Application of Real-Time ESP Data Processing and Interpretation in Permian Basin “Brownfield” Operation
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Abstract
Electrical submersible pump (ESP) operation, like many other segments of the oil industry, is recovering from having been drowned in large number of data, the aftermath of information technology revolution, and refocusing on effective utilization of reservoir and production data. This paper presents results of the application of real-time data processing and interpretation in a mature field (Permian basin) through operating and service company alliances. The process involves application of production system efficiency management coupled with newly developed advanced ESP technology and analysis tools-computer simulation software packages that could simulate actual ESP and downhole performance. Data are acquired from the wellsite using data acquisition panels and are sent over a secure network connection to a data hub. The data are also sent for intelligent real-time ESP data processing and interpretation. Well and reservoir monitoring, surveillance, analysis, and diagnosis are also performed. Active collaboration with producing companies at every stage of the process was encouraged through the formation of a new alliance. Finally, various recommendations and suggestions that could operate, optimize the ESP system, reduce well downtime, and prevent catastrophic and premature ESP failures were made.

This new approach to ESP operation reduces daily challenges in operating brownfields, such as keeping wells economically viable, solving production problems associated with operating mature assets in today’s oil industry that is plagued with continuous declining of manpower resources. As might be expected, lease operating expense (LOE) and/or deferred oil production is reduced. Operational case studies and individual benefits are highlighted and included in this paper. This new approach is a significant departure from the conventional ways of operating ESP where service companies traditionally supply ESPs to producing companies to operate.

This new alliance will have a decided influence on future ESP operation and the survival of many brownfields worldwide.

Introduction
ESP applications as a form of artificial lift method have continued to increase through the years, and significant growth is expected in the next decades as artificial lift requirements increase to a greater extent than current usage. ESP application covers all aspects of hydrocarbon exploitation. Its usage ranges from mature marginal onshore wells to high profile, deep-water subsea wells. ESP capability to produce high-liquid volume; handle more free-gas production; accommodate changing reservoir conditions with time, when used with variable-speed drives (VSD); produce from low-bottomhole pressure, and, an extensive operational versatility are major factors for having been the fastest growing method of artificial-lift, well-pressure support.

In the past, only the majors and superindependent oil companies could equip ESP wells with real-time automation because of the large capital investment needed for such projects. Even when ESP wells were automated, they were limited to data gathering and some basic controls. Operators received more data than they could store, process, analyze, and interpret. Supervisory control and data acquisition (SCADA), which was the most common system differed from field-to-field, even in the same company and ranged from limited to extensive usage.

Another major problem with real-time ESP data processing and interpretation in the past was that matured marginal ESP wells, including Permian Basin ESP wells, were not equipped with downhole monitoring sensors. The primary ESP monitoring method includes plotting measured electrical current data on amperage charts at the surface, shooting fluid level routinely using acoustic method, and other production data, whenever they are available. Downhole sensors on ESP wells were considered a luxury. These practices are still common today and require huge manpower and regular wellsit visits to collect data, and then make necessary adjustments to pump and well operation. This process was very inefficient, and resulted in many under-performing ESP wells.

Real-time ESP data processing and interpretation is now readily available for both major and small independent producing companies through operating and service company alliances. Permian Basin ESP operators that are faced with the onerous task of producing oil and gas from these “aging dinosaurs” are embracing new production technology, including real-time data processing and interpretation.
Data Process, Analysis, and Interpretation
Data process, analysis and interpretation involve the application of production system efficiency management, coupled with newly developed, advanced ESP technology and analysis tools, including computer simulation software packages that simulate actual ESP and downhole performance.

ESP Technology
Newly developed ESP technology can handle increasing gas and solids production. An advanced gas handler with axial flow multiphase stages capability can pump gas-liquid (dual-phase) fluid mixtures up to 75% free gas [gas volume factor (GVF)] without gas locking. For some low-percentage solids production, abraison-resistant materials with enhanced, stabilized ceramic bearings are the most technologically advanced development currently available in ESP manufacturing. High-resistant Monel™1* and plastic coatings, and ferritic steel pump stage construction are readily available today for adequate protection in corrosive environments.

Recent advances in ESP technology also include a fit-for-purpose ESP system with specially designed pumps, protectors, motors, and cables for high-temperatures in heavy-oil steamflood applications. New downhole monitoring equipment that is more reliable and accurate, integral pumps and motors with reduced connectors, and newly designed integrated motor controllers and data acquisition panels have also been developed.

Data Processing
ESP performance data, and downhole and surface power data are acquired from the wellsite in real time using data acquisition panels, and then sent over a secure network connection to a data hub. The data in the hub are made readily available and can be accessed by various team members and experts in different geographical locations worldwide by means of the Internet. Data are also sent for intelligent, real-time ESP data processing and interpretation. This generates a predictive and proactive workflows rather than reactive approaches. Secure, two-way communication is achieved between ESP wells and ESP experts of the producing team and the ESP manufacturer (see Fig. 1) eliminating the need for on-site visits or monitoring.

Remote control capability, which includes ESP starts, stops, and speed-control functionality are utilized as necessary. Streaming and episodic data with retained history are available to ESP specialists to determine well status and performance trends.

Data Analysis and Interpretation
Data analysis begins by setting ESP protective alarms, which are based on pump, motor, well, and reservoir performance limits. Some alarms are set on site while others are set and monitored remotely. Alarm notification is programmed directly to pagers, cell phones, faxes, or e-mails. Availability of real-time alarms and alerts offer quick response to shutdown alarms (red alarms). Often, a remote start is used to return the ESP well back to production within a short time after shutdown cause analysis is performed. This would not have been possible without real-time data processing and interpretation. In active collaboration with the producing companies, well and reservoir monitoring, surveillance, analysis, and diagnostics are performed at the every stage of the process. Monitoring and performing surveillance on hundreds, and possibly thousands of ESP wells in a field is further simplified by selective grouping. ESP-lifted wells within a field are prioritized, and ranked alarm status as well as deferred oil-production volumes of each individual well.

Fig.—1—Communication, connectivity, collaboration, and control

Green, yellow, and red surveillance codes indicate the status of the wells. The green code indicates that the pump is operating normally. A yellow alarm code means that there are potential well or pump problems, or that the pump is operating outside the recommended operating range. A red alarm code tells the surveillance expert that the pump has gone into a shutoff condition or that there is no communication with the wellsite remote terminal units (RTUs). These color-coded groups allow experts to manage large numbers of wells effectively by focusing primarily on wells that require immediate attention. Wells on yellow alarm; i.e., ESP wells that are running but operating outside their recommended ranges and thresholds are then analyzed. This procedure improves production management efficiency because quality time is spent solving problems rather than searching for them.

Sophisticated computer simulation and engineering software packages are used at this stage of data analysis and interpretation. For increased accuracy, pump performance is modeled based on in-situ fluids and compared with pump bench test performance curves for each specific pump rather than using a generic catalog pump curve. Well performance is then compared with the software-generated well model. Pressure data at each node, combined with completion and fluid properties information, enable periodic well and reservoir diagnostic checks. Underperforming ESP wells can be easily identified at this time.

Downhole data also provide opportunities for pressure-transient analysis. For example, pressure drawdown during

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1 Monel is a trademark of Inco Alloys International, Inc.
production and buildup during shutdown can be useful in determining permeability, skin, and reservoir pressure. Reservoir void management, characterization, homogeneity, and fault analysis can also be provided on a reservoir and field level.

Significant production increases were achieved in most instances without well intervention by using VSDs. However, prior to increasing VSD speed, critical flow velocity is analyzed using updated geomechanical software to provide formation integrity information.

Various recommendations and suggestions are made to optimize ESP system operations, reduce downtime, and prevent catastrophic and premature ESP failures. The ESP data are processed, analyzed, and transformed into informed action and business decisions that in real time, maximize mature assets and increase field economic viability. As it might be expected, lease operating expense (LOE) or deferred oil production or both are reduced as a result of increased pump uptime, improved pump operation, and optimized production. Operational case studies and individual benefits are presented in the subsequent section of this paper. This systematic approach to ESP operation is a significant departure from the conventional ways of operating ESP where manufacturers traditionally supply ESP to producing companies to operate.

**Case 1: Intervention**

**Company:** Stephens & Johnson Operating Co.

**Field:** FMU

**Well Depth:** 8,195 ft Plug Back Total Depth (PBTD)

**ESP setting:** 8,072 ft

**Geometry:** Vertical

**Casing:** 7 in., 26-lbm set at 8,175 ft

Having the capability to acquire and analyze downhole data in real time prevented a catastrophic ESP failure and potential loss of equipment. FMU well was an ESP well test installed on October 13, 2004. The well was on a beam pump and at an earlier time, on temporary abandoned (TA) status.

As expected, the intake and motor temperature (Ti and Tm) began to increase soon after installation. The ESP unit performed and ran well except for a small number of shutdowns, which were due to power failures and high-tank level.

On November 8, 2004, the recorded trends turned dynamic and interesting. The ESP unit began to experience an abnormal increase in temperature and became inoperable as shown in the last segment of **Fig. 2**. The motor temperature rose and reached the maximum set point limit of 240°F in less than 5 hr of operation in some cases. There were nine shutdowns within nine days, all being due to increased motor temperature. The maximum motor temperature was set to 240°F because the J-thermocouple measured the motor oil inside of the motor. Based on experience, the temperature difference between the motor oil and the motor winding could be as high as 150°F.

The ESP provider and the operating company team analyzed downhole data and decided to pull the unit out of the hole because a tubing leak was suspected. It was interesting to find collapsed casing above the pump intake at 3,300 ft measured from the surface. There was well inflow above the pump from the casing leak and fluid flow into the pump intake directly. The motor was bypassed without enough flow to cool the motor and as a result, the motor temperature increased.

**CASE 2: Optimized production**

Cowden Well No. 12 in Andrews County, West Texas is an example of an optimized and protected ESP operation. Having the capability to acquire and analyze downhole and surface data provided for an efficient operation. Pressure transducers were installed on the wellhead and casing to measure and record wellhead pressure (WHP) and casing head pressure (CHP), respectively. These data were linked automatically into

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**Fig. 2**—Well FMU No. 215 intake pressure, motor and intake temperature trend

**What Might Have Happened?**

The possibilities include:

1. Motor temperature will increase until the motor will burn due to excessive heat.
2. Length of collapsed casing will become significant; thereby, increasing the risk of potential equipment loss.
3. Continuous water production from leaking water-saturated zones.
4. All three possibilities would have resulted in lost revenue (over $100,000) for the servicing company or producing company or both.

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an existing ESP acquisition and control panel, in which alarms and trips were set to activate on wellhead pressure and casing pressure for additional protection and monitoring.

The wellhead and casing pressure data that were acquired reduced well performance uncertainty. While the wellhead data allows for controlling and monitoring the flowline and other surface pressure devices, the casing head pressure data provides valuable information on casinghead gas behavior (gas partial pressure). A combination of intake pressure and casinghead pressure and fluid specific gravity was used to obtain real-time and continuous fluid above pump (FAP) data rather than occasional fluid shot data. Cowden field operator production team monitor and analyze these streaming data on a daily basis, or whenever an alarm threshold is breached. Better-informed decisions are made based on the availability of adequate real-time data. The VSD frequency was adjusted stepwise as required (see frequency trends in Fig. 3); thereby, preventing abnormal ESP operational conditions such as pump off, gas lock, and solid ingestion.

Benefits
The benefits realized included:
1. Optimum production was achieved and sustained on Cowden well no. 12.
2. Abnormal ESP operation was prevented.

CASE 3: Well performance review
The availability of real-time ESP data processing and interpretation became even more important on Cowden well no. 8. This particular well was shut down manually on April 4, 2005 for about 1 hr. When the ESP was restarted, it pumped down the well fluid as was expected. However, after approximately seven hours of pump operation, without a shutdown, the intake pressure (Pi) began to buildup as shown in Fig. 4.

The operator and service company production teams both responded to the sudden change in well behavior. The well was tested immediately and placed on production test periodically. Test results showed an increase in gross fluid and water production by about 200 BLPD and 200 BWPD in addition to a reduction in oil cut and gas production. These test results confirmed that the pump performed as it was designed. Other ESP parameter trend analysis showed that motor current, motor temperature and vibration were all within acceptable thresholds, although there was a 2°F drop in BHT at the same time as the abnormal increase in intake pressure.

Conclusion
Based on all available data, both Cowden field operator and services company suspected:
1. Casing leak (either from repaired old casing leak or a new leak).
2. Unpredictable flood response on Well No. 8.

Planning
The operator plan to re-enter Well No. 8 whenever, the current ESP unit fails. Casing leak and leak location will be confirmed, and repaired before running a replacement ESP unit back into the hole.

Benefits
The availability of adequate ESP data in real time enabled the operator to understand the complex well behavior and prepare
for future remedial work on this well whenever the ESP unit is pulled. This is a significant departure from the conventional way of operating an ESP well where a replacement unit is already in the hole and running before the well condition is analyzed.

**Case 4: Scaled-up ESP unit**

**Company:** Apache Corporation  
**Field:** Flanagan “B”  
**Well:** No. 10  
**Well Depth:** 7,155-ft total depth (TD)  
**Perforated zone:** 4,902 to 7,120 ft  
**Geometry:** Vertical

Acquiring and analyzing ESP data in real time made it possible to recognize a scaled-up ESP unit early enough before a catastrophic failure could occur. Flanagan “B” No. 10 well in West Texas Gaines County was installed as a long-time lease well test on December 4, 2004. The well was on a beam pump artificial lift method before being converted to an ESP well.

The ESP ran fairly smooth after installation except for a few occasional spikes; i.e., high and low current and increased intake pressure (see Fig. 5). Analysis showed that on some of the spikes, the current dropped from an average of 25 A to about 18 A, and then climbed to over 30 A in couple of hours before stabilizing again at 25 A. Intake pressure followed a similar upward trend during the same periods. The motor temperature decreased 7°F in some instances, which is very unusual.

**Analysis**

A gas breakout was considered to be a possibility; however, the decreased motor temperature did not indicate a gassy flow across the motor. Also, there were no casinghead pressure data that could be used to confirm increasing annulus gassy flow. A change in fluid composition was then considered a possibility until there was a dramatic change in ESP data trends on March 25, 2005 which turned out to be a partially plugged intake and pump as shown on the trend (see Fig. 5). These results led to a better understanding of the occasional current and pressure spikes seen earlier on the data. The reason for the spikes were that when the pump intake plugged momentarily, less fluid flowed into the pump through the intake, which created a higher annulus fluid level shown as increased intake pressure in Fig. 5. The current decreased in response to a lower volumetric flow rate. As scale on the plugged intake was pushed into the pump, the fluid composition changed with increasing fluid density, and the current increased. When the pump intake unplugged, more fluid was ingested into the unplugged intake, and the fluid level began to drop until the system return to normal.

By March 25, 2005, the changes in trended data became pronounced. Motor temperature increased significantly and eventually shut down the motor. There were four high-motor temperature shutdowns before the end of the day. A technician went out the next day to check the well. He attempted to trick the system by lowering the drive speed without any success. In 3 days, ESP unit shut down 12 times, all due to high-motor temperature shutdown. The operator was informed of the analysis results, and the ESP unit was shut down. The pumps and intake were found to be full of scale when the ESP unit was brought to the surface.

**Case 5: More accurate data**

**Field:** Shafter Lake  
**Well:** No. 460

A reliable and dependable downhole gauge coupled with remote real-time data acquisition, monitoring, and control led to better-informed decisions that resulted in a production increase. Shafter Lake No. 460 was installed on February 4, 2005 as an ESP test well in Andrews County, Texas. The well was automated and put on a surveillance and control system for monitoring, in addition to downhole artificial lift monitoring equipment.

During installation, the VSD frequency was set to operate at 55 Hz. This frequency was maintained as the well drawdown from intake pressure of 1,470 psi at start up decreased to about 450 psi in a few months. In preparation for permanent equipment installation, Shafter Lake No. 460 operator shot a fluid level that indicated 100-ft fluids above the pump (FAP).
At this point, there was a significant difference between the downhole gauge reading of 450 psi—approximately 990-ft FAP and fluid shot of 100-ft FAP. The operator did not know which data reading to believe and use in the decision-making process. ESP Provider and Shafter Lake No. 460 operator decided to increase the VSD frequency and draw down the unit significantly. If the well pump off at 45 psi ~ 100-ft pressure differential from the gauge reading of 450 psi, then, the fluid shot was going to be considered more accurate; otherwise, the downhole gauge would be considered to be the more accurate.

On April 7, 2005, the drive frequency was increased remotely to 56 Hz and computer monitored. Within 10 hr of operation, there was additional drawdown; i.e., pressure differential of 63 psi ~ 139-ft FAP without pump off. The VSD frequency was once again increased remotely to 60 Hz and 61 Hz, respectively. By the next shutdown, (see Figs. 6), which was due to a power failure on May 2, 2005, the downslope was 149 psi, which was equal to pressure differential of 301 psi. This means that the fluid level was drawn down 662 ft with the pump running, and confirmed that the downhole artificial lift monitoring equipment reading. There was no way of drawing down a well that had 100-ft FAP by an additional 662-ft FAP without pumping off of the well. Intake pressure was dropped to 149 psi, which is far above 100-ft FAP; yet, the well did not pump off as speculated by the fluid shot. Shafter Lake No. 460 operator and the service company concluded that the downhole artificial lift monitoring data met the needs for their analysis. It is interesting to note that as at the time of writing this paper, the intake pressure has dropped to 100 psi, yet, without pumping the well off.

**Benefits**

The benefits realized during this analysis procedure included:

1. Additional production increase on current installation was realized.
2. Future permanent equipment will be properly designed and sized to optimize future production.

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**Case 6: Shut-in casing valve detection**

Being able to acquire, process, and interpret data in real time, coupled with adequate ESP protection, led to discovering a shut-in casing valve on George Herder No. 13 well in West Texas.

At 4:45 p.m. on May 4, 2005, the intake pressure began to increase while the ESP unit was running but with no change in frequency; however, the motor temperature did not increase. The motor current began to drop below the underload set point but did not stay there sufficiently long (based on underload delay activation set time) to activate the underload alarm until May 5, 2005. ESP Provider and George Herder No. 13 operator analyzed the data in hopes of determining the cause of the intake pressure increase. Well production dropped off also. A check of all other well parameters showed that the well went down on underload shutdown as shown Figs. 7, stayed shutdown for 2 hr until the underload start time-out delay was completed. The ESP unit then restarted itself. Intake pressure continued to increase until the Wellsite technician that was dispatched by the service company, as a result of well performance analysis found a shut-in casing valve and opened it.

Further investigation found that a chemical injector operator shut-in the casing valve to drop treatment chemicals through the annulus and forgot to reopen it. This oversight could have easily led to premature ESP failure.
Conclusions
As the field examples showed, Permian basin “brownfield” ESP operators have benefited tremendously from the application of realtime data processing and interpretation. It strongly believed that new alliances and joint ESP operations developed between ESP manufacturer and the oil and gas producer will continue to have a significant impact on the economic viability of mature marginal wells. This will also usher in some unprecedented breakthroughs in ESP applications.

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