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FOCUSED TECHNOLOGY WORKSHOP MANUAL

Marginal Gas Well Production Technology & Techniques

Farmington, New Mexico

Robert Blaylock
Project Director

June 24, 1997

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Petroleum Technology Transfer Council
FOCUSED TECHNOLOGY WORKSHOP

Marginal Gas Well Production Technology & Techniques
June 24, 1997
Farmington, New Mexico

AGENDA

8:00	Registration
8:30	Introductions
8:45	Plunger Lift Design & Operation
10:00	Break
10:15	Automatic Casing Swab
11:00	Downhole Injection Tool
12:00	Lunch
1:00	Sucker Rod Pump & Rod String Design
2:00	Self Agitating Soap Stick Design
3:00	Break
3:15	Velocity String Sizing & Installation
4:00	Open Forum Discussion
5:00	Close

TRAINING/TROUBLESHOOTING GUIDE FOR PLUNGER SYSTEMS

Dan Phillips and Scott Listiak
Conoco Inc.

ABSTRACT

Plunger lift has become a very popular and economical artificial lift alternative, especially in high GLR gas and oil wells. Success in plunger lift systems depends on proper candidate identification, good wellbore mechanical integrity, and the effectiveness of the production or lease operator. This paper will focus on the production operator, and describe the basic principles necessary for effective training and the sound operation of a plunger lift system.

In many instances the plunger controller is the main focus of training. However, a clear understanding of why a plunger system is needed, the proper operating parameters, and the relationship of IPR curves and unloading rates are more important to effective operator training. If an operator does not clearly understand these principles, a plunger system is unlikely to be operated at peak efficiency. Knowing how a gas well loads up, what options exist to remedy this problem, and what the remedies actually accomplish are necessary to maximize efficiency and profits.

This paper describes foundational principles required to understand and operate a plunger lift system, and explains some common misconceptions. Also included are a description of plunger parts that need to be maintained, a parts "survival kit", a description of some common problems to plunger operation, and a basic trouble-shooting chart. With this information an operator will be able to keep a plunger system running efficiently in order to maximize well production.

BACKGROUND

A plunger is a pipeline pig that runs vertically in a well to remove liquids from the wellbore. As a gas well declines, it loses its ability to lift liquids, due to the fact that gas velocity declines and liquid droplets fall to the bottom of the wellbore. These liquids need to be removed to ensure minimal back-pressure and optimized production. A plunger fulfills this task of liquid removal. A plunger cycle consists of three stages **(Figure 1)**. In stage one-- shut-in-- the well is shut-in to build casing pressure required to lift the plunger and a liquid column. In stage two-- unloading-- the tubing is opened and stored casing pressure lifts the liquid column and plunger to the surface. In stage three-- afterflow-- the well is allowed to flow while the plunger is at the surface. During afterflow, the well is producing gas and flowing liquids into the wellbore in preparation for the next shut-in period. At the end of the afterflow period, the well is shut-in and the plunger falls to the bottom of the well. A more detailed explanation of plunger operation can be found in the references **(1,2,3,4,5)**.

In Conoco's installation of over 200 plunger lift systems in the San Juan Basin, it was learned that the plunger operator is the single most important factor in keeping a plunger system operating efficiently. If an operator knows certain foundational principles of plunger operation and gas well mechanics, he can effectively maintain and trouble-shoot his system. His goal will be to optimize the system, keep a good maintenance schedule, and attempt to flow the well against the lowest pressures possible. If an operator does not understand these principles, a system will lose efficiency due to maintenance, and probably not be optimized. An operator who does not understand basic principles may try to "just keep the plunger running," and he may be frustrated when the system does not work well.

One of the best improvements in plunger technology has been the addition of microprocessors to control plunger cycles (6). These new electronic plunger systems reduce operator time spent in lining out a system, and optimize run times. However, operators are still necessary for maintenance, troubleshooting, and for recognizing conditions which indicate a plunger is not operating efficiently. With the understanding of certain foundational principles, an operator can become effective at plunger operation and ensure maximum production from plunger lifted wells.

FOUNDATIONAL PRINCIPLES

What principles does an operator need to know to effectively manage a plunger lift system? An operator must be familiar with Inflow Performance Relationships (IPR), the prediction of loading conditions, interpreting tubing and casing pressures, and the importance of plunger seal and velocity. How well an operator knows these foundational principles can lead to the success or failure of a plunger system.

Inflow Performance Relationship (IPR) Curves

IPR curves (7,8) for a typical low pressure and high pressure gas well are shown in **Figure 2**. An IPR curve describes the effects of flowing pressures on production rates. The concept is simple: The lower the flowing pressure (same as back-pressure), the higher the production rate. At a flowing pressure equal to reservoir pressure, a well will not produce. At a flowing pressure of zero, a well will produce its absolute open flow (AOF), or at its maximum rate. The operator's goal in producing a well efficiently should be to produce at the lowest possible flowing pressure.

Another important concept to understand about IPR curves is their dependence upon reservoir pressure. Higher pressure wells are much less sensitive to changes in flowing pressure than are lower pressure wells. A curve for a higher pressure gas well is shown in **Figure 2**. For every 100 psi reduction in flowing pressure, flow rate increases approximately 60 mscfd. For the lower pressure well a 100 psi reduction in flowing pressure amounts to a flow rate increase of approximately 100 mscfd. The lower the reservoir pressure, the more sensitive a well is to small changes in flowing pressure.

Unloading Curves

Most gas wells produce some liquids, and at some time will experience liquid loading. As a gas well depletes, production rates fall. When gas velocity in the tubing falls below a minimum unloading velocity, liquids will accumulate in the wellbore. This accumulation builds a liquid column in the bottom of the tubing and increases flowing pressure (back-pressure). As shown in the IPR discussion, this will inhibit well production. The gas velocity at which liquids accumulate is predictable, and can be related to flowrates in various tubing sizes (9). Unloading curves show this relationship (**Figure 3**). Using these curves, an operator can determine whether a well may be in a loaded condition. Of additional importance is an understanding of the effect of surface flowing pressure on the minimum unloading rate. At lower surface flowing pressures a lower flowrate is required to keep a well unloaded. At higher flowing pressures, a higher flowrate is required. With this in mind, the goal for the operator in keeping a well unloaded is to operate at the lowest possible flowing pressure.

Tubing and Casing Pressures

It is important for an operator to understand the meaning of tubing and casing pressures. This data provides a wealth of information that can be used to determine if a well is loaded or experiencing mechanical problems. A typical gas well produces through tubing with the casing shut-in. Usually, the tubing is either hanging open-ended or a packer is in the well. The following discussion will focus on wells that do not have a packer. The equations listed below describe the meaning of flowing tubing pressure and shut-in casing pressure in a well with hanging tubing.

FTP = FBHP - Tubing Friction - Scale/Paraffin - Flowing Gas Column - Stagnant Liquid

FTP = Flowing Tubing Pressure
Tubing Friction = Pressure loss due to flowing gas friction in tubing
Scale/Paraffin = Pressure loss due to scale or paraffin buildup on the inside of tubing
Flowing Gas Column = Pressure exerted by weight of gas column in tubing
Stagnant Liquid = Pressure exerted by weight of stagnant liquid (loaded well)

FSICP = FBHP - Gas Column - Stagnant Liquid in Casing

FSICP = Shut-in casing pressure measured while the well is flowing up the tubing
Gas Column = Pressure exerted by weight of gas in casing
Stagnant Liquid in Casing = Pressure exerted by weight of liquid in casing

An optimized well will normally produce with the flowing shut-in casing pressure slightly higher than the flowing tubing pressure. The difference between the pressures is flowing gas friction in the tubing. For example, a typical San Juan Basin gas well flowing at 200 mscfd in 2-3/8" tubing has a pressure loss of 30 psig due to friction. An optimized producer will flow at a flowing tubing pressure of 100 psig and a flowing shut-in casing pressure of 130 psig (**Figure 4**).

If a well has a high differential between the tubing and casing pressures (higher than estimated friction pressure), there is a problem. The most common problems are plugged or crimped tubing, or liquid loading. The reason crimped or plugged tubing causes a differential is obvious. Liquid loading is not so obvious. When a well loads up, most of the liquids in the wellbore will try to flow up the tubing. If the casing is shut-in, the tubing is the only place that liquid can go. The liquid will build a column in the tubing until the well will not flow, or the well only bubble a small amount of gas out of the perforations. As long as the well is open to flow and loaded up, there will be a high differential pressure between the tubing and casing. This is exactly like the effect of a manometer, and tubing pressure + the liquid column will equal the casing pressure. This condition is shown in **Figure 4**, and can been seen in the tubing and casing pressures of 100 and 220 psig, respectively.

Tubing and casing that are at the same pressures while flowing can also indicate well problems. The most common are tubing leaks or casing leaks. If there is a tubing leak (**Figure 4**), gas will flow up both the tubing and casing and enter the tubing at the leak. The minimum unloading rate changes in this situation, since the area of flow increases to include both the tubing and casing, and the well easily becomes loaded. Liquids accumulate in both the tubing and casing since there is flow in both places. Eventually, the well will load up completely and leave no tubing or casing differential. In a casing leak, a lack of differential pressure could be seen due to flow from the leak or into the leak.

The last case-- where tubing pressure is higher than casing pressure-- is not normal unless the tubing is shut-in and the well is being flowed up the casing. If the well is not flowing up the casing, this could be an indication of a casing leak (**Figure 4**), bad surface gauges, a packer in the hole, or leaking surface equipment.

Plunger Seal and Velocity

Plunger seal and velocity control the efficiency of lifting liquids in a plunger lifted well, and are the two most important contributions to running the system efficiently (6, 10). Plunger seal is the interface between the tubing and outside of the plunger. A plunger does not have a perfect seal. This allows the plunger to drop through liquids when falling to the bottom of the well, and allows gas to flow by the plunger when lifting liquids and moving up the tubing. If the seal is efficient, minimal amounts of gas will flow by the plunger when lifting liquids, and the gas energy will be used to push the plunger and liquid column. If the seal is inefficient, a large volume of gas will flow by the plunger, wasting energy and even causing the plunger to stall before reaching the surface. Various plunger types have different seal efficiencies, with a brush type plunger having the best seal, and a bar stock plunger having the worst. Plungers also lose seal efficiency due to wear. Numerous trips up and down the tubing wear the plunger's outer surfaces and reduce its seal efficiency.

Plunger velocity is the speed at which the plunger moves from the bottom of the well to the surface. For a well to be operating effectively a plunger must be traveling up the wellbore between 600 and 900 feet per minute (fpm). If plunger velocity is less than 600 fpm, the plunger is likely to stall before reaching the surface. If plunger velocity is greater than 900 fpm, the well is being allowed to build up pressure for too long, and is not producing at the maximum production rate (the well is producing at a high flowing pressure on the IPR curve). Velocities greater than 900 fpm are also rough on plunger equipment.

Plunger velocity can be easily determined by measuring the time it takes a plunger to travel from the bottom of the well to the surface (travel time), and dividing by tubing depth. Most automatically controlled plunger systems on the market today measure travel time and make automatic adjustments based on this time. However, initial settings for these systems require input of what are considered fast and slow travel times. Fast and slow times are based on whether a plunger is in the 600-900 fpm velocity window, or out of it. An operator should understand how to take target velocities (600 fpm for a slow trip, 900 fpm for a fast trip), divide into well depth and calculate a target travel time. (Ex: 9000' well/ 900 fpm target velocity = 10 minute expected travel time or quicker for a "fast" plunger run.) With this knowledge, fast and slow travel times can be determined and a plunger system can be effectively programmed.

COMMON MISCONCEPTIONS

An incomplete understanding of gas well mechanics and plunger systems can lead to misconceptions about how they function. Compounding this problem may be experiences or rules of thumb used with flowing oil wells or wells on beampump. Following is a collection of common misconceptions about plunger lift systems. The **underlined statements are false**, and are followed by an accurate explanation.

A well loads up when it is shut-in. A well actually loads up when it is flowing. When a gas well is shut-in, there is little or no flow into the wellbore. In light of IPR curves, this is obvious. Some flow will occur when the well is first shut-in, but gas will quickly "pressure-up" the casing and tubing, and fluid flow will cease. Liquids will not enter the wellbore once flow has ceased, and therefore the well cannot "load-up". In fact, after shut-in, a well will tend to push liquids back into the formation (this is one reason why shutting in a well overnight can help get the well flowing again the next day). As the well is left shut-in, gravity segregation will cause gas to migrate out of the perforations and to the top of the wellbore. As gas pressure in the well builds, liquid is forced out of the casing and tubing and into the formation, actually reducing the amount of liquid in the wellbore. A technique that can speed up this process is equalizing the tubing and the casing at the surface. This forces gas in the casing to flow into the tubing at the surface, and allows the liquid levels in the tubing and casing to equalize.

There is one exception to this condition. If the tubing is set below gas entry (below the perforations) gas will not migrate down to enter the tubing during gravity segregation. Therefore, liquids that started in the tubing will remain in the tubing when gravity segregation occurs. As the well builds pressure, additional liquid in the casing can actually be pushed down and into the tubing. The well can build a greater liquid column in the tubing due to gravity segregation. A more detailed explanation of the effects of tubing depth on gas well loading is presented in following sections.

This misconception that a well loads up when it is shut-in is most likely a carryover from beam-pumped oil wells. A typical beam-pumped well has a pumping unit that is oversized, and can pump much more fluid than the well can produce. As the well becomes pumped down, the pumping unit is shut-down to allow fluids to enter the wellbore. The fluid level in the well builds and the well can then be pumped again. There is one major difference between a shut-in beampumped well and a shut-in gas well (on plunger lift). In a beampumped well, only the pumping unit is shut-in. Usually the casing is left open to the flowline to allow gas to be produced. The well is never shut-in, but left open to gas and oil inflow into the casing. In a plunger-lifted gas well, the entire well is shut-in, eliminating inflow after the well equalizes.

Choke Back Your Well to Keep From Loading Up. In most cases, choking back a well may prolong the amount of time a well will flow, but it will not prevent a well from loading and it will limit gas production. Well loading is controlled by gas velocity; gas velocity is proportional to flowing tubing pressure. Figure 3 shows the relationship between flowing tubing pressure and minimum unloading rates. As you increase the flowing tubing pressure (choke back the well), it takes an increasing amount of gas rate (gas velocity per flow area) to keep the well unloaded. Turner, Hubbard, and Dukler (9) showed that this is due to gas expansion and the fact that a given mcfd (or flow rate) of gas takes up more space at lower pressures. At lower flowing pressures, expanded gas flows at a higher velocity for a given flow rate. At lower pressures, less flow rate is required to keep velocity in the tubing above the minimum unloading velocity.

It is interesting to note that most operators will agree that blowing a well to atmosphere can help unload liquids, but many may still operate a well against a choke to prolong well production. Blowing a well to atmosphere unloads liquids by reducing wellhead pressure to 0 psig. The unloading rate required to move liquids is at its minimum when flowing against a wellhead pressure of 0 psig. This can be seen in Figure 3. One additional point about choking back a well: flowing a well against a choke may prolong the time a well will flow before loading, but the volume will still be less than if the well was opened completely from the beginning.

It Is Better to Operate a Plunger at a higher casing pressure-- Long Shut-in Times. An understanding of the Inflow Performance Relationship shows this to be untrue. Operating a plunger at high casing pressures may result in guaranteed plunger trips, but it will ultimately hurt well production. J.D. Hacksma (11) stated the problem as follows:

> "The producing tendency of plunger lift is directly opposed to that of the well. Plunger lift requires an increase in casing pressure for increased production whereas the well itself requires a decrease in casing pressure for increased production. The compromise that always yields the greatest production is found when cycling the plunger at the maximum frequency possible without killing the well."

In summary, a plunger will lift more liquids with higher casing pressure, but a well has more production at a lower casing pressure (See the IPR curve discussion above and **Figure 2**). An operator's goal should be to produce the well at the lowest possible casing pressure, with the highest frequency of plunger trips. This will keep casing pressure at a minimum and well production at a maximum.

Set the Tubing Below the Perfs in a Plunger System (like a pumping unit). A good rule of thumb for gas wells is to set the tubing across from gas producing perforations somewhere between the middle and top perforations. (Also, the smaller the tubing, the higher the tubing should be set.) A higher pressure, higher rate gas well is very forgiving on this point, but setting the tubing too low or too high can be disastrous for a lower pressured gas well (like those typically put on plunger lift).

When tubing is set below the perforations (**Figure 5**), all gas and liquid produced from the well must travel down to the bottom of the tubing and up through the tubing. Any time the well goes down or is shut-in, such as during a pipeline shut down, facility problems, or normal plunger operation; liquids fall down to the bottom of the wellbore. Gravity segregation will occur, allowing gas to push liquid into the perforations, but any liquid below the perforations remains in the wellbore or gets pushed into the tubing. When the well is opened again, gas must force all the liquid in the tubing and casing out of the well before the well becomes unloaded. Compounding this problem is the fact that the casing usually holds a larger volume of liquid per foot than the tubing does, and this volume can become a large hydrostatic pressure when forced into the tubing. For example, in a well with 5-1/2" casing and 2-3/8" tubing set 15' below the bottom of perforations, one quarter barrel of liquid occupying 15' of tubing/casing annulus below the perforations will occupy 65' in the tubing, increasing the hydrostatic pressure 4.5 times. A small column of liquid in the tubing/casing annulus can quickly become a large column of liquid in the tubing. For plunger operation, this situation requires a much higher casing pressure to keep the system operating (in direct opposition to the IPR).

The problem with tubing set high above the perforations is more obvious (**Figure 5**). Flowrates required to unload liquids in casing are much higher than those in tubing, so the space between the end of tubing and the top perforation can allow liquid to settle and increase back-pressure.

Plunger Weight is the Most Important Contribution to Efficient Plunger Operation. Plunger weight actually makes very little difference to a well. Most plungers are about 1.5' long and weigh 10-15 pounds. The pressure required to lift a 15 pound plunger in 2-3/8" tubing is about 5 psi (Psi = Wt / Area). This energy is usually minimal when compared to the pressure required to lift a slug of fluid. A plunger weighing 5 pounds would only conserve about 3 psi of pressure. More important than plunger weight is plunger seal efficiency. A plunger with a good seal allows less gas to flow by, and increases lifting efficiency (6,10).

It Is More Difficult to Operate a Plunger Lift System in Large Tubing. In most cases, it is easier to operate a plunger in larger tubing. A liquid slug requires less pressure to lift in larger tubing than in smaller tubing. For example: One barrel of liquid requires a minimum of 75 psi of pressure in 2-7/8" tubing versus 112 psi in 2-3/8" tubing (not accounting for pressure/gas slippage). Equipment costs do increase as tubing size increases, so although it is easier to operate a plunger in larger tubing, it may not be economically feasible to do so.

PLUNGER MAINTENANCE

A well maintained plunger system will operate more efficiently and achieve higher production rates. An operator should be familiar with the maintenance of the mechanical and electronic components of a plunger system. Parts requiring regular maintenance are the plunger and lubricator spring. Other equipment needs to be inspected periodically, but should require minimal maintenance.

Plungers

Plunger seal efficiency is extremely important in getting the maximum production from a plunger lift system. Over time, plungers will become worn due to contact with the tubing, and lose diameter. This loss in diameter results in a loss of plunger seal efficiency. Most plungers should be changed every six months to a year depending on the type of plunger, number of cycles, fluid type, and GLR.

Lubricator Spring

The lubricator spring buffers the plunger's impact at the surface. After a period of 6 months to 1 year of service, the spring will become fatigued, allowing the plunger to wear quickly from hard impacts at the surface. A good lubricator spring will extend plunger life and save money, since a spring is usually about 1/2 to 1/8 of the cost of a plunger. Factors that affect lubricator spring wear are the number of plunger cycles, fluid type, GLR, plunger weight (the heavier the plunger, the harder the impact), and the speed of the plunger when making trips.

Control Valves

The control valves rarely need maintenance unless operated in a corrosive environment. Control valves, however, should be kept in the trouble-shooting process. A leaking valve can prevent a well from being completely shut-in, inhibiting proper pressure buildup in the casing, or allowing liquid to enter the well during shut-in and increasing liquid slug sizes. Also, tank venting valves that do not open properly can keep a plunger from making trips.

Electronics

The electronic components of a plunger lift system include an electronic controller module (a programmable logic controller), latch valves, a battery, a plunger sensor, and a solar panel. These components are fairly reliable and do not often fail. They should withstand at least 2 years of service. Latch valves may fail more frequently if the supply gas is not dry and clean.

Survival Kit- Be Prepared

Many times wells are located in remote areas. If a plunger system fails, parts may be hours away. For this reason, it is a good idea to carry a "plunger survival kit" (**Figure 6**). A kit should include surface springs, plungers, o-rings, filters, fuses, wire clips, extra plunger sensors, cleaner and lubricants for the sensors, motor valve seats & trims, and additional controller modules and latch valves.

Tracking Maintenance

Tracking plunger maintenance and failures is as important as tracking any artificial lift system. The more data available about a particular well, the easier trouble-shooting can be. Tracking failures and problems also leads to establishing patterns of operation that can lead to improved production. An example of this is shown in **Figure 7**. This shows a well that was in need of a plunger change, and the effect after the plunger was changed out. Good tracking may have indicated a plunger change was necessary earlier. **Figure 8** is an example of a Plunger System Tracking form used by Conoco. This form is completed for all plunger system changes or failures and is available as a reference to operators when trouble-shooting wells.

TROUBLE-SHOOTING

Figure 9 is a chart that can be used to aid in troubleshooting a plunger lifted well. On the left side of the page are symptoms of plunger lift problems. Solutions are listed across the top of the page and ranked in order of the most likely solution. The guide should be useful for most electronically controlled plunger systems that base plunger runs on time (not pressures). Definitions to some of the terms used in this chart can be found at the end of this paper.

Some of the most common problems when installing and operating a plunger lift system are listed below:

Tubing Problems. Tubing problems include tubing leaks, crimped tubing, and tubing set too high or too low. Any of these problems almost guarantee plunger failure. Tubing leaks can be detected from tubing and casing pressures. Tubing depth should be in the middle to upper half of the perforations (or other depths if there is gas inflow). Checks for damaged tubing should be conducted with wireline gauge ring runs before plunger installation.

Wellhead Problems. Wellhead problems can be either leaks or variations in the internal diameters within the wellhead. A wellhead leak can be examined by inspection. Variations in ID can prevent a plunger from reaching the surface and being detected by the plunger sensor. If the internal diameter of the wellhead is larger than that of the tubing, gas can by-pass the plunger in the wellhead, and the plunger will never travel into the lubricator assembly. If wellhead ID's get larger and smaller, the plunger can be caught on the bevel or "lip" of a wellhead component. The solution is to change components on the wellhead so that there is a constant ID from the tubing to the lubricator spring.

Plunger Sensor Errors. The plunger sensor is the acoustic or magnetic component that detects plunger arrival at the surface. When the plunger reaches the lubricator assembly (usually travelling at 800 feet per minute) there is a loud collision. The sensor detects this sound and records a plunger's arrival. If the electronic controller does not detect plunger arrival, it can not make adjustments to keep the plunger operating efficiently. Errors in this sensor include sensor failures, broken wires in the sensor, the sensor sticking in sensing mode, dirty components, poorly adjusted sensitivities, and improperly connected sensors. In magnetic sensors, a plunger may get stuck in the wellhead, causing the sensor to read the plunger at all times.

Incorrect Controller Settings. An electronic controller is designed to make adjustments to optimize the plunger lift system, but controller settings must still be programmed by the operator and make sense. Settings that are of vital importance are 1) travel time window settings, 2) incremental change settings, and 3) initial shut-in and afterflow settings. Travel time window settings consist of a fast trip time, slow trip time, and a "no-trip" time. These settings are based on well depth and target plunger speeds of 600-900 feet per minute. If the electronic controller senses that a plunger is arriving outside of this time window, adjustments will be made to the system. If the window is set incorrectly, the controller will make unnecessary adjustments to the system.

Incremental change settings control how much time is added or subtracted to the shut-in or afterflow times when the plunger is not arriving within the travel time window. If the increments are too large (over 15-20 minutes), the plunger may never find the proper window. If the settings are too small (less than 1 minute), the controller will take an extremely long time to get the system running efficiently.

Initial shut-in and afterflow settings define where the plunger system will begin operation. These settings should be set as closely as possible to shut-in and afterflow times expected during continuous operation.

However, if an estimate of operating shut-in and afterflow times is unknown, initial settings should be set conservatively. Initially, a longer shut-in time and shorter afterflow time will insure that the plunger will make trips, and with proper time window settings, the system should eventually make adjustments to minimize shut-in and maximize afterflow.

Not Accounting for Large Line Pressure Increases. Most electronic controllers are designed to handle small changes in line pressure and still keep the plunger lift system optimized. However, large line pressure increases like those caused by compressor or system shut-downs can keep a plunger from making trips. If these system upsets occur frequently enough, additional planning or equipment, such as high line pressure delays and tank vent valves, may be necessary. High line pressure delays are devices used to postpone plunger operation until line pressure is in the normal operating range. If line pressure is too high, the plunger lift system will be delayed one or two cycles until pressures return to normal. A tank vent valve is a motor valve installed to allow gas to flow to an oil tank instead down the sales line. If the plunger does not reach the surface after a given amount of time, the electronic controller will open the tank valve. This will allow gas flow to atmospheric pressure in the tank, reducing the surface back-pressure on the system. When the plunger reaches the surface, the tank valve shuts and allows gas to flow to the sales line. The only drawback to this method is that a portion of the well's gas volume is vented.

CONCLUSIONS

Proper operator training and knowledge of foundational principles can lead to the success or failure of a plunger lift system. An operator should be familiar with gas well mechanics such as IPR curves, unloading curves, interpretation of tubing and casing pressures, and factors that influence good plunger operation (plunger velocity and seal efficiency). An operator should also be able to adequately track plunger performance and trouble-shoot plunger lift systems. With these skills, an operator can be assured of peak plunger lift performance.

DEFINITIONS

Afterflow--	flow from well after plunger has arrived at surface.
Catcher--	plunger catcher located on top of wellhead
Fast Plunger Arrival--	the time it takes the plunger to travel from bottom to surface is faster than the target time for good operation.
Fatal Error Code--	electronic controller module shows system not working
Good Trip--	plunger arrives at surface within a proper time window
Latch Valve--	valve in control box that electronically controls supply gas to motor valves
Module--	circuit board holding electronic components located in plunger control box
No Count--	plunger controller fails to count plunger arrival at surface
Plunger Error-	An error code indicating the system has been shut-in due to the plunger either not arriving at surface, or arriving slowly.
Sales Valve--	motor valve that opens and shuts-in well
Sensor--	Acoustic or magnetic device used to sense plunger arrival at the surface.
Sensor Error--	Error code indicating sensor switch is making permanent contact-- sensor has failed
Settings--	Plunger parameters input into the plunger controller box
Slow Plunger Arrival--	the time it takes the plunger to travel from bottom to surface is slower than the target time for good operation.
Tank Valve--	valve that can allow gas flow to a tank instead of sales

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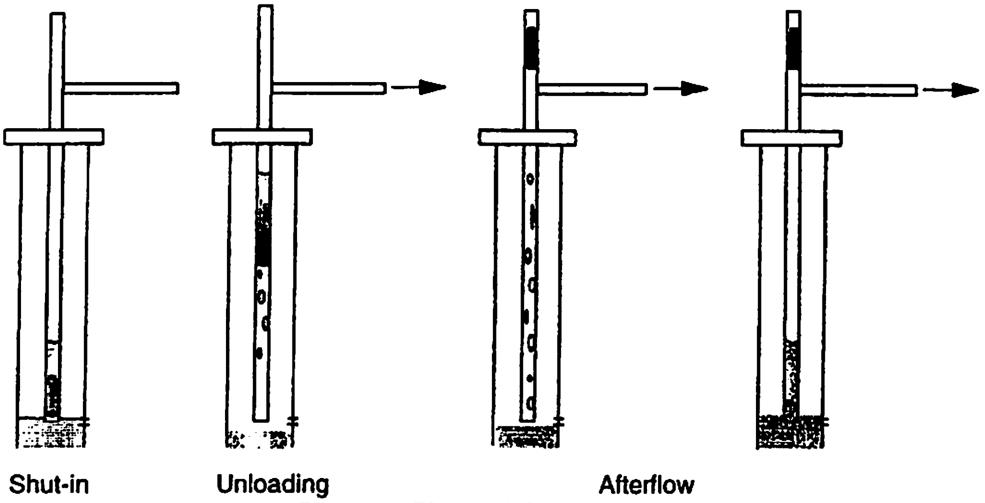

Shut-in
Unloading
Afterflow

Figure 1 - Plunger Lift Cycles

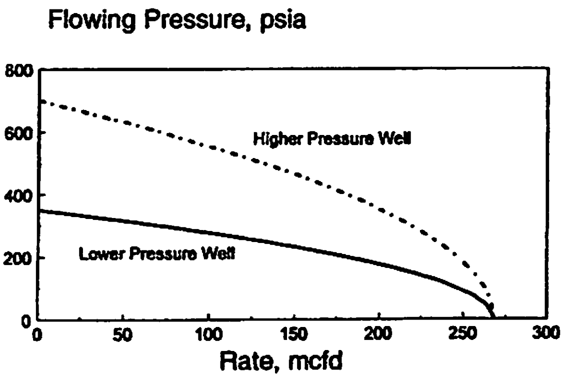


Figure 2 - Typical IPR Curves for a San Juan Gas Well

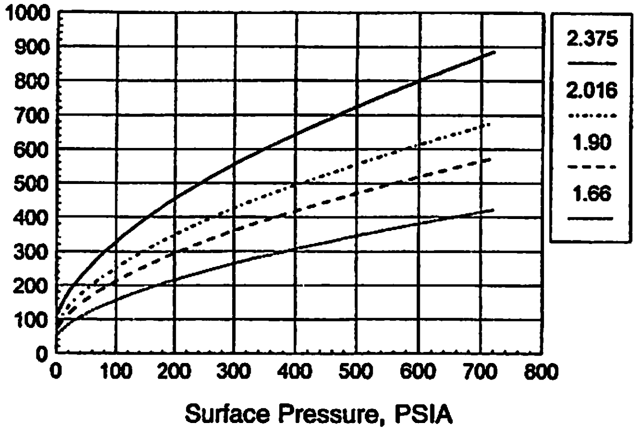


Figure 3 - Turner et al Unloading Rates for Various Tubing Sizes

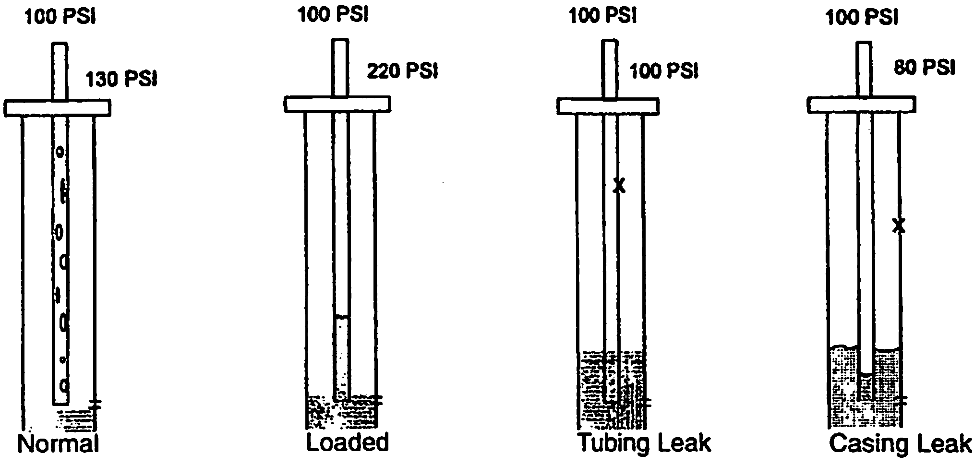

100 PSI
130 PSI
Normal
100 PSI
220 PSI
Loaded
100 PSI
100 PSI
Tubing Leak
100 PSI
80 PSI
Casing Leak

Figure 4 - Tubing and Casing Pressures
What do they mean?

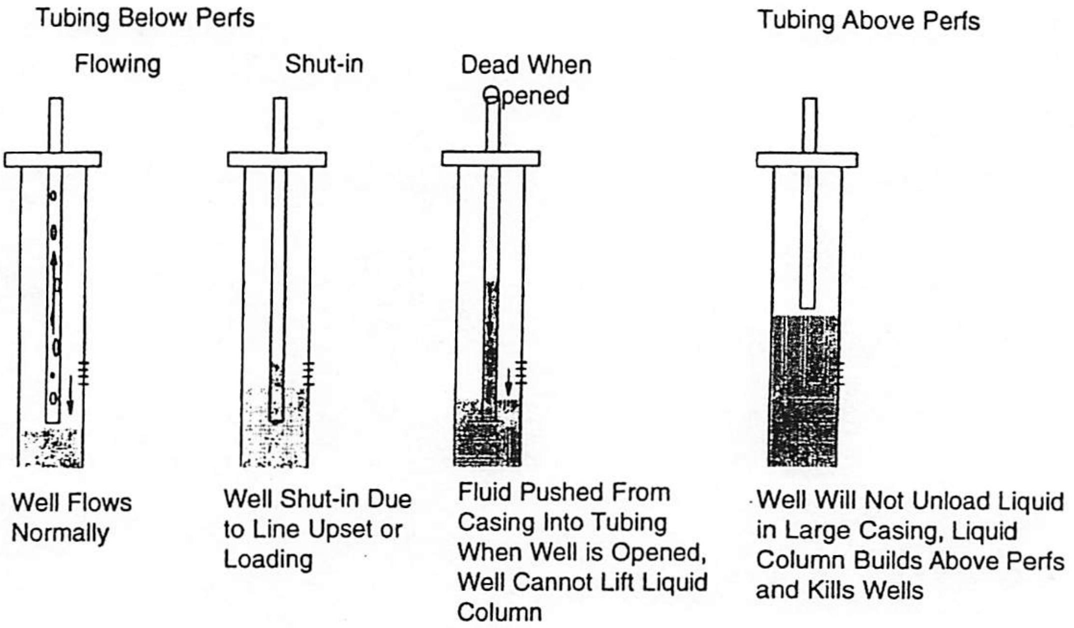

Tubing Below Perfs
Flowing
Shut-in
Dead When Opened
Tubing Above Perfs
Well Flows Normally
Well Shut-in Due to Line Upset or Loading
Fluid Pushed From Casing Into Tubing When Well is Opened, Well Cannot Lift Liquid Column
Well Will Not Unload Liquid in Large Casing, Liquid Column Builds Above Perfs and Kills Wells

Figure 5 - Effect of Tubing Depth on Gas Wells

Minimum

__Surface Shock Spring-Sizes and quantity per operator area
__Plungers (With Necessary Sizes and Types)
__O-Rings
__Filters
__Wire Clips (silicone filled)
__Fuse Links
__Motor Valve Seat & Trim (Necessary Sizes)
__Spare Sensor
__Sensor cleaner and lubricant

Add for Remote Locations

__Controller Module
__Latch Valves

Figure 6 - Plunger Survival Kit

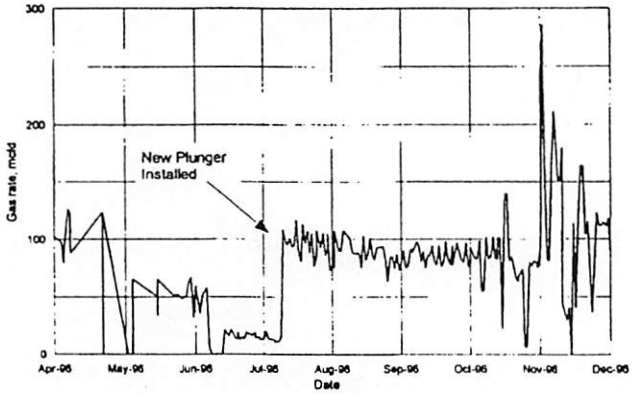


Figure 7 - Effect of Plunger Change on Well Production

	CHECK/CHANGE PLUNGER	OPTIMIZE PROGRAM SETTINGS	MORE OFF TIME	MORE AFTERFLOW	LESS OFF TIME	LESS AFTERFLOW	CHECK WELL TBG (RESTRICTION/HOLE)	CHECK WELLHEAD (DESIGN)	CLEAN SENSOR/CHECK WIRING	CHECK MODULE/WIRING	CHANGE (+) LEAD FUSE LINK	POWER DOWN & RESTART MODULE	SET SENSITIVITY OF SENSOR	CHANGE SUPPLY GAS FILTER	ADJUST SUPPLY GAS PRESSURE (20-30 PSI)	CLEAN CONTROL BLEED PORTS	CHANGE O-RINGS UNDER LATCH VALVE	CHECK/CHANGE BATTERY	CHECK SOLAR PANEL	REPAIR MOTOR VALVE TRIM	ELIMINATE FLOW RESTRICTIONS	CHECK CATCHER	CHANGE MODULE	CHANGE LATCH VALVE	CHECK SPECIAL SETTINGS	CHECK MOTOR VAVLE DIAPHRAGM	INSPECT PLUNGER
NO PLUNGER ARRIVAL	8	3	2			1			5	7			4							9	10		8				
SLOW PLUNGER ARRIVAL	4	3	2			1	8	7												5	6						
FAST PLUNGER ARRIVAL		3		1	2		6															4					5
FAST PLUNGER ARRIVAL @ ALL SETTINGS OR PLUNGER WONT FALL		1					4						2									3					
SLOW PLUNGER ARRIVAL @ ALL SETTINGS OR PLUNGER WONT COME TO SURFACE	4	3	2			1	7	6													5						
SHORT LUBRICATOR SPRING LIFE		4		2	3		5															1					
SHORT PLUNGER LIFE		3		1	2		5	4																			
SENSOR ERROR									3	4			2									1	5				
PLUNGER ERROR	6	3	2			1	12	11	5	7			4							9	10		8				
GOOD TRIP, NO COUNT (PLUG-IN SENSOR)		1							3	4	5		2										6				
GOOD TRIP, NO COUNT (STRAP-ON SENSOR)		1							3		4		2														
FATAL ERROR CODE @ LED		1										3													2		
LED CONTROL SCREEN BLANK										1		4						2	3				5				
SALES VALVE WONT OPEN/CLOSE		1							5	10				4	3	6	7	2	8	9			11	12		13	
TANK VALVE WONT OPEN/CLOSE		1							5					4	3	6	7	2	8	9			10	11		12	
LATCH VALVE WONT SWITCH														4	3	5	6	1	2					7			
MOTOR VALVES WONT CLOSE OR CLOSE SLOW														4	3	1	2	5	6	8			9	7			
SHORT BATTERY LIFE										1								2	3				4				
WONT GO TO AFTERFLOW		2								3													4		1		

Figure 9 - Plunger Trouble-Shooting Guide

WELL NAME: ____________________

OIL ☐ DRIP ☐ BPD: ______ BWPD: ______

PLUNGER OK ☐ REPLACED ☐

TYPE: ____________
DATE INSTALLED: ____________
DATE REMOVED: ____________
# OF CYCLES COMPLETED: ____________
CONDITION/REASON FOR CHANGE : ____________

LUBRICATOR SPRING OK ☐ REPLACED ☐

DATE INSTALLED: ____________
DATE REMOVED: ____________
# OF CYCLES COMPLETED: ____________
CONDITION/REASON FOR CHANGE: ____________

MODULE OK ☐ REPLACED ☐

DATE INSTALLED: ____________
DATE REMOVED: ____________

Figure 8 - Plunger System Tracking

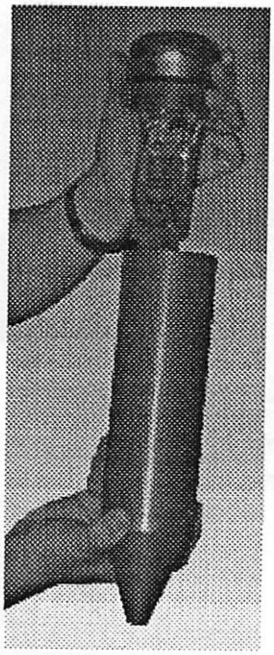
Applied Production Technology

Sandia National Laboratories

AUTOMATIC CASING SWAB

A Project of the Natural Gas & Oil Technology Partnership

The use of the "automatic" casing swab (ACS) can extend the economic life of a stripper well over that of either a tubing plunger-lift system or wire-line swabbing. ACSs have the advantage of requiring lower gas volumes to operate in comparison to a tubing plunger. Also, the ACS is more economical to operate than a rod pump and more efficient than a wire-line swab. Unfortunately, the reliability of ACSs had slowed the commercialization of this pumping technology. The objective of this project was to increase the successful application of ACSs by improved design and the ability to identify the wells for which ACSs are suitable.



The problems with ACSs were mainly due to cup or seal sizing, cup stretching/swelling, mechanical tool problems, or poor casing condition. It is difficult to identify when, where, and why these failures occurred, because direct observation of the tool and cups is not possible. The leakage of gas around the ACS cups must be very low. This makes the performance and design of the cups critical, an area for the application of advanced technology.

The Belden & Blake and Sandia cooperated to improve ACS performance including ACS design, surface monitoring of performance, identifying the wells in which ACSs work best, downhole instrumentation to diagnose failures, finite element analysis of cups, and force balance modeling of ACS motion. As a result of this work, the ACS now meets the reliability goals set at the beginning of the project.

Publications:

1) Haynes, C.D., Corp, J.G., and Miller, T.C.: "Field Experiments With Automatic Casing Swabs," SPE 21695, Production Operations Symposium, Oklahoma City OK, 1991.
2) Cramer, J.W., and Wood, D.D.: "Automatic Casing Swabs: A Production System That Can Add Years of Productive Life to Wells," SPE 30981, Eastern Regional Meeting, Morgantown, west Virginia, 1995.

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Automatic Casing Swabs

- Normally, a well delivers maximum production when the pressure drop across the formation face is as large as possible
- Sales line pressure will always exert some back pressure on the formation and thus reduce production
- One way to maximize the pressure drop across the formation face is to remove any accumulated wellbore fluids on a timely basis

Automatic Casing Swabs

- As pressure increases below the ACS, the plunger and accumulated fluids begin to travel toward the surface
- The formation will continue producing gas at a fairly constant rate
- All gas is produced through a 3/8" orifice in the surface lubricator
- The ACS will slow as fluid is produced through the 3/8" orifice. This reduced speed will reduce the impact force that occurs when the ACS enters the lubricator

Automatic Casing Swabs

- Immediately following conversion, an ACS well may produce slightly greater fluid volumes in response to producing at lower pressures
- Normally a well will return to its' original gas-liquid ratio in a short period of time

Automatic Casing Swabs

- ACS cycle times can be optimized to achieve maximum economic returns by balancing gas production, fluid production, and pumper involvement
- Many operators are installing electronic controllers or intermitters to operate ACS wells
- Properly adjusted, an ACS operated by a controller or intermitter allows the well to produce at near steady state conditions

Automatic Casing Swabs

- ACS should be considered for new well application
  - Pay out may be reached sooner since the well can be produced at its' maximum capacity from the first day of production
  - Incremental installation costs will be lower since a service rig is already present performing initial completion work
  - New well AFEs could be lower since tubing and other associated down hole and surface equipment may not be required

Automatic Casing Swabs

- Summary
  - ACS allow a well to produce at its' full potential by minimizing the head of wellbore fluids that restrict production
  - ACS uses positive rubber sealing elements to hold wellbore fluids above ACS plunger
  - Formation pressure is trapped below the ACS tool lifting the tool and fluids to the surface
  - ACS are simple and dependable
  - ACS have distinct advantages over rabbit, pumping unit, swab, and open flow wells
  - ACS are appropriate for new wells

Automatic Casing Swabs

- Open flow and swab wells should be considered for ACS conversion
- Both open flow and swab well can lose significant volumes of gas to the atmosphere when they are serviced
- Open flow wells seldom remove most of the fluids from the wellbore and thus rarely produce to full potential
- Since swab wells are normally only serviced in good weather, they may be unable to reach maximum production during winter months

Automatic Casing Swabs

- Candidate Selection
  - The most important factor to consider when choosing a conversion candidate is the available lifting pressure
    - Lifting pressure is equal to reservoir pressure minus the sum of sales line pressure and 6 PSI (pressure necessary to overcome ACS weight and friction created by rubber sealing elements)
    - If reservoir pressure is not known, a 48 to 72 hour pressure buildup is normally sufficient

Automatic Casing Swabs

- Candidate selection
  - A well's gas to liquid ratio should be determined
    - Although sufficient lifting pressure maybe present, a well with a low gas-liquid ratio may operate so slowly as not to be practical or economic to operate.
    - A general rule of thumb is that 3 to 5 MCF/BBL total fluid is required for an ACS to operate efficiently when sales line pressure is less than 100 PSI

Automatic Casing Swabs

- Candidate selection
  - Production decline curves should be studied
    - If a well displays a typical decline for an area, any decision to convert to ACS should be based solely on lowered operating costs.
    - A well which displays a sudden or unexplained decline curve may indicate production problems which may be alleviated with an ACS system

Automatic Casing Swabs

- Physical considerations
  - Production casing should be in good condition
    - All casing should be of uniform weight
    - Determine if any internal casing attachments were ever present in well
    - Casing should be scraped to remove any buildup of scale or paraffin
    - Knowledge of all perforations is critical
    - Determine and compare original casing TD, plug-back TD, and current TD
  - Conventional gate or "frac" valves are not compatible with ACS systems

Automatic Casing Swabs

- Let us assume that we are working with 4.5"-10.5#/FT casing. Wellbore fluids(oil and water) weigh 8.5 PPG
  - 1 BBL of fluid will fill 61.7 feet of casing
  - This fluid column will exert 28 PSI of hydrostatic head on the formation
- Knowing the available lifting pressure in a well, it is a simple calculation to determine the maximum amount of fluid that can be lifted by an ACS

Automatic Casing Swabs

A complete ACS cycle consists of:

- ACS is released from the surface lubricator
- ACS free falls through the gas column and any accumulated wellbore fluids
- ACS encounters the bottom hole stop, the weight of the plunger closed the traveling valve trapping the accumulated wellbore fluids above the ACS
- Reservoir pressure builds "lifting" the plunger and fluids to the surface
- ACS reaches the surface, enters and latches into the lubricator simultaneously opening the traveling valve allowing continuous flow of gas

---

Automatic Casing Swabs

- Operating principles of the ACS:
  - Rubber sealing elements are always in intimate contact with the ID of the casing
  - Combination of the rubber sealing elements and the closed traveling valve effectively isolates any accumulated wellbore fluids from gas being produced from the formation
  - Approximately 6 PSI of pressure is required to overcome the weight of the ACS plunger and the friction created between the rubber sealing elements and the casing

---

Automatic Casing Swabs

- The ACS is a simple, economical production system that allows the timely removal of wellbore fluids
- The ACS does not require an external power source
- The ACS utilizes reservoir pressure to lift fluids from the well
- Only 6 PSI of pressure is required to lift the ACS tool
- Amount of fluid that can be lifted is dependent upon the available lift pressure (Reservoir pressure minus Sales line pressure)

Automatic Casing Swabs

- ACS cycle times may vary from 4 hours to 1 week depending upon gas and fluid production, and the amount of available lifting pressure
- Normally an ACS cycle is designed to recover 1 to 3 BBL of total fluid
- Some ACS cycles have recovered up to 27 BBL of total fluid on a single cycle
- ACS cycle times can be adjusted to consider gas and fluid production , as well as well tender schedules.

Automatic Casing Swabs

ACS vs Rabbits

ACS	Rabbits
Positive seal	No seal present
Lifted by pressure	Lifted by velocity
Uses only formation pressure to operate ACS	Relies on gas stored in annulus to chase rabbit
Repaired in field	Not repairable
Approx 28 PSI can lift 1 BBL fluid	Approx 111 PSI to lift 1 BBL of fluid
Will maintain fluid above ACS if sales cease or sales line pressure increases	If sales cease or pressure increases, rabbit and fluid may stop and fall to bottom

---

Automatic Casing Swabs

ACS vs Pumping Units

ACS	Pumping Units
Positive seal	Sealed by pump
Lifted by pressure	Lifted by rods
Uses only formation pressure to operate ACS	Pump powered by gas or electric motors
Easily repairable in field	Repairs are seldom simple or easy
Operates in casing	Requires tubing
Approx 28 PSI can lift 1 BBL fluid	Power to lift fluid will vary

SPE 30981
Automatic Casing Swabs: A Production System That Can Add Years of Productive Life to Wells

John W. Cramer, P.E., SPE,
Target Oilfield Pipe and Supply,
and
Daniel D. Wood, SPE,
Belden & Blake Corporation

AUTOMATIC CASING SWABS

A PRODUCTION SYSTEM THAT CAN ADD YEARS OF LIFE TO WELLS

JOHN W. CRAMER, P.E.
TARGET OILFIELD PIPE & SUPPLY

PRESENTED AT THE 55TH APPALACHIAN
GAS MEASUREMENT SHORT COURSE
AUGUST 16, 1995

Automatic Casing Swabs

- History of Automatic Casing Swabs (ACS)
- Description of the ACS system
- Operating principles of ACS
- Advantages of ACS production
- Comparison of ACS with:
  - Tubing plungers or "rabbits"
  - Pumping unit wells
  - Swab and open flow wells
- Candidate selection
- Examples of ACS conversions

Automatic Casing Swabs

- An ACS is generally characterized by:
  - A hollow steel mandrel
  - Externally actuated traveling valve
    - Valve may be internal or external
  - 2 external rubber sealing elements
- Bottom hole stop which is installed above the perforations
- Bottom hole stop may be either:
  - Installed in a casing collar
  - Installed on free standing tubing

Automatic Casing Swabs

- Concept of the ACS has been around since about 195
- Numerous patents have been granted documenting hardware and technological advances
- The harsh environment has proven too severe for some novel methods of operation
- Most present day systems utilize an external rod attached to a traveling valve that relies on a surface and bottom hole stop to actuate a simple valve assembly

---

Automatic Casing Swabs

- An ACS system consists of:
  - The Automatic Casing Swab
    - Provides the barrier that separates the wellbore fluids above the swab from the gas pressure trapped below the swab
  - A surface lubricator
    - Serves as a flow manifold at the surface
    - Opens the ACS when it surfaces allowing continuous uninterrupted gas flow
    - Houses the ACS between ACS cycles
    - A bottom hole stop, which limits the downward travel of the ACS

CASING PLUNGERS:
SOLVING OLD PROBLEMS WITH NEW TECHNOLOGY

Steve Belden
JetStar Casing Plungers

INTRODUCTION

Marginal oil and gas prices, dwindling reserves and increasing costs suggests that today's prudent producer must look for new ways to cut costs and improve production. Casing plungers are one example of ways to use a relatively new production method to prolong well life and operate wells more efficiently and economically.

WHAT IS A CASING PLUNGER?

Casing plungers are a spinoff of the tubing plunger or "rabbit" production method. Unlike rabbits, however, they are operated directly in 4 1/2 inch diameter casing. A casing plunger is a mandrel type tool, 3 to 4 feet long, that generally weighs 60 to 80 pounds. A pair of inverted rubber swab cups are attached around the plunger and are designed to remain in constant contact with the casing walls. An internal valve/rod assembly, portions of which protrude from both ends of the plunger, allows gas and fluid to flow through the tool during its descent. When closed, the valve helps to isolate the formation pressure needed for operation. Adjustable orifices at the top of the plunger throttle the flow of gas and control the plunger's free-fall.

Components of a casing plunger "system" include a down-hole stop set just above the uppermost perforations. These "stops" can either lock in to the gap created between the casing joints, or are attached to a premeasured length of tubing and set directly at the bottom of the well. The stop keeps the plunger from entering the perforations, and closes the plunger's internal valve. A wellhead assembly or "catcher" is used in conjunction with a full opening ball valve to catch and release the plunger between cycles and also assists in its removal for routine service and maintenance. The "catcher" has a built-in 3/8 inch orifice in the flow outlet that restricts the flow of gas so the plunger can fall while the well is in production. This orifice also helps to control the speed of the plunger's upward travel. Another component of the catcher is a latching mechanism, similar to a door latch, that catches the tool for removal, and holds it in place between cycles. Other available equipment include various controllers for automatic operation.

HOW DOES IT OPERATE?

A typical cycle begins when the plunger is released from the catcher either manually or automatically. As it free-falls down the well, the opened internal valve allows gas and eventually accumulated fluid to pass through and out the orifices at the top. When the plunger reaches the down-hole stop, the internal valves' connecting rod, or the protruding valve itself, is forced upward and the valve closes. This initiates the seal between the plunger, cups and the casing walls which creates a complete interface between the accumulated fluids above the plunger and the formation pressures below. Pressure begins to build until it is sufficient to lift the plunger and fluids to the surface. When the fluid column reaches the surface, it is unloaded through the catcher, separator and into the storage tank. As the plunger hits the top of the catcher, the upper portion of the valve/rod is shifted down which opens the internal valve, releasing the trapped gas beneath the plunger into the separator and into the sales line. This completes the operating cycle; however, the latching mechanism can be disengaged to allow the tool to repeat this process immediately if fluid production necessitates. Otherwise, the well is allowed to produce until the accumulation of fluid requires another cycle.

WHY DO CASING PLUNGERS WORK?

Hydraulics is one of the keys to casing plunger operation. The inner diameter of 4 1/2 inch casing is 4 inches, with a cross section of about 12.5 square inches (4 inches x 3.14). During operation, every pound of pressure beneath the plunger generates 12.5 pounds of lifting force. A barrel of oil, with a minimum brine content, weighs about 300 pounds (figure oil at 7.5 pounds per gallon). Therefore, approximately 25 pounds of formation pressure is adequate to lift each barrel to the surface (300 divided by 12.5 = 25.20).

Another key to operation is the sealing effect created by the plunger and cups against the casing walls. The cups are normally run in pairs and spaced apart by at least 6 inches. Minimal gas and fluid are lost as the plunger moves up the well. As it passes through casing imperfections and gaps created by the casing collars, the seal is always held by at least one of the cups.

WHY ARE CASING PLUNGERS SUCH A GOOD PRODUCTION METHOD?

A key to producing most wells is to keep the wellbore as dry as possible, which, in turn, minimizes the hydrostatic pressure on the formation. This reduction in back pressure allows gas to flow more freely which helps to drive additional fluid to the wellbore. The well's operating pressure also plays a factor in reducing the formation's ability to flow into the wellbore and to the surface. Operating pressure can be artificially controlled to necessitate rabbit well operation or is simply dictated by line pressure. Typically, the lower the operating pressure, the better the production.

Casing plungers are generally operated at line pressure. If operated properly, fluid removal is virtually complete, with only small amounts of fluid left above the perforations after each cycle. Ideally, each cycle should lift between 1 and

3 barrels. This is sometimes not possible with high fluid, low gas volume wells. Other wells, however, may show significant gas sales increases with the removal of half or even a quarter barrel of fluid per cycle.

CASING PLUNGERS VERSUS RABBIT WELLS

Some of the best conversion candidates are older rabbit wells. Although the rabbit is a good production method, operational and production problems begin to occur as the well depletes. Cycle times are eventually limited to once or twice a day to build additional operating pressure which ultimately affects production.

The operating procedure for a typical rabbit well consists of cycling the well on and off with a controller and motor valve. Gas pressure and volume are built and stored in the annulus (the space between the tubing and the casing) between cycles. When the well begins its cycle, the stored annular pressure helps to overcome line pressure and forces the column of gas, fluid and rabbit to the surface. The pressure build-up between cycles also controls fluid accumulation in the wellbore.

Production and cycle times are dictated by the pressure recovery rate, line pressure and gas and fluid volumes. The rabbit does not form a complete interface between the gas and fluid unless it travels at an optimum speed of about 800 to 1,000 feet per minute. Worn, undersized rabbits affect performance and production due to the additional "blow-by" they allow. And as formation pressures begin to deplete, rabbit wells become increasingly pressure sensitive, and line pressure increases can play havoc with their operation.

Wells operated with casing plungers are normally produced continuously and operated at line pressure. Typically, it is not necessary to build additional operating pressure because the plunger forms a complete seal. The plunger's cycle time is directly related to the well's gas volume, pressure recovery rate, and fluid quantity above the plunger.

Line pressure fluctuations will affect gas sales and travel time, but will not affect the casing plunger's overall performance. For example, if the line pressure increases while the plunger is travelling to the surface, it will simply slow down or stop. In fact, the well can be "shut in" indefinitely while the plunger is travelling to the surface. As pressure continues to build, the gas column above the plunger and fluid will become compressed until it equals the formation pressure minus the fluid weight.

The following principle helps to exemplify why virtually any rabbit well will also operate as a casing plunger. The column of liquid suspended in the tubing or casing creates the same amount of hydrostatic pressure at its base regardless of the inner diameter of the pipe. This means that the pressure reading at the bottom of a column of fluid is the same assuming the height of the column is the same, regardless of its volume.

The 2-3/8" tubing needs 258 feet to hold one barrel of fluid. This creates about 111 psi of hydrostatic pressure. The 4-1/2" casing needs only 61.7 feet to hold the same 1 barrel which creates about 28 psi of hydrostatic pressure.

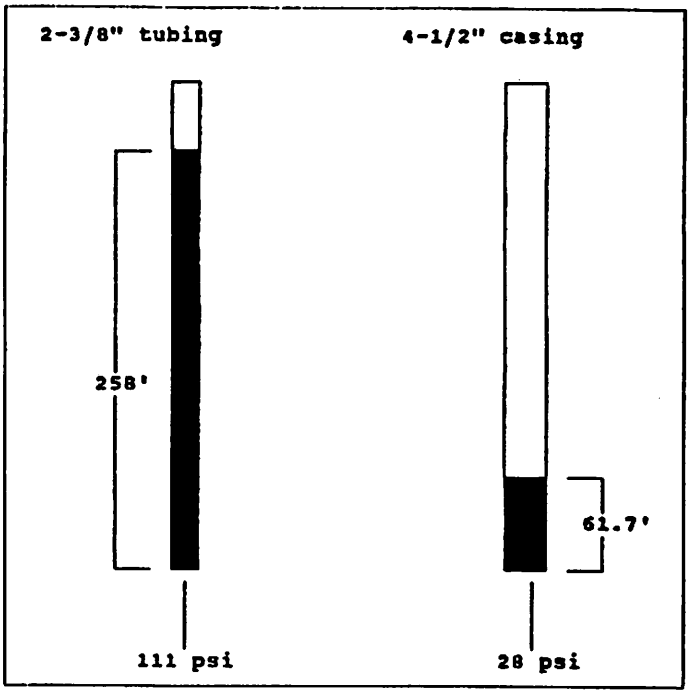

FIGURE A

If the well's pressure and volume are sufficient to lift the 258 foot column in a 2-3/8 tubing string, it is also sufficient to lift the same 258 foot column in the 4-1/2' casing, which would be almost 4 barrels.

CASING PLUNGERS VERSUS PUMPING UNITS

In general, pumping units are an efficient production method. However, pumping unit operation is expensive. Electrical costs, repair and maintenance to the unit, pump replacements and stripping jobs often consume profits. Due to fluid depletion, many pumping units operate only several hours a week.

Production increases are not as dramatic, and sometimes nonexistent, when these wells are converted to casing plungers when compared with rabbit or swab conversions. There are, however, other benefits. Converting pumping units to casing plungers can reduce high operating costs, while the salvaged tubing and equipment can be sold or installed on more productive wells.

CASING PLUNGERS VERSUS SWAB OR OPEN-FLOW WELLS

Open-flow and swab wells are often ideal conversion candidates. Open-flow wells are produced by venting gas and fluid directly to the storage tank to remove or "unload" accumulated fluids. Swab wells, due to lack of volume and pressure, must be swabbed with a wire-line unit. Unfortunately, both techniques release large amounts of gas to the atmosphere. Open-flow wells rarely produce to their full potential because it is virtually impossible to remove all of the fluids. Cost and location conditions generally keep swab wells from being serviced more than a couple of times per year. Consequently, these wells quickly load with fluid before the next scheduled swabbing. The casing plunger's ability to remove fluid on a daily basis can create significant production increases.

CASING PLUNGERS FOR NEW WELLS

Casing plungers can be a good choice as the initial production method for new wells. The cost of a casing plunger and associated equipment is about the same as a rabbit installation and far less than a pumping unit. Operating pressures of new wells normally need to be lowered slowly over a period of time to control fluid accumulation and premature depletion of the formation's gas drive. The operating pressure can be controlled with a controller, motor valve and a pressure switch gauge better known as a "murphy switch". Some motor valve controllers also have this feature, known as a "high/low" option, built in. When the operating pressure of the well reaches a minimum pressure, the murphy switch signals the controller to shut the motor valve, which shuts the well in. When the well regains sufficient pressure to trigger the switch gauges' preset high limit, the motor valve opens. In this manner, the well can be "cycled" on and off, effectively holding operating pressures within the desired parameters. The plunger, due to its ability to remain in place when the well is shut in, simply moves and stops as the well is opened and closed. A Pressure Differential Controller (PDC), which will be discussed further, will help provide a steady flow of gas during the well's "on" cycles.

CHOOSING CANDIDATES FOR CONVERSION

There are two rules of thumb that must be kept in mind when choosing candidates for conversion. First, the well must have enough bottom-hole pressure to lift the accumulated fluids at line pressure.

For example: If a well has the ability to "pressure up" to 500 pounds after a 48 to 72 hour shut in, makes mostly oil and the line pressure averages 100 pounds, the following can be determined;

500 lbs. = maximum shut-in pressure
−100 lbs. = average line pressure
400 lbs. = maximum operating pressure

400 divided by 25 (pressure needed to lift one barrel) equals 16. This well has the capability to lift a maximum of 16 barrels maximum per cycle while in line.

The second rule of thumb is that a good candidate should have a gas/oil ratio of at least 3 mcfd per barrel. Although a well can lift the casing plunger to the surface with pressure alone, sufficient gas volume is necessary to lift it in a reasonable time period to be economical.

Many wells do not exhibit these characteristics but are still good candidates for casing plunger conversion. They are often loaded, have leaks in the tubing, salt accumulation and sand fill up in and around the perforations. A swab, shut-in test can be a good way to determine their viability.

A question that is commonly asked is, once a well has been determined to be a good candidate, what kind of production increases can be expected? It is generally difficult to determine exactly what production increases will be on a given well. But, comparing the well's decline curve against actual production can be a key to determining a well's potential profitability after conversion. Wells that show a fairly dramatic production decline compared to their projected decline curve usually have better production increases. Quite often, the difference between actual and projected declines is initially made up as "flush" production. After several years, it is believed, production rates will fall back to originally forecasted levels. Belden and Blakes' C. & H. Kline #1 well is a good example.

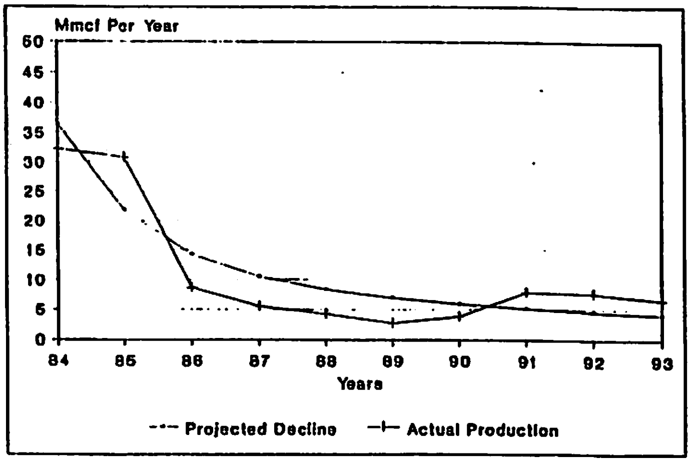

FIGURE B

Drilled in 1984, and originally produced as a rabbit well, gas production soon began to fall below original projections. In 1990, a casing plunger was installed, which brought gas production above the original decline curve. According to John Corp, Manager Production Engineer, Belden & Blake Corporation, "Sales should eventually level off to the original projections, and current production increases will offset 'lost' production. If this well was not converted, it may have been prematurely plugged."

WELL PREPARATION-PROPER INSTALLATION

Before well conversion can begin, some key information must be obtained. Top and bottom perforation location, total depth, and size of casing are key to successful installation. If setting a collar stop, location of the casing collars will also be necessary. Wells that have a history of heavy salt or paraffin accumulation may be shut in and treated accordingly several days prior to conversion. NOTE: If treating for paraffin, it is important to use only diesel or kerosene. Chemical based treats can react adversely with the cup material. Once pertinent data has been collected, conversion can begin.

The first step is to determine current total depth of the well in case of sand fill up. If the production string is still in the well, several extra joints may be attached and the entire string run to bottom. When the tubing is removed and tallied, this will give an accurate total depth which may be compared to the original records. A depthometer should be used to check its accuracy against original records and the tubing tally. Depthometers can be inaccurate and this will give the rig crew the opportunity to recalibrate it. Also during this procedure, a marker should be attached to the wireline of the rig that will indicate the location of the top perforation. This will later aid in identifying that the down-hole stop is set accurately. If the well has already had its production string removed, the depthometer will be the only verification of total depth. If it is evident that sand fill up has occurred, the sand should be removed accordingly.

The next step is to broach the casing with a casing scraper to remove deposits including salt, scale and paraffine. Particular attention should be paid to the last 500 to 1,000 feet above the perforations, because this is typically where salt deposits form. A minimum of three round trips is recommended. This procedure is critical to the performance of the casing plunger. Poor casing preparation and condition is one of the biggest problems associated with casing plunger operation. Failure to properly follow this procedure will result in the plunger's failure to reach the down-hole stop and trigger its internal valve. It is also important to run the casing scraper below the eventual position of the down-hole stop. Failure to do this may result in an accumulation of "well trash" above the stop. The wire line indicator should help in this procedure as well.

The next step is to set the down-hole stop. When setting a tubing stop, the distance between the well's total depth and the top perforation should be calculated and an additional twenty feet added to position it above the perforations. The appropriate quantity of tubing, with the tubing stand attached, is then lowered into the well with a setting hook attached to the rig's wire-line. The hook automatically releases when the assembly reaches bottom.

The collar stop should be considered if continued sand accumulation is a concern, sand removal is impractical, or the distance between total depth and the top perforation is more than several hundred feet. The collar stop is a device with feet that lock into the gap left between the joints of casing. The stop is set with a special setting device that locks onto a "fishing head" located at the top of the stop. It is necessary to know the approximate position of the collar directly above the top perforation. The assembly is lowered into the well past the collar and then pulled back through. Wire clips catch in the collar and release the stops' feet, which spring outward against the casing walls. The assembly is then lowered into the collar where, simultaneously, the feet catch, and the stop locks in place. A brass pin is sheared in the setting tool, which disengages it from the stop.

The final procedure is to swab the well as thoroughly as possible. Typically, the well will make a large amount of "flush" production during its first month or so of operation. A thorough swabbing will ensure that "well trash" from the broaching procedure is removed, and that the plunger will not struggle to remove too much fluid.

IMPROVED INTEGRATION—AN ADDED BENEFIT

Casing plungers can solve integration problems. One common difficulty is choosing an appropriately sized orifice plate for the master meter when several different production methods are used in one gathering system. For example, to operate and record gas sales from rabbit wells properly, a 1 inch or 1.25 inch orifice plate is necessary. Pumping unit, open-flow and swab wells generally require a smaller plate size due to the constant gas flow associated with their operation. If a large orifice plate is used at the master meter to record the sales from the rabbit wells, the sales from the remaining wells may not be accurately recorded. Conversely, a smaller plate size can cause production problems for the rabbit wells by periodically increasing the system's line pressure as they cycle on and off.

There are two possible solutions to this problem. Ideally, all rabbit wells can be converted to casing plungers. If all of the wells in the system are producing in a similar fashion, a smaller plate size can be installed and gas sales recorded properly. If the quantity of rabbit wells far outweighs the other production methods, the other alternative is to convert the pumping units and/or swab wells to casing plungers. Since the casing plunger has the capability to slow down or stop, without affecting its operation, the well can be cycled on and off with a controller/motor valve similar to a rabbit well. The master meter can be fitted with a large orifice plate, and the casing plunger wells will register their gas sales just like the rabbit wells.

The use of a Pressure Differential Controller (PDC) in conjunction with a casing plunger is one of the best ways to improve integration. After the plunger cycles and unloads its fluid, gas sales generally increase substantially as the pressure is released from beneath the plunger. A mechanical choke can be used to control this "spike", but the PDC provides a constant gas flow and a "clean" chart much more effectively. Ideally, the PDC should be installed directly ahead of the master meter and the individual wells controlled with mechanical chokes.

Even when PDC's are not used, chart interpretation can be easier for the person reading the chart. According to Jim Dick of East Ohio Gas, "The average flow rate from the time the tool is released until the end of the 'flush delivery' following the return, is exactly the same as the rate between

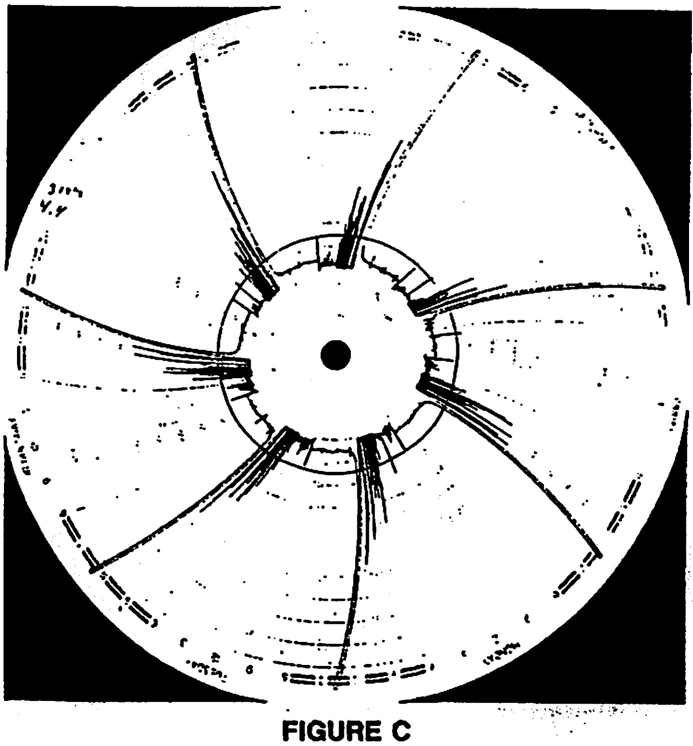

FIGURE C

the fluid removal cycles." He went on to say, "Since the rate is consistent, an integrator operator can integrate the easy part, and pro-rate that result over the entire chart." The following are several examples of orifice charts from wells that have been converted to casing plungers.

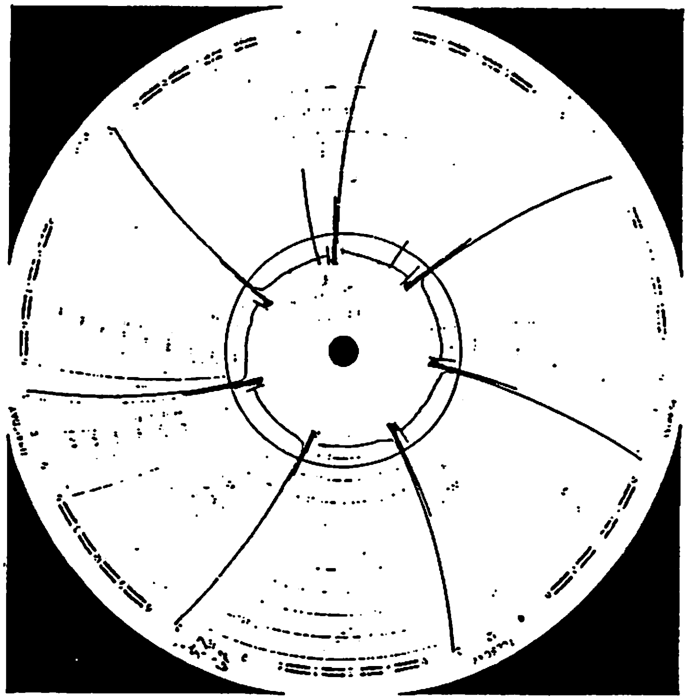

FIGURE D

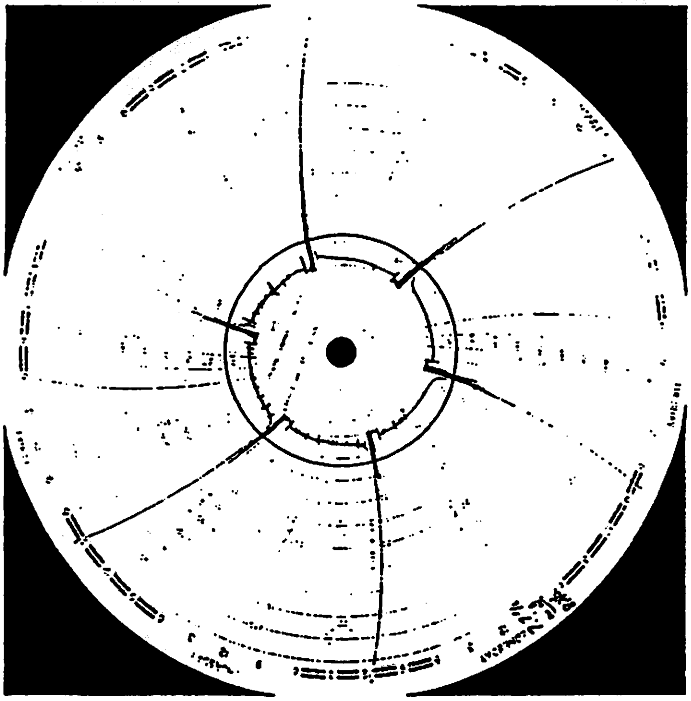

FIGURE E

RESTRICTED OR REGULATED SYSTEMS

One problem associated with rabbit well operation is their use in regulated gathering systems. In many cases, proper rabbit operation is virtually impossible where sales lines are regulated or restricted. Rabbits rely on velocity to reach the surface. When the rabbit begins its cycle, the sales line can become "packed", causing the rabbit to stall before reaching the surface. A casing plunger will slow down and suspend until there is adequate room in the sales line.

CASE HISTORIES

The first graph shows the gas production improvements from a 42 well conversion program done by Belden and Blake. Most were older rabbit and swab wells that were becoming increasingly difficult and expensive to operate. It is reported that this group of wells is still averaging a 10 mcf per day, per well increase, compared to pre-conversion production rates.

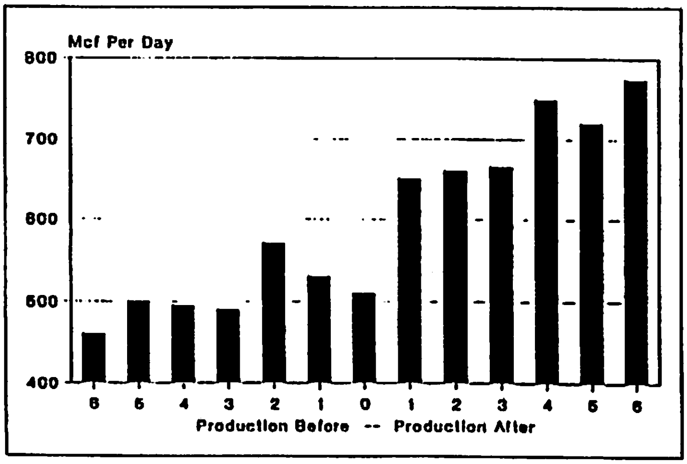

FIGURE F

Kingston Oil Corporation converted these rabbit wells to casing plungers. The missing months of production were a result of a temporary shut-in for flow line and sales line repair, respectively.

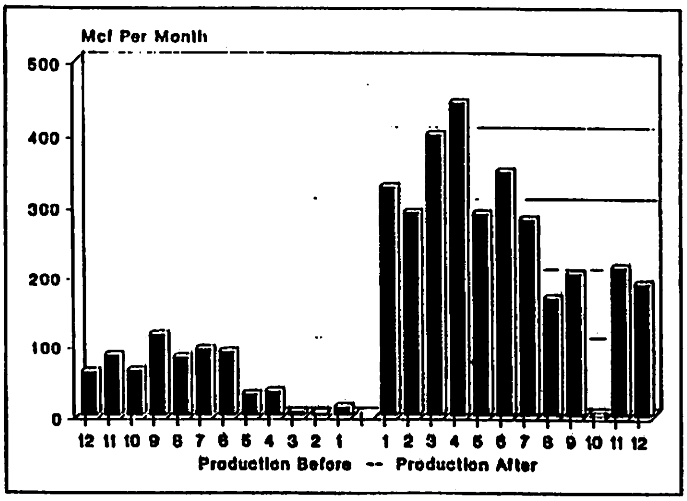

FIGURE G
OHIO POWER MAR 66

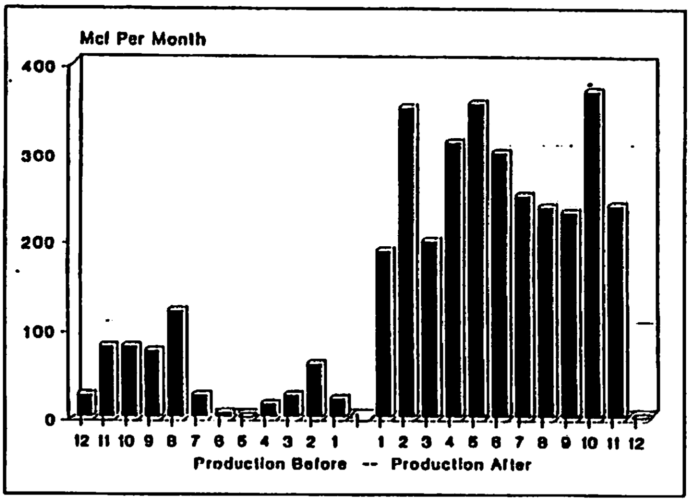

FIGURE H
OHIO POWER 2A

M & B Operating provided the following results from two swab well conversions.

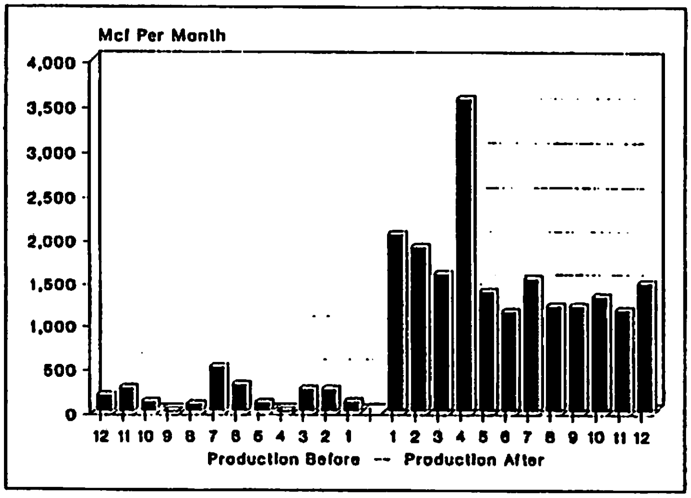

FIGURE I
M.W.C.D. #8

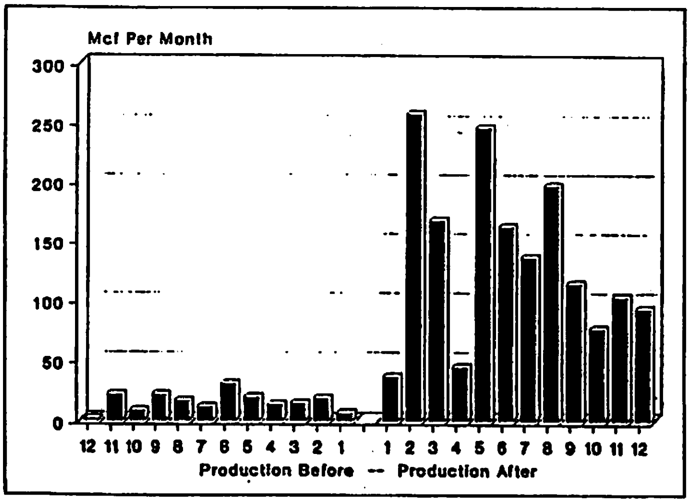

FIGURE J
STAINER #1

Ohio L&M converted this temperamental rabbit well to a casing plunger with the following results.

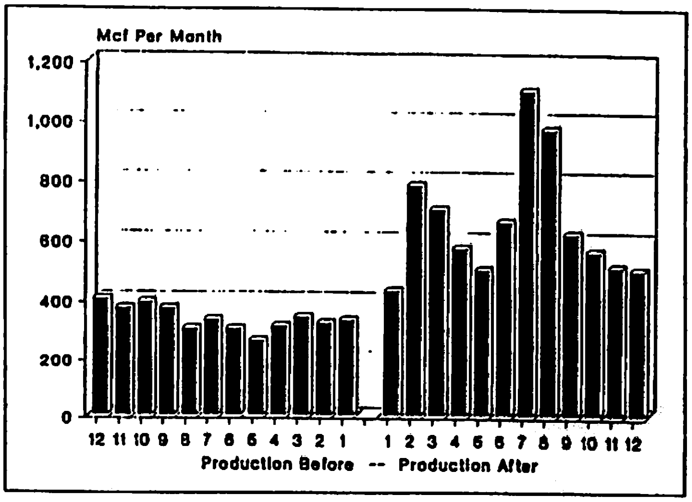

FIGURE K
J. BAUERBACH #4

Weinsz Oil & Gas chose to use a casing plunger as the initial production method for this new well. The well was drilled in an affluent suburb. The use of a pumping unit was out of the question, due to land owner concerns. To make matters worse, the sales line was regulated, which made rabbit well operation impossible.

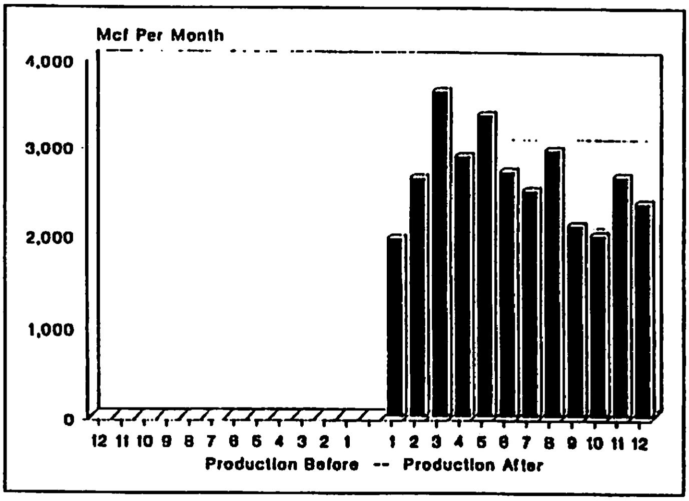

FIGURE L
ARBUCKLE #1

CONCLUSION

It should be evident that casing plungers have the ability to solve a wide variety of problems. More and more producers are finding significant value in the casing plunger as an initial production method, or as a way of adding new life to older less productive wells. Casing plungers have the ability to be used as a primary production method, solve a wide variety of operational problems, alleviate high operating costs, and prolong the production life of depleted wells. Casing plungers are one way to solve old problems with new technology.

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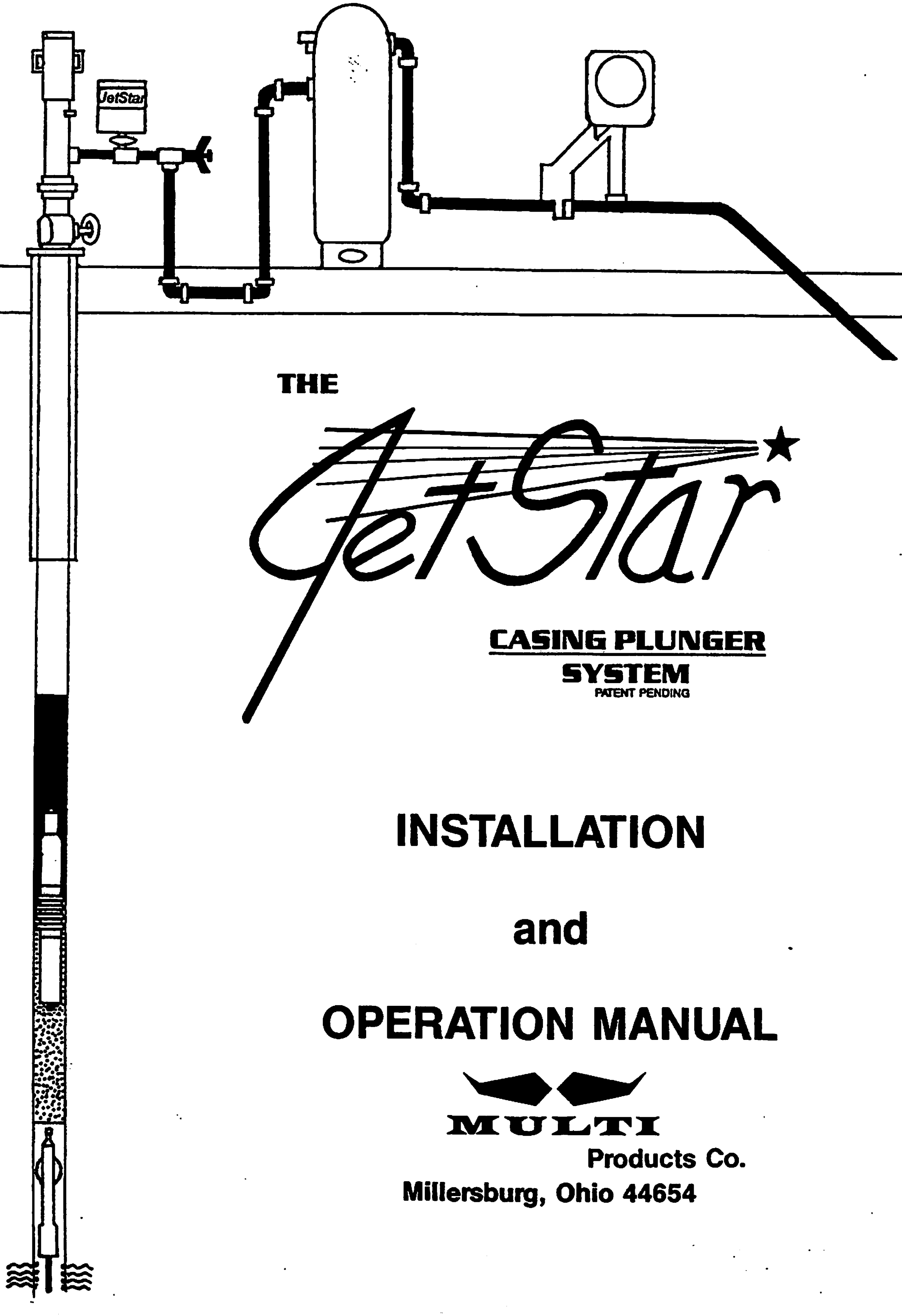
BIOGRAPHY

Steve Belden

Steve Belden, general manager of JetStar casing plungers, joined Target Oilfield Pipe and Supply Company (TOPS) in January, 1992. Prior to joining TOPS, Steve was employed by Belden and Blake Corporation. Previous experience includes well servicing, production and research and development of the casing plunger.



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Automatic Casing Swabs: A Production System That Can Add Years of Productive Life to Wells

John W. Cramer, P.E., SPE, Target Oilfield Pipe and Supply and Daniel D. Wood, SPE, Belden & Blake Corporation

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Abstract

This paper will describe the operating theory, hardware, safe operating principles, and troubleshooting of Automatic Casing Swab(ACS) tools. An analysis of conversions will show that ACS are a viable production tool that can be used as an initial production method or be used to add years of productive life to wells.

A brief history and the operating principles of the ACS will familiarize the reader with the complex interactions of the various well components that can affect the successful operation of ACS tools. Examples of pressure transducers mounted in an operating ACS will offer some insight into the very dynamic nature of how an ACS tool operates.

The paper will share the knowledge and experience gained through 5 years of choosing wells to be converted to ACS. The paper will draw on one company's experience of installing and operating over 100 ACS in Ohio, New York, West Virginia, and Pennsylvania.

A criterion will be developed that assists the operator choose the wells that have the highest potential of benefiting from ACS technology. Some of the factors considered in developing this criterion are well history, decline curve analysis, gas to fluid ratios, and pressure analysis.

A discussion of the relative strengths and weakness' of the various components of the ACS will be offered. This will allow the operator to recognize some of the critical factors, such as pipe roughness, that cannot be practically measured but must be considered when selecting potential conversion candidates.

The paper will review the economic impact of the 100+ ACS well conversions. The costs associated with installation and conversion, changes in operating expenses, and differing production rates are considered in the overall economic analysis of the converted wells. The analysis will show that the ACS offers an alternative method of production that can be appropriate as an initial production method as well as a tool that can potentially add years of productive life to a well.

Introduction

This paper will describe the experience gained in the 5 years of operation of over 100 ACS wells. Information will be offered that will allow an operator to determine if a well could benefit by using ACS technology.

This paper will offer a brief history of ACS hardware. A discussion of the operating principles of the ACS will illustrate the flexibility and wide ranging applications for the ACS system.

Since well candidate selection is critical to the economic success of an ACS conversion, this paper will develop a criterion to assist operators choose wells with the highest potential of benefiting from ACS technology. Similarly, well characteristics that hinder the successful operation of the ACS will be noted.

This paper will compare and contrast the operating principles of the ACS as compared to tubing plunger, pump jack, swab, and open flow wells. A discussion of the application of ACS technology to new wells as an initial production method will be offered.

The paper will describe the steps necessary to properly prepare a well for ACS hardware. It will detail a step by step procedure for the installation of hardware. Start-up and production operations will be covered.

Routine maintenance and trouble shooting suggestions will be offered to help an operator minimize remedial services that might be incurred should the tools cease operation. The paper will offer simple preventative maintenance procedures that can keep the ACS running at peak performance which will maximize production and keep service rig time and operating expenses to a minimum.

Producing High GLR Stripper Wells with an Automatic Casing Swab

C.D. HAYNES, P.W. JOHNSON, E.S. CARLSON
University of Alabama

Abstract

An automatic casing swab system has been developed and tested over a two-year period in high gas/liquid ratio (GLR) stripper wells in the Appalachian Basin. Wells in the Basin typically produce lesser amounts of liquids in their later productive lives. These amounts are usually too small for efficient operation of the rod pumps or tubing plunger systems that were originally installed. Normal practice has been to periodically remove the liquid with a wireline casing swab or to plug and abandon the well. The system described herein is capable of prolonging the economic producing lives of these wells.

This system consists of a cylindrical swab tool configured to seal against the casing wall when moving upward, but capable of falling through wellbore fluids when released from a specially-designed wellhead. A "stop" in the casing prevents the swab from falling into the perforations and closes the liquid bypass valve. The cycling frequency of the swab is dependent on the strength of the individual well.

The automatic swab system is usually less expensive to purchase, install, and operate than sucker rod pumps or tubing plungers. It can operate unattended for extended periods, can frequently increase gas output, and provide a smoother orifice meter chart for easier integration. In addition, the system is suitable for operations in remote locations.

Field experimentation has shown the ideal candidate well for this system to have a GLR over 900 std m³/st m³, a bottomhole pressure between 1.4 and 6.9 MPa, low fines production, and modest paraffin output.

Introduction

The typical stripper oil and gas well is characterized by low total liquid output, low reservoir pressure, and a relatively high gas-liquid ratio (GLR). Wells of this type are plentiful throughout the world, but are predominantly located in the United States and Canada. Because of the relatively poor output from these wells, they are first to face abandonment at times of low product prices.

Beam pump-sucker rod (pumpjack) and tubing plunger (rabbit) systems are ordinarily found in use on these stripper wells. They were typically installed when the well had greater reservoir pressure and liquid output. Once the well declines in pressure and output, each of these systems becomes inefficient. The pumpjack may tend to pump-off the well even though it may operate only a few hours each month, or gas lock and fluid-pound from the scarcity of liquid entering the wellbore. The tubing plunger will become less efficient because of slow plunger movement to the surface, liquid fallback, and the necessity of "blowing-down" the well to atmospheric pressure periodically in order to bring the plunger to the surface.

A common practice is to convert these wells to "swab wells," where all downhole equipment is removed and the wells are produced by periodically removing accumulated liquids by a wireline swabbing unit. Gas production continues for a certain period of time before the well "loads-up" and requires swabbing once again. Even though it may appear simple and inexpensive, this practice can be even more expensive than before when factoring in the cost of the swabbing unit and the frequent need for it. Also, the mobile equipment sometimes cannot service wells located in remote or relatively inaccessible areas because of seasonal weather and road conditions.

The foregoing problems indicate the need for an artificial lift system to bridge the gap between the pumpjack/plunger systems and ultimate wireline swabbing of marginal wells. Ideally, this system would remove fluids from the wellbore automatically as the reservoir pressure permitted, be inexpensive to purchase and operate, and could be operated and serviced by the lease operator with a minimum of outside support.

The Automatic Casing Swab

Automatic devices for lifting wellbore fluids using reservoir pressure alone are plentiful in the literature(1). Numerous patents have been filed on mechanical and hydraulic mechanisms to provide an interface between wellbore liquids and the energy in the reservoir(2). Many of these devices, most of which were never used commercially, were studied in an attempt to find examples with simplistic designs suitable for the demands of oilfield service. The system eventually selected is shown in Figure 1, and consists of the following components:

- a swab configured to seal against the wall of the casing when moving upward, but capable of falling against the upward flow of produced fluids in the hole;
- a "stop" located slightly above the topmost casing perforation to halt the downward movement of the swab; and
- wellhead fittings to catch and retain the swab when it arrives at the surface.

The swab (Figure 2) is a steel cylinder about 10.8 cm in diameter and about 91.4 cm in length. It contains an internal valve operated by a sliding axially-oriented rod designed to protrude on either end of the swab. This valve controls the flow of wellbore fluids through the swab. An elastomer seal similar in design to a swab cup seals the area between the swab and casing wall.

There are two types of "stop" employed with this system. The first type is attached to a measured length of tubing and is lowered into the well by wireline. The second type, also installed by wireline, expands to anchor itself in the recess adjacent to the casing

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Field Experiments With Automatic Casing Swabs

C.D. Haynes, J.G. Corp, and T.C. Miller, Belden & Blake Corp.
SPE Members

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ABSTRACT

This paper describes the development and field testing of an automatic casing swab in northeast Ohio. This swab, operating in Clinton sandstone wells to depths of 5000 feet (1523 m), demonstrated an ability to increase gas production, improve orifice meter chart configurations and reduce operating costs on existing wells. On new wells, its use in lieu of tubing plunger and beam pump-sucker rod pumping systems has resulted in lower capital cost and enhanced profitability.

Development of the swab tool is continuing, and results to date indicate this system ultimately will be used in many of the 2500 Belden & Blake wells in the Appalachian Basin.

INTRODUCTION

The typical Appalachian Basin oil and gas well is characterized by low total fluid output, low reservoir pressure, and a relatively high gas/oil ratio. Beam pump-sucker rod pumps (pump jacks) and tubing plungers (rabbits) are considered "standard" artificial lift systems for these wells. They are best used in the early stages of a well's operating life when reservoir pressures are highest and fluid production is greatest. The typical Clinton sandstone well, however, can produce for as long as 50 years, albeit at a very low production rate.

The operating strategy for these wells is to greatly reduce operating costs as the well ages. It is not unusual to have one lease operator responsible for as many as 75 wells. A pump jack installation designed for a 5000-foot (1523 m) effective lift and approximately 30 barrels (4.77 m^3) per day will become oversized as production declines and will be operated only a few hours each month to remove all available reservoir fluids.

The tubing plunger installation is less expensive than the pump jack, but is very sensitive to reservoir pressure. As the well declines, it soon cannot lift wellbore fluids unless the well is flowed directly to

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References and illustrations at end of paper.

GIBSON

TechLine

Performance tables & casing plunger operation

By Ron Gibson—Casing plunger performance tables have been developed to screen candidate wells for casing plunger use. These tables permit the estimation of 1) bottomhole flowing pressures under casing plunger operations, 2) probable increases in stabilized production rate, and 3) incremental reserves resulting from casing plunger use.

Proper screening of candidate wells, and the use of designed plunger cycling, should nearly eliminate the time consuming trial and error approach currently used to evaluate casing plungers in specific wells. Estimating flow rate improvements and additional reserves will result in higher casing plunger success ratios.

Casing plungers are becoming more popular in the Appalachian Basin as producers work to improve reserve recovery under limited budgets. This production method uses reservoir energy from the producing formation to lift and drive the casing plunger and produced fluid from the wellbore.

Casing plungers generally compete with sucker rod pumps and tubing plunger ("rabbit") systems as methods of removing oil and water from gas wells. Initial installation costs for casing plungers are comparable to tubing plunger systems and considerably lower than sucker rod pump systems.

Casing Plunger operations

The casing plunger system consists of a large, heavy mandrel equipped with rubber sealing cups and an internal valve. The plunger travels up and down the production casing (usually 4.5" OD) between the producing formation and the wellhead. A stopping device is installed just above the casing perforations or open hole section. A lubricator or

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Ron Gibson is a registered petroleum engineer with the consulting firm of R.A. Gibson & Associates, Inc. Prior to establishing his consulting firm in 1988, Mr. Gibson was employed by Ameritrust Bank in Cleveland, Ohio and Phillips Petroleum in Oklahoma City.

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President

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"catcher" is installed at the surface, above a 4.5 inch, full port ball valve on the production casing.

Generally, two rubber sealing cups are mounted on the plunger and create a nearly 100% seal against the production casing wall. The internal valve permits gas and liquid to flow through the plunger upon arrival at the surface and until it is returned to the stopping device on bottom. On bottom, the valve shuts and the plunger and liquids above it are pushed up the hole by formation gas. The casing plunger can run continuously, or it can be run intermittently. Intermittent operation can be handled manually or automatically with the use of a plunger arrival sensor, an electronic controller, and a catcher release device.

Advantages and Disadvantages

Casing plungers do offer the advantages over rod pump systems through significantly lower installation costs and increased safety (no external moving parts). Casing plungers also offer the advantages of constant feed production, which is desirable on pressure regulated gathering systems or smaller compressed gathering systems.

However, due to the nature of their operation, casing plungers do have some disadvantages in comparison to rod pump systems and tubing plunger systems. Casing plungers systems have a greater potential for mechanical problems, and their use is limited by certain reservoir properties.

Mechanical problems are generally attributed to poor casing conditions. Sealing cups can be worn excessively by rough surfaces or torn by burrs in the pipe. Casing plunger manufacturers are continuously working to improve sealing cup materials and design, and stress the importance of thorough casing preparation (scraping).

Like tubing plungers, the casing plunger operates on reservoir energy. As such, reservoir properties and pipeline pressures dictate if, and how, the plunger will perform in any given wellbore. It is physically impossible for casing plungers to work in some wells. Limiting factors are generally low reservoir pressures, low gas/liquid ratios, and high pipeline pressures.

Forecasting Improvements

Reductions in average bottomhole flowing pressures do result in increases in oil and gas production rates and reserves. This can be accomplished by 1) reducing pipeline pressures, 2) reducing wellhead backpressure, or 3) reducing fluid loading on the producing formation.

continued on next page

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Casing plungers, tubing plungers, and rod pumps all work to remove produced fluids from the wellbore, and thereby reduce fluid loading on the producing formation. Unlike rod pump or tubing plunger systems, casing plungers offer no direct means to measure bottomhole pressures. There is no tubing, hence no tubing/casing annulus to permit reading pressure and conducting fluid level surveys.

> *Since the bottomhole pressure calculations are complex and involve many variables, casing plunger performance tables were developed for nearly any possible wellbore/production scenario*

Bottomhole flowing pressure must be calculated using the available surface pressure and production information. Since the necessary calculations are complex and involve many variables, casing plunger performance tables were developed for nearly any possible wellbore/production scenario.

The casing plunger performance tables provide bottomhole flowing pressures that are needed to forecast improvements in production rate and reserves. Use of the tables requires knowing current gas, oil, and water production, pipeline pressure, depth of producing formation, and the well's bottomhole shut in pressure (3 to 7 day shut in). Once bottomhole flowing pressures are determined, production rate improvements can be estimated using a simple deliverability equation (see the following example).

Engineers can use the reduction in bottomhole flowing pressure to estimate a new field abandonment pressure. A material balance can then be used to estimate incremental reserve recovery, which determine the real economics of casing plunger installation.

Optimizing Casing Plunger Operations

Optimizing casing plunger operations requires consideration be given to 1) minimizing bottomhole flowing pressure, and 2) maximizing sealing cup life. Bottomhole flowing pressures are minimized by reducing fluid loads per cycle and increasing cycle frequency. However, sealing cups wear out with use and cup life is maximized by reducing cycle frequency. Most casing plunger manufacturers and operators have found that fluid loads of 1.0 to 2.5 bbls per cycle usually provide for the best cup wear and plunger efficiency.

In addition to providing bottomhole pressures, the casing plunger performance tables provide an estimate of 1) the volume of gas required to unload the plunger, and 2) the afterflow volume required to build the designed fluid load. These gas volume requirements dictate when the plunger must be released from the lubricator. Orifice meter chart integration in the field can easily determine the volume of gas produced during the cycle.

It is critical in low gas/liquid ratio wells that afterflow gas is managed wisely. If too much gas is produced after the plunger arrives at the surface, the next fluid load may be too large to unload without a separator bypass or swab rig service call. In extremely low gas/liquid ratio wells, the gas volume requirements dictate as to whether a casing plunger will operate at all. Well #3 in the following examples shows the critical nature of low gas/liquid ratio wells on afterflow volumes.

High gas/liquid ratio wells also benefit from afterflow gas management. Releasing the plunger after sufficient fluid has accumulated above the bottom stopping device will assure a good seal and longer seal cup life.

Performance Table Examples

The following examples are provided to show the effect of gas/liquid ratios on casing plunger operations. The performance tables were generated assuming smooth casing conditions with minimal drag resistance and a 100% seal efficiency. Therefore, the performance table values may provide results that are optimistic, depending on actual casing conditions and actual seal cup wear.

Well/Pipeline Data:

Line Pressure	150 psig
Fluid Load Volume	2 bbls
Fluid Oil/Water Ratio	0.67
Fluid Density	8.66 #/gal
Perforation Depth	4000 feet

	Well #1	Well #2	Well #3
Gas/Liquid Ratio	10 mcf/bbl	5 mcf/bbl	2.5 mcf/bbl
Maximum BHFP (Pwf)	270 psia	285 psia	313 psia
Minimum BHFP (pwf)	202 psia	217 psia	245 psia
Average BHFP (Pwf)	236 psia	251 psia	279 psia
Gas required to unload	5.1 mcf/trp	5.1 mcf/trp	5.0 mcf/trp
Gas required to build load	20.0 mcf/trp	10.0 mcf/trp	5.0 mcf/trp
Afterflow gas volume	14.9 mcf/trp	4.9 mcf/trp	0 mcf/trp

Comments
Well #1: Trip plunger with every 20 mcf produced
Well #2: Trip plunger with every 10 mcf produced
Well #3: Trip plunger continuously. Plunger will not run at higher line pressures or lower GLRs

Continuing with Well #2 example (GLR = mcf/bbl)

Flow data under current operations:

Daily production	7 mcfd and 1.5 bpd
Avg. casing pressure	350 psig surface = 400 psia (bottomhole)
Shut in csg. prs./7day	460 psig surface = 520 psia (bottomhole)

Estimating production under casing plunger operations:

$$q_2 = q_1 * (\bar{P}^2 - P_2^2)/(\bar{P}^2 - P_1^2) = 7\ \text{mcfd} * (520^2 - 251^2)/(520^2 - 400^2)$$
$$= 13.2\ \text{mcfd}$$

Incremental stabilized (post flush) rate = 6.2 mcfd = 186 mcf/month

The example presented above as Well #2 gives performance table results for a 4,000 foot gas well producing 5 mcf per barrel of fluid against a 150 psig pipeline pressure. The produced fluid has an oil to water ratio of 0.67 (2 bbl oil to 3 bbl brine). The well has a shut in casing pressure of 460 psig, which equates to a bottomhole shut in pressure of 520 psia.

The performance table indicates a maximum bottomhole flowing pressure (BHFP) of 285 psia, a minimum BHFP of 217 psia, and an arithmetic average BHFP of 251 psia. The casing plunger will require 5.1 mcf to reach the surface. Ten (10) mcf are required to build a 2 bbl fluid load on the casing plunger. The afterflow gas volume is 4.9 mcf (10.0 total - 5.1 unload requirement).

The post-flush production rate for Well #2, based on producing the well with a 2 bbl load, is 13.2 mcf per day, an increase of 6.2 mcfd. This rate was determined as a result of reducing the flowing bottomhole pressure from 400 psia to an average of 251 psia. Incremental reserves were not estimated for this example well due to the complexity of calculation.

It must be noted that additional afterflow gas would have resulted in larger fluid loads, greater bottomhole flowing pressure, and reduced gas flow rates. The 13.2 mcfd rate would require that the well is cycled more frequently if a load volume of 2 bbl is strictly followed. In reality, the well would be tripped once per day, the load would be somewhat more than 2 bbl, and the stabilized rate would be somewhat less than 13 mcf per day.

Conclusions

Casing plungers are becoming a competitive tool in removing wellbore fluids and offer advantages over rod pumps and tubing plungers. Casing plunger performance tables permit operators to screen candidate wells for the application of casing plungers. The information in the tables can be used to 1) evaluate potential increases in production rate and reserves, and 2) optimize casing plunger operations through casing plunger cycle scheduling. The use of the performance tables should nearly eliminate the wasteful trial and error approach currently taken by most operators.

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The

Down Hole Injection Tool

(DHI Tool)

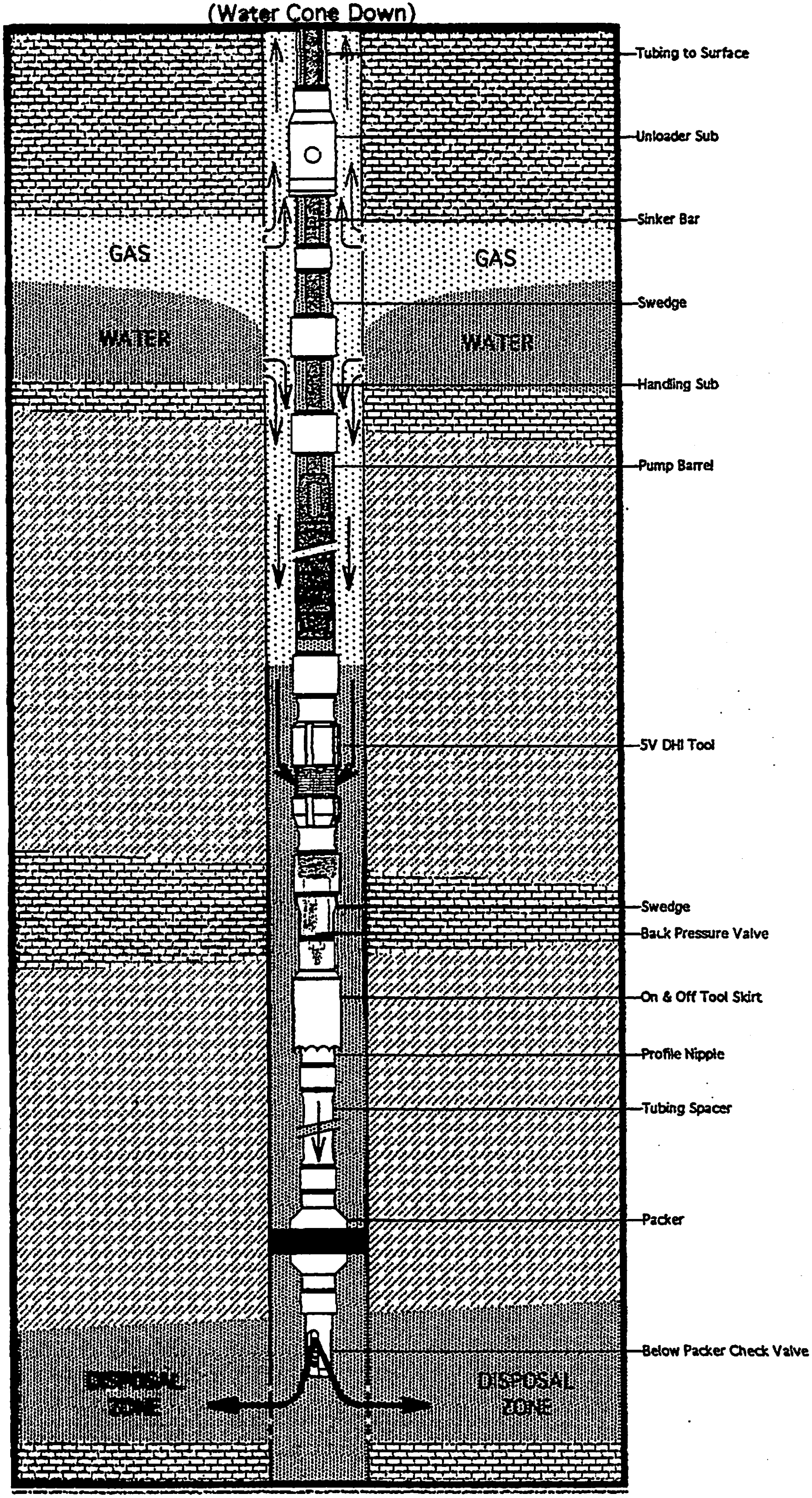
The "Tool"

Simultaneous

Gas Production &

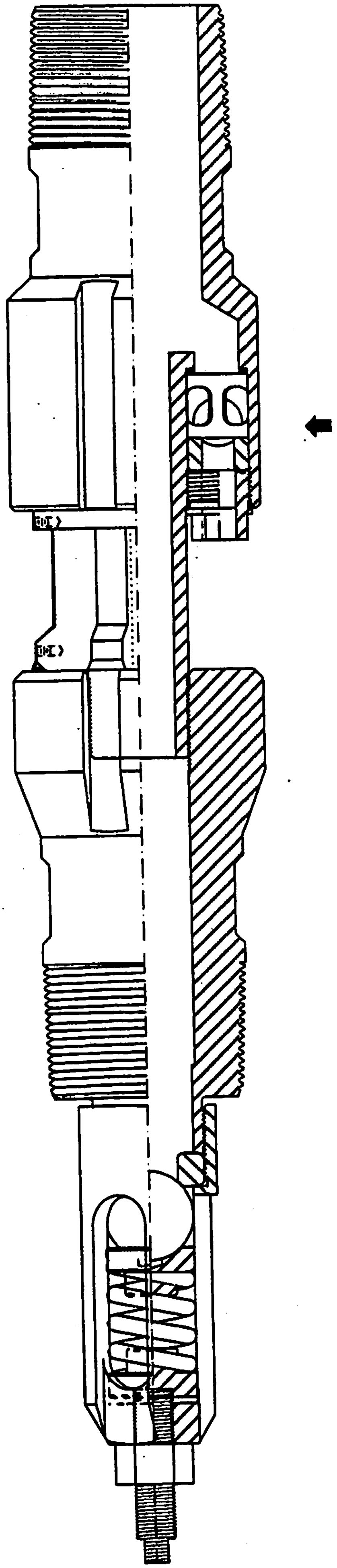
Water Disposal

SIMULTANEOUS
GAS PRODUCTION / DISPOSAL METHOD
(Water Cone Down)

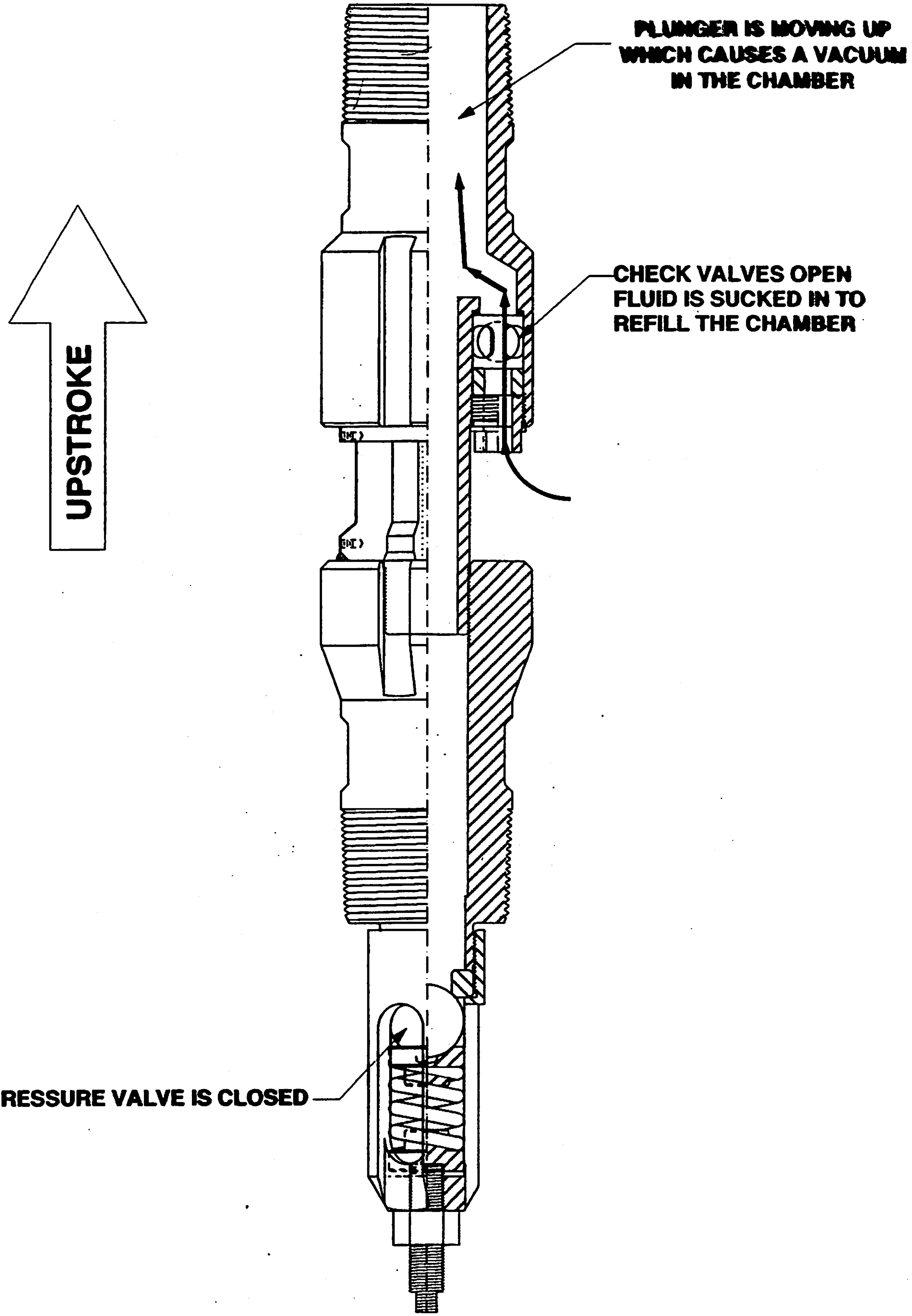

Tubing to Surface
Unloader Sub
Sinker Bar
GAS
GAS
Swedge
WATER
WATER
Handling Sub
Pump Barrel
5V DHI Tool
Swedge
Back Pressure Valve
On & Off Tool Skirt
Profile Nipple
Tubing Spacer
Packer
Below Packer Check Valve
DISPOSAL ZONE
DISPOSAL ZONE

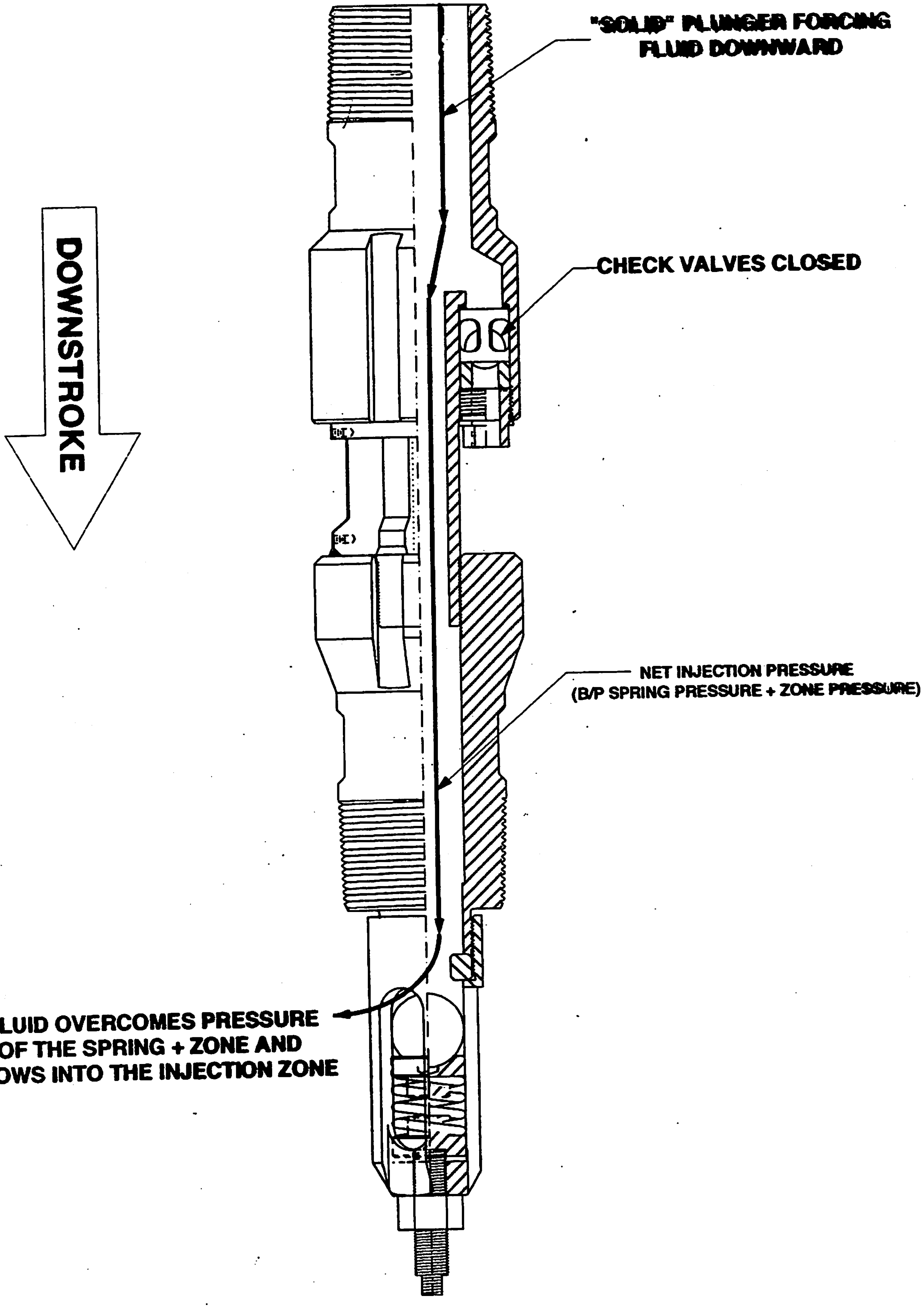
Down Hole

Injection Tool


Intake Ports

Cut Away View

PLUNGER IS MOVING UP WHICH CAUSES A VACUUM IN THE CHAMBER
CHECK VALVES OPEN FLUID IS SUCKED IN TO REFILL THE CHAMBER
UPSTROKE
BACK PRESSURE VALVE IS CLOSED



"SOLID" PLUNGER FORCING FLUID DOWNWARD

CHECK VALVES CLOSED

NET INJECTION PRESSURE (B/P SPRING PRESSURE + ZONE PRESSURE)

FLUID OVERCOMES PRESSURE OF THE SPRING + ZONE AND FLOWS INTO THE INJECTION ZONE

WELL PRODUCTION SUMMARY

WELL NAME: SNAIDER 31-30
WELL NO : 1000
COUNTY,STATE:
LOCATION: NW/4 SEC 30-14N-2E
PRODUCING ZONE: [illegible]

CRUDE PURCHASER: NONE
GAS PURCHASER: ORYX
DATE OF 1ST SALES: 07/92
WELL OTC #: 081-95802

METER TUBE DIAMETER:
ORIFICE DIAMETER :
GAS CLASSIFICATION: 06
OIL CLASSIFICATION:

MO	YR	DAYS PRD	OIL/BBL MONTHLY	OIL BBL/D.	OIL/BBL CUMULATIVE	OIL/BBL SOLD/MO	WATER MONTHLY	WATER BBL/D.	WATER/BBL CUM.	GAS/MCF SOLD/MO	GAS MCF/D.	GAS/MCF CUMULATIVE	AVG CHK	AVG FTP	AVG CP	AVG SITP
JAN	95	31	8	0.27	34	0.00	1352	43.61	52546	4003	129.13	176565	14	172		
FEB	95	28	0	0.00	34	0.00	1069	38.18	53655	3616	129.14	180181		171		
MAR	95	31	0	0.00	34	0.00	1224	39.48	54879	3373	108.81	183554				
APR	95	30	0	0.00	34	0.00	1226	40.87	561[illegible]	3833	127.7[illegible]	187387				
MAY	95	31	0	0.00	34	0.00	1331	42.94	57436	3994	128.84	191381	14	159	515	
JUN	95	31	0	0.00	34	0.00	1089	35.13	58525	3642	117.48	195023	14	162		
JUL	95	31	0	0.00	34	0.00	1252	40.39	59777	3692	119.10	198715		153	503	
AUG	95	31	0	0.00	34	0.00	1324	42.71	61101	3726	120.19	202441	14	142	488	
SEP	95	30	0	0.00	34	0.00	1273	42.43	62374	3710	123.67	206151	14	137		
OCT	95	31	0	0.00	34	0.00	1242	40.06	63616	3750	120.97	209901		133		
NOV	95	30	0	0.00	34	0.00	1181	39.37	64797	3682	122.73	213583				
DEC	95	31	0	0.00	34	0.00	1200	38.71	65997	3727	120.23	217310		121		
YTD			8			0.00	14763			44748						

WELL PRODUCTION SUMMARY

WELL NAME: SHRIMER 31-30
WELL NO : 1000
COUNTY,STATE:
LOCATION: NW/4 SEC 30-14N-2E
PRODUCING ZONE:PERU

CRUDE PURCHASER: NONE
GAS PURCHASER: ORYX
DATE OF 1ST SALES: 07/92
WELL OTC #: 081-95802

METER TUBE DIAMETER:
ORIFICE DIAMETER :
GAS CLASSIFICATION: 05
OIL CLASSIFICATION:

MO	YR	DAYS PROD	OIL/BBL MONTHLY	OIL BBL/D.	OIL/BBL CUMULATIVE	OIL/BBL SOLD/MO	WATER MONTHLY	WATER BBL/D.	WATER/BBL CUM.	GAS/MCF SOLD/MO	GAS MCF/D.	GAS/MCF CUMULATIVE	AVG CHK	AVG FTP	AVG CP	AVG SITP
JAN	96	21	0	0.00	34	0.00	221	10.52	66218	2925	139.29	220235	14		130	
FEB	96	28	0	0.00	34	0.00	238	8.50	66456	3797	135.61	224032	18		136	660
MAR	96	31	0	0.00	34	0.00	0	0.00	66456	6148	198.32	230180	16		85	
APR	96	30	0	0.00	34	0.00	0	0.00	66456	6517	217.23	236697	16		51	
YTD			0			0.00	459			19387						

Down Hole Injection Tool

The "Tool"

Benefits

- Preventing contamination of fresh water resources (surface water) and surface soils
- Eliminating water hauling expenses
- Restoring uneconomical and marginal wells to production

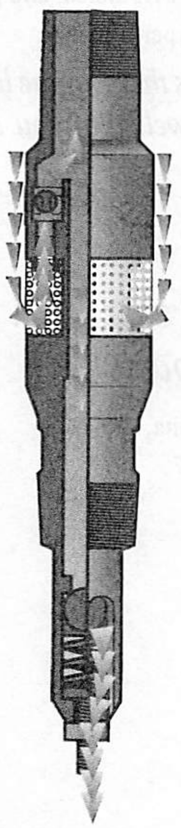
- Maximizing recoverable reserves
- Maximizing profitability
- Encouraging future exploration
- Removing environmental problems caused by water production and disposal

It can pay you to check out the potential value of the DHI family of tools . . . now!

Here is the basic story of how the DHI tools can bring the gas up and send the water down. If your well fits any one of our tools, there's a real potential for improving profits—a potential that you might miss if you don't check out the story of the DHI system and family of tools presented below.

Below Production zone Disposal (BPD System)

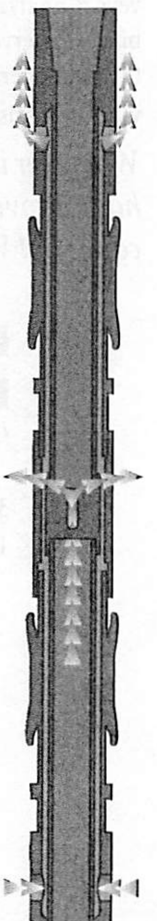
This system allows produced water to be injected into a disposal zone below the gas producing reservoir. Gas flows up the tubing-casing annulus to the surface. It can also be used for injection service in waterflood operations. A water source zone uphole can be completed, and the BPD system will allow the source water to be injected into a lower reservoir being waterflooded.



Two types of BPD tool are now available: the 5-valve and a 1-valve tool.

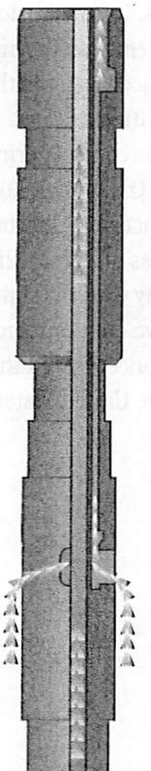
Above Production zone Disposal (APD System)

In wells which have not been drilled and cased deep enough to allow the completion of a disposal zone below the gas producing reservoir, an APD system is used. This system allows a disposal zone to be completed above the gas producing reservoir. Produced water is injected into the disposal zone isolated by packers above and below. Gas flows up the tubing-casing annulus after flowing through a by-pass system. Like the BPD system, the APD system also has application in injection wells for waterflooding operations. A lower water source zone can be used to supply water for injection into an uphole oil reservoir being waterflooded.



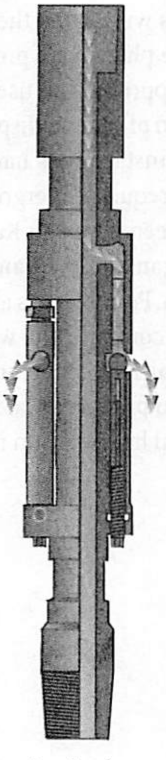
Dual Annulus Production (DAP System)

The DAP system has application in wells with casing leaks, to protect casing from corrosion, and in sour gas (H_2S) wells which require a packer to be set above the producing zone and the annulus above the packer to be loaded with fluid. Concentric tubing strings are used with gas allowed to flow up the tubing-tubing annulus to the surface. Produced water can be injected into a disposal zone below the gas producing reservoir or pumped to the surface through the smaller diameter inner tubing string.



Multi-Well Injection Tool (MWIT System)

This system allows gas to flow up the tubing-casing annulus while produced water from the gas producing reservoir and other wells tied into the tubing at the surface is injected into a lower disposal zone. Even if the gas well with the MWIT system produces no water, the well can be used as a disposal well in multi-well oil or gas fields in which other wells do produce water.



Field testing is planned to determine the use for the MWIT tool in "hot oiling" oil wells with paraffin deposition problems.

The DHI system… more than just a tool

The DHI system provides comprehensive assistance from research to installation and analysis of results. Here's what you can expect from DHI.

Technical support provided by the DHI organization and distributors will assist in the pre-planning and system installation design once a client has called for information and provided a completed Well Data Questionnaire. During the actual field installation of the DHI system, a DHI field technician will supervise the running of the DHI equipment and start-up of the well. Operator personnel will be involved with the well planning, equipment installation details and start-up operating procedures. Upon start-up of the pumping unit, the DHI field technicians will obtain fluid levels and dynamometer surveys to analyze equipment and well performance until the well stabilizes. Thereafter, the DHI field technicians will maintain contact with the field operating personnel to monitor the DHI system performance and provide any assistance required to optimize well performance. Periodic fluid level and dynamometer surveys can be taken by the DHI field technicians whenever required by the client.

Although the DHI systems are new to the oil and gas industry, state regulatory agencies have been receptive to their use and installation. These state agencies recognize the DHI systems can prevent pollution, reduce oilfield waste streams, and improve producer economics by lowering operating costs. The improved producer economics will extend the life of producing wells and prevent the premature plugging of producing wells. To date, various state agencies have approved the use of DHI systems for the simultaneous production of gas and disposal of produced water in the same wellbore. These installations have been classified as Class II injection wells which require underground injection control permits. Such permits have been issued in Kansas, Texas, Oklahoma, Louisiana, Indiana, Michigan and the Canadian provinces of Alberta and British Columbia. Permitting is also in progress in New Mexico and Colorado. DHI is committed to working closely with the state agencies to foster a spirit of cooperation to achieve environmentally sound solutions to produced water disposal concerns and the recovery of additional hydrocarbon reserves in the United States and elsewhere.

THE DOWN HOLE PUMP AND HOW IT WORKS

While the DHI systems allow the separation of gas and water dowhhole in the wellbore, an energy source is required to force the produced water into a disposal zone. The energy source used with the DHI systems is a conventional beam rod pumping system with a surface pumping unit, sucker rods and modified bottomhole pumps. This system together with a full hydrostatic column of fluid in the tubing provides the necessary energy to force the produced water into the disposal zone which has been completed in the wellbore.

We're there for the long haul

As effective and unique as it is, the tool is only part of the DHI system advantage.

The rest of the story is the great lengths we undertake to support field operating personnel in their efforts to optimize well performance. Pre-Installation engineering for customized sizing and analyzing the DHI assembly paired with the data obtained from the Well Data Questionnaire insures proper and reliable service of the DHI process.

After installation of the tool and start-up of the pumping unit DHI field technicians will obtain fluid levels and dynamometer surveys to analyze equipment and well performance until the well stabilizes. Afterwards DHI field technicians will remain in contact with the field operating personnel to monitor the DHI system and provide any assistance required to optimize well performance.

Whatever it takes…you'll find DHI is there for the long haul, providing solutions for your well that you can count on! We guarantee it!

DOWN HOLE
INJECTION, INC.
"A Solutions Company"

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Below Production zone Disposal
(BPD SYSTEM)

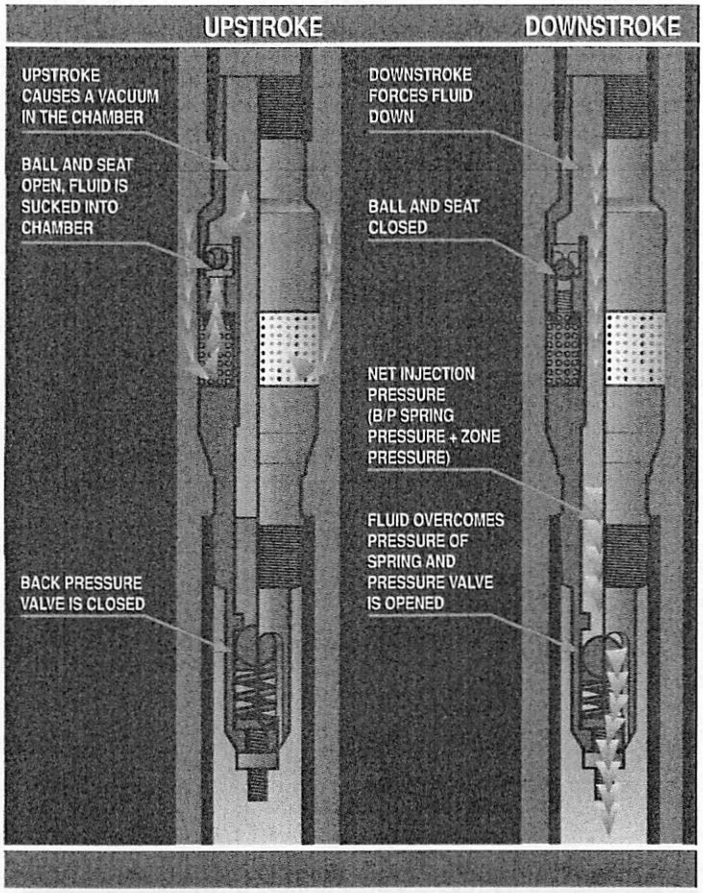
Here's how the DHI BPD System works to... PROTECT YOUR PROFITS!

It's true! If your well fits our tool you can get real profit protection from our BPD system. Read how the system works and how it might apply to your well.

Upon completion and testing to determine the injectivity of the disposal zone below the gas producing reservoir, an isolation packer is run and set above the disposal zone. This packer can be a wireline set permanent type, or double grip tubing set retrievable packer similar to a Loc-Set type packer. Selection of the packer is based on well conditions and depths. A spring loaded ball and seat snubber cage is installed below the packer and connected to the packer mandrel base. This serves as a downhole check valve. A tubing on/off tool is run above the packer. This arrangement allows the tubing to be pulled for well servicing operations without allowing the disposal zone to backflow into the producing zone, or back to the surface.

The BPD tool is then made up with tubing below, a modified tubing pump above and tubing to surface. This assembly is run in the hole and connected to the on/off tool above the packer. The BPD tool replaces both the traveling and standing valves of a typical bottom hole pump used for rod pumping. The upper body of the BPD tool has five (5) equally spaced inlet cages in the port head valve body. Different types of pump balls and seats can be installed in the inlet cages depending upon well conditions. The five valve arrangement allows for high volumetric efficiency, minimal turbulence, and allows large bore high volume tubing or insert pumps to be used. A one (1) valve BPD tool is also manufactured for special applications, such as low water volumes or high sand production conditions. The upper body of the BPD tool is connected to the lower discharge body of the tool by a threaded connection. An adjustable back-pressure valve is thread connected into the I.D. of the lower discharge body connector neck. On the pump upstroke, the back-pressure valve serves as a check valve allowing water to flow from the annulus through the five inlet valves into the pump barrel. On the pump down stroke, the five inlet valves seal closed and the back-pressure valve is forced open when the hydrostatic and rod load forces exceed the preset pressure of the back-pressure valve. This opening pressure is matched to the disposal zone injectivity and allows the water in the tubing below the pump to be forced into the disposal zone.

A piston plunger arrangement is then run in the tubing along with the sucker rod string and properly spaced out in the tubing barrel. Sufficient sinker bars are run above the piston plunger assembly to insure the fluid weight in the tubing along with the sinker bars provides the necessary force to inject water into the disposal zone. Rod guides can be included in the rod string design to improve overall system performance.


UPSTROKE
DOWNSTROKE
UPSTROKE CAUSES A VACUUM IN THE CHAMBER
BALL AND SEAT OPEN, FLUID IS SUCKED INTO CHAMBER
BACK PRESSURE VALVE IS CLOSED
DOWNSTROKE FORCES FLUID DOWN
BALL AND SEAT CLOSED
NET INJECTION PRESSURE (B/P SPRING PRESSURE + ZONE PRESSURE)
FLUID OVERCOMES PRESSURE OF SPRING AND PRESSURE VALVE IS OPENED

The greater the distance between the producing zone and the disposal zone the lower the BPD tool can be set in the wellbore. This will allow better separation of gas and water in the wellbore.

WATER FLOODING APPLICATIONS

The BPD injection tool system can play a role in enhanced oil recovery. Water flooding of oil reservoirs can be accomplished. After selecting a pumping well to be used as the injection well, a known compatible water-bearing formation above is perforated, and the packer is positioned between the source water and the producing formation. By using this method, an existing well becomes the water source, and existing equipment becomes the injection/pressure system. This method is a closed system, and eliminates surface injection systems.

An Oklahoma oil company is using the system to flood the Bartlesville Sand. An infield well was selected as the supply well, and is taking the source water from perforations from 2,659-2,684 feet. This water is being pumped into existing Bartlesville Sand perforations at 4,522-4,558 feet. The downhole injection assembly was sized to deliver 650 barrels a day into the zone.

DHI PERFORMANCE DATA

SEWARD COUNTY, KANSAS

Casing: 4 1/2 inch
Tubing: 2 3/8 inch
Rods: 3/4 inch
Pump size: 1 3/4 inch
Production: Chase Group (2,606-2,684 feet)
Disposal Depth: Lansing/Kansas City (4,668-78 feet) (4,694-4,707 feet)

The following production data was supplied by the operator from the pumper's daily gauge reports. The tool was operational on October 19, 1993 at 1:45 P.M. On the morning of October 23, 1993, it was selling 186 MCF/D.

BEFORE INSTALLATION

The last three months of production is used by daily "before" production rates.

Date	MCF/month	Water	Days	MCF/D
8/93	2,916	66	31	94
9/93	2,630	66	26	101
10/93	2,462	66	21	117

Total MCF 8,008 over 78 days= 102.7 Mcf/day

AFTER INSTALLATION

Date	MCF/month	Water	Days	MCF/D
11/93	3,457	0	26	132
12/93	4,055	0	31	130
01/94	3,593	0	25	143
02/94	3,887	0	28	138

Total MCF of 14,992 over 110 days=136.6 Mcf/day

MONTHLY AND ANNUAL INCOME GAIN

(Gross before taxes and operations)

BEFORE:	102.7 MCF/D x 1.75 x 30.5	$ 5,479.
	Water disposal cost	$ -2,013.
	Monthly gross income	$ 3,466.
AFTER:	136.3 MCF/D x 1.75 x 30.5	$ 7,274.
	Water disposal costs	$ 0.
	Monthly gross income	$ 7,274.
	Monthly Gross Gain	**$ 3,808.**
	Estimated Yearly Gross Gain	**$ 45,696.**

DHI PERFORMANCE DATA

TEXAS COUNTY, KANSAS

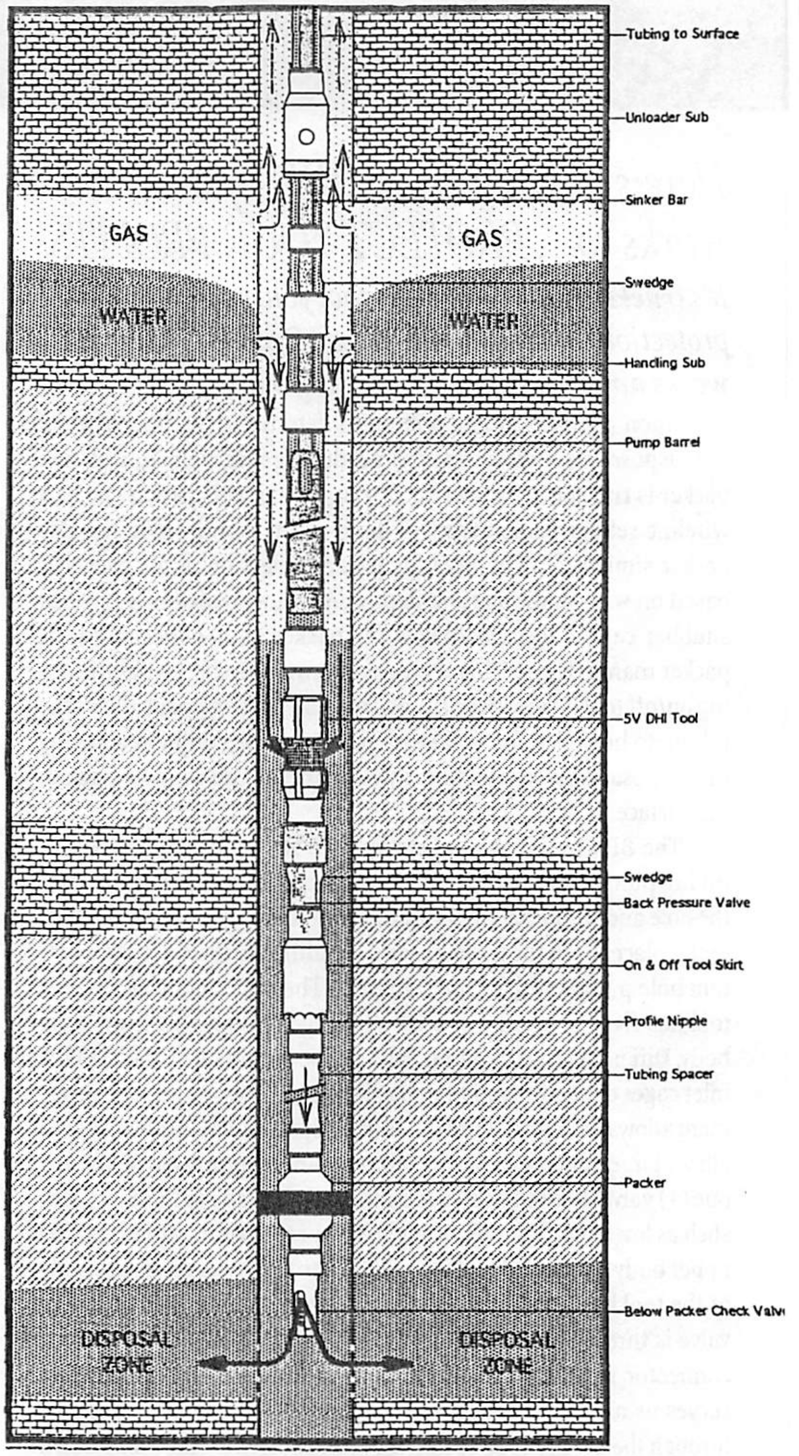
Casing: 4 1/2 inch
Tubing: 2 3/8 inch
Rods: 3/4 inch
Pump size: 1 3/4 inch
Production Depth: Upper Morrow (6,120-6,126 feet)
Disposal Depth: Lower Morrow (6,215-6,240 feet)

MONTHLY AND ANNUAL INCOME GAIN

(Gross before taxes and operations)

BEFORE:	220 MCF/D x 1.75 x 30.5	$ 11,742.
	Water disposal cost	$ -2,440.
	Monthly gross income	$ 9,302.
AFTER:	343 MCF/D x 1.75 x 30.5	$ 18,307.
	Water disposal costs	$ 0.
	Monthly gross income	$ 18,307.
	Monthly Gross Gain	**$ 9,005.**
	Estimated Yearly Gross Gain	**$ 108,060.**

SIMULTANEOUS
GAS PRODUCTION / DISPOSAL METHOD


Tubing to Surface
Unloader Sub
Sinker Bar
GAS
GAS
Swedge
WATER
WATER
Handling Sub
Pump Barrel
5V DHI Tool
Swedge
Back Pressure Valve
On & Off Tool Skirt
Profile Nipple
Tubing Spacer
Packer
Below Packer Check Valv
DISPOSAL ZONE
DISPOSAL ZONE

Above Production zone Disposal

(APD SYSTEM)

Here's the kind of profit protection you can count on from our APD system

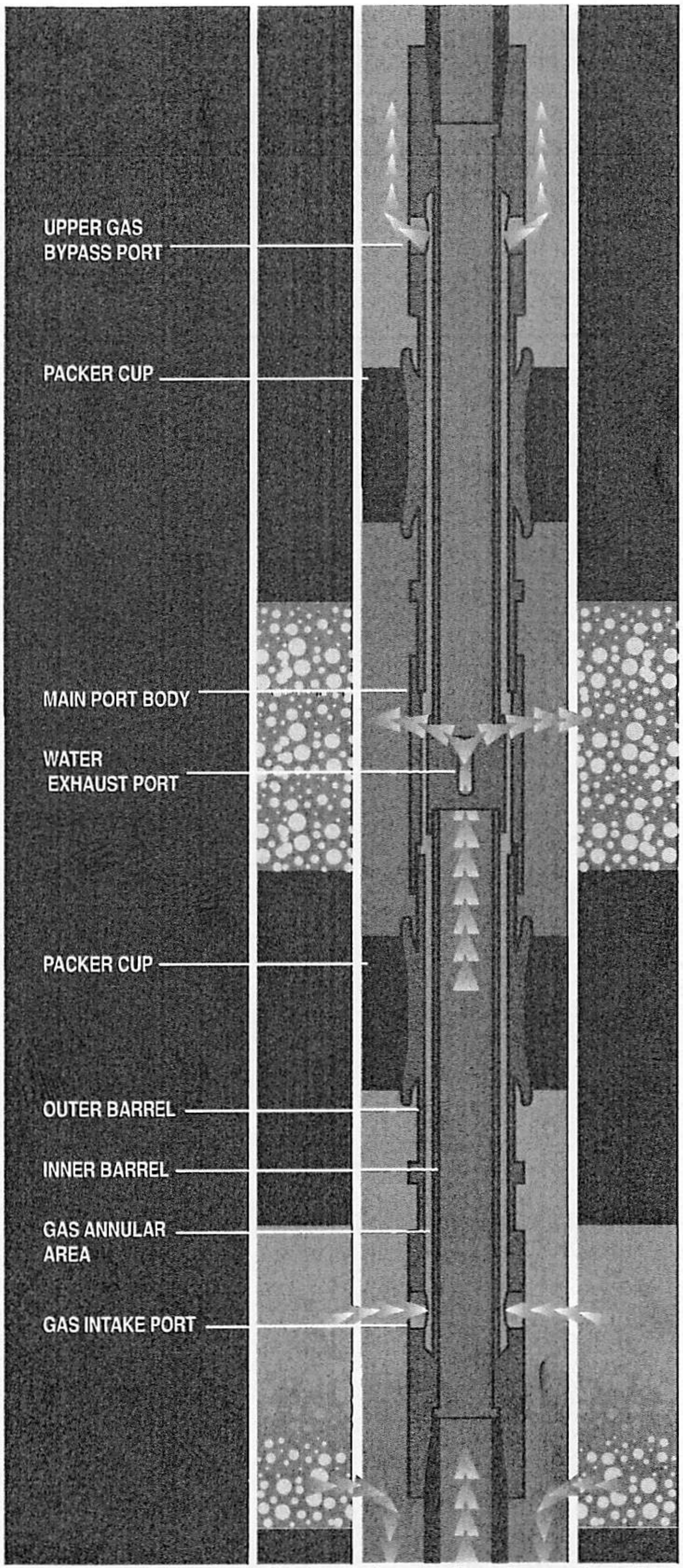
You can take it to the bank: The DHI system for Above Production zone Disposal is a very real, very practical profit protector. Here's how it works to bring new efficiency to Above Production zone Disposal.

Once the disposal zone has been completed and its injectivity determined, the APD system is run in the well. A mud anchor, seating nipple with standing valve and pump barrel are run on tubing and set at a sufficient depth below the gas producing zone. The deeper the pump can be set the more ideal will be the conditions to allow gas and water separation in the wellbore. Cup type packers are included in the APD tool system and positioned above and below the disposal zone perforations to isolate the zone for water injection between the straddle packer arrangement. Immediately below the lower cup packers, a gas by-pass port is installed as is another gas by-pass port immediately above the top cup packers.

The tool body of the APD system consists of an outer tube and an inner tube. In between the upper and lower cup packers, a port collar is run which connects the inner tube to the outer tube. This port collar has by-pass holes which allow gas to flow past the port collar. Produced water moves up the inside of the tubing, through the inner tube of the APD tool and exits out the port collar for injection into the disposal zone. Gas enters the lower most gas by-pass port, flows up the annulus between the inner and outer tubes, through the by-pass holes in the port collar, on up the annulus between the tubes and exits into the tubing-casing annulus via the upper gas by-pass port. From there the gas flows to the surface for treatment and sales. Another tubing pump barrel is included in the tubing string immediately above the APD tool.

A standard tubing pump plunger is used in the lowermost tubing pump barrel while a tubing seal assembly is used in the uppermost tubing pump barrel. Sucker rods connect the plunger and tubing seal assembly and sucker rods are run from the tubing seal assembly to surface. The tubing is loaded with fluid to lubricate the rod string and provide additional force for injection into the disposal zone. During the normal pumping operation, fluid is drawn into the lower pump barrel on the upstroke. At the same time, the upper tubing seal assembly allows the fluid to continue to move upward inside the tubing. On the down stroke, the lower plunger displaces fluid up the tubing while the tubing seal assembly movement downward forces the fluid out the port collar and into the disposal zone.

The APD system can be run in most casing sizes from 4.5 inches and above. A tubing anchor is set just below the APD tool to anchor the tubing and centralize the pump barrels.



A mud anchor, standing valve in seating nipple and pump barrel are set below the gas producing zone. Water is drawn into the lower pump barrel, then up the tubing and forced into the disposal zone.

DHI CASE HISTORY

PRATT COUNTY, KANSAS

INITIAL COMPLETION: MISSISSIPPI ZONE (AUG. 1994)

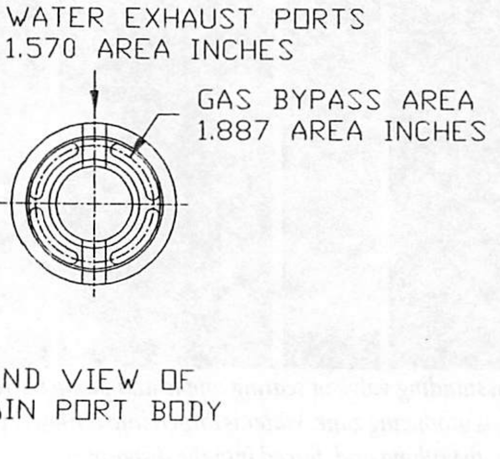
Mississippi pay zone at 4,180 feet would not flow after perforating or acid stimulation treatment. Fracture treated zone with 60,000 gallons of fluid with 90,000 pounds of sand. Established flow of 290 MCF/D with 30 BWPD.

Isolated Mississippi zone below bridge plug and completed well in Lansing-Kansas City zone at 3,734 - 3,734 feet. Produced for 2 years before zone "watered out" from active water drive in reservoir.

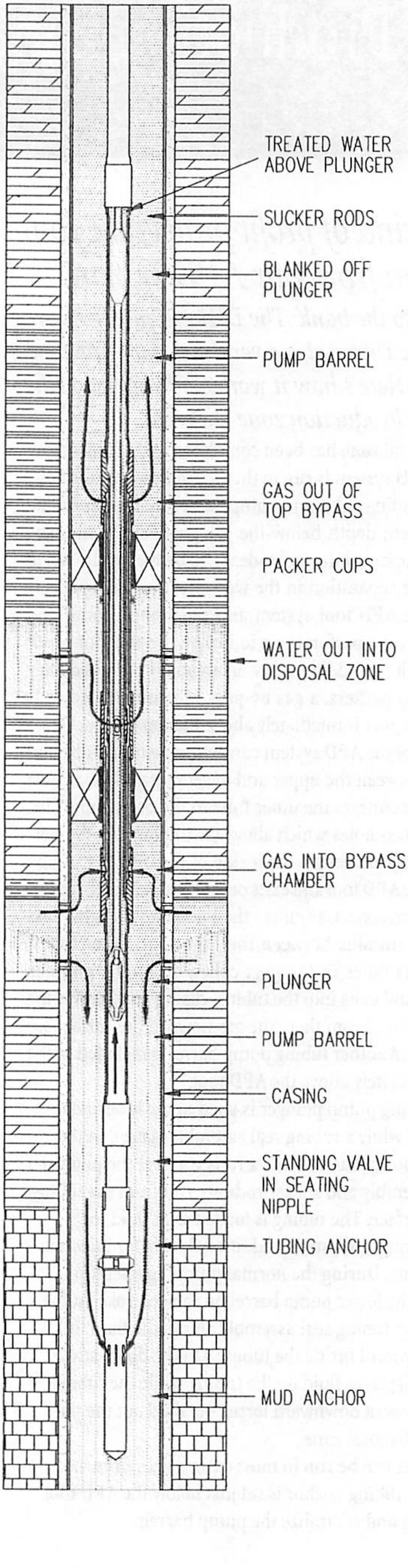
APD COMPLETION (DEC. 1996)

Drilled out bridge plug above Mississippi zone and installed APD system in well. Production from Mississippi zone at 4,180-4,209 feet with bottom hole pump at 4,232 feet and water disposal into Lansing-Kansas City zone at 3,734-3,738 feet.

Initial production from Mississippi: 200 MCF/D with 55 BWPD being injected into Lansing-Kansas City zone without being brought to surface.


WATER EXHAUST PORTS
1.570 AREA INCHES
GAS BYPASS AREA
1.887 AREA INCHES

END VIEW OF
MAIN PORT BODY


TREATED WATER
ABOVE PLUNGER
SUCKER RODS
BLANKED OFF
PLUNGER
PUMP BARREL
GAS OUT OF
TOP BYPASS
PACKER CUPS
WATER OUT INTO
DISPOSAL ZONE
GAS INTO BYPASS
CHAMBER
PLUNGER
PUMP BARREL
CASING
STANDING VALVE
IN SEATING
NIPPLE
TUBING ANCHOR
MUD ANCHOR

THE AMERICAN OIL & GAS REPORTER®

MARCH 1997

The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

Tool Solves Produced Water Problems

By Jeff Miller

WICHITA, KS.–The economic and environmental benefits of producing natural gas and disposing of water in the same well bore at the same time are obvious to any producer who has had to deal with produced water problems, particularly in mature fields where hydrocarbon production is declining in the face of escalating water disposal and handling costs.

One solution is a patented below-production disposal zone (BPD) system (formerly called the DHI tool) that allows produced water to be injected into a formation below the gas-producing reservoir under pressure using a conventional beam rod pumping system. However, most existing wells have not been drilled or cased deep enough to allow the completion of a disposal zone below the producing reservoir. Such natural gas wells are cased just deep enough to allow produced water to pool at the bottom, and then be pressured or conventionally-pumped to the surface for disposal.

For these wells, new technology has led to the development of a patented above-production zone disposal (APD) tool that allows produced water to be disposed up hole into a water-bearing zone above the gas-producing reservoir under pressure using a beam rod pumping system.

APD System

The APD method is accomplished by straddling the injection zone that has been completed and its injectivity determined utilizing a packer cup arrangement, standard pumping unit, sucker rods, two conventional pumps, and a single string of tubing (Figure 1). A standard mechanical lift tubing pump is positioned below the production interval, while another standard tubing barrel is positioned directly above the APD tool with a valveless (plugged) plunger.

As shown in Figure 2, the tool body consists of an outer and an inner tube. A port collar is connected to the outer tube and to the inner tube between the upper and lower packer cups. The port collar design permits water to exit between the isolated area and into the disposal zone. Gas enters the tool below the bottom packer cups, travels up between the outer and inner tubes through bypass holes in the port collar, exits out the tool above the top packer cups, and flows to the surface.

When the APD system is run into a producing well, the pumps are spaced out and the rods are hung off. The tubing is filled with an inhibited fluid from the upper pump to the surface. This fluid remains static, and becomes part of the power source. With the dual-pump design and positioning, produced water is drawn into the lower pump chamber on the up stroke. The upper plunger is raised simultaneously, allowing for the upper movement of the fluid. On the down stroke, fluid is displaced into the tubing by the lower plunger. The upper plunger's down stroke movement forces the fluid into the disposal zone, providing the force needed for injection pressure.

JEFF MILLER

Jeff Miller is the technical service manager for Down Hole Injection, Inc. of Wichita, Ks., which manufactures the APD and BPD tools for simultaneous production/water disposal. He has 25 years of oil and gas well completion experience in special tools, and contributes to product design, engineering, and development of the technology. Miller also assists with technical support in training for the company DBUs.

The force required to pump into the disposal zone does not rely on casing gas pressure. The downhole injection system uses the principle that the weight of the fluid load in the tubing from the pump to the surface (along with rod string weight) supplies the necessary force to push the plunger down, creating a positive mechanical displacement. Sucker rod compression is greatly minimized over conventional pumping methods.

The effects of the tool on the pump jack and sucker rod string have been a subject of continued dynamometer testing and engineering study. There are similarities and differences between the up- and down strokes. Briefly, the downhole injection process requires less peak torque, less horsepower, and allows greater pumping efficiencies. The power required to drive the pumping unit is not related to the amount of water injected, because tubing fluid and rod weight never change. Pump bore size, stroke length, and strokes per minute are set to match the water inflow rates from the producing zone with the amount of water to be injected into the disposal zone.

Test Well

Ritchie Exploration Inc. of Wichita, Ks., agreed to install the first prototype APD tool in its Travis No. 1 Well in Pratt County, Ks. Pertinent data on the installation report included:

- The well was shut-in (non-commercial);
- 5.5-inch casing was set to 4,435 feet total depth (a cast iron bridge plug was set at 4,150 feet);
- The Mississippi was perforated at 4,180-4,209 feet with one shot per foot (pay zone); and

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- The Lansing-Kansas City (LKC) "A" zone was perforated at 3,734-3,738 feet with four shots per foot (watered out).

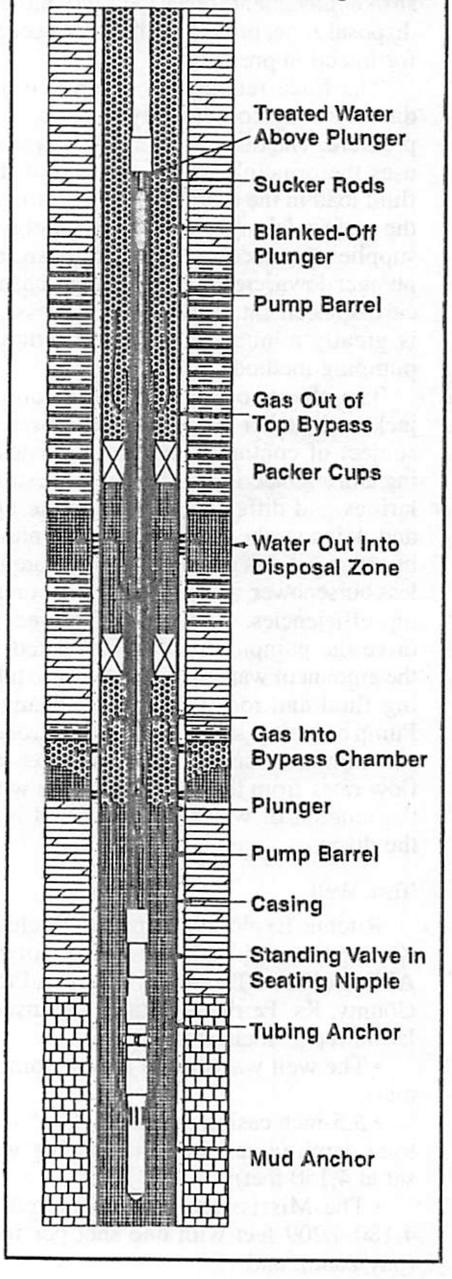
The objective of the installation was to simultaneously produce Mississippian gas and dispose produced water into the LKC A zone. On Dec. 13, 1996, a cable tool rig was moved on location to drill out the cast iron bridge plug. The bridge plug was pushed to 4,290 feet to the top of left over frac sand, but problems were encountered with kicking, and efforts to clean out deeper were abandoned.

The target depth for the bottom pump intake was 4,259 feet, which would leave 15 feet of rat hole below the mud anchor. With the prospect of the zone giving up more frac sand, it was agreed to position the pump only 23 feet below the producing zone at 4,232 feet, leaving a limited area for gas and water separation to occur.

On Dec. 17, a retrievable packer was run to test the integrity of the casing above the Lansing-Kansas City zone to 500 psi, and witnessed by an official representing the state. The APD system was installed the next day.

FIGURE 1

APD Tool Downhole Configuration


Treated Water Above Plunger
Sucker Rods
Blanked-Off Plunger
Pump Barrel
Gas Out of Top Bypass
Packer Cups
Water Out Into Disposal Zone
Gas Into Bypass Chamber
Plunger
Pump Barrel
Casing
Standing Valve in Seating Nipple
Tubing Anchor
Mud Anchor

Tubing, Sucker Rod

A 1.75-inch by 15-foot precision-honed tubing pump with a 15-foot mud anchor and a 6-foot gas anchor was picked up and lowered into the well. A 4-foot axite plunger, 16-foot polish rod (pull rod), spiral rod guide, and an on/off coupler were then positioned inside the pump barrel. A measurement was recorded from the pump seat to the rod on/off coupler, and 15 joints of 2.375-inch EUE 8rd tubing were tallied and run above the pump.

The APD tool, with a standard tubing anchor/catcher and a tubing centralizer, was picked up, tallied, and run above the 15 joints. Another 1.75-inch by 16-foot tubing pump was internally chromed, picked up, tallied, and lowered into the well above the APD tool with 119 joints of tallied 2.375-inch EUE 8rd tubing. The total length needed was spaced out at the surface so that the packer cups on the APD tool were equally spaced on either side of the 4-foot LKC disposal zone. The tubing anchor/catcher was set and landed with 18,000 pounds of tension, and the wellhead was nippled up. At that point, 25 barrels of salt water with corrision-inhibitor was pumped down the tubing to flush, and to test the straddled area for correct placement of the APD tool.

A 1.25-inch by 25-foot sinker bar was then picked up with the rod on/off overshot, tallied, and lowered into the tubing, followed by 17 sucker rods (0.75-inch) with slim hole couplings. Next, a 4-foot rod sub, a full 25-foot rod, and a 6-foot rod sub were run, all with 0.75-inch slim hole couplings (this rod configuration was extremely important to the spacing of the two plungers, and had a direct relation to not having a rod coupling inside the inner barrel of the APD tool during the pump stroke).

A 1.75-inch by 4-foot axite plunger (plugged internally) with a six-seating cup mandrel connected below the top cage was picked up and connected to the lower rod string. The upper plunger was run in the tubing with 148, 0.75-inch sucker rods. The rod string was then spaced out to the lower pump plunger at the on/off coupler using rod subs and the polish rod.

A pump test was performed on the tubing to ensure the proper spacing of rods and plunger with inhibited salt water. A size 114 Sentry pumping unit with a 64-inch stroke was set, and the rods were hung off. A 200-barrel tank was brought in and plumbed into the flow tee at the wellhead, and filled with 60 barrels of inhibited salt water. This allowed for any tubing fluid slippage that might occur during the pumping/injecting process.

Start Up

Production commenced on Dec. 19. A well performance survey is shown in Table 1. Corresponding dynamometer cards are shown in Figure 3. By Jan. 6, 1997, the APD tool was injecting approximately 50 barrels of water while flowing 115-125 Mcf of gas a day by maintaining a solid fluid level at the pump intake and maximizing the gas flow rate. Given the relative area from the producing perforations, the "fine tuning" process began.

Downhole injection works well with a long and slow pumping system. Selecting the 114 Sentry pumping unit with a 64-inch stroke allowed for moving a large

FIGURE 2

Tool Body

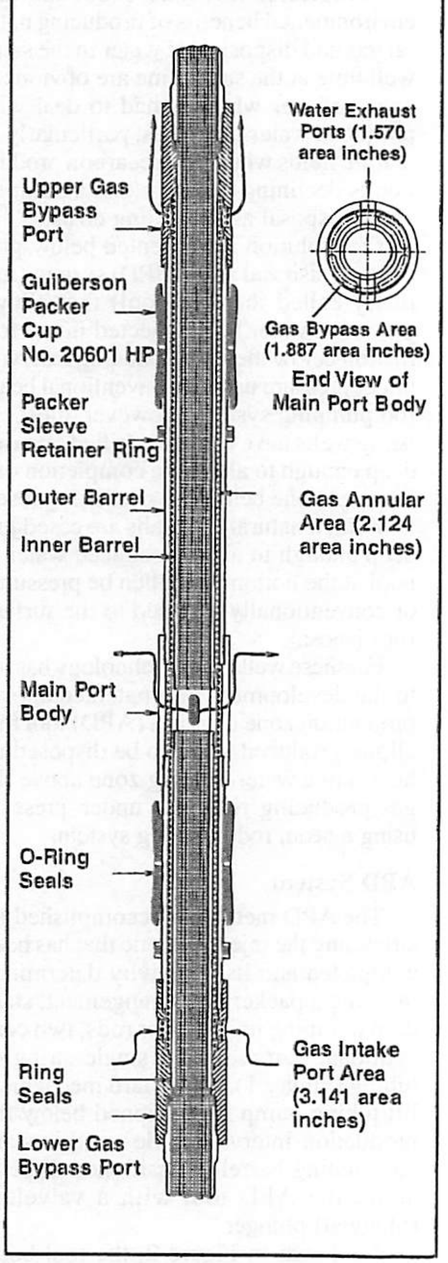

Water Exhaust Ports (1.570 area inches)
Upper Gas Bypass Port
Guiberson Packer Cup No. 20601 HP
Gas Bypass Area (1.887 area inches)
End View of Main Port Body
Packer Sleeve Retainer Ring
Outer Barrel
Gas Annular Area (2.124 area inches)
Inner Barrel
Main Port Body
O-Ring Seals
Ring Seals
Gas Intake Port Area (3.141 area inches)
Lower Gas Bypass Port

TABLE 1

Well Performance Survey

Company: Ritchie Exploration Inc.
Location: Pratt County, Ks.
Lease: Travis No. 1
Date: Dec. 19, 1996

Date	Time	Dynamometer Card	Remarks	Csg. #	MPRL/ PPRL	SPM
Dec. 19	6 p.m.	1	Start up-csg. Shut in-fl.@1443 ft. 46 jts.	0	7.6-8.0	6.23
Dec. 20	8:30 a.m.	2	Check O.K.-Fl.@2520 ft. 81 jts	588	7.0-8.0	6.17
	noon		Check O.K. Fl.@2849 ft. 92 jts	758	6.1-8.2	6.10
	3 p.m.	3	Dyno shows gassy fluid displ. Fl.@3063 ft. 98 jts	880	7.6-8.0	6.85
	4:30		Rig up to turn down line		7.6-8.1	6.85
	5:45		Shut down pumping unit			
	6:45		Start pumping unit-open csg. on 7/64 in. ck.	500	7.0-8.2	6.85
	7:00		Check O.K.	400	6.8-8.4	6.85
	7:45	4	Slow unit down	350	6.8-8.2	5.19
	8:45		Check O.K. 200 Mcf	250	6.8-8.4	5.19
	10:30		Check O.K. 200 Mcf	125	6.6-8.4	5.19
Dec. 21	midnight		Check O.K. Leave loc. 200 Mcf	125	6.6-8.4	5.19
	7:30 a.m.		Check O.K. 150 Mcf	100	6.5-8.4	5.26
	8:45	5	Dyno shows load quickly picks up, then severely less than halfway up, then on down stroke, load increases sharply then falls sharply before bottom of stroke			
	9:00		Slow unit down. 140 Mcf	70	6.0-9.0	5.19
	10:00		Shut csg. In. Tried fl. Slot, no success			
	11:00		Well pump down-dry	70	8.0-8.0	5.19
	11:15		Shut unit down			
	2:15 p.m.		Start unit			
	2:30	5	Slow down unit. Dyno shows full card		6.8-8.8	4.50
	4:30		Check O.K.		6.8-8.8	4.50

volume of fluid initially, while maintaining the capability to adjust the pump for smaller amounts once flow rates stabilized. As noted in the circled area of the dynamometer graphs, the stroke length of the two bottom-hole pumps are significantly less.

There have been no indications of a visible fluid pound. During the testing period, the well was allowed to pump off three times. The dynamometer was able to feel "gassy" fluid at the pump once, and adjustments were made to slow the pumping unit. A hydraulic load cell has been installed between the polish rod clamp and the carrier bar for quick indication of peak to minimum loads on the pumping unit stroke. A 3,000-pound swing (plus or minus 100 pounds) is presently being observed. Should a gas lock or pump-off occur, the swing would be greatly reduced.

Daily checks of the reserve tank show little or no fluid slippage occurring at the upper pump. The cup mandrel installed on top of the axite plunger has wood-type seating cups. Along with this arrangement and sufficient bottom-hole pressure at the injection zone, concern of additional water hauling may be eliminated. Although an occasional gas lock or pump-off may occur, it has been noted that a knock-off could remedy the situation by jarring the ball free from its seat on the standing valve of the lower pump.

To date, the APD tool installation and simultaneous pumping/injecting process has been a success. The pumping system dynamics seem to be well within its parameters, and is powered by its own well gas. Once slated for plugging and abandonment, this may be the most efficient commercial well in its class.

Candidate Well

Candidate wells considered for the APD system should meet the following requirements:

- Production casing must have cement bonding above and below the injection zone;
- Reservoir capacity that permits disposal of large volumes of water;
- Sufficient geological features to form a natural barrier that would prevent injected fluids from migrating into adjoining formations; and
- State regulatory agencies must be notified, because permitting may be required.

Together, the APD tool, which injects produced water into a disposal zone above the producing reservoir, and the BPD tool, which inject produced water into a disposal zone below the producing reservoir, constitute the down hole injection (DHI) systems. This technology also extends into solutions with the development of other tools, such as a multi-well injection tool and the dual annulus production tool (patents pending on both).

The multi-well injection tool (M-WIT) allows operators to dispose moderate amounts of produced water from nearby wells to a well equipped with the BPD system. Such nearby wells may not have been drilled deep enough, have a suitable disposal zone, good cement bonding, or economically qualify for other DHI systems. The dual annulus production (DAP) tool provides gas production to flow to the surface in areas where regulations require the casing-to-tubing annulus be filled and maintained with a non-corrosive fluid above a packer. Primarily designed to be run in conjunction with the BPD system, the tool offers advantages in other types of production with regard to protecting production casing.

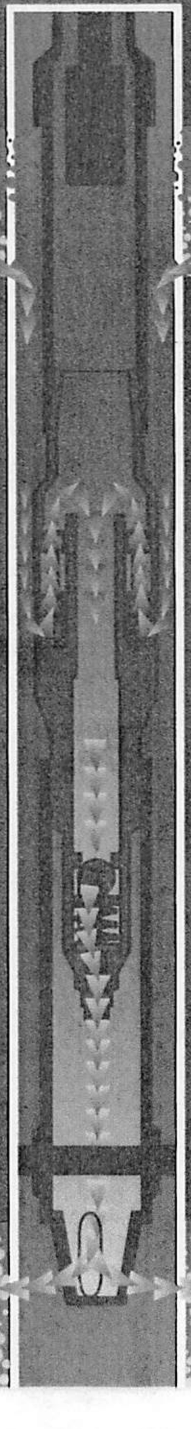
The DHI systems are primarily used in gas production, although research is continuing for water-driven oil wells. Simultaneously producing gas while disposing of produced water by positive mechanical displacement in the same well bore offers both short- and long-term environmental and economic benefits, including:

- Preventing the contamination of fresh water resources and surface soil;
- Eliminating water hauling expenses;
- Restoring non-commercial and marginal wells to production;
- Maximizing profitability;
- Encouraging future exploration; and
- Removing environmental problems associated with water disposal. ❒

The Gas comes up
The Water goes down

...all at once in the same wellbore.

DHI's new patented systems allow gas and produced water to be separated downhole in the wellbore, eliminating the need for disposal wells or surface holding ponds/pits. Gas flows to the surface for final treating, produced water is injected into a disposal zone either below, or above, the gas producing reservoir.



If your well fits our tool
You're losing money until you install it

- INCREASED CASH FLOW, eliminates produced water disposal costs and increases gas production.
- CAPTURE OF ADDITIONAL RESERVES lowers the economic limit of marginal wells, or returning shut-in/uneconomic wells to production.

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"A Solutions Company"

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Wichita, Kansas
Jay Miller—DHI Sales Mgr.
Houston, Texas 77095
281-345-2866 • Fax: 856-0959

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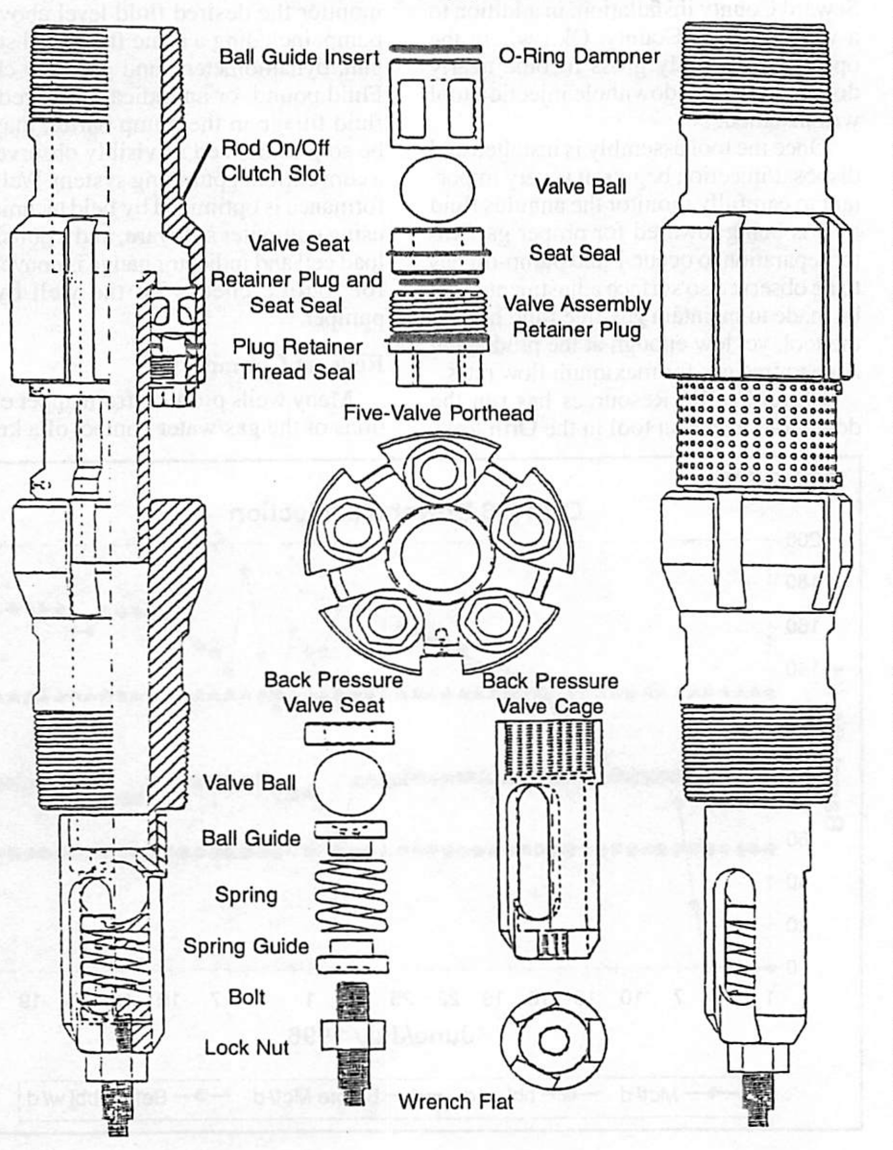
Tool Reduces Produced Water Costs

FIGURE 1

Downhole Injection Tool


Ball Guide Insert
O-Ring Dampner
Rod On/Off Clutch Slot
Valve Ball
Valve Seat
Seat Seal
Retainer Plug and Seat Seal
Valve Assembly Retainer Plug
Plug Retainer Thread Seal
Five-Valve Porthead
Back Pressure Valve Seat
Back Pressure Valve Cage
Valve Ball
Ball Guide
Spring
Spring Guide
Bolt
Lock Nut
Wrench Flat

By Jeff Miller

WICHITA, KS.–The escalating cost of disposing salt water produced from oil and gas wells is nothing new to oil and gas producers as an economic burden. Produced water can make commercially-viable wells marginal or uneconomical to produce, and many leases may go undeveloped. Because of this, countless dollars worth of production are lost.

To alleviate problems with produced water, a new tool that allows simultaneous production and downhole injection of produced water has been introduced. The technology allows operators to produce gas and dispose of water in the same well bore at the same time. Since waste water is never brought to the surface, water hauling, disposal fees, contamination of surface soil and fresh water resources are eliminated.

As the primary inventor of the technology, Clarence Michael, explains, "This tool will allow a modified conventional down hole mechanical lift pump to displace, under pressure, large quantities of unwanted salt water down hole rather than up."

However, concurrent disposal-injection may not be appropriate for all wells. Using downhole injection, prospective wells require a porous or a water-bearing formation below the production interval and sufficient production casing depth to cover the intended zone. However, technology has broadened for wells that do not have sufficient depth, and has led to the development of tools for disposing of water above the production zone and for multi-well injection.

Down Hole Assembly

The downhole injection tool is designed to be used in conjunction with standard rod/plunger-lift pumping tools. The tool

Reprinted for Downhole Injection Inc. with permission from The American Oil & Gas Reporter is connected at the base of a modified tubing-type pump. The valves are removed from the plunger and a plug is installed at its base. A tubing on/off tool is connected between the downhole injection tool and a lock-set or permanent packer with a below-packer check valve. The on/off tool provides a disconnect for maintenance, while the packer provides a temporary bridge plug.

Constructed in 304 stainless steel (Figure 1) and internally placed in the port head valve body of the downhole injection tool are five equally-spaced balls and seats. An adjustable back pressure valve is thread-connected to the lower discharge body. In theory, the tool becomes both the traveling valve and standing valve in the injection process.

The pre-set back pressure valve acts as a check valve on the up stroke, which forces the pump to draw the annulus fluid through the intake valve ports and into the barrel. The amount of back pressure needed is determined by the injection pressure of the disposal zone. On the down stroke, the intake valves close and fluid is discharged through the back pressure valve and packer into the prepared zone under pressure.

The force required to pump down into disposal zones does not rely on gas pressure or casing gravitational forces. The downhole injection system uses the principle that the weight of the fluid load in the tubing from the pump to the surface supplies the necessary force to push the plunger down, creating a positive mechanical displacement. Sucker rod compression is greatly minimized over conventional pumping methods.

The effects of the tool on the pump jack and sucker rod string have been a subject of continued dynamometer testing and engineering study. There are similarities and differences between the up and down strokes. Briefly, the downhole injection process requires less peak torque, less horsepower, and greater pumping efficiencies. The power required to drive the pumping unit is not related to the amount of water injected because tubing fluid and rod weight never change. Pump bore size, stroke length, and strokes per minute determine the amount needed to displace on a daily basis.

Test Well

A Hugoton gas well located in Seward County, Ks., pumped 66 barrels of water a day by conventional means, and flowed an average of 103 Mcf of natural gas per day from the casing with 100 psi. In October 1993, the prototype downhole injection tool and a modified pump were installed. Casing pressure was reduced to 50 psi line pressure and an estimated 100 barrels of water a day was injected. An average daily gas sale was 136 Mcf over the first four-month test period, resulting in a net economic gain of nearly $4,000 a month.

TABLE 1

Monthly and Annual Income Gain (Before Taxes and Operations)

Seward County, Ks.		Texas County, Ok.	
Before		**Before**	
102.7 Mcf/d x $1.75 x 30.5	$5,479	220 Mcf/d x $1.75 x 30.5	$11,742
Water disposal cost	$-2,013	Water disposal cost	$-2,440
Monthly gross income	$3,466	Monthly gross income	$9,302
After		**After**	
136.3 Mcf/d x $1.75 x 30.5	$7,274	343 Mcf/d x $1.75 x 30.5	$18,307
Water disposal cost	$0	Water disposal cost	$0
Monthly gross income	$7,274	Monthly gross income	$18,307
Monthly gross gain	$3,808	Monthly gross gain	$9,002
Estimated yearly gross gain	$45,696	Estimated yearly gross gain	$108,060

The tool is still in the well, producing/disposing, and has never been pulled for maintenance in more than three years. Table 1 shows performance data for the Seward County installation, in addition to a well in Texas County, Ok., where the operator's monthly gross income nearly doubled after the downhole injection tool was installed.

Once the tool assembly is installed and disposal/injection begins, it is very important to carefully monitor the annulus fluid as it is being lowered for proper gas/water separation to occur. Fluid pump-off has to be observed so surface adjustments may be made to maintain gas-free fluid head at the tool, yet low enough at the production zone to free gas for maximum flow rates.

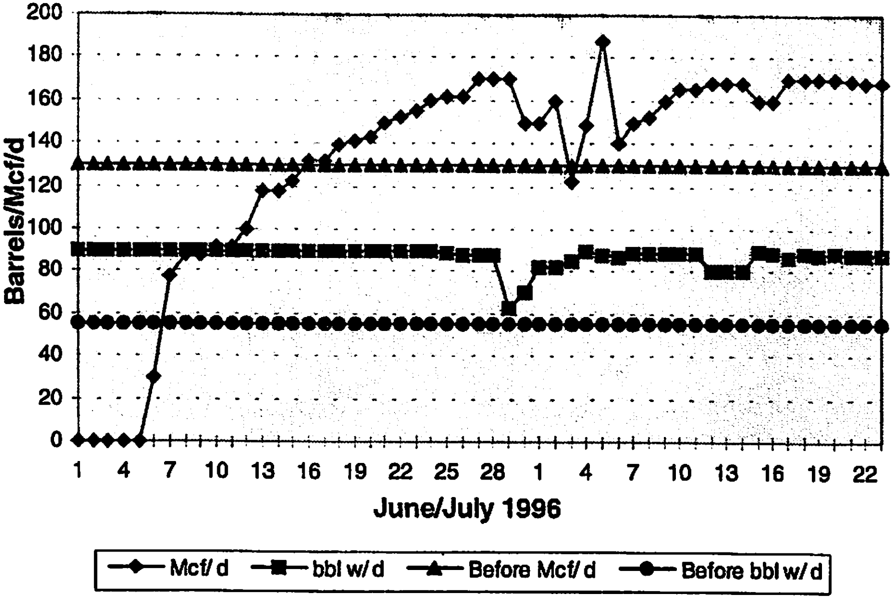
Union Pacific Resources has run the downhole injection tool in the Orth lease located in Haskell County, Ks. Figure 2 shows the dips in both water displacement and gas production when pump-off occurred and adjustments were made. Here again, flow rates for both gas and water increased. In retrospect, Union Pacific Resources is now permitting other candidate wells.

A number of methods may be used to monitor the desired fluid level above the pump, including a sonic fluid level survey gun, dynamometers, and gas flow charts. Fluid pound, or an indication of reduced fluid fillage in the pump barrel, may not be so pronounced as visibly observed on a conventional pumping system. Well performance is optimized by field technicians using computer software, and a polish rod load cell and indicator gauge is convenient for routine checks on the well by the pumper.

Reverse Coning

Many wells produce from upper elevations of the gas/water contact of a known

FIGURE 2



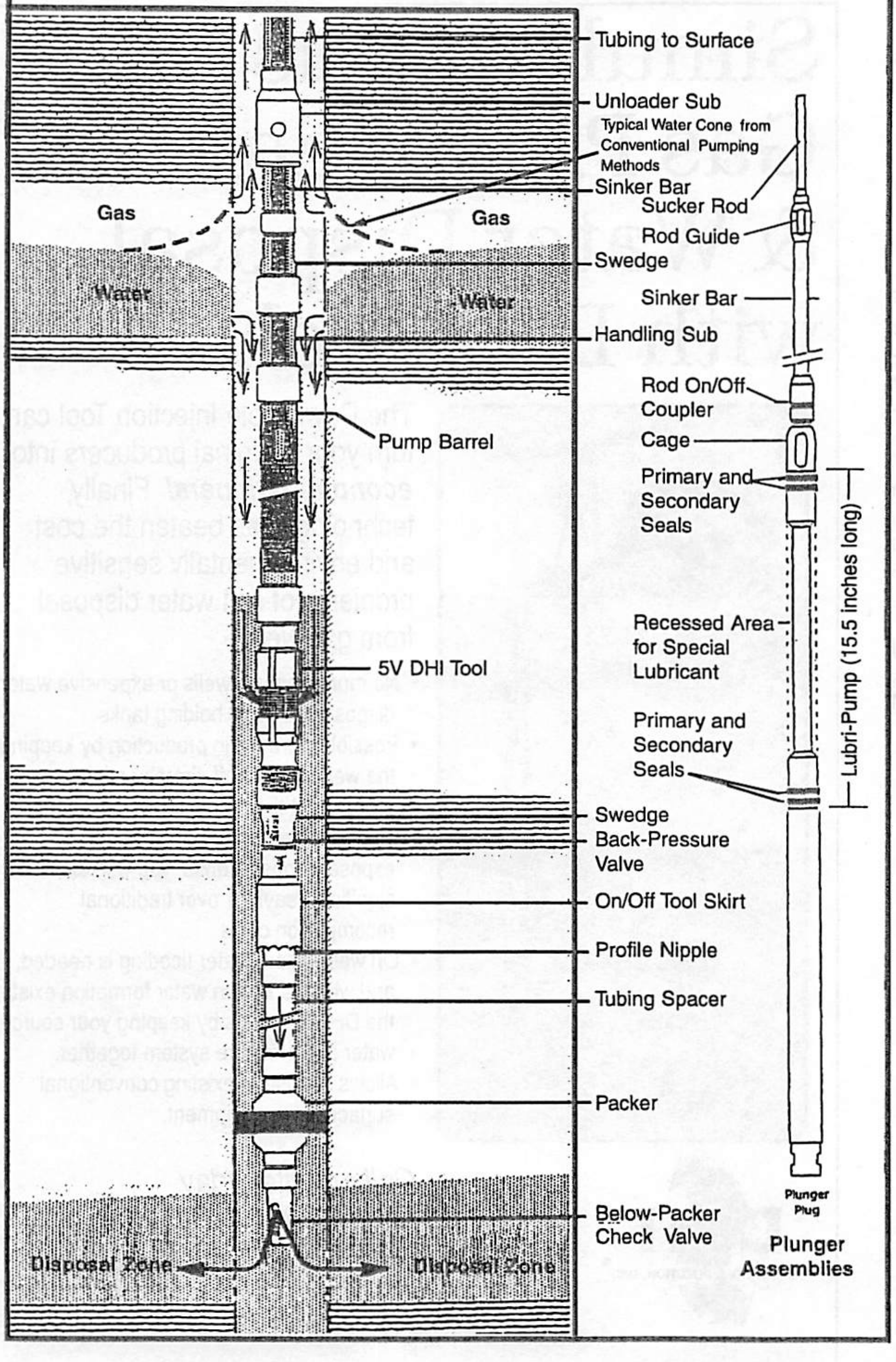
Orth 2-6 Downhole Injection

formation, and it appears that the water table can only be lowered down to the base of the perforated interval (Figure 3). Geologically-structured, and if there is sufficient zone thickness, strong supporting evidence shows that with lower drainage perforations, gas/water separation is actually occurring in the formation, not the cased well bore. This allows additional gas flow rates and additional reserves to be freed up that would be economical to produce.

In January 1996, a downhole injection tool was installed in the Snyder No. 1-30 in Lincoln County, Ok. Prior to the tool's installation, gas production averaged 124 Mcf/d, along with 41 barrels of water. Production perforations are at 4,516-4,530 feet (Peru), and disposal perfs are at 4,922-4,942 feet (Skinner sand). Casing pressure while producing was 500 psi. New perforations were shot at 4,531-1,540 feet, and preparation was made to handle 250 bbl of water a day.

FIGURE 3

Simultaneous Production/Disposal Method


Tubing to Surface
Unloader Sub
Typical Water Cone from Conventional Pumping Methods
Sinker Bar
Gas
Gas
Water
Water
Swedge
Handling Sub
Pump Barrel
5V DHI Tool
Swedge
Back-Pressure Valve
On/Off Tool Skirt
Profile Nipple
Tubing Spacer
Packer
Below-Packer Check Valve
Disposal Zone
Disposal Zone
Sucker Rod
Rod Guide
Sinker Bar
Rod On/Off Coupler
Cage
Primary and Secondary Seals
Recessed Area for Special Lubricant
Primary and Secondary Seals
Lubri-Pump (15.5 inches long)
Plunger Plug
Plunger Assemblies

When the process began, proper separation was difficult. In early March, gas sales were rapidly increasing and casing pressure was reduced (Figure 4). By mid-summer, a clock-timer was installed on the pumping unit as produced water was diminishing. In early October, pumping time was reduced to six hours a day, ending with the disposal of approximately 60 bbl of water and selling approximately 190 Mcf at 80 psi casing to sales line pressure. It has been recommended to the operator that he install a gear reducer on the pumping unit to improve the efficiency of the downhole injection process and enhance gas sales.

Water Flooding

Applying the downhole injection tool assembly and the disposal injection process plays a role in enhanced oil recovery. Water flooding of oil and gas-drive pools are being accomplished. After selecting a pumping well to be used as the injection well, a known compatible water-bearing formation above is perforated, and the packer is positioned between the source water and the producing formation. By using this method, an existing well becomes the water source, and existing equipment becomes the pump/pressure system. This method is a closed system, and eliminates oxidation of the flood formation.

An oil company with a well in Payne County, Ok., is using the tool for its water flood application to flood the Bartlesville sand. The Nottingham No. 1, an infield well selected as the supply well, is

JEFF MILLER

Jeff Miller is the technical service manager for Down Hole Injection, Inc. of Wichita, Ks., which manufactures the Down Hole Injection (DHI) tool for simultaneous production/water disposal. He has 25 years of oil and gas well completion experience in special tools, and contributes to product design, engineering, and development of the technology. Miller also assists with technical support in training for the company DBUs.

taking the source water from perforations from 2,659-2,684 feet. This water is being pumped into existing Bartlesville sand perforations to 4,522-4,558 feet. The downhole injection assembly was sized to deliver 650 barrels a day into the zone.

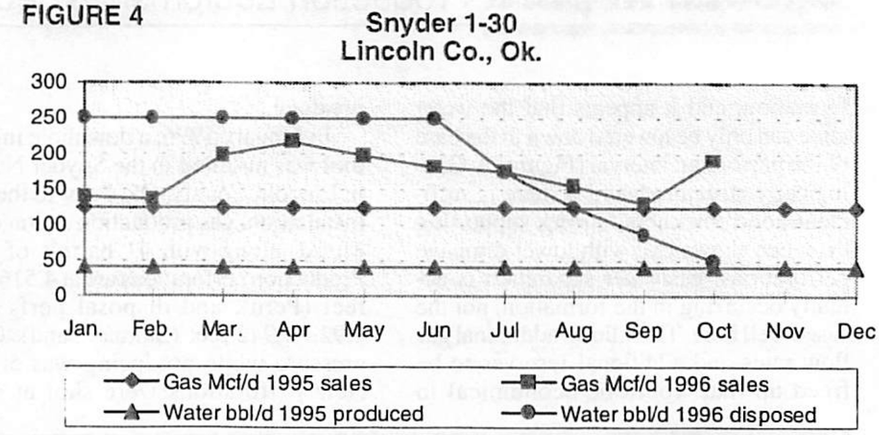
Primarily, the downhole injection tool is used in gas production, although research is continuing for the downhole injection process for water-drive oil wells. A prospective well requires a formation zone that has sufficient porosity and permeability, with a geological barrier that will accept waste water. Commonly, the well should be cased at the intended injection zone, but that may not be mandatory. A sufficient depth interval is necessary between the isolated injection zone and the producing zone, where flow rates and pressures are assessed for proper water/gas separation. Current well data is used as a basis for sizing the tool assembly.

Before installing the tool, the appropriate state regulatory commission must be notified, since it may require a permitting process. David Norby, president of Ener-Tech Tool Company LLC of Denver and a distributor of the downhole injection tool, remarks, "My states have welcomed this new technology very favorably."

Simultaneously producing gas while disposing of water by positive mechanical displacement in the same well bore offers desirable features for both short- and long-term environmental and economic benefits, including:

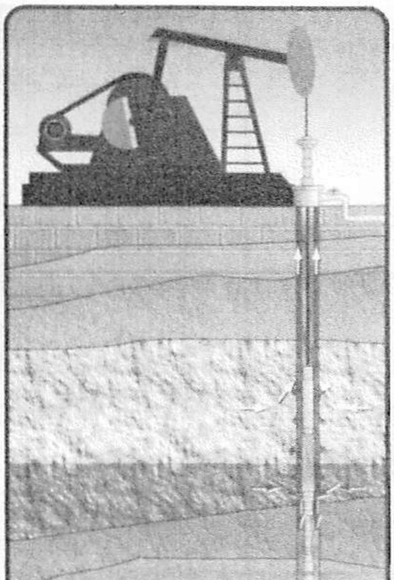
- Preventing the contamination of fresh water resources and surface soil;
- Eliminating water hauling expenses;
- Restoring non-economical and marginal wells back to production;
- Maximizing profitability;
- Encouraging future exploration; and
- Removing environmental problems associated with water disposal. ❐

FIGURE 4



1996 started at 245 bbl water/d disposed. June 1996 installed unit on timer (30 min. on, 30 min. off) = 120 bbl water/d. Average set timer 45 min. on, 15 min. off = 60 bbl water/d.

Simultaneous Gas Production & Water Disposal with DHI Tool



The Down Hole Injection Tool can turn your marginal producers into ***economic winners!*** Finally, technology has beaten the cost and environmentally sensitive problems of salt water disposal from gas wells.

- No more disposal wells or expensive water disposal lines and holding tanks.
- Possible increase in production by keeping the well pumped off, thereby minimizing pressure at the production perforations.
- By drilling new wells deep enough to expose disposal zones, you will realize significant savings over traditional recompletion costs.
- On wells where water flooding is needed, and where a known water formation exists, the DHI cuts costs by keeping your source water and pressure system together.
- Allows the use of existing conventional surface lifting equipment.

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APIRP11L

APIRP11L is a spreadsheet program to aid in the design of rod pumping units and based on API RP 11L bulletin. The API method is based upon correlations of research test data. The results are presented in nondimensional parameters which may be determined from a series of curves. APIPUMP utilizes a series of equations that attempt to match the published curves from the API bulletin.

The API PR 11L design procedure is a trial and error method with the repetition of three steps required to obtain the pumping unit design.

(1) A preliminary selection of components for the installation must be made.
(2) The operating characteristics of the preliminary selection are calculated by using formulas, tables, and figures in the API RP 11L.
(3) The calculated pump displacement and loads are compared with the volumes, load ratings, stresses, and other limitations of the preliminary selection.

Use of program

The designer must select the displacement variables to produce the desired rate. Normally assume a pumping displacement efficiency of 75 % for design purposes. The pumping speed normally should be less than 20 SPM and the resulting minimum polished rod loads (MPRL) should be greater than 10 % of the peak polished rod load (PPRL). The non- dimensional pumping speed should be kept below 0.45. Keep the SPM less than 65% of free fall. The following maximum SPM are suggested for various stroke lengths: 64"=20; 74"=18; 86"=17; 100"=16; 120"=14.5; 168"=12.5 spm. Long stoke lengths are preferred but require larger gear boxes and cost more. Standard maximum stroke lengths are: 16; 20; 24; 30; 36; 42; 48; 54; 64; 74; 86; 100; 120; 144; 168; 192; 216; 240". Next select a standard size API pump--preferable a rod insert type. Common sizes are: 1 1/4"; 1 1/2"; 1 3/4"; 1 25/32"; 2"; 2 1/4"; 2 1/2"; and 2 3/4"; and sometimes 3 3/4"; and 4 3/4". Larger size plungers normally result in higher efficiencies. Alter the SPM, stroke length, and pump size until the desired production rate is obtained.

Enter the specific gravity of the produced fluids. Unless known, a value of 1.0 is normally used for design purposes. The tubing size will govern the size of pump and the size sucker rods. For 2 3/8" OD tubing (ID=1.995"), the largest API tubing pump that can be run (without an on-off type tool) is 1 25/32" and the largest API rod pump is 1 1/2". Standard 3/4" rods and couplings can be run and fished. If 7/8" rods are run, slim hole couplings should be used. For 2 7/8" tubing the largest API tubing pump is 2 1/4" and the largest rod pump is 2". For 2 7/8" tubing, 1" rods can be used but need slim hole couplings. See the API specifications on units, pumps and rods. If the tubing is anchored, a greater downhole stroke will result. Enter the depth of fluid. For design purposes, the fluid level is often assumed to be only 100 feet above the pump.

Select the API class/type rod. API class C rods are the most commonly used sucker rod and have a tensile strength of 90,000 psi. In some corrosive areas, API class K rods are used and have a tensile strength of 82,000 psi. For higher load cases, API class D rods are used and have a tensile strength of 120,000 psi. Specialty rods are used for very high stress ranges. Enter 50,000 psi if these rods are to be used. Next enter the footage of each size rods. API RP 11I table 4.1 lists various combinations. A common design for 2 7/8 inch tubing would be to use a 86 rod string (a combination of 1", 7/8", and 3/4" rods) with about 33 % of each rod size when using a 2" diameter pump.

Check the results and enter changes to obtain a suitable design. The desired production at 75% efficiency should be possible without overloading the rods or unit. Note the safety factor, (SF), for the various cases. The SF value should be less than 100%. If possible, try to keep SF less than 90%. Alter displacement or sucker rod design until acceptable rod loads are obtained. In most designs, the prime mover should be sized to about 2 times the polished rod horsepower.

The designer must select a unit with an adequate structure rating and gear box rating. These ratings should be greater than the calculated values by the APIPUMP program. In the example shown, a C-320D (gear box peak torque rating in 1000 in-lbs); 200 or 246 lb (structure in 100 lb); and 74 inch (maximum stroke length) would be needed. Also select a 25hp NEMA D 1200 rpm electric motor.

Nomenclature/definitions

N : pumping speed in strokes per minute (SPM)
PPRL : peak polished rod load in lbs
MPRL : minimum polished rod load in lbs
PT : peak crank torque in inch-lbs
API-PT : peak torque using API RP 11I formula
MILLS-PT: peak torque using the Mills formula
PRHP : polished rod horsepower
CBE : counterweight required in lbs
SF : safety factor (based on modified Goodman diagram)
HHP : hydraulic horsepower (actual work done)
N/No : non-dimensional pumping speed
Fo/Skr : non-dimensional fluid load
F1/Skr : non-dimensional PPRL factor
F2/Skr : non-dimensional MPRL factor
F3/Skr : non-dimensional PRHP factor
Sp/S : non-dimensional STROKE length factor
2T/S2kr : non-dimensional PRHP factor

The program uses a common correlation to calculate the gas compressibility factor (Z), and the gas viscosity (Ug). A gas formation volume factor (Bg) is then calculated.

An important variable in high velocity gas flow rates is the Beta ratio (Br). The Beta ratio is called the "velocity coefficient" after Firoozabadi and Katz [2].

Cooke [3] has shown that the Beta ratio for gravel can be calculated as follows:

$$Br = 3.0889 \times 10^7 \times b / K^a \quad \text{(K IN DARCIES)}$$

Cooke listed the "a" and "b" values for typical gravel pack sands. The program calculates a Beta ratio based on the input values of Kg.

For consolidated relatively low permeability sandstones or carbonates, the program uses the following equation to determine the Beta ratio:

$$Br = (2.6E+10)/(Kr^{1.2}) \quad \text{where k is in MD}$$

PROGRAM OPERATION

Enter the input data in the highlighted cells. A total of 19 items must be entered. The program calculates Z, Ug, Bg Brf AND Brg. These values can be input from PVT data (rather than the program calculating the values) by removing the program protection.

To calculate, the user must Press [F9]. Page down to view the tabular results. Press [F10] to view graphical results. Find the pressure drop for various rates on interest. If the pressure drop is high, then consideration should be given to perforating additional footage of pay (i.e. increase the net pay open or increase the perforation density). For damaged zones, the program may show the benefits of a stimulation treatment.

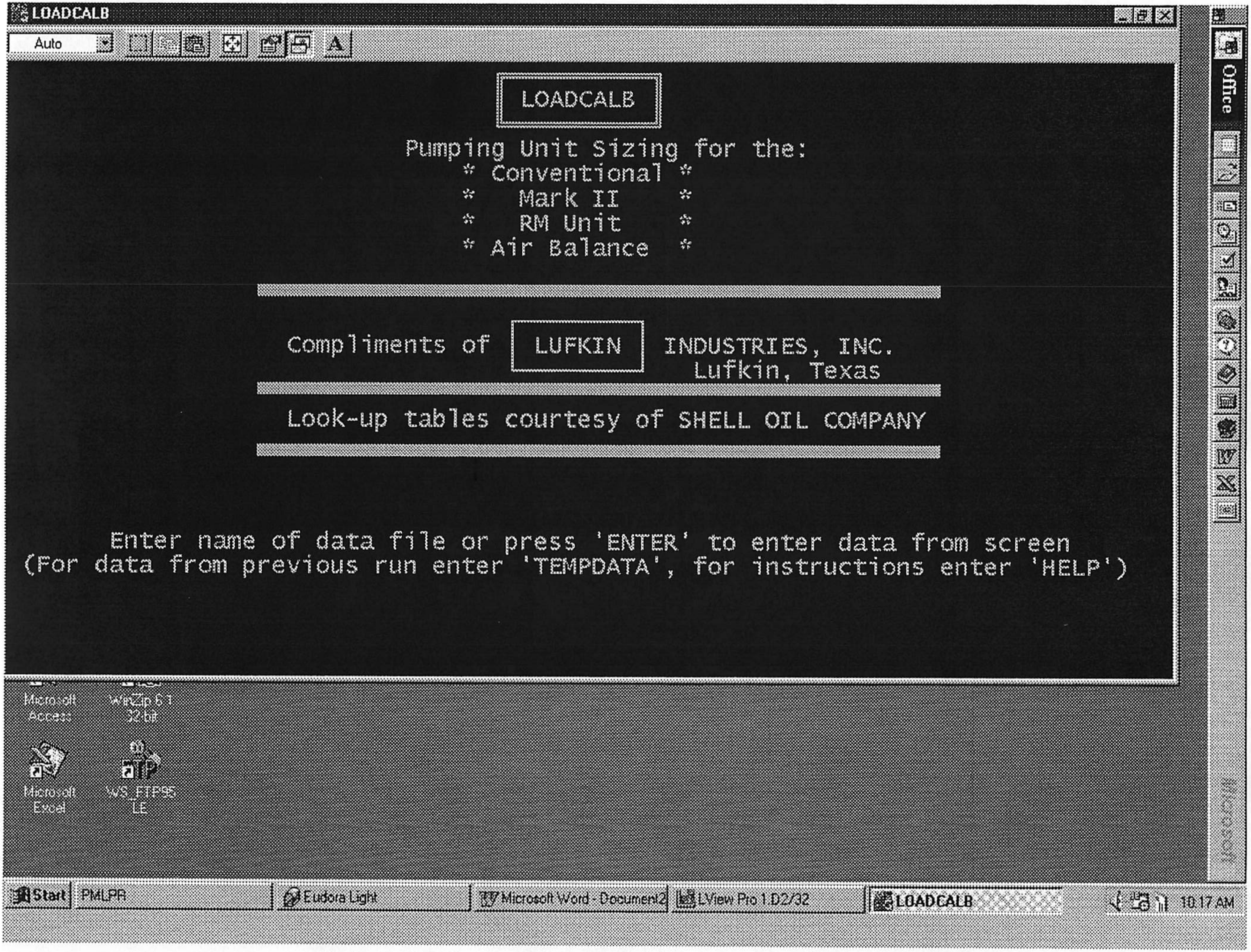
Press [Alt] [P] to printout the data. Press [Alt] [G] to save the graph for later printout. Change the file name to save for future evaluation.

You can change switch this program between metric and english units by pressing [Alt][M] and entering either a "E" for english or a "M" for metric. Pressing the [Home] key will bring you back to the input area.

[1] HARRY O. McLEOD, "THE APPLICATION OF SPHERICAL FLOW EQUATIONS TO GRAVEL PACK EVALUATION," PAPER SPE 23769 PRESENTED AT THE ELEVENTH SPE INTERNATIONAL SYMPOSIUM ON FORMATION DAMAGE CONTROL HELD IN LAFAYETTE, LA, FEBRUARY 26-27, 1992.

[2] FIROOZABADI, ABBAS AND KATZ, D.L.: "AN ANALYSIS OF HIGH-VELOCITY GAS FLOW THROUGH POROUS MEDIA." JPT, FEB 1979,211-6

[3] COOKE, C. E. JR.: "CONDUCTIVITY OF FRACTURE PROPPANTS IN MULTIPLE LAYERS," JPT SEPTEMBER 1973, 1101-07.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                    Pumping Unit Sizing for the:
                        * Conventional *
                        *   Mark II    *
                        *   RM Unit    *
                        * Air Balance  *

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   Enter name of data file or press 'ENTER' to enter data from screen
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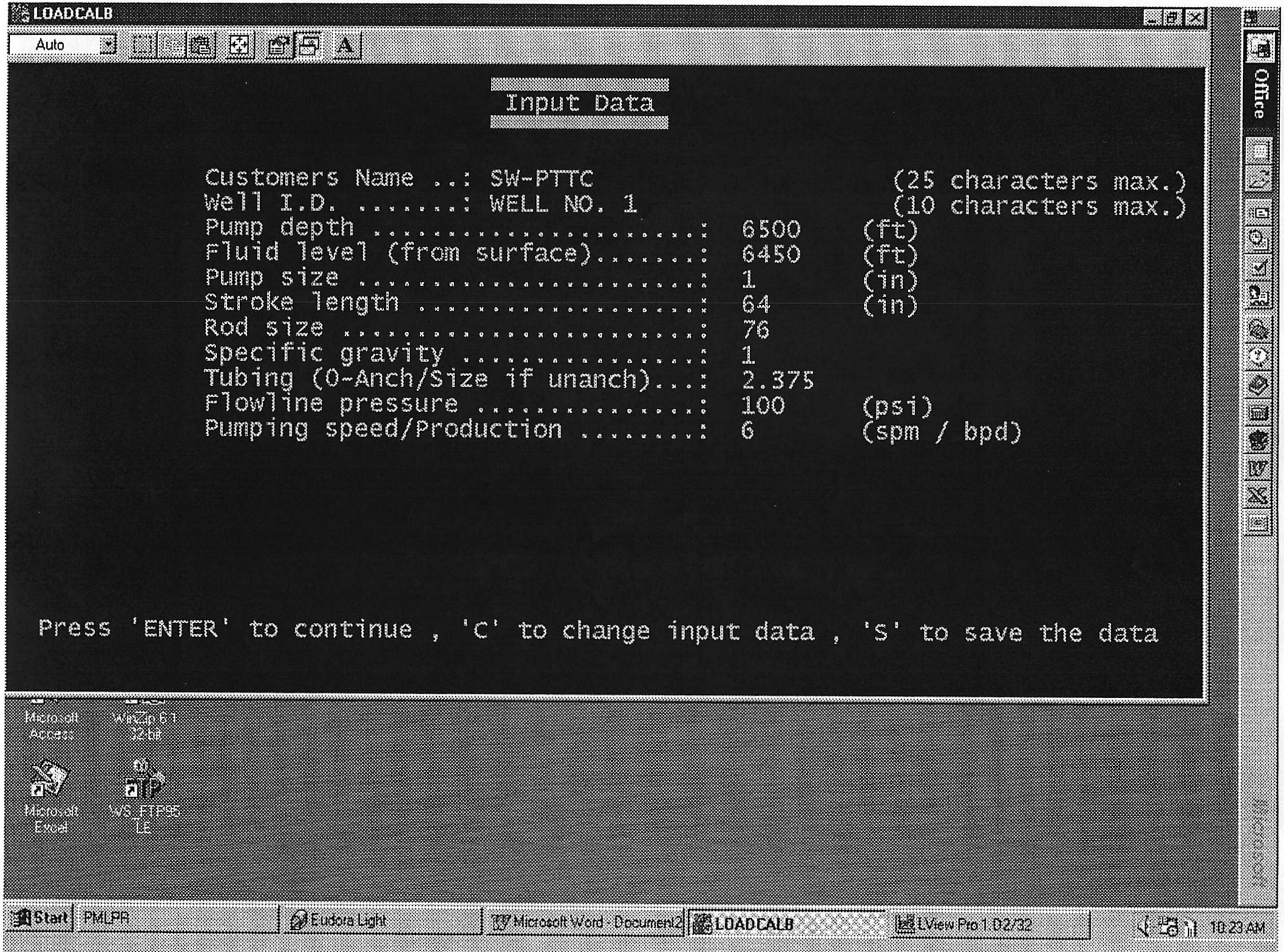

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Microsoft

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                              Input Data

          Customers Name ..: SW-PTTC                    (25 characters max.)
          Well I.D. .......: WELL NO. 1                 (10 characters max.)
          Pump depth ......................:  6500    (ft)
          Fluid level (from surface).......:  6450    (ft)
          Pump size .......................:  1       (in)
          Stroke length ...................:  64      (in)
          Rod size ........................:  76
          Specific gravity ................:  1
          Tubing (0-Anch/Size if unanch)...:  2.375
          Flowline pressure ...............:  100     (psi)
          Pumping speed/Production ........:  6       (spm / bpd)




 Press 'ENTER' to continue , 'C' to change input data , 'S' to save the data
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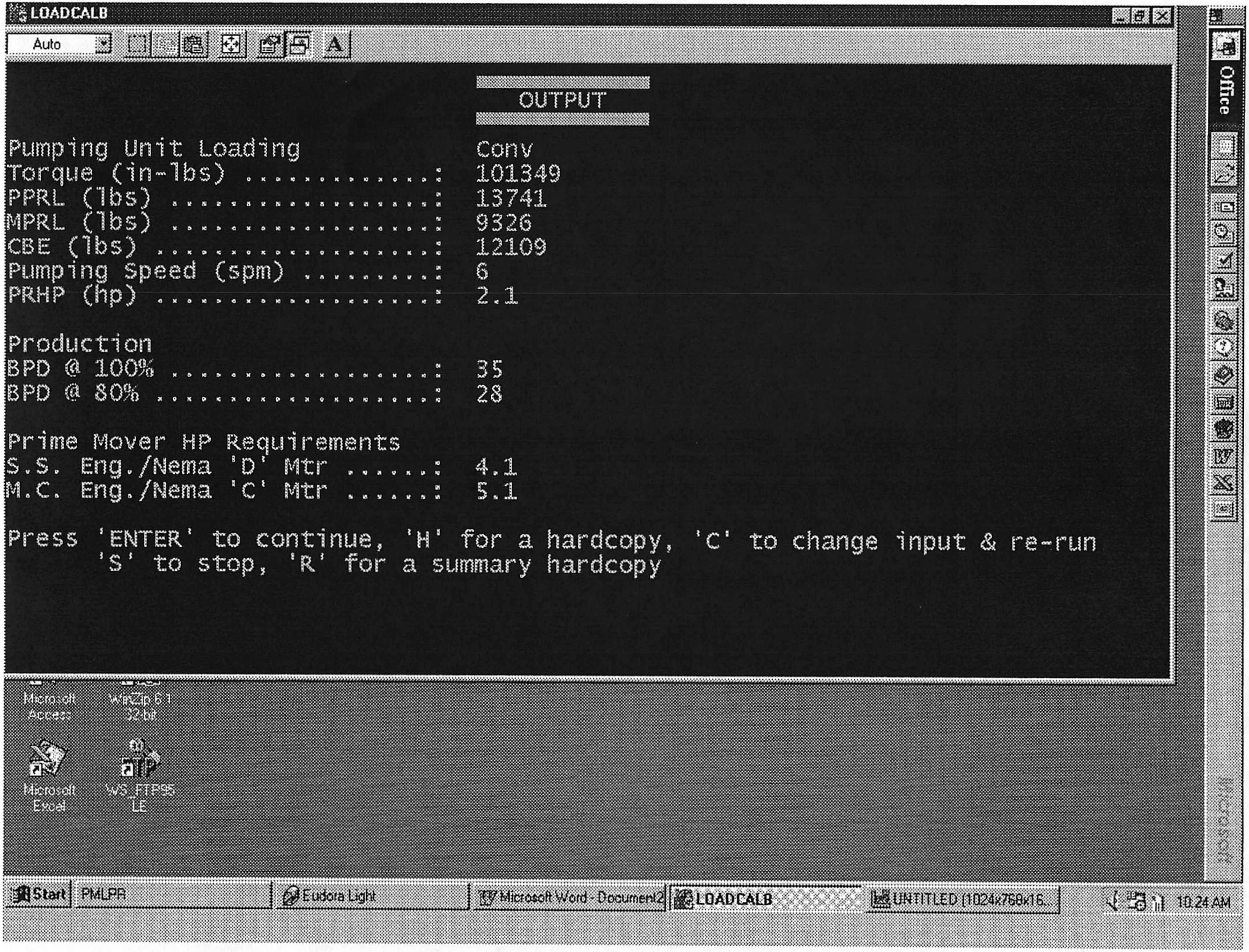
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                                    OUTPUT

Pumping Unit Loading                Conv
Torque (in-lbs) ..............:     101349
PPRL (lbs) ...................:     13741
MPRL (lbs) ...................:     9326
CBE (lbs) ....................:     12109
Pumping Speed (spm) ..........:     6
PRHP (hp) ....................:     2.1

Production
BPD @ 100% ...................:     35
BPD @ 80% ....................:     28

Prime Mover HP Requirements
S.S. Eng./Nema 'D' Mtr .......:     4.1
M.C. Eng./Nema 'C' Mtr .......:     5.1

Press 'ENTER' to continue, 'H' for a hardcopy, 'C' to change input & re-run
      'S' to stop, 'R' for a summary hardcopy
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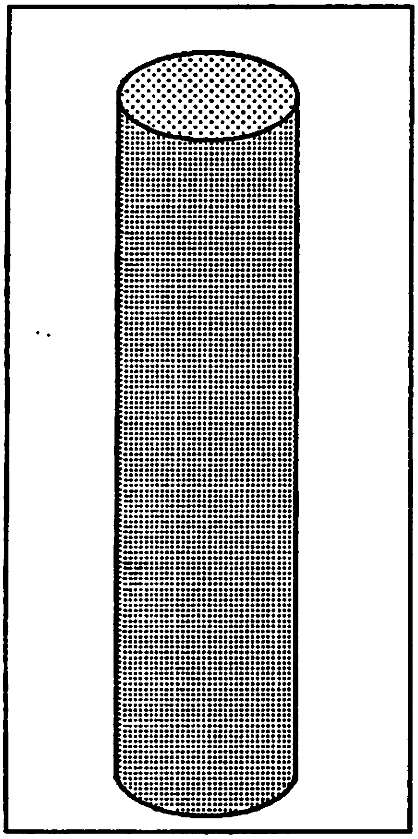
Method and Apparatus to Revive Dead Gas Wells (Self-Agitating Soap Stick)

Mr. M. Glenn Osterhoudt

DRAFT



A method and apparatus for reviving water-plugged gas wells. The method utilizes chemicals delivered downhole to diminish the magnitude of the water plug.

Introduction

Practically all gas wells produce some water along with the natural gas. As long as the quantity of water is small, and the gas pressure and velocity are sufficiently high, the gas will carry the water out of the well. However, as gas is produced from the well, the gas pressure drops and its velocity diminishes. With time, water begins to accumulate and obstruct further gas production. Eventually, the hydrostatic pressure of the column is high enough to completely plug the well and stop gas production.

The water must be removed in order to restore gas production. Current water removal methods have significant disadvantages: some may require energy to pump it out; others pump in a displacing gas; still others can be quite expensive if special equipment is required, i.e., swabbing.

Design Benefits

Mr. Glenn Osterhoudt has developed a new technique for dealing with the water-plug problem. The first step is to customize a mixture of chemicals for each well based on the pH of the downhole water and other measurable characteristics. The mixture is then delivered to the bottom of the water plugged wells.

The intervention instantly transforms the static column of fluid into a column of foam, which allows the existing bottom hole pressure to restart flow from the well. When enough water has been removed by the technique, the natural gas pressure becomes sufficient to permit renewed gas production which will continue without constant treatment.

Operational Benefits

The chemicals for treating one well cost approximately $100. The customizing of the formula is relatively quick and inexpensive. The well treatment process is simple, and it does not require renting complicated machinery with moving parts. Results in field tests have been excellent. The system was successful in restoring gas production to over 90% of water-plugged wells treated. The process is simple enough to permit an operator's on-hand personnel to treat wells, thus eliminating additional labor costs.

Department of Energy Sponsorship

The Department of Energy's Energy-Related Inventions Program awarded $70,240 on September 9, 1992, to develop support data sufficient to field test the technology and determine its capabilities.

Market Potential and Status

In view of the excellent results from field tests, the ease and the attractive economics of utilizing this technology, it should soon assume a significant market share. Worldwide, the problem of water plugging is increasingly expensive to correct, and this new technology should enable economical extension of the productive lifetime of an estimated 100,000 gas wells. Thousands of these are domestic wells that are suitable candidates for this procedure. This technology can be regarded as proven.

Inventor's Goals

The inventor wishes to license several oilfield chemical companies to market his product(s) in both domestic and international markets.

Patent Status

The inventor has applied for patents covering the specific products and techniques for customizing the formulas.

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Prepared by U.S. Department of Energy's Energy-Related Inventions Program

Compiled by Systems Engineering Management and Associates, Inc., under DOE contract DE-AC01-91CE10566

2198

Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells

R. G. Turner, SPE-AIME, Baker Oil Tools, Inc.
M. G. Hubbard, SPE-AIME, U. of Houston
A. E. Dukler, U. of Houston

Introduction

Gas phase hydrocarbons produced from underground reservoirs will, in many instances, have liquid phase material associated with them, the presence of which can affect the flowing characteristics of the well. Liquids can come from condensation of hydrocarbon gas (condensate) or from interstitial water in the reservoir matrix. In either case, the higher density liquid phase, being essentially discontinuous, must be transported to the surface by the gas. In the event the gas phase does not provide sufficient transport energy to lift the liquids out of the well, the liquids will accumulate in the wellbore. The accumulation of the liquid will impose an additional back pressure on the formation that can significantly affect the production capacity of the well. In low pressure wells the liquid may completely kill the well; and in the higher pressure wells there can occur a variable degree of slugging or churning of the liquids, which can affect calculations used in routine well tests. Specifically, the calculated bottom-hole pressures used in multirate backpressure tests will be erroneous if the well is not removing liquids on a continuous basis, and gas:liquid ratios observed during such a test may not be correct.

Several authors[1,3,8,14] have suggested methods to determine if the flow rate of a well is sufficient to remove liquid phase material. Vitter[14] and Duggan[1] proposed that wellhead velocities observed in the field would be adequate for keeping wells unloaded. Jones[8] and Dukler[3] presented analytical treatments resulting in equations for calculating, from physical properties, the minimum necessary flow rate. An analysis of these studies indicates the existence of two proposed physical models for the removal of gas well liquids: (1) liquid film movement along the walls of the pipe and (2) liquid droplets entrained in the high velocity gas core. Although there probably is a continuous exchange of liquid between the gas core and the film, they will be treated separately for the purposes of this study. The development and comparison of these separate models with experimental data will permit the determination of which, if either, is the controlling mechanism for the removal of liquids from gas wells.

The Continuous Film Model

Liquid phase accumulation on the walls of a conduit during two-phase gas/liquid flow is inevitable due to the impingement of entrained liquid drops and the condensation of vapors. The movement of the liquid on the wall is therefore of interest in the analysis of liquid removal from gas wells. If the annular liquid film must be moved upward along the walls in order to keep a gas well from loading up, then the minimum gas flow rate necessary to accomplish this is of primary interest. The analysis technique used follows Dukler[2] and Hewitt[5] and involves describing the profile of the velocity of a liquid film moving upward on the inside of a tube. The minimum rate of gas flow required to move the film upward is then calculated.

From an analysis of two models — in one, the movement observed is of a liquid film on the wall of a tubular conduit where the liquid is moved upward by interfacial shear, and in the other it is of the entrained liquid drops in a vertically upward flowing gas stream — it is evident that the minimum condition required to unload a gas well is that which will move the largest liquid drops that can exist in a gas stream.

The results of this analysis are presented in Fig. 3 and Table 1, and the mathematical film flow model is developed in the Appendix.

Entrained Drop Movement

The existence of liquid drops in the gas stream presents a different problem in fluid mechanics, namely, that of determining the minimum rate of gas flow that will lift the drops out of the well. Since the drop is a particle moving relative to a fluid in the gravitational field, particle mechanics may be employed to determine this minimum gas flow rate.

A freely falling particle in a fluid medium (Fig. 1) will reach a terminal velocity, which is the maximum velocity it can attain under the influence of gravity alone, i.e., when the drag forces equal the accelerating (gravitational) forces. This terminal velocity is therefore a function of the size, shape and density of the particle and of the density and viscosity of the fluid medium.

By a transformation of coordinates, a drop of liquid being transported by a moving gas stream becomes a free falling particle and the same general equations apply. If the gas were moving at a velocity sufficient to hold a drop in suspension (i.e., motionless relative to the conduit), then the gas velocity (the relative velocity between the gas and the drop) would be equal to the free fall terminal velocity of the drop. Since any further increase in the gas velocity would make the drop move upward, the limiting gas flow velocity for upward drop movement is the terminal free settling velocity of the drop.

$$v_t = \sqrt{\frac{2 g m_p (\rho_p - \rho)}{\rho_p \rho A_p C_d}} \quad . \; . \; . \; . \; . \; . \; (1)$$

The general free settling velocity equation (Eq. 1) shows dependence on the densities of the phases and on the mass and projected area of the particle. Since the surface tension of the liquid phase acts to draw the drop into a spheroidal shape, Eq. 1 can be rewritten in terms of the drop "diameter" (Eq. 2).

$$v_t = 6.55 \sqrt{\frac{d(\rho_L - \rho_g)}{\rho_g C_d}} \quad . \; . \; . \; . \; . \; (2)$$

Eq. 2 shows that the larger the drop, the higher the terminal velocity, all other things equal. Hence, the larger the drop, the higher the gas flow rate necessary to remove it. The problem, therefore, requires determining the diameter of the largest drop that can exist in a given flow field, and then calculating the terminal velocity of this largest drop. This will insure the upward movement of all drops in the gas stream.

Hinze[9] showed that liquid drops moving relative to a gas are subjected to forces that try to shatter the drop, while the surface tension of the liquid acts to hold the drop together. He determined that it is the antagonism of two pressures, the velocity pressure, $v^2 \rho_g / g_c$, and the surface tension pressure, σ / d, that determines the maximum size a drop may attain. The ratio of these two pressures is the Weber number $N_{We} = v^2 \rho_g d / \sigma g_c$. Hinze showed that if the Weber number exceeded a critical value, a liquid drop would shatter. For free falling drops, the value of the critical Weber number was found to be on the order of 20 to 30. If the larger of the observed values is used, a relationship between the maximum drop diameter and the velocity of a liquid drop is obtained.

$$d_m = \frac{30 \sigma g_c}{\rho_g v_t^2} \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; (3)$$

Substituting the maximum diameter expression into Eq. 2, the terminal velocity equation becomes

$$v_t = \frac{1.3 \sigma^{1/4} (\rho_L - \rho_g)^{1/4}}{C_d^{1/4} \rho_g^{1/2}} \quad . \; . \; . \; . \; . \; (4)$$

The solution of Eq. 4 requires a knowledge of the interfacial tension and the drag coefficient. The interfacial tension can be obtained with sufficient accuracy from handbooks, since it appears to the fourth root. The drag coefficient is influenced by the drop shape and the Drop Reynolds number, $N_{Re} = d \rho_g v / \mu_g$. A correlation of C_d vs N_{Re} for spheres[11] shows that for a N_{Re} range from 1,000 to 200,000 the drag coefficient is approximately constant (the Newton's law region). For typical field conditions,[1,12] the particle Reynolds number ranges from 10^4 to 10^5, based on the drop size prediction of Eq. 3. This is the range where the drag coefficient is relatively constant at a value of 0.44. If this value is used, and the coefficient is corrected to allow the use of the values of surface tension in dynes per centimeter, Eq. 4 reduces to

$$v_t = 17.6 \frac{\sigma^{1/4} (\rho_L - \rho_g)^{1/4}}{\rho_g^{1/2}} \quad . \; . \; . \; . \; (5)$$

Eq. 5 may be used to calculate the minimum gas flow velocity necessary to remove liquid drops.

Comparisons with Field Data

The film and drop models have been tested independently with field data obtained from gas wells producing liquids. A small portion of the data was the result of tests performed specifically to determine the minimum lift flow rate. Because of the limited range of conditions involved, these data were insufficient; therefore, previously published data[1,12] and conventional well test data were combined with them to form the current test data matrix.

Included in the data matrix are the two most common flow geometries, standard production tubing in API sizes, and annular completions where the gas is flowed between the casing and the tubing (as in single-tubing-string dual completions).

The conduit sizes included in the data range from 1.750 in. ID (2¹⁄₁₆ in. OD) for tubing to 8 in. for casing. Several annular areas are included, with both 5½-in. and 7-in. OD casings being represented.

Liquid phase material included salt water and condensate, ranging in API gravity from 43° to 70°.

Some of the data were incomplete for the purpose of this investigation, and it was necessary to estimate the values of some properties.

Interfacial tension is not usually determined in routine analysis and it was therefore not obtainable for the individual well fluids. The surface tension of the hydrocarbon liquids was estimated from a correlation based on molecular weight.[10]

Virtually all of the data were incomplete in that the *bottom-hole temperatures* were not reported. In these cases, estimates were made from area geothermal gradient charts, since the location and depth of the wells were known.

The *density of the liquid phase and gravity of the gas* are very important to the developments and, unfortunately, were not available for most of the data. However, the data that were insufficient in this respect did contain the liquid:gas ratio. It is generally true that in wells that produce a small quantity of liquid, the liquid will be clear, very light (high API gravity), and volatile and there will be a correspondingly light (low gravity) gas. And a rich well with a high liquid:gas ratio will generally have more dense liquid and gas phases. Based on these principles and on a knowledge of the ranges of these quantities normally encountered in the field, approximations were made. In the case of water, the specific gravity was taken to be 1.08.

The use of data collected primarily for purposes other than to determine the minimum lift velocity requires a special technique. The conditions (pressure, temperature, tubing size, etc.) of a datum point are used to calculate minimum flow rates by each of the models. The calculated rates are then compared with the observed rate. If the observed rate is known to be adequate, then it should be higher than a properly calculated minimum. If the observed rate is not adequate, then it should be lower than the calculated minimum. Sufficient data should provide statistical validation or invalidation of the mathematical models. An IBM 7094 computer was programmed to test the data in both the film and drop models. Eq. 5 was used to calculate gas velocities in developing the drop model, and integration of Eq. A-3 in the Appendix was performed for the film model calculations. The results are shown graphically in Figs. 2 and 3 and are listed on Table 1.

The figures are constructed in such a way that if a well's actual test flow rate equals its minimum calculated flow rate for liquid removal, the datum point will plot on the diagonal. If the method for calculating the minimum flow rate is accurate, then all wells that are tested at conditions near load-up (shown as circles on the graphs) should plot near this diagonal. Wells that unload easily during a test (shown as squares) should plot above the diagonal and those that do not unload (shown as triangles) should plot below the line. The ability of a given analytical model to achieve this data separation is a measure of its validity.

The drop model (Fig. 2) shows a good separation of the adequate and inadequate flow rates; however, the calculated minima are, in most cases, too low. This can be attributed to the use of drag coefficients for solid spheres rather than for oscillating liquid drops in the development of Eq. 5, and to the fact that the mathematical development predicts stagnation velocity, which must be exceeded by some finite quantity to guarantee removal of the largest drops. Another contributing factor could be the Critical Weber number, which was established for drops falling in air experimentally and not for conditions that

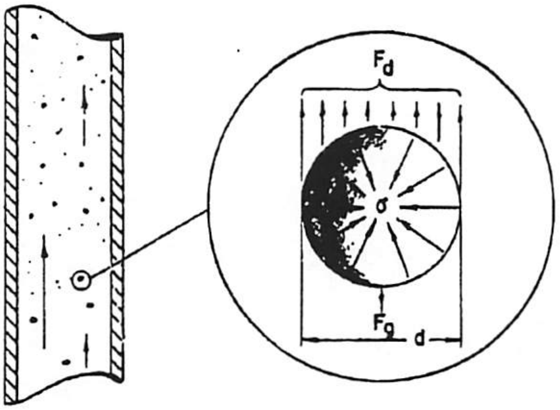

Fig. 1—Entrained drop movement.

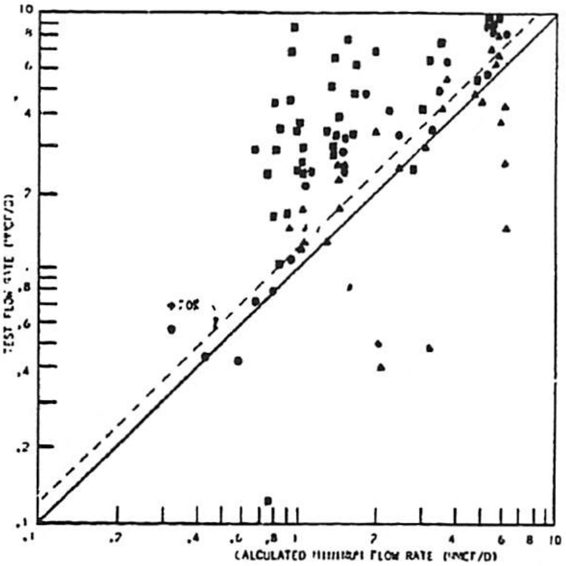

Fig. 2—The drop removal model.

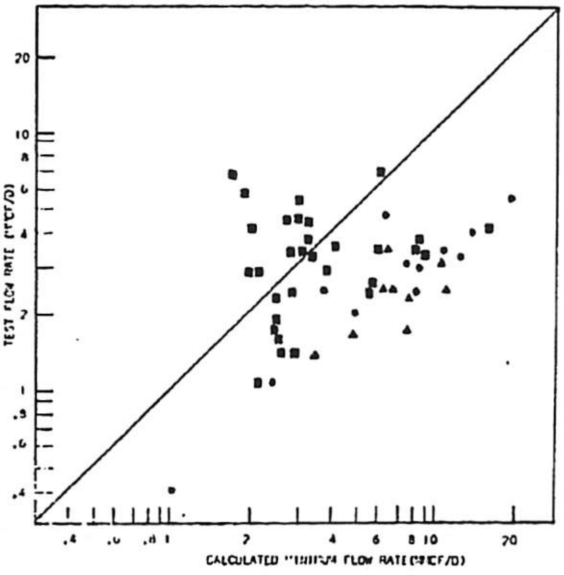

Fig. 3—The film movement model.

TABLE 1—DATA AND PREDICTIONS OF MINIMUM GAS FLOW RATE FOR UNLOADING GAS WELLS

Producing Depth (ft)	Wellhead Pressure (psi)	Condensate Gravity (°API)	Condensate Make (bbl/MM)	Water Make (bbl/MM)	Tubing ID (Inches)	Tubing OD (Inches)	Casing ID (Inches)	Test Flow (Mcf/D)	Drop Model (Mcf/D)	Film Model (Mcf/D)	Status During Test
6404	725	63.8	6.0	0.	2.441			775	779		Near L.U.
6739	400		0.	18.0	1.995			417	583	1098	Near L.U.
6529	108	64.3	9.6	12.4	2.041			568	306		Near L.U.
6700	540	70.8	10.5	10.5	1.995			712	661		Near L.U.
6770	450	61.0	11.3	0.	1.995			442	419		Near L.U.
200	3607	61.0	37.4	0.	1.995			1525	1156	3453	Loaded Up
11200	3434	61.0	37.4	0.	1.995			2926	1150	3866	Unloaded
11340	3773	58.0	36.8	0.	1.995			2494	1158	3811	Questionable
11340	3660	58.0	36.8	0.	1.995			3726	1142	4235	Unloaded
11416	3340	56.4	130.8	0.	2.992			2611	2412	13028	Loaded Up
11416	3295	56.4	130.8	0.	2.992			3264	2401	14199	Questionable
11416	3280	56.4	130.8	0.	2.992			4095	2395	15511	Questionable
11417	3540	56.4	113.5	0.	2.441			1814	1635	7247	Loaded Up
11417	3330	56.4	113.5	0.	2.441			2915	1600	8551	Questionable
11426	3525	55.0	106.9	0.	1.995			1792	1108	4780	Loaded Up
11426	3472	55.0	106.9	0.	1.995			2572	1085	5410	Unloaded
11355	3338	55.0	117.6	0.	2.441			2261	1623	7952	Loaded Up
11355	3245	55.0	117.6	0.	2.441			2503	1610	8212	Questionable
11355	3092	55.0	117.6	0.	2.441			3351	1574	8992	Unloaded
11390	3556	55.0	104.3	0.	1.995			2069	1091	4916	Questionable
11390	3455	55.0	104.3	0.	1.995			2769	1082	5505	Unloaded
8690	3665	60.0	68.3	0.	2.441			2542	1660	6867	Loaded Up
8690	3644	60.0	68.3	0.	2.441			3182	1654	7439	Questionable
8690	3615	60.0	68.3	0.	2.441			3890	1648	8040	Unloaded
8840	3212	60.0	54.8	0.	2.441			2547	1604	6057	Loaded Up
8840	3025	60.0	54.8	0.	2.441			3517	1569	6580	Unloaded
11850	8215	67.5	10.8	0.	2.441			3472	1956	6495	Loaded Up
11850	7950	67.5	10.8	0.	2.441			4896	1941	6524	Questionable
11850	7405	67.5	10.8	0.	2.441			6946	1930	6676	Unloaded
6995	2335	65.0	17.9	0.	1.995			1116	936	2563	Questionable
6995	2226	65.0	17.9	0.	1.995			1959	910	2504	Unloaded
5725	2182	70.0	2.5	0.		4.500	6.184	5501	3767		Loaded Up
5725	2175	70.0	2.5	0.		4.500	6.184	6405	3757		Questionable
5725	2169	70.0	2.5	0.		4.500	6.184	7504	3747		Unloaded
5515	1590	65.0	13.1	0.	3.958			3009	3281	10983	Loaded Up
5515	1550	65.0	13.1	0.	3.958			3551	3233	10820	Questionable
5515	1520	65.0	13.1	0.	3.958			4150	3195	10711	Unloaded
6180	1245	67.0	10.3	0.		2.875	6.184	4441	4920		Loaded Up
6180	1184	67.0	10.3	0.		2.875	6.184	4843	4793		Loaded Up
6180	1117	67.0	10.3	0.		2.875	6.184	5513	4649		Unloaded
6031	1958	62.5	24.8	0.		2.875	6.184	8185	5931		Loaded Up
6031	1938	62.5	24.8	0.		2.875	6.184	9039	5902		Questionable
6031	1913	62.5	24.8	0.		2.875	6.184	9897	5857		Unloaded
5962	2040	65.0	31.8	0.		2.875	6.184	6702	6082		Loaded Up
5962	1993	65.0	31.8	0.		2.875	6.184	8210	6015		Questionable
5962	1953	65.0	31.8	0.		2.875	6.184	9289	5957		Unloaded
5906	2284	67.5	15.1	0.		3.500	6.184	7109	5580		Loaded Up
5906	2271	67.5	15.1	0.		3.500	6.184	8406	5559		Questionable
5906	2256	67.5	15.1	0.		3.500	6.184	9747	5535		Unloaded
5934	2352	70.0	3.7	0.		3.500	6.184	6361	5641		Loaded Up
5934	2338	70.0	3.7	0.		3.500	6.184	8057	5671		Questionable
5934	2223	70.0	3.7	0.		3.500	6.184	9860	5485		Unloaded
5934	2003	70.0	3.7	0.		3,500	6.184	11767	5212		Unloaded
6850	2042	65.0	26.7	0.		4.500	6.184	4124	3613		Loaded Up
6850	1818	65.0	26.7	0.		4.500	6.184	4998	3412		Questionable
6850	1600	65.0	26.7	0.		4.500	6.184	6423	3199		Unloaded
7346	1835	52.7	27.8	0.4	1.995			8672	12[illegible]		Unloaded
7346	2421	52.7	27.8	0.4	1.995			6654	1407		Unloaded
7346	2705	52.7	27.8	0.4	1.995			5136	1467		Unloaded
7346	2894	52.7	27.8	0.4	1.995			3917	1502		Unloaded
8963	5056	43.9	7.5	1.4	1.995			3376	1770		Unloaded
8963	4931	43.9	7.5	1.4	1.995			4830	1732		Unloaded
8963	4786	43.9	7.5	1.4	1.995			6221	1705		Unloaded
8963	4575	43.9	7.5	1.4	1.995			7792	1659		Unloaded
5294	1902	71.0	30.9	0.	1.995			1138	851	2276	Unloaded

exist in gas wells. Analysis of the data reveals that the total contribution of these factors requires an upward adjustment of approximately 20 percent. Instead of being distributed as individual contributions among the pertinent parameters in the development, this value is lumped in the constant of Eq. 5 to produce Eq. 6.

$$v_t = 20.4 \frac{\sigma^{1/4} (\rho_L - \rho_g)^{1/4}}{\rho_g^{1/2}} \quad . \; . \; . \; . \; . \quad (6)$$

Since the contributing factors are individually obtained from experimental correlations, their adjustment, in this case, to fit the specific data does not alter or affect the rigor of the development.

The predictions of the film model (Fig. 3) do not provide as clear a definition between the adequate and inadequate rates as do those of the drop model. Additionally, the theoretical development for the film model indicates that the minimum lift velocity depends upon the gas:liquid ratio. Analysis of the available field data shows no such dependence in the range of liquid production associated with most gas wells (1 to 100 bbl/MMcf). The drop model, on the other hand, is independent of a liquid rate. This indicates that the film model does not represent the controlling liquid transport mechanism.

The data were tested for the minimum flow rate that would be required at the top and the bottom of the conduit. The results indicated that the wellhead conditions were, in most instances, controlling (i.e., required the higher flow rate). This is fortunate, since it allows the use of the more easily obtained surface data.

Since in some of the field observations the wells were known to be unloading, but the film model predicted the gas rates to be inadequate, it appears that the liquids can be continuously removed by liquid drop movement alone. It is of interest, therefore, to know what happens to a film that is not moving upward with the gas. If the liquid film moves downward,

TABLE 1 (Contd.)—DATA AND PREDICTIONS OF MINIMUM GAS FLOW RATE FOR UNLOADING GAS WELLS

Producing Depth (ft)	Wellhead Pressure (psi)	Condensate Gravity (°API)	Condensate Make (bbl/MM)	Water Make (bbl/MM)	Tubing ID (Inches)	Tubing OD (Inches)	Casing ID (Inches)	Test Flow (Mcf/D)	Drop Model (Mcf/D)	Film Model (Mcf/D)	Status During Test
5294	1737	71.0	0.9	0.	1.995			1712	814		Unloaded
5294	1480	71.0	0.9	0.	1.995			2473	750		Unloaded
5294	1246	71.0	0.9	0.	1.995			2965	686		Unloaded
5234	1895	71.7	54.1	0.	1.995			1797	875	2652	Unloaded
5234	1861	71.7	54.1	0.	1.995			2502	859	2863	Unloaded
5234	1784	71.7	54.1	0.	1.995			3460	832	3108	Unloaded
5234	1680	71.7	54.1	0.	1.995			4439	803	3309	Unloaded
7639	2814	53.5	3.3	1.0	1.750			1596	1216		Unloaded
7639	2582	53.5	3.3	1.0	1.750			2423	1176		Unloaded
7639	2104	53.5	3.3	1.0	1.750			3598	1070		Unloaded
7639	1575	53.5	3.3	1.0	1.750			4410	918		Unloaded
7475	2783	52.4	3.4	0.	1.750			2939	834	2155	Unloaded
7475	2655	52.4	3.4	0.	1.750			4140	817	2097	Unloaded
7475	2406	52.4	3.4	0.	1.750			5820	770	1953	Unloaded
7475	2205	52.4	3.4	0.	1.750			6871	746	1884	Unloaded
7546	2574	52.2	4.1	0.6	1.750			1943	899		Unloaded
7546	2224	52.2	4.1	0.6	1.750			2910	833		Unloaded
7546	1839	52.2	4.1	0.6	1.750			3742	755		Unloaded
7546	1509	52.2	4.1	0.6	1.750			4485	683		Unloaded
7753	2611	52.6	5.5	0.	1.995			3436	1082	2954	Unloaded
7753	2527	52.6	5.5	0.	1.995			4471	1058	2881	Unloaded
8162	2556	56.7	7.7	0.	1.995			1550	1026	2801	Unloaded
8162	2415	56.7	7.7	0.	1.995			1804	996	2697	Unloaded
8162	2149	56.7	7.7	0.	1.995			2385	941	2512	Unloaded
8162	1765	56.7	7.7	0.	1.995			2949	856	2246	Unloaded
7810	2862	52.2	5.0	0.		2.375	4.974	3024	5098		Unloaded
7810	2823	52.2	5.0	0.		2.375	4.974	3863	5045		Loaded Up
7531	760	54.9	46.1	45.1	2.441			1247	1148		Loaded Up
7531	704	54.9	31.6	40.8	2.441			1313	1099		Loaded Up
7531	822	54.9	26.7	26.3	2.441			1356	1197		Loaded Up
7531	1102	54.9	26.1	23.8	2.441			1365	1419		Loaded Up
7531	552	54.9	25.1	22.3	2.441			1607	958		Near L.U.
3278	315	50.0	10.0	0.	7.386			5740	5093	19974	Loaded Up
3278	422	50.0	10.0	0.	7.386			3890	5923		Loaded Up
3278	459	50.0	10.0	0.	7.386			2780	6186		Loaded Up
3278	484	50.0	10.0	0.	7.386			1638	6359		Loaded Up
5080	500	50.0	14.0	0.		2.375	4.974	400	2184		Loaded Up
7200	500	0.	0.	5.0		2.375	4.052	800	1726		Loaded Up
6776	660	0.	0.	3.5		2.375	6.276	4300	6367		Loaded Up
3077	280	0.	0.	28.0		2.375	4.974	500	2083		Loaded Up
2250	210	0.	0.	24.0		2.375	6.276	470	3248		Loaded Up

it is then moving countercurrent to the gas and "flooding" occurs. This is a condition in which the film thickens and bridges the tube, causing film break-up and slugging, which leads to the production of drops and to increased entrainment. The flooding of the film, along with the activity of the liquid at discontinuities such as the coupling recess, provides an ample source of liquid drops for transport by the drop mechanism.

Application to Field Design

For field application it is highly desirable to have a simple method of determining the minimum flow rate necessary to insure continuous liquid removal. Although the equations required to calculate this rate are not particularly complex, a slide rule or logarithm tables are necessary. It is worthwhile, therefore, to investigate methods of simplifying the equations.

Since drop removal is the limiting liquid removal mechanism, Eq. 6 for terminal drop velocity will be used for the field application. The grouping of parameters is such that we can simplify the equation to a relationship suitable for graphical solution.

Since the fourth root of the surface tension of low molecular weight hydrocarbons varies only slightly with changes in molecular weight and temperature, a consolidation of the $\sigma^{1/4}$ term into a constant for condensates is indicated. For water, another constant may be used. (Values of 20 dynes/cm for condensate and 60 dynes/cm for water were chosen.) The liquid phase density for condensates will vary between 51.5 lb mass/cu ft (40° API) and 43.8 lb mass/cu ft (70° API). Therefore, the liquid phase density for condensates (the fourth root of which is also used) may be treated as a constant (45 lb mass/cu ft). Water will also have a relatively constant density (67 lb mass/cu ft).

This leaves two equations (one each for water and condensate) in which the terminal velocity is a function of the gas phase density. Gas density is a function of the pressure, temperature, and gas gravity. An investigation of the relative impact of variations of these parameters in ranges normally encountered in gas wells shows that gas gravity and absolute temperature have less effect than do variations in pressure. Further simplification is possible by using an average value of gas gravity (0.6) and gas temperature (120°F). This yields Eqs. 7 and 8, which are the gas velocity equations for water and condensate, respectively.

$$v_g\,(\text{water}) = \frac{5.62\,(67 - 0.0031p)^{1/4}}{(0.0031p)^{1/2}} \quad . \quad (7)$$

$$v_g\,(\text{condensate}) = \frac{4.02\,(45 - 0.0031p)^{1/4}}{(0.0031p)^{1/2}} \quad . \quad (8)$$

The interdependence of flow rate and pressure, due to reservoir deliverability, precludes having a direct minimum flow rate calculation for a particular well. However, a minimum flow rate for a particular set of conditions (pressure and conduit geometry) can be calculated using Eqs. 7 and 8 and Eq. 9.

$$q_g\,(\text{MMcf/D}) = \frac{3.06\,p\,v_g\,A}{T\,z} \quad . \; . \; . \; . \; . \quad (9)$$

Eqs. 7 through 9 allow the construction of a nomograph for direct solution of these equations (Fig. 4). Fig. 4 allows consideration of all values in the foregoing equations except the gas deviation factor z.

The nomograph is used by starting at the pressure of interest, going vertical to the proper line, then horizontal to the edge of the grid. This is the minimum gas velocity. From this point a line is drawn through the p/T line to the intermediate line, and from this line through the flow area line to the qz line.

For accurate flow rates, the deviation factor for the existing conditions should be divided into the qz term. The sample problem shown in Fig. 4 was for a hypothetical well with a wellhead pressure of 1,150 psia, producing through a 5½-in., 15.5-lb × 2⅜-in., 4.5-lb casing-tubing annulus (0.11 sq ft) and a wellhead temperature of 140°F, producing salt water along with the gas. The grid portion of the nomograph shows a required minimum gas velocity of 8.2 ft/sec, and subsequent progression through the nomograph shows a qz product of 5.4 MMcf/D. For these conditions a deviation factor of approximately 0.88 would exist, and the resulting minimum required flow rate would be 6.15 MMcf/D.

Conclusion

The minimum flow conditions necessary to remove liquids from gas wells are those that will provide a gas velocity sufficient to remove the largest drops that can exist. This velocity can be calculated using particle and drop break-up mechanics. The equation derived must be adjusted upward by approximately 20 percent to insure removal of all drops. The gas flow rate required to produce this velocity may be calculated and compared with existing conditions to determine the adequacy or inadequacy of the particular flow test. The derived equations are not limited to tubing, but can be used in annular and other flow geometries also. The gas:liquid ratio does not influence the minimum lift velocity in the observed ranges of liquid production up to 130 bbl/MMcf, and the liquid may be water and/or condensate. If both liquids are present, the properties of the denser of the two should be used in the equation, since the higher density material will be the controlling factor.

Nomenclature

A = flow area of conduit, sq ft
A_p = projected area, sq ft
C_d = drag coefficient
d = diameter of conduit, ft
d_p = diameter of liquid drop, ft
d_m = maximum diameter of liquid drop, ft
g_c = gravitational constant = 32.17 lb mass ft/lb force sec^2
g = local acceleration of gravity, ft/sec^2
k = constant = 0.36
h = film thickness, ft
m_p = mass of falling particle, lb mass
N_{Re} = Reynolds number = $\rho\,d\,v/\mu$
N_{We} = Weber number = $\rho\,v^2\,d/\sigma\,g_c$
p = pressure, lb force/sq in
q_g = gas flow rate, MMcf/D
T = temperature, °R

v = velocity, ft/sec

v_t = terminal velocity of free falling particle, ft/sec

w_L = liquid phase flow rate, lb mass/sec

y_m^+ = dimensionless distance parameter evaluated at center of conduit

z = gas deviation factor

$\left(\frac{\Delta p}{\Delta x}\right)_{TP}$ = two-phase pressure drop, lb force/sq ft/ft

μ_g = gas phase viscosity, lb mass/ft sec

μ_L = liquid phase viscosity, lb mass/ft sec

ρ_g = gas phase density, lb mass/cu ft

ρ_L = liquid phase density, lb mass/cu ft

ρ_p = density of particle, lb mass/cu ft

σ = interfacial tension, dynes/cm

τ = shear stress, lb force/sq ft

τ_0 = shear stress at the wall, lb force/sq ft

τ_i = shear stress at the gas/liquid interface, lb force/sq ft

$\phi = (y_m^+ - 60)/22$

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APPENDIX

Film Model Development

The co-current vertical upward flow of gas core-liquid film systems has been studied in several laboratory investigations, and its theoretical understanding has advanced to a point where mathematical modeling is possible. The approach presented here is after Hewitt[5] and his treatment of the Dukler[2] analysis.

In an annular liquid film (thickness h) on the walls of a vertical tube, the transport in the upward direction is a result of the interfacial shear (τ_i) of the moving gas on the surface of the liquid (Fig. 5). This motion is resisted by the action of gravity and wall friction. At any point y distance from the wall, there

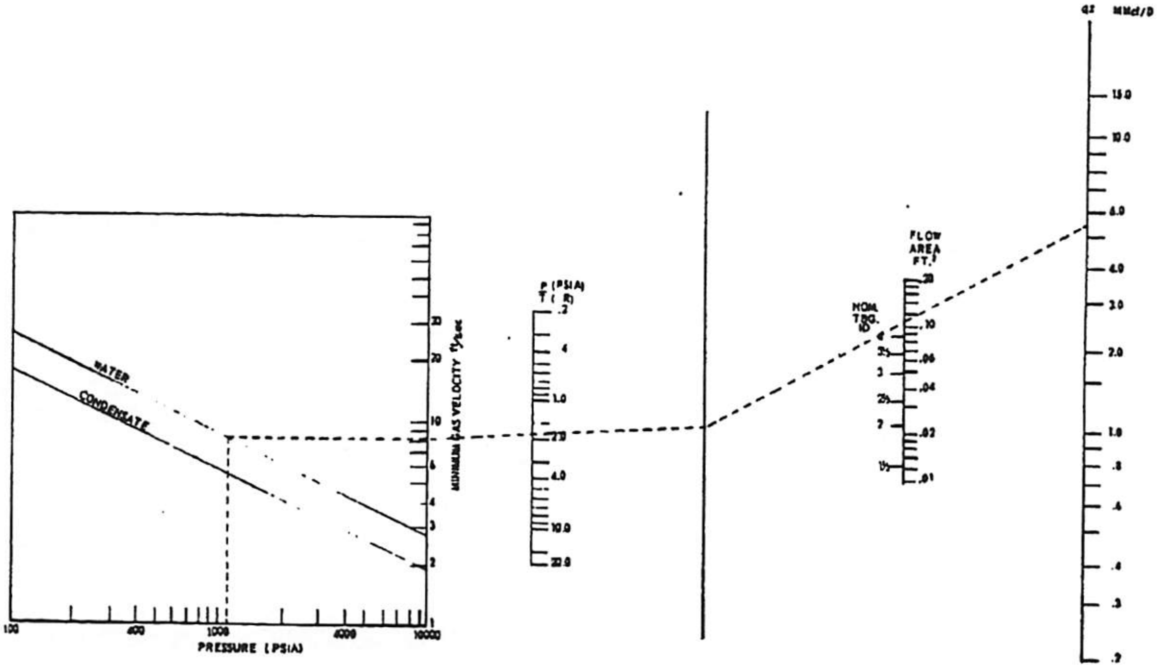

Fig. 4—Minimum flow rate nomograph.

exists a velocity ν and a shear stress τ. The resisting shear stress at the wall is τ_0. A steady-state force balance shows that at any point y,

$$\frac{\tau}{\tau_0} = 1 + \frac{y \rho_L g}{\tau_0 g_c} \quad . \; . \; . \; . \; . \; . \; . \; . \quad \text{(A-1)}$$

In dimensionless form, Eq. A-1 becomes

$$\frac{\tau}{\tau_0} = 1 + y^+ \frac{\sigma^3}{\eta} \quad , \; . \; . \; . \; . \; . \; . \; . \quad \text{(A-2)}$$

where

$$\sigma^3 = \frac{h^3 \rho_L^2 g}{\eta^2 \mu_L^2}$$

$y^+ = \dfrac{\nu^* y \rho_L}{\mu_L}$ (dimensionless distance parameter)

$\nu^* = \sqrt{\dfrac{\tau_0 g_c}{\rho_L}}$ ("friction" velocity)

$\nu^+ = \dfrac{\nu}{\nu^*}$ (dimensionless velocity parameter)

$\eta = \dfrac{h \nu^* \rho_L}{\mu_L}$ (dimensionless film thickness)

Eq. A-2 is the shear stress distribution as a function of the distance from the wall of the tube. By using the Gill and Scher[4] momentum transport hypothesis (eddy viscosity equation) and Eq. A-2, the dimensionless velocity distribution in the flow stream is obtained.

$$\nu^+ = \int_0^{y^+} \cdot \frac{2\left(1 + y\dfrac{\sigma^3}{\eta}\right)}{1 + \sqrt{1 + 4k^2 y^{+2}\left(1 - e^{\frac{-\phi y^+}{y^+ m}}\right)^2\left(1 + y^+\dfrac{\sigma^3}{\eta}\right)}}\, dy^+ \quad . \; . \; . \; . \; . \; . \; . \; . \; . \quad \text{(A-3)}$$

The velocity distribution in the liquid film can then be integrated to find the liquid-phase flow rate:

$$w_L = \pi d \mu_L \int_0^{\eta} \nu^+ dy^+ \quad . \; . \; . \; . \; . \quad \text{(A-4)}$$

Eqs. A-3 and A-4 may be used to evaluate the minimum gas flow rate required to move the film steadily upward. For this application it is necessary to establish the relationship between the shear stresses and the gravitational forces in the film at the minimum condition of upward flow. Since the interfacial shear (τ_i) provides the motivating force for moving the film upward, and the gravitational shear stress, $h \rho_L g/g_c$, and the shear stress at the wall (τ_0) are resisting movement, the minimum flow condition for film movement will be when the interfacial shear (τ_i) approaches the value of the gravitational "shear" and the shear stress at the wall (τ_0) approaches zero.

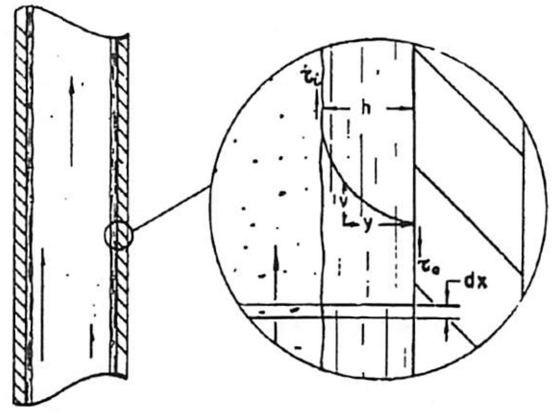

Fig. 5—Liquid film movement.

The ratio $\dfrac{h \rho_L g/g_c}{\tau_i} = X$ approaches 1.0 (i.e., the gravitational shear stress approaches the interfacial shear stress) at the limiting condition. For the purpose of analysis, X must be slightly less than 1 (i.e., the interfacial shear must be slightly larger than the gravitational shear stress, and τ_0 must be greater than zero).

If it is assumed that $X = 0.99$ at the minimum gas flow rate condition, it is possible to evaluate the necessary parameters to integrate Eqs. A-3 and A-4. The relationships utilized are

$$\sigma^3 = \frac{X}{1 - X}; \quad \frac{\beta}{\eta^{2/3}} = \frac{1}{X^{2/3}(1 - X)^{2/3}}$$

where

$$\beta = \frac{F d \rho_L^{2/3} g^{1/3}}{4 \mu_L^{2/3}}; \quad F = \frac{\dfrac{\Delta p}{\Delta x} - \rho_g \dfrac{g}{g_c}}{\rho_L \dfrac{g}{g_c}}.$$

$\Delta p/\Delta x - \rho_g(g/g_c)$ = the two-phase pressure drop = $(\Delta p/\Delta x)_{TP}$. A modification of the Martinelli[9] two-phase pressure drop correlation is employed to evaluate the $(\Delta p/\Delta x)_{TP}$.

The calculation procedure to test the development against field data requires numerical integration and iteration. A computer program was written to perform these calculations and the results are shown in Table 1 and Fig. 3. **JPT**

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Minimum Gas Flow Rate for Continuous Liquid Removal in Gas Wells

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ABSTRACT

Several publications on the prediction of minimum gas flow rates for continuous liquid removal in gas wells are indicative of the interest the industry has in this subject. Some of the noteworthy studies are those of Duggan (1961) and Turner, et al, (1969). One limitation of Turner's work is the treatment of entrained liquid drops in the gas core independent of the continuous film region, even though it is acknowledged that interactions between the two regions exist and are continuous in the entrainment process. Other treatments of the subject have been mainly empirical, based on observation in particular gas fields, with no claims to general application.

A large bank of available experimental data by several investigators for upward annular dispersed flow was used to develop correlations for the prediction of entrainment, film thickness and pressure drops by Hughmark (1973). These correlations have been applied, with some modifications to the gas well situation. Duns and Ros pressure drop correlation has been incorporated in this model because of its better accuracy in the annular-mist flow region.

Comparison of results from this model with field results show marked improvement in minimum gas flow rate prediction accuracy that should be beneficial to the industry.

INTRODUCTION

A lot of interest has been generated in the past years over the problems of associated liquids produced along with gas in gas wells. These liquids are water, gas condensates and/or oils. Whether the situation is that of producing extraneous water or the more useful varieties, there is a basic problem posed, which is the means of adequately transporting these liquids to surface.

From the number of published works on this subject, it is apparent that the man in the field recognizes the dilemma of dealing with the problem. Many discussions abound on how to unload the liquids that accumulate in the wellbore through methods like opening up the casing annulus to atmospheric pressure to "blow" the contents out or the better controlled method of installing a down-hole pump to periodically lift the liquids to surface. These discussions presuppose, however, that nothing can be done to transport these liquids to surface under the natural flowing pressures of the reservoir. There is an assumption that the liquids entering the wellbore from the reservoir cannot be entrained in the gas flow to surface.

Reservoir engineering analyses show, however, that for a low permeability reservoir such "loading up" of liquids can be dangerous to the life of the gas well. As long as production is continued somehow, the permeability to gas is maintained. If, however, enough water accumulated to result in a shut down, the water may imbibe back into the sand face and create a water block that may completely seal off a low permeability well. Wells have been lost this way even after attempts to re-stimulate production by swabbing.

Another aspect of consideration in the investigations has been that of predicting the critical flow rates or production parameters under which liquid entrainment is impossible. Such knowledge has very practical relevance to the industry since the danger point can be foreseen and prepared for. For economic reasons, it is good to know that a well has enough natural capacity to entrain the liquids being produced. Deferment of the installation of artificial lift mechanisms means savings in operating costs. Knowing just when to install the pumps will prevent the impairment of reservoir production potential by the imbibition of liquids to form the liquid block.

The task therefore is to adequately predict, for various hole geometries and pressure-volume-temperature conditions, the critical gas flow rates for given liquid production rates. Many investigators[1-3] have used purely empirical approaches. These results have made no claims to generalized utility but are useful for the particular conditions under which deductions were made.

Turner et al[4] made a major contribution to this subject in 1968. They predicted critical gas flow rates semi-empirically and in a more generalized form. Two physical models were recognized for the removal of gas well liquids: (1) liquid film movement along the walls of the pipe and (2) liquid droplets entrained in the high velocity gas core. Although there is usually an actual

References and illustrations at end of paper.

continuous exchange of liquid between the gas core and the film, they were treated separately. The gas core droplet entrainment was considered the most significant and controlling factor for the removal of liquids from the gas wells. Comparisons of Turner et al's predictions with field data suggest a need for better predictive models.

This paper uses correlations developed by Hughmark[5]. These correlations are based on extensive experimental studies of many investigators[6-15]. Hughmark's correlations were modified with regard to pressure gradient prediction by using Duns and Ros correlations which have been found to be accurate in the mist and annular-mist flow regimes.

THEORY

The flow of gas and liquid with continuous liquid transportation up the wellbore with the continuous gas phase occurs in the annular-mist flow regime. This regime is characterized by an upward moving continuous smooth to wavy film of liquid on the tube wall and a much more rapidly moving central core of gas, containing entrained droplets of liquid in concentrations which vary from low to high. The annular mist flow can be divided into the "small ripple" regime and the "disturbance wave" regime. In the small ripple regime, small waves develop on the liquid surface and move at about interfacial velocities and then disappear. At the higher liquid flow rates the waves are higher and travel at two to three times the interfacial velocity. These are the disturbance waves.

For any liquid rate, a decrease in gas rate causes more of the liquid to be present in the film, the liquid film velocity to decrease and its thickness to increase. At a low enough gas flow rate the liquid film velocity becomes zero and below this rate a negative velocity of film near the wall develops. The film thickness increases and penetrates the gas phase resulting in froth flow. For an increase of gas rate however, turbulence occurs in the liquid film, the film thickness decreases, waves develop at the interface and droplets are torn off the film and entrained in the gas. The upper limit therefore is the complete destruction of the film layer as all the liquid is transported as droplets. This would be the pure mist regime with no annulus to talk about.

Force Balance on the Film

In Figure 1 we consider a section of the tubing of length dl with a liquid film of thickness δ flowing upward. Under steady state conditions, the momentum equation reduces to a force balance. In the area bounded by the cylindrical surfaces at radii (R-y) and (R-δ) the following forces are acting:

1. A downward force acting at a radial distance (R-y) from the tubing center line.

   $$\tau \; 2 \pi (R-y) dl$$

2. An upward force acting at a radial distance (R-δ) from the center line (the interface).

   $$\tau_i \; 2 \pi (R-\delta) \, dl$$

3. A downward force as a result of the gravitational force.

   $$F_g = \frac{\pi}{4} [(D-2y)^2 - (D-2\delta)^2 \, dl \, \rho_L \, g \quad \ldots\ldots (1)$$

   where D = 2R

4. An upward force as a result of the pressure gradient.

   $$- \frac{\pi}{4} [(D-2y)^2 - (D-2\delta)^2] \, dP$$

A force balance on the film in this section results in the equation:

$$\tau = \tau_i \left(\frac{D-2\delta}{D-2y}\right) - \left(\frac{dP}{dl} + \rho_L g\right) (\delta - y) \quad \ldots\ldots (2)$$

if second order terms y^2, δy, δ^2 are negligible.

Force Balance on the Gas Core

A relationship between shear stress at the gas-liquid interface and the pressure gradient can be obtained by a force balance for the gas phase in the core. Again, these forces are identifiable:

1. A downward force at a radial distance (R-δ) away from the center line.

   $$\tau_i \; 2\pi (R-\delta) \, dl$$

2. A resultant downward gravitational force.

   $$\pi (R-\delta)^2 \rho_g \, g \, dl$$

3. An upward force as a result of the pressure gradient.

   $$- \pi (R-\delta)^2 \, dP$$

A force balance gives the following equation:

$$\tau_w = - \frac{dP}{dL} \frac{R}{2} - g\rho_L (R-a) - \frac{a^2}{2R} \rho_g \, g \quad \ldots\ldots (3)$$

Equation 3 can be rearranged in the form presented by Hughmark[5]:

$$\tau_w = \left[- \frac{dP}{dL} - g\rho_L \left(1 - \frac{a^2}{R^2}\right) - g\rho_g \frac{a^2}{R^2}\right] R/2 \quad \ldots\ldots (4)$$

At high velocities the liquid density term of Eq. 4 is small in comparison to the pressure loss so that $\tau_w = \tau_i$. At low gas velocities representing the lower limits of the annular flow regime, the wall shear stress is considerably smaller than the interfacial shear stress.

Using data from Hewitt and Collier[15], correlations of dimensionless liquid film thickness y_L^+ with liquid film Reynold's number R_{eL} were obtained:

$$R_{eL} = 4\rho_L \, Q_L / \pi D \, \mu_L \quad \ldots\ldots (5)$$

$$U_L^* = [(\tau_w + \tau_i) / 2\rho_L]^{1/2} \quad \ldots\ldots (6)$$

$$U_G^* = [(\tau_w + \tau_i) / 2\rho_g]^{1/2} \quad \ldots\ldots (7)$$

$$y_L^+ = y U_L^* / \nu_L \quad \ldots\ldots (8)$$

$$y_G^+ = yU_G^*/\nu_G \quad \ldots\ldots \quad (9)$$

These data are shown in Figure 2. An empirical fit of the data resulted in the following equations:

$$2 < R_{eL} < 100, \; y_L^+ = 0.66\,(R_{eL})^{0.53} \quad \ldots \quad (10)$$

$$100 < R_{eL} < 1000, \; y_L^+ = 0.347\,(R_{eL})^{0.667} \quad (11)$$

$$1000 < R_{eL}, \; y_L^+ = 0.13\,(R_{eL})^{0.81} \quad \ldots\ldots \quad (12)$$

Hughmark also obtained a composite correlation for the equivalent dimensionless number for gas, y_G^+, using experimental data of Hewitt and Collier[15], Alia et al[12,13], and Cousins et al[16,17]. The term "volumetric flow ratio" taken from Gill et al[14] was used to plot these data as function of y_G^+. An empirical fit of the correlation resulted in the following equations (see Figure 3):

$$y_G^+ < 36 \; ; \quad \alpha = 0 \quad \ldots\ldots \quad (13)$$

$$36 < y_G^+ < 42 \; ; \; \alpha = -0.000442 + 0.000013 y_G^+ \quad (14)$$

$$42 < y_G^+ < 60 \; ; \; \alpha = -0.000625 + 0.0000172 y_G^+ \quad (15)$$

$$60 < y^+_G \; ; \; \alpha = 5 \times 10^{-8} {y_G^+}^{2.2} \quad \ldots \quad (16)$$

$$\alpha = W_E \rho_g / W_g \rho_L \quad \ldots\ldots \quad (17)$$

Duns and Ros[18] pressure gradient correlation was used in this work because it has been found to give accurate results in the annular-mist flow regime. A subroutine[19] was used to obtain pressure gradient, dp/dl, for shear stress calculation.

The liquid film Reynolds number R_{eL} can be calculated for an assumed film thickness . The dimensionless liquid film thickness, y_L^+, is calculated from Eqs. 10 to 12. Equation 8 gives a calculated value of δ, and by an iterative procedure a true value of δ is obtained. It is necessary, however, to know the densities and viscosities of the gas and liquid at prevailing in-situ conditions.

The equivalent dimensionless liquid film thickness for gas, y_G^+, is obtained from Eq. 9 and the volumetric flow ratio, α, is calculated from Eqs. 13 to 16. In Eq. 17 the volumetric flow ratio is written in terms of the mass rate of liquid entrainment, W_e, and the mass flow rate of gas, W_g. The liquid entrainment possible with a specific gas flow rate can thus be determined. A systematic reduction in gas flow rate naturally results in reduced entrainment until the critical point is reached when entrainment is zero.

This model is easily programmable and can be run for different hole geometries and PVT conditions.

RESULTS

The most important parameters affecting entrainment are tubing size, pressure, gas specific gravity, and liquid hold up. The effect of these parameters will be discussed qualitatively in this section.

The example well used for the computer runs has the following characteristics:

Depth: 6000 feet
Ambient surface temperature: 80°F
Temperature gradient: 1.4°F/100 feet
Bottom hole pressures: (1100-700) psia
Tubing sizes: (3.068, 2.441, 2.347, 1.991) inches I.D.
Gas specific gravities: 0.6, 0.7, 0.8
Produced liquid: Water

Effect of Tubing Size

One of the methods used in the field to combat liquid loading problems in gas wells has been to install smaller size tubing. The success is because a reduction in flow area means an increase in gas velocity which results in a greater carrying capacity. For the tubing sizes investigated, it can be seen that the smaller tubing sizes have a lower critical flow rate under comparable conditions. It is conceivable, however, that the reduction of tubing sizes cannot be advantageous to entrainment ad infinitum. This fact is pointed out by Tek, et al[20], since below a certain tubing diameter, neither the flow of gas nor liquid is permitted by the choking action of the small conduit. Therefore the frictional effects become predominant. Within the range of tubings examined here, which are typical oil field sizes, entrainment efficiency has been found to decrease with increase in diameter (Table 1 and Figs. 4 to 7).

Effect of Pressure

Increase in bottom hole pressures have an adverse effect on entrainment. A comparison of minimum flow rates is shown in Table 2. Pressure effect is not very sensitive to slight changes in pressure. In fact, hardly any change is noticed between a 900 psia and a 1100 psia bottom hole situation. A difference is noted, however between 1100 and 700 psia and this trend is repeated for any appreciable pressure differences. Larger pressures mean a smaller gas volume for the same mass rate of gas. A lower gas volume means a lower gas velocity for the same flow area; and since we notice a reduction in entrainment efficiency, we see another pointer in the role of gas velocity.

Incompressible fluids such as water are relatively unaffected by pressure variation, but the lighter and more volatile condensates are definitely affected by pressure and temperature variations. A means of accounting for the percentage in the gaseous and liquid phase and the density of the phases is necessary for improved accuracy of prediction.

The idea of opening up a gas well to reduce wellhead pressures and consequently bottom hole pressure to improve liquid entrainment is endorsed by the results of this study.

Effect of Gas Specific Gravities

Higher gas specific gravities have been found to result in a better entrainment capacity. As shown in Table 3 and Figures 8 and 9, a gas gravity 0.6 has a minimum entrainment flow rate higher than those of gases with 0.7 and 0.8 specific gravity. This would indicate therefore that momentum is a vital factor in the ability of a gas to carry liquid droplets up a wellbore. It was mentioned earlier that increased pressure which results in increased gas density was found to decrease entrainment efficiency. There is no contradiction here since an increase in pressure results in an increase in density and a decrease in volume, and a constant mass. An increase in specific gravity means an increase in density at no expense to the volume of the gas. Momentum, which is a product of mass and velocity, is therefore the deciding factor in a gas' ability to transport liquid.

Concersely, the denser the liquid to be transported, the more difficult it is to entrain and the more momentum is needed to move it.

Effect of Gas Velocity and Liquid Hold-Up

A peculiar trend was found in this investigation regarding a reduction of the critical gas flow rate with increase in liquid production. This trend is found to be much steeper in the first increments of liquid production from zero. This phenomenon can be explained in the following way:

The liquid droplets are responsible for lowering the area of flow to gas. This in turn results in a higher actual gas velocity for an increased concentration of droplets. It must be realized, however, that in the realm of our consideration, gas is the continuous phase and this analogy should not be extrapolated too far.

Just as smaller size jet nozzles are installed in drill bits for increased nozzle velocity and better hole cleaning for the same liquid flow rates, an increase in droplet concentration has been seen to result in a lowering of the minimum gas flow rate to ensure entrainment. This suggests therefore that for wells that produce liquid at very small rates, there is a loading problem earlier than we actually realize. If 10 BWPD were being produced through a 2.347 inch I.D. tubing at 6000 feet and bottom hole pressure of 700-1000 psia, we could expect the following trend. At a gas flow rate of 600 mcf/d this liquid entrainment will fail, resulting in loading and accumulation. The continued production of water results in an actual in-situ liquid rate greater than 10 BWPD and therefore entrainment occurs (see Figure 6). Table 4 illustrates this decreased entrainment efficiency with decreased concentration. This is an actual record of the upward flow of gas and liquids in a situation where entrainment failed. It is therefore more significant in liquid entrainment to discuss actual gas velocity and not just the superficial velocity.

The rest of the Figures, 10 to 16, are plots of the entrainment values for the various pressures, tubing sizes and gas specific gravities evaluated.

It is evident that this correlation ceases to be sensitive to variations in liquid concentration at values of water production greater than 70 BWPD for the pressure values investigated. In the comparison runs made with other data, it is clear that it is adequate for the real situations encountered. It was pointed out by Turner, et al[4] that concentration of 130 bbl/MMSCF was an upper limit of liquid production problems generally encountered in the field. Seventy BWPD at a gas flow rate of 400 MSCF/D is at a liquid concentration of 175 bbl/MMSCF which is above this upper limit. It also is a gas-liquid ratio of 5714 STB/SCF which is definitely tending away from the continuous gas phase situation assumed in the entraiment. This therefore explains the relative flatness of the curve beyond this liquid rate.

Comparison with Field Data

Some data were collected from the field by Turner to check the predictive accuracy of his model. Among the limitations encountered by this author in the evaluation of Turner's data were the unavailability of several data that definitely play a major role in the entrainment efficiency of a gas-liquid system. Such missing data included 1) gas specific gravity, 2) the bottom hole temperature, 3) the temperature gradients of the locations of the well, 4) the specific gravities of the liquids which consisted of both water and volatile condensates (Turner made assumptions of API gravities for the condensates and used a water specific gravity of 1.08), and 5) the actual status of the wells at the time of data collection, i.e. unloaded or loaded up.

Assumptions of gas specific gravities, bottom hole temperatures and temperature gradients were made, and the assumptions made by Turner for the liquid gravities were used for the input into this model. Table 5 is the only available mode of comparison with field data. Efforts are in progress to obtain more field data.

The first five sets of data in Table 5 deserve closer scrutiny since the status of the wells are reported as "near loaded up" which suggests the threshold point we are attempting to predict. This model's predictions are seen to compare more closely with three of the five cases. It would also appear that the predictions were better for the 1.995 inch tubings and water production. It is difficult to make categorical statements of worth from the scanty data available, but it is apparent that this model is an alternative worth considering for better prediction if field data are available.

CONCLUSION

The objective of this study has been to develop a model for prediction of the minimum gas flow rate in a tubing wellbore to ensure continuous liquid removal. This model is able to predict the maximum amount of liquids that can be entrained for any gas flow rate.

This study has shown that a higher specific gravity gas is a better carrier than a lower specific gravity gas. It has been shown also that entrainment is dependent not just on the superficial gas velocity but on the actual gas velocity. This was borne out by the fact that the minimum gas flow rate for entrainment actually decreased with increase in water production rate for the same pressure and temperature conditions.

This model was found to be insensitive to liquid concentrations above 175 bbls/MMSCF. Since this exceeds the predominant range of conditions encountered in actual field operations, not much of a problem is posed by this limitation.

Comparisonswere made with field data obtained from Turner, et al and with Turner et al predictions. A consistent difference could not be seen since the Turner predictions were higher in some cases and lower in other cases. A categorical statement of how close to actual data this model is cannot be made because of insufficient data. The closeness in three of the five cases in the "near loaded up" status is remarkable. This model should be tested with more field data.

NOMENCLATURE

δ = Liquid film thickness (ft.)

τ_i, τ_w = Shear stress at gas-liquid interface and pipe wall, respectively, (lb_f/sq. ft.)

g = Acceleration due to gravity

ρ_L, ρ_g, = Density of liquid, gas

$\frac{dP}{dl}$ = Pressure gradient (psi/ft.)

D = Pipe inside diameter

a = Gas core radius

R = Tubing inside radius

y_L^+ = Dimensionless liquid film thickness

y_G^+ = Equivalent dimensionless number for gas

R_{eL} = Liquid film Reynolds' number

ν_L and ν_G = Kinematic viscosities of liquid and gas, respectively

U_L^* and U_G^+ = Liquid and gas shear velocities, respectively

Q_L = Liquid volume flow rate

W_E = Entrainment mass rate

W_g = Gas mass rate

α = Volumetric flow ratio

μ_L and μ_g = Absolute viscosities of liquid and gas, respectively

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21. Ilobi, M. I.: "Prediction of Minimum Gas Flow Rate for Continuous Liquid Removal from Gas Wells," M. S. Thesis, University of Tulsa (1981).

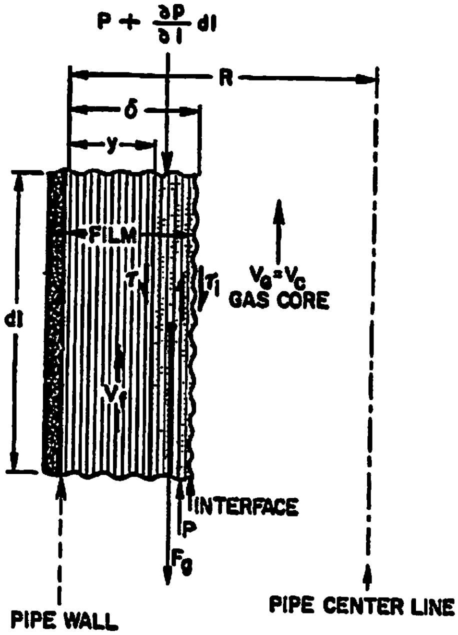

$P + \frac{\partial p}{\partial l} dl$
R
δ
y
FILM
τ_f
τ_i
$V_g = V_c$
GAS CORE
dl
V_f
INTERFACE
P
F_g
PIPE WALL
PIPE CENTER LINE

Fig. 1 – Forces on an element of the liquid film in annular flow

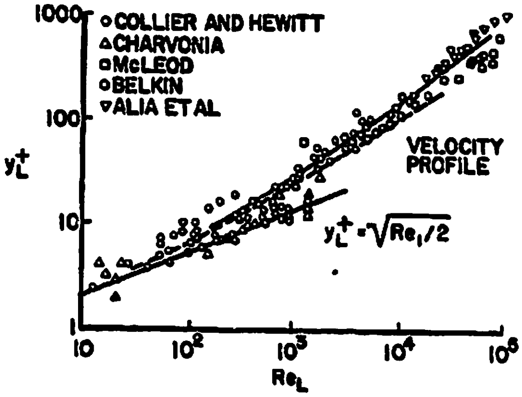


Fig. 2 – Film thickness

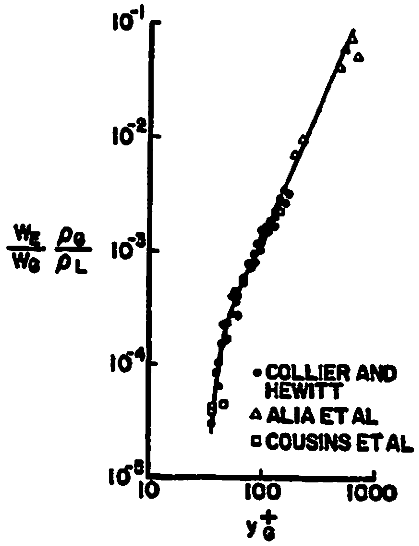


Fig. 3 – Volumetric ratio versus y_G^+ for entrainment

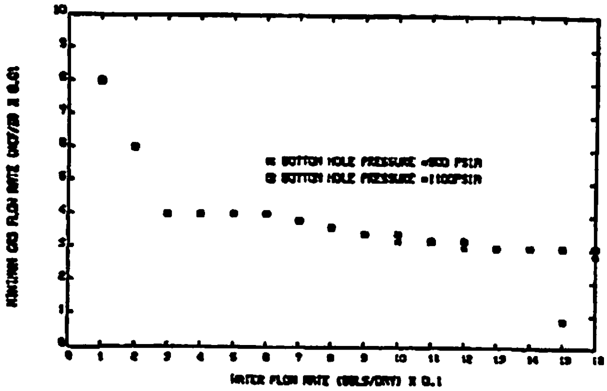


Fig. 4 – Plot for gas S.G. = 0.6; tubing I.D. = 3.068 in.

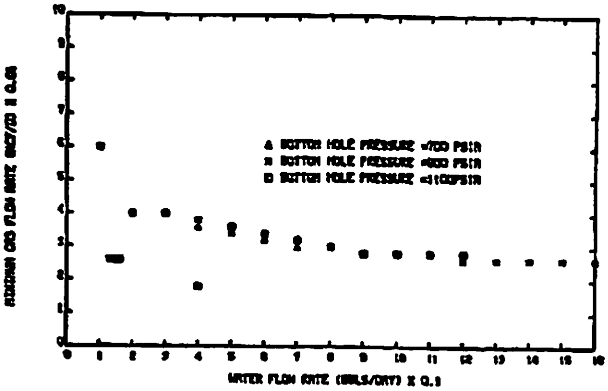


Fig. 5 – Plot for gas S.G. = 0.6; tubing I.D. = 2.441 in.

TABLE 1

EXAMPLE OF EFFECT OF TUBING SIZE

Minimum Gas Flow Rate for Water Entrainment (MCF/D)

Tubing . in inches	Produced Water BWPD 10	20	30	40	50	60	70
1.991	400	380	320	300	280	260	240
2.347	400	400	360	320	300	280	260
2.441	600	400	380	340	320	300	300
3.068	600	400	400	400	380	360	340

TABLE 2

EXAMPLE OF PRESSURE EFFECT

Gas S.G. = 0.7 Tubing I.D. = 2.347"

Minimum Gas Flow Rate for Water Entrainment (MCF/D)

Bottom Hole Pressure (Psia)	Produced Water BWPD 10	20	30	40	50	60	70
1100	600	400	380	340	320	300	280
700	400	400	360	320	300	280	280

TABLE 3

EXAMPLE OF GAS S.G. EFFECT

Bottom Hole Pressure = 900; Tubing I.D. = 1.991"

Minimum Gas Flow Rate for Water Entrainment (MCF/D)

Gas S.G.	Produced Water BWPD 10	20	30	40	50	60	70
0.6	400	400	360	320	300	280	260
0.7	400	380	320	300	280	260	260
0.8	400	340	300	280	260	260	240

TABLE 4

EXAMPLE OF ENTRAINMENT EFFICIENCY TREND WITH LIQUID CONCENTRATION

Depth (Feet)	Pressure (Psia)	Liquid Mass Flow Rate (Lbm/day)	Liquid Entrainment (Lbm/day)	% Entrainment
6000	1100.000	3608.871	2557.749	70.87
5850	1073.415	2557.749	1555.910	60.83
5700	1051.060	1555.910	754.607	48.50
5550	1029.012	754.607	262.064	34.73
5400	1007.257	262.063	24.611	9.39
5250	985.772	24.611	0	0

Bottom Hole Temperature = 164°F
Water Production Rate = 10 BWPD
Water Specific Gravity = 1.03
Gas Flow Rate = 600 MSCF/D
Gas Specific Gravity = 0.600
Tubing Inside Diameter = 2.441"

TABLE 5

COMPARISONS WITH FIELD DATA AND TURNER ET AL. PREDICTIVE MODEL

	Depth	Wellhead Pressure	Condensate bbl/mm	Water bbl/mm	Tubing ID	Field Data mcf/d	Turner Drop Model Prediction mcf/d	[illegible]-Ilobi Prediction Model SG=0.6 mcf/d	SG=0.7 mcf/d	SG=0.8 mcf/d	Status
1.	6400	725	6.0	0	2.441	775	779	1600	1440	1360	Near loaded up
2.	5770	400	0	18	1.995	417	383	480	410	360	Near loaded up
3.	8530	108	9.6	12.4	2.041	568	306	470	410	360	Near loaded up
4.	6700	540	10.5	10.5	1.995	712	661	550	480	440	Near loaded up
5.	6770	450	11.3	0	1.995	442	419	840	760	700	Near loaded up
6.	11200	3087	37.4	0	1.995	1525	1156	1680	1520	1440	Loaded up
7.	11200	3630	37.4	0	1.995	2575	1150	1620	1500	1410	Unloaded
8.	11240	2773	35.1	0	1.995	2495	1150	1640		1410	Questionable
9.	11240	3667	35.1	0	1.995	3725	1142	1620	1500	1410	Unloaded
10.	11416	3240	130.8	0	2.992	2611	2412	1380	1260	1170	Loaded up
11.	11416	3185	130.8	0	2.992	3264	2401	1350	1260	1170	Questionable
12.	11416	3280	130.8	0	2.992	4075	2435	1350	1260	1170	Questionable
13.	11417	2540	113.5	0	2.441	1818	1635	1200	1110	1020	Loaded up
14.	11417	3330	113.5	0	2.441	2918	1600	1140	1080	990	Questionable
15.	11425	2525	106.9	0	1.995	1792	1105	960	870	810	Loaded up
16.	11425	3472	106.9	0	1.995	1577	1085	1170	1080	1020	Unloaded
17.	11355	3336	117.6	0	2.441	2261	1623	1110	1050	960	Loaded up
18.	11355	2745	117.6	0	2.441	2503	1610	870	810	750	Questionable
19.	11355	3092	117.6	0	2.441	2351	1574	840	780	720	Unloaded
20.	11390	3518	104.3	0	1.995	2040	1091	1200	1110	1050	Questionable
21.	11390	3185	104.3	0	1.995	2769	1082	960	880	830	Unloaded
22.	8490	3625	68.3	0	2.441	2542	1660	1400	1320	1260	Loaded up
23.	8490	3644	68.3	0	2.441	3182	1624	1430	1320	1260	Questionable
24.	8490	3615	68.3	0	2.441	3690	1648	1440	1380	1260	Unloaded
25.	8840	3212	34.8	0	2.441	2547	1604	1520	1400	1320	Loaded up
26.	8840	3025	34.8	0	2.441	3317	1569	1445	1380	1240	Unloaded
27.	6995	2335	17.9	0	1.995	1116	936	1500	1400	1320	Questionable
28.	6995	2226	17.9	0	1.995	1959	910	1530	1440	1320	Unloaded
29.	9315	1590	13.1	0	1.958	3059	2781	2880	2610	2440	Loaded up
30.	9315	1550	13.1	0	1.958	3301	3213	2840	2600	2400	Questionable
31.	9315	1520	13.1	0	1.958	4150	3195	2800	2560	2360	Unloaded
32.	7346	1875	27.8	0.4	1.995	8672	1239	880	800	760	Unloaded
33.	7346	2421	27.8	0.4	1.995	6654	1407	1040	960	920	Unloaded
34.	7346	2705	27.8	0.4	1.995	5136	1467	1120	1040	980	Unloaded
35.	7346	2880	27.8	0.4	1.995	3317	1502	1200	1080	1000	Unloaded

GASLOAD

This program estimates the miminum required gas rates needed to lift either condensate or water from the wellbore. Needed input is surface pressure, current gas rate, and gas properties. The bottom hole flowing pressure, gas viscosity, and minimum flow rates are calculated.

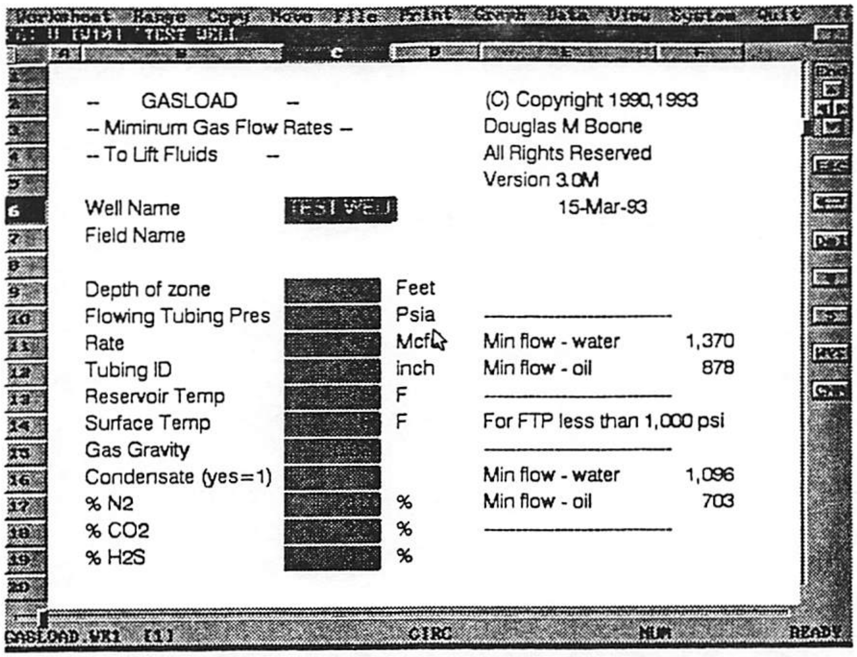
This calculation is based on a paper: Turner, R.G. et al.: "Analysis and Prediction of Minimum Flow rate for the Continuous Removal of Liquids From Gas Wells," JPT (Nov 1969) 1475-82; Trans., AIME, 246

Another paper was published by Coleman, S.B. et al: "A New Look at Predicting Gas-Well Load-up," JPT (March 1991) 329-333. In this paper the authors pointed out that the Turner paper covered wells with higher flowing tubing pressures and resulted in numbers that were about 20% high. Turner had used a 20% adjustment to his basic equations to match some of the test data that they were checking the theory against.

Figure #1 illustrates the "Information" screen or how the program will appear when first retrieved. The individual numbers might be different but the data descriptions and input areas will be the same. If the user has anything else on the screen then the [HOME] key should be pressed to come back to the "Information" screen. The normal arrow keys are used to move around this screen and to make data entries. The user can get brief instructions on how to use this program by pressing the [Alt][H] key while in the "Information" screen. These instructions are shown in Figure #2. Return to the "Information" screen by pressing the [Home] key. The user can make data changes only in the highlighted cells. The highlighted input cells are the cells that are either shown in green on color screens or are reverse video on monochrome monitors.

Macro Descriptions

[Alt][H] - displays the "instruction" screen
[Alt][P] - To print the work sheet


Worksheet Range Copy Move File Print Graph Data View System Quit
GASLOAD.WK1 [1] CIRC NUM READY

– GASLOAD –
– Miminum Gas Flow Rates –
– To Lift Fluids –

(C) Copyright 1990,1993
Douglas M Boone
All Rights Reserved
Version 3.0M
15-Mar-93

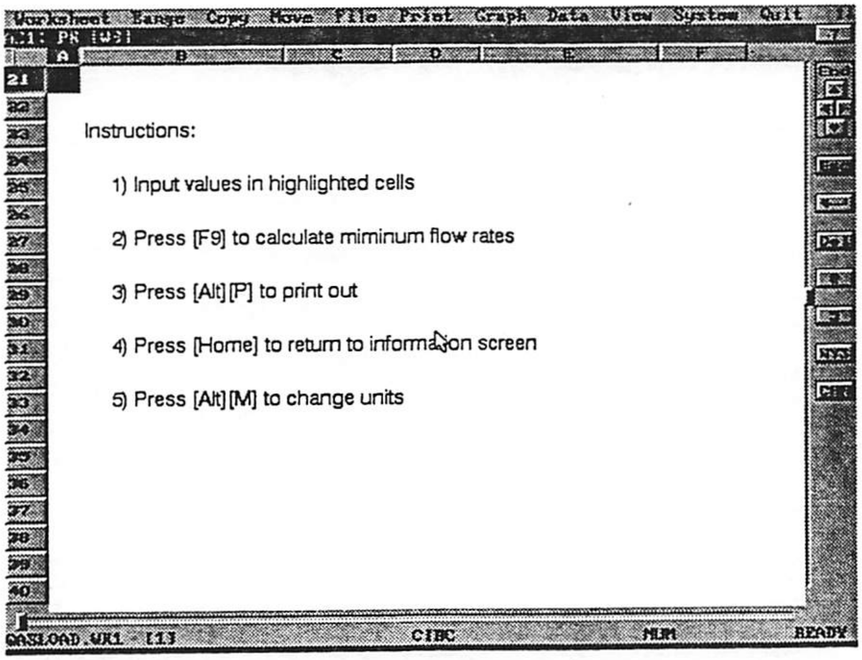
Well Name TEST WELL
Field Name

Depth of zone Feet
Flowing Tubing Pres Psia
Rate Mcf
Tubing ID inch
Reservoir Temp F
Surface Temp F
Gas Gravity
Condensate (yes=1)
% N2 %
% CO2 %
% H2S %

Min flow - water 1,370
Min flow - oil 878

For FTP less than 1,000 psi

Min flow - water 1,096
Min flow - oil 703


Worksheet Range Copy Move File Print Graph Data View System Quit
GASLOAD.WK1 [1] CIRC NUM READY

Instructions:

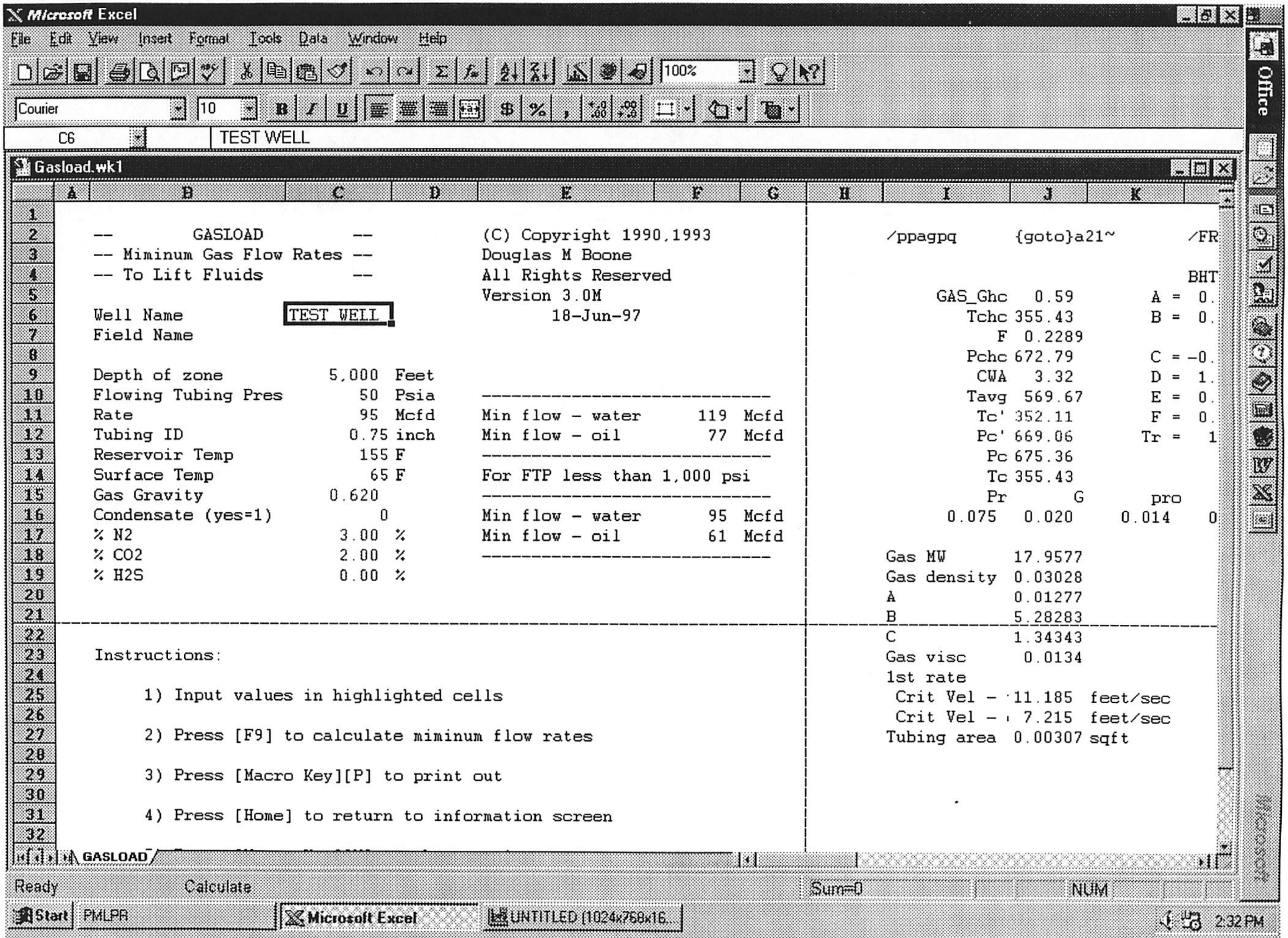
1) Input values in highlighted cells

2) Press [F9] to calculate miminum flow rates

3) Press [Alt][P] to print out

4) Press [Home] to return to information screen

5) Press [Alt][M] to change units



Microsoft Excel
File Edit View Insert Format Tools Data Window Help
100%
Courier
10
C6
Gasload.wk1
GASLOAD
Ready
Calculate
Sum=0
NUM
Start
PMLPR
Microsoft Excel
UNTITLED (1024x768x16...
2:32 PM
Office
Microsoft

C6 TEST WELL

```
  --         GASLOAD          --          (C) Copyright 1990,1993
  -- Miminum Gas Flow Rates --            Douglas M Boone
  -- To Lift Fluids          --           All Rights Reserved
                                          Version 3.0M
  Well Name            TEST WELL               18-Jun-97
  Field Name

  Depth of zone           5,000  Feet
  Flowing Tubing Pres        50  Psia     ------------------------------
  Rate                       95  Mcfd     Min flow - water      119  Mcfd
  Tubing ID                0.75  inch     Min flow - oil         77  Mcfd
  Reservoir Temp            155  F        ------------------------------
  Surface Temp               65  F        For FTP less than 1,000 psi
  Gas Gravity             0.620           ------------------------------
  Condensate (yes=1)          0           Min flow - water       95  Mcfd
  % N2                     3.00  %        Min flow - oil         61  Mcfd
  % CO2                    2.00  %        ------------------------------
  % H2S                    0.00  %


  Instructions:

       1) Input values in highlighted cells

       2) Press [F9] to calculate miminum flow rates

       3) Press [Macro Key][P] to print out

       4) Press [Home] to return to information screen
```

```
/ppagpq        {goto}a21~          /FR

                                  BHT
     GAS_Ghc   0.59          A =  0.
        Tchc 355.43          B =  0.
           F  0.2289
        Pchc 672.79          C = -0.
         CWA   3.32          D =  1.
        Tavg  569.67         E =  0.
         Tc' 352.11          F =  0.
         Pc' 669.06         Tr =   1
          Pc 675.36
          Tc 355.43
          Pr        G          pro
      0.075   0.020       0.014     0

Gas MW       17.9577
Gas density  0.03028
A            0.01277
B            5.28283
C            1.34343
Gas visc      0.0134
1st rate
 Crit Vel - ·11.185  feet/sec
 Crit Vel - ׀ 7.215  feet/sec
Tubing area  0.00307 sqft
```

LOADUP

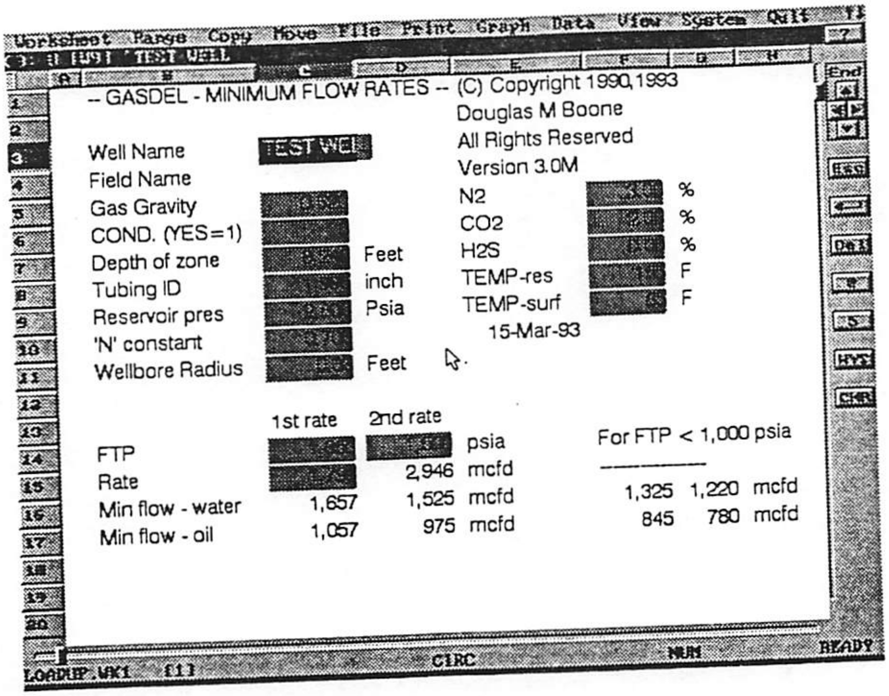
This program is similar to GASLOAD.WK1 which estimates the minimum required gas rates needed to lift either condensate or water from the wellbore but also does it at the current conditions and at a new rate calculated from a change in flowing tubing pressure.

This program will be helpful if you are trying to determine how effective gas compressions will be in helping the well to unload and if increasing the tubing pressure, as required in curtailing a well, will cause associated loading problems.

Figure #1 illustrates the "Information" screen or how the program will appear when first retrieved. The individual numbers might be different but the data descriptions and input areas will be the same. If the user has anything else on the screen then the [HOME] key should be pressed to come back to the "Information" screen. The normal arrow keys are used to move around this screen and to make data entries. The user can get brief instructions on how to use this program by pressing the [Alt][H] key while in the "Information" screen. These instructions are shown in Figure #2. Return to the "Information" screen by pressing the [Home] key. The user can make data changes only in the highlighted cells. The highlighted input cells are the cells that are either shown in green on color screens or are reverse video on monochrome monitors.

Macros Utilized

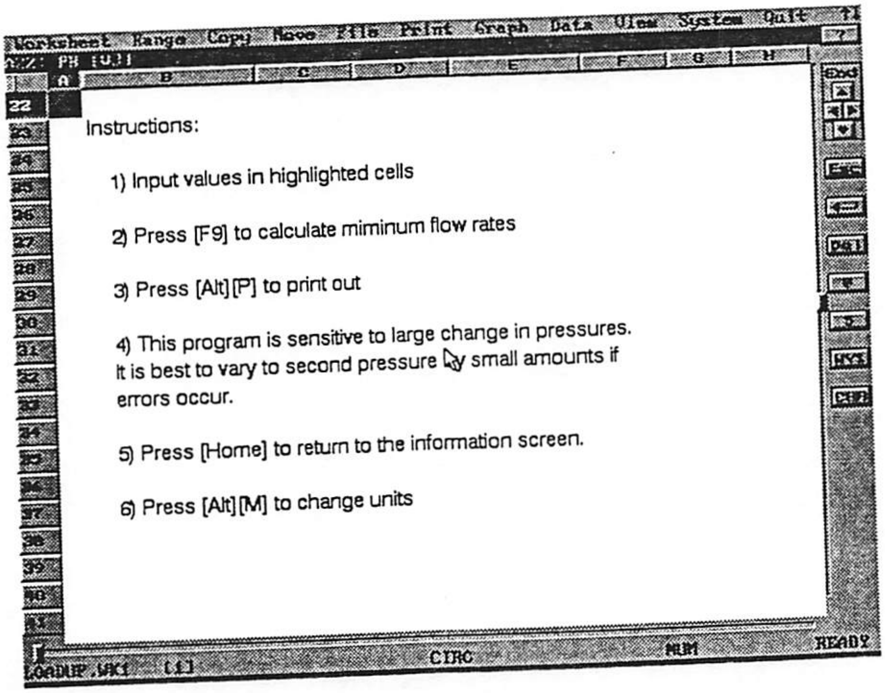
[Alt][H] - displays the "instruction" screen
[Alt][P] - To print a work sheet


Worksheet Range Copy Move File Print Graph Data View System Quit
LOADUP.WK1 [1] CIRC NUM READY

-- GASDEL - MINIMUM FLOW RATES -- (C) Copyright 1990,1993
Douglas M Boone
All Rights Reserved
Version 3.0M

Well Name	TEST WEL				
Field Name					
Gas Gravity	[illegible]		N2	[illegible]	%
COND. (YES=1)	[illegible]		CO2	[illegible]	%
Depth of zone	[illegible]	Feet	H2S	[illegible]	%
Tubing ID	[illegible]	inch	TEMP-res	[illegible]	F
Reservoir pres	[illegible]	Psia	TEMP-surf	[illegible]	F
'N' constant	[illegible]		15-Mar-93		
Wellbore Radius	[illegible]	Feet			

	1st rate	2nd rate		For FTP < 1,000 psia		
FTP	[illegible]	[illegible]	psia			
Rate	[illegible]	2,946	mcfd			
Min flow - water	1,657	1,525	mcfd	1,325	1,220	mcfd
Min flow - oil	1,057	975	mcfd	845	780	mcfd


Worksheet Range Copy Move File Print Graph Data View System Quit
LOADUP.WK1 [1] CIRC NUM READY

Instructions:

1) Input values in highlighted cells

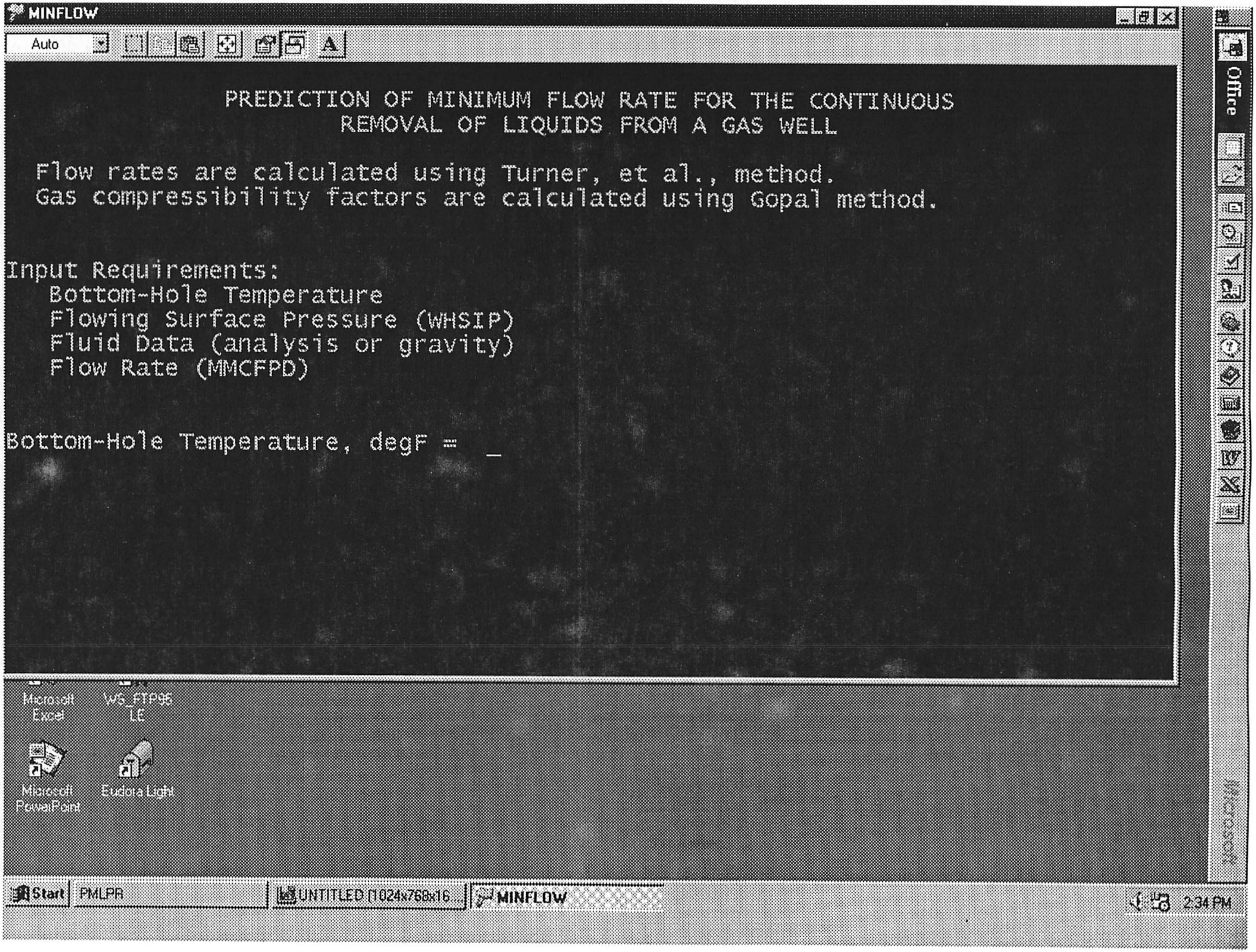
2) Press [F9] to calculate miminum flow rates

3) Press [Alt][P] to print out

4) This program is sensitive to large change in pressures. It is best to vary to second pressure by small amounts if errors occur.

5) Press [Home] to return to the information screen.

6) Press [Alt][M] to change units


MINFLOW
Auto
Office
Microsoft Excel
WS_FTP95 LE
Microsoft PowerPoint
Eudora Light
Microsoft
Start
PMLPR
UNTITLED (1024x768x16...
MINFLOW
2:34 PM

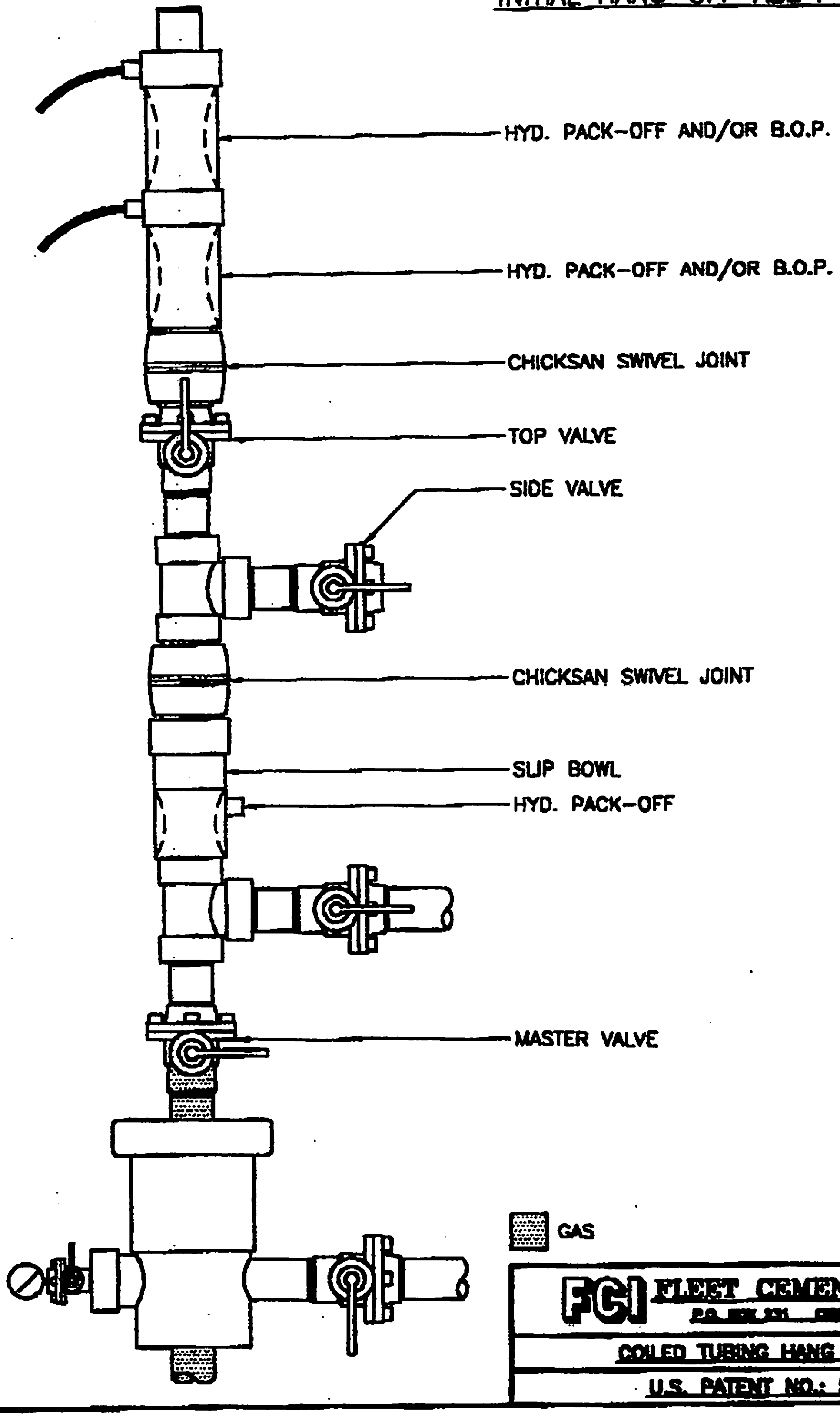
```
                  PREDICTION OF MINIMUM FLOW RATE FOR THE CONTINUOUS
                          REMOVAL OF LIQUIDS FROM A GAS WELL

  Flow rates are calculated using Turner, et al., method.
  Gas compressibility factors are calculated using Gopal method.


Input Requirements:
   Bottom-Hole Temperature
   Flowing Surface Pressure (WHSIP)
   Fluid Data (analysis or gravity)
   Flow Rate (MMCFPD)


Bottom-Hole Temperature, degF =  _
```

INITIAL HANG-OFF ASS'Y INSTALLED


HYD. PACK-OFF AND/OR B.O.P.
HYD. PACK-OFF AND/OR B.O.P.
CHICKSAN SWIVEL JOINT
TOP VALVE
SIDE VALVE
CHICKSAN SWIVEL JOINT
SLIP BOWL
HYD. PACK-OFF
MASTER VALVE

▨ GAS

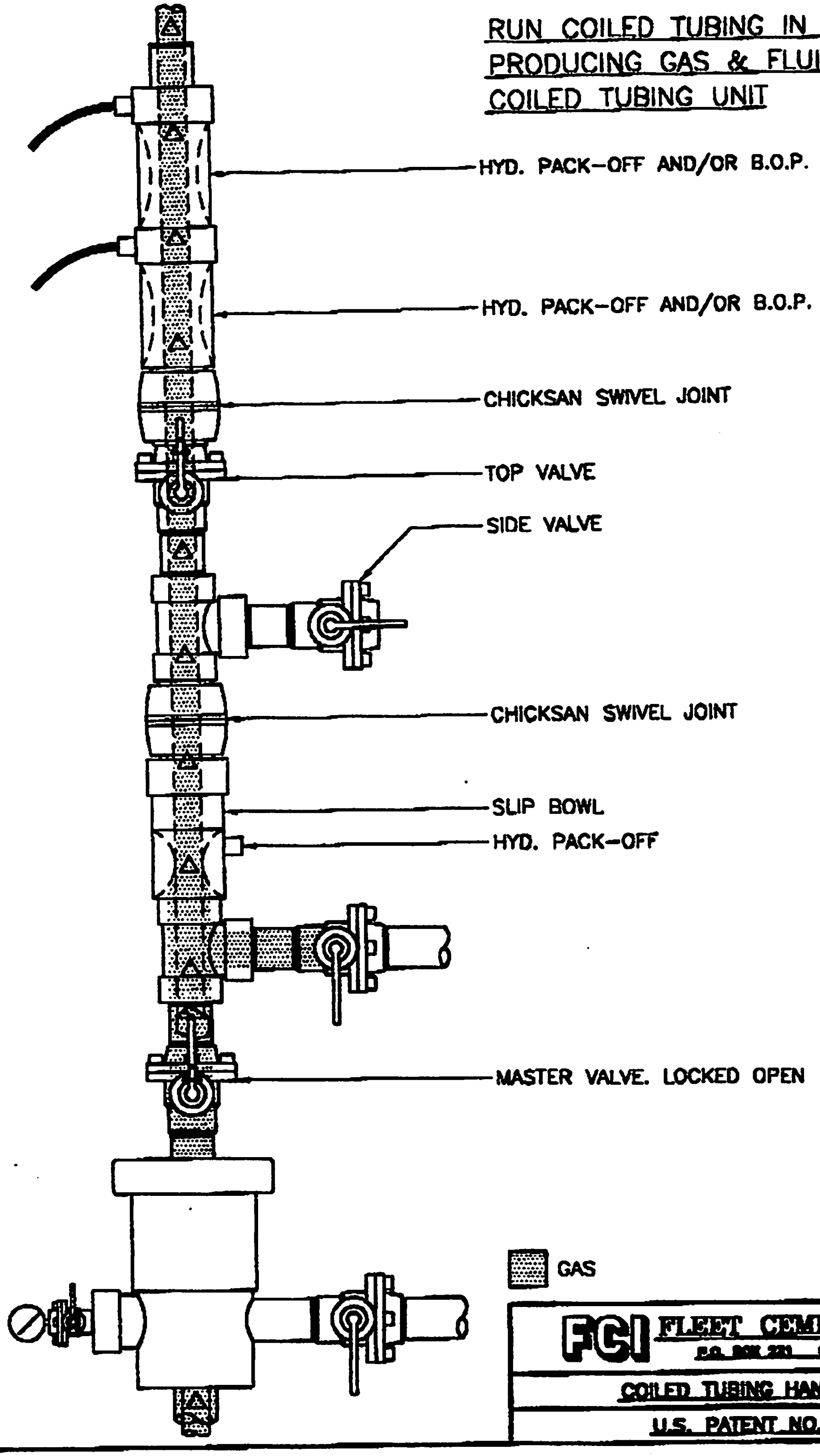
FCI FLEET CEMENTERS, INC.
P.O. BOX 231 CISCO, TEXAS 76437

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903

1 OF 10

RUN COILED TUBING IN WELL– PRODUCING GAS & FLUIDS THROUGH COILED TUBING UNIT

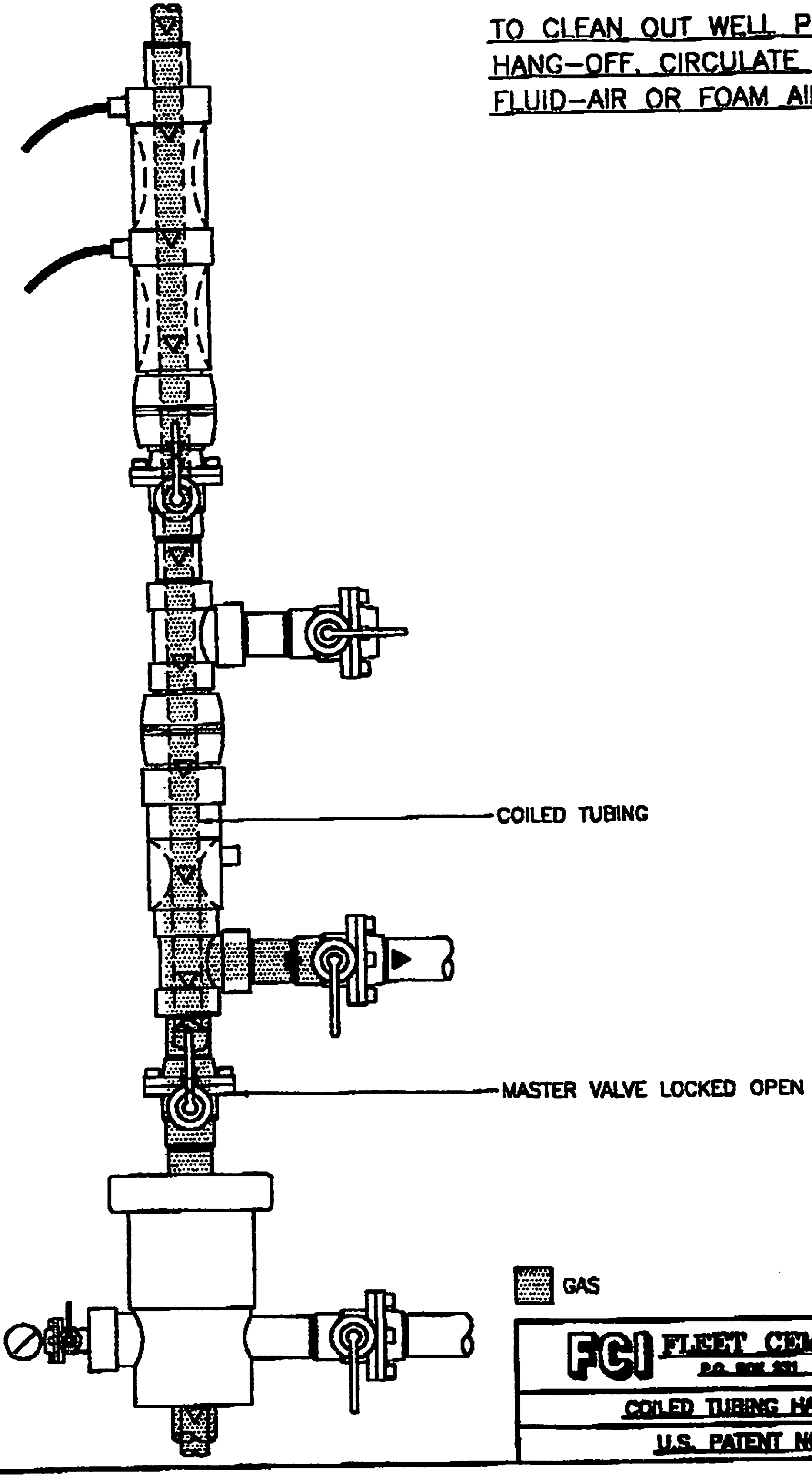

HYD. PACK–OFF AND/OR B.O.P.
HYD. PACK–OFF AND/OR B.O.P.
CHICKSAN SWIVEL JOINT
TOP VALVE
SIDE VALVE
CHICKSAN SWIVEL JOINT
SLIP BOWL
HYD. PACK–OFF
MASTER VALVE. LOCKED OPEN
▨ GAS

FCI FLEET CEMENTERS, INC.
[illegible]

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903 [illegible]

TO CLEAN OUT WELL PRIOR TO
HANG-OFF, CIRCULATE W/N_2–
FLUID-AIR OR FOAM AIR


COILED TUBING
MASTER VALVE LOCKED OPEN

▨ GAS

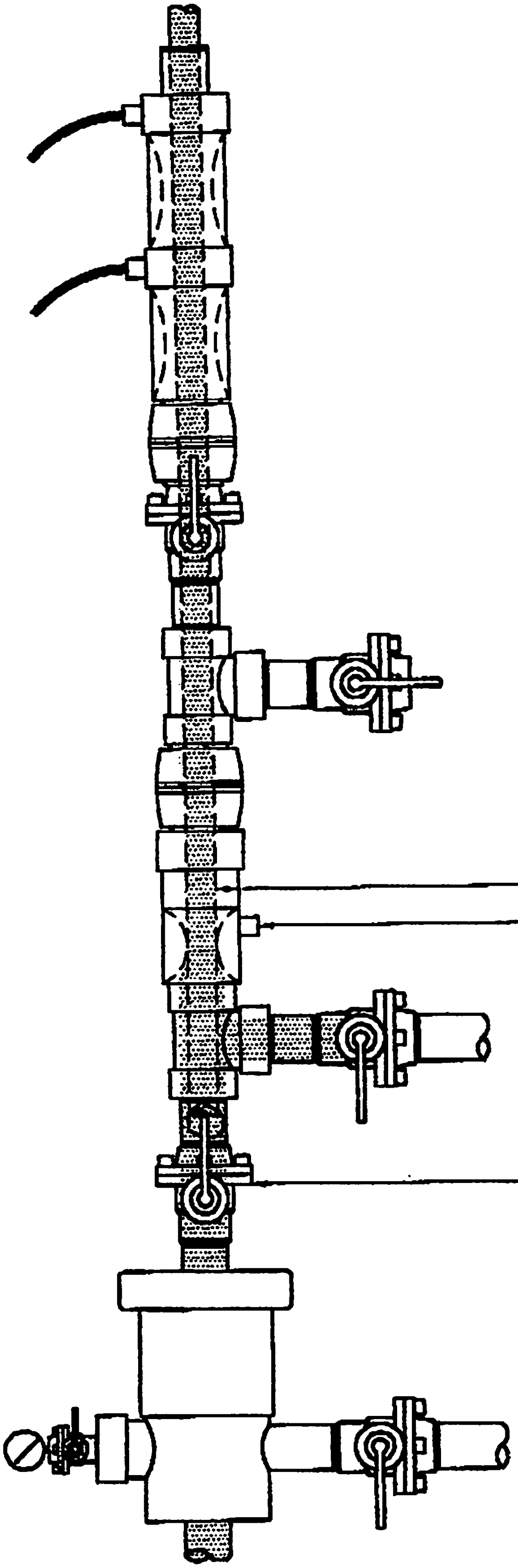
FCI FLEET CEMENTERS, INC.
P.O. BOX [illegible] [illegible] TEXAS [illegible]

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903

4 OF 13

COILED TUBING RUN TO TOP OF MASTER VALVE & CLOSE HYD. PACK-OFF


COILED TUBING
CLOSE HYD. PACK-OFF CLOSED
MASTER VALVE

▨ GAS

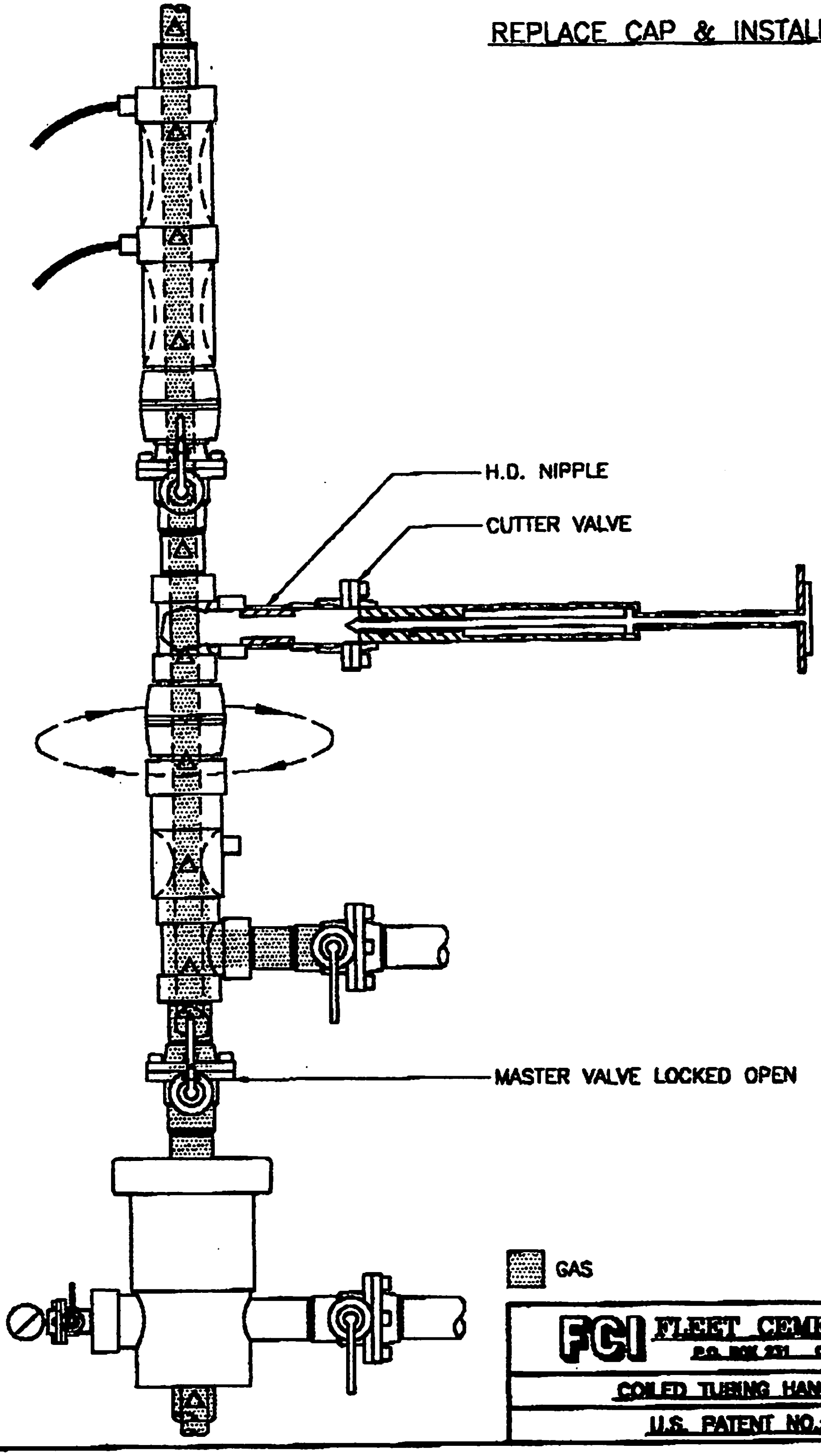
FCI FLEET CEMENTERS, INC.
P.O. BOX 231 CISCO, TEXAS 76437

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903

[illegible]

REPLACE CAP & INSTALL CUTTER ASS'Y

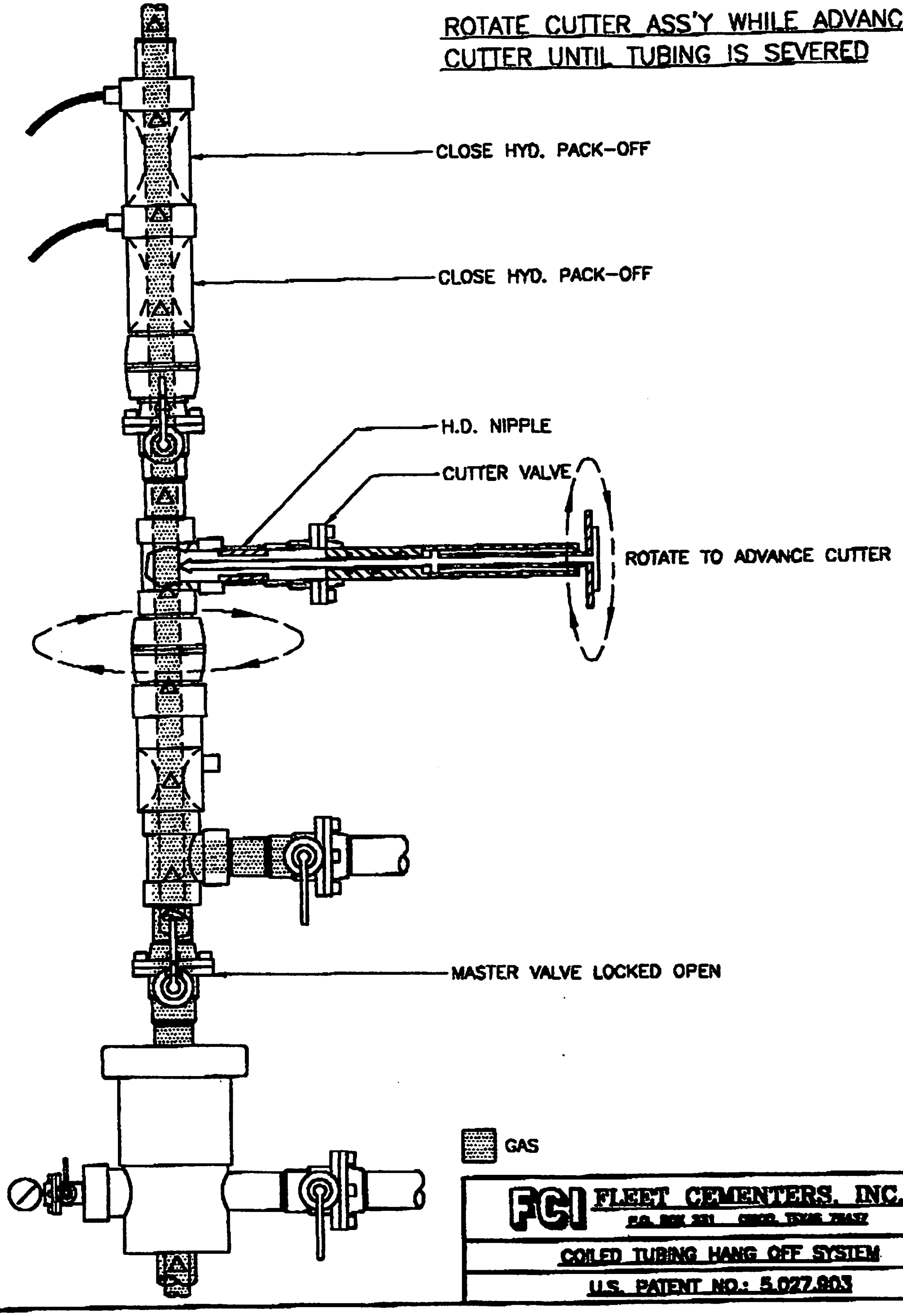

H.D. NIPPLE
CUTTER VALVE
MASTER VALVE LOCKED OPEN
▨ GAS

FCI FLEET CEMENTERS, INC.
P.O. BOX 271 [illegible]

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903 | [illegible]

ROTATE CUTTER ASS'Y WHILE ADVANCING CUTTER UNTIL TUBING IS SEVERED


CLOSE HYD. PACK-OFF
CLOSE HYD. PACK-OFF
H.D. NIPPLE
CUTTER VALVE
ROTATE TO ADVANCE CUTTER
MASTER VALVE LOCKED OPEN
▨ GAS

FCI **FLEET CEMENTERS, INC.**

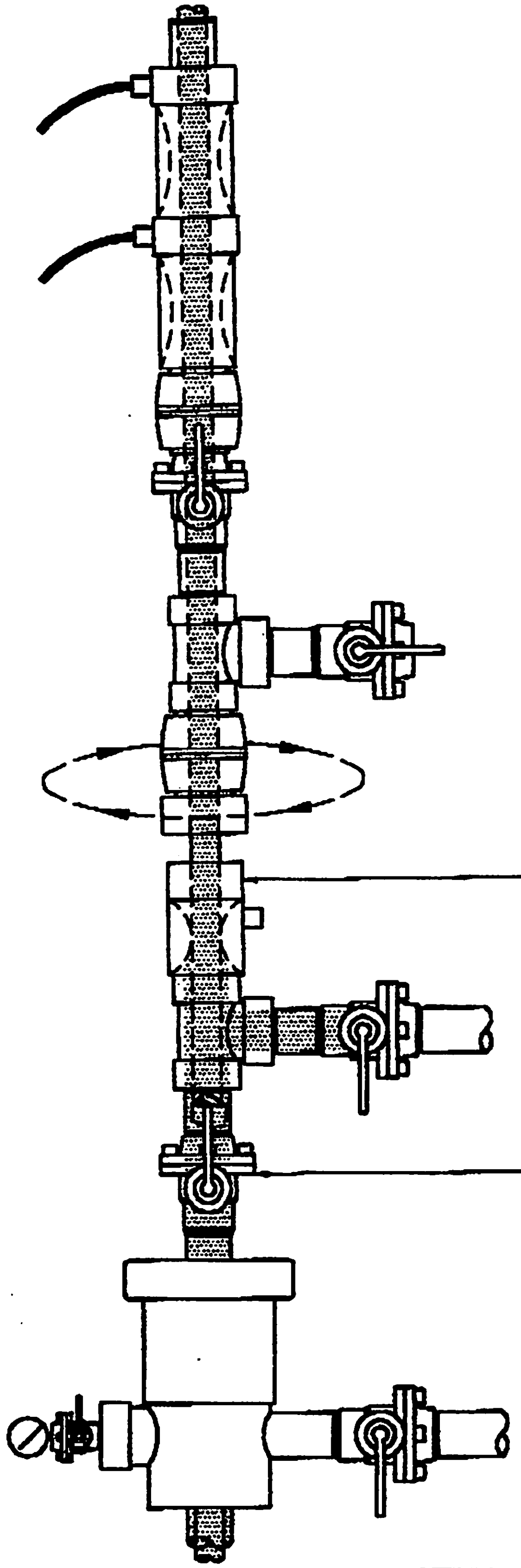
[illegible]

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903

7 of 16

TO HANG-OFF, UNSCREW TOP CAP
& ELEVATE TO SET SLIPS


SLIPS INSTALLED & TUBING SUSPENDED
MASTER VALVE LOCKED OPEN

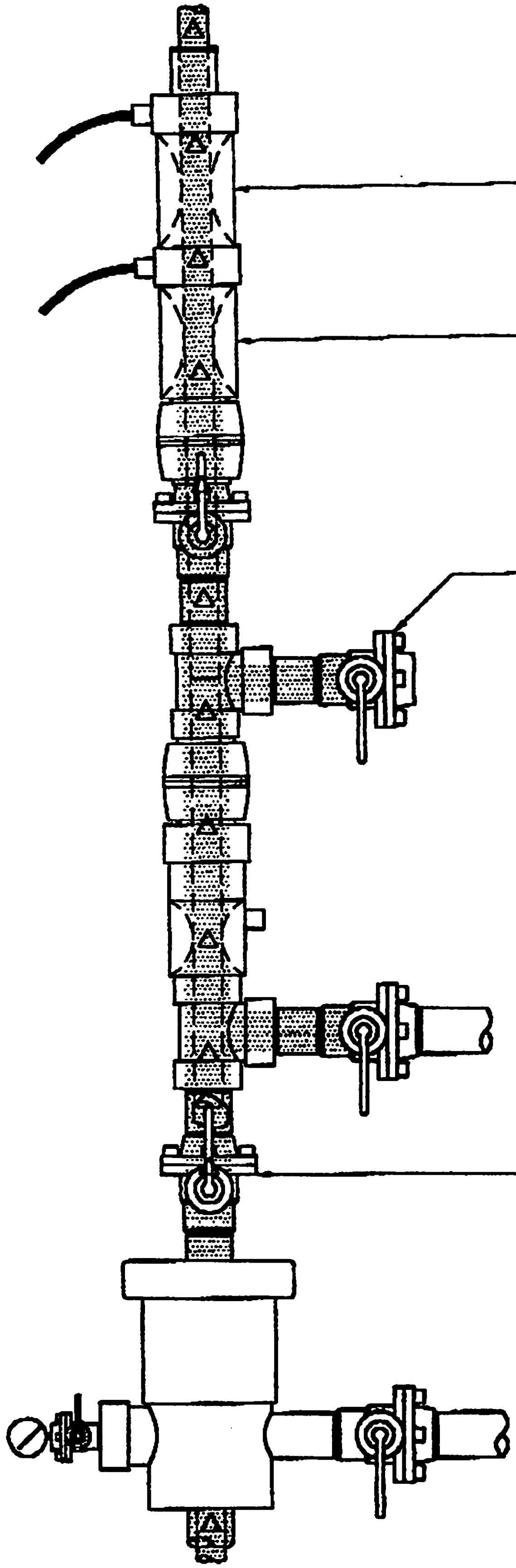
▨ GAS

FCI FLEET CEMENTERS, INC.
[illegible]

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903 | [illegible]

WHEN TUBING IS CUT, RETRACT CUTTER & CLOSE CUTTER VALVE



CLOSE HYD. PACK-OFF

CLOSE HYD. PACK-OFF

CUTTER VALVE CLOSED

MASTER VALVE LOCKED OPEN

▨ GAS

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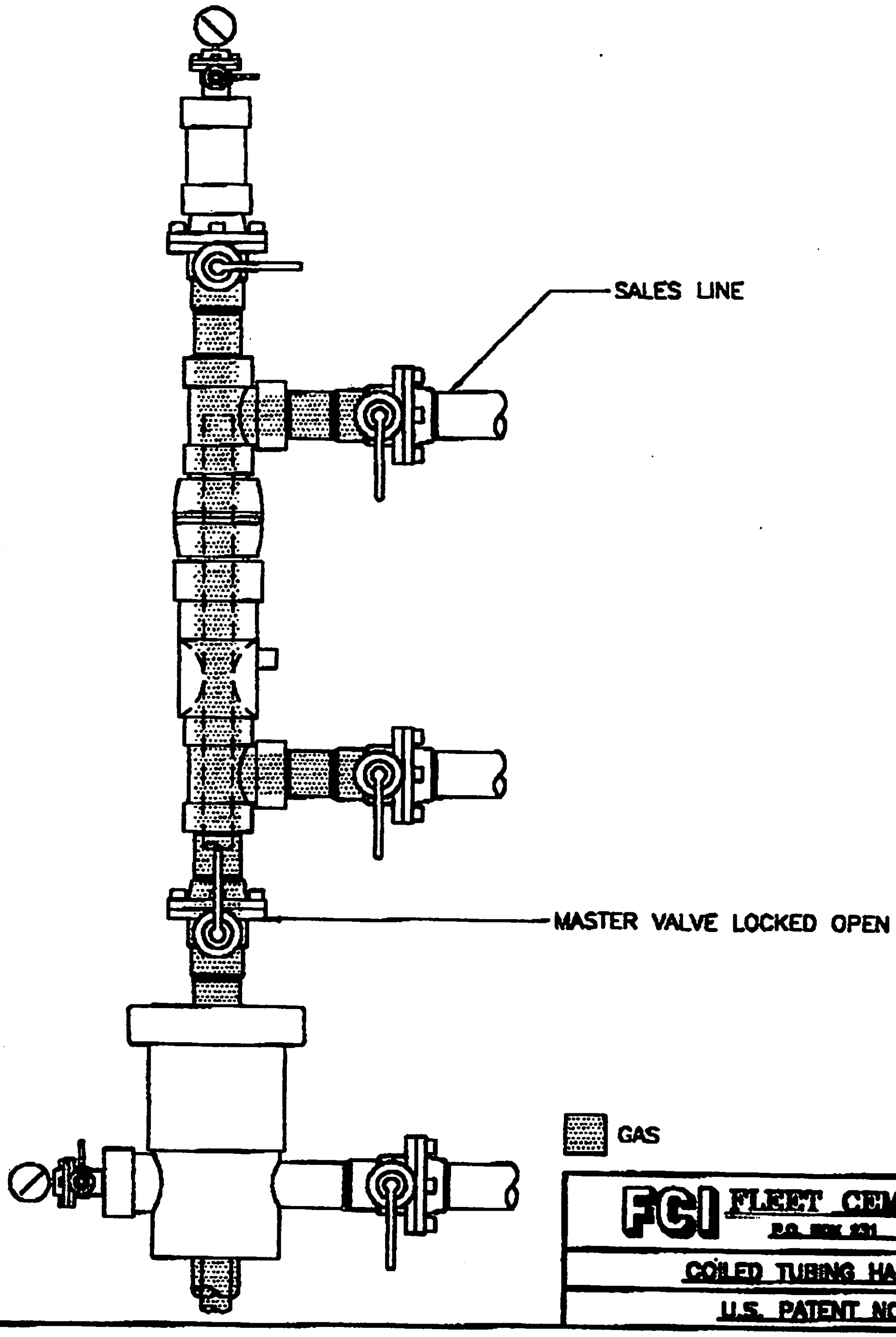
P.O. BOX 231 [illegible]

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903 [illegible]

FINAL WELL HEAD CONFIGURATION W/COILED TUBING INSTALLED


SALES LINE
MASTER VALVE LOCKED OPEN

▨ GAS

FCI FLEET CEMENTERS, INC.
P.O. BOX 931 CISCO, TEXAS 76437

COILED TUBING HANG OFF SYSTEM

U.S. PATENT NO.: 5,027,903

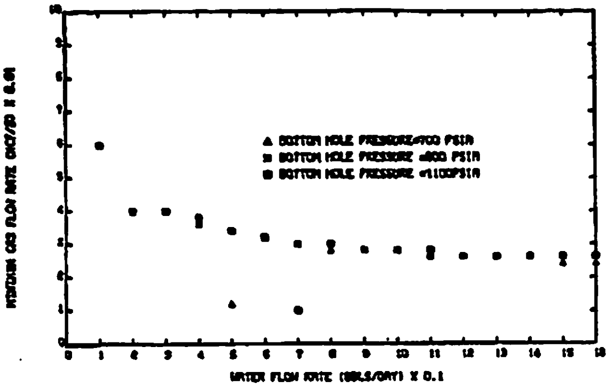


Fig. 6 – Plot for gas S.G. = 0.6; tubing I.D. = 2.347 in.

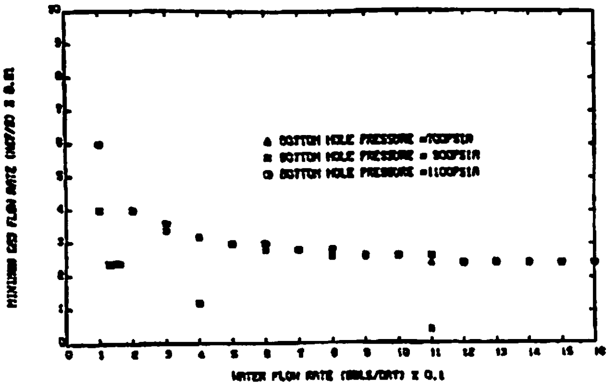


Fig. 7 – Plot for gas S.G. = 0.6; tubing I.D. = 1.991 in.

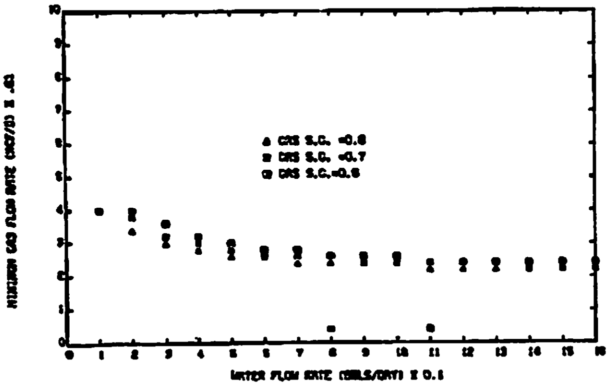


Fig. 8 – Plot for B.H.P. = 900 psia, tubing I.D. = 1.991 in.

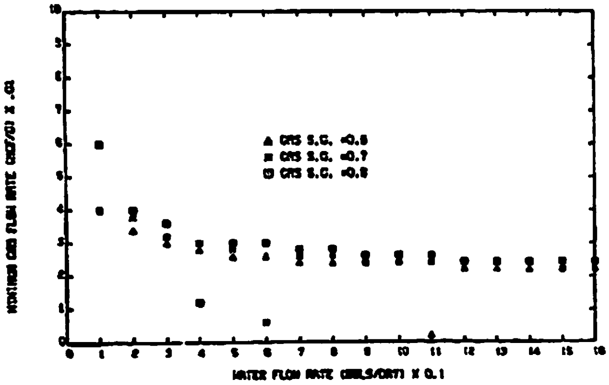


Fig. 9 – Plot for B.H.P. = 1100 psia, tubing I.D. = 1.991 in.

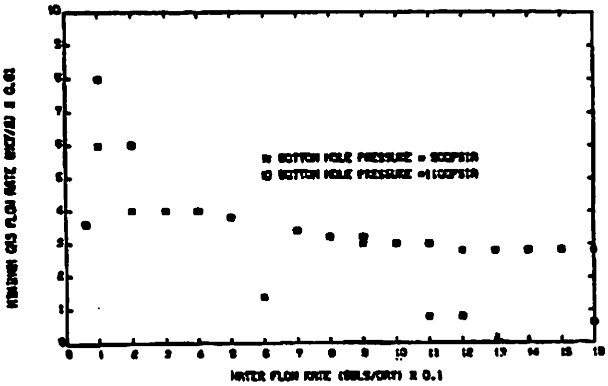


Fig. 10 – Plot for gas S.G. = 0.7; tubing I.D. = 3.068 in.

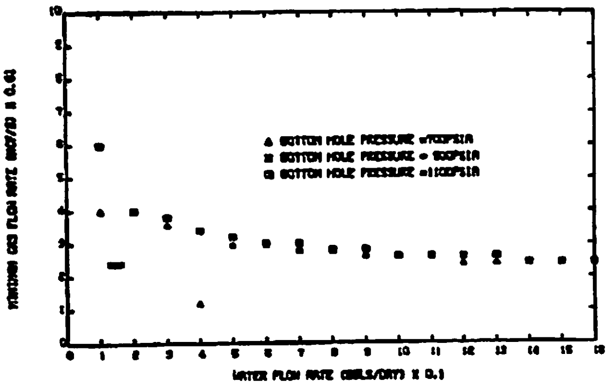


Fig. 11 – Plot for gas S.G. = 0.7; tubing I.D. = 2.441 in.

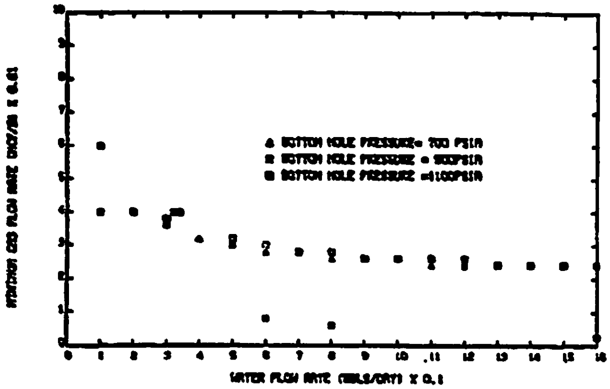


Fig. 12 – Plot for gas S.G. = 0.7; tubing I.D. = 2.347 in.

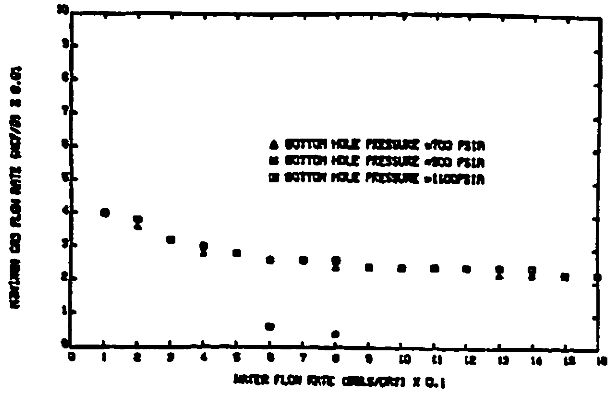


Fig. 13 – Plot for gas S.G. = 0.7; tubing I.D. = 1.991 in.

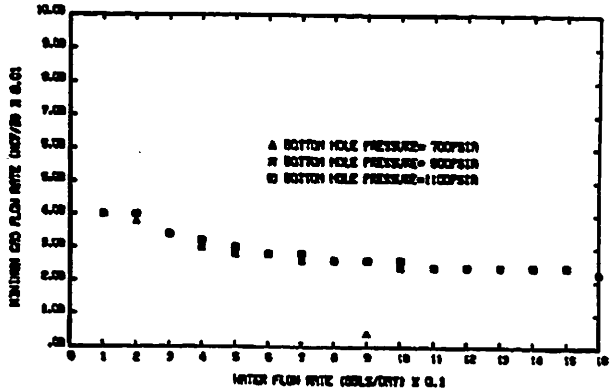


Fig. 14 – Plot for gas S.G. = 0.8; tubing I.D. = 2.441 in.

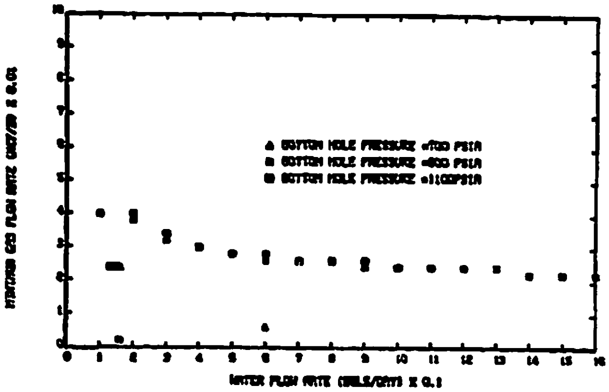


Fig. 15 – Plot for gas S.G. = 0.8; tubing I.D. = 2.347 in.

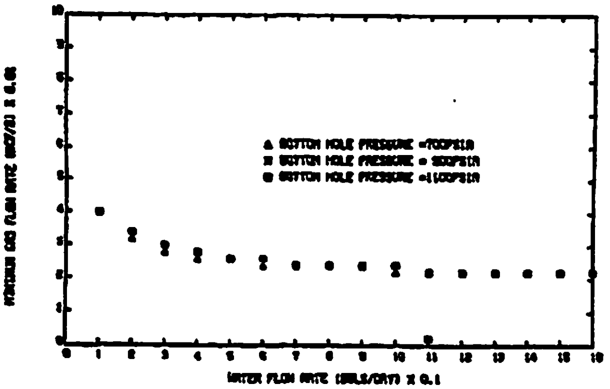


Fig. 16 – Plot for gas S.G. = 0.8; tubing I.D. = 1.991 in.

Engineering "Tool Kit" Descriptions

The Reservoir Engineering **"Tool Kit"** series is a group of 129 worksheet programs developed for the oil and gas professional. The "Tool Kit" programs are designed to perform the calculations that are required while engineering oil and gas properties on a daily basis. Versions of the programs are designed to run on Lotus 123, Quattro Pro, Symphony, Excel, and Excel on the Mac. Anyone familiar with spreadsheet software will have no problems using the "Tool Kit" programs. These programs are currently used by thousands of engineers and other oil and gas professionals. Complete printed documentation is provided with all programs. They represent one of the best values in the oil and gas software business.
Many of the tasks that the "Tool Kit" series allow you to do include:

- **Calculate fluid properties**
- **Calculate oil and gas in place and recoverables from volumetric and pressure information**
- **Calculate abandonment pressures for gas wells**
- **Predict fluid loading problems in gas wells**
- **Predict future well performance from reservoir properties**
- **Calculate the changes in gas volumes that can be expected when evaluating a well for compression**
- **Forecast the oil production from waterfloods or water drive reservoirs under different fluid withdraw rates**
- **Size pumping units**
- **Evaluate the pressures and calculate the gas in place in water drive gas reservoirs**
- **Make log calculations including porosity cross plots**
- **Calculate pressure drops in tubing and flowlines.**
- **Perform well economics**
- **Waterflood calculations**

The following are descriptions of the Petroleum Engineering "Tool Kit" programs.

Economic "Tool Kit" Series

ECONMOD, ECONMOD2 - These programs are full blown economic models for any oil and gas property. It can handle up to 40 years and is comparable to many of the economic programs on the market. These programs calculate well life, economic limit, present worth profiles, RORs and payouts. It also prints yearly cashflow;
ECONSUM - This program works with ECONMOD to allows the summary of many individual lease cashflows;
SUM2 - Used to sum individual cashflows to make a summary file for ECONMOD;
AMORT - Makes the amortization calculation and produces a table;
DISCOUNT - Performs an end of month discounting from annual values;
ECLIMIT - Estimates the economic limit for known production and prices;
EXP3 - This program calculates up to three different declines and generates yearly production schedules that can be imported into ECONMOD;

HYPER, HYPER2, HYPER3 - Solves the hyperbolic constants using three production values. Also generates a 40 year production schedule that can be imported into ECONMOD.

Reservoir Engineering "ToolKit"

Log Calculations

LOG, LOGND, LOGSN - Calculates water saturations from the Archie equation with neutron - density cross plot and sonic - neutron cross plot ;
RWSAL - Calculates formation water salinity and resistivity
SWPOR - Calculates water saturations from SP and porosity
SWPORSS - Calculates water saturations for shaly sands

Pressure Build-ups

BUGAS, BUOIL - Calculates reservoir permeability and skin damage of a well utilizing build-up pressure data;
HORNER - Generates a Horner plot of pressure build-up data and allows the user to pick two pressure points that are used to determine the slope, P 1hr and P*;

Fluid Properties

CWCALC - Compressibility of water
FORMCOMP - Formation compressibility for over pressured reservoirs
GASCOMP - Gas compositional analysis;
GASGRAV - Calculates the gas gravity as corrected for condensate yields.
GASVIS, H2OVIS, OILVIS - Calculates viscosities;
ZFACTOR - Calculates gas compressibility factor;
PBP - Calculates bubble point pressure;
GOR - This program calculates the gas oil ratio for gas condensate reservoirs.

Volumetric and Material Balance Calculations

BHPCUM - Calculates gas in place and recoverable reserves from cumulative gas production and pressures;
BHPOVER - BHP/Z vs cum plot for over pressured reservoirs
BHPTIME - Plots bottom hole pressures vs time
GASMBE - Full gas material balance calculation with water influx;
GASVOL, GASVOL2 - Calculates volumetrics and recoverable reserves for a gas well;
OILMBE - Oil material balance calculations with water influx and gas cap;
OOIP, OOIP2 - Calculates original oil in place from oil properties and reservoir properties;

Production Calculations

CUMGAS - Generates a cum gas versus rate plot
CUMOIL - Generates a cum oil versus water cut plot
DECLINE - Exponential decline calculation. Calculates two remaining parameters after the other three are entered;
DECLINET - Same as DECLINE except allows the user to look at the change in reserves or production rates with either a positive or negative monthly adjustment;
PRODOIL, PRODGAS - These are files for storing monthly production data and generating a semilog plot;

Four Point Calculations

1POINT - Calculates gas well AOF with one test point and the slope from the four point test;
4POINT, HI4POINT, 4POINT3 - Calculate absolute open flow and slope from four point tests for a gas well;

Darcy Flow Calculations

DARCY - Calculates the expected gas rate for initial reservoir, gas properties and bottom hole pressures. **DARCY2** - This program is similar to DARCY except that it calculates the pressure at the formation face based on surface pressure, well depth and tubing ID;
DARCY3 - This is the Darcy equation for a gas well that will solve for the permeability directly from a measured flow rate;
DARCYW, DARCYO - These are Darcy radial flow equations.

Inflow Calculations

GASDEL - Calculates new flow rate with a change in surface flowing pressure;
INFLOW - Generates a plot of bottom hole flowing pressures for different tubing pressures and gas rates; **PSEUDO** - Generates a gas deliverability using the pseudo pressure equations;
VOGELIPR - Calculates the IPR values and curve using the Vogel method;

Bottomhole and Pressure Drop Calculations

OILFLOW, GASFLOW, H2OFLOW - Calculate pressure drops of fluids flowing in pipe;
BHPCALC - Bottom hole calculation for gas wells from shut-in pressure;
BHPWHP - Calculates the bottom hole pressure at the formation face for either a flowing or shut-in gas well;
BHPWHP2 - Calculates the pressure at the well face for a deviated gas well;
FLOWBHP - Calculates flowing bottom hole pressures for a gas well with oil and water production;
DEEPBHP - This program uses the Cullender-Smith method for calculating the bottomhole pressure and allows for wells greater than 12,000 feet;

Waterflood Calculations

CRAIGWF - Produces relative permeability curve and calculates the oil recovery at different water cuts using the Craig method;
CUTCUM - The program predicts the future performance with the option to change future fluid withdrawal rates;
H2O_INJ - Calculates the injection rates in a waterflood well for different waterflood patterns;
OILPERM - Calculates oil well permeability using three producing rates and flowing pressures;
PERMVAR - Calculates the permeability variance factor for up to 100 permeability values. This factor is used in CRAIGWF;
RECOVERY - Similar to APIFORE except uses the Guthrie-Greenberger equation to estimate an oil recovery factor;
RPERMOG, RPERMWO - This program uses the Wyllie equation to calculate the relative permeability curves for oil, gas, and water;
SWEEP - Calculates the sweep efficiencies for different waterflood injection patterns.

Quick Economics

ECONGAS, ECONOIL - A quick economic model that calculates a present worth profile, ROR, DROR, IRR and payout;
ECONGASD, ECONOILD - Similar to ECONGAS/ECONOIL except that the property decline is entered and reserves calculated instead of having the reserves entered directly;

Misc Reservoir Calculations

AFE - This is a drilling AFE form;

APIFORE - Uses the API formula to calculate an estimated oil recovery factor for a waterflood field;

CURVE - Does curve matching of data by linear, exponential, logarithmic, and power functions;

DIRSURV1, DIRSURV2 - Well deviation surveys

GASLOAD - Estimates the minimum required gas rates needed to lift either condensate or water from the wellbore;

LOADUP - This program is similar to GASLOAD but will handle multiple rates;

METRIC - This program makes most of the common English-Metric and Metric-English conversions;

REC_OIL - Uses API method to calculate the oil recovery for a gas drive reservoir;

SCALE - Predicts scale formation of oil field fluids

SLANT - Calculates corrected formation thicknesses based on measured values from logs and well and bed dip;

Production Engineering "ToolKit" Series

Gas Lift Design

AGL_DSN - Finds the gas injection depth and injection pressure to produce various production rates for a gas lift well;

AGL_FLD - Calculates the test rack opening pressure for spring loaded production pressure operated gas lift valves;

AGL_GRAD - Used in gas lift to determine the required total GLR needed and the tubing producing pressure at depths;

AGL_SET - Calculates the test rack opening pressure for nitrogen charged bellows injection pressure gas lift valves;

AGL_SPAC - Used for spacing both injection pressure or production pressure operated gas lift valves;

AGL_TEMP - Calculates the temperature profile for both flowing and gas lifted wells;

Beam Pumping Design

APIRP11L - Designs a sucker rod pumping system using the procedures outlined in API RP 11l;

ROD_FCF - Finds the frequency correction factor for sucker rod design

ROD_TAP - Checks loads for taper sucker rod designs

ROD_GA - Plots a graph of needed BH displacement for gas anchors

Other Calculations

ESP_DSN - An electrical submersible pump design is made using the procedures outlined in API RP 11U;

FREE_GAS - Calculates the free gas at various down hole pressure conditions;

LIFT_SLCT - Economics program to analyze artificial lift selections.

Gas Flow Calculations

GAS_LPD - Calculates the linear flow pressure drop for gas wells producing through a small, short perforation tunnel;

GAS_RPD - Finds the radial flow pressure drop for high rate gas wells flowing through either formation or a gravel pack;

GAS_TCF - Finds pressure drop in a gas well producing through a gravel pack

GAS_VEL - Can be used for predicting erosion and calculating the tubing or surface size lines needed for gas wells. Uses the procedures outlined in API RP 14E;
GAS_IPR - Finds gas IPR and predicts tubing performance for gas wells

Inflow Calculations
IPR_DCL - Predicts IPR decline for oil well in dissolved gas reservoir
IPR_FET - Uses the Fetkovich formula for oil wells to find the production rate vs the flowing bottom hole pressure;
IPR_VOG - The Vogel IPR correlation is used to give a production rate vs the flowing bottom hole pressure;
IPR_DMG - Uses Klims & Majcher method to predict IPR with skin damage.

Tubing Design
TBG_DSN1 - Used to check the design of a single taper tubing string. Checks tension, collapse and burst typical conditions and notes if design acceptable;
TBG_DSN2 - Used to check the design of a two taper tubing string. Checks both tubing tapers;
TBG_MVMT - Checks tubing length and load changes after setting a packer

Oil well flow calculations
OIL_LPD - Finds linear pressure drop through tunnel/tubing in a oil well
OIL_RPD - Finds the radial flow pressure drop in oil wells
OIL_TCF - Finds pressure drop in a oil well producing through a gravel pack
PERM_AVG - Finds Avg permeability for reservoir with multiple permeabilities
PERM_SER - Finds effect on production for series of parallel permeabilities

Misc Production Programs
CMT_DSN - Designs a primary cement job in straight/deviated well
COMPRESS - Calculates # of stages and HP of gas compressor
UND_PERF - Guideline for needed underbalance pressure when perforating

Ordering Information

The **Reservoir Engineering "Tool Kit"** cost $495, **Production Engineering "Tool Kit"** is $295 and the **Economic "Tool Kit"** is $195. There is a 20% discount if all the programs are purchased. With this discount the total package is $790 as compared to $985. Call for special upgrade pricing from older versions of the "Tool Kit" programs. The programs all require spreadsheet software to run. If ordering please specify if you want Lotus 123, Quattro Pro, Excel on PC, or Excel on the Mac versions. Also specify if you want 5 1/4 or 3 1/2" disks. You can order the "Tool Kit" programs through **Integrity Consulting, 6907 N Trailway Cir, Parker, CO 80134, (303) 841-9410.**

Volume discounts and corporate licenses are available for all the "Tool Kit" programs as is upgrades from previously purchased "Tool Kit" software. Please call Integrity Consulting for more information.

Training Opportunities

Integrity Consulting currently conducts two day seminars on computers and the operation of the "Tool Kit" programs in a number of cities. The first day of the seminars are designed for people who are new to the world of PCs. The second day consists of extensive training with the "Tool Kit" programs in making field evaluations. Also available is one and two day in house training on the "Tool Kit" programs.

Running "Tool Kit" with Metric Units

All of the "Tool Kit" programs can be converted to accept and generate metric units. Some programs are unit neutral but most of the programs require that you specify the units needed. Where the units are changed depends on the program. Most of the Production Series have a single entry on the main screen where you can specify which units to use. Most of the Reservoir Series require that you press [Alt][M] to move to a screen that will allow the user to change the units on each input variable. The user would enter either a "Y" if you want metric unit or "N" to use english units. You can either enter the "Y" and "N" in upper or lower case. In most cases you must recalculate (press [F9]) before the new units and labels appear on the screens. You would then need to save the worksheet if you want the units to be used as the default.

The Production "Tool Kit". series has one entry for switching to metric units. The entries are "O" for oilfield units and "M" for metric units.

Marginal Gas Well Production Technology & Techniques

Topics

- Plunger lift design and operation
- Automatic casing swab
- Downhole injection tool
- Sucker rod pump sizing & design
- Velocity string sizing & installation
- Soap stick design & performance

Who should attend?

Any engineer, geologist, lease operator, or manager who is active in the oil and gas industry, specifically in the areas of marginal well operations or old field rejuvenation, should attend.

How will you benefit?

Attendees will be introduced to technology and techniques that can increase the daily gas production from their wells, minimize the investment required to maintain production, and increase the profit from marginal gas wells.

What will you learn?

- **Alternative Solutions**–for marginal gas well production problems, elimination of produced water, low investment solutions, and low operation expense solutions.

- **Design/operation criteria**–for designing, installing and continued operation of plunger lift systems.

- **Case histories**–and development of the automatic casing swab by Sandia National Laboratories in conjunction with Belden & Blake for low volume marginal gas wells with some liquid production.

- **Elimination of produced water problems**–by injecting the produced water downhole without ever bringing the water to the surface, a system currently being tested in the San Juan Basin.

- **Sucker rod pump sizing and design**–using several software packages of varying sophistication and expense. A copy of a shareware software package will be given to each attendee.

- **Velocity string sizing and installation**–the background and development of the method for determining the minimum tubing size for liquid removal from a well, demonstration of different software available to assist in sizing the string, and a copy of a shareware for sizing the velocity string.

- **Soap stick design**–the information required for custom design of the composition of soap sticks for a particular field or well, including case histories of successful applications.

Course Information

Course Schedule

The course will be held on Tuesday, June 24, 1997. Classes will be in session from 8:00 to12:00 am and 1:30 to 5:00 pm.

Location

Classes will be at the San Juan College Fine Arts Building in Room 9006, Farmington, New Mexico.

Fee and Registration

The fee of $25.00 covers the cost of instruction, course notes, reference materials, refreshments, and lunch.

Cancellation/Substitution

A full refund will be made if cancellation notice is received no later than five working days before the course begins, or if the course is canceled. Rather than cancel find someone to take your reservation–they will thank you for it.

For additional information contact:

Robert Blaylock
Phone (505) 835- 5938
FAX (505) 835-6031
e-mail: reb@baervan.nmt.edu

Registration Form

Marginal Gas Well Production Technology & Techniques

June 24, 1997
Farmington, New Mexico

Name

Title

Company

Mailing Address

City

State Zip

Phone

FAX

e-mail:

Payment Option ($25.00)

☐ Check enclosed
☐ Discover Card ☐ Mastercard ☐ Visa
Expiration date:___/19___
No.________ ________ ________ ________

Make payable to:

New Mexico Tech
Petroleum Recovery Research Center
Kelly Building
Socorro, NM 87801
Phone (505) 835-5981 FAX (505)835-6031

Postage Required

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Socorro, NM 87801

PTTC Petroleum Technology Transfer Council

Focused Technology workshop

Marginal Gas Well Production Technology & Techniques

at

San Juan College
Fine Arts Center
Room 9006
Farmington, New Mexico

June 24, 1997

8:00 am- 5:00 pm
$25.00 per person

Engineers, geologists, lease operators and managers: Discover proven methods of maximizing production from your marginal gas wells.

Register Today

Registration includes workshop books, software, and lunch. Workshop is limited to the first 40 registrants.

Sponsored by

Petroleum Technology Transfer Council
Southwest Regional Lead Organization
Petroleum Recovery Research Center

a division of

New Mexico Institute of Mining and Technology
Socorro, New Mexico