A CASE HISTORY: 131 FAILURES TO 30 – FAILURE CONTROL PRINCIPLES IN THE MIDLAND BASIN

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ABSTRACT

Depressed oil prices drive producers to reduce operating expenses and maximize profit margins. Some of these expenses are necessary for day-to-day operations, and are dictated by vendor pricing. Others are a function of the operator's activity, and can be controlled within certain limits. Workover costs are a prime example of these "controllable" expenses. That being said, well failure control programs are essential to maximizing profits and limiting expenses.

In 2014, Resolute Energy recognized the need for a more effective failure program in their Gardendale, TX asset. Through organizational, managerial, and engineering means, Resolute successfully decreased well failures by 101 year-to-year, resulting in expense savings of over $4.4 million. These savings, along with other expense control efforts, cut operating expenses per BOE by over 40% throughout the 101 wells. This paper describes these control efforts in detail to reinforce their importance, particularly in current market conditions.

INTRODUCTION

In December 2012, Resolute Energy acquired a 67 well asset in Gardendale, Texas. Since the acquisition, Resolute drilled and completed 31 vertical and deviated wolfberry wells, and 3 Wolfcamp B horizontals. The majority of the wells were artificially lifted by rod pump systems. In 2014, monthly well failures began to increase, resulting in high workover costs and lost production due to downtime. In only the first half of 2014, 71 well failures were reported in Gardendale.

As commodity prices began to decline in 2014, Resolute recognized a need to significantly reduce operating expenses in their Gardendale asset. Accounting for 35% of all operating costs, workover expenses became a top priority. In response, the engineering staff launched a new failure prevention program. The goal of the program was to lower operating costs per barrel of oil produced ($OPEX/BOE) by reducing well failures throughout the field. This goal was to be achieved through reorganization of personnel and responsibilities, proper data management, and application of standard engineering principles. Since implementing the failure program in August, 2014, operating expenses were lowered by over $8.00/BOE. During the same time frame, well failure frequency was lowered from 1.34 failures/well/year to 0.30 failures/well/year.

BACKGROUND

Gardendale Field

Resolute Energy's Gardendale asset was acquired in December, 2012. The field is comprised of 4,600 net acres in Midland and Ector counties. The majority of the acreage lies between commercial and residential development, limiting surfacehole locations. Therefore, many of the wells were drilled from shared pad sites, reaching bottomhole locations by means of directional drilling. At the time of acquisition, 67 deviated and vertical wells were drilled and completed by two previous operators. Completed intervals include the Spraberry, Dean, Wolfcamp, Cline, Strawn, and Atoka formation groups. After taking over ownership, 31 additional "wolfberry" wells were drilled, along with 3 5,000' horizontals in the Wolfcamp B formation. Vertical wells average a total depth of approximately 11,500', and horizontals average approximately 10,500'. In the second quarter of 2015, these 101 wells accounted for a daily production average of 1,649 BOEPD. Although various lift mechanisms were applied after flow back, the preferred means of artificial lift is rod pump.

Failure History Analysis

In August, 2014, a historical failure analysis of Gardendale was conducted to identify areas for improvement. Through July, 2014, 89 well failures were reported in Gardendale since the start of the year. As seen in Figure 1, 70% of failures during this time period were categorized as tubing failures, 20% as pump failures, and 10% as rod failures. Further analysis of tubing failures during this time period revealed 47% of failures were due to deviation and rod-tubing wear. 53% were categorized as tubing failures due to downhole issues, typically occurring within 30 joints of the pump depth. Typical causes of downhole failures were tagging, fluid pound, severe gas interference, improper rod design, and other causes of downhole rod buckling. Workover costs exceeded $4.25 MM during this time frame, and failure frequency was 1.34 failures/well/year for July, 2014.

Failure Prevention Program

Beginning in August, 2014, a new failure prevention program was introduced to Gardendale, with the objective of lowering operating costs by reducing well failures. As a prerequisite, engineering conducted a historical failure analysis, as summarized in the previous section of this paper. Based on this analysis, engineers and management concluded that changes to the team organization, data collection process, and engineering process were necessary to efficiently reduce failures. The details, adjustments, and results of the failure prevention program are presented below.

TEAM ORGANIZATION

A critical component to an effective failure control program is an effective organization. To properly address well failures, communication of failure details must be clear, timely, and accurate. In August, 2014, field and engineering personnel were reorganized to effectively diagnose, treat, and prevent well failures. Figure 2 is a simplified organizational diagram outlining the flow of information between personnel and databases during the workover process. Table 1 describes the responsibilities for each team member. This model, as summarized below, was adopted to more efficiently address well failures.

Within the presented team organization, the engineer has decision authority over any workover. Before a workover begins, he is responsible for collecting production, wellbore, and artificial lift data, from which he prepares an initial analysis and procedure. This procedure is first implemented by the workover supervisor. During the job, the workover supervisor or foreman provides failure details and samples to the necessary team members. The production field technician and engineer analyze the failure details to adjust the artificial lift design. The chemical field technician analyzes the physical failure samples, and provides the engineer with a chemical analysis, along with workover and chemical recommendations. Using these two analyses, the Engineer adjusts the workover procedure accordingly, and relays the adjustments to the workover supervisor for implementation. Full workover details and information are recorded by the workover supervisor and foreman in the well file database. After a workover is completed, the production field technician records and archives fluid levels, dynamometer data, and other artificial lift data. Using this data, the Engineer analyzes the effect of the implemented design changes, and applies the conclusions to future workover, design, and operational standards.

Although not every company adopts the exact organization described above, effective team organizations at the field level have the following similarities. First, an effective team organization clearly defines responsibilities, draws upon the experience of team members, and allows for quick decision making and flexibility. Secondly, an effective organization efficiently manages the documentation and flow of information/data. Thirdly, an efficient team studies the results of their work, and makes appropriate adjustments going forward. Regardless of the structure, an organization that embraces these characteristics is essential for reducing failures on a large scale.

INFORMATION AND DATA MANAGEMENT

The acquisition of the Gardendale field in December, 2012 left Resolute with unorganized data files. Since the field was drilled and operated by multiple groups, well data was scattered between different formats such as excel files, word files, paper files, and WellView files. Finding important well data was cumbersome and inefficient. Accurate and easily accessible data is crucial to making confident decisions during the workover process. Recognizing this, efforts were taken to consolidate information into specific databases.

Well Files

Previously, operators populated Gardendale well files in excel and word documents, detailing important wellbore and artificial lift information. Realizing the need for a single well file database, all historical well files were populated into WellView during the spring of 2014. As a result, failure analysis and workover design improved. With historical well information in a single location, tracking down important data was easier, and decisions could be made with fewer assumptions or errors. All field personnel were trained to become proficient at recording information in WellView, and tech support was provided to assist with maintaining accurate well files. With complete well files, engineers were able to easily interpret failure data, test and analyze different designs, and develop better operations, workover, and design standards.

Fluid Levels and Dynamometer Cards

Fluid levels and dynamometer cards are used to analyze rod-pump systems, and identify any design or downhole issues. Without the installation of pump off controllers, the majority of wells in Gardendale required routine fluid level and dynamometer data collection. Previously, acquiring this data required hiring a contract technician. As part of the failure prevention program, a production field technician was provided the necessary Echometer equipment, and was tasked to collect data monthly for each well. Fluid level and dynamometer data was archived in a central database (Total Asset Manager) for easy access. As a result, the frequent fluid level and dynamometer data allowed personnel to more confidently analyze pump conditions, set percent timers, trigger preventative maintenance, and flag wells at risk of failure. Operations and engineering designs improved as a result of the lessons learned from the improved data set.

Consistent Production Reporting

For the production software, tank battery production is reported daily, and production is allocated to each well based on monthly well tests. Previously, portable testing vessels were used to test wells on a rotational basis. Efforts were made to improve the accuracy of the allocated well production by improving the quality and frequency of well tests. In August, 2014, a lease operator was dedicated to managing well tests throughout the field. His tasks included scheduling well tests, maintaining testing equipment for accuracy, entering testing data into the allocation software, and checking test data quality. In addition, well test frequency was increased to one well test per month. Permanent testing vessels and plumbing was installed at specific batteries to meet the monthly testing criteria, and improve test accuracy. As a result of the quality improvements in production data, engineers and field personnel were able to draw clear conclusions about well work, quickly address production changes or issues, and develop a better understanding of production profiles.

In conclusion, accurate well information is often taken for granted, and is critical to conducting any sort of analysis. Management should consider what data is critical to understanding field operations, and custom select databases and responsibilities to match. For failure analysis, wellbore, artificial lift, and production data are essential. Without it, identifying root causes of failures, and testing designs to mitigate them, becomes strenuous and ineffective.

ENGINEERING AND TECHNICAL

With a proper organization in place, and improved data collection, engineering designs and principles could be confidently tested throughout the field. In the first half of 2015, tubing failures accounted for 70% of all failures in

Gardendale. Therefore, designs were focused on preventing tubing failures, either by preventing downhole buckling issues, or addressing wellbore deviation issues.

General Rod Design

Of all tubing failures, 53% were due to downhole issues leading to rod buckling. Going forward, engineering adopted a design philosophy to reduce downhole buckling, specifically by reducing the effects of fluid pound, gas interference, and tagging. Rod strings were designed on a well-by-well basis in consideration of these causes of rod buckling. But field-wide, a few general design changes were applied: reduce strokes per minute, increase stroke lengths, increase sinker bar count, and reduce the use of fiberglass rods.

In general, lowering the strokes per minute (SPM) of a given pumping unit lowers the buckling tendency throughout the rod string by reducing forces throughout. SPM was lowered on cycling wells, where daily production would not suffer as a result. When fluid or gas pound is relevant, slower speeds reduce the chance of rod buckling and failure. As a pump plunger falls at a slower velocity, it will "hit" the fluid within the pump bore with less force. This translates to less force throughout the rod string, and a reduced the chance of rod deflection and failure. Additionally, slower SPMs that match inflow reduce the on-off cycles of a given unit. With fewer shut-down and start-up strokes, the downhole equipment produces the same fluid with fewer net strokes, extending the life of downhole equipment.

Increasing the stroke length of a pumping unit increases the compression ratio of a downhole pump, and can reduce the effects of gas interference and gas locking. An increase in compression ratio translates to an increase in discharge pressure of a pump during the down stroke:

$$P_{Discharge} = P_{intake} \times (C.R.) \qquad \text{where} \qquad C.R. = \frac{(SL_{downhole} + Spacing\ off\ bottom)}{Spacing\ off\ bottom}$$

This pump bore pressure is essential to opening the traveling valve during the down stroke, and allowing gas and fluid to be produced. Assuming a 10 in. downhole spacing, an increase of 20 in. in downhole stroke can increase discharge pressure by 1000 psi. This increase in pressure reduces the net effect of gas locking and gas interference, and will increase the effective stroke length downhole. Additionally, increasing stroke lengths will allow a system to lift the same amount of fluid to surface with fewer strokes, extending the life of the downhole equipment as they endure fewer cycles over time.

Increasing the amount of sinker bars per well reduces the buckling tendency by adding tension throughout the rod string. This, in turn, reduces the effect of fluid pound, gas interference, and tagging. However, the increased tension throughout the rod string increases side loading forces throughout, and can exacerbate rod-tubing wear in deviated sections above the sinker bars. Additionally, deviation throughout the sinker bar section can cause significant wear problems, since sinker bars have a lower tendency to bend, compared to smaller diameter rods. Therefore, sinker bar count should be determined on an individual well basis. But without deviational issues, sinker bar sections were generally increased throughout Gardendale.

Lastly, fiberglass count was reduced where applicable. Under the same conditions, fiberglass rods will stretch over 4 times as much as steel rods. As a well first produces after a workover, the fluid level begins to drop from a static level. This reduction in fluid level results in a reduction in pump intake pressure, and as a result the differential across the traveling valve increases over time. This translates to an increased downward force on the rod string, causing more stretch. As a result, a pump may begin to tag as the fluid level decreases, causing severe pump, rod, and tubing damage. By installing all-steel rod strings, the stretch throughout the string is significantly reduced, and the tendency for tagging is significantly reduced as fluid levels fluctuate. In many instances, pumping unit structure and gear box constraints prevented the use of all-steel designs. In these circumstances, fiberglass was reduced as necessary and spaced out using the following standard equation:

$$Pump\ Spacing\ (in.) = \frac{(9 \times FG\ lenght\ ft.) + (2 \times Steel\ lenght\ ft)}{1000}$$

Fiberglass wells were closely monitored after a workover, and spacing adjustments were made as necessary.

Tubing Design

Before acquiring Gardendale, a mixture of 2 7/8” J-55 EUE (8RD) and 2 7/8” L-80 EUE (8RD) tubing strings were commonly used downhole by the previous operators. At an average depth of 11,000’, new J-55 tubing has enough strength to withstand downhole pressures over 5000 psi. But with and internal yield pressure of 7,260 psi, J-55 tubing is more prone to failure than L-80 tubing at the same depth. With and internal yield pressure of 10,570 psi, 2 7/8” L-80 can withstand significantly more wear before failure. Therefore, J-55 tubing was replaced with L-80 as necessary to extend run times.

Tubing designs that were run below the perforations were previously installed with tubing anchor catchers (TACs) above the perforations. While rod pumping, free-hanging tubing beneath the TAC will stretch during the down stroke as the tubing string bears the hydrostatic weight of the fluid in the tubing. As a consequence, the effective pump stroke is reduced, decreasing the fluid load per stroke. Additionally, the free hanging tubing can sway, buckle, or deflect, causing a higher tendency for wear with the rod string. As a new standard, “slim line” TACs were run below the perforations to pump depth. Compared to conventional TACs, “slim line” TACs have a smaller OD, providing significantly more area for fluid, gas, and solids migration. The added area reduces the risk of solids build up on top of the TAC, sticking it. Since running the “slim line” TACs, no operational issues or stuck TACs were encountered and the effective pump stroke improved, as represented by the dynamometer cards in Figure 3.

Gas Separation

Gas interference is a common rod pumping concern throughout the Midland Basin. Wolfberry wells in Gardendale average gas-liquid ratios between 3 – 4 MCF/BBL. In many instances, this volume was significant enough to cause gas interference. The result was inefficient pump action, reduced fluid production per stroke and downhole buckling failures. To counteract this effect, multiple styles of gas separators were tested in the field. At lower gas volumes (below 100 MCFD), poor-boy separators effectively separated gas downhole. The standard poor-boy (or mother hubbard) separator used was a 3 ½” OD mud joint (bull-plugged) with a 16 ft. x 1” diameter dip tube. In wells with solids issues, an additional mud joint was applied. Poor boy separators are inexpensive and effective at low volumes, but at higher gas volumes, packer style separators were most effective. Although more expensive, packer style separators use the tubing-casing annulus for more efficient separation. Packer-style separators were applied to the 3 horizontal wells in Gardendale, averaging over 150 MCFD. As represented by the dynamometer cards in Figure 4, gas interference was completely alleviated as a result. The increase in pump efficiency also increased well production by nearly 100%, as displayed in Figure 5.

Installation of Pump Off Controllers

Pump-off controllers (POCs) are pumping unit controllers that operate on downhole pump analysis. The Lufkin LWM controller collects real-time load and position data to build dynamometer cards. From this data, the controller can shut-down or continue to run the pumping unit based on the condition of the pump. Additionally, pump off controllers can analyze well problems, record historical fluid data, optimize cycle times, change SPM on variable speed drives, and more.

Understanding these benefits, a study between wells with and without installed POCs was conducted. As Table 2 concludes, wells with POCs averaged 80 more days of tubing run life then wells without POCs on the same lease. In response to the study, 15 POCs were installed on wells with high failure frequencies in April, 2014. In combination with then new design standards, failures were significantly reduced. As of January 1st, 2016, only 3 failures have occurred over the 15 wells, representing a failure rate of 0.27 failures/well/year, down from 2.6 failures/well/year. In short, preventing failures after a workover is substantially easier using POCs.

Rod Guide Application

Due to surface location limitations, many wells in Gardendale were directionally drilled from multiple well pads to reach bottomhole location. As previously mentioned 47% of tubing failures in the first half of 2014 were due to rod-tubing wear in deviated wellbores. To reduce these failures, deviation data was correlated with failure depths to pinpoint the problem intervals within each wellbore. Rod guides were installed in deviated sections to centralize the rods within the tubing, and reduce rod-tubing wear within doglegs. Through trial and error, engineers concluded that "soft" guides (~15% fiberglass material) were optimal. Higher fiberglass content was found to be too hard, cutting tubing and causing failures. As a standard 4 guides per rod was used, except in higher severity sections (over 2°/100 ft.) where higher guide concentrations were recommended. In addition to adding rod-guides, stabilizer bars were installed in sinker bar sections where multiple wear failures had occurred. Applying these standards, runtimes generally improved in deviated wells. On 4 test subject wells, runtime was increased by an average of 140 days by adding or adjusting rod guide designs, as represented in Table 3.

Application of Plunger Lift

As another solution to producing deviated wells, plunger lift systems were installed on wells with sufficient gas production. As a rule of thumb, plunger lift requires about 0.4 MCFD/1,000 ft. TVD to be considered a candidate. Wells with routine rod/tubing wear failures that met the GLR criteria above were considered for plunger lift.

3 such wells were converted to plunger lift in 2014. The majority of the failures on these wells were caused by deviation, with an average runtime of 148 days. The average gas-liquid ratio (GLR) for the three wells was 3.9 MCF/BBL, slightly under the gas requirement at an average depth of 10,000'. Despite this, none of the subject wells have failed or required a workover since the installation of plunger lift. As of January 1st, current runtime average has been extended to 494 days, with almost no fall-off in production. Due to reduced workover, electricity, chemical, and materials costs, operating expenses ($OPEX/BOE) were reduced by an average of 52%, as represented in Table 4.

Pumping Up High

In some instances, wellbore deviation proved manageable with the application of rod guides or conversion to plunger lift. Yet, in some cases, GLR did not support plunger lift, and the addition of rod guides proved ineffective for extending run life. In these instances, it was elected to pump the wells from above significant doglegs.

Two deviated wellbores continued to produce high failure rates due to rod-tubing wear. In both wellbores, the dog leg severity exceeded 2.5°/ 100' near 6,000' TVD. The original pump depths on both wells were below the deviated sections at roughly 8,200' TD. The wells averaged runtimes of 57 and 70 days, respectively. It was decided to raise the seating nipple depths above the deviated sections in both wells. As a result, runtimes increased to 571 and 514 days, respectively. As of January 1st, 2016, both wells were still pumping. However, both wells experienced a decrease in production volumes due to the expected increase in flowing bottomhole pressure. Production decreased by an average of 70%. However, operating costs for both wells decreased by an average of 67% as a result of the reduced workover costs. Operating costs were lowered on each well by $11.11/BOE and $25.00/BOE, respectively. In conclusion, the increase in runtimes outweighed the decrease in production, and the wells generated higher cash flow as a result.

RESULTS

The implementation of the new failure program in Gardendale resulted in significant reduction of well failures and operating costs. Figure 6 displays the monthly well failure count and workover expenses over time. A dashed vertical line in August, 2014 marks the start of the failure prevention program. Well failures dropped from an average of over 10 failures per month to stabilize near 2 failures per month by the end of 2015. Predictably, workover expenses followed the same pattern, dropping from an average of over $600,000 per month to below an average of $125,000 per month by the end of 2015. Failure Frequency for any given month, represented in Figure 7, is defined as a moving 1 year failure count per well count:

$$Failure\ Frequency = \frac{\sum well\ failures\ (past\ yr.)}{Well\ Count}$$

As an example, the failure frequency in for August, 2014 is calculated by summing all well failures from September, 2013 through August, 2014, and dividing that sum by the Gardendale well count of 101 wells. In August, 2014, the recorded failure frequency was 1.34 failures/well/year. Failure frequency began to decline with monthly failure count, and by December, 2015, failure frequency was reduced to 0.30 failures/well/year.

The effect of this reduction in failure frequency on operating expenses is represented in Figure 8. Operating expenses per BOE ($OPEX/BOE) averaged approximately $18.00/BOE in the first half of 2014. In the fourth quarter of 2015, operating expenses averaged $8.24/BOE as a result of the decreased workover costs associated with the decrease in well failures. This was achieved despite natural production decline, and no added production volumes from a drilling program. Broken down further, Figure 9 displays the percentage of total operating expenses by category: well operating, facilities, and workover costs. In the first half of 2014, workover expenses accounted for 36% of all operating expenses. This percentage was decreased to 19% of all operating costs by the second half of 2015.

Comparing 2014 and 2015 results in Table 5, failures were decreased by 101 year-to-year, and failure frequency was decreased by 1 failure/well/year. Workover spending in 2015 was reduced by $4,463,900.

CONCLUSION

An effective workover and failure prevention program requires a well-organized team, efficient data collection, and sound engineering practices. An effective team learns and improves from every well failure, and adjusts roles and responsibilities for efficiency. As a result of good organization and data management, engineering principles can be properly designed, tested, and analyzed. Solid conclusions can be made, and the learnings can be applied on a large scale to maximize profits, which is crucial in today's price environment.

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ACKNOWLEDGEMENTS

Thank you to the following for their support and contributions: Trenton Hancock, Tyler Guthrie, Frankie Cantu, Jason Trent, John Tinker, John Tolbert, Rached Hindi, Mike Ethridge, Sonya Rodgers, Doug Dietrich, Bill Morrison

Table 1

Role	Responsibilities / Description
Engineer	• Has complete decision authority over workover • Uses historical well data to build pre-job procedure and analysis • Adjusts procedure during job based on chemical, failure, and system analysis • Analyze results of job post-workover • Adjust future workover, design, and operational standards based on results
Chemical Field Technician	• Retrieve and analyze failure samples in a timely-manner • Report failure analysis to Engineer • Provide chemical recommendations for workover • Adjust regular treatment chemicals and schedule accordingly
Production Field Technician	• Provide fluid levels, dynographs, and production system data to Engineer • Analyze and adjust artificial lift design in collaboration with Engineer • Collect fluid levels, dynographs, and production system data after workover • Archive relevant data and information in appropriate database (TAM/XSPOC) • Draw conclusions from artificial lift design changes with Engineer • Optimize percent timers and pump off controllers accordingly
Workover Supervisor/Foreman	• Responsible for rig activity and safety • Provide failure samples, details, and important job information to appropriate personnel • Record job, equipment, and cost details in well files (WellView) • Implement procedure as provided/adjusted by Engineer

Table 2

Effects of POCs on tubing life: Midkiff Lease - Gardendale				
	Total Well Count	**Average Tubing Run Life**	**Total Failures**	**Failures per well**
Wells w/o POCs	7	139	7	1.00
Wells with POCs	12	219	10	0.83

Table 3

Well Study - Application/Modification of Rod Guides		
Well Name	**Average Runtime Before**	**Average Runtime After**
Haag A 1204	181	491
Leverette 2603	150	248
Leverette 2615	105	127
Munn-Clark 2617	281	411

Table 4

Well Study - Conversion to Plunger Lift					
Well Name	**Prior Runtime Average (days)**	**Runtime After Plunger Install (days)**	**Production Impact (BOEPD)**	**Operating Costs Before ($/BOE)**	**Operating Costs After Plunger Install ($/BOE)**
Crown Royal 104	149	417	-0.5	$7.69	$2.43
Haag 1202	195	560	-1.2	$11.70	$5.78
Haag 1213	101	505	-1.7	$30.91	$15.79

Table 5

2014 & 2015 Failure Comparison			
	2014	**2015**	**Change**
Total Failures	131	30	**101**
Total Wells	101	101	-
Failure Frequency (failures/well/yr.)	1.30	0.30	**1.00**
Workover Spending	$ 6,099,021.08	$ 1,635,038.71	**$ 4,463,982.37**

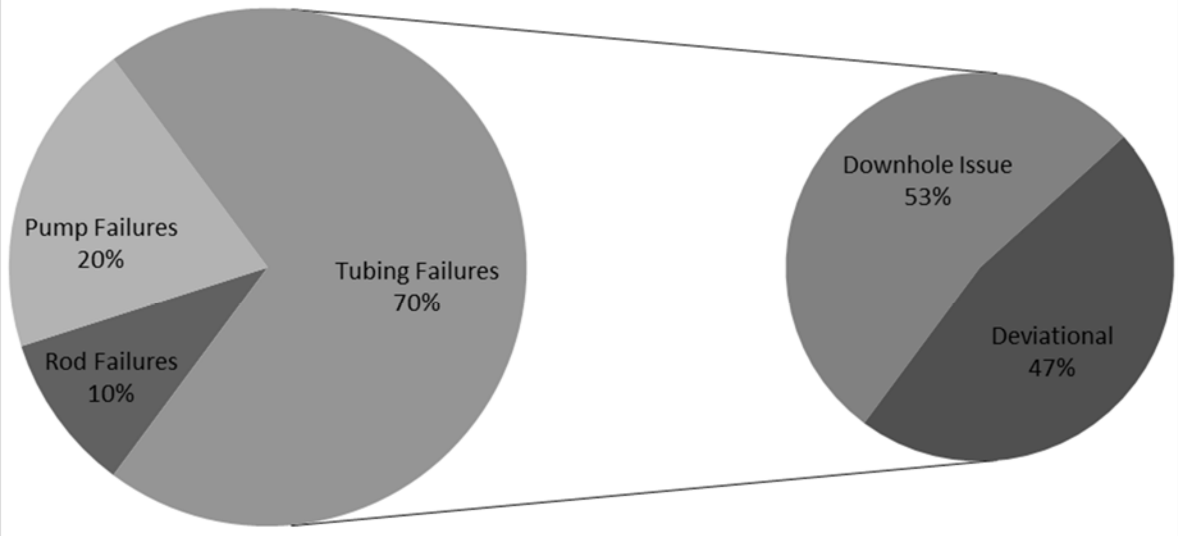

Figure 1 – Gardendale Failure Distribution 1H 2014

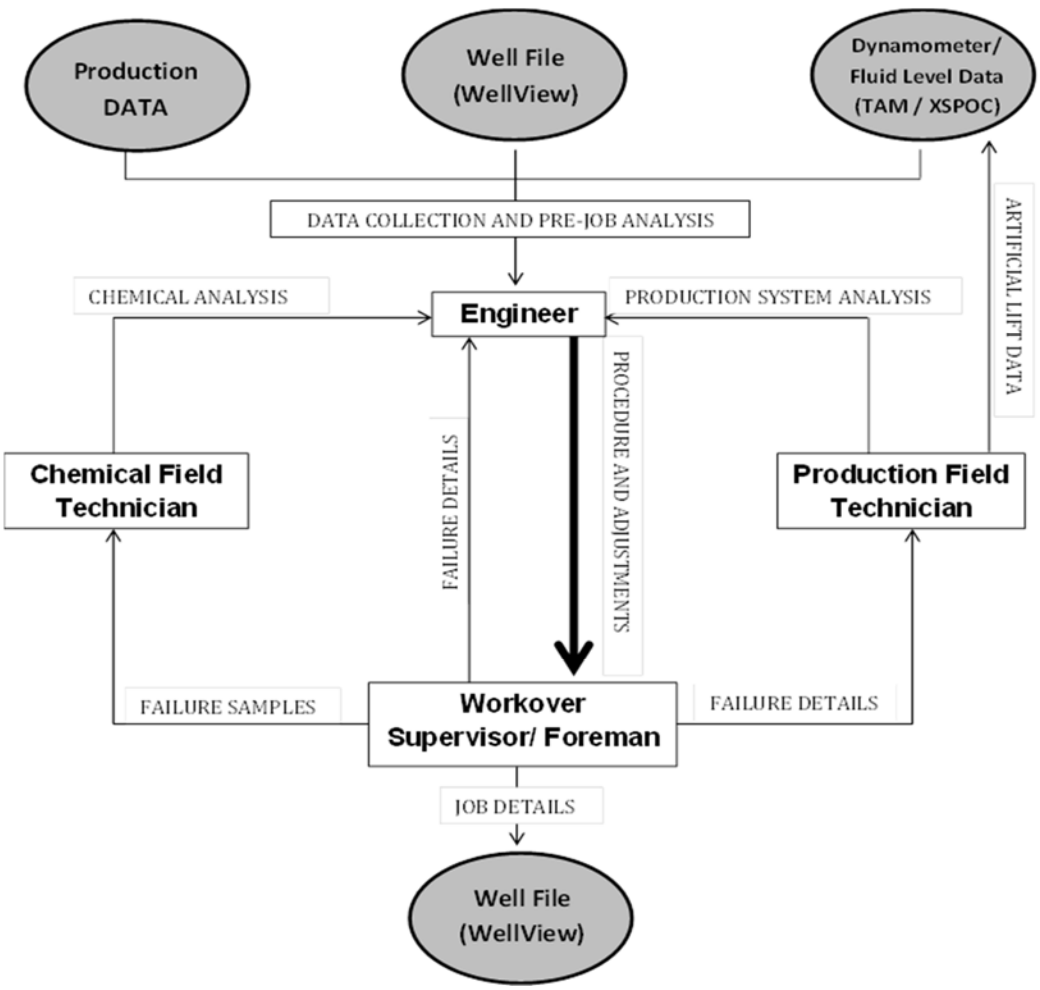

Figure 2 – Workover Organizational Chart

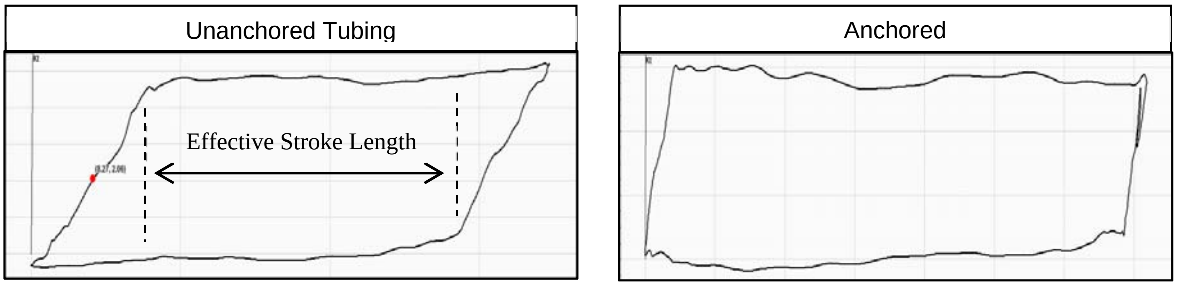

Figure 3 – Effective Stroke Length, Anchored vs. Unanchored

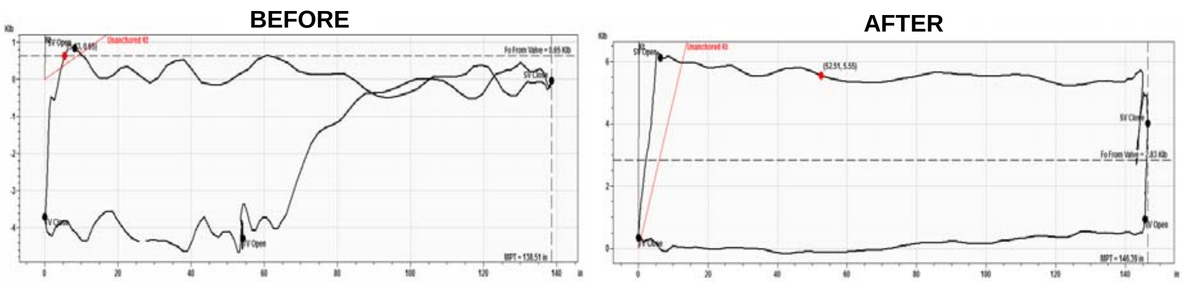

Figure 4 – Installation of Packer-Style Separator, Gardendale Horizontal Well

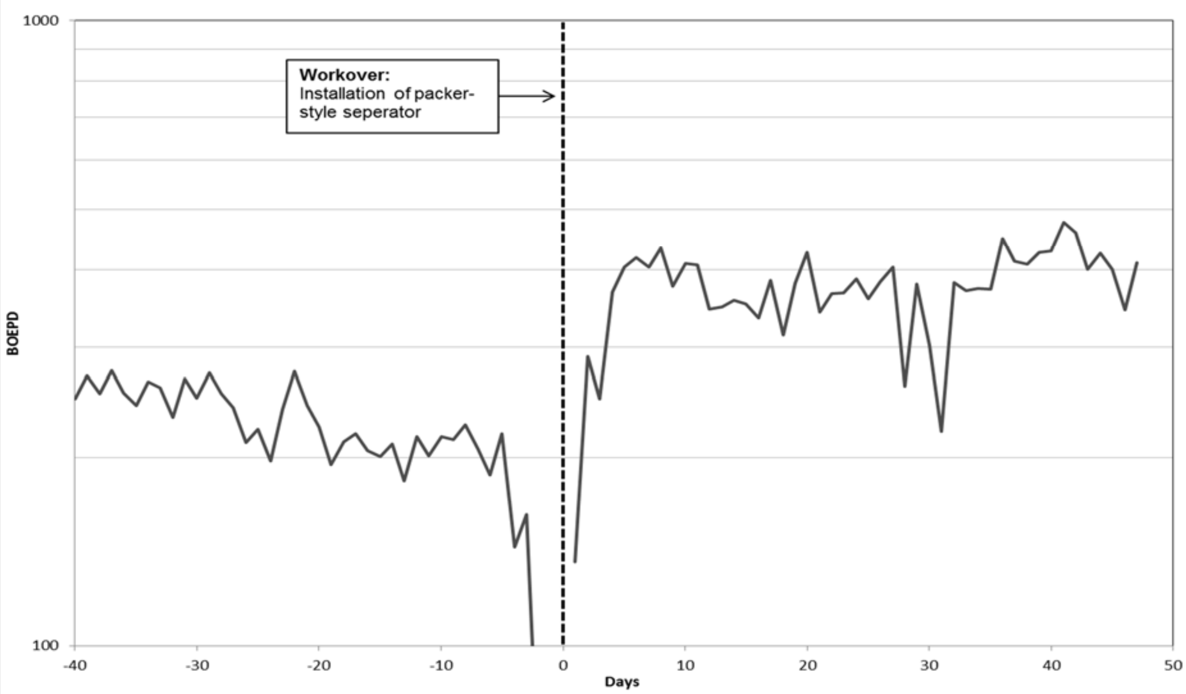

Figure 5 – Production Impact of Packer-Style Separators

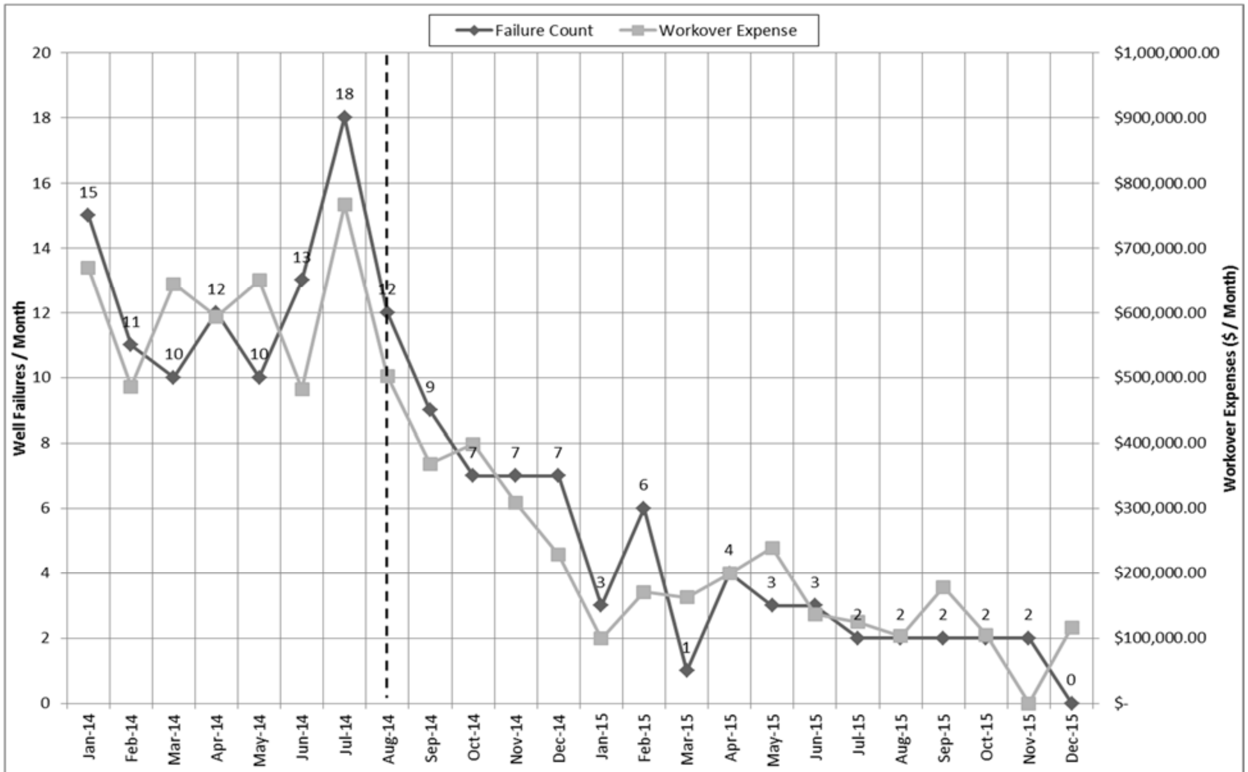

Figure 6 – Gardendale Monthly Failure Count vs. Workover Spending

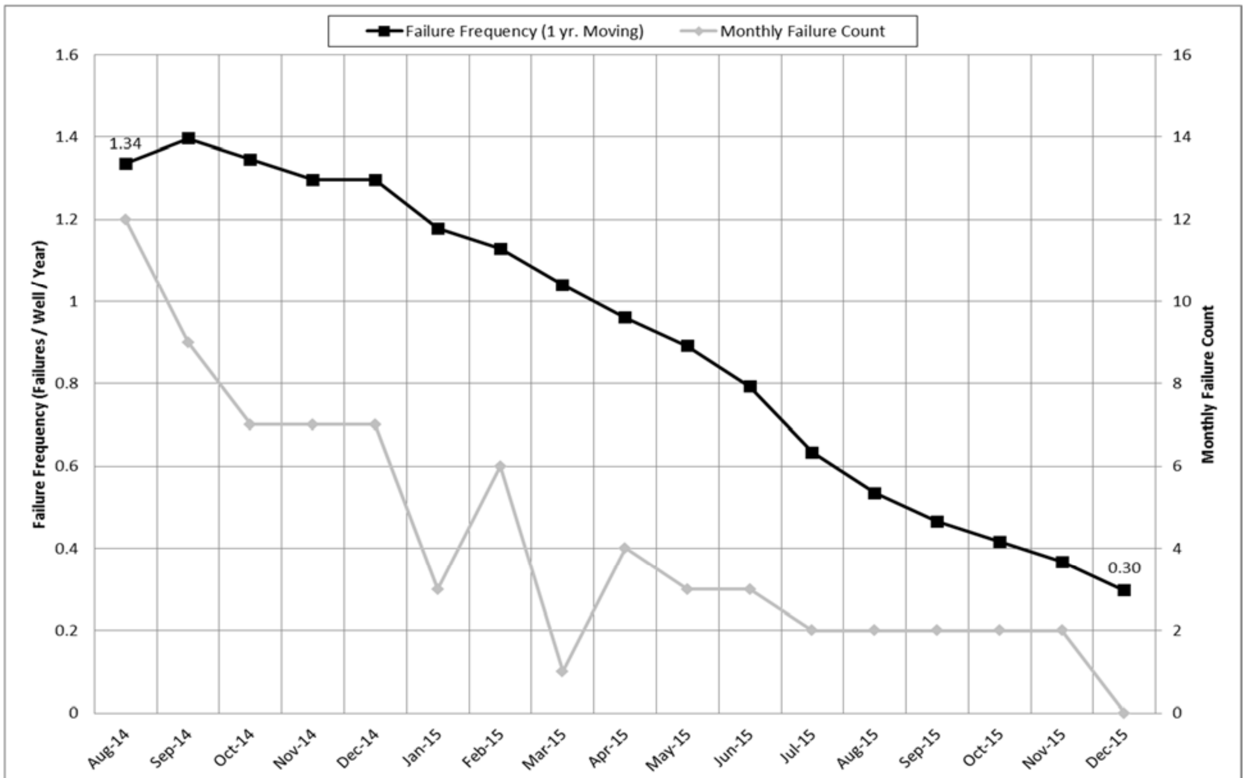

Figure 7 – Failure Frequency vs. Monthly Failure Count

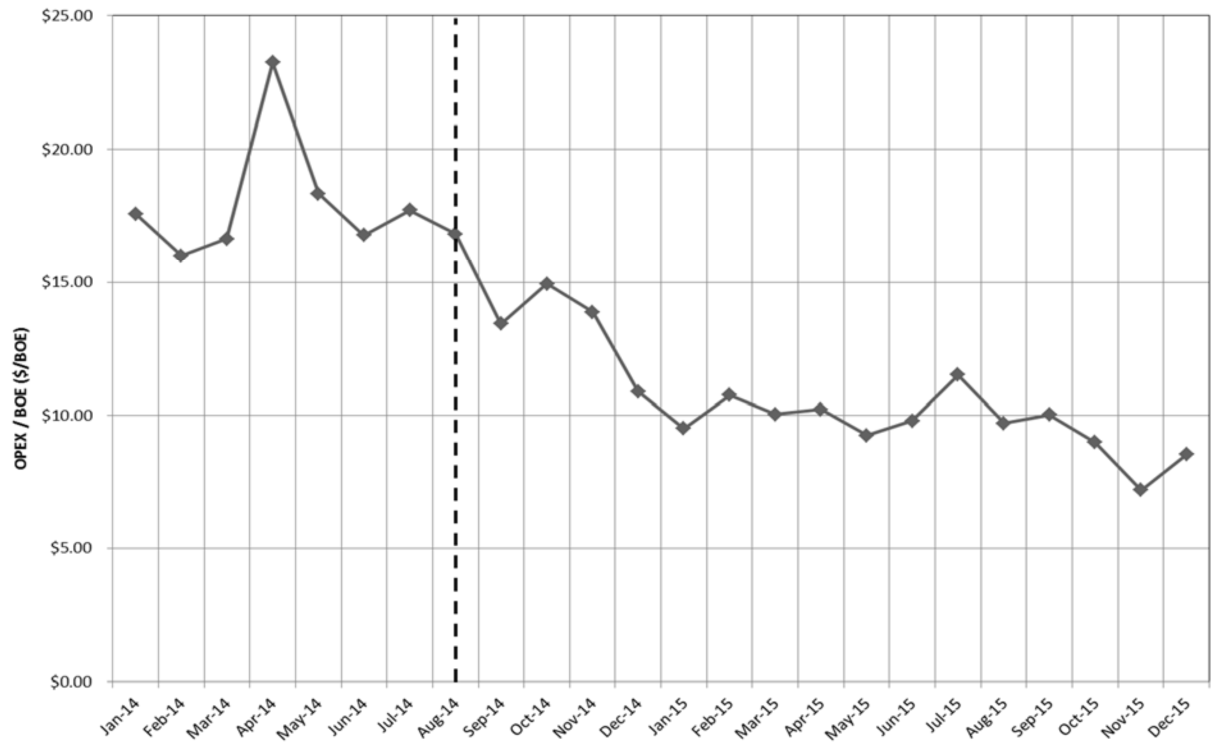

Figure 8 – Operating Expenses per BOE

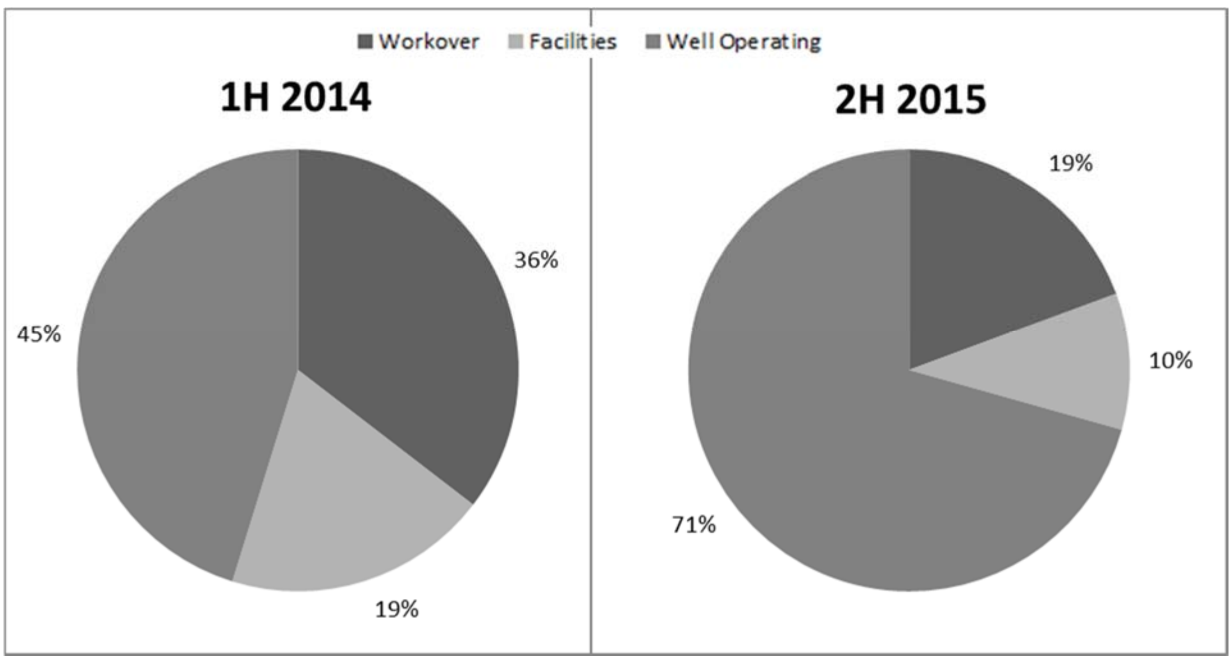

Figure 9 – Operating Cost Comparison