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CASE STUDY – REDUCING DRILLING HOURS BY UP TO 54% IN THE BARNETT SHALE

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ABSTRACT

In 2006 and 2007, a drilling performance improvement program was undertaken by a major operator in the Barnett Shale. The performance improvement initiates included optimization of the drilling fluids management, and the drilling rig. Analysis of the data from more than 160 wells and more than 10 drilling rigs, demonstrates the impact that drilling fluids and rig selection make on drilling hours and total well time. While many elements contributed to the performance improvements, the most significant contributor was the drilling fluid which permitted each of the other components to contribute their maximum benefit.

This paper reviews the performance results achieved through the use of a "solids free" drilling fluid (SFDF) and demonstrates the impact that can be achieved through the use of New Technology Drilling Rigs (NTDRs). In this project, the average drilling hours were reduced by approximately 38% which resulted in average well times (spud to release) being reduced by 38%. When we look at the performance of the NTDRs, we find that drilling times were reduced between 46% and 54% with total well times reduced by 41% to 48%. The paper will discuss how these results were achieved and the additional benefits realized including reduction of water usage, drilling waste minimization and reduced land use.

INTRODUCTION

The Barnett Shale is recognized as one of the most significant unconventional gas developments on a global scale. Much has been learned on how to develop shale gas plays and this knowledge is being transferred to other plays domestically and internationally. It has been said that there are two common themes to every successful unconventional gas play: the continuous search for improvements in technology and the relentless pursuit of cost and operational efficiencies. The optimization program discussed in this paper addresses these two success factors.

The global recession and drop in commodity prices has brought into sharp focus the economic realities of unconventional gas plays like the Barnett Shale. It is estimated that sustained natural gas prices of \$5/mmBTU is required for the core area and \$6 to \$7/mmBTU is required for non core areas.[1] Given that a high percentage of a wells reserves are produced in its first two years of production, a combination of low well construction cost and reasonable commodity price at the time of tie-in are required for a successful field development.

The drive to reduce well construction cost has been ongoing throughout history. In the Barnett Shale, well times have been reduced from well over 30 days to less than 20 days.[2,3] There have been many papers written documenting drilling optimization in the Barnett Shale, most of them focusing on drill bits, directional drilling, drilling rigs and solids control. This case history builds upon the previous experience and introduces optimizations related to hole sizes, drilling fluids, solids control and new technology drilling rigs.

Description of wells

As with many field developments today, the initial exploration and early development wells are drilled vertically to establish an understanding of the geology and reservoir characteristics. Later, as the reservoir is better understood, horizontal drilling often becomes the preferred way to develop the reservoir. The Barnett Shale was developed in this manner. Today, most of the development wells are horizontal.

Wellbore Geometry

Most of the wells drilled in the Barnett Shale are drilled with 12 ¼" surface hole to a depth of approximately 1,000 ft where 9 $^5/_8$" casing is run and cemented. Surface hole is drilled using fresh water with occasional gel sweeps. Typically surface hole is completed and cased in approximately one day. The next interval of the well is typically 8 ¾" hole drilled from surface casing shoe to KOP. KOP is typically between 5,000 ft and 6,500 ft. This interval is generally drilled using fresh water with gel sweeps and takes 2 to 3 days to drill. It is generally drilled without significant problems. The final wellbore interval is the curve and lateral. It is typically 7 $^7/_8$" to 8 ¾" hole and is drilled from KOP to a total measure depth of 8,500 ft to 10,500 ft, however, the depths vary depending upon the field location. Since the Barnett Shale is vertically shallower in the western part of the field, the total depths are less in the west. The curve and lateral are typically drilled in 10 to 12 days. This puts the total well time at 13 to 16 days from spud to TD.

Fluid systems

Fluid systems in use prior to this project consisted of freshwater with gel sweeps for drilling surface hole. For the intermediate hole from surface casing to KOP, freshwater was used with minimal additives. The curve and lateral sections were drilled with a gel chemical mud with additions of LCM and lubricants as and when required. The fluid systems were basic and inexpensive.

Solid Control

Typically, solids control consists of shale shakers and sometimes mud cleaners. Over time, additional solids control equipment has been added, particularly in urban areas where pits were not allowed and closed loop systems were required.

Rig description

When this project began in 2006, the drilling rigs in use were 1,000 to 1,500 HP rigs that had been around since the early 80's. When the industry required additional rigs, often rigs were assembled from refurbished parts and pieces. These rigs would often have only one triplex pump and consisted of 40 loads or more. It would take 3 to 4 days to move and rig up. Rig design is such that cranes are required for rig up adding both time and cost to the well AFE. Top Drives were available as a rental item requiring additional rig up time. Move times were often a function of truck and/or crane availability.

Drilling performance

Drilling performance has improved dramatically during the development of the Barnett Shale field. For example, in a drilling optimization program undertaken by Devon Energy in 2005, the average well days were decreased from 31.2 days to 19.1 days.[2] This performance improvement was the result of a structured project that looked at BHAs, bits, drilling practices, rigs with top drives, higher output mud pumps, larger drill pipe and improved drilling practices. The optimization continued and by 2007 the average well days had been reduced to 16.1.[3]

DRILLING OPTIMIZATION PROGRAM

What was done

In 2006, this drilling optimization program was initiated in the Barnett Shale aimed at driving drilling cost to the lowest total cost per foot. This initiative employed new technologies and services aimed at driving performance improvement that would result in the lowest total well cost. Every facet of the drilling process was scrutinized and open for change.

Hole Sizes

One of the major changes was hole geometry. Surface hole was reduced from the traditional 12 ¼" hole to 9 $^7/_8$" hole. This allowed a change from 9 $^5/_8$" casing to 7" casing. This resulted in a reduction of cuttings, lower cement volumes and lower casing cost. The main hole section was reduced from 8 ¾" hole to 6 $^1/_8$" hole and the long string was reduced from 7" casing to 4 ½" casing. Again significant reduction in drill cuttings and cement volumes were noted. This also reduced casing cost while providing the added benefit of improved supply as 7" casing was in high demand and 4 ½" casing was readily available in the local market.

The first wells in the project were drilled with 7 $^7/_8$" - 8 ¾" main hole. In total, 32 wells of the 157 wells drilled had this size main hole. The majority of the wells (125 of the 157) had main hole bit diameters of between 6 $^1/_8$" and 6 ¾".

Main Hole Diameter (in)	# wells
6 $^1/_8$ to 6 ¾	125
7 $^7/_8$ to 8 ¾	32
Total # of Wells	157

One of the significant concerns related to the change in hole size was ROP. It is generally thought that the optimum hole size for maximum ROP is 7 $^7/_8$" to 8 ¾". This is related to the ability to provide optimum WOB, and the flow rate capability of the larger diameter directional drilling tools. As will be shown later in this paper, the smaller hole size did not impair ROP and in fact ROP increased with the smaller hole size, the reasons for the ROP increase will be discussed in a later section of the paper.

The other concern with small hole sizes is bit and directional tool reliability. The bit reliability issue is easily addressed by using PDC bits and fortunately, the Barnett Shale is PDC drillable. Directional tool reliability is always a concern and it is generally a bigger concern with the smaller tools. The project did not experience any increase in directional tool failure rate with the smaller tools. In fact, the incidence of tool failure decreased as the total drilling hours on the well decreased.

Fluid Systems

One of the key optimizations was the drilling fluid. A "solids free" drilling fluid (SFDF) was chosen for this application. The fluid needed to address all of the known issues of drilling wells in the Barnett Shale. It had to have the ability to provide inhibition and density in solution. The fluid selected provided density and inhibition through the use of Calcium Nitrate. Densities of up to 9.5 ppg were easily attainable in solution and while fluid densities of up to 10.5 ppg were used, fluid density averaged 9.2 ppg. In the event that additional density was required for well control, the fluid was "mudded up" with polymer to provide viscosity for suspension of barite. A couple of wells required higher densities for well control so the fluid was converted to a polymer system and barite was added.

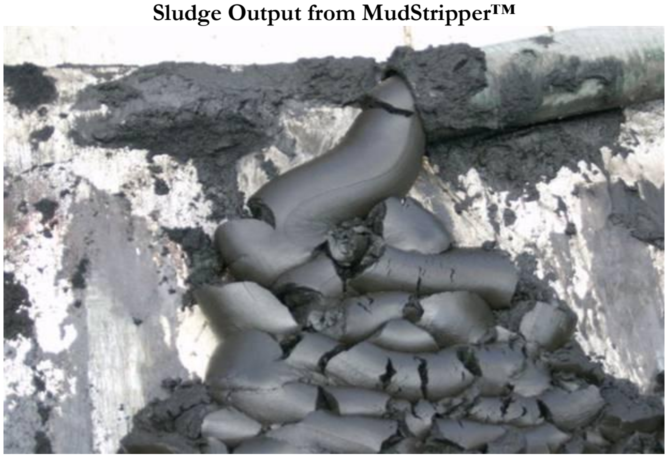
In some instances, production brine was readily available and it was used as the base fluid. Additions of Sodium Chloride or Calcium Chloride were made to control the density. The only concern with using production brine was the high chloride content which created an environmental disposal concern for the cuttings and the fluid.

Solids Control

The use of a SFDF requires complete removal of the solids in the fluid on each circulation of the fluid. This was accomplished by removal of the large cuttings using coarse screens on the shaker and then passing the underflow through the MudStripper™. The MudStripper™ is a patented solids control device where coagulants and flocculants are added to the fluid. As the fluid is passed through a settling chamber, the flocculated solids settle out leaving the fluid clear of suspended solids. The solids from the MudStripper™ are transferred by a positive displacement pump to either a sump or solids collection tank. The MudStripper™ is able to return the fluid to the active system with suspended solids content of less than 1%, and usually 0.5%. The MudStripper™, while designed primarily as a solids control device functions as a closed loop system.

The solids output from the MudStripper™ are discharged as sludge with a density of approximately 14.5 ppg and as high as 17.5 ppg depending on the formations being drilled. The sludge is collected in a cuttings bin or small cuttings sump. Any free liquid that accumulates on top of the cuttings is pumped back to the receiving tank of the MudStripper™ and reprocessed for return to the active system. Generally the sludge can be transported by dump truck as there is no free liquid.

Sludge Output from MudStripper™



Waste Disposal

Depending upon the base fluid being used and the concentration of the particular salt being used, the cuttings may be spread on the drilling location in accordance with the local environmental regulations. One of the primary reasons for using Calcium Nitrate as the base fluid is that Calcium Nitrate is a commonly used agricultural fertilizer.

The SFDF is a low rheology fluid designed to maximize the efficiency of the MudStripper™ while providing the required shale inhibition and density. Since 99.5% of the drill solids can be removed from the fluid on each circulation, the fluid can be reused indefinitely from well to well. Also, since the fluid is always clean of drill solids, dilution is eliminated and the only volume that must be built on each well is the volume required for the new hole being drilled and to replace volume lost down hole (seepage and lost circulation). This reduces the waste volume to the volume of cuttings generated and the volume of fluid retained on the cuttings. The dense sludge produced by the MudStripper™ reduces the volume of fluid lost on the cuttings.

On this project, the volume of waste was reduced by over 70% through the combination of hole size reduction, reuse of fluid, elimination of dilution and reduction of fluid on cuttings. The average volume of fluid consumed per well dropped to approximately 1,800 bbls. The NTDRs averaged 1,480 bbls while the conventional rigs averaged 2,200 bbls. The NTDR mud tanks proved to be more effective at fluid management as they were able to isolate individual tanks to reduce the volume of the active system to the minimum necessary.

Rig Selection

One of the key opportunities identified in the optimization project was to incorporate the use of "fit for purpose" drilling rigs or NTDRs. The rigs were selected to specifically:

- Improve safety and drilling efficiency by having integrated top drives with automated pipe and casing handling systems
- Reduce the number of rig loads for moving (the rigs used on this project were 12 to 15 loads)
- Reduce location size by having a smaller footprint

The introduction of NTDRs has been an integral part of the drilling optimization, providing improved operational performance with a LTA frequency of zero on this project.

One of the primary differences between the NTDRs and the conventional rigs is the rig tear out, move and rig up time. The NTDRs are optimized for location to location moves, which were the bulk of the wells in this project. Since they move in 12 to 15 loads and do not require a crane for rigging up, a typical move is less than a day depending upon the distance between locations. It is not uncommon to rig release, move and spud in the same day.

What was achieved

The optimization project resulted in a reduction in the drilling cost per foot at a time when material and services prices were increasing. The cost savings were achieved though reductions in well time, water volume used, waste volume disposal and location sizes. The total well cost reduction was achieved even though the daily cost of the rig and directional drilling services increased. The drilling fluid and solids control cost was comparable to the cost of drilling fluid and closed loop system.

Drilling hours

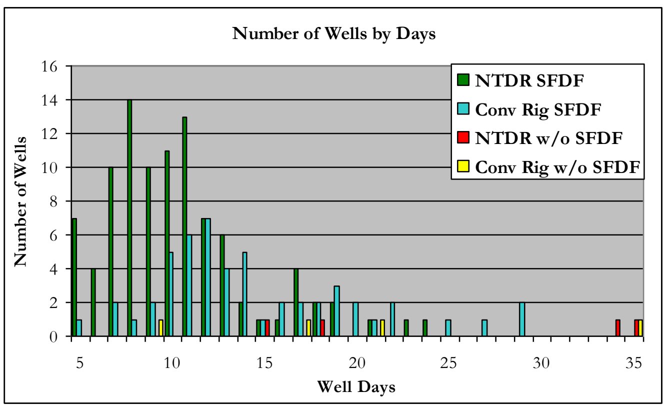
Average drilling hours prior to this project were in excess of 220 hours/well. The average drilling hours on the wells drilled by 10 rigs was 133 hrs/well; a 41% reduction. Within the 10 rigs, 8 rigs were NTDRs. The 8 NTDRs averaged 123 hrs/well (45% reduction in drilling hours) while the other two rigs averaged 155 hrs/well. The two best performing rigs averaged 103 drilling hours on 34 wells, achieving a 54% reduction in drilling time. One NTDR rig drilled 31 wells with the SFDF and averaged 131 drilling hours on these wells. This same rig then drilled 7 wells without SFDF and averaged 153 drilling hours per well, a 16% increase clearly demonstrating the effect of the SFDF on ROP.

Papers have been written on the correlating hole cleaning and drill solids accumulation in the fluid with ROP[4,5]. The challenge has always been to maintain drill solids as low as possible. On a recent drilling optimization project, the goal was to maintain drill solids at 5% or less using a closed loop solids control system.[6] The goal was revised to 7% as the 5% goal was unattainable. On the 149 wells drilled using SFDF, the suspended drill solids averaged 2.3% while the 8 wells without SFDF averaged 6.2% drill solids.

Equivalent circulating density (ECD) also has an effect on ROP. As ECD increases, ROP decreases. ECD is a function of the density of the fluid, the fluid frictional losses in the annulus and the drill cuttings in the annulus.[4] On this project, the fluid density was maintained as low as possible, and since the SFDF is a low rheology fluid, the fluid frictional losses were minimized. With a low rheology fluid, hole cleaning is accomplished through maintaining high fluid velocities ensuring the particle transport velocity is maintained well above the particle slip velocity. Pump rates were designed to provide transport ratios in excess of 80% based upon the expected and observed ROPs. This ensured adequate hole cleaning and controlled the ECD by minimizing the build up of cuttings in the annulus. ECD, transport ratio and CCI (Carrying Capacity Index)[4] were calculated monitored and reported to ensure adequate hole cleaning was being achieved. Occasional viscous sweeps were run to ensure the annulus was clean, particularly in the lateral section of the early wells. As experience was gained with monitoring hole condition the number of sweeps was dramatically reduced.

Total well times

The improved ROP is only one aspect of drilling performance and while important to total well time, other drilling operations can be as or more important. There is no advantage to fast ROP if additional circulating time and hole conditioning is required. And, more importantly if the higher ROP results in stuck pipe or other non-productive time any gains made by reducing drilling hours is quickly lost. When we look at total well times, average well times prior to this project were approximately 20 days. The average total well time on the 157 wells drilled was 12.5 days, a 38% reduction. The average total well time for 149 wells drilled with SFDF was 11.9 days, a 41% reduction in the days/well. Of these wells, NTDRs drilled 97 wells and averaged 10.5 days while the conventional rigs averaged 14.5 days. The following figure shows the distribution of well times by fluid system and drilling rig type.



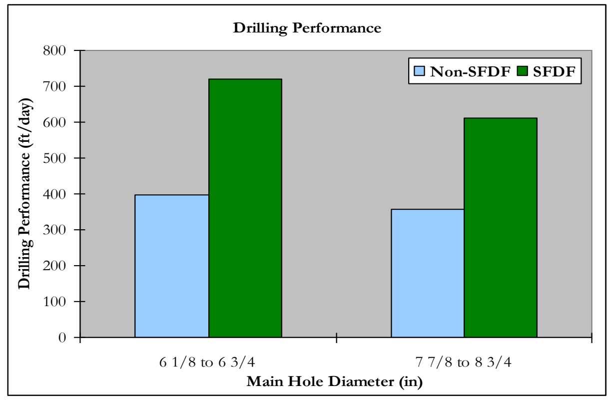
It should be noted that this data set includes all of the 157 wells drilled in the project. Some of the wells include pilot holes, significant rig repairs, new rig start up and hole stability problems. It is beyond the scope of this paper to analyze the problems on individual wells, however, none of the data has been filtered to remove any of these wells from the performance averages. It should also be noted that 77% of the wells were less than 15 days and only 4% of the wells were longer than 25 days. The rig days on these wells represents 11% of the total rig days.

These wells were drilled in 8 counties and as well depths vary across the field, it is important to look at normalized drilling performance in average footage drilled per day. For this project, drilling performance is calculated as footage per well day (spud to rig release). As can be seen, the drilling performance on wells using SFDF was better than wells without SFDF.

Drilling Performance	All wells	SFDF
# wells	157	149
days/well	12.5	11.9
ft/day	670	700

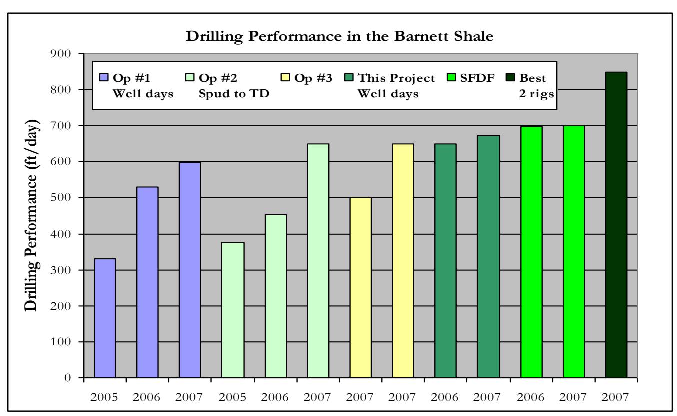
The following table and graph summarize the drilling performance as a function of main hole bit diameter:

Main Hole Diameter (in)	# wells	Total Drilling Days	Average Drilling Days/well	Average Drilling Performance (ft/day)	Average Drilling Performance w/SFDF (ft/day)
6 1/8 to 6 ¾	125	1,582	12.7	692	719
7 7/8 to 8 ¾	32	373	11.7	577	613
	157	1,955	12.5	670	700



The drilling performance of the smaller diameter hole exceeded that of the conventional hole sizes drilled in the Barnett Shale. This is in contrast to the "conventional belief" that the optimum hole size for maximum ROP is 7 7/8". While an 11.5% ROP improvement was noted for drilling the smaller hole with conventional drilling fluid, a 17.4% improvement in ROP was observed for the wells drilled using SFDF.

The drilling performance achieved compares favorably with offset wells drilled at the same time. The following graph shows the drilling performance achieved by three other operators compared to what was achieved on this project[2,3,7,8] (Note that one set of performance data is based upon days from spud to TD with an assumed average well depth of 10,000 ft.). The performance of wells drilled with SFDF is shown as well as the performance attained by the 2 best performing rigs. These rigs drilled a total of 45 wells.



While these results demonstrate "average" performance, there were some notable milestones:

- Seven one bit runs from surface casing to TD
- Most footage drilled in 24 hours = 4,240 ft (177 ft/hr)
- Fastest well = 4.6 days Spud to TD (8,400 ft [1,826 ft/day])

- # of wells that averaged more than 1,000 ft/day = 31 wells. These 31 wells, 19.7% of the 157 project wells, averaged 1,168 ft/day based upon well days.
- 50% of the wells achieved 763 ft/day or more. These 79 wells averaged 989 ft/day based upon well days.

Fluid volumes

Fluid volume was reduced on average from 10,000 bbls to 1,729 bbls. Of this volume reduction, 800 to 1,000 bbls can be attributed to the reduction in hole size (seepage losses and volume retained on cuttings), 5,000 bbls to the elimination of sumps and 2,000 bbls is due to the elimination of dilution. The volume reductions are significant in that not only is the volume of water brought to the location reduced, but the volume of waste being transported away from the location is also reduced. Since the SFDF can be reused indefinitely, the fluid is transported from one well to the next which can significantly reduce trucking costs in projects where well locations are in close proximity to each other.

Reducing consumed volume has the immediate benefit of reducing waste disposal volume. With the SFDF, dilution is eliminated so disposal volume is significantly reduced. The small hole size also reduces the volume of cuttings requiring disposal.

One of the concerns with a SFDF is the seepage losses to the formation. Since the fluid does not contain any solids to form a filter cake, seepage losses can be high in shallow unconsolidated formation or formations with high porosity. In some areas, significant lost circulation was encountered. In these cases, LCM pills were circulated to cure the losses. In mid 2007, an alternate approach was tried to cure downhole losses. Fibrous LCM was added to the SFDF just prior to drilling the lost circulation zone. Additions of LCM were maintained until the complete interval was drilled. This approach seemed to be effective and it showed dramatic results in one county where the average downhole fluid loss per well was reduced from 2,167 bbls to 620 bbls.

Location size

When the project began, wellsite locations included large sumps and were approximately 400 ft x 400 ft. As the project progressed, the sump sizes were reduced and eventually eliminated. The NTDRs with their small footprint and the MudStripper™ with its approximate 15 ft x 60 ft working area allowed the wellsite location to be optimized to approximately 200 ft x 200 ft. This is less than the average location size for most rigs with Closed Loop Systems being used in the urban drilling locations. This resulted in a significant reduction in wellsite preparation cost. This small footprint for a rig with a closed loop system is ideal for the urban drilling environment of many Barnett Shale locations.

CONCLUSIONS

This 20 month optimization program resulted in a significant reduction in drilling cost per foot in a time of rising prices for materials and services. While a number of changes were made, the most significant contributors to this improved drilling performance were the SFDF and NTDR. The smaller hole sizes contributed significantly to the reduction in fluid volumes, casing and cementing costs, but the most significant cost reduction was the result of the reduction of drilling days. The total cost reduction was achieved even though some individual costs like rig day rate increased. The cost of the SFDF and MudStripper™ are comparable to the cost of conventional drilling fluid used with a conventional closed loop solids control system.

Importance of the SFDF fluid

The SFDF in conjunction with the MudStripper™ provided the following benefits:

- Increased ROP
- 100% reusable drilling fluid
- Elimination of dilution volume
- Reduction in disposal volume
- Reduction in fluid on cuttings
- Reduction in downhole tool failures.
- Closed Loop Solids Control
- Reduced location footprint
- Shale stability control
- Extended bit life
- Less wear and tear on mud pumps
- Increased reliability of directional tools

Importance of the NTDR

The NTDRs provided optimized drilling performance through:

- Integrated top drive and pipe handling systems
- Range 3 drill pipe (45 ft joints) reduces the number of connections
- A design that allows tear out, move and rig up in less than a day.
- Mud tanks that allow effective fluid management – tanks can be isolated to control active system volumes.
- Small footprint that allowed reduction of wellsite location

These rigs provide a safer drilling operation with increase performance. Their ability to tear out, move and rig up in less than a day provides a significant reduction in well days which results in more productive drilling days per year. This allows each rig to drill more wells per year.

Importance of other technologies

The reduction in hole size contributed significantly to the cost saving by:

- Reducing casing cost and improving casing availability in a tight market.
- Increased ROP
- Reduced cement volumes
- Reduced bit cost
- Reduced cuttings volume = reduced waste disposal
- Reduced fluid volumes

Importance of project integration

The success of any optimization project is directly related to how effectively all of the pieces are managed and coordinated. In this project, the SFDF relies upon the MudStripper™ to be effective and the MudStripper™ relies upon the SFDF to operate efficiently. The SFDF enhanced the performance of the NTDRs through the use of small diameter bits. While we do not have access to reliability data for the directional tools, our perception is that the SFDF improved tool reliability and bit life; we certainly did not experience many tool failures. Obviously, reducing the total drilling hours on a well provides a direct reduction in the risk of tool failure on that well.

ACKNOWLEDGEMENTS:

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