"LONG AND SLOW" OR "SHORT AND FAST" IS NOT THE WAY TO GO

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ABSTRACT
More efficient operations and lower failure rates will result if sucker rod lifted wells are operated with a pump filled with liquid. Dynamometer and fluid level surveys can be used to identify when the well is operating properly and when there are operating problems. There are a variety of recommended practices for operating sucker rod lifted wells to provide low operating cost and low failure rate. Data will show that long and slow versus short and fast both can result in high failure rates when the sucker rod pumping system has incomplete pump fillage. Frequently inspection of dynamometer data collected on sucker rod lifted wells operated using pump-off controllers, variable speed drives or timers show incomplete pump fillage. Incomplete pump fillage is often associated with a "pumped-off well" or gas entering the pump replacing liquid fillage. This presentation will show data collected on several wells to address problems created by operating a pump not filled with liquid.

INTRODUCTION

There are a variety of recommended practices for producing sucker rod lifted wells to provide optimum operations and profits. Dynamometer and fluid level surveys are used to identify when the well is properly operating and when there are operating problems. One recommended practice that is often ignored is to produce wells with complete pump fillage. More efficient operations and lower failure rate will result if wells are operated with a pump filled with liquid. Data from 6000 Permian Basin wells will be used to show stroke length combined with strokes per minute are important; but the primary reason for a long run life is to always operate with a pump filled with liquid. Data will show that long and slow versus short and fast both result in high failure rates when the pump has incomplete pump fillage. Common operating practice seen when inspecting dynamometer data collected on sucker rod lifted wells shows incomplete pump fillage.

RECOMMENDED PRACTICES

Recommended practices include properly installing equipment in the well, providing proper chemical treatments, preventing rod on tubing wear, identifying cause of well failures, and periodic surveillance of the well. Applying the recommended[1] practices to beam pumped systems will result in lower operating cost and longer equipment life. Any time the operator makes changes to his normal practices, then follow-up analysis should made to confirm that the new operating practice is working as desired. Beam pumping is the most widely used form of artificial lift. Beam pumped wells should be periodically monitored with dynamometer surveys and the diagnostic pump card shapes should be used to ensure that the pump has no mechanical problems and efficient operations are maintained. Fluid level surveys should be used to confirm all the available liquid is produced from the well. Percentage timers, POC and Variable speed drives should operate the Beam Pump system only when the downhole pump is filled with liquid else low efficiencies and equipment damage usually result from gas interference and fluid pound. To maintain efficient and generally trouble-free operation requires that pumping should be done only when the pump has a high degree of liquid fillage.

Identifying cause of well failures by analyzing failed equipment components and taking action to prevent future repeat of same type failures will increase system run times and increase Mean Time Between Failures [MTBF] ~ reducing failure frequency. Part of failure analysis is to be present when failed equipment is pulled from the well and to attend tear down of pumps when repaired at the pump shop. Inspect failing component is usually required in order to identify and understand cause(s) of failure. To be able to use the knowledge gained during failure analysis some type of computer system is recommended to store results of the analysis in an accessible database. Having team meetings with all parties connected to the failure will allow personnel to become more effective in making recommendations on equipment and equipment configurations; if reasons for failures are known. Preventing failures can be accomplished by monitoring the operation of sucker rod lift equipment, identifying a problem and making a change before the equipment fails. Recommended practices that increase equipment life are preventing mishandling of equipment while being installed in the well, inspecting new and used equipment to preventing equipment with defects from being installed in a well, and operating equipment within operational limits to prevent overload or misuse of equipment used to operate the well.

Incomplete pump fillage, tagging on the downstroke, and other downhole conditions contribute to rod buckling and accelerated rod/tubing wear. Commonly applied solutions to reduce rod/tubing wear are proper spacing of the pump, use of weight bars to maintain tension on the rod string, where mechanical friction occurs use rod guides, in some cases use poly-liner if required. When incomplete pump fillage is caused by gas interference a properly sized downhole gas separators should be installed with sufficient gas separation capacity for the well's net pump displacement. Full pump fillage also requires an efficient downhole gas separator that results in a full pump, if insufficient liquid is present to fill the pump controlling run time is also required. Full pump fillage generally requires controlling the run time of the pumping unit to match the pump capacity to the maximum well inflow rate. More efficient operations and lower electrical power usage will result if wells are operated with a pump that is filled with liquid.

Dynamometer and fluid level surveys are used to identify when the well is properly operating and when there are operating problems. Use predicted and measured dynamometer data as cross-check; calculate what is measured 1) Rod Parts are often caused by wear, 2) Rods-on-Tubing Contact, 3) Pump fillage (fluid pound or gas interference), 4) Avoid sudden impact loads (tagging) on upstroke or down stroke

In general, sucker-rod pumping is the one of the primary forms of producing a well. Long lived efficient operation of sucker rod pumping systems is possible when recommended practices are employed in the operation of the well, plus action is taken to produce the well with a pump filled with liquid. Applying recommended practices to operate a sucker rod lifted well is important in long life operation with a minimum of issues.

ROD DESIGN

All rods should be designed with loadings using your field established service factor. If field established Service Factor is not available, then use 1.0 for service factor. Do run high strength rods until rod loading on D grade rods exceed 100% when using a 1.0 service factor (some fields use a 1.25 service factor) .

During the time period of 1980-2000 two operating believed that each company's internally developed sucker rod software design software was a primary reason for having the lowest failure rates in the Permian Basin. Their practice of operating their sucker rod lifted wells with respect to respect to N/No' and Fo/Skr range was different and could be described as opposite. Company J strongly believed in operating their sucker rod lifted wells with a long stroke with a slow pumping speed, where Company H believed operating at a fast-pumping speed and short stroke. The N/No' and Fo/Skr design/operation limits that were used are shown graphically in **Figure 2 and 3**. Figure 2 shows contour lines that were used by the sucker rod design program of Company J. When a rod string was designed by Company J, the design software would alert the designer that his design was acceptable or if outside the red line, then the design program would not allow the rod string design to be displayed. Company J belief was by adhering to these design limits led to a long-lived sucker rod string life. Sucker rod designs by Company J using this technique tended toward slower in SPM and longer in stroke length (long and slow). The other operating Company H had the sucker rod design philosophy (short and fast) of keeping the dimensionless parameters with-in the bounds of 0.2 to 0.35 N/No' and 0.2 to 0.5 Fo/Skr. With respect to N/No' and Fo/Skr the permissible sucker rod designs by Company J and H methodologies were exclusive of each other. Company J would not accept rod designs by Company H, nor would Company H accept rod designs by Company J. But both companies believed that their proprietary sucker rod design practices led to long operational life as shown by their industry leading low failure frequency. Company H bounding of N/No' was based on recommendations from Howell and Hogwood[8], that to obtain the best efficiency from motors, N/No' should be greater than 0.20. However, the N/No' should not exceed 0.35 since it becomes more difficult to counter balance the pumping unit. Company H minimum and maximum for Fo/Skr was to balance the cost of the pumping equipment versus the cost of operating failures.

While there was a difference in approach to using the design and non-dimensional operating parameters, both of these J and H companies at least had a design philosophy. However, probably equally or more importantly, both companies:

- Had an active program where production technicians

    - Acquired field data
    - Analyzed problems, and
    - Followed-up recommendations
- Practiced a “company” methodology to analyze, troubleshoot and optimize wells
- Tracked causes and condition of downhole failed equipment in an internal proprietary failure date base
- Determined root cause failure analysis and made appropriate repairs and changes to prevent future failures.

Properly analyzing failures, redesigning equipment, repairing and optimizing wells should be conducted if low operating costs, optimum production and maximum well and field value are important. Both companies operated their pumps filled with liquid, but were surprised to discover that operating their sucker rod lifted wells “**LONG AND SLOW**” vs “**SHORT AND FAST**” had no impact on their run life when their failure data was shared during the 9-year ALEOC study.

ALEOC 9-year STUDY

Failure frequency results from the Artificial Lift Energy Optimization Consortium, ALEOC, for 11 operators in the Permian Basin was obtained and provided by Texas Tech University[4]. These failure frequencies provide the number of sucker rod, pump and tubing failures per well per year and included data from over 25,000 producing wells. **Figure 4** shows the failures frequencies per year along with the average and one standard deviation for the companies providing their failure data. Even though Company J and H had very different rod string design practices concerning permissible Fo/Skr and N/No’ values, it is interesting to note that both companies had failure frequencies of approximately 0.4. The 0.4 failure frequency was the lowest of all the operating companies in the ALEOC study.

The 11 operators that participated in the 9-year ALEOC project shared recommended practices within the group. Meetings were held about every 3 months where a recommended practice of a company was presented to the group and positives and negatives of the practice were discussed. Comparison of the failure frequency show in **Figure 4** were made by the individual operators, seeing that most operators had higher failure frequencies they made an effort to analyze the well’s operation and they took action to fix problems that were discovered. All 11 operators in the ALEOC study group recognized their performance could be improved and they took action to reduce failures. Their different actions with-in their individual companies resulted in a reduction of failures for all companies in the study group. Based on the improvement in the failure frequency during the time period of the 9-year project, any operator in the Permian basin should expect a 0.4 failure frequency in their field. Companies H and J never revealed what they considered their proprietary sucker rod design limits during ALEOC meetings, the design limits were key in each company believing that they should operate their wells either “**LONG AND SLOW**” (J) vs “**SHORT AND FAST**” (H).

Notice the 1.6 failure frequency of operator L during year 1990 shown in **Figure 4.** This operator was a strong proponent of applying recommended practices to their wells. All of their wells were operated using pump-off-controllers, but the settings in the controller resulted in excessive number of pump-off strokes per cycle. One of the actions taken by operator L to reduce failure frequency was to count pump-off strokes and adjust the controller settings to reduce the number of pump-off strokes per cycle. There was a significant reduction of failure frequency for operator L over the 9-year ALEOC project.

INCOMPLETE PUMP FILLAGE

The causes of incomplete liquid fillage[5] can be classified in three categories:

1- Fluid present at the pump intake consists of a mixture of free gas and liquid and consequently both phases enter the pump through the standing valve. This condition is normally labeled “gas interference”.
2- Production liquid rate from the reservoir (flowing through perforations) is less than the pump displacement rate and consequently there is not sufficient liquid in the annulus to fill the pump barrel.

This condition is normally labeled "pumped off"

3- Flow rate of liquid entering the pump is restricted so that the liquid cannot fill the pump barrel fast enough during the plunger upstroke. Flow restriction may be caused by deposits of scale, paraffin, sand, rust or other materials or by excessive friction losses related to viscous crude. This condition is normally labeled blocked pump.

When fluid entry into the pump is blocked by a choked intake, then no gas is in the pump barrel and plunger actually "collides" into the liquid inside the pump barrel. Large negative compressive loads are only seen when the plunger collides with the liquid inside the pump barrel of a choked intake. Large negative loads are not usually seen when the plunger contacts the liquid in cases of gas interference or fluid pound, because gas compression reduces the plunger velocity before the plunger contacts the liquid in the bottom of the pump barrel.

Figure 5 shows a detailed analysis of the polished rod velocity, the plunger velocity and pump load as a function of time for the complete stroke. The vertical dashed line indicates the point where the TV opens after the gas in the barrel is compressed to the pump discharge pressure. Notice how the velocity of the plunger at the beginning of the down stroke from 4 seconds to 5 seconds follows exactly the velocity of the polished rod reaching a maximum velocity of about 91 inches per second. From this point to about 5.5 seconds both the polished rod and the plunger slow down, but the plunger slows down more due to the resistance from compressing gas. At the point where the TV opens the plunger is moving at 54 inches per second while the polished rod is moving at 86 inches per second. This velocity difference causes compressive loading of the rods as indicated by the negative pump load of 370 Lbs. After the TV opens (from 5.5 to 6.1 seconds) the plunger velocity increases to 77 inches per second, exceeding the downward velocity of the polished rod. These velocity variations cause the load oscillations noted at the bottom of the pump dynamometer card. Compressive loading of the lower section of the rods results in helical buckling of the rods and excessive wear of the tubing.

Figure 6 shows a detailed analysis of the polished rod velocity, the plunger velocity and pump load as a function of time for a complete stroke. Notice how the velocity of the plunger at the beginning of the down stroke from 5 seconds to 7.2 seconds follows roughly the velocity of the polished rod reaching velocity of about 35 inches per second. From this point to about 7.6 seconds both the polished rod and the plunger slow down, but the plunger almost stops at the point where it reaches the gas-liquid interface in the barrel and the TV opens. At this point (8 seconds) the plunger is moving at 3 inches per second while the polished rod is moving at 30 inches per second. This rapid velocity differential causes a minor amount of compressive loading of the rods as indicated by the negative pump load of 180 Lbs. After the TV opens (from 8 to 9 seconds) the plunger velocity increases to 33 inches per second, exceeding the velocity of the polished rod. This variation causes the load oscillations noted at the bottom of the pump dynamometer.

PUMP-OFF TAG

The pump stroke can be longer than the surface stroke when the dynamic motion of the beam pump system adds momentum to the rod string, resulting in the pump stroke length increasing. Pump position in the barrel changes when the pump is not full compared to a stroke when the pump is filled with liquid. When incomplete pump fillage occurs, the plunger tends to over travels on the down stroke moving deeper into the barrel. In some cases, tagging can occur due to pump spacing, plus increased over travel. Dynamometer data collected at a well showed a full pump card and when pump off occurred the pump card would display a tag at the bottom of the pump stroke. When a fluid pound happens on a stroke, then the plunger over travels and the plunger can move deeper into the barrel on the down stroke. Tagging the pump occurs due to the pump spacing, higher loads on down stroke and higher downward inertia created by the higher velocity on the down stroke. During incomplete pump fillage portion of the down stroke the loads applied by the pump to the rods is higher thereby causing the pump stroke to be longer than when pump is full. On the down stroke when the pump is not full and the traveling valve has not opened, the velocity of the plunger suddenly slows to open the traveling on the down stroke. In a fluid pound card prior to opening the TV the full fluid load is still applied to the rod string. **Figure 7** the plunger is moving pretty fast, almost at the velocity of the polished rod. The fast velocity and rod loading quickly change, when the plunger stops/slows to open the traveling valve. Once the TV opens momentum in the rod string is not lost and the plunger accelerates, the energy stored in the rod string causes the plunger to move deeper into the barrel. Pump load on the up stroke is the same when a pump is filled with liquid or not filled (pumped off) and the rod weight is the same. A fluid pound Pump-OFF tag can occur, because: 1) Plunger over travels on the down stroke, 2) Plunger moves deeper into the barrel, 3) Tagging due to pump spacing, 4) Higher load on down stroke and higher downward inertia is created by higher downward velocity.

If the pump position during the stroke were plotted relative to the tubing, then bottom of stroke can move farther down when the pump is not full. **Figure 7** is a well that tags on the first pump off stroke. The pumping speed is 6.16 SPM and the 5439 Lb tag is severe. Sometimes a tag is wide with the beginning of the tag to the right of the bottom of the pump stroke, but this tag width is narrow and the tag appears to occur just at the bottom of the stroke. The full stroke pump stroke bottom is positioned at zero of the surface stroke. **Figure 7** showing the tag stroke over travels on the down stroke by 5.6 inches and over travels on the upstroke by about 15 inches. The total 20.6 inches of over travel occurs on both the upstroke and the down stroke creating a pump stroke of 150 inches in the fluid pound stroke compared to 130 inches in the full pump card. The surface and pump card show the initial tag, plus the tag repeats throughout the stroke at the resonating frequency of the rod string. If the pump tags at the end of the pump off stroke, then the pump may be spaced out too close at the bottom of the stroke.

When there is a sudden release in the fluid pound release, then that creates an additional force/inertia/energy that has momentum in the system that causes the plunger to travel more on the upstroke and/or down stroke. Sudden release/application of pump load results in plunger position changing relative to the pump barrel. Severe damage to the downhole pumping equipment can result when a pump-off occurs, if the plunger is spaced out to minimize the upswept volume in the pump, then the plunger can over travel to tag at to bottom of the stroke.

During a study[7] of ~6,000 beam wells in the Permian Basin, it was found that polish rod velocity (SL*SPM) could be used as a prediction tool for failure frequency (ff) (MTBF=1/ff). **Figure 8** shows the relationship between polished rod velocity and Mean Time Between Failures (MTBF). **Figure 9** shows the relationship between stroke length, pumping speed, and MTBF. For a long time, there has been a disagreement over the recommended practice of operating sucker rod lifted wells "Short and Fast" Or "Long and Slow". **Figure 9** displays the solution to this disagreement. If the Operator desires a long operating life of 10 MTBF, then a "Short and Fast" stroke length of 62 inches at 12 SPM results in the exact same failure frequency of a stroke length 168 inches at a 4.4 SPM pumping speed (shown in **Table 1** – SPM and Stroke to Achieve MTBF of 10 Years when Pump Filled with Liquid). Operational experience/results displayed in **Figure 8** show both "Short and Fast" and "Long and Slow" can result in a low failure frequency. When long run life is important, if a long stroke length is desired then a slow pumping speed should be maintained and if a fast-pumping speed in desired, then a short stroke is required. If the pump is operated more than 2% of its run-time with incomplete pump fillage due to gas interference or fluid pound, then run life is dramatically reduced.

<u>MECHANICAL FRICTION</u>

Mechanical Friction[8] in the well can occur at any location along the rod string from the stuffing box down into the pump. The increase in mechanical friction normally results in higher measured surface loads on the upstroke and lower measured surface loads on the down stroke. The location along the rod string where mechanical friction is applied to the rod string is normally not known. The amount of force acting on the rod string from the mechanical friction is also unknown. Since the location and magnitude of the mechanical downhole friction forces are not known, then the pump card shape is impacted by any mechanical friction loads applied to the rod string that cannot be removed by the wave equation.

When the mechanical friction forces are not removed, then the resulting plot of the pump card displays abnormal loads and excessive horsepower. There are many potential sources of mechanical friction: 1. paraffin, 2. scale, 3. over tight stuffing box, 4. misalignment between pumping unit and well head, 5. dogleg severity, 6. deviated wellbore, 7. pump friction, 8. crimped tubing, plus many other possible sources. Increased forces acting on the rod string due to mechanical friction result in loss of down hole pump stroke. When damping factors are properly adjusted with up and down stroke loads being plotted flat, the pump card loads are higher than expected on the upstroke or plot below the zero-load line, then these pump loads outside the expected load range often indicate the presence of mechanical friction from one of these sources. When the pump card load is impacted by mechanical friction and the pump card plots below the zero-load line or above the expected loads on the upstroke (Fo from the Fluid Level), then the amount of load below zero load or above Fo from the Fluid Level is called a friction force unaccounted for by the wave equation (mechanical friction is not modeled by the wave equation).

The presence of mechanical friction results in less production from the well due to reduced down hole stroke. Reduced pump displacement results in a higher-than-normal fluid level. Increased friction results in less efficient operation due to increased motor horsepower required to overcome extra frictional horsepower. Increased mechanical friction also results in an increase in downhole failures.

Current practices in drilling oil and gas wells have been to drill a well as rapidly as possible and to drill wells with intentional wellbore deviation from the same location to reduce cost. This practice has resulted in many wells that have severe dog-legs with high tortuosity. Dogleg severity limits[9] should be enforced when the well is drilled, if sucker rod lift is a potential lift method for the well. Severe Doglegs in the upper section of the well should be avoided, because of resulting extreme mechanical friction forces being applied to the rod string result in high failure rate, high operating cost and reduced ultimate recovery from the well.

CONCLUSION

When long run life of a sucker rod lift system is important to the operator, if a long stroke length is desired then a slow pumping speed should be maintained and if a fast-pumping speed in desired, then a short stroke is required. If the pump is operated more than 2% of its run-time with incomplete pump fillage due to gas interference or fluid pound, then run life is dramatically reduced. Severe doglegs in the upper sections of any sucker rod lifted well should be avoided because the increased mechanical friction forces due to the dogleg severity will result in increased failures and high operating cost. Applying the recommended practices to sucker rod lifted systems can result in lower operating cost and longer equipment life, but excessive mechanical friction and operating a pump with incomplete pump fillage can negate the benefits of applying recommended practices to the operation of a well. An operator desiring efficient long-life operation of their sucker rod lifted cannot do everything correct (apply recommended practices to the operation of their wells) but operate the sucker rod lifted well with incomplete pump fillage or in wellbores with severe mechanical friction; because failure rate will be high. The study[7] of ~6,000 beam wells in the Permian Basin proves that operating wells with a sucker rod pump filled with liquid is required for a low failure rate. The ALEOC study showed that applying recommended practices to operate well can result in a significant reduction in operating cost. Just doing one thing wrong like permitting wells being drilled with severe dog-legs or pumping wells with incomplete pump fillage will result in high failure rate and high operating cost of your sucker rod lifted well. The pump-off tag shows that just one (1) incomplete pump fillage stroke can be too many. When operator L during the ALEOC study counted pump-off strokes and slightly reduced the number of pump-offs but saw no reduction in his failure rate, this result was likely due to a lack in guidance that having more than 2% of run-time pump-off strokes would result in significant loss in sucker rod equipment operating life. Finally, “**LONG AND SLOW**” OR “**SHORT AND FAST**” is not the way to go! The way to go is to apply recommended practices to operate your wells, do not operate your wells with incomplete pump fillage more than 2% of the time, when a failure occurs then identify the cause and strive to prevent a repeat occurrence of the failure in the future.

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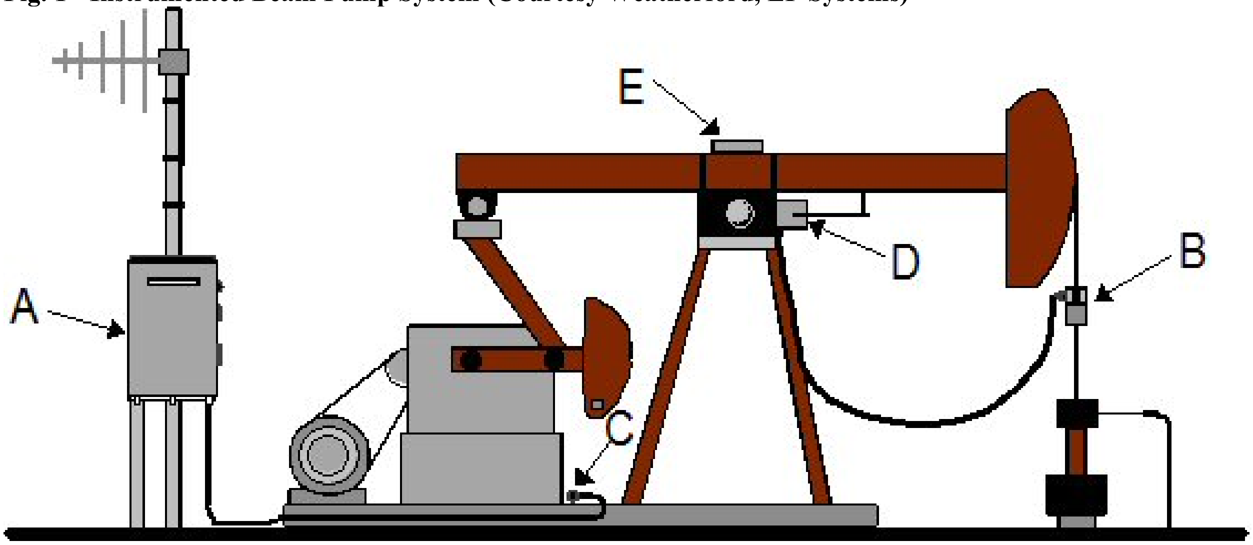
Table 1 – SPM and Stroke to Achieve MTBF of 10 Years when Pump Filled with Liquid

MTBF 10 Years	
SPM	Stroke (In)
13.9	54
10.1	74
7.5	100
5.2	144

Fig. 1 - Instrumented Beam Pump System (Courtesy Weatherford, EP Systems)



A - Rod Pump Controller B - Polished Rod Load Cell C - Position Sensor Switch
D - Optional Continuous Position Transducer E - Optional Beam-Mounted Strain Gauge

Fig. 2. Company J Rod String Design Limits bounds for N/No’ and Fo/Skr.

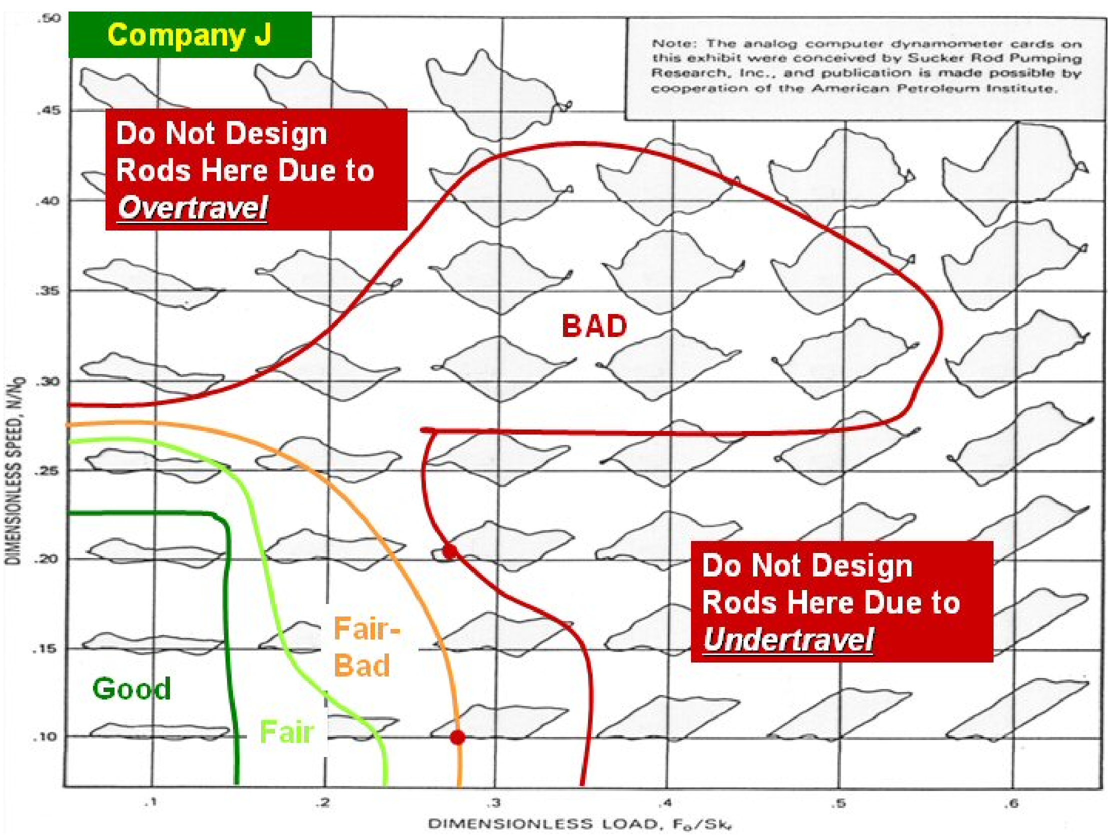


Fig. 3 Comparison of two different companies recommended sucker rod non-dimensional operating parameter Company H; bound by 0.2 to 0.35 N/No' and 0.2 to 0.5 Fo/Skr

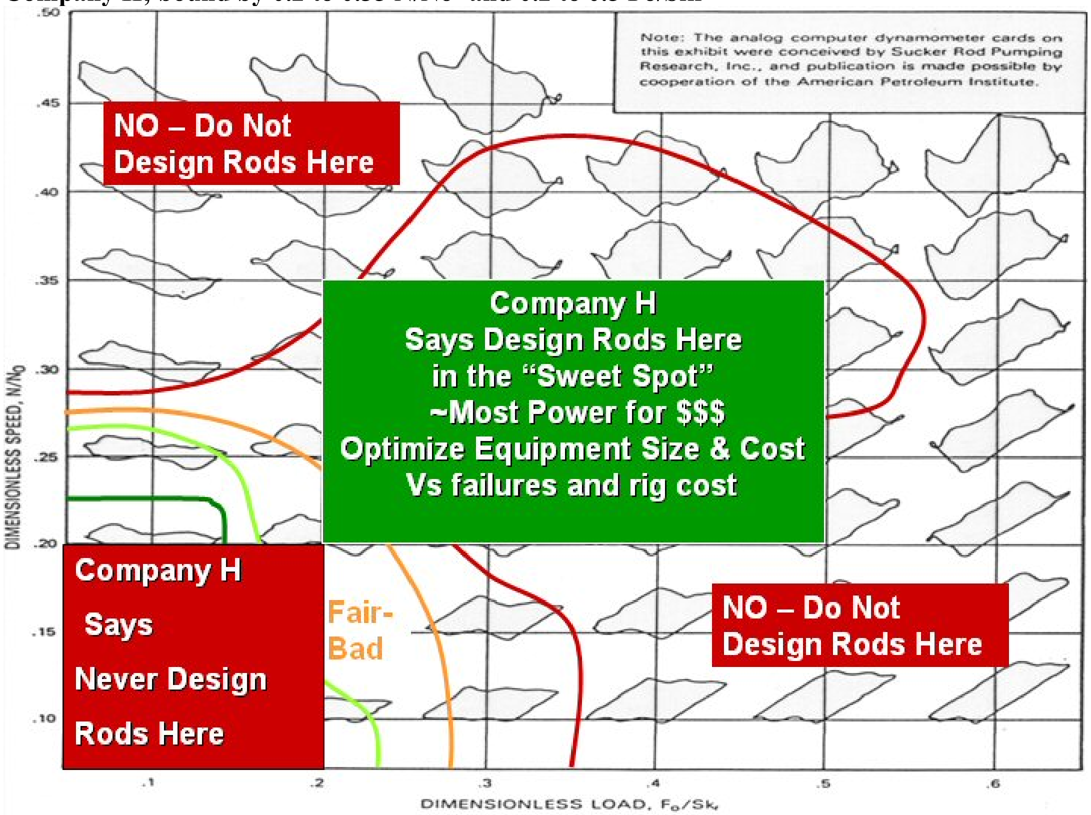


Fig. 4 ALEOC total sucker rod equipment failure frequency vs. year data provided for the member companies which also show company H and J similar failure frequencies even though different rod string design philosophy. Ref. 9.

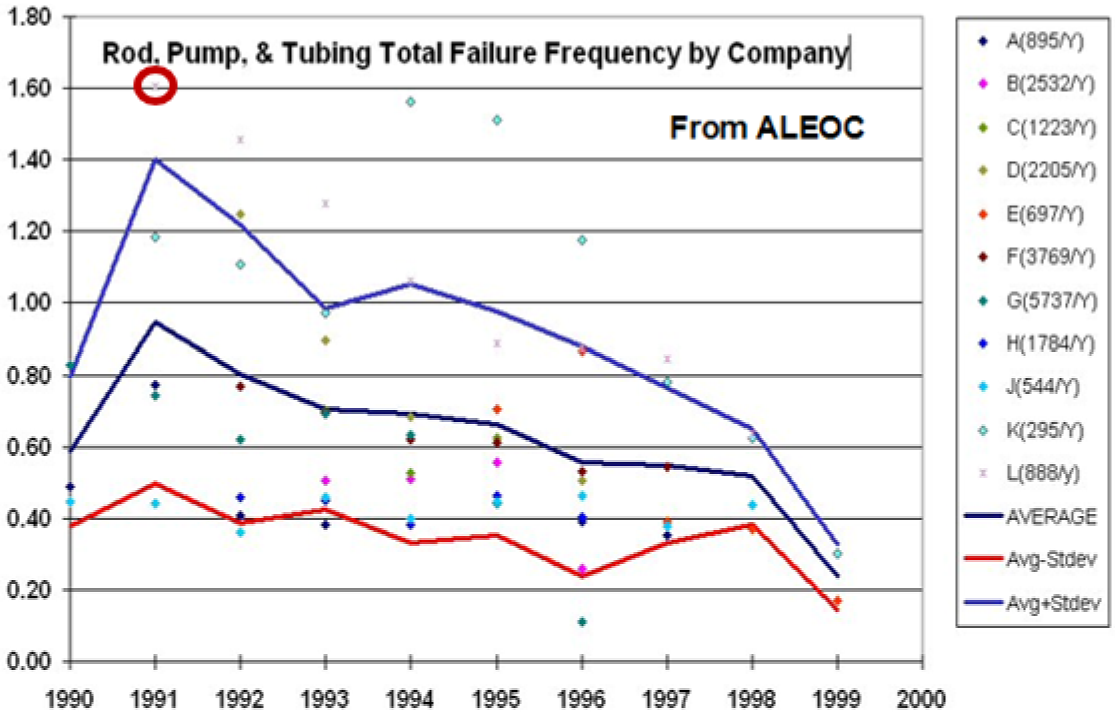


Fig. 5 – Effect of Compression of high-pressure gas on Plunger Velocity and Load.

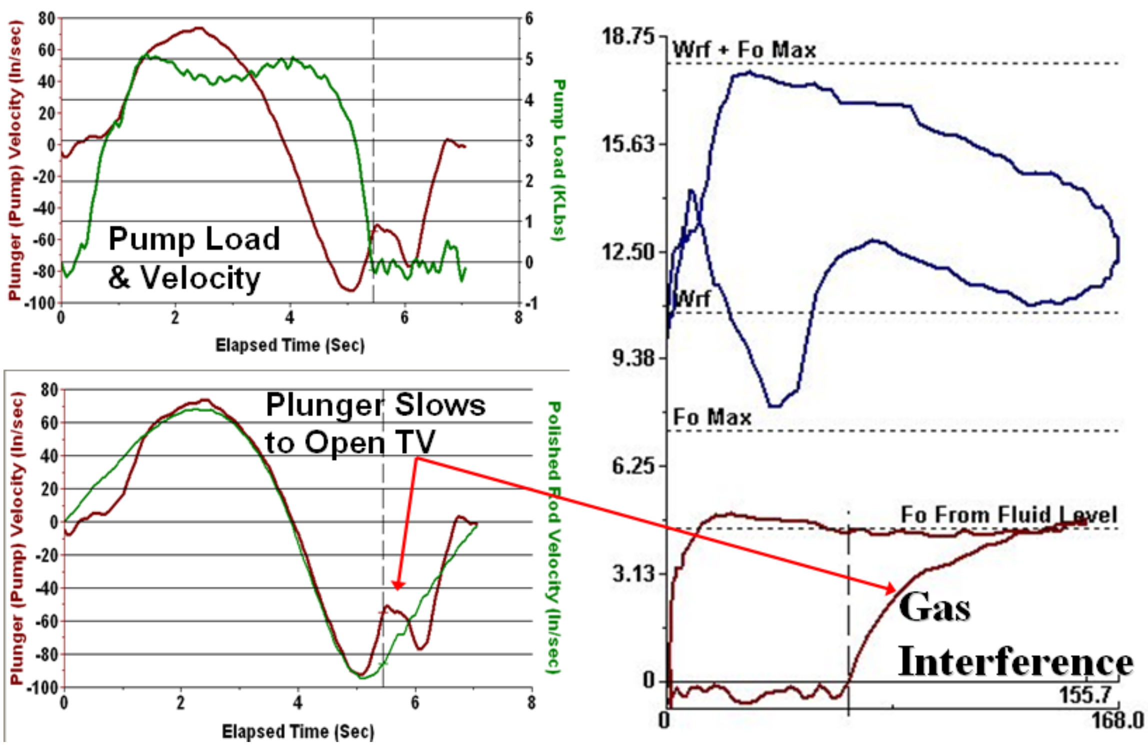


Fig. 6 – Effect of compression of low-pressure gas on Plunger Velocity and Load

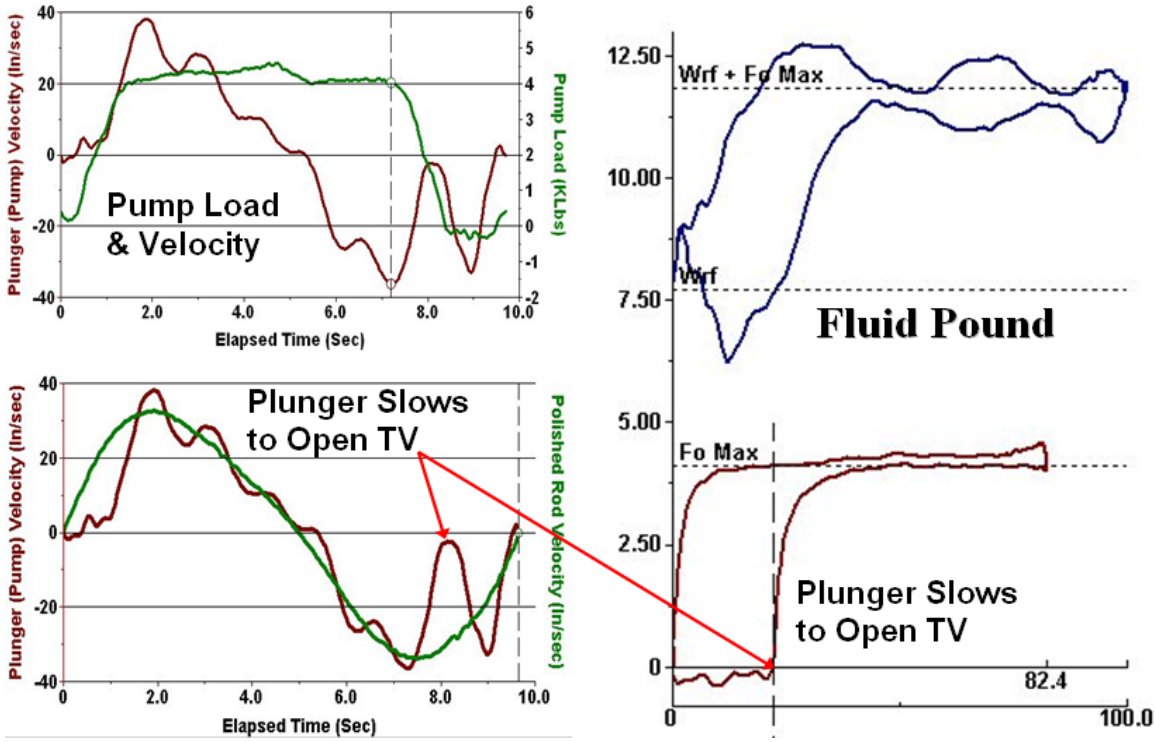


Fig. 7 – Plunger Moves 5.5” Further Down and Tags Due to Velocity Profile and Momentum

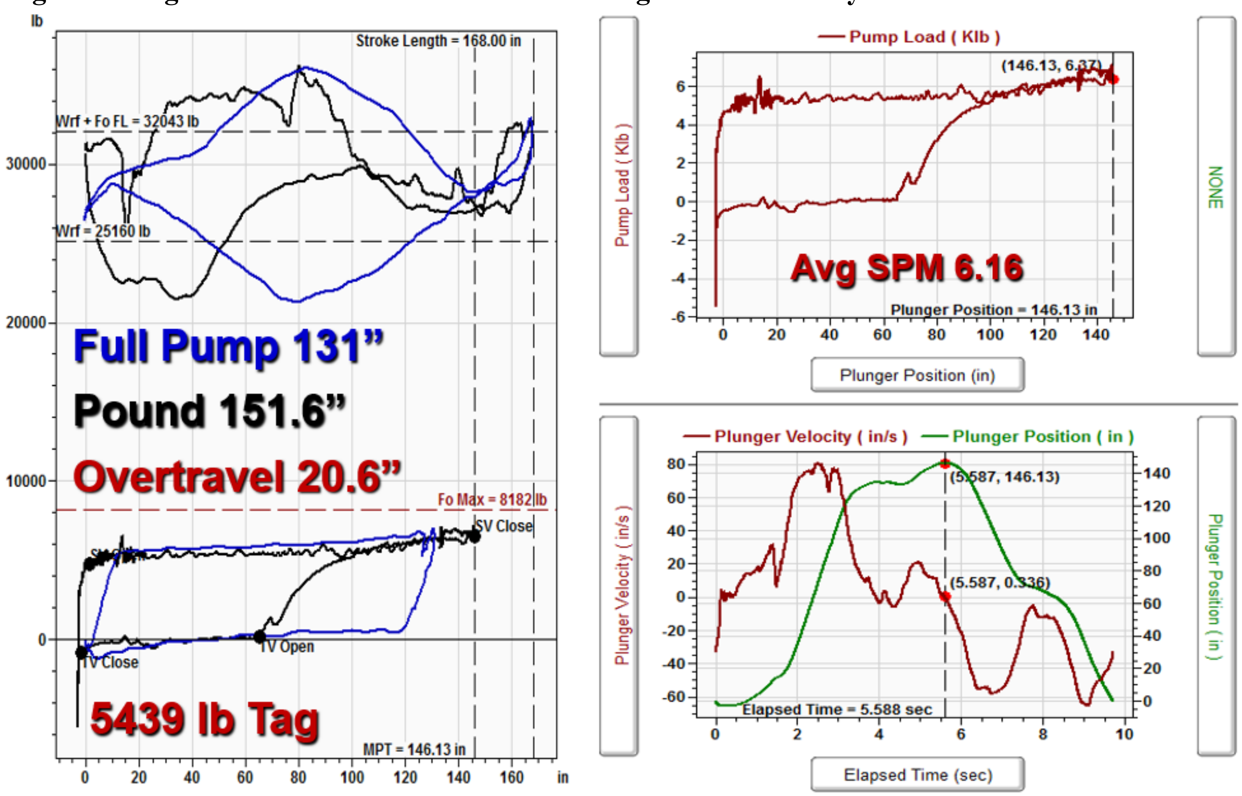


Fig. 8 – Relationship Between Polished Rod Velocity and Mean Time Between Failures

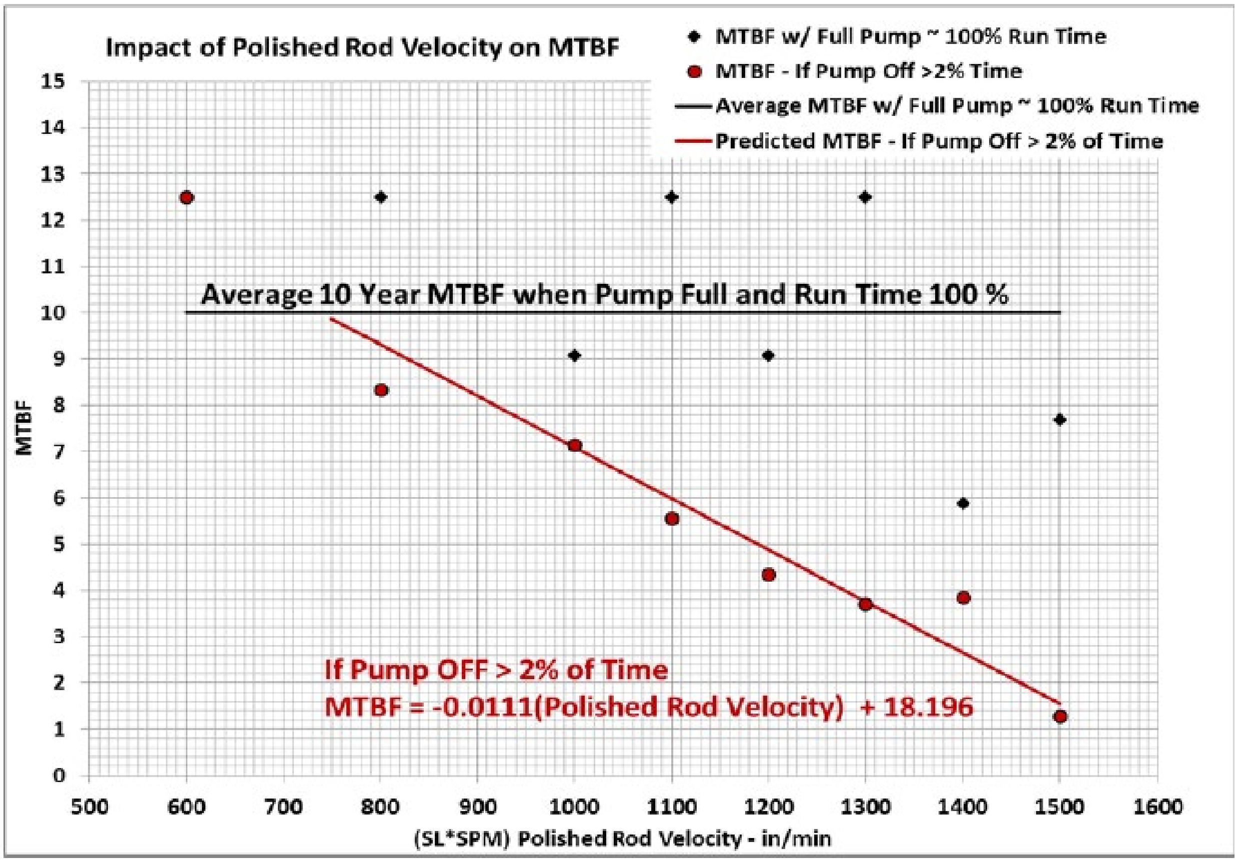
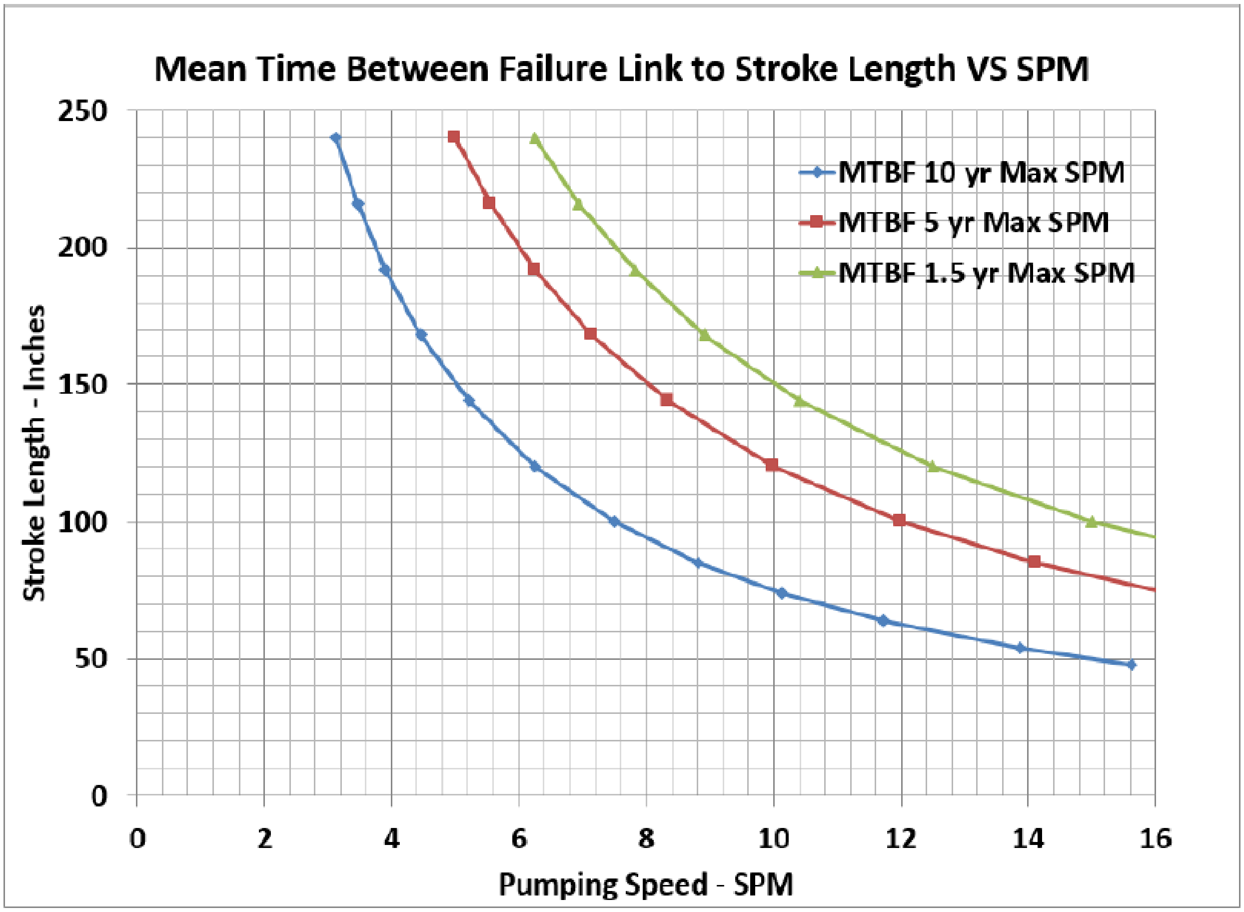


Fig. 9 – Relationship Between Stroke Length, Pumping Speed, and MTBF



Mean Time Between Failure Link to Stroke Length VS SPM
Stroke Length - Inches
Pumping Speed - SPM
MTBF 10 yr Max SPM
MTBF 5 yr Max SPM
MTBF 1.5 yr Max SPM
250
200
150
100
50
0
0
2
4
6
8
10
12
14
16