NEW TECHNOLOGIES FOR PC PUMPS

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ABSTRACT

Progressing cavity pumps have been used on an application-limited basis throughout the world for the past twenty plus years. A vast majority of these systems are deployed in Canada and South America producing heavy, viscous oil with high sand content. Product development and numerous specialty ancillary products have most generally favored heavy oil production. A few of the ancillary products such as spin-thru rod guides, torque anchors, heavy-duty wellhead drive, etc transcend across application boundaries, however, the heavy oil market dominates most of the research and case studies.

This paper will focus on P C pump product enhancement and design changes for applications that are more typically encountered by US operators. These wells can be grouped into the following: secondary recovery, light oil, high water cut, high volume, or water source wells and coal bed methane applications. These wells require a different philosophy and certainly different pump geometries than what was previously available through the manufacturers.

Continuing, the paper will report on several of the products that have been developed, tested and are now being used within the Permian Basin. We will share the results of field-testing on down hole pressure sensors and a specialty rotor coating as an alternative to chrome. Benefits of new elastomers that have been brought upon the market will be examined.

BACKGROUND

P C pumps used in the oilfield, as applied to the artificial lift market, were initially installed in the heavy oil sand projects of Alberta Canada. The pumps inherent ability to produce viscous fluids and large amounts of abrasive solids with the produced fluids were a perfect match. Not only were the P C pumps a more economical method of producing these wells, but in many cases the only viable method. Improvements in manufacturing techniques for the rotors and stators and ancillary products continued to be developed for the international heavy oil market.

Until the coal bed methane (CBM) market developed in the 1980's in the black Warrior Basin of the U S, P C pumps were used very sparingly outside of heavy oil applications. When they were utilized, they were more commonly used on striper well production. Only when the other attributes of the P C pump were brought to the forefront was there resurgence in interest from area operators. There are two other characteristics of the P ***C*** pumps that gained local attention. First, the positive displacement pump provided high overall system efficiency that was unequalled in reducing energy cost per barrel **per** foot of net lift. Secondly, the pumps were now available in larger displacements putting them well above beam pump capability and in direct competition with electrical submergible pumps. Now rather than being installed in stripper wells, the pumps were being installed in shallow wells making up to 4,000 BFPD. Conceptually, the P C pumping system proved easy to endorse and easy for operators to buy into.

INTRODUCTION

The early 90's ushered in a time of numerous P C pump installations in the Permian Basin. Applications here in the basin proved far different than those encountered in the heavy oilfields of Canada. The pump's, ancillary equipment, and technology designed for the heavy oil application provided less than satisfactory results for the most part. Within a two-year period, more than half of the installations were withdrawn from service due to repeated failures and high operational cost.

With present technology and understanding, it is easy to **look back** and analyze the reasons for lack of success. Polling prior operators whom installed P C pumps during the early 90's, most all would identify with one or more of the following contributions to their P C pump failures.

- Rotor fit to stator elastomer was too tight
- Elastomer technology at the time was not compatible with H2S & FeS & high aromatic conditions that was

present in most wells

- Service personnel to service and install the equipment were not made available by the seller
- Braking tubular components and welds near the bottom hole assembly due to H2S and hydrogen imbrittelment of the metal
- Poorly designed stuffing boxes that leaked and contributed to polish rod failures
- Backspin brakes (retarders) that did very little for slowing down backspin
- No effective means of monitoring or controlling pump off
- No substitute for chrome coated rotors that were worn out within a short period of time by the FeS
- P C pump's installations being misapplied to the application.

The last category is a catch all that includes running the pumps too deep, too high of RPM, in too high of API gravity oil, in too high of gas cut wells, with too high of H2S or C02 etc...

NEW TECHNOLOGY FOR THE PERMIAN BASIN

The remainder of this paper will focus on product changes that have been implemented for local Permian Basin applications. These changes and the results will be demonstrated in a case study presented by Marathon Oil Company whereas P C pumps were used for ***3*** years with success. The changes made were as follows:

- Rotor fit to stator elastomer was loosened up considerably compared to the heavy compression fit that was being used for heavy oil, low temperatures and low RPM applications. (See attachment 1) Additionally, where applicable, the pumps were over staged to allow the pumps to operate in the middle of the perfor mance curve. This is opposed to running them previously at the tail end of the curve where they would be operating at 100% of their rated pressure. In summary, rather than run a 75-90% efficient pump at rated head, it **is** common now to select a 20-40% efficient pump operating at 60-75% of rated head pressure. When the elastomer encounters aromatics and/or becomes water saturated under pressure, the elastomer does swell and usually deliveries 80 - 90% pump efficiency. If the pump were to start out to tight initially, as was the previous scenario, only detrimental responses can and do occur.
- P C pump manufacturers that were previously unexposed to the Permian Basin were brought into the area with their technology. Their new elastomers combined with better application selection and looser fit rotors have demonstrated a marked improvement in performance and longevity. Even in wells that were previously classified as unsuccessful installations are now being operated with P C Pumps. Those applications being primarily mild H2S with medium to high API sour oil.
- Rotor coatings availability has expanded to include a chromium tungsten carbide inlayed within a nickel matrix. The field results concluded what the lab test predicted, that being the coating is eight times as abrasion resistant as hard chrome. Where applicable and economics allow, **this** is a viable option for wear resistance. It has not proven to be better for corrosion. To obtain corrosion resistance, the base material requires either a pre-coating or fabricated from stainless steel.
- There are now companies in the area that solely focuses on P C pump sales and service. As an operator, it is up to you to select a product source accordingly. Your comfort level should be derived from your supplier's knowledge of the products, application expertise and their service capability. It has been said that working with PC pumps is more of an art than a science. It is actually more science, but there are not as many PC pump technicians out there as there are beam pump specialist.
- Reducing down hole weld failures was as easy as removing the components that had welds on them. Welded cross pin tag bars are not used in applications where there is H2S or in deep wells where the pump is set high. We no longer utilize stators with welded on connections and lift subs in H2S applications. Change over pin-to-pin swedges is not permitted on our installations as heavy-duty change over collars are selected. Knowing that the P C pump rotor eccentricity causes a fair amount of vibration within the pump, we try to place our torque anchor or tubing anchor catcher one to two tubing joints below the stator. It is our belief that this separates the rigid anchoring system away from the origin of the vibration, which reduces stress on localized tubular components. (See attachment # 2)
- Aftermarket centralizing stuffing boxes that are self-adjusting have greatly reduced chronic packing prob lems. This feature has also contributed to reducing polish rod failures due to misalignment or running slightly bent polish rods. In order to reduce polish rod failures, service personnel must have proper tools. A digital leveling device can digitally displays the thickness of a dollar bill placed under one side of it, hence forth there is no excuse for not installing the wellhead drive perpendicular with the casing.
- Monitoring and controlling pump off on P C pumps can be very elaborate or very simple. One option is

running a down hole sensor and hard wiring it back to a surface variable speed drive that adjust RPM accord ingly to obtain a pre-selected down hole pressure. The other option is much simpler whereas an amp chart or digital display device calibrated with a fluid level gun can be set to shut the unit down once amps exceed a certain high/low level.

GENERALLY ACCEPTED AS BEING GOOD APPLICATION FOR P C PUMPS

In regard to applications, there could be a whole paper allotted to what makes for a good application. In short, this is typically what is recognized as being a good candidate for P C pumps.

- Shallow wells less than 5,000' pump setting depth.
- High volume lift beyond current lift method or to replace an ESP.
- Wells whereas solids interfere with normal operations or cause high maintenance or operational cost.
- Water flood source wells where lift cost needs to be reduced for non-revenue producing lift.
- Slim hole applications that have more production potential than can be obtained with beam lift.
- Newly drilled wells where reduced capital outlay per barrel of lift is less with a P C pump.
- With energy deregulation in small cooperatives, P C pumps can keep energy cost at a minimum.
- Low profile units in circular irrigation areas.
- Tubing less completions in small casing

APPLYING THE TECHNOLOGY. A MARATHON OIL COMPANY CASE STUDY

Foreword: Since this paper was originally pinned, the subject property has been sold by Marathon Oil Company. The current operator of the property, Belco Energy Corporation has graciously allowed us to continue with the case study report.

The Howard Glasscock East Unit (HGEU) water flood was identified as potential candidate for PC Pump installations in 1998. Water injection rates had recently been increased and the producing wells were responding very favorably with higher production rates. Within a short period of time, the beam units that were in place were unable to keep the wells producing at maximum potential. The Mark II 320 long stroke units were limited to approximately 700 BFPD running **24** hours per day. MOC preferred not to utilize electrical submergible pumps to increase production. The wells in the field were considered to be ideal applications for PC pumps due to the following: The wells were less than 3,000' in depth, maximum volume rates were expected to fall between 700 and 1,500 BFPD, the wells were known to be corrosive and produce mild to heavy FeS, and the selected pump would have to have a wide production range.

In early 1998, MOC purchased three PC pumping systems from three different suppliers. All three pumps purchased were from different manufacturers. Elastomer compatibility test were performed to assure that the elastomers within the stator were compatible with the produced fluids (30 API oil). In all three installations, chrome rotors were initially installed. To obtain flexible production rates, variable speed drives were installed on each system to allow for RPM changes with minimal efforts. Initially all three systems provided adequate service and production rates.

One system operated for less than six months before experiencing a pump failure. During the initial learning curve, several other unexpected problems developed such as tubing back offs, polish rod breaks and severely worn rotors due to FeS. The remaining two pumps demonstrated that the systems would be economical if the failure rate could be reduced to a failure frequency similar to what the rod pumps had established. This was established as a goal for 1999.

During 1999, the second year of the field study, MOC decided to move forward with several more installations that would encompass changes obtained from information learned within the first year of testing. Having seen first hand that there is a difference in product performance and longevity, and a difference in application knowledge and service capability of the supplier, MOC elected to work with one of the original three suppliers for future applications. Starting in January 1999, installation incorporated the following:

NEW INSTALLATIONS

Due to FeS abrasion wear, it was decided that all future rotors would have a tungsten carbide chromium coating that would provide protection from abrasive wear. We knew thru testing that the coating had eight times the abrasion resistance of chrome. Additionally, using rotors that were so coated would provide additional stator life as well. Stators typically swell from oil and fluid exposure. The elastomer will also harden as a result of a post curing process from exposure to sulfur found in oil and H2S gas in the Permian Basin. FeS abrasion wear did not affect the stator elastomer. Reason being is that it adheres to the elastomer, thus eroding the rotor surface as it passes over it with each revolution. With loss of the rotor coating, a P C pump will begin to slip. Once the slippage production is not able to be overcome with RPM increases, it becomes necessary to change out a warn chrome rotor. With replacing chrome rotors in warn pumps, it is difficult to obtain an exact rotor fit due to elastomer swell and hardening. In the case with the carbide-coated rotors, the rotor coating did not wear and the stator elastomer was not allowed to continue to swell after the initial introduction to the application. The hardening is not as big of a problem due to building the pumps loose and providing additional stages to compensate for looseness.

It was decided that we would use 4,000-foot pumps (1740 PSI differential head rating) in the 3,000-foot (1352 PSI differential head rating) applications when applicable. This would allow the pump to work in the middle of the performance curve and also allow **us** to build the pumps looser expecting the swell and hardness mentioned above.

In selecting a rotor fit, we targeted a 35 - 45% output efficiency rating at nameplate pressure (1740 PSI). (see exhibit # 1) Building the pumps any tighter does not allow for expected swell and hardening. If built too tight, they would experience shorter run times and would probably fail from hysterisis, high torque associated failures or would be unable to restart once the pump is stopped for any period of time.

To minimize potential problems due to down hole vibration, we made it standard operating procedure to separate the anchor device from the stator by at least one joint of tubing and by two joints when well bore conditions warrant. The vibration originates due to the eccentricity within the rotor, which increases with larger volume pumps and higher RPM's. This separation of components eliminated tubular breakage problems and back-off problems as a result of TAC and torque anchor failures and premature releases.

Obtaining a fluid level on the HGEU wells was all but impossible. All of the P C pump applications were co-mingled formation perforated from 1,250 to 2,900. (see attachment # 3) In trying to shoot fluid levels, the technicians would inevitably get a kick on the first set of perforations. On three of the last well installations in 2000, down-hole pressure sensors were installed that fed a 4-20ma signal back to the surface. The signal was tied into a vector variable speed drive on the surface that is field programmed to interpret the signal and to control the RPM of the WHD, within the limitation of the equipment, to obtain the desired bottom hole pressure.

When installing the WHD's, a digital level was utilized to assure that the units were installed perpendicular to the casing. Conventional levels would not allow for this degree of precision.

To combat expected rod and tubing wear, spin thru rod guides designed for PC pumps were used on the first three installations. It was found that the FeS would get below the spin thru guides, thus wearing out the races within a short period of time. To compound the problem, once the race was warn out, the sucker rod would continue to turn within the guide further wearing on the sucker rod body itself. On all subsequent installations, poly sucker rod guides made for P C pumps were used. In addition to being much more economical, they were also more effective. Note: In using the poly guides, they do create more flow restrictions in higher volume wells than does a spin thru rod guide. However on the HGEU wells, production volumes were not as such that this was deemed to be a major concern.

CONCLUSION

MOC had six P C pumps running in the HGEU with commitments to install three additional units by years end 2000 prior to announcing that the field was for sale. Judging the achievement of running P C pumps in this field, the records will indicate that the test was a success. Economically and operationally, the systems performed well. The failure frequency goal that had been established early in 1999 was achieved. Results worth noting are as follows:

- The carbide rotors solved the FeS wear problems. There were no rotors that showed any wear thru the protective coating. The carbide coating allowed the rotors to stay in for longer periods of time than the chrome rotors usually allowed. Henceforth, corrosion within the field began to be a problem with the rotors. Corrosion was penetrating the coating causing the base material to corrode allowing the coating to flake off. It was found that we had to go with a higher grade of coating that applies the coating material with more density into the matrix.

- The selected manufacturer and distributor have not had any stator failures. The first stator ran in 1998 is still operating. The only stator taken out of service was after the field was announced to be for sale. The first well ran in January 1999 with a prototype carbide rotor failed due to a hole in the tubing caused by corro sion. When pulling the well, the rotor showed severe corrosion on its bottom half. The rotor was taken out of service and the stator was re-ran into another MOC field. Knowing the field would be sold within several months a less expensive P C pump was leased.

- Selecting higher volume pumps that allow the system to operate at lower RPM's was beneficial. Of the six P C pump wells, daily production ranged from 600 thru 1,500 BFPD. They all had the same size pumps. Only the RPM on the WHD's controlled by VFD's had to be increased to obtain the additional production.

- Torque controls system placed on the WHD's protected the systems against having any rod failures.

- Since separating the stator from the TAC/ torque anchors and doing away with the cross pin tag bar, there were no tubular failures or back offs of any type.

- In running the three down hole sensors, they provided less than satisfactory performance. Conceptually and in application, they worked very well with the variable speed drive. However, problem within the cable and the splice back to the sensor caused premature failure from three days to four months after installs. The problem was associated to the connection between the cable and sensor. It appears that the aromatics found in the oil broke down the bond & filler within the splice.

- A cursory look at the electrical consumption on one **P** C pump compared to a similar application with an ESP pump in a different field showed a **37%** decrease in lift cost per barrel. Once again this was a cursory look, but worth noting.

ACKNOWLEDGEMENT

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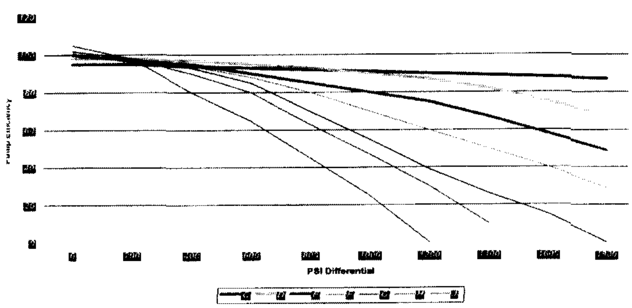
Thanks to Belco Energy Corporation for allowing the test to be resumed after the purchase of the HGEU field.

Geometry to **Application**



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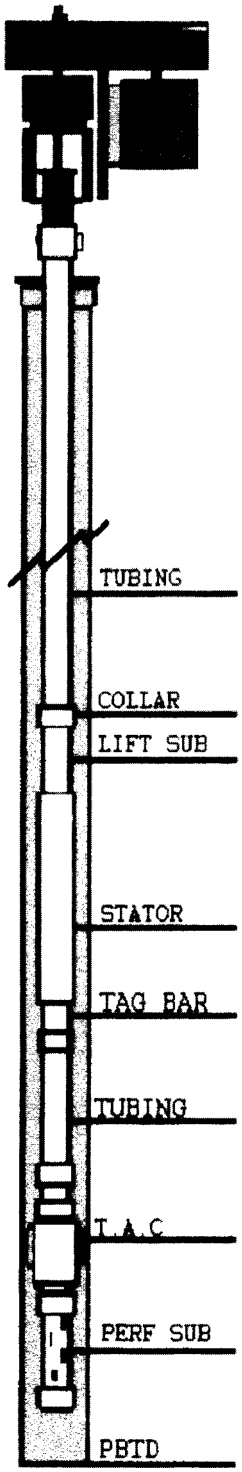

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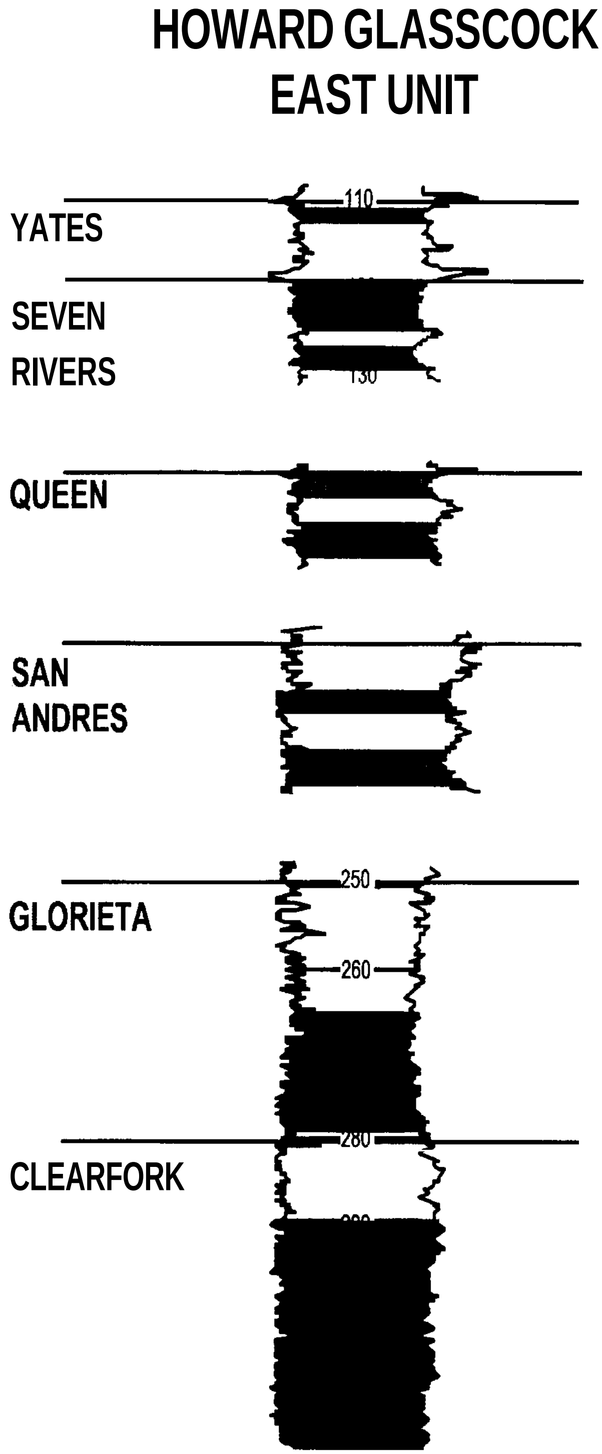

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