Principles and Applications of Gas Lift

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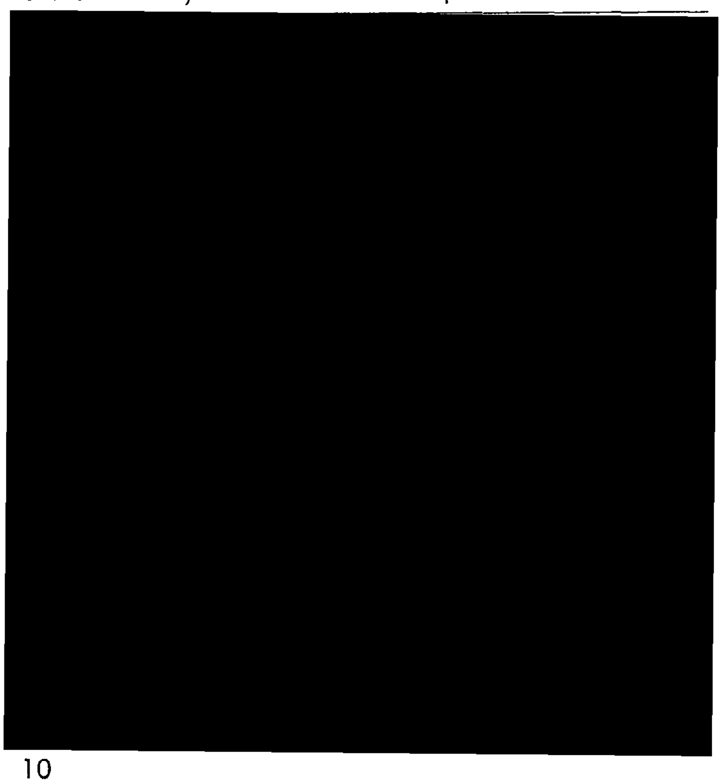
Abstract

This paper deals with the general principles and applications of gas lift. Various types of gas lift operations are discussed. The mechanical operations of flow valves are explained. Types of installations are analyzed. A detail design technique for the most efficient point of gas injection is outlined. Valve spacing calculations are presented. Flow valve operating pressure design is commented upon. Operational hints to increase efficiency are suggested, the closed rotative gas lift system and the future trend in retrievable gas lift equipment are mentioned. The advantages of gas lift are emphasized.

Introduction

The removal of fluids by gas lift principles dates back to the 18th century when compressed air was used to remove water from old mines. Around 1865 the famous Sherman well was successfully lifted at the rate of 40 to 60 barrels per day after other artificial lift methods of that era proved insufficient. Getting closer to home, M. T. Chapman used compressed air at Corsicana in 1899 for periodically unloading oil from wells. By 1923 - 1924, rates as high as 10,000 barrels of fluid per day per well were being recovered from well depths of 2300 to 2600 feet in the Smackover Field in Arkansas. In 1925 the recycling of gas and extraction of gasoline were begun in California in conjunction with gas lift. Gas lift operations began in the Seminole Field of Oklahoma in late 1926 and during the next few years thereafter an intensive study of these operations was carried on. The knowledge of gas lift gained in the Seminole Field was used to advantage in the prolific Oklahoma City Field. In this field the "Kick-off" valve was originated which initiated the gas lift industry of today.

This simple "kick-off" valve has evolved into many types of well engineered gas lift valves constructed of durable corrosive resistant materials to meet the operators' many individual well requirements. With the



advancement of surface controlled gas lift valves, data has been collected and evaluated to permit calculated valve spacings. With the increasing value of high pressure gas and the stringent enforcement of gas conservation, the design of a gas lift installation has become a science whereby the operator can intelligently predict the well performance and gas requirements.

Information is available to the operator from the gas lift equipment manufacturers in the form of manuals, catalogs, and bulletins that will aid him in the design of a gas lift installation. However, it must be realized that the data required to design a well engineered gas lift installation is in the hands of the operator. Progress in the gas lift industry to date has been made possible by the evaluation and application of field performance data released by the producing operators. The gas lift manufacturers sincerely appreciate this data and all constructive criticism which will assist them in the manufacture of more applicable and efficient equipment. The manufacturer in turn offers the operators trained personnel to assist them with any problems relating to gas lift.

This paper is developed in the following order:

1. Definition of Gas Lift
2. Types of Gas Lift Operations
3. Gas Lift Flow Valves
4. Gas Lift Installations
5. Design Data and Application
6. Flow Valve Spacing Design
7. Design of Valve Operating Pressure
8. Gas Lift Operational Hints
9. Closed Rotative Gas Lift System
10. Future Trend in Equipment
11. Advantages of Gas Lift
12. Conclusions

Definition of Gas Lift

What is gas lift? Gas lift is the supplementing of the formational energy with high pressure gas for the continued production of fluid from the reservoir. Why does it work? A perfect gas when compressed or expanded isothermally, which means at the same temperature, follows Boyles Law. This law states that at *a constant temperature, the volume of a given mass* of gas varies inversely as the pressure to which the gas is subjected; in other words, volume times pressure is a constant. An increase in pressure results in a decrease in volume; and conversely, a decrease in pressure results in an increase in volume. As gas travels from the point of gas injection in a well to the surface, the reduction in pressure will result in an increase in gas volume. The work accomplished by the expanding gas can be applied for aeration or displacement depending upon the particular well conditions.

Types of Gas Life Operations

A gas lift well generally falls under one of two categories of operation; namely intermittent or continuous flow. Occassionally a well will not readily lend itself to either classification. This type of well will have a productivity index of approximately 0.5 or less for normally available pressures and will be capable of producing around 300 barrels of fluid per day. A borderline well should be designed for both types of operation and the category which indicates the greatest producing efficiency accepted. Some valve installations are designed with both intermittent and continuous flow operation in mind. Continuous flow is employed during the early producing life of the well and intermittent flow is used for depletion.

Intermittent flow is attained by injecting gas of sufficient volume and pressure in the tubing to lift a column of fluid to the surface with a minimum of slippage and fall-back. This type of lift is comparable to ballistics. The column or slug of fluid is the projectile and the gas is the powder. The operation of opening and closing the working valve in its entirety is known as a cycle. This cycle should be of a sufficient length of time to allow the slug of fluid and tail gas to reach the separator and also permit a suitable fluid head to build up above the operating valve. These cycles are controlled at the surface by a timing device known as a surface controller which is simply a clock operated motor valve that automatically delivers gas into the casing annulus at previously set intervals of time. Wells suited to this type of flow are characterized by a low productivity index—low bottom hole pressure, a low productivity index—high bottom hole pressure, or a high productivity index—low bottom hole pressure. These wells will generally have a productivity index of less than 0.5 and will not be capable of producing large quantities of fluid.

Continuous flow is the controlled injection of gas into a fluid column to provide sufficient aeration to obtain the flowing bottom hole pressure for a desired rate of production. It is imperative that a constant pressure be maintained on the casing annulus for a controlled injection of gas into the moving fluid column. A surface controller designed to operate as a pressure reducing regulator can be used to establish and maintain this constant pressure. Some operators prefer the use of a choke or metering valve. This type of well should be capable of producing in excess of 300 to 400 barrels of fluid per day depending upon the tubing size and should have a high productivity index and high bottom hole pressure. Efficient continuous flow operation approaches the natural flowing characteristics of the well.

Gas Lift Blow Valves

The two general types of flow valves are the differential valve and the pressure operated valve. The differential valve succeeded the jet collar and the U-tubing of gas. The operation of this valve is governed by the differential across the valve between the casing annulus pressure and the tubing pressure. The valve is a normally open, spring-operated valve. The force of the spring is set for a predetermined pressure differential of ordinarily 100 to 150 PSI. The spring differential works with the force of the fluid in the tubing on the valve stem to open the valve. The casing annulus pressure acting upon the piston end of the stem, which is the same size as the valve port, closes the valve. If a valve with a set differential of 125 PSI were run in a well with an injection casing pressure of 500 PSI, a fluid head build up over the closed valve of 375 PSI would be required to open the valve. After the valve opened, the casing gas would pass from the annulus through small choke orifices in the valve and out into the tubing through a larger valve port. Because the choke orifices have much less area than the valve port, gas passage creates a low pressure chamber inside the valve. When the pressure in this chamber becomes less than 375 psi, the valve will close, awaiting another tubing build-up equivalent to the 375 psi necessary to open the valve. These valves are recommended to be used in wells with a high fluid level and high productivity index where surface control is not essential. They are used as unloading valves in gas wells that have a tendency to become water-logged and are frequently recommended for one string in a dual lifted well to permit fluid operation in gas lifting one zone. Differential valves are also used in conjunction with a stop-cocker, which automatically opens and closes a well, to utilize the well's own formational energy to prolong its natural flowing life. This produces the effect of raising the point of gas injection, thus lightening the flowing gradient and reducing the work requirements of the formation gas.

The pressure operated valve is the most widely used valve in the gas lift industry. Variations of this valve are used for intermittent and continuous flow. The basic components of the valve are a pressure dome, bellows, body, stem and seat. The stem is attached to the bellows which in turn is attached to the pressure dome. Since the pressure charge in the dome and bellows holds the stem on its seat, this valve is considered a normally closed valve. The opening pressure of this valve can be set for any desired operating condition and is that pressure necessary to overcome the charge within the bellows and move the stem off its seat. When the valve is closed, the casing annulus pressure is applied over the effective area of the bellows minus the area of the stem; but after the valve opens, this same casing pressure is applied over the entire effective area of the bellows. The force applied by the charge over the effective area of the bellows does not change from open to closed position; therefore, the casing annulus pressure necessary to open the valve is greater than the casing pressure at the instant the valve closes because of the difference in areas. This difference between opening and closing pressure is known as the spread. It is readily apparent that the larger the port size for the same effective bellows area, the greater the theoretical spread. Excessive spread can result in increased input gas-fluid ratios. It is extremely detrimental to wells having a large oil string and small tubing size because only a few pounds of casing pressure bleed-down represents a sizeable quantity of input gas. Most flow valve manufacturers offer an intermitting valve with a large port size that is partially balanced to minimize the effects of spread. This balancing mechanism is accomplished by a sealed chamber built into the valve whereby tubing pressure can be brought to bear upon a portion of the top of the valve stem in opposition to the tubing effect. After the valve has opened, the casing annulus pressure is free to apply its force within the effective area of the sealed chamber which results in a spread comparable to a small ported valve. These large ported valves are recommended for use in extremely deep wells and wells with low injected gas pressures in order to pass a sufficient volume of gas to maintain an efficient lifting velocity of the fluid slug. Increased port size also results in greater tubing effect toward opening the valve. The port size of a pressure operated continuous flow valve is made purposely larger than the conventional un-balanced intermitting valve to utilize the back pressure in the tubing as an effective opening force. This allows the valve to operate somewhat on a differential principle but still retain the complete surface control afforded a pressure operated valve. A metering orifice or orifices are included in the valve to permit a controlled volume of gas for aeration to maintain the designed continuous flow rate.

Gas Lift Installations

There are many special types of flow valve installations to fit varying well conditions, but the two generally employed types are the closed and open installations. The closed installation is by far the most widely used and consists of a hookwall or casing packer set below the bottom flow valve, thus utilizing the casing annulus as a gas volume chamber. The perforations are run below the packer in order to prevent the gas from U-tubing. A standing valve is generally run between the perforations and bottom valve in a low bottom hole pressure well to prevent excessive pressure from reaching the face of the formation when the flow valve is open. The closed installation is recommended for all intermittent and most continuous flow installations. When employing a closed installation for continuous flow, it is generally a good practice to install one or more intermitting valves below the continuous flow valves in order to unload the fluid in the annulus more readily.

An accumulation chamber installation is a variation of the closed type which is particularly adapted to low productivity index—low bottom hole pressure and high productivity index — low bottom hole pressure wells. The chamber can be constructed of large pipe run on the end of the tubing string or devised by running two packers far enough apart to allow for a properly designed chamber. In either case a standing valve must be installed above the perforations and an eductor tube extended to lower end of the chamber. The chamber enables the operator to drop the point of gas injection to the lower end of the eductor tube in the chamber and increase the volume of fluid recovered per cycle by affording a larger volume for feed-in buildup of reservoir fluids.

The open type of installation eliminates the use of a packer or standing valve. This installation is occasionally recommended for wells having a high productivity index and high bottom hole pressure. Differential valves are suited to this type of installation whereby the well can be produced by continuous flow with the addition of input gas pressure upon the face of the formation.

A few of the special types of installations for which gas lift is applicable are; duals for producing one or more zones by artificial lift, casing flow for producing tremendous volumes of fluid, and macaroni strings for running inside of tubing which cannot be pulled.

Design Data and Application

Before an installation can be efficiently designed, the operator should furnish as much of the following information as possible for an accurate analysis of the well's producing characteristics.

1. Daily oil production
2. Water-oil ratio
3. Producing gas-oil ratio
4. Gravity of the produced oil, water and gas
5. Tubing and casing pressures
6. Depth of well
7. Tubing and casing sizes
8. Static bottom hole pressure
9. Static fluid level
10. Flowing bottom hole pressure or productivity index
11. Wellhead flowing temperature
12. Bottom hole temperature

In addition any bottom hole sample data such as solution gas-oil ratio, saturation pressure, and liquid volume factors would aid in determining the point of gas injection for a critical continuous flow installation. Most of the above data is readily available from company or regulatory body required well tests. Other portions of the data can be reasonably assumed from field wide subsurface surveys run periodically in the majority of oil fields. If there is no known bottom hole sample data, the information required can be obtained from empirical data correlations. This empirical data is available to the producer in the form of graphs, tables, etc. However, actual field data should be used when available, rather than empirical correlations, to increase the reliability of the analysis.

Before designing a gas lift installation, it is necessary to know the maximum available and desired operating input gas pressures and gravity. Knowing this and the above well information, flowing pressure gradient traverses below and above the point of gas injection can be calculated and plotted for various injected gas-oil ratios. After determining the required injected gas-oil ratio for the desired point of gas injection and pressure differential between the casing annulus and tubing pressures at this point, a valve spacing can be calculated that will result in the most efficient operation for the stated set of conditions.

A more detailed analysis can be calculated for placing a group of wells or field on a closed rotative gas lift system. It becomes necessary to determine the casing injection and wellhead tubing pressures which will yield the maximum production at a minimum theoretical horsepower requirement. The first part of the solution is approached in the same manner as outlined above for a single well except a family of injected gas-oil ratio curves is calculated and plotted for various tubing back pressures to determine the casing annulus pressures at each point of injection. These injection pressures are then plotted versus the injection gas-oil ratios. The next step is to calculate the theoretical adiabatic horsepower requirements for each curve and plot this against the injection pressure. Hence, selection of the injection pressure that yields the minimum horsepower requirement will represent the optimum design conditions. From this optimum injection pressure, the injection gas-oil ratio can be determined from the graph of injection pressure versus injection gas-oil ratio. The flowing pressure gradient traverse above the point of gas injection can now be plotted for the optimum condition.

The method of calculating a gas lift analysis as related above is completely outlined step-by-step in a gas lift manual entitled "The Power of Gas" by Mr. C. V. Kirkpatrick, Professor of Petroleum Engineering at the University of Houston. This complete manual on the production of oil by Gas lift is published and distributed by Camco, Incorporated, in Houston, Texas.

Flow Valve Spacing Design

The top flow valve is conventionally located at the fluid level or at a depth equal to the maximum available input gas pressure divided by the static fluid gradient. The greatest resulting depth is used to locate the top differential or pressure operated flow valve.

The spacing between the differential valves depends upon the differential created by the force of the spring. To space these valves, this differential is divided by either the static gradient or 0.5. The result is the spacing in feet between the valves. The valves are run to the design depth, each being spaced the same distance apart. Back pressure is not considered in the spacing calculations. Since differential valves can be opened by excessive back pressure, the installation will only work satisfactory as designed against very low back pressures.

The spacing between pressure operated valves is calculated by dividing the operating pressure of the valve above minus the flowing gradient times the distance from the surface to the valve above, by the static gradient. The flowing gradients found in most gas lift catalogs and handbooks are greater than the actual gradient because the user of these gradients assumes the well has reached the designed rate of production from the instant the well is put on lift. Therefore, before the drawdown across the formation is sufficient to produce the designed rate of flow, the actual flowing gradient is less than the assumed. No difficulty should be encountered unloading a well whose valve spacings were calculated by using the accepted handbook flowing gradients. If the well has excessive tubing back pressure, the fundamental spacing equation must be altered to account for this pressure. The difference in calculation is the additional subtracting of the back pressure from the operating pressure of the valve above, before dividing by the static gradient. The spacing equation will space the valves consecutively closer together with increased depths. Frequently, the spacing calculations will indicate stacking of the valves near the desired working depth. Gas lift personnel have found from experience that it is unnecessary to space valves any closer than 350 to 400 feet for 2" tubing and only slightly closer for larger size tubing.

Design of Valve Operating Pressures

Before designing a string of pressure operated gas lift valves, two factors should be considered in addition to the maximum and design operating injection pressures. These factors are the temperature and the gas column weight at each valve depth. Contour maps of the geothermal gradients in Texas indicate these gradients can vary from 0.4 to 2.2 degrees F per 100 feet of depth. In other words, the bottom hole temperature of a 10,000 foot well with a mean surface temperature of 70 degree F could vary from approximately 110 degrees F to 290 degrees F, depending upon its geographic location. Most gas lift manufacturers charge their flow valves with nitrogen at 60 degrees F. Unless the injection gas has a high gravity the valves must be set at a pressure lower than the design pressure in wells with a high geothermal gradient. In the low geothermal temperature areas of West Texas where the gas lift installations are opearted by high pressure and high gravity injection gas from a gas well, the weight exerted by the column of gas is greater than the temperature effect which permits setting the valves higher than the design pressure. The temperature correction for flow valves operating in an intermittent installation will be comparable to the earth's geothermal gradient, while flow valves in wells producing high rates of water under continuous flow conditions will be operating at a significantly higher temperature.

In an installation of intermitting valves each consecutively lower valve is usually dropped in pressure with the valve near the surface being the highest pressured valve. The drop in pressure permits initial unloading of the well. When the hole is loaded with fluid and pressure is applied to the casing, all valves in the string are open because of the pressure exerted by the gas and hydrostatic column of fluid above them. The gas is metered or intermitted into the casing at a rate not to exceed the capacity of one intermitting valve port. As each flow valve is uncovered by the fluid in the casing annulus, the casing pressure drops to the closing pressure of that valve; and the valve closes. This process continues until the working valve at the designed point of injection is reached. With the casing annulus full of gas, the well is ready to intermit.

In an installation of continuous flow valves, all valves are normally charged to the same pressure. Although these valves have the same charge, only one valve at a time will theoretically pass gas. The casing annulus pressure will be less than the opening pressure of the valves above the working valve, and gas cannot enter the valves below the operating valve because the fluid column in the tubing at the depths of these valves exerts a greater pressure than the casing annulus pressure.

Since it is not necessary to drop the charge pressures of continuous flow valves, they are ideally suited to run as unloading valves in low fluid capacity wells where the operator is certain of lifting through deeper intermitting type valves. This permits higher operational pressure at greater depths. Higher injection pressures mean lower injection gas-oil ratios and higher efficiency.

Gas Lift Operational Hints

To obtain maximum efficiency after the well has been placed on gas lift, the tubing should be free of foreign matter such as paraffin and scale. The wellhead should be streamlined by eliminating all surface chokes, right angles and restrictions. If the flow line should tend to hold back pressure on the tubing, it should be enlarged or paralleled. The trap pressure should be reduced to a minimum.

The significance of eliminating unnecessary back pressure is readily apparent after calculating the foot-pounds of work performed by the isothermal expansion of one cubic foot of a perfect gas. From 900 psig to 100 psig, an 800 psig drop, 4.395 footpounds of work are available. From 100 psig to atmospheric pressuric approximately the same amount of work is developed or 4.349 footpounds. Therefore, to utilize all of the available energy from the high input pressure gas, the wellhead tubing pressure should be maintained as near atmospheric as possible.

To insure continued efficient operation of the gas lift installation, a two pen pressure recorder should be connected to the casing annulus and tubing of the well to be lifted. The flow valve operation is reflected by the casing and tubing pressures. The pressure recorded will indicate any change in flow valve performance, consequently, the operator will have a daily record of his gas lift installation. If troubles should occur the operator knows it immediately and can remedy the difficulty, thus preventing loss of production and the waste of high pressure gas.

Closed Rotative Gas Lift System

After initially charging a closed rotative gas lift system, it theoretically requires only enough make-up gas to operate the compressor's prime mover provided there are no leaks in the system. This system operates by collecting the low pressure gas from the separator and compressing it for gas lifting the wells tied into the compressor station. Providing the formation gas is of sufficient quantity to supply the needs of the system, no outside source of gas is required. Lifting costs have proved extremely low for this type of artificial lift. The initial cost of equipping several wells adaptable to gas lift for artificial lift generally favors a closed rotative gas lift system. The savings from gas lift methods will increase with depth.

Future Trend In Equipment

Wireline retrievable gas lift equipment is rapidly capturing the operator's interest. Its successful operation in conjunction with permanent type well completions has resulted in the major gas lift equipment manufacturers concentrating on the development and improvement of all types of retrievable gas lift equipment. Retrievable flow valves are ideally suited for all off-shore installations and deeper inland wells. Retrievable equipment enables the operator to correct any difficulty with his gas lift installation in less time and at less expense than a conventional installation for the reason that it is unnecessary to "round trip" the tubing. High overall operational efficiency can be maintained because the valves and auxiliary equipment can be inexpensively repaired or adjusted to fit fluctuating well and field conditions.

Advantages of Gas Lift

The primary advantages of gas lift are: (1) The initial equipment cost is low provided high pressure gas is available. (2) It is readily adaptable to deep wells. (3) High daily producing rates are possible. This is of particular importance in the depletion of a water drive field. (4) Abrasive material in the producing fluids does not appreciably affect operation of the equipment. (5) It is readily adaptable to a directional or crooked hole. (6) Maintenance costs are low and not time consuming. (7) It permits a controlled back pressure on the formation. Pressure control on the producing formation can prevent the coning of water, an excessive gas-oil ratio, and an influx of sand. (8) It permits an increased ultimate recovery. The formational energy is relieved of the work necessary to lift the oil and is utilized in moving the fluids through the

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reservoir rock toward the wellbore, thus increasing the drainage efficiency. (9) It is readily adaptable to offshore operations. This application has become more widely used with the introduction of completely retrievable wire line gas lift equipment.

There are other advantages which can result in individual isolated cases. One example of this is the operator with a high pressure gas well in the center of an oil field with no sales outlet for high pressure gas. Since there is usually a market for low pressure gas in the regulated oil fields of today, this operator could place his artificially lifted wells on gas lift and sell the gas from the gas well at trap pressure after it had been enriched lifting the oil. Another example is the operator with wells located near a high pressure gas sales outlet who desires to gas lift his wells but has no source of high pressure gas. This operator can design his compressor installation to permit sales of all excess formation gas picked up in the closed rotative system and pressured sufficiently to enter the high pressure line. The additional profit derived from the sales of high pressure gas will substantially aid in the justification of the initial capital outlay for purchasing the compressor plant.

Conclusions

Today's gas lift equipment is designed to meet the operators' various well requirements. This equipment is constructed of durable corrosive-resistant materials for long life. New design techniques are available which permit the calculation of the most efficient point of gas injection. Workover costs have been greatly reduced by the use of retrievable gas lift equipment. The retrievable gas lift flow valve plus the new well design analysis offer the operator the optimum in operational efficiency for artificial lift.