Gas Control In Producing Wells

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In the past decade, gas control in producing oil wells in reservoirs with gas caps has become one of the major problems facing the oil and gas producer. This problem has gained in significance insofar as the oil producer is concerned, since Regulatory Bodies have increased their activity in curbing the unnecessary wasting of reservoir energy. Evidence of this fact is shown by the downward trend in permissible gas-oil ratios for many fields in the state of Texas. The Railroad Commission of Texas normally requires a general gas-oil ratio survey once each year on all producing oil wells in the field. The results of these surveys are studied, and the gas limit for each well is set; therefore, the penalized allowable is that amount of oil that can be produced with the daily gas limit. As an example, we will consider a well in a reservoir that has a limiting gas-oil ratio of 2000 to 1. We will assume that this well has an allowable of 60 barrels of oil per day; therefore, the daily gas limit for the well will be 60 times 2000, or 120,000 cubic feet per day. If the well has a gas-oil ratio of 6000 to 1, the penalized allowable will be 120,000 divided by 6000, or 20 barrels of oil per day.

It is readily seen that the high gas-oil ratio has reduced the allowable on one particular well by 40 barrels of oil per day, or approximately 66 percent. This example has been shown as a hypothetical case; however, an examination of the proration schedules issued by the Railroad Commission will reveal the magnitude of penalty oil due to the high gas-oil ratios.

High gas-oil ratios are a result of free gas entering the well bore which, necessarily, must be produced with the accompanying well fluid; therefore, the primary purpose in gas control work is to prevent the gas from entering the well bore. Work-overs, subsurface mechanical devices, and surface means of control have all been employed in an effort to control the gas problem.

Subsurface Methods of Gas Control

1. WORKOVERS

Workovers represent the greater portion of successful remedial work done in the gas control problem. These include such jobs as formation packer installations, running liners and perforating, cement squeezes, plastic squeezes, plugging agents, and selective acidization. Selection of the proper workover method is dependent upon the particular well conditions.

The first problem in the selection of an applicable workover is the determination of the source of excessive gas. It may be the result of gas coming from the cap, saturation of the oil pay by gas originally in solution in the oil, or a combination of both. In the event the source of free gas is from solution gas, it is doubtful that any workover will be successful; however, if the source of free gas is from coning or channelling, there are several workover methods that will be applicable. In any event, the first recourse will be to determine the source of free gas by means of a temperature survey. In order to obtain the best results on the temperature survey, it is necessary to produce a cooling effect on the tubing string opposite the point of gas entry into the well bore. This is accomplished by closing in the tubing and flowing the well through the casing for a sufficient length of time, usually 24 hours, to produce the necessary cooling effect. A temperature gauge is then run to the bottom of the tubing string, withdrawn, and the results analyzed. The temperature survey is a graphic plot of depth versus temperature. A normal temperature curve will show a gradual increase in temperature from the surface to the bottom of the hole with the bottom hole temperature the hottest point. The point of gas entry into the well bore will be represented on the curve by an abrupt change in the slope of the curve denoting a cooling effect. The point of gas entry on the curve can then be correlated with the depth scale to determine the zone of gas entry. The next step then will be to determine the cause of free gas entry and the possible solution to the problem.

After investigation, we may find that the free gas flow has been caused by any one of several reasons. Production rates may have been excessively high and caused the gas-oil contact to drop below the casing seat, allowing free gas to enter the well bore. Gas may be channeling around the cement job on the oil string, caused by either a poor cement job or by acidizing around the cement. Also, we may find that the oil string was set too high during the completion process and a portion of the gas zone was left open to the well bore.

In order to determine what workover will be applicable, it will be necessary to determine the hole condition, permeability through the open hole, and the actual hole size. This can be done by running a permeability survey in conjunction with a caliper survey. The permeability survey is conducted by first running a spinner in the casing and establishing a zero-point by pumping fluid, usually oil, past the spinner. The spinner is then lowered out of the casing into the open hole with the pumps set on the zero-point rate. As the spinner passes permeable zones or hole enlargements, its rate of speed will drop; therefore, as the spinner passes through impermeable zones lower in the hole, the spinner speed will remain the same as that speed through permeable zones until other points of fluid loss are entered. Through correlation of the temperature survey, permeability survey, and caliper survey, the impermeable zones of the well bore can be detected.

With this information on hand, we find that the most applicable workover will be either setting a formation packer, running a liner, or possibly performing a cement squeeze. Of these three workovers, the formation packer installation is the least costly; therefore, its possibilities should be investigated thoroughly. In order to run the formation packer, it will be necessary to locate a good impermeable zone in a uniform section of the hole below the point of gas entry. If all these conditions can be fulfilled, the packer can be run and set and sealing material pumped down the casing to aid in sealing the gas above the packer. However, it might be impossible to find a good packer seat due to hole enlargement, no impermeable zone or for other reasons. If this is the case, the next most logical solution will be to run and cement a liner to bottom and perforate the pay zone.

The workover discussion thus far has been on gas control problems in wells which were completed in the open hole; however, the same problem would hold true in wells with the oil string set through and perforated. The same investigations of the gas source would be conducted in these wells as in the open hole completions. Once the zone of free gas entry had been established, the perforations could be squeezed with cement and another section perforated. Another method of shutting off the gas would be to set a production packer below the zone of gas entry and load the casing annulus with mud.

The operators of the Permian Basin Area have performed many workovers in an attempt to control the gas-oil ratios. Out of a total of 503 repair jobs completed from 1932 to 1950, formation packer installations accounted for 267 jobs, while cement squeezes and liner installations amounted to 79 and 44 jobs, respectively*. The remaining 113 jobs represented plastic squeezes, plugging agents, selective acidization, and others. Of the 267 formation packer jobs performed, 50 percent were successful.

**Lambert, T. B., and Hippard, R. M.: Summary of Gas-Oil Ratio Repair and*

Control in West Texas and New Mexico, Drill and Production Practice, API 53 (1950)

37 percent were partial successes, and 13 percent were failures. Of the 79 cement squeeze jobs performed, 40 percent were successful, 38 percent were partial successes, and 22 percent failures. Of the 44 liner installations, 55 percent were successful, 34 percent were partial successes, while 11 percent were failures. The average life of these jobs was found to be from two to three years. For the purpose of this discussion, the success rating was given to those jobs which reduced the gas-oil ratio below the field limit for a period of from six to 12 months. Partial success was applied to jobs which reduced the gas-oil ratio appreciably for a period of from six to 12 months, but still above the field limit. Also, any job which reduced the gas-oil ration below the prevailing field ratio for a period of approximately six months and gradually rose to the pre-workover level was rated a partial success. Failure was the rating applied when an apparent gas-oil ratio reduction was realized.

In one field, an operator installed 84 Guiberson Spiral formation packers during the years 1945, 1946, and 1947 in an effort to reduce gas-oil ratios. Each packer was set on the basis of information obtained from the temperature, caliper, and permeability surveys. Of the 84 formation packers installed, 43 percent were successful, while the remaining 57 percent were classified as partial successes. The average life of these jobs was approximated at two and one - half years.

In summarizing workover applications, we can say that workovers are most applicable in wells which have a source of free gas such as gas coning or channelling. If the gas problem is caused by gas from solution, a workover will probably be unsuccessful. In order for formation packer installations to be successful, the formation must contain impermeable zones with a uniform wall face which will offer conditions suitable for the packer seat. This packer seat must be a sufficient distance below the point of gas entry to afford a complete shut-off. Liners may be installed in wells which will not suffice as formation packer installations. In the event the well is cased to total depth, cement squeezes or production packers set in the perforations would offer a mean of gas control.

II. MECHANICAL DEVICES

A. Bottom Hole Chokes

Bottom hole chokes are used primarily as a means of controlling excessive gas volumes at high pressures which in many cases cause freezing conditions in the well head surface equipment and flow lines. Bottom hole chokes are essentially positive choke beans which can be set by means of a wire line unit at any pre-determined point in the tubing string. The bottom hole choke assembly consists of a plug bean housed in a cage assembly and attached to the lower end of a mandrel assembly. The mandrel assembly consists of a carrier mandrel which provides the fishing neck for the tool during running and pulling operations, the slip assembly for locking in place in the tubing, and packing rings which prevent flow of fluid past the tool when set.

Bottom hole chokes have been used successfully to combat the problem of surface control freezing in a number of high pressure flowing wells in the Permian Basin Area. By setting the bottom hole choke in the lower portion of the tubing string the point of pressure drop has been moved from the surface choke to a point down the hole which allows the bottom hole temperature to act as a heater on the expanding gases moving out of the well bore. In this manner, the well fluid and gases reach the surface at sufficiently high temperature to prevent freezing conditions in the well head equipment.

B. Plunger Lift

Even though plunger lift is a method of artificial lift, it has been used as a means of reducing gas-oil ratios. This type of gas control mechanism has been used in wells which have reached the depletion stage where the bottom hole pressure is insufficient to produce normal flowing characteristics but still have high gas-oil ratios.

The plunger lift system is composed of an expanding type free plunger, removable bottom hole stop, bumper housing assembly, and a flow line controller. The free plunger contains a valve which is the only operating element in the system. A brief description of the operation of this lift system is as follows: The free plunger is inserted into the tubing string with the plunger valve open and allowed to fall to the bottom stop. When the plunger strikes the bottom stop, the plunger valve is automatically closed. During the descent of the plunger, the well is closed in and the casing pressure rises. The plunger remains on the bottom stop until the pre-determined casing pressure high - point is reached. When this casing pressure high-point is reached, the flow controller automatically opens the well which allows the tubing pressure to decrease rapidly. The rapid decrease in tubing pressure causes the free plunger to move upward. As the plunger moves from its surrounding fluid, the gas below the plunger expands at an increasing rate and propels the plunger to the surface with its load of fluid. At the time the plunger strikes the bumper housing on the well head, it activates a pneumatic control which closes in the flow line. Upon striking the bumper housing, the plunger valve is also automatically opened and the plunger falls for another cycle of operation.

As shown in the operating cycle, the plunger forms a seal between the fluid to be lifted and the solution gas below the plunger. This seal prevents much of the slippage of free gas through the fluid during the flow process and, for that reason, may be an aid in gas-oil ratio reduction.

Plunger lift is most applicable in wells with the following characteristics: (1) The bottom hole pressure should be a minimum of 400 psi; (2) a P. I. of 0.2 or less is recommended; (3) the gas-oil ratio should be a minimum of 250 - 350 cubic feet per barrel per 1,000' of lift; and (4) the gas-oil ratio should not exceed 10,000 to 1.

The success of the plunger lift as an instrument in gas-oil ratio control is doubtful. From information obtained from several operators using the plunger lift, it can be concluded that the lift system has been used chiefly to prolong the flowing life of the well and not as a gas control measure; however, in some instances, the gas-oil ratio has been reduced below the normal flowing ratio of the well.

Surface Methods of Gas Control

I. STOP-COCK FLOW

Stop-cock flow is probably the most used surface method of gas control in the oil industry. Through this method of flow, the well's allowable may be produced during one continuous flow period or through a series of short-time flow periods, depending upon the flow characteristics of the individual well. In either case, stop-cock flow is normally controlled by the use of intermitters or flow controllers, either pressure operated or time controlled.

Gas-oil ratios can be reduced by the stop-cock flow method; however, it is necessary to make preliminary investigations of the well's flowing characteristics. If the well is a low productivity well with a large volume of free gas, it will have the normal tendency to flow the oil out of the well bore and then blow around the bottom of the tubing, producing nothing but gas and a mist of oil. To successfully stop-cock this well, it will be necessary to conduct sufficient tests to determine the maximum amount of oil that can be produced for a given length of time and still maintain an oil seal in bottom of the hole. By leaving the oil seal after each flow period, the free gas cannot blow around the bottom of the tubing. Once the stop-cock flow rates have been established, the automatic flow controllers can be installed and put into service. This same procedure of testing would also apply to a high gas-oil ratio, high productivity well. In either case, the information needed is the stop-cock flow interval that will produce the allowable at the lowest gas-oil ratio.

The success of stop-cock flow as a gas control measure has varied, depending upon the individual well characteristics and the manner in which the preliminary tests were conducted. Stop-cock flow is not a permanent gas control measure by any means; however, many operators in the Permian Basin Area have found that by using this means of flow many barrels of would-be "penalty" oil have been recovered.

II. Production Unit Plan

The production unit plan can be used as a means of gas control because, under this plan, it is permissible to close in certain wells and transfer their allowables to other wells in the same unit. This type of plan has been used in several fields in the Permian Basin. The size of units are determined by hearings, and in each case generally a maximum of one-half of the wells can be closed-in, their allowables being transferred to the other wells in the same unit.

The conditions which control the production unit plan are as follows: (1) When closing in wells in a unit, the highest ratio wells must be closed-in first; (2) no more than one-half of the wells in a unit may be closed-in; and (3) the amount of oil transferred to a producing well cannot exceed its own allowable.

It can be understood that this plan of gas control has certain limitations. It is most successful on leases which contain relatively large blocks of contiguous acreage; also, there should be a sufficient number of low ratio wells capable of producing the transferred allowable. When these conditions can be met, it is possible to produce the lease allowable at lower gas-oil ratios.

Summary

Gas control problems are most prevalent in fields which contain either an expanding gas cap or solution gas type depletion mechanism. In these types of reservoir, it is the natural tendency for the gas-oil ratio to increase with the increase in cumulative production and the decrease in bottom hole pressures.

In summarizing, we can say that, where favorable conditions exist, gas-oil ratio reduction can be accomplished through the proper application of workovers, this being true primarily in reservoirs with expanding gas caps. The conditions are found in many of the wells in the Permian Basin Area which are produced from limestone and dolomite. The physical characteristics most favorable are: (1) relatively thick pay sections and (2) impermeable zones between the oil and gas deposits which will prevent intra-zonal communication and provide suitable packer seats. Factors which make gas control difficult are: (1) gas coning or an expanding gas cap drive which causes the continual lowering of the gas-oil contact, (2) vertical permeability or vertical fracturing which causes intra-zonal communication, and (3) premature reduction of bottom hole pressure below the saturation pressure, thereby forming free cap in the oil saturated zones. In fields where unfavorable conditions exist, it is still possible to gain some benefits from gas-oil ratio work.

The use of subsurface mechanical devices in gas-control work is limited; at best they are a temporary means of reducing gas-oil ratios. Surface methods of gas control, such as stop-cocking and production unit plans, provide an economical method of gas-oil ratio reductions; however, these methods are also temporary and require the constant vigilance of the operating personnel. Therefore, we may conclude that gas control work will not fall into any uniform pattern for any particular field or area, but is dependent upon the characteristics of each individual well.