OPTIMIZING SPRABERRY OPERATING PRACTICES

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INTRODUCTION

BP Permian's Spraberry production consists of 400 rod pumped wells located primarily in Midland, Martin, and Glasscock Counties. Of these, the Spraberry Core Production Area located in Glasscock County includes 80 wells, which have been producing for 30+ years. Development of the Wildfire Production Area in Midland and Martin Counties began in 1996. Wells in both areas are typically completed to about 9500' through the Spraberry, Dean, and Wolfcamp formations. Pump depths fluctuate from 7600' to 9700' through the field. A variety of operating challenges have been encountered and worked through over the years to optimize profitability. The purpose of this paper is to discuss the teamwork and technology utilized in resolving these challenges.

PROGRAM STRATEGY

It was recognized that the Spraberry operation's profitability could be improved by focusing on key issues, specifically reducing cost and increasing production. The team identified the following opportunities:

- Reduce rod pump system failures
- Reduce downtime
- Remediate casing leaks
- Improve pump efficiencies
- Optimize organization staffing

After the key issues were identified, teams were organized to implement the strategy and improve performance. Teams typically consisted of Engineering, Operations, and Contract personnel.

ROD PUMP FAILURE REDUCTION

Rod pump system failures are economically detrimental especially in mature fields. On average, a workover to repair tubing, rods or rod pumps on wells of Spraberry depth range from $3500-$6000/well. In addition, the downtime resulting from the failure delays production from the well. Typically, the most common downhole failure in mature Spraberry operations is that of tubing and rod wear. Several methods to reduce wear have been applied over the years, usually applied sequentially:

1. Anchor tubing in tension
2. Reduce polish rod velocity
3. Reduce friction in pump (control sand)
4. Increase weight at bottom of rod string
5. Control paraffin and scale deposition
6. Install completions that reduce friction

Although all of these methods have been found to improve run times between failures on specific wells, cost and individual well characteristics should be considered to determine the best method for each well. One method to reduce friction in downhole assemblies is to install either polyethylene lined (polylined) or internally plastic coated (IPC) tubing with guided rods. The polyline substantially eliminates abrasion, but the trade off is the considerable reduction in tubing ID. The liner thickness ranges from 120 to 200 mil. IPC with amodel guided rods provide two smooth surfaces and minimal reduction in tubing ID. Utilizing well histories, candidates were chosen by identifying wells with frequent wear failures. Candidates also consisted of wells with repeated localized tubing wear failures. Initial results from the two designs have successfully extended well runtime and decreased wear failures. The Lane 37-7, polylined tubing well, increased its runtime from approximately 5 months between failures to over a year. After modifying the polyline design, the runtime between failures has increased to over 2 years. Similar results have been found with the IPC tubing and guided rods design. The Driver 14-9 was experiencing failures due to wear on 120-day intervals.

Refinement of the IPC tubing with guided rods has increased the runtime between failures to over two and a half years. Casing size, tubing size, and pump size are essential factors that must be evaluated before utilizing IPC tubing. While 2-718" tubing with polylining does not require a pump change, turned down collars will be required in wells 4-112" casing. Wells with 2-3/8" tubing are generally considered better IPC candidates because running polylining in 2-3/8" tubing would require running a slim hole pump.

CHEMICAL PROGRAM

The Wildfire drilling program consisted of several new wells coming on line over a short period of time. Unlike the consistent operation at the Spraberry Core field, the Wildfire operation was very dynamic, offering challenges in the chemical arena not typically experienced in routine operations. Some of those issues were:

1. Relatively high corrosion failure rates from a formation considered sweet
2. Emulsions causing treating problems at production facilities
3. High paraffin deposition rates in certain areas within the field
4. Higher than normal water cuts in certain areas within the field
5. Higher than expected fluid levels during the first several months of production

Due to the added challenges of this dynamic operation, the chemical vendor became an integral source of additional support and expertise for the team. Specific goals were provided for each of the items outlined above to assist the chemical vendor in focusing on the issues most relevant to operation's needs. However, early in the project it was evident that goals were not being adequately met. Therefore, a second chemical company was employed to share in the challenge at hand. Each chemical company was assigned a geographic area, which included both surface and downhole treating. A scorecard was reviewed with each chemical vendor quarterly to provide consistent feedback to each.

One of the larger chemical related issues was that of paraffin control. The crystal modifier initially used was unable to significantly hinder the paraffin deposition downhole and resulted in many wells requiring hot oiling as often as every 30 days. In an effort to provide relief from the newer wells' prolific paraffin production, increased chemical treatments were used. **As** these wells pumped off, chemical slugs were produced and sent to the central batteries resulting in upset conditions. During the winter, paraffin build up in flowlines would trigger high-pressure shut down valves that would require the attention of the lease operator and delay production. Field operations were hot oiling heavy paraffin flowlines on a two-week frequency during the winter months. Due to difficulties associated with chemicals and the concern over asphaltene deposition from hot oiling, the organization decided to begin treating with condensate produced by BP's Crane Gas Plant. After successful field-testing, a program was developed to treat paraffin using 70 bbls of condensate on a 60 day cycle. Six months after the program commenced, the treatment size was changed to 40 bbls of condensate. Based on well histories, frequencies were also changed. Heavy paraffin producers were treated on a 75-day frequency, while light paraffin producers were treated every 120 days. Field-testing was used to verify the effectiveness of the new treatments. In 2000 the frequency for the worst paraffin producing wells were extended to 90 days and lightest paraffim producers were treated twice a year. Field-testing before implementation to the entire program verified the program step changes were appropriate. The benefits from the condensate treating program are the elimination of flowline hot oiling, eliminates concern with formation damages, transporter cost equivalent to hot oiling charge, less safety exposure to contractors due to longer durations between treatments, removes paraffin build up, and above all reduce failures associated with paraffin.

AUTOMATION

Early in the life of the Wildfire project, it was decided that technology would be used to the greatest extent possible to maximize the projects profitability. Therefore, a study was performed to review the benefits of utilizing an automation system to monitor and control rod pump controllers (RPCs) and to monitor key inputs from the production facilities. Previous research into the benefits of an automation program indicated there were tremendous upsides in many areas, which were verified on the Wildfire project:

1. Reduction of failure costs (30%)
2. Reduction in electrical usage (15%)
3. Increase in production (10%)
4. Downtime reduction (3%)
5. Personnel reduction (38%)

Failures were reduced by ***60%*** from 1.0 to **0.4** failures/well/year over a two-year period. Not all the reduction could be attributed to the automation/RPC system directly, but its share of reducing the failure frequency was significant. The automation system provided a simple and efficient means for reviewing **400** wells and easily prioritizing them for reduction of polish rod velocity, pump size changes, rod pump controller adjustments, and other key variables.
The rod pump controllers were the primary device that improved electrical efficiency of the rod pump system. With the addition of the automation software, the electrical usage was reduced even more by easily identifying those units where additional enhancements to the system could be made. The automation/RPC system was responsible for reducing electrical usage by 15%.

Production increases were provided in many ways due to the implementation of the automation/RPC system. Wells that have lost the ability to pump off due to pump efficiency loss or other reasons are now quickly and easily identified. Therefore, wells not performing under optimal conditions are repaired in a shorter time frame, increasing the overall output from that well in the near term. The automation system has also been utilized to identify wells with high levels of gas interference and poor pump efficiencies. The pumps have been lowered in many of these wells resulting in greatly improved pump efficiency, increased rate performance and reduced fatigue on the rod string. Overall rate improvement due to these efforts is estimated to be approximately 10%.

A typical Spraberry operation similar to the Wildfire and Spraberry Core leases requires approximately eight pumping personnel. With the automation system that number has been reduced to five. The five personnel consist of a well analyst, three pumpers, and an I&E technician. Wells are pumped by exception with a regular well visit once every seven days. Utilization of the automation system has dramatically improved manpower efficiency.

In addition to those enhancements that are quantified above, there are many intangible benefits not mentioned. Implementation and utilization of an automation system with trained, open-minded personnel is the only way of fairly assessing its worth.

CONCLUSIONS

System efficiency was increased through a series of incremental steps. Automation identified opportunities and provided real time results of each process implement. Failure reduction was achieved through competition and a new approach to the Operator's standard practices. Competition chemical companies generated improved products and better customer service by setting clear expectations and providing regular feedback. Implementing IPC and polylined tubing program, identifying and repairing casing leaks, and removing paraffin through backside treatments of condensate were new approaches taken to achieve significant step changes in combating failures. While unit slowdowns and lowering below increased system efficiency, the changes also resulted in economic benefit to less electrical use and increased production.