REDUCING ROD PUMPS STUCK IN TUBING IN THE HIGHWAY 80 FIELD

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ABSTRACT

In 2019, we presented the early results of a design change on our insert sucker rod pumps in the Highway 80 Field. Those results included 18 months of data after the design change has been made. We also included more than seven years of data prior to the change. This paper provides an update with 48 months of data collected after the design change, and reviews more than 11 years of history of sucker rod pumps stuck in tubing in this field.

When an insert rod pump gets stuck in tubing, increased well servicing events drive costs and safety risks. The Highway 80 area team reviewed the number of pumps stuck in tubing from 2010 to July 31, 2021. A total of 1,159 insert rod pumps could not be pulled with the rods to retrieve the pumps. Pioneer Natural Resources previously chose to use a rubber fin element below the discharge of the insert sucker rod pumps to prevent lodging from occurring. With this change, the number of pumps stuck in the tubing was reduced, but approximately 10% of the pumps continued to get stuck.

In 2017, Harbison-Fischer began installing the brush sand shield on all of Pioneer's insert pumps in the Highway 80 Field. This paper will discuss 48 months of results since the first brush sand shields were installed. We will compare the pumps that were stuck in tubing with and without the design change since the implementation.

INTRODUCTION

Sucker rod pumps are the most popular form of artificial lift. They get this title because of their strength, ease of automation, energy efficiency, and drawdown capability.

BACKGROUND

Conventional API sucker rod pumps can be used in any well depending on the fluid volume and depth. There are two basic types of sucker rod pumps: insert and tubing. The insert rod pump's design allows it to be run into and retrieved from the well with the sucker rod string. The tubing pump barrel assembly must be installed on the tubing. The bottom hold-down pump is the most common design due to its ability to be installed at a greater depth. A bottom hold-down pump's disadvantage is its propensity for getting stuck in the tubing. Because the pump's discharge is at the top of the pump, any particulates produced in the well fluid will fall in the barrel/tubing annulus, building on top of the hold-down assembly. The tubing must be pulled to retrieve the pump, which is more costly than pulling only the sucker rods. Additional issues are that the rods will need to become disconnected from the pump in some manner, or they will need to be pulled along with the tubing; this is commonly known as a stripping job.

DISCUSSION

Modifications can be applied to bottom hold-down insert rod pumps to lower the chance of becoming stuck in the tubing. One modification is placing a barrier right below the insert rod pump's discharge, which reduces the number of particulates falling into the barrel/tubing annulus. More than 20 years ago, Pioneer Natural Resources started using a rubber fin element below the discharge of bottom hold-down insert pumps. Although the improvement was not documented, we believe the use of rubber fin elements resulted in a reduction of pumps stuck in the tubing. Pioneer Natural Resources converted to the Harbison-Fischer Brush Sand Seal in 2017, giving us an opportunity to document how this design change performed.

PUMPS STUCK IN TUBING

When pumps are stuck in the tubing, there are other costs and concerns that should be mentioned. When the pulling unit tries to unseat the pump, and it is stuck, there is a possibility that the sucker rod string could be damaged. Operators of pulling units must be properly trained to not exceed the yield strength of the sucker rods. To avoid a stripping job, the operator will attempt to disconnect the sucker rods from the insert pump. If the "clutch" on the rod pump is in good shape, the rods can be "backed off." meaning the crew can rotate the rods counterclockwise at the surface to disconnect the sucker rods from the pump. A safer way is to install an "on and off tool" at the pump when it is run into the well. This tool allows the rod string to quickly disconnect from the pump with a quarter turn at the pump. When pulling tubing because of a stuck pump, additional costs can be incurred to contain the well fluid that is trapped above the pump. Many steps must be followed to ensure that no well fluid contaminates the ground. As mentioned, the least desirable way is to strip out the rods and tubing at the same time. This process is done by disconnecting a tubing joint followed by disconnecting a rod, and then repeating this operation connection by connection until the pump is reached.

THE PROJECT

When the decision was made to convert to the Harbison-Fischer Brush Sand Seal, we wanted to capture the results and see if the additional costs were justified. We discovered that one pump stuck in tubing would support the cost of multiple Brush Sand Seals. Data recorded from the beginning of 2010 until the conversion to the Brush Sand Seal on August 1, 2017, shows interventions in 8,010 wells. In 825 of these interventions, the pump was stuck in the tubing. The 825 stuck pumps had an average run time of 974 days. There is a higher percentage of wells with 2-3/8" tubing versus 2-7/8" tubing in this field. For that reason, there were 633 pumps stuck in 2-3/8" tubing and 192 stuck in 2-7/8" tubing. The drift of 2-3/8" tubing averages 1.901, leaving little room between the OD of 1.75" of the 1-1/4" RH and 1.875" of the 1-

1/2” RX insert pumps. Rubber fin elements were used on both these designs, but because the rubber fin element was not available for the 1-1/16” and the 1-3/4” RH insert pump, they had no protection.

48 MONTHS OF DATA

Through July 31, 2121, there had been 2,417 well interventions in the field since implementing the Brush Sand Seal 48 months earlier. Of that 2,417 total, 334 pumps pulled were stuck in the tubing. Only 41 of those stuck pumps had the Brush Sand Seal, while 63 had no protection and 229 had the old-style rubber fin element. Nineteen of the 41 stuck pumps with the Brush Sand Seal would have been pulled regardless because of tubing leaks. A total of was 573 wells pulled during this time had a Brush Sand Seal installed, and only 7% of these were stuck in tubing. Included in the 573 Brush Sand Seal wells were 285 wells with histories of pumps stuck in tubing that were pulled and not stuck. 1,844 of the wells pulled had a rubber fin element or no protection, and 16% of these wells had the pump stuck in tubing.

LOOKING FORWARD

We plan to continue monitoring the occurrences of pumps stuck in tubing and look for ways to improve.

CONCLUSION

Well interventions that have a pump stuck in the tubing add to the producers operating costs. When the tubing must be pulled, the average amount budgeted per occurrence is $10,000. Pulling the tubing also introduces significantly more exposure to injury and environmental risks. The results point to a decrease of pumps stuck in the tubing of pulled wells with a Brush Sand Seal. With the number of pumps using the old design decreasing and number of pumps using the new design increasing, we believe there will be a continued reduction of pumps stuck in tubing in the field.