

SUCCESSFUL INSTALLATION OF CURVE ESP SYSTEMS IN THE PERMIAN MAXIMIZING ECONOMICS AND RECOVERY IN HIGHLY DEVIATED WELLBORES

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ABSTRACT

Horizontal drilling is an essential technology for exploiting unconventional resources. However, wellbores often include zones with high Dog Leg Severity (DLS), which can limit the installation of Electrical Submersible Pumping (ESP) systems at the deepest possible setting depth. Placing the ESP as deep as possible is critical to maximizing recovery and cash flow. This work highlights the successful application of curve ESP systems in Permian Basin wells with DLS values of 17°/100 ft, and discusses both the challenges encountered and the potential benefits of this technology.

The industry standard tolerance for deviation is approximately 6° per 100 ft for a conventional ESP system to reliably pass through the curved section of a wellbore. In this study, deviation surveys from several wells were carefully evaluated, and stress analysis was performed to assess mechanical stresses and the potential risk of equipment failure when navigating high-DLS zones. A group of wells with elevated DLS values was selected as pilot candidates for deployment of the new curve ESP system. Well models were developed, and sensitivity analyses were conducted to evaluate the impact of pump setting depth on production performance. The ESP systems were subsequently designed and installed, with production data collected and operating parameters closely monitored.

Based on stress analysis simulations, a standard ESP system wouldn't be able to pass through zones with high DLS. In the first install a conventional ESP was installed and the system setting depth was shallow. The unit was subsequently pulled and replaced with a curve ESP system, allowing for a deeper setting depth while passing through zones with DLS of 12°/100 ft. The pump setting depth was increased from 6,660 ft to 7,800 ft—an additional 1,100 ft. As a result, production increased by 75%, adding 550 BOPD and generating approximately USD 1 million in the first 30 days of operation. The unit has since demonstrated stable operating trends with minimal X- and Y-axis vibration, indicating limited mechanical wear.

In a separate case study, a CENesis curve ESP system was successfully used to set the ESP in a zone with DLS ranging from 4° to 6°/100 ft, achieving a run life of 802 days, further demonstrating the reliability and field-proven performance of this technology.

The standardized industry practice for deploying ESP systems in wells with high DLS is to avoid traversing the curved section by setting the pump at a shallower depth. Alternatively, operators may attempt to pass through by reducing pump length, which typically requires decreasing the number of stages, thus limiting lift capacity and selecting smaller motors, which reduces available power. Both approaches compromise system performance and production potential. The curve ESP system provides a viable solution to these mechanical and hydraulic limitations, enabling reliable installation at greater depths and unlocking the full production capacity.

INTRODUCTION

In mature and unconventional reservoirs, artificial lift systems play a key role in sustaining and enhancing production once natural reservoir energy declines. Among these technologies, Electrical Submersible Pumps (ESPs) are widely used because of their ability to handle high liquid production rates and operate efficiently in a wide range of well conditions (Takacs 2009).

The Permian Basin, one of the most prolific oil-producing regions in the world, has experienced significant growth in production due to advances in horizontal drilling and hydraulic fracturing technologies. Horizontal drilling has become essential for the development of unconventional reservoirs, allowing operators to increase reservoir contact and improve hydrocarbon recovery (Holditch 2013). However, horizontal wells often include sections with high dogleg severity (DLS) due to complex well trajectories required to reach target zones and optimize reservoir exposure. These high-DLS sections present significant challenges when installing artificial lift systems, particularly ESPs, which are traditionally designed to operate in wells with relatively smooth trajectories.

Installing the ESP as deep as possible in the wellbore allows the pump to maintain sufficient intake pressure, reduce gas interference, and maximize the available drawdown across the reservoir. As a result, deeper placement generally leads to higher production rates and improved recovery, which ultimately increases the economic value of the well (Brown 1984). However, in horizontal wells with high-DLS sections, mechanical limitations can prevent conventional ESP systems from being deployed at the desired depth. Excessive curvature can introduce mechanical stresses on the pump, motor, and cable, increasing the risk of equipment damage during installation or operation.

Industry guidelines typically recommend that conventional ESP systems operate in well sections with dogleg severity values of approximately 6° per 100 ft or less to ensure safe installation and reliable long-term performance. When the well trajectory exceeds this limit, the risk of mechanical failure increases due to bending stresses, cable

damage, and difficulty in running the equipment through the curved section of the wellbore.

To address this challenge, new curve-compatible ESP technologies have been developed to enable installation in wells with higher deviation and curvature. These systems incorporate specialized equipment designs and installation practices that allow the ESP assembly to safely navigate sections with higher DLS while maintaining operational integrity.

This work presents the successful deployment of curve ESP systems in Permian Basin wells with dogleg severities as high as 17°/100 ft. The study highlights the operational challenges associated with installing ESPs in highly deviated wells and discusses the technical considerations required to mitigate mechanical risks. Furthermore, the results demonstrate the potential of curve ESP technology to enable deeper pump placement, improve production performance, and increase the economic value of wells with complex trajectories.

CENESIS CURVE SYSTEM CONCEPT

Figure 1. shows standard and curve ESP system configurations. In a standard configuration, bolts are used to connect between the ESP system components, while the curve system configuration uses patented boltless connections. This boltless design allows the ESP string to pass through buildup rates upwards of 25° per 100 ft with no damage to the system, where the industry standard buildup or deviation rate is 6° per 100 ft for an ESP system to reliably pass through the curved section of the wellbore.

Broken shafts and one-sided wear, which result in low or no production, are among the leading causes of ESP downtime. When traditional ESP travels through deviation rate above 6° per 100 ft, the internal components exceed its elastic deformation and reach plastic deformation, which leads to unbalanced weight distribution. Once equipment starts to operate, this imbalance leads to premature failure, shaft fatigue, reduced pump efficiency, and accelerated component wear forcing premature shutdown.



Figure 1. Standard and curve system configurations.

The boltless connection technology increased the tensile strength to 120,000lbs compared to 33,000lbs with standard bolted connections (Figure 2). During the ESP installation, the boltless system required shorter procedure compared to standard bolted connection, which reduces installation time and mitigates human error. Eliminating the use of bolts reduces the rig time during the installation and removes the risk of tools or bolts being dropped downhole. This reduces OPEX and avoids customer cost of re-drill or sidetrack.



Figure 2. Tensile strength tests

The curve system allowed the ESP string to sit at the deepest setting depth possible, which produced closer to target zone allowing greater bottomhole pressure reduction. Deeper setting depth has higher intake pressure and larger fluid column above the pump, which increases head production, and prevents gas locking. Additionally, the motor has more constant fluid bypass helping with cooling and reducing thermal cycling. This mitigates equipment downtime and reduces the need for additional field visits.

CASE STUDIES

The following case studies illustrate field applications of CENesis curve ESP system. These examples highlight the operational performance, challenges encountered, and the impact of each system on equipment run life and overall well reliability.

Case Study – Well 1

Well 1 was drilled and completed with **5.5-in., 20-lb/ft** casing targeting the Jo Mill (Spraberry L B1) formation. The perforated interval extends from 8,706 ft to 25,349 ft. The operating company initially opted to install a conventional ESP system (Vendor B). The deviation survey is shown in Figure 3, highlighting a critical section between 6,650 ft and 7,121 ft, which presents a significant challenge due to high dogleg severity (DLS). The maximum recorded DLS in this interval was 11.72°/100 ft at 6,660 ft. As a result, the ESP setting depth was limited to 6,600 ft to avoid potential mechanical risks. Following installation, the well's average production was 1,590 BPD total liquid, with 75% water cut and a GOR of 560 scf/STB.

M. Depth	INC	AZM	C.L	TVD	DLS
26	0	360	26	26	0
156	0.3	264.6	130	155.9994	0.230769
2203	6.54	182.5	95	2132.028	0.878021
4468	6.89	179.3	94	4380.26	0.270693
6036	4.78	188.85	57	5937.796	0.284702
6185	4.69	210.02	158	6095.269	1.101215
6279	6.44	199.14	94	6188.825	2.165891
6373	7.03	191.31	94	6282.178	1.159741
6467	8.09	186.15	94	6375.361	1.338022
6562	6.97	184.35	95	6469.54	1.204668
6661	6.34	182.16	99	6567.873	0.68595
6710	8.38	190.9	52	6619.443	4.464216
6744	11.27	200.04	34	6652.943	9.633229
6780	13.65	216.31	36	6688.103	11.71894
6838	14	239.65	58	6744.467	9.571629
6932	9.7	237.41	94	6836.442	4.599719
7027	9.09	208.6	95	6930.219	4.939178
7121	5.52	195.27	94	7023.448	4.179515
7215	3.85	191.47	94	7117.13	1.806051
7309	0.55	225.56	94	7211.05	3.626022
7404	0.2	295.01	95	7306.048	0.542155
7499	0.25	332.73	95	7401.047	0.161018
7593	0.11	94.66	94	7495.047	0.342561
7688	0.28	35.52	95	7590.046	0.255472
7782	0.76	71.49	94	7684.043	0.593794
7877	1.14	67.64	95	7779.029	0.40538
7971	1.48	72.73	94	7873.005	0.38195
8066	2.49	9.81	95	7967.956	2.36178
8132	5.99	345.2	83	8050.722	4.659358
8170	5.63	6.02	38	8088.531	5.594338
8200	5.74	20.27	30	8118.385	4.707397
8227	6.9	10.75	27	8145.221	5.776072

Figure 3. Well 1, deviation survey.

The pump operating trends are presented in Figure 4. The Vendor B unit operated for less than one month before failure. During operation, the intake pressure was approximately 500 psi, and the motor temperature reached 180°F. The unit was subsequently pulled, and the operating company decided to re-evaluate the ESP design and installation strategy.

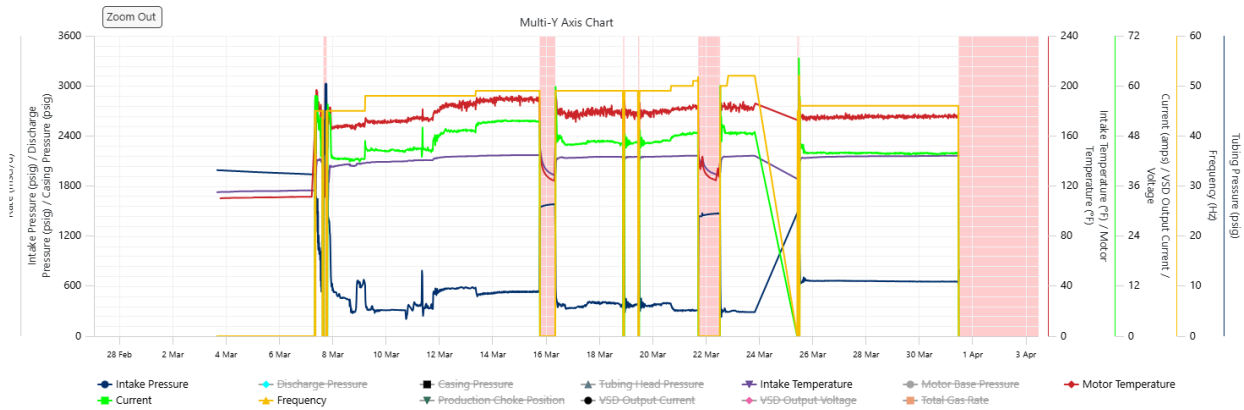


Figure 4. Well 1, operating trends, Vendor B.

A second installation was planned using an alternative supplier (Vendor A). A detailed review of the deviation survey identified a potential window to set the pump deeper, between 7,400 ft and 7,970 ft. Sensitivity analysis indicated that placing the pump at

approximately 7,800 ft could increase the intake pressure by approximately 450 psi and improve production by up to 40%, due to increased drawdown and improved fluid handling.

An initial design using a conventional ESP system was evaluated; however, an internal mechanical stress analysis conducted at 6,780 ft (see Figure 5) indicated that the stress limits of the seal section would be exceeded, resulting in a high risk of shaft failure and premature equipment damage. Consequently, a conventional ESP design was deemed unsuitable for this application.

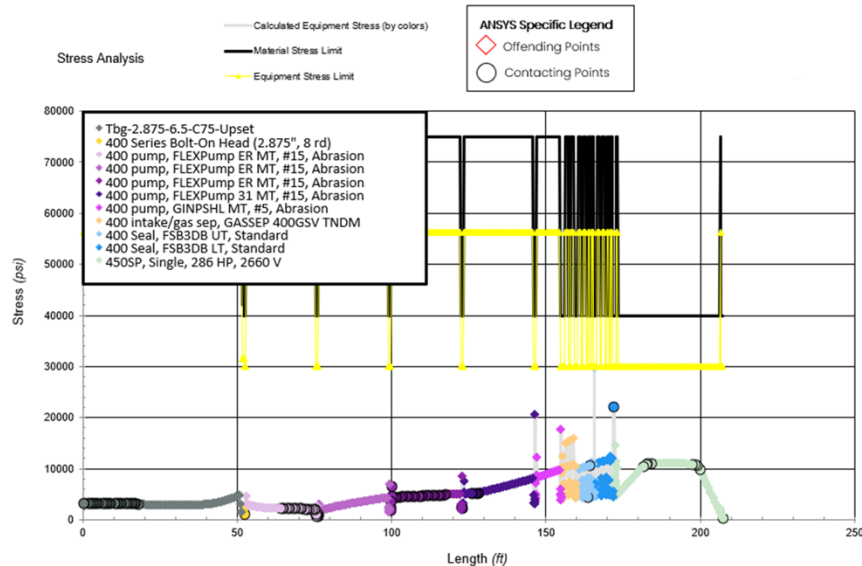


Figure 5. Stress analysis, standard ESP.

To address this limitation, the CENesis curve ESP system was evaluated. The results of the stress analysis are shown in Figure 6, demonstrating that the equipment can safely traverse the high-DLS section without exceeding mechanical limits. Based on these findings, the ESP was designed to be installed at a deeper setting depth of 7,800 ft.

The curve ESP system was installed in April 2025, and the operating trends are presented in Figure 7. The unit has been operating for approximately one year, showing significantly improved performance compared with the previous installation. The system has stable operating trends, with higher intake pressure and lower motor temperature, indicating improved flow conditions and enhanced cooling efficiency.

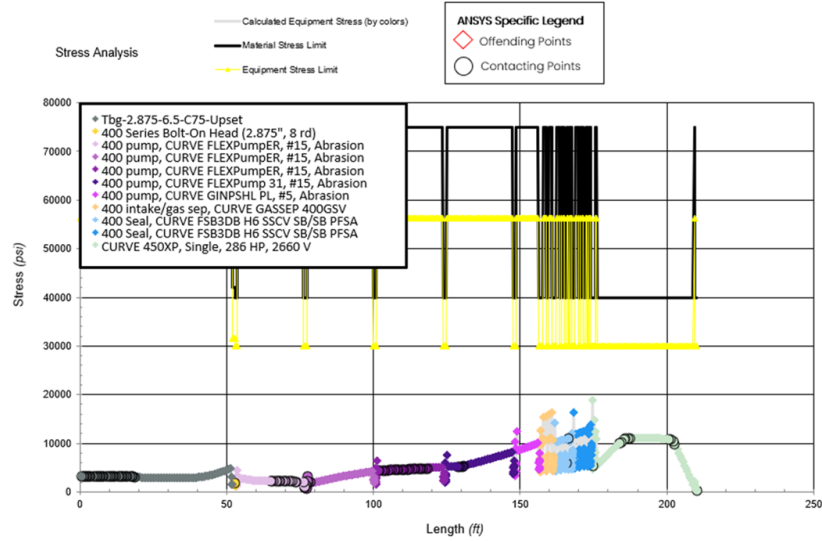


Figure 6. Stress analysis, CENesis curve ESP System.



Figure 7. Operating trends, Vendor A.

Production performance and GOR trends are shown in Figure 8. The results indicate a **75% increase in total production** compared with the initial installation. Despite the observed increase in GOR, current operating parameters (Figure 9) show that the unit is running at a fixed frequency, with no significant fluctuations or shutdown events.

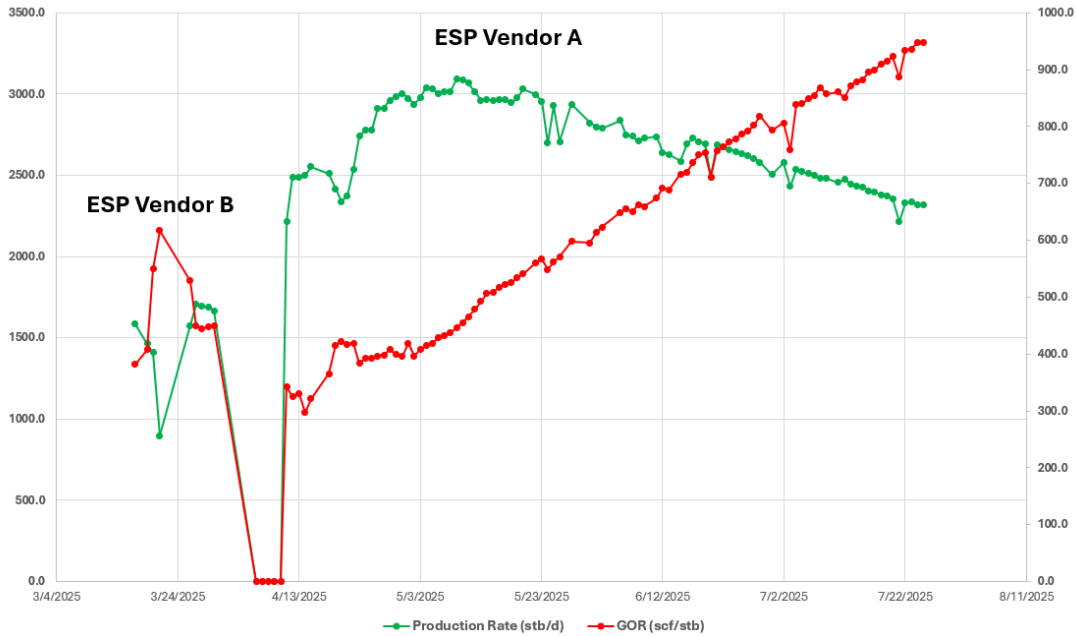


Figure 8. Production and GOR trends.

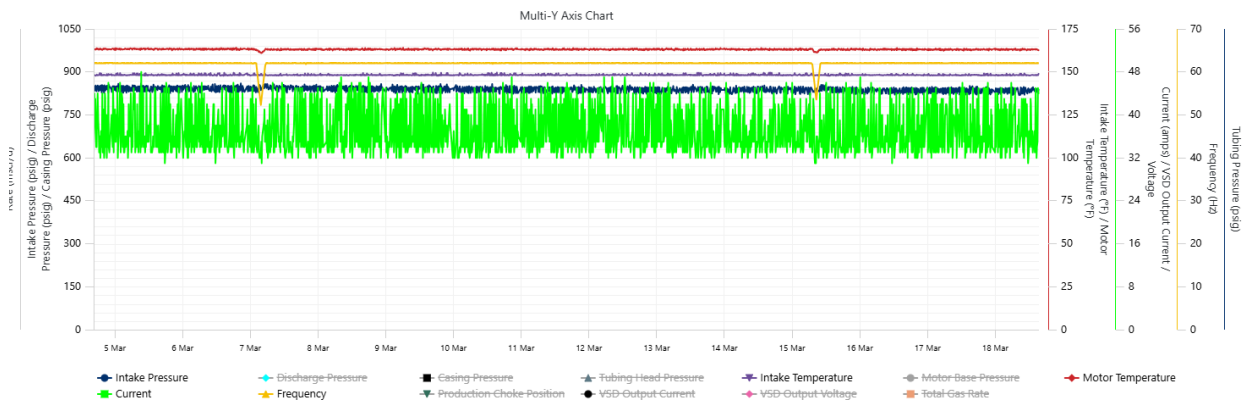


Figure 9. Current operating parameters

Case Study – Well 2

An operating company in the Permian Basin targeted maximizing production from Well 2 by installing an Electrical Submersible Pump (ESP) at the deepest feasible setting depth. The well was completed with 7-in., 29-lb/ft casing, and the deviation survey is presented in Figure 10. Industry best practices typically recommend avoiding ESP installation in zones where the dogleg severity (DLS) exceeds approximately 2°/100 ft for conventional systems. However, the surveyed wellbore trajectory showed consistently elevated DLS values ranging from 4° to 6°/100 ft, with a peak of 11.4°/100 ft at approximately 4,300 ft, posing a significant challenge for standard ESP deployment.

To achieve the desired pump setting depth of 4,200 ft, a curvature (stress) analysis was first conducted for a conventional ESP system. The simulation results indicated that key components—including the seal section, gas separator, and pump—would exceed their allowable curvature limits (Figure 11). This condition would introduce excessive mechanical stress, resulting in a high risk of shaft twisting, component deformation, and premature failure. Based on these findings, a conventional ESP design was deemed unsuitable for this application.

MD	Inc	Azimuth	TVD	DLS
0	0	0	0	0
761	8.86	12.68	757.76	2.55
849	9.74	352.92	844.63	3.74
939	8.8	341.47	933.46	2.3
1030	6.96	327.44	1023.61	2.91
1115	4.99	314.63	1108.14	2.78
2961	5.85	17.01	2950.43	5.47
3003	7.2	27.28	2992.16	4.24
3048	8.77	42.84	3036.73	5.9
3090	10.02	56.24	3078.17	5.98
3135	11.69	66.59	3122.37	5.68
3223	15.4	83.8	3207.94	6.18
3310	18.74	89.54	3291.1	4.29
3399	23.15	85.89	3374.21	5.16
3486	27.1	83.79	3452.96	4.65
3574	30.59	82.29	3530.03	4.06
3661	34.4	82.25	3603.4	4.37
3748	38.05	82.53	3673.57	4.21
3834	42.76	83.37	3739.04	5.51
3922	46.93	83.93	3801.42	4.76
4009	50.34	86.22	3858.91	4.39
4094	54.91	88.22	3910.5	5.69
4180	58.59	88.49	3957.64	4.29
4308	62.24	88.7	4020.83	2.85
4354	67.49	88.72	4040.37	11.43

Figure 10. Deviation survey, Well 2

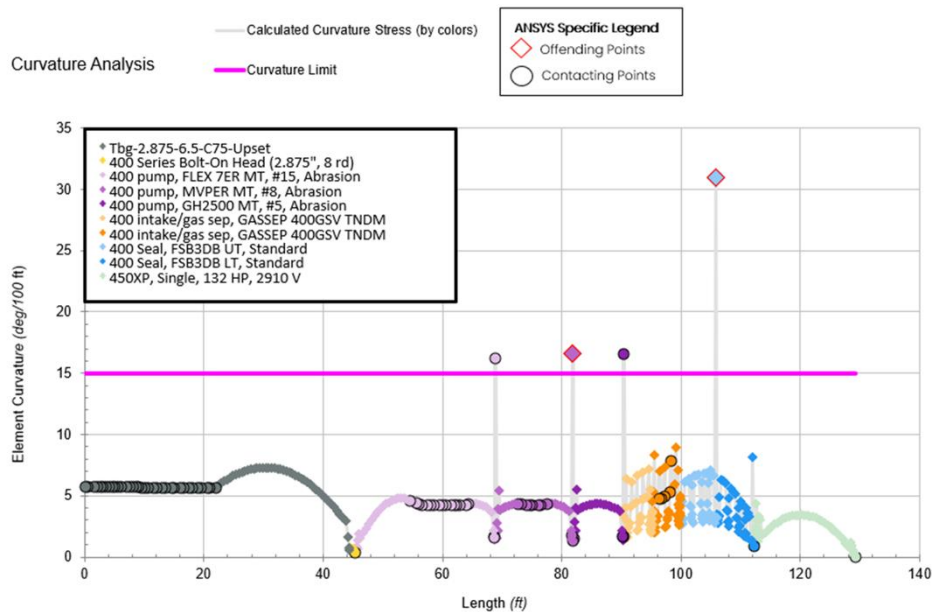


Figure 11. Curvature analysis, standard ESP, setting depth at 4200 ft.

As an alternative, the CENesis curve ESP system was evaluated. A similar curvature analysis was performed using the curve ESP system configuration (Figure 12), and the results demonstrated that the equipment could safely operate without exceeding mechanical limits. The boltless connection design and enhanced flexibility of the curve ESP system enabled it to accommodate the wellbore curvature while maintaining structural integrity.

Based on the analysis, the operating company proceeded with the installation of the CENesis curve ESP system at a setting depth of 4,200 ft in November 2021. The system achieved a run life of 802 days, demonstrating strong reliability and mechanical resilience under challenging wellbore conditions.

This case highlights the effectiveness of curve ESP technology in high-DLS limitations, enabling deeper pump placement and unlocking additional production potential. The successful deployment confirms that curve ESP systems are a viable and robust alternative to conventional ESPs in highly deviated wells, allowing operators to maximize production while minimizing the risk of mechanical failure.

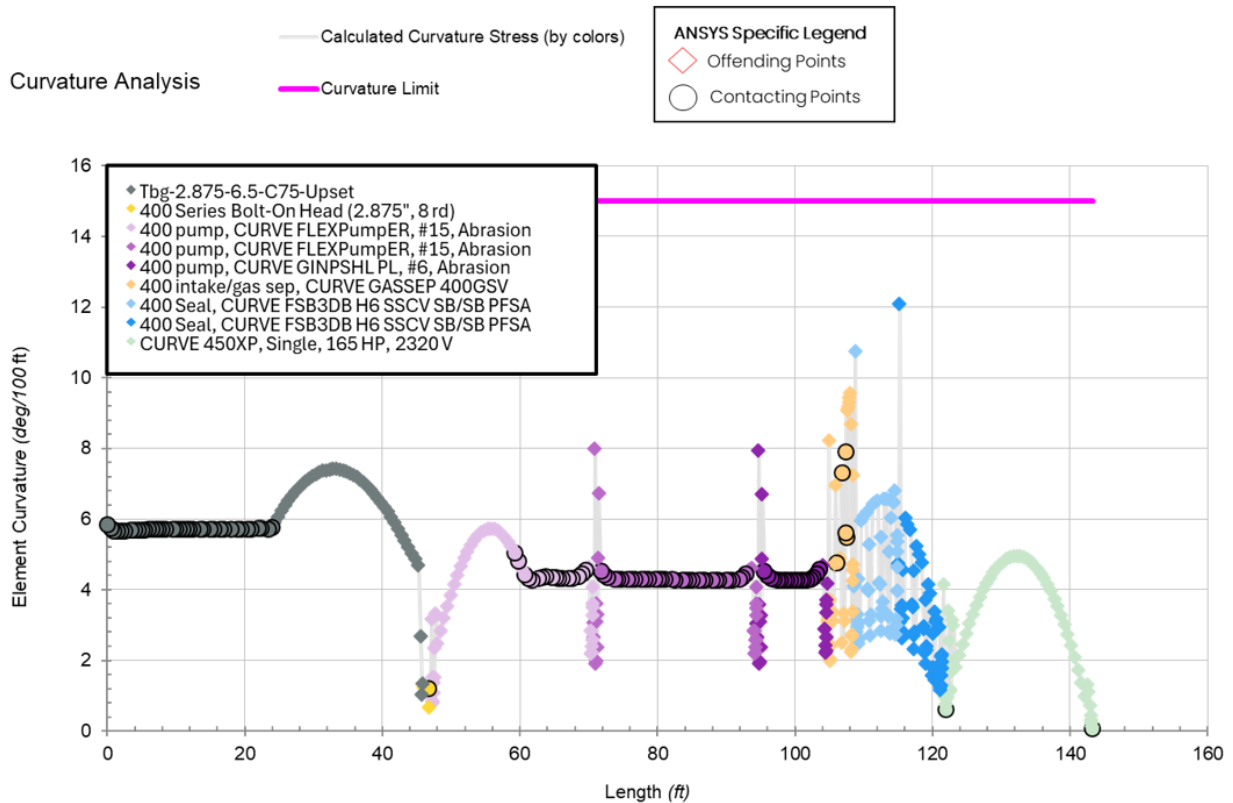


Figure 12. Curvature analysis, CENesis curve ESP, setting depth at 4200 ft.

CONCLUSIONS

1. High dogleg severity (DLS) restricts conventional ESP deployment, as standard systems are unable to safely traverse sections with elevated curvature without exceeding mechanical limits, resulting in risks such as twisted shafts and premature failure.
2. CENesis curve ESP technology enables successful deployment in high-DLS wells, allowing the system to safely navigate zones with DLS values up to approximately 12°/100 ft without exceeding equipment limits.
3. Deeper pump placement significantly enhances production performance, as demonstrated in Well 1, where installing the ESP 1,100 ft deeper resulted in a 75% increase in production.
4. Curve ESP systems enhance operational stability and reliability, with both wells demonstrating stable operating trends and extended run life, including over one year of continuous operation in Well 1 and approximately 800 days in Well 2.
5. CENesis curve ESP systems provide a practical and effective solution for maximizing production in challenging wellbore conditions, enabling operators to overcome deviation constraints, safely optimize pump setting depth, and improve overall asset performance.

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