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Next Generation Shale Drill Pipe to Revolutionize Drilling Efficiency in Shale Plays

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Abstract

Drilling horizontal wells typically require a tremendous engineering effort since they create operational challenges with wellbore hydraulics, borehole cleaning, drillstring buckling, poor weight-on-bit transfer and reduced drill pipe service life. Typical symptoms include reduced rate of penetration, difficulty sliding, frequent wiper trips, excessive back-reaming, high torque/drag and severe drill pipe wear coupled with potential connection damage.

In response to these industry needs, a new type of drill pipe optimized for shale drilling was developed – an illustration is shown in figure 1. Modelling with several software packages was performed to compare the new 4-1/4” Shale Drill Pipe against conventional 4” drill pipe in a typical 10,000 ft Bakken well. Three main areas of improvement were identified as hydraulics, buckling resistance, and reduced tube wear.

For one operator in Western Oklahoma, the Shale Drill Pipe (SDP) promised to provide a sure solution to some of their operational restrictions; on this basis Peregrine Petroleum Partners decided to use the SDP on a five well trial. This particular operator elected to use the SDP primarily due to standpipe pressure limitations of the drilling rig (+/- 3,400 psi). This drill pipe would potentially allow Peregrine Petroleum Partners to improve performance in these wells, while still offering an economic alternative to other, more costly solutions such as using a larger rig

This paper examines the field results of eight horizontal wells drilled in Western Oklahoma. The first three, which served as the baseline, were drilled to the planned total depth using a drillstring with conventional 4” drill pipe; the other five wells were drilled using the newly developed 4-1/4” shale drill pipe. This paper focuses on showing improvements in the drilling process that this new technology offers by way of key metrics, such as improved hydraulics and hole cleaning.

This innovative new design in drillstring technology is one of the industry’s first solution’s addressing drilling challenges at a more fundamental level.

Introduction

Many operators in North America have made significant investments in shale gas development to optimize drilling efficiency and ultimately reduce the drilling cost per foot. Several other regions such as Asia and Eastern Europe have also discovered shale gas and drilling in these reservoirs are expected to expand rapidly in upcoming years.

Drilling these horizontal wells creates operational challenges due to slow ROP’s, flat time – time spent on activities other than drilling - and potential difficulty in running casing. Non-productive time due to stuck pipe issues, lost circulation, excessive back-reaming and tripping issues may also be reduced, not to mention reduced costs by increasing the drill pipe life.

Present day drilling operations leave many avenues for improvement and further cost reduction requires elimination; or at a minimum, reduction of many of the above adverse factors in the drilling operation. Ideally every operator would like to streamline the operation to the extent that “factory style” drilling is practiced.

The newly developed Shale drill pipe (SDP) promises solutions to some of these problems. It is important to note that the majority of the benefits of SDP can be realized in any formation, or in any hole size that can utilize a 4” OD drill pipe. This first trial was done in the Lower Cleveland Sand and provided the operator with sufficient hydraulic benefits to justify use over a five well trial. On longer laterals such as typical Bakken shale wells the SDP promises increased drill pipe service life (with resultant reduced total cost of ownership), coupled with fewer days on location.

Peregrine Petroleum Partners drilled the eight wells in Western Oklahoma between mid-2014 and early 2015 while utilizing a two rig program. These wells utilized similar drilling programs and targeted the same reservoir, the primary difference being the use of the 4-1/4” Shale Drill Pipe. This provided an excellent opportunity to test the new 4-1/4” pipe in a known environment with established metrics and to judge well-to-well performance improvements. Fig. 4 shows the wells used in this case study. Out of the 8 wells used in this study, three out of five of the fastest wells were drilled with shale drill pipe.

What is Shale Drillpipe?

Shale drill pipe has a 4-1/4” OD 15.40 lb/ft S-135 tube pipe with a wall thickness (WT) of 0.330” (Fig. 2) with 4-7/8” OD x 2-11/16” ID high torque tool joints. The connections feature a 21,200 ft-lbs makeup torque, 6-7 turns to makeup, a single start design, and rugged threads with elliptical thread roots.

They are made with a 5-1/4” dual OD for improved elevator capacity and additional tube standoff while maintaining fishability in smaller hole sizes.

Performance

Simulations with several software packages were done to compare 4-1/4” 15.40 lbs/ft drill pipe with 4” 14.00 lbs/ft (0.330” WT) drill pipe in a typical Bakken well. This was a 10,000 ft deep well with a 10,000 ft lateral with an 8-3/4” or 8-1/2” vertical section with a 5-7/8” or 6” lateral. Benefits were seen in three main areas.

Buckling: The 4-1/4” tube stiffness is 7.9 in^4 compared to 6.5 in^4 for the typical drill pipe. This additional stiffness results in a 65% improvement in max weight on bit (WOB) before lock-up when slide drilling in the vertical section and a 15% improvement in max WOB before helical buckling while rotary drilling in the lateral.

Hydraulics: Up to 700 psi improvement in stand pipe pressure was predicted for the vertical section. In the lateral, a 30% efficiency improvement was predicted for the time required to clean the hole after drilling.

Tube wear: Advanced simulations were done to look for is tube to wellbore contact, which is believe to be one of the main contributors to the rapid tube body wear that seen in some regions. In the build section, tube to wellbore were about 250 lbs with 4” drill pipe but 150 lbs with 4-1/4” drill pipe. In the lateral, a small standoff was seen between the tube and wellbore, 1/4” with 4-1/4” drill pipe and a little more than 1/8” with 4” drill pipe.

Special equipment

Special equipment is needed to run and inspect 4-1/4” drill pipe. Standard slip bodies dressed with special slip inserts are required. API 4-1/2 IU / IEU elevators (4-25/32” elevator bore) can be used with 4-1/4” drill pipe, but special elevators with a 4-19/32” elevator bore are recommended for additional elevator capacity. Pipe ram packers were used during the trials, and were tested every three weeks per the local laws. Finally, a special buggy is needed to UT inspect the pipe. Proper training of the rig personnel is necessary when running the VX39 connections. The use of a stabbing guide is critical to limit damage to the threads.

Cleveland Formation

The target formation of the wells presented in this paper is the Lower Cleveland Sand which is found at an average depth of 9,250’ TVD in southern Ellis County, Oklahoma, and has a thickness that ranges from 20’to 77’ across Peregrine Petroleum Partners’ acreage. The Lower Cleveland is a sandstone, interbedded with 2 to 8 ft. shale stringers. The Lower Cleveland Sand is underlain by the Marmaton Shale and overlain by the Mid-Cleveland sand/shale sequences. Fig 6 shows the Operator’s typical lateral section in the targeted pay zone.

Case Study in Western Oklahoma

For the purposes of this paper, data was used from eight horizontal development wells drilled in the Lower Cleveland Sand Formation in Ellis County, Oklahoma. This section of the paper will compare the key metrics of the baseline wells to the offsets and highlight the benefits that the SDP offers. The key performance indicators for comparison include hydraulics/hole cleaning, days on location and reduced cost of total ownership (pipe rental and repairs).

All the wells were drilled by Peregrine Petroleum Partners, Ltd. and used the same rig (Atlas #5) and crews with the exception of the Word 1-30H baseline well (Atlas #7). The wells were drilled using the same drill bit program, directional drilling program (conventional) and oil based mud systems with very similar properties. This case study examines the results achieved in all three sections of the wells –vertical, curve and lateral leg.

Peregrine Petroleum Partners’s typical Lower Cleveland Sand well design is illustrated in Fig. 3. After setting the intermediate casing, the water based mud system is replaced by an oil based mud system. Figure 4 shows the drilling curves for these wells.

Peregrine Petroleum Partners elected to use the SDP in an attempt to mitigate an issue stemming from the maximum allowable standpipe pressure (SPP) of approximately 3,400 psi on the drilling rig. The surface pressure would frequently reach this limitation when drilling the intermediate and lateral sections of the well when pumping at the desired flow rates needed for hole cleaning and bit RPMs.

Difficulties are encountered when drilling the lateral section of these wells due to the depositional nature of the Lower Cleveland Formation. The lateral section of these wells were drilled up-dip with an average regional dip of 1.0 degrees. When drilling with conventional directional tools, a significant amount slide drilling is required to maintain directional control and remain in the targeted zone. When drilling in slide mode, the on-bottom ROP is decreased by upward of 60-70% when compared to rotating. The use of downhole vibrating tools has been found to significantly increase the ROP while sliding so as to achieve only a 50% reduction when compared to rotating.

Baseline Wells

Three wells were chosen as a baseline for use of standard 4” DP from which we compared the results of 5 wells where Peregrine used the 4 1/4" SDP. This 3 well base group of wells consists of the Johnston Trust 1-33H, Shrewder 2-13H and Word 1-30H. These wells used 4”, 14.00 lb/ft, S-135 drill pipe with VX39 connections (tool joint OD 4-7/8”). The base line horizontal wells, were drilled to total depths of +/-14,400’ MD and +/- 9,180’ TVD with 4,500’of lateral leg. Fig 7 shows the time taken to drill each section of the offset wells, at an average of 23.6 days from spud to TD.

When designing the BHA, additional design requirements had to be taken into consideration due to the SPP pressure limitation of 3,400 psi. Attention to the design had to be made for the pressure drop ratings and ID restrictions of the downhole tools. In certain instances, tools that could potentially improve the drilling process could not be considered because of this.

In order to properly clean the wellbore and maximize ROP while drilling the targeted flow rates were 550-600 gpm in the 8-3/4" intermediate and 250 GPM in the 6-1/8” lateral. When nearing TD in each of these sections the SPP would frequently approach the limits of the rig’s capabilities, particularly in the lateral. These instances required the flow rate to be decreased, which compromised hole cleaning and ROP. Fig 9 and 10 shows the standpipe pressure and total pump output versus measured depth of an offset and a subject well.

The repairs to the 474 joints of 4”, 14.00 lb/ft, S-135, VX39 drill pipe is averaged over two inspections covering the drilling of 6 wells. The results are as follows; 130 boxes and 32 pins required refacing, 167 were marked for hard banding (122 pin and 45 box) and 3 pins and 10 boxes required re-cuts. A total of 9 joints were marked class II (2 cuts and 7 low wall thickness).

Subject Wells

These 5 wells were drilled in succession using the Atlas #5 drilling rig. The first three wells were drilled in the same 640 acre section before moving approximately 3.5 miles southwest to drill the two remaining wells. All five (5) horizontal wells were drilled to total depths of +/-14,400’MD and +/- 9,180’TVD with +/-4,500’of lateral leg. Fig 4 shows the time taken to drill each section of the subject wells, with an average of 24.4 drilling days from spud to TD. During the drilling of the first subject well with the SDP (Leroy Davis 2-9H), lost circulation was encountered while drilling the lateral. Three additional days were spent treating the well with LCM and making five additional trips for directional tool failures due to the LCM concentration in the mud system.

Figs 11 and 12 show the stand pipe pressure and total pump output versus depth of the subject wells. The larger ID of the drill pipe allowed the intermediate section to be drilled at the desired flow rate of 550 GPM, with an average SPP reduction of 6%.

In the lateral section, the pump rate was decreased by 12% while still obtaining the desired annular velocities to sufficiently clean the hole due to the increased OD of the SDP. This resulted in a 24% reduction in SPP at the end of the lateral.

All of the subject wells reached TD where a rotational cleanup cycle was performed. Wiper trips were not necessary as the 4-1/2" production casing was run to bottom without any issues.

Typically Peregrine Petroleum Partners will perform a category III inspection at the well site on the drill pipe every three wells. This inspection could not be performed in the field due to a lack of portable test equipment. This required the pipe to be sent in to a shop that had the proper tools. Since this was a new string of pipe, Peregrine elected to perform the inspection after all 5 subject wells were drilled.

Peregrine Petroleum Partners did perform a field visual inspection after drilling the first 3 subject wells on the 475 joints of SDP. The results were as follows; 45 damaged box faces, 9 pin faces, one pin was recut, and one joint straightened. The pipe was sent in after the five subject wells were drilled and a category IV inspection was performed. The results are as follows; 90 boxes and 26 pins were refaced and one tool joint required hard banding and all 475 joints graded Class I Premium.

Conclusions

From the field trial

- Days between spud to TD were within Peregrine Petroleum Partners' expectations.
- A standpipe pressure reduction of 6% at the end of the intermediate and 24% at the end of the lateral was observed. There was a 12% reduction of needed pump rate in the lateral for adequate hole cleaning.
- It should also be noted that although the SDP **was optimized for long shale laterals,** it is equally applicable to drill any wellbore profile and in any lithology.

From theoretical modeling

- 40% reduction in tube side force from 250 lbs to 150 lbs.
- 10-15% less WOB could be applied to achieve equivalent ROP's.
- SDP may save rig time since it can be used to drill the entire well – vertical section, curve and lateral leg.
- On longer laterals such as typical Bakken shale wells the SDP promises increased drill pipe service life (with resultant reduced total cost of ownership.

Acknowledgments

The authors wish to thank Vallourec's management team for providing us the opportunity to present this paper. We would also like to thank the members of the development team that spent countless nights ensuring that all testing was performed on schedule and to industry standards. Special thanks go to Western Workstrings (Tubular Rentals), Circle W Inspections, Atlas Drilling and the Atlas 5 rig crew. Finally, thanks to Peregrine Petroleum Partners for working with us on this project.

Nomenclature

API = American Petroleum Institute
BHA= Bottomhole assembly
GPM = Gallons Per Minute
ISO = International Organization for Standards
OD = Outer diameter
PSI = Pounds per Square Inch
ROP = Rate Of Penetration
SDP= Shale Drill Pipe
SPP= Stand Pipe Pressure
WOB= Weight-on-bit

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Figures

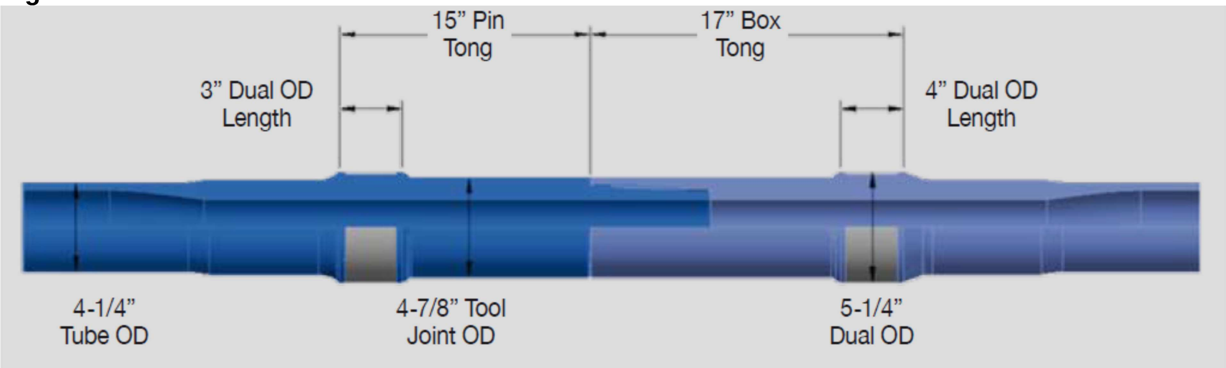

Fig. 1 – Schematic of the 4-1/4" Shale Drill Pipe

vallourec

Performance Datasheet

Drill Pipe

Size:	**4-1/4 IEU X 15.40 lbs/ft**
Connection:	**VAM Express VX39**
Pipe grade:	**S-135**
Range:	**2**

DRILL PIPE DIMENSIONS & MATERIALS

		NEW
PIPE		
OD	in	4-1/4
Wall thickness	in	0.330
ID	in	3.590
Yield Strength	KSI	135
TOOL JOINT		
Connection		VAM Express VX39
OD	in	4-7/8
ID	in	2-11/16
Box tong length (Lb)	in	17
Pin tong length (Lp)	in	15
Make-up loss (MUL)	in	5.750
Yield Strength	KSI	130
Dual OD	in	5.250

ASSEMBLY		HANDLING
Sh to Sh length	ft	31.5
Approx weight	lbs	551
Adjusted weight	lbs/ft	17.50
		HYDRAULICS
Open end disp.	US gal/ft	0.27
Closed end disp.	US gal/ft	0.76
Capacity	US gal/ft	0.49
		DRIFT
Drift diameter	in	2-9/16

DRILL PIPE ASSEMBLY DATA

		NEW	PREMIUM min	CLASS 2 min
PIPE				
% Remaining body wall	%	100	80	70
OD	in	4-1/4	4.118	4.052
Wall thickness	in	0.330	0.264	0.231
Cross sectional area	in²	4.064	3.196	2.773
TOOL JOINT				
OD	in	4-7/8	4-23/32	4-19/32

DRILL PIPE MECHANICAL PERFORMANCES

		NEW	PREMIUM min	CLASS 2 min
PIPE				
Tensile strength	lbs	549,000	432,000	374,000
Torsional strength	ft-lbs	48,000	37,600	32,500
80% Tors. strength	ft-lbs	38,400	30,100	26,000
Collapse pressure	PSI	18,000	12,000	8,860
Internal pressure	PSI	21,000	16,800	14,700
New internal pressure based on 100% wall				
TOOL JOINT				
Tensile strength	lbs	783,000	783,000	707,000
Torsional strength	ft-lbs	35,400	30,100	26,100
Recommended make-up torque (1)	ft-lbs	21,200	18,100	15,700
Maximum make-up torque	ft-lbs	22,300	19,000	19,000
Minimum make-up torque	ft-lbs	21,200	18,100	18,100
Balance OD	in	5.002	5.002	5.002
Torsional ratio TJ/pipe	in	0.74	0.80	0.80

(1) Performances calculated with a friction factor of 1.0

All data nominal and calculated per standard methods. Vallourec Drilling Products does not assume responsibility for results obtained through the use of this information. No warranty expressed or implied.

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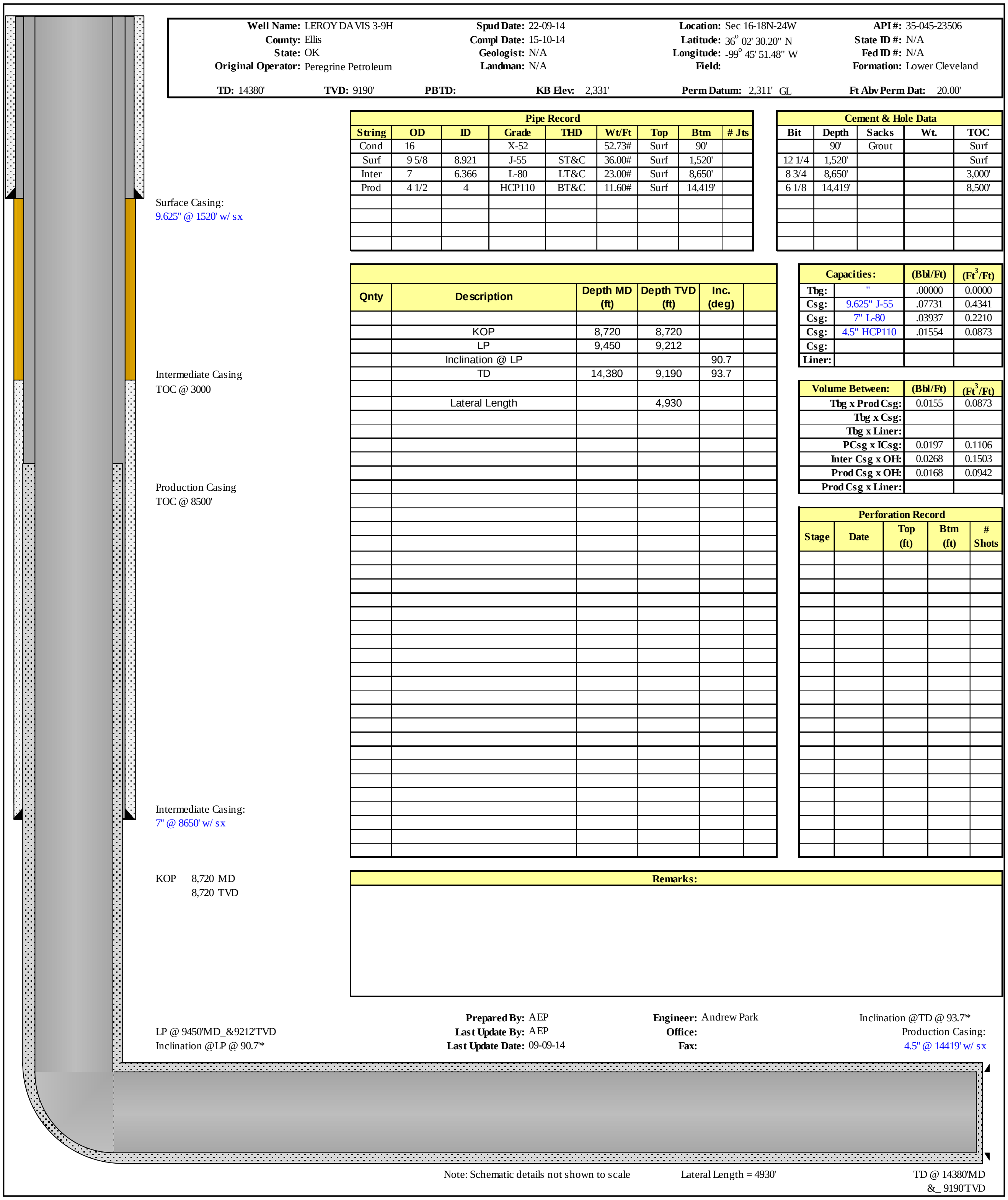
Vallourec Drilling Products

Fig. 2 –4-1/4" Shale Drill Pipe Datasheet



Pipe Record								
String	OD	ID	Grade	THD	Wt/Ft	Top	Btm	# Jts
Cond	16		X-52		52.73#	Surf	90'	
Surf	9 5/8	8.921	J-55	ST&C	36.00#	Surf	1,520'	
Inter	7	6.366	L-80	LT&C	23.00#	Surf	8,650'	
Prod	4 1/2	4	HCP110	BT&C	11.60#	Surf	14,419'	

Cement & Hole Data				
Bit	Depth	Sacks	Wt.	TOC
	90'	Grout		Surf
12 1/4	1,520'			Surf
8 3/4	8,650'			3,000'
6 1/8	14,419'			8,500'

Qnty	Description	Depth MD (ft)	Depth TVD (ft)	Inc. (deg)	
	KOP	8,720	8,720		
	LP	9,450	9,212		
	Inclination @ LP			90.7	
	TD	14,380	9,190	93.7	
	Lateral Length		4,930		

Capacities:		(Bbl/Ft)	(Ft^3/Ft)
Tbg:	"	.00000	0.0000
Csg:	9.625" J-55	.07731	0.4341
Csg:	7" L-80	.03937	0.2210
Csg:	4.5" HCP110	.01554	0.0873
Csg:			
Liner:			

Volume Between:	(Bbl/Ft)	(Ft^3/Ft)
Tbg x Prod Csg:	0.0155	0.0873
Tbg x Csg:		
Tbg x Liner:		
PCsg x ICsg:	0.0197	0.1106
Inter Csg x OH:	0.0268	0.1503
Prod Csg x OH:	0.0168	0.0942
Prod Csg x Liner:		

Perforation Record				
Stage	Date	Top (ft)	Btm (ft)	# Shots

Remarks:

Fig. 3 – Leroy Davis 3-9H wellbore schematic

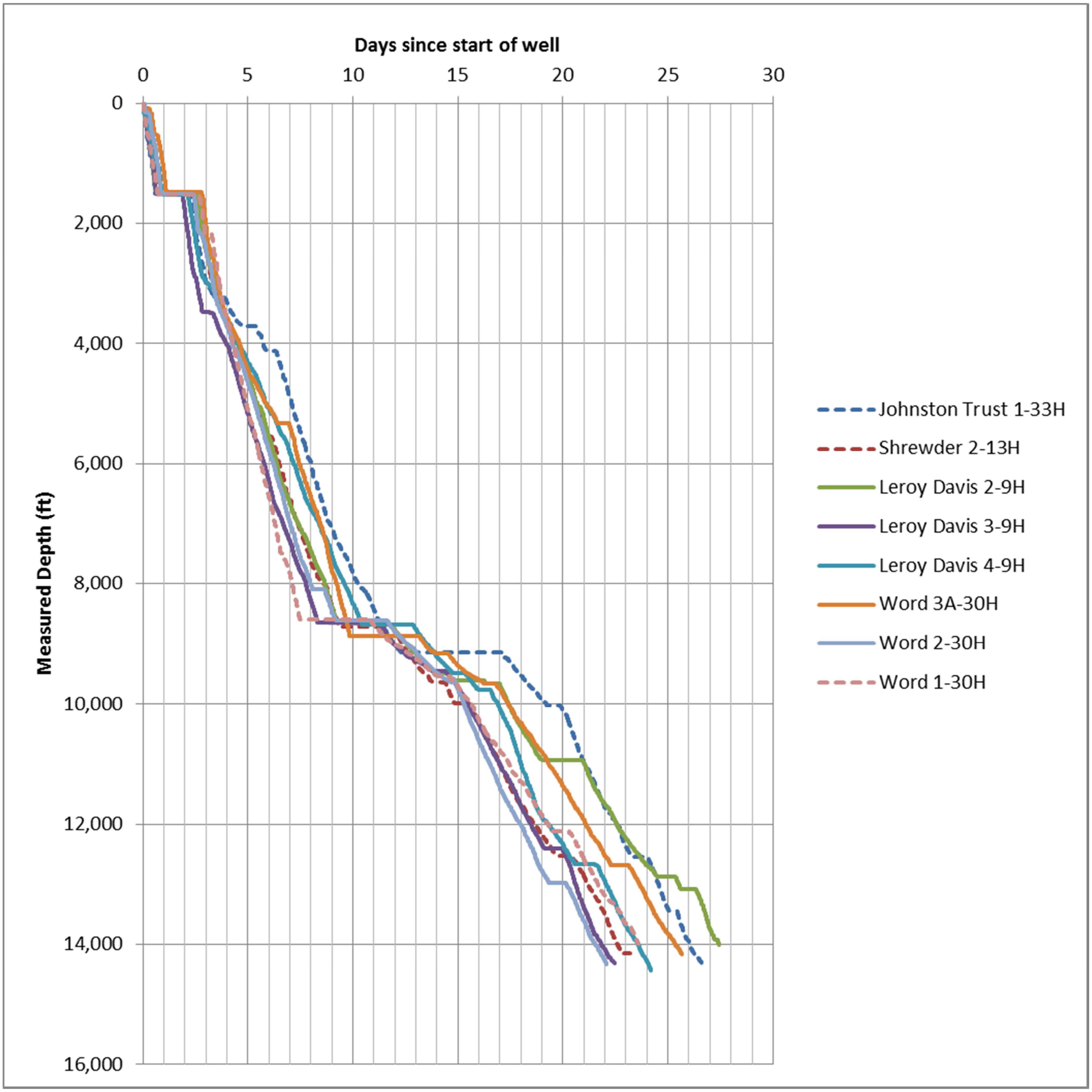


Fig. 4 –Drilling Time Curve (Dashed lines are baseline wells, solid wells are SDP wells)

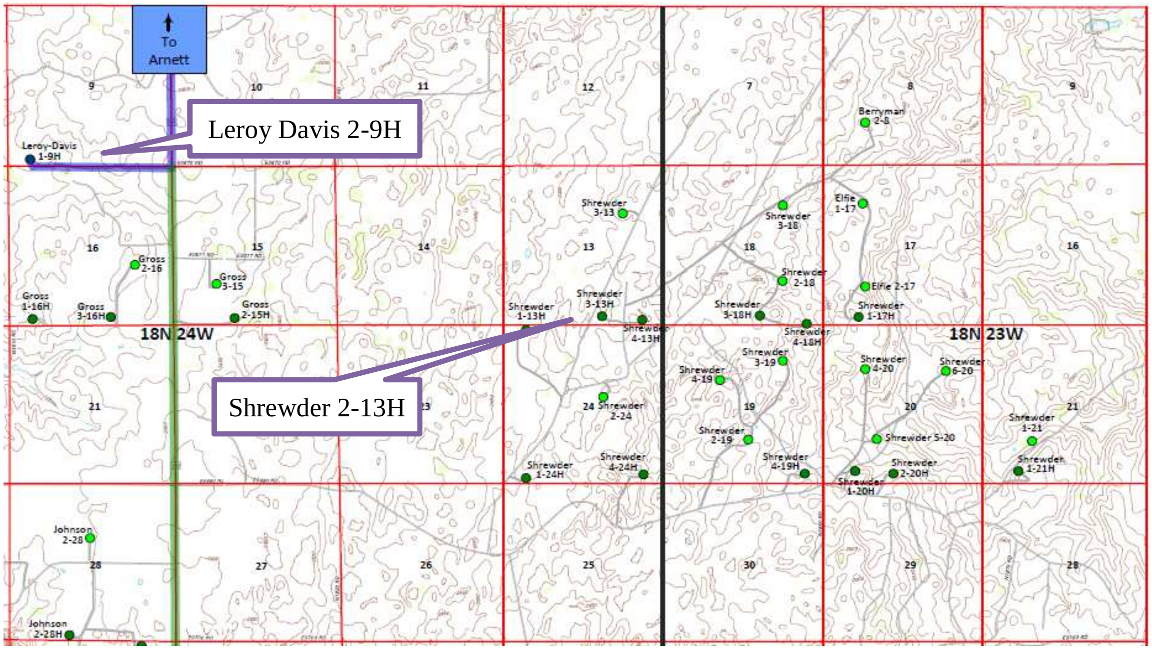


Fig. 5 – Location Map for Peregrine Wells

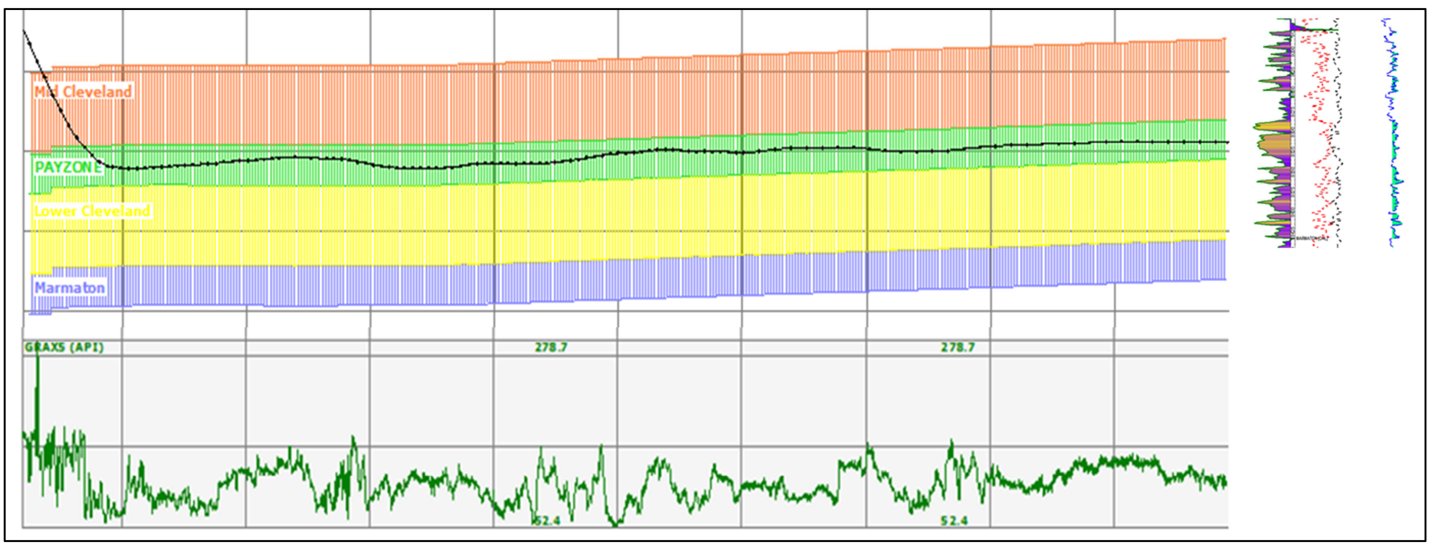


Fig. 6 – Cross Sectional plot of Lower Cleveland Sand well

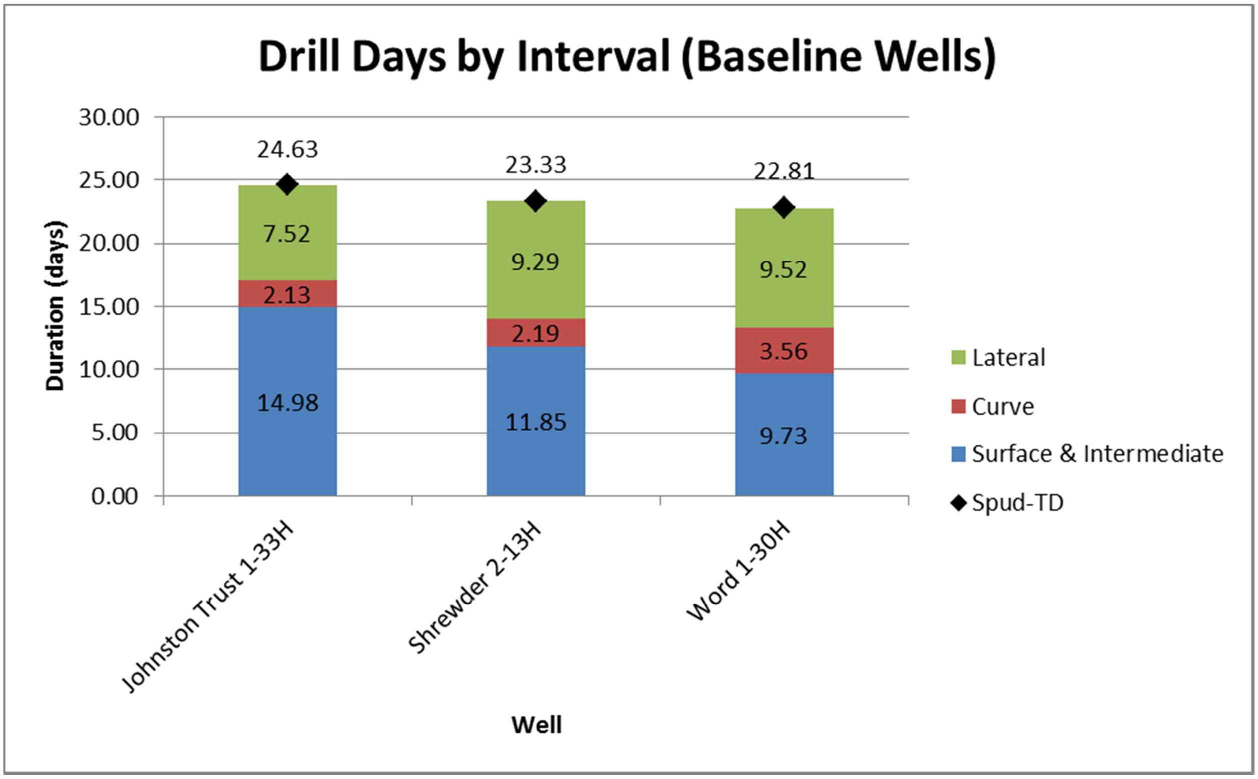


Fig. 7 – Drilling Days by Interval (Baselines)

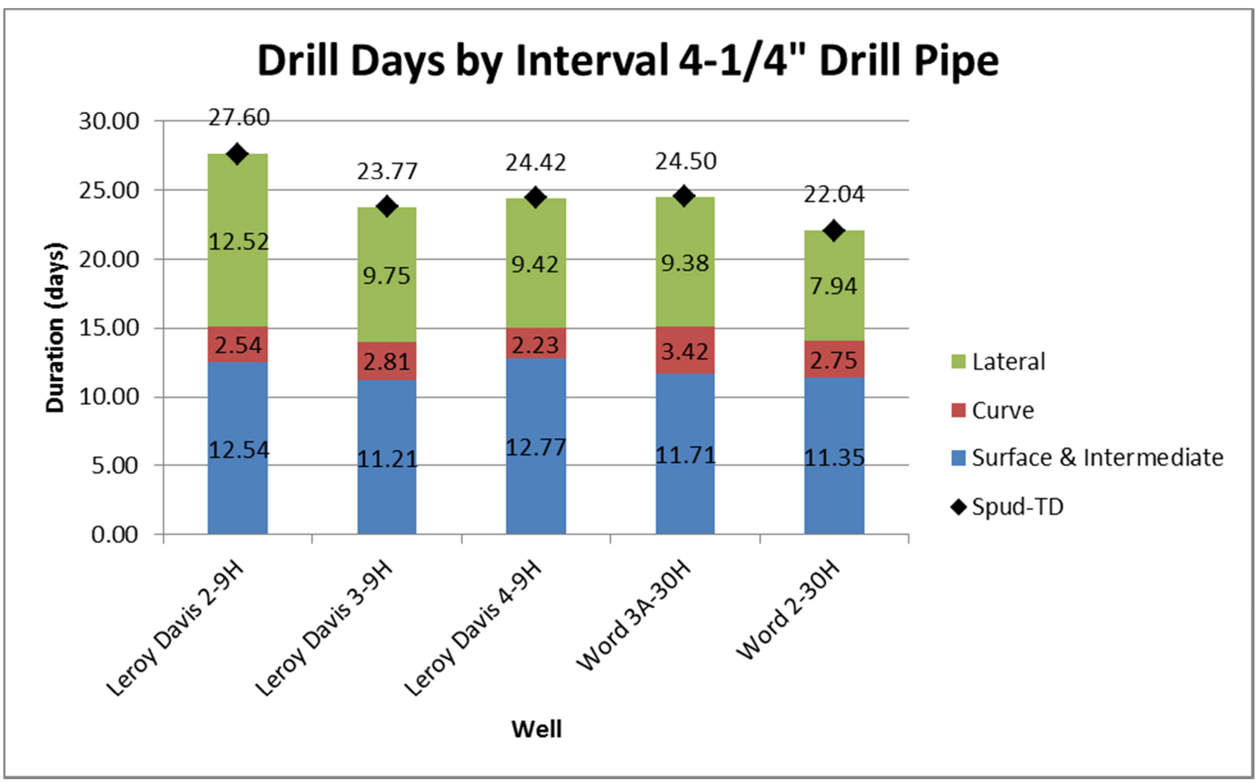


Fig. 8 – Drilling Days by Interval (SDP Offsets)

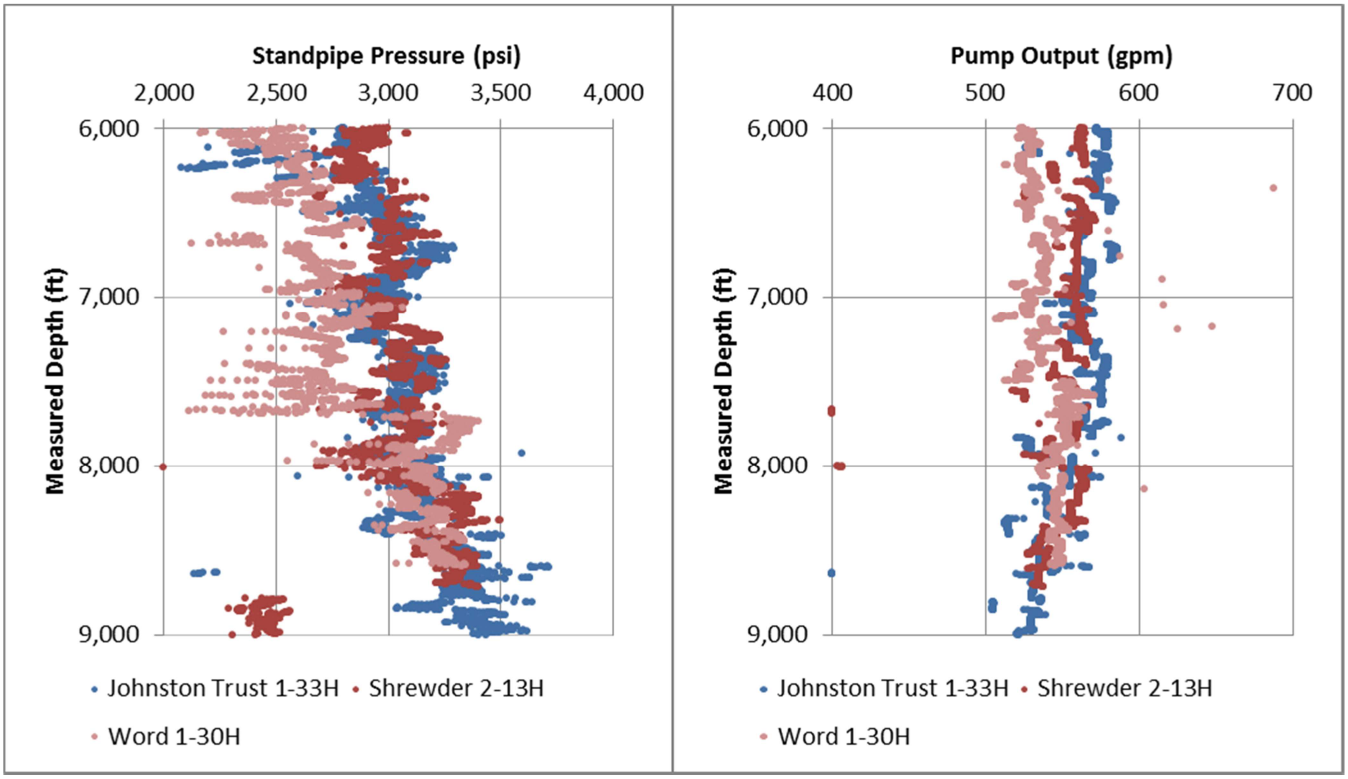


Fig. 9 – Standpipe pressure and total pump output for baseline wells in the vertical section

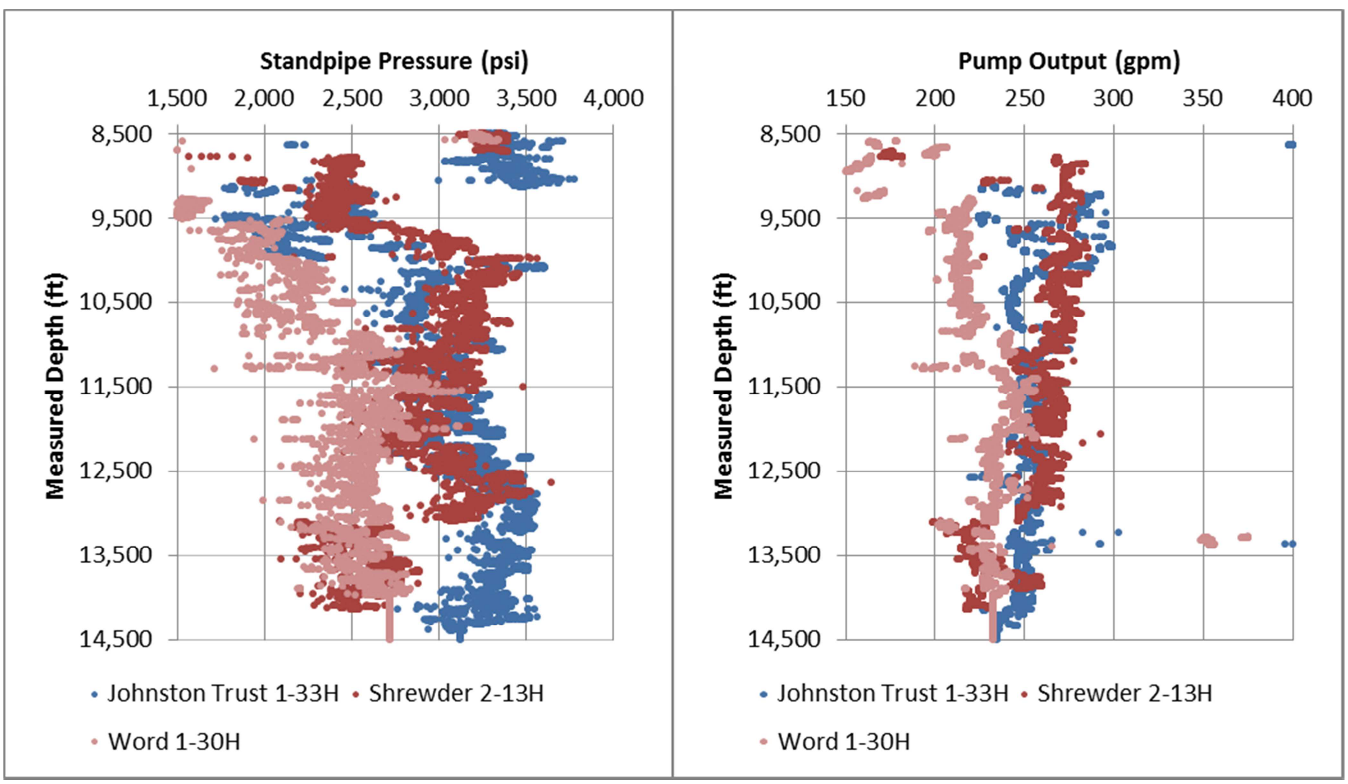


Fig. 10 – Standpipe pressure and total pump output for baseline wells in the lateral

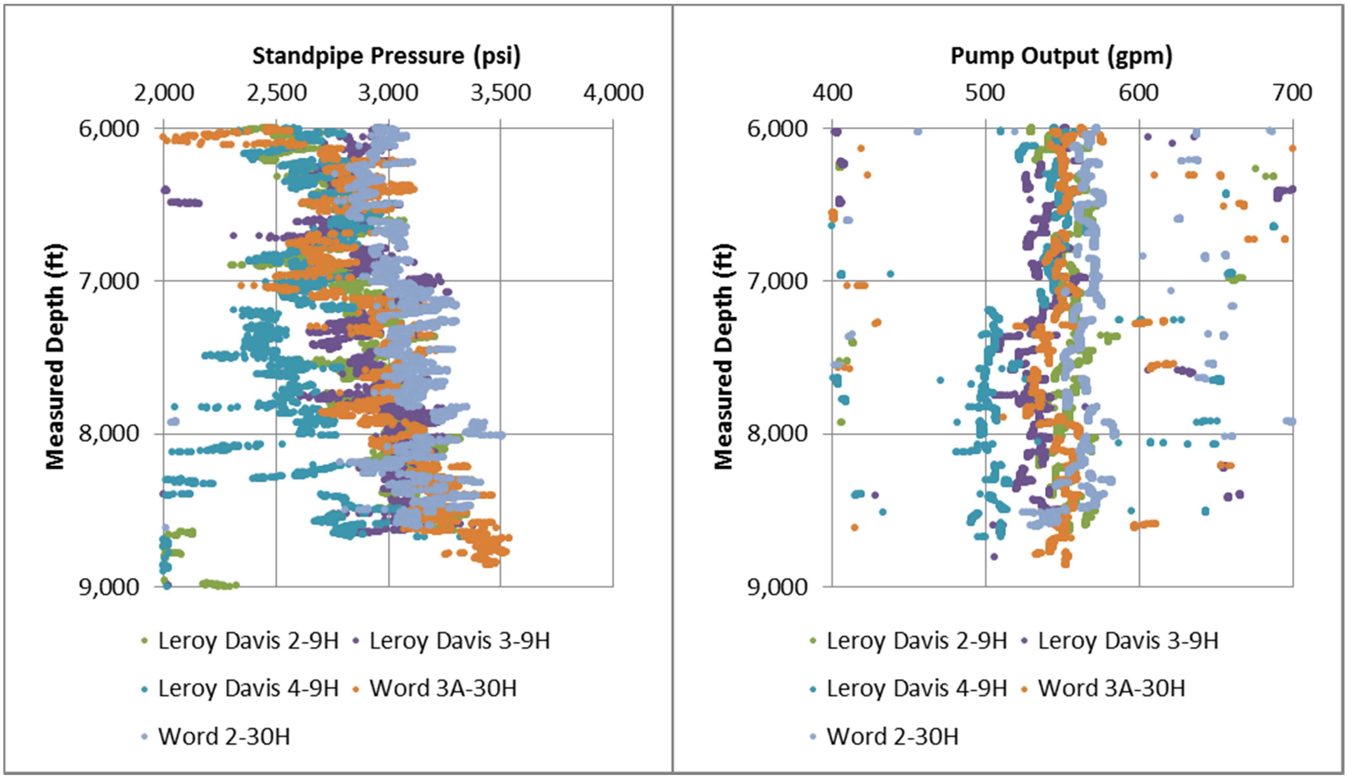


Fig. 11 – Standpipe pressure and total pump output for subject wells in the vertical section

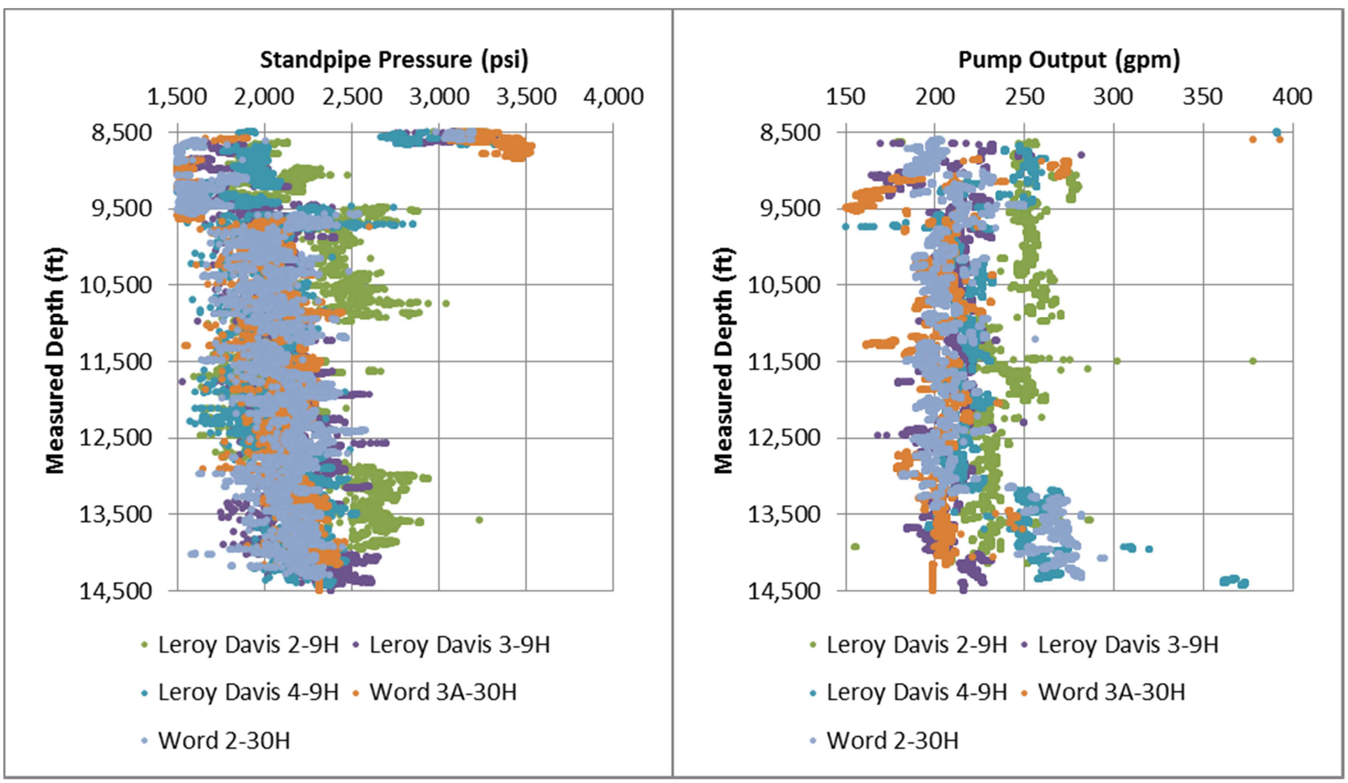


Fig. 12 – Standpipe pressure and total pump output for subject wells in the lateral