



DOWNHOLE CORROSION - THERE IS VALUE IN THE PROCESS

Kirk Miner
Baker Hughes Incorporated
208 Saskatchewan Drive
Redcliff, AB

Jason Thomas
Baker Hughes Incorporated
2323-91 Ave
Edmonton, AB

Copyright 2010 NACE International

Requests for permission to publish this manuscript in any form, in part or in whole must be in writing to NACE International, Publications Division, 1440 South Creek Drive, Houston, Texas 77084-4906.

The material presented and the views expressed in this paper are solely those of the author(s) and not necessarily endorsed by the Association. Printed in Canada

ABSTRACT

Pipeline failures are tracked and closely monitored in today's industry due to the costs and environmental and safety concerns of companies and regulatory bodies. While these failures have been tracked, and initiatives exist to reduce the number of failures across industry, the same attention often doesn't apply to downhole equipment. Downhole failures, impacting production and resulting in costly repairs, are often not tracked or not viewed holistically to the same degree as pipelines. Even though we would like to eliminate failures, extending the run life is the main objective. Rod and/or submersible pumping equipment will always be subject to failure due to mechanical or chemical situations. It has become critical to operations to understand the root cause of failure and how to extend the run life of pumping wells.

This paper uses a case history to outline the importance of understanding failure rates, identifying the root cause, and developing a program to reduce the number of failures to maximize the economics of pumping wells. Failures cannot be eliminated, but they can be economically managed. The concepts in this paper can also be used for differentiating critical wells that require a mitigation strategy rather than implementing a generic program where the value of the program may be questioned.

INTRODUCTION

Failures in the Oil and Gas Industry can be attributed to a number of things such as corrosion or mechanical damage. Pipeline or vessel failure regulatory boards (such as the Energy Resources Conservation Board or Alberta Boilers Safety Association in Alberta) ensure a plan is implemented to understand the root cause and reduce future failures. Downhole failures are not governed by the same rules and therefore are dealt with differently. While downhole failures occur they are not tracked closely due to the lack of regulatory and environmental consequences. Financial consequences are looked at by engineering staff or operations but operations tend to not have time or the resources to track failures and relate failure data to economic terms, especially for a large field. Often the impact of the failures isn't realized by the producer as they are looked at individually rather than holistically or as a trend.

When overseeing the impact of a failure there are a lot of issues that need to be considered to implement a successful plan. The impact of a downhole failure should be measured through both direct and indirect consequences. Direct consequences of a failure are seen in things like the price of workovers, repairs, inspections and new equipment; however the trends and total impact can be missed. Indirect consequences such as lost production, manpower and loss of revenue are not associated with the initial failure. Therefore the total impact of the failure will often be underestimated.

Wells that require artificial lift are susceptible to a number of failure mechanisms. Artificial lift is employed when assistance is required to lift the fluids from the reservoir (either the well requires this from the onset or it is required as the reservoir pressure decreases and the reservoir depletes). Examples of artificial lift include sucker rod wells, hydraulic pumps, electrical submersible pumps (ESPs), progressive cavity pumps (PCPs) and gas lift. This paper will not deal with the details on the various types of artificial lift. It will, however, review concepts associated with failures. With no corrective actions (chemical and/or mechanical solutions) an artificial lift well will fail to a "natural" point. Natural point or natural failure rate is the failure rate of a well or group of wells where there are no mechanical or chemical changes made to impact run life. When a well fails it is repaired and put back into service with no actions to extend this run life. In actual practice very few fields ever achieve a natural failure rate.

DEVELOPING A PROCESS

Understanding Economic Gains

In order to effectively track failures it is important to have a consistent approach for inspecting and evaluating downhole equipment failures. Collecting accurate historical data from the field, and turning it into meaningful information, can be a challenge and initially time consuming. But, this step needs to be included before corrective actions can take place and evaluated. Figure 1 shows an example of a natural failure rate graph that can show the predicted failure rate over a period of time for an unmitigated scenario. Natural failure rate

rarely occurs. Problems are dealt with rather than just repair and produce the well. Producers use two basis models to deal with failures on artificial lift wells – either mechanistic or economic.

Mechanistic models focus around dealing with isolated failures. Essentially if a failure occurs it is either immediately fixed or a program is put in place (such as a corrosion inhibition program). This model is effective; however the big picture can be lost. During a time of economic restraints and cost cutting initiatives simply repairing failures as they occur can lead to big expenses that can easily get out of control. During a downturn in the economy it is more likely to shut in a well rather than repair it as it is often unknown how long the “fix” will work. Obtaining a holistic view of the number of potential downhole failures allows producers to determine whether the failure rate is at an acceptable rate according to their risk matrix.

The second model, called Economic, deals with understanding the run life and expected changes to determine the economic impact. The run life of a well is determined by how long the well is continuously running before it is shut in for repair or a workover. Table 1 gives an example of how to calculate run life of a well or group of wells. When changes are required (either chemical or mechanical), a review is required to understand impact of the change. An example of reviewing the impact of putting in corrective actions and evaluating their success is shown in Figure 2. In the figure a mechanical change was initially implemented and then a chemical program was added to decrease the number of failures occurring on a monthly basis in comparison to the unmitigated scenario. This provides a predicted failure rate in a mitigated scenario.

Once the run life and impact of changes are understood it is important to use that data to determine the economic impact. Economic gains are calculated from a comparison of what it would have cost if nothing was done (unmitigated) and the results of the change in failures with something being done (mitigated). Artificial lift operations are generally more conducive for such monitoring and calculations. Failures that occur are considered real or actual and not subjective therefore they provide a consistent and measurable method for evaluating programs. Figure 3 displays the failure rate by showing the difference between the unmitigated and mitigated scenario. This graph can be used to justify mechanical and chemical expenditures to upper management by creating a dollar value on the savings that resulted from the changes. This data also allows all parties to understand the value and magnitude of the changes and to ensure the message is not lost over time.

In an era where companies are being either sold or going through a merger it is imperative that mechanical/chemical changes in the field are understood by the current operations staff. Rather than continue to make quick fixes, this method allows producers to ensure high impact changes with a high rate of return are made to keep the failure rates in the field to an acceptable level.

Mechanistic Versus Economic Model

It is important that the difference between the mechanistic and economic model is understood so that producers are able to make educated decisions on how to evaluate their systems.

As mentioned earlier the Mechanistic model waits for a well to fail before implementing change. Another characteristic of this model is for all the wells in a field to be blanketed with a chemical program or undergo a mechanical change without understanding which changes provide the biggest benefit and which wells might have unique issues. The failure mechanism is often noted on an individual basis and the one time cost is recorded. The major cost of the work over is communicated but often other changes may not be recorded (e.g., a pump failure may occur where the pump is replaced however the replacement of 50 joints of tubing may not be captured). If the well is still viable, the well is either put on a program or undergoes a mechanical change in an attempt to prevent future failures. Once the change is made reviews consist of evaluating things like the chemical program costs and determining if there are ways to optimize the program.

There are several pros to this Mechanistic approach. These benefits include the fact that once a failure occurs it is investigated and the failure mechanisms are clearly documented. In this model the run life is calculated on a per well basis and by normalizing the data to a failure/well/year basis the producer can track changes in the wells for a growing or declining field to recognize if the issues are escalating.

The cons to the Mechanistic approach are that it can be labour intensive. Each well is reviewed on an individual basis to determine an appropriate program for that well. This approach is considered reactive, as the remaining wells are often not looked at until they fail or the entire field is blanketed with a similar program that may not be warranted. While it is believed the main cause of the failure is identified after each investigation there is a potential that it may be overlooked because of more costly secondary issues. For example corrosion in the tubing that results in several tubing joints that need replacement might be overlooked because of a costly pump repair even if the repair may have been attributed to corrosion occurring downhole. The biggest downside to this approach is that you cannot predict a failure, which in effect means it is very difficult to create a budget for failure costs.

In contrast, the Economic model focuses on creating a trend analysis of all wells in the field and categorizes them by failure mechanism. In order to make the trends meaningful the run life of the well and cost of a failure are compared to the field average and goal. This will assist in evaluating whether a well requires a chemical or mechanical change. Failure/Well/Year (fwy) and average failure costs are used for changing field conditions. Figure 4 displays how the data can be organized to assist in the decision making of what changes to make on a specific well depending on what equipment is experiencing the problem. Changes to the well include the addition of chemical inhibition programs, coatings, metallurgy changes or a combination of each.

The pros of the Economic model are it utilizes individual failure investigations and works on identifying the root cause of the failures and developing patterns. This now allows the data to be organized and rolled up into a field overview of the failure rates and the average costs are predictive. The trends are used to show the success (or failure) of programs and changes conducted in the field in a holistic manner. All of this data is important when assessing the rate of investment and for budgeting chemical or workover costs. The shift from a reactive to a proactive approach on dealing with downhole failures is evident in using this method. Effectively monitoring downhole programs is extremely difficult using conventional methods such as coupons, iron/manganese counts, probes, etc. Such "Indicator" measurements might not, and often do not, correlate directly or linearly to the field operating costs. They can give a

false sense of security unless there is some method by which the real economics are correlated to the “Indicators”. The failure trends associated with the Economic model are one of the most representative monitoring tools that can be used to evaluate issues that are occurring downhole.

The cons to this approach are that the key data to be collected and tracked has to be an economic indicator, and data collection can be difficult and time consuming. The key is that a process needs to be set up to approach each failure in a similar manner to drive the decisions. Routine reviews of the data are also critical and should involve key decision makers for implementation of downhole programs and evaluating the run life.

IMPLEMENTING A CHEMICAL SOLUTION

Initial Steps Required to Establish a Program

With the overview of the Economic model it is important to understand how to build the trends and use the data. Putting together a process for consistently categorizing the root cause of failures is very important. Typically one or two years of data is required to trend failures by the root cause so that a pattern can start to materialize. Along with the root cause the average failure costs need to be recorded and trended. This data is then used to determine the average run life of the field for all operating wells. Finally, documenting the changes on a timeline (chemical and mechanical) to determine what does and does not work will allow the operator to make educated choices on how to effectively decrease their failure rates.

To help guide the process on evaluating which change to make there are several questions that should be asked that are summarized below.

1. What is the problem? Determining what the problem is involves good communication between the customer and the vendor when putting together a program. It is important that all the problems (big and small) are identified.
2. What actions have been taken in the past or present to remedy the problem?
3. Which actions were successful? This can often give a good indication of potential actions for solving the problem. It is also good to know the unsuccessful actions. Sometimes a variation of an unsuccessful action can provide benefits (e.g. application).
4. What is the “Frequency of Failure”? Knowing the failure rate will allow for reasonable and economical actions to be taken. A high failure frequency rate with a very low cost per failure or low failure rate with a high cost per failure will dictate potential and economical actions.
5. What is the “Cost per Failure”? Everything in business is based on economics so it is important to know the cost of the failure to the producer/customer so economical actions (chemical and/or mechanical) can be taken. Money can often solve problems, but at what cost and what return of investment.

Implementation of the Program

Once a trend has been established to justify a change in the mitigation program the next step is implementing the right solution. As shown in Figure 4 there are several options for making changes downhole. This section will focus on the chemical inhibition programs that may be required.

When putting together a chemical mitigation strategy it is important to know the failure mechanism, review application options and what the associated costs might be. The best product may not always be the best option. A combination of the best application and best suited product is the correct solution for reducing the failure rate in the field. A properly applied chemical solution is dependent upon receiving all relevant information regarding the well. The major questions that need to be answered are:

- 1) Completion data: tubing depth, casing size, tubing size, rod size and fluid level (required to calculate the wetted surface area). It is ideal to work from a downhole schematic which will contain a lot of these details;
- 2) Production volumes (oil, water and gas) both up the tubing and the casing;
- 3) Acid gas concentrations;
- 4) Downhole pressures and temperatures;
- 5) Type of pump and pump efficiency.

Once this information has been gathered a chemical program and recommendation can be put together. A few guidelines to follow include:

1. Should all of the wells be treated the same – Do well parameters allow all wells to be treated in the same manner? For example, varying fluid levels may require different volumes, application method or chemical.
2. Chemical compatibilities – It may be easier to build a demulsifier to handle the corrosion inhibitor than to build a corrosion inhibitor to handle the emulsion.
3. Cost effectiveness – The cost of the program should be reviewed against the average cost of failure and the current failure rates. Economics drive the choice to add or modify mitigation programs.

When reviewing the program it is very important to review the failures on a routine basis. Failure trends need to be compared to pre-established targets to determine if changes are required. Also, the economics of those potential changes should be taken into consideration. The direction of the trend (whether the failures are increasing or decreasing) is also important to proactively determine if the current programs (unmitigated or mitigated) are acceptable and if there are areas of improvement that can be investigated. As failures occur it is important that the root cause is determined and the trends are reviewed to assess if they are a concern. Rather than look at any programs or changes as an expense, the rate of investment, based on the reduction of failure from target or natural failure rate, is the key to justifying existing programs and validating additional changes. An example of this process can be seen in the case study which reviews the implementation of a chemical program and how it was evaluated.

CASE STUDY

A field in Southern Saskatchewan that consists of over 175 wells was put on a corrosion inhibition program in 2000. Roughly 25% of the wells are treated by either batch or continuous injection. The wells in the field are pumpjack, progressive cavity pump or electrical submersible pumps.

Both the vendor and producer decided to use the Economic model for evaluating the failures and mitigation programs in the field. Initially significant time was spent reviewing well files to determine the root causes of the failures that were occurring in the field. After this a program was put in place but was not optimized or reviewed for three years. In 2003 another field survey was completed with the vendor and producer setting some key performance indicators which included:

- Determining the minimum run life of the wells
- Communicating the average cost per workover
- Reviewing revenue versus run life and failure costs
- Setting treating parameters with the background data collected

Using these guidelines a batch program was conducted in the field. The batch volume was calculated using the wetted surface area of the equipment downhole. The frequency of the batches varied depending on the water cut, total production and failure history. All the wells were put on a batch and circulate application method. Product evaluations were conducted and the chemical was switched out without altering the treatment volume or frequency.

The chemical program was reviewed after a failure. Some of the wells were found to be under-treated and volumes had to be increased or frequencies changed. Some of the wells failed but the run lives were adequate according to the key performance indicators previously established. For these wells the programs were left the same or no programs were initiated. Some of the wells had applications and/or chemicals changed due to different operating conditions such as high fluid levels that required high circulation times. From the data and experience gathered in the field the batch frequency formula was adapted to field learnings to optimize the chemical program. Table 2 shows how the failure rate, failure costs and return on investment (ROI) over the time period tracked. As normal, the initial results showed great improvements in failure rate, with normal fluctuations that are also impacted by specific operating conditions. The most interesting point is that the lowest failure rate had the highest corresponding average failure cost, and even though there was a significant ROI, investment was lost due to an investment that did not equal the run time needed to support it. Since that time, an optimized run life is maintained by monitoring failure rates and failure costs.

Even with the success the field staff and vendor continue to meet on a quarterly basis to review all failures and discuss the failure trends in the field. Run time is the most important factor for this field that governs whether changes are required. The savings of over \$11 million in five years has not only justified the chemical program in the field but also provided an excellent opportunity to add value to the operations.

CONCLUSIONS

This paper outlines two approaches (Mechanistic and Economic models) that can be used in establishing a process for evaluating the system. It is rarely economical to eliminate well failures totally in artificial lift applications, so the ability to effectively manage failure rates based on the current economic conditions becomes the goal. Equipment used in artificial lift is built to run for a predetermined amount of time. For example, pumping rod run life can be calculated by the number of cycles (strokes per minute over days run), and once this cycle is surpassed that equipment is running on borrowed time. A full understanding of the system and the natural failure rates is important to maximize the run life. Using monitoring techniques along with failure trends, root cause analysis, effective communication and failure trending becomes important.

Once an approach is established it is important to implement the right mitigation strategy. Understanding the failure mechanism, reviewing options for change and determining a cost associated with the change will assist in determining this strategy. Linking this process to a Mechanistic or Economic model will allow the producer to implement the best solution for their field.

Finally a team approach of all involved can yield huge benefits captured through reduced failure costs, failure rates and lost production. Reviewing this data on a routine basis with a team committed to a common task becomes the last step needed to effectively manage production assets. In the end a return on investment is calculated not based on one fix, but on all changes whether mechanical, chemical or operational, to manage run life and repair costs in a holistic manner.

ACKNOWLEDGEMENTS

1. Steve Thacker, Baker Hughes Incorporated
2. Husky Energy

TABLE 1:

FAILURES/WELL/YEAR (FWY) = TOTAL FAILURES IN 1 YEAR DIVIDED BY # OF ACTION WELLS FOR THAT 1 YEAR

Failure Rate (fwy)	Years Run Between Failures	Months Run Between Failures	Comments
2.50	0.40	4.8	
2.00	0.50	6.0	
1.75	0.57	6.9	
1.50	0.67	8.0	
1.00	1.00	12	
0.75	1.33	16	
0.50	2.00	24	Industry Average
0.40	2.50	30	
0.30	3.33	40	
0.25	4.00	48	
0.15	6.67	80	
0.10	10.00	120	

TABLE 2:

SUMMARY OF CHEMICAL PROGRAM SUCCESS

Note: workover costs are based on an average of \$35,000/year

Year	Failure Rate (Failures/Well/Year)	Run Time (Years)	Ave Failure Cost (\$/Failure)	ROI (\$ 000)
1999	1.2	0.83	\$ 12,000.00	
2003	0.889	1.13	\$ 19,021.00	\$ 645
2004	0.645	1.55	\$ 22,888.00	\$ 1,618
2005	0.701	1.43	\$ 25,954.00	\$ 1,333
2006	0.447	2.24	\$ 47,046.00	\$ 1,916
2007	0.624	1.6	\$ 33,357.00	\$ 2,179
2008	0.564	1.77	\$ 27,880.00	\$ 3,400
				\$ 11,091

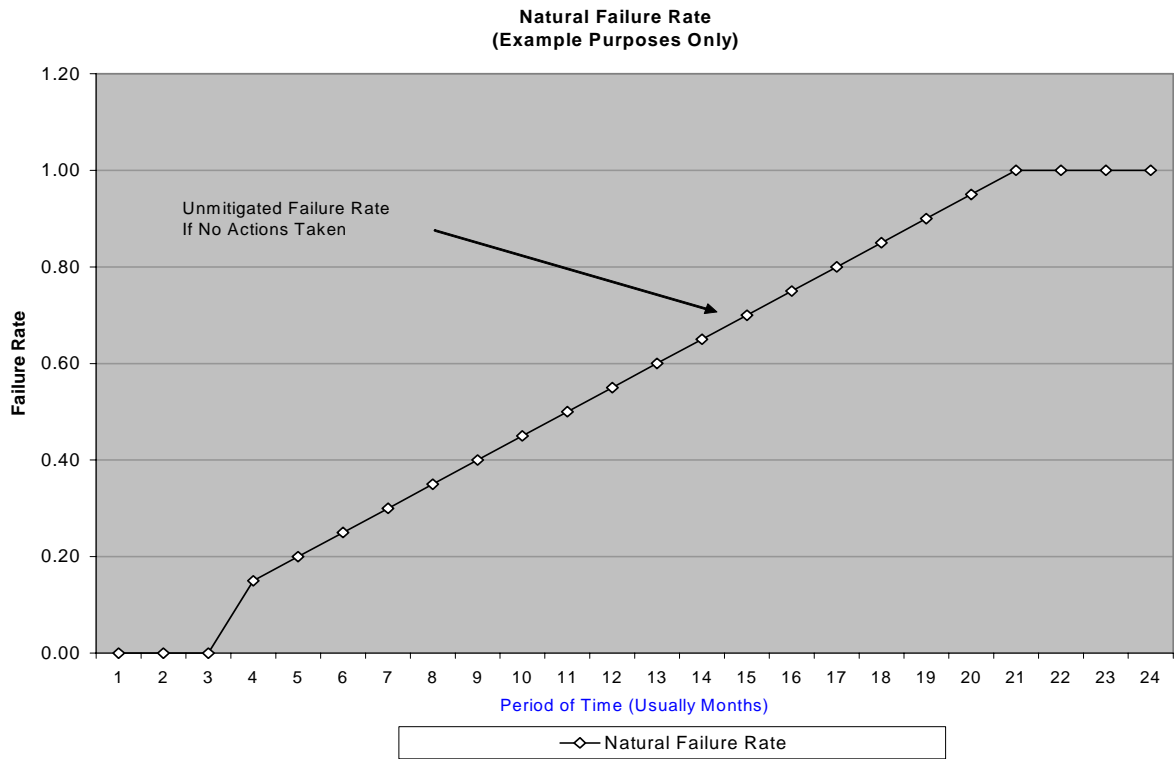


FIGURE 1 – Typical artificial lift failure trend

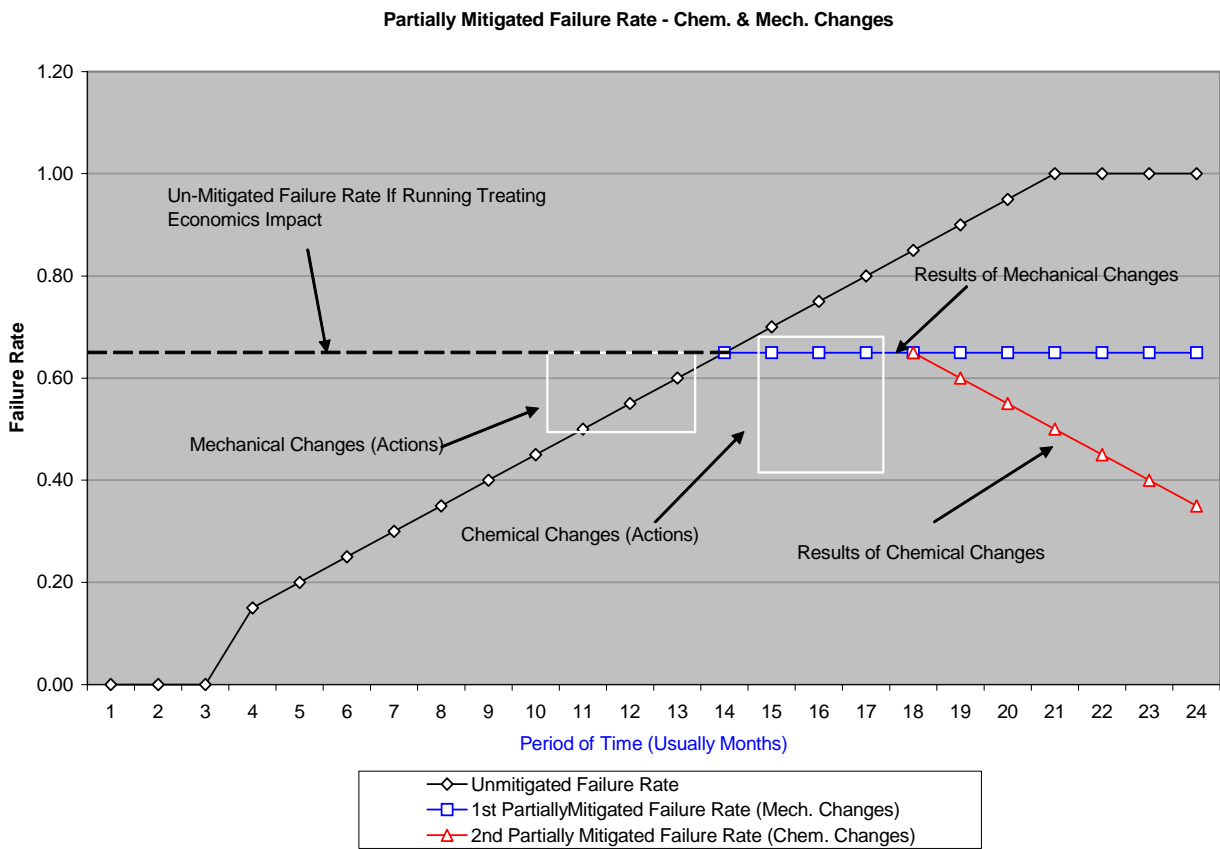


FIGURE 2 – Corrective actions and their impact on the failure rates

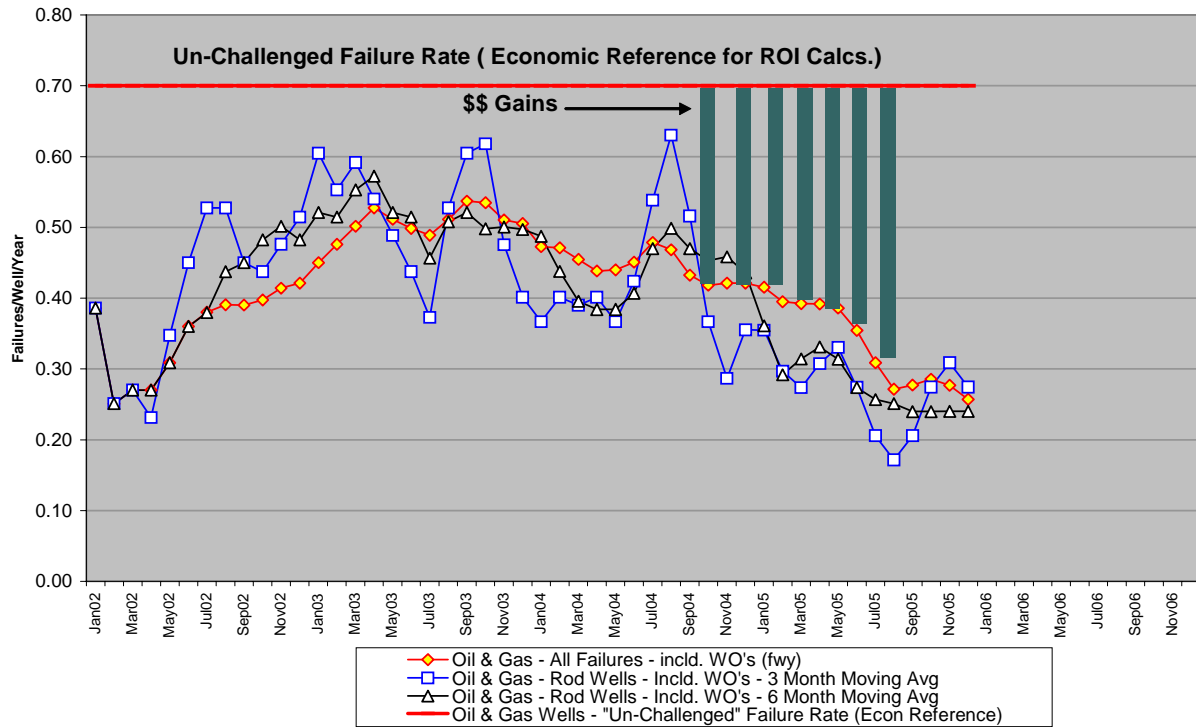


FIGURE 3 – Results measured against the natural failure rate

Equipment	Chemical Inhibition	Coatings	Coatings & Chemical	Metallurgy	Metallurgy & Chemical
Downhole Pumps	Choice			Choice	
Sucker Rods	First Choice				Choice (CO ₂)
Rod Well Tubing - Wear	Choice	Choice			
Rod Well Tubing - Corrosion	First Choice				
Wellheads, Flow Tees, BOP's	First Choice				Choice (CO ₂)
Sub Pump Tubing	Choice	Choice			First Choice
Injection well Tubing	Choice	First Choice			
Gas, Gas Condensate, Flowing Oil & Gas lift Tubing	Choice	Choice	1st Choice (if can be coated)	Choice (1st if can't be coated)	
Wellheads, Packer, Mandrels		1st Choice (if can be coated)	Choice	Choice (1st if can't be coated)	

FIGURE 4 – Example of a decision tree to use for making changes downhole