PIONEER NATURAL RESOURCES 10 YEAR "BEST PRACTICES" PROGRAM AND DATABASE

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PROGRAM RESULTS

August 17, 2006 marked the 10th Anniversary of the Pioneer Natural Resources, Preston Spraberry Unit (PSU) "Best Practices" Failure Reduction Program. This program was initiated during the 3rd quarter of 1996 when Pioneer Natural Resources (then Parker & Parsley) realized that they were experiencing high downhole failures rates in the Preston Spraberry Unit.

This 10 year partnership between Pioneer Natural Resources, Flexbar Inc., Norris Rods, Tommy White Supply and Kel-Tech has resulted in a significant reduction in downhole failures and a huge savings in operational costs for Pioneer Natural Resources.

An estimated $17.9 million in 2006 dollars was saved in reduced downhole failures during the 10 years of this PSU "Best Practices" 150 well program. This 10 year savings represents an average of $1.8 Million per year. This savings was estimated using the following 2006 failure costs:

$16,000 per Tubing Leak
$ 9,000 per Rod Failure
$ 8,000 per Pump Failure

The 10 year performance (FPWPY) for this 150 well, PSU "Best Practices" program is displayed in figure 1 and is listed below;

94 % Reduction - Tubing Leaks
75 % Reduction - Rod Failures
80 % Reduction - Pump Failures
88 % Reduction - Total Failures

The greatest reduction in total failures (71 %) was experienced during the first four years of this program. Interestingly, during years 4 through 10, there was still a significant reduction (58 %) in total failures. Refer to figure 1-A.

PRESTON SPRABERRY UNIT HISTORY

The Preston Spraberry Unit is located in the southwest corner of Midland County, approximately 25 miles southwest of Midland, Texas. The Spraberry formation is the producing horizon. Additional producing information at the start up of this "Best Practices" Program is as follows:

1. Average pump depth is 6,850 feet
2. Production tubing is 2-3/8" located inside 4-1/2" casing
3. Tubing anchor catchers are set below the seating nipples
4. An estimated 90% of all seating nipples are located above perforations
5. Average stroke length is 86 inches
6. Average pump speed is 8.0 strokes per minute
7. Producing interval is located from 7,000 feet to 8,700 feet

HOW THE PROGRAM STARTED

During the 3rd quarter of 1996, several existing producing wells in the Preston Spraberry Unit were identified as high failure rate wells. The ranking process for these high failure rate wells started with those wells with the highest failure rate and ended after a total of 87 wells were selected for this program. These 87 wells became the first group of wells selected to initiate this Best Practices" Program.

A review of failure performance for the two (2) years prior to initiation of the "Best Practices" program indicated that the frequency of tubing leaks for these 87 wells was increasing and quickly approaching 2 tubing leaks per well per year. The frequency of total failures was also very high and close to 3 failures per well per year (FPWPY) with no indication of a future reduction in tubing leaks or total failures.

The number of tubing leaks for the next 12 months was projected at 174 tubing leaks using the failure frequency of 2 tubing leaks per well year. The total cost of repairing these projected 174 tubing leaks was estimated at $957,000 based on a repair cost of $5,500 per tubing leak in 1996 dollars.

The decision was made to formalize a "Best Practices" program incorporating these 87 existing wells because tubing leak failures were the highest frequency failure and the most expensive failure to repair. Some of these 87 wells had been operating with 5-6 year old artificial lift equipment installed at initial completion of these wells.

The performance benchmark for these 87 existing wells was established by calculating the failure rate during the 12 months prior to initiating this "Best Practices" program. The unit of measurement used to establish this benchmark was failures per well per year (FPWPY). This performance benchmark for these 87 wells is listed below by individual failure and by total failures;

Tubing Leaks	**152**	**1.75 FPWPY**
Rod Failures	**45**	**0.52 FPWPY**
Pump Failures	**40**	**0.46 FPWPY**
Total Failures	**237**	**2.73 FPWPY**

WHAT IS A BEST PRACTICES PROGRAM?

The "Best Practices" program that was originally initiated utilizing these 87 wells was created to reduce downhole failures. The best general description of a "Best Practices" program should involve the following steps;

1. Optimize artificial lift performance for each well
2. Monitor and record all downhole failures and create a database to document this information
3. Challenge existing practices and strive for continuous improvement at all levels
4. Involve well technicians, rod, pump, chemical and sinkerbar suppliers

This "Best Practices" program more specifically, involved the following specific points:

1. Receive program support and buy-in from Pioneer Natural Resources Management.
2. Complete and individual well diagnostic analysis.
3. Individual well optimization using predictive software and / or dynamometer surveys to match existing or future lift operations with existing or future equipment. Optimization included modification of pump diameters, strokes per minute, stroke lengths, tubing anchor catcher set points and downhole gas separation.
4. Re-evaluation of rod string designs to establish balanced loading at the top of each taper.
5. Removing 750' of guided 7/8" rods installed above the pump.
6. Installation of an average of 375' of 1.5" Grade-C Sinkerbars to reduce buckling during the downstroke.
7. Installation of pump-off controllers to manage production rates, optimize run times and monitor equipment performance.
8. Evaluation of each downhole failure to determine the root cause of and solution to the failure.

THE SUCCESS OF THE ORIGINAL 87 EXISTING WELLS

The 10 year "Best Practices" program performance (FPWPY) of the original 87 existing wells is displayed in figure 2 and is listed below;

	95-96	**05-06**	
Tubing Leaks	**1.75**	**0.13**	**93 %** Reduction
Rod Failures	**0.52**	**0.18**	**65 %** Reduction
Pump Failures	**0.46**	**0.11**	**76 %** Reduction
Total Failures	**2.73**	**0.42**	**85 %** Reduction

The greatest reduction in total failures (69 %) for these 87 wells was experienced during the first four years of this program. Interestingly, again during years 4 through 10, there was still a significant reduction (50 %) in total failures. Refer to figure 2-A.

EXPANDING THE PROGRAM - THE NEXT GROUP OF WELLS

The initial success of the original 87 existing wells led to the decision to include an additional 63 newly drilled wells to this "Best Practices" program. Each of these new wells was operating with all new artificial lift equipment installed during initial completion of each well. Including newly drilled wells with new equipment in this failure reduction program proved to have great impact on the success of this "Best Practices" program.

The addition of these 63 newly drilled wells increased the total well count for this "Best Practices" program to 150 wells. At this point it was decided to not add any additional wells to this program. These 150 wells would be monitored and their performance evaluated to determine the success of this "Best Practices" failure reduction program.

THE SUCCESS OF THE 63 NEWLY DRILLED WELLS

The 10 year failure reduction performance (FPWPY) of the 63 newly drilled wells is displayed in figure 3 and is listed below;

	96-97	**05-06**	
Tubing Leaks	**0.25**	**0.09**	**64 %** Reduction
Rod Failures	**0.17**	**0.07**	**59 %** Reduction
Pump Failures	**0.67**	**0.07**	**90 %** Reduction
Total Failures	**1.09**	**0.23**	**79 %** Reduction

The greatest reduction in total failures (70 %) for these 63 additional wells was experienced during the first four years of this program. Interestingly, again during years 4 through 10, there was still a significant reduction (31 %) in total failures. Refer to figure 3-A.

TOTAL PROGRAM SUCCESS

The 10 year failure reduction performance (FPWPY) for this 150 well, PSU "Best Practices" program involving the 87 existing wells and the 63 newly drilled wells is listed below;.

	95-96	**05-06**	
Tubing Leaks	**1.75**	**0.11**	**94 %** Reduction
Rod Failures	**0.52**	**0.13**	**75 %** Reduction
Pump Failures	**0.46**	**0.09**	**80 %** Reduction
Total Failures	**2.72**	**0.33**	**88 %** Reduction

An estimated $17.9 million in 2006 dollars was saved in reduced downhole failures during the 10 years of this PSU "Best Practices" 150 well program. This 10 year savings represents an average of $1.8 Million per year. This savings was estimated using the 2006 failure costs of $16,000 per Tubing Leak, $9,000 per Rod Failure and $8,000 per Pump Failure.

OTHER BENEFITS FROM A "BEST PRACTICES" PROGRAM DATABASE

Could there be other information extracted from this "Best Practices" program and "Best Practices" database?

Could the fatigue life be estimated for the existing steel rods used in this failure reduction program?

All the required information for this estimation of fatigue life was contained in the "Best Practices" program database. Every downhole failure during the last 10 years had been recorded by date of failure, type of failure and depth of failure.

ADDITIONAL INFORMATION FROM THE 63 NEWLY DRILLED WELLS

During the 10 year history of this "Best Practices" program all 63 newly drilled wells had operated with Norris-78 Grade-D rods since initial completion. A review of individual well performance data for these 63 wells resulted in the following observations:

1. A total of 37 wells (59%) had operated with Norris-78 Rods without a rod body failure. (There had been coupling and pin related failures, but these type of failures were not included in this estimate of fatigue life)

2. These 37 Wells had operated 10 years without a rod body failure with 26.0 Million cycles at an estimated 75 % runtime

3. These 37 Wells had operated 10 years without a rod body failure with an average range of cycles of 19.4 - 36.8 Million cycles at an estimated 75 % runtime

4. The Modified Goodman Diagram assumes infinite life at the following;
   a. 10 Million cycles without a failure
   b. Stress Loading of 100 %
   c. Service Factor of 1.0

Further investigation discovered that there were two different rod string designs used by these 37 newly drilled wells. Reviewing performance data for these 37 wells from the 10 year database resulted in the following observations:

1. A total of 17 Wells (46%) were operating with all steel rodstrings utilizing a 7/8” Steel Rod - 3/4” Steel Rod and 1.5” Steel Sinkerbar design

2. A total of 20 Wells (54%) were operating with fiberglass-steel rodstrings utilizing a 1” Fiberglass Rod – 7/8” Steel Rod and 1.5” Steel Sinkerbar design

It was decided to further investigate the performance of the 17 wells utilizing the 7/8” Steel - 3/4” Steel and 1.5” Steel Sinkerbar rodstring designs. Reviewing performance data for these 17 wells from the 10 year database resulted in the following observations:

1. These 17 wells had operated 10 years without a rod body failure with 24.7 Million Cycles at an estimated 75% runtime

2. These 17 wells had operated 10 years without a rod body failure with an average range of cycles of 19.9 - 33.5 Million Cycles at an estimated 75% runtime

3. These 17 wells had operated 10 years with average stress loading of 77% at a service factor if 1.0 using the Modified Goodman Diagram. (Adjusted from service factors of 0.9 used by predictive programs and dynamometer analysis)

4. These 17 wells had operated 10 years with maximum and minimum stresses determined from actual dynamometer surveys or predictive computer programs as follows;
   a. Top Max. Stress 31,707 PSI
   b. Bottom Min. Stress 15,117 PSI

CONCLUSIONS - “BEST PRACTICES” DATABASE

17 Wells had operated 10 years with Norris-78 Grade-D rods without a rod body failure.

Each of these 17 wells had operated 10 years with a 7/8” Steel Rod - 3/4” Steel rod -1.5” Steel Sinkerbar design.

Average Cycles:	25 Million Cycles
Average Range of Cycles:	20 to 34 Million Cycles
Average Stress Loading:	77 %
Service Factor:	1.0

The Modified Goodman Diagram assumes infinite life at the following;

Cycle Life without a failure:	10 Million Cycles

Stress Loading: 100 %
Service Factor: 1.0

Since these 17 wells are still waiting for their first rod body failure to establish their fatigue life, the fatigue life for these 17 wells could not be estimated at the time of this paper.

It can be estimated that the average fatigue life for these 17 wells will be in excess of 25 Million Cycles. This average fatigue life represents 2.5 times the 10 Million Cycles suggested by the Modified Goodman Diagram for infinite life. This conclusion does not factor in the difference in average stress loading of 77 % and 100 %.

CONCLUSIONS - "BEST PRACTICES" PROGRAM AND DATABASE

This "Best Practices" program and "Best Practices" database realized a $17.9 Million savings (2006 dollars) in downhole failures during the first 10 years of this failure reduction program.

A "Best Practices" program and database will provide you with the tools to reduce failures, monitor existing performance, project future performance and document performance by:

1. Total project
2. Existing wells & new wells (or any other kind of sub-set comparison)
3. Type of downhole failure and failure cost; (tubing leak, rod failure or pump failure)

A "Best Practices" Program and Database will allow you to market project performance to:

1. Operating company management and field personnel
2. All supporting vendors
3. The oil and gas industry

A "Best Practices" program and "Best Practices" database can provide additional performance information like estimated rod fatigue life as compared to the Modified Goodman Diagram.

If your company has not initiated a "Best Practices" program and database and you have not yet realized the reductions in tubing leaks, rod failures and pump failures described in this paper, then the results of this paper strongly suggests that you initiate and monitor such a program.

If your company has a "Best Practices" program and database in operation and you have yet to realize comparable reductions in tubing leaks, rod failures and pump failures, then re-evaluate your current program. If your current program has not involved procedures presented in this paper, consider adopting those specific procedures.

Best results from a "Best Practices" program and database will be realized when the program can be initialized on newly drilled wells installed with new tubing, rods, sinkerbars and pumps.

ACKNOWLEDGMENTS

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The 12th Annual 2006 Artificial Lift Forum, November 7-8, 2006 in Midland, Texas
The 2nd Annual 2006 Calgary Artificial Lift School, November 28-29, 2006 in Calgary, Alberta Canada

REFERENCES

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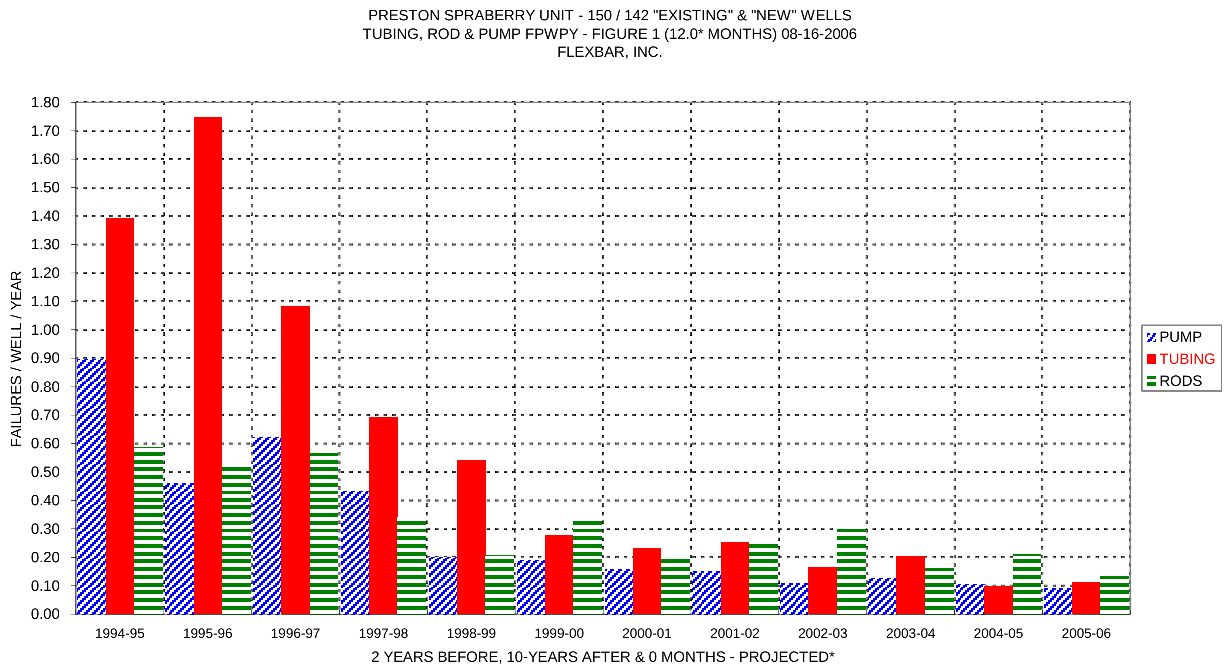

Figure 1

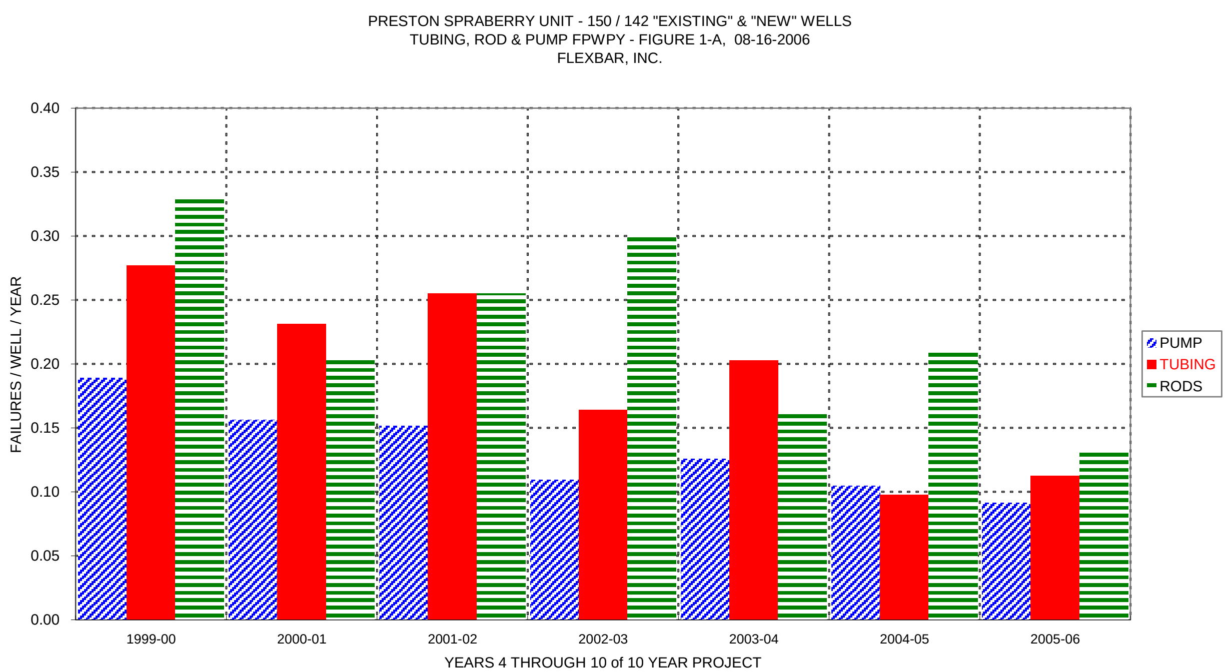

Figure 1A

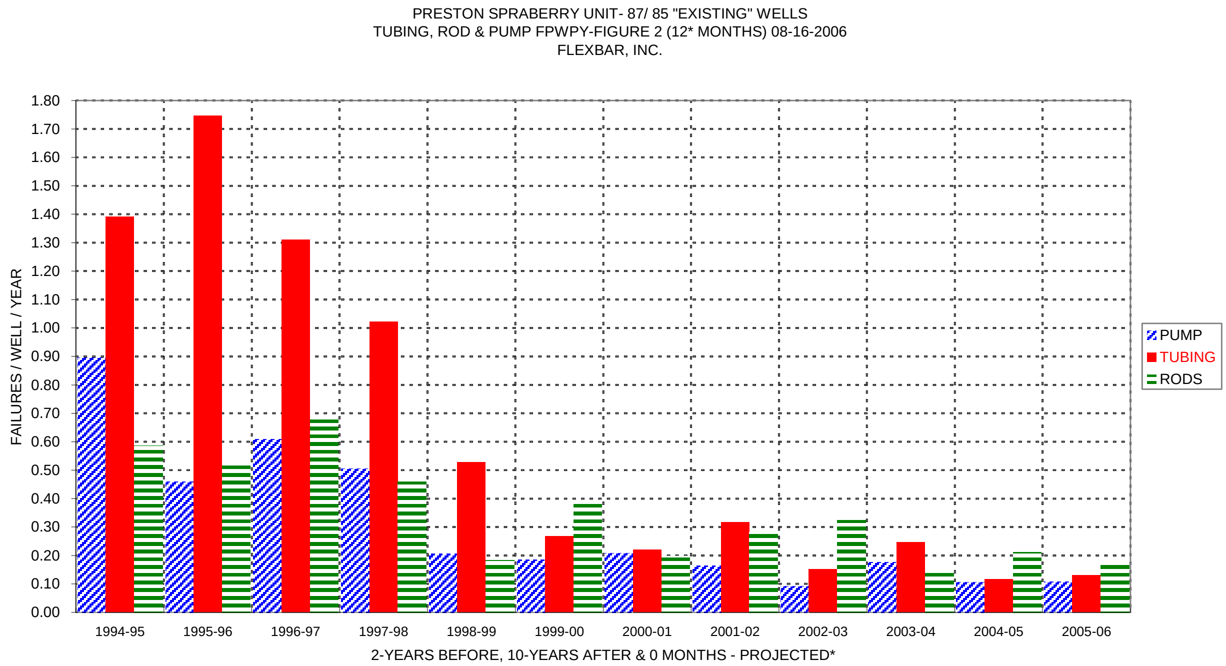

Figure 2

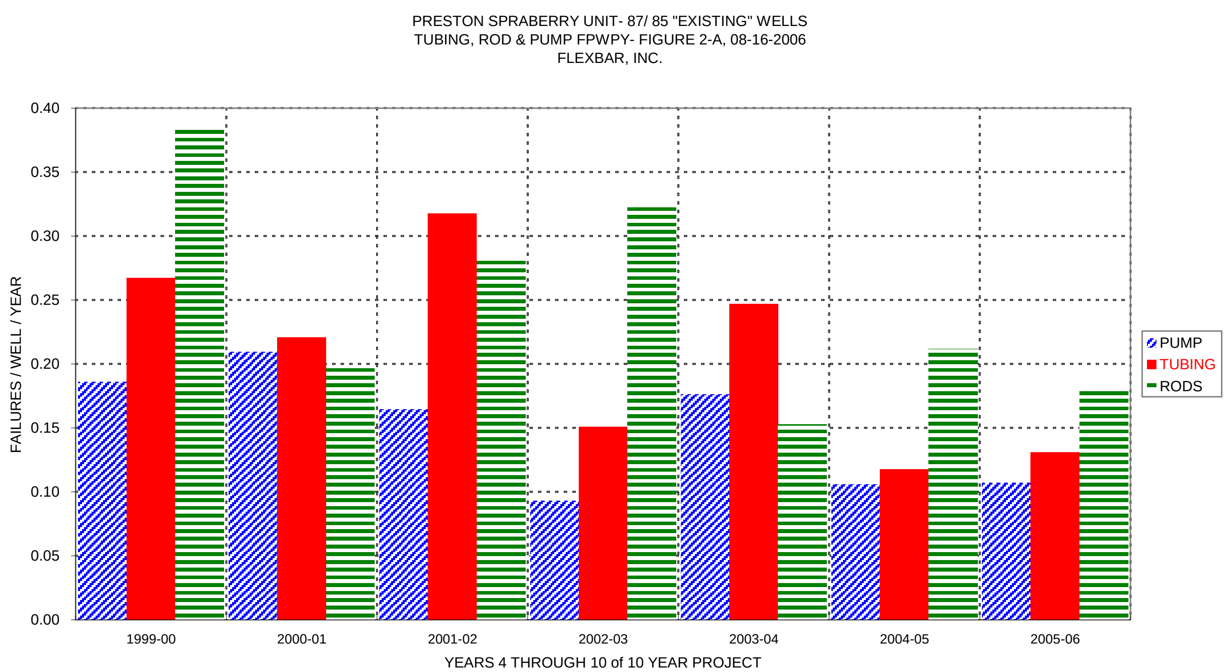

Figure 2A

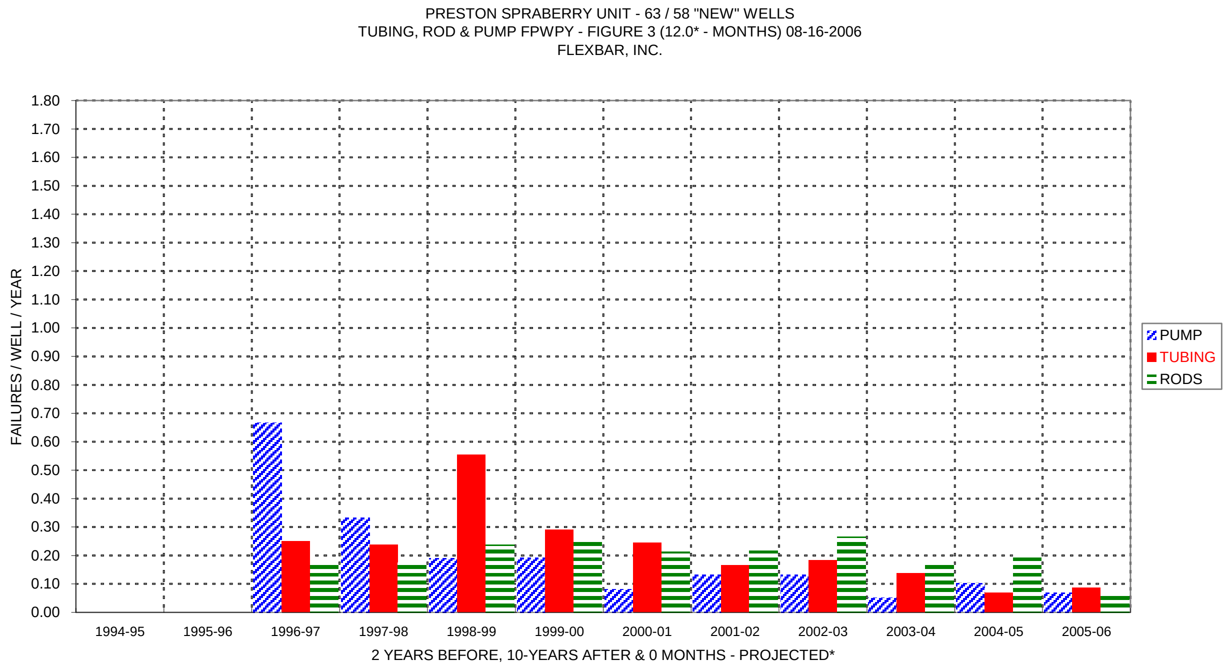

Figure 3

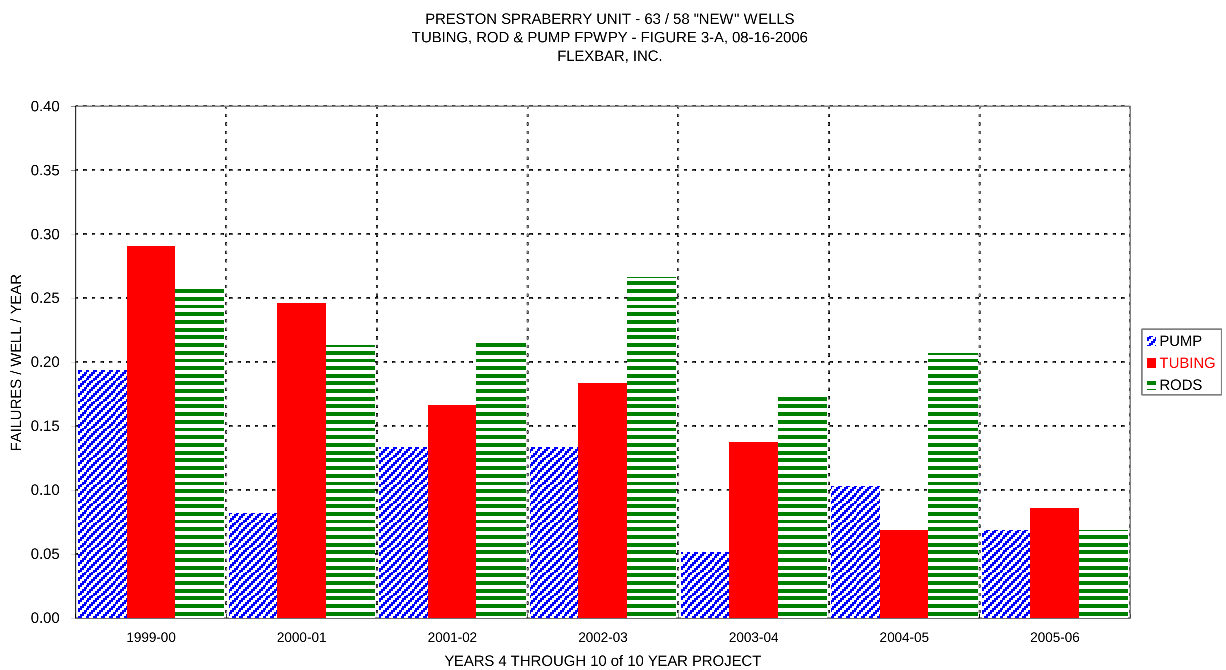

Figure 3A