Abstract

Occidental Exploration and Production Company (OEPC) uses one hundred Electric Submersible Pumps (ESPs) to produce approximately 410,000 barrels of fluid (approximately 100,000 barrels of oil) from two producing areas in Ecuador’s Block 15. In 2004, as part of a global automation process, hardware and software were installed to allow remote data acquisition and control, automated protection of the ESPs and semiautomated diagnosis of well performance.

After installation of the automation system, it became apparent that automated data collection and analysis would not in itself result in ESP optimization and runlife improvement. In order to achieve maximum improvement in monitoring, diagnosis, and analysis of well and ESP performance, it was necessary to train and coach OEPC and alliance partner staff in analytical techniques and use of the software.

As part of the training process, opportunities to improve the overall ESP management process were identified in areas such as completion design, ESP specification, protection philosophy, operating procedures and well analysis.

The ESPs in Block 15 are operated under a ‘pay per day of operation’ incentive contract. Any changes to the ESP management process needed to involve the ESP supplier. Through the application of a proactive cooperative approach between OEPC and the ESP supplier it was possible to implement these changes to the benefit of both parties.

This paper will provide specific details of:

- the training process;
- automated ESP protection;
- how well analysis software is used to understand well and ESP performance;
- the improvements to the ESP and completion;
- changes to the ESP management process;
- and key components of a successful ESP operations contract.

Introduction

Occidental Exploration & Production Company (OEPC) operates Block 15 in the east of Ecuador (figure 1) through a participation contract with Petrolecuador (Ecuador's state oil company). Block 15 is an area of 494,000 acres located in the Amazonian rainforest in the Oriente Basin of northeastern Ecuador. Since commencing operation in Block 15 in 1985 OEPC has made commercial discoveries in the fields of: Indillana; Yanaquinchia; Jivino; Laguna; Napo; Itaya; Limoncocha; and Eden-Yuturi. OEPC produces a total of approximately 100,000 BOPD through two production facilities CPF and EPF (figure 2).

The fields have multiple productive sands which are identified as M1, M2, U, T and Hollin. The sandstones are quartzite, fine to medium and medium to coarse, well sorted with normal grain size distribution, siliceous cementation with some kaolinite. The sands are of varying thicknesses in the different fields and in some areas are unconsolidated;
permeability (250-2500md) and porosity (13-22%) are considered to be good.

A highly active aquifer provides good pressure support but can result in early and rapidly increasing watercut in the wells.

Table 1 provides a summary of the range of operating conditions.

**Overview of ESP Operations**

Operations within block 15 are managed from offices at two processing facilities: CPF and EPF. EPF is the base for all Eden Yuturi operations and CPF the base for all of the other field operations (Indillana, Limoncocha, Yanaquinchca, Jivino, Laguna, Napo, Itaya). To minimize environmental impact the wells are directionally drilled from pads. A typical pad may have as many as 15 wells. The oil from each pad is transported through a pipeline to the processing facility. Each pad has well test facilities (newer pads have multiphase meters, older pads have a separator or wellcomp unit so that the production from each well can be measured. Each pad also has a chemical injection skid, power generation (CPF wells, EPF wells are supplied power from a central generation and Variable Speed Drives (VSDs) and transformers for each of the wells.

Each production facility has a team of personnel which work on a rotational basis and includes a Production Superintendent, Production Engineers, Production Operators, Well Technicians and ESP supplier personnel. This team, historically, was responsible for design, installation monitoring and failure analysis of the ESPs. The geographical separation of the teams in CPF and EPF resulted in different working practices in each location.

The wells are completed with 9 5/8” casing or 7” liner across the productive interval. Many of the wells are perforated in multiple sands but a downhole completion comprising downhole packers and sliding sleeves is often used to select the interval for production. Production tubing is normally 4.5” 12.7 lb/ft although there are some lower rate wells completed with 3.5” 9.2 lb/ft.

Well flowrates vary from 1000 BFPD to 16000BFDP. The pumps carried as standard inventory to meet this flowrate range are DN 1100, DN1750, G2700, GN3200, GN5200, GN5600, GN7000, SN2600, SN8500, JN10000 and JN16000. Seal units are tandem units featuring a combination of labyrinth and bag modules. The motors are typically 562 dominator and range from 180 to 900 HP. The power cable is flat lead braided galvanized #1 5kV cable is used, often with a 3/8” capillary tube included for downhole chemical injection. Almost all of the ESP systems have a downhole sensor (measuring intake pressure) and a bypass (y-tool) system to allow access to change the producing interval or perform logs across the productive zone. See Figure 4 for typical completion.

**Automation Process**

As part of a global automation process the Case Services system (csLIFT) for data acquisition and automation (see figure 3) was installed in OEPC in early 2004. The system installed for OEPC has the following capabilities:

- acquire individual well and ESP operating parameters and store them in a database;
- view operating data in tabular or graphical format;
- configure alarms and trips such that when an operating parameter goes above or below a set value an alarm can be activated or the equipment shut down;
- well test database for each well;
- production and downtime reporting;
- analysis of ESP and well performance (Subs Analysis).

When the system was implemented, training was given to OEPC personnel by Case and ePSolutions personnel. (Note: the csLIFT software suite is supported from a hardware and field service standpoint by ePSolutions). However, training was in English, delivered in a very short timeframe and covered a large amount of new information. For local operations staff the language barrier, dealing with the unfamiliar interface of the new software and trying to absorb the capabilities of the system resulted in very little transfer of knowledge.

After installation of the automation system the ESPs and wells were operated as they were prior to installation of csLIFT. ESPs continued to be run with local control at the VSD and protection being set based on traditional underload (85% stable current) and overload (120% stable current) settings.

On a theoretical level, application of automation to artificially lifted wells (level of sophistication dependent) can result in the following five benefits:
1. obtain real time P&T downhole data (downhole sensors);
2. acquire downhole and surface data simultaneously (communication);
3. perform protection and alarming based on P&T (control);
4. get the data to where it can be used (communication and database);
5. use of data to optimize production (analysis and action).

Initially when OEPC implemented the automation system benefits 1, 2 and 4 were achieved – benefits 3 and 5 were not.

As time went on, operations personnel became disenchanted with the automation system: well completion data were not updated when wells were worked over or was entered incorrectly. This resulted in an inability to use the Subs Analysis feature of the package as the analysis and results were based on incorrect data.

OEPC management recognized that in order to get the benefit from the automation system it was apparent that some additional action was going to be required!

A process was initiated to go ‘beyond automation’ by:

- providing training in ESP Analysis and Diagnosis;
- reviewing and improving operating procedures;
- reviewing and improving ESP completion and design practices;
- reviewing and changing organization;
- reviewing roles and responsibilities for operational staff;
- performing an audit of the data quality in Subs Analysis and validate calculation processes;
- teaching people how to use Subs Analysis;
- preparing a training/reference manual on use of Subs Analysis;
- identifying opportunities for production gains.

The focus of the training was to:

- understand limitations of existing operating philosophy;
- develop recommendations to improve ESP operations;
- apply diagnosis and analysis techniques;
- develop strategies to minimize downtime;
- assess staff competency.

Three batches of training were performed and resulted in over 30 people undergoing basic training.

To bring about improvement of ESP operations it was necessary to show people why protection solely on electrical parameters does not benefit production optimization. Figure 5 shows a case of progressive recirculation (leak above the ESP). It can be observed that amps (the top line) shows very little change despite the fact that production was decreasing. This undiagnosed problem, having occurred over a 6 month period, resulted in a loss of production of 40,000 barrels of oil. This well was protected with traditional overload and underload protection and monitored using a SCADA system. However, to diagnose the lost production requires an alarm on intake pressure followed by analysis of the pressure information.

When looking at data sets where all of the operating parameters are acquired simultaneously, it often becomes evident how insensitive amps are in the majority of operating problems.

In order to reinforce this understanding the course attendees were then asked to think through a set of typical situations and determine how pressures, temperatures and current would respond in cases such as:

- pump wear (due to sand);
- watercut increase;
- change in well inflow;
- pump scaling, etc.

The abundance of downhole pressure data now available, dictates that historical analysis techniques (i.e. what amps mean) are no longer enough. People must have a good understanding of inflow and outflow performance and the effect of the ESP in the wellbore so that problems can be thought through in terms of pressure.

Having reached this level of understanding it was then
It was possible to develop a new protection philosophy based on pressures and temperatures as well as amps.

In addition to developing a new protection philosophy of the ESP wells each of the classes generated a series of recommendations to improve the ESP operations. These recommendations form the basis for the section of this paper titled ‘Improvements to the ESP and Completion’.

A second level of training was then implemented in order to teach the operations staff to use the Subs Analysis module of the automation package. The key aspects of this training were to:

- develop understanding of calculation process in Subs Analysis;
- process to validate input data (well test and completion);
- determine whether ESP is functioning correctly;
- validate well inflow (PI and Pr);
- analyze trends;
- determine levels for setting pressure and temperature alarms;
- know when production is being lost!

Following the course each attendee was assigned four wells to analyze. This was perhaps the most important part of the whole training process as this is the conversion of the theory to a tangible benefit to OEPC.

To analyze the wells the following procedure was applied:

1. validate input data for accuracy;
2. compare measured intake pressure to theoretical (ideal);
3. evaluate whether ESP is functioning correctly – if not, there is a need for quantifying its impact on production;
4. determine well inflow information for use in future design;
5. review ESP sizing vs. production rate and make recommendation for replacement ESP immediately in the event of failure;
6. establish value and set alarms on intake pressure, motor temperature and intake temperature.

A key focus of this process is to minimize lost or deferred production by always having the design and equipment ready for the next installation when the existing system fails. This means that a workover can be performed as soon as a rig is available, with no waiting for equipment.

Presently, 46 wells had been thoroughly reviewed and alarms set, based on downhole sensor values. The findings from these wells were as follows:

- 65% of the wells had data incorrectly entered in csLIFT;
- 23.6% of the ESPs were out of range (13% of the ESPs were in downthrust, 10.6% of the ESPs were in upthrust);
- 28% of the wells had a problem resulting in loss of production and opportunity for optimization.

Future plans involve completing the analysis process for the remainder of the wells. A further training workshop will then be held to share learnings and present the findings from the analytical process.

**Automated ESP Protection**

To move beyond the traditional approach of using electrical parameters to protect the ESP it is necessary to understand which additional parameters are useful. In OEPC the following parameters, in addition to current overload and underload, are used for protection of the ESP system:

- intake pressure;
- discharge pressure (when available);
- motor temperature;
- intake temperature.

Initially, when configuring these alarms a percentage basis of stable operating value was used as the basis for the alarm. However, due to the wide range of intake pressure (300 - 800) values and the fact that a 40 psi increase in intake pressure could result in a loss of production of 400 stb/lpd on a well with a PI of 10 stb/lpd/psi it was deemed more practical to set the alarms at intake pressure +/- 20 psi.

Prior to the training, the generally held view was that the motor temperature alarm should be set at the same value as the temperature specification at the motor. However, if we consider an ESP running in a well with a stable motor temperature of 180 degrees F, why should we wait for the motor to get to a temperature of 250 degrees F before shutting it down? If the motor has a steady operating temperature of 180 degrees F and it starts getting hotter, something is wrong! It is better to shut the ESP down than risk damaging the motor. OEPC now use a guideline of stable motor temperature +10 degrees for the alarm. No low
motor temperature alarm is used. This level of protection can normally be implemented locally at the wells. A complicated automation system is not required. OEPC understand the benefit of such protection and have set pressure and temperature alarms using csLIFT.

The Well Analysis Process

There are many software tools that are marketed as being capable of performing ESP analysis and diagnosis. Most of these tools take a nodal approach to analysis of the system and always have to force the inflow and outflow at the node to match to achieve a solution. This procedure is effective for design but has limitations when it comes to analysis and diagnosis of ESP performance.

Consider the well test data shown in table 2 where total liquid rate is declining and pump intake pressure is increasing, even though frequency has been increased. Clearly there is a problem. But, is it a well inflow problem, a change in fluids, an ESP problem or well test measurement error?

Most software would present an analysis of such an example as a pump curve and a system curve (figure 6). The pump curve is a function of the pump type, number of stages and frequency of operation and the system curve is a function of fluid properties, wellhead pressure, friction, PI and reservoir pressure.

In order to simulate the data for the 20th of October (lower flowrate), the system curve would need to move to the left to intersect the pump curve at the lower flowrate or the pump performance would need to be de-rated (move down the system curve) or both! But which is it? Is there a well inflow problem, a pump problem or something else happening – there are many uncertainties.

An improvement over the nodal approach is to perform a ‘top down’ analysis of the well pressures. This involves calculating from the tubing head pressure (THP) down to the pump, across the pump and then below the pump to the perforations to calculate a bottom hole flowing pressure. Such an approach removes an unknown i.e. the well inflow (Pr and PI) from the calculation.

Figure 7, shows a graph of pressure vs. depth in the well, which will be called the Zorro Graph (or Gradient Traverse Plot)².

Looking at the graph and calculating from the top down, the steps can be summarized as follows:

1. \[ PDP = THP + \Delta P_{\text{hydrostatic}} + \Delta P_{\text{friction}} \]
2. \[ PIP = PDP - \Delta P_{\text{pump}} \]

Comparison of measured pump pressures to the ideal or calculated values is a powerful tool to determine whether the pump is working correctly. Any time the actual pump intake pressure is higher than the theoretical value this indicates that the pump has a problem (assuming the fluid properties and wellhead pressure have been validated).

Having determined whether the pump is working correctly, it is possible to calculate the flowing bottomhole hole pressure (FBHP), based on validated data as follows:

3. \[ FBHP = PIP + \Delta P_{\text{hydrostatic}} + \Delta P_{\text{friction}} \]

The FBHP and reservoir pressure (SBHP) can then be used to determine the actual PI of the well.

4. \[ PI = \frac{\text{Rate(STB/day)}}{SBHP - FBHP} \]

When this technique is performed in conjunction with measured pump intake and discharge pressure it results in:

- validated PVT and watercut;
- validated flowrate;
- known pump performance;
- and accurate bottom hole pressure which can then be used to determine the well PI.

OEPC now has a methodology whereby, through use of Subs Analysis, it is possible to:

- calculate the pressure at any point in the wellbore;
- compare the calculated value based to a measured value (PDP and PIP);
- compare measured $\Delta P_{\text{pump}}$ to ideal (calculated) $\Delta P_{\text{pump}}$;
- compare flowrates to indicated rate based on measured $\Delta P_{\text{pump}}$;
- perform diagnosis of the well and pump as a system;
- optimize production.

There are a number of things that happen in the wells in question. Certain distinctions may be made by using diagnostic tools in order to establish the difference between a normally occurring event, which has to be accepted, and a problem (see table 3), which may be addressed and rectified. Problems undiagnosed and not treated cause loss of production.

In order to ensure standardization in the approach to performing well analysis and diagnosis our ESP supplier is required to perform diagnosis using Subs Analysis rather than other software products.

**Improvements to the ESP and Completion**

The ESP system design was originally developed and applied to the Indillana field. In order to manage the ESPs inventory four or five ‘standard’ ESPs were stocked. As new fields were discovered and produced e.g. Eden Yuturi, Limoncocha, etc., it has been found that different fields and wells have different behavior (sand, corrosion, scale producing).

These issues affect the ESP and require different subtleties of design to address the producing well conditions. This dictates that a ‘standard’ design doesn’t work for all wells and in many cases customized designs are needed for specific well behavior.

A process has been undertaken to identify and group the wells by their producing characteristics and develop fit for purpose designs for each well. While this will make inventory management more difficult there is a definite need to ensure that the ESP design is suitable for the producing environment.

Some of the solutions being applied or considered are shown in table 4.

When talking about a standard ESP design it transpires that there isn’t really a ‘standard’ configuration, but rather a base model plus many options (a little like buying a car).

For example, consider that a 100 stage GN4000, with tandem seal and 330 HP 1950Volt 102.5Amp 562 series motor is going to be installed in a well. To perform a detailed design for this system some of the options that need to be examined are:

**The PUMP:**
- What is the bearing material?
- How often are the bearings placed?
- What upthrust and downthrust protection is provided?
- What is the metallurgy ie abrasion or corrosion resistant?
- Are any coatings used?
- What is the material of the elastomer seals between each stage (nitrile, aflas, viton)?
- What is the shaft strength?
- Floating impellers or compression pump?

**The SEAL:**
- How many chambers?
- Connected in series or parallel?
- Bag or Labyrinth for each chamber?
- Upthrust bearing?
- Which elastomers are used in the bag seal (can they resist, temperature, aromatics and chemicals)?
- Is the ESP in the vertical section – will labyrinth seals be effective?
- Will the seals be effective in sand producing environment or will they plug?
- High load or standard load downthrust bearing?

**The MOTOR:**
- What kind of protection (insulation) is provided on the windings?
- Which motor dielectric oil used?
- High temperature or high load bearings?
- BHT and flowrate past the motor
- Single or tandem unit

Most people do not have the required knowledge to assess this level of detail. Throw in cable and gas handling or processing issues and it becomes more challenging to develop a fit for purpose design. It is only through working in close cooperation with the ESP supplier that these issues can begin to be addressed.

It also has to be remembered that improvements in specification of the system results in an increase in cost! There are many things that may be warranted on a high cost
offshore ESP well to improve the chance of a long runlife that may not be justified onshore.

In order to improve the runlife of the ESP system or improve OEPC’s ability to optimize production the following system improvements were identified.

- Use sensors with discharge pressure
- Acquire VSD frequency and wellhead pressure real-time simultaneously with sensor parameters.
- Prevent excessive motor heating during startup by using a shroud or packer.
- Improve wellbore cleanout process.
- Ensure power quality study to determine level of harmonics, surge, sag, overvoltage, transients, etc.
- Evaluate ESPs installed in new drilled wells to determine whether ESP design appropriate – is there a need to test new wells to determine inflow before completion.
- Measure motor winding temperature (improved sensitivity compared to motor oil temperature) – ESP supplier to provide motors with motor winding thermocouple.
- Use round power cable to eliminate phase imbalance
- Use round cable all the way to pothead, eliminates MLE and splice.
- Use centralizers and clamps to protect larger round cable and ensure centralization.

ESP Management Process

As part of our training process OEPC staff and alliance partners were constantly challenged to look at how things were being done and whether they could be done differently or better. This resulted in recognizing that the existing written procedures for management of the ESP operations did not reflect reality nor the ideal state.

In addition to implementing improved protection of the ESP system and performing real analysis of the ESP operating data the following improvements were identified as being required:

- more ESP engineering support in the office;
- more educated/trained ESP expertise within OEPC;
- more expertise for ESP supplier;
- standardization of procedures and practices between two operations (CPF and EPF);
- eliminate redundant data collection
- move to focus on genuine ESP runlife improvement (step changes) rather than just meeting the contract targets (gradual);
- improve investigation of failure analysis and action based on findings;
- revise roles and responsibilities for key positions.

The revision of operating procedures is on hold until some of the organizational, reporting and operational practices have been improved. As and when operations are aligned to best realistic practices the procedures manual may be rewritten.

ESP Operations Contract

The contract with our ESP supplier is based on a pay per day of operation for the ESP. The cost per day is derived from the price of the ESP system divided by the target MTBF. The target MTBF for the wells increases by a percentage for every year of operation over the four year contract. Payment for ESP operation commences after the ESP has been running for 150 days. The target runlife (TRL) escalates over the life of the contract as shown in figure 9.

The contract is not perfect for OEPC, and the ESP supplier has things that they wish were different. By working together and by both parties being flexible it is possible to work through the issues.

Some of the realities that were not envisioned when the contract was signed have been identified.

- OEPC has pulled a number of ESP systems prior to failure to change zones, perform cement squeeze or stimulation. There is no mechanism in the contract to compensate the supplier for equipment that is pulled before it reaches the target runlife.
- Runlife does not necessarily relate to production. For example if we diagnose that a pump is doing 30% less than it should, due to wear, then we are losing production. The ESP supplier would like to leave the pump in the well as it is still running, thereby increasing the MTBF for the field. OEPC would rather replace the ESP and recover the lost production.
- The MTBF is calculated on a field by field basis. It is easy to improve the runlife on the new fields which have very little historical data. It is difficult to impact the MTBF on the older fields. See figures 9 and 10.
The percentage improvement in runlife on an annual basis is not really a motivator for step changes in system runlife. Supposing the MTBF is 751 days but some of the wells achieve runlives of 1300 days. The contract calls for 818 days in the subsequent year but perhaps the driving force should be an aim to make all of the ESPs run for 1300 days.

The ESP supplier has made suggestions for design improvements. OEPC personnel chose not to implement them. What is the way forward?

Implementation of the intent of the original contract has not been perfect on the part of OEPC nor the supplier. However, these issues are being addressed by working closely together and through honest communication on a technical and commercial basis.

A few guidelines for successful ESP contract management may be adopted.

- The contract is a starting point for the relationship: as the relationship evolves, the contract will likely have to evolve.
- A contract with truly aligned objectives probable needs to have a tie to production rather than ESP runlife.
- If the relationship is not a win/win for both parties, it will not be a harmonious relationship. A supplier that is not making a reasonable profit cannot afford to dedicate the same resources (experience level, personnel) to improving a company’s operation. An operator that feels he has been exploited is unlikely to award the contract to the same supplier the next time around.
- The operator NEEDS to have trained knowledgeable personnel with respect to ESP produced wells.
- The ESP supplier needs to have trained knowledgeable personnel. ESP monitoring and diagnosis methods and techniques have evolved - ensure your ESP supplier has too.

This has required OEPC to spend lots of time on training OEPC staff and ESP supplier personnel.

Training on its own wasn’t the complete solution: it has required an ongoing process of coaching, reinforcement and learning by doing. The process is not yet complete, but the required educational, organizational, procedural and contractual changes are being addressed.

The following provides a summary of OEPC’s main conclusions in going ‘beyond automation’.

1. Analysis has shown that the opportunity exists to increase production on 28% of OEPC Ecuador’s wells.
2. Automation in itself provides little or no advantage unless it is used to change the way that operations are managed.
3. Use collected data constructively by performing analysis
4. The analytical process creates additional work – don’t expect automation to reduce the workload.
5. Alarms were set based on pressure and temperatures from the downhole sensor in addition to electrical (amps) protection. It has emerged that amps is insensitive to changes in many cases.
6. ESP diagnosis and analysis skills should be a core competency for the production engineers of any operator who intends to use ESPs. Don’t assume that the ESP supplier knows it all.
7. Coaching as well as training is required to bring about long lasting genuine change.
8. When performing analysis of measured pressure data, use a software tool or technique that allows separation of the wellbore pressure response from the reservoir inflow performance.

Conclusions

When OEPC installed an automation system, there was a perception that it would improve the day-to-day operation of the ESPs. However, in order to get the benefit from what is a good automation and analysis package, procedures have had to be changed.

References


Tables

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<tr>
<th>QUANTITY</th>
<th>FROM</th>
<th>TO</th>
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<tr>
<td># OF WELLS</td>
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<td>AVG. BFPD</td>
<td>1000</td>
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<td>SIBHP, PSI</td>
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<tr>
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<td>EMULSION (yes or no)</td>
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Table 1 – Block 15 Operating Conditions

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<tr>
<th>Well Test Date</th>
<th>WC</th>
<th>Total Fluid</th>
<th>Motor Hz</th>
<th>Tubing Press</th>
<th>Tubing Tmpr</th>
<th>PIP (psi)</th>
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<td>547</td>
<td>64</td>
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Table 2 – Well test data for a developing problem

<table>
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<th>Natural Events</th>
<th>Problems</th>
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<tbody>
<tr>
<td>Tubing head pressure change</td>
<td>Bad well tests</td>
</tr>
<tr>
<td>Frequency change</td>
<td>PI change (damage / sand control)</td>
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<tr>
<td>Reservoir pressure decline</td>
<td>Tubing restriction (scaling)</td>
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<tr>
<td>Increasing watercut</td>
<td>Broken shaft (less pump stages working)</td>
</tr>
<tr>
<td></td>
<td>Pump wear</td>
</tr>
<tr>
<td></td>
<td>Gas interference</td>
</tr>
<tr>
<td></td>
<td>Scaling perforations</td>
</tr>
<tr>
<td></td>
<td>Scaled pump</td>
</tr>
<tr>
<td></td>
<td>Plugged Intake</td>
</tr>
<tr>
<td></td>
<td>Pump rotating in wrong direction</td>
</tr>
<tr>
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<td>Leaking y-tool blanking plug</td>
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<tr>
<td></td>
<td>Hole in production tubing</td>
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<tr>
<td></td>
<td>Pump off</td>
</tr>
<tr>
<td></td>
<td>Pump wrong size</td>
</tr>
<tr>
<td></td>
<td>Well to well interactions</td>
</tr>
</tbody>
</table>

Table 3 – Comparison of natural events and problems
<table>
<thead>
<tr>
<th>Problem</th>
<th>Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand</td>
<td>Improved sand control (gravel pack, mesh)</td>
</tr>
<tr>
<td></td>
<td>Bearings with ceramic inserts</td>
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<tr>
<td></td>
<td>More frequent placement of bearings</td>
</tr>
<tr>
<td></td>
<td>Mixed Flow pump Stages</td>
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<tr>
<td></td>
<td>Improved (abrasion resistant) metallurgy</td>
</tr>
<tr>
<td></td>
<td>Overstage the pump and run at lower speeds (rpm)</td>
</tr>
<tr>
<td></td>
<td>Non return valve above pump</td>
</tr>
<tr>
<td>Corrosion</td>
<td>Improved metallurgy</td>
</tr>
<tr>
<td></td>
<td>Chemical injection (chemicals may require improved seal design)</td>
</tr>
<tr>
<td>Scaling</td>
<td>Chemical Injection</td>
</tr>
<tr>
<td></td>
<td>Mixed Flow Pump Stages</td>
</tr>
<tr>
<td></td>
<td>Periodic acid / solvent treatments</td>
</tr>
</tbody>
</table>

Table 4 – Range of potential solutions for well specific issues

Figures

Figure 1 – Location of OEPC Block 15
Figure 2 – OEPC Block 15

Figure 3 – Automation Architecture
Figure 4 – Typical ESP completion
Figure 5 – Undiagnosed production loss

Figure 6 – Analysis of data from 16th October
Figure 7 – The Zorro plot
**Figure 8** – Target runlife improvement over contract

**Figure 9** – Eden Yuturi MTBF improving
Figure 10 – CPF MTBF resistant to change