Real-Time Development of New Technology Saves Operator $5.1 Million Drilling Deep Exploration Well, Colombia
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Abstract
Due to the challenging topography, lack of suitable surface locations and reinterpreted seismic data after construction work had commenced on a chosen location, the operator modified the wellbore directional profile from being the preferred “natural drift” to near vertical. The drilling of vertical wells, utilizing conventional equipment and procedures, had never been successful in Colombia. Based on the success in Argentina of this type of well, the operator requested the technical assistance of a drilling optimization service. The operator and service company developed a flexible, yet detailed strategy to address the anticipated challenges. The plan had the following main components: (1) the application of a straight hole drilling device used in combination with PDC and roller cone bits; (2) implementation of a teamwork philosophy to ensure all personnel felt committed to delivering significant performance improvement.

Because of slower than prospected penetration rates using conventional bit technology and the corresponding negative impact on the 14 3/4” hole section performance curve, the operator and service company elected to build a new-style diamond impregnated bit that had been discussed during the planning phase. A prototype was designed using a multidisciplinary team comprised of operator and service company personnel. Members of the team who determined that the relatively short run length and excessive wear on the nose of the bit could be designed out of subsequent bits analyzed the initial run in the field. The changes that could be built into the next prototype within a short “turn around time” would be a different matrix type that would optimize diamond grit exposure, increased diamond volume and maximization of the cutting structure’s contact area on the bottom of the hole. They also recommended a more aggressive anti-sticking gauge configuration to allow the bit to efficiently drill-out of a tight hole. The engineers returned to Houston and the optimized bit solution was manufactured and shipped back to Colombia in one week.

Due to the optimized design, the 14-3/4” impregnated bit IADC M842 set a new world single run footage record drilling 499 ft at 3.9 ft/hr. To capitalize on the new design’s success, the engineers designed a 10-5/8” and 8-1/2” versions of the IADC M842 bit with the 10-5/8” version achieving another world single run footage record drilling 585 ft at 3.3 ft/hr. To measure the effectiveness of the plan flexibility and the service company’s ability to solve unexpected challenges, the authors will document cost savings relative to offset wells. The typical Colombian foothills exploration well takes an average of 188 days per 10,000 feet to complete. However, because of the service company’s ability to develop and deliver new technology to the well site in real-time, the operator was able to cut the time required to drill the exploration well by 86 days saving BP $5.1 million versus utilizing conventional technology and procedures.

The authors will review each section outlining success and areas for improvement. They will also discuss the development of the innovative technology and give examples on how to best apply it to achieve maximum performance.

Introduction
The Niscota E-1 exploration well (30 km from nearest production) was a critical prospect for BP and the Colombian petroleum industry. The wildcat venture was the first major exploratory effort by the operator in the region in over five years. The Niscota play is key for the operator in terms of its potential to open up both new development and exploration opportunities. The critical need to ensure that the well delivered the exploration objectives efficiently required that the well be planned and executed to a very high standard.

Because of the extremely high stakes, the operator was determined to bring the latest technology and philosophy to bear on wellbore construction to ensure technical success. The best way to achieve this was to start new from scratch not
depending on traditional technology, procedures and operations to drill the highly problematic overthrust structures with their steeply dipping formations. This included implementing the Beyond the Best drilling initiative for the first time in Colombia to extensively map out contingency plans. The project was committed to allowing sufficient time for unprecedented Front End Loading to insure all personnel were involved in the detailed planning phase. This extended time allowed the operator and key service companies to provide critical input to resolve all outstanding issues, set goals and objectives and give all personnel plan ownership. This included outstanding communication between the subsurface and drilling teams. The drilling team concluded that well plan flexibility, total team involvement and commitment as well as using and implementing new technology would be the keys to success. Essentially, the right tool for the right application.

**Niscota Location/Challenges**
The Niscota prospect is located in the northeast part of Colombia on the most productive trend in the country (Figures 1 & 2). The project was a major exploratory effort and presented the operator a number of distinctive challenges including:

- First Well in the Structure
- High Geological Uncertainty
- Minimal Vertical Displacement (300 ft - 680 ft)
- High Dip Angle > 65°
- Tectonics ⇒ Borehole Instability
- High Compressive Strength/Abrasive Formations
- High Focus on Borehole Quality
- Deviation Control (Vertical Trajectory)
- Reaming & Backreaming
- Down Hole Tool Failures & Frequent BHA Inspections
- Unsuccessful Casing Runs
- Necessity for high quality wireline logs to determine reservoir rock and fluids characteristics
- Logistical Challenges

Additionally, because of the mountainous nature of the Andes foothills in Colombia, options for the surface location were extremely limited. This increased wellbore complexity because engineers could not use the “natural drift” strategy where the surface location is offset from the target and the BHA is permitted to drift up-dip to the target reservoir. Unlike previous BP operations in the region, the Niscota wellbore would have to be near vertical. This led the operator to examine a variety of new technologies and to challenge existing paradigms to deliver the well objectives.

**Pre-Drill Analysis**
Due to tight contractual deadlines, construction activities for the access road and surface location commenced prior to the finalization of the subsurface targets. After review of all of the recently acquired seismic data, the bottom hole location was moved to a position where a near vertical well would be required. A vertical well had never been successfully completed in the Llanos foothills of Colombia due to the steeply dipping beds and the drill string’s tendency to “walk” and be influenced by formation dip. The vertical well concept introduced risks and operational considerations that had not been previously planned for.

In order to capitalize on their worldwide experience, the Niscota drilling team discussed lessons learned from drilling in the Gulf of Mexico, Canada, offset wells in Colombia and similar complex stratigraphic sections in Argentina, Bolivia and Italy. Also, lessons learned regarding drilling fluids design from previous BP Colombia operations proved advantageous (sealing agents and mud properties). In order to identify and implement the most economical solution, the operator requested the technical assistance of a drilling optimization service to help evaluate all potential options and the risks associated with each option.

Critical to the overall project success was the continuous use of peer reviews to challenge the merits of the modified well design. Engineers considered every potential problem interval in the overburden section and mapped out decision trees that outlined how to efficiently manage that risk. This risk management helped team members understand what the options were in advance to avoid non productive time (NPT). This process led into the creation of an entirely new well plan for Niscota instead of utilizing the procedures and operations from an earlier design.

To successfully re-engineer the well plan, engineers challenged traditional wisdom in Colombia to strive for continuous improvement by applying new procedures and technology to a given application. For example, by pushing the technical limits and implementing a new procedure, the operator set a new world record getting 9-5/8” liner in a 10-5/8” hole to 16,606 ft. The original liner setting depth was 13,000 ft but the well design (Figure 3) was flexible enough to allow for this change based on the geological uncertainties.

**Implementing Solutions**
To address the vertical hole section challenge, the operator elected to use a vertical drilling system (VDS) that has solved similar challenges in Argentina (et al). The VDS consists of a single closed loop automated down hole tool and a surface system that has the ability to drill vertical wells. The major components include a high torque power section, the control sub and the pulser housing. The VDS tool is an individual closed loop system with the option of 2-way communication with the driller at surface.

Three hydraulically controlled spring loaded steering ribs are located at the upper bearing housing approximately 2 ft behind the bit. The short distance to the bit and the ability to control each rib individually keeps the BHA at its desired vertical path. The steering ribs are connected to the control sub by three hydraulic lines drilled through the mud motor section to energize either one or two steering ribs should the BHA deviate from its near-vertical well path. Highly dipping formations are an ideal application to deploy VDS to minimize expensive corrections runs due to high borehole inclination. To maintain a near-vertical well path in this challenging drilling environment, the VDS can apply up to 6,600 lbs of
side force against the borehole wall. A continuous steering process minimizes local doglegs resulting in a high-quality ingauge wellbore.

The VDS is mainly operated without rotating the drill string. This lack of drillstring rotation reduces the power available at the bit. To compensate for this power loss, the VDS down hole motor features a pre-contoured steel stator tube (Figure 4). This technology enables the tool to generate up to 50-100% more power relative to conventional existing stators. This feature further opens a wider range of drilling applications in regards of higher circulating temperatures.

A 3-D accelerometer package is attached to the electronic module measure deflection from a true vertical position to automatically correct back to a vertical position. Within each steering cycle either one or two ribs will be energized to deliver continuous well path correction (Figure 5).

After the extensive pre-drilling analysis, the Niscota E-1 well spud February 11, 2003, 20 days ahead of plan. Mobilization was implemented to take full advantage of the December/March dry season. Outlined below are the significant successes and failures in each particular hole section.

### 42” vs 36” Section
The plan was to drill 42” hole through problematic boulder sections instead of a 36” hole to ensure 30” conductor string reached bottom without incident. Casing was set without incident.

### 26” Section
The plan was to drill vertically with VDS and a roller cone bit. However, due to slight angle building tendencies (5°), the plan was modified and TD called early in order to control verticality. This was possible because of real-time risk analysis and original plan flexibility that allowed for a contingency to be successfully applied. The penetration rates with roller cone were two/three times higher than anticipated and the VDS system provided a smooth high-quality wellbore.

### 18-1/2” Section
The plan was to drill a vertical hole in three PDC runs with VDS. However, the BHA started to build angle and the drilling team decided to make changes to the existing operating parameters in order to successfully deliver well objectives. On the advice of rig personnel, the team did not run a wiper trip or cement stabilization plugs prior to setting casing. Through real-time hole condition evaluation, the team recognized the improvement in borehole quality from not rotating the drill string. Engineers also realized that mud weight window optimization contributed to enhanced borehole quality. New PDC bit technology was key to performance improvement.

### New PDC Bit Technology
A new technology for steerable PDC bits was developed in 2001 that improved performance with conventional steerable systems. The team recognized that tool face issues might also affect the function of the VDS and these tool face issues could be addressed with similar bit technology. The high torque capability of the mud motor would result in higher ROP if the bit could drill smoothly without torque oscillations affecting steering functions of the VDS. The tool’s steering function also placed significant side load on the bit for the entire run and so the bit side-cutting aggressiveness had to be matched with the control system of the VDS to optimize system response.

#### Bit Aggressiveness
The aggressiveness of a bit can be defined in terms of a bit specific coefficient of sliding friction that relates an applied weight-on-bit and the resulting reactive torque. Mathematically, the definition is as follows:

\[ \mu = \frac{\text{bit aggressiveness}}{\text{weight window}} \]

Graphically, bit aggressiveness is proportional to the slope of the curve that relates drilling torque to weight-on-bit. Example curves for a typical roller cone and PDC bit in firm limestone (UCS = 15 kpsi) are shown in Figure 6. From the figure it is evident that PDC bits are much more aggressive (higher slope) than roller cones (lower slope). As a result of the higher aggressiveness, changes in instantaneous WOB cause much greater changes in reactive torque for PDC bits than for roller cones.

The colored lines showing torque levels demonstrate this effect for the case where downhole WOB ranges from 10-15 klb; the reactive torque variation for the roller cone is approximately 200 ft-lb, while that for the PDC is nearly 1,000 ft-lb. For the VDS, the WOB fluctuations are not the primary issue; it is the high torque level required by PDC bits to drill. Fluctuations in torque constantly occur as WOB is applied to the bit to make it drill and as the bit drills differing rock types with different compressive strengths (especially in interbedded formations).

#### Depth of Cut Control
Depth of cut control technology was utilized to engineer the bit’s torque response to minimize oscillation and provide a smooth torque response to applied WOB. Basically, the exposure of the cutters above the blade are carefully adjusted so that when ROP increases above a predetermined level, a bearing surface engages the hole bottom. At higher ROP, the bearing area increases exponentially while torque increases linearly. The overall effect is that aggressiveness decreases suddenly after the depth of cut limit is reached. This approach also has the advantage of fully utilizing an efficient, aggressive cutting structure while staying within the operating torque window of the VDS tool. Figure 7 shows the example curves with the torque response of the new technology PDC bit added and the resulting improvement. In a conventional steerable application, this technology absorbs WOB and allows the bit to generate smaller increases in reactive torque than a standard PDC bit. The depth of cut control technology
functions as penetration rate control for the VDS which helps limit and smooth the reactive torque.

**Side Cutting Aggressiveness**
Gauge length was adjusted to provide both stabilization for the bit and support the side load applied by the VDS while maintaining adequate side cutting aggressiveness for deviation control.

**PDC Cutter Technology**
Cutter technology also played a role in the performance improvement. Engineers determined that residual stresses in PDC cutters are a source of cutter failures. A new style cutter was used in the PDC bit that contains an interface between the diamond table and the carbide substrate that has been engineered to break up the high residual stress concentrations from the portion of the cutter which will see the highest service induced stress. The cutter interface has improved the management of these stresses which helps it to resist spalling and impact failures. These cutters utilize the latest in the layered diamond table technology.

The PDC bit performed better than expected delivering penetration rates three/four times higher than anticipated. The bit was designed to drill 25 ft/hr at 80-90 RPM. However, due to a change in the VDS power section, actual RPM reached 180 so the new design PDC bit had ROP in the 40 - 50 ft/hr range and the final average ROP was 175 ft/hr factoring in the first 700 ft was drilled at 250 ft/hr.

The 18-1/2” section was considered a major success. The well section was completed 14 days ahead of the target time with virtually no deviation from vertical. A quality, in gauge wellbore was delivered due to the VDS/PDC combination and changes in procedures that did not include wiper trips or reaming runs. By comparison, offset wells drilled in this section experienced up to 40% washout. The new bit design (Figure 8) established two new world records in a single run.

**14-3/4” Section**
Similar to the 26” and 18-1/2” hole sections, the 14-3/4” section included a performance contract that aligned objectives between the operator and the drilling optimization service that allowed both companies to share risk and reward to contribute to overall section success. However, in this hole section, the outcome of this cooperation was a new custom built impregnated bit specifically designed for a VDS application.

**10-5/8” Hole Section**
The lower sections proved to be the most challenging due to the geological uncertainties. The lessons learned in the upper hole sections (regarding increased hole stability associated with minimal pipe rotation) were successfully applied. Traditional procedures and wisdom indicated that ROP’s while sliding would be considerably less than while rotating. This wisdom was challenged and a low AKO motor/diamond impregnated bit system was used to fight the severe building tendencies of the formation. This system allowed for 100% sliding and resulted in both higher ROP’s and improved borehole quality compared to conventional drilling with a high AKO motor utilized in a slide/rotate mode.

This performance was probably due to more efficient WOB transfer derived from the verticality and smooth trajectory. Based on the lithology, engineers selected diamond impregnated bits to maximize ROP and on bottom drilling time.

The impregnated bit was run with a conventional directional BHA (motor with AKO) provides smooth tool face without motor stalling issues. As a result, the directional job was completed without problems or ROP penalty even though sliding 100% of the time. The bit design also established a new world record.

The 10-5/8” hole section was “open” for 120 days. At this time the total depth approached the safe operating limits for the 6-5/8” drill string and 9-5/8” liner equipment. This, combined with hole deterioration in identified fault zones, led to the decision to set a 9-5/8” liner. Although the original liner setting depth was 13,000 ft, the well design flexibility and new operating procedures allowed the pipe to be run to 16,606 ft, setting new world record liner length runs for both the new VAM FJL connection with a Baker Oil Tools SDD liner hanger.

After setting the liner, the project NPT was 4.5%, which is considered excellent by area standards. The average NPT for offset exploration wells is 38% and the best performance is 7%. The Niscota target was 15%. Many paradigms were challenged and broken drilling these hole sections including setting a new minimum flow rate required to clean the well. Most importantly, there were no HS&E incidents. Time and cost savings of the original well design vs the new designs are summarized in Figure 9.

**Impregnated Bit Technology**
Impregnated bits have always drilled long footages in hard and abrasive formations with excellent durability. These bits have hard, synthetic diamonds impregnated in a matrix of hard tungsten carbide particles with a softer binder. The cutting structure abrades by abrasive drilling action which exposes new diamonds in what is referred to as self sharpening wear. The rate of the abrasion should occur fast enough to expose new diamonds before the existing diamonds develop large wear flats and slows the ROP. Conversely, the abrasion rate should be slow enough so that the bit does not wear out prematurely.

However, because of the limited drilling mechanism and relatively low ROP capabilities, impregnated bits are typically chosen as a last resort. The classic impregnated application is a single impregnated bit replacing multiple roller cone runs in deep intervals where increasing on-bottom drilling time and reducing costly trips for new roller cone bits balances the economics and reduces drilling risks.

By increasing the percentage of time on bottom, operators can often economically justify slower drilling rates. The
traditional impregnated cutting structures often clog with shale and life is drastically reduced by overheating and rapid wear.

To address ROP issues associated with traditional impregnated bits, the operator and the bit manufacturer selected a new style of impregnated bit that could efficiently drill hard and abrasive sandstone interbedded with shale formations. Recently, extensive laboratory and field testing had introduced new generation of more aggressive diamond impregnated bits offering unique advantages drilling hard/abrasive intervals more economically. The cutting structure focused on maintaining ROP and bit life while drilling hard formations in the target interval, but with the added capability of drilling faster in the softer shale and non-abrasive rock.

The bit company worked in conjunction with the operator to cooperatively develop and apply this new technology that included an innovative new interrupted cutting structure that avoided the clogging tendencies of the earlier bits and drilled more efficiently. Also, three different types of newly developed matrix material allowed design engineers to adjust the abrasion resistance to the interbedded lithology.

After examining the dull bit and drilling parameters from the initial run, engineers re-designed/manufactured a unique post-on-blade impregnated bit specifically for the application (Figure 10) and had this new design back on location in just 12 days after the previous run. The bit was successfully run in the lower section setting a new world record for single run footage. As a result of this “almost real-time” improvement, the new impregnated design was able to save 14 drilling days relative to roller cone performance in spite of pushing the sealed bits to their technical krev limits.

From the directional point of view, the impregnated bit responded similar to roller cone and PDC in booth cases, holding angle. The first impregnated (HH) run started with 0.06º and finished at 0.07º inclination. The impregnated bit provided smooth tool face control and a good side cutting capabilities.

The combination of the VDS methodology (sliding mode versus rotating the drill string) and the modified operational procedures delivered excellent borehole quality and the operator was able to get logging tools to bottom without incident. Because of excellent contact between the open hole and logging equipment, log quality was the best of any BP exploration well drilled in Colombia in spite of 110 days of open hole exposure.

Significant performance improvement was achieved with regards to bit life, motors, MWD, drilling parameters and increasing time between BHA inspections to 300 rotating hrs vs 150 rotating hrs. As a result, the section reached TD just eight days behind schedule (AFE) even though the casing point decision was pushed 500 ft deeper than planned. Average deviation was just 1.15º vs 2.1º planned. The interval was completed with only 1.5% NPT and no HS&E incidents.

New World Record Runs
- 18-1/2" HCM606 PDC (Single Run Footage) New Record 1734 ft; Old Record 1657 ft
- 18-1/2" HCM606 PDC (Rate of Penetration) New Record 175 ft/hr; Old Record 33.9 ft/hr
- 14-3/4" HH178 Impregnated (Single Run Footage) New Record 499 ft; Old Record 423 ft
- 14-3/4" HH178 Impregnated (Single Run Footage) New Record 500 ft; Old Record 499 ft
- 10-5/8" HH178 Impregnated (Single Run Footage) New Record 585 ft; Old Record 413 ft

Performance Improvement
In spite of the complex overthrusted geology and numerous drilling hazards, the Niscota project was an overwhelming technical success. The average well drilled in the Colombian foothills averages 188 days per 10,000 feet to complete. However, by applying application specific technology, new procedures, real-time adjustments and challenging traditional wisdom in the area, the team cut the average time required to drill this well to 140 days per 10,000 feet (Figure 11) saving the operator $5.1 million.

Recommendations
1. The development and utilization of new technology involves calculated risks that both operator and service company must share. The full involvement of both the service company and operator engineering and design staffs in the evaluation of the effectiveness of new technology is required. This was demonstrated when the first 18 ½” PDC bit was pulled early due to angle building tendencies. Neither the initial dull bit evaluation nor the post run checks of the VDS provided operational personnel insight as to the cause of the angle building. The identical drilling system (VDS and PDC) were rerun and only after consultation with design engineers was the cause of the initial problem understood and related back to the initial ROP design and depth of cut criteria.

2. Evolution and real-time refinement of new technology may be required before full value is realized. The initial 14-3/4” impregnated bit run was a failure compared to the previous roller cone performance and cost per foot. The potential for improvement was recognized and additional design modifications resulted in both world record runs in the large size and improvements that were critical to the drilling success in the lower hole intervals.

Acknowledgments
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Reference Papers


Figure 1 – General Location Map

Figure 2 – Specific Niscota Location
Figure 3 – Original vs New Optimized Slim Well Design
Figure 4 - Stator Cross Section

Figure 5 - Vertical Drilling System (VDS)
Figure 6– Example Curves for Typical Roller Cone and PDC Bits

Figure 7 - Example Curves for Typical Roller-Cone and PDC Bits with new technology PDC
Figure 8 - VDS optimized 18-1/2” six bladed PDC bit with depth of cut control technology

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Figure 9 – Performance Results, Original vs New Optimized Slim Well Design
Figure 10 – New Impregnated Diamond bit style HH178 (14-3/4” (left) & 10-5/8”)

Figure 11 – Niscota Days vs Depth Performance Comparison vs Piedemonte