EXTENDING RUN TIMES IN DEVIATED WELLS
CASE STUDIES

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ABSTRACT
A greater number of directional wells are being drilled to increase production rates and maximize the life of the investment. Many times the build rates are very high and result in a well that is very difficult to produce artificially. Designing an efficient pumping system that will give extended run times is an important part of maximizing profits. Working with Crimson Resources and Tidelands Oil Production in Bakersfield, CA and ChevronTexaco in the Eunice, NM, R&M Energy Systems has completed several case studies. We will examine these studies, showing best practices, actual cost savings and planned improvements.

INTRODUCTION
Determining the best method for extending run times in deviated wells can be extremely difficult. Very few options are available. The use of rod guides to prevent rod on tubing contact can significantly increase run times in directional and deviated wells. For fifty years, rod guides have been used as sacrificial components and to help stabilize the rod strings. Rod guide spacing, number per rod, guide design and placement of the guides in the rod string are very important in establishing a long run life. R&M Energy Systems has developed a method of recommending and tracking rod guide installations and their effect on the run life. By using the latest edition of RGAP (Rod Guide Advisory Program), R&M Energy Systems is able to recommend the best rod guide design, material, placement, number per rod, rod guide spacing and track the results.

ROD GUIDES
Rod guides are manufactured from various grades of thermoplastics and can be injection molded directly onto a sucker rod. Other guide designs can be field installed by "snapping" the guide on the sucker rod. Mold-on rod guides are superior to field installed rod guides in many aspects. Mold-on guides have greater gripping or adhesion to the rod and are much less likely to move under side load. Guides must have sufficient material to prevent the rod couplings from wearing against the production tubing. This material is referred to as erodible wear volume (EWV) and is the amount of material outside the coupling outer diameter. Another important aspect of rod guides is the drag force that each design has while falling through the production fluid. Drag forces vary greatly and can be as much as 11 lbs per guide on some field installed guides.

ROD GUIDE ADVISOR PROGRAM (RGAP)
RGAP is a computer program that was first developed in 1993. It is a rules based program that is used to recommend rod guides for wells with or without deviation surveys. The latest version of RGAP utilizes visual tools, failure analysis, deviation surveys, and several other well factors to recommend the optimum rod guide design. Using a number of visual tools, such as 3D well plots, failure charts and side load charts, helps identify and solve wear related problems.

Several case studies will be presented, first of an individual well, a group of wells and then of an entire field. All of the wells in this study have mold-on guides and a rod rotator installed. It is imperative to use a rod rotator to extend the life of the rod guides. Rod rotators rotate the rod string to evenly distribute the wear.

CASE STUDY 1
The first case study is a ChevronTexaco well located in Eunice, New Mexico, the GL Erwin #9. The GL Erwin A#9 is intentionally deviated. The kickoff begins at 3150 ft, reaching a maximum angle of 33.6° at a depth of 4091ft. The well was initially put on pump on March 8, 2001. With the following equipment:

- Lufkin RM640D-365-168
- GE 50hp Electric Motor
- 2-7/8" Tubing J-55 6.5lb/ft
- Tubing Anchor at 6300ft
- 1.25" Pump, set at 6450'

- 95-7/8” K Grade Rods with 4 per Stealth XL Guides
- 161-3/4” K Grade rods with 4 per Stealth XL Guides

This well is considered to have a moderate amount of corrosion, including H_2S < 1% and brine. On March 27, 2001 (19 days of run time), the well was pulled to perforate an additional zone. As the well was being pulled, the rods and rod guides showed significant wear. The rig crew laid down all but one of the 95 - 7/8” rods and all of the 161-3/4” rods.

ChevronTexaco approached R&M Energy Systems for help to extend the run life of this problematic well. All of the available information was gathered about the well, including failure information.

Using RGAP, R&M Energy Systems recommended the following from 1500 ft – 6450 ft:

- 10 Guides Per Rod
- Stealth XL mold-on Rod Guides
- SB1 Material
- New Era Spacing
- Rod Rotator

Figure 1 shows the 3D plot of the well bore. This well is an “S” curve well with a fairly high rate of change. **Figure 2** shows the side load plot. The maximum side load of 1864 lbs is located at a depth of 5025ft. The side load plot clearly shows the potential for rod / tubing contact between 1900 ft and 5900 ft. In many areas, the dog leg rate of change exceeds 5° per 100 ft.

To date (as of January 9, 2004), the GL Erwin #9 is still running without a failure – 1018 days**.** Although the well did not fail in the first 19 days it was initially placed in production, enough wear was present to lay down almost the entire rod string. If we assume that the well would have continued to run for 75 days before it failed and that work-over costs average $1,500 per job, over the 1018 days of run time, the well would have required 13 work-over jobs, totaling almost $20,000, plus replacement equipment. With these unrealized cost savings and no losses in production, the benefit of an engineered solution to wear related problems is evident. Note that the original rod string design included rod guides. However, improper placement and spacing of those guides resulted in the entire rod string being laid down.

CASE STUDY 2

This case study consists of five wells owned by Tidelands Oil Production Company. Only four of these wells have enough well history for a case study. These wells are located in the Long Beach lease in Los Angeles, California. Do to wear related failures, these were Tidelands most costly wells. All four wells are on beam pump and range in depth from 2128 – 3300 ft. The well specifications are in **Figure 4**.

The first well, Z-233, history starts in August 1992. This well has eleven failures, nine related to rod and tubing wear since that time. The average run time between wear related failures is 297 days. **Figures 5** and **6** show the side load and 3-D chart with the failure locations. The horizontal bars indicate failure depths. RGAP made the following recommendation from 0 – 2128 ft (bottom):

- 8 guides per rod
- Stealth XL rod guides
- SB1 Material
- New Era Spacing
- Rod Rotator

This recommendation was installed on March 14, 2001. On May 1, 2002 this well was pulled for a plunger problem. Since the March 14th installation to date (January 9, 2004), the well has had no wear related failures. This gives a run time without a wear related failure of 1032 days.

Well number two, J-111, well history starts in April 1996. Since 1996, this well has had eight failures, six of which are wear related. **Figures 7** and **8** show the side load and 3-D chart with failure locations. The average run time between failures is 231 days, with the longest run time between failures of 704 days. RGAP recommended the following from 1- 3330 ft (bottom):

- 8 guides per rod

- Stealth XL rod guides
- SB1 Material
- New Era Spacing
- Rod Rotator

The above recommendation was installed on March 28, 2001. To date, this well has not failed, giving a run time of 1018 days.

Well number three, E-138, history starts in January 2000. Since then, well rig work history shows six pulls, four of which are wear related. The average run time between failures is 89 days, with the longest run time between failures of 192 days. **Figures 9** and **10** show the side load and 3-D chart with failure locations. RGAP recommended the following from 990ft – 2075ft:

- 4 guides per rod
- Stealth XL rod guides
- SB1 Material
- Wear Spacing
- Rod Rotator

This recommendation was installed on February 22, 2001. To date (January 9, 2004), the well has not failed, giving a run time of 1052 days.

Well number four, M-253, history starts in May 2000. Since then, well rig work history shows two failures. Both of these failures are wear related. The average time between failures is 140 days, with the longest run time of 156 days. A plot showing failure locations can be seen in **Figure 11**. RGAP recommended the following from 1884ft – 2490ft:

- 8 guides per rod
- NETB rod guides
- SB1 Material
- New Era Spacing
- Rod Rotator

This recommendation was installed on February 14, 2001. Since installation this well has had two failures, one tubing leak in the unguided portion of the well and a corrosion failure. This give an average run time of 173 days (extended down time after failure). This well does not have a deviation survey and predicting high wear problem areas becomes more difficult. This could attribute to the lower than average return rate for this well.

A rudimentary cost analysis is provided in **Figure 12**. This cost analysis does not take into account replacement tubing, rods or lost production. This cost analysis shows a cost savings for three of the four wells in this study. Well Z-233 had one pump failure which dropped the cost savings below investment costs. One of the most important items to consider is the virtual elimination of wear related failures for all four wells. **Figure 13** shows the average and maximum run days for all four wells in this case study. **Figures 14** and **15** are pie charts showing the number of failures by type before rod guides and after rod guides. Only one well logged a wear related failure. This occurred in the well that did not have a deviation survey and the failure occurred in an unguided section of the well. Wells without deviation surveys require accurate failure records for an optimum guide recommendation.

CASE STUDY 3 – FIELD WIDE STUDY

This study uses data gathered by Crimson Resources. In February of 2001 R&M Energy Systems began working with Crimson Resources to lower the wear failure rate for the Buena Vista Hills Lease. This lease has approximately 221 producing wells and, by February 2003, 173 of the wells had rod guides installed. All of the wells used Stealth XL rod guides. The recommendations of the wells fall into the following scenario:

- 90% of wells with 2-3/8" tubing have 6 guides per rod, the remaining have 8 guides per rod
- 80% of wells with 2-7/8" tubing have 4 guides per rod
- 15% of wells with 2-7/8" tubing have 6 guides per rod
- 5% of wells with 2-7/8" tubing have 8 guides per rod

Figure 12 shows the well service history by job type for the Buena Vista Hills Operations. By the end of 2002, the chart indicates:

- 33% fewer well pulls for tubing and rod failures
- 75% fewer tubing holes

- 800% increase in RTP (return to production) work
- 340% increase in RTP and pump size increase activities

Crimson was able to go from three active work-over rigs to two, and at the same time increase the amount of RTP work. In 2002, Crimson Resource spent approximately $117,000 for rod guides. By contrast, the cost savings by eliminating a rig is approximately $480,000 per year. Due to the increase in RTP, the lease increased in production by an average of 35 BPD.

CONCLUSION

A properly designed rod guide system is vital to lowering production costs in deviated wells. In most instances, rod guides easily paid for themselves by reducing work-over costs. Rod guides were able to save a significant amount of money for the operators of these wells. All three of the companies involved in these case studies were extremely satisfied with the outcome of this wear reduction program. The use of rod guides in deviated wells can significantly increase run times and lower production costs by virtually eliminating rod and tubing wear.

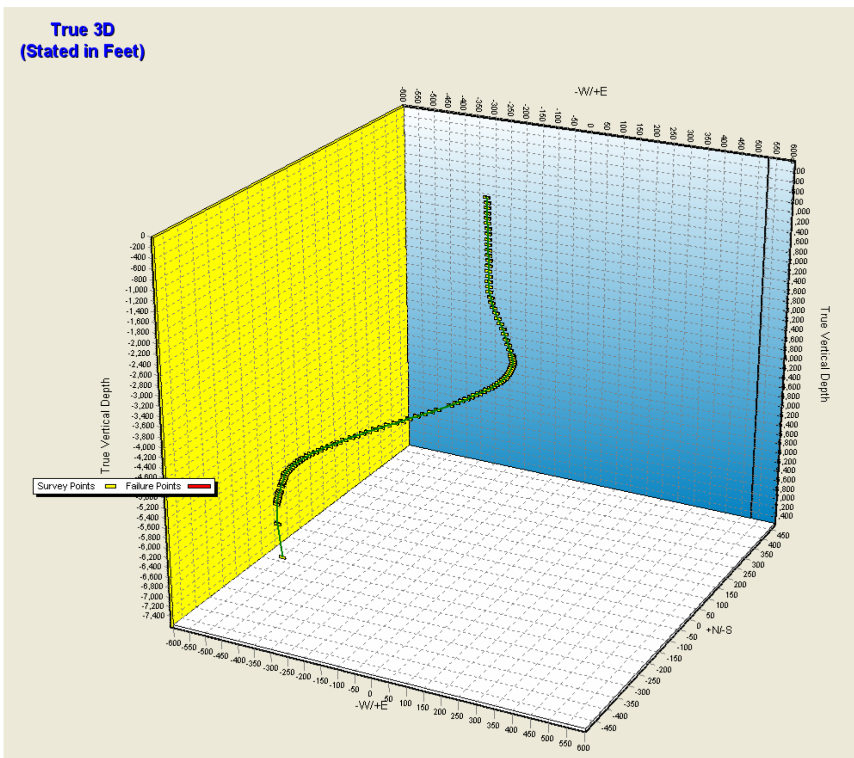

Figure 1- Screen Shot of 3D Well Bore Plot

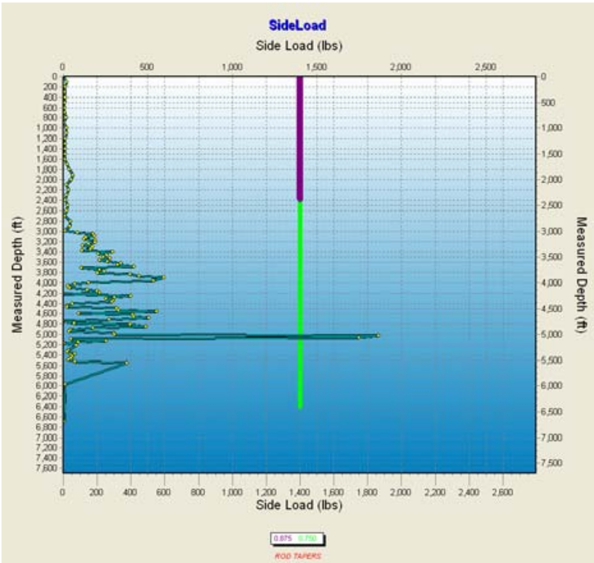

Figure 2 - Side Load Plot vs. Depth with Rod Taper

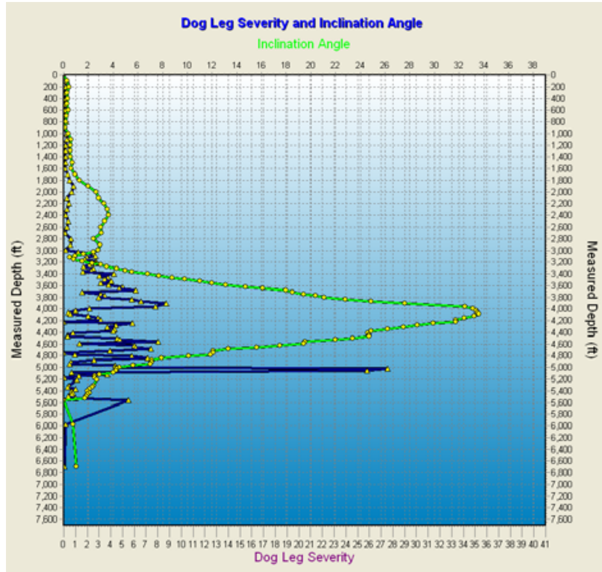

Figure 3 - Graph Showing Dog Leg Severity and Inclination Angle vs. Depth

	Z-233	J-111	M-253	E-138
Depth (ft)	2128	3330	2498	2884
Stroke Length (in)	76	85	74	144
SPM	9	10	11.5	8.5
Plunger Diameter (in)	2.25	2	2	2.75
Tubing Size (in)	2.5	2.5	2.5	3
API Gravity (°)	14	13	13	17
Oil Cut (%)	4	3	5	2
Corrosion	Moderate CO2	Moderate CO2	Moderate CO2	Moderate CO2

Figure 4 - Tidelands Oil Case Study Well Specifications

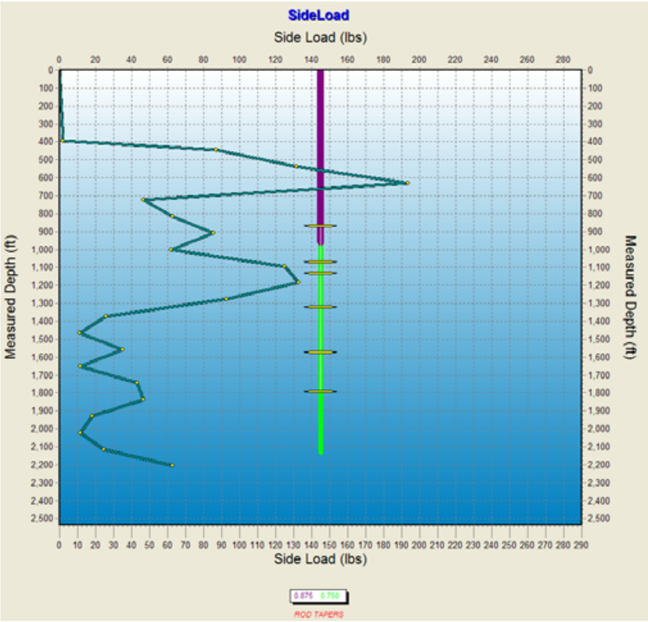

Figure 5 - Z-233 Side Load Chart

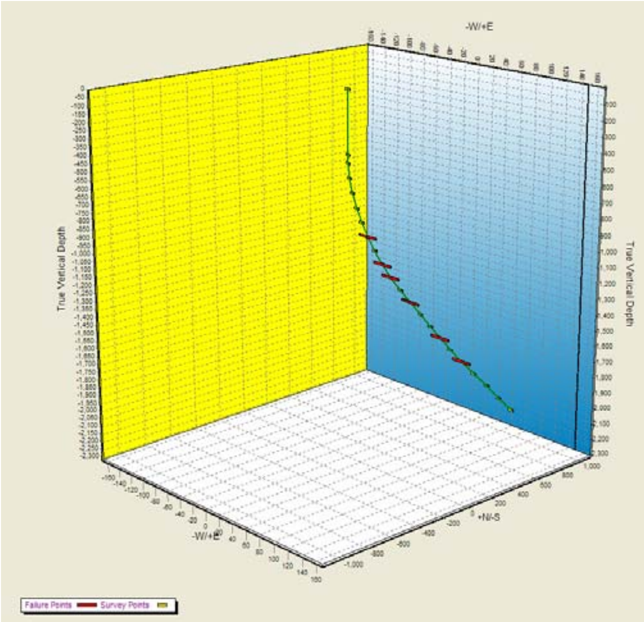

Figure 6 - Z-233 3-D Plot Showing Failure Points

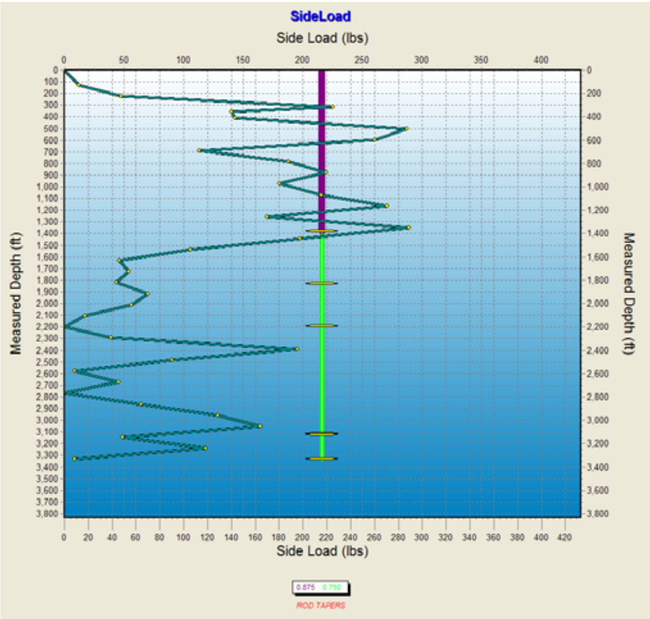

Figure 7 - J-111 Side Load Chart

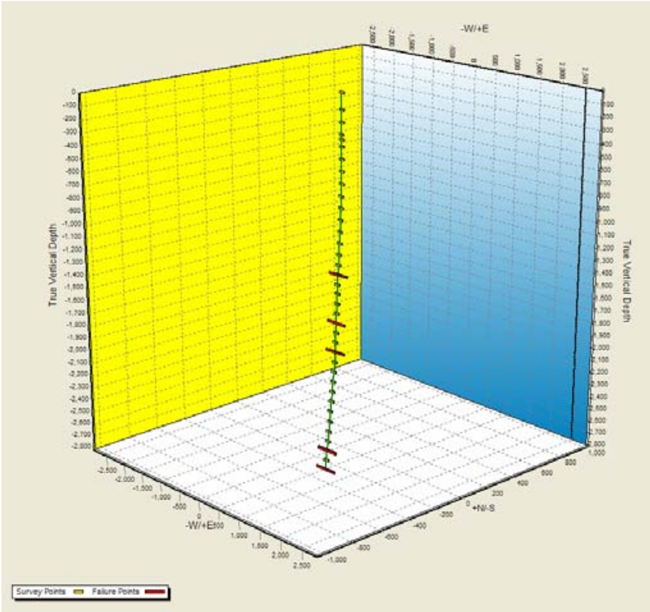

Figure 8 - J-111 3-D Plot With Failure Points

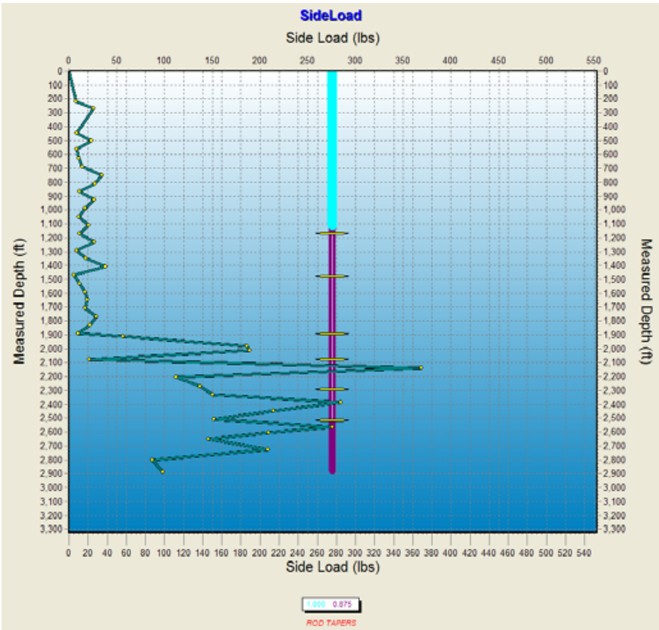

Figure 9 - E-138 Side Load Chart

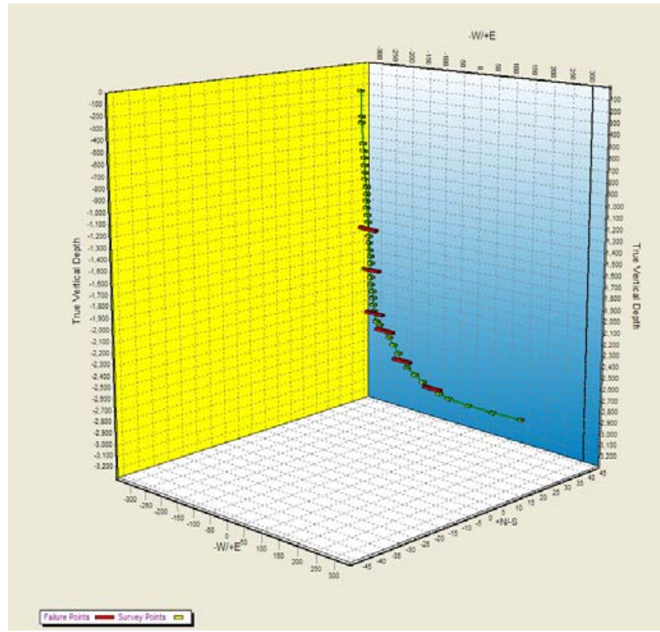

Figure 10 - E-138 3-D Plot With Failure Point

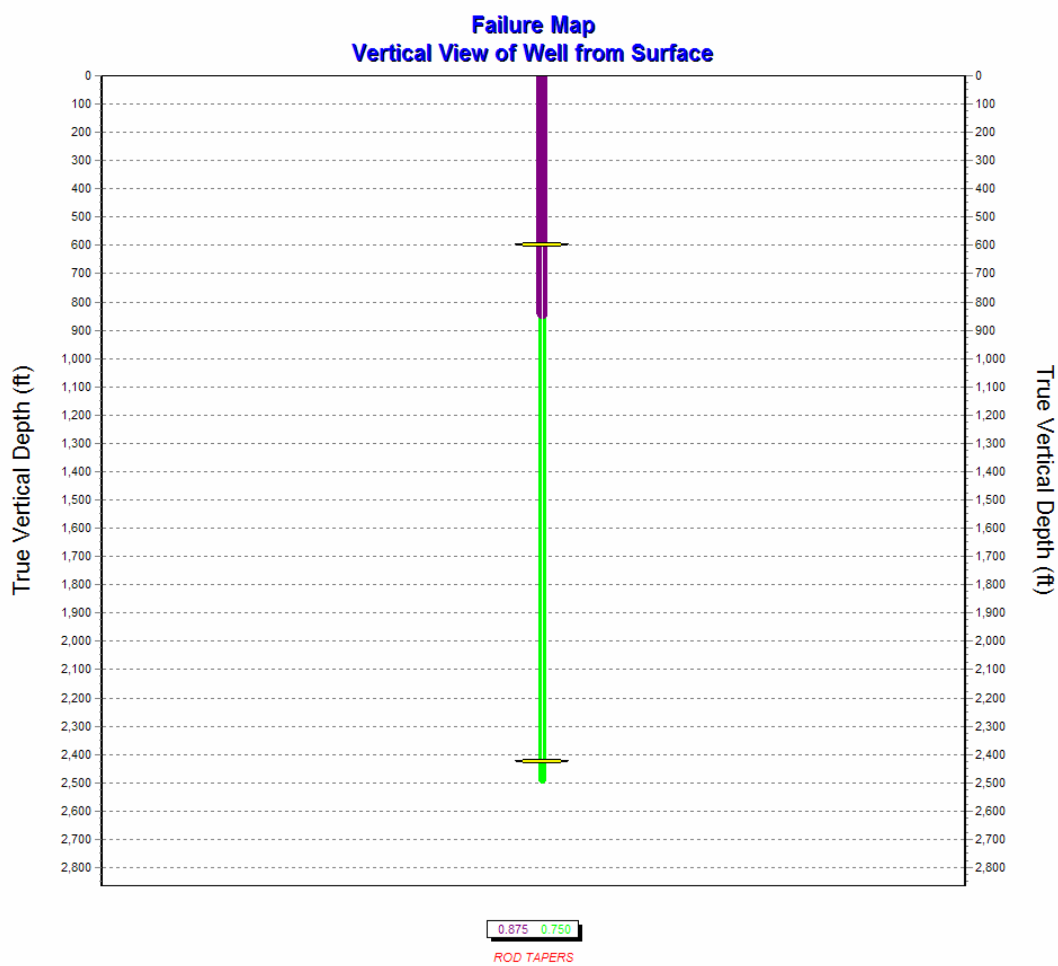

Figure 11- M-253 Failure Map

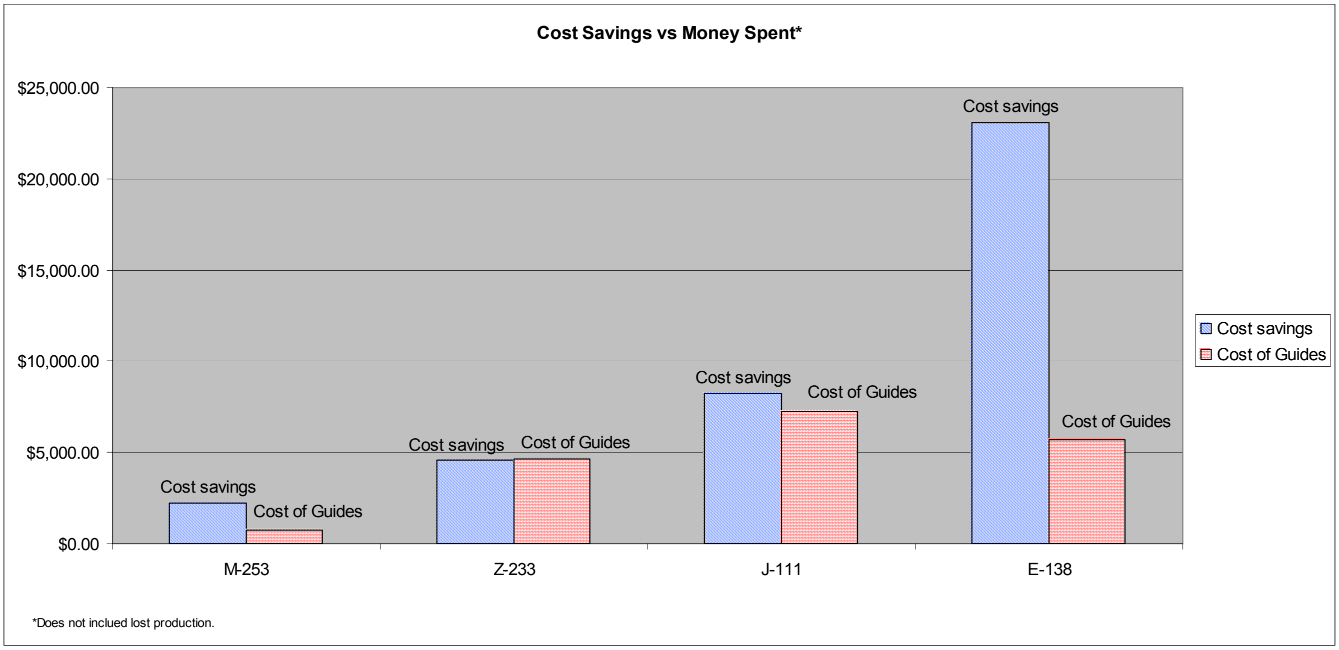

Figure 12 - Chart Showing Cost Savings Versus Money Spent

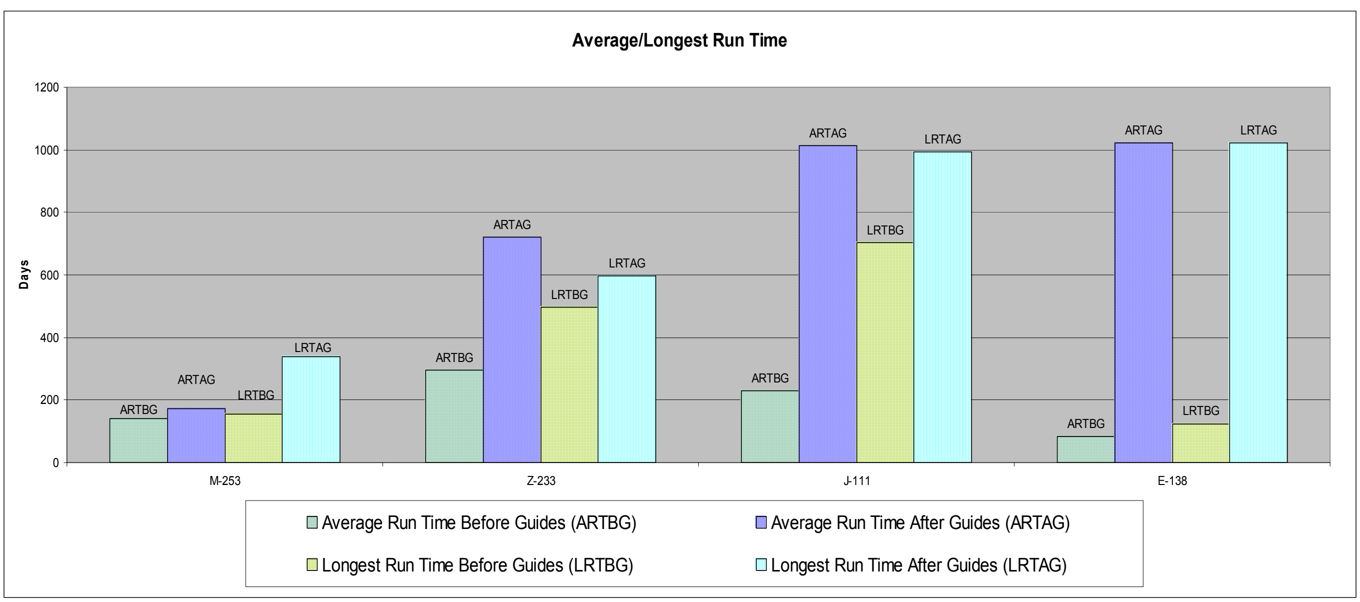

Figure 13 - Chart Showing Average Run Times Before and After Rod Guide Installation.
Blue represents after rod guide installation.

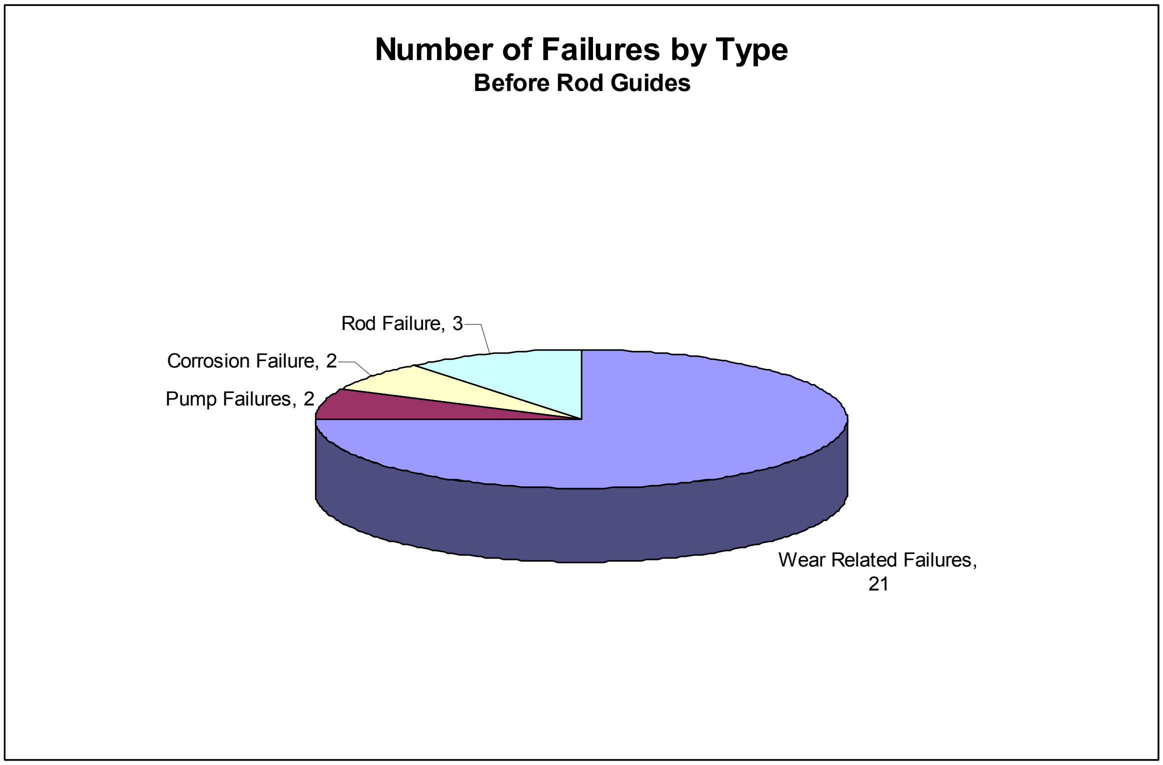

Figure 14 - Pie Chart Showing Number of Failures Before Rod Guides Were Installed For Tidelands Oil

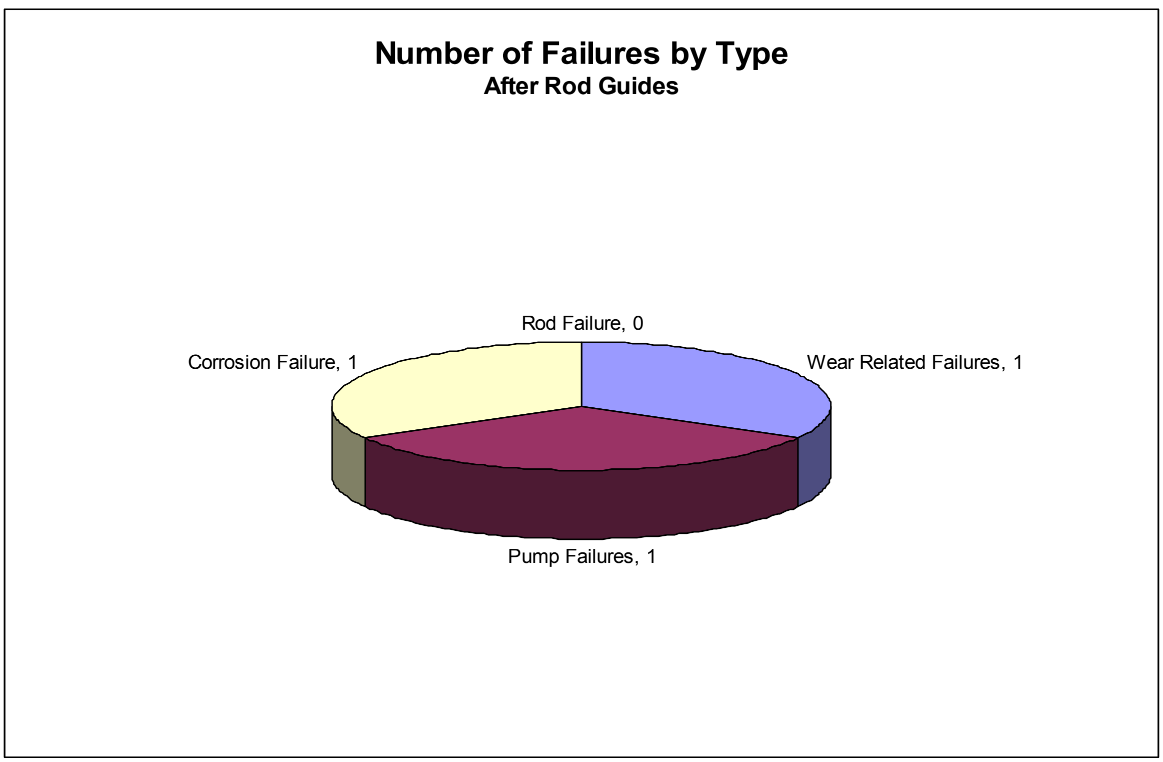

Figure 15 - Pie Chart Showing Number of Failures After Rod Guides Were Installed For Tidelands Oil

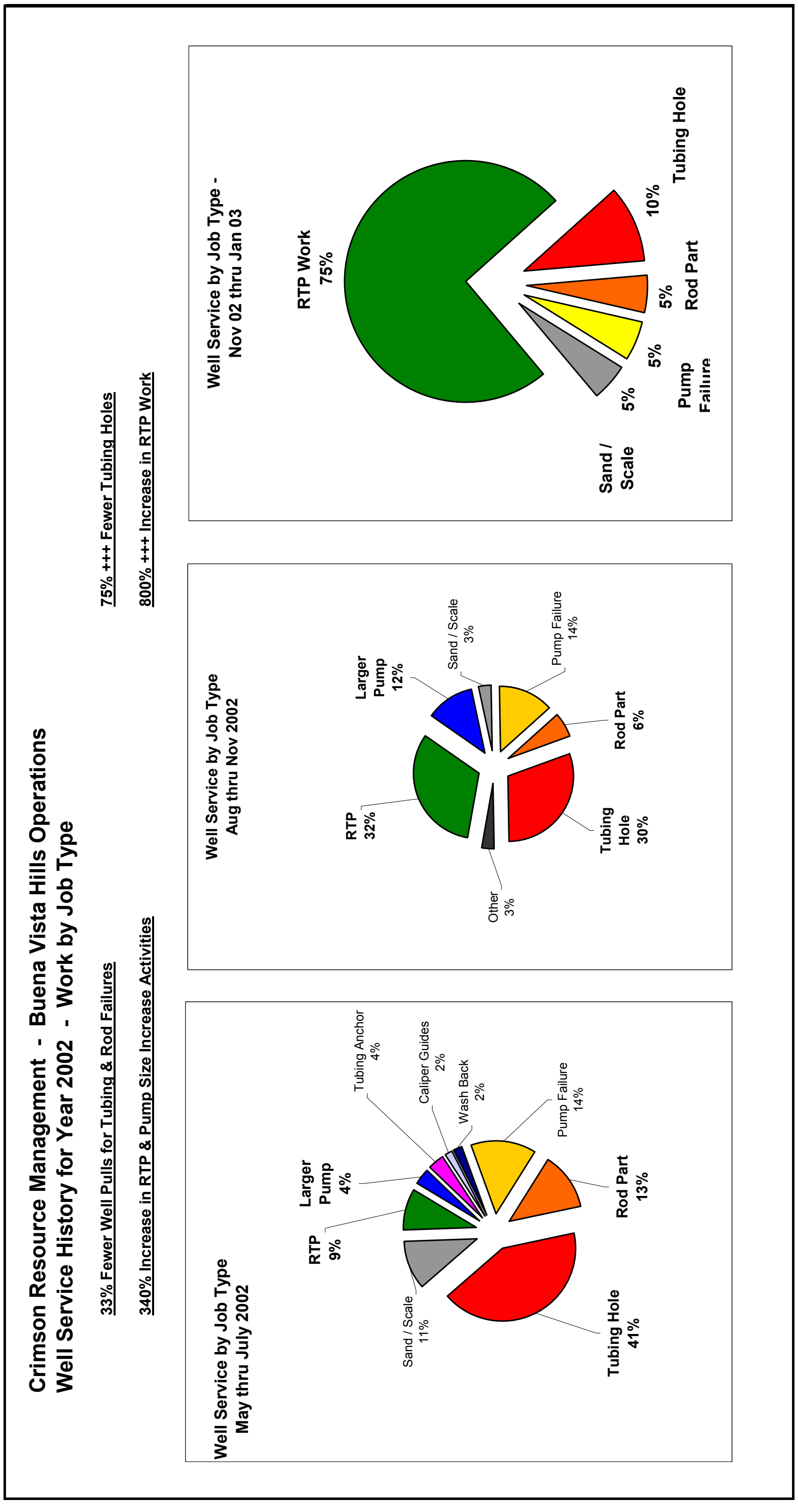

Figure 16 - Buena Vista Hills Well Service History by Job Type