Pump Intake Pressure: Comparison of Values Computed from Acoustic Fluid Level, Pump Dynamometer and Valve Check Measurements.

A. L. Podio, University of Texas at Austin
J. N. McCoy and O. Lynn Rowlan, Echometer Company

Abstract

These three methods available to the operator to estimate the Pump Intake Pressure (PIP) in sucker rod lifted wells are discussed in detail. Field data for a significant group of wells are used to compare the PIP results of the three methods. The results show that the PIP computed using the max and min loads from the pump card may yield too low PIP, while PIP computed using loads from the valve test usually are too high. Data processing techniques for improving the quality of the results from dynamometer data are presented. Values of PIP obtained from Acoustic Fluid level measurements, in wells with moderate pump submergence, yield estimates of PIP that agree with those from pump card analysis. If PIPs do not match, then the operator using the proposed techniques can make corrections to consider unusual conditions affecting the fluid load. The pros and cons of using each method are discussed.

Pump Intake Pressure (PIP)

Downhole pump submergence is defined as the amount (height) of liquid that exists above the pump intake. Since the early times of oilfield pumping pump submergence has been the parameter most used for monitoring and troubleshooting well operation. Acoustic determination of the depth to the liquid in the wellbore was introduced in the 1930s by C.P. Walker who also outlined graphical methods to obtain the pressure distribution in the well [1,2,3]. The advent of digital data acquisition and processing provided the tools to routinely convert fluid level measurements to estimates of downhole pressure distribution in the wellbore[4]. Today, pump submergence is easily converted to pressure at the depth of the pump intake.

Figure 1 shows schematically the wellbore configuration and pressure distribution that exists in a well producing by pumping means regardless of the type of pumping system employed. The fluid level depth measurement is undertaken in the casing-tubing annulus. The casing-head pressure is measured and is used to compute the pressure at the bottom of the annular gas column using the gas properties and the geothermal temperature profile. Then the pressure at the depth of the pump intake is computed using the gradient of the annular fluid below the gas/liquid interface. The Pump Intake Pressure (PIP) *determined acoustically* is in reality the pressure in the *casing-tubing annulus* at the *depth of the pump intake*. Depending on the configuration of the piping installed below the pump (strainer, gas anchor, mud joint, etc) this PIP may or may not be equal to the pressure at the actual pump intake but in most instances it will be relatively close to the same value.

In rod pumping, the measurement of pump rod load as a function of plunger position was first introduced by Gilbert's development of a mechanical dynagraph that was installed downhole at the bottom of the rod string and just above the pump plunger[5]. In addition to diagnosing pump problems such as gas interference and gas locking, he applied the measured downhole load information to calculate the pressure inside the pump barrel and used it to compute the actual oil and gas pumping rates through the pump, essentially using the pump as a flow meter. In this paper he states: "*During the upstroke, the pressure in the pump is nearly constant at ordinary pumping speeds and nearly equal to the fluid level pressure outside the pump*" The main difference between the two is due to "*…pressure loss developed by restrictions to flow of fluid through entrance passages, including those of the standing valve.*" Thus the Pump Intake Pressure (PIP) *determined from dynamometer measurements* is in reality the pressure in the *pump barrel* during the upstroke. This pressure is generally a good approximation of the pressure at the pump intake (below the standing valve) and of the pressure in the annulus at the depth of the pump, provided that additional pressure losses are not present.

Figure 2 shows schematically the wellbore configuration and pressure distribution in a pumping well highlighting the relationship between the pump discharge pressure (PDP) and the Pump Intake Pressure (PIP). The figure indicates that for a rod pumped well, the measurement of the fluid load (difference between upstroke and downstroke plunger loads) allows computation of the PIP when the pump discharge pressure can be estimated from a measurement of the tubing head pressure and computation of the gradient of the fluid in the tubing string.

The difference between the average upstroke and downstroke pump loads can be approximated by measuring the static loads obtained from the conventional valve leakage test. Thus an estimate of the PIP can also be computed from the loads measured after running a standing valve (SV) and traveling valve (TV) load test.

The development of digital processing allowed practical conversion of surface dynamometer measurement to the corresponding pump load and displacement through modeling of the rod string motion, elasticity and inertia using the well known "damped wave equation solution"(6). The computed "pump dynamometer card" yields values that approximate the actual loads as if the measurements were taken by a downhole instrument located above the plunger as in the case of Gilbert's tests or the more recent Sandia(7) tests where a digital memory dynamometer was used to record the data.
Regardless of the method by which the pump loads are obtained, the calculation of the PIP from dynamometer data requires a good estimate of the tubing fluid gradient present in the tubing so that the pressure at the pump discharge can be computed. This requirement is similar to the requirement of the calculation of PIP from fluid level measurements where the gradients of all the annular fluids need to be estimated.

PIP from Acoustic Fluid levels

Acoustic fluid level measurements can be obtained in all wells regardless of the type of artificial lift being used (ESP, PCP, Hydraulic, Plunger lift and Gas Lift) so that PIP (or tubing intake pressure) can be estimated readily (provided a downhole packer is not present) without the use of wireline-conveyed or permanently installed pressure recorders.

Acoustic fluid level measurements have been used routinely to compute downhole pressures in wellbores that contain mixtures of gas and liquids based on measurement of surface pressure, determination of the depth to the fluid level and estimation of the gradients of the fluids in the wellbore. This method was first sanctioned by the Energy Resources Conservation Board of Canada in 1978 and has since been adopted throughout the World as the most practical means of obtaining bottomhole pressures in rod pump wells without the need to pull the rods and/or tubing for installation of a downhole pressure gauge(8).

The pressure calculation assumes that, when the fluid level measurement is made, a pumping well is operating at a stabilized condition so that the volumes of fluids produced at the surface are equal to the fluid volumes entering the well from the formation. There is no accumulation of material in the wellbore and the wellbore is functioning similar to a three-phase separator with steady interfaces between the fluids: oil, brine and gas. This mode of stabilized operation is verified when the following conditions are met:

- The fluid level does not change as a function of time
- The casing head pressure is constant under normal operation
- The produced water oil ratio is constant

These conditions can be established not only in wells that have pumps operating continuously but also in those on time clocks or pump-off controllers provided their on-off periods are not excessively long (within 30 to 45 minutes) so that an average value of the fluid level can be measured.

Figure 3 indicates that most rod pumping wells can be classified into three groups, depending on the position of the pump intake relative to the producing formation and the position of the fluid level relative to the pump intake. Type A wells are common in depleted reservoirs or where the casing valve is closed forcing all free gas through the pump. Type B wells imply that only liquid is flowing through the perforations into the wellbore. Type C wells comprise the bulk of wells where determination of PIP is required to analyze the efficiency of the pumping system and production potential.

The most general configuration is illustrated in **Figure 4** where the pump intake is set above the perforations and free gas is flowing into the wellbore from the formation. Some of the gas will enter the pump and the remaining volume of gas will flow to the surface bubbling through the annular liquid generating what is defined as an "annular gaseous liquid column".

<u>PIP Calculation Method using Acoustic Fluid Level Survey</u>

In all cases, the pressure at a certain depth in the wellbore is computed as the sum of the measured surface pressure plus the pressure due to the columns of fluids that exist above the point of interest. The pressure due to a column of fluid is expressed as the product of its height (true vertical) times the gradient of the fluid. The fluid may be single phase (gas, oil or brine) or may consist of a mixture of gas and liquid. Since fluid gradients should be computed at the pressure and temperature conditions that exist in the wellbore an iterative calculation is undertaken beginning with the known pressure and temperature at the surface to calculate initial values of the fluid densities and then stepping down to the point of interest in small increments of pressure and temperature.

Pressure at the pump intake = Pressure at Casing-head + Pressure due to Columns of Fluids in Annulus

Pressure due to Column of Fluid = Fluid Gradient * Vertical Height of Fluid Column.

Assuming well stabilization as discussed earlier and considering the configuration in **Figure 4**, once the depth to the gas/fluid interface has been computed, the main questions are:

- Determination of the casing gas gravity, and
- Determination of the fraction of liquid that is present in the annular gaseous liquid column.

These values are required to compute the corresponding fluid gradients.

The average annular gas gravity may be computed from the measured acoustic velocity, the average temperature and casing-head pressure. Alternately a sample of the gas may be obtained at the casing-head and the gravity of the gas is measured directly.

The fraction of gas present in the gaseous liquid column may be determined directly by performing the test known as the "Walker Liquid Level Depression Test" [3] or using one of the accepted correlations that relate the annular gas flow rate to the fraction of liquid [4,9,10]. A properly performed Walker test yields the most accurate estimate of the gaseous liquid column gradient but requires installation of a back pressure regulator at the casinghead and usually takes several days. Use of the correlations implies that the flow conditions in the particular well are similar to the conditions that existed in the wells that were used to establish the correlation. The uncertainty in the computed fraction of gas increases when the well's characteristics are outside the range of parameters represented by the correlation.

The correlating parameter involves the annular gas flow rate computed from a short-term pressure monitoring test when performing the acoustic fluid level test after closing the casing valve. An increase in casing pressure is an indication of annular gas flow. The gas flow rate is proportional to the rate of pressure increase and the annular volume occupied by gas. As such it is related to the casing and tubing sizes.

When the pressure remains constant after shutting in the casing valve to the flowline, then there cannot be any free gas entering the wellbore through the perforations and the annulus contains only liquid overlain by gas. Zero gas inflow is typical of wells that have been shut down for an extended period of time (voluntarily or due to pumping equipment failure) so that bottom hole pressure has equilibrated with the reservoir pressure and fluid inflow has ceased. The fluid level survey can thus be used to obtain a good approximation of the Static Bottom Hole Pressure (SBHP).

Figure 5 is an example of the pressure distribution in the wellbore of a pumping well. The basis of the figure is the well completion diagram where the conventional schematic has been augmented with the real time distribution of fluids and the pressures at key points, including the PIP.

<u>Requirements for accuracy</u>

The accuracy of the computed pressures is dependent on many factors each affecting the final result with different weight as discussed below:

Stabilization: The algorithm used to compute the PIP assumes that flow stabilization, as described earlier, has been achieved so that the fluid level is steady and the oil/water interface in the annulus is at the pump intake. When this condition is not satisfied the computed PIP underestimates the actual value. The uncertainty in PIP increases as the difference in density between the produced oil and produced water increases. The following table illustrates the effect of assuming a stabilized condition while in reality the oil/water interface is half way up the annular column above the pump intake, as a function of the oil API gravity. The following parameters are constant: gas-free liquid height = 587 feet, casinghead pressure = 46.1 psi, water density 1.05.

Condition	API gravity of Oil	Pump Intake Pressure @ 5226 ft in psi	Difference: (computed minus actual), psi	% difference from actual
Computed PIP Assuming Stabilized	42	252.7		
Actual PIP with oil/water interface at ½ of annular liquid height	42	285.1	-32.4	-11.4
Computed PIP Assuming Stabilized	30	268.5		
Actual PIP with oil/water interface at ½ of annular liquid height	30	294.0	-25.5	-8.67
Computed PIP Assuming Stabilized	20	285.4		
Actual PIP with oil/water interface ½ of annular liquid height	20	302.6	-17.2	-5.68

As the gravity of the oil decreases from 40 to 30 API, the difference between the PIP computed by the software assuming the well is stabilized and the actual PIP for the correct position of the oil/water interface, decreases from -11.4% to -5.6%.

Percentage of Liquid in Annular Gaseous Column: The gas/liquid fraction that exists in the annulus can be determined accurately using the Walker[(3)] test. In practice this test is not done very often, due to logistical and time constraints, so that one must calculate the liquid fraction by using a correlation that relates the well conditions (pressure, temperature, gas flow, fluid properties, etc.) to the gas/liquid fraction. Several correlations have been presented in the literature but the most commonly used is that of McCoy [(9)]. All correlations have limitations related to the range of parameters used in their construction and yield results with some uncertainties. Based on past experience the McCoy correlation is fairly accurate for well conditions characteristic of the Permian basin of Texas and New Mexico.[*] For conditions outside the correlation parameters, such as wells producing heavy oil (API less than 15) the McCoy correlation underestimates the liquid content by about 10 percentage points.

Fluid Level Depth: The depth of the gas/liquid interface generally can be determined acoustically with an accuracy of +/- 30 feet (1 pipe joint), and sometimes better. Assuming 30 API oil and 50% liquid this is equivalent to +/- (0.38 psi/ft X 30 ft X 0.5) = +/-5.7 psi. The relevance of this quantity must be considered in relation to the existing casinghead pressure. The greater the casinghead pressure the lower the percent error introduced by the uncertainty in gaseous column height.

Height of the Gaseous Liquid Column: When the height of the gaseous liquid column is large, the effect of the uncertainty in the percentage of liquid in the gaseous column (discussed in the previous section) is amplified, when computing the PIP. As the height of the gaseous column increases, the uncertainty in PIP increases. In the previous example assuming that the correct liquid percentage is 40% (instead of 50%) the difference in fluid gradient would be (0.38 X 0.1) = 0.038 psi/ft. For a gaseous column of 1000 feet in height, the computed PIP would be too high by 38 psi compared to the actual PIP of 152 or an error of 25% assuming the casinghead pressure is zero. The percent error in PIP due to the uncertainty of the gaseous column gradient decreases as the casinghed pressure increases.

These considerations show that the uncertainty in PIP computed from a fluid level decreases when the gaseous liquid column is short and the casinghead pressure is high in relation to the gaseous column pressure.

In deviated wellbores it is important to enter the correct well deviation survey data since all pressure calculations are based on True Vertical Depth (TVD) while the acoustic survey yields the fluid level Measured Depth (MD)

Guidelines: In summary, to obtain a best estimate of PIP from fluid level measurements the following should be considered:

- Check that the well production is stabilized by monitoring casing pressure and fluid level over an extended period of time until their values remain fairly constant.
- Verify that the wellbore directional information is correct so that calculation of PIP uses the proper TVD values.
- Verify that correct values of API gravity, BHT and surface temperature are entered in the well file.
- Verify that the correct values of casing ID and tubing OD are entered in the well file in order to compute accurate values of annular gas flow rate.
- Verify that the correct average joint length is used in the calculation of the fluid level depth
- Be aware that the value of the annular liquid percentage is obtained from a generalized correlation that is applicable mainly for a certain range of parameters.
- If a high (several thousand feet) gaseous column is present when gas is flowing up the annulus, minimize the height of the gaseous fluid column by allowing the casinghead pressure to increase and depress the fluid level to a few hundred feet above the pump intake. Use a back-pressure regulator to increase casinghead pressure and stabilize the fluid level.

Past experience has shown that by following these recommendations the Acoustic Fluid Level survey can yield values of PIP that are within 5% of those obtained with downhole pressure recorders.

PIP from Dynamometer Valve Checks

Typical dynamometer measurement of polished rod load and position to obtain a surface dynamometer card is generally performed in conjunction with a series of measurements to determine the degree of pump leakage past the valves and plunger-barrel clearance. The results of this “Valve Check” load test may also be used to estimate [11] the PIP. Several polished rod load measurements are taken in sequence first by carefully and gradually stopping the pumping unit on the upstroke (Traveling Valve test, TV) and setting the brake to monitor the load for a short time. Then, after resuming pumping and completing a few pump strokes, stopping the unit on the downstroke (Standing Valve test, SV) to monitor the load for a short time. The initial load measured after stopping on the upstroke should be close to the Weight of the rods submerged in the tubing’s fluid (Wrf) plus the fluid load (Fo) on the plunger. When stopping on the downstroke, the initial load value should be close to the Weight of the rods in fluid (Wrf). In both tests a change of the load while the unit is stopped is an indication of fluid leakage. The upper right hand of **Figure 6** shows a typical record of the valve test for a case where there is no leakage. The vertical axis is polished rod load, in kLb and the horizontal axis is elapsed time, in seconds.

<u>PIP Calculation Method using Valve Check Measurements</u>

When the valves are operating with no or little leakage the load relations at the beginning of each test are thus:

$$TV = Wrf + Fo \qquad (1)$$

$$SV = Wrf \qquad (2)$$

These are <u>static</u> force balances that assume <u>zero</u> friction. Subtracting the second from the first yields:

$$Fo = TV - SV \qquad (3)$$

Where Fo is the fluid load defined as the cross sectional area of the plunger (Ap) multiplied by the difference between the pressure above the traveling valve and the pressure below the traveling valve (the pressure in the pump barrel) at the moment when the plunger stops during the upstroke:

$$Fo = Ap\,(\text{Pressure above TV} - \text{Pressure below TV}) \qquad (4)$$

This last relation is used to estimate the pressure at the pump intake based on the following assumptions:

1. The pressure in the pump barrel during the upstroke after the SV opens is equal to the pressure at the pump intake (PIP). That is, there is no pressure drop through the SV.
2. There are no friction forces acting on the rod string, the polished rod or the plunger.
3. The pressure above the traveling valve is equal to the tubinghead pressure (P_t) plus the hydrostatic pressure due to the fluid in the tubing (Ph_t).
4. The tubing fluid is characterized by an average specific gravity (γ_t)
5. The pump is set at a true vertical depth equal to Dp

Thus:

Pressure below TV = PIP
Pressure above TV = $P_t + Ph_t$
$Pht = 0.433 * \gamma_t * Dp$

Substituting above:

$$Fo= Ap*(Pt + 0.433*\gamma_t*Dp - PIP) = (TV - SV) \qquad (5)$$

Solving for PIP:

$$PIP = Pt + 0.433*\gamma_t*Dp - (TV-SV)/Ap \qquad (6)$$

The objective in presenting this simple derivation is to highlight the assumptions and discuss the practical requirements for accurate estimation of PIP from the valve test.

Figure 7 shows a sample valve test worksheet with the values used in the calculation of the PIP.

Requirements for accuracy

The accuracy of the computed PIP is contingent primarily in satisfying the assumptions listed above. In practical terms this implies that:

- the well is fairly vertical and without dog legs,
- the stuffing box is not too tight,
- paraffin is not present or
- the fluid in the tubing is not too viscous so that
- frictional forces do not affect the measured static loads.

The accuracy of the measured loads impacts directly the results since the computed pressure is related to the difference in loads,

- the linearity,
- stability and
- absence of hysteresis

of the load transducer are more important than its absolute precision. The load sensor must be in good condition, properly installed and calibrated.

The assumption that the pressure inside the pump barrel is equal to the PIP implies that there are no flow restrictions at the pump intake. Also, to fully satisfy this requirement the plunger has to stop smoothly when the polished rod is stopped. Otherwise any vibrations induced in the rod string by a sudden stop, may cause the plunger to oscillate and the TV could open momentarily modifying the pressure in the barrel. Thus proper execution of the valve test is an important requirement.

The PIP calculation involves estimating the specific gravity of the fluid in the tubing. This quantity can be related to the specific gravity of the total produced fluids (oil+water+gas). When little or no gas is produced through the pump, the common assumption is that in the tubing string the water/oil ratio is equal to the water/oil ratio from the well test. This is an approximation that neglects the effect of slippage of the oil relative to the water that causes the in-situ water cut in the tubing to be higher than the produced water cut (holdup of the heavy phase). Thus the computed pressure above the traveling valve will be less than the actual pressure and the computed PIP will also be lower than the actual PIP.
When significant volume of gas is produced through the pump, due to gas interference or a pumped-off condition, then the overall gradient of the fluid in the tubing will be much less than that obtained from the well test water/oil ratio. Estimation of the tubing oil-water-gas gradient can be done by using multiphase flow correlations but is beyond the scope of most dynamometer analysis software. Some dynamometer analysis programs allow the user to modify the tubing fluid gradient based on his previous experience.

The tubinghead pressure must be measured accurately.

The plunger area is used to convert the measured load difference to differential pressure. Thus it is imperative that the correct plunger size be used in the calculation.

Assuming that all these conditions are met, which is difficult and in general practice, it has been estimated that it is possible to calculate the PIP from valve tests with an average difference of +/- 10.6% from measured pressure. This statement is based on a series of 18 tests that compared PIPs calculated from valve test data to PIPs measured using a downhole pressure gage installed at the bottom of the tubing[12].

PIP from Dynamometer Pump Card

As mentioned in the introduction, direct measurement of plunger load and position was originally done via a specially designed mechanical sensor installed at the bottom of the bottommost sucker rod[5]. More recently, solid state, load and acceleration sensors with digital memory were used experimentally to record downhole dynamometer data[7]. The main objective of these tests was to verify that numerical calculation of pump load and position from surface dynamometer data, using the “damped wave equation” model, yields quantitative values that can be used in detailed analysis of pump operation. The results of this experiment were positive so that today the industry accepts this technique as sufficiently reliable also for calculation of pump intake pressure from the difference in loads measured during the upstroke and downstroke of a pump cycle.

The left half of **Figure 6** illustrates a typical dynamometer record showing the surface and pump dynamometer cards plotted on the same graph. The polished rod stroke is 42 inches while the plunger stroke is 35.6 inches due to stretch of the rod string. The indicated values FoUp and FoDn correspond to “average” values of the pump rod load during the upstroke and downstroke of the plunger. The difference between these average values represents the fluid load Fo, as defined earlier.

PIP calculation Method using Pump Dynamometer Values

Based on these definitions and the earlier derivation for the valve check analysis, the following relation can be written:

$$Fo = FoUp - FoDn = Ap*(Pt + 0.433*\gamma t*Dp - PIP) \quad (7)$$

From where the PIP can be obtained:

$$PIP = Pt + 0.433*\gamma t*Dp - (FoUp-FoDn)/Ap \quad (8)$$

Equation (8) is a dynamic force balance (as opposed to equation (6) which is a static balance) since the pump load levels are determined during the motion of the plunger as calculated from the wave equation transformation of the polished rod load and position. As such, in addition to the requirements for accuracy of the computed PIP listed above for the valve check calculation, other conditions must be satisfied as discussed below. **Figure 8** shows a typical pump card and the values used in the PIP calculation worksheet. Default calculation uses the average of the upstroke loads to define FoUp and the Zero Load reference to define FoDn. Note that the user has other options for estimating the appropriate values of these parameters.

Requirements for Accuracy

Damping Coefficient: the wave equation calculation of the pump load and plunger position uses an empirical damping coefficient to account for energy losses related to movement of the rod string relative to the fluid in the tubing and other dynamic losses proportional to velocity. These losses are lumped into a damping coefficient that is proportional to the length of the rod string. From experience, the damping coefficient should have a value of 0.01 per 1000 feet up to a depth of 5000 feet with an additional 0.01 for every additional 2000 feet increment. The distance (Fo) between the FoUp and FoDn lines in **Figure 6** is dependent on the value of the damping coefficient and thus the value of Fo will vary accordingly. An excessively large damping coefficient causes a decrease in the distance between FoUp and FoDn, resulting in a too small value of Fo and too large a value of computed PIP. An experienced dynamometer analyst can adjust the value of the damping coefficient to an acceptable value using some guidelines related to the geometry of the computed pump dynamometer card. In wells producing low API, viscous crudes the damping factor can be greater than five times these default values.

Pump card shifted off the zero load line: generally the pump load for the portion of the downstroke at the point where the traveling valve opens should be close to zero. A shift above or below zero is an indication of possible errors in the description of the rod string composition (diameters and lengths of tapers), or errors in load sensor calibration, or abnormal conditions in the pump such as scale, sand, etc.

Hydraulic friction: Pressure losses due to flow of fluid into or out of the pump are generally assumed to be small in comparison with the hydrostatic pressure difference across the plunger as shown in **Figure 9**. This assumption is not valid in those cases where the valves are undersized in relation to the viscosity of the fluid and in those cases where diameter restrictions are present. One such case occurs when an oversized tubing pump is run to maximize the pump displacement, also know as a “bottled up pump”, where the plunger diameter is larger than the tubing ID. Typically this is used in relatively shallow wells. It causes an additional load at the beginning of the upstroke as the fluid above the plunger is over pressured to force the fluid from the pump barrel into the tubing. This results in an average value of FoUp that is too large and a computed PIP that would be too small.
Another instance of hydraulic friction may occur during the downstroke. When the traveling valve opens and the plunger slides through the fluid in the barrel the load should be close to zero but if the valve is undersized in relation to the viscosity of the fluid the value of FoDn will be less than normal (possibly negative) due to frictional losses across the TV and its cage. The computed PIP will not be lower than normal because this negative load is ignored by using the default value of FoDn equal to zero.

Tubinghead pressure variation: The tubinghead pressure varies during the stroke from a minimum to a maximum value. In most wells the variation is small and does not greatly affect the pump discharge pressure. The PIP calculation includes a single tubinghead pressure value and in this case the operator should measure and enter the average tubinghead pressure.
A tubing back pressure regulator is often used in wells that have a tendency to flow intermittently due to gas interference. The back pressure regulator is used to apply several hundred psi of pressure at the tubinghead with the objective of minimizing gas expansion that would unload the liquid in the tubing, stop normal pump action and reduce lubrication of the stuffing box. The back pressure can cause the values of FoUp and FoDn to be shifted, where they are not necessarily representative of the pump intake pressure.

Pump tagging: This practice should be avoided since it damages the pump and rods. PIP calculation can be affected adversely if the impact loads shift the average value of FoDn.

Guidelines: In summary, to obtain a best estimate of PIP from fluid Dynamometer and/or Valve check measurements the following should be considered:

- Check that pump operation has stabilized
- Measure tubinghead pressure and enter in software for PIP calculation
- Preferably use a direct load measuring load cell sensor (Horseshoe, Donut or Leutert) that is properly calibrated, zeroed and centrally loaded.
- Perform TV and SV valve check several times and select the most representative load values for PIP calculation.
- Verify that Pump Card does not exhibit unusual features and average FoUp and FoDn can be established with confidence.
- Verify that the following data is correct and up to date:
  - Pump Diameter and depth,
  - Rod String description
  - Oil, water and gas densities
  - Oil, water, and gas Production Rate
  - Damping Coefficients
- Verify that the tubing fluid gradient is representative of the producing conditions. (difficult in wells that flow or have lots of gas).
- Consider effects of unaccounted friction: deviated wells, tight stuffing boxes, bottled up pumps, or paraffin when assigning possible error range of computed PIP

Comparison of Methods for Typical Rod Pump Data

To compare the results of PIP calculations based on routine acoustic and dynamometer measurements a fairly large data set was compiled from data supplied by various users of the Echometer Well Analyzer system. (The interested reader can easily obtain and analyze these well data by downloading and installing the free TWM software from the web[13])
A total of 38 data sets from different wells were included initially but only 16 well records included all three tests: acoustic, dynamometer and valve checks as shown in Table 2 where the data set name reflects the particular condition present in that well.

In the construction of Table 2, the acoustic fluid level records for each well were analyzed using the default settings of the TWM software and the computed PIPs tabulated in the "A" column. Pump dynamometer cards were studied and used to compute PIP from FoUp and the zero load reference. These values are tabulated in column "D". Finally the PIP was computed using the valve check data and are tabulated in column "V". From these three quantities an average value of PIP is computed for each well and is used to compute a % difference between the average value and the PIP value from each method. Finally the maximum absolute deviations are presented in the last two columns.
The somewhat unexpected result of this table indicates that the range of PIPs computed by each method, for a given well, can be very large with an average absolute difference of 436 psi or 64.3%.

The large difference prompted investigating possible causes of these fluctuations and one reason was ascribed to the inaccuracies that may be incurred due to incorrect performance of the valve test and a second reason was that some records included the presence of some severe pump problems.
Table 3 shows the comparison results after excluding all valve test data from the average calculations. The average deviation has decreased to 242.1 psi or 30.5 %.
Table 4 shows results after excluding the valve tests and the pump dynamometer records that exhibited severe pump problems. The average deviation has decreased to 55.7 psi or 23.1%.
No adjustments were made to the data and the default analysis was followed in the computation of PIP. Thus the results in Table 4 should be considered that can be achieved by most users of fluid level and dynamometer systems that take reasonable care and follow the guidelines presented in this paper.

Finally, the data was processed further by an experienced analyst that was able to identify and justify manual adjustment of some of the parameters as presented in Table 5. Results show that it is possible to achieve an average difference of 4.5 psi or 3% by judicious use of the adjustments based on experience.

Conclusions and Recommendations

The numerous assumptions and requirements must be considered when using one of the three methods to estimate pump intake pressure or calculations will yield unrealistic values of PIP. This paper attempts to point out some of the potential problems and presented detailed guidelines that will assist in improved analysis of the data.

As a general rule the user should not accept default computation of PIP by any of the three methods. The user must review the results based on his knowledge and experience and verify that the computed values are realistic. As shown by the example data, when no review of the PIP calculation was done, the Average PIP difference between the three methods was 436 psi and the Maximum difference was 2556 psi.

In general:

- The PIP computed from valve tests has the greatest uncertainty unless special care is taken when performing the test and the wellbore conditions (verticality an absence of friction) are ideal.
- The PIP computed from dynamometer pump card has a medium uncertainty but is subject to instrumentation and measurement inaccuracies so that an error of +/-1% in the polished rod load can translate into an error of +/-85 psi in the computed pressure.
- The PIP computed from acoustic fluid level measurements and default interpretation is considered to have the least uncertainty since an error of one tubing joint (30 ft) in fluid level depth translates to an error of +/- 11 psi in computed PIP.

Quality control of the acquired data, instrumentation calibration and procedures used in acquisition of the data is of major importance to obtain reliable values of computed PIP.

A discrepancy greater than 30-35% between the PIP determined from a fluid level measurement and that computed from the pump dynamometer card is likely to be an indication of a problem with the quality of the well data or the acquisition procedures or of a mechanical problem with the pumping system. The causes of the discrepancy should be investigated and resolved by the user.

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9 - McCoy et al.:"Acoustic Determination of Producing Bottom Hole Pressure" paper SPE 14254 presented at the 1985 SPE Annual Technical Conference and Exhibition, Las Vegas NV.

10 - McCoy et al.:" Acoustic Static Bottom Hole Pressures" paper SPE 13810 presented at the SPE 1985 Production Operations Symposium, Oklahoma City, OK.

11- Eickmeier, J. R. "How to Optimize Pumping Wells" The Oil and Gas Journal, August 6, 1973, pages 49-56

12-Ben Elgert, personal communication.

13- TWM Example Files – Download and install free Total Well Management software from www.Echometer.com/software/index/

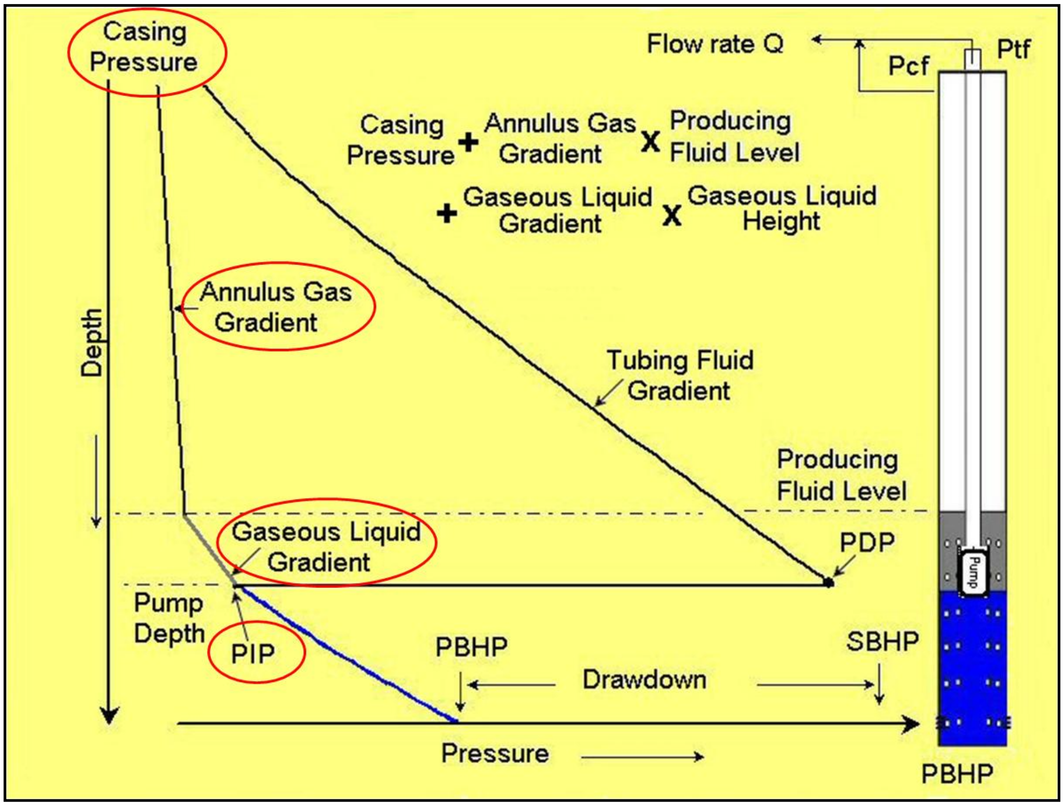

Figure 1 – Definition of Pump Intake Pressure from Acoustic Fluid Level Survey

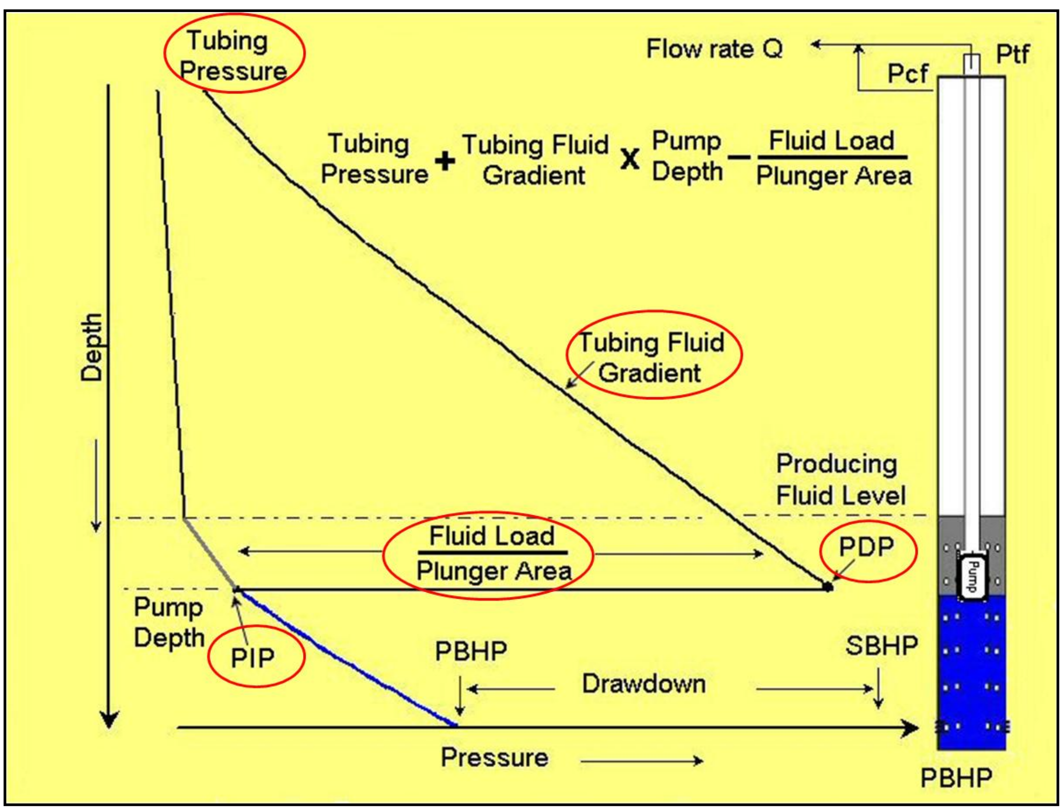

Figure 2 – Definition of Pump Intake Pressure from Dynamometer Measurements.

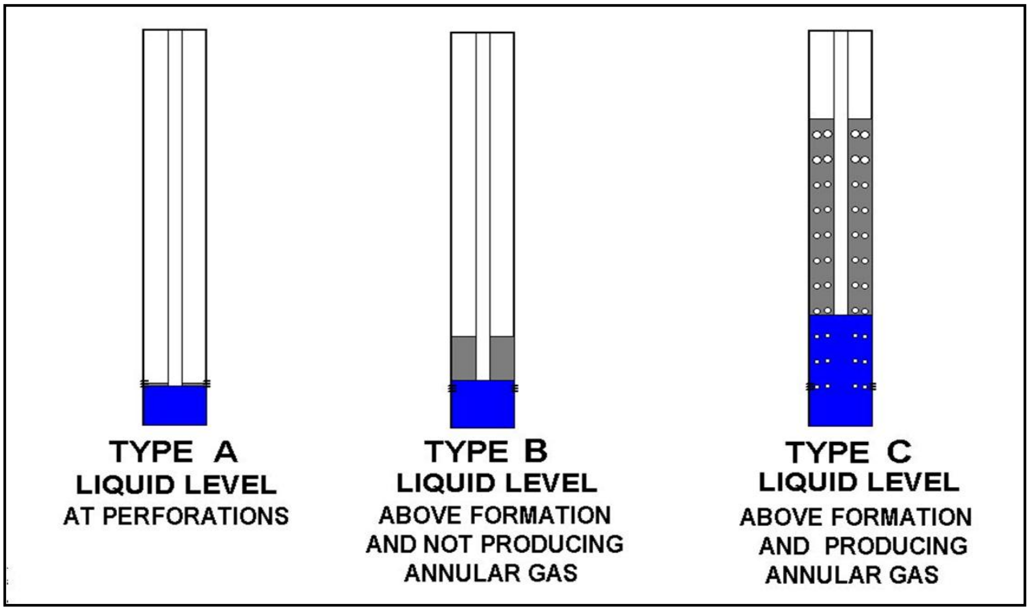

Figure 3 – Classification of Pumping Wells Based on Position of Liquid level and Presence of Gas Inflow.

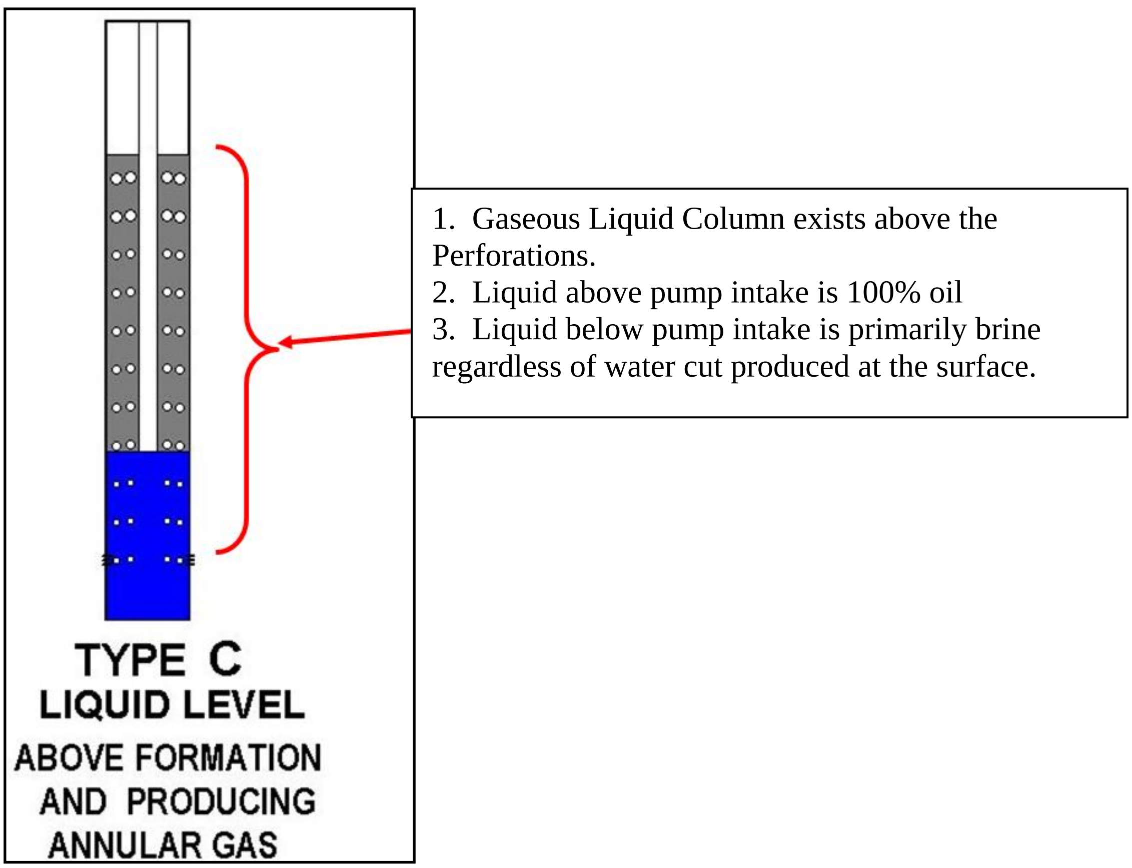

Figure 4 – Separation of Fluids in a Stabilized Pumping Well

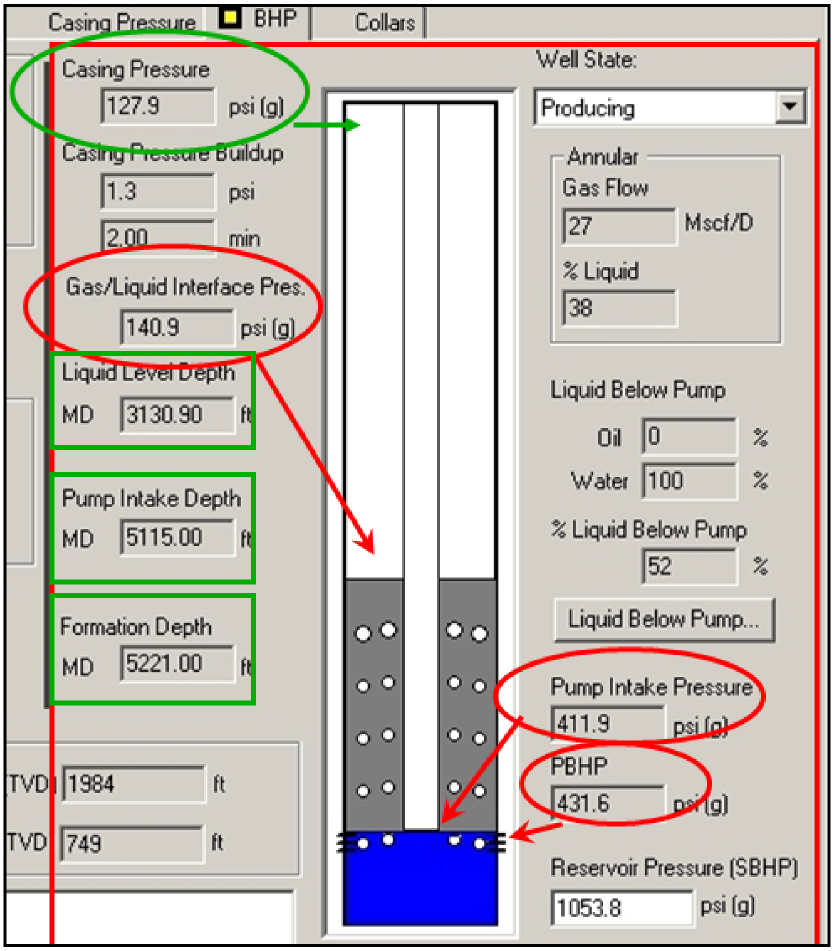

Figure 5 – Presentation of Acoustic Wellbore Pressure Analysis

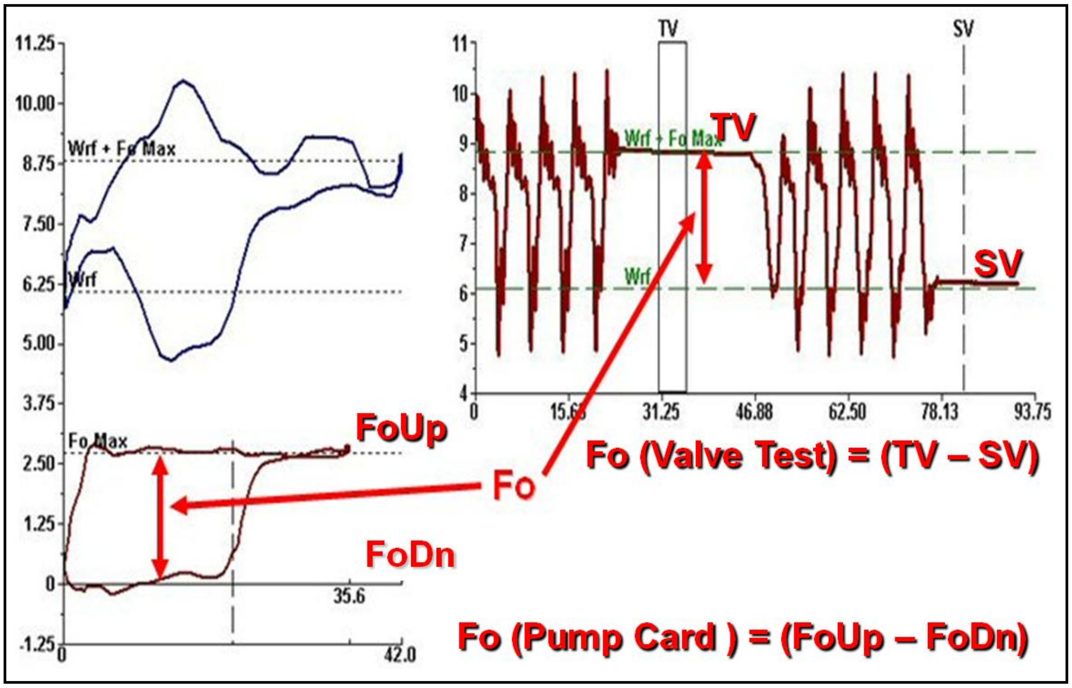

Figure 6 – Definition of Fluid Load from Pump Dynamometer Card and from Valve Test

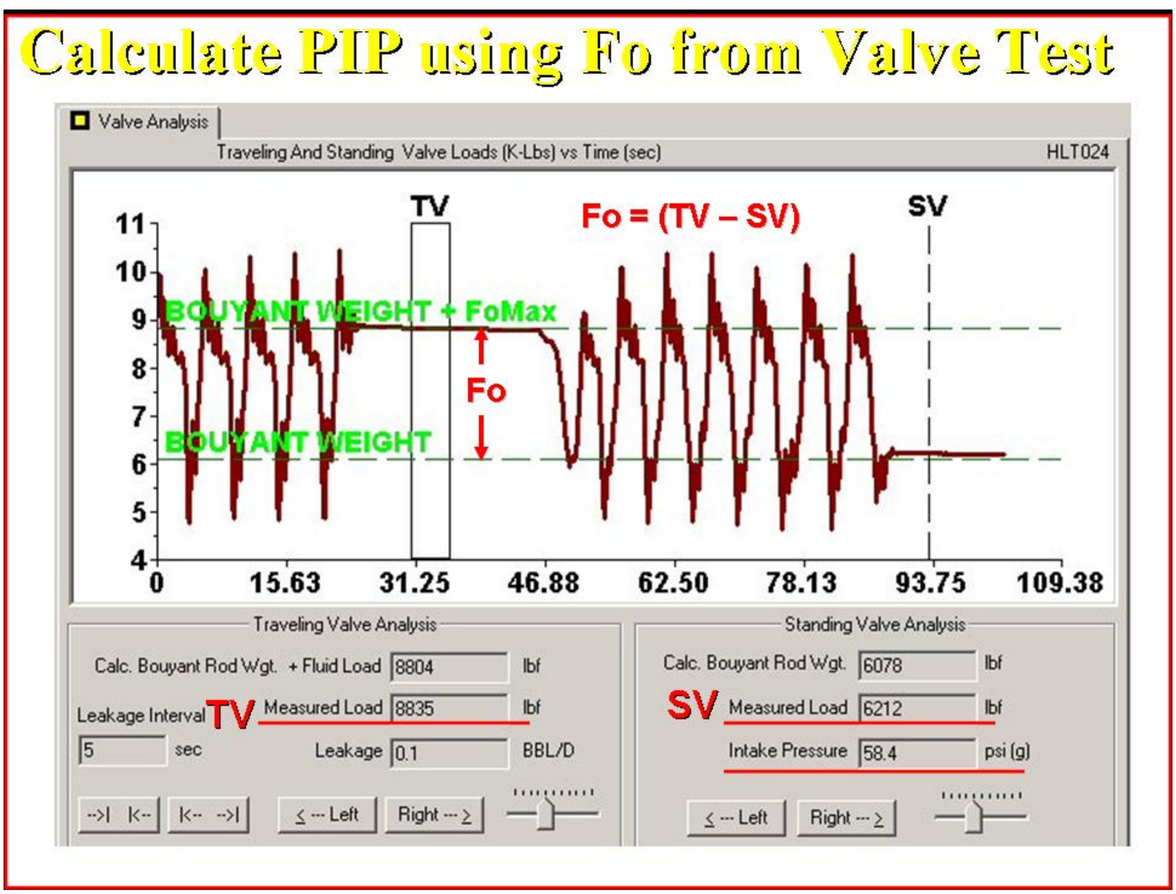

Figure7 – Sample valve Test showing measured values used in calculation of PIP

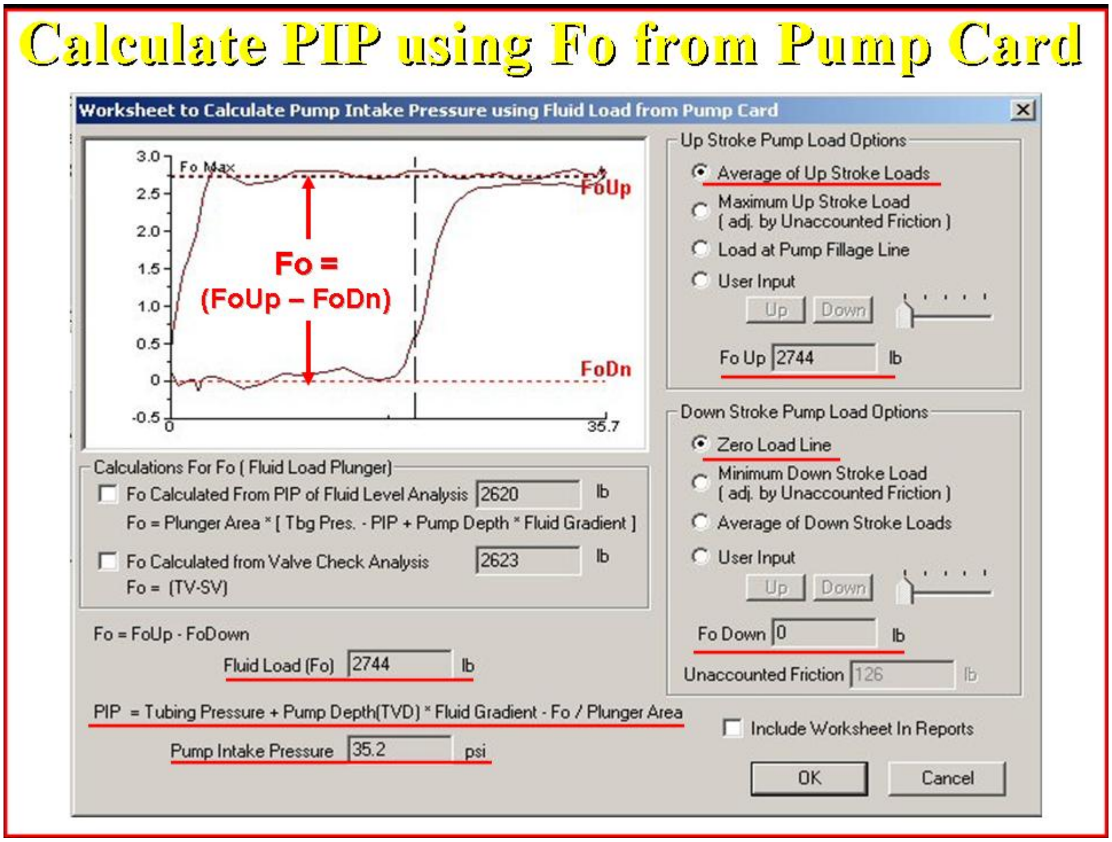

Figure 8 – Sample Pump Dynamometer card showing values used in default PIP calculation

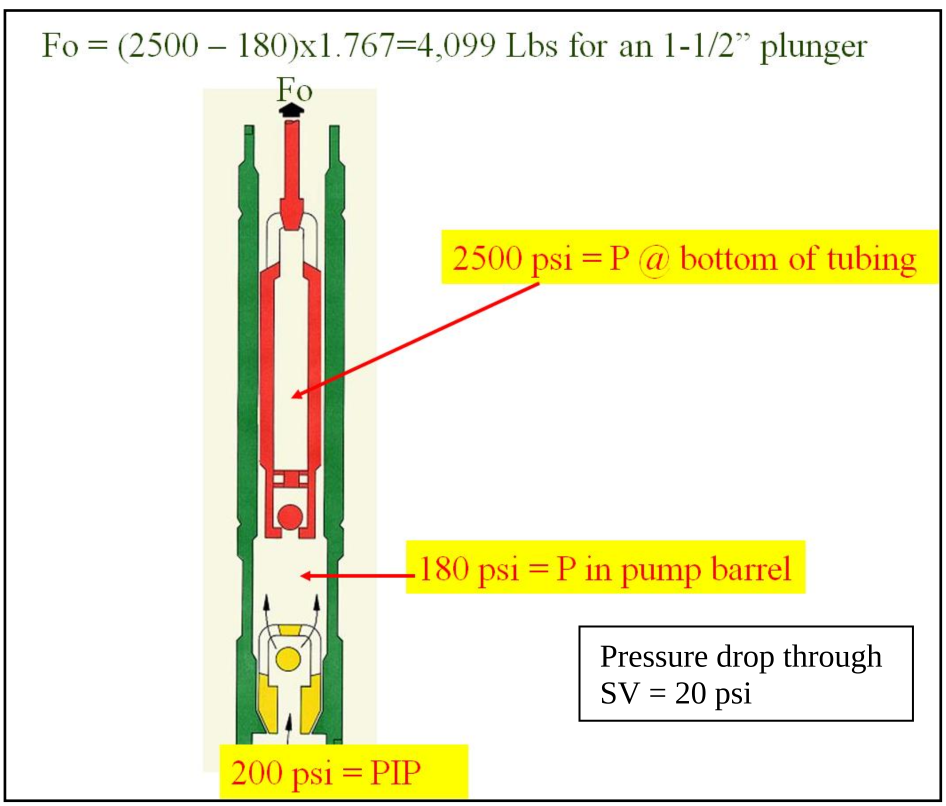

Figure 9 – Pressures at Tubing Pump during Upstroke and Relation to Fo

Table 2 – Sample data sets including acoustic, Dynamometer and Valve Check Data

#	Example Dataset Well Name	DYNO Data	Pump Intake Pressure Pisg			Average	Difference % (Meas - Avg)/Avg			Abs Max Diff.	Abs Max Diff.
		D	A	D	V	Psig	A	D	V	%	Psig
38	V11	HT 3 1	62	66.2	42.7	57.0	8.8	16.2	-25.0	25.0	14.3
7	FluidPoundUnAnchoredTubing	L 2 1	45.4	109.9	58.4	71.2	-36.3	54.3	-18.0	54.3	38.7
9	Gas Interference	L 1	722.3	734.6	647.1	701.3	3.0	4.7	-7.7	7.7	54.2
33	Tagging Unanchored	L 1	62.9	53.6	187	101.2	-37.8	-47.0	84.8	84.8	85.8
16	Need Gas Separator	HT 1	228.4	117.3	271.9	205.9	10.9	-43.0	32.1	43.0	88.6
18	PFL_DHM_CasingWtChange	HT 1	286.5	386.3	550.4	407.7	-29.7	-5.3	35.0	35.0	142.7
32	Tagging Fiberglass Rods on Downstroke	HT 2 1	338.6	58.1	58.1	151.6	123.4	-61.7	-61.7	123.4	187.0
1	Anchored but NOT Set	L 1	400.3	65.3	165.3	210.3	90.3	-68.9	-21.4	90.3	190.0
5	Bad Tail Bearing	L 2 1	568.4	955	731.9	751.8	-24.4	27.0	-2.6	27.0	203.2
37	Unaccounted Wellbore Friction	HT 1	340.5	329.8	18	229.4	48.4	43.7	-92.2	92.2	211.4
2	Anchored With Rod Stretch	HT 47	176	118.3	542.7	279.0	-36.9	-57.6	94.5	94.5	263.7
10	GearboxBalance	HT 1	827.3	810.2	1649.4	1095.6	-24.5	-26.1	50.5	50.5	553.8
35	Trash Sticks TV Open	HT 1 12	305.1	364.7	1228	632.6	-51.8	-42.3	94.1	94.1	595.4
3	Asphaltenes in Pump	L 2	527	1545	1523	1198.3	-56.0	28.9	27.1	56.0	671.3
36	TV Action Erratic	L 1	622.7	2318.3	2303	1748.0	-64.4	32.6	31.8	64.4	1125.3
12	Leak Hole In Pump Barrel	HT 1	405.1	3989.8	4492.1	2962.3	-86.3	34.7	51.6	86.3	2557.2
								Average =		64.3	436.4
								Maximum =		123.4	2557.2
								Minimum =		7.7	14.3

Table 3 – Sample data including only Acoustic and Dynamometer Data

#	Example Dataset Well Name	DYNO Data	Pump Intake Pressure Pisg			Average PIP	Difference % (Meas - Avg)/Avg			Abs Max Diff.	Abs Max Diff.
		D	A	D	V	Psig	A	D	V	%	Psig
38	V11	HT 3 1	62	66		64	-3.3	3.3		3.3	2.1
33	Tagging Unanchored	L 1	63	54		58	8.0	-8.0		8.0	4.7
37	Unaccounted Wellbore Friction	HT 1	341	330		335	1.6	-1.6		1.6	5.4
9	Gas Interference	L 1	722	735		728	-0.8	0.8		0.8	6.2
10	GearboxBalance	HT 1	827	810		819	1.0	-1.0		1.0	8.5
2	Anchored With Rod Stretch	HT 47	176	118		147	19.6	-19.6		19.6	28.9
35	Trash Sticks TV Open	HT 1 12	305	365		335	-8.9	8.9		8.9	29.8
7	FluidPoundUnAnchoredTubing	L 2 1	45	110		78	-41.5	41.5		41.5	32.3
18	PFL_DHM_CasingWtChange	HT 1	287	386		336	-14.8	14.8		14.8	49.9
16	Need Gas Separator	HT 1	228	117		173	32.1	-32.1		32.1	55.6
32	Tagging Fiberglass Rods on Downstroke	HT 2 1	339	58		198	70.7	-70.7		70.7	140.3
1	Anchored but NOT Set	L 1	400	65		233	72.0	-72.0		72.0	167.5
5	Bad Tail Bearing	L 2 1	568	955		762	-25.4	25.4		25.4	193.3
3	Asphaltenes in Pump	L 2	527	1545		1036	-49.1	49.1		49.1	509.0
36	TV Action Erratic	L 1	623	2318		1471	-57.7	57.7		57.7	847.8
12	Leak Hole In Pump Barrel	HT 1	405	3990		2197	-81.6	81.6		81.6	1792.4
								Average =		30.5	242.1
								Maximum =		81.6	1792.4
								Minimum =		0.8	2.1

Table 4 – Sample data Excluding Pump Problem data.

#	Example Dataset Well Name	DYNO Data	Pump Intake Pressure Psig			Average PIP	Error % (Meas - Avg)/Avg			Abs Max Error	Abs Max Error
		D	A	D	V	Psig	A	D	V	%	Psig
38	V11	HT 3 1	62	66		64	-3.3	3.3		3.3	2.1
33	Tagging Unanchored	L 1	63	54		58	8.0	-8.0		8.0	4.7
37	Unaccounted Wellbore Friction	HT 1	341	330		335	1.6	-1.6		1.6	5.4
9	Gas Interference	L 1	722	735		728	-0.8	0.8		0.8	6.2
10	GearboxBalance	HT 1	827	810		819	1.0	-1.0		1.0	8.5
2	Anchored With Rod Stretch	HT 47	176	118		147	19.6	-19.6		19.6	28.9
35	Trash Sticks TV Open	HT 1 12	305	365		335	-8.9	8.9		8.9	29.8
7	FluidPoundUnAnchoredTubing	L 2 1	45	110		78	-41.5	41.5		41.5	32.3
18	PFL_DHM_CasingWtChange	HT 1	287	386		336	-14.8	14.8		14.8	49.9
16	Need Gas Separator	HT 1	228	117		173	32.1	-32.1		32.1	55.6
32	Tagging Fiberglass Rods on Downstroke	HT 2 1	339	58		198	70.7	-70.7		70.7	140.3
1	Anchored but NOT Set	L 1	400	65		233	72.0	-72.0		72.0	167.5
5	Bad Tail Bearing	L 2 1	568	955		762	-25.4	25.4		25.4	193.3
3	Asphaltenes in Pump	L 2									
36	TV Action Erratic	L 1									
12	Leak Hole In Pump Barrel	HT 1									
								Average =		**23.1**	**55.7**
								Maximum =		**72.0**	**193.3**
								Minimum =		**0.8**	**2.1**

Table 5 – Sample data after manual adjustments

#	Example Dataset Well Name	DYNO Data	Pump Intake Pressure Psig			Average PIP	Difference % (Meas - Avg)/Avg			Abs Max Diff.	Abs Max Diff.
		D	A	D	V	Psig	A	D	V	%	Psig
38	V11	HT 3 1	62	66		64	-3.3	3.3		3.3	2.1
33	Tagging Unanchored	L 1	63	54		58	8.0	-8.0		8.0	4.7
37	Unaccounted Wellbore Friction	HT 1	341	330		335	1.6	-1.6		1.6	5.4
9	Gas Interference	L 1	722	735		728	-0.8	0.8		0.8	6.2
10	GearboxBalance	HT 1	827	810		819	1.0	-1.0		1.0	8.5
2	Anchored With Rod Stretch	HT 47	127	118		123	3.5	-3.5		3.5	4.3
35	Trash Sticks TV Open	HT 1 12	352	365		358	-1.8	1.8		1.8	6.4
7	FluidPoundUnAnchoredTubing	L 2 1	45	35		40	12.7	-12.7		12.7	5.1
16	Need Gas Separator	HT 1	228	227		228	0.3	-0.3		0.3	0.7
18	PFL_DHM_CasingWtChange	HT 1	287	301		294	-2.5	2.5		2.5	7.3
32	Tagging Fiberglass Rods on Downstroke	HT 2 1	339	58		198	70.7	-70.7			
1	Anchored but NOT Set	L 1	400	401		401	-0.1	0.1		0.1	0.4
5	Bad Tail Bearing	L 2 1	568	562		565	0.6	-0.6		0.6	3.4
3	Asphaltenes in Pump	L 2									
36	TV Action Erratic	L 1									
12	Leak Hole In Pump Barrel	HT 1									
								Average =		**3.0**	**4.5**
								Maximum =		**12.7**	**8.5**
								Minimum =		**0.1**	**0.4**

#	Example Dataset Well Name	Corrections
38	V11	Normal Well
33	Tagging Unanchored	Pumped Off, Pluid Level at Pump, No unaccounted Friciton
37	Unaccounted Wellbore Friction	Adjusted Pump Card, Fo
9	Gas Interference	Adjusted Tubing Fluid Gradient
10	GearboxBalance	Normal Well
2	Anchored With Rod Stretch	Collars difficult to count, manually selected intereval 7.5 - 8.5 sec
35	Trash Sticks TV Open	dPdT not representative, changed from 0.7 to 0.3
7	FluidPoundUnAnchoredTubing	Use defaults for FoUp and FoDn
16	Need Gas Separator	User selected FoUp Load - Unaccounted Friction
18	PFL_DHM_CasingWtChange	User selected FoUp Load
32	Tagging Fiberglass Rods on Downstroke	Average Joint Length May be incorrect, resulting too high of PFL, exclude data
1	Anchored but NOT Set	User selected FoUp ans FoDn
5	Bad Tail Bearing	Avg of Downstroke Loads, Change Avg tubing from 0.412 to 0.38
3	Asphaltenes in Pump	Bad Dyno - TV not Picking up Fluid Load
36	TV Action Erratic	Bad Dyno - TV not Picking up Fluid Load
12	Leak Hole In Pump Barrel	Bad Dyno - TV not Picking up Fluid Load

End Note

* The wells tested during the study of Reference 9 included casing sizes from 4.5 to 7 in. [11.4 to 18 cm] and oil gravities between 32 and 43°API [0.86 and 0.81 g/cm3]. Long gaseous liquid columns of more than 5,000 ft [1525 m] were studied in wells up to 9,000 ft [2745 m] deep. Annular gas flow rates ranged from 13 to 120 Mcf/D [368 to 3400 m3/d] and oil fractions ranging from 20 to 77% were measured. The wells were located in regions of normal temperature gradients in the range of 0.9 to 1.2°F/100 ft [16.4 to 21.9 mK/m].