USING REAL TIME AUTOMATED OPTIMISATION AND DIAGNOSIS TO MANAGE AN ARTIFICALLY LIFTED RESERVOIR- A CASE STUDY

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INTRODUCTION

The time taken to safely optimize a reservoir produced by artificial lift can be measured in weeks or months.

Typically the well by well process is as follows:

- Well testing
- Amalgamation of the well test data with down hole gauge and ESP controller data
- Analysis of the data to find the existing operation conditions
- Analysis of the ESP pump curve operating point and optimisation limitations
- Sensitivity studies in software to assess the optimum frequency and WHP
- Notification for the field operations to action the changes
- Further well tests to verify the new production data.
- Analysis of the data to ensure the ESP and well are running optimally and safely at the new set points

New technology enables this process to be performed in real time across the entire reservoir or field, significantly shortening the time to increased production and enabling real time reservoir management.

Each artificially lifted well in the reservoir was equipped with an intelligent data processing device programmed with a real time model of the well. The processors were linked to a central access point where the operation of field could be remotely viewed in real time.

Each well's processor was provided with a target bottom hole flowing pressure to enable the optimum production of the reservoir. The real time system automatically compared the desired target drawdown values with the capability of the pumping system installed in each well, and automatically suggested the optimum operating frequency and well head pressure to achieve the target. Where the lift system was not capable of producing to the target bottom hole pressure, a larger pump was automatically recommended. As production conditions change the system adapted its recommended operating points to compensate and maintain target production.

This paper discusses three case studies where real time optimization and diagnosis lead to improved production from the reservoir.

Optimizing an ESP well is a perpetual operation as reservoir and well conditions change. The process of optimization involves many steps which take time and resources, and in turn defer production.

The typical process for effectively optimizing one ESP well can be listed as follows.

1. Test the well to establish current production
    i. Oil , Gas and Water Rates
2. Production Log the well (if possible) to measure the inflow conditions
    i. Bottom Hole Flowing Pressure
    ii. Amalgamate the well test data with down hole gauge, log data, and ESP controller data to verify
    iii. Well Productivity Index (PI) verification
    iv. Inflow and Outflow Performance verification
    v. ESP pump curve operating point and power requirements
3. Perform sensitivity studies in software to assess the optimum frequency and WHP within the well draw down and ESP capabilities
4. Notify the field operations to action the changes
5. Perform further well tests to verify the new production data
6. Analyze the new production data to ensure the ESP and well are running optimally and safely at the new set points
7. Continue the process as reservoir & well conditions change

The efficiency of this process can be greatly increased by implementation of real time well modeling and surveillance. This more efficient process is listed below

1. Reservoir engineers provided the desired bottom hole flowing pressures for each well to appropriately manage drawdown on the reservoir.
2. This data was entered into the system as the target for optimizing each well.
3. The automated optimization calculations checked if the target BHFP was achievable on the IPR curve, and then calculated the potential rate increase.
4. The potential rate was automatically cross checked by the real time technology against the ESP’s operational capacity, and operating limits, to validate if the pumping system could safely delivery to target without effecting run life.
5. The real time system provided the optimum operating frequency and well head pressure recommendation to achieve the target rate within the boundaries of each ESP’s capability.

AUTOMATION OF THE OPTIMISATION PROCESS

An automated surveillance and optimization system implemented on three wells has been proven to reduce the cycle time to increased production. This paper discusses the three case studies where the system has returned a faster turnaround to increased production and also automatically highlighted ESP operational problems.

An intelligent surface panel and down hole dual pressure ESP gauge was installed on each of the three well sites to enable automatic analysis of the key ESP data

- Pump Intake and Discharge Pressures
- Pump Operating Flow & Head
- Motor Cooling Rate
- Gas at Intake
- Efficiency & Wear
- Fluid Density through the ESP
- Intake and Discharge Flow Rates
- Frictional losses in the tubing
- Fluid Level above the pump intake

- Motor Temperature
- Vibration

The real time well model in the panel calculated the well test data and inflow data in real time.

- Total Liquid Flow Rate
- Water Cut
- GOR
- Bottom Hole Flowing Pressure
- Well draw down from reservoir pressure
- Productivity Index Value
- Operating point on IPR Curve

A well test or multiphase meter is therefore required less frequently to optimize the well with this system. The surface panels were interfaced to the VSDs to automate the surveillance and optimization process and enable remote VSD control. All well and ESP operational information was available at the well site, and also transmitted to control rooms and office personnel using the real time system's remote access server (see figure 1)

.REAL TIME VIRTUAL WELL TESTING

The calculated real time well test parameters described above were validated by a well testing unit in case study 1 to assess the performance and accuracy of the system. The real time well test data reduces the frequency with which a well test unit is required on the well. The process used to provide the virtual real time well test was as follows.

1. A real time well model running at the well site is calibrated by the live down hole gauge, WHP and VSD readings
2. Validated PVT , IPR and well completion data are incorporated into the well model
3. The well model uses the measured tubing pressure gradient from WHP to discharge pressure to verify fluid density and therefore water cut and GOR
4. The well model sensitizes on well inflow and outflow curves to verify surface and down hole flow rates based on pressure changes in the well bore and across the pump
5. The pump curve and measured pump head are used to cross check the calculated rates

OPTIMISATION AND DIAGNOSIS FUNCTIONALITY

The real time system's surface panels were installed at each well site to enable real time optimization sensitivity studies on live well data. Suggested operating frequency and WHP opportunities were displayed at the VSD and also relayed remotely to all personnel involved in the operations.

To ultimate decision on frequency adjustment was to remain under the control of the operators. Therefore the optimization suggestions were not automatically implemented at the well sites but were performed manually and by remote control. ESP diagnosis was performed automatically at the well site by the surface panel, and the results relayed by remote communication. The system analyzed the optimization changes in real time against the live well data and ESP limitations to avoid well or ESP damage. All alarm and trip functionality was performed at the well site where it provided ultimate protection for the ESP, even if communications were lost. ESP resizing was performed by artificial lift engineers when it was automatically recommended by the automated system. Sizing was based on the real time well test data obtained from the system.

CASE STUDY 1

Optimisation of a well thought to be at maximum potential.

The real time system highlighted that the well production could be optimised by increasing the frequency of the VSD.

The suggested optimum ESP frequency of 61.9Hz was automatically calculated to be within the limits of both the ESP performance window and well draw down capability as specified by the company reservoir engineers. The new frequency was suggested to achieve an additional 123 bfpd from the well.

The VSD frequency was adjusted manually from 55 Hz to 56 Hz, and then remotely from 56 Hz to 58 Hz. Adjustment was performed in 1 Hz steps so as to verify the systems recommendations. For the initial remote frequency increase, company personnel were located at the well site to verify the remote frequency change was safely implemented.

The accuracy of the real time production calculations for flow and water cut were verified by an independent well test as shown in the results table below.

55 HZ

Well test total liquid flow at 55 Hz	935 stb/day
The real time system total liquid flow at 55 Hz	971 stb/day (+3.8% variance from well test)
Well test water cut at 55 Hz	22%
The real time system water cut at 55 Hz	19.5% (-2.5% variance from well test)

57 Hz

Well test total liquid flow at 57 Hz	998 stb/day
The real time system total liquid flow at 57 Hz	1031 stb/day (+3.3% variance from well test)
Well test water cut at 57 Hz	22%
The real time system water cut at 57 Hz	19% (-2.5 % variance from well test)

The ESP well's production was boosted by 66 barrels of oil per day by following the optimization recommendations of the automated system. The operating frequency of the VSD was adjusted remotely to achieve the optimum production rate for the ESP installed thereby reducing the time cycle to implementation.

Results

The total turnaround time for the optimization was 6 days which was due partly to well test flow validations and also manual analysis of the real time systems data to independently verify the real time systems calculations. The remote frequency increases from 56 to 58 Hz were conducted in 24 hours once confidence in the system was established as can be seen in figure 2.

CASE STUDY 2

Optimizing a well with emulsion problems.

A minimum bottom hole flowing pressure limitation of 370 psi was specified by the company reservoir engineers and programmed into the real time system's surface panel. The ESP was running at 43 Hz but not achieving the target draw down. The automated optimization immediately highlighted that optimum frequency of the ESP was 47.1Hz.

The automated pump performance diagnosis showed that the head performance of the ESP was unstable, dropping intermittently by up to 22%. The reduction of head performance was thought to be due to formation of emulsions. Frequency was increased in small steps from 43Hz to 47Hz while monitoring the effect of the emulsions on the pump head performance.

Refer to the following figures

Figure 3: First Optimisation Step increasing from 43hz to 44hz whilst monitoring stability in real time.

Figure 4: The final optimization adjustment from 45 to 47Hz

Figure 5: The pump operating point at 47Hz is shown to fall below the pump curve due to reduced head performance of the ESP whilst emulsions were forming. The ESP was design was slightly oversized to compensate

Figure 6: The gradient plot taken at 47Hz shows bottom hole flowing pressure has achieved the target of 370psi

Results

The VSD frequency was increased from 43Hz to 47Hz over the course of optimization. Correspondingly the production rate was increased from 570 stb/day to 671 stb/day. With water cut averaging 73% this equated to a 27 bopd increase in production (approx $2500 per day additional revenue). The ESP was shown to be within range, and sized to compensate the reduced head performance of approx 22%

<u>CASE STUDY 3</u>

Optimisation of a well with an ESP not capable of meeting the target BHFP

A minimum bottom hole flowing pressure limitation of 1131 psi was specified by the company reservoir engineers and programmed into the real time system's well model.

The wells gradient plot showing current and target BHFP is shown in Figure 7

The automated optimization system immediately highlighted that the production capability of the well exceeded the flow capability of the ESP installed and the automated ESP diagnosis highlighted that the ESP was underperforming by 30%

However, the system recommended that the ESP frequency could be safely increased from 42Hz to 46.7Hz. The system automatically showed that 46.7Hz was still not sufficient to achieve the target draw down, because further increases of frequency were limited by the ESP sizing (pump range).

After increasing frequency the bottom hole flowing pressure stabilized at 1267 psi with a liquid rate of 2720 stb/day. The target bottom hole flowing pressure for the well was 1131 psi, providing scope for an additional 1142 stb of fluid. The ESP installed was not capable of providing this additional flow rate and so in January 2012 the ESP was resized based on the recommendations of the real time system and draw down was optimised to the target bottom hole flowing pressure. Flow rate was increased to 4027 stb/d.

Results

Automated diagnosis and frequency optimization of the underperforming ESP provided an additional 73,000 barrels of oil ($7.15 Million) in the 334 days of operation with the real time system. The ESP under performance issue was highlighted immediately the automated system was implemented on the well.

Resizing of the ESP to achieve the target BHFP in January 2012 resulted in an additional 562 bopd production ($55,070 per day)

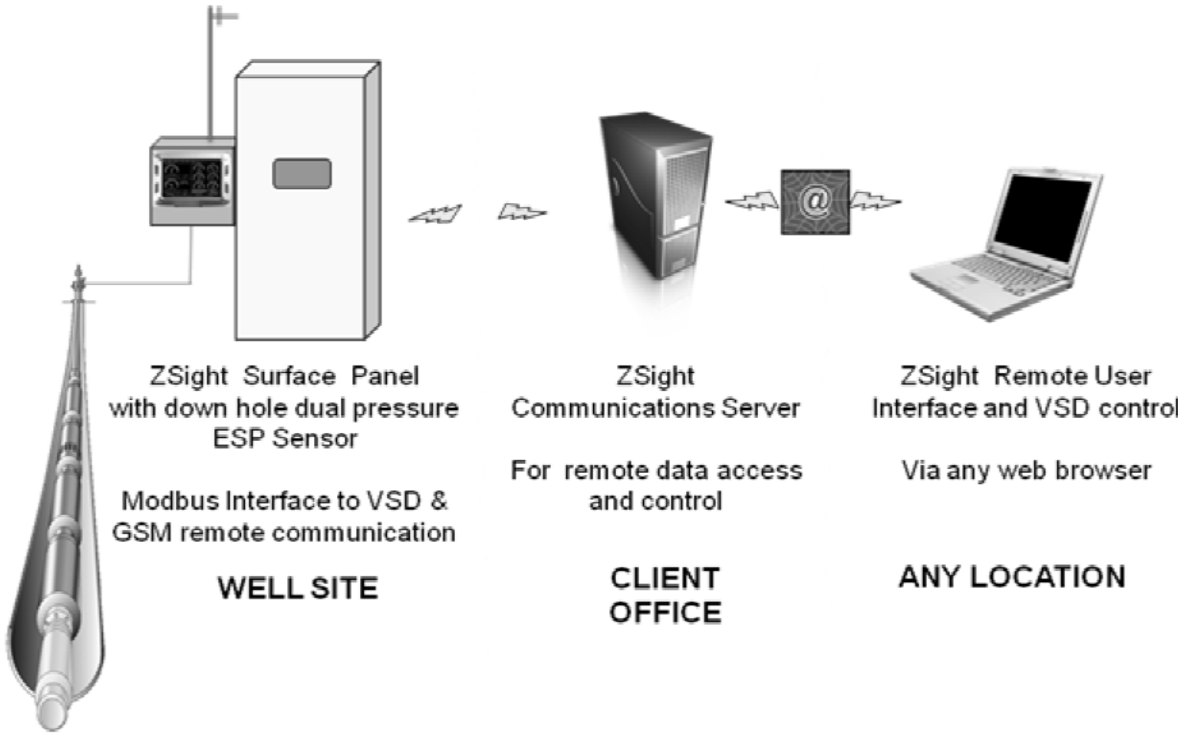

Figure 1 – System Architecture

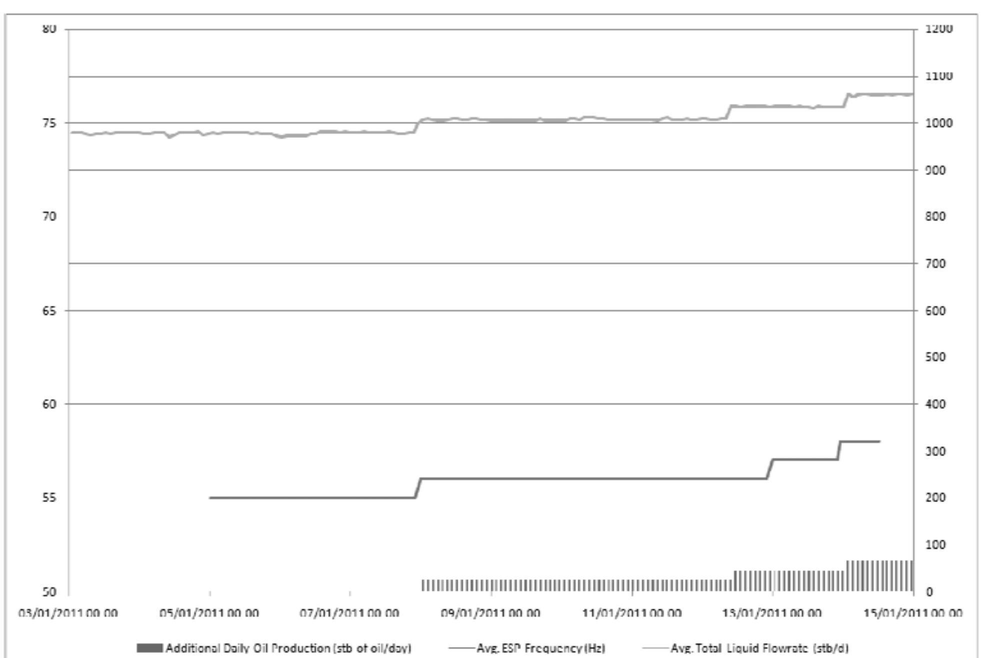

Figure 2 – Case Study 1: Optimisation Results

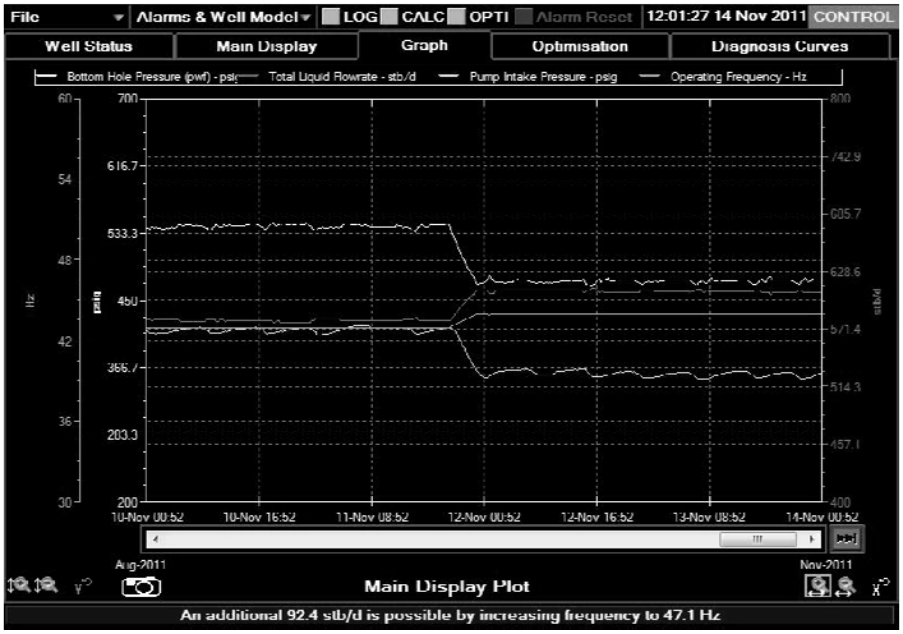

Figure 3 – Case Study 2: First Optimisation Step increasing from 43hz to 44hz whilst monitoring stability in real time.

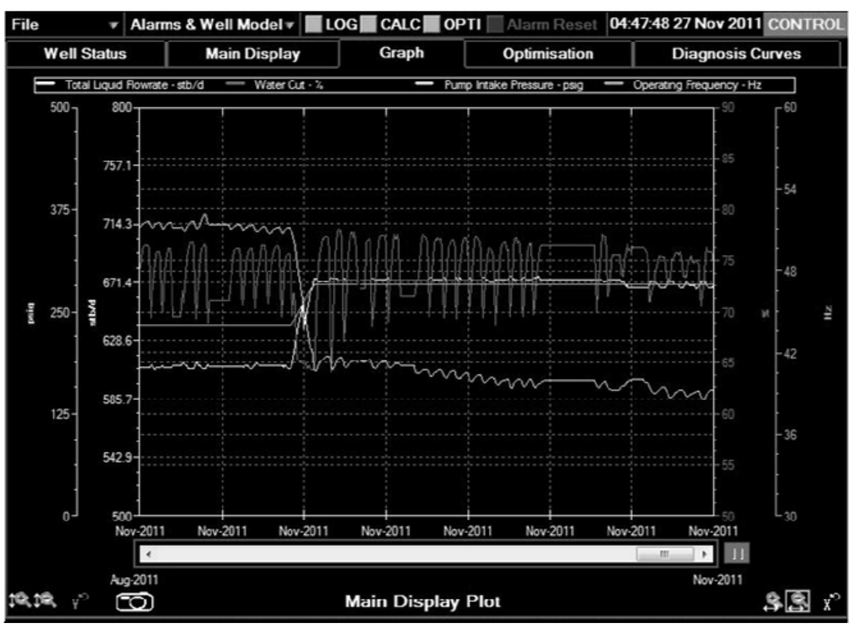

Figure 4– Case Study 2: The final optimization adjustment from 45 to 47Hz

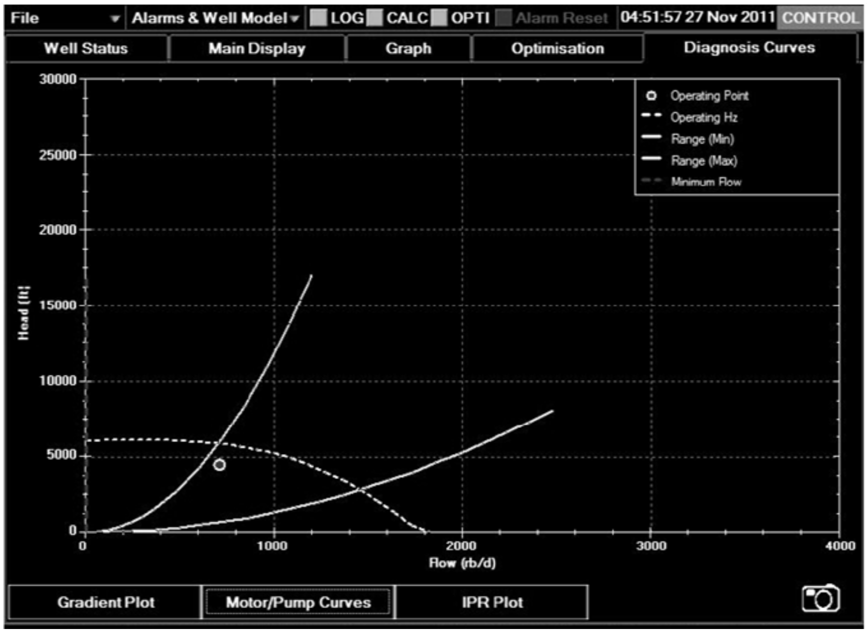

Figure 5– Case Study 2: The pump operating point at 47Hz

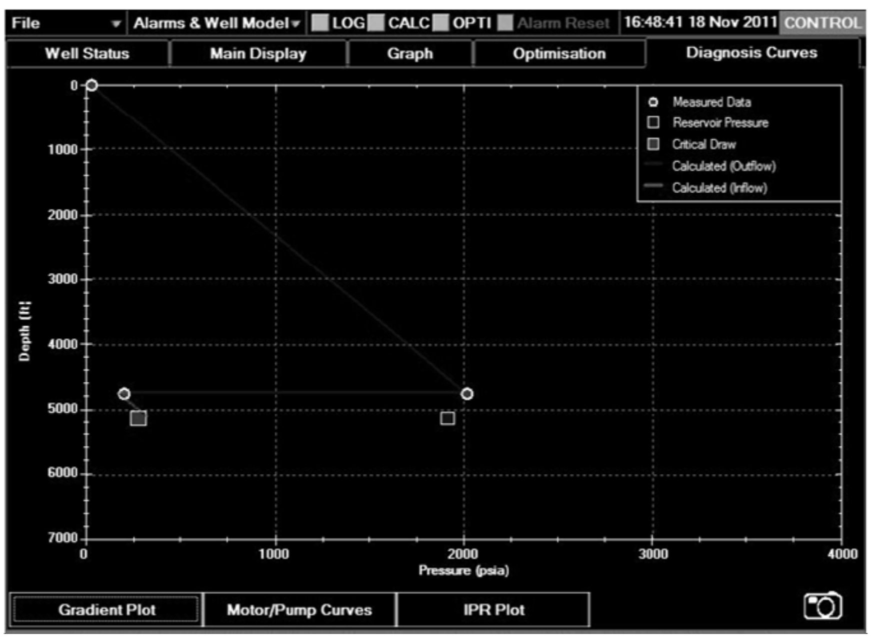

Figure 6– Case Study 2: The gradient plot taken at 47Hz shows bottom hole flowing pressure has achieved the target drawdown

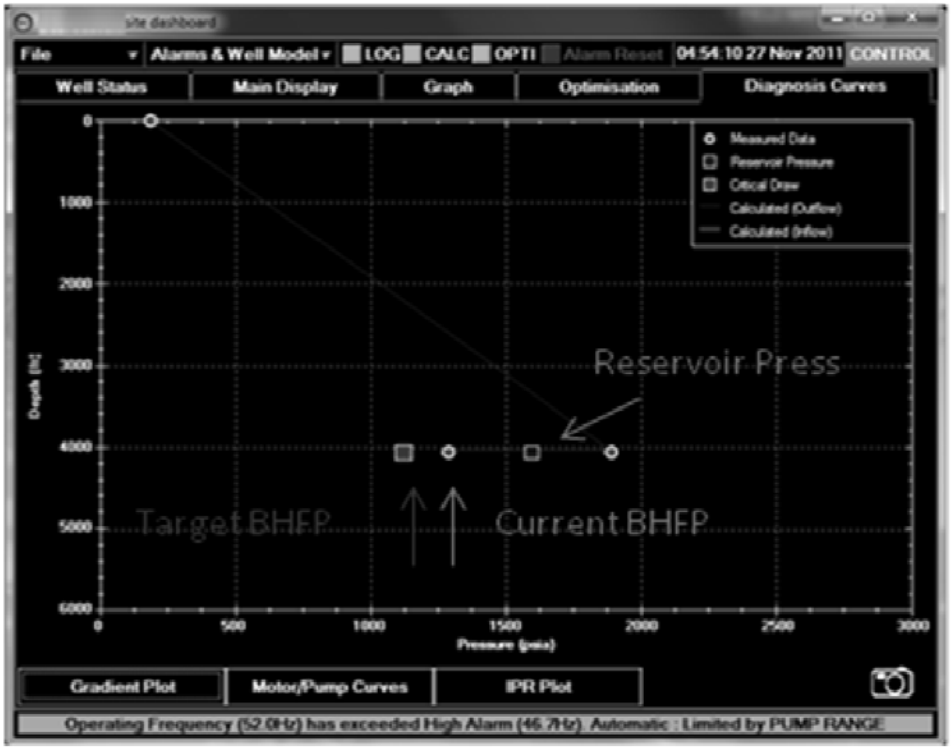

Figure 7 – Case Study 3: Gradient plot showing current and target BHFP