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.

<u>Choke Back Your Well to Keep From Loading Up.</u> 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.

<u>It Is Better to Operate a Plunger at a higher casing pressure-- Long Shut-in Times.</u> 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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ACKNOWLEDGEMENTS

The authors wish to express their appreciation to Conoco Inc., especially to Ron Bishop, Daniel Sanchez, and Bill Elmer for providing assistance and support in the publication of this paper; to Randy Thille and Bill Meyers of Ferguson-Beauregard for their assistance in preparing material for the plunger lift classes taught at Conoco locations; and to Brett Thompson, student at Colorado School of Mines, for his assistance in preparing the trouble-shooting guide and maintenance forms presented in this paper.

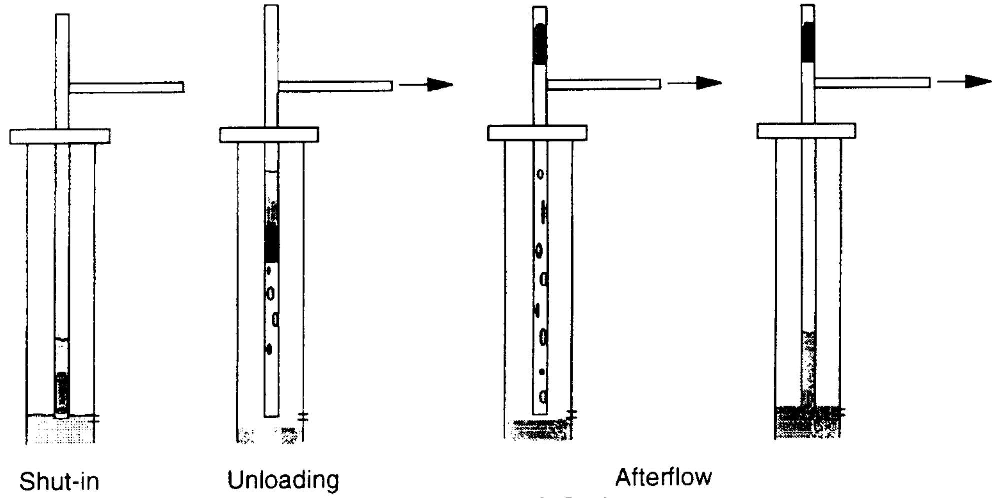

Figure 1 - Plunger Lift Cycles

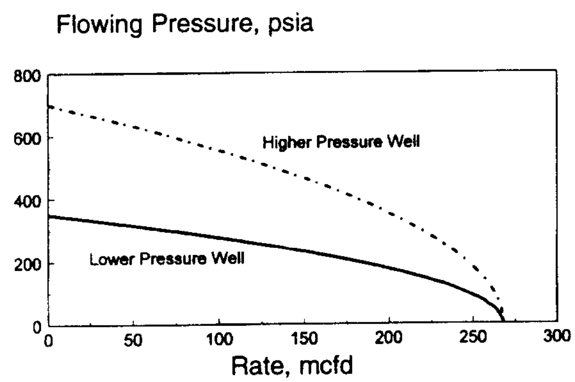

Figure 2 - Typical IPR Curves for a San Juan Gas Well

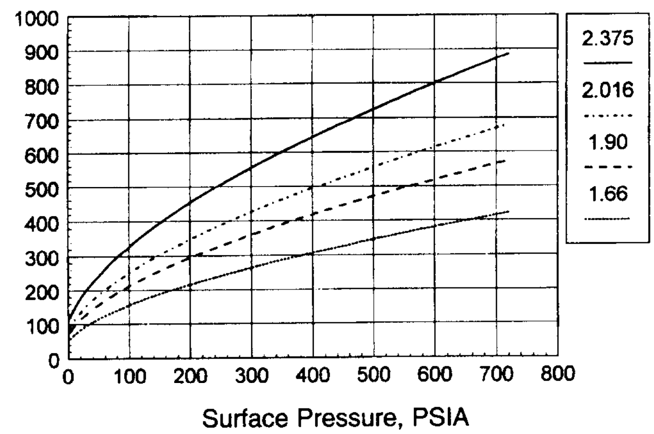

Figure 3 - Turner et al Unloading Rates for Various Tubing Sizes

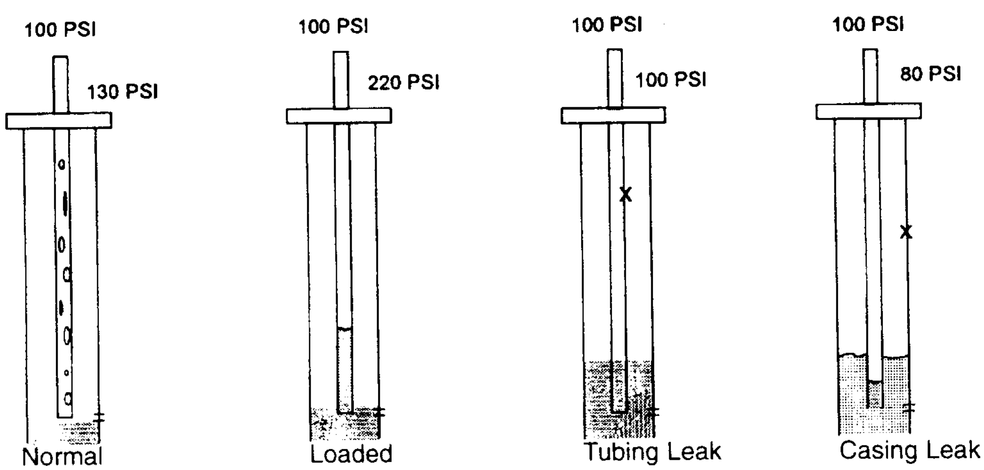

Figure 4 - Tubing and Casing Pressures
What do they mean?

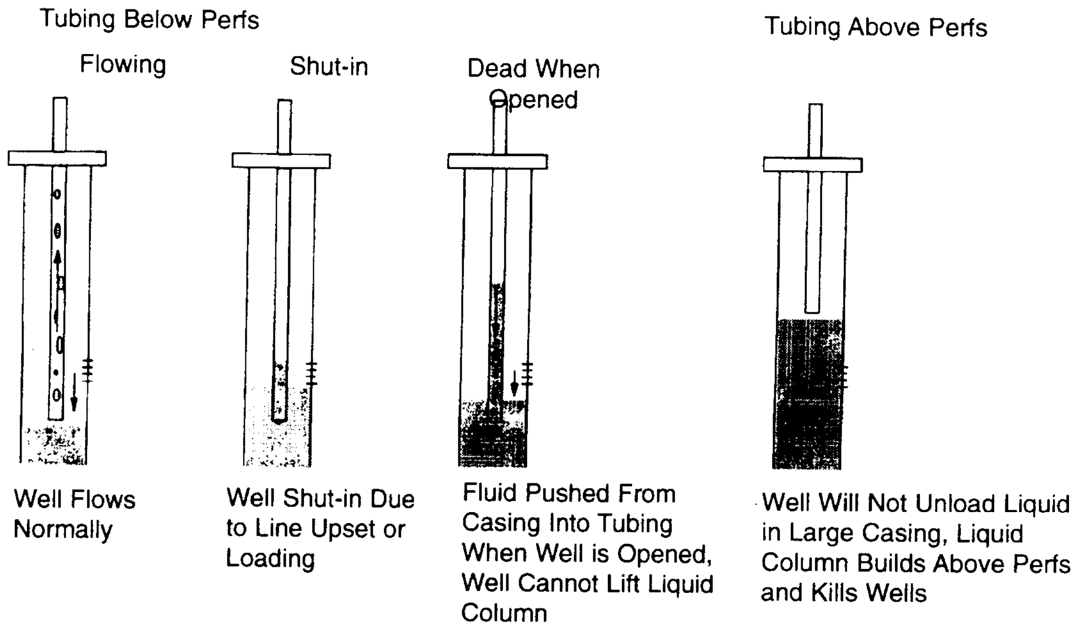

Figure 5 - Effect of Tubing Depth on Gas Wells

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

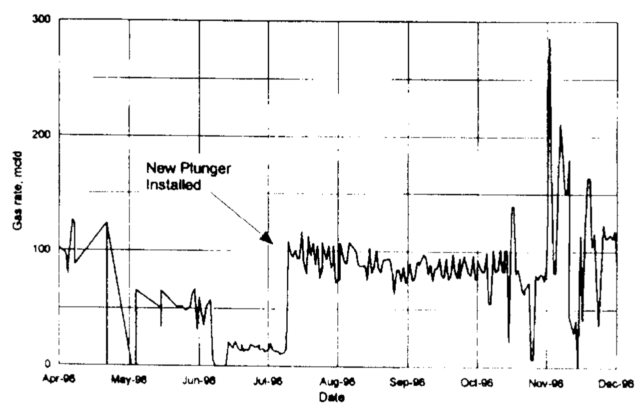

Figure 7 - Effect of Plunger Change on Well Production

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

	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	6	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