GENTLE PUMP-OFFS CAN REDUCE OPERATING EXPENSES

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ABSTRACT

Pumping hard on sucker-rod lifted wells involves a tradeoff between increased operating expenses and decreased revenues from deferred production. While pumping a well harder will likely increase failure frequency, a higher fluid level in the well increases backpressure on the reservoir and decreases production. Pump-off controllers (POCs) are used to reduce both costs and failures by regulating runtime on many Permian Basin wells involved in CO2 and water floods. In these EOR floods, many opportunities exist to pump wells less hard – more gently – while limiting impacts on production. This can be achieved by moving set points, changing the number pump-off strokes, and decreasing pumping unit speeds. The production impact should be minimal because reservoir pressures are maintained relatively high in these floods and permeability is moderate. This paper will discuss specific examples of using POCs to pump wells gently. It will also describe a calculation method used to evaluate the economic tradeoff.

BACKGROUND

In the Permian Basin, Occidental Petroleum (Oxy) operates more than 6,000 beam-pumping units in fields undergoing secondary or tertiary recovery operations. Nearly all of these wells utilize pump-off controllers (POCs) to regulate runtime of the beam unit. The POCs provide a means to manage cost-effectively the pressure drawdown from the injector to producer wells. Low fluid levels are maintained in the producers, while surface and downhole equipment damage is reduced by sensing and mitigating incomplete downhole pump fillage. The POC is ideally used to achieve a balance between production, equipment failures, and energy usage that maximizes the net present value of the field.

The POCs provide the operator control of four primary variables:

1. Pump-off setpoint – determined from either the surface or calculated downhole card.
2. Number of consecutive pump-off strokes required after the setpoint is reached.
3. Idle time between pump-off cycles.
4. Pump-up delay – the number of strokes at the beginning of each cycle until the setpoint criteria are recognized.

The beam unit will start up and shut down based on a combination of (1), (2), and (3) above. The pump-up delay is set largely according to the knowledge and experience of the operator, and typically will have the least influence on runtime and the number of daily cycles. All of these parameters can be manipulated by the operator at no direct cost. A fifth operational variable that will significantly influence the runtime and cycles is the pumping unit speed; however, this is not a variable specifically dictated by the POC. Unlike the POC-controlled parameters, there is typically some cost associated with changing the speed of the pumping unit.

Of course, the operator must also consider production impacts when making decisions regarding optimal POC operation. All else being equal, additional backpressure on the reservoir will result in some production loss (i.e., deferment), but this loss may be relatively insignificant depending on the specific reservoir properties, notably permeability and reservoir pressure. For many of Oxy's water and CO2 floods, reservoir pressure is maintained relatively high, and permeability is moderate (< 5 md). In general, the amount of inflow will likely be more sensitive to changes in producing bottomhole pressure where reservoir pressure is lower. Conventional multiphase inflow theory also states that reductions in flowing bottomhole pressure are less impactful when the wells are operated near a pumped-off condition [1]. For these reasons, the value of eliminating incomplete fillage strokes by modifying POC operation should offset any associated production impacts.

The remainder of this paper considers two related topics. First, the results of two recent Oxy pilot projects in the Permian Basin (“Gentle Pump-offs” Phase I and Phase II) are presented. In these field tests, the goal was to reduce or eliminate incomplete fillage strokes on POC-controlled wells and monitor the associated production impact. Second, we will discuss a calculator tool that was developed to aid operations personnel in determining the optimal idle time on a well-by-well basis.

GENTLE PUMP-OFFS PILOT: PHASE I

A pilot project was conducted in an Oxy-operated San Andres CO2 flood located just outside of Lubbock, Texas, to study optimizing the balance between production and beam pump failure frequency by modifying POC operation. For Phase I, nine wells were selected, and the pump-off set points and number of consecutive pump-off strokes were modified to pump the wells less aggressively. The goal of this nine-well pilot was to reduce or eliminate potentially destructive incomplete fillage while also monitoring the associated production impact. No changes were made to the idle-time, pump-up strokes, or pumping unit speed.

An example of a pump card prior to any setpoint changes is presented in Figure 1. Surface and downhole (calculated) full and pump-off cards are shown in addition to the “pump-off buffer” cards. These buffer cards are the five surface cards just prior to the pump-off card. The pump-off setpoint is indicated on the surface card by a circle intersected by two perpendicular lines. It is evident from both the surface and downhole cards that each buffer stroke is associated with some level of incomplete fillage. For this reason, there is potential to move the setpoint “to the right” in an attempt to reduce the total number of strokes and the degree of incomplete fillage per stroke while not appreciably changing the fluid level at pump-off.

Summary results of Phase I are presented in Table 1. An average of 150 strokes per day per well were eliminated with no discernable production loss. While the total production actually appeared to increase after the POC parameter changes, it should be noted that the test site is not accurate to within 1-2 BOPD. In addition to eliminating potentially destructive incomplete fillage strokes, the POC changes also resulted in both gearbox and rod stress reductions of approximately 2% and 3%, respectively. While it is difficult to measure the associated monetary impact of each reduction, there is no downside or cost because no production loss was observed.

Figure 2, Figure 3, Figure 4, and Figure 5 show two examples included as a part of Phase I, depicting the surface and downhole cards both before and after the setpoint changes.

GENTLE PUMP-OFFS PILOT: PHASE II

Following the success of Phase I, Phase II expanded the pilot to a larger population of wells, including wells with higher than average failure frequencies. Wells were chosen at similar test sites so that the test site total fluid production meter could be used to monitor production impacts, as opposed to relying on individual well test data.

Importantly, Phase II also included idle time increases and stroke-per-minute (SPM) reductions. Idle time increases for cycling wells will reduce the number of daily pump-off cycles and shouldn’t significantly impact runtime. In contrast, SPM reductions will not only reduce daily cycles, but will also increase unit runtime. All else being equal, increases in runtime should have many associated benefits, including reductions in: (1) the severity of fluid pound strokes, (2) rod buckling, and (3) the likelihood for solids to settle in and around the pump. In addition, these runtime increases could possibly reduce the average bottomhole producing pressure and potentially improve the effectiveness of chemical treatments by promoting more consistent fluid movement. SPM reductions do have an associated cost, but in many cases this cost is less than $500 per well, which is relatively insignificant compared with the potential cost of a failure.

Figure 6 and Figure 7 present the total production trends before and after the adjustments were made at two separate Phase II test sites, one with 9 wells and one with 14 wells. In both cases, total production and downtime are plotted approximately one month prior to Phase II initiation and for one month afterwards. The vertical line indicates when Phase II was initiated. Not surprisingly, production is highly influenced by the changes in downtime, but there is also no apparent decrease in total production observed as a result of the associated POC and SPM changes. Early results indicate an associated decrease in the failure frequency following the adjustments at both test sites. At test site 1, the annualized failure frequency prior to the adjustments was 0.33/year, and so far the annualized failure frequency is 0.14/year after the changes. At test site 2, the annualized failure frequency prior to the adjustments was 0.21/year, and so far the annualized failure frequency is 0.10/year after the changes.

IDLE TIME CALCULATOR

Part of Phase II included idle time increases intended to reduce the number of daily pump cycles and incomplete fillage strokes. Such idle time increases should theoretically be associated with losses in production and a deferment in reserve recovery. In order to quantify the production and economic impact of these changes, a calculator was developed that combines an inflow and outflow model. The inflow component is a Vogel-based model, and outflow is simply determined using a displacement calculation depending on the specific operating parameters, including pump size, stroke length, and SPM [1].

Figure 8 shows the calculator’s user interface. Each of the shaded cells require custom entry. The calculator has two primary functions: (1) determine the associated production impact, and (2) calculate the incremental economics associated with a specified idle time change.

The total anticipated production impact is dependent on many reservoir factors. To illustrate, consider a “high” and “medium” productivity well as defined by productivity indices (PI) of 0.14 bbl/day/psi and 0.09 bbl/day/psi, respectively. Given these assumptions, Figure 9 and Figure 10 present expectations of total fluid production versus the desired fluid level above the pump (FAP) at shutdown, given idle times ranging from 10 to 53 minutes. For a well that is considered pumped-off, it may be reasonable to assume a FAP value ranging from 0 ft to 500 ft, but this value depends on the prevailing POC set points and on the amount of gas production and downhole gas separation efficiency, among other factors. Given a constant FAP at pump-off, it is evident that for both high and medium PI wells, the differences in idle time make relatively little difference in total fluid production. In these cases, the magnitude is generally in the range of 1 – 3% for an idle time change from 10 to 53 minutes. These percentage losses are on a basis of total fluid, but the oil cut has to be considered when determining the economic impact.

Determination of the associated economic impact requires a correlation that relates pump-off cycles to failure frequency. Ultimately, a correlation from the aforementioned pilot study could be integrated into the calculator; however, such results have not yet been integrated as of this writing. The current version of the calculator uses an assumed correlation between cycles per day and polished rod velocity. Further work is needed to refine this particular correlation.

Figure 11 and Figure 12 depict economics examples for the same theoretical high and medium PI wells. Estimated net present value (NPV) is plotted versus idle time at two particular Vogel numbers, 0.2 and 1.0. The Vogel number allows one to modify the shape of the Vogel curve given particular considerations on a well-by-well or field-wide basis. For the high PI example with Vogel number equal to 1.0, it is clear that the maximum NPV is achieved with the minimum idle time of 10 minutes. When the Vogel number is 0.2, the NPV is relatively flat across the range of idle times. For the medium PI example with Vogel number equal to 1.0, the NPV curve is also quite flat across the spectrum of idle times. When the Vogel number is only 0.2, the curve more clearly indicates that NPV is maximized at the highest value of idle time equal to 60 minutes. For a well described by this particular inflow profile and having relatively low idle time, there may be an opportunity to enhance the value of that well by extending the idle time.

CONCLUSION

This paper described the early results of a pilot study conducted in a San Andres CO_2 flood in the Permian Basin where POC setpoint adjustments and SPM decreases have been performed in an effort to reduce beam pump failures while maintaining oil production. To date, two pilot phases have been performed, and no discernible oil production loss has been observed. Early results also indicate a potential decrease in failure frequency. In addition, a new calculator method was presented that helps users understand the cost-benefit analysis of idle time changes on a well-specific basis. This is achieved using an inflow and outflow model in combination with a failure frequency correlation that relates failures, polished rod velocity, and the number of daily pump-off cycles.

REFERENCES

1. Vogel, J.V.: "Inflow Performance Relationship for Solution Gas-Drive Wells," paper SPE 1476 presented at the SPE Annual Fall Meeting held in Dallas, Texas, USA, 02-05 October 1968.

Table 1. Gentle Pump-Off Pilot Phase I Results

	Before Adjustment	After Adjustment
Sum of Average Production (BOPD)	73	75
Average Number of Strokes (per well per day)	6,778	6,628
Average Gearbox Stress (% per well)	74.8%	72.6%
Average Rod Stress (% per well)	76.4%	73.3%

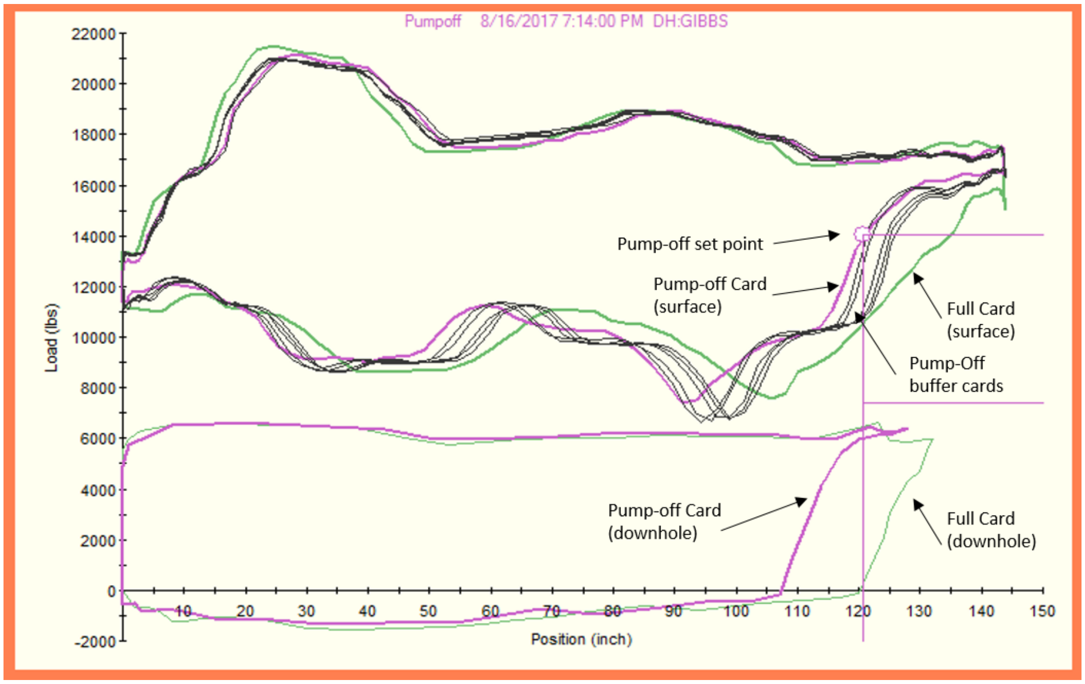

Figure 1. Example of set point change identified for Phase I of the Gentle Pump-Off Pilot

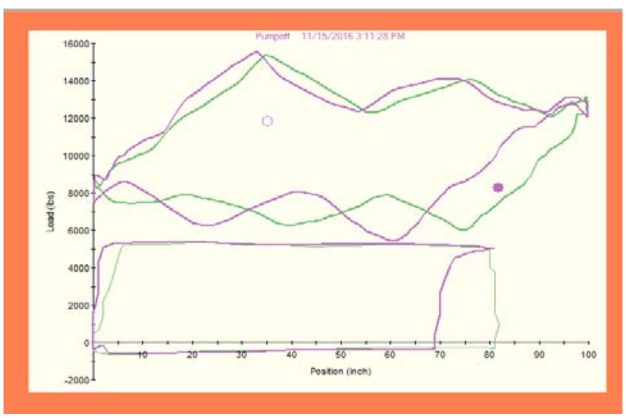

Figure 2. Phase I Example 1 before setpoint adjustment

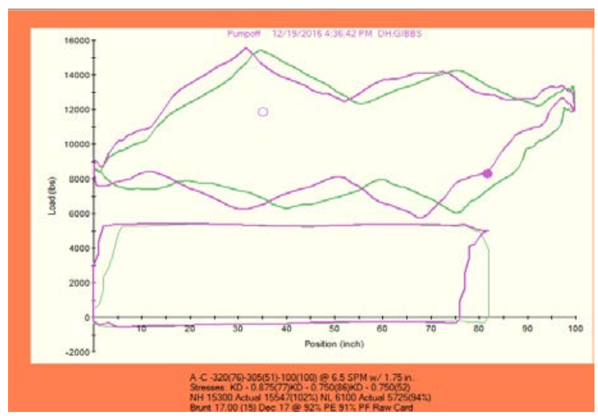

Figure 3. Phase I Example 1 after setpoint adjustment

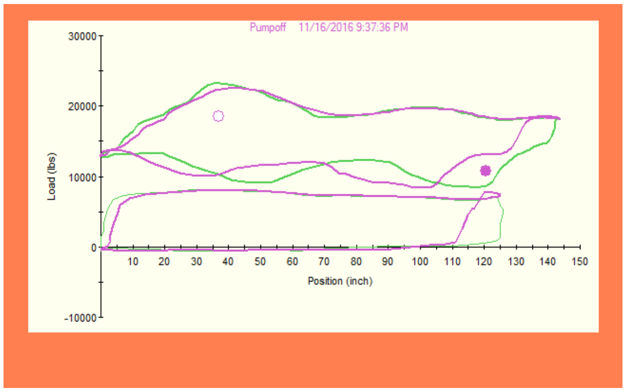

Figure 4. Phase I Example 2 before setpoint adjustment

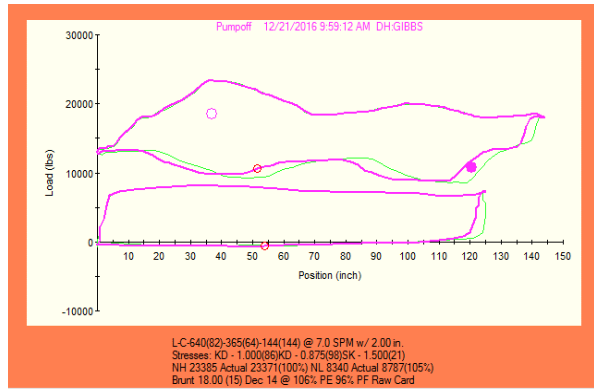

Figure 5. Phase I Example 2 after setpoint adjustment

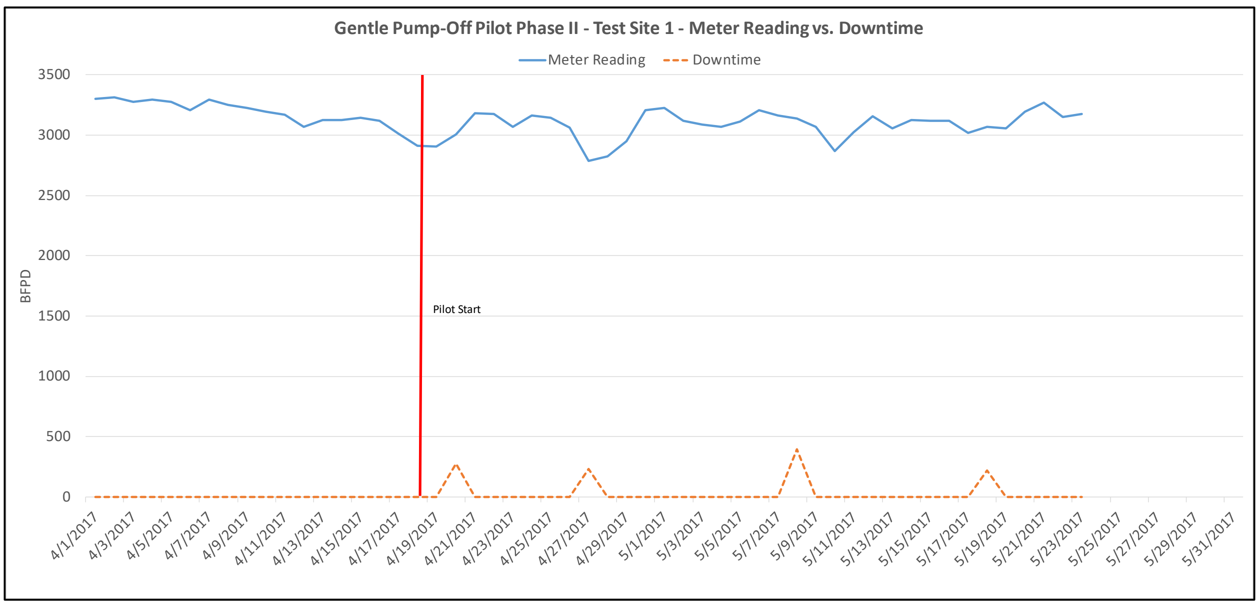

Figure 6. Phase II Test Site 1 Total Fluid Production and Downtime Plot

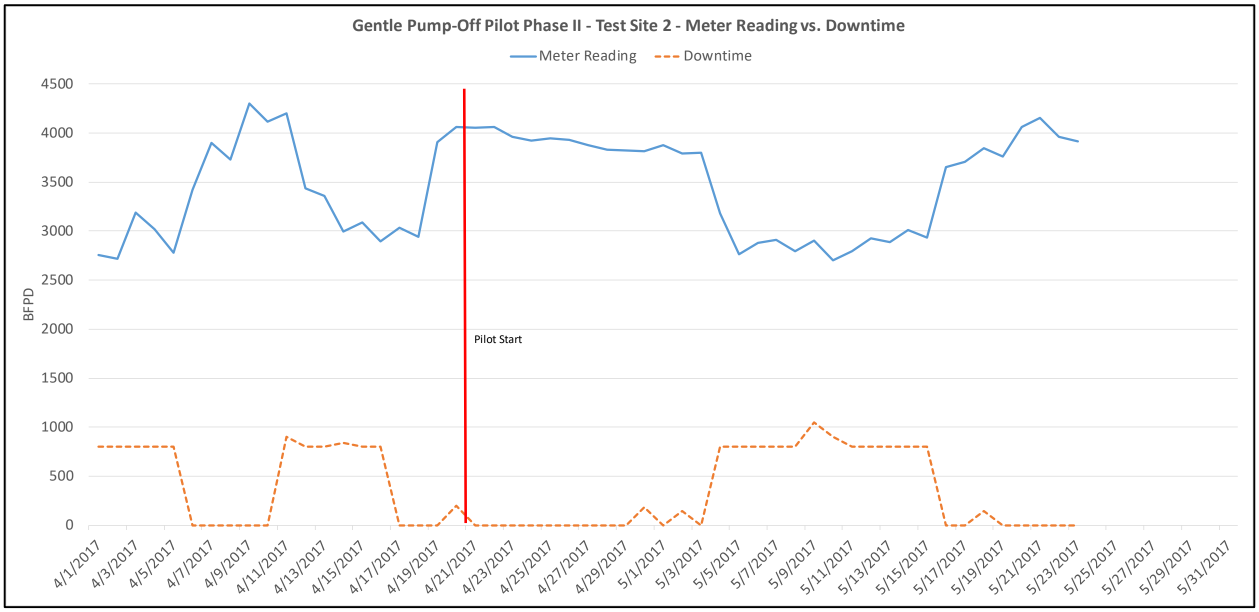

Figure 7. Phase II Test Site 2 Total Fluid Production and Downtime Plot

	Inputs		
Current Rate (BFPD)	**250**		
Pump Off FAP (ft)	**500**		
Vogel #	**0.2**		
Casing Pressure (psi)	**100**		
Idle Time, Current (min)	**20**		
Idle Time, Projected (min)	**60**	BWPD	BOPD
BFPD, 20 min idle time	**260**	234	26.0
BFPD, 60 min idle time	**257**	231	25.7
Cycles/d, 20 min idle time	**37**		-1.3% **oil decrease**
Cycles/d, 60 min idle time	**13**		
% RT, 20 min idle time	**48%**	11.6	hrs
% RT, 60 min idle time	**48%**	11.5	hrs
Oil Cut %, low idle time	**10%**		
Oil Cut %, high idle time	**10%**		
Oil Loss (BOPD)	**0.3**		
PRV (in/min)	**1,440**		
Failure Rate, 20 min idle time	**0.292**		
Failure Rate, 60 min idle time	**0.131**		
Delta Failure Rate (failure/yr)	**0.16**		
Value of Idle Time Change, 60 min idle time NPV15 LESS 20 min idle time NPV15	**$17,834**		

Run Idle Time Comparison

	Inputs
Pump Size (in)	**2.00**
SPM	**10.0**
SL, downhole (in)	**144.0**
Tubing OD (in)	**2.875**
Casing ID (in)	**4.950**
Pump Efficiency	**80%**
Pump Depth (ft)	**5170**
Mid Perf (ft)	**5170**
Theoretical 24-hr Capacity (BFPD)	**537**

Figure 8. Idle Time and Production Loss Calculator Interface

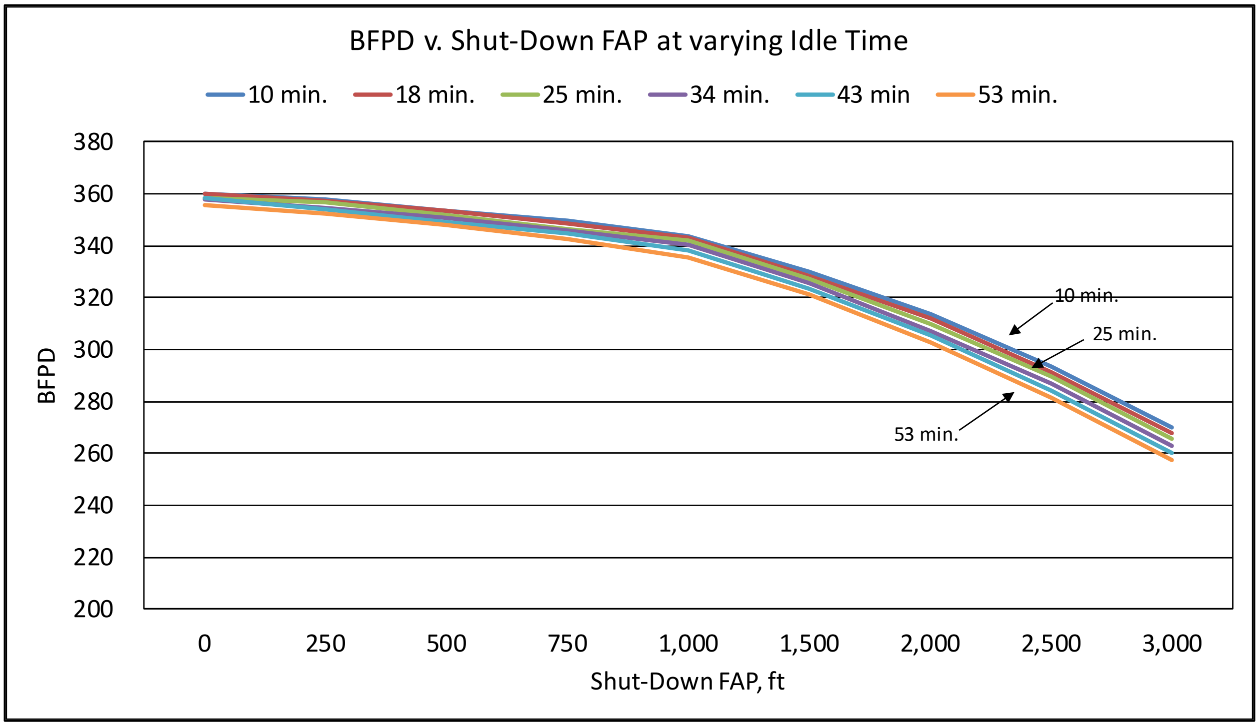

Figure 9. Production Loss vs. FAP at end of pump-off cycle---Example for a High PI well

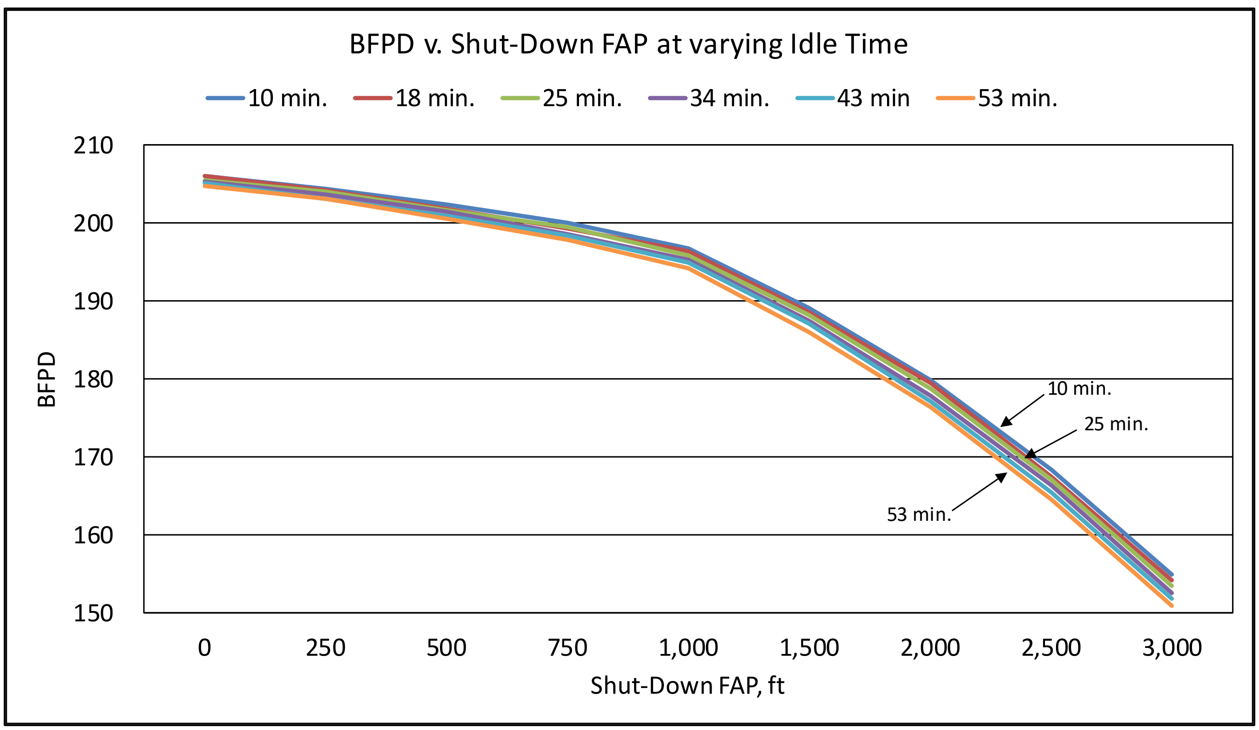

Figure 10. Production Loss vs. FAP at end of pump-off cycle---Example for a Medium PI well

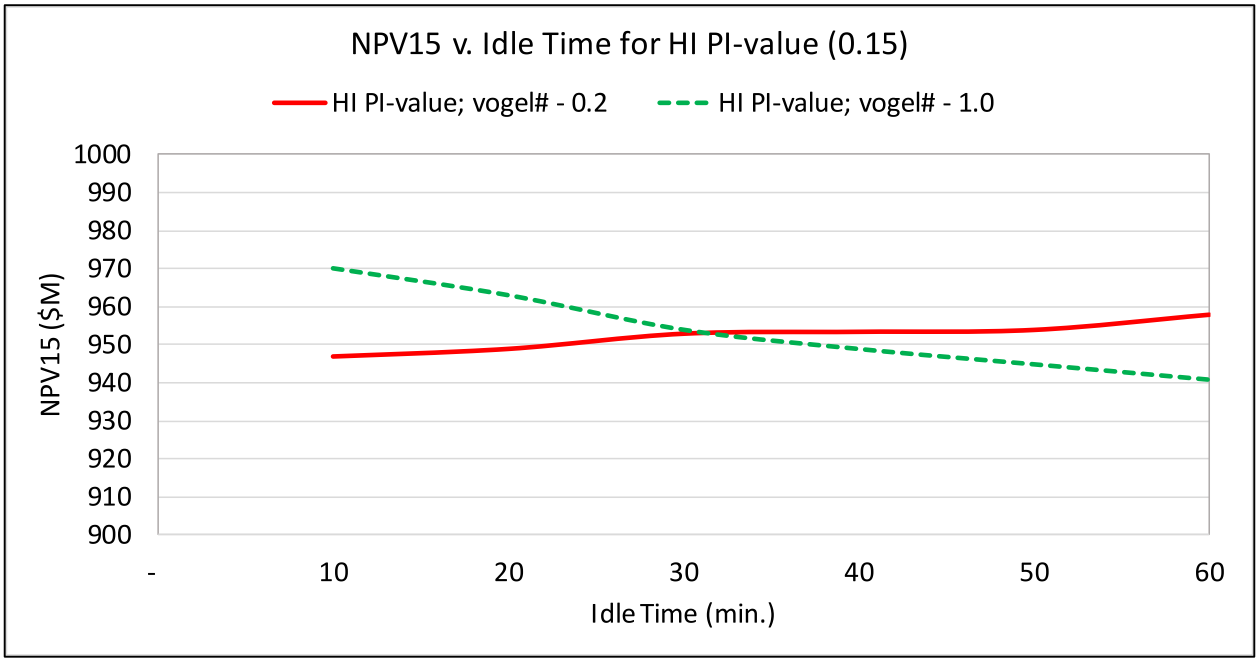

Figure 11. Example Economics for High PI well

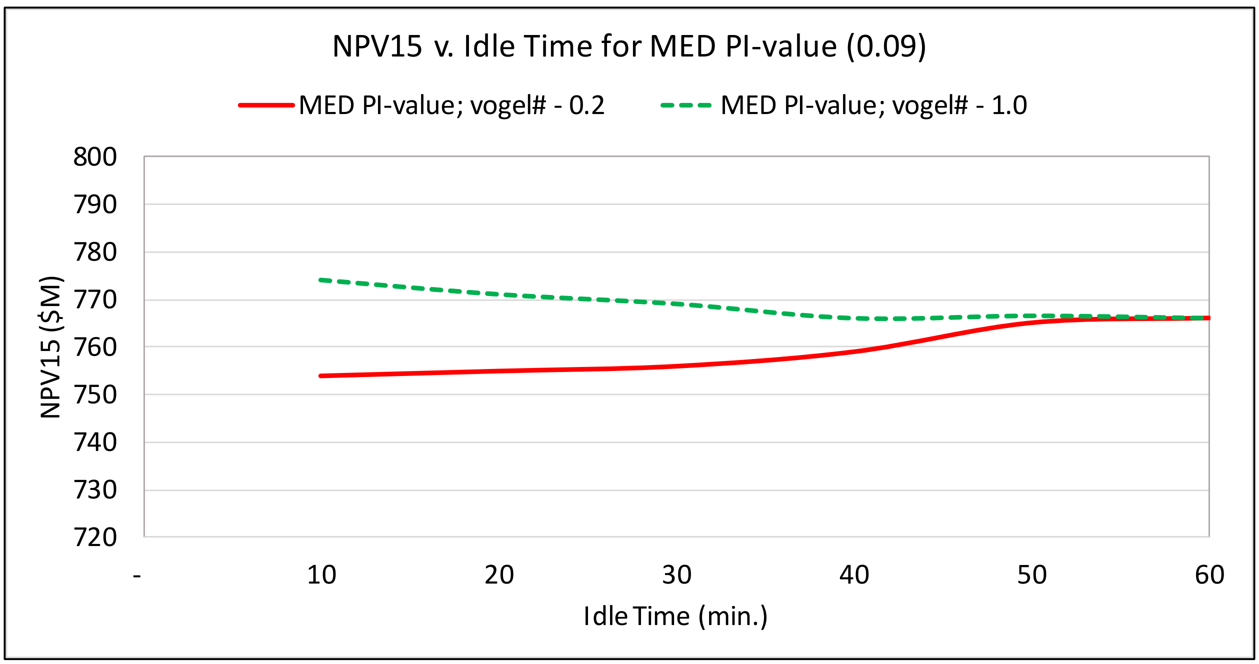

Figure 12. Example Economics for a Medium PI well