



Record Drilling Performance in HPHT Field

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Abstract

Discovered in 1975 by Chevron Oil Company drilling in Point Coupee Parish, Louisiana¹, the Tuscaloosa Trend has had nearly continuous drilling development in one of the seven main fields in Louisiana since 1977. The Tuscaloosa Trend is an Upper Cretaceous fluvial-deltaic sandstone which trends upward from the west, in Louisiana, to the northeast, through Mississippi and into Alabama. These sandstones are encountered from 23,000 feet on the southern perimeter, to 17,000 feet on the northern perimeter. There are many complexities encountered when drilling this formation. The most notable of these are the geologic uncertainties and varying pressure profiles encountered through the trend, and the drilling challenges they present. Over the years, many drilling advances and technologies have been applied to address these drilling challenges, in an attempt to lower drilling costs and reduce the time required to drill these deep, high temperature gas wells.

On a recent well in the False River Field, an alternate drilling method was employed. By utilizing the latest in bit technology, coupled with a high performance Turbodrill, the drilling accomplishments that had been established over years of continuous improvement work, have been shattered. By analyzing the drilling obstacles, and addressing these obstacles with applied technologies, the time required to drill the interval was reduced more than 400%, while more than doubling the previous ROP record. This paper will explain, in detail, the engineering behind the planning for this well, and will compare performance to offset wells.

Introduction

In 1975, Chevron Oil Company spudded the Alma Plantation #1 Well, which reached 22,500 ft. into the Tuscaloosa Formation, and served as the discovery well of the False River Field.² Two years later, the Parlange #1 Well, drilled by Chevron, was put on production at 140 mmscfd and proved the viability of the discovery. Since 1977, there have been ongoing drilling operations in the Tuscaloosa Trend.³ The Tuscaloosa Trend is geologically identified as a 20 to 30 mile wide belt that progresses updip from south Louisiana, to the northeast, where it eventually outcrops near Tuscaloosa, Alabama, thus deriving its name. As the formations

trend updip, it pinches out much of the Upper Cretaceous fluvial-deltaic deposition that lies below 17,000 feet, to the southwest in Louisiana. Drilling in south central Louisiana has identified the Upper, Middle and Lower Tuscaloosa Formations. The Lower Tuscaloosa has been subdivided into three distinct sections; the Pilot Lime at the top, the "A" and "B" Series Sands in the middle, and the "Massive" Sand at the bottom. In the seven producing fields in south central Louisiana; the Morganza Field, Moore-Sams Field, Judge Digby Field, False River Field, Port Hudson Field, Irene Field and Lockhart Crossing Field, extending from Pointe Coupee Parish southeast to Livingston Parish, the Pilot Lime provides no commercial production, due to its low porosity and permeability with limited vertical exposure (Figure 1).⁴ The "A" and "B" Series Sands, along with the "Massive" Sand underneath, provide commercial hydrocarbon production. Since 1977, more than 2.5tcf of gas has been produced from these five main fields. Monthly production rates from the "Massive" Sand have been sustained at up to 1.8 bcf or 60 mmscfd.

Tuscaloosa History

The drilling environment in the Tuscaloosa Trend section of Louisiana is extremely harsh. Wells are drilled with oil based mud (OBM), weighted to 15+ ppg, and bottom hole circulating temperatures (BHCT) exceed 380°F. OBM has been the primary drilling fluid at deeper depths due to its ability to remain stable at the higher BHCTs. At higher temperatures, OBM remains thin and less viscous, which also reduces the ECD concerns associated with deeper drilling.

The casing design for the development of the deeper reservoirs has remained basically the same over the last decade, with some recent alterations made to accommodate drilling through depleted sands below the Pilot Lime. 30" casing is driven to 250 ft, then a 20" hole is drilled with 9-9.2ppg WBM and 16" casing is set at 5,150+/- ft. In the next section, 14-3/4" hole is drilled with 9-10.5ppg WBM and then swapped to OBM, where 11-7/8" casing is set at 15,900+/- ft. The 10-5/8" hole section is drilled with 16ppg OBM to a TD of 20,600+/- ft, where a 9-5/8" liner is set. An 8-1/2" hole is then drilled to a TD of 22,100+/- ft using 15.5+ppg OBM and a 7"

liner is set. Any drilling beyond this point utilizes either a 5-7/8" or 5-3/4" bit, and is cased off using a 4-1/2" liner.

Over the years, various methods have been utilized to drill the deeper sections, but there have been drawbacks to them all. Using rotary assemblies has resulted in casing wear issues and drillstring failures, as is the norm when drilling depths increase. The use of positive displacement motors (PDM) in these harsh drilling environments has resulted in shorter runs due to increased failures.

The 8-1/2" hole section on Well A in the Judge Digby Field, from 21,500 to 22,364 ft, required six bits to drill the 864 ft in 309.5 hours. This interval was followed by three 5-7/8" bits which drilled 427 ft, to 22,775 ft, at which point the drillpipe twisted off. The well had to be sidetracked at 22,435 ft, and the sidetracked hole required four bits to drill from 22,490 to TD, at 23,472 ft, in 488.5 hours, with a ROP of 2 fph. The original well averaged 33 ft/day and the sidetrack well averaged 39 ft/day. On Well B in the Judge Digby Field, a 5-3/4" hole, instead of 5-7/8", was drilled from 21,768 to 23,220 ft, which required four bits and 562.5 hours to complete, at a ROP of 2.6 fph. This well averaged 41 ft/day. The Well C in the Judge Digby Field also drilled the deeper section using four 5-3/4" bits, to drill 1,008 ft, from 21,692 to 22,700 ft. 378 hours were required to drill the interval, equating to a ROP of 2.7 fph. A 5-3/4" hole section was also drilled on Well D. The 1,150 ft section, from 21,812 to 22,962 ft, required six bits and 540.5 hours to complete, at a ROP of 2.1 fph. These performances are summarized in Table 1.

During the 2000 drilling campaign, Turbodrills and diamond impregnated bits were attempted with little success. This was due to several factors. First, the bit bond was too hard and failed to expose the diamond during drilling. Second, the Turbodrill was underpowered and attempts to apply weight to increase the ROP stalled the Turbodrill. It was also believed that drilling through the highly depleted sands created plastic behavior by the formation, which slowed the ROP significantly.⁵

M. W. Bellelo #1 Well

The M. W. Bellelo #1 Well was drilled in the first part of 2004. The standard casing design for this field was followed, and 9-5/8", 53.5ppf casing was set at 19,744 ft. Drilling of the 8-1/2" hole section then commenced to 22,518 ft, where a 7", 41ppf liner was set. A 5-3/4" hole was then drilled to TD at 23,693 ft. For the purpose of this paper, comparative analysis will focus on the hole section below 21,000 feet.

8-1/2" Hole Section

The objectives set forth on this well were to improve the drilling efficiency over the interval, improve the rate of penetration (ROP), decrease the casing wear experienced in prior wells, and increase the hole quality to eliminate issues running liners after the interval was drilled.⁶ By employing a high powered, three stage 7-1/4" Turbodrill with a specifically designed high speed hybrid diamond impregnated bit, the section from 21,538 to 22,518 feet was drilled in a single run, with 16.8-17ppg OBM, averaging 4.1 fph. The flow rate was maintained at 337 gpm to optimize the power of the Turbodrill. The baseline offset well was Well E, which required 10 runs and 49 days to complete, while averaging less than 2 fph over the interval. By totally revamping and re-evaluating the current drilling methodology, over 38 days were trimmed off the drilling curve for this interval, providing a new standard (Figure 2). Five of the twelve days required to drill this interval, on the M. W. Bellelo #1 Well, drilled over 100 feet. On day 10, a field record was set by drilling 156 feet. The previous record of 108 feet was eclipsed on all five days where drilling exceeded 100 feet.

The bit was graded 1-1-WT-S-XXX-IN-PN-TD. In certain sections, where the shale content reached 100%, ROP was as high as 3.5 fph, and through the sandstone and siltstone sections, the instantaneous ROP reached as high as 16 fph. A breakdown of the ROP versus offset wells is summarized in Table 1. Based on the overall ROP and the dull, the durability of this bit was more than sufficient, with room for improving the ROP performance in the future.

Comparing the objectives set forth on this well to the actual performance, yielded the following results. The ROP was improved to 4.1 fph versus 1.83 fph on the offset Well E (Figure 3). Drilling efficiency was significantly improved in every facet of the operation. Total Rig time to drill the interval was decreased from 937.8 hours on Well E to 244.5 hours on the M. W. Bellelo #1 Well (Figure 4). Trip time was also significantly decreased, going from 239.5 hours on the offset well to 40 hours (Figure 5). The footage drilled in the two intervals, 8-1/2" and 5-3/4", on the M. W. Bellelo #1 Well were 980 ft and 1,051 ft respectively, which compares to a previous best of 619 ft. Behind that previous best was 381 ft with the average of Wells A-E being 189 ft and the average on Well E being 123 ft (Figure 6).

Casing wear was significantly reduced by utilizing the Turbodrill. The ROP was faster, and the rotary RPM was slower than with either the PDM, or drilling with the top drive. The total revolutions inside the casing with the Turbodrill were less than 250,000, versus more than 1,750,000+ with PDM assemblies and 3,000,000+ with

rotary drilling assemblies.

The cost and time savings for this well was exceptional. Over eight days and \$500,000 were saved in trip time alone, over 38 days and \$2,500,000 were saved in rig time, and \$180,000 was saved in bit costs. For the interval, the cost per foot was \$990, versus the best offset of \$1,775 (Figure 7). Production was also initiated more than a month earlier than planned, which significantly enhanced the ROI.

5-3/4" Hole Section

After setting the 7", 41ppf liner, another record breaking drilling performance was established in the 5-3/4" hole section. Using a high powered, two stage 4-3/4" Turbodrill to drive a specifically designed high speed 5-3/4" diamond impregnated bit, the interval from 22,642 to 23,693 ft was drilled in a single run. The drilling assembly stayed in the hole for 346 continuous hours, and averaged 3.4 fph across the interval. The BHCT over the entire interval was above 400°F. As with the prior hole section, the durability of the bit drilling this 1,051 ft section was extremely good, and the bit graded 1-1-WT-A-IN-PN-TD.

The above results are impressive, but one of the most impressive aspects of drilling these intervals was the lack of incidents. By following the five P's; Proper Planning Prevents Poor Performance, and utilizing experienced personnel, there were no incidents or well control issues. These are the benefits that can be achieved through properly planned applied technology. Since 90% of all incidents (health, safety and well control) occur when tripping pipe in or out of the hole, the elimination of trips plays a major role in not only reducing costs, but eliminating health, safety, environmental and well control issues. Drilling of these two intervals accounted for 2,031 ft, in 591 hours, without a failure or having to trip, other than reaching TD.^{7,8}

Future Optimizations

The performance improvements on the M. W. Bellelo #1 Well were very significant. One of the major enablers in terms of this enhanced performance is found in the vast improvements realized in fixed cutter drill bits. Many great successes have been realized worldwide with a variety of fixed cutter drill bits, including PDC drill bits, TSP drill bits, natural diamond drill bits, and diamond impregnated drill bits (impreg bits) run in conjunction with Turbodrills. In applications such as the one described here, the advancements made in impreg bits have yielded excellent results. These advancements have only been realized through a multi-faceted development approach which takes into account the combined affect of new bit designs, new materials, and

an enhanced application analysis method. It is the process of concurrent work with all three of these aspects of bit development that has produced the results seen in this case study. Any work done on each of these given aspects, in the absence of the others, cannot have the same performance result. This is simply an effect of the complex development process for impreg bits. The interconnected nature of these three bit development aspects will become obvious in the following detailed discussion.

Diamond Impregnated Drill Bit Design

The design of impreg bits is very different from any other fixed cutter drill bit due to the way an impreg bit drills. There are many terms used in the industry to describe the cutting action of an impreg bit, but the most common is 'grinding'. That is very much opposed to the more common 'shearing' mechanism employed by most fixed cutter drill bits. The reason impreg bits 'grind' is that they use very small diamonds (either natural or synthetic, and more frequently, a combination of both), which take a very small depth of cut (DOC). The DOC is defined as the length of forward progress made during one revolution of the drill bit. In most fixed cutter drill bit applications, the DOC is normally over 0.050" (1.3mm).(Figure 8). In many PDC drill bit applications, the DOC is even larger, sometimes over 0.250". With most impreg drill bits, the DOC is less than 0.005" (0.13mm) (Figure 9). In addition to an extremely low DOC, impreg bits have thousands of diamonds for cutting (the cutting structure of an impreg bit is similar to a grinding wheel), opposed to less than 100 PDC cutters on a normal PDC drill bit. Therefore, the actual amount of rock removal performed by each individual diamond is incredibly small. Because of this structural difference, the design of the bit is very different from the design of other fixed cutter drill bits. In order for the impreg cutting structure to drill effectively, it must be designed to clean very well. In order to maximize cleaning effectiveness, the surface area of the bit that is in contact with the formation needs to be as small as possible. However, because this type of drill bit is specifically configured to drill the hardest and most abrasive formations around the world, the surface area needs to be as large as possible to maximize durability (the entire blade is part of the cutting structure and designed to wear away as the bit drills). These two critical design criteria are in conflict. In order to find the best solution to this complex problem, new technologies and specialized design geometries have been developed. One such specialized geometry can be seen in Figure 10.

Diamond Impregnated Drill Bit Materials

An impreg bit drills by continuously sharpening itself through a process of wearing away the bond material (normally comprised of a tungsten carbide matrix) in order to expose new diamonds which are impregnated in

the blade itself. As the diamonds wear, more bond material is worn away, exposing fresh diamonds underneath. This process continues throughout the life of the bit, until the entire blade structure is worn away. One of the most critical design parameters with impreg bits is that the bond material and diamonds be properly matched to the formation being drilled, and the drive system being used. If the bond is too hard, it will not wear away effectively, and when the diamonds exposed on the surface wear out, the bit will stop drilling. If the bond is too soft, the material holding in the diamonds will wear away before the diamonds, causing them to fall out, and the bit will have a shorter wear life. The drive system is also important, since a given bond, used in a given formation, can be too hard if run with a low power drive system, or too soft if run with a high power drive system. For this reason material science is critically important to the success of any impreg bit run.⁹

Enhanced Application Analysis

In order to optimize the design and materials of impreg bits, new methods of analyzing applications needed to be developed. Using a combination of log analysis, historical performance studies, and a detailed matrix of designs and material performance under different conditions, the correct configuration of design geometry and material composition (including the details of diamond size, type, shape, etc.) can be created for each application. However, as mentioned above, this analysis must be carried out in conjunction with a detailed study of the intended drive system. In the excellent run detailed in this paper, the highest power drive system available on the market, the Turbodrill, was used to power the bit. Therefore, in applications that utilize a high power Turbodrill, the analysis used to select the correct design geometry and material configuration for the bit, must account for the higher power and speeds. This situation is well documented in a previous run in this area where the impreg bond did not wear away as desired, resulting in a poor run.⁵ It is possible that, if that same drill bit was used on a higher power Turbodrill today, the bond would have been adequate for the application, and would have worn away quickly enough to expose the diamonds properly. There are many examples in the history of Turbodrilling that follow this trend. In some cases, the bond used for a given bit design worked well when run on a low power positive displacement motor (PDM), but had very short life when used on a Turbodrill. Even the lowest power Turbodrill creates more power than most PDMs, so accelerated wear can be even more pronounced when run with a high power Turbodrill. It is only through an extensive analysis of the impreg bit design geometry, material configuration, diamond configuration, Turbodrill configuration, and how each of those variables is affected by the application variables (formation type, rock hardness, porosity, mud type, etc.) that an

optimized assembly can be selected. The result of all of this analytical effort can be easily seen in the excellent performance detailed in this case study.

New Turbodrill Developments

Turbodrills create power very differently from any other drive system used in the industry. The principle behind a Turbodrill is not unique, to convert hydraulic energy contained in the drilling fluid into mechanical horsepower in the form of output shaft rotary speed and torque, but the way that the power is generated is very different from any other downhole drive system. The power generation section of the Turbodrill consists of a number of turbine stages (a stage consists of a rotor and stator). This setup allows fluid to pass through each stage where the fluid flow is redirected from the stator to the rotor resulting in a rotational force on the rotor that is transferred to the shaft and down to the drill bit (Figure 11).

There are many advantages to the transformation of hydraulic power to mechanical power through the use of turbine blades, but one of the most important is that they are capable of producing very high output power. In the world of downhole motors, mechanical power is created through a variety of hydraulic variables. However, to greatly simplify the situation for the purposes of this discussion, the pressure drop that is created across any downhole drive system, coupled with the flow rate of the fluid, will govern the performance of the tool (assuming for argument that the density of the fluid is a given). The greater the pressure drop capacity of the tool, the greater is the potential for generating mechanical power to drive the bit. Because the power generation system of a Turbodrill is entirely metallic, Turbodrills are capable of supporting a very high pressure drop and are therefore capable of creating very high mechanical power. The many additional benefits of the unique configuration of the Turbodrill have been well documented in industry literature, so, for the purposes of this discussion, not all aspects will be detailed.^{10,11}

As with selecting the correct configuration of impreg bit for an application, selecting the correct Turbodrill configuration is crucial to optimizing performance. Many of the successes being realized in Turbodrill applications around the world are a direct function of an improved understanding of how specific tool configurations affect overall performance. As with impreg bits, there are many variables that must be considered when selecting the best Turbodrill for an application. These variables include blade type, stage count, and system flow rate, based on the mud properties (mud type, mud weight, etc). For any application, the output power of the Turbodrill can be modified to best fit the type of bit (PDC or impreg) and formation to be drilled. Different blade types designed for today's advanced Turbodrills offer

different characteristics of speed, output torque, and pressure drop. The output power of the tool can be dictated by using different types of blades, or a different numbers of blades. For example, a Turbodrill can be configured in two very different ways by using the same blade type, depending on the application requirements. Assuming that the pressure drop through tool needs to be a certain value, it can be achieved by running more stages at a lower flow rate, or fewer stages at a higher flow rate. Running fewer stages at a higher flow rate will produce more RPM at the bit, and running more stages will produce more torque at the bit. Therefore, depending on whether the application will drill more effectively with higher RPM or higher torque, the tool configuration can be optimized for each situation. One of the most important developments in enhancing the performance of Turbodrill systems is extending the pre-run analysis to include all of the different aspects of drill bit configuration and Turbodrill configuration described above. Complete optimization of the overall system performance can only be achieved through a very close collaboration between Turbodrill and drill bit engineering and configurations.

Conclusions

The rotary and PDM performances in drilling the intermediate and production intervals of the Tuscaloosa trend were inefficient and very costly, with sacrifices required for each method. With rotary drilling, the primary issue was casing wear, and, when drilling with a PDM, the primary issue was motor failure, requiring numerous trips. By analyzing the difficulties with past performance and applying relevant new technology, significant drilling improvements have been made. In 2000, Turbodrills were used sparingly, and it was obvious that the performance suffered due to a lack of available drive power and to the type and style of impreg bit being used. Over the last two years, much work has been done to increase the power output of the Turbodrill, while optimizing the bits used in these specific applications.

By using historical performance to quantify the data and then using specialized programs, the correct bit style and type, complete with specific materials and diamonds, can be coupled with the appropriately powered Turbodrill to optimize performance in any given formation.

As witnessed on the M. W. Bellelo #1 Well, the engineering work to improve the power output of the Turbodrill and to put the proper bit on the end of the string in order to achieve enhanced performance was accomplished. By evaluating all of the available technology and history, a superior system was put in the hole to achieve all of the set forth objectives.

Further optimizations are ongoing to achieve even better results. Turbodrills are currently being designed and modified to increase power where new and improved rigs are being deployed to drill these historically expensive wells. Bit technology is progressing rapidly to handle the higher power and higher speeds associated with Turbodrills. Progression of these technologies will continue to increase performance and lower drilling costs.

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Nomenclature

<i>bcf</i>	=	<i>billion cubic feet</i>
<i>BHA</i>	=	<i>Bottom Hole Assembly</i>
<i>BHCT</i>	=	<i>Bottom Hole Circulating Temperature</i>
<i>BHT</i>	=	<i>Bottom Hole Temperature</i>
<i>DLS</i>	=	<i>Dog Leg Severity</i>
<i>DOC</i>	=	<i>Depth of Cut</i>
<i>ECD</i>	=	<i>Equivalent Circulating Density</i>
<i>ERD</i>	=	<i>Extended Reach Drilling</i>
<i>fph</i>	=	<i>feet per hour</i>
<i>IADC</i>	=	<i>Int. Association of Drilling Contractors</i>
<i>LBS</i>	=	<i>Lower Bearing Stabilizer</i>
<i>mmscfd</i>	=	<i>million standard cubic feet per day</i>
<i>MTBF</i>	=	<i>Mean Time Between Failures</i>
<i>OBM</i>	=	<i>Oil Base Mud</i>
<i>PDC</i>	=	<i>Polycrystalline Diamond Compact</i>
<i>PDM</i>	=	<i>Positive Displacement Motor</i>
<i>ppg</i>	=	<i>pounds per gallon</i>
<i>ROI</i>	=	<i>Return on Investment</i>
<i>ROP</i>	=	<i>Rate of Penetration</i>
<i>RPM</i>	=	<i>Revolutions per Minute</i>
<i>tcf</i>	=	<i>trillion cubic feet</i>
<i>WOB</i>	=	<i>Weight on Bit</i>

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Well Name	Hole Size	# Bits	Footage	ROP (fph)	ft/day	Depth In	Depth Out
Bellelo #1	8-1/2"	1	980	4.1	98	21,538	22,518
Bellelo #1	5-3/4"	1	1,051	3.4	73	22,642	23,693
Well A	8-1/2"	6	864	2.79	41	21,500	22364
Well Ast	5-7/8"	7	1,409	2	37	22,348	23,472
Well B	5-3/4"	4	1,452	2.6	41	21,768	23,220
Well C	5-3/4"	4	1,008	2.7	39	21,692	22,700
Well D	5-3/4"	6	1,150	2.1	38	21,812	22,962
Well E	6-3/4"	10	1,110	1.83	18	21,372	22,482

Table 1 – Offset Well Comparisons



Figure 1- Map of Louisiana showing location of fields in Tuscaloosa Trend.

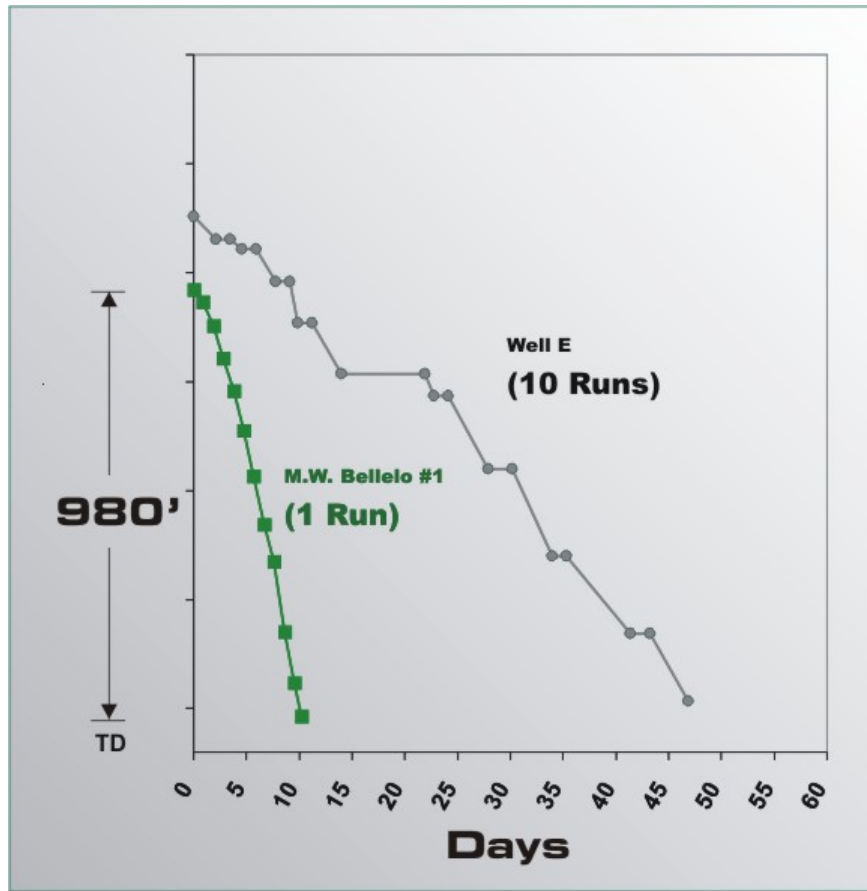


Figure 2 – Days versus Depth comparison

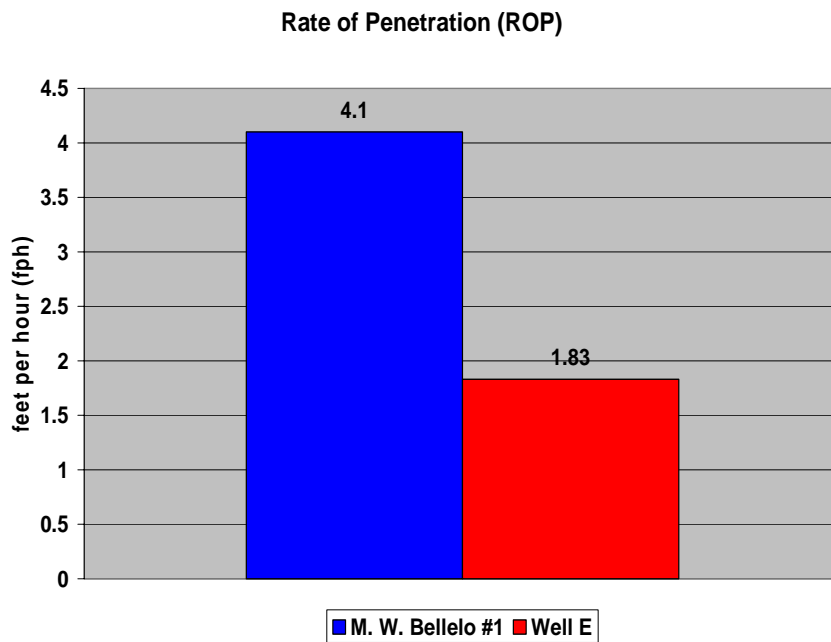


Figure 3 – ROP comparison for M. W. Bellelo #1 Well and offset Well E

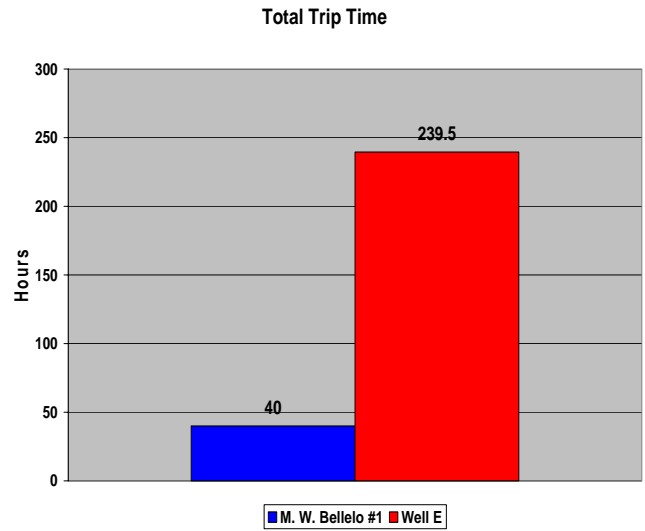
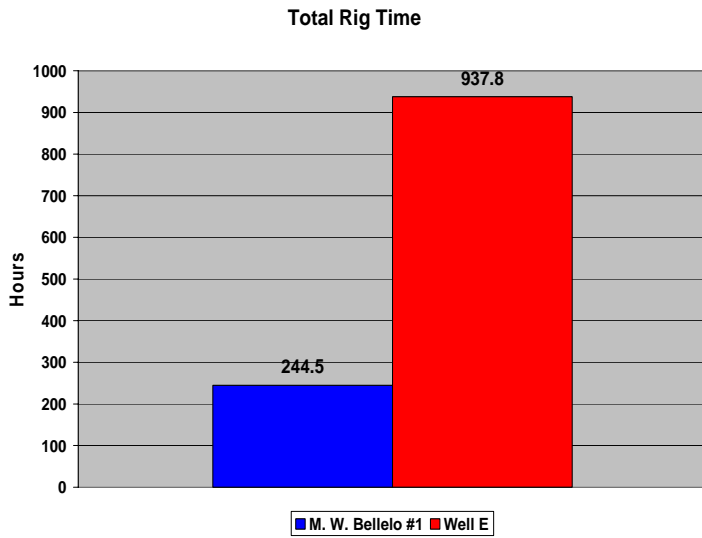


Figure 4 – Comparison of Total Rig Time for the M. W. Bellelo #1 Well and offset Well E.

Figure 5 – Comparison of Trip Time for the M. W. Bellelo #1 Well and offset Well E.

Footage Comparison by Well

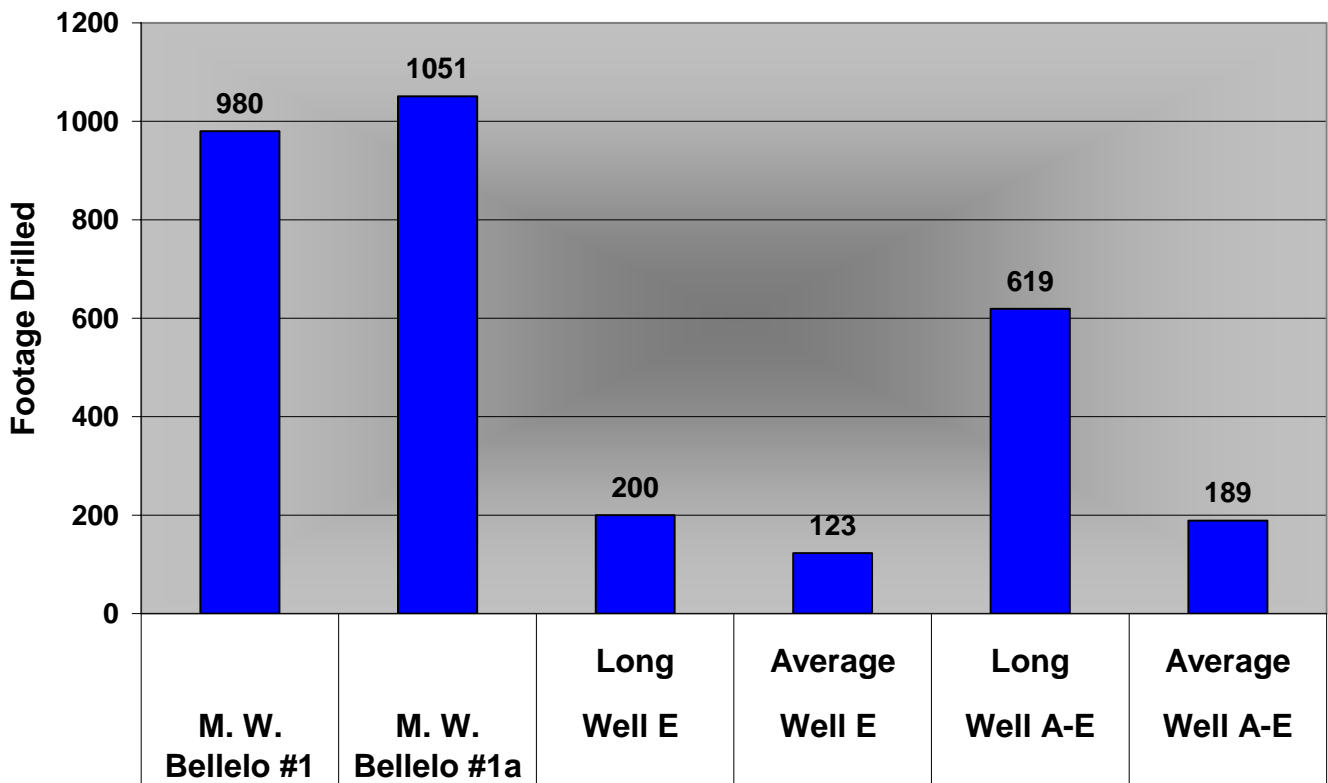


Figure 6 – Footage Drilled comparison by well.

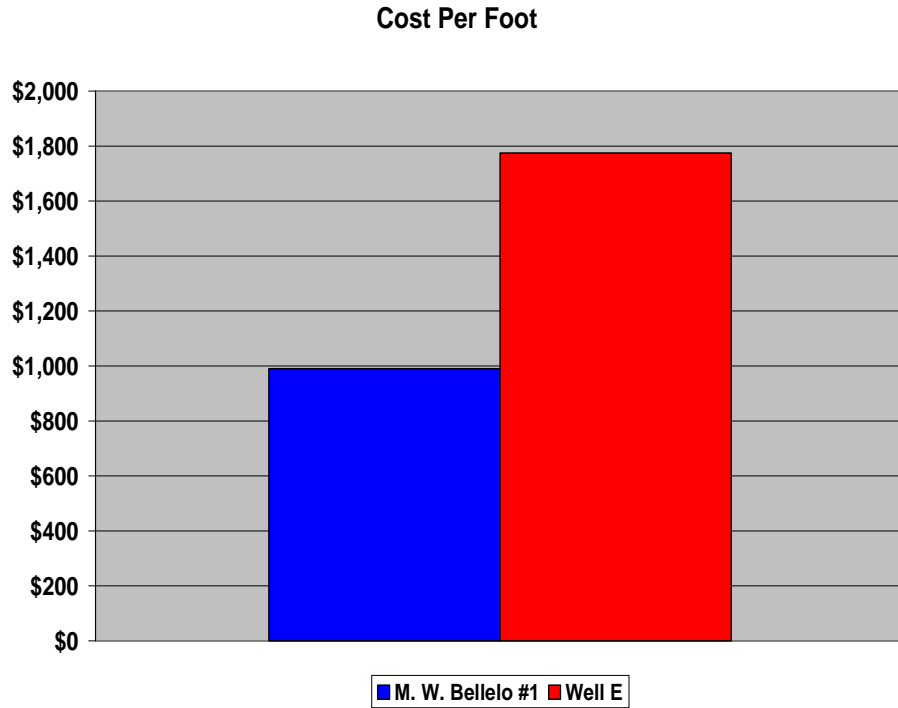


Figure 7 – Cost Per Foot Comparison of M. W. Bellelo #1 Well versus Well E, the previous best.

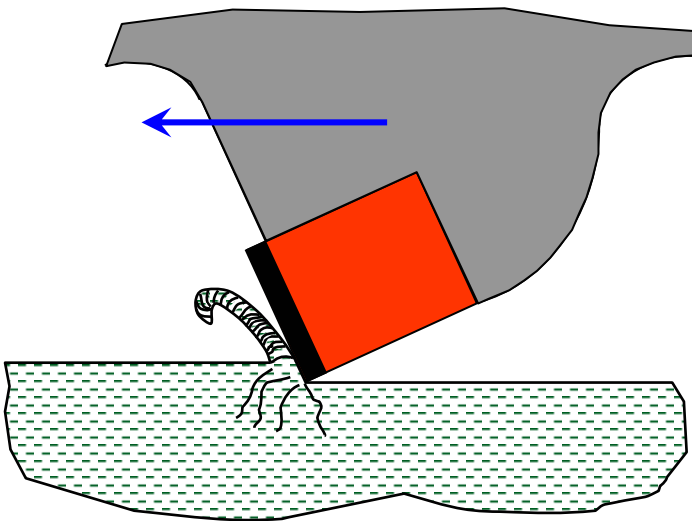


Figure 8 – Mechanics of a PDC cutter shearing rock

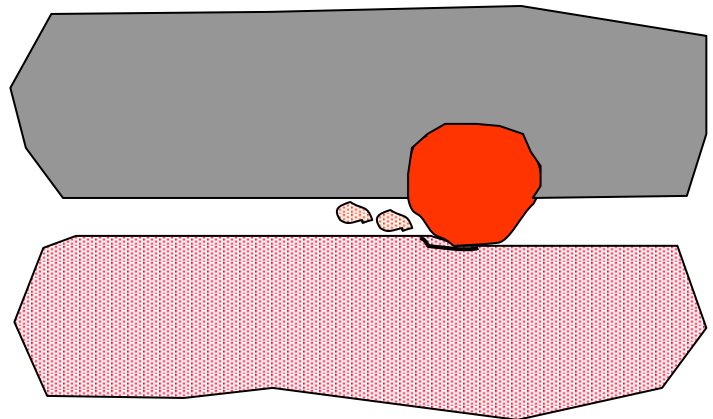


Figure 9 – Mechanics of Impregnated Diamond grinding rock

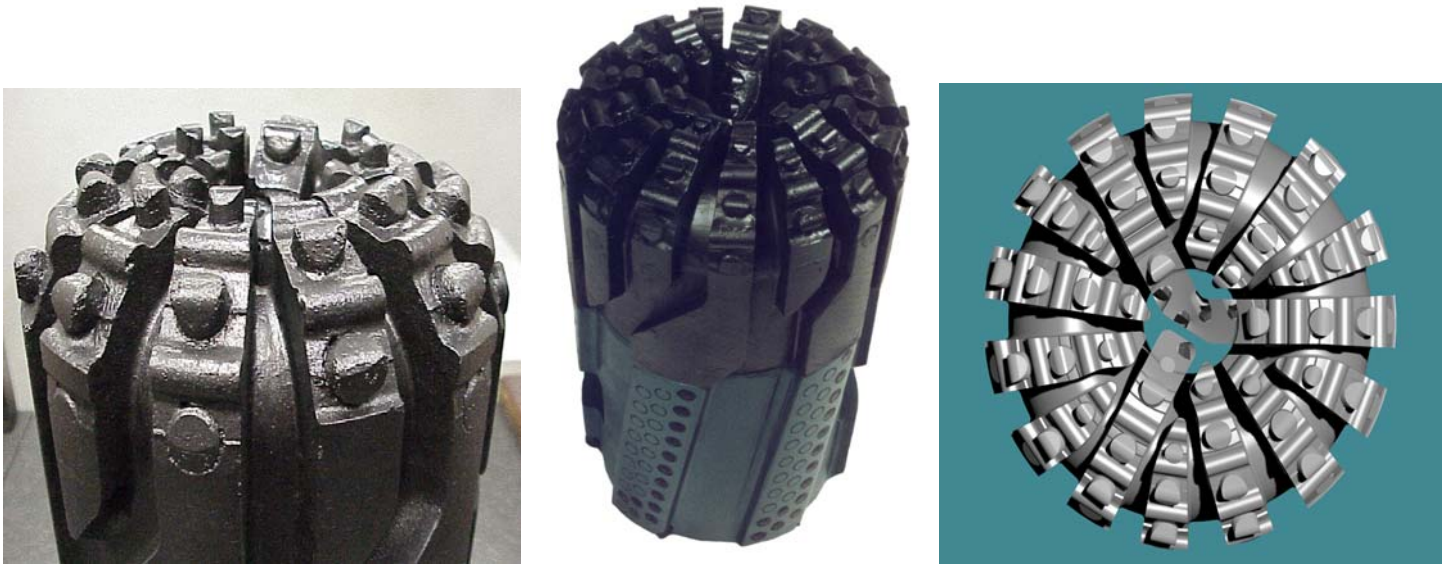


Figure 10 – Special geometries of Impregnated Diamond Bit

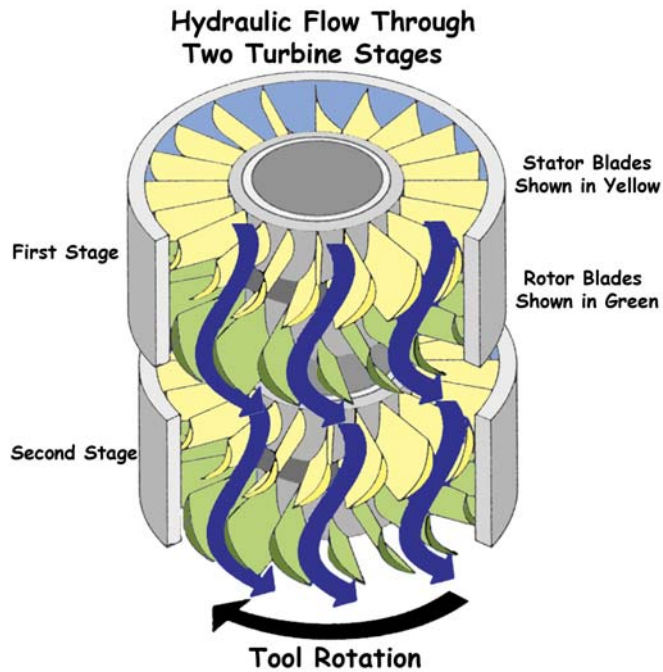


Figure 11 – Turbine Rotor Stator Stage configuration