PERFORMANCE EVALUATION OF CENESIS PHASE SYSTEM ON WELLS WITH HIGH GLR AND LOW PRODUCTION OUTPUT (CASE STUDY)

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ABSTRACT

The objective of this paper is to present oil and gas industry the advancement and improvement of the Baker Hughes ESP phase system on wells with relatively high GLR, moderate water cut, and suggest considering the presented design system in comparable wells for an extended run-life.

Paper presents run-life analysis and comparison of a conventional design versus the phase system in terms of power consumption, cost savings, and reductions of the emissions due to differences in surface power consumption between two different ESP systems. Operator after installing the standard design for a given well output conditions eventually decided to test the new system on their well to minimize maintenance and avoid consecutive shutdowns on multiple occasions.

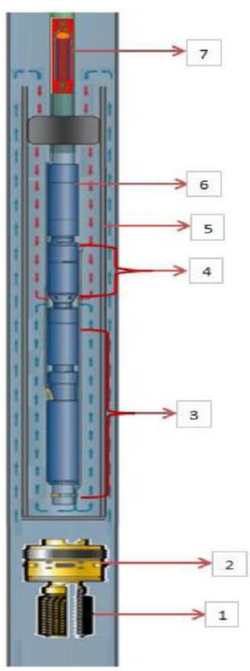
The baseline for the case study is chosen to be real running parameters of three units at different timeframes. Real electrical and mechanical parameters are used to match in-house software and produce power consumption and pump operating conditions which are crucial for a unit run life and therefore operator’s capital investment. In short, it is observed that with an initial design of low GLR, high water cut, and high total liquid rate for a given well standard pump design has been failing to perform and reasons will be discussed later. Further in time, as water cut remained relatively the same on average, total liquid production dropped, while GLR increased, phase system showed better performance and more optimistic expectations of unit run life. Running old design at late time production system at the same frequency indicated more power consumption and therefore higher capital expenditure. The performance of new design allowed for a frequency increase of 7-15% which allowed for better drawdown. This indicates the improvement in power consumption and in turn suggests better efficiency of recovery.

The design discussed in this paper is relatively new to the industry and it aims to reinforce and support previous publications. Purpose is to show an implementation of this design on a new case with real performance evaluations. It may be beneficial for number of operators to have another example of ESP applications in the Permian Basin.

UNIT OVERVIEW

The structure and hierarchy of field and reservoir development across multiple unconventional plays in the US is quite consistent. Wells are drilled to the target layers, depending on the reservoir surveillance and characterization well stacking pattern is chosen. Further, wells are hydraulically fractured and flown back until finally companies decide on the artificial system to be used. Currently, in the Permian and Delaware Basins multiple operators are focused on utilizing electric submersible pumps (ESP) as means

of artificial lift production. There are many challenges associated with the production from unconventional wells. From the reservoir perspective one of the main unknowns is the parent-to-child well relationship, effective formation permeability, dimensions and structure of stimulated rock volume (SRV), duration of linear flow, and many other key reservoir characterization properties. In general majority of the wells are low in oil cut and high in gas-to-liquid ratio. Normally at the start of a production water cut is high and total liquid rates drop rapidly in a matter of weeks or months. At the same time gas to liquid ratio keeps rising and starts dropping later in life of a well. Many wells nowadays are drilled and completed with 5.5-inch casing with 20 or 23 pound-per-foot weight. Internal diameters are 4.778 and 4.67 respectively, and therefore, primary equipment of choice for these types of wells are 4.0-inch ESP equipment. However, due to the high gas content many units suffer from risks of gas-locking and in turn failure due to the motor lead extension and/or motor failure due to the high temperatures. This heavily affects the run-life of the unit and in turn may negatively impact operator's cashflow. Whenever the units are pumping high gas cut fluid overall efficiency of tandem pumps drops and negatively affects the power consumption on the surface.
Aside from choosing the 400 series equipment some operators choose to run encapsulated shroud with 300 series equipment placed inside (Figure 1). Encapsulated shroud primarily helps to handle gas slugs during the production as well as physical protection from motor lead extension damage (Elmahbes et al., 2017).



1. Sand Control Screen System (***Optional component***)
2. SC-2TM Packer (***Optional component***)
3. Motor, Motor Lead Extension (MLE) and Seal
4. Recirculation Pump
5. Inverted Shroud System
6. Main Pump
7. Sand Trap (***Optional component***)
8. Other Tools (***Optional components not shown***)

Figure 1: Encapsulated shroud system schematic (Elmahbes et al., 2017).

Figure 1 shows that past the intake unit houses the recirculation pump. As all of the dynamic gas interference noise is separated by the shroud wall, most of the fluid inside the shroud is drawn to the intake at lower speeds, this poses a challenge in terms of motor temperature since fluid speed passing by the motor is low. Therefore, recirculation system has a small discharge port with low profile recirculation line that is ran down to the bottom of the motor with the purpose of helping to cool it down. Shroud length itself is subject to design-based application purposes. Depending on target production, wellbore parameters, and the gas slug time duration, appropriate length of the shroud is selected.

ORIGINAL DESIGN

Originally operator requested a design for a well that was targeted to pull roughly 450-700bfpd of total liquid, 60-70% water cut, 1700-2000 SCF/STB, and PIP of roughly 500psi. Initial design was constructed with high volume gas handling pump (G42), two high volume charge pumps (P35), and three low volume housing pumps (FlexER). Design sums to 636 stages, customer initially was offered to run encapsulated shroud system, however decided to run regular ESP system. Gas entering the pump after the high-volume gas separator ended up being anywhere between 70-80%, which exceeds the standards. Nonetheless, during the short run-life of this design unit was shutting down multiple times on motor stall and later had high motor temperature alarms and was shut down on manual stop (Figure 2).

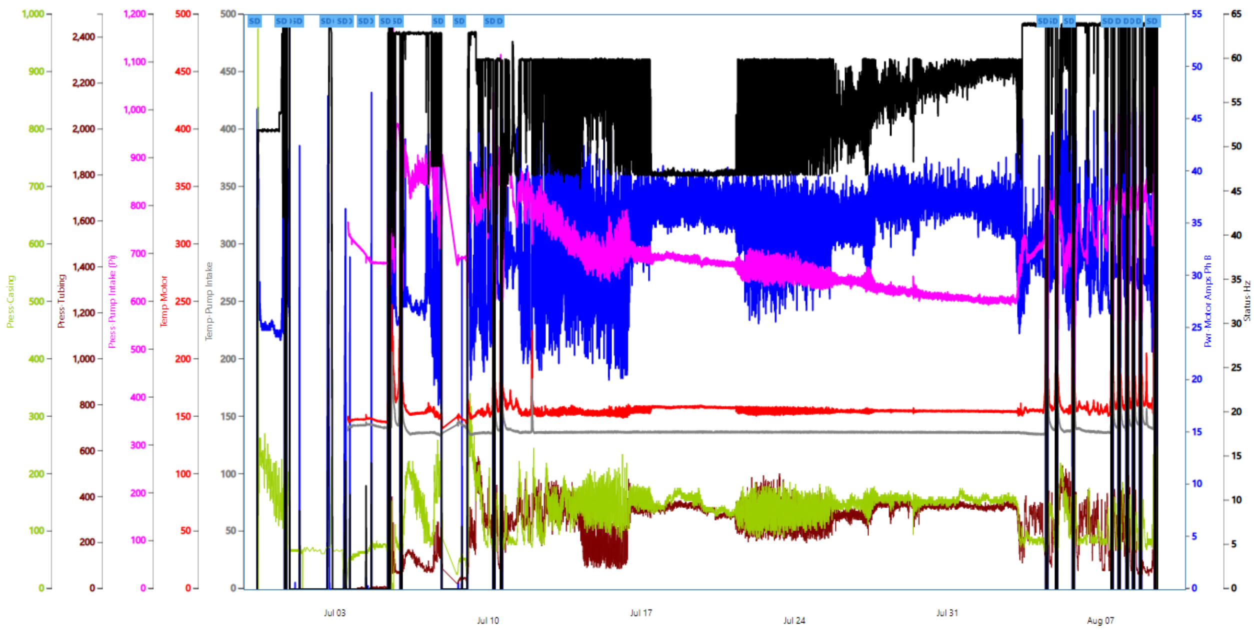


Figure 2: Performance curves of original 400-series equipment.

Unit was struggling in maintaining setpoint frequency and was forced to pass to PID current control mode targeting roughly 38 Amps with gas purge mode activated on the VSD. It looked like equipment accepted the change and customer increased the frequency up to 64Hz, but unit started gas locking and failed to maintain the production. Overall, despite the severe gas slugging intake pressure showed steady and gradual drawdown during the operation from ~950 down to ~600 psi.

Eventually, unit was found to be grounded downhole and was pulled for further investigation. Effectively, equipment was running ~42 days online and had nearly 30 alarms only on motor stall. Reliability and teardown team executed the investigation and found out that half of the pump housings were locked, and this explains constant motor stall shutdowns. Key elements that caused pump lockage were sand particles as well as the precipitation of iron sulfide (Figure 3). It was offered to the customer to cleanup the well and revise their chemical program that is being used to enhance the quality of future run-life.

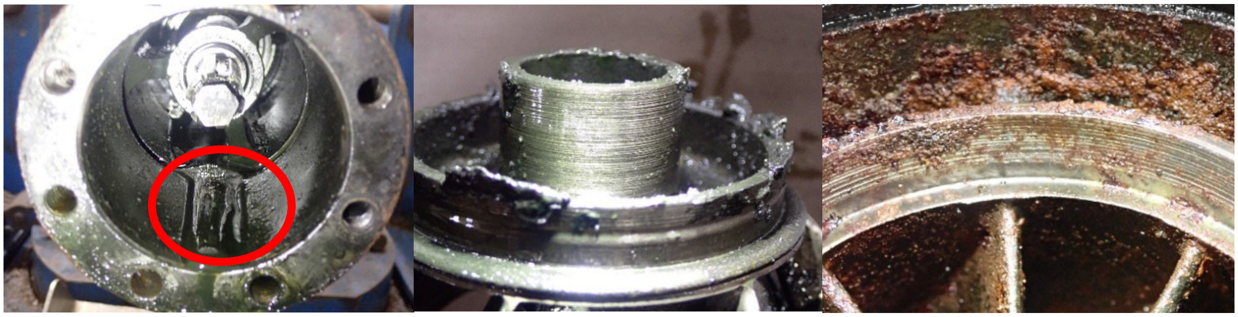


Figure 3: Original 400 series teardown findings.

<u>CENESIS PHASE</u>

While well of interest was on cleanup operation, operator wanted a design that would prolong the run-life of the unit and meet target production rates. Also, main concerns and goals were to minimize the downtime.

Due to the casing size 4.5-inch encapsulated shroud system was chosen with 300 series equipment inside. Equipment was sized in Autograph PC targeting similar production. Unit consisted of regular intake, 375 series motor, one recirculation pump (GINPSHL) and five high volume 300 series FlexER pumps. Total unit stage count ended up being 429. Unit was put online late August and since then it kept running with minimal number of shutdowns (Figure 4). From figure below it can be seen that the unit off to a rough start at the beginning but stabilized at roughly 62Hz.

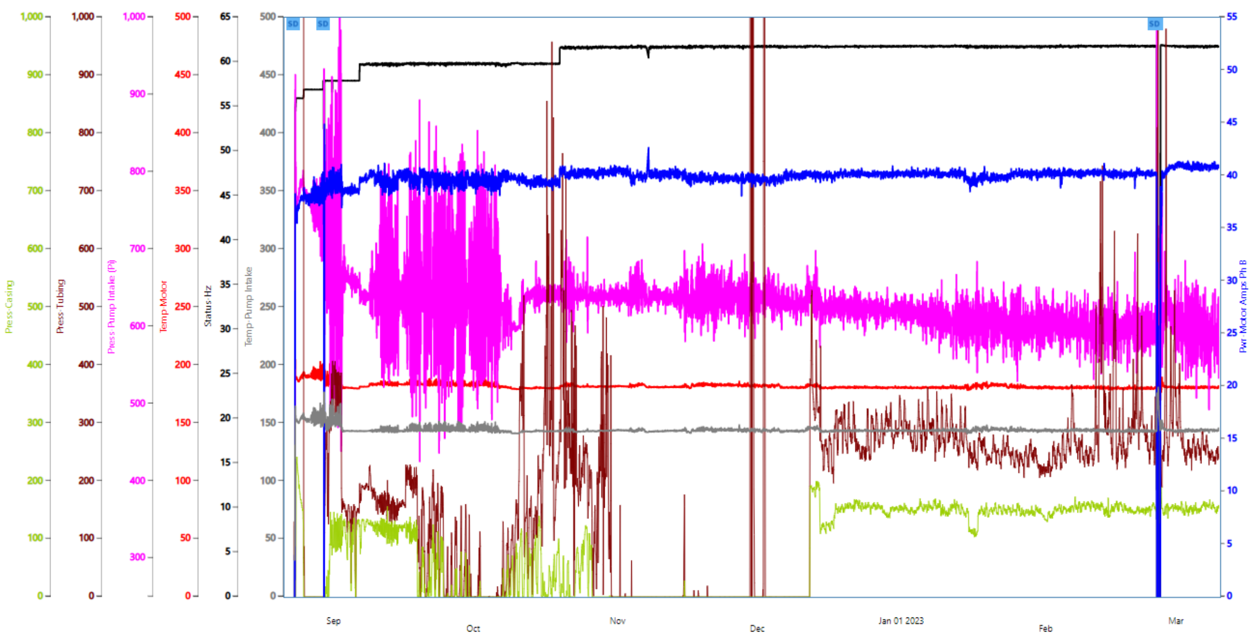


Figure 4: Performance curves of CENesis Phase unit.

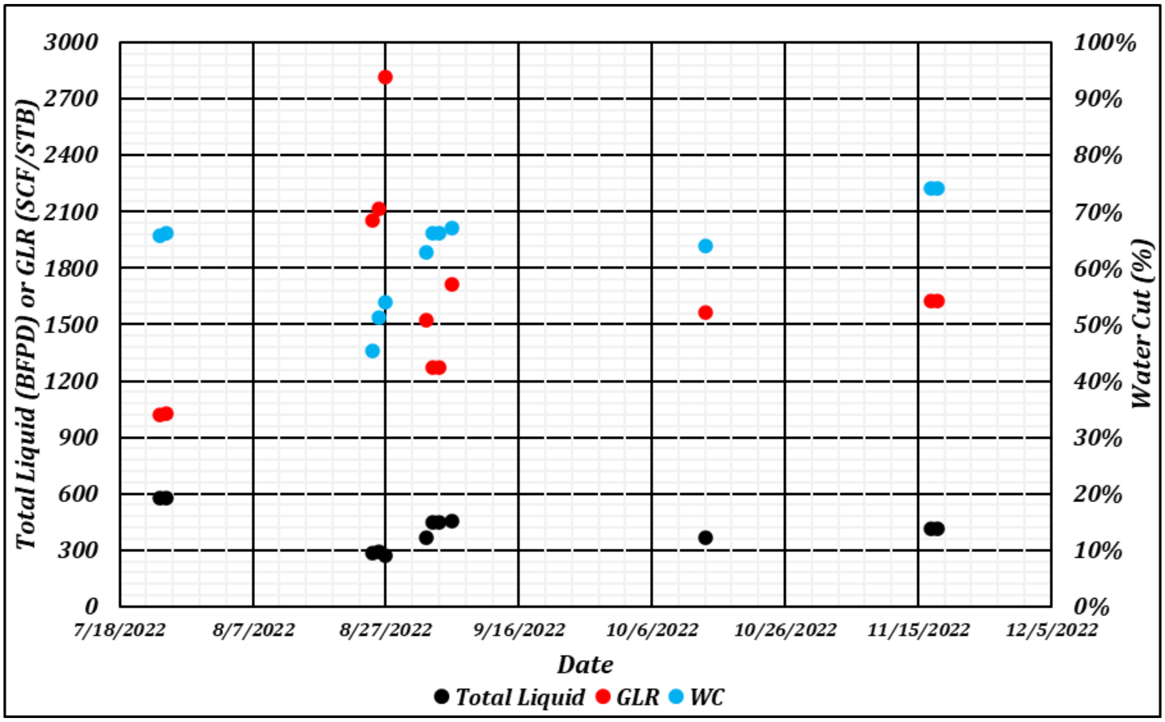


Figure 5: Combined production trends 400 series and CENesis Phase.

Production trend plot above shows that before August, although having a hard time during the operation, 400 series had stable production rates. Unit with the shroud, on the other hand, peaked on gas production (~2000-2900 GLR), low total liquid (~280-300 bfpd) and watercut (~40-50%). However, the noise of pump intake pressure from Figure 4 above is more related to surface pressure changes due to defective back pressure valves. After some time, gauges were fixed, and unit was running on stable trends. Drawdown is shown to be gradual over time and PIP declined from ~850 psi down to ~550 psi. Latest shutdowns were due to the motor stall similarly to the original design and may be due to slight scale inside the pump housings. Since the beginning, due to the surface gauges unit was passed to PID current control mode targeting similar amperage as before ~38-40 Amps. There was one shutdown event on external intervention, could be surface facility related and not due to the ESP alarms. However, unit had a hard time starting up due to the motor stall, which can be related to minor scale buildup inside the housing. Luckily, the issue did not last long, and unit quickly started back up online and kept pushing same performance as previously.

DISCUSSIONS ON DESIGN

Original 400 series design was well suited for gassy well applications. It was intentionally over staged and pump selection was dictated by target production rates and equipment suitability. Therefore, choice was to taper the design and combine high volume pumps with low volume. Encapsulated shroud design had 300 series pumps with nearly 200 stages less than the original 400 series pumps.

Based on the performance readings from Figures 2 and 4 it is obvious that original 400 series pumps drew PIP down at a much sharper rate than CENesis phase. Due to the high gas cut it to lift the fluid to the surface it was required to operate in PID Current control mode. Majority of the gas more than likely was slugging over the liquid front inside the wellbore and eventually caused pumps to lock out, however, this requires a more comprehensive and detailed scientific study. On top of gas slugging issues there was evidence of scale and frac sand movement during the production which reduced the run-life of the unit even further. Based on the real match case in Autograph PC, on July 24, 2022, G42 had nearly 66-70% gas entering the pump after the gas separator. Both P35 pumps had 56-60% gas in pump, and FlexER pumps gas in pump ranged from 30-44%. As mentioned before, this gas cut entering the pump passed the gas separator is a lot higher than what is pump unit is comfortable with. Operating point in gas handler G42 was out of the range and indicated that at a given production rates for a pump to operate within the range required high total liquid content.

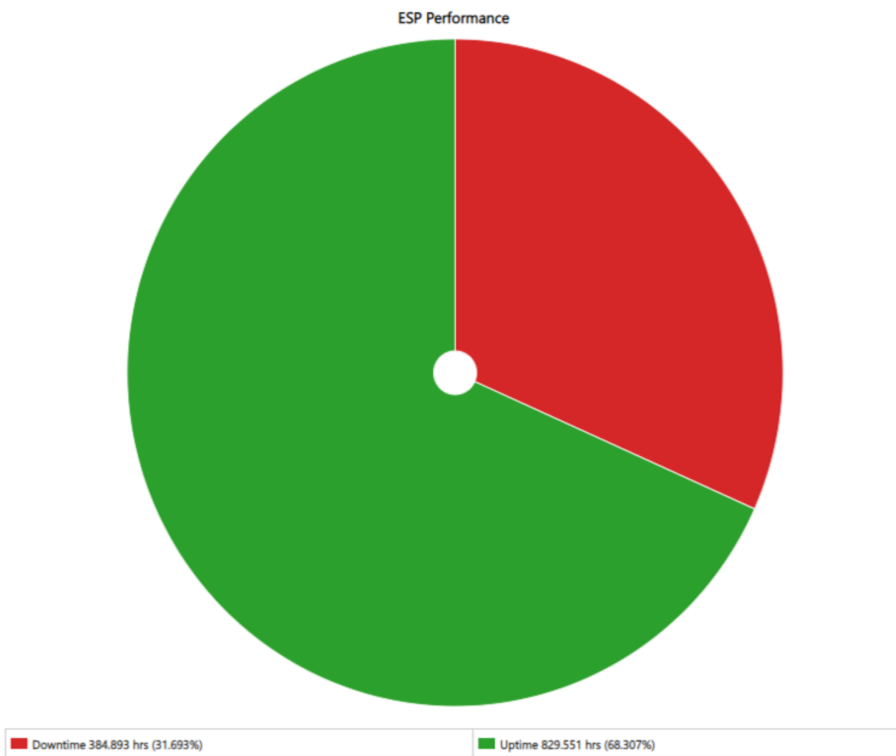


Figure 6: Original 400 series unit uptime/downtime.

In case of encapsulated shroud system based, unit was running more steady overtime even with consideration of some surface gauge issues. Total number of stages being smaller than original design unit still met target production. Drawdown was a lot more gradual and spread out over long period of time. Unit is still running with only recent minor shutdowns on external interventions as well as on motor stalls. Unit is also running in PID mode chasing target amperage. It seems that encapsulated shroud system helped significantly to deal with the gas slug time. This is reflected based on the performance.

Comparing the performance curves on both units it is evident based on amperage readings that severe gas slugging was causing the underperformance of the original equipment. Encapsulated shroud isolating most of the gas slug noise allowed unit inside to operate at desirable frequency with a much more stable amperage readings and even speed up the unit even more over time. The only drawback of the shroud system now by design is the solids and scale settlement at the bottom of the shroud, therefore, proper well clean up well suites the future operation of such design. On top of it many operators tend to install desanders and a tailpipe at the bottom of any ESP, which helps to prevent the significant mass of sand entering the unit on top. Similarly, to original 400 series design match cases were executed to see approximately how much gas in pump there was in pump housing after the separation (Table 1).

Table 1: Phase unit gas in pump based on production matches	
Match Date	**GIP (%)**
8/25/2022	Recirculation: 15%, FlexER: 0-11%
9/3/2022	Recirculation: ~20-26%, FlexER: 5-6%
11/18/2022	Recirculation: ~22-28%, FlexER: 10-20%

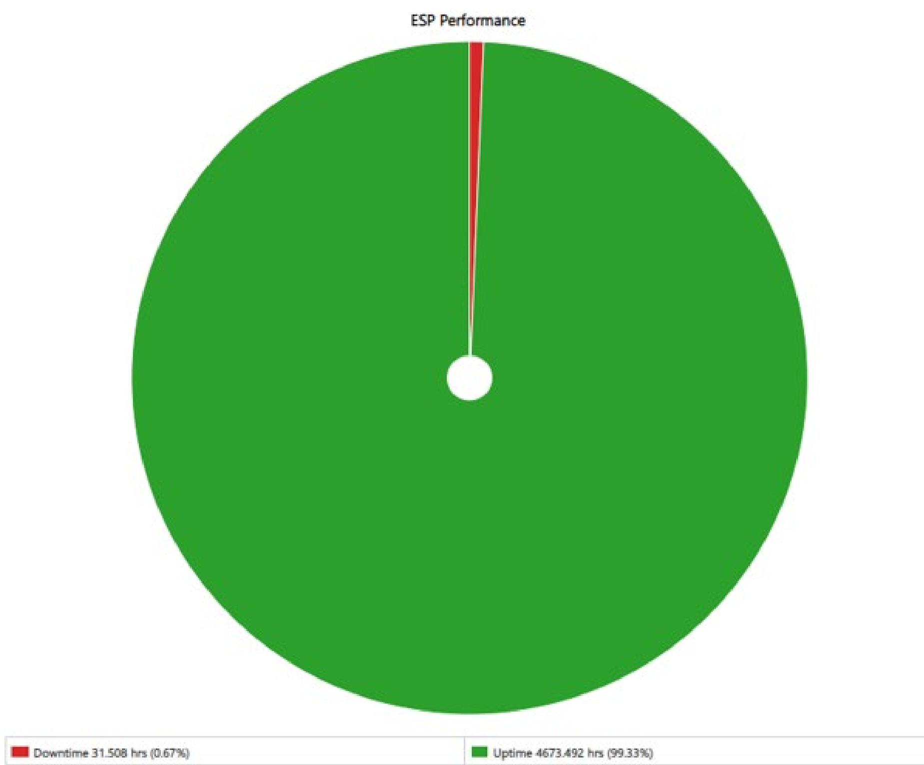


Figure 7: CENesis phase unit uptime/downtime.

POWER CONSUMPTION

Another key segment to pay attention to is power consumption. As oil and gas industry is moving forward, more companies are looking for different ways to decrease the carbon footprint during the operations. In order to execute a more comprehensive analysis on power consumption it is best to keep track of the true power being supplied to variable speed drive (VSD) at a given production output by downhole equipment. In this case study such information is not given, however, using our sizing software there is a way to get an estimate on expected surface power consumption. Original 400 series equipment was cross-matched and simulated at the production dates at which CENesis phase system was operating. The goal was to see how much estimated power 400 series would consume at the same production rates and similar electrical parameters. Since the motors and pumps are not the same there was less stress put on matching or getting close on motor amps readings.

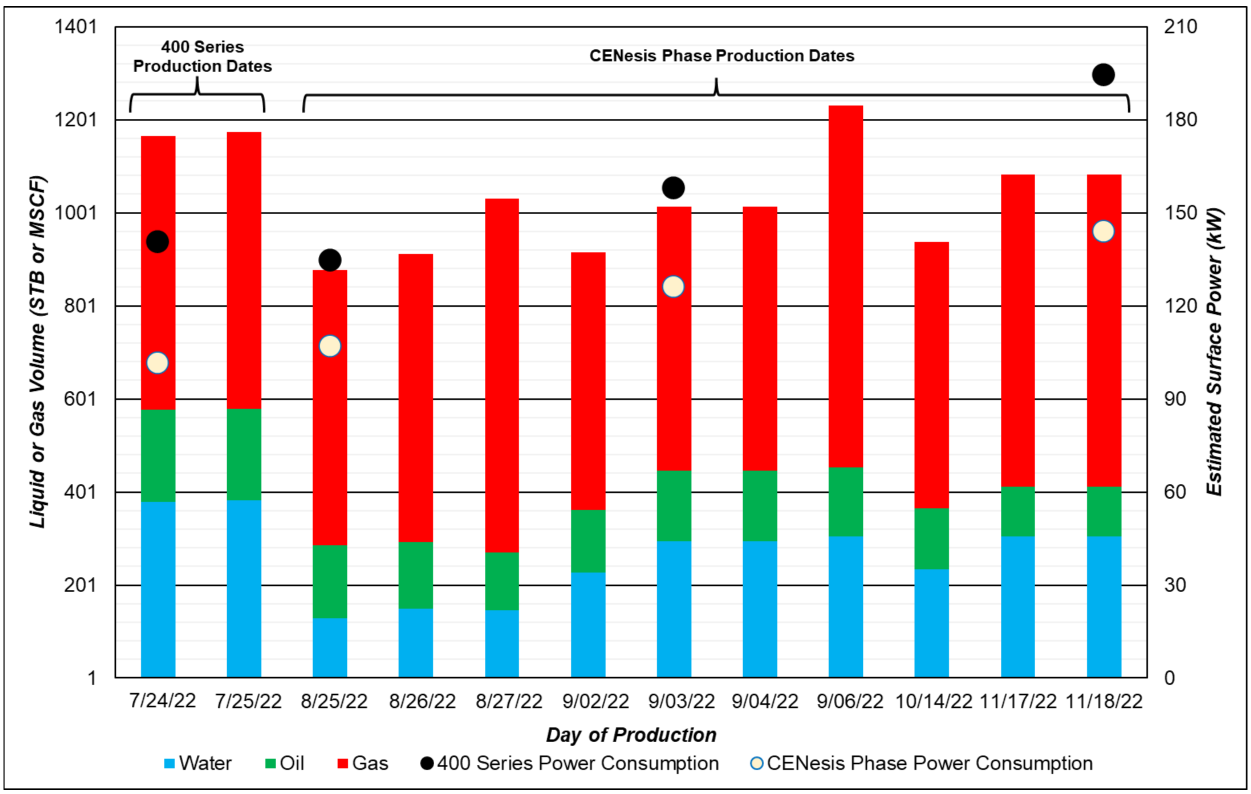


Figure 8: Power consumption over production rates at match cases.

Figure 8 shows the production volumes delivered at certain dates. In this case, four distinct production data points were picked for matching and simulation cases, and both ESP systems were cross matched for overall power consumption comparison. It is estimated that for both units power consumption rises as total liquid levels drop and more gas comes in. It is a well-known issue during the production; however, the case seems to hint at the fact that further optimization of artificial lift ESP units could potentially help reduce surface power costs, reduce the operational expenditure, and help lower down the carbon emissions depending on the energy source. CENesis phase shows to operate at a better power consumption number compared to original 400 series equipment. Overall, unit with encapsulated shroud is estimated to consume 20% less kW power and therefore reducing the power costs by almost the same percentage. However, it is important to re-emphasize that complete conclusion requires more match cases and more datapoints throughout the whole run-life of each unit.

CONCLUSION

In this case study 400 series tapered design ESP was compared with CENesis phase 300 series ESP. Original design had only ~40 days of run-life while shroud unit is having more than 200 days of run-life at the time when this paper is written and is still running. 400 series equipment struggled to handle the gas and teardown work has revealed that the equipment was partially plugged with some iron sulfide scale mixed with frac sand. Drawdown in both cases was similar, but phase unit had it more spread out over time of the production without risks of gas locking and meeting the desired rates by the operator. The limitations of the phase unit are mostly related to the slug time duration, which is rarely known, as well as sand or scale precipitation at the bottom of the shroud. First, proper slug time duration is the key in determining the size of the shroud from top to bottom. Second, sand and scale can start building up from bottom of the shroud, potentially burying the motor and intake, however, it can be mitigated by installation of desanders. Overall, phase unit is showing highly competitive performance compared to regular ESP designs and on estimate shows to be more power efficient on the surface, therefore projecting to minimize the operational costs for the operator. Further investigation of true power consumed throughout the operation is required, but the key message is the same and in turn it may help further optimize the production and reduce the carbon footprint on a well-by-well basis.

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