Production Management of Electric Submersible Pumps Using Expert System Technology


Abstract
Management of electric submersible pumps (ESP) at wellsites can be improved using expert system technology to combine real time sensor information with production engineering knowledge rules. When abnormal conditions exist on an ESP well it is not always apparent that there is a problem until significant production loss and/or the results of pump damage become apparent. By applying expert system technology and elements of artificial intelligence, visualization of well performance in relation to the pump manufacturers’ operating limits can be presented to operations personnel in real time. The well performance can then be maximized once the operating constraints are known and algorithms to optimize production can logically follow. The expert application described in this paper demonstrates this ability and can be extended easily to multiple well sites. The application was written for production at ARCO Alaska’s West Sak field in parallel with the field development.

Introduction
ARCO Alaska Inc. has developed a new field on the North Slope called West Sak. With respect to control system and operations, a number of new technologies were implemented. One of these new technologies involved using a commercial expert system software package to demonstrate the capability of managing wells equipped with electric submersible pumps. Because of the oil rates and API gravity, both ESP and PCP artificial lift are being used. Since the development plan was to try to significantly automate the field drillpads and operate the field with the same amount of operations staff, it was felt that a software tool was required, in addition to the basic capability of SCADA, to analyze and advise of abnormal situations arising at individual wells. MacAllister, Day and McCormack explained a number of uses of expert systems, but none of which were designed to operate in a real time environment physically connected and communicating with live control systems. Issues of connectivity and data throughput, as well as client server technology have significantly improved allowing the offline concepts to now be applied on-line.

There are many offline software packages available to assess well performance. The application developed for the ARCO West Sak field applies first principles to get to the root of the problem, namely producing wells with ESP’s within the design constraints of the down-hole equipment. The same methodology has been applied to progressing cavity pumps (PCP), and will be extended to gas lift.

Problem Definition
Production management currently is not a real time function. Price pressures on both ends of the spectrum lead to this subject not being well served. When the price of oil is high, increasing the production through finding and development is the norm. When the price is low, management looks to reduce operating cost by removing people rather than optimizing current production. Significant reductions of operating cost and increased well productivity can be realized through the use of intelligence systems which combine real-time wellhead sensor information with knowledge of well characteristics and production operations by people. The proactive approach to declining prices is to reduce operating cost. The component of operating cost that can be addressed with this technology is increasing well on production time and optimizing deliverability of the well.

Another factor is that producing wells at their optimum requires analysis tools and data from the wellhead quickly. Without a SCADA infrastructure and the analysis tools, this process can take months. Making the wellhead information available to multiple users is not an easy task in a multi-layered corporate environment where the data must pass from department to
department. Every user has a specific need and the data may not be in the form required specifically for their use. Analysis tools are now available to provide the analysis portion of this solution, which contain elements of artificial intelligence to capture and apply practical knowledge and assist in the management of the field assets. Figure 1 indicates a partial PID describing how the expert system application fits into the regulatory control scheme for a typical well.

**Instrumentation**
Throughout this discussion it will be noted that both the pump intake pressure and the annulus gas rate are measured data. Initial wells were so equipped with the appropriate sensors. In the absence of these sensors as is normal practice, the application includes estimations of gas separation and will not correct the pressure traverse calculations based on intake pressure. It is also noted that variable speed drive technology is utilized. Information from the wellpad is made available to the application from the installed SCADA system through a production reporting database, as well as real-time data required to trigger rules. Tables 1 and 2 indicates the variables used by the application.

**Analyzing Well Performance**
A submersible pumping system can be analyzed on the basis of a single point stable test when the pump intake pressure and the annulus gas rate are known. The results will be tubing flow performance, an estimate of pump discharge pressure, pump performance from suction to discharge, and a single point on the top of perforations well inflow capability curve for the operating tubing head pressure when the test was obtained. By applying known characteristics for the producing zone, the well inflow capability at the top of the perforations depth can be established for the entire range of producing pressures between static reservoir pressure and zero. Pressure traverse procedures can be applied to transpose the well inflow characteristics to the pump intake depth, and the well capability at pump intake depth is established. Data provided by the pump manufacturers is overlaid on the pump intake depth well capability data to provide a bench mark data set of operating constraints associated with the well and the installed equipment for the current test. Figure 2 indicates a block diagram of the analysis procedures.

**Inferring Flow from Tubing Head Pressure**
Assuming that the gas separation efficiency at the pump intake does not change with minor changes in tubing head pressure, tubing pressure traverse procedures can be coupled with pump performance procedures to arrive at a tubing head deliverability curve. The result is data that can be used between tests to infer well production rates. Production rates can also be inferred from the measured pump intake pressure value. But, pump intake pressure sensors frequently malfunction; in which case the tubing head deliverability data becomes the only producing rate inference source. Figure 4 shows a graph of well inflow from the application.

**Rules Definition – Purpose of Rules**
Natural language rules are used to generically control the behavior of the objects represented graphically. The interaction of variables with each other and knowledge embedded in the rules is what makes the application unique. The purpose of the rules is to provide intelligent analysis of situations that can be recognized by sensor inputs trending in directions unknown by the operator of the field. Figure 3 shows an example rules in practice. It is interesting to note that the syntax of the rules is natural language, hence revisiting the rules for their meaning does not require a translation from programming code as would be necessary with a more traditional software language.

**Unloading / Start Up Procedures**
An acceptable unloading process must first be accomplished before a well can be operated, and managed, in the stable-producing mode. Many premature down hole equipment failures occur as a result of damage inflicted during initial start up, or during start up following an extended shut down period. D.J.Cohen et al. explained the significance of start-up procedures, especially for large HP pumps and the significance of kill fluids on pump start strategies cannot be omitted. These types of failures can be avoided by applying real time on-line start up procedural rules, automated within the expert system, which never allow the pumping equipment to be operated beyond design constraints during the start up process.

**Optimizing Individual Well Performance**
Many individual well optimization rules can be established by the end user; the real time on-line AI System would adhere to these rules, and would inform the operator on an informational basis when exceptions are approaching, and on an urgent basis when exceptions actually occur. Examples:
1) Operate the down hole equipment within design constraints.
2) Maintain the well at a desired pump intake pressure.
3) Operate the well at a desired production rate.
4) Limit the amount of draw down allowed.
5) Maintain the well at a desired draw down level.

**Optimizing Field Performance**
Many field wide optimization rules can also be established by the end user; the real time on-line expert system would administer these rules. Such administration would be accomplished either by informational recommendations to the operator, or through a totally automated process. The individual wells would be ranked on an economic contribution basis, and the ranking would be continuously refreshed as new tests are obtained. A real time on-line inventory of available process system capacities would be maintained:
1) Water handling capacity.
2) Oil handling capacity.
3) Gas handling capacity.
4) Power generation capacity.
5) Any other constraint.

Real time on-line decisions would be made to "ramp up" or to "ramp down" individual wells so that maximum economic benefit is achieved within the available process system capacity constraints.

Each individual well would have a maximum and minimum allowed operating frequency specified in the rules. Starts and stops are detrimental to electric submersible pump run lives. No well should be shut down due to process system capacity constraints until all wells have been "ramped down" to the minimum allowed frequency specified by the operator in the rules.

**Defining Users of the Application**

Since the intent of the application is to increase production of a new field with the same operations staff, a primary control room operator receives the alarms and advice generated by the application. Several users can log on to the application at the same time and in addition to operations staff, surveillance engineers can view performance curves over time history. In addition, production engineers can use the application to test a typical pump configuration for the well test data sets being provided, to more closely match equipment to well conditions.

**Modular Procedures in the Application**

**Pressure-Volume-Temperature (PVT) Calculations**

PVT properties calculations are used extensively throughout the application whenever mixture physical properties are required. In the demonstration configuration the model utilizes a generalized form of Standing’s Correlation. These simplified procedures can readily be replaced with the end user’s sophisticated PVT calculations as required.

**Down Hole Operating Temperatures**

The tubing head temperature and the motor operating temperature are measured data elements, while the formation temperature is known. The following assumptions are applied:

1) A straight line temperature gradient from the tubing head to the pump discharge.
2) A constant temperature across the pump.
3) A straight line temperature gradient from the pump intake to the top of the perforations.

More sophisticated thermodynamic calculations can readily be added as required to meet the needs.

**Tubular Pressure Traverse Calculations**

Pressure traverse calculations are used as required in the following procedures for either upward or downward flow, and for both vertical and deviated wells:

1) Tubular flow in the tubing between surface and the pump discharge.
2) Annular flow from the pump intake to the bottom of the motor.
3) Tubular flow between the bottom of the motor and the top of the perforations.

In the demonstration configuration the model utilizes the Hazen and Williams method for pressure drop estimates, modified to compensate for mixture specific gravity and mixture viscosity. These simplified procedures can readily be replaced with pressure traverse calculations as required.

**Pump Traverse Calculations**

The pump traverse procedures utilize one stage by stage polynomial calculation procedure to determine the accumulated pump differential pressure, and another stage by stage polynomial calculation procedure to determine the resulting accumulated pump shaft load.

The pump manufacturers provide six polynomial constants for calculating stage differential pressure, and six polynomial constants for calculating resulting shaft load.

The results of the polynomials are adjusted for mixture specific gravity, then further adjusted by Mark’s Handbook centrifugal pump theory.

These calculations apply for either suction to discharge calculation procedures, or discharge to suction calculation procedures.

**Pressure Traverse Adjustment Factor**

When the pump intake pressure and the annulus gas rate are known, a comparison can be made between the tubing head downward pressure traverse calculated pump discharge pressure, and the pump suction to pump discharge stage by stage calculated pump discharge pressure.

The comparison result should be near unity for reasonable input data. This value is used to calibrate all subsequent pressure traverse calculations performed by the application.

**Seal and Motor Pressure Traverse Calculation**

These calculations determine the net cross sectional area available for flow, convert the area to an equivalent diameter, and then apply the tubular pressure traverse calculation procedures. Flow can be either upward or downward.

**Casing Pressure Traverse**

The tubular pressure traverse calculation procedures are applied using the casing inner diameter. Flow can be either upward or downward.
Perforation Depth Well Inflow Capability Options
In the demonstration configuration the model utilizes the Back Pressure Equation method for gas inflow, constant oil to gas ratio for oil inflow, and a straight-line productivity index for water inflow.

There are many other options that can be added to meet the needs.

Well Capability at Pump Intake
The perforation depth well inflow capability data is transposed to the pump intake depth by applying pressure traverse calculation procedures.

Pump in Range Calculations
The pump manufacturers as part of the pump specifications provide maximum and minimum recommended daily volumes for each pump stage model.

A solution for the pump intake pressure which matches the upper limit for the smallest stage (in a tandem situation) with the pump intake well inflow capability determines the no separation pump in range suction condition; a pump traverse then determines the no separation pump in range discharge condition. A solution for the pump intake pressure which matches the lower limit for the largest stage (in a tandem situation) with the pump intake well inflow capability determines the maximum separation pump in range suction condition; a pump traverse then determines the initial maximum separation pump in range discharge condition. A looping process is repeated until the pump discharge volume condition matches the lower limit for the pump.

Allowable Tubing Head Pressure Range
Assuming that the separation efficiency does not change with changes in tubing head pressure, a looping process is repeated with incremental increases in tubing head pressure until the volume at pump intake available from the pump intake capability data matches the lower volume limit for the pump. This tubing head pressure value defines the maximum allowed operating tubing head pressure.

Again assuming that the separation efficiency does not change with changes in tubing head pressure, a looping process is repeated with incremental reductions in tubing head pressure until the volume at pump intake available from the pump intake capability data matches the upper volume limit for the pump. This tubing head pressure value defines the minimum allowed operating tubing head pressure.

The end result of the above two procedures is an allowable operating tubing head pressure window.

Graphical Presentations
The results of each test analysis are presented in graphical format:
1) Top of perforations STP and reservoir volumes well inflow capability, including any defined draw down limitations.
2) Pump intake depth STP and reservoir volumes well inflow capability, including any applicable transposed top of perforations depth draw down limitations. Figure 5 illustrates the graph from the application.
3) Pump in range plot illustrating no gas separation, maximum gas separation, and actual test analysis conditions. Figure 6 illustrates this graph.
4) Tubing head deliverability, and tubing head pressure allowable operating window. Figure 7 illustrates the graph.

Motor and Cable Calculations
The tornado curve issue is addressed by applying the affinity laws:
1) Speed varies with RPM
2) Head varies with RPM^2
3) Load varies with RPM^3

Motor operating RPM is adjusted for both operating frequency, and operating fraction of full load.

Ideal motor and cable electrical calculation procedures are completed for comparison of ideal calculated electrical values versus actual surface electrical readings.

Equipment Inventories
Pop up menu pick choices are provided for inventoried equipment such as pump stage specifications, shaft strength specifications, motor specifications, cable specifications, etc.

This facilitates ease of cloning wells, and accurately defining the hardware specifications for the new well. Figure 8 illustrates the inventory availability for adding wells to the application.

Output of Rules Analysis
The whole point of the exercise is to be able to notice abnormal situations and provide conclusive advice. The rules interact with the tubing head deliverability, as this is the measure from surface instruments of what the production range for the installed pump is at the time of last well test. Should other sensor inputs be noticed deviating from the benchmarked values, then the appropriate rules fire to generate an alarm queue. Figure 9 illustrates a typical alarm queue.

Target Benefits
Based on an average production of 300 BPD and a pad of 32 producing wells and 32 injection wells, $10US/bbl. Operating cost, the economics for the application are as follows;
Module 1 Rules Analysis - $5M based on saving 2 ESP failures/year
Module 2 Well Performance - $192K/pad based on 2-hours/month/well downtime saved
Module 3 Well Optimization - $630K/pad/yr based on 1% production improvement on setpoints
Total of conservatively $1.3M US/yr. for approx. a $250K applications development cost.

Additions for Other Artificial Lift Methods
Initial development of the expert system was to address the requirements for conventional electrical submersible pumps. The scope was then expanded to address the requirements of progressive cavity pumps being driven by conventional electrical
submersible motors and seals incorporating a gear reducer. Development is now under way to address the requirements of gas lift systems.

Conclusions
Artificial lift using electric submersible pumps continues to gain popularity, however the impact of non-flowing conditions is a source of production loss and equipment damage that is difficult to detect and rationalize. Combining the knowledge of operating experience, empirical relationships, and specific oil properties into a single management software tool can have enormous potential benefit to exploration and production operators. This paper has proven that what once was a problem involving many transactions and many departments within an operating business unit, can be solved using expert software tools to combine the tasks and do so in real time.

Nomenclature

DP = differential pressure
ESP = Electric Submersible Pump
LC = Level Controller
PCP = Progressive Cavity Pump
PID = Piping and Instrument Diagram
PC = Pressure Controller
PT = Pressure Transmitter
PVT = Pressure-Volume-Temperature
RES = Reservoir Units
SCADA = Supervisory Control and Data Acquisition
SIC = Speed Indicating Controller
SP = setpoint
STP = Standard Temperature and Pressure, atmospheric conditions
THP = Tubing Head Pressure
Tornado curve = Pump manufacturer’s published relationships of speed vs. pumping efficiency
VFD = variable frequency drive
WIP = Well Inflow Pressure

References


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Table 1 - Inputs to Application for Rules

<table>
<thead>
<tr>
<th>Input Description</th>
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<tbody>
<tr>
<td>Start up sequence initiated status</td>
</tr>
<tr>
<td>Tubing head back pressure valve open/closed status</td>
</tr>
<tr>
<td>Status of whether well is producing to test facility or not</td>
</tr>
<tr>
<td>Status of VFD instrumentation transmitting positive power consumption</td>
</tr>
<tr>
<td>Back pressure controller full open status</td>
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<tr>
<td>Pump intake pressure</td>
</tr>
<tr>
<td>Annulus gas rate</td>
</tr>
<tr>
<td>Desired ultimate unloaded pump intake pressure</td>
</tr>
<tr>
<td>VFD frequency</td>
</tr>
<tr>
<td>Test results accepted status</td>
</tr>
<tr>
<td>Well removed from test - status</td>
</tr>
<tr>
<td>Electrical power consumption</td>
</tr>
<tr>
<td>Power supply voltage</td>
</tr>
<tr>
<td>Power supply integrity</td>
</tr>
<tr>
<td>Operating tubing head pressure</td>
</tr>
<tr>
<td>Operating tubing head temperature</td>
</tr>
<tr>
<td>Pump intake temperature</td>
</tr>
<tr>
<td>Status of whether the pump intake pressure sensor is operational</td>
</tr>
<tr>
<td>Pump intake pressure SP</td>
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<tr>
<td>High pressure shut down SP</td>
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<tr>
<td>Control system over pressure shut down SP</td>
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<tr>
<td>Low pressure shut down SP</td>
</tr>
<tr>
<td>ESP motor amperage draw</td>
</tr>
<tr>
<td>VFD over load shut down SP</td>
</tr>
<tr>
<td>ESP motor operating temperature</td>
</tr>
<tr>
<td>VFD motor operating temperature shut down SP</td>
</tr>
<tr>
<td>Casing head temperature</td>
</tr>
<tr>
<td>Minimum allowed producing perforation depth pressure SP</td>
</tr>
<tr>
<td>Manufacturer's specified allowable load on gear reducer</td>
</tr>
<tr>
<td>Manufacturer's specified allowable DP SP for Housing</td>
</tr>
<tr>
<td>Preset min. critical pump intake temperature</td>
</tr>
<tr>
<td>Preset max. critical pump discharge velocity</td>
</tr>
<tr>
<td>Inferred PCP operating RPM (calculate on basis of VFD operating freq.)</td>
</tr>
<tr>
<td>Manufacturer's specified max. allowable RPM</td>
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<tr>
<td>Manufacturer's specified max. allowable head</td>
</tr>
<tr>
<td>Manufacturer's specified max. allowable hp</td>
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</tbody>
</table>

**Outputs from Application**

Well test data collection complete
Table 2 - Well Test Data to Application

<table>
<thead>
<tr>
<th>Parameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well name</td>
</tr>
<tr>
<td>Well test complete</td>
</tr>
<tr>
<td>Well test complete date</td>
</tr>
<tr>
<td>Well test completion time</td>
</tr>
<tr>
<td>Annulus gas rate</td>
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<tr>
<td>Test fluid rate</td>
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<tr>
<td>Test oil rate</td>
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<tr>
<td>Test gas rate</td>
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<tr>
<td>Tubing head pressure</td>
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<tr>
<td>Tubing head temperature</td>
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<tr>
<td>Pump intake pressure</td>
</tr>
<tr>
<td>Pump intake temperature</td>
</tr>
<tr>
<td>Pump discharge temperature</td>
</tr>
<tr>
<td>VFD Hz</td>
</tr>
<tr>
<td>VFD amps</td>
</tr>
<tr>
<td>VFD voltage</td>
</tr>
<tr>
<td>Water Cut</td>
</tr>
</tbody>
</table>

Figure 1 – PID Block Diagram of Optimum Well Control
TUBING PRESSURE TRAVERSE

ESP PUMP TRAVERSE

SEAL TRAVERSE

PCP WELL?

Yes → GEAR REDUCER TRAVERSE

No → MOTOR TRAVERSE

CASING TRAVERSE

WELL INFLOW CAPABILITY

PUMP INTAKE CAPABILITY

PCP WELL?

Yes → PCP PUMP IN RANGE

No → ESP PUMP IN RANGE

ESP TUBING HEAD CAPABILITY

RESULTS AS SETPOINTS/INPUTS FOR RULES

PCP TUBING HEAD LIMITATION

uses the back-pressure equation
Figure 3 - Example of Inference Rules
Figure 4 – Well Inflow Capability
Figure 5 – Pump intake capability
Figure 6 – Pump in Range Illustration from Application
Figure 7 – Tubing Head Deliverability Graph
Figure 8 – Pump inventory for adding wells
7 Jun 98 9:04:06 p.m. RULE 58. The current Pump Intake Pressure of well ESP-TEST is more than 50 psia BELOW the latest test value: re-test the well.

7 Jun 98 9:04:06 p.m. RULE 27. Well ESP-TEST is producing at or below the maximum allowed draw down level. (1) Reduce the production rate to eliminate the excess draw down condition by increasing the pump intake pressure Bench Mark setpoint. (2) Any significant change in VFD frequency requires a new test to re-establish the G2 Bench Mark data.

7 Jun 98 9:04:06 p.m. RULE 1.7. The Bench Mark maximum allowed production rate for well ESP-TEST cannot be maintained! Switch the VFD to pump intake pressure control.

Figure 9 – Alarm Queue for Operators