Case Study: Value in Drilling Derived From Application-Specific Technology

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Technology is critical to drilling economics. Case studies from around the world now confirm that efficiencies from emerging drilling technologies result in lower overall costs, particularly in increasingly difficult and complex applications. Cost-effective drilling can mean a variance of as much as 50% for wells in the same geologic area with the same objectives, and prudent use of new and existing techniques and technologies adds to the decrease in drilling and completion costs.

Recent case studies bear this out. For three major industry players, the result of new technologies on drilling efficiencies has been noticeably positive. In Indonesia, Total experienced the safe and successful integration of three new technologies that enable surface-stack drilling with modified second- and third-generation semisubmersible rigs in ultradeepwater applications, resulting in reduced drilling costs. The introduction of steerable reaming-while-drilling (SRWD) bits in conjunction with multilateral (ML) Level 6 technology served to meet strategic cost initiatives and region-specific environmental requirements for Shell Nigeria. And the use of underbalanced drilling in fractured carbonates in northern Thailand by Amerada Hess not only overcame severe losses resulting from the use of conventional drilling techniques by attaining safe maintenance of pressure control, but also led to a potential major gas discovery.

Extending Value in Ultradeep Water

Older offshore drilling rigs that have been surpassed in size and capacity are enjoying a renaissance as a result of three new technologies—surface-stack blowout preventers (BOPs), the environmental safeguard (ESG) subsea shutoff device, and expandable casing. The first implementation of the ESG device using a BOP was performed by Total in East Kalimantan, Indonesia. Total plans to use this technology combination in other areas.

If conventional casing had been used on that exploration well in more than 6,000 ft of water, the planned total depth (TD) of 13,000 ft would have been impossible to attain and economically unfeasible without the use of a fourth- or fifth-generation semisubmersible or drillship. The combined technologies chosen for this project, coupled with the use of smaller rigs, are proving to be a reliable means of reducing drilling costs in ultradeep water. The project is described in detail in paper SPE 90830, "New Technologies Combine to Reduce Drilling Costs in Ultradeepwater Applications," by N. Touboul of Total, L. Womble and J. Kotrla of Cameron Drilling Systems, and N. Keith of Enventure Global Technology.

When the operator began drilling the well using a 13 3/8-in. casing riser, several challenges were encountered, including avoiding penetration of a shallow gas zone. The conventional casing had to be set higher than expected. Following a kick while drilling the next hole section, the 11 3/4-in. liner was set prematurely and cemented at 8,300 ft. If conventional technology had been used at this point, Total's drilling team would have been faced with several less than optimal alternatives.

One option involved drilling ahead and setting the 9 5/8-in. casing followed by the 7-in. casing string. But after setting the 7-in. casing string higher than was called for in the well plan, they would have had to drill deeper using smaller casing sizes. And the smaller hole would have to be drilled using slimhole tools, which would have presented the difficulty of a smaller internal diameter at TD and difficulty in logging and testing for formation evaluation.

A second option was to plug and abandon the well and continue exploration in a different area. A third alternative was to start with a larger conventional casing size to maintain adequate hole size in the target zone. However, larger conventional casing alternatives were limited by rig size.

Installation of an expandable liner **(Fig. 1)** enabled Total to get back on the original well plan and reach the target zone with adequate wellbore size. A 1,300-ft string of 9 5/8x11 3/4-in. solid expandable openhole liner was run to depth and set at 9,400 ft. Liner expansion was performed with hydraulic pressure up the liner. As each stand of drillpipe was removed from the hole, the pressure was bled off, and the stand was broken out and racked back in the derrick. The process of reconnecting the top drive and resuming upward expansion was repeated until the entire liner had been expanded and sealed. The liner was pressure tested to 1,000 psi for 30 minutes. The expansion cone was then pulled out of hole, and the float shoe was drilled out.

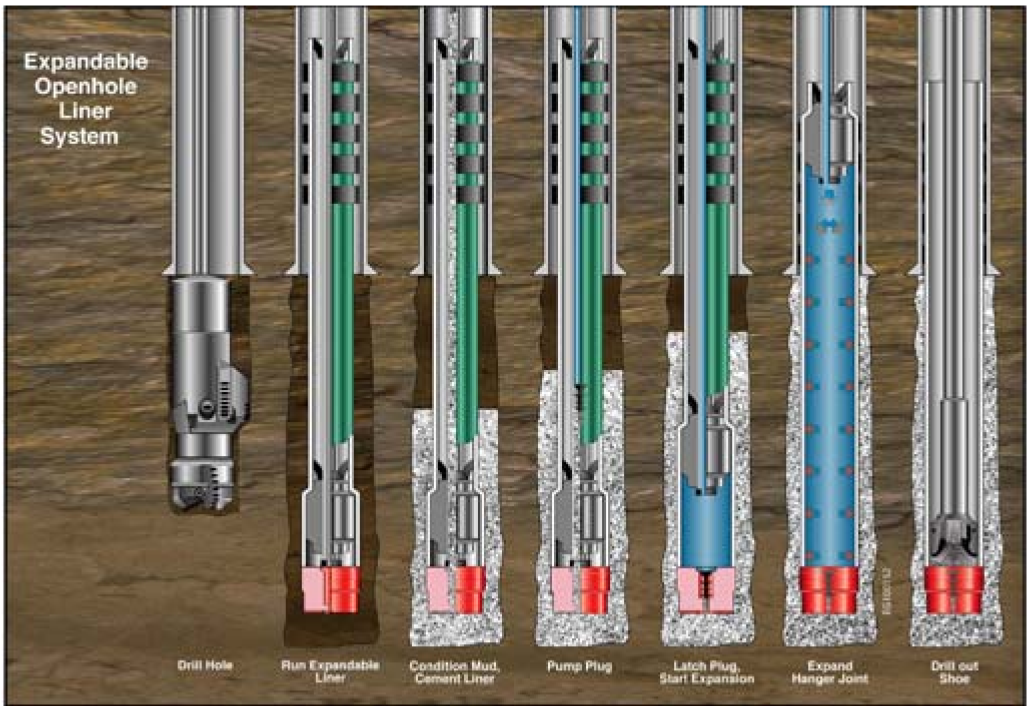

Fig. 1—Expandable-openhole-liner installation sequence used on a well in East Kalimantan, Indonesia.

The concept of a surface-BOP operation (the practice of using a floating drilling unit fitted with a BOP that is suspended above the waterline in the moonpool area) **(Fig. 2)** was initially deployed by Unocal Indonesia to drill inexpensive exploration wells in benign sea conditions in water depths between 100 and 500 ft, saving several days' time. This concept has been refined to move into deeper waters at a reduced cost per well.

Including an ESG device in the surface-BOP system **(Fig. 3)** offers a practical means of disconnection in an emergency. The ESG device has the capability to shear, seal, and disconnect from the seabed; in an unplanned disconnect, the release of mud from the riser into the sea is reduced by nearly 60%.

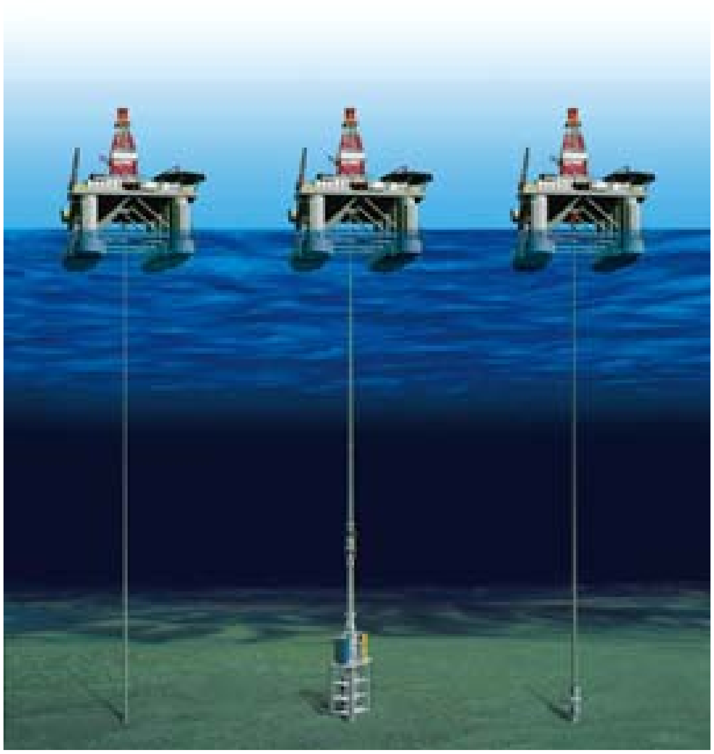

Fig. 2—From left to right: Traditional drilling with surface BOP; drilling with subsea BOP; and drilling with surface BOP and ESG.

"Since the ESG offers a means of disconnect, drilling with this combination of technology can now be considered a viable option for environmentally less benign areas such as the Gulf of Mexico, West Africa, South America, and the Mediterranean," says Neal Keith, project manager for Enventure Global Technology. "Even when starting with a relatively small casing size at the top of the well, the use of expandable casing enables an operator to reach TD with an optimum hole size."

The implications of using this technology combination extend beyond project cost; operators can now reach ultradeepwater targets using a wellbore size that was previously possible only by use of subsea-BOP technology. Also, surface-BOP drilling enables the use of smaller, cheaper drilling units (with reduced safety risks) because surface-BOP operations require fewer casing strings to be run and smaller hole sizes to be drilled more quickly. There are fewer heavy and complex pieces of equipment to be handled.

Savings realized from the use of second- and third-generation rigs are based on:

- Use of a high-pressure riser as opposed to a low-pressure riser used with fourth- and fifth-generation rigs.
- Lower mobilization costs.
- Significant reduction in day rates.
- Less fuel consumption.
- Reduced mud volume.
- Lower bit costs based on smaller hole size.
- Reduced casing cost as a result of eliminating a number of strings.

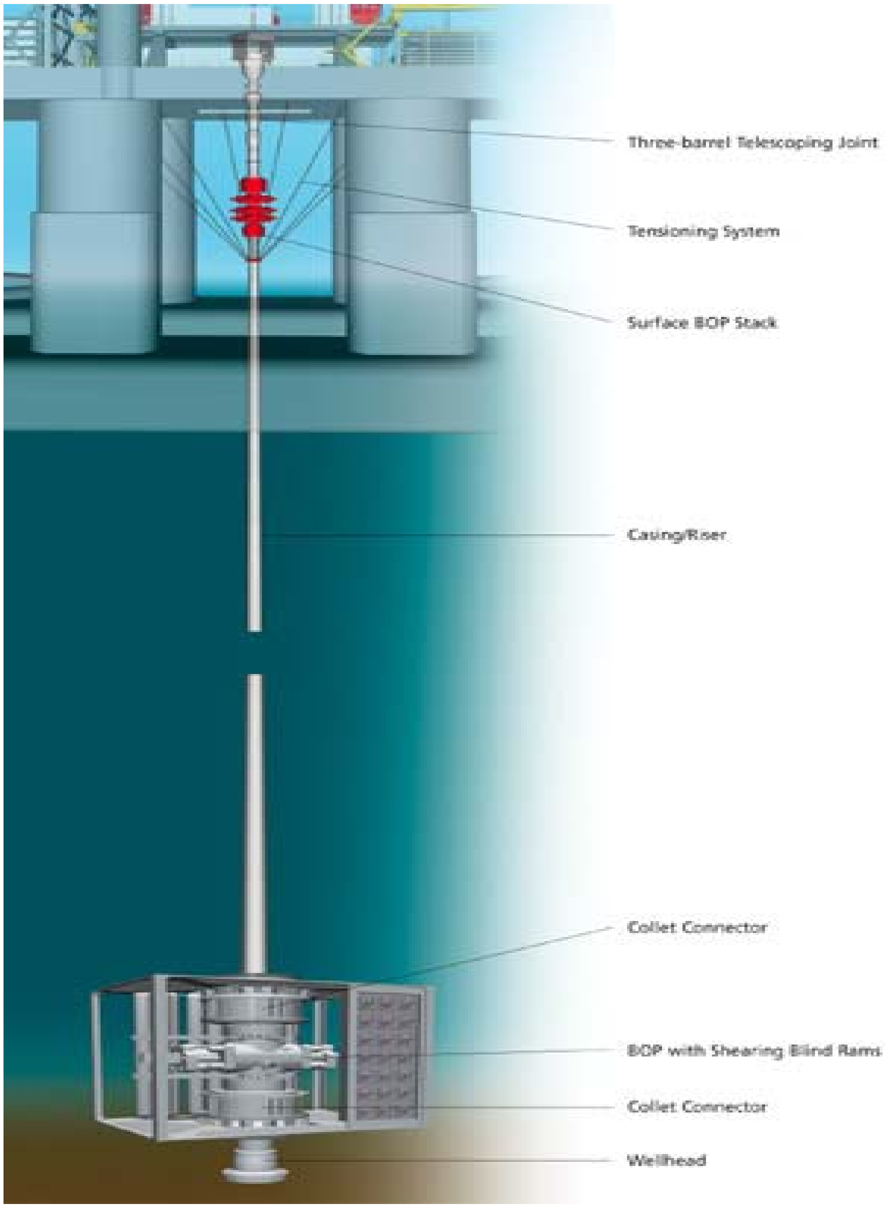

Fig. 3—A complete ESG system as used in Indonesia to ensure environmental protection in the event of an unplanned disconnect.

Reducing Well Costs Using Level 6 ML

As part of a strategic initiative to drive down development costs in Nigeria and increase string months available per rig, Shell selected and implemented Level 6 ML technology, applicable on land, in swamplands, and offshore. The distinctive geology of stacked reservoir sequences and region-specific legislative requirements in the Niger delta constrained available drilling and completion options. So Shell Nigeria assembled a multidisciplinary project implementation team and empowered the team to define an ML strategy based on low risk and low cost that could be used for land, swamp, and offshore operations, and to evaluate existing ML technologies technically and commercially. This project is highlighted in paper SPE 90423, "Level 6 Multilateral Experiences in the Niger Delta—A Review," by O. Erivwo and R. Ugboaja of Shell Petroleum

Development Co. Nigeria and E. Ikoh and A. Banks of Baker Nigeria Ltd.

By definition, ML well technology offers the means to reduce well costs in a multiple well target development or to increase the value of planned wells. ML classification is based on the Technical Advancement of Multilaterals (TAML) system Level 1 through 6, which refers to the nature and type of required junction hydraulic seal. Functional and technical considerations for the introduction of ML wells in the Niger delta included reservoir selection to be typical of regional horizontal-well plans, having legs targeting various reservoirs in line with the field-development plan. Because of government regulations requiring the accounting of hydrocarbons flowing from each reservoir and prohibiting commingled production, the ML wells needed to possess mechanical, hydraulic, and pressure integrity at the junction and the option to selectively re-enter both laterals.

The operator decided that Level 4, 5, and 6 ML options satisfied these criteria. At the time of this project, only four Level 6 ML completions had been installed worldwide, one of which was a field trial. Level 6 ML technology was selected for Phase One implementation because it was considered to have lower overall associated risk than Levels 4 and 5, even though the technology was new; because it satisfied functional specifications; and because it was the most applicable in the various environments. Other technologies were introduced by Shell on the Niger delta project, including SRWD bits used to drill and build angle from 0 to 90°, a wireline tractor tool for logging in cased hole to horizontal, and the application of slimhole systems (measurement-while-drilling tools, mud motors, and bits). Some cleanout and production tests were carried out with the rig off location, resulting in cost savings and improved rig availability.

Seven Level 6 ML wells were planned—wells 1 and 2 with a deep-set splitter (DSS) at 4,000 ft, wells 3 and 4 with a formation junction at 7,000 ft, and wells 5, 6, and 7 with a formation junction at 10,000 ft. Key success factors were the position of the junction, isolation of the first lateral while operations were ongoing on the other lateral, and the need to place the junction in a stable formation to avoid excessive collapse pressure at the junction.

For the DSS wells, running the junction on the surface casing limited its depth to above the shallowest hydrocarbon sand and the deviation to near-vertical inclination. With several exposed reservoir layers before the target sand, zonal isolation was mandatory; 5 1/2-in. liners were set and cemented below each 7 5/8-in. leg before drilling the drainhole. For the formation junction, it was critical that the 100-ft, 12 1/4-in. hole section be underreamed to 17 1/2 in. to accommodate re-formation of the collapsed 7-in. leg before cementing and drillout. To offset the concerns of cuttings transport and hydraulics in the larger top casing, a riser diverter system was designed. Also, the requirement to drill each section individually made it essential to optimize drilling fluid across the junction depth to prevent fluid mix-up and contamination.

The Level 6 ML technology scored extremely high on environmental performance, having a positive impact on the deforestation for flowline and access-road construction. Also, use of this technology reduced generation of surface hole waste by 40%.

From the cost standpoint, the DSS wells in the Niger delta were delivered at approximately 1.7 times the average for horizontal wells drilled in the field, which is expected to be significantly reduced with time and experience in using Level 6 ML technology. The four drainage points obtained in the DSS wells eliminated the need for one location, resulting in a savings of approximately U.S. $700,000. Actual costs for the formation-junction wells compared favorably with the previous estimate of 1.5 times the cost of one horizontal well. Also, the prospect of comfortable ML construction costs is indicated by a downward slope on a plot of delivery trends **(Fig. 4).**

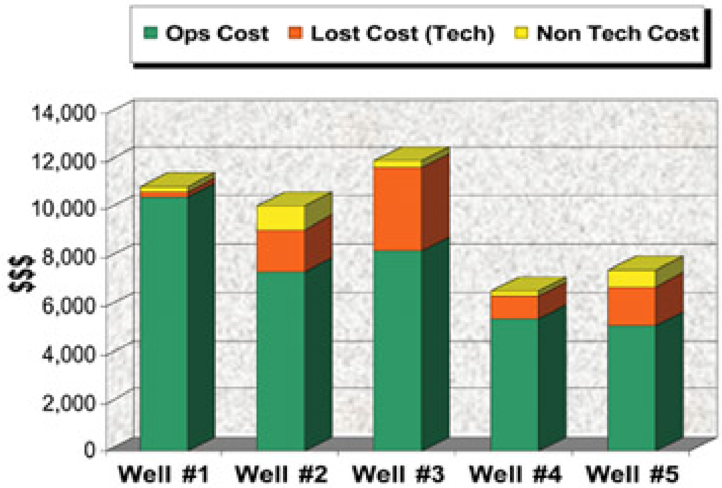

Fig. 4—Cost trend for ML wells in the Niger delta.

The complexity of multilateral wells ranges from simple to extremely complex. They may be as simple as a vertical wellbore with one sidetrack or as complex as a horizontal extended-reach well with multiple lateral and sublateral branches. The industry is seeing fresh approaches to application of this technology, bringing about the acceptance and expansion of ML drilling that was predicted some years ago; today, application of ML technology is preferred over horizontal wells.

Attempts are now being made to combine ML technology with expandable tubulars to increase the versatility of ML deployments. "Combining ML and expandable tubular technology presents a major opportunity for the future," says Ochuko Erivwo, Well Engineer-Deepwater Operations for Shell Malaysia. Mitigating the constraints of one with the strengths of the other can create step-change improvement in well delivery with possibilities of 'subsurface pipelines nested together on laterals'. This will induce a major paradigm shift in the way hydrocarbon assets are developed and create high end value for its pioneers."

Generating Profits In a Once Subeconomic Field

For Amerada Hess, the use of underbalanced drilling (UBD) technology turned a subeconomic field in northern Thailand into a potential major gas discovery. The field is composed of predominantly carbonate formations, and the primary reservoir is a dolomite, with limestone being the secondary reservoir (marginally overpressured) above the dolomite. The permeability of the carbonate matrix is very low; however, the formations were thought to be extensively fractured in some areas of the field.

The first two wells drilled in the Phu Horm field in the 1980s had been deemed subeconomic even after stimulation. A new location thought to intersect as many open macro and micro fractures as possible was selected. Drilling commenced on the Phu Horm 3 well in the top of the limestone reservoir using conventional methods and a specially formulated drill-in fluid water-based mud. Severe lost circulation and fluid losses were encountered, and loss of the hydrostatic head resulted in a gas kick with 1,200 psi at surface. After pumping large quantities of loss circulation material to block the fractures, the BHA became stuck. The drillstring was severed and the well suspended.

A feasibility study to determine the best method for re-entering and drilling the sidetrack well was conducted. The study indicated that UBD offered the opportunity to drill while maintaining pressure control and minimizing the potential for severe fluid loss, reduce formation damage in the natural-fracture system, and obtain good-quality reservoir data. Paper SPE 90185, "Underbalanced Drilling of Fractured Carbonates in Northern Thailand Overcomes Conventional Drilling Problems Leading to a Major Gas Discovery," by A. Timms and H. de Vries of Amerada Hess Thailand and H. Pinkstone, S. McMillan, and R. Doll of Halliburton Energy Services, offers an account of the study parameters and results.

As a UBD project, the Phu Horm 3 is categorized as a Level 5B5 well because of circulating wellhead pressures in excess of 3,000 psi and gas flow rates of 50 MMscf/D seen during the course of operations.

Fresh water was chosen as the ideal drilling fluid as underbalanced conditions could be maintained while circulating at the shoe without the use of injected nitrogen **(Fig. 5).** It also had the advantage of having less environmental impact and being cheaper than mud with chemicals, and being easier to maintain with no weighting material or addition of chemicals.

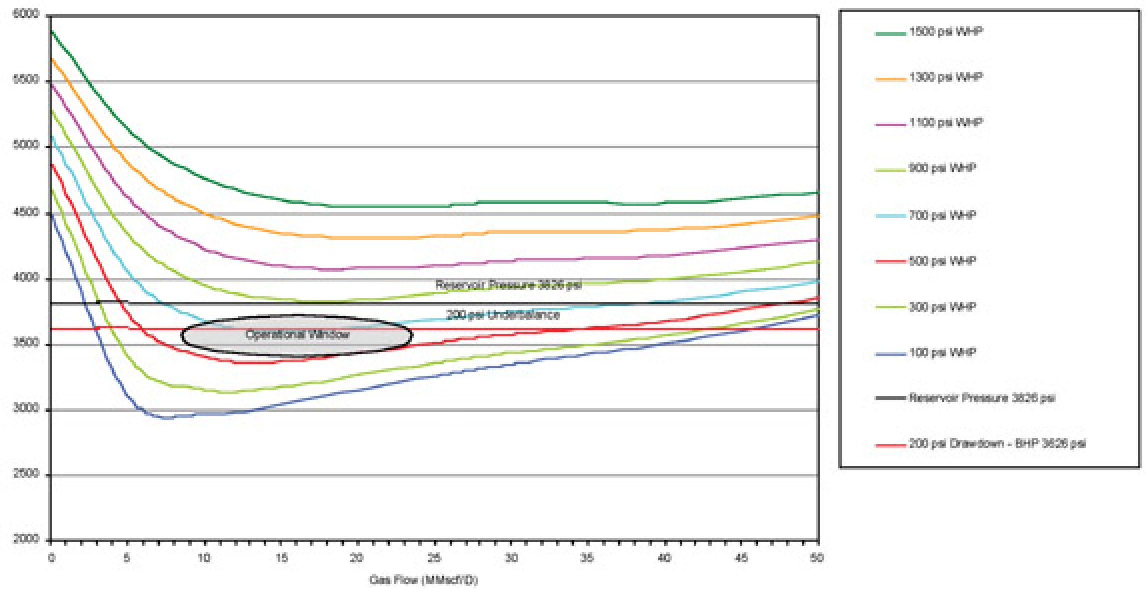

Fig. 5—UBD operational window on the Amerada Hess Phu Horm 3 well. Multiphase-flow modeling is required for UBD. The UBD operational window is selected to ensure that operating conditions while drilling do not go outside the target range (i.e., remain below reservoir pressure at all times, but not so low as to induce formation instability).

Because no other rigs were available in Thailand, a small 650 horsepower double rig without a top drive was used for both the original and the UBD operation, and some operational inefficiencies had to be accepted even though substantial upgrades to the rig had been performed. The upgrades included an entire new substructure to accommodate a new BOP stack (for UBD operations), zone-rating the drawworks engine to hazardous area zone 1, a certified 5,000-psi stand-pipe manifold, new hexagonal Kelly and bushing, and an additional fire pump for UBD spread coverage. For future drilling operations in this field, selection and capacities of the rig will become a critical component to added efficiency.

An underbalanced-drilling project continues in the Udon Thani province in northern Thailand.

While completing the rig-up operation, pressure testing, and commissioning of the UBD equipment while circulating fresh water, the first UBD assembly was run in hole. Drilling commenced, and while drilling ahead with only fresh water, higher-than-expected first-gas production was encountered upon penetration of the Hua Hin Lat Sandstone formation. Drilling continued into the limestone while flowing gas at 3 to 10 MMscf/D. As compared to the conventional drilling operation of this section, the rate of penetration was improved and bit life lengthened. No drilling or hole problems were encountered.

The secondary limestone target was successfully reached and final gas rates were significantly higher than predicted. These very high gas rates, combined with poor hole conditions due to the fact that the actual lithology was different than predicted possibly due to faulting, meant the primary dolomite formation was not reached. The well was completed barefoot. A lower completion assembly with production packer and tailpipe with nipple was set underbalanced on electric-line in the live well. The well was circulated above the packer to 9.6 ppg brine, and the upper completion, hanger, and tree were installed.

Although the primary reservoir target was not reached, the Phu Horm 3 sidetrack well proved that UBD techniques can be successfully used to develop this challenging field, and a potential major gas zone was uncovered. "The use of UBD techniques in this field confirms that this technology has real application in drilling fractured carbonate reservoirs," says Scott McMillan, Asia Pacific Project Manager-ITP/UBA, Tools, Testing, and TCP for Halliburton Energy Services. "The future potential for growth of UBD in the international arena is very promising, as more and more major operators start to discover the significant benefits of this technology in terms of production enhancement, accessibility of incremental reserves, and the reduction or elimination of drilling problems."