A COST-EFFECTIVE SOLUTION TO CORROSION-INDUCED ROD FAILURES

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ABSTRACT

When rod pump wells are operated in corrosive environments, corrosion induced sucker rod parts can lead to premature well failure and expensive, repeat workovers. Many corrosion mitigation solutions exist to combat this type of failure, including metallurgy, chemical inhibitor, and epoxy coatings, but they can be costly and not all solutions are appropriate for all types of wells.

In deep wells that require higher tensile rod strength, corrosion friendly metallurgy is generally not an option. In low producing wells, epoxy coatings may not be economically justifiable, depending on lead times and coating plant proximity. Corrosion inhibitor can work in some wells, but it can require constant monitoring to ensure the treatment is working and is not compatible with some well environments.

In wells where traditional mitigation techniques have not been effective or economic, RodGuard has been successfully used to reduce the frequency of corrosion-induced rod parts.

This paper explores a study performed in California between July 2019 and March 2021 in which RodGuard was used to coat rods in high failure, corrosive wells.

INTRODUCTION

The two most common corroding agents in the oil and gas industry are CO_2 and H_2S. When these gases are present, the well environments can become acidic which promotes electrochemical reactions with carbon steel. These reactions lead to pitting on the surface of the rod which can lead to premature failure of the well. It is estimated that as many as two thirds of all sucker rod body parts are corrosion related, and these numbers can be even higher in extremely corrosive fields. There are a few common practices to avoid corrosion related sucker rod failures and they all have their advantages and disadvantages.

One of the most common, cost-effective forms of corrosion mitigation is selecting a sucker rod with special metallurgy and increased nickel content such as a K grade rod or a DS grade rod. The addition of nickel and other alloyed material is designed to increase the corrosion resistance of the sucker rod, but often, the percentage of corrosion resistant material in the rod is relatively low and the rods are still susceptible to corroding. In addition to the relatively low percentage of corrosion resistant material, these sucker rod grades have lower tensile ratings and are not recommended for highly loaded wells. When wells are deep and the sucker rods have a relatively high load, high strength sucker rods are required. Most high strength sucker rods do not have a corrosion resistant metallurgy so other forms of corrosion mitigation must be used in these situations.

Another common solution for corrosion mitigation is the use of a chemical inhibitor. Chemical inhibitors are pumped in to the well to create a protective film that prevents corrosive agents from coming into contact with sucker rods and production tubing. Corrosion inhibitors do not always work because they can get wiped off when sucker rods and tubing come in to contact with each other, which is common in deviated wells. Corrosion inhibitors can also be challenging to circulate through the well effectively, especially if the well environment is gassy, preventing the inhibitor from fully covering the sucker rods and tubing. Chemical inhibitors can have varying costs depending on how much or little is used. Batch treatments can be relatively affordable, but they are not nearly as effective as continuous treatments, which can come with a large price tag. Chemical inhibitor programs can require constant monitoring to ensure proper dispersion throughout the well, potentially requiring additional manpower and expense. Due to these factors, chemical inhibitors can be an effective corrosion mitigation technique but may be limited by external factors that can affect efficacy.

Further solutions for corrosion mitigation include sucker rod coatings. There are two common types of rod coatings currently on the market for traditional sucker rods: a stainless-steel spray metal coating and epoxy coatings. These coatings create a barrier between the corrosive environment and the rod which protects the steel substrate. Coatings are generally more robust than chemical inhibitor, but they can come at a greater capital expense. The other drawbacks to sucker rod coatings are availability and lead times. These factors make this solution more prohibitive when needing a quick turnaround to meet workover schedules.

The solution that this paper explores, RodGuard, works similarly to a coating because it creates a protective barrier, but unlike a traditional coating it can be applied at any Tuboscope sucker rod handling facility. It can be applied to any traditional sucker rod, including high strength grades, and it does not require monitoring. RodGuard is versatile and relatively low maintenance compared to other solutions, which can make it more economically viable.

HISTORY OF RODGUARD

RodGuard is an oil based preservative lubricant that can be applied to steel sucker rods for protection against corrosive downhole environments. RodGuard uses oil-based polymers to form a bond with metal surfaces, creating a barrier against corrosive agents. Penetrating lubricants such as this typically have a low viscosity and they are designed to infiltrate small imperfections on the surface of the sucker rod.

This product was initially applied to steel sucker rods in the early 2000s when customers of Patco Rod Service (bought by Tuboscope in 2003) requested a corrosion-resistant coating to be applied to their sucker rods. The Rosedale Ranch field was experiencing 40-50% CO_2 concentration in their gas production at the time, leading to severe CO_2 corrosion in their sucker rod strings. When they originally tested RodGuard on sucker rods, the product had only been applied to the hulls of ships to decrease barnacle attachment. Loosely correlating barnacle attachment to ship hulls to scale adhesion to sucker rods, Patco Rod Services applied this material to help protect sucker rods while downhole. The product was successful and wells with previous runtimes of 6 months were achieving runtimes of 3 years, establishing this oil-based lubricant as a viable rod servicing tool in protecting rods from corrosion attack.

The use of RodGuard lost traction as other mitigation techniques became popular, but its use was revisited a few years ago when an operator had some wells that were not reaching their run time targets. These wells were low oil producers with high CO_2 concentrations and tight economics, which made them good candidates for RodGuard install. RodGuard was put into service in wells over 10,000' of total depth in the Ventura and Central San Joaquin basins. These wells were seeing gas breakout in the top 500' resulting in repeat CO_2 corrosion related rod parts in that section. The initial target runtime between failures for these wells was 2 years, but with the CO_2 corrosion the average runtime for these wells was 292 days. In the first 11 wells that trialed RodGuard, there were 40 corrosion related rod failures before installation.

After installation, runtimes for these 11 wells increased by 83% on average (535 days) with numerous wells meeting or exceeding their two-year goal. Of those 11 wells installed with RodGuard in these areas, all exceeded their previous runtimes, while one is still running with its original installation.

With the extension of life in these 11 wells, RodGuard was installed in a larger set of high failure wells and the performances were tracked to determine if RodGuard was a viable corrosion mitigation tool.

FIELD OPERATING PARAMETERS AND WELL SELECTION

For this trial, RodGuard was installed in 36 wells across 13 fields from July 2019 to March 2021. These fields and the well distribution for each can be found in Table 1. A map of the locations is included as Figure

1. The 36 wells have varying depths and CO_2 concentrations, but they all had a similar history of rod related failures.

Most of these wells were experiencing rod failures in the top sections of the well. The top taper of the well was generally where RodGuard was applied and the rods below the top taper were uncoated. When RodGuard was installed, most of the rods were guided with a straight vane rod guide to protect against deviation and prevent as much rod and tubing contact as possible. Prior to the installation of RodGuard, the 36 wells had an average runtime of 214 days.

FIELD TRIAL RESULTS

Of the 36 monitored wells, 19 have experienced a failure since RodGuard install and the remaining 17 are still running at the time this paper was written. The majority of the 19 wells that experienced a failure surpassed their previous runtimes. Only 3 wells did not meet this target, and none of those three failures were in the RodGuard section (one was due to a polished rod failure, the second failed because of a tubing leak, and the last failure was due to a rod part below the RodGuard section). Between the wells that have failed and the ones that are still running, the new average runtime is 476 days, exceeding the previous average by 269 days, which is a 122% increase. A table of the wells and their runtimes can be found as Table 2, and the corresponding figure can be found as Figure 2.

The installation of RodGuard adds an approximate 25% cost to the purchase price of new, HS slick rods. If RodGuard were to be applied to the top third of a rod taper, similar to in this trial, it would increase your rod costs by ~8.33% (less if the string was guided). In a well with 90 1” rods in the top taper, this would equate to an approximate increased cost of $2,225 assuming a rod price of $100. A typical workover for a rod part failure can cost anywhere from $15-25k depending on rig time and material recovery. In this study, the average run time before the installation of RodGuard was 214 days. Using this value, we get to a failure rate of 1.7 failures per year. This failure rate equates to a yearly workover cost of $25,584 using the lower end cost for rod repairs. After RodGuard install, runtimes averaged 476 days equating to a failure rate of 0.77 failures per year. With this failure rate, workover costs equate to $11,550.

With an initial investment of $2,225, these wells obtained a total savings of $11,809 based on the difference of $14,034 in workover costs. This calculation does not include the lost production saved, which would further improve the overall impact. This breakdown can be found in Table 3.

CONCLUSION

While there are many potential solutions for corrosion related rod failures, there is no one size fits all option. RodGuard may be a viable solution for lower oil producing wells with tighter economics. These wells were not near any traditional rod coating plants, corrosion inhibitor wasn’t mitigating rod parts effectively, and metallurgically enhanced rods were not practical due to the high loading on the rods. RodGuard’s use in the 36 monitored wells increased runtimes 122% while leading to decreased workovers.

RodGuard may not be the most effective solution for all wells, but it did help achieve longer runtimes in this study and its use has spread to other operating areas.

REFERENCES

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FIGURES

Figure 1: Well Locations

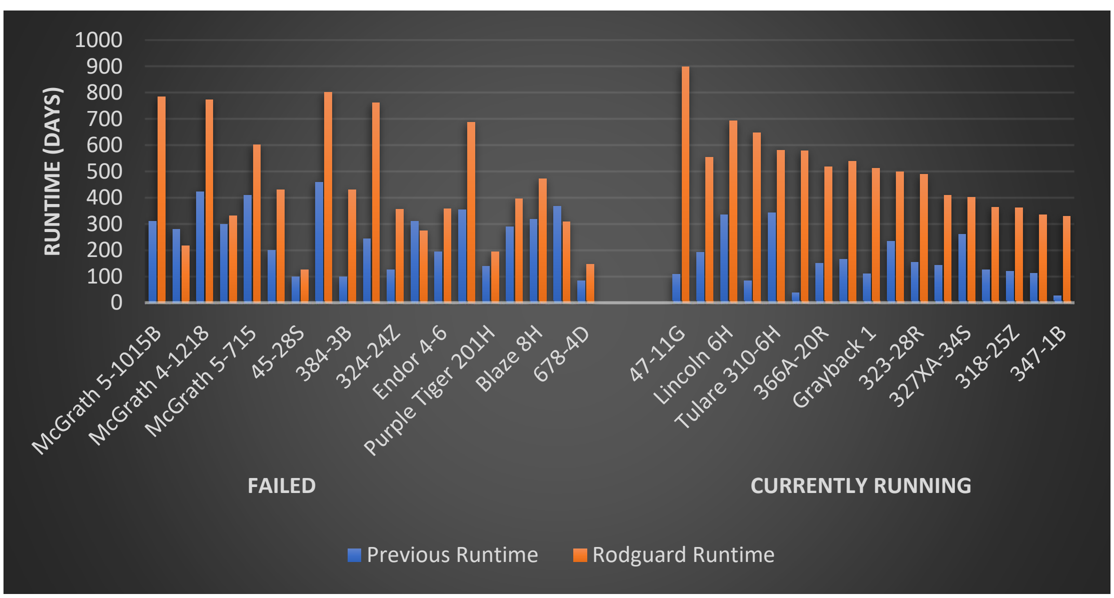

Figure 2: Pre and Post RodGuard Runtimes

Table 1: Well Locations

Field	No. of Wells
Bardsdale	1
Buena Vista Hills	3
Elk Hills Shale	12
ESOZ	1
Helm	1
Kettleman	1
North Shafter	3
Rio Viejo	1
Rose	3
San Mig/Rincon	4
South Mountain	1
SOZ	2
West Montalvo	3

Table 2: Well Names and Pre/Post RodGuard Install Runtimes

Well Name	RodGuard Install Date	Pre-RodGuard Runtime (Days)	Post-RodGuard Runtime (Days)
McGrath 5-1015B	7/9/2019	310	784
Grubb 476	8/7/2019	280	217
McGrath 4-1218	9/18/2019	422	773
Oak Grove 010-23	10/4/2019	299	332
McGrath 5-715	10/14/2019	409	602
Bains 674-9	11/19/2019	200	430
45-28S	11/25/2019	99	125
532X-8D	12/10/2019	460	801
384-3B	12/14/2019	99	430
365X-24Z	1/18/2020	245	762
324-24Z	1/23/2020	125	357
Grubb 358	1/29/2020	311	275
Endor 4-6	2/10/2020	194	359
Grubb 398	2/12/2020	355	688
Purple Tiger 201H	2/26/2020	139	195
34-17Q	3/6/2020	290	395
Blaze 8H	3/23/2020	317	472
22-32G	12/30/2020	367	309
678-4D	2/10/2021	84	147
47-11G	9/4/2019	108	898
636-13Z	11/1/2019	192	554
Lincoln 6H	3/27/2020	336	693
67SW-28S	5/12/2020	83	647
Tulare 310-6H	7/17/2020	342	581
Poznoff 4-1H	7/20/2020	38	578
366A-20R	8/18/2020	150	518
365-25S	8/27/2020	165	540
Grayback 1	9/23/2020	110	513
Rio Viejo 36X-33	10/7/2020	234	499
323-28R	10/17/2020	155	489
381-3B	1/5/2021	143	409
327XA-34S	1/12/2021	262	402
Lincoln 10-H	2/19/2021	126	364
318-25Z	2/22/2021	119	361
366B-36S	2/23/2021	113	336
347-1B	3/11/2021	27	330

Table 3: Cost Savings Breakdown for an 8,000' well

Pre-RodGuard Install		Post-RodGuard Install	
Average Runtimes (Days)	204	Average Runtimes (Days)	476
Failure Rate	1.7	Failure Rate	0.77
Yearly Workover Costs	$25,584	Yearly Workover Costs	$11,550
		RodGuard Install	$2,225
Total Yearly Workover Costs	$25,584	Total Yearly Workover Costs	$13,775