

PUMPING FLUMPING SUCKER ROD LIFTED WELLS

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Abstract

The definition of flumping is when a well flows fluid to the surface up the casing annulus, plus at the same time fluids are pumped by the sucker rod pump up the tubing to the surface. Oil wells usually flump due to high producing bottomhole pressure or due to high rates of gas flowing up the casing annulus. In a flumping well the operator must maintain high surface tubing wellhead pressure while pumping or the gas in the tubing can unload too much liquid out of the tubing and pump action will stop.

The most frequently used method to prevent loss of pump action due to flumping up the tubing is through the use of a back-pressure regulating valve. The additional tubing backpressure applies more pressure on the fluid in the tubing, increasing the pump discharge pressure and stabilizing flow in the tubing. Dynamometer and fluid level data from various wells will be presented to identify and troubleshoot the many flumping symptoms.

Introduction

Flumping is when a sucker rod lifted well is flowing fluids to the surface up the casing annulus and simultaneously fluids are being pumped to the surface up the tubing. If an oil well is flumping up the casing annulus and gas entering the tubing through the pump is lightening the tubing fluids, then the tubing fluids may become unstable and unload the liquids from the tubing. Flow can be stabilized by using backpressure on the tubing and/possibly on the casing. The producing bottomhole pressure can be reduced if pump action can be maintained; then the casing pressure can be gradually reduced to see if the well will also flow in a stabilized condition up the casing at the same time the well is being pumped up tubing. Often the operator must maintain high tubing pressure with a back-pressure regulating valve or the gassy conditions in the tubing will result in all of the liquid blowing out of the tubing and pump action stopping. Lack of liquid produced up the tubing at the surface results in reduced lubrication of the stuffing box and possibly damage to the stuffing box packing and a leak. Flumping wells often continue to flump for a long time period until the producing bottomhole pressure is reduced or the gas rate is decreased.

Use of a back-pressure regulating valve on the tubing is a reliable method to prevent the liquids in the tubing from unloading, when the tubing liquids are lightened from gas being pumped into the tubing. The surface tubing discharge pressure is higher when compared to the surface pressure if no back-pressure regulating valve were present. The additional tubing backpressure results in increased pressure on the pump discharge and requires additional horsepower at the pump to lift the liquid to overcome the higher surface pressure. Surging, slugging, or unstable flow up the tubing is the frequent symptom caused by too much gas flowing up the tubing at too low of tubing discharge pressure. If the tubing were to blow dry, then the tubing may need to be initially filled with water to create sufficient discharge pressure and provide the discharge conditions that will allow the pump to initially operate. To determine if a backpressure valve will help an unstable well to be produced continually, a quick test is to close the tubing flow line valve and see if the pump can increase the tubing pressure to approximately 400-500 psig. The idea of using a back-pressure regulating valve on the tubing can be proven, if the closed surface valve can be slightly opened and steady pumping continues. The slightly opened valve will become fluid cut if left cracked open for an extended time period. Since the well continued to pump with a slightly opened flow line valve, then the tubing can most likely be controlled by replacing the slightly opened valve with a backpressure regulating valve.

In some wells with no backpressure applied to the casing, then all of the liquids in the casing annulus may unload. Unstable pumping conditions will result if flumping all of the casing liquids occurs and the lack of liquid at the pump intake results in the pump being starved of fluid entry; if all of the casing annulus liquids are unloaded then gas locking of the pump may result. Even if flumping up the casing annulus appears to be causing problems producing the well, it is usually best to first try stabilizing the well by only adding back-pressure to the tubing.

If the high gas rate flowing in the tubing is resulting in all of the liquids being blown out of the tubing, then the best remedy may be to prevent the gas from entering the pump. If a downhole gas separator is used then the casing must be open to the flow line and the casing gas must be vented at the surface through a check back into the flow line. If the casing valve is closed, then all gas is produced through the pump and any type of downhole gas separation will not be effective. When gassy fluids are encountered, if possible set the pump below the perforations. Using a cased

interval below the perforations, rat hole, is the best type of downhole gas separation possible. If a dead space below the bottom perforations is not available, then the pump should be set as deep as possible in the casing and an improved offset high capacity downhole gas separator² should be ran. If your well has a rat hole, be sure to clean out any debris in the wellbore before placing the pump below the perforations. Downhole gas separators do not separate gas in solution in the produced liquids, but only separate the free gas from the liquids at the pump intake.

If flow into the pump through the standing valve is restricted, then the additional pressure drop can occur from the well's intake pressure to the pressure inside the pump barrel. This pressure drop will cause gas to breakout of the fluids entering the pump. Two standing valves can result in extra pressure drop into the pump and using double standing valves on gassy wells should be avoided. Special standing valve/cages can be ran having increased flow clearance through the cage which allows for high flow rates without excessive pressure drop into the pump.

Do not run a long section of tail pipe! Use of tail pipe guarantees any gas in solution at the tail pipe intake pressure is trapped and will result in free gas inside the pump. This type of gas interference due to gas evolving from solution at the lower pressure is worsened as the tail pipe intake vertical depth is set at farther distance from a shallower pump depth.

Production methods used to produce flumping wells are: 1) set the pump intake as deep as possible. 2) set the pump intake in the rat hole, if one exist, 3) if no rat hole, run an improved downhole gas separator 4) Use a specialty pump such as a VSP pump to handle gas, 5) Increase pump compression ratio with a longer stroke length, 6) space out the pump to minimize dead space at bottom of stroke to increase compression ratio to the maximum, 7) Use a backpressure valve on the tubing 8) sometimes a backpressure valve is required on casing. Dynamometer and fluid level data from various wells will be presented to identify and troubleshoot the many flumping symptoms listed above. In addition to no pump action, flumping up the tubing can result in damage to the sucker rod equipment and may results in reduced run life due to increased rod-on-tubing wear.

Identifying Flumping Well

Fig. 1 displays dynamometer and fluid level data collected on a sucker rod pumped well while gas and liquids were flowing to the surface up both the tubing and the tubing/casing annulus. The tubing/casing annulus fluid level was determined to be very near the surface. The dynamometer data shows the pump action to be poor with a production rate of 1 BOPD and 9 BWPD having decreased significantly from the initial flowing conditions of 600 BWPD and 200 BOPD. The pump card is applying little load to the rods due low differential pressure acting across the traveling valve on the upstroke, this type of data is common when the tubing conditions have become unstable from a flumping well or from a well when too much gas is being pumped into the tubing. The procedure to determine the gas flow rate when shooting a fluid level is to close the casing valve to stop all flow from the annulus down the flow line as fluid continues to be produced up the tubing. Free gas at the pump intake bubbles up through the gaseous liquid column and collects in the known annular volume between the casing and tubing. The change in casing pressure with respect to time is recorded. The annular gas flow rate is calculated from the annular volume and pressure buildup rate.² A well producing a lot of gas up the casing annulus is easy to identify based on the rapid casing pressure build-up plus a high gaseous fluid level. The light 0.134 psi/ft tubing fluid gradient is an indication of a high percentage of gas in the tubing and the narrow gas interference pump card indicates the pumping action is providing little energy to lift fluids to the surface. This well has both high producing bottomhole pressure and too high rates of gas flowing up the tubing and tubing/casing annulus. This well requires addition of backpressure to the tubing to regain pump action.

Set the Pump Below the Bottom of the Perforations

Too much gas produced up the tubing and the resulting unstable pump operation is frequently caused by gas interference as a result of poor down hole gas separation^{3,4}. Poor down hole gas separation can be identified through the use of an acoustic liquid level instrument and a dynamometer. If the liquid level measurement indicates a high gaseous liquid column above the pump, yet the dynamometer indicates no pump action, then there may be a problem with down hole gas separation. Correcting down hole gas separation problems results in increased system efficiency, increased production, reduced runtime, lower electrical costs and reduced maintenance^{5,6}.

The preferred method of down hole gas separation should be to set the pump intake below the fluid entry zone. If the pump is set above the fluid entry zone then a gas separator should be used that has an efficient gas/liquid

separation chamber with low dip tube friction loss. This type of separator should result in complete pump fillage if sufficient liquid inflow from the formation is available.

If the pump intake depth is placed a few feet below the bottom of the fluid entry zone, then efficient gas separation will occur in the annulus without using an extension below the seating nipple. In the case the casing acts as the outer barrel of the separator. A perforated tubing extension, sometimes called a mud anchor, can be used. This extra joint of tubing allows the operator to tag the bottom below the perforations to determine if debris fillage is present without forcing debris into the seating nipple. The extension can be a perforated sub or a joint of tubing below the perforated sub. A bull plug is usually used below the bottom collar; however the bottom of the tubing can be orange-peeled to prevent sticking in fill. A dip tube is commonly run below the bottom of the pump. Using a dip tube when the pump intake is set below the bottom of the perforations is not needed since it increases friction losses and results in less efficient gas separation.

When setting the tubing intake below the perforations and the liquid capacity of the tubing sized separator does not exceed the pump capacity, then a higher capacity separator should be used (see reference 2). In this case to increase the separation area between the inner diameter of the casing and outside diameter of the dip tube, nothing is attached to the tubing below the seating nipple and a small diameter dip tube is run below the pump. The dip tube should be sized such that the friction loss within the dip tube is low. The dip tube should extend at least ten feet below the bottom of the fluid entry zone. Using only a dip tube increases the liquid capacity by providing a greater gas separation area, than the area between the tubing at the pump and the casing. Gas bubbles rise about 6 inches per second in water and most low viscosity oils, so the liquid capacity is approximately 50 barrels per day per square inch of annular area.

Set the Pump Intake As Deep As Possible

The well in figure **Fig. 1** had the pump intake depth set at 4510 feet with a pump displacement of 350 BPD. The tubing was set high in the well above the four zones of perforations from 8376 through 8428 feet, because the well would initially flow at a high rate. Other well conditions can prevent placing the pump below the fluid entry zone. Conditions such as insufficient rat hole, drilling department did not drill a rat hole, fill problems from produced solids, liners, and undersized pumping units may require setting the pump intake above the fluid entry zone. Setting the pump above the fluid entry zone requires different design considerations for the down hole gas separators. There are several gas separator designs that are suitable in this situation.

The most commonly used gas separator is the conventional or “poor boy” separator. This separator is relatively inexpensive, yet can be efficient if properly designed and sized. This separator is typically built from standard oilfield tubing and perforated subs. It consists of fluid entry section such as a perforated sub, an outer barrel such as a joint of tubing with a bull plug on bottom and a dip tube on the bottom of the pump. The downward fluid velocity between the outer barrel and the dip tube should be less than 6 inches per second. Gas bubbles rise approximately six inches per second and downward velocity less than this is required to insure that the free gas will be liberated from the produced fluids. Another design consideration must be the area between the outer barrel of the separator and the casing. Gas flow velocities in excess of approximately ten feet per second will lift the liquid and mist flow will carry gas and liquid into the tubing. The annular area must be sufficient to allow liquid to enter the separator by maintaining a gas velocity below the critical rate and preventing the occurrence of mist flow.

A “poor boy” downhole gas separator was installed prior to collecting the data on the well shown in **Fig. 1**. The separator had been constructed using a 4 foot slotted perforated pump joint and a 18 foot 1 inch dip tube, this configuration resulted in 3.9 square inches of flow area with a 195 BPD liquid capacity. In this well the gas separator 195 BPD liquid capacity was less than the 350 BPD pump capacity, the under-sized gas separator resulted in liquid and large volumes of gas being pumped into the tubing.

Use Improve Gas Separator

Thin wall pipe can be used instead of conventional oilfield tubing to manufacture the outer barrel. The outer barrel should also have the same OD as the tubing collar. Conventional tubing generally has heavy walls and is upset at the collar connections². These conditions reduce the liquid capacity of the tubing by reducing the cross sectional area between the dip tube and the outer barrel. The use of collar-sized thin wall pipe results in a greater area between the dip tube and the outer barrel. This increases liquid capacity by reducing the downward liquid velocity in the separator.

The use of large fluid entry ports instead of a perforated sub improves the efficiency of the gas separator. The large ports result in a gravity feed of the liquid from the casing annulus to the gas separator resulting in more liquid and less gas entering the separator. Generally, four large ports are used. The area of each port is sized to be the same as the area between the dip tube and the outer barrel of the separator. A properly sized 2 7/8" improved gas separator has a liquid capacity of 415 BPD which is greater than the pump displacement in the well shown in **Fig. 1**, but this type of separator was not ran.

Use a Backpressure Regulating Valve on the Tubing

When the pumping conditions shown in **Fig. 1** are encountered, there may be little that can be done to improve the operation of the well without pulling the equipment and re-running a modified downhole design. If the pull and re-run option is not available, then the operator may only be left with the option of putting a back pressure valve on the tubing. Increasing the tubing discharge pressure using a backpressure valve can prevent flumping up the tubing and can result in more consistent pump action. **Fig. 2** is a diagram for a backpressure regulating valve. The compression force on the spring is increased by tightening a bolt to apply a force as pressure acting against the tubing flow. A pressure gage can be mounted to observe the increase in tubing discharge pressure as the bolt is tightened. The spring force from the back pressure valve is used to exert pressure on the fluids at the tubing discharge and maintain a higher constant tubing pressure. Increased tubing pressure 1) reduces the size of the gas bubbles in the tubing, 2) increases the tubing fluid gradient, 3) increases the tubing discharge pressure, and 4) keeps some gas in solution in the produced oil. The down hole sucker rod pump maintained pump action because increased tubing pressure prevented gassy fluid from blowing the tubing "dry" and maintained a constant discharge pressure on the pump.

Table 1 summarizes the results of adding back pressure to the tubing on the well shown in **Fig. 1**. Increasing the tubing discharge pressure in steps of 250 psig from 250 psig to 1000 psig through use of a back pressure regulating valve resulted in: 1) increased the tubing fluid gradient, 2) increased the fluid load applied by the pump to the rods by 66.6 %, 3) increased polished rod horsepower, 4) increased the load on the prime mover, 5) reduced the plunger effective stroke length due to increased static stretch, and 6) reduced the effective pump displacement by 23%. The increased polished rod horsepower is equivalent to an increased load on the prime mover, the 39.7% increase in polished rod horsepower resulted in a reduced pumping speed of (8.8-6.3) 2.5 strokes per minute. The pumping speed with the 1000 psi tubing discharge pressure was 81.4% of the pumping speed at 250 psig of tubing discharge pressure. The increased back pressure on the tubing appears to have stabilized the tubing fluid gradient and allows the well to be pumped with the sucker rod pump, but all of the other changes discussed in this paragraph result in increased loading and potentially higher operating cost to pump the well.

From **Table 1** both surface and pump cards are displayed in **Fig. 3** for back pressure of 250 and 1000 psig. The peak load, load range, and surface and pump horsepower are much higher for a back pressure of 1000 psig when compared to the same parameters for a back pressure of 250 psig. The fluid load applied to the rods by the pump increased by a factor of 1.666 when the pump load increased from 2337 lbs to 3893 pounds. But, the percentage rod loading of the top 7/8 inch diameter rod of the allowable stress range by API modified Goodman only increased from 40.1% at 250 psig to 43.3% at 1000 psig, due to the higher allowable stress range at the lower minimum stress from the 1000 psig back pressure. In this well even though there was a large increase in the rod loading as the back pressure increased, there was almost no change in the percent stressed of allowable API Goodman allowable stress range. When the pump intake pressure is high the addition of back pressure to the tubing has minimal impact on the allowable rod stress as shown by the data on this well. But once the well has been produced for a period of time and the pump intake pressure is low, then the back pressure should be removed or reduced. When the pump intake pressure is low, then extra or unnecessary back pressure may result in overloading of the rod string and result in inefficient operation of the sucker rod system.

Conversion of a Flowing Well to Sucker Rod Lift

Fig. 4 displays an initial fluid level and dynamometer survey collected at the time sucker rod pumping began, immediately after the well was converted from a flowing oil well to a sucker rod artificial lift installation. When this data was collected the pump was full of liquid, pumping at a speed of 5.7 SPM, and producing 180 BOPD, 25 BWPD and 200 MscfD. After the initial dynamometer survey the pumping speed was increased in 7 SPM. 5 days after the initial dynamometer data was collected, the follow-up data in **Fig. 5** was collected showing a high fluid

level, incomplete pump fillage, and very little pump load is being applied to the sucker rods. The follow-up data shown in **Fig. 5** was acquired 5 days later that the data shown in **Fig. 4**, over this 5-day time period the sucker rod pump had produced all of the kill fluid and the well had began to intermittently flump up the casing, pump up the tubing, and sometimes unload the tubing fluid. The sucker rod pump was having problems maintaining pump action, with the well flowing liquids up both the tubing and the tubing/casing annulus. The series of pump cards shown in **Fig. 6** show sporadic pump action; sometimes gas interference, sometimes delayed closing of the traveling valve at the beginning of the stroke, and finally at the end of the series of data no pump action. The well was pulled due to the difficulty in maintaining pump action, then equipment was re-ran with an improved down hole gas separator and a Harbinson-Fisher, VSP®, Variable Slippage pump. Once the VSP® pump was spaced out properly and 300 psig of back-pressure was maintained at the surface, then the well could be pumped with out problems. **Fig. 8** shows the dynamometer and fluid level data acquired on the well 7 months after the VSP® pump had been ran. The fluid level was at the pump intake and the pump was approximately 50% filled with liquid. The next operational change that should be made would be to match pump displacement to the inflow from the formation. The reduction in pump displacement will increase the efficiency of the pumping system and prevent excessive operational cost due to pumping off the well.

Pumping Gas into the Tubing with a Variable slippage Pump

A diagram showing the operation of the Harbinson-Fisher Variable Slippage pump is shown the **Fig. 9**. The VSP® has a tapered pump barrel at the top of the pump where the clearance between the plunger and the barrel increase as the plunger moves higher into the tapered section of the barrel. Notice the right side of the pump card in **Fig. 7**, this pump card shape is typical for a properly spaced VSP®. Notice the sudden drop in load as the VSP® enters the taper and the plunger “uncorks” from the barrel, this release in pump load results in longer pump stroke due to overtravel. The following steps must be taken to properly space out the VSP® at the well site:

- a. Touch bottom with tubing loaded with fluid
- b. Pick up overtravel length
- c. Pick up spacing allowance, normally 12"
- d. The lower end of the plunger should slightly enter the start of the VSP® taper. This position gives the least amount of bypass slippage. After well has stabilized, space the plunger higher in small increments for more bypass slippage to achieve desired results.

Re-space well as needed after stabilized:

- a. Lower rods for a light tag at pump, then raise slightly for stroking close to bottom without entering VSP® taper.
- b. After accomplishing raise rods in 6 inch increments until bottom of plunger enters taper.

To achieve the stabilized pump action as shown by the pump card shape of **Fig. 8** required several changes to the pump spacing. The VSP® pumps gas into the tubing and the gassy fluid in the tubing changes the tubing fluid gradient and increases the static rod stretch, but reduces the fluid load applied to the rods by the pump. Additional back-pressure must be applied to the tubing or the gassy tubing fluid can result in the liquids flumping up the tubing. Drawing the well down under the stabilized pumping conditions displayed in the **Fig. 8** would have been difficult to achieve without using the VSP® and back-pressure regulating valve.

Summary and Conclusions

Gassy wells are difficult to produce when using sucker rod lift equipment, due to both gas interference problems in the pump and due to unloading the tubing fluids when the tubing fluid gradient becomes too light. Using a back-pressure regulating valve on the tubing of a gassy well was shown to improve the performance of the sucker rod pumping system. Application of too much back-pressure can be detrimental to the operation of a sucker rod lifted well. Back-pressure should be removed or decreased as the gassy conditions in the well decrease. Wells that will flump up the casing annulus at the same time maintaining stabilized pumping up the tubing can produce more liquids than pumping up tubing alone. Use of downhole gas separators did not keep gas out of the tubing, when downhole pumping conditions exceed the capacity of the gas separator. A VSP® was used to effectively to drawdown the bottom hole pressure.

Following are the recommended procedures to use to produce flumping oil wells with sucker rod pumping systems:

1. Set the pump intake as deep as possible.
2. Set the pump in the rat hole, if one exist
3. If no rat hole, run an improved gas separator

4. Increase pump compression ratio with long stroke length
5. Space out the pump to minimize dead space at bottom of stroke
6. Use a specialty pump such as a VSP® pump to handle gas.
7. Use a backpressure valve on the tubing and sometimes on casing, if pump action erratic or stops.

References

1. McCoy, J.N., Podio, A.L. and Huddleston, K.L.: "Acoustic Determination of Producing Bottomhole Pressure," paper SPE 14254 presented at the 1985 SPE Annual Technical Conference and Exhibition, Las Vegas, NV, Sept. 22-25.
2. McCoy, J.N. and Podio, A.L.: "Improved Down hole Gas Separators," presented at the Southwestern Petroleum Short Course, Lubbock, TX, Apr. 7-8, 1998
3. Clegg, J.D.: "Understanding and Combating Gas Interference in Rod Pumped Wells" Oil and Gas Journal, April 29, 1963
4. Clegg, J.D.: "Gas Interference in Rod Pumped Wells", World Oil, June 1979
5. Ryan, Jeff: "Production Optimization Through Improved Down hole Gas Separation", Proceedings of the Southwestern Petroleum Short Course, Texas Tech University, April 1994
6. Clegg, J.D.: "Another Look at Gas Anchors", Proceedings of the Southwestern Petroleum Short Course, Texas Tech University, April 1989

Table 1 – Summary of Adding Pressure to the Tubing by Using a Back-pressure Valve

Tubing Head Pressure (Psig)	Estimated Tubing Fluid Gradient (psi/ft)	Fluid Load on Pump (Lbs)	Polished Rod HP	Strokes per Minute	Effective Pump Disp. BPD
250	0.160	2337	6.3	8.74	381.0
500	0.187	2700	7.7	8.14	334.1
750	0.202	3461	8.9	7.83	312.4
1000	0.202	3893	8.8	7.11	293.4

Ratio 1000 to 250	1.666	1.397	0.814	0.770
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Figure 1 – Well Flowing off Tubing and Casing with Fluid Level at/near Surface: Poor Pump Action & Low Production Rate

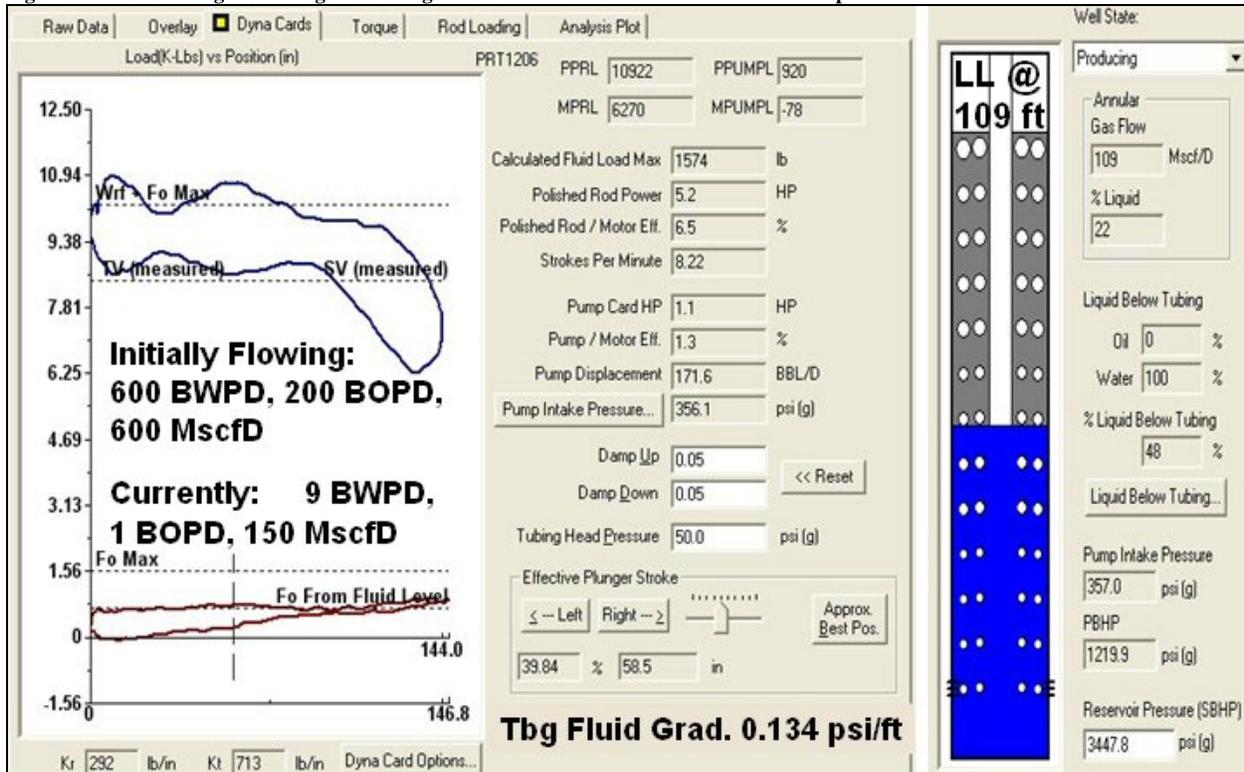


Figure 2 – Backpressure Regulating Valve

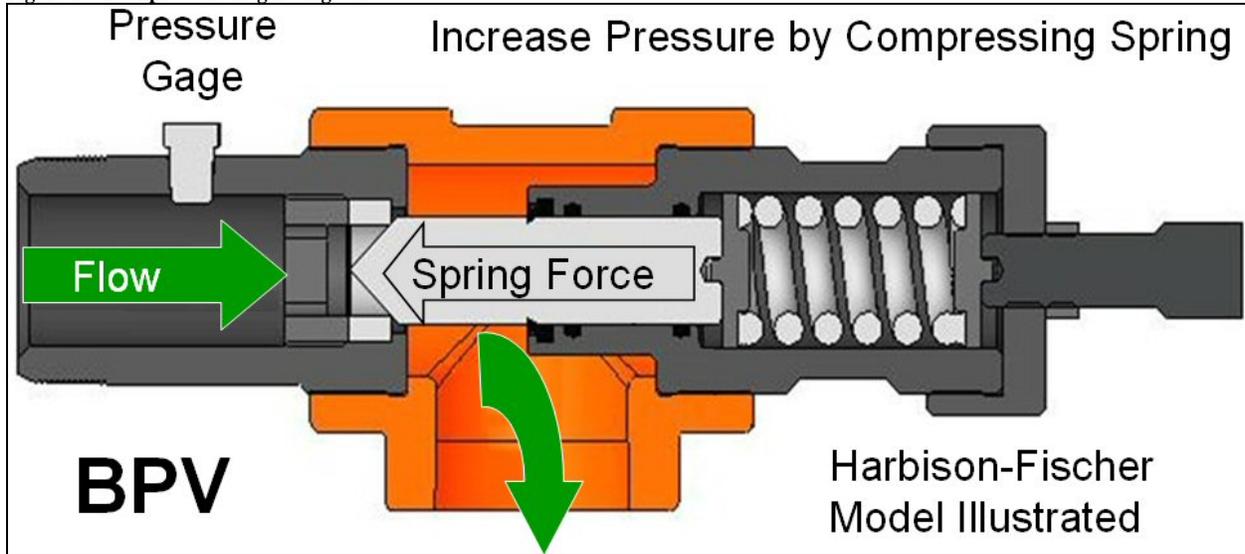


Figure 3 – Compare Dynamometer Cards of 250 to 1000 psig of Backpressure

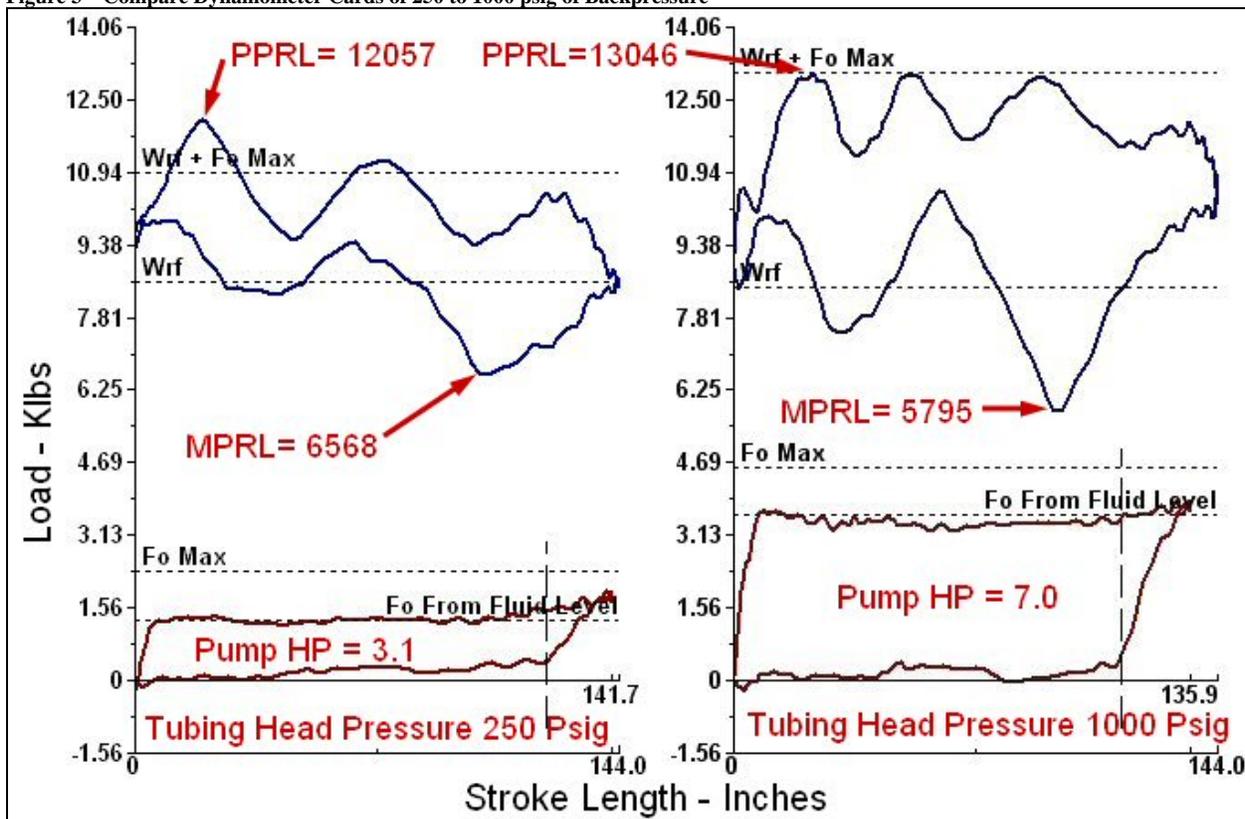


Figure 4 – Initial Fluid Level and Dynamometer Data Collected at Initiation of Sucker Rod Lift

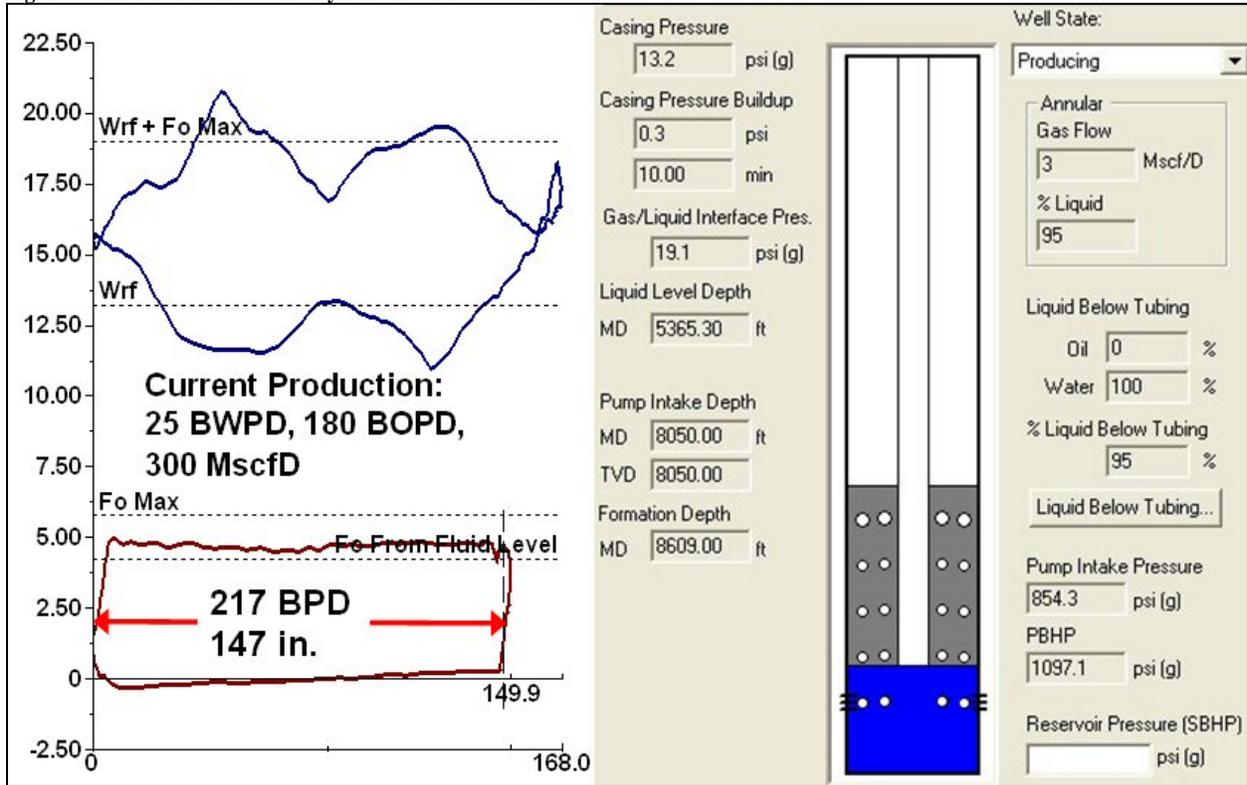


Figure 5 – Follow-up Fluid Level and Dynamometer Data Collection 5 Days After Initiation of Sucker rod Pumping

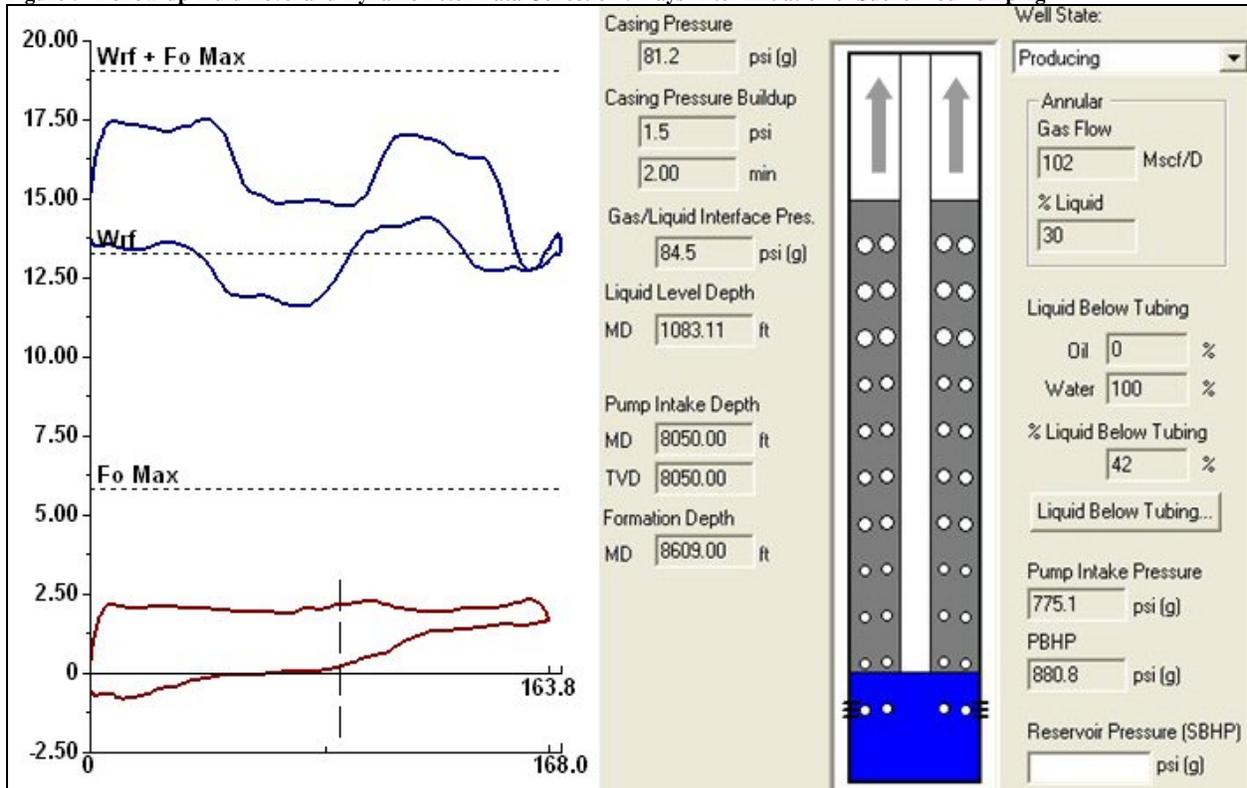


Figure 6 – Sequence of Pump Cards Showing Unstable Pump Action

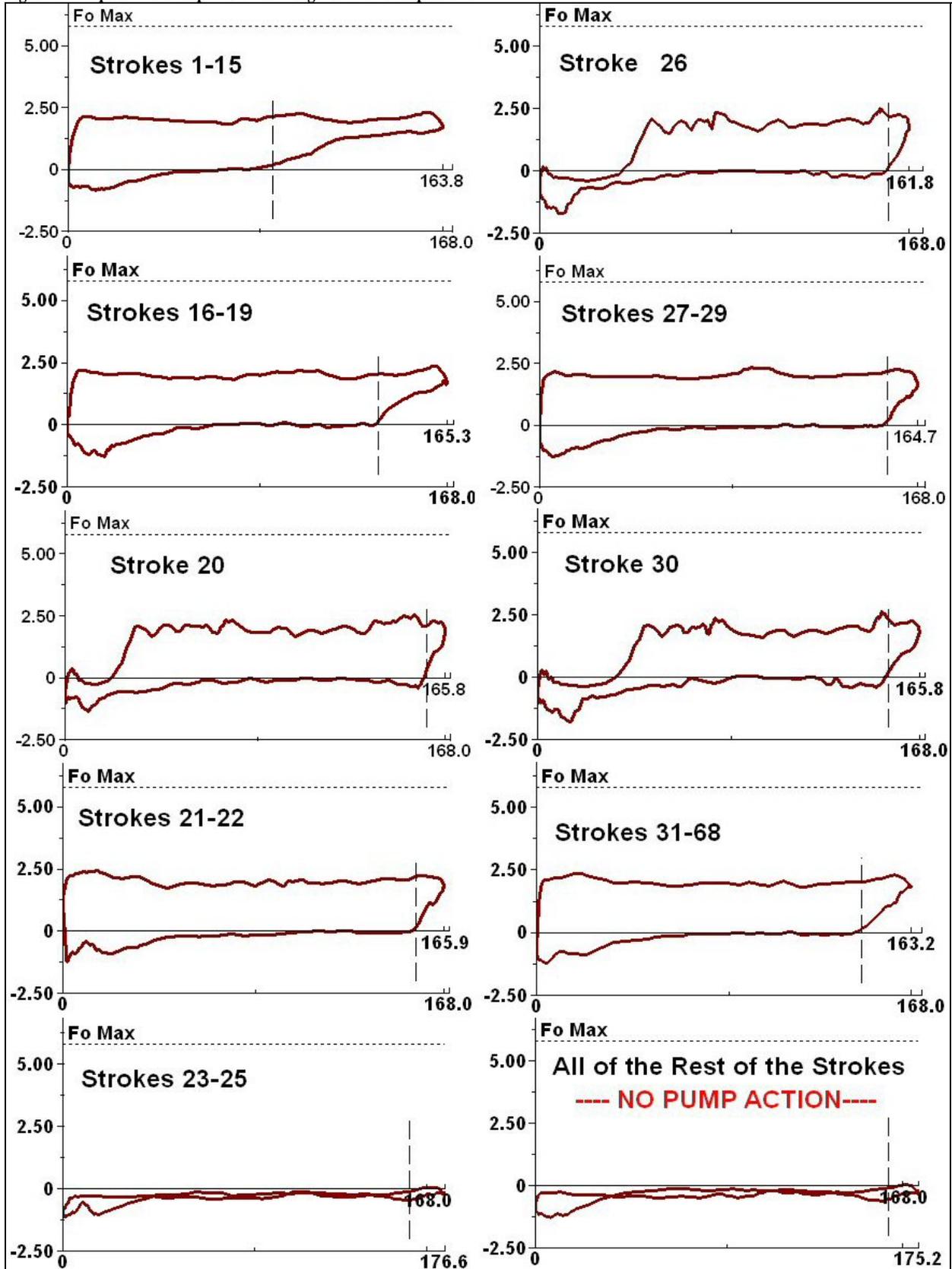


Figure 7 – Dynamometer and fluid Level Data after Variable Slippage Pump and Improved Downhole Gas Separator Installed

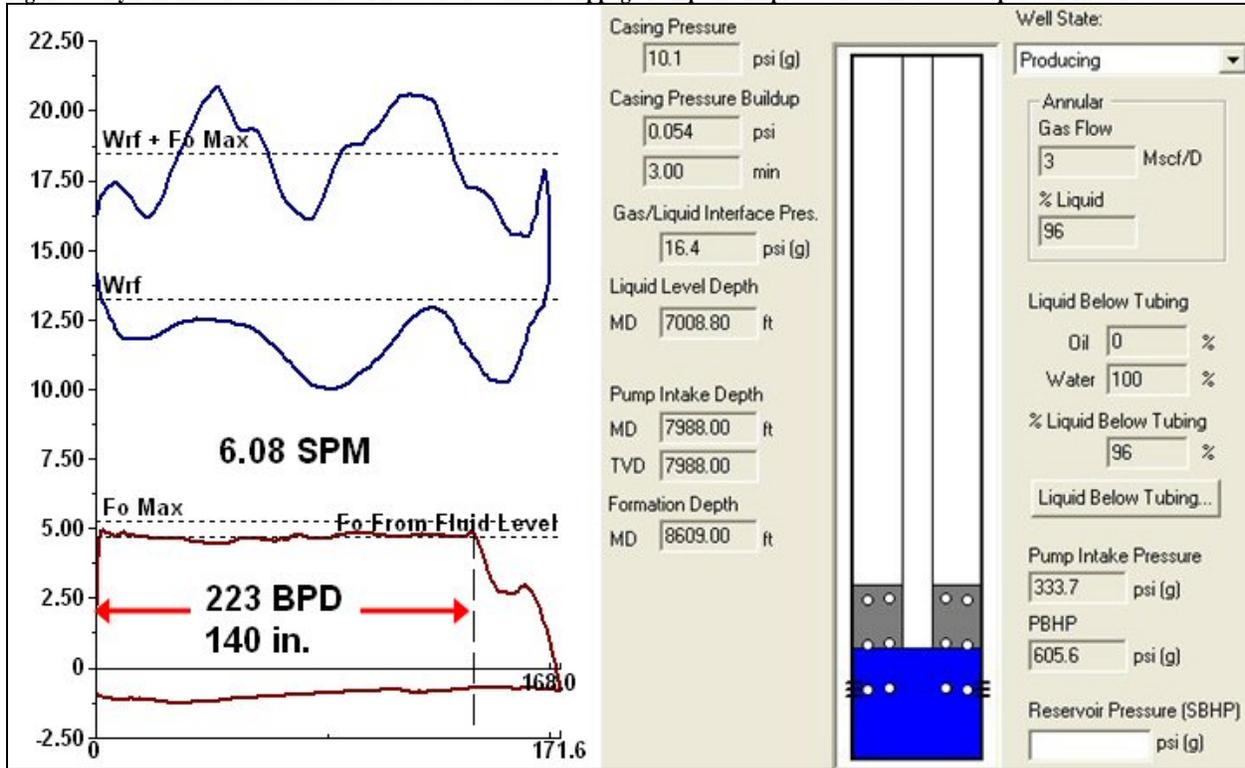


Figure 8 – Dynamometer and Fluid Level Data Seven Months Later

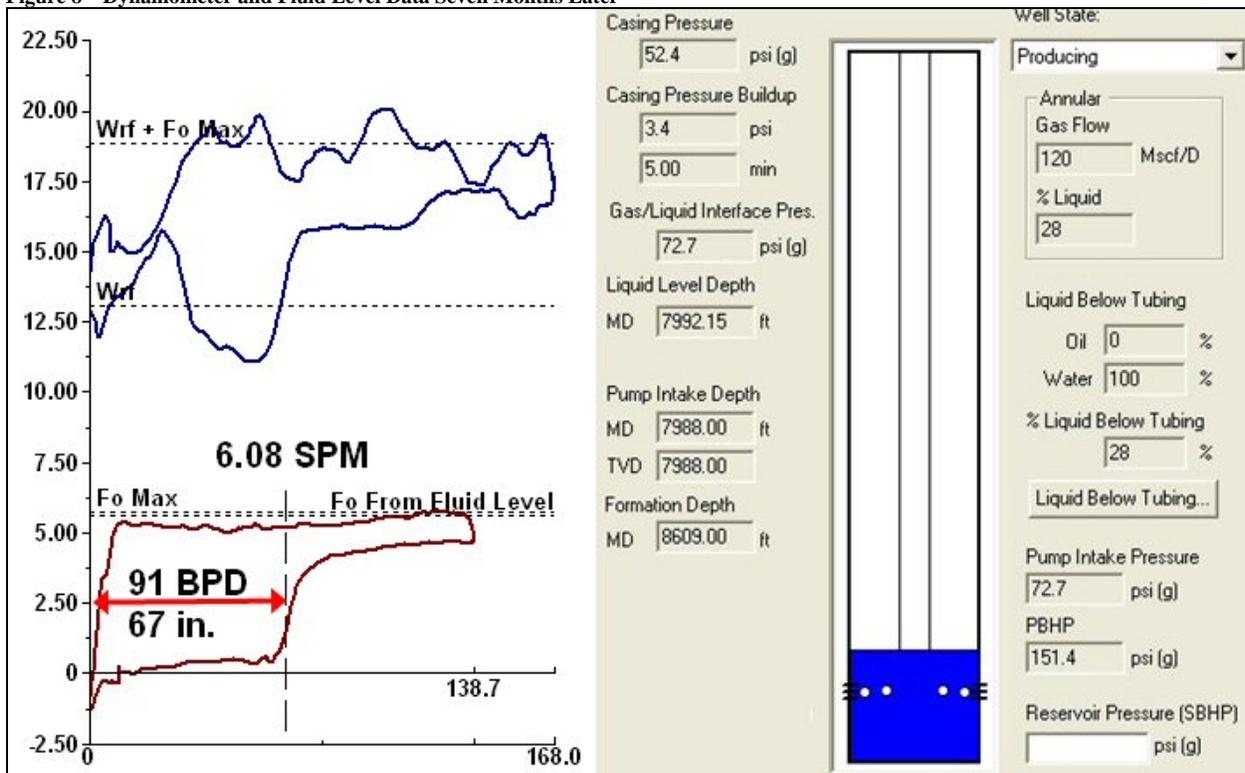


Figure 9 – Harbin-Fisher Variable Slippage Pump

