BEST PRACTICES IN THE PRESTON SPRABERRY UNIT

Scott W. Long, Flexbar, Inc.
Elton Smith, Charlie Hoff, and Albert Garza
Pioneer Natural Resources USA, Inc.

Abstract and Scope

During the last several years the Petroleum Industry has adopted the term "Best Practices" to describe an efficient method of producing oil and gas. The definition of this "method" is very subjective and is continually changing with acceptance of newer improved and proven rod pumping knowledge. The best way to describe the term "Best Practices" is to use the phrase "Work in Progress".

This paper describes and presents the implementation of a "Best Practices" program in the Preston Spraberry Unit located in West Texas. This accepted "Best Practices" program is presented as follows;

1. Complete initial pumping well analysis
2. Matching lift operations to current producing rates by optimizing the following;

   Plunger Diameter
   Strokes Per Minute
   Stroke Length
   Tubing Anchor Catcher
   Downhole Gas Separation

3. Managing downhole rodstring buckling by re-evaluation of rodstring designs and installation of sinkerbars.
4. Installing pump-off controllers to manage production rates, optimize run times and monitor equipment performance.
5. Follow-up well-site diagnostic analyses after several months of operation to evaluate initial well analysis, original well work and implement further modifications.

Due to the successful implementation of this "Best Practices" program, tubing leaks were reduced 61%, rod parts were reduced 35%, and pump repairs were reduced 6% during the two-year test period.

Recognition and continued development of these successful "Best Practices" will provide the Oil and Gas Industry with improved artificial lift guidelines. Implementation of these guidelines will allow for a more efficient use of all valuable resources to efficiently produce oil and gas.

Summary of Results

A total of 150 producing wells from the Preston Spraberry Unit were selected for evaluation of this "Best Practices" program. Tracking performance for these 150 wells during this two-year test identified a decrease in tubing leaks, rod parts and in some cases, pump repairs. The greatest reduction in failures was tubing leaks.

These 150 producing wells were comprised of two unique data sets. There were 87 producing wells with lift equipment in operation prior to the initiation of this "Best Practices" program. These wells are labeled in this paper as "Existing" wells. The word "Existing" refers to used rods and used tubing of unknown condition. The remaining 63 producing wells were newly drilled wells completed with new lift equipment during this "Best Practices" program. These wells are labeled in this paper as "New" wells. The word "New" refers to new rods and new tubing in new condition.

Tracking performance of the total 150 well project of both "Existing" and "New" wells identified a decrease in tubing leaks, rod parts and pump repairs over the two-year period.

Tracking performance of the "Existing" wells identified a decrease in tubing leaks, decrease in rod parts and a slight increase in pump repairs over the two-year period.

Tracking performance of the "New" wells compared to the "Existing" wells identified the lowest frequency of tubing leaks, rod parts and pump repairs. This low frequency of failures was sustained by these "New" wells throughout the second year of this "Best Practices" program.

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. Relevant producing information is as follows;

The average pump depth is 6,850 feet.
Average oil cut is 35% and water cut is 65%.
Production tubing is 2-3/8" inside 4-1/2" casing.
Tubing anchor catchers are set below the seating nipples.
An estimated 90 % of all seating nipples were located above the perforations.
An estimated 85% of the tubing strings were plain, non-internally coated tubing.
An estimated 15% of the tubing strings were internally plastic coated.
Average stroke lengths are 86 inch.
Average pump speed is 8.0 spm.
Rodstrings are 7/8"-3/4" steel-1.5" sinkerbars and 1" fiberglass–7/8" steel-1.5 sinkerbars
An estimated 80% of downhole pumps were insert type with 1.25" diameter plungers.

The Producing intervals are located from 7,000 feet to 8,700 feet.

Description of "Best Practices" Program

The "Best Practices" Program at the Preston Spraberry Unit can best be described as a program that is continually improving with greater knowledge and awareness gained from further reductions in tubing leaks, rod parts and pump repairs. The five-step program is as follows;

1. Complete initial pumping well diagnostic analysis on existing wells. Complete predictive analysis on wells yet to be on production.
2. Well optimization to match existing or future lift operations with existing or future equipment. These optimization steps include modification of the following;

    Pump Diameters
    Strokes Per Minute
    Stroke Length
    Tubing Anchor Catcher
    Downhole Gas Separation

3. Re-evaluation of rodstring designs and installation of sinkerbars to manage downhole rodstring buckling.

4. Installation of Pump-off controllers to manage the following;

    Production Rates
    Optimize Run Times
    Monitor Equipment Performance

5. Follow-up well-site diagnostic analysis after several months of operation to evaluate initial analysis, original well work and implement further modifications.

These five (5) steps were applied to this project study involving a total of 150 Preston Spraberry Unit Wells. Refer to **Graph No. 1** for a presentation of the rate of Sinkerbar installations, pump-off controller installations and completion of well optimizations.

For the 150 Well Preston Spraberry Unit Project, all 150 wells were installed with sinkerbars during the two-year test period. Refer to **Graph No. 2** for a footage presentation of Sinkerbar installations. This graph presents in individual well footage of sinkerbars installed from August 17, 1996 to August 17, 1998.

The range of sinkerbars installed was from 50 feet to 625 feet. The average footage for the total 150 well project was 375 feet. Average footage for all steel designs was 300 feet. Average footage for fiberglass-steel designs was 475 feet.

Program Parameters and Procedures

The time period for this paper evaluating the Preston Spraberry Unit "Best Practices" program initiated on August 17, 1996 with the installation of 625 feet of 1.5" sinkerbars in Preston Spraberry Unit, Well No. 4145-A. The last installation for this program was on August 14, 1998. The Preston Spraberry Unit Well No. 2605-A was installed with 325' of 1.5" sinkerbars.

The two-year evaluation period concluded on August 17, 1998. The "Best Practices" program is still in operation and is being monitored. This program will continue to evolve and improve with continued improvements in tubing leaks, rod parts and pump repairs.

To evaluate the individual impact of different parts of the "Best Practices" program on reductions in tubing leaks, rod parts and pump repairs, "Best Practices" implementations were organized into three (3) groups. These groups are listed and defined as follows;

1. Sinkerbar Wells – Wells installed with 1.5" sinkerbars
2. Optimizations – Wells experiencing optimization improvements involving the following;

    Plunger Diameter
    Strokes Per Minute
    Stroke Length
    Tubing Anchor Catcher
    Downhole Gas Separation

3. P.O.C.'s – Installation of Pump-off Controllers

During the two-year test period, the "Best Practices" program involved;

150 Sinkerbar installations
143 Well Optimizations
48 installations of Pump-off Controllers.

Refer to **Graph 1** for a chronological presentation of the implementation of sinkerbars, well optimizations and pump-off controllers during the two-year test period.

Refer to **Graph 2** for a presentation of Sinkerbar footage installed per well during the two-year test period.

Implementation of well optimizations in the 150 Preston Spraberry Unit Wells was also an ongoing effort during the two-year test period. When several well optimizations occurred during the same workover, each optimization was recorded as a separate well optimization. The initial installation of sinkerbars was not considered a well optimization. The lowering of tubing was considered a re-evaluation of rodstring designs.

Program Parameters and Procedures - Continued

At the conclusion of this two-year test period, 103 wells of the 150 wells had received well optimizations. The remaining 47 wells never received well optimizations because they operated without failure from installation of sinkerbars to the end of the test period.

Of these 47 wells, 24 wells were "Existing" wells that operated without a failure from installation of sinkerbars to the end of the test period. The longest operating "Existing" well without a failure is Preston Spraberry Unit #4014-B. Sinkerbars were installed on February 5, 1997 and this well was operating as of January 8, 1999 without a failure.

Of the 47 wells, 23 wells were "New" wells that operated without a failure from installation of sinkerbars to the end of the test period. The longest operating "New" well without a failure is Preston Spraberry Unit #2804-A. Sinkerbars were installed on June 8, 1997 and this well was operating as of January 8, 1999 without a failure.

Well optimizations are presented from highest to lowest frequency of occurrence.

Non-routine Replacement of Bottom 10-100 Joints of Tubing	34 %
Changing Strokes per Minute	23 %
Re-evaluating Rodstrings Designs (not including sinkerbar installation)	16 %
Changing Pump Diameter	14 %
Installing and / or Adjusting Tubing Anchor Catchers	7 %
Changing Stroke Lengths	5 %
Installing and / or Adjusting Gas Anchors	1 %
Total for 143 Well Optimizations	100 %

In the above distribution of 143 Well Optimizations involving 103 wells, 87 % of the total optimizations involved 10-100 joint tubing replacements, changing strokes per minute, re-evaluating rodstrings design and changing pump diameters.

Rodstrings for the "Existing" wells prior to start-up of the "Best Practices" program consisted of 7/8" steel – 3/4" steel - 450' of 7/8" rods with molded rod guides and 1" fiberglass – 7/8" steel - 450' of 7/8" rods with molded rod guides.

After start-up of the "Best Practices" program, rodstrings designs were re-evaluated for both "Existing" and "New" wells. The resulting rodstrings consisted of 7/8" steel - 3/4" steel – 1.5" sinkerbars and 1" fiberglass – 7/8" steel – 1.5" sinkerbars.

Program Parameters and Procedures – Continued

The replacement of tubing should not be considered the most important well optimization. Installation of new tubing in areas of tubing wear along with improved rodstring and sinkerbar designs in "Existing" wells, provided the best equipment and operating conditions to minimize tubing failures. New tubing eliminated tubing failures above the seating nipple due to tubing of questionable or unknown condition. Improved rod designs incorporating sinkerbars reduced rod wear above the pump due to rod buckling.

Pump-off controllers were installed on 48 of the 150 wells in this project. These installations occurred from June 1, 1996 to May 20, 1998. Run times for these 48 wells were reduced by an estimated 35% during the two-year test period.

Results – General Explanation

The following discussion of the results of the "Best Practices" program on the Preston Spraberry Unit incorporates data presented as Failures Per Well Per Year (FPWPY). The "Per Year" time period begins and ends on August 17 of each appropriate year.

The two-year period from August 19, 1995 to August 17, 1996 is used to compare failure performance prior to start-up of the "Best Practices" program on August 17, 1996. The two-year period from August 17, 1996 to August 17, 1997 and August 17, 1997 to August 17, 1998 present failure performance as a result of the "Best Practices" program.

Results - Total 150 Well Comparison of "Best Practices" Program

Results of the "Best Practices" program involving the total 150 Preston Sprabery Unit Wells, comparing the 12-month period prior to program start-up to the first and second full year of the program is as follows;

Failure Reductions (FPWPY) for 150 Preston Spraberry Unit Wells

	1995-1996	1996-1997	1997-1998	96-97 to 95-96 Percent Change	97-98 to 95-96 Percent Change
Tubing Leaks	1.75	1.08	0.69	38 % **Reduction**	61 % **Reduction**
Rod Parts	0.52	0.57	0.34	10 % Increase	35 % **Reduction**
Pump Repairs	0.46	0.62	0.43	35 % Increase	6 % **Reduction**

The above results involve 87 "Existing" and 63 "New" Preston Spraberry Unit Wells. Refer to **Graph 3** for a bar graph presenting these results.

Results - "Existing" Well Comparison of "Best Practices" Program

Results of the "Best Practices" program involving the 87 "Existing" Preston Spraberry Unit Wells, comparing the 12 months prior to program start-up to the first and second full year of the program is as follows;

Failure Reductions (FPWPY) for 87 "Existing" Preston Spraberry Unit Wells

	1995-1996	1996-97	1997-1998	96-97 to 95-96 Percent Change	97-98 to 95-96 Percent Change
Tubing Leaks	1.75	1.31	1.02	25 % **Reduction**	42 % **Reduction**
Rod Parts	0.52	0.68	0.46	31 % Increase	12 % **Reduction**
Pump Repairs	0.46	0.61	0.49	33 % Increase	7 % Increase

The above results involve 87 "Existing" Preston Spraberry Unit Wells. Refer to **Graph 4** for a bar graph presenting these results.

Results - "New" Well Comparison of "Best Practices" Program

Results of the "Best Practices" program involving the 63 "New" Preston Sprabery Unit Wells, presenting the first and second full year of the program is as follows;

Failure Reductions (FPWPY) for 63 "New" Preston Spraberry Unit Wells

	1995-1996	1996-1997	1997-1998	96-97 to 95-96 Percent Change	97-98 to 95-96 Percent Change
Tubing Leaks	No Data	0.25	0.24	Not Applicable	Not Applicable
Rod Parts	No Data	0.17	0.17	Not Applicable	Not Applicable
Pump Repairs	No Data	0.67	0.33	Not Applicable	Not Applicable

The above results involve 63 "New" Preston Spraberry Unit Wells. Since the first of these 63 wells were drilled and completed on August 23, 1997, after the start of the test program, no prior comparison of "New" Preston Spraberry Unit Well data can be referenced. Refer to **Graph 5** for a bar graph presenting these results.

Conclusions

A successful "Best Practices" program was initiated on the Preston Spraberry Unit involving 150 producing wells. This program was initiated on August 17, 1998 and performance data was collected for a two-year test period, ending on August 17, 1998.

Conclusions - Continued

The "Best Practices" program included the following;

1. Complete diagnostic well analysis on "existing" wells and predictive well analysis on "new" wells.

2. All wells were optimized to match existing or future lift operations with existing or future equipment. The process of well optimization involved evaluating and modifying when necessary the following;

   Pump Diameters
   Strokes Per Minute
   Stroke Length
   Tubing Anchor Catcher
   Downhole Gas Separation

3. Re-evaluation of rodstring designs and installation of sinkerbars to manage downhole rodstring buckling.

4. Installation of Pump-off controllers to manage the following;

   Production Rates
   Optimize Run Times
   Monitor Equipment Performance

5. Follow-up well-site diagnostic analysis to evaluate initial diagnostic or predictive analysis after several months of operation.

Results of this successful 150 well "Best Practices" program was a 61 % reduction in tubing leaks, 35 % reduction in rod parts and a 6 % reduction in pump repairs over a two-year period.

The results of this 150 well "Best Practices" program occurred during a two-year test period. Reductions in tubing leaks, rod parts and pump repairs were determined when compared to well performance (FPWPY) of the same 150 wells during the two years prior to program start-up. The use of a FPWPY analysis allowed for the normalization of both "Existing" and "New" performance data on a per well basis.

Conclusions - Continued

If your company has yet to initiate a "Best Practices" program, the results of this paper strongly suggest that such a program be initiated and monitored, so your company can realize similar reductions in tubing leaks, rod parts and pump repairs.

If your company has a "Best Practices" program in operation that has not been able to realize comparable reductions in tubing leaks, rod parts and pump repairs as presented in this paper, evaluate your current "Best Practices" program. If your program does not involve procedures presented in the "Best Practices" program described in this paper, consider adopting those specific procedures.

Best results from a "Best Practices" program will be realized when that program can be initiated on newly drilled wells with new tubing, new rods and new sinkerbars.

Contributors

Pioneer Natural Resources USA, Inc.
Flexbar, Inc.

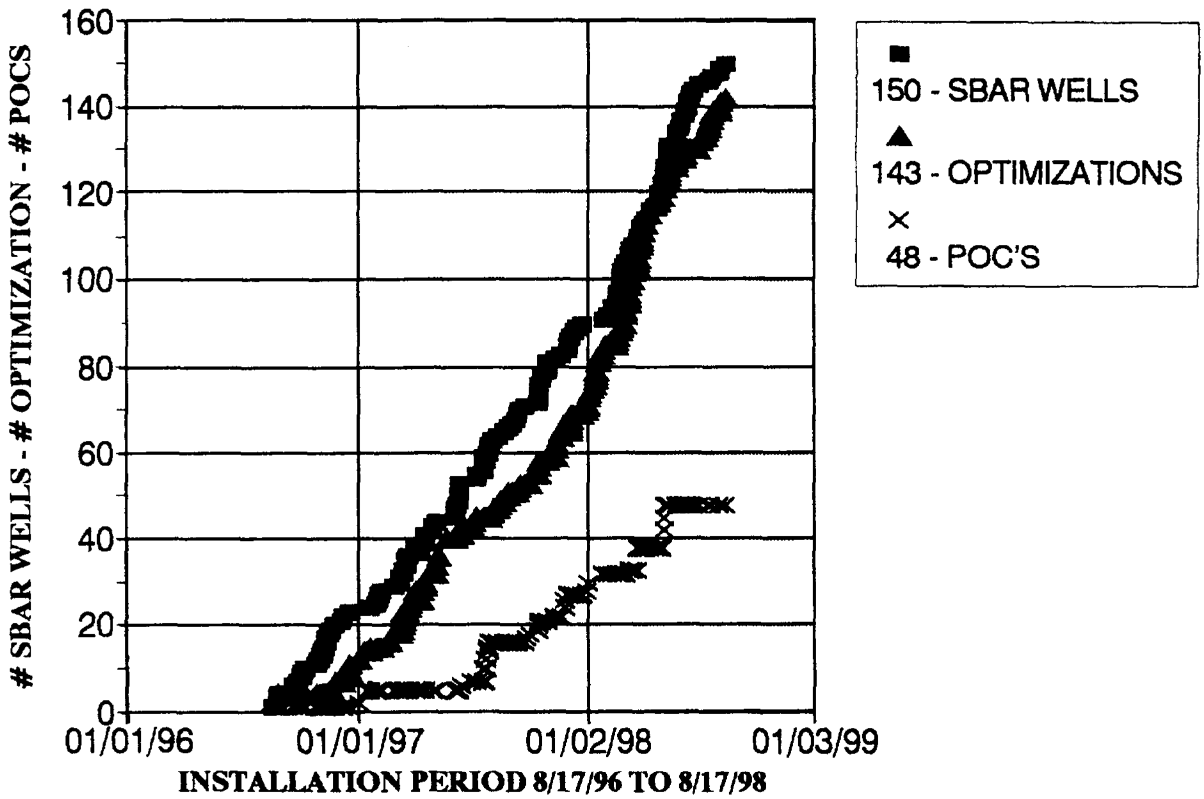

Figure 1 - Preston Spraberry Unit - 150 Wells
Cum. "Best Practices" Installs

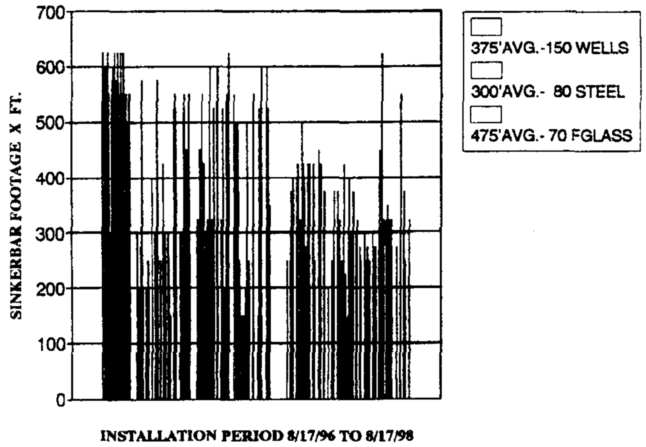

Figure 2 - Preston Spraberry Unit - 150 Wells
Sinkerbar Footage Per Well

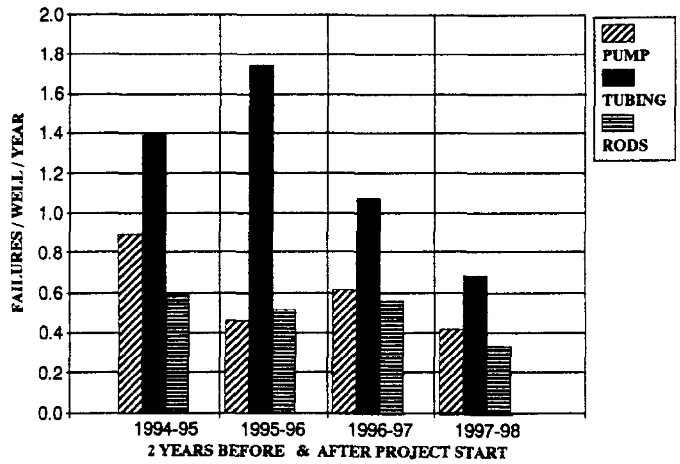

Figure 3 - Preston Spraberry Unit - 150 Total Wells
Tubing, Rod and Pump FPWPY

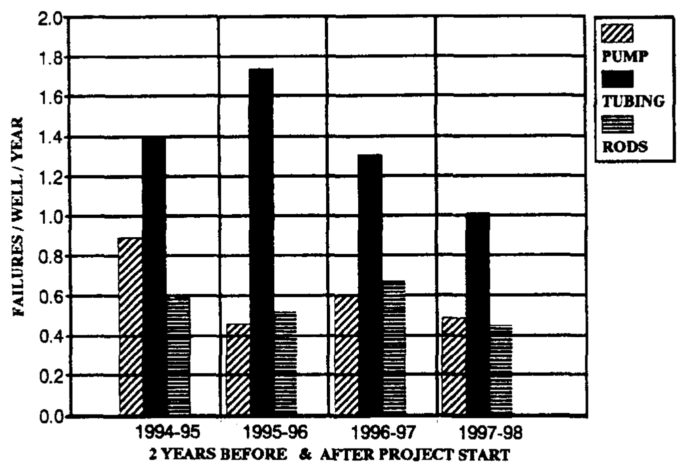

Figure 4 - Preston Spraberry Unit - 87 "Ex." Wells
Tubing, Rod and Pump FPWPY

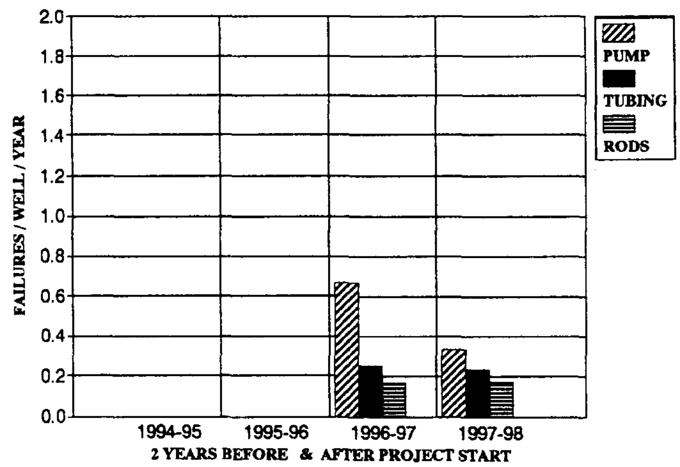

Figure 5 - Preston Spraberry Unit - 63 "New" Wells
Tubing, Rod and Pump FPWPY