UTILIZING ALGORITHMS TO DETERMINE PRODUCTION INCREASES ON WELLS OPERATING WITH A FLUID LEVEL ABOVE THE PUMP

Ian Nickell
ChampionX

ABSTRACT

One of the benefits of utilizing a Sucker Rod Pump for artificially lifted oil and gas wells is that they can achieve total drawdown the casing fluid above the downhole pump. This allows for the artificial lift method to maximize the production of the well by minimizing the back pressure on the reservoir caused by the fluid level in the casing anulus. However, in some cases the original design of the sucker rod pump system may not be able to achieve the capacity required to drawdown the entire fluid level in the casing anulus. To increase production operators are tasked with identifying these wells and prioritizing them based on their opportunity for increased production and then perform the necessary operational changes to ensure the wells are producing more optimally. Previously this process was done entirely manually and could take several hours per well.

To combat this, algorithms were developed to apply rules across several thousand wells to determine if they are good candidates for increase production. Using a host software solution tied into wells running on pump off control, algorithms were developed to determine if a well was pumped off. If this criterion was met well test information was used to infer the well's maximum production. Then leveraging software with predictive wave equation capabilities, several outcomes where the speed was modulated in the rod pumping system were generated. After analyzing all the possible scenarios, the algorithms then determine the optimal solution based on equipment loading, well performance, and production information. Operators can leverage this automated process to determine real opportunities for increased production on the rod lift artificially lifted wells. By automated the process of discovery, prioritization, and speed changes required, the software eliminated unnecessary man hours in the process of optimizing wells for maximum production and allows the end users to quickly identify wells with actionable changes that will lead to production increases.

INTRODUCTION

In oilfield production pumping off rod pump wells is a crucial operation that helps maintain optimal production levels and extend the life of the well. A rod pump is a mechanical device that extracts fluids from a well by lifting the fluids to the surface through a plunger attached to a rod. Rod pump, also known as rod lift, is an advantageous form of artificial lift because it allows full drawdown of fluid level in the casing anulus which enables maximum production extraction. However, in some cases, wells on fixed speed motors are not operating at maximum capacity and have a fluid level above the pump that is increasing the back pressure on the reservoir and restricting flow. Therefore, it is important to draw the fluid level in the casing anulus down to the pump intake depth, or pump off the well. Pumping a well off enables maximum production and ROI in sucker rod applications.

In the past, pumping off rod pump wells was done based on experience, with operators relying on their judgment to determine which wells needed to be pumped off and how to manage speeds to achieve pump off. However, with the increasing demand for oil and gas and the complexity of well operations, having a more autonomous solution for understanding which wells are underperforming has become increasingly important. Therefore, algorithms were developed to analyze production data and well parameters to identify which wells are operating at suboptimal levels and need to have changes to achieve pump off.

The use of algorithms in the oil and gas industry has revolutionized the way companies manage their assets. By analyzing large amounts of data, algorithms can identify patterns and trends that previously would have to be recognized by users. This allows companies to make data-driven decisions about which wells to prioritize for pumping off, ultimately resulting in increased production and profitability.

The algorithms leverage operational data to determine which wells are not pumping off, then utilize predictive wave equation to understand which wells that have opportunities for production increases and can increase speed without being overloaded. Understanding these two variables the host software can determine which wells have opportunities to increase production and can prioritize wells by potential production gains.

One of the ways algorithms can help increase production levels is by speeding up the well. Algorithms can analyze the well parameters, such as the depth, fluid properties, and pump size, to identify which wells are able to speed up and reduce the fluid level or even pump off completely. By prioritizing these wells for pumping off, the operator can increase production levels and maximize their return on investment.

The importance of pumping off rod pump wells cannot be overstated, and the use of algorithms to determine which wells can be pumped off more efficiently is a critical tool for maximizing production and profitability for operators. With the increasing demand for oil and gas and the complexity of well operations, it is essential to optimize production from existing wells in the most efficient and reliable way possible. The use of algorithms can help operators achieve these goals by analyzing substantial amounts of data and identifying opportunities for improvement. By leveraging the power of algorithms, the oil and gas industry can continue to meet the world's energy needs in a safe, sustainable, and cost-effective manner.

STATEMENT OF THEORY AND DEFINITIONS

Pumping off rod pump wells is essential for maintaining optimal production levels and extending the life of the well in the oil and gas industry. A rod pump is a mechanical device that extracts fluids from a well by lifting them to the surface through a plunger attached to a rod. However, as the fluid level in the well increases, the well can experience an increase in flowing bottomhole pressure (FBHP) which reduces production. By pumping off the well on a regular basis, operators can maximize production and extend the life of the well and its profitability.

In this case algorithms are utilized to populate and recommend which wells are most likely to benefit from an increase in speed. Many of these wells are likely on fixed speed motors, which means a speed increase is most likely to be achieved through changes the gearbox sheave size.

A cornerstone technology for this algorithm is the concept of the predictive wave equation. The wave equation is fundamental in understanding how a sucker rod pump system is operating in terms of downhole and surface health. In this case the algorithms are leveraging a predictive wave equation to understand the effects of speed changes. Speed changes can increase loading on the rods, gearbox, and pumping unit structure. It can also cause compression explained by the calculated values for bottom minimum stress (BMS). In order to have the optimal recommendations for speeding units up the algorithms must be able to accurately predict how the equipment will react to speed changes.

Another key in determining opportunities for production increases is understanding how the reservoir will react to speed increases. In cases where the pumping unit can speed up, it doesn’t always necessarily follow that the reservoir will produce more. That is why it is also important to understand the well’s inflow performance relationship (IPR). By understanding the wells current fluid level the host software application can understand how increasing the production from the well will reduce the fluid level and increase the production. It is not simply increasing production by producing the available fluid in the casing anulus, but reducing the back pressure on the reservoir and increasing the flow to the wellbore that stimulates higher production rates. In other words in order for a well to truly increase production in this case we expect it to be running with a fluid level over the pump.

All these theories and concepts are combined to produce the algorithms to determine which wells are ripe for production increases and how much the well can produce using the existing equipment onsite.

DESCRIPTON AND APPLICATION OF EQUIPMENT AND PROCESSES

The algorithms designed to determine production increases on wells were developed by combining the diagnostic wave equation, the predictive wave equation and IPR models. The fluid level was calculated using the measured downhole dynamometer card. Once the fluid level was determined, the predictive wave equation and IPR models were used to understand how much production was available and how fast the well could be sped up in order to increase the production. The algorithms run in tandem to understand how speed increases will affect the equipment loading and BMS as well as understand if the speed increase will generate a meaningful production change.

By running all these models in tandem a recommendation that can be reliably transformed into a speed change that will result in production increases without overloading the pumping unit structure or decreasing the BMS is made. The user can then prioritize these recommendations based on production increases and make the changes that will have the greatest return on investment. Once the algorithms were developed, they were deployed on a large sample of wells for piloting and testing.

PRESENTATION OF DATA AND RESULTS

The algorithms were piloted in a field with over seven thousand wells to evaluate the validity of the algorithms and see if there were any opportunities for production increases on a large sample set of wells. There were two challenges the operator was trying to overcome. First identifying wells with opportunities for production increases and secondly to confirm how much incremental production could be expected by increasing the speed before they overloaded the unit or pumped the well off.

The +7000 wells included depths varying from 1,000 – 2,000 ft. The algorithm identified 80 wells that were running twenty four hours a day with a fluid level above pump and identified an additional 60 wells as good candidates for speed changes. During the pilot 95% of the wells the host software recognized as being candidates for production increases were able to make speed changes that resulted in incremental production without overloading the existing equipment.

Case Study 1:

Case study 1 is an example of a well that is running 24 hours with a fluid level above the pump according to the host software (figure 1). According to the calculated fluid level and IPR models an opportunity of an additional 1643 bpd total fluid is detected which is a result in an incremental 62 bpd of oil. However, the equipment loading will limit the maximum speed to by 9.3 SPM which will result in an incremental uplift of 204 bpd of total fluid and 8 bpd of oil (figure 2). Leveraging this recommendation from the software, the operator re-sheaved the unit and pumped at the recommended speed. The speed change resulted in an increase of 25 bopd which came as a result of the oil cut increasing after the speed change (figure 3). In this case the algorithm achieved a significant increase in production without overloading any of the existing equipment or causing compression on the rod string.

Case Study 2:

The second case study shows a well running 24 hours a day with a full pump (figure 4). The IPR models show the well is capable of having a max production that would result in 1587 bpd gross and 46 bpd oil increase. However, based on the predictive models the algorithms show the maximum production given the existing equipment would result in an increase of 333 bgpd and 10 bopd (figure 5). After making the suggested changes the well responded with an incremental production increase of 7 bpd of oil and 200 bpd gross which is slightly less than the predicted increase (figure 6).

Case Study 3:

The final case study shows another well running 24 hours a day with a full pump (figure 1). In this case after maximizing the speed of the pumping unit there was a production increase of 200 bpd gross and 7 bpd oil (figure 2 &3). However, the IPR model showed that still more production was possible on this well so the operator installed a larger pumping unit and was able to increase production by an additional 500 bpd gross and 14 bpd oil.

CONCLUSION

Operators need a reliable way to determine which wells have opportunities for production increases without having to individually run through their software applications and look for wells with opportunities and then run through design products and trial different speeds and change variables to understand the maximum capacity of the existing equipment. Using these algorithms in the host software that leverage the predictive wave equation as well as diagnostic analysis and IPR models can make effective recommendations on speed and where production can be increased on wells that are running 24 hours a day with a full pump. These reliable recommendations can be brought straight to the user with minimal input and interaction, which is a huge improvement compared to the current manual process. As algorithms continue to propel host software to the forefront of optimization, algorithms like these will be an important ingredient for full autonomous control from the host software application.

ACKNOWLEGEMENT

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FIGURES

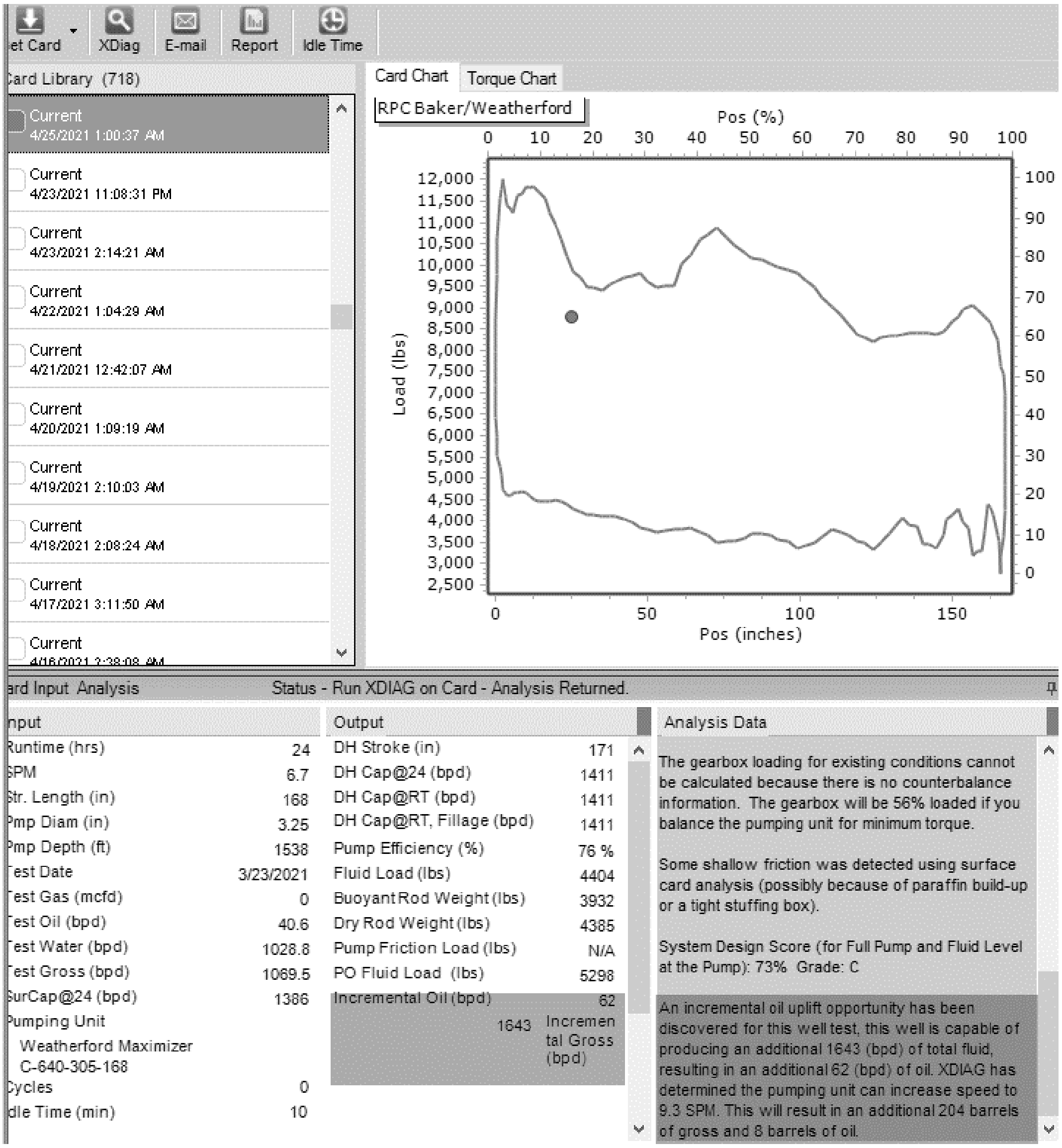

et Card
XDiag
E-mail
Report
Idle Time
ard Library (718)
Card Chart
Torque Chart
RPC Baker/Weatherford
Pos (%)
Load (lbs)
Pos (inches)
ard Input Analysis
Status - Run XDIAG on Card - Analysis Returned.
nput
Runtime (hrs) 24
SPM 6.7
Str. Length (in) 168
Pmp Diam (in) 3.25
Pmp Depth (ft) 1538
Test Date 3/23/2021
Test Gas (mcfd) 0
Test Oil (bpd) 40.6
Test Water (bpd) 1028.8
Test Gross (bpd) 1069.5
SurCap@24 (bpd) 1386
Pumping Unit
Weatherford Maximizer C-640-305-168
Cycles 0
Idle Time (min) 10
Output
DH Stroke (in) 171
DH Cap@24 (bpd) 1411
DH Cap@RT (bpd) 1411
DH Cap@RT, Fillage (bpd) 1411
Pump Efficiency (%) 76 %
Fluid Load (lbs) 4404
Buoyant Rod Weight (lbs) 3932
Dry Rod Weight (lbs) 4385
Pump Friction Load (lbs) N/A
PO Fluid Load (lbs) 5298
Incremental Oil (bpd) 62
1643 Incremental Gross (bpd)
Analysis Data
The gearbox loading for existing conditions cannot be calculated because there is no counterbalance information. The gearbox will be 56% loaded if you balance the pumping unit for minimum torque.
Some shallow friction was detected using surface card analysis (possibly because of paraffin build-up or a tight stuffing box).
System Design Score (for Full Pump and Fluid Level at the Pump): 73% Grade: C
An incremental oil uplift opportunity has been discovered for this well test, this well is capable of producing an additional 1643 (bpd) of total fluid, resulting in an additional 62 (bpd) of oil. XDIAG has determined the pumping unit can increase speed to 9.3 SPM. This will result in an additional 204 barrels of gross and 8 barrels of oil.

Figure 1

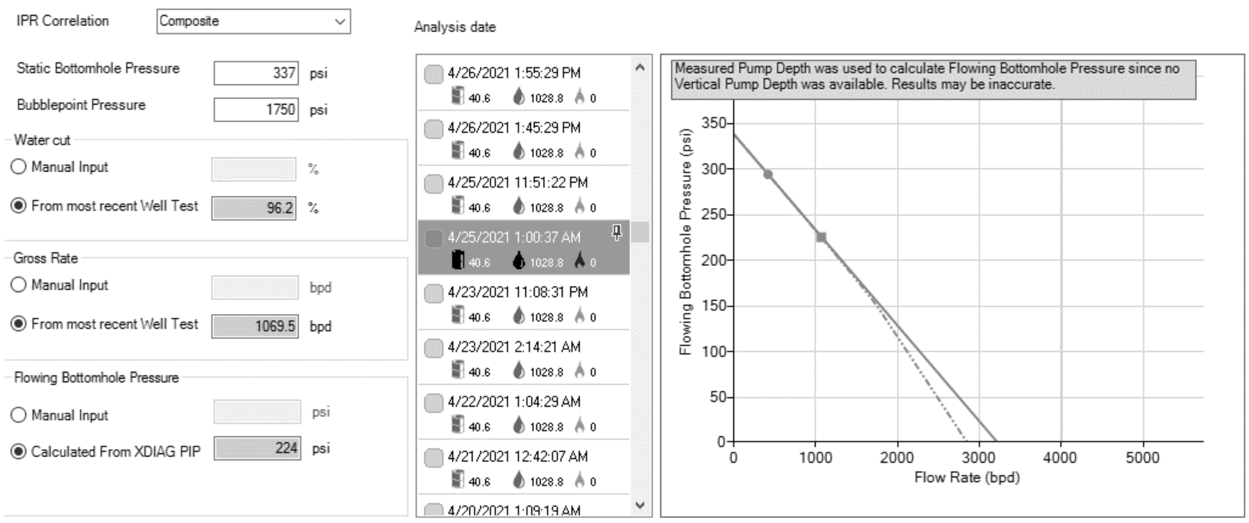


Figure 2

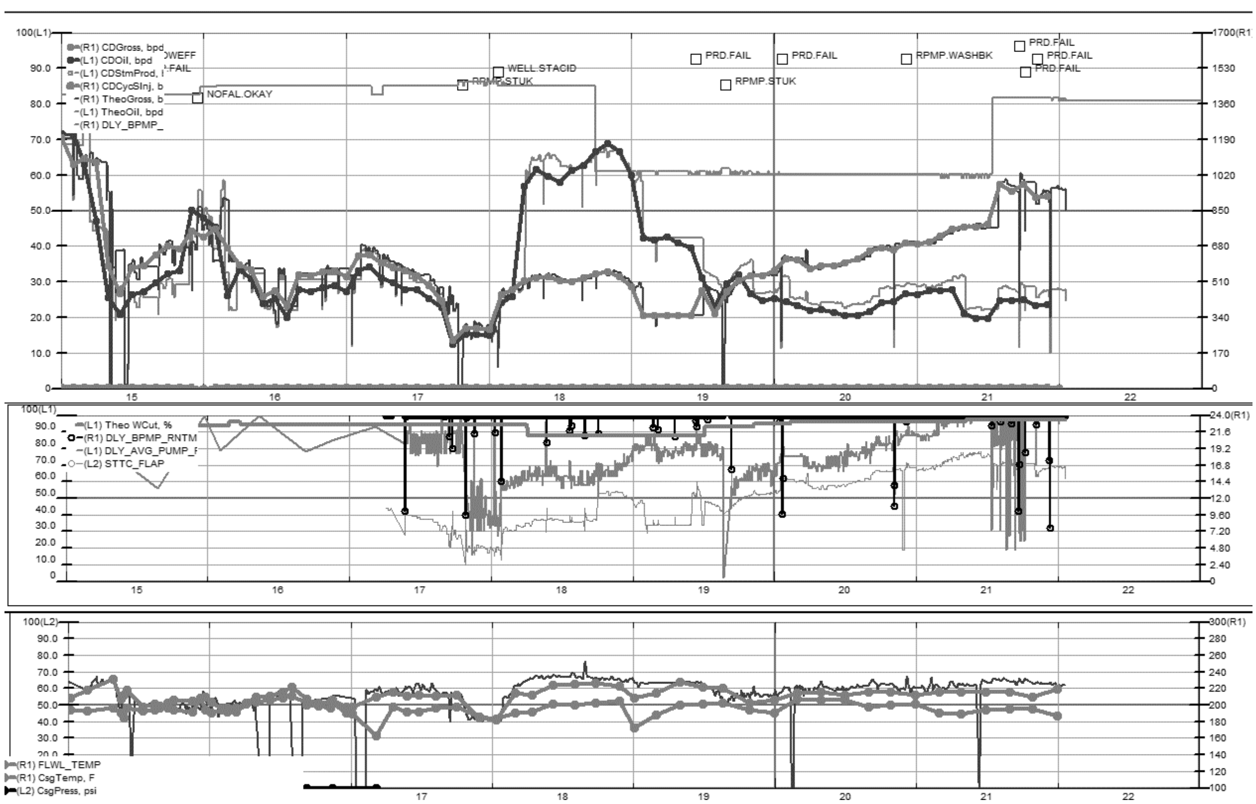
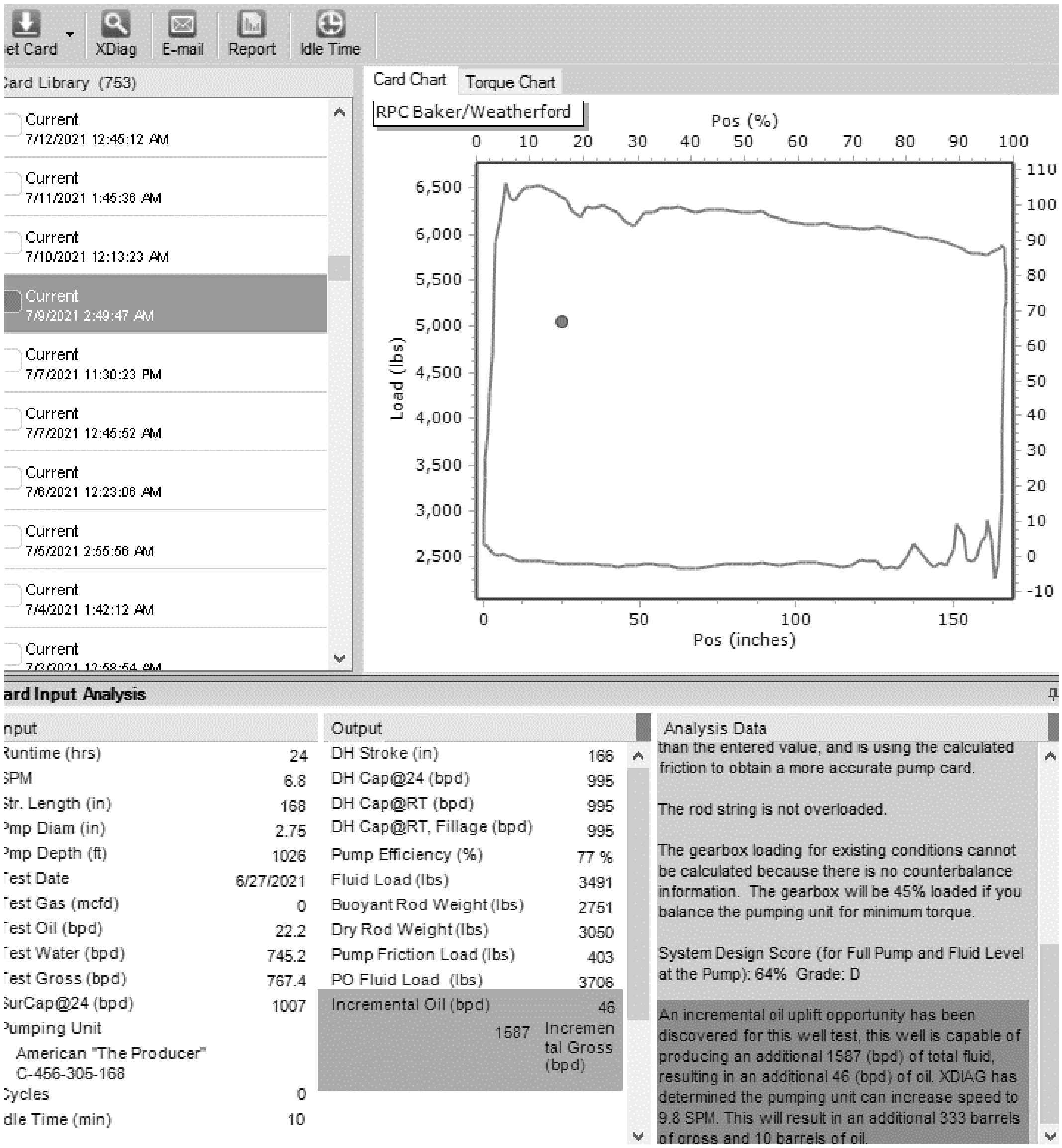


Figure 3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XDiag
E-mail
Report
Idle Time
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Current 7/9/2021 2:49:47 AM
Current 7/7/2021 11:30:23 PM
Current 7/7/2021 12:45:52 AM
Current 7/6/2021 12:23:06 AM
Current 7/5/2021 2:55:56 AM
Current 7/4/2021 1:42:12 AM
Current
Card Chart
Torque Chart
RPC Baker/Weatherford
Pos (%)
Load (lbs)
Pos (inches)
ard Input Analysis
nput
Runtime (hrs) 24
SPM 6.8
Str. Length (in) 168
Pmp Diam (in) 2.75
Pmp Depth (ft) 1026
Test Date 6/27/2021
Test Gas (mcfd) 0
Test Oil (bpd) 22.2
Test Water (bpd) 745.2
Test Gross (bpd) 767.4
SurCap@24 (bpd) 1007
Pumping Unit
American "The Producer" C-456-305-168
Cycles 0
Idle Time (min) 10
Output
DH Stroke (in) 166
DH Cap@24 (bpd) 995
DH Cap@RT (bpd) 995
DH Cap@RT, Fillage (bpd) 995
Pump Efficiency (%) 77 %
Fluid Load (lbs) 3491
Buoyant Rod Weight (lbs) 2751
Dry Rod Weight (lbs) 3050
Pump Friction Load (lbs) 403
PO Fluid Load (lbs) 3706
Incremental Oil (bpd) 46
1587 Incremental Gross (bpd)
Analysis Data
than the entered value, and is using the calculated friction to obtain a more accurate pump card.
The rod string is not overloaded.
The gearbox loading for existing conditions cannot be calculated because there is no counterbalance information. The gearbox will be 45% loaded if you balance the pumping unit for minimum torque.
System Design Score (for Full Pump and Fluid Level at the Pump): 64% Grade: D
An incremental oil uplift opportunity has been discovered for this well test, this well is capable of producing an additional 1587 (bpd) of total fluid, resulting in an additional 46 (bpd) of oil. XDIAG has determined the pumping unit can increase speed to 9.8 SPM. This will result in an additional 333 barrels of gross and 10 barrels of oil.

Figure 4

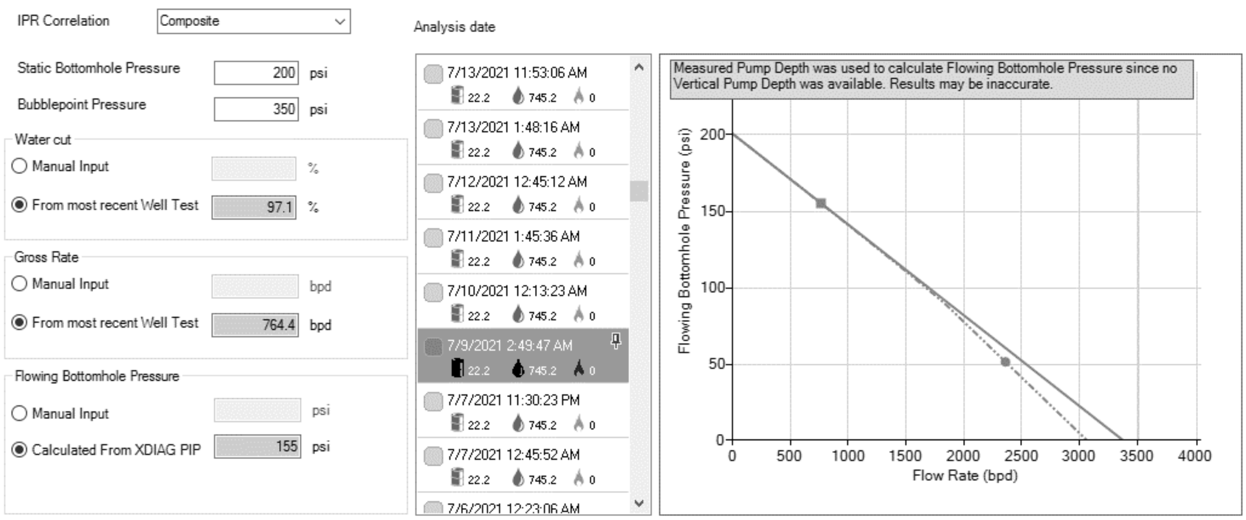


Figure 5

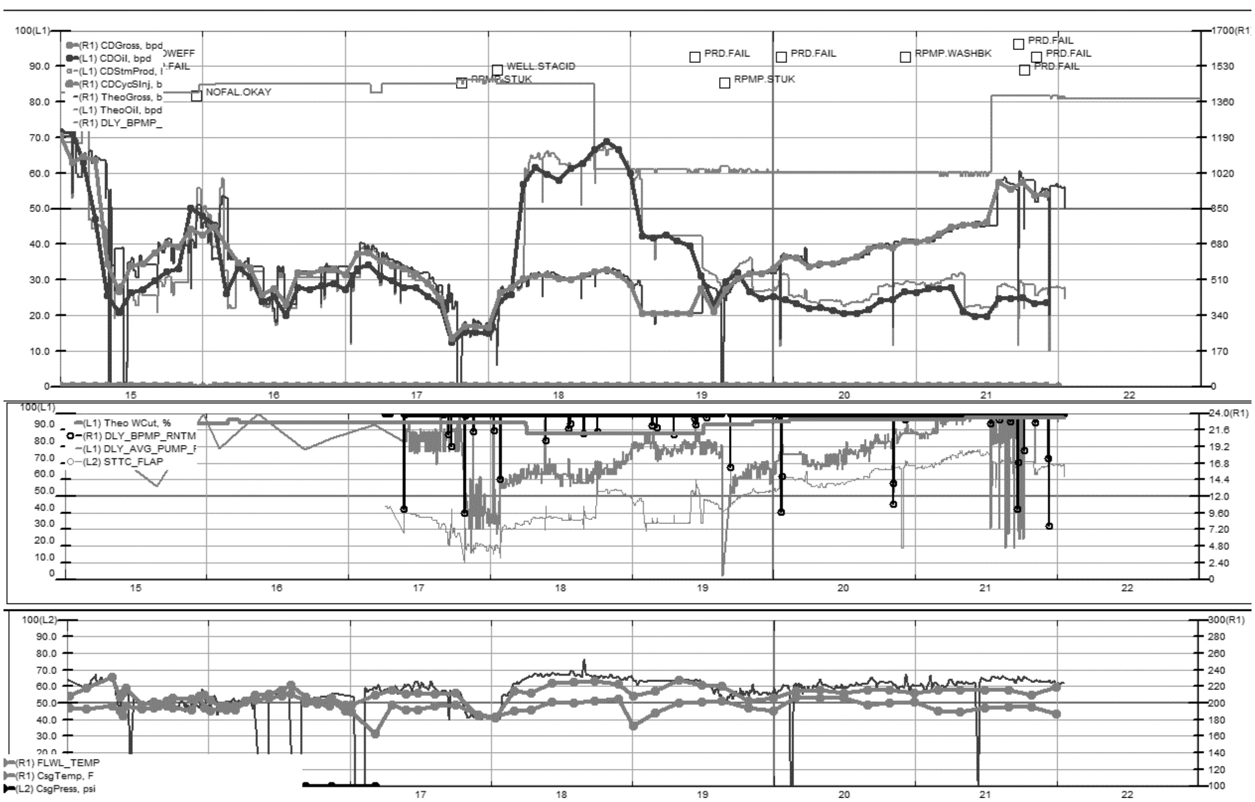
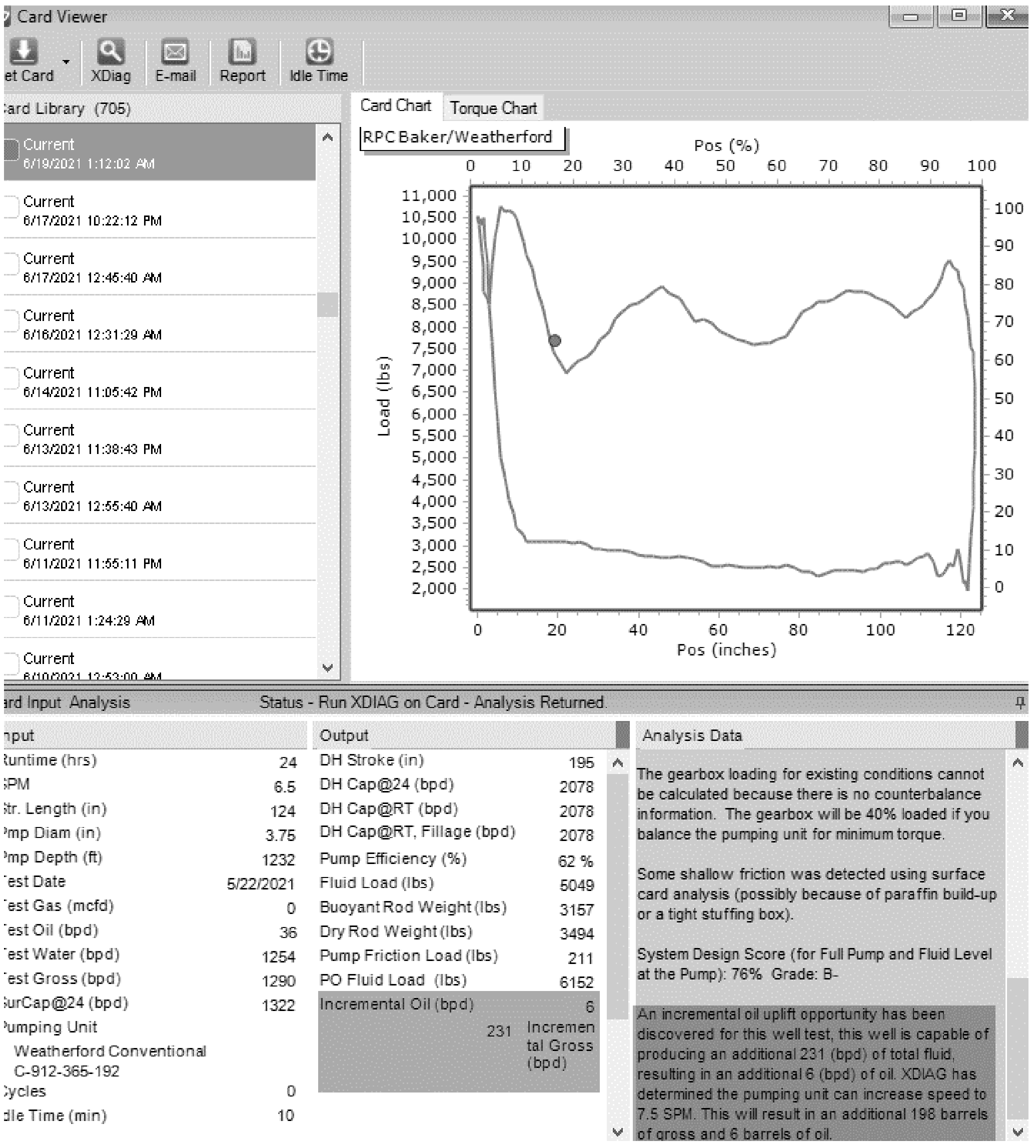


Figure 6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XDiag
E-mail
Report
Idle Time
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Current 6/19/2021 1:12:02 AM
Current 6/17/2021 10:22:12 PM
Current 6/17/2021 12:45:40 AM
Current 6/16/2021 12:31:29 AM
Current 6/14/2021 11:05:42 PM
Current 6/13/2021 11:38:43 PM
Current 6/13/2021 12:55:40 AM
Current 6/11/2021 11:55:11 PM
Current 6/11/2021 1:24:29 AM
Current
Card Chart
Torque Chart
RPC Baker/Weatherford
Pos (%)
Load (lbs)
Pos (inches)
rd Input Analysis
Status - Run XDIAG on Card - Analysis Returned.
nput
Runtime (hrs) 24
SPM 6.5
Str. Length (in) 124
Pmp Diam (in) 3.75
Pmp Depth (ft) 1232
Test Date 5/22/2021
Test Gas (mcfd) 0
Test Oil (bpd) 36
Test Water (bpd) 1254
Test Gross (bpd) 1290
SurCap@24 (bpd) 1322
Pumping Unit
Weatherford Conventional C-912-365-192
Cycles 0
Idle Time (min) 10
Output
DH Stroke (in) 195
DH Cap@24 (bpd) 2078
DH Cap@RT (bpd) 2078
DH Cap@RT, Fillage (bpd) 2078
Pump Efficiency (%) 62 %
Fluid Load (lbs) 5049
Buoyant Rod Weight (lbs) 3157
Dry Rod Weight (lbs) 3494
Pump Friction Load (lbs) 211
PO Fluid Load (lbs) 6152
Incremental Oil (bpd) 6
231 Incremental Gross (bpd)
Analysis Data
The gearbox loading for existing conditions cannot be calculated because there is no counterbalance information. The gearbox will be 40% loaded if you balance the pumping unit for minimum torque.
Some shallow friction was detected using surface card analysis (possibly because of paraffin build-up or a tight stuffing box).
System Design Score (for Full Pump and Fluid Level at the Pump): 76% Grade: B-
An incremental oil uplift opportunity has been discovered for this well test, this well is capable of producing an additional 231 (bpd) of total fluid, resulting in an additional 6 (bpd) of oil. XDIAG has determined the pumping unit can increase speed to 7.5 SPM. This will result in an additional 198 barrels of gross and 6 barrels of oil.

Figure 7

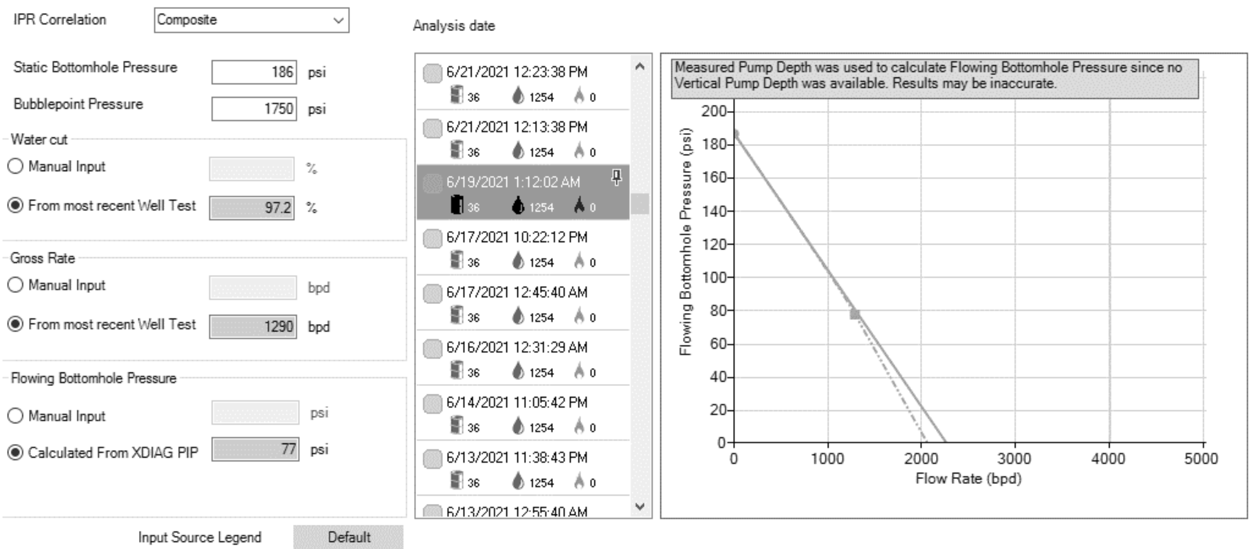

Figure 8

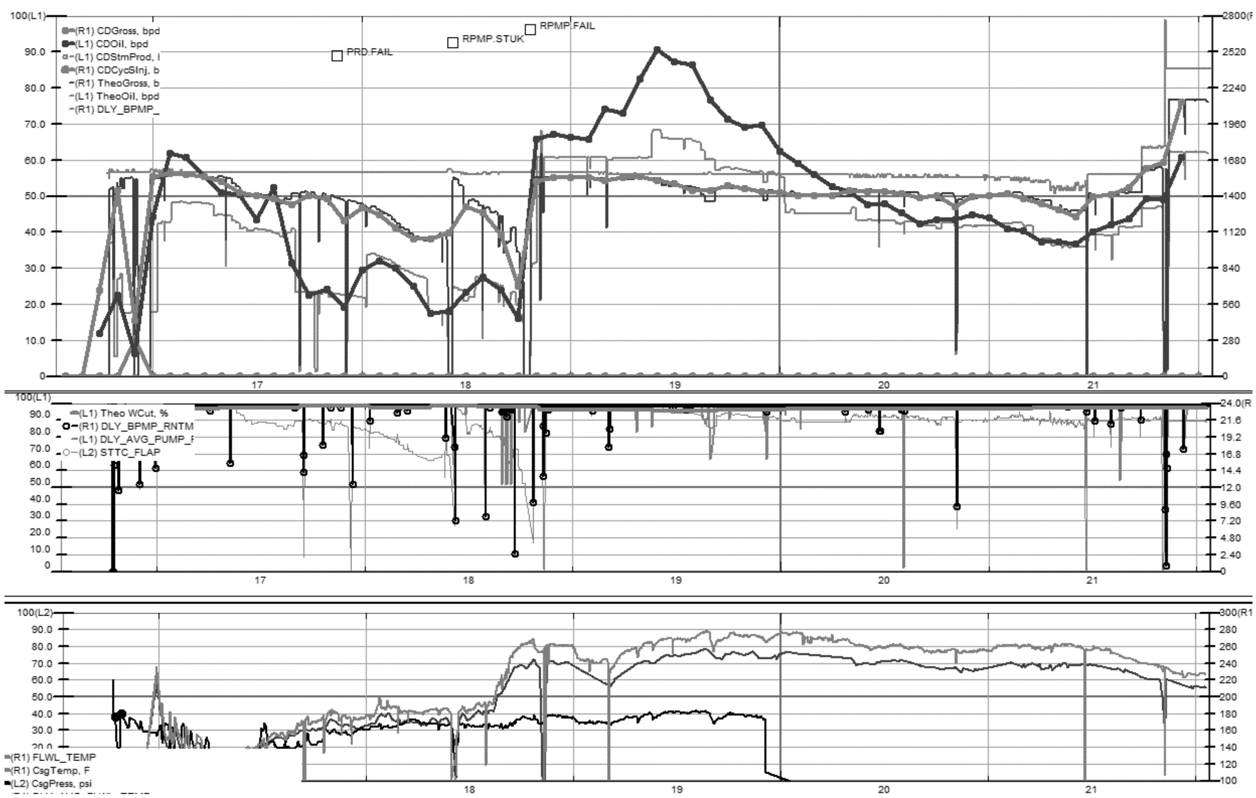

Figure 9

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