LESSONS LEARNED WITH JET PUMPS IN LOW PRESSURE GASSY AND SANDY RESERVOIR WITH HIGH DEVIATION

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ABSTRACT

Jet pumps are the preferred artificial lift method for many oilfields that require its ability to recover the downhole pump by reverse circulation. This reduces the need for intervention equipment and the lost production that can be caused by waiting on remediation. Some of these fields are in remote locations with minimum infrastructure to transport heavy equipment. Other oilfields that prefer jet pumps have challenges of severe deviation, high sand and/ or gas production. One of Indonesia's oilfields accessible by a 6-hour speed boat rid has all these challenges so when new areas in the field were found, jet pumping was selected to pump the new wells. The field has been using jet pumps since the early 80's where observations in equipment shortcomings and failures identified areas of concern. A proposal to mitigate these problems was accepted for the new acquisitions. Unidentified pressure losses in downhole equipment were suspected because actual production rates failed to meet theoretical pump performance calculations and erosion damage showed where areas of high fluid velocities with sand were critical. Computer mathematical modeling allowed visualization of improvements in design and geometries, (Hernandez et al. 2016). Modifications proved to perform better on start-up, but unexpected rapid reservoir pressure decline made it difficult to confirm data for comparisons. Surface equipment designs were also updated with process modeling to minimize pressure drop while minimizing sand and gas. These new systems provided the desired results; however, automation is considered necessary to provide reliable service. Finally, the horizontal pump system (HPS) that had proven more tolerant to gas, resulted in a better understanding of comparative performance features with the historical work horse of hydraulic lift, the positive displacement (PD) pump. In new well applications where reservoir pressures are not stable, the HPS's is not sufficiently flexible because large variations in power fluid requirement while still requiring high pressure can result in high down thrust. Modifications to nozzles and throat combinations, fluid by-pass and VSD speed flexibility were implemented but the continued reservoir decline required frequent adjustments that lacked the monitoring to mitigate. Lessons learned have contributed a more holistic understanding of the jet pump process and confirmed results expected while also confirming the importance of reservoir characterization in artificial lift selection.

BACKGROUND

The high cost of having a well service unit on location permanently to service a few wells in a remote region creates a vital need for the reverse circulation recovery of the downhole pump that jet pumps offer. The pump can be repaired or replaced without well intervention equipment. Development of this remote swampy field originally required wooden bridges to transport rigs and heavy equipment. Drilling rigs and production process systems were disassembled in pieces small enough to transport using wooden logs under equipment pieces for towing with multiple motorcycles. There is more infrastructure today with dirt roadways sufficient to facilitate heavy moving equipment, but it is still it's still considered minimum infrastructure. Directional drilling and well pads were also implemented to drain the asset at a lower cost. The reservoir originally had GOR's ranging from 1000 scf/bbl to 6000 scf/bbl, and a high sand production. In the mid 80's, artificial lift selection lacked complete reservoir characterization or reservoir pressure decline trends, so the lift system had to provide a wide range of flexibility. The jet pump provided a good range of production flexibility for start-up, but if the reservoir pressure declined rapidly and sand stabilized, the hydraulic reciprocating piston pump could continue to provide acceptable lift, (Gaul et.al. 1986). The jet pump was introduced in the 70's by manufacturers of hydraulic reciprocating piston pumps that had developed a complete product line of bottomhole and surface equipment. The jet pump was initially offered as an option which could be easily adapted to existing piston pump equipment. Throughout the years observations of pressure drops that were not significant with the lower capacity piston pump have been known to choke the lift effects of some jet pump models. In some models the landing cavity (Bottomhole assembly) and standing valve introduce losses not simulated in design programs. Today's mathematical modeling technology, not available during initial development of this equipment allowed identification of areas requiring redesign. A gas vented piston pump BHA was selected to allow downhole gas separation and gas flow up the casing annulus. As in the 80's the new jet pump was adapted to the BHA because it provided the target production rates in recently drilled wells. The 2-7/8" x 2-3/8" (coupling OD reduced), parallel tubing BHA and well completion allowed the setting of the jet pump below perforations to inject power fluid down one tubing and the mixed exhaust power fluid with production flowing up the second tubing string, (Gaul et al. 1986). This well completion design has proven successful for over 30 years. The pump is often set below perforations to gain submergence and improve gas separation while the jet pump keeps sand out of the well. Throughout the years the original BHA has been adapted to the short jet pump model but without optimizing internal flow passages. Start up production indicated production temporary increases of 25% to 45%, but production targets were much less than planned and reservoir pressures continuously declined. As production dropped below 500 bfpd, the horsepower required to produce a barrel with the new jet pumps was the same as results with the old systems.

WELL COMPLETION

Producing a gassy low pressure well (below bubble point) with the most popular casing free well completion where a packer is to allow the jet pump discharge of mixed power fluid with production to flow up the casing annulus with power fluid injected to the jet pump down the tubing has led to shortcomings in production expectations. The jet is tolerant to gas and in low quantities it serves to reduce the gradient of fluid flowing to surface, but in higher quantities, gas takes up a lot of space and reduces the density of the fluid being lifted. On one had larger jet pump orifices are needed to allow for gas flow, while the lowering the density of inflow. The high velocity power fluid (water/ dense fluid) injected from surface more easily shears through the lower-density production increasing mixing losses in the energy transfer process. Increasing power fluid helps to mitigate but this measure can quickly reach the volumetric circulating capacity the wellbore. With all gas having to flow through the casing, gas build up and surging common in horizontal wells can also displace fluid in surface vessels leading to shut down. Parallel tubing or concentric tubing well completions allow gas separation downhole so gas can flow up the casing annulus. Locating the Parallel BHA below perforations increases gas separation and pump submergence. The higher PIP and reduced gas flow through the pump increases the density and inflow velocity reducing mixing losses to increase efficiency. Placing the BHA below perforations also keeps sand moving to surface. Nodal analysis is used to select tubing sizes sufficient for fluid circulation rates at the target production and PIP, (Hernandez et.al 2016). The concentric tubing well completion provides similar benefits of the parallel completion in the Permian Basin in sand removal services offered by some companies. Figure 1.0 shows the schematics of the three-jet pump well completions outlined above. Successful production has been obtained to fluid levels of 100 feet above perforations with gas vented jet pump well completions. This is competitive with beam pump production while offering greater tolerance to sand and well bore deviation. The smaller casing sizes used today limit the size of multiple tubing that can be run in wells. Smaller tubing sizes lead to lower fluid injection and production capacity, so Nodal analysis is essential to design as is the analysis of jet pump equipment internal flow losses. Concentric tubing requires coil tubing of small diameter pipe; however, there are frequent reports of threading shortcomings that discourage the use of small diameter pipe while the cost of the standard coil tubing unit creates investment shortcomings. The small diameter or "Umbilical" continuous tubing unit proposed in 2018 could provide a solution as did continuous sucker rods in beam pumping. Figure 2.0 shows a schematic of the proposed continuous umbilical unit designed specifically for hydraulic pump installation complete with complete pressure control throughout the installation.

MODIFIED BHA

The originally parallel piston pump receiving cavity or bottomhole assembly (BHA) was designed to include a special check valve or standing valve (SV) provided by the jet pump manufacturer. The jet pump sits on a tapered seat at the top of the standing valve and BHA passages are designed to minimize area for sand build up during the phases of operation; however, the discharge of the downhole pump is not aligned with the BHA outlet. Mathematical modeling confirmed high losses with larger fluid circulation rates and/ or nozzles sizes which were going to be necessary with 1500 bpd production targets. The BHA installed in previous wells was selected to allow installation of either the piston pump or the jet pump, so it was original designed for piston pump production capacity and there were no indications of higher production rates. The piston pump has a near one-to-one ratio of power fluid to produced fluid while the jet pump has a ratio greater than three-to-one (power fluid rate to produce fluid rate). The misalignment of pump discharge ports with BHA ports inherent in the original BHA causes little effect with lower fluid circulation rates, but the higher rates targeted with new wells showed losses that would choke the production capacity of the jet pump. The jet pump and BHA were modified to align the discharge of the jet pump with BHA communication ports. Figure 3.0 shows the original bottom section of the BHA with the original jet pump discharge and location of the BHA discharge ports with restricted areas. The special standing valve (SV) supplied by jet pump manufacturers with a 1.25" ball has also been identified as a flow restriction for high volume (1500 bpd) production. To allow for the projected production rates of 1500 bpd, the SV was also changed to a 2.31" model R with 1-1/2" diameter ball.

Historically, theoretical jet pump performance calculations for wells with higher circulation rates in this field had never correctly simulated jet pump lift requirements. Field personnel had learned to increase the nozzle size than determined by the computer program because extra horsepower was needed to obtain the production target. Jet pump performance simulation programs include an algorithm with a constant increase in losses related to flow rate without recognizing the actual passage dimensions to recognize limits. Textbooks do state that nozzles larger than a 0.035 sq.in. area should be limited to jet pumps larger than the 2-1/2" (Petrie et al 1986). The high-volume model was designed to minimize the above losses and align them with fluid circulation capacity of tubing/ casing they can fit into. The high-volume model has been recorded to produce over 20,000 bfpd. The importance of mitigating pressure losses or restrictions is not in the wear of components but the reduced production from choked flow. Figure 5.0 and Figure 6.0 show results of a CFD pressure analysis that indicates where high pressure's locations influence the energy transfer process and overall efficiency.

Lesson Learned: While optimization is needed to provide a more efficient jet pump with high production, changes are not merited where circulation rates are within the capacities standard designs. Due to variation in well conditions, pump wear, jet pump nozzle and mixing tube selection, comparison required is best accomplished over the long-term monitoring of production per horsepower (power fluid volume and pressure); however, rapid reservoir pressure decline and pandemic protocol in the remote location created challenges that prevented acquisition of data for this observation.

POWER FLUID PROCESS SYSTEM

Central power fluid process systems were first introduced with the hydraulic piston pump to process well return fluid and gas to atmospheric pressure that optimizes gas separation, sand removal with oil and water separation is holding tanks providing acceptable retention time. Piston reciprocating pumps require very clean power oil to lubricate reciprocating components moving at 30 to 150 strokes per minute and tolerances of seven ten thousandths. Power fluid quality sufficient for piston pump operation are still the target quality of power fluid treatment for jet pumps; however, the jet pump does not require the same quality of power fluid, (Petrie et al. 1986). The need for central power fluid treatment facilities kept hydraulic lift from competing with beam pumping systems that didn't require long high-pressure power fluid distribution tubing or well site processing. The portable two vessel hydro-cyclone power fluid treatment system was introduced around the same time the jet pump was gaining popularity in the late sixties. The process requires a differential pressure across two vessels to feed fluid through the cyclones to remove solids after most of the liberated gas is separated and removed in the first vertical vessel. Pressure control valves maintain the first vertical vessel pressure 35 psi to 55 psi above the horizontal vessel. The second, reservoir vessel provides retention time to separate fluid gravities (oil/ water) so water can feed the surface pump for recirculation to the jet pump. Figure 6.0 shows a diagram of the Two Vessel Power Fluid treating System. Fluid levels are maintained through gravity dump systems (Hernandez et al. 2016). This well site solution is an alternative to the cost and space needed for complete separation at atmospheric pressure that also requires fluid transfer, on site storage, and gas compression equipment. However, well site power fluid treatment vessels must operate at sufficient pressure to discharge fluid into production flowlines and feed the surface pump with sufficient pressure to prevent cavitation. This is a simple concept with a little complexity in pump suction pressure requirements that is to be addressed below, but the added pressure differential required by the hydro cyclones is an increase in back pressure against the jet pump's lift effort. Production managers frequently order by-passing of the hydro cyclones when they see an increase in production when it's done.

The search for improved well site processing led to CFD modeling targeting reduction in pressure losses to under 10 psi while maintaining efficient removal of solids and gas. Figure 9.0 shows the new power fluid treatment system with internal cyclonic inlet to separate solids and gas and allowing fluid to continue to the second vessel for separation of oil and water. The system proved to perform to expectations while vessels were drained at timely intervals; however, changing well conditions required continued modification to drain periods. Budget constraints prevented inclusion of automation systems to monitor sludge levels to control draining.

Lesson Learned: Mathematical modeling used today for production process systems and cyclone optimization have a place in hydraulic lift and must include monitoring and automation to keep the system operating within design parameters.

SURFACE PUMP

The historical workhorse of the hydraulic lift system is the positive displacement (PD) plunger pump. The PD pump is rugged, efficient, and field repairable, but the pump does not work well when gas is present. Unfortunately, jet pumps in remote locations require pressurized power fluid process systems as mentioned above. Premature PD pump valve and plunger packing failures are the common complaint of jet pumps worldwide. There is no other PD pump application where the pump receives live well flow (oil, water, and gas at well temperatures). Failures are more common in fields with higher gas production, higher temperatures, or light oil. Vapor pressure at wellhead conditions needed for net suction head required is normally not available. Acceptable suction pressure is frequently the result of suction pressure variation to minimize vibration. Extreme conditions can be mitigated with suction stabilizers and lower operating speeds, but neither are a common practice. In most if not all cases the surface pump operates at 100% of rated speed because it leads to increase production and the pump operates with some level of cavitation.

Recognizing that the multistage pump or ESP is more tolerant to small amounts of gas at the suction, in 2008, the first horizontal pumping system (HPS) was installed in this field. THE HPS provided power fluid to four jet pumps. Figure 8.0 shows the first HPS unit installed in the field with a 5' x 20' 150 # power fluid vessel that is part of a two-vessel system. The PD pumps that had provided power fluid for these wells had a history of frequent valve and plunger packing failures. The HPS unit was started and operated for more than ten years without more than preventative maintenance and one failed thrust chamber mechanical seal in 2019. The reduced shutdown time, reduced maintenance and reduced lost production of this first unit led the operator to specify HPS units for the new development. HPS capacity for one to three jet pumps was specified at 3500-bpd with a maximum discharge pressure of 3000 psi. Figure 9.0 is the HPS pump performance curve showing the projected operating point for the power fluid required for three jet pumps. Unfortunately wells failed to produce the target rates reducing jet pump power fluid volume requirements, but pressure requirements remained about the same. By-pass systems were in place to recirculate fluid that was not needed, but by-pass valve capacity was not enough for the volume of recirculation required even with reduction of pump speeds because discharge pressure had to be maintained. Several HPS units operated with a total volume requirement of less than 1500 bpd but also required more than 2500 psi placing the HPS in severe down thrust.

Rapid reservoir pressure declines also required frequent adjustments, while constant field personnel rotation in compliance with local community commitments to provide opportunities for employment led to shortcomings in adapting to the more sensitive equipment. The HPS did demonstrate more tolerance to solution gas, but less flexible to wide ranges in power requirements. One failed HPS pump has been replaced with a PD pump while the wells continue to decline, and some have already been shut down. The HPS is still considered low maintenance and highly reliable solution for stable well jet pump operation.

Lesson Learned: There is an application for both the PD pump and the HPS in jet pumping, but more emphasis should be placed on the specific needs of the application and a better and holistic understanding of all the processes in a hydraulic lift system

CONCLUSION

Jet pumping systems can be optimized and improved using technology that was not available to model dynamic conditions during initial development; however, this case history places more importance on characterizing the reservoir and well characteristics for life cycle planning in artificial lift design. The jet pump does provide well testing benefits if designed for that purpose and a permanent system can be designed to provide reliable service. The extensive experience with hydraulic lift around the world and recent uses of jet pumps in the Permian leads us to believe that several of the issues involved in this case history can help mitigate the shortcomings. All lift systems have developed through the years, those with the largest use come first. Jet pumps can be applied on many problem wells in most oilfields, but holistic engineering is vital. We hope the examples of improvements and results provide encouragement for continued optimization for everyone that finds the features of hydraulic lift of interest. It is the only lift system that has proven successful energy transfer to pump from 25,000 ft.

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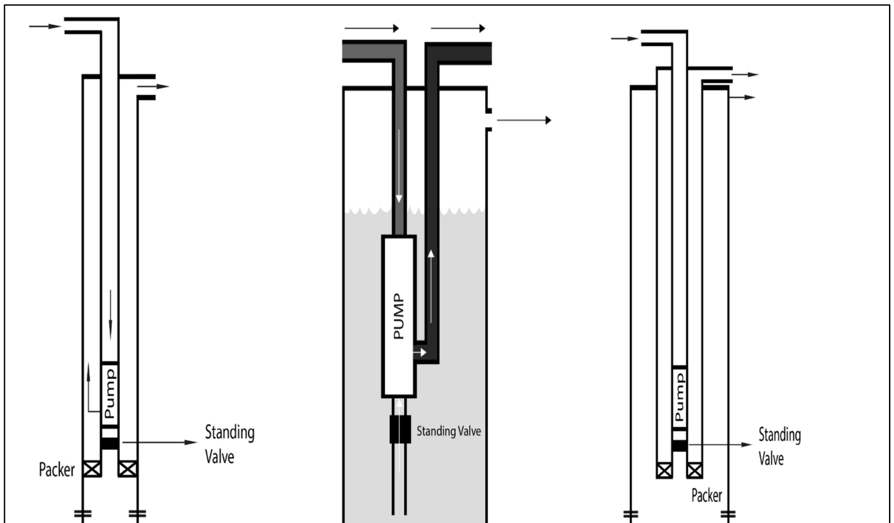

Casing Free Parallel Concentric

Fig 1.0 Jet Pump Well Completions

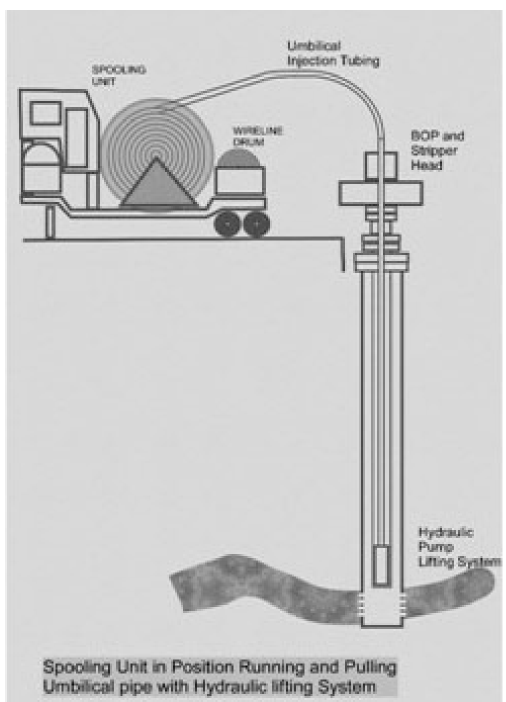

Fig. 2 Umbilical Spooling Unit Concept for Hydraulic lift

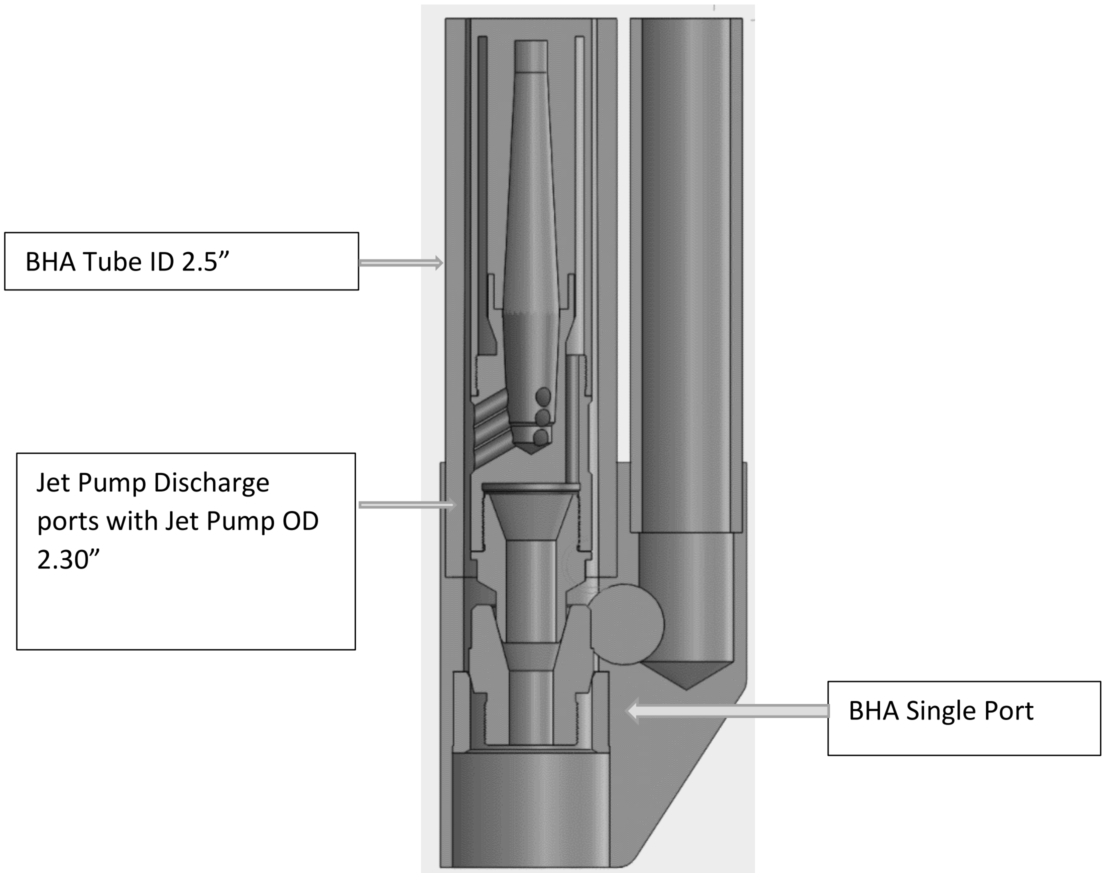

Figure 3.0 Jet Pump discharge is located above the BHA discharge ports casing abnormal pressure drops with high volume production or high lift production requirement.

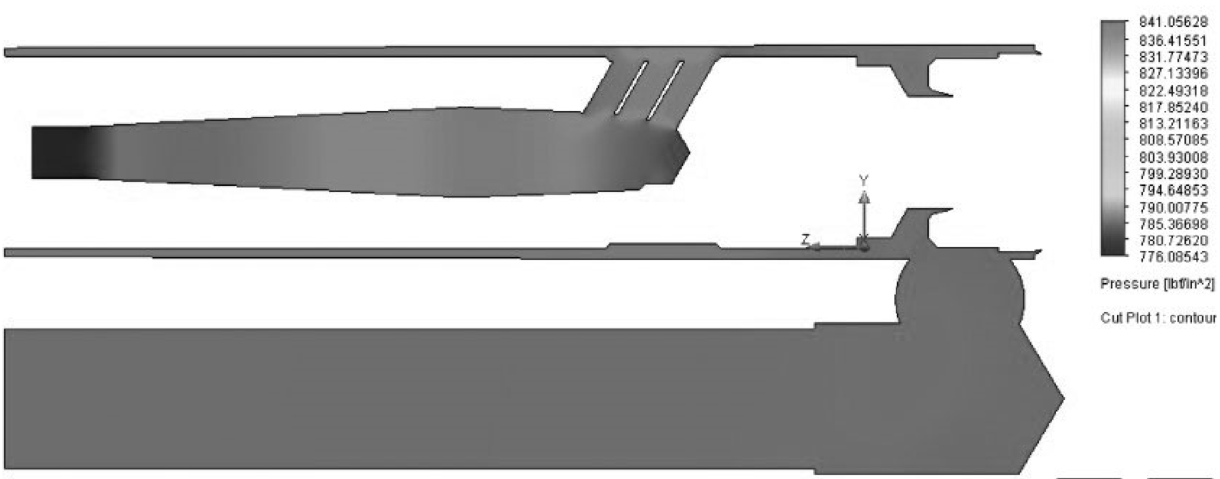

Figure 4.0 of the same section shown in Figure 3.0 shows where pressures increase even in black and white diagrams. The original color diagrams create a greater impact.

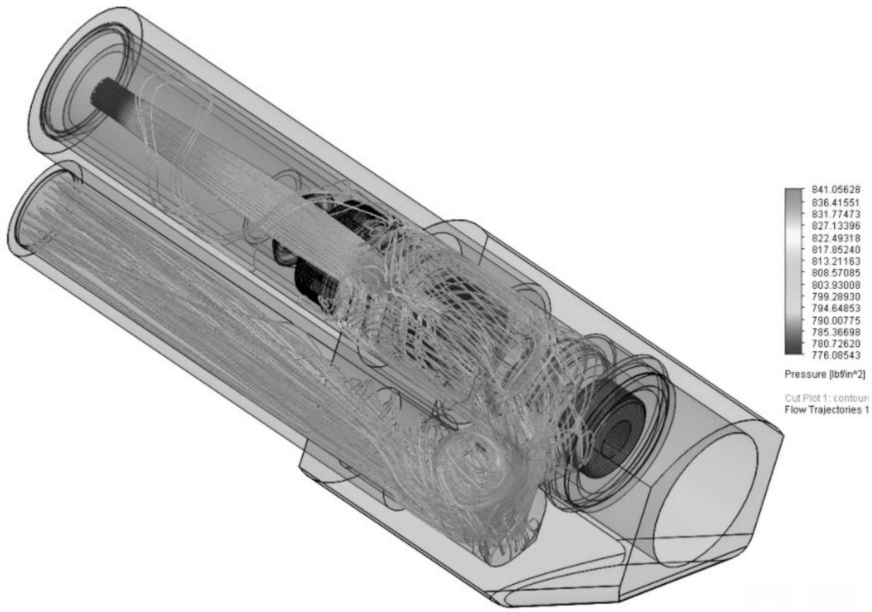

Figure 5.0 are CFD results indicating where high pressures throughout the section cause back pressure on jet pump energy transfer or lift capacity. The original color pictures provide better detail.

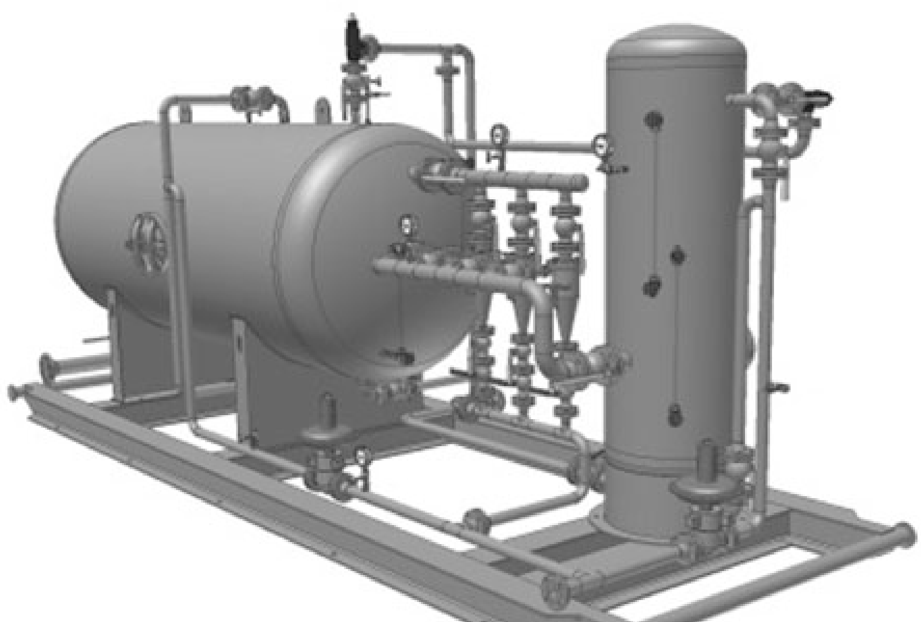

Figure 6.0 Two Vessel Power Fluid Treatment System

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Figure 7.0 New Power Fluid Treatment System with 10 psi Pressure Drop

Figure 8.0 The first HPS installed in 2008 and operated until 2021 with only two thrust chamber mechanical seal failures.

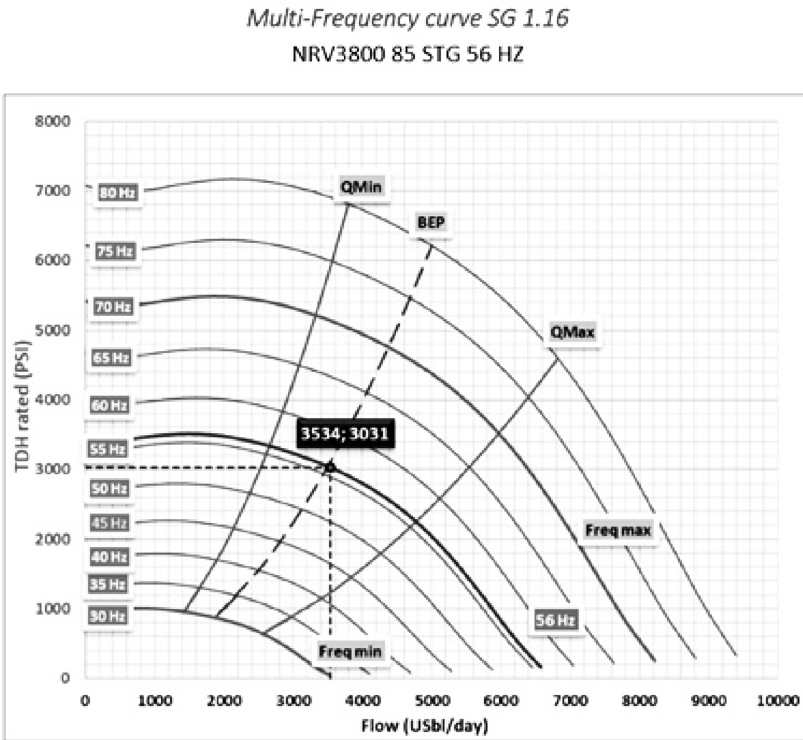

Figure 9.0 HPS Pump Performance curve with the projected operating point required to provide power fluid to three jet pumps. ©2020 NOVOTMET