A NEW APPROACH TO CONTINUOUS ROD IN THE PERMIAN BASIN

Anthony Allison, Oxy

Taylor Krenek and Reed Vogt, Lifting Solutions

ABSTRACT

Continuous sucker rod has been used for many years in sucker rod pump applications. However, several challenges have limited its acceptance in the past. The availability of service equipment, welding methodology, and selection of metallurgy all contributed to premature failures and operator frustration with the timeliness of installation and repairs.

A new approach to implementing continuous rod started with establishing a robust service infrastructure to install and repair the rod. Improved welding procedures and personnel training address a frequent point of past failures. Changes in the design approach and sizes used enable new opportunities that may have previously not been addressed with continuous rod. A shift to metallurgy more similar to the predominant grade used for conventional sucker rods aims to improve fatigue resistance of continuous rod in corrosive environments.

These changes in material and service capability are enabling longer run times, reduced workover time, and extending the capabilities of rod pump wells to produce greater volumes at deeper depths. Multiple installations in the Permian Basin will be discussed to demonstrate the recent successes seen with continuous rod.

BACKGROUND

Continuous sucker rod differs from conventional sucker rods by forming the rod string from a single, continuous piece of steel instead of multiple individual rods that are coupled together. The first mention of continuous rod at the Southwestern Petroleum Short Course is from Patton (1970). Patton describes many benefits of continuous rod over conventional sucker rods, including:

- Reduced connection failures: A 5,000-ft rod string comprised of conventional sucker rods would have 200 connections. Each connection represents a potential point of failure due to mishandling and improper make-up procedures. When replaced with a continuous rod string, the installation requires a minimum of two connections, one at each end of the string. Additional connections are only required for pony rods and sinker bars. Having significantly fewer connections reduces the potential for failures at the couplings or pins.
- Lighter rod string: When compared against a conventional rod string, with or without rod guides, the continuous rod string will be lighter. Consider a well that

is 5,000 ft deep, with a rod string that is half 7/8-in. rods and half 3/4-in. rods. An unguided conventional rod string will be 9% heavier than continuous rod. A fully guided rod string, using five guides per rod, will be 20% heavier than continuous rod. The lighter continuous rod string may allow an operator to increase production with a larger pump, reduce capital costs with a smaller surface pumping unit, or increase drawdown by pumping from a greater depth.

Rod Design	76 Continuous	76 Unguided	76 Guided
Buoyant weight (lb)	7,660	8,369	9,213
Weight increase	-	9%	20%

Table 1—Comparison of rod weight between continuous, unguided, and guided rod strings.

- Reduced wear between the rods and tubing: In a deviated well, a conventional rod string without guides will contact the tubing every 25 ft at each coupling. This concentrates the side loading between the rods and tubing at those locations, accelerating wear of the coupling and/or the tubing. Continuous rod distributes this side loading along the entire length of the rod string, reducing the force between the rods and tubing and increasing their run life.
- Reduced outer diameter: With no need for upsets and rod shoulders, a continuous rod string will have a smaller outer diameter compared to the same size conventional rod (Figure 1). This allows for larger rod to be run in slimhole completions with 2 3/8-in. tubing that is limited to using 7/8-in. rods with slimhole couplings. For 2 3/8-in. tubing, the largest continuous rod diameter that has been installed is 1 in., and for 2 7/8-in. tubing the largest diameter is 1 1/8 in. This increase in allowable rod size allows for deeper pump setting depths or larger pump installations, without having to move to a higher-strength rod grade.

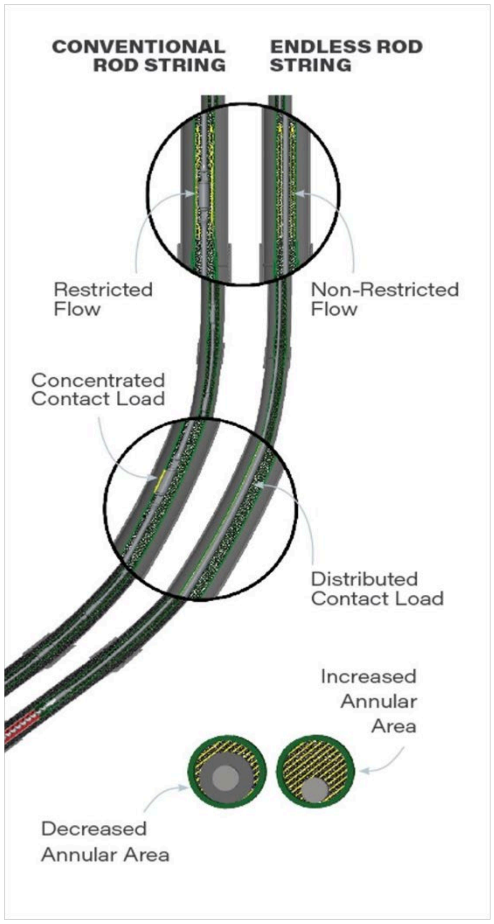

Figure 1—Comparison of distributed contact area and annular area between conventional rod and continuous rod.

Despite these advantages, continuous rod still makes up a small portion of the total sucker rod market. The most obvious obstacle to broader adoption is the availability of service equipment. Continuous rod requires a special gripper for running and pulling the rod string in place of the elevators used for lifting conventional sucker rods. Historically, the limited availability of this equipment has resulted in greater downtime after a well fails and can cause scheduling issues when converting to rod pump from another form of lift. At times, certain geographical areas may have the equipment available, but lack locally trained crews to operate the equipment. This lack of trained personnel can lead to delays when a crew must travel from another area to service the continuous rod string.

The welding process used to join multiple lengths of continuous rod together has also been an area of concern. Welding may occur at multiple steps between manufacturing the rod and installing it in a well. During the manufacturing process, multiple coils of rod provided from a steel mill will be welded together to form a longer, continuous coil of rod. These welds are of less concern, as they happen prior to heat treatment of the rod. During heat treatment, the weld and heat-affected zone (HAZ) around the weld will normalize with the rest of the steel and have nearly identical mechanical properties to the rest of the coil.

The welds that occur after heat treatment have a greater potential for issues to arise during operation of the well. These welds are necessary to join rods of different sizes together and produce a tapered rod string for a specific installation, to attach the pin ends to the rod that adapt the continuous rod to conventional sucker rod pins and couplings at each end, and to repair a damaged rod string after it has parted. Special care must be taken in the operation of the welding equipment, post-weld heat treatment, finishing of the weld, and non-destructive testing to ensure a quality weld.

Earlier installations of continuous rod used flash-butt welding for any repairs or installation of pin ends in the field. This welding method applies electrical voltage across the two ends to be joined together. As the ends move closer together, electricity arcs from one end to the other, allowing current to flow. This high-amperage current heats the ends of the metal, allowing the ends to be fused together. This method of welding is commonly used to join sections of rail line together. However, experience with this welding method and continuous rod found it to be generally unreliable. The weld was often a point of failure, due to trapped inclusions, poor fusion of the two ends, and poorly treated HAZ. The high current required to effectively use this welding method was often difficult to maintain in remote locations where the welding current was supplied through the use of batteries.

Eventually, all vendors moved to a forge welding process. For this type of weld, the ends are heated by use of a gas-fired torch prior to being mechanically forced together. The rod ends soften at higher temperatures, allowing them to be fused together. Since heat is supplied by a gas flame, and not through electricity, it is easier for the welder to maintain a consistent heat output during the welding process. This more controlled heating process helps to ensure a more consistent, higher-quality weld.

In the past, the selected metallurgy and rod grade contributed to issues with corrosion-fatigue failures. The most common steel alloy previously used for continuous rod was AISI-41xx. This is the same alloy used for API D grade rods. This grade is not commonly used for conventional sucker rods today. Instead, KD grade rods are preferred for their ability to better tolerate some corrosion pitting without propagating a fatigue crack and ultimately a rod part.

KD grades commonly use AISI-43xx alloy steel, which has a slightly higher amount of nickel and chromium when compared to the 41xx alloy steel. It should be noted that the increased nickel and chromium content does **not** contribute to increased corrosion resistance. The modified chemical composition contributes to the material's mechanical properties after heat treatment, which will allow for a larger corrosion pit before fatigue cracking begins to damage the rod. This failure mechanism is known as corrosion-fatigue. The continuous rod grade that was the focus of these installations is a 43xx alloy steel, heat treated to a minimum tensile of 115 ksi, and is metallurgically very similar to a conventional KD sucker rod.

Another issue with past continuous rod designs is the 41xx alloy steel was often heat treated to a minimum tensile of 140 ksi, similar to a high-strength rod grade. As a general rule, as the minimum tensile rating increases, the material hardness also increases, which reduces the corrosion-fatigue resistance of the rod. This resulting decrease in corrosion-fatigue resistance, meaning a smaller corrosion pit is required to initiate fatigue cracking, causes high-strength rods to commonly be described as less "corrosion resistant". Highly corrosive wellbore fluids, especially in CO_2 floods, would often experience premature failure of continuous rod due to corrosion.

A NEW APPROACH

Oxy began working with a new vendor to install continuous rod in the Permian in 2021. This new vendor brought several new approaches to the process of deploying continuous rod. The first is a focus on only using rod grades manufactured from 43xx alloy steel. This material change, combined with the practice of using larger diameter continuous rod at the top of the rod string as necessary (i.e., 1-in. rod in 2 3/8-in. tubing and 1 1/8-in. rod in 2 7/8-in. tubing), has eliminated the need for high-strength grades of continuous rod in Oxy installations to date.

As mentioned above, practically all suppliers of continuous rod have replaced flash-butt welding with forge welding in their operations. However, a significant difference with the new approach is minimizing the amount of welding required at the wellsite. Rod tapers are built and pin ends welded to the rod at the vendor's yard, in an enclosed building where the welding process is protected from the elements. This "pin-to-pin" process allows for a consistent, repeatable process to be followed that is not affected by environmental factors such as rain and wind-blown sand. This process both improves the consistency and quality of the weld and reduces the time required to install the rod. Rig time is not wasted waiting for the welds to be completed for each pin end and any taper junctions along the length of the rod string.

Another new process is to use any available deviation surveys, preferable from a high-resolution gyro, to ensure that welds are not placed in any areas of high dogleg severity. This practice helps reduce the amount of bending load applied to the rods in these areas, which are usually harder than the surrounding steel as a result of the welding process. This applies to both taper transition welds and welds made during manufacturing to join multiple coils together into a single bulk reel. Though the manufacturing welds are performed prior to heat treatment, and thus will be more homogeneous with the surrounding steel, this extra caution helps to minimize any potential risk of failure near a weld during operation. This level of care requires a significant investment in tracking of the rod from manufacturing to the field to properly identify those weld locations.

Finally, service availability has been addressed with a combination of equipment permanently based in the Permian and sufficient personnel available to manage the servicing of continuous rod. The personnel dedicated to this operation are a combination of local employees and rotational employees from other regions. The rotational employees provide both additional manpower and significant experience that is valuable for training new employee. Prior vendors would supplement their personnel on an as-needed basis, potentially causing extended downtime after a well failure. The new approach continually rotates employees through the Permian, so personnel availability is no longer an issue.

Figure 2—Continuous rod servicing equipment.

INSTALLATIONS

Problem Wells

Problem wells operated with rod pumps are those wells with two or more failures in a twelve-month period. Continuous rod may be used to address problems such as repeated failures caused by rod-on-tubing wear or parted 7/8-in. slimhole couplings run inside 2 3/8-in. tubing. Table 2 shows the performance of several problem well installations that were converted to continuous rod.

Well P had a reasonably long run of 292 days before a rod part occurred in March 2021. This failure was attributed to corrosion initiating a fatigue failure. The next two installations only lasted 55 days before a tubing leak and 88 days before another rod part occurred. The tubing leak was attributed to wear; it is not clear what the main factor was that contributed to the second rod part. Knowing the well had a tubing failure caused by rod-on-tubing wear, it is also possible the prior corrosion-related failure was caused by the same wear preventing corrosion inhibitor from properly filming on the rod. This “inhibitor-wipe” is the cause of many corrosion-related failures in even mildly deviated wells. This well was converted to continuous rod in December 2021, and is currently running with 470 days of runtime.

Well M is an example of a problem well with numerous challenges that make operating a conventional rod string difficult. When this well was converted from an electric submersible pump (ESP) to a rod pump, the decision was made to install lined tubing. This was due to several areas of high side-loading in the well. In particular, two points near 2,000 and 3,500 ft respectively had side loads of approximately 350 and 250 lb. The first installation lasted 635 days before failing with a rod part. However, the next three rod failures were all coupling failures, lasting an average of 157 days.

The failed couplings were all 7/8-in. slimhole spray-metal couplings. Slimhole couplings are required with 7/8-in. rods inside lined tubing, because the liner has an inner diameter that is equivalent to 2 3/8-in. tubing. Spray-metal couplings are used so the coupling has a smooth surface finish that will not damage the liner. Slimhole 7/8-in. T couplings are particularly vulnerable to premature failures due to their lower strength (90 ksi) and smaller size compared to a KD-equivalent grade of rod (115 ksi). Spray metal couplings are at greater risk because some of the base material must be removed before applying the spray-metal coating, further weakening the coupling.

The most recent installation required a casing repair with a 4.5-in. liner prior to reinstallation of the rods and tubing. With the 4.5-in. liner, running 2 7/8-in. lined tubing was no longer an option. Though some consideration was given to running a 1-in. fiberglass rod design, the decision was made to upsize the unit (from a 192-in. stroke length to 240 in.) and run an 87 continuous rod design with a KD-equivalent grade of material. Since the continuous rod only requires couplings at the ends, the larger 1-in. rod can be used for loading purposes, with high-strength 7/8-in. slimhole couplings used at the top of the rod string. This installation is currently running with 370 days of runtime.

Well D is another case of multiple short runs inside 2 3/8-in. tubing. After three runs of less than 40 days in early 2022, a continuous rod string was installed in June 2022. This well also had the pumping unit upsized from a 640-305-144 unit to a 1280-365-240 unit. Though the polished rod velocity of both installations is very similar, the longer stroke and elimination of guides and couplings should distribute wear between the rods and tubing over a much broader area. This well is currently running for 280 days without failure.

ESP Conversions

In many areas, rod pumps are the next form of artificial lift installed after ESP. As well production naturally declines, ESPs lose efficiency caused by operating in the lower end of their operating range and struggle with gas lock or overheating motors due to increasing gas-to-liquid ratio. Continuous rod may be considered during these conversions due to constraints such as 2 3/8-in. tubing or side loading beyond the range of what traditional guides can handle.

Table 3 shows the history of several installations where continuous rod was used during the first conversion from ESP to rod pump. For each well, the first rod pump installation was also the date of the continuous rod installation. The values in the Oil and Water columns are the average well test values during that installation period. If the last well test on ESP deviated significantly from the average, that value is listed in the Notes column. The decision of when to convert from ESP to rod pump is a balance of trying to maintain the pre-conversion production volumes while also achieving an economical equipment runtime.

Well S31 was converted in November 2021. Though the average well tests for the prior ESP installation were 171-bbl/D oil and 281-bbl/D water, the last well test prior to conversion had declined to 59-bbl/D oil and 109-bbl/D water. The side-load plot in Figure 3 shows an example where continuous rod may be considered over guided rods. Though the maximum side load is within the range that conventional guided rods might be used, it is the sudden transition from low side loads, to significantly higher side loads, and back to lower values that is of concern. Such areas increase the likelihood of concentrated wear on the rod guides and compression of the rods above that deviation. Production from Well S31 with the rod pump installations has exceeded the pre-conversion amount. The only failure has been a polished rod failure, which is easily repaired with minimal expense. The total run days on rod pump is now within one month of matching the previous ESP runtime.

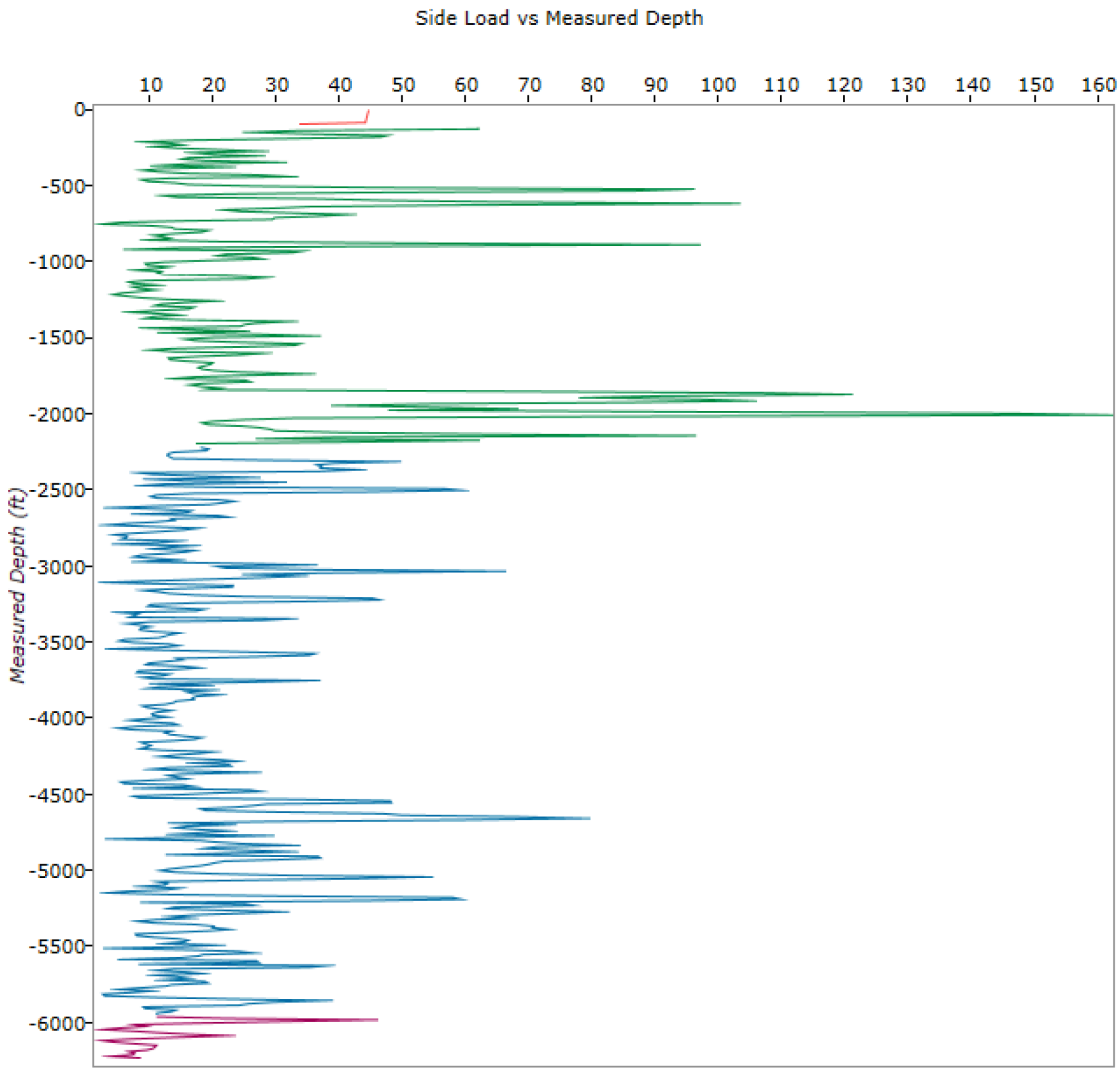

Figure 3—Well S31 side load vs. depth.

Well S2 was operated with a rod pump from June 2019 through September 2020. It was then converted to ESP after multiple short runs due to tubing leaks caused by rod-on-tubing wear. The high side loading in the lower portion of the well (Figure 4) certainly contributed to these failures. Unfortunately, production declined and the runtime of the ESP did not exceed that of the previous installations. This well was converted back to rod pump with a continuous rod string in December 2021, and achieved a runtime of 287 days before being shut in for a casing leak.

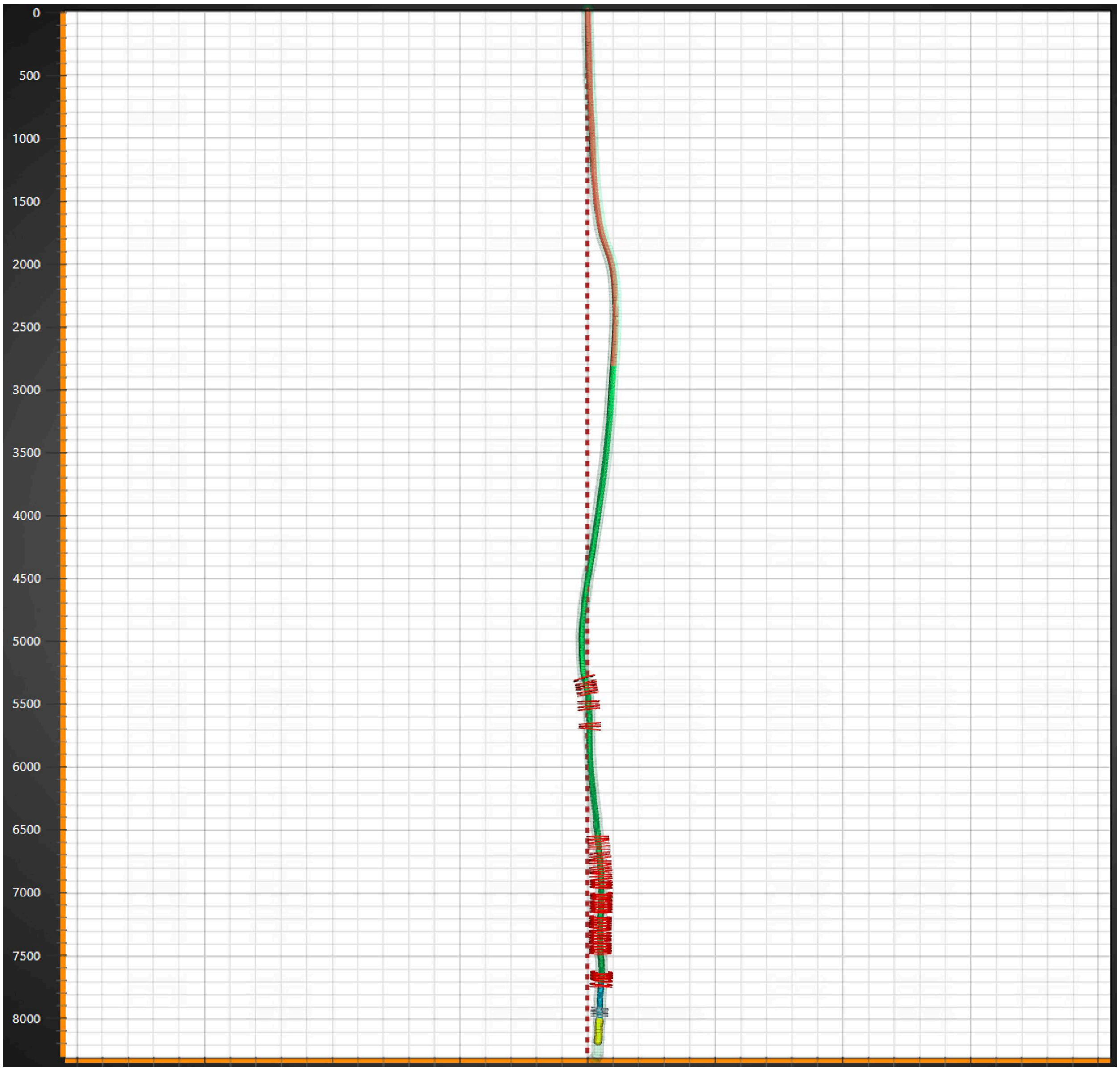

Figure 4—Well S2 north-south view.
Red markers indicate side loading greater than 100 lb.

Prior to converting to rod pump, Well R had multiple ESP runs of less than a month, producing over 1,500 bbl/D of water. As part of the rod pump conversion, the water-producing zone was isolated to reduce water production as much as possible. This well shows a similar sudden transition from low to high side loads as Well S31, leading to the decision to use continuous rod. The current runtime is now 467 days with comparable oil production to the previous ESPs.

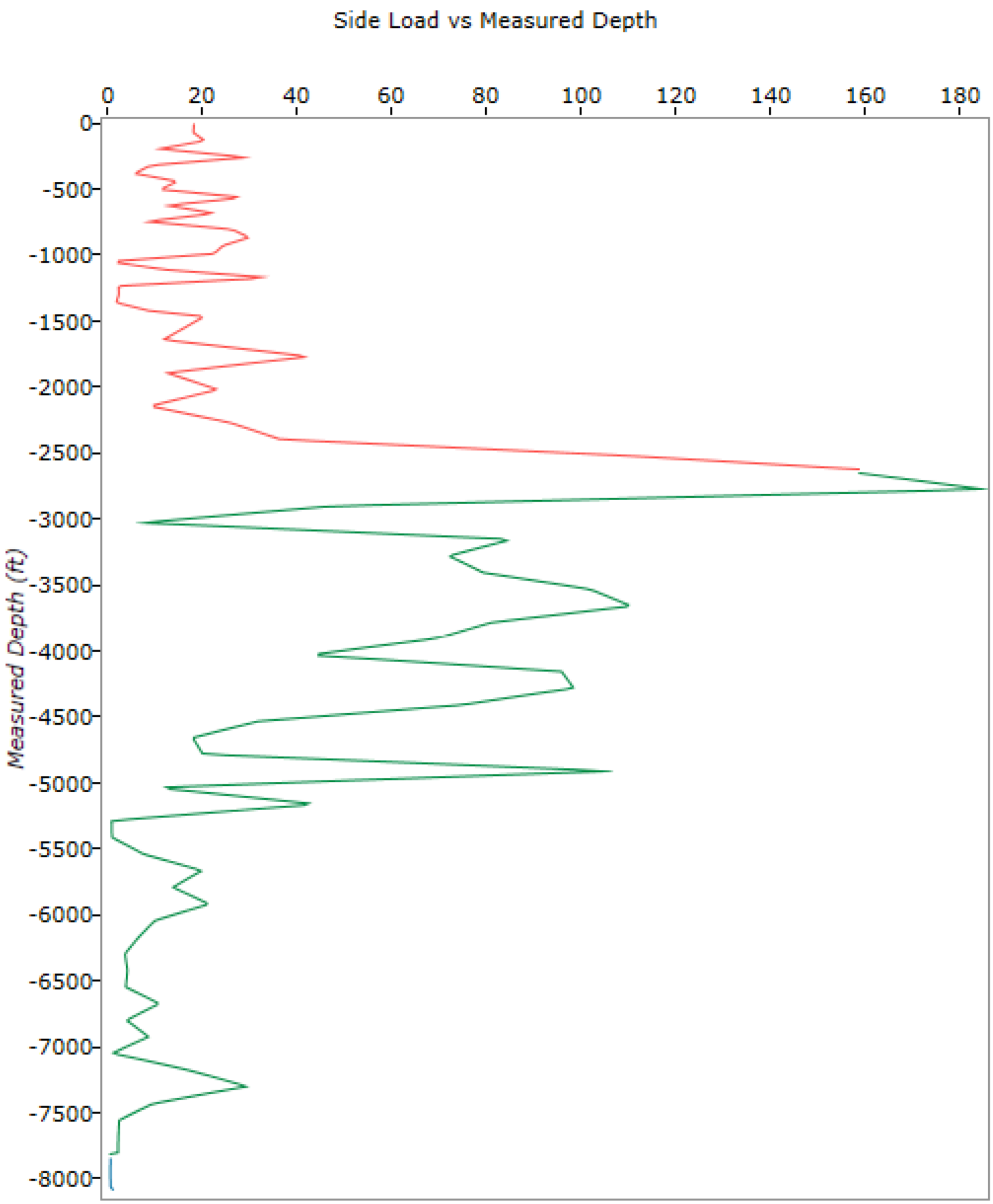

Figure 5—Well R side load vs. depth.

Well A was converted to rod pump in December 2021. The pump plugged with asphaltenes 60 days later, but has now run for over 350 days since being repaired. This exceeds the runtime of three of the last four ESP installations, which failed to reach 150 days of operation. A maximum side load of 286 lb, along with significant side loading of 50–100 lb throughout the entire wellbore, let to the selection of continuous rod for this conversion.

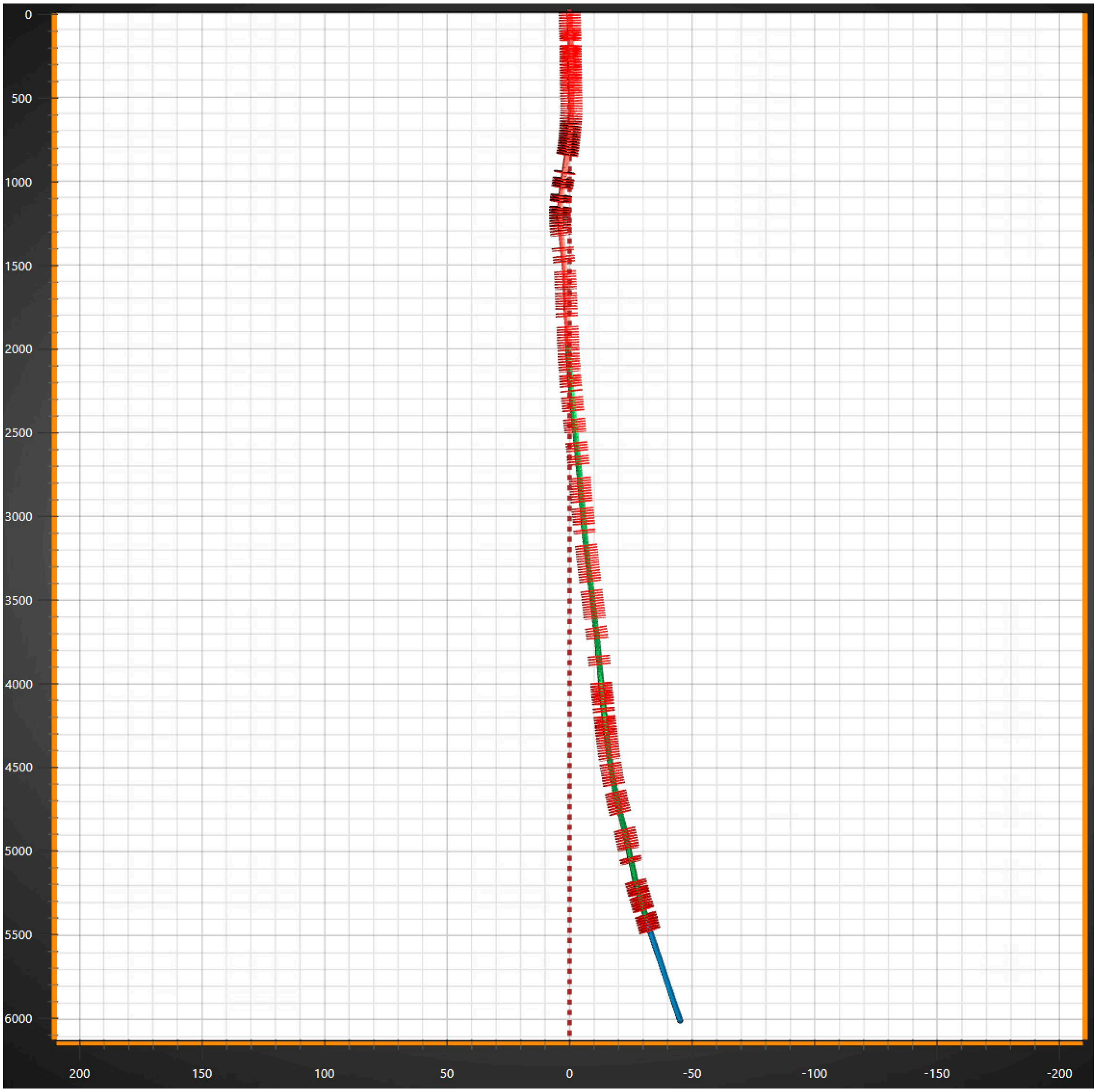

Figure 6—Well A north-south view.
Red markers indicate side loading greater than 50 lb.

Well S3 illustrates how both inclination and azimuth combine to create areas of high side loading. After multiple runs of less than two months on ESP, this well was converted to rod pump. Continuous rod was chosen because of the generally high side loading throughout the wellbore, but especially the peak of 236 lb near 2,000 ft. The north-south view does show some inclination changes, however the plan view shows how the areas of side load greater than 100 lb are where changes in inclination and azimuth both occur at the same time. These combined changes in direction make not only rod pumping hard, but make it difficult to install long ESP assemblies and ESP cable without damage.

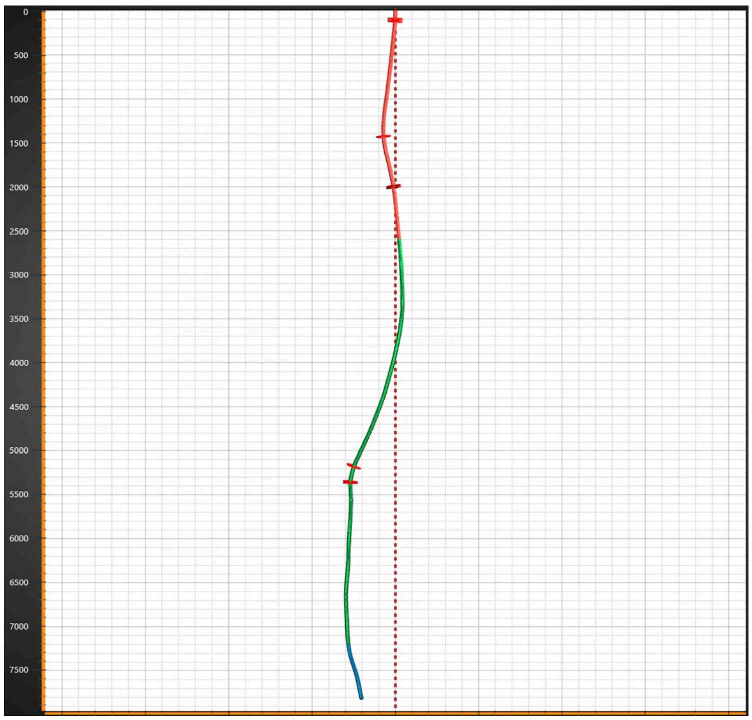

Figure 7—Well S3 north-south view.
Red markers indicate side loading greater than 100 lb.

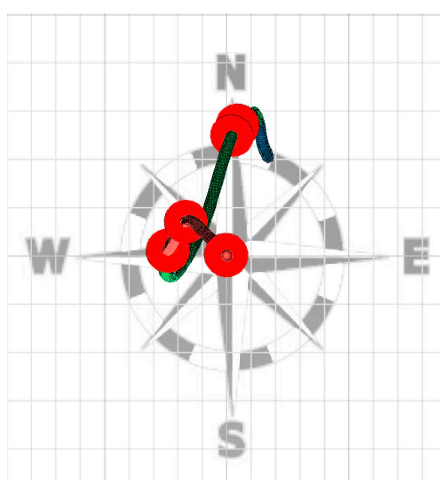

Figure 8—Well S3 plan view showing azimuthal changes of the wellbore.

NEW DEVELOPMENTS

A new area of interest for selecting continuous rod is long-stroke, high-volume rod pumping applications. Well S34 and Well L were designed to move 400–500 bbl/D total fluid from 7,000–8,000 ft, after accounting for poor pump efficiency due to gas interference. Both installations used a 2560-500-320 pumping unit, a 2-in. insert pump and a 97 continuous rod design. Using 1 1/8-in. continuous rod at the top of the taper allowed for the use of a KD-equivalent grade of rod. Running a guided, conventional rod string would have required the use of high-strength materials that would be more susceptible to corrosion-fatigue.

Figure 9—2560–500–320 conventional pumping unit next to a very small rental car.

The 2560 installations were both completed at the end of 2022, but the initial results indicate this is a promising new area to consider skipping an ESP installation and moving to rod pump earlier in the life of a well. Oxy has since used the 97 continuous rod design in additional long-stroke applications: one with a conventional 1824-427-300 and another with a 350-500-306 tower unit.

CONCLUSION

Continuous rod has a long history in rod pump applications, but faced many challenges to widespread adoption. Limited availability of service equipment and personnel, metallurgy selection, and welding processes resulted in a product that failed to reach its full potential.

Recent changes in the choice of metallurgy, moving to forge welding, more carefully planned designs, and increased service infrastructure have combined to provide a reliable alternative to conventional guided rods. Continuous rod helps to improve the runlife in deviated wells, slimhole wellbores, and high fluid rate applications. Oxy has seen a significant performance increase in problem wells, ESP to rod pump conversions, and now with long stroke applications using 97 rod tapers.

ACKNOWLEDGEMENTS

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REFERENCES

Patton, L. D. 1970. Concepts of Continuous-Rod Pumping. Paper presented at the Southwestern Petroleum Short Course.

TABLES

Well Name	Rod Type	Start Date	Stop Date	Run Days	Failure	Notes
Well P	Conventional	05/22/2020	03/10/2021	292	Rod part	Corrosion
	Conventional	03/26/2021	05/20/2021	55	Tubing leak, wear	Rod/tubing wear
	Conventional	09/01/2021	11/28/2021	88	Rod part	
	Continuous	12/09/2021		469		
Well M	Conventional	09/26/2018	03/04/2019	159	Coupling part	7/8-in. SHSM
	Conventional	03/29/2019	04/02/2019	4	Stuck pump	
	Conventional	04/29/2019	10/25/2019	179	Coupling part	7/8-in. SHSM
	Conventional	11/08/2019	03/22/2020	135	Coupling part	7/8-in. SHSM
	Continuous	03/17/2022		369		
Well D	Conventional	01/15/2022	01/20/2022	5	Tubing leak	Rod/tubing wear
	Conventional	02/15/2022	03/21/2022	34	Rod part	
	Conventional	04/09/2022	05/05/2022	26	Rod pin	
	Continuous	06/16/2022		280		

Table 2—Problem well installations.

Well Name	Lift Type	Start Date	Stop Date	Run Days	Oil (bbl/D)	Water (bbl/D)	Failure	Notes
Well S31	ESP	05/15/2020	10/08/2021	511	171	281	Cable	Last ESP test 59 oil x 109 water
	RP	11/09/2021	08/21/2022	285	72	82	Polished rod	
	RP	09/07/2022		197	91	177		Rod total run time 482 days
Well S2	RP	06/11/2019	11/13/2019	155	86	95	Tubing leak	Rod/tubing wear
	RP	12/27/2019	03/20/2020	84	103	153	Tubing leak	Rod/tubing wear
	RP	04/21/2020	06/11/2020	51	104	113	Tubing leak	Rod/tubing wear
	RP	07/15/2020	09/26/2020	73	111	167	Tubing leak	Rod/tubing wear
	ESP	02/04/2021	04/23/2021	78	60	102	Motor	
	ESP	04/29/2021	06/14/2021	46	48	74	Pump	
	RP	12/02/2021	09/15/2022	287	107	105		Down for casing leak

Table 3—ESP to rod pump (RP) conversions.

Well Name	Lift Type	Start Date	Stop Date	Run Days	Oil (bbl/D)	Water (bbl/D)	Failure	Notes
Well R	ESP	05/25/2019	06/04/2019	10	2	1606	Cable	
	ESP	07/17/2019	08/17/2019	31	8	1500	Recompletion	Isolated water zone
	RP	12/11/2021		467	6	106		
Well A	ESP	09/11/2018	01/31/2019	142	31	380	Pump	
	ESP	03/09/2019	08/04/2019	148	24	288	Cable	
	ESP	08/21/2019	12/09/2020	476	27	335	Cable	
	ESP	01/05/2021	05/05/2021	120	31	372	Cable	
	RP	12/31/2021	03/01/2022	60	7	364	Rod Pump	Plugged with asphaltenes
	RP	04/05/2022		352	9	211		
Well S3	ESP	07/01/2021	02/09/2022	223	157	246	Pump	Gas locked
	ESP	02/15/2022	04/03/2022	47	39	32	Pump	Gas locked
	ESP	04/22/2022	05/17/2022	25	2	36	Pump	Intake plugged
	RP	06/17/2022	02/09/2023	237	83	174	Rod part	Buckling related

Table 3—ESP to rod pump (RP) conversions. (continued)