AADE-25-NTCE-014

# Extreme Slim-hole Connection Design Improves Drilling Efficiencies and Reduces Potential Opportunities for Safety Issues

Glenn Brown and Andrei Muradov, Grant Prideco™; A.J. Gherardi, Quail Tools; Curt Jones, Kaiser-Francis Oil Company



## Abstract

This case history examines the successful deployment of drill pipe featuring a connection for extremely slim-hole drilling in US land operations. Traditionally, a dual-string design is used with a 5-in. NC50 string for the upper sections and then a full 4-1/2-in. slim-hole Double-Shouldered Connection (DSC) string inside the 6-3/4-in. lateral hole section.

The evaluation criteria focused on the operational efficiency gains, particularly as they relate to streamlining the drilling process and limiting possible operations that could cause safety incidents. Moving to a single string of 5-in. drill pipe with an extreme slim-hole 4th generation DSC design allowed every well to be drilled with the same configuration of pipe—top to bottom.

After the change to a single string design, several operational efficiency gains were realized. The automatic racking system could be used for the entire length of the well, enabling a reduction in crew size from six to five. By not laying the pipe down between wells and on rig moves, drilling efficiency increased, and opportunities for safety issues were reduced due to less pipe handling. The same bottomhole assembly (BHA) and blowout preventer (BOP) rams could be utilized, and the drilling crews could use the same maximum torque for the entire length of the well. Another added benefit was not needing to keep multiple sizes of accessories, such as crossovers and valves. All of this contributes to drilling every well as consistently as possible. This paper will present the quantification of these efficiency gains.

## Introduction

Drilling in the Eddy and Lea counties of New Mexico requires lateral sections to be either 8-1/2-in. or 6-3/4-in., depending on the target formation to be drilled. Almost all of the wells are drilled from multi-well pads, with between two and eight wells per pad. The lateral lengths for the wells are between 1 mile and 2 miles, with most right around the 1-1/2 mile mark.

When drilling the upper sections, the original drill string is generally rig-supplied pipe, which is 5-in. 19.50 lbs/ft S-135 with API NC50 connections. The NC50 connection has a tool joint outside diameter (OD) of 6-5/8-in. and an inside diameter (ID) of 3-1/4-in., which is an API standard configuration. For the 6-3/4-in. lateral sections, the 5-in. drill pipe is laid down, and another rental string of 4-1/2-in. 16.60 lbs/ft S-135 with a slim-hole 1st or 2nd generation DSC is picked up and ran. Depending on which generation of DSC is used, the tool joint ODs could range from 5-1/4-in. to 5-3/8-in. and the IDs could range from 2-13/16-in. to 3-in. Changing out to the 4-1/2-in. slim-hole drill string for the lateral section is time consuming and expensive, as well as increases the risk of safety events. As a result, an evaluation was performed, and it showed that having a single string of drill pipe with higher torque available through the lateral section would improve the drilling rate of penetration (ROP) for those wells drilled past 1 mile.

## The Double Shoulder Connection Evolution

Since the introduction of the Double Shoulder Connection (DSC) in the early 1980s (Thomas et al., 1996), the following three decades saw the development of several generations of these DSCs. Each generation (Chandler et al., 2007) was developed to meet industry needs for increasing the performance (more torque, enhanced hydraulics, and greater reliability) of the connection to achieve industry firsts and set records for extended-reach drilling (ERD) wells.

The most recent, 4th generation of the DSC (Plessis et al., 2018), introduced in late 2016, resulted from a comprehensive two-year research and development program carried out to evaluate various design options. This latest generation, in addition to slight performance enhancements, also incorporated design features to optimize the connection stresses, provide broader tolerances for field damage, reduce the material loss on repairs, and provide greater connection ruggedness. All features are targeting increased field life and a reduction in operating costs.

An additional benefit of all DSCs is that they can be streamlined, providing better annular clearance as well as improved hydraulic performance. For rig crews, there is virtually no difference between running a 4th generation DSC and running an API connection. Care must be taken to ensure that the secondary internal shoulder is cleaned to remove any dirt picked up while the pipe is racked back in the derrick, and finally, ensure thread compound is applied to the internal secondary shoulder. Otherwise, the same care and handling procedures used with API connections are applicable, making it efficient and simple to use.

## The Original String Limitations

Drilling the Eddy County and Lea County wells with the original dual drill string design presents several inefficiencies and hurdles. The drilling torque in the lateral section was limited due to the original connection capacities. Table 1 shows the different make-up torque (MUT) values that the drilling crew is required to maintain for the 5-in. and the 4-1/2-in. drill strings. Also included in the table are the corresponding tensile limits of the tubes and connections. During operations requiring 'rocking', the 4-1/2-in. strings often have the connections back out due to the reactive torque that is built up in the string, exceeding the breakout torque (BOT) of the connections.

As a result of having two separate strings, it was required to have a bottomhole assembly (BHA) design for each size of drill string. Also, handling tools and accessories (crossovers, valves, etc.) must be changed out, and an additional BOP test is required. After running the 4-1/2-in. string and returning it from rental, added costs related to inspecting and shipping the string are incurred. These are on top of the significantly high repair costs attributed to the high drilling torques and back outs. Due to the supply shortage in the market, it is then also difficult to source another rental string of 4-1/2-in. when the next lateral sections are up for drilling.

During rig moves and between wells, the pipe needs to be laid down and then picked back up, which takes time and reduces drilling efficiency. The additional pipe handling during the lay-down and pick-up operations also creates more opportunities for safety issues. Finally, the automated pipe handling equipment could not be used for both sizes of drill string, meaning the 4-1/2-in. string required manual pipe handling.

## Updated String Design

The results of the drill string design evaluation showed that drill pipe with increased torque available through the lateral section would improve ROP for those wells drilled past 1 mile. One well was pilot tested with a new drill string design, consisting of a single size of 5-in. 19.50 lbs/ft S-135 with an extremely slim profile 4th generation DSC. The connection OD was reduced to 5-7/8-in. and the ID was expanded to 3-1/4-in. The pilot well validated the drill string design evaluation and showed improvements in ROP performance and overall drilling efficiencies.

## Applications

The drill pipe torsion-strength ratio (TSR) is a calculated term defined in API specification 5DP (API, 2020-05). It is the torsion strength of the tool joint connection divided by the drill pipe body torsion strength. Good drill pipe design requires a balanced configuration with tool joint dimensions chosen such that they are suitable for use with a specific size, weight, and grade of tube. The API recommendation is to maintain a TSR of 0.8 or greater. Other OD/ID 'alternative configurations' can result in a lower TSR. The purchaser determines if the lower TSR is suitable for the intended application.

The DSC allows for increased torsional strength in the tool joint. The correlating effect of increased torsional strength means that slimmer profile tool joints can be used while still maintaining the API-recommended TSR.

Table 2 shows the TSR values for four drill pipe configurations. The first three configurations are based on the original dual-string design. Configuration number one is the 5-in. 19.50 lbs/ft S-135 tube compared to the NC50 (6-5/8-in. x 3-1/4-in.) connection. The TSR for this configuration is 0.69, which falls below the API recommendation. The second configuration is for the original 4-1/2-in. 16.60 lbs/ft S-135 tube with a 2nd generation DSC (5-3/8-in. x 3-in.). The TSR for this configuration is 0.85, which is above the API recommendation. The third configuration is also for the original 4-1/2-in. 16.60 lbs/ft S-135 tube but with 1st generation DSC (5-1/4-in. x 2-13/16-in.). The TSR for this configuration is 0.68, which again falls below the API recommendation.

The final configuration in the table is the new string design and compares the same 5-in. 19.50 lbs/ft S-135 tube with the new 4th generation DSC (5-7/8-in. x 3-1/4-in.). This configuration also has a TSR of 0.85; however, the connection is on the larger 5-in. string. By switching from the dual-string design to a single string design from top to bottom, the TSR can be maintained at 0.85 for the entire length of the well. This paper is the first to discuss a streamlined 5-in. pipe configuration being used to replace a dual 5-in. and 4-1/2-in. string design.

## Field Results

A Tulsa-based oil and gas exploration and production company picked up the first string of the 5-in. drill pipe with a 4th generation DSC toward the end of 2019. From that time until present, all wells requiring either an 8-1/2-in. lateral or a 6-3/4-in. lateral are utilizing this single string design. The new string design has been used to drill all hole sections from the 17-1/2-in. to 6-3/4-in.

After the change to this single string design, several operational efficiency gains were realized. Firstly, the hydraulic pressure losses are significantly less. Figures 1 and 2 show the decrease in pressure losses of the new 5-in. single string compared to the original 4-1/2-in. strings in the lateral sections. For an 18,000-ft string and a flow rate of 600 gal/min, this reduction in pressure losses equates to approximately 3,200-psi in both the 8-1/2-in. and 6-3/4-in. lateral sections. This reduction in pressure losses contributes to less wear and tear on pumps and savings in fuel costs for the rig. It also enables better hole cleaning and faster drilling.

Secondly, as can be seen in Tables 1 and 3, with the increased MUT of the 4th generation DSC, there is a corresponding ability to have higher drilling torques in the laterals. The result of this increased MUT is that the occurrences of connection back out are eliminated. The reactive torque that is built up in the string during the 'rocking' operation no longer exceeds this higher BOT.

Thirdly, because only one string is used to drill from the top to the bottom of the well, there are immediate time and cost savings from eliminating an additional BOP test, as well as the elimination of changing out parts of the BHA. Additionally, the automatic racking system could be used for the entire length of the well, enabling a reduction in crew size from six to five. With only one connection being run for the entire well, operational efficiencies were realized since the crew did not have to make changes to equipment. The MUT for the pipe was the same for drilling the entire well. Also, as a result of only a single drill string, cost savings were realized by not needing to keep multiple sizes of accessories, such as crossovers and valves. As a consequence of not having to lay pipe down between wells and on rig moves, drilling efficiency increased, and the potential for safety issues was reduced due to less pipe handling.

Lastly, there is a significant increase in ROP in the lateral sections. With better hydraulics and a slightly more stiff 5-in. drill pipe, more weight on bit (WOB) can be transmitted to the bit before buckling occurs. The higher drilling torques also allow for more efficient 'rocking' to push the laterals farther and faster. For the 8-1/2-in. lateral, the ROP increased by 54%, and for the 6-3/4-in. lateral, the ROP increased by 71%. All of this contributes to drilling every well as efficiently and consistently as possible.

So far, this discussion has been relatively positive toward the change to a single string design. However, not everything was positive. Consideration needs to be given to the risks associated with fishability. The tool joint OD on the new string design (5-7/8-in.) is difficult to fish inside the 6-3/4-in. hole section. However, it is not often necessary to fish a tool joint. Also, if there is a tight equivalent circulating density (ECD) window for the 6-3/4-in. lateral, it would be recommended not to use the new 5-in. string design and switch out to a string of 4-1/2-in. with a 4th generation DSC. Another potential issue could arise if the correct elevator bushings are not used. Standard elevator bushings for 5-in. NC50 will jam with the new 4th generation DSC. It is important to have the correct bushings supplied with the rental string.

## Connection Repair Trends and Learnings

As previously discussed, the 4th generation DSC incorporates design features to optimize the connection stresses, provide broader tolerances for field damage, reduce the material loss on repairs, and provide greater connection ruggedness. All these features target increased field life and reduced operating costs.

The repair analysis data, provided by a major US land rental tool company, covers a period of just over 5 years and approximately 50 separate inspections. Nearly 23,000 NC50 connections and almost 36,000 4th generation DSC were inspected during this time.

Figures 3 and 4 show the repair rates of the API NC50 and the 4th generation DSC based on data collected by the rental company. The figures are the number of repairs for both connections and the steep reduction with the 4th generation DSC compared to the API NC50. The recut rates dropped from 7% for boxes and 5% for pins of the NC50 to 3% and 2%, respectively for the 4th generation DSC. This is a 2.5-fold reduction in recut rates. The analysis also showed that the reface (face & chase) rates dropped from 15% for boxes and 12% for pins of the NC50 to 8% and 4%, respectively for the 4th generation DSC. This is up to a three-fold reduction in the reface rates. Typically, this type of repair is more attributed to care and handling on the rig and is not directly related to connection design; however, the 4th generation DSC has been designed to allow for an additional reface before requiring a recut.

We can then use this same data and equate it to a cost of repair saving. To do this, we also need to factor in the repair costs for the different connections. From Table 4, we can see that based on a string of 580 joints for a 1-1/2 mile lateral, the resulting repair cost for the 4th generation DSC was nearly 59% lower than the API NC50 connection.

It should also be noted here that if the comparison had involved comparing the repair rates of the 1st generation DSC or the 2nd generation DSC, the reductions would have been even greater since these connections typically have higher repair rates when compared to API.

## Tables

Table 1 - String Performance

| Original String Design | Tensile Strength (lbs) | Max Make-Up Torque (ft-lbs) |
|---|---|---|
| 5-in. 19.50 lb/ft S-135 Tube Body (Premium Class) | 560,764 | --- |
| NC50 (6-5/8-in. x 3-1/4-in.) | 1,118,535 | 30,700 |
| 4-1/2-in. 16.60 lb/ft S-135 Tube Body (Premium Class) | 468,297 | --- |
| 2nd Generation DSC (5-3/8-in. x 3-in.) | 707,092 | 25,100 |
| 1st Generation DSC (5-1/4-in. x 2-13/16-in.) | 652,130 | 22,500 |

Table 2 - TSR for Three Connections on Two Drill Pipe Sizes

| Original String Design | | Torsional Strength (ft.lb.) | Ratio |
|---|---|---|---|
| Configuration #1 | 5-in. 19.50 lb/ft S-135 Tube Body | 74,100 | --- |
| | NC50 (6-5/8-in. x 3-1/4-in.) | 51,200 | 0.69 |
| | 4-1/2-in. 16.60 lb/ft S-135 Tube Body | 55,450 | --- |
| Configuration #2 | 2nd Generation DSC (5-3/8-in. x 3-in.) | 47,160 | 0.85 |
| Configuration #3 | 1st Generation DSC (5-1/4-in. x 2-13/16-in.) | 37,510 | 0.68 |
| **New String Design** | | **Torsional Strength (ft.lb.)** | **Ratio** |
| Configuration #4 | 5-in. 19.50 lb/ft S-135 Tube Body | 74,100 | --- |
| | 4th Generation DSC (5-7/8-in. x 3-1/4-in.) | 63,100 | 0.85 |

Table 3 - String Performance

| New String Design | Tensile Strength (lbs) | Max Make-Up Torque (ft-lbs) |
|---|---|---|
| 5-in. 19.50 lb/ft S-135 Tube Body (Premium Class) | 560,764 | --- |
| 4th Generation DSC (5-7/8-in. x 3-1/4-in.) | 623,806 | 44,200 |

Table 4 - Comparison of Repair Costs for API NC50 and 4th Generation DSC

| | | | | |
|---|---|---|---|---|
| **5-in. NC50 Drill Pipe** | | | | |
| **Box Conns** | **580** | **# Repairs** | **Repair Conn $** | **Total Repair $** |
| Box RC | 7.1% | 41 | $ 151.35 | $ 6,235.70 |
| Box RF | 15.2% | 88 | $ 20.00 | $ 1,762.04 |
| | | | **Box Subtotal** | **$ 7,997.74** |
| | | | | |
| **Pin Conns** | **580** | | | |
| Pin RC | 5.2% | 30 | $151.35 | $4,594.32 |
| Pin RF | 11.9% | 69 | $20.00 | $1,382.98 |
| | | | **Pin Subtotal** | **$5,977.30** |
| | | | | |
| | | **Total Box & Pin NC50** | | **$ 13,975.05** |
| | | | | |
| **5-in. 4$^{th}$ Generation DSC Drill Pipe** | | | | |
| **Box Conns** | **580** | **# Repairs** | **Repair Conn $** | **Total Repair $** |
| Box RC | 3.5% | 20 | $ 170.25 | $ 3,472.19 |
| Box RF | 7.7% | 44 | $ 42.00 | $ 1,868.71 |
| | | | **Box Subtotal** | **$ 5,340.90** |
| | | | | |
| **Pin Conns** | **580** | | | |
| Pin RC | 2.0% | 12 | $170.25 | $1,983.72 |
| Pin RF | 3.7% | 21 | $42.00 | $901.97 |
| | | | **Pin Subtotal** | **$2,885.70** |
| | | | | |
| | **Total Box & Pin 4$^{th}$ Deneration DSC** | | | **$ 8,226.60** |
| | | | | |
| **Repairs on 580 joint string** | | | | |
| NC50 | | | $13,975.05 | |
| 4$^{th}$ Generation DSC | | | $8,226.60 | |
| **Cost Savings** | | | **$5,748.45** | |
| **% Savings** | | | **58.9%** | |

## Figures

For Reference Only

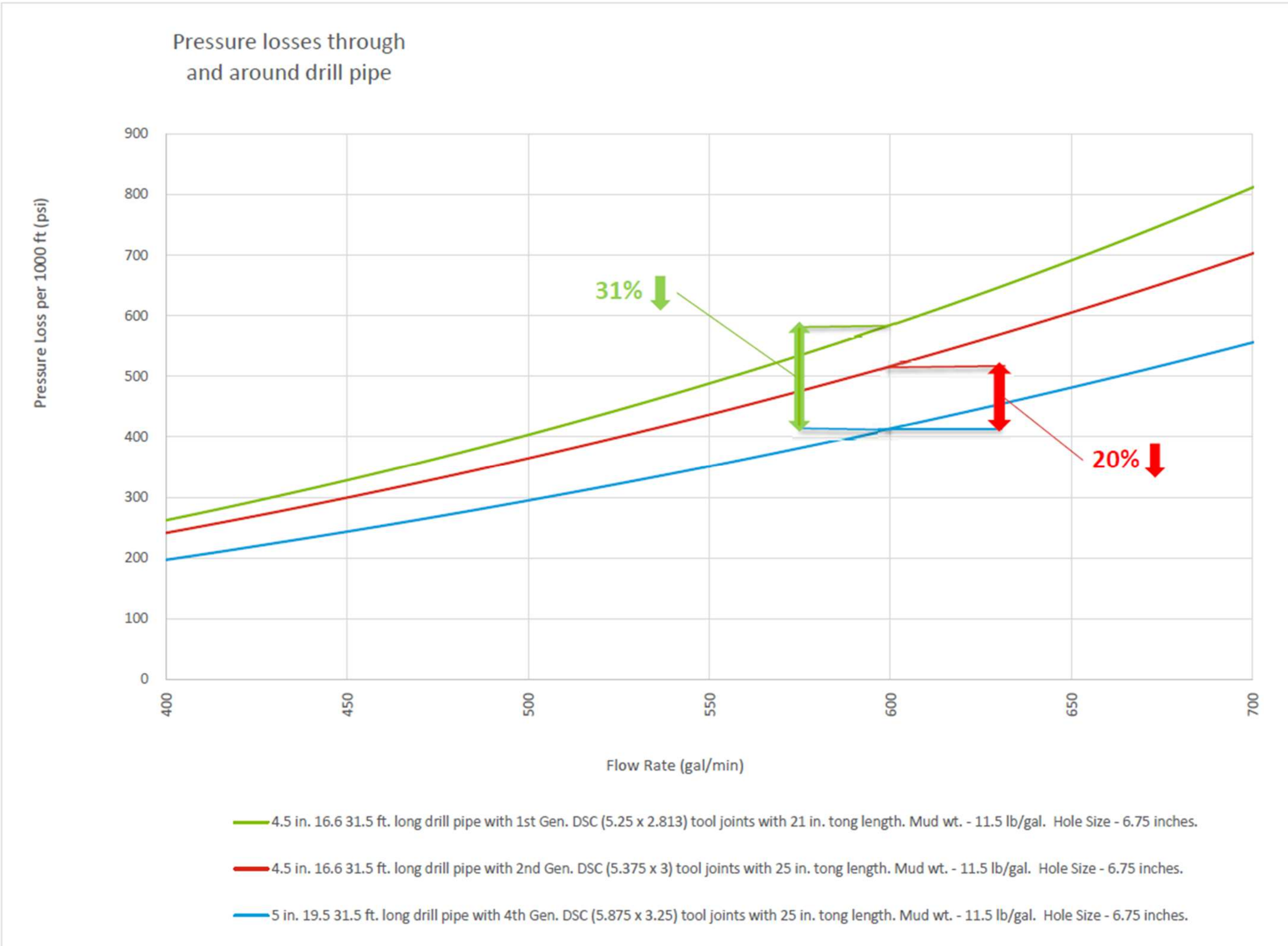


Figure 1 – Comparison of the pressure losses through and around drill pipe for three drill pipe configurations in a 6-3/4-in. hole section with a mud weight of 11.5 lb/gal and a flow rate of 600 gal/min.

**For Reference Only**

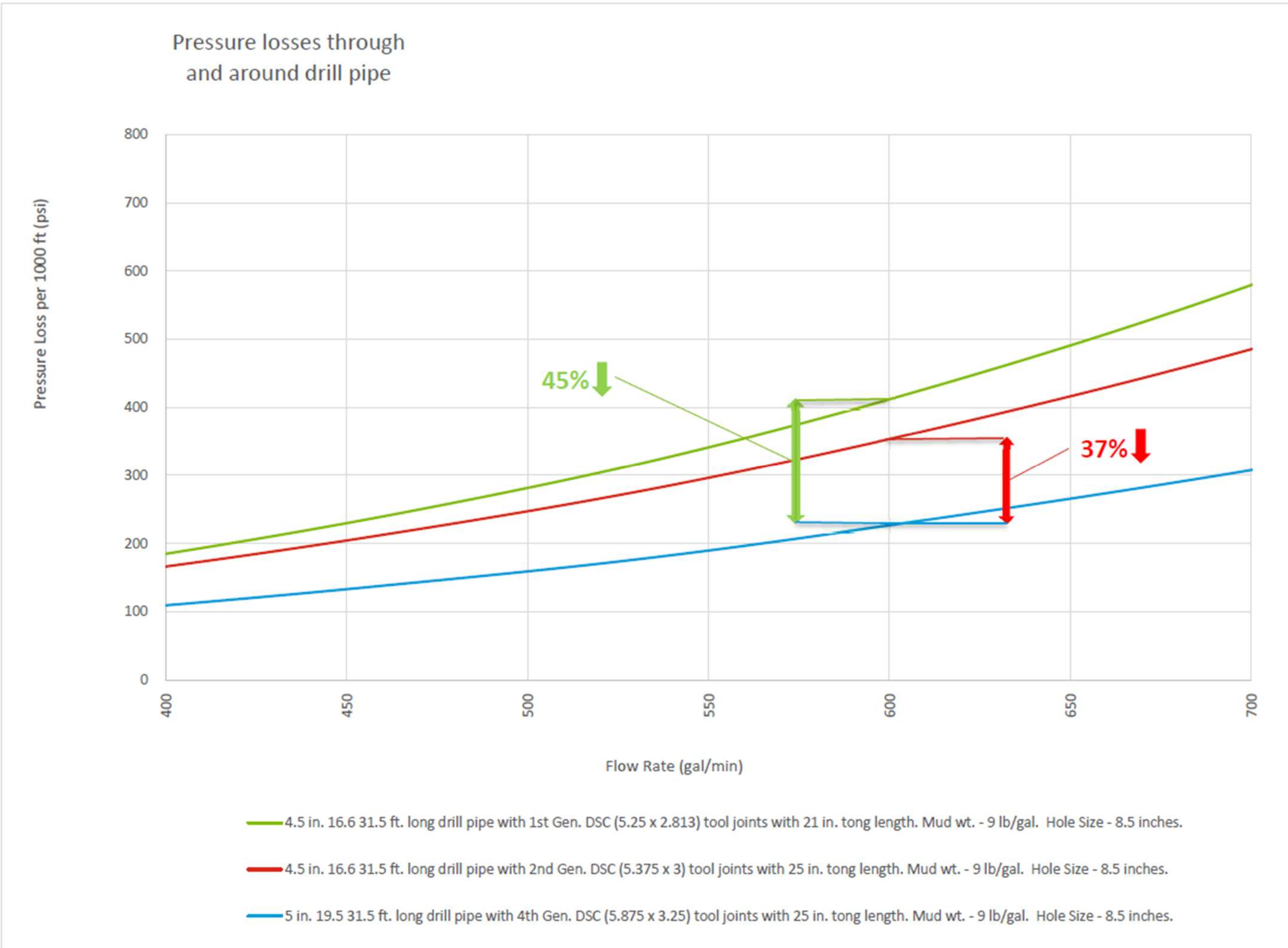


Figure 2 – Comparison of the pressure losses through and around drill pipe for three drill pipe configurations in an 8-1/2-in. hole section with a mud weight of 9 lb/gal and a flow rate of 600 gal/min.

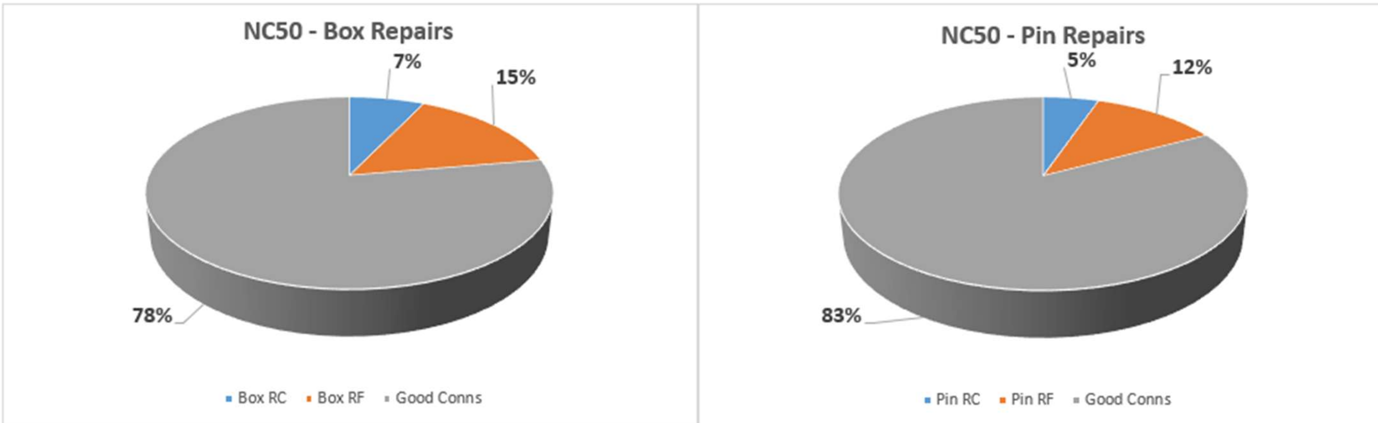


Figure 3 – Repair rates for API NC50 Connection. Inspection frequency was roughly every 4 wells. Approximately 54 inspections of a 424-joint string, equating to almost 23,000 pin and box connections.

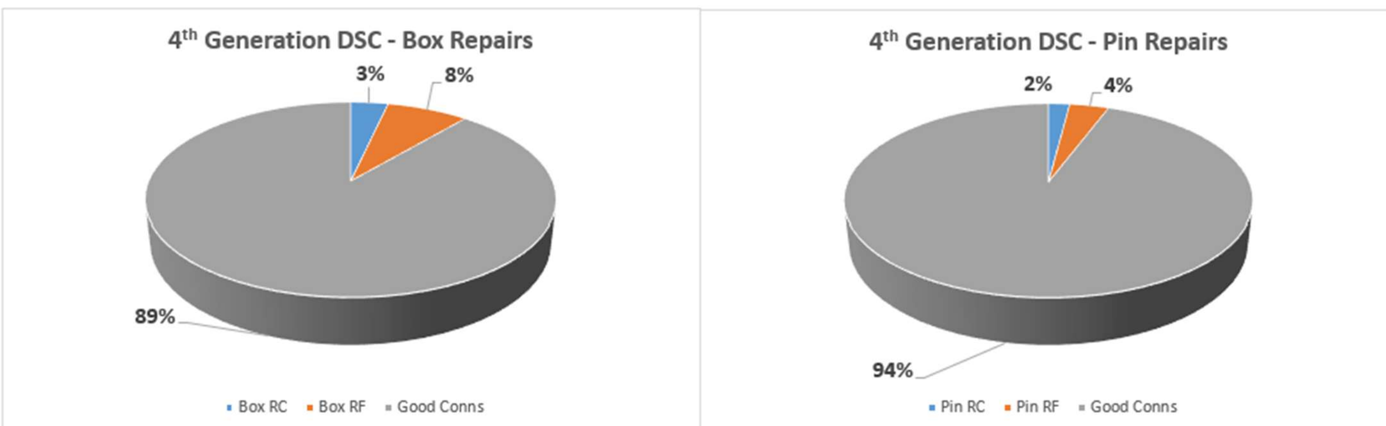


Figure 4 – Repair rates for 4th Generation DSC. Inspection frequency was roughly every 4 wells. Approximately 50 inspections of a 720-joint string, equating to almost 36,000 pin and box connections.

## Conclusions

The single string design of 5-in. 19.50 lb/ft S-135 with a 4th generation DSC used in the Eddy and Lea counties of New Mexico was considered a success for several reasons. The high torsional strength of the connection enables its use in an extremely slim-hole version on 5-in. drill pipe that can be run in both an 8-1/2-in. and a 6-3/4-in. lateral hole.

A potential downside to the larger 5-in. drill pipe size in the 6-3/4-in. lateral is an increase in ECD which could be problematic on wells with a tight ECD window. However, the larger 5-in. drill pipe comes with other associated benefits and, in particular, a massive improvement of the string hydraulics (added internal and annular). This enables better hole cleaning and faster drilling.

Another important advantage to the driller is that he now manages only one size of pipe and one type of connection, making inventory management on the rig significantly safer, as well as saving time while running the drill pipe.

Finally, the more ruggedly designed 4th generation DSC has drastically driven the repair rates down over the five-year period analyzed. Both the number of repairs and the associated cost for the 4th generation DSC were reduced to over half of what was previously seen with the API NC50 connection over the same period.

Due to the reductions in potential safety incidents, cost savings, and efficiency gains, the decision was made to change out all rigs under contract to utilize the new string design. As of the writing of this paper, all wells still on contract in New Mexico continue to use this new string design.

## Acknowledgments

The authors wish to thank the management of Kaiser-Francis Oil Company, Quail Tools, and Grant Prideco™ for their support and encouragement in preparing this paper.

## Nomenclature

*API* = *American Petroleum Institute*
*BHA* = *Bottomhole Assembly*
*BOP* = *Blowout Preventer*
*BOT* = *Breakout Torque*
*DSC* = *Double Shouldered Connection*
*ECD* = *Equivalent Circulating Density*
*ERD* = *Extended Reach Drilling*
*GAL/MIN* = *Gallons Per Minute*
*ID* = *Inside Diameter*
*LBS/GAL* = *Pounds Per Gallon*
*LBS/FT* = *Pounds Per Foot*
*MUT* = *Make-Up Torque*
*OD* = *Outside Diameter*
*PSI* = *Pounds Per Square Inch*
*ROP* = *Rate Of Penetration*
*TSR* = *Torsional-Strength Ratio*
*WOB* = *Weight on Bit*

## References

American Petroleum Institute (API). May 2020. "Specification for Drill Pipe – 2nd Edition". Available from www.api.org.

Chandler R. B, Muradov A., Jellison M. J. et al. 2007. "Drill Faster, Deeper and Further with Ultra-High Torque, Third Generation Double-Shoulder Connections". SPE/IADC Drilling Conference, Amsterdam, Feb 20-22, 2007. SPE-105866-MS. http://dx.doi.org/10.2118/105866-MS

Plessis, G., Muradov, M., Wright, C. et al. 2018. "Breaking the Performance/Cost Paradigm in Drill Pipe Connections in Extended Reach Drilling." SPE/IADC Drilling Conference and Exhibition, Fort Worth, Texas, USA, Mar 6-8, 2018. SPE-189588-MS. https://doi.org/10.2118/189588-MS

Thomas M., Smith J.E. 1996. "Box OD Stability of Double Shoulder Tool Joints at Catastrophic Failure". SPE/IADC Drilling Conference, New Orleans, USA, Mar 12-15, 1996. SPE-35035-MS. http://dx.doi.org/10.2118/35035-MS