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Acoustic Liquid-Level Determination of Liquid Loading in Gas Wells

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Abstract

Acoustic liquid level tests are performed successfully on many different types of wells throughout the world. The most common application of an acoustic liquid level instrument is to measure the distance to the liquid level in the casing annulus of a well. A less common technique is acquiring an acoustic fluid level by "shooting" the well down the tubing. The results from this type of test on a gas well can be used to determine 1) the amount of liquid and backpressure on the formation, 2) the gas rate into tubing, 3) the equivalent fluid gradient below the liquid level, and 4) the flowing bottom hole pressure. In this paper, surface acoustic data (via shooting down the tubing) and bottomhole data were acquired simultaneously to confirm the calculated results from the acoustic data. The benefit of using the portable fluid level instrumentation is such that it permits a simple cost effective test to be conducted quickly to immediately identify underperforming gas wells due to liquid loading problems. The information obtained during this straightforward test provides critical data in determining the well's potential and the ideal artificial lift technique. Fluid level instruments can be used to inexpensively determine liquid loading and its severity for gas wells as opposed to traditional methods, which are more intrusive and costly.

Introduction

According to 2004 statistics[1] from the Department of Energy in the US there are 385 thousand natural gas wells producing on average of 126 thousand standard cubic feet of gas per day per well. On average these gas wells are at a stage in their life where the volume of gas being produced continues to decline and all of the liquids are not being lifted to the surface. Very few of these gas wells produce completely dry gas; liquids may be produced from the reservoir and/or both condensate and water can condense as the temperature and pressure decrease as the gas flows to the surface. In the early stages of a gas well's life the flow rate is often high enough that the produced liquids are removed from the wellbore and carried to the surface by the high gas velocity. In the later stages of the well's life liquid accumulates in the bottom of the well as the gas flow rate declines and the gas velocity becomes too low to remove the liquid. As the liquids accumulate in the wellbore additional pressure is applied to the formation and this increased pressures reduces the gas flow from the formation and in some wells the liquid loading bach pressure will increase until eventual all of the gas flow from the well stops.

Flowing gas wells may be characterized as falling in one of three types as illustrated in **Fig. 1**. In the first case (Type 1) any liquid being produced with the gas or condensing due to temperature and pressure changes is uniformly distributed in the wellbore. The gas velocity is sufficient to continuously carry liquid as a fine mist or small droplets to the surface and sufficient to establish a relatively low and fairly uniform flowing pressure gradient. In the second case (Type 2) the gas velocity is not able to uniformly carry sufficient liquid to the surface resulting in a higher percentage of liquid accumulating in the lower part of the well. The flowing pressure gradient will show dual values, a low gradient (close to that of the flowing gas) above the gas/liquid interface and a higher gradient in the lower section of the well. In the lower section of the well the flow is characterized as practically zero net liquid flow with gas bubbles or slugs percolating through the liquid and then gas flowing to the surface. Some of these wells may periodically unload liquid from the bottom of the well. As the gas rate is further decreased, even to the point close to ceasing, the concentration of liquid at the bottom of the well increases to more than 90%, while discrete gas bubbles are flowing through the liquid. The Type 3 well diagram represents this condition when there is practically no fluid flowing into the wellbore. Type 3 also includes wells that have been shut-in for an extended time. In shut-in wells the combination of the tubing head gas pressure plus the gradient of the liquid column may temporarily exceed the reservoir pressure causing liquid to back flow into the formation.

Knowledge of the flowing gradient and fluid distribution in the well is of paramount importance in determining whether inflow from the formation is being restricted by excessive liquid in the flow string, thus requiring application of some deliquifying technique such as installation of plungers, pumps, or redesign of the flow string to increase gas velocity. For further details on liquid loading of gas wells please refer to the papers by Turner[2] for high pressure gas wells, and article by Coleman[3] for lower pressure gas wells.

Acoustic fluid level tests are designed to determine which flowing gradient conditions exist in a well by performing a series of fluid level and surface pressure measurements while the flow at the surface is stopped for a length of time sufficient to identify the behavior and distribution of the fluids in the flow string. The advantages of this technique over wireline flowing pressure surveys include lower costs and lower risks (safety and potential remedial operations) since it is not necessary to introduce measurement tools in a flowing well.

Acoustic Fluid Level Survey

An acoustic fluid level survey may be conducted to determine the depth to the fluid level and the pressure distribution in a flowing gas well. Generally the acoustic fluid level survey down the tubing is acquired while the well's flow is momentarily shut-in. The measured values are used to determine the extent of liquid loading of the well and may be used to optimize the production performance. The principal objective of the acoustic measurements in a flowing gas well is the determination of the quantity of liquid that is resident in the tubing (or annulus when the tubing is used for deliquifying the wellbore by means of a pump) and whether the liquid is uniformly distributed over the length of the wellbore in a mist or annular flow pattern or has fallen back, accumulating towards the bottom of the well.

The flowing gas well acoustic fluid level surveys should answer the following well performance questions:

- At what rate is gas flowing at the time of the survey?
- What is the depth to the top of the liquid in the tubing and/or casing?
- What is the percentage of liquid in the fluid column?
- How does the liquid level drop as the gas flow decreases?
- How much liquid is in the tubing above the tubing intake?
- What are the producing and static BHP's?
- How much is the flow rate restricted due to backpressure from liquid loading?
- Does tubing gas/liquid pressure push liquid out of tubing?
- What is the maximum production rate available from the well?

The following field examples are presented to illustrate the procedures used in acquiring and interpreting acoustic fluid level tests in gas wells.

Type 1 Flowing Gas Well

This well is completed with 2-3/8 tubing set in a packer at 5596 feet. Three zones are perforated in the lower 4.5 inch casing at depths of 5741-5761, 5828-5844 and 5914 -5936 feet. The flow rate has a variation from 180 to 1400 MSCF/D, but during the test period the flow rate was fairly consistent indicating that the well was behaving as a Type 1 well although on a longer term the well would be classified as a borderline Type 2 well.

At the time of the test the well was reported to be flowing at 750 MSCF/D up the tubing. With a tubing head pressure of 644 psi, the 750 MscfD flow rate is above Coleman's critical rate for 2 3/8" tubing and the gas/water mixture should be produced at the surface in the mist flow regime.

Over the entire tubing string the gas velocity averages 8.32 ft/sec @ 750 MSCFD. Calculations of Turner's critical rate for this well show that gas must be flowing up the 2-3/8 inch tubing at a velocity greater than 10.4 ft/sec at the tubing inlet. Turner's Critical Velocity would predict this well's status as being liquid loaded. In addition the casing section of the well below the packer has a diameter of 4.095 inches resulting in a superficial gas velocity of 1.97 ft/sec. Based on various flow regime maps[4] the casing section of the wellbore is significantly liquid loaded and the gas and water are flowing in the churn-slug regime. This seems to be validated by the production history that shows periods of constant gas flow followed by periods of heading with the gas rate oscillating between 350 and 1200 MCF/day.

Gas production varies periodically from a low of 180 to an occasional high above 1400 MCF/D with an average below 800 MCF/D. The water production rate is fairly constant at about 20 Bbl per day. All of the water appears to be produced to the surface as a mist. A calculation assuming mist flow using a gas velocity of 10 ft/sec assuming no liquid was falling back (zero liquid slip velocity), determines that approximately 1/10 BBL of water vapor would be contained in the gas stream in the tubing. The tubing depth is 5661, so at 10 ft/sec a molecule of gas takes 566.1 seconds to traverse the tubing. The tubing would be emptied 152.6 times per day. If the water production rate is 20 BPD, then a minimum of 0.13 Bbls of water would be flowing through the tubing at any one time. This neglects any liquid that may be coating the tubing walls as an annulus.

Acoustic Tests

Nine fluid level shots were acquired on this well using the explosion technique with the remote fire gas gun (shots 1-5) and using the implosion technique with the 5000 psi gas gun (shots 6-9). The acoustic velocity could not be determined with certainty from the tubing collar's recess reflections. At this high pressure there should not have been a problem in seeing the echoes from the collar recesses. It is possible that the reason that the collar recess reflections are very weak could be due to:

1) Noise from the high gas flow rate being greater than the amplitude of the reflected signal from the collar recesses,
2) Liquid droplets falling out of the mist to form annular flow that covers the tubing collar recesses.

An acoustic velocity of 1312 ft/sec was determined using the data from the last fluid level shot, where the up-kick on the acoustic trace was used as a downhole marker equal to the tubing depth. Also it can be noted that manual analysis of the collar reflections for the first shot also yields a similar velocity of 1313 ft/sec, but the quality of the collar echoes is marginal.

The distance to the liquid level on all nine shots was determined using the 1312 ft/sec acoustic velocity. In this well it was necessary to take several shots before the gas/liquid interface could be detected with some confidence. Gas wells flowing above critical rate usually have the tubing filled with mist and the gas/liquid interface may not be detected from the first few acoustic shots. After a period of time the gas/mist interface (liquid level) was detected. When enough dry gas is trapped at the surface and the gas/mist interface can be detected as a typical liquid level echo.

Figure 2 shows the liquid level depth as a function of time. The speed at which the gas/mist interface was pushed down the tubing, varied between 146 and 192 feet per minute

Figure 3 shows the height of the gaseous liquid column plotted as a function of the pressure at the gas/liquid interface. All the gas/liquid interface pressure and height of the gaseous liquid column data points fall along a straight line indicating a constant pressure gradient exist below the gas/mist liquid level interface. Extrapolation of the pressure at the gas/mist interface to a zero height of the gaseous liquid yields an estimate of PBHP of 804 psi at the depth of 5936 feet. The slope of the line corresponds to the gradient of the mist that exists below the liquid level. Since the liquid produced by the well is mainly water, the gradient value of 0.029 psi/ft is converted to an equivalent 6.8 % of liquid present in the tubing at the time of the test (0.068 = 0.029/0.433). When a gas well is flowing in the mist flow regime, then the gas rate is greater than critical, liquid mist is being carried out of the well by the gas, and liquid is not falling back collecting in the bottom of the tubing. The annular “S” curve is based on field data where gas is flowing through a static liquid column in the bubble or slug flow regime[5,6]. The 6.8% liquid is one third of the value calculated by the “S” curve. The Walker Fluid Level Depression Test[7] must be used in Gas Wells flowing above critical rate to get a more accurate gradient below the liquid level and to determine a more accurate PBHP.

In gas wells with gas flowing 20% or more below critical rate, then the standard methid of using a single fluid level shot and the change in surface pressure versus time (dP/dT) to determine % liquid is an accurate method to determine PBHP. When the gas flow rate is above the Coleman or Turner rates and a mist flow regime exist in the well, then the annular “S” curve does not apply and its use will calculate too high of % liquid, too high of gaseous liquid gradient, and too high of PBHP.

Recommended Test Procedure

To determine the percentage of liquid below the liquid level in a flowing gas well, it is recommended that one or more fluid level measurements be undertaken shortly after stopping the flow at the wing valve. A plot of the gas/liquid interface pressure and height of the gaseous liquid column should be made in order to observe the depression of the gas/liquid interface with the increase in wellhead pressure.

In wells with a low percentage of liquid in the flow stream (that is the gas rate is above or near the critical flow rate) the gas liquid interface will be depressed fairly rapidly.

Several measurements should be taken (preferably at constant time intervals of about 3-5 minutes) to insure the accurate detection of the gas/liquid interface and to establish the gaseous column gradient and computing the PBHP as previously discussed.

Type 2 – Liquid Loaded Flowing Gas Well

In this type of well, gas is flowing to the surface though significant liquid accumulation in the lower section of the wellbore. Liquid loading has occured because liquids accumulated in the bottom of the wellbore, adding pressure and restricting flow from the formation. The liquid loading increases the back pressure on the formation and reduces the flow rate of gas. A liquid loaded condition in a gas well can be identified from an acoustic fluid level measurement or by running a wireline pressure survey.

Simultaneous Wireline and Acoustic Pressure Survey

The following discusses the results of a unique field test in a liquid loaded gas well where the acoustic fluid level measurements were undertaken simultaneously with a wireline survey of flowing and static pressures every second by means of a 0.01 psi resolution quartz pressure sensor. The well is completed with 2-7/8 tubing as a monobore completion. The well was producing gas at the time of the test at an average rate of about 172 MSCF/D, but had a history of cyclic flow because it was treated on a daily basis with soap sticks.

Wireline survey

The objective of the wireline survey was twofold:

1) Obtain a flowing pressure gradient and
2) Compare the measured bottom hole pressure to that computed by the TWM[8] software.

The complete record of pressure and temperature as a function of time is shown in **Fig. 5**.

Flowing Pressure Gradient

The wireline tool was stopped for about 15 minutes at a depth of 6000 feet and again at 7000 feet to obtain two pressure points at a distance of 1000 feet to compute the flowing pressure gradient.

Computation of the pressure gradient in a two phase flow case must take into consideration the variation of pressure with time due to the nature of the existing flow patterns that are characterized by fluctuations in gas/liquid concentration with time. It is not possible to define a single gradient, but it must be expressed as a statistical quantity based on maximum and minimum observed pressures.

Fig. 6 shows the variation of pressure vs. time for the tool stops at 6000 and 7000 feet. The near-periodic pressure fluctuations are clearly visible. At 6000 feet these variations result in an average pressure of 224.9 psi with a Standard Deviation of 4.94 psi, yielding a Maximum pressure of 234.1 psi and a Minimum pressure of 211.0 psi.

The pressure variation at the 7000 ft station during the corresponding 15 minutes of stoppage of the wireline tool result in an average pressure of 303.8 psi with a Standard Deviation of 2.14 psi, yielding a maximum pressure of 309.2 psi and a minimum pressure of 298.69 psi. The smaller deviation at this depth where the pressure is about 100 psi greater than the pressure at 6000 ft. may indicate the existence of a different flow regime at the 7000 ft depth.

Computation of Flowing Pressure Gradient

Computation of the pressure gradient is not straightforward since the pressure measurements at the two depths were done at different times so the actual gradient between the two depths is unknown. Assuming the average flowing conditions did not change significantly, then the difference of the average of the pressures at 6000 and 7000 feet computes a gradient of 0.0782 psi per foot. This value does not give a measure of the variability of the gradient vs. time due to multiphase flow variations. Another option is to compute a gradient time series using pairs of pressure points from the two series of measurements (shown in **Fig. 6**) at the two depths. Data points were first paired in the sequence they were acquired. The statistics for this series are: average gradient = 0.0778 psi/ft with a standard deviation of 0.00495 psi/ft. The maximum gradient was 0.0929 psi/ft and the minimum computed gradient was 0.0701 psi/ft.

A second calculation was done after scrambling the order of data points of the data series at 7000 ft then pairing them as stated above. The statistics for this second gradient series are: average gradient = 0.0778 psi/ft with a standard deviation of 0.00513 psi/ft. The maximum gradient was 0.0918 psi/ft and the minimum computed gradient was 0.0682 psi/ft.

The statistics are very similar for the two methods, indicating that the average values and the standard deviations are representative of the population.

In summary, using a wireline pressure survey to determine flowing gradients in multiphase flow must be analyzed carefully and characterized not just by a single value but also in terms of statistically meaningful quantities. In this well the flowing gradient between 6000 and 7000 ft can be expressed as follows:

- Based on Average of the pressure readings during 15 minute stops = 0.0782 psi/ft
- Based on of gradients from individual samples = 0.0778 psi/ft with 0.0051 standard deviation
- Maximum computed gradient = 0.0929 psi/ft
- Minimum computed gradient = 0.0682 psi/ft

The actual flowing gradient, even when measured by wireline with a very accurate quartz pressure sensor, cannot be known and to be meaningful must be expressed as a best estimate with an average value and a confidence interval such as 0.078 psi/ft +/- 0.01 psi/ft with a 95% confidence (that is 0.068 to 0.088 psi/ft).

Equivalent Liquid Percent in Gaseous Column

The average gradient may be used in conjunction with the density of the liquid mixture to estimate an equivalent percentage of liquid in the tubing between 6000 and 7000 feet. The average gradient of the condensate-water mixture was computed from the well test data and the individual fluid properties as 0.4213 psi/ft so that the equivalent percent liquid in the gaseous column is computed as: (0.0778/0.4213)*100 = 18.5%. This quantity is termed “equivalent” since it is computed from a flowing gradient that includes both the density and the energy loss terms of the total gradient, thus it yields an estimate of the liquid percent that is greater than the actual liquid percent present in the pipe.

Fluid Level Measurements

The first fluid level measurement (at 9:16:55) was made while the well was flowing normally before the wireline tools were rigged up on the tree. This test shown in the upper left corner of **Fig. 7** and shows a distinct echo corresponding to a gas-liquid interface. Since the flow was interrupted only for the duration of the acoustic data acquisition (about three minutes) and since the interface was detected at a depth of over 3600 feet, the conclusion is the well was producing gas through a gaseous liquid column in the wellbore. This is characteristic of a Type 2 well, with gas continually flowing through the liquid at a rate of about 98 MSCF/day computed from the rate of increase in tubing head pressure while the wing valve was closed.

Fluid levels were periodically measured; at each stop while the tool was lowered into the well (at 2500, 5000, 7000, and 7150 ft) and also at each stop while the tool was retrieved at the end of the test (6000, 5000 and 1000 ft). The acoustic echo from the top of the wireline tools is clearly seen in the second figure on the left hand side of **Fig. 7** (the echo from the bottom of the long tool assembly is also visible). The acoustic records however show it was possible to detect the collar echoes and the acoustic velocity determined from the collar count was very similar to the average acoustic velocity determined from the echoes generated at the top of the tool.

Fluid level measurements were also made after the wireline tools reached the 7150 ft depth and the flow was stopped at the wing valve during the shut-in time. Acoustic measurements were made at approximate 5-minute intervals, in order to accurately monitor the depression of the gas-liquid interface and to compute the pressure at the fluid level. The bottom hole pressure was also computed, at the depth of the pressure bomb, from the fluid level measurement with the purpose of comparing the two values. **Table 1** summarizes the results of the acoustic test.

The results show the following:

- As the tool was ran in the hole and before the flow was shut in at the surface the gas/liquid interface in the tubing rose, by about 1350 ft feet, while the tubing pressure varied from 57 to 63 psi. This may have been caused by the introduction of the wireline tools creating a significant change in the flow pattern in the tubing above the tools.
- After shutting-in the flow the tubing pressure increased from 63 to over 100 psi in less than 10 minutes but then tended to stabilize near 126 psi for the rest of the test.
- Correspondingly, the gas/liquid interface dropped from 2392 to 6523 feet (4131 ft in 24.5 minutes)
- The rapidly decreasing value of dp/dt during the shut-in period indicates a rapid decrease of gas flow up the tubing.
- At the end of the test the flow of gas from the formation is virtually zero, because there was almost no change in the fluid level or surface pressure.
- At the end of the test at the bottom of the tubing there was a column 685 ft high, of mostly water.

The measured tubing pressure is used to compute the pressure at the gas-liquid interface using the gas gravity determined from the acoustic velocity. The depth of the gas/liquid interface is plotted in **Fig. 8** showing the variation of the liquid level before shutting in the well while the tool was being run and during the tubing pressure buildup.

Pressure Distribution during Test Sequence

Having fluid level and tubing pressure data as well as the pressure measured with the quartz gage, allows drawing a detailed pressure-depth traverses during the test sequence for each time when the fluid level measurement was taken.

Fig. 9 gives an accurate picture of the distribution of fluids and the average pressure gradients at the time of each recorded acoustic shot and also shows how pressure conditions change when the wireline tool is being lowered into the well while gas was being produced at the surface. Shot No. 1 was taken before the tool was introduced into the well and shows the gas liquid interface at a depth of 3753 feet. The second shot was taken when the tool was at 2500 feet and in the gas column. The recorded pressure at that depth and the surface tubing pressure were used to compute the gas gradient of 0.00187 psi/ft. Shot No. 3 corresponds to a tool depth of 5000 feet and the measured tool pressure and the computed gas/liquid interface pressure were used to compute an average gradient above the tool of 0.0501 psi/ft as shown on **Fig. 9**. Similarly shots No. 4, 5 and 6 with the tool at 6000, 7000 and 7150 ft, yield an average gradient of 0.05 psi/ft [(0.050/0.4213)*100 = 11.9% Liquid] for the gaseous liquid mixture above the tool. Note that the gradient of the fluid above the tool remains unchanged as the tool is lowered into the well. Since the gas flow remained unchanged, it can be assumed that during this time the flowing BHP remained unchanged and that the last pressure, measured at 7150 is representative of the flowing BHP, it is possible to compute an average flowing gradient below the tool by joining the measured pressure points at the various depths. This line represents the pressure gradient of the fluid below the tool and has a value of 0.0719 psi/ft. Note that this value is very close to the average value (0.078 psi/ft +/- 0.01) computed from the statistical analysis of the pressures at the gradient stops.

This detailed analysis of the pressure distribution during the time the tool is introduced in the well yields the important observation that the tool must affect the flow pattern of the gaseous liquid column to the extent that the flowing gradient above the tool (0.0501 psi/ft) is lower than the flowing gradient below the tool where the flow has not been disturbed. One of the effects of the reduced gradient above the tool is that the fluid level increases due to the lighter gaseous liquid column above the tool.

Fig. 10 shows the pressure traverses when the pressure gage is at 7150 feet and the flow is stopped at the tubinghead. The first shut-in shot corresponds closely to the condition that existed in the well when gas was flowing. It may be considered that the pressure distribution corresponds to the average flowing condition. Subsequent graphs show how the pressure at the tubing head is increasing and the gas/liquid interface is moving down as well as the gradual increase of the gradient of the gaseous liquid column. The gradient increase corresponds to the liquid falling back to the bottom of the tubing as the gas flow rate decreases. The last plot (Shut-in 14) was taken prior to retrieving the wireline tools and shows that a 700 ft column of mostly liquid (97 % liquid) has accumulated at the bottom of the tubing and the pressure at 7150 feet has stabilized at about 404 psi.

Estimation of BHP from Fluid level Measurement

The TWM program, that was used to analyze the acoustic data, estimates the gaseous column gradient using a percent liquid in the annular gaseous column obtained from a generalized empirical correlation ("S" curve) that was developed from field data in pumping wells. This correlation is thus primarily applicable to stabilized annular flow with some confidence but it may be less accurate when applied to tubular flow. In this special test, having the pressure data from the quartz gage gives invaluable information regarding the applicability of the S curve to gas flow in tubing. **Fig. 11** compares the measured pressure at 7150 feet with the pressure computed from each fluid level record using the annular "S" curve correlation to determine the effective gradient of the gaseous liquid column.

Shot no. 1 was acquired while stabilized gas flow was occurring in the well. The tool had not disturbed the flow regime. The pressure of 379 psi at 7150 ft. determined from fluid level shot no. 1 was 65 psi higher than the 314 psi pressure determined when the tool stopped at 7150 feet depth 2 hours and 8 minutes later. The acoustic fluid level S curve flowing gradient of the gaseous liquid column was determined to be 0.0862 psi/ft, which is 10.1% higher than the average 0.0778 psi/ft gradient determined by using the wireline survey with the quartz crystal pressure gage. The acoustic fluid level determined equivalent percent liquid in the gaseous column is computed as: (0.0862/0.4213)*100 = 20.4%. At a depth of 7150 ft. there is good agreement with pressure, gaseous liquid column gradient, and % liquid determined from shot no. 1 and the pressure determined from the tool at 7150 prior to shutting in the well.

There is a significant difference at the beginning of the shut-in period between the tool-measured pressure (314 psi) and the TWM "S" curve computed pressure (464 psi). Based on the surface gas flow rate the annular "S" curve is estimating 20.4% liquid in the gaseous column which is almost double the 11.9% liquid actually present. This difference is casued by running the tool in the well, disturbing the flow regeme and lightenting the gradient to 0.05 psi/ft. above the tool.

As the gaseous liquid column collapses and liquid accumulates near the bottom of the tubing, the difference between the two values decreases and towards the end of the test when almost no flow is occurring, then the computed (407.4 psi) and measured (402.84 psi) values differ by 1.1%.

From this the following may be concluded:

- The annular "S" curve does a reasonably accurate estimate of the gaseous liquid column when the liquid loaded bubble or slug flow regeme is not disturbed.
- The annular, "S" curve, gaseous column effective gradient overestimates the percentage liquid present in the gaseous column, when it is applied to tubular flow disturbed by running a wireline survey.
- In a near static shut-in gas well, the pressure computed by the TWM program is within 1.1 % of the value obtained by the wireline gage.

In a liquid loaded well the annular "S" Curve predicts a reasonably accurate gradient of the gaseous liquid column and is a good technique to determine flowing BHP, and liquid loading. One 5-minute acoustic fluid level shot probably yields results as accurate as those from running a day long wireline pressure gradient survey.

Determining Liquid Loading in a Gas Well

Fig. 12 shows the automatic analysis where the back pressure on the formation due to liquid load is calculated for a Type 2 well. The well is flowing in the liquid loaded flow regeme in an undisturbed state and the results displayed are from a single acoustic fluid level shot down the tubing. The annular "S" curve is used to determine the gradient of the gaseous liquid column and the flowing BHP acting on the formation. Based on the analysis of Shot no. 1 there is 3427 ft. of gaseous liquid in the well. The "S" curve determines there is an equilivent 685 ft gas free liquid applying 297 psi of back pressure from liquid loading acting on the formation. Since the current 172 Mscf/D average gas flow rate is below Turner's critical rate of 430 Mscf/D gas flow rate for continuous water removal in 2.441inch ID tubing, then the well is currently flowing in a loaded condition. For any tubing size if the Turner or Coleman critical rate is greater than the existing flow rate, then the well stays loaded.

At a glance various tubing sizes can be evaluated to determine if the critical gas flow rate could be exceded and the well would unload or if for a specific tubing size the well stays loaded. The intersection of the inflow and outflow curves for the formation and specific tubing sizes show that this well would flow in an unloaded state with a tubing internal dimension of 1.25 inch. With a 1.25 inch velocity string the well would continuously flow at 204 Mscf/D, resulting in a 32 Mscf/D incremental incrase in the gas production rate.

A single acoustic fluid levels "shot" down the tubing in flowing gas wells can be used to determine: 1) Amount of liquid in the bottom of the tubing, 2) Backpressure on the formation due to liquid, 3) Gas flow rate into the tubing, 4) Equivalent fluid gradient below the liquid level, 5)Flowing bottom hole pressure, 6) Feasibility of using various lift methods to remove the liquid loading and 7) Incremental Gas Flow Rate if Liquid Loading Removed.

Summary and Conclusions

Acoustic fluid level surveys can be used not only for static bottom hole pressure calculations but this technology has been extended to flowing pressure gradient surveys in gas wells. The procedure involves monitoring fluid level and pressure in the tubing during a short-term test sequence. The procedure is inexpensive and non-intrusive. As shown in this paper, the tests clearly show the redistribution of flowing gas and liquid and allow the construction of the corresponding tubing pressure traverses and the determination of the flowing gas/liquid ratio, liquid fallback volume and flowing BHP.

The following conclusions are divided according to the type of fluid distribution in the gas wells.

Type 1 Wells

A light uniform mist/annular flowing gradient was shown to exist in the tubing string from the liquid level down to the bottom of the tubing in gas wells where the gas flow rate is above critical rate. In this type of well, flow can be shut-in and acoustic fluid level surveys can be used to determine the tubing fluid gradient and the flowing bottom hole pressure. In these wells at least two fluid level measurements can be used to calculate the gradient below the fluid level. The gradient is then used to extrapolate to the flowing BHP.

Type 2 Wells

In wells that are flowing below critical rate and liquid has accumulated near the bottom of the well, then the 1st few acoustic fluid level measurements are most accurate in determining the flowing bottom hole pressure. After well is shut-in for a period of time the flow regime in the tubing is disturbed and liquid falls back toward the bottom of the tubing. Acoustic fluid level surveys acquired while the liquid is falling may result in flowing bottom hole pressures that are not accurate. The annular "S" curve was developed under stabilized flowing conditions and shutting the well or running a wire line will disturb the flow regime and result in calculating inaccurate bottom hole pressures. The Echometer annular S-curve does not calculate the correct gaseous column gradient after the valve is closed for an extended period of time. After the well stabilizes under the new conditions, then acoustically determined bottom hole pressures are accurate.

Type 3 Wells

Use of acoustic surveys to determine the static shut-in pressure shown in **Fig. 13** is an accepted[9] and accurate method. Using acoustic fluid level instruments for determining bottom hole pressure provides advantages over downhole gauges in that the operator is not restricted by road bans or rough terrain. Safety issues are reduced because of using less manpower and using less heavy equipment to acquire the static reservoir pressure. Fluid level instruments can be used to inexpensively determine the shut-in static reservoir pressure for gas wells as opposed to traditional wire line methods, which are more intrusive and costly.

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Table 1 Wireline and Acoustic Survey in Type 2 Well

Elapsed Time, from start of test	Elapsed Time, from flow shut in	Measured Tubing Pressure, psi	Tubing pressure buildup, psi	Buildup time, minutes	Computed Gas/liquid Interface Pressure, psi	RTT, seconds	Gas/liquid Interface Depth, ft	Height of Gaseous Liquid Column, ft
0:00:00		61.7	7.5	1.50	68.1	5.566	3626	3607
0:37:33		57.7	15.8	2.50	63.2	5.043	3332	3901
0:36:13		59.0	8.4	1.25	64.7	4.752	3165	4068
0:19:25		60.2	10.4	1.00	64.5	3.819	2530	4703
0:19:06		63.4	12.9	1.25	67.5	3.435	2276	4957
2:08:13	0:00:00	63.0	17.5	2.00	67.6	3.611	2392	4841
2:12:44	0:04:31	95.6	6.6	2.00	103.5	4.400	2926	4307
2:17:36	0:09:23	109.4	6.1	4.00	120.4	5.463	3632	3601
2:22:56	0:14:43	116.9	2.1	2.00	129.9	6.359	4233	3000
2:27:54	0:19:41	121.7	2.6	4.20	138.4	7.508	4967	2266
2:32:40	0:24:27	124.4	0.3	4.00	143.8	8.975	6000	1233
2:38:54	0:30:41	124.9	0.239	4.00	144.9	9.204	6148	1085
2:43:32	0:35:19	125.2	0.208	4.00	145.4	9.269	6192	1041
2:49:37	0:41:24	125.5	0.161	4.00	145.9	9.356	6257	976
2:54:38	0:46:25	125.8	0.153	4.50	146.4	9.420	6317	916
3:02:38	0:54:25	126.1	0.081	4.00	147.8	9.518	6382	851
3:07:43	0:59:30	126.2	0.154	8.25	148.1	9.568	6415	818
3:17:48	1:09:35	126.4	0.200	13.00	148.5	9.662	6478	755
3:27:47	1:19:34	126.4	-0.104	6.00	148.7	9.730	6523	710
3:37:35	1:29:22	126.2	-0.062	3.50	148.4	9.736	6528	705
3:51:05	1:42:52	126.0	-0.057	2.00	148.2	9.740	6529	704
4:10:33	2:02:20	125.6	-0.093	4.25	147.0	9.762	6546	687
4:24:35	2:16:22	125.4	-0.122	5.00	147.6	9.765	6548	685

Fig. 1 The Three Types Of Two Phase Flow Conditions In Gas Wells

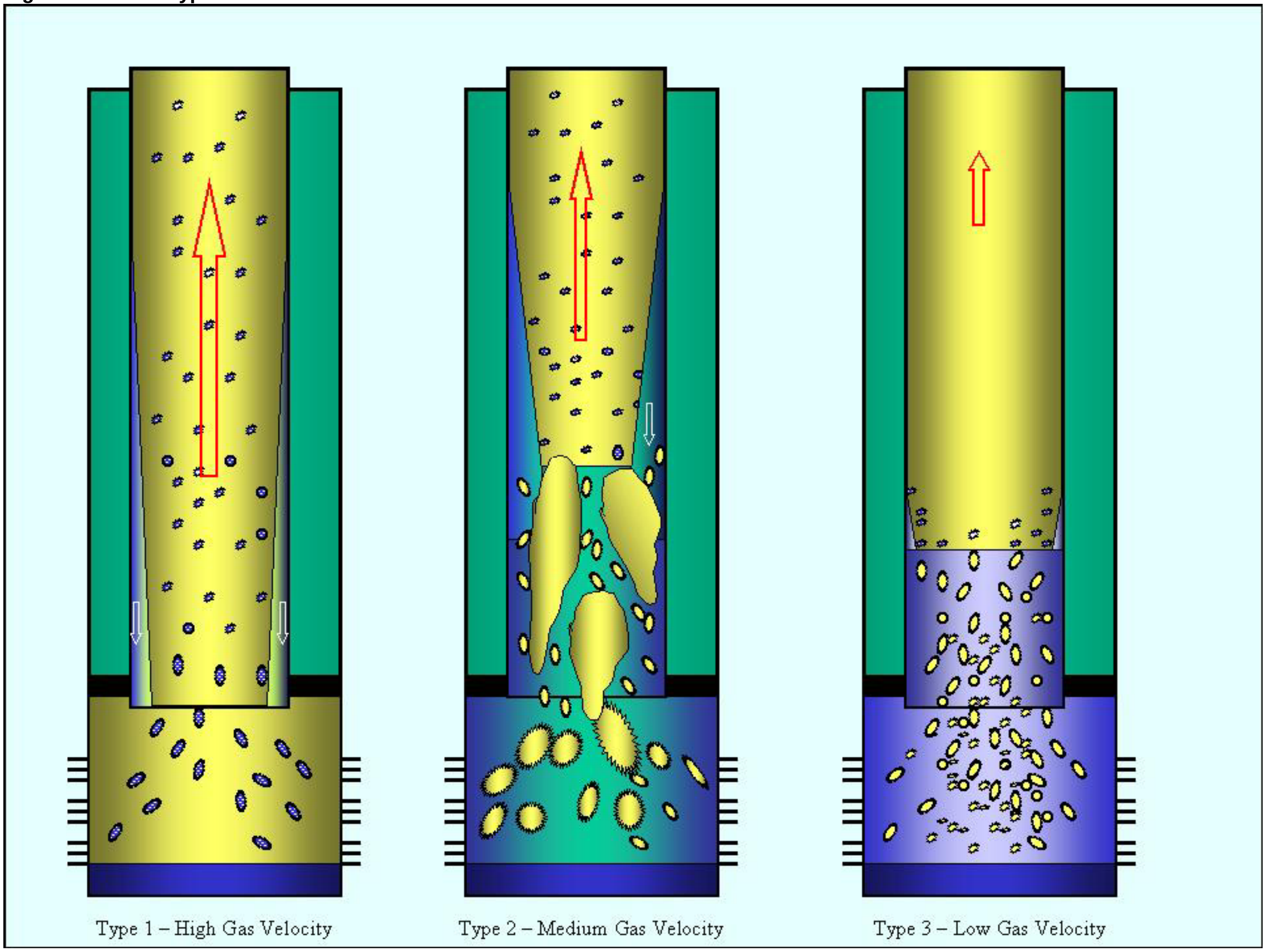


Fig. 2 – Depressing Liquid Level Depth as a Function of Time for Type 1 Flowing Gas Well

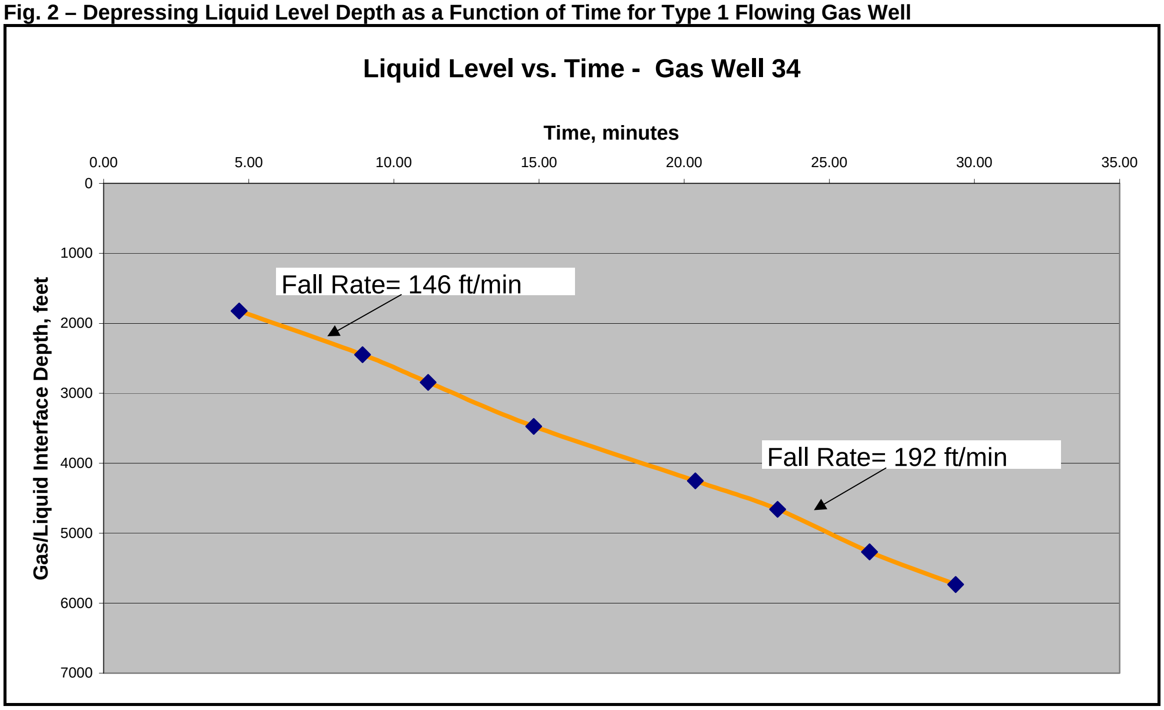


Fig. 3 - Height of Gaseous Liquid Column as a function of Pressure at the Gas/Liquid Interface

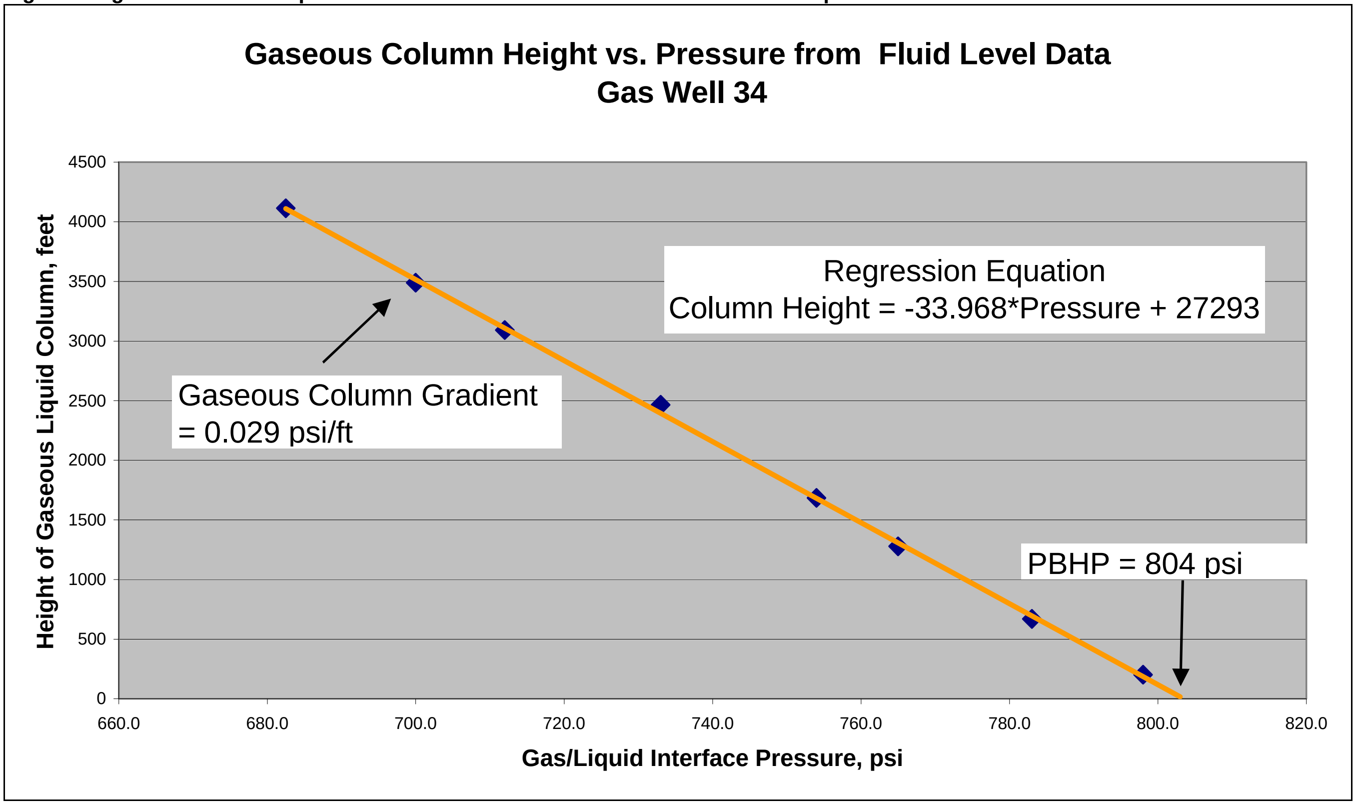


Fig. 4 - Tubinghead Pressure vs. Time During Acoustic Surveys

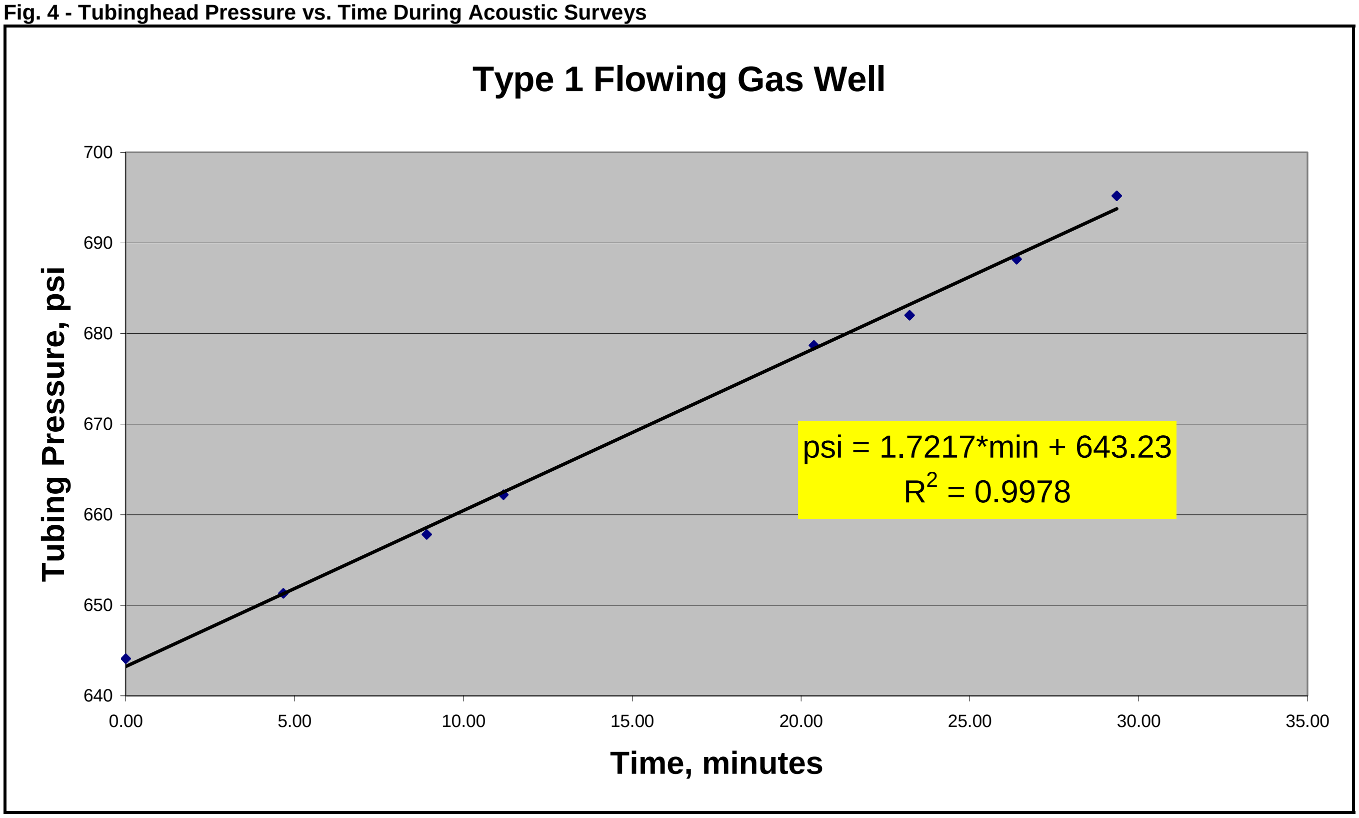


Fig. 5 - Pressure and Temperature Record for Wireline Survey

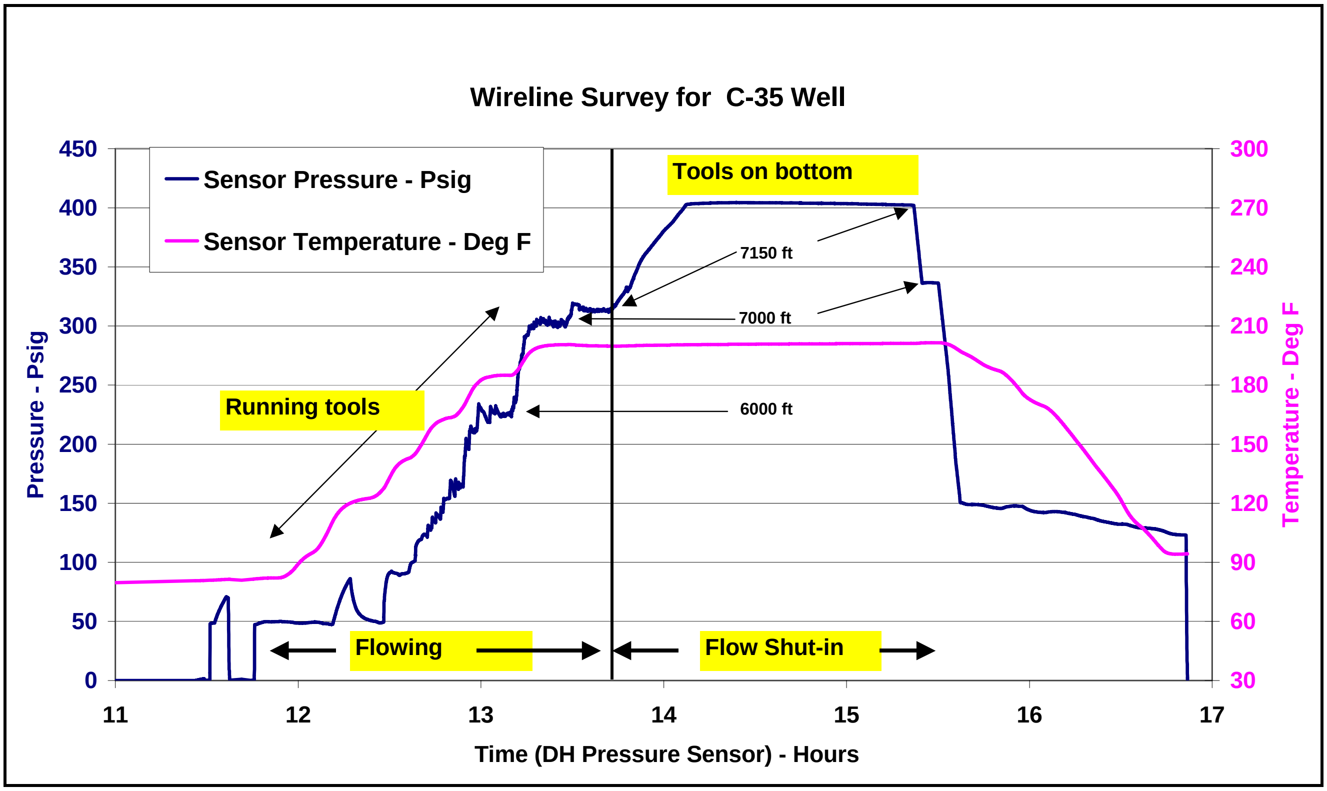


Fig. 6 - Wireline Tool Pressures as a Function of Time During Gradient Stop

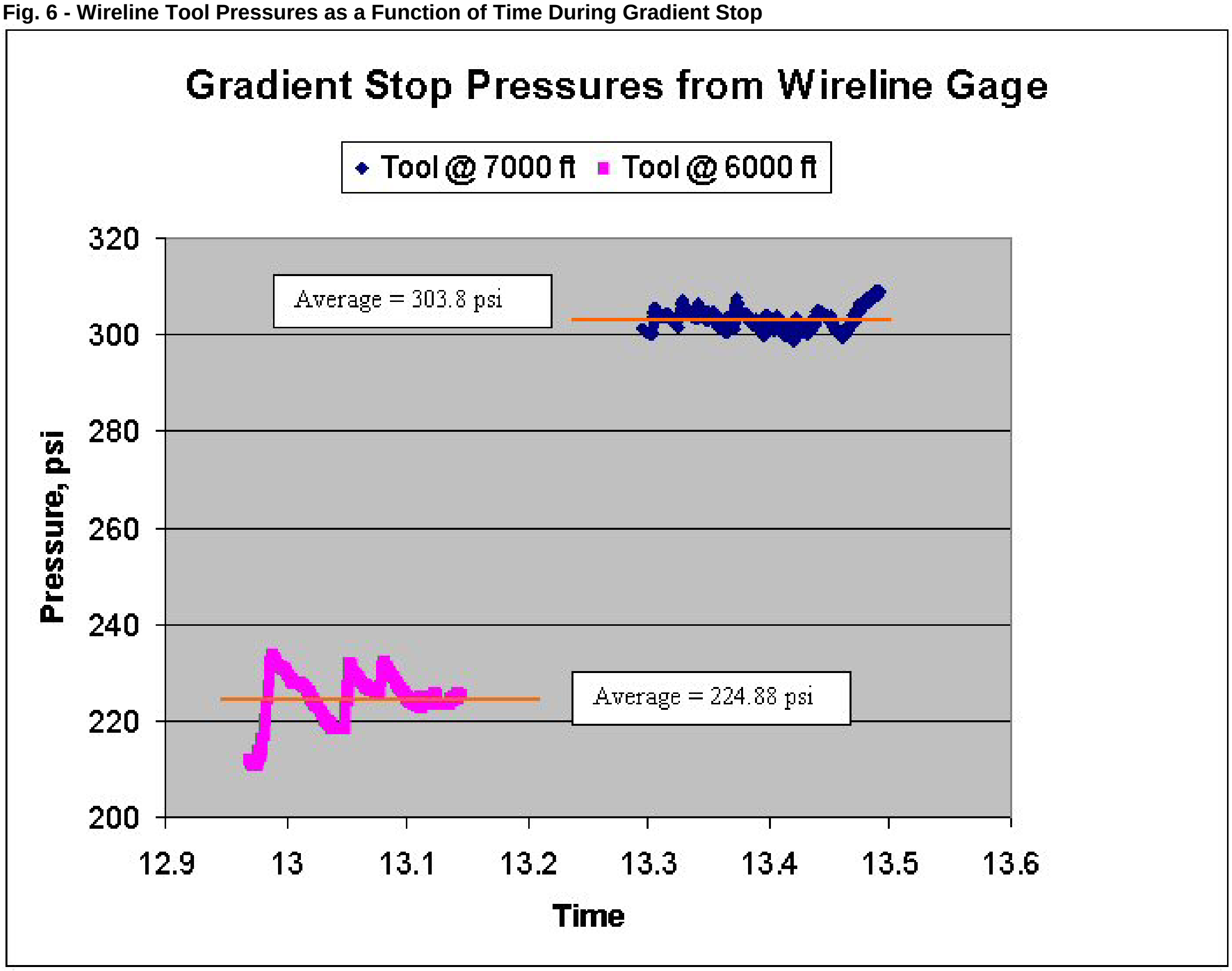
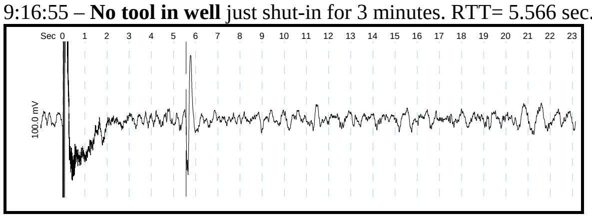
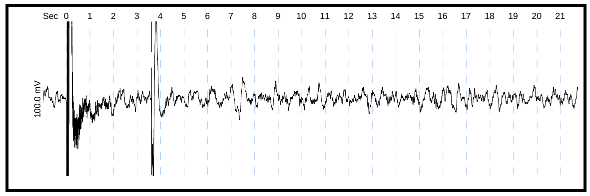


Fig. 7 - Sequential Acoustic Records for Simultaneous Wireline and Acoustic Survey

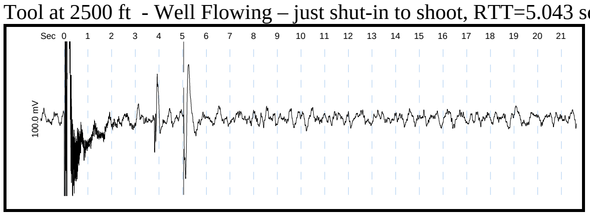
9:16:55 – **No tool in well** just shut-in for 3 minutes. RTT= 5.566 sec.



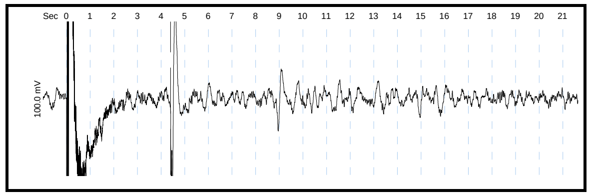
Tool at 7150 ft - **Closed in well** - 0 minutes RTT = 3.611 sec.



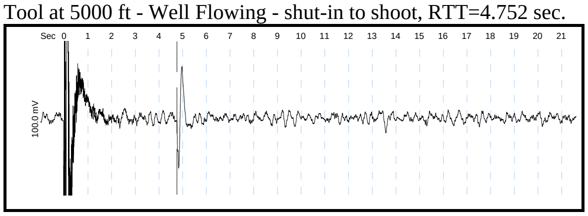
Tool at 2500 ft - Well Flowing – just shut-in to shoot, RTT=5.043 sec.



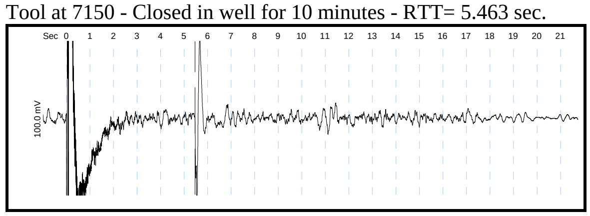
Tool at 7150 – Closed in well for 5 minutes - RTT= 4.4 sec.



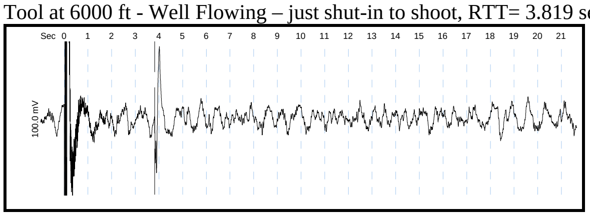
Tool at 5000 ft - Well Flowing - shut-in to shoot, RTT=4.752 sec.



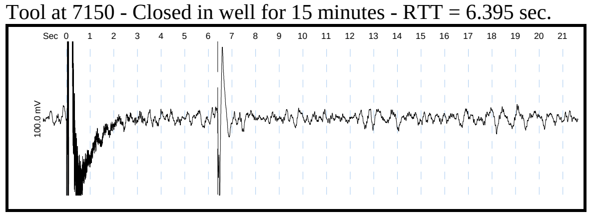
Tool at 7150 - Closed in well for 10 minutes - RTT= 5.463 sec.



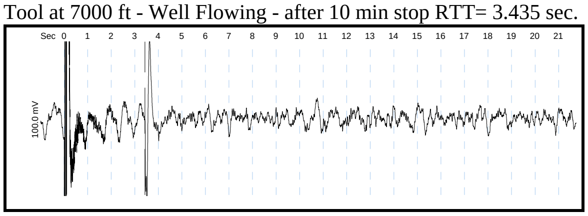
Tool at 6000 ft - Well Flowing – just shut-in to shoot, RTT= 3.819 sec.



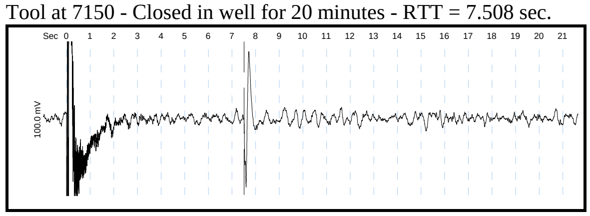
Tool at 7150 - Closed in well for 15 minutes - RTT = 6.395 sec.



Tool at 7000 ft - Well Flowing - after 10 min stop RTT= 3.435 sec.



Tool at 7150 - Closed in well for 20 minutes - RTT = 7.508 sec.



Tool at 7150 - Closed in well for 28 minutes - RTT = 8.975 sec.

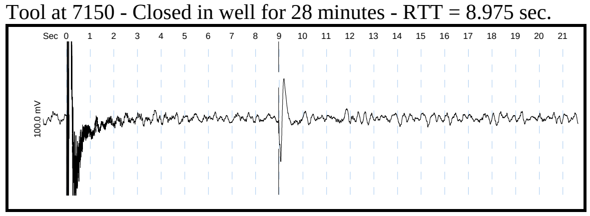


Fig. 8 - Liquid Level Depth for Type 2 Flowing Gas Well

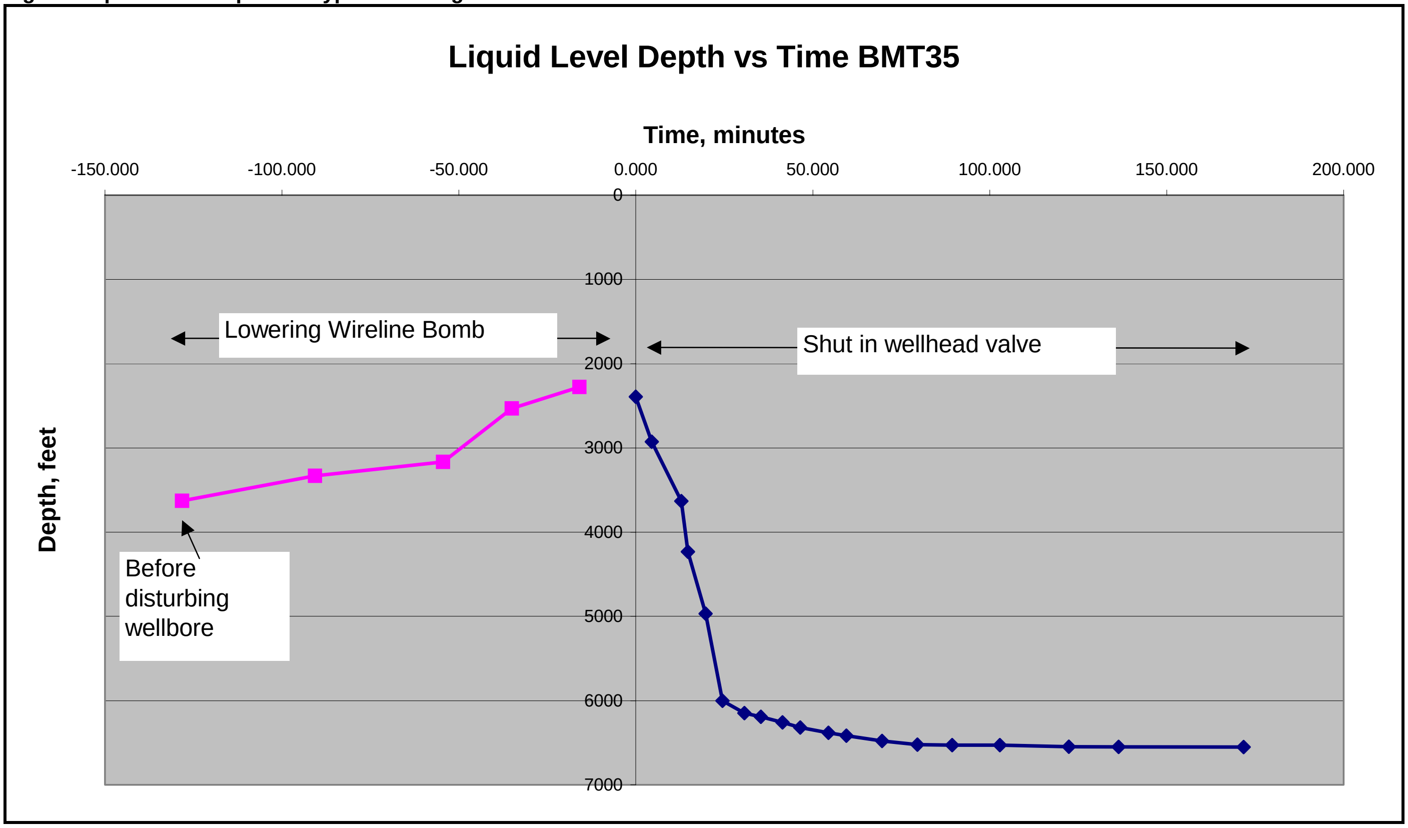


Fig. 9 - Pressure Traverses While Lowering Wireline Tools

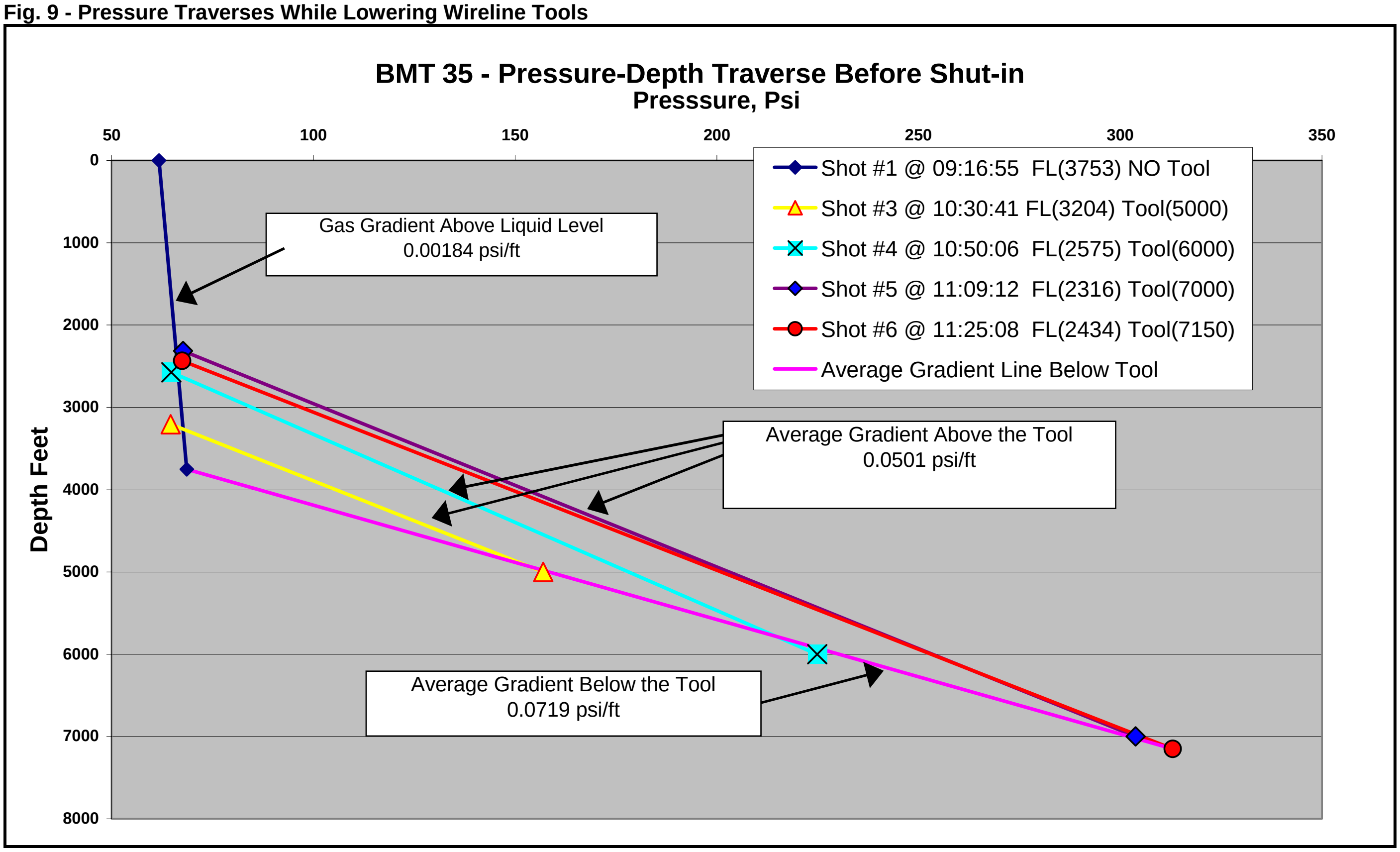


Fig. 10 – Pressure Distribution as a Function of Depth During Test

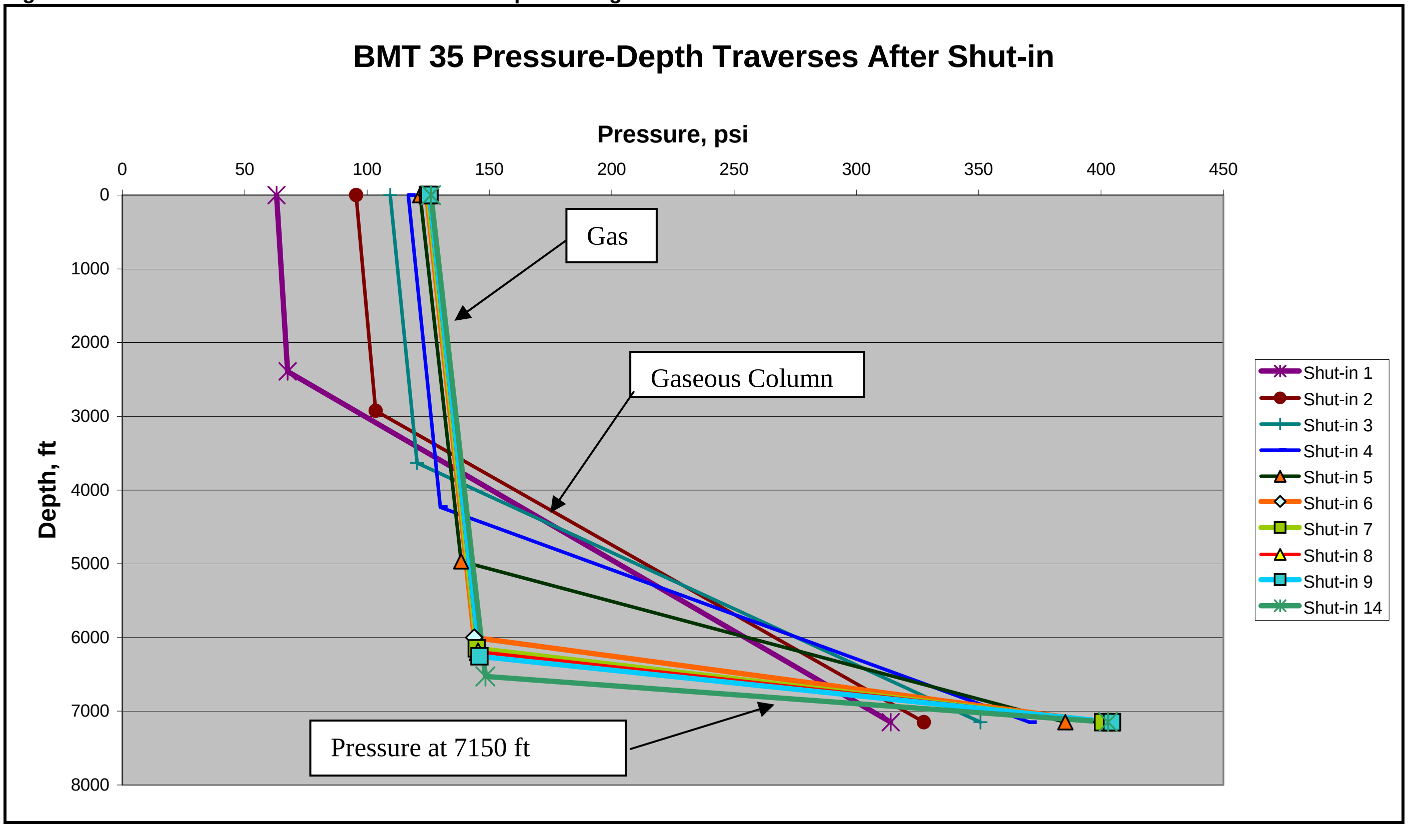


Fig. 11 – Comparison of Measured and Computed Pressure at 7500 Feet

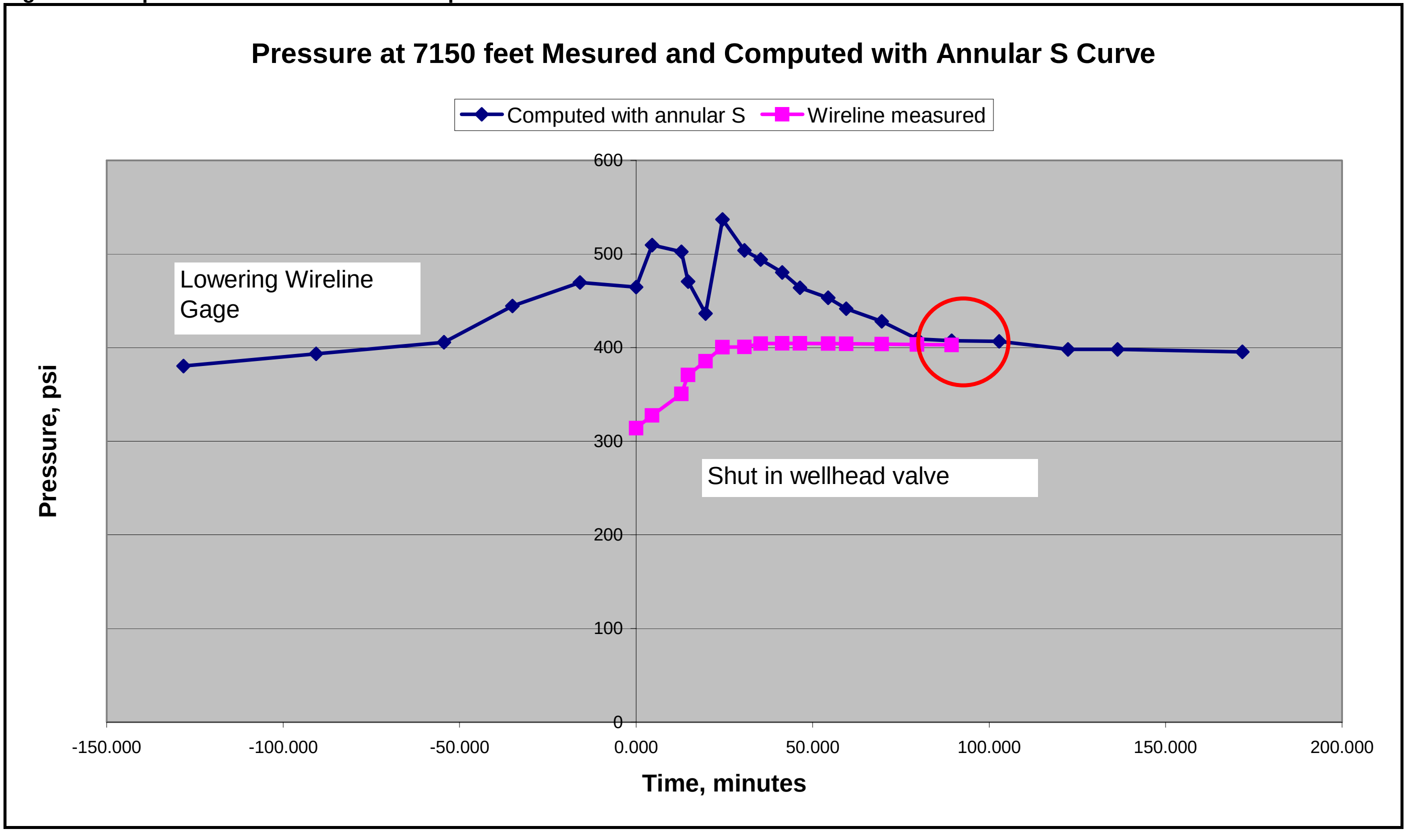


Fig. 12 – Back Pressure on Type 2 Well Due to Liquid Loading

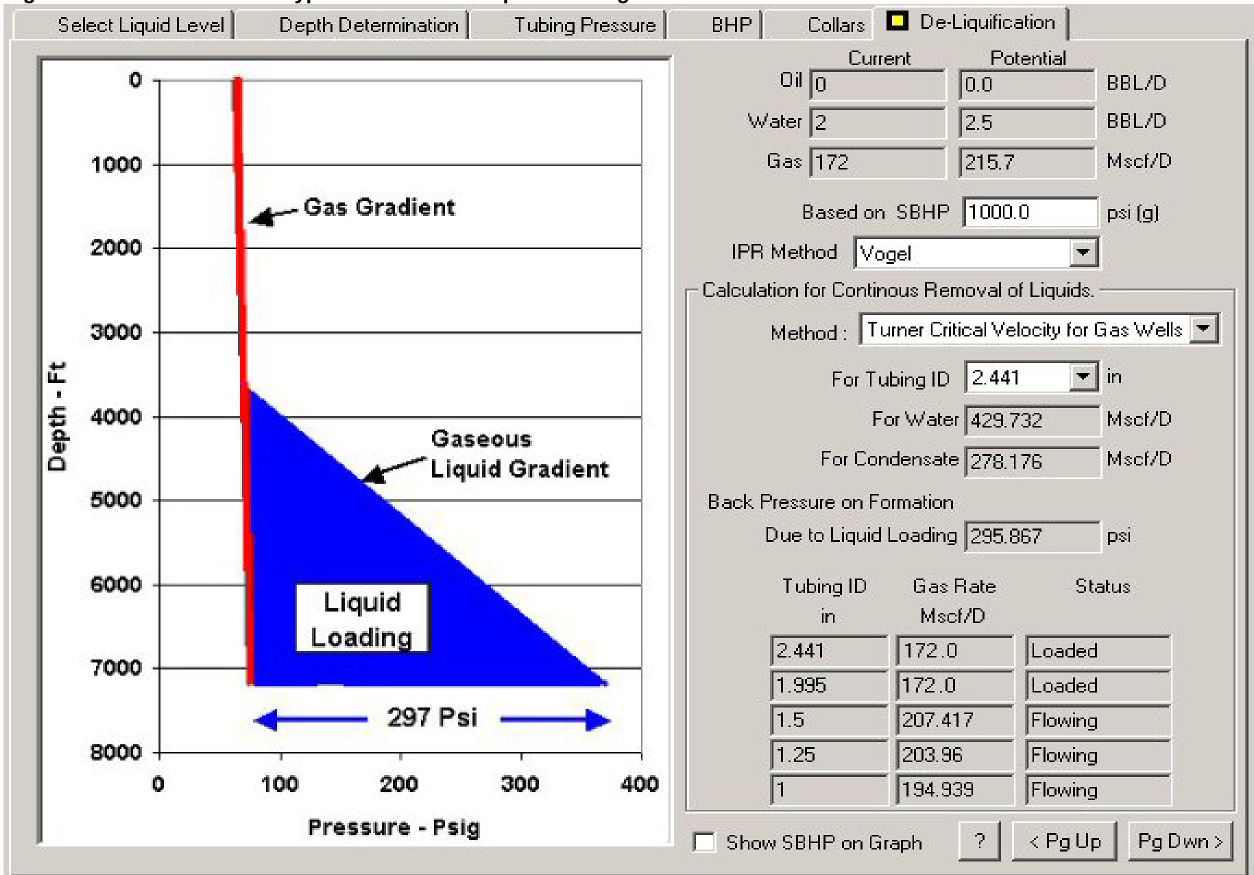


Fig. 13 – Static Bottom Hole Pressure for Type 3 Well