ARTIFICIAL LIFT: MAKING YOUR ELECTRICAL SUBMERSIBLE PUMPS TALK TO YOU

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ABSTRACT

Using a diagnostic technique incorporating the use of a gradient traverse plot combined with basic physics and validation principles, this paper will show how an Electrical Submersible Pump (ESP) can be designed, installed and operated to increase reliability and extend run-life.

Since interactions between the wellbore and an ESP are complex, a method is required to assist in the analysis of such interactions. Case histories will demonstrate application of the technique and highlight the practical benefits where well intervention is costly and must be eliminated or minimised.

Our industry understands how to design, commission and operate surface pumps to attain reliability. By applying the same laws of physics and increasing our understanding of ESP performance we can improve ESP reliability. A discussion of the Gradient Traverse plot analysis technique will highlight the hierarchy of measured parameters (pressures, temperatures, amps etc) and show how these parameters can be used to validate well and ESP performance. The technique will then be applied to interpret complex examples of ESP operating problems and demonstrate how measured parameters can be used to understand the ESP and well interactions and prevent ESP failures.

This technique facilitates a ‘holistic’ approach to the design, performance monitoring and failure analysis of an ESP as a system. Consideration of all aspects of well design (well inflow, fluid properties, completion design, desired rates, cost) is critical to understanding the operating environment of an ESP. By implementing a technique that allows validation of well and reservoir data and ESP performance, a better understanding of the system is developed and ‘fit for purpose’ design can be implemented resulting in a more reliable system, thereby reducing well intervention costs.

INTRODUCTION

The subject of this paper is ‘a technique to make your ESP talk to you’; when designing and operating ESPs the first thing that you need to do is give the ESP a ‘mouth’, then you can attempt to understand its language and let it talk to you.

Traditionally, the ESP ‘mouth’ was an amp chart and a fluid level shot on the annulus. Interpretation of the data then told you something about motor load and pump intake pressure. Today’s ESP technology is such that the prudent operator can obtain ESP operating parameters by using a downhole sensor. The dilemma when faced with the wealth of data that comes from such a sensor is ‘which parameters are most important?’. By recognising which variables respond most quickly to a change in operating conditions, you can give your ESP the ability to talk to you.

<table>
<thead>
<tr>
<th>Surface Parameters:</th>
<th>wellhead pressure, wellhead temperature, choke setting, total flow rate, oil rate, gas rate, water rate, produced gas oil ratio, density of produced fluids, frequency, amps, volts.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Downhole Parameters:</td>
<td>pump discharge pressure, pump intake pressure, pump intake temperature, pump discharge temperature, motor oil temperature, motor winding temperature, vibration, current leakage, flowrate.</td>
</tr>
</tbody>
</table>

Table 1 – Summary of operating parameters for an ESP well.
Table 1 identifies some of the parameters that an operator may routinely collect on an ESP well.

To focus on which parameters are the most important, the purpose of the ESP needs to be recognised - to assist a well to produce fluid (hopefully oil) to surface. As such, the ESP should be considered a part of the well system rather than a pump in isolation. Flow occurs in the well as a result of reservoir drawdown; an ESP assists the well to flow (or to flow at higher rates) by increasing the drawdown. Consequently, a change in well behaviour will manifest itself as a pressure change in the wellbore. This paper will show how pressure information from a downhole sensor on an ESP can be used to match and diagnose well and ESP performance.

**THE TECHNIQUE**

The technique utilises the gradient traverse plot to present wellbore pressure and depth information in a format that makes it easy to grasp the controlling factors in a well. By combining well inflow and the physics of fluid dynamics it is possible to understand the theory behind the shape of the gradient traverse plot. The theory can then be applied as part of a step-by-step process to validate ESP performance, well information and reservoir data.

**The Gradient Traverse Plot**

![Gradient Traverse Plot](image)

*Figure 1 – Typical trend plot of data from an ESP start-up.*

The graph in figure 1 shows a typical trend plot of data obtained during the first 24 hours runlife of an ESP. From the plot it can be seen that increasing frequency causes a greater drawdown at the pump intake, discharge pressure stays relatively constant. Motor oil and intake temperatures increase as warmer fluids flow from the reservoir into the wellbore. The first few hours of data for a well are important as these provide the signature of how the ESP interacts in the producing wellbore. Changes in these parameters will represent a change in well or pump performance. By observing trends over time, changes can be identified and the well analysed to determine what has caused the change. The trend plot is essentially the life story or ‘movie’ of the pump system in the wellbore.
To analyse the well when a change occurs takes a little more work but can be done fairly easily with most production optimisation software. The key to understanding what is happening in the wellbore is to develop an understanding of the pressure regime in the wellbore. The pressure regime can then be plotted on a graph of pressure vs. depth, known as the gradient traverse plot (or the ‘snapshot’ of what is happening at any moment in time). To best explain the gradient traverse plot it is easiest to consider a naturally flowing well (see Figure 2).

This plot shows wellhead pressure (WHP), bottomhole flowing pressure and reservoir pressure. The plot was produced for a rate of 1700 BOPD with 0% watercut, a reservoir pressure of 3500 psia and a wellhead pressure of 100 psig. It can be observed that the curve of the pressure vs. depth line is fairly straight below a depth of 6000 ft. The change in the slope of the line from 6000 ft to surface is due to a reduction in fluid density due to gas break out (the bubble point was approx. 1600 psia).

Using the gradient traverse plot it is relatively easy to demonstrate graphically the effect of a change in an operating parameter. Figure 3 shows the same well but this time the plot is produced for an increased wellhead pressure of 200 psig. The effect of this change is to reduce production to 565 BOPD. Looking at the plot shows that the line has moved to the right; increased wellhead pressure has resulted in a higher bottomhole pressure (less drawdown) which means the well will flow less.
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Figure 4 – Gradient traverse plot for a well killed due to increased watercut. Flowrate 0 BFPD, Watercut 12%, Reservoir pressure 3500 psia, Wellhead pressure 200 psig.

Figure 4 shows the gradient traverse plot for the same well but represents the case where the well is producing water as well as oil. For the case shown, the water-cut is 12%. Notice also that the plot of pressure vs. depth is more of a straight-line i.e. the effect of the gas is not as significant. The hydrostatic of the fluid column is such that the bottomhole pressure is approximately equivalent to reservoir pressure, there is no drawdown and the well can no longer flow.

A quick review of these plots shows that pressure changes in the well bore will move the curve across the chart whereas a change in density of fluids causes a change in the slope of the line…and now for the good bit …we get to put an ESP in the well!

Figure 5 – Gradient traverse plot for an ESP lifted well. Flowrate 3330 BFPD, Watercut 12%, Reservoir pressure 3500 psia, Wellhead pressure 200 psig.

Figure 5 shows the same well producing at 12% watercut but with the assistance of the ESP the well can now produce at a rate of 3330 BFPD. Take a close look at the gradient plot, observe how the plot to a depth of 10000ft is almost the same as the case represented in figure 4 (there is a slight difference due to frictional pressure drop).

Now, notice the effect of the ESP (at a depth of 10000 ft) - the head produced by the pump causes the pressure at the pump intake to be reduced. The line representing flow below the pump is shifted to the left causing a much lower bottomhole flowing pressure and allowing the well to flow at significantly higher rates than the when the well was flowing naturally. Examination of the gradient traverse plot for a well with an ESP installed illustrates a fundamental principle - ESPs suck rather than push!
The useful thing about the gradient traverse plot is that it can be used to draw a picture of what’s happening in the wellbore. By presenting the data in this format it is easy to understand what the controlling issues are that govern productivity of the well. You may even stand a chance of being able to explain it to your supervisor!

**Figure 6** – Figs 2, 3, 4 & 5 presented as inflow-outflow performance.

**Figure 6** shows the same information as the gradient traverse plots but presented in the more traditional inflow-outflow relationship. Note the unusual (but characteristic) shape of the ESP lift curve.

**Theory**

To make the gradient traverse plot useful we need to do something more meaningful than draw nice plots. A good starting point is to consider the physics behind the shape of the curve. Examining the gradient traverse plot for a well fitted with an ESP we observe that there are three points that characterise the shape of the curve; wellhead pressure, discharge pressure and intake pressure. In most cases the reservoir pressure will also be known. The relationship between the parameters can be defined as follows:

**Above the pump:**
\[ P_d = WHP + \Delta P_g \text{ above pump} + \Delta P_f \text{ above pump} + \Delta P_a \text{ above pump} \]

**Across the pump:**
\[ P_i = P_d - \Delta P_{pump} \]

**And below the pump**
\[ P_{wf} = P_i + \Delta P_g \text{ below pump} + \Delta P_f \text{ below pump} + \Delta P_a \text{ below pump} \]

**Also from an inflow perspective we can say**
\[ P_{wf} = Pr - (Q / P_i) \]
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Where

\[ P_d = \text{discharge pressure (psi)} \]
\[ P_i = \text{intake pressure (psi)} \]
\[ \text{WHP} = \text{wellhead pressure (psi)} \]
\[ \Delta P_g = \text{hydrostatic head (gravity pressure loss in psi)} \]
\[ \Delta P_f = \text{frictional pressure loss (psi)} \]
\[ \Delta P_a = \text{acceleration pressure loss (psi)} \]
\[ \Delta P_{pump} = \text{(Head in feet x fluid specific gravity/2.31) (psi)} \]
\[ P_{wf} = \text{bottomhole flowing pressure (psi)} \]
\[ P_r = \text{reservoir pressure (psi)} \]
\[ Q = \text{well flowrate in stock tank barrels liquid (stbl/day)} \]
\[ PI = \text{productivity index (stbl/day/psi)} \]

By using the above relationships to understand the output from your production optimisation software it is possible to calculate water cut, mixture density, pump head, bottomhole flowing pressure and flowrate.

For oil wells the acceleration term is negligible and so can be ignored in the majority of cases (particularly on wells that are ESP lifted). Also, in oil wells the gravitational term comprises a minimum of 80% of the pressure change in the wellbore and in some cases can be as high as 99%, the frictional term therefore becomes the secondary factor rather than the governing parameter.

Since software is available to calculate the pressure drops in the wellbore we do not need to concern ourselves, for the purpose of this paper, with how to calculate the values manually. Suffice it to know that gravity forces are the big bit.

Table 2 – Comparison of friction and gravity effects on the ESP produced well.

<table>
<thead>
<tr>
<th>Wellhead</th>
<th>Friction</th>
<th>Gravity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure</td>
<td>100</td>
<td>90</td>
</tr>
<tr>
<td>Q</td>
<td>50</td>
<td>45</td>
</tr>
<tr>
<td>PI</td>
<td>0.5</td>
<td>0.45</td>
</tr>
<tr>
<td>WHP</td>
<td>1000</td>
<td>900</td>
</tr>
<tr>
<td>Pd</td>
<td>1000</td>
<td>900</td>
</tr>
<tr>
<td>Pwf</td>
<td>100</td>
<td>90</td>
</tr>
</tbody>
</table>

Table 2 provides the density and friction terms used to produce figure 6 and illustrates, in this case, that the gravity term is 95% of the pressure loss whereas friction is only 5%. Note: For viscous crudes, emulsion-forming fluids or in the case of high rate and narrow tubing the frictional pressure drop can become as high as 20%.
Since flow in the wellbore occurs due to pressure effects, it is evident that the parameters that respond most quickly to tell us what is happening in the wellbore are discharge and intake pressure at the pump. Historically, amps have been used to analyse ESP performance - in actual fact what they are measuring is motor load and change in motor conditions in response to change in pressure or flow in the wellbore. Why not just analyse pressures from the start?

**Validation**

In the majority of cases the hierarchy of parameters for giving an indication of what is happening to the ESP system is:

- Discharge and Intake pressure,
- Intake and Motor Temperature,
- Amps and Flow.

None of these parameters used in isolation will tell you what is going on in the ESP but when used in conjunction with the gradient traverse plot (and the previously stated relationships) it becomes possible to analyse and determine what is happening in the wellbore by applying the following process:

1. Work top (WHP) down
2. Match pump discharge
3. Match across pump (gives pump intake pressure)
4. Calculate $P_{wf}$
5. Compare to well inflow

Consider flow in the well above the pump. We have already developed the relationship for what happens above the pump:

\[ P_d = WHP + \Delta P_g + DP_f \]

The known parameters, from measurement, should be WHP and discharge pressure, if these two parameters are known then the beginning and end point for the curve above the pump are known. The density of the fluid and frictional forces in the tubing affects the shape and slope of the curve. By using the output from our production software we can match our wellhead and discharge pressures to determine water cut, tubing gas oil ratio (GOR), frictional pressure drop, specific gravity of the fluid at the pump discharge and in the process we validate (principally) our fluid property (PVT) and watercut information.

Similarly, across the pump

\[ P_i = P_d - \Delta P \]

The known parameters are discharge pressure and intake pressure. The DP produced by the pump is affected by frequency, flow, number of stages, specific gravity of fluid and pump efficiency. Normally the frequency and flow are known (but not always). The DP value can be converted to head and plotted on the pump curve. When the operating point fits the pump curve then we have validated our data, when the operating point does not fit the curve then we must look at frequency, flow, number of stages (broken shaft), gas effects (or specific gravity of fluid), pump wear, viscosity and emulsion effects. Note: The operating point on the pump curve should always be the volume downhole (i.e. surface volume with formation volume factors applied to correct to a downhole volume).
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And below the pump
\[ \text{Pwf} = \text{Pi} + \Delta \text{Pf} + \Delta \text{Pg} \]

Since the PVT and watercut should already have been validated above the pump, it should be straightforward to model down from the pump intake to the reservoir interval and calculate a bottomhole pressure (note that the friction term below an ESP is usually small due to the larger casing diameter.) The bottomhole pressure should also correspond with that calculated from the inflow performance relationship for the given flow rate. Knowledge of the bottomhole pressure allows you to determine PI or reservoir pressure (one has to be known and the other can be calculated).

<table>
<thead>
<tr>
<th>Above the pump</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Validate PVT</td>
<td></td>
</tr>
<tr>
<td>• Watercut</td>
<td></td>
</tr>
<tr>
<td>• Fluid specific gravity at pump discharge</td>
<td></td>
</tr>
<tr>
<td>• Tubing GOR</td>
<td></td>
</tr>
<tr>
<td>• Measure friction effect</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Across the pump</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Validate Q, frequency, number stages</td>
<td></td>
</tr>
<tr>
<td>• Measure viscosity and emulsion effects</td>
<td></td>
</tr>
<tr>
<td>• Fluid specific gravity at the pump intake</td>
<td></td>
</tr>
<tr>
<td>• % free gas at the pump intake</td>
<td></td>
</tr>
<tr>
<td>• Obtain operating point for pump curve</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Below the pump</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Calculate bottomhole Pwf</td>
<td></td>
</tr>
<tr>
<td>• Obtain PI or Pr</td>
<td></td>
</tr>
</tbody>
</table>

Table 3 – Summary of calculated / derived parameters that can be obtained from the gradient traverse plot.

Table 3 provides a summary of the parameters that can be derived using the gradient traverse plot. By focusing on the wellbore rather than just the pump and motor, it is possible to determine more than “is the pump happy?”; the information can be used to perform production allocation and prediction of future well performance including production optimisation. Additionally, this information can be used for intelligent control systems or to define well specific alarm and trip settings to assist in failure prevention.

Using the analogy of pump in a refinery or platform topsides, facilities engineers use flow indication in conjunction with pressure and temperature readings as the main indicators of what is happening to a pump (of course the motor would also be protected using current trips). Why, when we put a pump downhole, do we try and diagnose the performance of the pumping system using a current (amps) reading? By putting comprehensive instrumentation on a downhole pump and using the data from the pump we can listen to our pump talking to us.
THE APPLICATION

Consideration of the following examples and case histories should help to explain how the technique is applied in practice to analyse and predict the performance of the well and ESP.

Case 1 - Failure Analysis or Failure Prevention – Your choice!

Figure 7 – Trend analysis plot for an ESP start-up and failure in less than 2 hours.

The ESP in this well failed in less than 2 hours. Why? The trend analysis plot (figure 7) shows a typical pattern of the ESP being started and intake pressure reducing, the well is brought on against a closed choke and so a rise in discharge pressure is observed. Choke changes at surface cause some changes in the discharge pressure reading but essentially the discharge pressure remains stable; changes in frequency cause the intake pressure to decline further (to 54 Hz). It can be observed from the plot of pump dP (Pd minus Pi) that from 54 Hz onwards the pump dP is declining. Normally a declining pump dP over time is indicative of higher flow (i.e. the operating point on a head curve moves from left to right), in this case the declining dP is not due to increasing flow. At around 17:40 the frequency is increased to 55 Hz, the pump dP continues to decline and the motor temperature starts to increase. The ESP failed eventually on downhole over-current.
Figure 8 – Gradient traverse plot for Match #2.

**Figure 8** shows the gradient traverse plot for the point shown as Match #2 on the trend plot (figure 7). From the gradient traverse plot it can be seen that even with the pump operating the bottomhole pressure is 150 psi higher than reservoir pressure. The well is unable to flow. Plotting the head on the pump curve (calculated from measured dP) also confirms that the pump is in a no flow condition. At this point everything is operating ‘normally’, even though the well is not flowing, the pump head developed conforms to the head curve at the operating frequency. (Note: A downhole flowmeter was installed in this well and was reading zero flow. The flowmeter was deemed to be not working correctly.) A reduction in bottomhole pressure below reservoir pressure to create a flowing condition could have been achieved in two ways; by reducing the wellhead pressure by 200 psi or by increasing the frequency to 58Hz. Neither of these actions was taken.

Figure 9 – Gradient traverse plot for Match #3.
Figure 9 shows the gradient traverse plot shown as Match 3 on the data trend plot after the frequency had been increased to 55 Hz. The plot shows that the pump head has decreased and no longer conforms to the expected head curve for the operating frequency indicating damage to the pump impellers / diffusers. The ESP ran a further 30 minutes before failing on over-current.

At no time during the life of this pump was enough reservoir drawdown achieved to allow the well to flow; this was the fundamental cause of failure. This analysis was performed as a failure analysis which could so easily have been failure prevention if the appropriate tools had been used during startup of the well.

Case 2 – Validation of PVT and PI

This example illustrates the extent of information that can be gained by an analysis of the data collected from monitoring an ESP system. Apart from diagnosing pump performance, the data has been used to infer fluid properties, well flowrate, watercut and bottomhole pressure.

This well is a recompletion to an upper reservoir zone. The zone had been tested during a drill stem test in an offset well as part of the original field discovery. No PVT data existed for this zone. The ESP system for this well was designed using PVT for the lower reservoir. By using the trend analysis plot in combination with the gradient traverse plot it was possible to highlight that hydrocarbon (PVT) properties were very different from those that had been used for the ESP design.

Matching the discharge pressure (above the pump) for a known WHP and watercut proved to be unsuccessful using the PVT for the lower zone. Validation indicated that to match the discharge pressure a light but dead oil fluid (32° API) with unusually low GOR (6 scf/stb) and bubble point (50 psia) would have to be present.
PI was calculated from the stabilised flow period on the 14-Jun-99 as shown in the trend plot in Figure 10. Watercut (5%) was calculated from the pump discharge pressure and known wellhead pressure, and flowrate was derived from the pump performance curve (1900 stbl/day) thus allowing accurate calculation of flowing bottomhole pressure. With a given reservoir pressure of 2404 psia, the PI was calculated to be 1.0 stbl/day/psi. This PI was used to cross-correlate flowrates in earlier time periods.

![Gradient traverse plot for Match #1.](image)

**Figure 11 – Gradient traverse plot for Match #1.**

<table>
<thead>
<tr>
<th></th>
<th>Match 1</th>
<th>Match 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>WHP (barg)</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>Pd (psia)</td>
<td>2335</td>
<td>2100</td>
</tr>
<tr>
<td>Pi (psia)</td>
<td>962</td>
<td>814</td>
</tr>
<tr>
<td>Total flowrate (stbl/d)</td>
<td>1370</td>
<td>1550</td>
</tr>
<tr>
<td>Watercut (%)</td>
<td>80</td>
<td>15</td>
</tr>
<tr>
<td>Pwf (psia)</td>
<td>1060</td>
<td>922</td>
</tr>
</tbody>
</table>

**Table 4 – Summary of parameter changes as the well cleans up.**

The two match points clearly show the well rapidly unloading from 80% down to 15% watercut with an associated decrease in bottomhole flowing pressures and hence increase in flowrates (from 1370 to 1550 stbl/day). The gradient traverse plot shown in Figure 11 represents match point 1. Table 4 summarises the key parameter changes between the two match points. The pump is operating in downthrust throughout the start-up period. This indicates that the PI used to design the ESP was higher than the actual productivity of the well. For the next completion of this well a smaller pump will most likely be run. This example shows how the data obtained from an analysis can be used as part of an iterative process to validate fluid properties and well inflow performance. This information can then be used to design future ESP installations.
Case 3 – Viscosity Correction

This example illustrates how knowledge of the pump intake and discharge pressures can be used to measure the effect of high viscosity on pump performance and flow in the tubing.

![Figure 12 – Reduction in pump performance with high viscosity.](image)

Many papers have been published concerning the effects of viscosity and emulsions on pump performance. The published material shows that the normal pump affinity laws do not apply for viscous crudes and the ability of a pump to generate head and handle throughput are reduced. Figure 12 shows a plot of this effect, produced from tests performed using high viscosity dead crudes.

The prediction of the effect of viscosity (or emulsions) on pump performance is very difficult. Any form of predictive analysis or modelling makes assumptions about the change in viscosity of the fluid (with heating and change in pressure) as it passes through the pump. Viscosity correlations are available for flow in the tubing but they are not valid for flow through the pump; attempts to model or calculate these viscosity effects are liable to miscalculate pump dP (head).

To design and size a pump for use in heavy crudes, correction factors are used for head and flowrate. These correction factors are based on laboratory tests that have been performed using selected pumps in a variety of dead crudes (typical correction factors are 0.8 on head and 0.5 on flow). The results of these tests are then extrapolated to other pumps to assign correction factors so that viscosity effects can be accounted for in pump design. This is a good approach where no existing data exists for pump performance in a specific field. However, for any operating ESP system the actual viscosity effect can be determined. Measured values of Pd and Pi give an exact pump dP and hence direct measurement of the viscosity effect at the operating condition.
If WHP, Pd and Pi are measured we can prepare a gradient traverse plot and plot an operating point on the head curve for the specific operating frequency (see figure 13). The gradient traverse plot allows us to:

- validate tubing viscosity effect (above the pump);
- determine the pump correction factor (across the pump) and;
- validate well inflow performance (below the pump).

This technique is particularly valuable in viscous crudes as the tubing viscosity effect determination can be used to refine flow correlations and the empirically derived pump correction factors can be used for design of future pumps. Well inflow performance is used for history matching and production profile prediction.

**Case 4 – Fluid level validation and well performance prediction**

*Figure 13 – Reduction in pump performance with high viscosity based on measured parameters.*

*Figure 14 – Fluid shot indicates very low pump*
In many land operations where ESPs are relatively inexpensive and can be worked over easily, no sensors are run downhole. Operators analyse such wells by performing a fluid level measurement and converting fluid level to pump intake pressure. In this case, the gradient traverse plot was used to validate well performance data and determine that the fluid level measurement was in error.

The well was known to be producing approx. 5000 stb/d with a watercut of 54% operating at a wellhead pressure of 160 psi. The pump installed in the well was direct on line and operating at a frequency of 60Hz. The indicated bottomhole pressure from a fluid level measurement was 2100 psig. Using production optimisation software the discharge pressure was calculated to be 2306 psig based on well PVT, watercut and WHP. Plotting this information on the gradient traverse plot (figure 14) shows a very low pump dP (200 psi). This would only be possible if either the flowrate is 30% higher or the pump is damaged (30% effective stages) and well PI is wrong. One of the initial input measurements has to be incorrect!

The operator was confident that the metered production from the well was accurate, the calculated discharge value for the produced fluid PVT should be within +/- 5% and since the pump was relatively new it was unlikely that 70 % of the stages were inoperative. By a process of elimination the pump intake pressure value determined from the fluid level measurement had to be wrong. Using a pump intake pressure of 1580 psig the data was re-examined (figure 15). The revised intake pressure is consistent with inflow performance assumptions of reservoir pressure of 4300 psig and a PI of 15 stb/day/psi.

It can also be observed that the pump is operating in upthrust. Using the gradient traverse plot in a predictive mode it is possible to determine what would have to be done to operate the pump ‘inrange’. Since the pump is direct-on-line it is not possible to alter frequency so wellhead pressure is the only means of control. Increasing the wellhead pressure to 250 psi will reduce the flowrate to bring the pump in range. Operating at a lower well flowrate will improve ESP efficiency and improve pump runlife, although whether or not the operator is prepared to accept lower production rates for longer ESP runlife requires a cost benefit analysis.

Note: In this case the fluid level measurement was shown to be 33% in error.
Case 5 – Production Allocation

Measured parameters can be used throughout the life of the ESP to derive watercut, flowrate, bottomhole flowing pressure and well productivity index (or reservoir pressure) to assist with production allocation and reservoir management.

The technique was applied to a well where it was not possible to perform well tests on a regular basis. By using measured values for WHP, Pi, Pd and frequency, derived values were obtained for watercut, flowrate, Pwf and PI. Table 5 tabulates the derived parameters for this well and shows how the technique was used to monitor well clean-up following a workover and to provide production allocation information for a 6-month period after the watercut had stabilised.

<table>
<thead>
<tr>
<th>Well</th>
<th>XX-1 (Nov-98 to May-99)</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Match Date</th>
<th>Time</th>
<th>WHP</th>
<th>Pi</th>
<th>Pd</th>
<th>Frequency</th>
<th>Water Cut %</th>
<th>Flowrate</th>
<th>Pwf</th>
<th>PI</th>
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<tbody>
<tr>
<td>10Nov98</td>
<td>17:30</td>
<td>2.3</td>
<td>2023</td>
<td>2476</td>
<td>35</td>
<td>100/1:09</td>
<td>8,120</td>
<td>3204</td>
<td>14.4</td>
</tr>
<tr>
<td>18Nov98</td>
<td>16:40</td>
<td>2.3</td>
<td>1965</td>
<td>2548</td>
<td>35</td>
<td>100/1:08</td>
<td>5,000</td>
<td>3154</td>
<td>12.3</td>
</tr>
<tr>
<td>19Nov98</td>
<td>19:08</td>
<td>2.5</td>
<td>1939</td>
<td>2466</td>
<td>40</td>
<td>99/1:07</td>
<td>8,120</td>
<td>3096</td>
<td>13.2</td>
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Table 5 - An example of production allocation using measured parameters.
BENEFITS / CONCLUSIONS

In the above examples an attempt has been made to focus on understanding ‘normal’ ESP performance and how being able to understand what is happening can prevent failures, determine what is occurring in the wellbore (reservoir, pump, tubing), provide information for ESP design and aid control and operation of the system. None of these examples used amps to perform diagnosis; the wells were analysed purely from a hydraulic standpoint (although amps should be used to verify that the electrical indications match the hydraulic interpretation).

The key to using this technique is to understand what is happening in your well when you first turn on your ESP. By understanding present and past performance we can quickly identify and analyse any change in performance. Using this same technique it is possible to diagnose problems such as plugging at the pump intake, gas locking, tubing leaks, broken pump shafts, pump wear or wrong PVT (design information). Additionally the method can be extended to predict future well behaviour based on sensitivity type analyses for watercut, GOR or reservoir pressure.

Understanding your wellbore from a holistic standpoint can help prevent premature ESP failure (as shown in case 1), be used to set appropriate alarms and trips on ESP control and protection systems (calculated specifically for each well) and gives the operator the tools to improve pump runlife.

This technique is inexpensive to implement and does not require any new equipment, software or tools. It simply requires a little education and an understanding of which parameters tell us the most about what is happening in a well. Most operators already collect the data required to perform this type of interpretation. In many cases so much data is being collected that people do not know where to begin analysing the data. This paper identifies the parameters and the technique that should be your starting point in attempting to understand well performance in ESP lifted (and other forms of artificial lift) wells. In essence this technique is no different from traditional nodal analysis techniques, the difference is that the way the information is presented is easy to understand. With a little practice you too can use this technique to let your ESP talk to you …….Are you prepared to listen?
BIOGRAPHY: SANDY WILLIAMS

Sandy Williams has worked in the Petroleum Industry for 24 years. He is the founder of Artificial Lift Performance Ltd (ALP), a company which specializes in helping operators get more oil - a skill which he explains to the layman as being ‘like Viagra for oil wells’.

Sandy worked 9 years for Amoco, then Phoenix and Schlumberger Artificial Lift before becoming a consultant focused on artificial lift and production optimization. He has worked and lived in the USA, Oman, Venezuela, Ecuador, Colombia and has taught over 150 courses related to production optimization and artificial lift and is fluent in Spanish.

He started ALP 10 years ago, a company focused on assisting operators: improve the application of artificial lift; reduce productions costs and; increase staff competency. ALP also offers a number of software products to help operators manage artificial lift. ALP is currently assisting operators on projects in the UK North Sea, Colombia, Oman, Qatar and the USA.

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