At some point in the operational life of an oil field, natural drive dwindles and additional energy is needed to sustain production rates. In the Casabe field waterflooding has been used to enhance oil recovery. However, a combination of sensitive lithology, structural complexity and water channeling caused hardware to fail and wells to collapse, disrupting the waterflood efficiency. New techniques in geologic analysis, waterflooding, drilling and production optimization are restoring this once-prolific field to its former glory.

Old fields have stories to tell. The story of the Casabe field, 350 km [220 mi] north of Bogotá and situated in the middle Magdalena River Valley basin (MMVB) of Colombia's Antioquia Department, began with its discovery in 1941. The field was undersaturated when production began in 1945, and during primary recovery the production mechanisms were natural depletion and a weak aquifer. In the late 1970s, at the end of the natural drive period, the operator had obtained a primary recovery factor of 13%. By this time, however, production had declined significantly to nearly 5,000 bbl/d [800 m³/d]. Seeking to reverse this trend, Ecopetrol SA (Empresa Colombiana de Petróleos SA) conducted waterflood tests for several years before establishing two major secondary-recovery programs in the mid to late 1980s.

Casabe: New Tricks for an Old Field

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During the secondary-recovery period, structural complexities, sensitive shales, heterogeneous sands and viscous oils all conspired to undermine the effectiveness of the waterflood. And although initially successful at increasing production, injected water broke through prematurely at the production wells, an indicator of bypassed oil (previous page). Sand production occurred in a high percentage of wells, contributing to borehole collapse and causing failure of downhole equipment. Water-injection rates were gradually decreased in an attempt to overcome these issues, and waterflooding became less effective at enhancing oil recovery; from 1996 onward the production rates declined between 7% and 8% per year.

In 2004 Ecopetrol SA and Schlumberger forged an alliance to revitalize the Casabe field. Using updated methods for managing highly complex reservoirs, the alliance reversed the decline in production: From March 2004 to February 2010, oil production increased from 5,200 to more than 16,000 bbl/d [820 to 2,500 m³/d]. Also, the estimated ultimate recovery factor increased from 16% to 22% of the original oil in place (OOIP).

This article describes the complexities of the reservoirs within the Casabe concession and the oil recovery methods employed over the last 70 years, concentrating primarily on the major reengineering work using updated methods that began in 2004.

A Prolific Yet Complex Region
The middle Magdalena River Valley basin is an elongated depression between the Colombian Central and Oriental cordilleras and represents an area of 34,000 km² [13,000 mi²]. Oil seeps are common features within the basin; their presence was documented by the first western explorers in the 16th century. These reservoir indicators motivated some of the earliest oil exploration and led to the discovery in 1918 of the giant field called La Cira–Infantas, the first field discovered in Colombia. Since that time, the MMVB has been heavily explored. Its current oil and gas reserves include more than 1,900 million bbl [302 million m³] of oil and 2.5 Tcf [71 billion m³] of gas.
The abundance of hydrocarbon resources in the basin attests to the prolific petroleum system active in this region. A thick, organic-rich limestone and shale succession was deposited in an extensive pericratonic trough along the northwest margin of the Guyana shield during the Cretaceous Period. These underlying source rocks are separated from the primary reservoirs by an Eocene unconformity. Major fluid-migration mechanisms to fields within the MMVB consist of direct vertical migration where La Luna Formation subcrops the Eocene unconformity, lateral migration along the Eocene sandstone carrier and vertical migration through faults.

The Colorado, Mugrosa and La Paz formations that make up the Casabe field were deposited during the Paleogene Period. These are found at depths of 670 to 1,700 m [2,200 to 5,600 ft]. The reservoir sands in the field are classified in three main groups: A, B and C, which are subdivided into operational units (above). Sands are typically isolated by impermeable claystone seals and have grain sizes that vary from silty to sandy to pebbly.

Structurally the Casabe field is an 8-km [5-mi] long anticline with a three-way closure, well-defined eastern flank and a southern plunge. The northern plunge is found outside the area of the Casabe field in the Galán field. A high-angle NE-SW strike-slip fault closes the western side of the trap. Associated faults perpendicular to the main fault compartmentalize the field into eight blocks. Drilling is typically restricted to vertical or deviated wells within each block because of heavy faulting and compartmentalization.

Throughout the history of the field, development planners have avoided placing wells in the area close to the western fault. This is because reservoir models generated from sparse 2D seismic data, acquired first around 1940 and later in the 1970s and 1980s, failed to adequately identify the exact location of major faults including the Casabe field in the Galán field. A high-angle NE-SW strike-slip fault closes the western side of the trap. Associated faults perpendicular to the main fault compartmentalize the field into eight blocks. Drilling is typically restricted to vertical or deviated wells within each block because of heavy faulting and compartmentalization.

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main strike-slip fault. The lack of a more accurate structural model caused two main problems: Reservoir engineers underestimated OOIP and waterflood planners found it difficult to locate injector-producer pairs within the same reservoir and, to a lesser extent, within the same fault block. These uncertainties led the managers and experts of the 2004 Casaba alliance to build a multicomponent redevelopment plan.

Ecopetrol SA has long-standing experience in and knowledge of the field and the measures undertaken to keep it producing decade after decade. Schlumberger provides new oilfield technologies to the operator, including seismic surveying, downhole measurements, data analysis and specialized drilling, as well as domain expertise to decipher the challenges faced. With these capabilities the alliance was confident it could obtain results within a year.

The key goals of the redevelopment plan were to increase reserves, manage the waterflood programs more efficiently and address drilling-related problems such as reactive lithology, tripping problems, low ROP, borehole collapse and washouts, and completion challenges such as poor cementing and casing collapse. Tackling each of these elements involved close collaboration between the operator’s professionals and technical experts from the service company. The first stage of the project involved a thorough field-wide analysis based on existing data and the gathering of new data using the latest technologies, such as 3D seismic surveys and 3D inversion.

Undeveloped Areas and Attic Oil
Forty years ago it was common to create structural maps by identifying formation tops from well data. With hundreds of evenly distributed wells this task was quite straightforward over most of the Casabe concession. However, a large undeveloped area near the main NE-SW strike-slip fault encompassed over 20 km² [7.7 mi²]. Smaller undeveloped locations also existed.

A lack of well log data in these undeveloped areas meant that formation tops were not available to create structural maps for several key areas of operator interest. As a result, significant potential oil reserves were possibly being overlooked. To improve structural understanding and help increase reserves, Ecopetrol SA commissioned a high-resolution 3D seismic survey.

Geophysicists designed the survey to encompass both the Casabe and Peñas Blancas fields and also the area in between. WesternGeco performed the survey during the first half of 2007, acquiring more than 100 km² [38 mi²] of high-resolution 3D seismic data; data interpretation followed later that year. The new data enabled creation of a more precise and reliable structural model than one obtained from formation tops, with the added advantage of covering almost the entire Casabe concession (below).

In addition to accurately defining the structure of the subsurface, seismic data can also give reservoir engineers early indications of oil-bearing zones. In some cases oil-rich formations appear as seismic amplitude anomalies, called bright spots. However, these bright spots do not guarantee the presence of oil, and many operators have hit dry holes when drilling on the basis of amplitude data alone.

^ Casabe structural maps and model. Structural maps of the field were generated using formation tops from well logs (Formation Tops). But operators avoided drilling along the main strike-slip fault for fear of exiting the trap; hence, tops were unavailable (Structural Sketch, red-shaded area). This poorly defined and undeveloped area represented significant potential reserves. High-resolution 3D seismic data were used to create a refined set of structural maps (Seismic Data). These maps indicate additional faults in the field and adjusted positions of existing faults compared to the formation top maps. Calibration of the new maps from existing well logs further improved their accuracy. Geophysicists input the maps into Petrel software to form a 3D structural model of the subsurface (inset, right). (Figure adapted from Peralta-Vargas et al, reference 1.)
fying them is difficult if the exact location of
there can be oil in these higher zones, but identi-
iers were able to confirm both undeveloped and
maps as an additional verification tool, interpret-
8 Oilfield Review
data during the common midpoint gathering
amplitude variation with offset (AVO) corrects
interpretation can distinguish them. Analysis of
amplitude anomalies, but careful processing and
process (above).
Uncorrected common
Midpoint gather
Minimizing uncertainty of amplitude anomalies. Bright spots (top left) are high-amplitude features on seismic data. These features can indicate oil accumulations, although they are no guarantee. One technique for understanding bright spots begins with modeling the amplitudes of reflections from reservoirs containing various fluids (top right). The amplitude at the top of a sand reservoir filled with water decreases with offset. The amplitude at the top of a similar reservoir containing gas can increase with offset. The results are compared with actual seismic traces containing reflections from a sand reservoir (bottom left) to more accurately characterize reservoir fluid. Combined with other information such as seismic inversion data, AVO-corrected amplitude maps (bottom right) can be a useful tool to confirm the presence of oil (light-blue areas). (Figure adapted from Gambaretto et al, reference 7.)

Several conditions can create misleading amplitude anomalies, but careful processing and interpretation can distinguish them. Analysis of amplitude variation with offset (AVO) corrects data during the common midpoint gathering process (above). Using AVO-corrected amplitude maps as an additional verification tool, interpreters were able to confirm both undeveloped and attic oil accumulations.
Attic oil is an old concept. Operators know there can be oil in these higher zones, but identifying them is difficult if the exact location of faults is uncertain. Interpretation of the Casabe 3D seismic data clarified field corridors where wells had not been planned because of the uncertainty surrounding the main fault position. Wells have since been drilled along these corridors with successful results (next page, top).

A detailed geologic model provided a better understanding of the subsurface conditions, which helped during the waterflood planning and drilling processes. Prestack inversion of the 3D survey data yielded fieldwide estimates of rock properties. Geophysicists calibrated these estimates using data acquired by a suite of new-generation logging tools (see “New Wells and Results,” page 15) in approximately 150 wells. Using these calibrated rock types, geologists created a facies distribution map, which they combined with the structural model to create a model of reservoir architecture.

The architectural model highlighted more than 15 reservoirs with an average thickness of 3 m [10 ft] each. Reservoir engineers analyzed 10 of these reservoirs and discovered an additional 5 million bbl [800,000 m³] of estimated reserves. The geologic model was then used during the waterflood redevelopment process to help improve both areal and vertical sweep efficiency.

Effective Waterflooding
When the Casabe field was switched from natural drive to waterflood in the late 1970s, the operator chose to use a typical five-spot pattern with approximately 500 injector and producer pairs. To sweep the upper and lower sections of Sands A and B, up to four wells were drilled per injection location (next page, bottom). During the initial waterflood period, injection rates peaked in 1986 and 1991. These dates correspond to the first and second year after the beginning of the two waterflood programs for the northern and southern areas of the Casabe field.

Two to three years after each peak there was a noticeable drop in the water-injection rates. This was due mainly to the restrictions imposed on the rates to avoid casing collapse. However, the reduction in water-injection rates was also influenced by several other factors. These issues were identified in the alliance’s redevelopment plan and became a large part of the requirements for reworking the Casabe waterflood programs.

The operator had recorded early water breakthrough in the field’s producers during both waterflood programs. This was a result of injection water channeling inside high-permeability layers. Also, a poor mobility ratio was present throughout the field: Viscous oils (14.8 to 23.3 API gravity in the upper sands and 15.4 to 24.8 API gravity in the lower sands) were pushed aside by the more freely flowing water, and once breakthrough occurred the water influx increased. These conditions caused a poor vertical sweep efficiency average of only 20%.

> Attic well. Experts had long predicted a field corridor along the main strike-slip fault, but the lack of accurate seismic data made the risk of drilling these zones too high. Interpretation of the 2007 3D seismic survey enabled geophysicists to identify undeveloped drilling locations (red ellipses, left) close to the major fault. A new offset well, approved for Block VIII, was very close to the main strike-slip fault (dashed-green box, left). 3D seismic data and structural maps (middle) visualized using Petrel software helped well planners position the well. The trajectory avoided major faults and targeted a large undeveloped zone and two attic oil zones in the B and C sands (right). The wells constructed during the first and second drilling campaigns were vertical; in the third campaign, especially from late 2008 onward, most of the wells drilled were offset wells in target pay zones close to faults. (Figure adapted from Amaya et al, reference 11.)

> Casabe field injection and production scheme. Original field-development plans included as many as four wells per injection location to flood the multilayered sands (blue wells). Up to two wells were used to extract oil, but in some locations a single production well commingled fluids from Sands A and B, B and C, or A, B and C (green wells). The current string design for new injector-producer pairs, shown in a later figure, limits drilling to only one well per location. This change has reduced cost and also the incidence of proximity-induced well collapse. (Figure adapted from Peralta-Vargas et al, reference 1.)
Sand production and high-velocity jetting of sandy water through perforations significantly eroded casing walls and completion hardware in the producers. During a critical period of the waterflood, numerous wells collapsed and were abandoned or taken off line. To sustain production levels the operator chose to convert many injection wells to producers, but this drastically affected the waterflood patterns (left).

Choking back injection rates to mitigate well collapses was another factor that caused an uneven water-flow pattern. Areal sweep was poor, resulting in many areas of bypassed oil. The field's redevelopment team wanted to reestablish patterns to improve areal sweep efficiency. Therefore, a large part of the third drilling campaign involved planning and placement of new injectors and producers. These were located to recreate an evenly spread network of wells throughout the field. However, areal sweep is largely dependent on obtaining good vertical sweep efficiency. Waterflood specialists first needed to design better injection control systems that would improve vertical sweep and also provide a mechanism to reduce the damaging effects of water channeling on the production strings.

Vertical sweep efficiency is determined by the effectiveness of water, flowing from injector wells, at pushing oil through permeable layers to formation-connected oil producers. The original multiwell injector design had no injection profile control, so water flowed preferentially through the most permeable formations. This water-channeling effect is aggravated by several mechanisms: Shallower sands can be unintentionally fractured during waterflooding, significantly increasing permeability. The injectivity index of deeper layers may suffer if low-quality injected water causes plugging of perforations or deposits of scale in the production casing. Also, injected water bypasses viscous oil, present in large amounts in the Casabe field, and breakthrough takes place in producers. As a consequence, water flows through the layer of highest permeability and may not be injected at all in others, especially in the deeper sands with skin damage. This has been a distinctive feature during Casabe production operations.

To optimize flooding, water management specialists recommended selective injection strings using waterflood-flow regulators (next page). These designs would enable the operator to choke back injection rates in specific layers irrespective of the reservoir pressure, permeability, skin damage or any other factors that would normally affect flow. Each layer is packed off to prevent any

\[ \text{Comparison of 1986 and 2003 waterflood patterns. By 1986 the operator had established an evenly distributed network of five-spot injection patterns throughout the Casabe field (top). Well collapses had occurred in nearly 70% of the wells in Block VI, and a significant number of collapses had been recorded in all other blocks in the field. In 2003 (bottom) many of the collapsed wells remained abandoned or inactive and numerous injectors had been converted to producers. Experts suggested a new drilling campaign to reestablish fieldwide five-spot patterns. (Figure adapted from Elphick et al, reference 12.)} \]
fluids within that zone of the wellbore from invading another zone. An injection nozzle is located within this section and is controlled from the surface. The new selective-string designs have improved the vertical sweep efficiency by enabling the operator to maintain higher injection rates into layers less affected by waterflood-induced problems. Conversely, the new designs have mitigated issues related to channeling by allowing a reduction of rates in problematic layers.

Use of a single well designed with packed-off flow control was also much more cost-effective than the previous design of up to four wells per injection location. Up to 16 water-flow regulators have now been installed in injectors in the Casabe field. This solution also addressed the possibility that drilling several injectors in close proximity to one another was one of the likely causes of casing collapse.

**Overcoming Drilling Difficulties**

From first production in 1945 to the end of 2006, approximately 45% of the production wells in the Casabe field had at some point collapsed, with different levels of severity. As a result, wells were abandoned, left inactive or reactivated only after costly workovers. The abandoned and inactive wells represented millions of dollars in capital investment in the field and in lost revenue due to lower production rates. The majority of casing collapses had occurred in Block VI, which also has the largest proven reserves. It was therefore the focus of a casing-collapse study.\(^{13}\)

In the first stage of the Block VI study, production engineers gathered casing-collapse statistics. In 2006 this block contained 310 wells. A total of 214 showed some degree of collapse. Slightly more producers than injectors collapsed, but the difference was minor and indicated no trend. Of the total number of wells with recorded collapse events, 67 were abandoned and 80 were inactive, a factor that the operator knew would severely impact injection and production rates. The remaining wells had been reactivated after costly workovers. The engineers then looked for a correlation between the 214 collapses and when these wells were drilled to identify any drilling practices that were incompatible with the Casabe field.

Three main drilling campaigns coincided with the primary-recovery, or natural-drive, period (1941 to 1975); the secondary-recovery, or water-flood, period (1975 to 2003); and finally the secondary-recovery, or water-flood, period (1941 to 1975); the secondary-recovery, or water-flood, period (1975 to 2003); and finally the primary-recovery, or natural-drive, period (1941 to 1975). Of the wells drilled in the first campaign, 78% had casing-collapse events during operation. In the second campaign this figure was slightly less, at 68%. This period, however, corresponded to the waterflood programs; hence many more wells had been drilled. During the study period there were no recorded collapse events in Block VI for wells constructed in the third drilling campaign. This change was considered to be a result of improved drilling practices, which are discussed later in this section.

To determine a link between casing collapse and subsurface conditions, the investigators considered the updated stratigraphic and structural models built from the new 3D seismic data. Petrel seismic-to-simulation software enabled the production engineers to display both models in the same 3D window. Using modeling tools, they could then tag and clearly see the wellbore depths and the locations along the Casabe structure where collapses had been recorded.

The engineers discovered that casing collapse had occurred in all stratigraphic levels. However, collapse distribution did highlight a strong correlation to the overburden and to the water-flooded formations. The analysis of well location
within the field and well-collapse distribution revealed an evenly spread number of events, which indicated no areal localization (above).

The next stage of the study was a probabilistic analysis to evaluate the frequency of events based on two variables: number of casing-collapse events and operational year. Production engineers created probabilistic distributions by plotting both variables for each drilling campaign using the Monte Carlo simulation component of the Crystal Ball software. The results showed the highest number of events (about 30) for the wells drilled during the first drilling campaign occurred in 1985, coinciding with the beginning of the first major waterflood program.

Interventions were more frequently performed on wells drilled during the second drilling campaign, which meant that the timing of each collapse event was recorded with greater certainty than for wells drilled during the first drilling period. Therefore, the probabilistic analysis was even more reliable. It revealed that casing collapse occurred primarily during the first few years of the waterflood project and peaked during 1988. Investigators identified a critical period of

Areal and stratigraphic localization of casing collapse in Block VI. Statistical analysis of casing-collapse events within each stratigraphic section (left) showed collapses in every formation. However, event frequency in the overburden and in the waterflooded zones (mainly Sands A1, A2, B1 and B2) was several times higher than in other zones, indicating these intervals are more likely to cause collapse. Using Petrel modeling tools, engineers included Block VI casing collapses in the structural model. A structural map of one reservoir (right) indicates collapses occurred throughout the block and not in any specific area. (Figure adapted from Olarte et al, reference 13.)

Critical fluid levels for production casing and liners of the first drilling campaign. Testing using TDAS software determined the critical load condition for fluid evacuation in Block VI wells from the first drilling campaign. Casing (green box, left) and liners (red box, right) were tested first to obtain critical fluid-evacuation levels based on original design specifications and again after calculations of 10%, 20% and 30% wall loss. All wells for the simulation were at depths of 5,000 ft; depending on the amount of wall loss, a collapse was probable as borehole fluid levels fell. For example, 7-in., 20-lbm/ft API Grade H40 casing strings could collapse even at their installed condition when the fluid was evacuated past 3,200 ft. Wells that passed the first simulated test failed when wall loss was increased. This result indicated that corrosion or general wear-and-tear (causing wall loss) would have weakened casing or liners to the limit of collapse when the fluid level dropped to values that had been recorded in the field. (Figure adapted from Olarte et al, reference 13.)
time during which collapse frequency was high. This period coincided with the most intense rates of water injection (right).

The next stage of the study evaluated the mechanical integrity of the wells in the Casabe field. This evaluation found that for the producers in Block VI collapses occurred only in the production liners and casing. To uncover the root causes for all these collapses, every event was evaluated using TDAS tubular design and analysis software. The application enables analysis of the mechanical performance of a casing in two scenarios. First, an initial installed state considers the original casing-design specification and downhole conditions such as temperature and pressure. The next scenario includes subsequent operationally induced events such as injection and production that are interpreted as forces on the casing, called case loads. Engineers analyzed case loads for compressional, tensional and triaxial stresses.

To begin, engineers needed to define the installed condition, characterized by temperature, pressure and casing strength, for casing designs in Block VI. Then they could apply case loads to determine when a casing would fail. Pressure and temperature profiles for each well were calculated using logs from the Casabe field. Because corrosion also significantly reduces casing strength, the USI tool, which measures ultrasonic acoustic impedance, was used to determine the loss of wall thickness attributed to corrosion (see “Scanning for Downhole Corrosion,” page 42). According to the USI data, wells exhibited wall losses between 10% and 35%. Engineers defined four corrosion profiles at 0%, 10%, 20% and 30% wall loss. These four profiles were combined with pressure and temperature data to generate the installed conditions that engineers needed to begin simulation of operational loads.

Engineers performed hundreds of simulations using the TDAS software. The first analysis considered fluid evacuation, a decrease of fluid level in the borehole, which can be a critical load condition for casing collapse. Fluid levels in the wellbore may become low during the productive life of a field for several reasons. These include low productivity, increased extraction during production, sand fill, decreased water injection, and swabbing and stimulation operations, all of which had taken place in the Casabe field. When fluid level drops, the internal pressure no longer balances the external pressure and the casing must sustain this force. The critical load condition for casing collapse occurs when the differential pressure is higher than the casing can withstand.

After analysis of the casing design chosen for wells during the first drilling campaign, engineers discovered that the specifications had resulted in casing strings that were not robust enough to withstand fluid evacuation combined with the wall losses observed in Block VI (previous page, bottom).

The final mechanical analysis was related to the main operational events leading to casing collapse. The reservoir pressure profile within the formation during water injection could impact the casing in both producers and injectors. The calculated increase in load from waterflooding was applied to casing that had passed critical load conditions in the earlier simulations; the new test would determine if the additional pressure could cause them to collapse. This analysis indicated that waterflooding increased the likelihood of casing collapse.

Once all critical limits and conditions for the Casabe field had been obtained, production engineers ran simulations for several casing strings with different specifications to find an optimal design for future wells. The TDAS simulations enabled them to specify an ideal model that would give an estimated service life of 20 years. This model has been applied to all new wells drilled throughout the field, with a successful reduction in the frequency of recorded casing collapse to less than 2% of wells from 2006 to 2009. This is a dramatic improvement compared with events during the previous 60 years, in which 69% of wells in Block VI experienced collapses.

> History of casing-collapse frequency. The frequency of collapse events by year was plotted for the first and second drilling campaigns (top). In 1985 the highest frequency (28) of reported events was recorded for wells from the first drilling campaign. For wells from the second drilling campaign, which occurred during the waterflood period, the peak frequency (20) of reported collapses occurred in 1988. Both values correspond to the beginning of the waterflood programs in the northern and southern areas of the Casabe field. A critical 10-year period from 1985 to 1995 was identified as coinciding with the highest rates of production and water injection (bottom). (Figure adapted from Olarte et al, reference 13.)
Together with the results from the other major milestones of the field-redevelopment plan, the new casing designs enabled the alliance to begin a new drilling campaign. The third campaign began in 2004, and by 2007 a total of 37 wells had been drilled. The alliance wanted to drill as efficiently as possible to improve production, but problems were encountered during drilling. These included stuck pipe caused by differential sticking in depleted reservoirs, problematic wiper trips resulting from highly reactive shales and well control issues introduced by water influx from the waterflooding.

To address the hole-stability and stuck-pipe problems, the redevelopment team began by improving the drilling fluid design. Drillers had been using the KLA-GARD mud additive to prevent clay hydration, but it had little to no success at inhibiting reaction in the troublesome Casabe shales. Consequently, Schlumberger and M-I SWACO initiated an investigation to find a more effective shale inhibitor.

Laboratory analysis of 13 different fluid additives was conducted to compare their reaction-inhibiting capabilities on Casabe lithology. Experts deduced, from core and cuttings samples, that the clays and shales were highly reactive to water; therefore, the optimal drilling fluid must prevent water from contaminating them. The KLA-STOP mud system was compatible with the Casabe shales and had the best properties for inhibiting these reactions: Its fluid composition includes a quaternary amine that prevents water from penetrating target formations by depositing a synthetic coating along the borehole wall.

When the new system was put to use, however, it did not meet expectations, and the reactive lithology continued to affect drilling time. Design iterations continued until 2008; at this point experts had increased KLA-STOP concentration to 2% and added 3% to 4% potassium chloride [KCl]. However, hole problems persisted and experts concluded that another contaminant could be affecting the mud system. Using core samples from a wide range of wells, analysts measured pore throat sizes and laboratory specialists performed mineralogical analysis to determine the causes.


^ New versus old drilling design. Original drilling designs included a traditional polycrystalline diamond compact bit (top), but swelling clays caused problems during tripping. Engineers designed a reaming-while-drilling (RWD) BHA that incorporated a smaller pilot bit and a reamer (tan box). RWD enabled oversized boreholes, which helped compensate for swelling and achieve target diameters for casing. Further optimizations included larger cutters and a backup set of cutters to improve ROP (blue box). A change in the number of nozzles and in the nozzle diameter dramatically reduced the washouts that were causing cementing problems (bottom). The decision to redesign the bit was made partly to cope with clay reactions. A new mud system has successfully inhibited the clay, and engineers are now reconsidering a concentric bit to improve drilling efficiency.
The tests indicated that concentrations of smectite, previously identified as the swelling clay, decreased with depth. But the mineralogical analysis also revealed the presence of illite and kaolinite, which were not included as part of the original mud system investigation. These dispersive clays break off into the mud upon contact with water, causing drilling problems such as bit balling, and also increase the viscosity of the mud, making mud-weight curves less accurate. A more complete understanding of downhole conditions enabled engineers to design a new mud system with improved KLA-GARD B and IDCAP D clay inhibitors. KCl was completely removed from the fluid, helping to reduce environmental impact and cleanup.

The mineralogy study showed why drilling in the waterflooded zones was obviously problematic. Existing methods to avoid water influx involved shutting in several injection wells up to several weeks before drilling to reduce pressure. In one extreme case 40 injectors were taken off line to drill just 2 wells, which ultimately reduced production rates.

Experts looked into the different ways they could reduce water influx while also limiting any effect on the waterflood programs. Instead of shutting in injectors they could increase production in layers that were drilling targets, even if this meant producing large volumes of water. In addition, connected producers that were currently shut-in could be reactivated, and if they had no pump, there was a possibility that enough pressure had built up for them to flow naturally. Only after these steps were taken and deemed insufficient would the alliance consider shutting in injectors.

Another part of the investigation involved reducing injector shut-in time. To avoid water influx, injectors were taken off line 15 days before drilling commenced. However, it was found that to avoid water delivery from the injector to the drilling location, injectors could be shut in just before the drill bit penetrated the connected zone. Also, with the production-based pressure-reducing measures, injector shut-in time was reduced from seven days to just two, depending on the level of production.

The continuing difficulties with stuck pipe and tripping problems led the alliance to seek other options. After initial analysis of the drilling-related issues, engineers selected a bicenter bit and reaming-while-drilling technologies. A pilot well, CB-1054, was drilled with the new hardware, and tripping times were notably reduced. Engineers used the results from the pilot well to optimize the bit and BHA designs. Experts ran unconfined compressive-strength tests on core samples taken at numerous depths from several wells in the Casabe field, which returned values from 585 to 845 psi [4.0 to 5.8 MPa]. The results from this analysis allowed the engineers to optimize the number of primary cutters and to introduce backup cutters on the drill bit (previous page).

Since the introduction of new technologies and updated practices, the drilling problems faced in the Casabe field have been resolved. Better quality holes have increased the effectiveness of cementing jobs. Tripping times have been reduced by more than 22%. Higher ROPs have been achieved with updated cutter configurations and a PowerPak XP extended power steeringable hydraulic motor (below). The majority of new wells in the Casabe field have directional S-type boreholes deeper than 5,200 ft [1.6 km] to avoid collisions with existing and new wells or to reach reserves in fault zones.

### New Wells and Results

The sands in the Casabe field have been extensively developed, but it is common in mature fields to find oil in unexpected places. For example, some zones in the Casabe field were overlooked because the presence of low-resistivity pay is difficult to detect using traditional resistivity tools; alternative tools are discussed later in this section. Other zones in the field were inaccessible because a lack of structural data made the drilling risk too high. Using structural information acquired by the alliance, the operator is now developing the highest section of the Casabe field’s anticline structure in the B sands within Block V.

Only one well in this block, the wildcat Casabe-01 located downdip in the flank of the anticline, exhibited oil shows in the thin sands within the attic zones, but these zones had never been tested. A new well, located updip of the wildcard well, was proposed to develop the A sands. After reviewing the new 3D seismic data and the projected length of the oil leg, geoscientists revised the total depth for this newly proposed well and suggested deepening it to reach the B sands.

![Drilling results. The new RWD and bicenter bit drilling technologies have had a considerable impact, improving hole quality, reducing total trip times, increasing ROP, minimizing stuck-pipe risk, reducing backreaming operations, and improving the quality of primary cementing jobs. Average drilling-job times have been cut from 15.3 days to 6.8 days.](image_url)
Data from this new well included chromatography performed on mud from the B sands, which revealed well-defined oil shows, and log interpretation confirmed the oil presence. This oil is due to a lack of drainage from the updip wells. New data acquired with the PressureXpress LWD tool indicated the compartment was at original pressure. Interpretation of data from the CMR-Plus combinable magnetic resonance logs confirmed movable oil (below). The interval was completed and the well produced 211 bbl/d [34 m³/d] of oil with no water cut. Historically,
experts did not look for oil downdip in the Casabe field because the deeper formation had been flagged as a water zone.

The field provided another surprise during a routine replacement of a retired well. A producing well had been mechanically damaged as a result of sand production induced by the waterflood. A replacement was planned using improved design factors garnered from the casing-collapse investigation. The operator drilled the well into the C sands for coring purposes. Before drilling, this zone was considered to be water prone, but during drilling, mud log interpretation suggested there might be oil in these deeper sands. Log interpretation was inconclusive because of the low resistivity, a new approach was required to identify movable oil (above).

Interpretation of CMR-Plus data suggested movable oil corresponding to the oil shows in the mud logs. Based on these results, the operator decided to test the well, which produced 130 bbl/d [21 m$^3$/d] of oil with no water cut. After six months, cumulative production reached 11,000 bbl [1,750 m$^3$] with no water cut. These values represent additional reserves where none were expected.

The Casabe field redevelopment project is now in its sixth year, revitalizing the mature oil field. Figures gathered at the beginning of 2010 show the Casabe alliance has increased overall production rates by nearly 250% since 2004. This improvement is due in part to a fast-track study that quickly identified the root causes impacting the efficiency of the waterflood programs in the field and discovered additional oil reserves using newly acquired data.

The collaboration between Ecopetrol SA and Schlumberger has been notably successful and the partnership is currently scheduled to continue the Casabe story until 2014. Production wells are being added in the newly defined southern Casabe field, enabled by the 2007 3D seismic survey and improved logging methods. The new drilling practices and waterflood technologies are expected to achieve commercial production rates for many years to come.

—MJM

Log confirmation of low-resistivity pay. Well CSBE 1060 log interpretation indicated shaly sand zones with salinities exceeding 50,000 ppm NaCl. Identifying oil in the presence of high-salinity formation water may be difficult because resistivity measurements cannot be used to distinguish the two (red-shaded area in Resistivity track). Shaly sands have higher water content than sand alone, and an alternative to resistivity measurements is needed. The CMR-Plus tool, which measures relaxation time of hydrogen molecules to identify oil and water, uncovered the presence of oil (Free oil, red-shaded area). Based on these results the interval was tested and returned clean oil, confirming low-resistivity pay in the Casabe field.