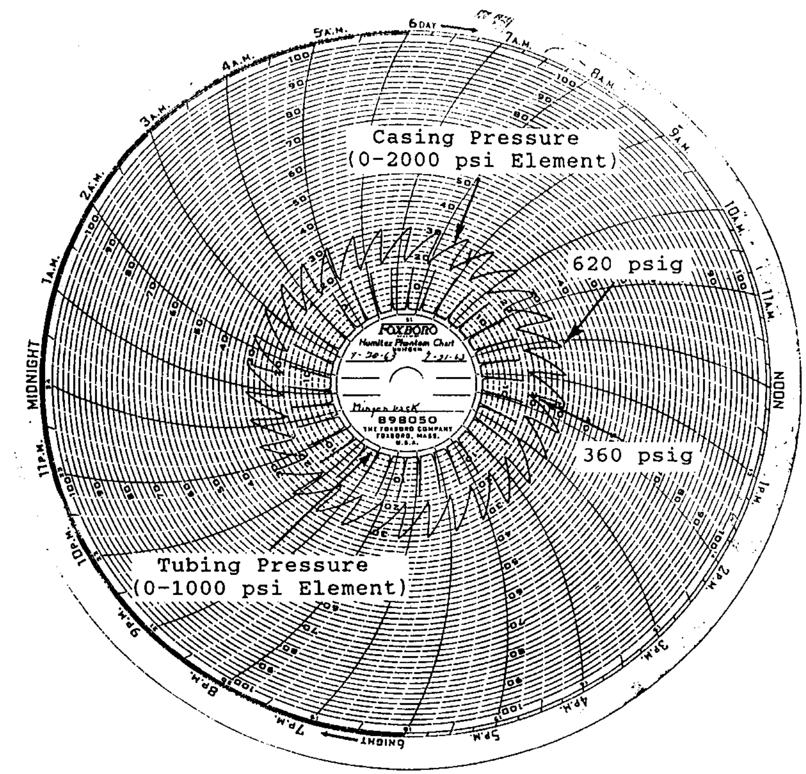

Figure 3 — Two-pen pressure recorder chart from intermittent gas lift installation in Figure 2

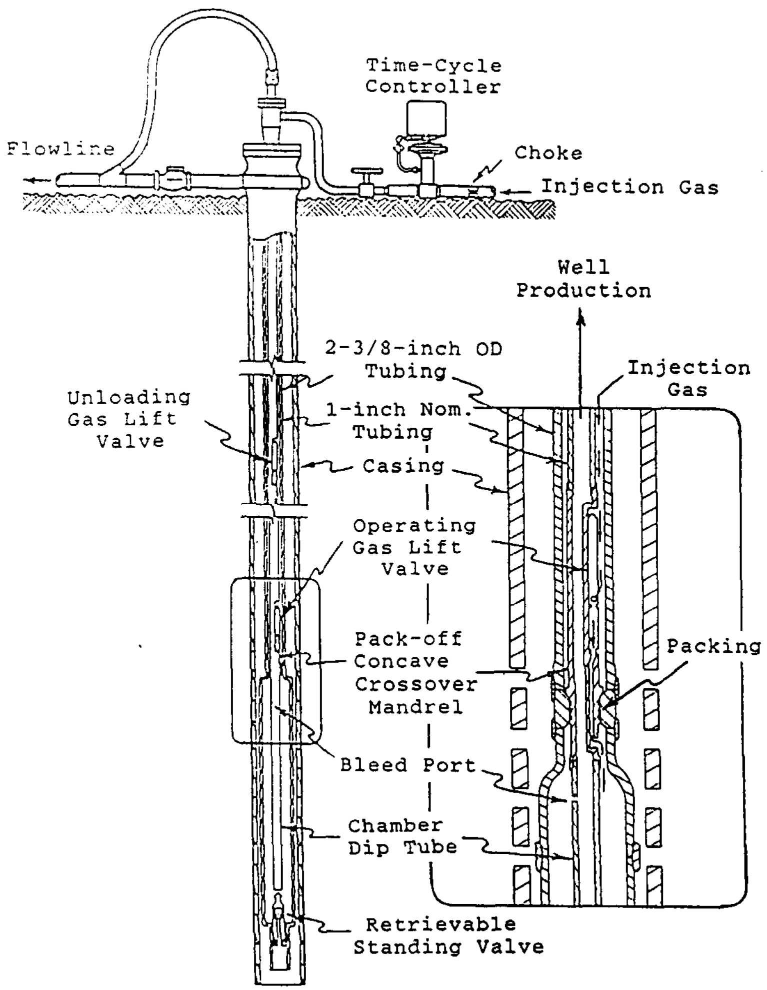

Figure 4 — Insert chamber installation with removable macaroni production tubing string

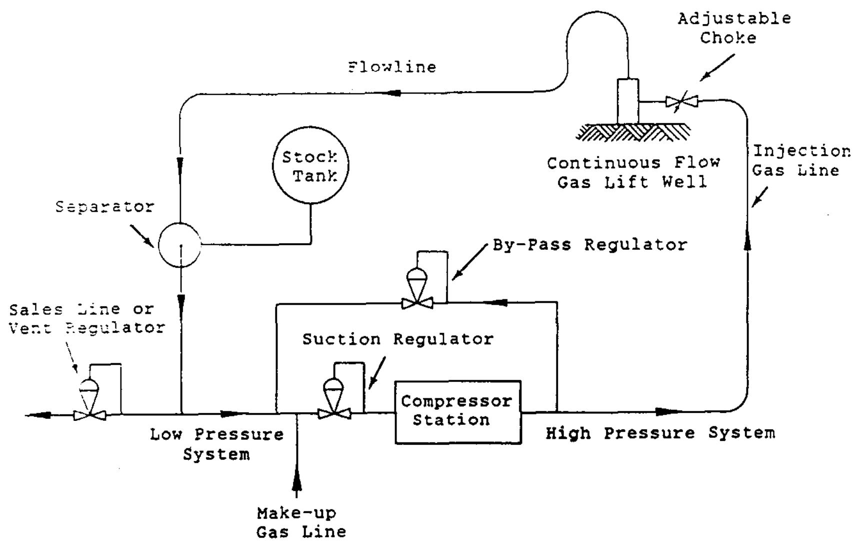

Figure 5 — Simplified flow diagram of a closed rotative gas lift system