Volver

MANAGED PRESSURE DRILLING TO OPTIMIZE COSTS FOR HORIZONTAL WELLS IN THE VACA MUERTA FORMATION

E.Bulant Ezequielbulant@halliburton.com, E.Caballero Ernesto.caballero@halliburton.com, Halliburton; Geobalance. L.Velasco, Luis.velasco@tecpetrol.com, Tecpetrol

Synopsis

Operational cost optimization is a common practice globally and is continuously improved, focusing on maximizing profits to allow continued development of various areas. Companies exploring and developing targets in the Vaca Muerta formation (shale oil and gas) in Neuquén, Argentina are not exempt from this practice.

Managed pressure drilling (MPD) applications have increased over the years, driven by the benefits obtained from drilling unconventional wells. Based on experience gained from projects by different companies, significant improvements were achieved to optimize rate of penetration (ROP) through pressure differential reduction, early kick detection, dynamic control, and managed pressure cementing (MPC).

A current well drilled in the Fortín de Piedra area (FP.1015(h)) used MPD techniques, and a positive outcome was achieved, minimizing potential nonproductive time (NPT) resulting from well control issues and reducing auxiliary cementing operational costs.

During drilling of the production section, pressure-while-drilling (PWD) data were received in real time and fed into proprietary software. When any variation was detected in bottomhole pressure (BHP), surface backpressure (SBP) was adjusted to control and circulate out of the well any input from the formation. This allowed continuous drilling by applying SBP without the need to kill the well conventionally, saving associated NPT and necessary components.

For the first time in Argentina, cementing of a production section was performed applying automated managed pressure cementing (AMPC). Because of the narrow operating window available in this section, an auxiliary cementing operation was considered. However, as a result of real-time modeling fed by pump rate and pressure data, automatically controlling the constant BHP provided minimal cementing losses and no influx. The most relevant outcome was eliminating the need for an auxiliary cement operation resulting from losses during primary cementing.

The technologies applied during this project helped mitigate potential additional costs resulting from well control issues and the need for an auxiliary cement operation, ensuring safe and efficient operations.

Introduction

MPD is defined as “an adaptive drilling process used to precisely control the annual pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process” (IADC 2017).

In the current economic climate of the energy industry, cost optimization represents an essential challenge for oil companies to overcome. One aspect that impacts costs substantially is the unexpected occurrence of operational events that were not considered in the original budget.

It is estimated that NPT accounts for between 15 and 20% of the time necessary to complete a drilling project. While some NPT events can result from equipment failures or operational mistakes, most are related to wellbore issues. Thus, with current industry conditions allowing for a minimal margin of error or delay, it is crucial to minimize operational issues that might jeopardize project completion.

MPD employs a collection of tools and techniques that can help mitigate the risks and costs associated with drilling wells having narrow downhole environmental limits by proactively managing the annular hydraulic pressure profile. The application of this methodology allows for faster corrective action to mitigate observed pressure variations. The ability to control annular pressures dynamically facilitates drilling of what might otherwise be economically unattainable prospects.

Project Description

The proposed well (TPT.NQ. FP-1015(h)) is located 17 m west from FP.x-1004(h) (Figure 1), while at drain vertical depth, both wells are separated 450 m from each other. The drain section navigates north (azimuth 0°) at 3103 m true vertical depth (TVD). It is important to note that this depth matches the first fracture depth on FP.x-1004.

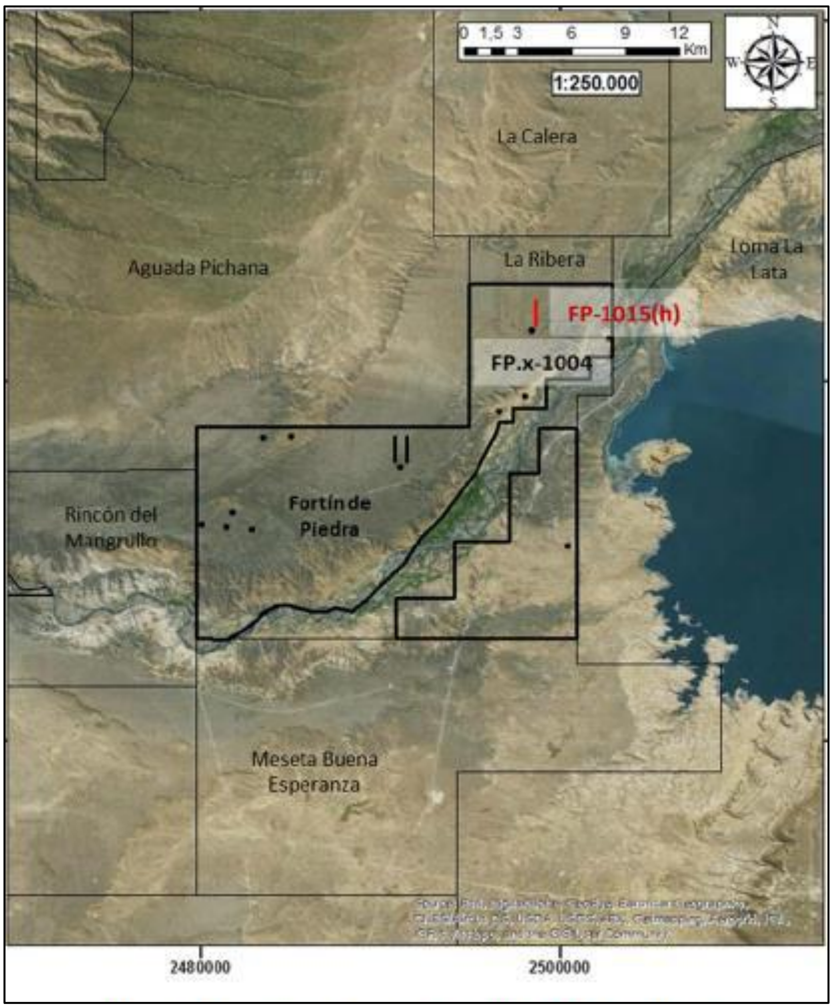

Figure 1—Fortín de Piedra area.

Objective

The objective was to drill the production section to 1960 m through the Quintuco formation, navigating horizontally at 3103 m TVD to the Vaca Muerta formation for a total of 1500 m to terminal depth (TD) at 4653 m measured depth (MD) (Figure 2).

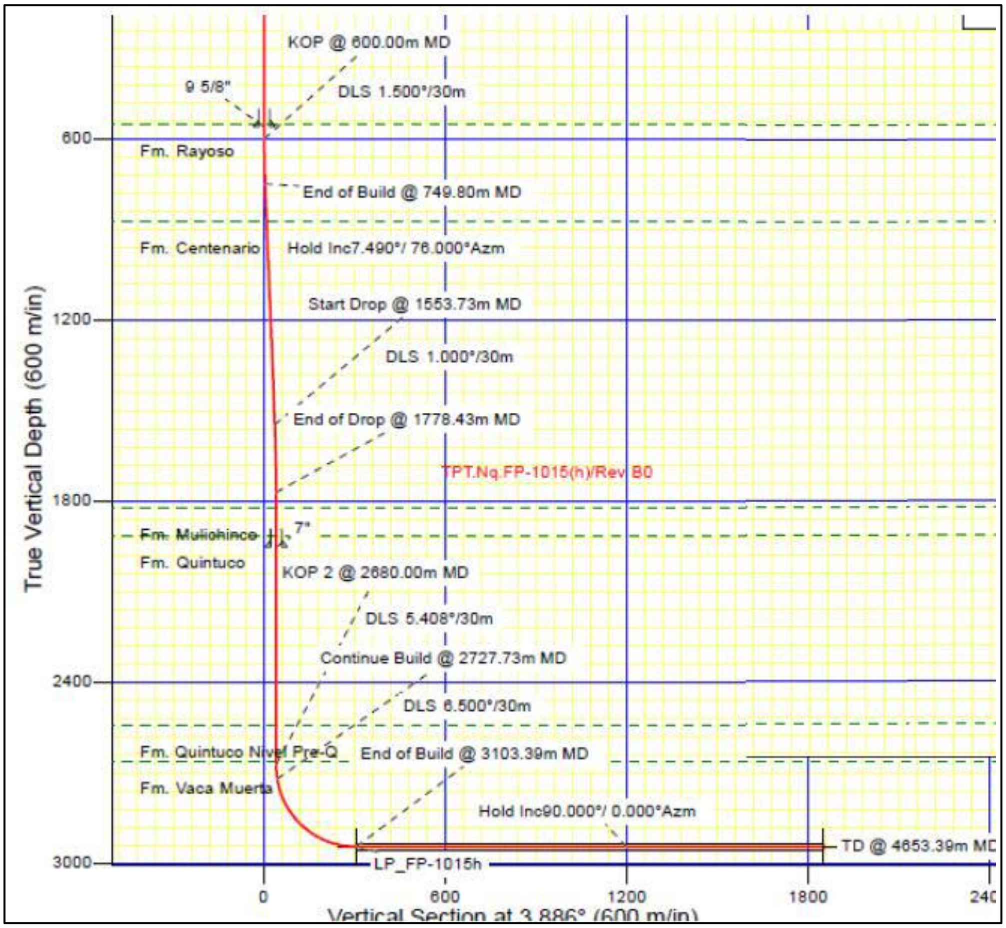

Figure 2—FP.1015(h) well trajectory.

Equipment and Tools

The following equipment (Figure 3) was used during operations**.**

Rotating Control Device (RCD)

The true bore RCD meets *API RP 16RCD* (2015) standards, with a high-pressure unit recirculating and cooling oil inside the bearing assembly. It also generates a pressure closed-loop system, which prevents wellbore pressures from invading the interior bearing, avoiding contamination of the hydraulic system.

MPD Autochoke Skid

The MPD autochoke Level 4 was controlled by a programmable logic controller (PLC) from three different modes: hydraulic, pressure mode, and position mode. The sensitivity of the chokes results in minimal pressure changes, allowing handling narrow operational windows and optimizing operational management of downhole pressure.

Atmospheric Mud Gas Separator
An ASME Stamp, Section VIII, Div. I, 125-psi maximum allowable working pressure (MAWP) mud gas separator was used at 200°F with a 10-inch gas line.

Coriolis Flow Meter
A Coriolis flow meter was used in MPD operations to measure mass flow, providing real-time information about the mud weight (MW), temperature, and flow rate of the circulating fluid.

Figure 3—MPD equipment.

Data Acquisition System (DAS)
The data acquisition control system used is a real-time hydraulics simulator for MPD and cementing. Because the real-time hydraulic model is designed based on proprietary mud service software engine, it can model fluid considering thermal effects, fluid compressibility, cuttings loading, pipe eccentricity, surge/swab, and rev/min in real time. It tracks multiple fluid densities and rheologies throughout the wellbore (Figure 4). These features provide accurate hydrostatic calculations.

Figure 4—Real-time hydraulics modeling.

The equipment was rigged up and connected as detailed by the valve numbering diagram (VND) (Figure 5).

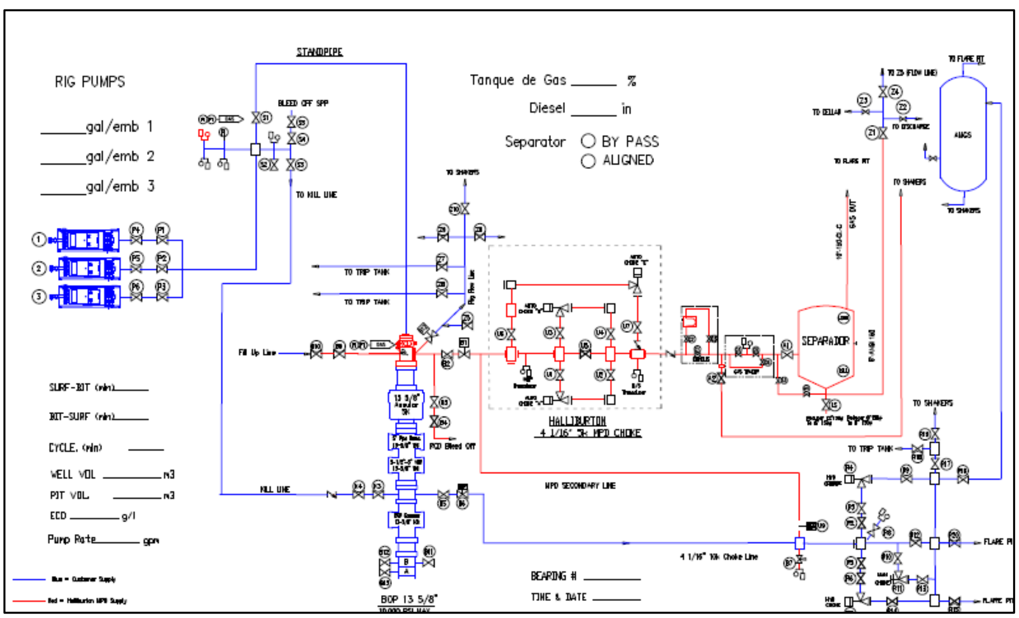

Figure 5—VND.

Dynamic Control and Circulation

Drilling of the 6 1/8-in. production section began at 1965 m MD with steady parameters: pump rate (Q) = 220 gal/min, upstream (U/S) choke pressure = 27 to 29 psi, MPD autochoke position 100% open, mud weight (MW) = 1600 g/L, and equivalent circulating density at bit depth (ECD_{bit}) = 1760 to 1700 g/L. When the bit nose reached 2756 m MD, already in the Vaca Muerta formation, a differential increase in the return rate was observed by the at Coriolis meter. Immediately, U/S pressure was increased to 430 psi and the RCD was isolated. After circulating the influx out of the well through a secondary line, the geological control crew observed a gas background increase to 140%. Parameters returned to steady conditions and drilling continued after 1 hour circulating.

At 2816 m MD, the Coriolis meter detected a sudden increase in the return rate followed by an increase in stand pipe pressure (SPP) of 1,000 psi. The RCD isolation procedure began, trapping 800 psi. As return flow continued increasing, additional U/S pressure was applied up to 2,750 psi, where the safety pressure limiter (SPL) activated, and the well was finally shut in with a high closure rate (HCR) valve. Conventional well control procedures were performed, increasing MW from 1600 g/L to 1730 g/L, which reduced SBP to a safe value. This allowed continued drilling using the MPD equipment after 9.5 hours of circulating with an ECD target of 1900 g/L maintained at 2816 m MD.

Consecutive dynamic controls were performed through the MPD autochoke, increasing the ECD target up to 2040 g/L at 3050 m MD and circulating every influx, which dynamically prevented safety incidents or well control lost time. The parameters used to drill the section to TD at 4659 m MD included U/S pressure = 474 to 490 psi, MW = 1800 g/L, ECD_{bit} = 2060 g/L, and ECD control depth (ECD_{cd}) = 2040 g/L.

Figure 6 shows the pressure managed during the control procedure.

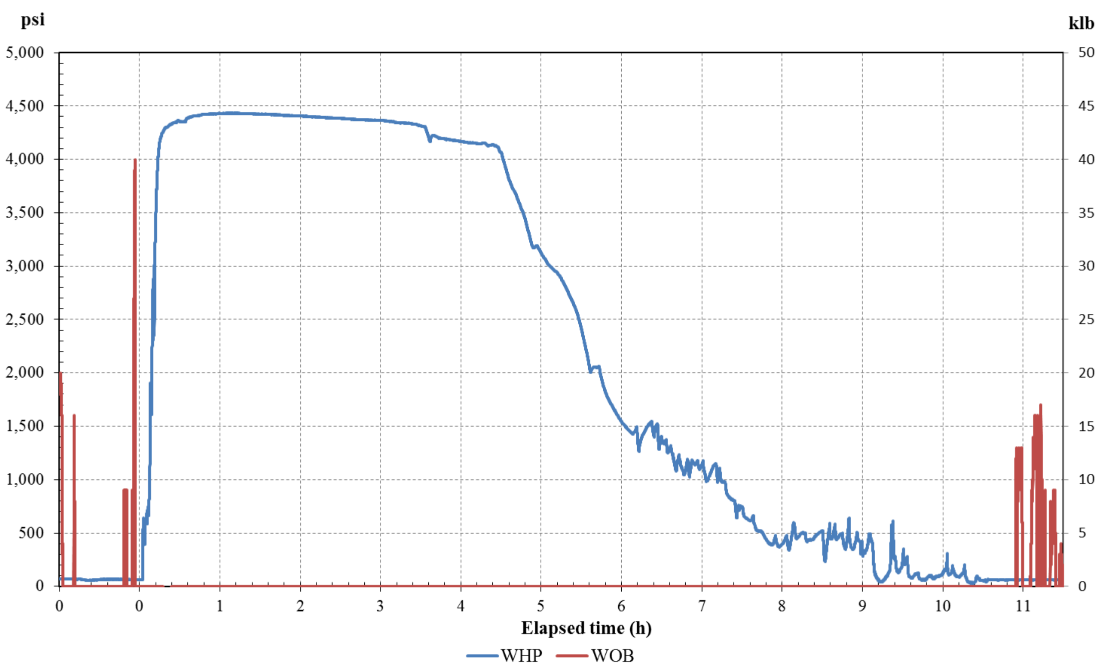

Figure 6—FP.1015(h) well control.

During drilling of the production section, a total of seven influx events was detected and controlled. As shown in Figure 7, the circulating time percentage increased by 5%; regarding the other two wells drilled in the same pad, no influxes were detected.

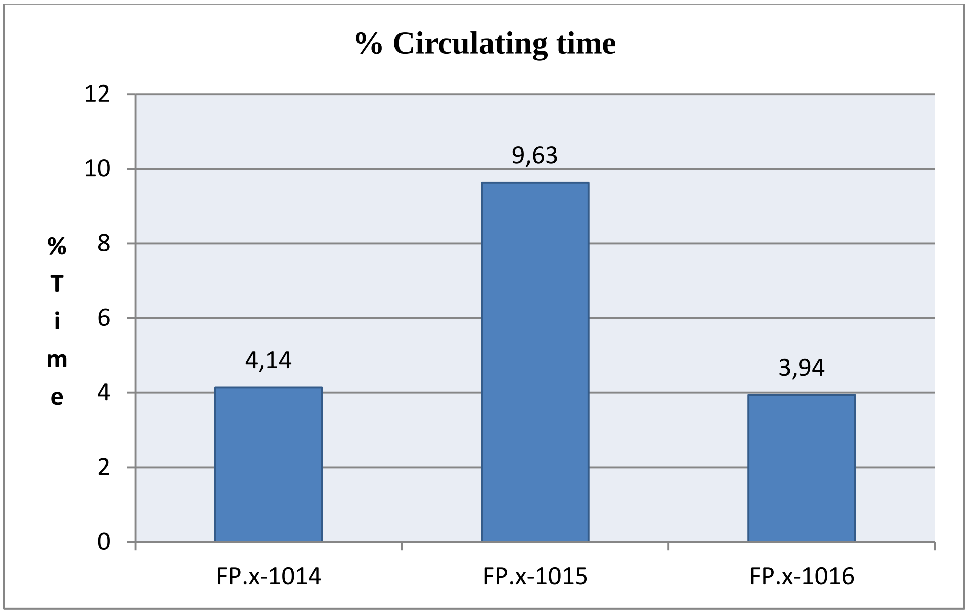

Figure 7—Circulating times comparison.

Figure 8 shows a clear increase in the pore pressure gradient at the influx depth during MPD drilling of the production section.

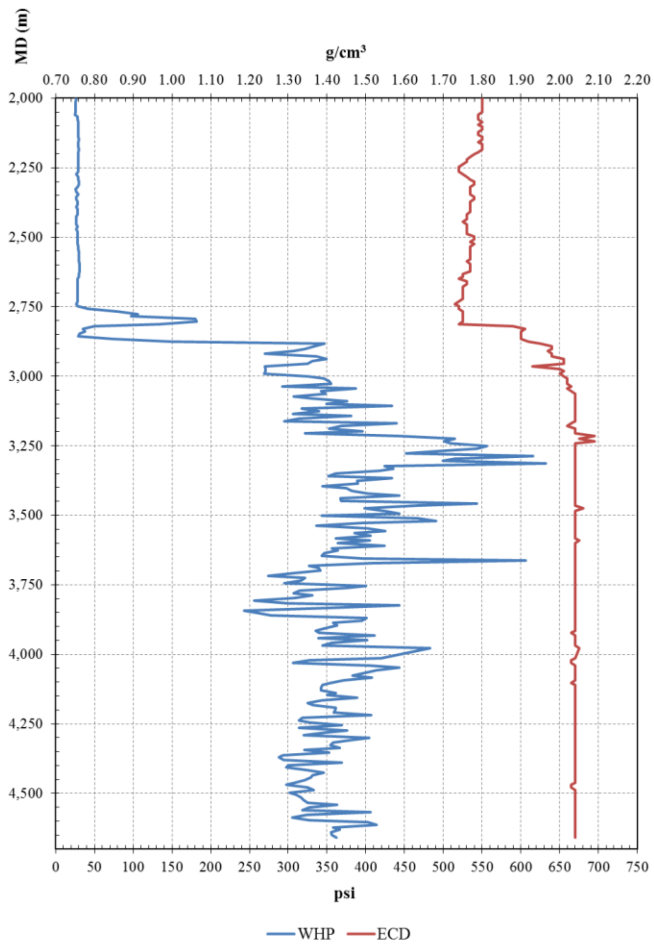

Figure 8—FP.1015(h) wellhead pressure (WHP) and ECD.

AMPC

Drilling of the production section was completed, circulating a mud weight of 1800 g/L at TD 4651m MD and ECD_{cd} = 2040 g/L. The drillpipe was stripped out of the hole, compensating for swabbing effects, circulating at surface, and maintaining a constant BHP using the MPD autochoke.

When the bit reached the landing point depth at 3163 m MD, kill mud (2040 g/L) was circulated, replacing drilling mud. A pressure buildup test was performed, with an increase of 900 psi observed. A sweep of kill mud was densified to 2400 g/L and pumped, with losses observed through a reduction of the return rate. Surface circulation was established from the kill line to the MPD autochoke, and stripping the drillstring to surface continued.

Casing running was performed through the MPD bearing assembly, with returns aligned to the trip tank controlling displacement.

When the 4 1.2-in. casing shoe reached TD, a casing hanger was set and the bearing assembly uninstalled. With the annular preventer in a closed position, the well was circulated with drilling mud at MW = 1800 g/L. Before cementing the production section, communication between the cementing van and DAS cabin was established, allowing automatic software input of cement pump pressure, pump rate, slurry density, and cumulative volume pumped. This communication allowed the autochoke to automatically compensate for any variations in the cementing pumps to maintain a constant BHP.

Pumping was performed as scheduled, with 110 bbl (17.49 m^3) of spacer at 1970 g/L and 154 bbl (24.5 m^3) of tail cement at 2090 g/L. Displacement was completed, successfully pumping 227 bbl (36 m^3) of water, controlling losses and preventing influxes by slightly adjusting WHP with the autochoke. Total losses were estimated at 6 bbl (0.95 m^3). When bumping the plug was confirmed by the cementing crew, pumps were shut off and the well closed, with the autochoke trapping 240 psi and a 605-psi increase observed (Figure 9).

Considering losses were minimal, no auxiliary cement operation was necessary, saving the associated time and costs. Taking in account the well behavior, the operating company planned an auxiliary cement operation as a bullheading treatment, with a pump schedule of 20 bbl (3.17 m^3) of 1080 g/L spacer, 67 bbl (10.63 m^3) of 1873 g/L tail cement, and displacing with 61.3 bbl (9.73 m^3) of fresh water.

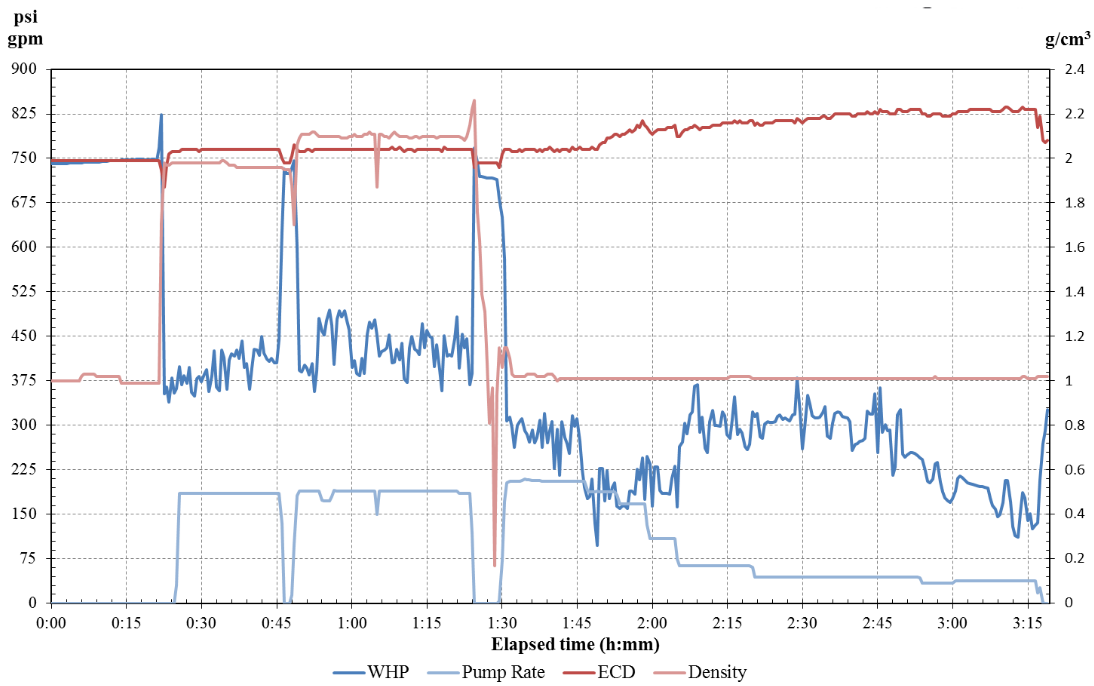

Figure 9—FP.1015(h) AMPC.

Conclusions

Using MPD and AMPC technologies, it was possible to reach TD and isolate the production section successfully and safely.

Taking into account the intensity of the influxes detected, the rig being lined up to the MPD equipment, and drilling in less than 12 hours with no need to kill the well, this operation represented a significant benefit to the operating company based on the time and mud components necessary to kill the well and the associated costs. Conversely, if drilling would have continued conventionally, circulating kill mud, the ECD generated would probably have induced formation losses and consequential influxes resulting from hydrostatic reduction.

The precise WHP adjustment provided by real-time hydraulic software controlling BHP within limits to control influxes and prevent losses allowed the successful and safe completion of the cementing operation. As a result of achieving planned depths with cement slurry, there was no need of an auxiliary bullheading cement operation, as planned based on the narrow operational window, which saved associated costs.

References

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About the Authors

Luis Velasco
Luis Velasco graduated from Industrial Engineering at Universidad Técnica Nacional (UTN), Regional San Rafael. Velasco has worked in the industry for 8 years with Tecpetrol as a drilling and workover engineer in El Tordillo (Comodoro Rivadavia) and Área Centro Oeste (Neuquén), Argentina.

Ezequiel Bulant
Ezequiel Bulant graduated from Industrial Engineering at Universidad Nacional del Centro de la Provincia de Buenos Aires (UNICEN). Bulant has worked in the industry for 6 years, initially with Tecpetrol as a drilling and workover engineer in El Tordillo (Comodoro Rivadavia), Área Centro Oeste (Neuquén) and Aguaragüe (Salta), Argentina and for the last 2 years with Halliburton Geobalance as a field engineer in Neuquén, Argentina.

Ernesto Caballero
Ernesto Caballero graduated from Electronics and Communications Engineering at Universidad Olmeca, Tabasco. Caballero has worked in the industry for more than 10 years with Halliburton Geobalance as a field engineer and supervisor in México, Saudi Arabia, and Argentina, both offshore and on land rigs.