Maximization of the Run Life of Electrical Submersible Pump through Effective Analysis of its Operational Problems in Egyptian Oil fields.

By

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ABSTRACT

Electrical submersible pumping systems (ESPs) are considered as effective and economical means of lifting large volumes of fluids from great depths, under a variety of well conditions. A short ESP run life introduces additional intervention costs and considerable production downtime. Based on ESP failure surveys collected from failure information from several major oil companies in Egypt which utilize ESP in a wide range of wells, many problems have been captured, which cause a reduction in the ESP performance and ESP failure. The goal of this work is to examine the problems that have been encountered and cause premature ESP Failure and identify the reason and potential solutions for these problems. An ESP surveillance and diagnosis model will be presented, which uses the ESP operational data, like sensor and surface parameters to diagnose degradation in the ESP performance due to effects, such as wear, deposition, plugging, gassy, spinning diffusers or even wrong pump rotation. As well as quantifying the amount of pump degradation, the model determines the amount of lost production (gross and net) and validates the well IPR. The implementation of the ESP Surveillance model and the results of such analysis will be presented for different cases. The use of this model across these wells will show a positive impact on proactively managing a large quantity of ESPs, resulting in the identification of changes to regain production and prolonging ESP run life.

Key words: ESP failure, run life, ESP performance, model and potential solution.

Introduction

In the early stages of a field development feasibility study, several different artificial lift methods are usually considered. For many such developments, especially in the high-volume applications, ESP's offer several advantages. They can work with relatively low bottom hole pressures, and therefore can accelerate production, increase reservoir recovery and improving the revenue obtained from a specific asset. On the cost side, the estimate of ESP run life is a key factor, which have a major impact on the results, so ESP run Life is a principal criterion that is typically evaluated before the initial design and throughout the well's Lifetime[1].

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[1]Takacs, G., 2009. Electrical Submersible Pumps Manual. Design, Operations, and Maintenance

To be able to continuously produce and maintain the required oil production rates, these ESP Systems need to be reliable. A downside of using this form of artificial lift is the requirement for a workover rig to replace the defective units. Therefore, a long average run life is essential to limit deferred production loss and control workover cost[2].

The life cycle cost of any piece of equipment is defined, as the total "lifetime" cost to purchase install operate, maintain and dispose of that equipment.

Determining the LCC involves following a methodology to identify and quantify all the components of the LCC equation.

The following equation can be used to estimate and identify the LCC Drivers for ESP.

$$\mathrm{LCC} = \mathrm{Cp} + \mathrm{Ce} + \mathrm{Cw} + \mathrm{Cd}$$

Where :

C_p is the Purchase price of ESP

C_e is the Energy costs (predicted cost for system operation, including pump driver and controls)

C_w is the Work-over costs

C_d is the down time costs (loss of production)

The Life Cycle Cost analysis was executed for an Egyptian Oil Field in the western desert with an estimated field life of 40 years and 30 ESP oil producer wells. Figure 1 illustrates the LCC calculation results. We can see that the LCC per year decreases significantly, when the ESP run life is prolonged. This gives us a picture, that enhancing the run life of ESP will be very cost beneficial. We see that, the LCC reduction is greatest from 1 to 2 years of run life.

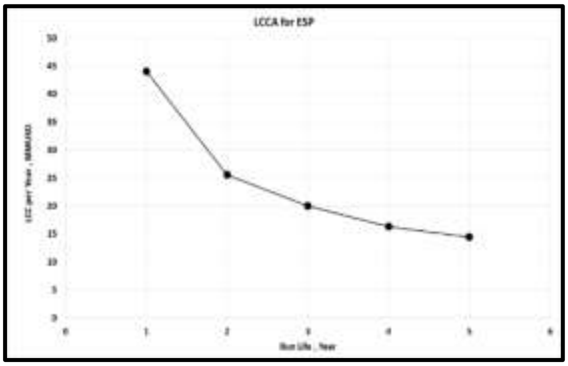

Figure 1. LCC per year, compared with the run life

[2]Hydraulic Institute, 2001. Pump Life Cycle Costs: A Guide To LCC Analysis For Pumping Systems. Executive Summary. Hydraulic Institute, Europump, And The US Department Of Energy's Office Of Industrial Technologies.

ESP Failure Analysis

It has been long identified that having a failure tracking system in place is a key to reduce the failure rates of ESP Systems. Problems with system design, equipment specification, manufacturing, installation, and day-to-day operation can be identified and corrected, contributing to increased run lives, lower operating costs and increased profits. As a result, many operators and vendors have set up database systems to track the ESP run life and failure information.

Data from existing ESP failure tracking database has been analyzed, in order to identify and classify the ESP operational problems.

A review of the current existent failure tracking system revealed that, there are many limitations, which could lead to get confused analysis and wrong conclusion of the root cause of ESP operational problems. The concluded limitations, based on initial analysis, can be summarized as follows:

1. Most of existing failure databases only track basic failure information, such as install data, fail date, pull date, equipment manufacture and failure cause.
2. Existing database does not differentiate between the failed item, failure mode and failure cause.
3. Lack of integration between the failure information and influential factors, such as operating conditions during the ESP run life.
4. Improper corrective action could be taken due to misleading failure cause classification.

For the purpose of effective analysis of ESP problems, a new failure tracking system structure and procedures are developed with the ultimate goal, for better understanding of factors affecting the ESP run life. The objectives of this new failure tracking system structure are as following[3]:

1. Provides a standard workflow for the ESP failure analysis.
2. Provides a general data set to be tracked for each failure.
3. Provide a common terminology to record and categorize the ESP Failure information.
4. Ensure consistency in performing Failure analysis with data gathered.
5. Gain a better understanding of ESP run life requires large amount of failure data, which covers a wide range of operating condition.

Table 1 below shows the data structure of the new failure tracking system.

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[3]Alhanati, F.J.S., 2001. ESP Failures: Can We Talk The Same Language?

Table 1. ESP Failures data structure

Group	Parameter	Description
Field Information	Field Name	General Field data like name and location
	Field Location	
Well Information	Well Name	General Well information data also include Reservoir , Completion types
	Well type	
	Reservoir name	
	Completion Type	
Run life Data	Date Installed	Run Life is the duration period between Date Stated and Date Ended
	Date Started	
	Date Ended	
	Date Pulled	
	Run Life	
Failure information	ESP System Failed?	Failure Data is input including Pull reason and Failure information
	Pull Reason (General & Specific)	
	Failed Component	
	Failure Cause (General & Specific)	

The ESP pull reason is determined, once the ESP must be pulled from the well because of either system failure or other circumstances. Figure 2 contains the reason of pull for an ESP system

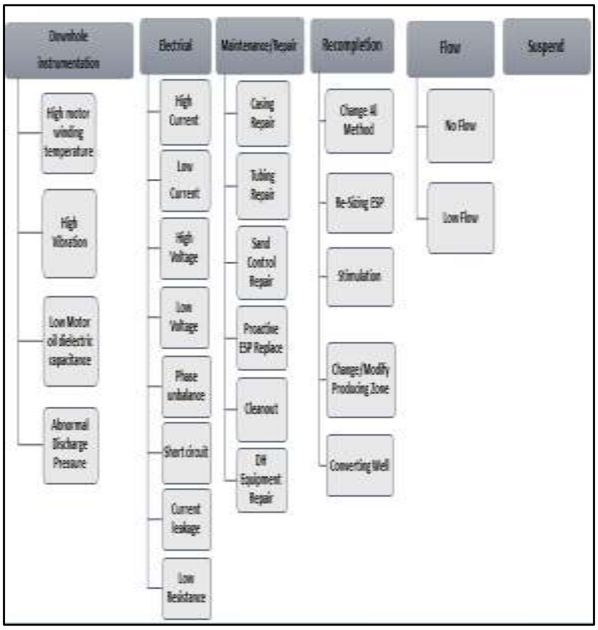


Figure 1. Pull reasons for ESP

The failed component is any part or component that has failed, as a result of a certain failure cause. Figure 3 contains failed components for an ESP system.

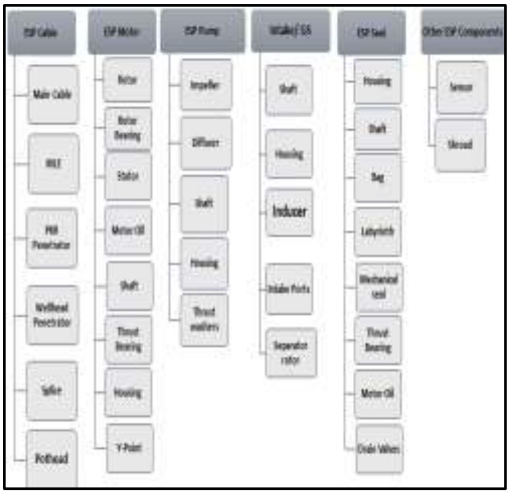


Figure 2. Failed components

The Failure Cause is the main reason, which has led to ESP system failure as shown in Figure 4.

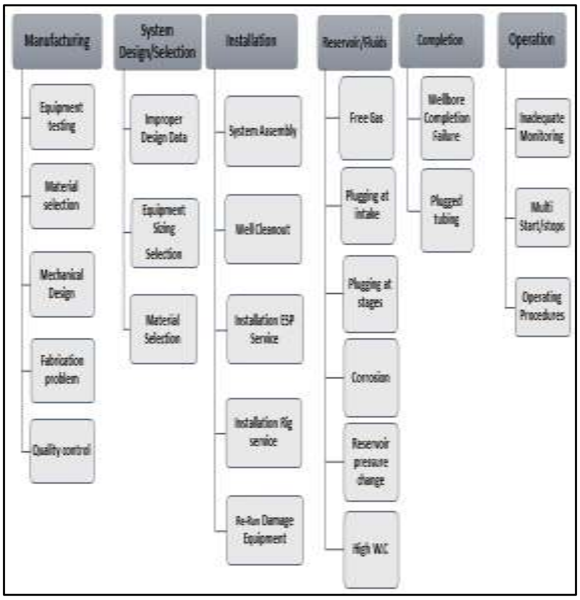


Figure 3. ESP failure causes

The analysis of the ESP failures is based on the ESP failure information belonging to 437 ESP failures to a number of 170 wells distributed by 5 egyptian oil fields.All 437 ESP failures under this study have been migrated from the old existing failure tracking system to the new developed system.

Categorizing for each failure has been done through collecting the following information related to such failure and going through it to reach the final decision on the main failure cause[4].

1. Well production data.
2. ESP Sensor & VSD Data.
3. Troubleshooting Reports.
4. Rig Pull report.
5. Final DIFA report.

Table 2 shows the failure ratesof the main ESP failure causes

Table 2 Failure Rates of main ESP. Failure Causes

Failure Reason	Failure Rate
Reservoir/fluids	26%
Operation	21%
System Design/Selection	16%
Installation	13%
Manufacturing	10%
Completion	9%
Unknown	5%

Reservoir/fluids conditions have a prime effect on the longevity of ESP Equipment

Table 3 Reservoir/fluids ESP failure causes

Failure Reason	Failure Rate
Decline in Reservoir Pressure	28%
Blockage at pump Stages	18%
Blockage at intake	15%
Blockage at perforations	13%
Free Gas	12%
Increase in Reservoir Pressure	8%
High Water Cut	6%

[4]Williams, A.J., 2003. 7th European Electric Submersible Pump Round Table Aberdeen Section. ESP Monitoring – Where's Your Speedometer?

Poor operating practices can cause an ESP failure. In this survey, the ESP failures due to operating procedures issues are listed in Table 4.

Table 4 Operation ESP Failure causes.

Failure Reason	Failure Rate
Excessive Start/Stops	41%
Improper Operating Procedures	38%
Inadequate monitoring	21%

ESP have a limited operating range and if operated outside its design operating range, reliability is dramatically reduced which in turn resulted into a high operating cost. ESP failures due to System Design and Selection are listed in Table 5.

Table 5. System design ESP failure causes

Failure Reason	Failure Rate
Improper Design Data	36%
Improper Material Selection	28%
Improper Equipment Selection	21%
Inadequate Motor Power Capacity	9%
Inadequate pump Capacity	6%

Equipment installation and proper handling are critical to the success and long life of any ESP installation. Regardless of how well, an ESP system has been sized for a well, if it is not properly installed, the unit will likely fail. ESP failures due to Installation issues are listed in Table 6.

Table 6. Installation ESP failure causes

Failure Reason	Failure Rate
Improper ESP String Assembly	44%
Installation- Service Rig	30%
Improper Equipment Handling	17%
Improper Well Cleanout	9%

Manufacturing defects could be the root cause of ESP failure, away from the operating conditions of the pump. ESP failures due to manufacturing issues are listed in Table 7.

Table 7. Manufacturing ESP Failure causes.

Failure Reason	Failure Rate
Improper Mechanical Design of Parts	42%
Improper Assembly of Parts	35%
Lack of Quality Control	23%

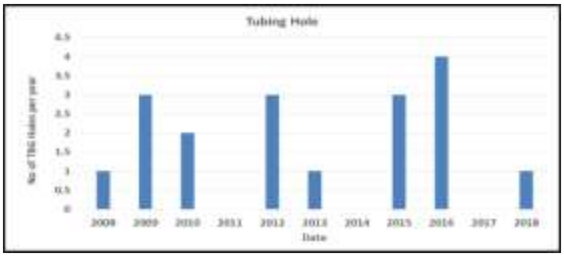
Completion failures are usually related to failure of other completion components that may lead to the ESP system failure. ESP failures due to manufacturing issues are listed in Table 8.

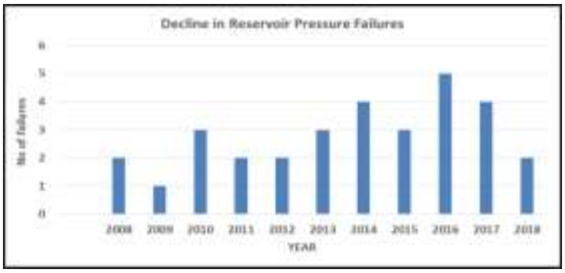
Table 8. Completion ESP Failure causes.

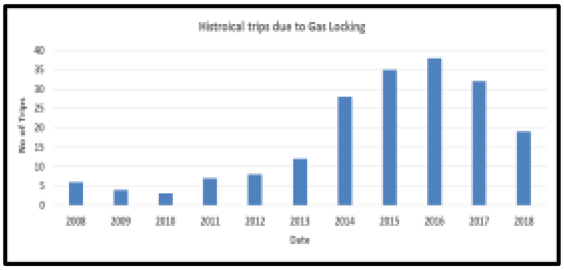
Failure Reason	**Failure Rate**
Wellbore Completion Failure	46%
Improper Sand Control	31%
Failure of Liner	23%

Summary of the ESP failure analysis results

When we investigate the historical trend of ESP Failures, most of the failures are repetitive. It is well known that, most of the observed ESPs failures have been seen in the past. As it can be seen from Figure 5, the ESP Failures are repetitive at increasing trend in some cases.







Combining the reasons, which led to either an ESP failure which requires a Workover or an ESP trip, which causes oil deferment, we have concluded, that the following are the most common reasons for ESP Failure or trips:

1. Blockage at Perforations.
2. Decrease in reservoir pressure.
3. Broken shaft.
4. Wearing Stages (erosion).
5. Hole in Tubing.

6. Blockage in Pump Stages.
7. Increase in Reservoir Pressure.
8. Shut in at Surface.
9. Increase in Water Cut.
10. Gas Locking.

ESP surveillance and diagnosis model

The ESP Surveillance and diagnosis model is a workflow or a technique that is used specifically for troubleshooting and diagnosis of the ESP, to track the ESP performance and well productivity, using real time ESP sensor data.

Building a computerized model needs programming skills and enough time for modification to finalize a successful, reliable, and usable program. Therefore, Microsoft Excel will be used to accomplish the model, as a numerical approach, which will provide various flexible options of editing and provide a simple window for use for engineers.

The model aims at aiding the operating engineers, both in the problem diagnosis of the ESP system and the recommended actions for troubleshooting the problem.

An ESP surveillance and diagnosis model were developed, using the classical nodal analysis and extends it with ESPs containing intake pressures gauges and discharge pressure gauges.

The model uses a technique, which moves beyond traditional nodal analysis to:

- Validate the ESP performance
- Allows evaluation of ESP performance independently from reservoir performance
- Able to categorically differentiate between an ESP problem and a reservoir inflow problem
- Quantify the degradation in the pump resulting in less production.
- Determine the amount of lost production

The application of the model will be conducted on two Stages:

First Stage: ESP Health Check

This is done by comparing actual to theoretical head exerted by the pump and quantify the difference if exists in terms of degradation factor.

Second Stage: Reservoir parameters check

Reservoir parameters check to identify any change in reservoir parameters.

Procedures of ESP Health Check

1. The pump discharge pressure PDP is determined (or real value is used, if a downhole sensor is available)
2. The pump intake pressure PIP is determined from downward gradient using IPR (or real value is used, if a sensor is available).
3. The actual pressure differential (DP) and Actual total dynamic head (TDH) across the pump is determined as following:

   Pump DP = PDP – PIP
   Actual ESP TDH (ft.) = pump DP / flowing Fluid gradient
4. The production rates measured at the surface are converted to downhole flowrates using PVT and multiphase correlations

   ESP DH rate (BBL/D) = ESP test rate (STB/D) * liquid Formation Volume Factor (LFVF)
   LFVF = Oil FVF * (1-W.C) + Water FVF * W.C
5. Using Pump Curve, the theoretical TDH, that the pump should produce for the downhole rate is determined as, per below Figure6.
6. Gradient Traverse plot can be constructed as per shown in Figure7.

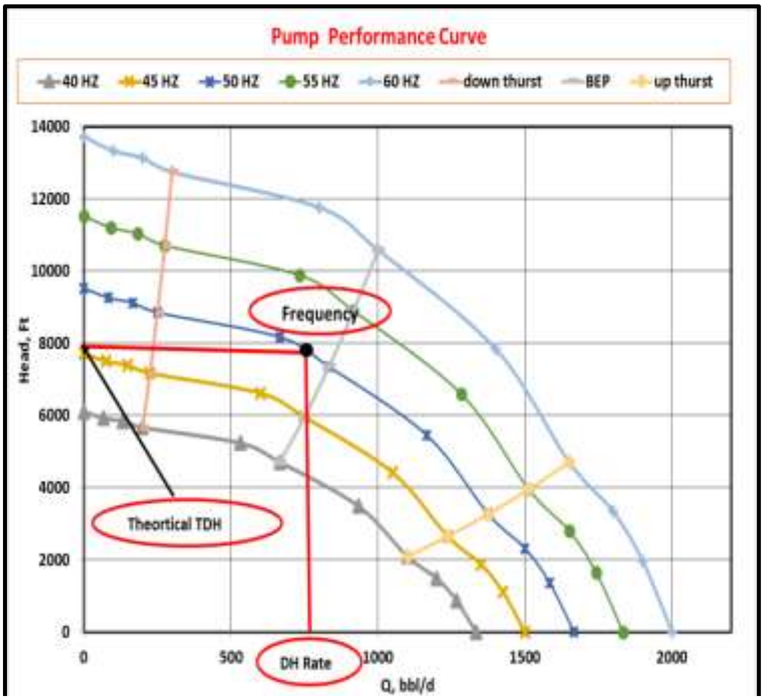


Figure 6. Determination of Theoretical TDH from Pump Curve

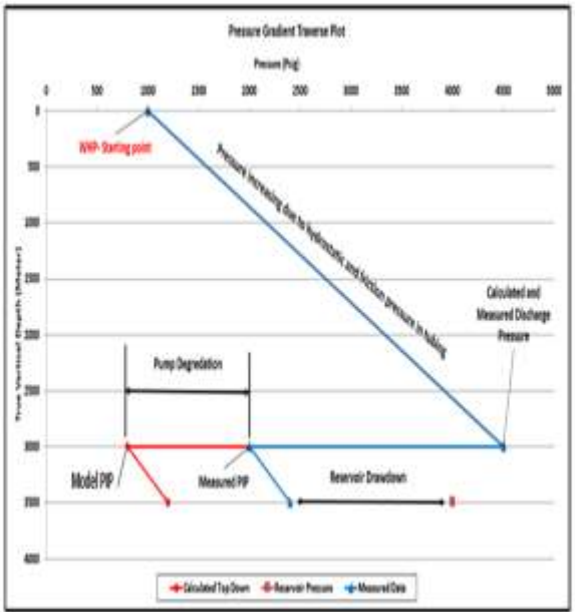


Figure7 Unmatched Gradient traverse plot for an ESP Well

If field and model readings coincide, so the ESP is performing well, without any performance degradation. Where a difference in theoretical TDH vs. actual TDH exists, this value is quantified in terms of pump degradation and can be determined as follows:

7. ESP head factor is determined as following
   ESP Head Factor = Actual ESP TDH / Theoretical ESP TDH at given frequency
8. ESP degradation Factor is determined as following:
   ESP Degradation Factor = 1- ESP Head Factor
9. After applying the degradation factor, we can obtain matched gradient traverse plot, as shown in Figure 8.

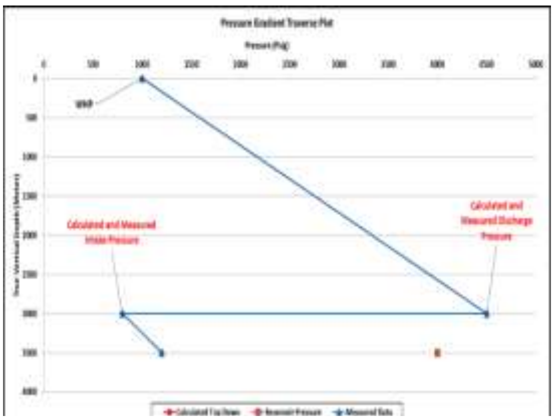


Figure 8 Matched Gradient traverse plot for an ESP

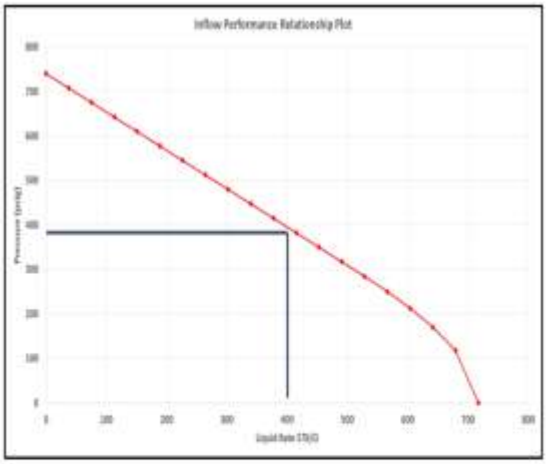


Figure 9 Calculation of BHP from the measured liquid Rate

Procedures of Reservoir parameters Check

1. Measured Liquid rate used to read the Flowing BHP from IPR curve, as shown in Figure 9.
2. From this BHP, Pump Intake pressure can be derived, using the fluid Gradient.

$$\textbf{PIP} = \textbf{P}_{\textbf{wf}} \_ \textbf{(TVD}_{\textbf{Upper Perf}} \_ \textbf{TVD}_{\textbf{Pump}}\textbf{)} * \textbf{Flowing Fluid Gradient}$$

3. The increase in pressure across the pump can be calculated for the given conditions using the calculated degradation Factor.
4. Pump Discharge pressure is then calculated, as:

Theoretical PDP = Actual Delta P across the pump + PIP

5. From the PDP, the gradient is performed up to the wellhead to find the calculated WHP and then compare with the actual WHP.

$$\textbf{Theoretical WHP} = \textbf{Theoretical PDP} \_ \textbf{(TVD}_{\textbf{Pump}} * \textbf{Flowing Fluid Gradient)}$$

6. Gradient Traverse plot can be constructed, as following, to compare the already matched gradient obtained in the ESP health check step by the gradient, calculated from the initial reservoir parameters used in the ESP Design.

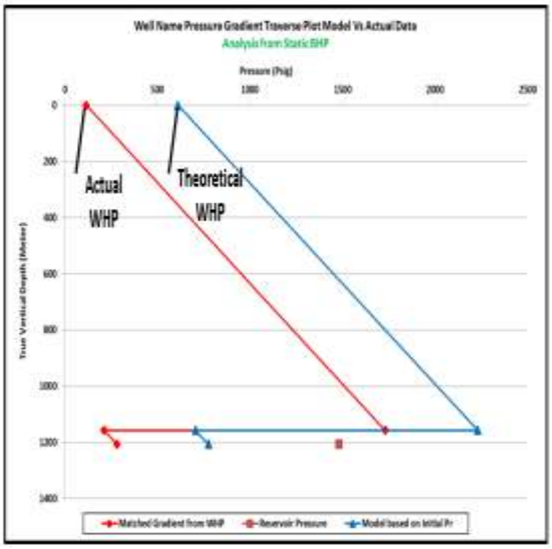


Figure 10 Unmatched Bottom-up Gradient traverse plot for as ESP Well

Summary

The developed integrated ESP Surveillance and diagnosis model will be conducted, using the ESP and production data in two stages with main objective to differentiate between an ESP efficiency problem and the reservoir inflow problem.

The first stage ‘’ESP health check’’ will be used to investigate the ESP downhole pump performance and quantify the degradation in performance if exists. Deterioration on the ESP performance can be due to increase of amount of gases into pump, deposition, broken shaft, ESP running backwards and tubing leak.

The second stage ‘’Reservoir parameters check’’ will be used to validate the initial reservoir parameters used in the ESP design and thus, it can be used to track the decline in well productivity or decline/increase in reservoir pressure.

The implementation of the ESP Surveillance model and the results of such analysis have been done for the previous ten common ESP operational problems and a sample of one case will be presented in this paper.

Decrease in reservoir pressure case

The below performance belongs to an ESP oil well and the following variation in ESP parameters from the normal pump parameters has been noticed, as per Figure 11:

- Slow decline in discharge pressure over the flowing period
- Continuous decline in intake pressure over the flowing period
- Gradual increase in the motor Temperature
- Slow decline in Motor AMP over the flowing period.

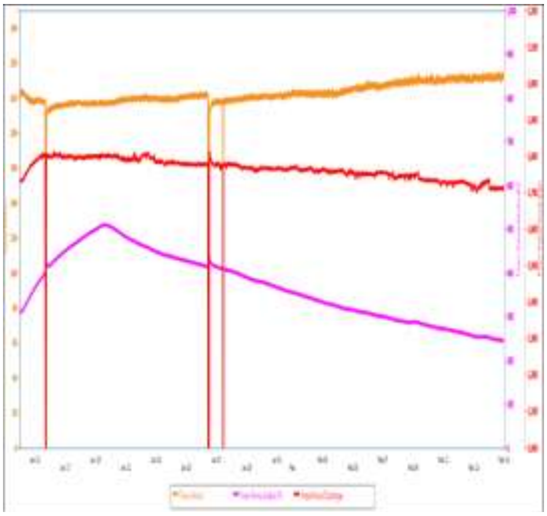


Figure 11. ESP parameters trend.

Due to variations in ESP parameters, the well has been tested two times. In January, the well tested with 1800 BPD. In February, the well tested with 1400 BPD, with further drop by 400 BPD

The test data is presented in the following pump performance curve in Figure12.

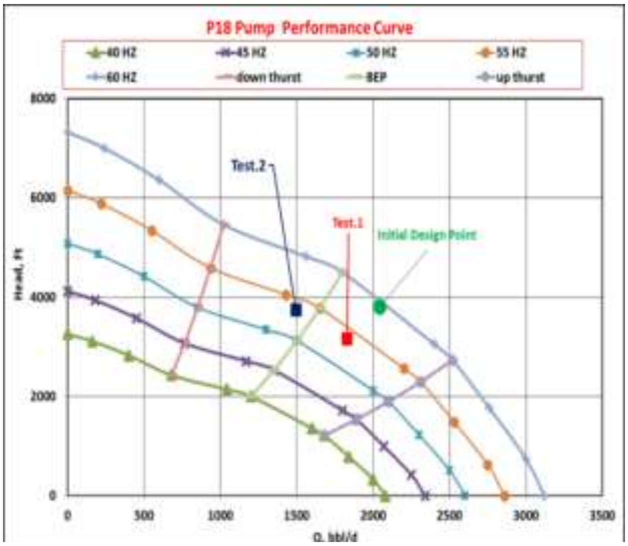


Figure 12. ESP performance curve of well #1

The case will be analyzed, using the proposed ESP diagnosis model, in order to investigate the following:

1. The difference between design point and Jan test.
2. The drop in well production rate from Jan to Feb by 400 BPD.

Analysis of the production test No. 1

Step 1: ESP Health check

Input Data	
Real-Time Intake Pressure, Psi	510
Real-Time Discharge Pressure, Psi	1805
Surface Production Rate, BPD	1800
Real-Time WHP, Psi	116

Output Data	
Actual Delta P across the pump	1295
Liquid Fluid Gradient, Psi/Ft	0.409
Actual TDH across the pump, Ft	3162
Downhole Flow rate, BPD	1829
Theoretical TDH across the pump, ft.	4025
ESP Head Factor	0.78
Pump Degradation Factor	0.22

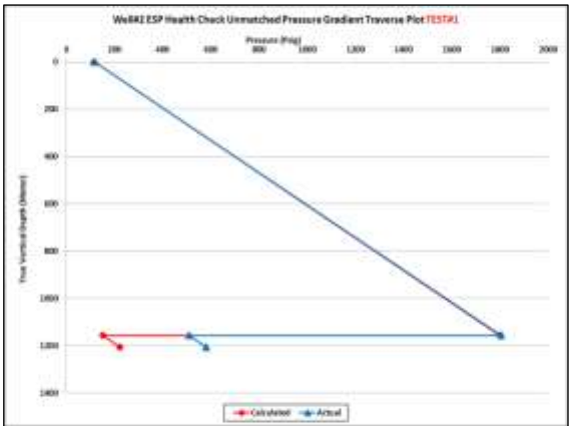


Figure 13 ESP Health check pressure gradient traverse plot Test.1

As per Figure13, the ESP pump suffers from degradation factor of 22 % lower than that of the theoretical pump performance curve.

Step 2: Reservoir parameters check

Input Data	
Static BHP, Psi	1500
Productivity index, BPD/Psi	2
Surface Production Rate, BPD	1800

Output Data	
Bottom Hole flowing Pressure, Psi	580
Pump intake Pressure, Psi	508
Pump Discharge Pressure, Psi	1790
Wellhead Pressure, Psi	118

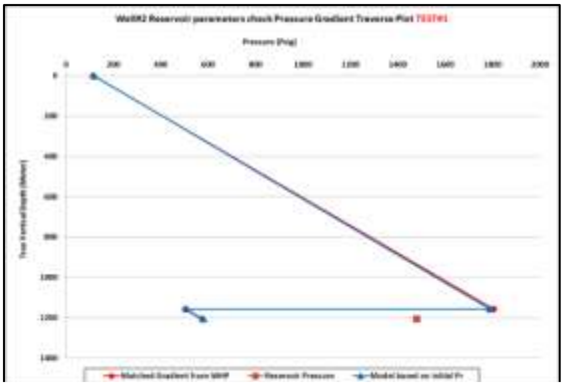


Figure 14 Reservoir check pressure gradient traverse plot Test. 1

As shown in Figure 14, there is a match between the actual data and the model data, as derived from reservoir parameters.

Investigation of Production Test No. 1

From the above analysis, it can be concluded that, the ESP is degraded by 22% and this matches the actual the well parameters, meanwhile there is no change in the reservoir parameters from one used in design.

Analysis of production Test No. 2

From the production test No.2 results, we can observe there is still decline in the well production rate which resulted in loss of extra 400 BPD Gross Rate and hence further investigation is required, in order to check if the ESP pump is additionally degraded so that a proactive replacement could be planned to restore the well production or there any other effect could be the reason of this decline.

Step 1: ESP Health check

Input Data	
Real-Time Intake Pressure, Psi	212
Real-Time Discharge Pressure, Psi	1731
Surface Production Rate, BPD	1416
Real-Time WHP, Psi	116

Output Data	
Actual Delta P across the pump	1519
Liquid Fluid Gradient, Psi/Ft	0.409
Actual TDH across the pump, Ft	3713
Downhole Flow rate, BPD	1494
Theoretical TDH across the pump, ft.	3718
ESP Head Factor	0.99
Pump Degradation Factor	0.001

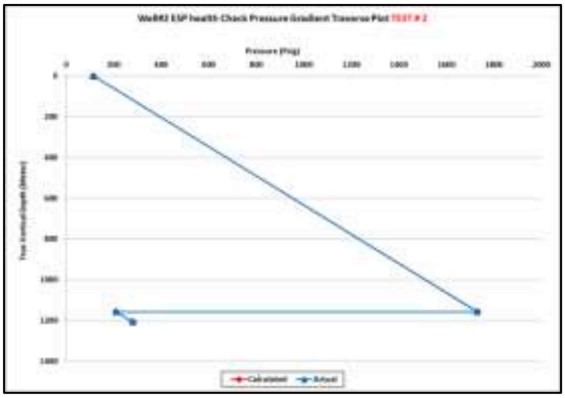


Figure 15. ESP Health check pressure gradient traverse plot Test.2

From Figure15, it can be concluded that the ESP performance is stable, and no further degradation occurred.

Step 2: Reservoir parameters check

Input Data	
Static BHP, Psi	1500
Productivity index, BPD/Psi	2
Surface Production Rate, BPD	1400

Output Data	
Bottom Hole flowing Pressure, Psi	776
Pump intake Pressure, Psi	706
Pump Discharge Pressure, Psi	2231
Wellhead Pressure, Psi	611

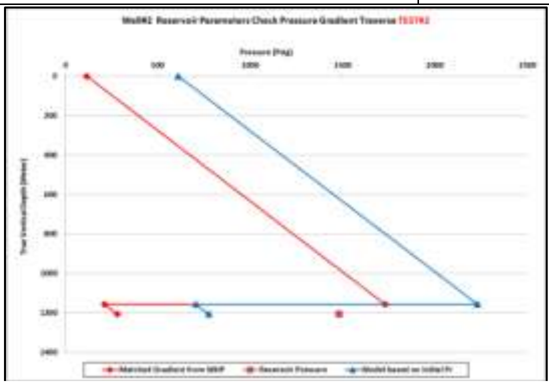


Figure 16 Reservoir check pressure gradient traverse plot Test.1

From Figure 16, there is a mismatch between actual data and model data derived from reservoir parameters, which mean that the drop-in production rate is due to the change in one of the reservoir parameters and not related to the pump efficiency.

In order to find the change in the reservoir pressure, Prosper Software has been used, in order to perform the sensitivity analysis on different reservoir pressure in order to match the current testing data as shown in Figure 17.

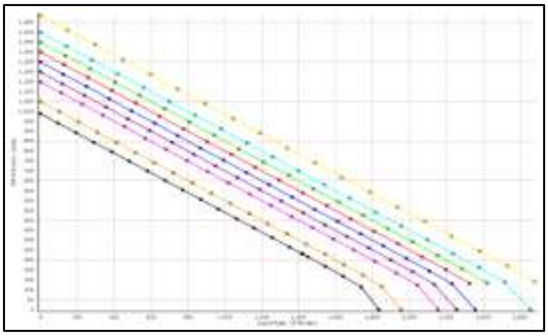


Figure 17 Prosper sensitivity analyses on reservoir pressure

From the plot, the matched Reservoir Pressure is 990 Psi, which represents 66% reduction from original Reservoir Pressure.

Base on the above analysis, we can see that, the model was able to differentiate between ESP and reservoir problem and pinpoint abnormal ESP operation and corrective action must be taken to protect the ESP from further depletion into the reservoir and drop in the production rate.

Conclusion

From the data obtained in this work and attained results, the following conclusions have been drawn;

1. Existing ESP failure tracking systems seldom integrate both failure information and a comprehensive set of influential factors, and thus lack enough breadth to assess the ESP run life under different operating conditions, which adding significant uncertainty to a project’s economic results.

2. The implementation of the new developed ESP failure tracking system helps to organize and focus efforts on the critical failures in ESP. the proper definition of the ESP failure root cause and its precise classification is essential for determination of the effective action plans to prevent recurrence of the failures.

3. An ESP surveillance and diagnosis model were developed, which uses the classical nodal analysis and extends it with ESPs containing the intake pressures and discharge pressure gauges. Analysis of any changes can quickly identify which part of the system is affecting the production performance. The developed model has been tested to the ten common operational problem to match the actual ESP problem case and resulted a good match.