his land of few trees and little water features the country’s largest basin, one that’s been producing oil for approximately 90 years. Featuring what geologists call one of the world’s thickest deposits of rocks from the Permian geologic period and measuring 102,000 sq miles, this hydrocarbon landmark is said to contain 29% of the estimated future oil reserve growth in the US. The Permian has 150,000 producing wells and many more are planned. According to the University of Texas of the Permian Basin, the basin yields more than 1 MMBbl/d of oil, or more than 20% of lower 48 production. As for natural gas, the basin produces 4 Bcf/d. Add to this the undiscovered resources of the Permian, which a 2010 US Geological Survey estimated to be 1,257 MMBbl of oil, 40,584 Bcf of gas, and 1,021 MMBbl of NGL.

“The Permian is an interesting beast. It doesn’t want to die,” said Don McClean, Packers Plus technical sales. “Not every formation in the Permian has hydrocarbons entrapped in it. It’s just a function of trying to get the technology to meet up with the economic recovery of it. I think we’re making some strides in that regard.”

How the Permian’s oil and natural gas has historically been produced using vertical technologies differs distinctly in some areas today. Vertical wells are still abundant but horizontal work is now starting to dominate the discussions of operators and service companies, especially when it comes to the Delaware Basin’s horizontal shale formations like the Wolfcamp, Bone Spring, and Cline, located below the Wolfcamp in the Midland Basin.

However, knowing the trend toward horizontal plays is only one small step in this equation. Executing successful completions in this realm involves a different set of tools and technologies, not counting dealing with the realities of limitations that exist from challenges like limited water, changing chemistry configurations, new infrastructures, and environmental regulations. Add to this the knowledge that drilling horizontally is no guarantee of success; wellbore collapses and sticking have turned more than a few away from this type of play.

A range of new or advanced products and technologies are being used today in the Permian, provided by a range of companies that includes Baker Hughes (AutoTrak Curve, H2prO, RockView, Spectralog, AziTrak, XPVision, AutographPC), Halliburton (MaxForce Perforating Charges, CleanStream, CleanWave), National Oilwell Varco (Stand Transfer Vehicle, AC Ideal Prime Rig, TDS-11SH Top Drive), Packers Plus (StackFRAC), Schlumberger (Litho Scanner, HiWAY, ThruBit), Supreme Services & Specialty Co. (Sand Dehydration Station), and Universal Pressure Pumping (PFR-21 “A”).

“There have been a lot of companies showing up with new processes, new gimmicks,” said Jeff Wilkinson, director of sales at Universal Pressure
Pumping. “Many of them are viable and many are not cost-effective. There are a lot of logistics in there that the operators are really learning.”

The drilling distances in the Delaware Basin are ranging from 3,500 ft to 5,000 ft for the Wolfcamp and Bone Spring. In the Midland Basin, the Wolfcamp will vary from 4,000 ft to 11,000 ft. In the Cline Formation of the Midland Basin, drilling distances are trending in the 4,000 ft to 4,500 ft range.

In the Delaware Basin, oil-based mud is used to drill the horizontal Wolfcamp and Bone Spring wells. The Cline is being drilled with a specifically designed clay-free oil-based mud, said Dean Prather, Halliburton area technology manager for the Permian Basin. The Wolfcamp is being drilled with a specifically designed brine mud that has shown higher penetration rates and the ability to push the lateral length out further. “The experience we are having is we are able to drill the laterals faster because of the properties it has,” he said. “It’s been gratifying to meet or exceed expectations.”

Many horizontal plays prove to be remarkably challenging. As David Fairhurst, Schlumberger Southwest Basin ES Wireline sales manager, said, “The Permian Basin, which is made up of three separate basins, is one of the most complex, highly laminated, especially unconventional resources in the world. It’s the proving ground for all of our formation evaluation tools – if they are going to work there, they will work anywhere, whereas in a lot of unconventional plays one will have several hundred feet with a payzone. In the Permian, one will have thousands of feet of gross thickness interspersed with various payzones. It requires the best formation evaluation available.”

**Spectroscopy tools for horizontal work**

The Schlumberger Litho Scanner high-definition (HD) spectroscopy service provides gamma ray spectroscopy for detailed description of complex reservoirs. This tool was designed for precisely measuring key elements in a variety of rock formations like those in these Permian plays. The Litho Scanner service has been run successfully in more than 80 wells in major shale plays in North America, South America, and several conventional reservoirs, the company reports.

“We have always thought that acquiring measurements and understanding the rock is important in these unconventional plays due to heterogeneity because of the way the rock changes and varies as one moves from one drilling location to another, or as one chooses a landing location or another for a horizontal well,” Fairhurst said. “The Permian is the place where we see this requirement most dramatically.”

A pulsed neutron generator and a cerium-doped lanthanum bromide gamma ray detector enable this tool to measure spectra for an expanded set of elements in comparison to previous spectroscopy tools, according to Schlumberger. In carbonates, for instance, the magnesium measurement can be used to accurately differentiate calcite from dolomite at standard logging speeds.

Total organic carbon (TOC) and kerogen content for shale gas plays is computed by subtracting the amount of inorganic carbon associated with carbonate minerals from the total inelastic measurement of carbon, according to the company website. The stand-alone TOC output is presented as a continuous wellsite log, independent of the environment and reservoir. Also, the delay in waiting for...
laboratory sample analysis has been eliminated. The Litho Scanner service can be combined with most openhole services via wireline.

ThruBit, a company recently acquired by Schlumberger, specializes in logging horizontal wells with a specially designed set of slimhole logging tools, which are conveyed through drill pipe and the company’s Portal bit. The technique permits data gathering in lateral wellbores at minimal risk and at low to moderate cost compared to more expensive methods. Openhole logging measurements included in the ThruBit system are resistivity, density and neutron porosities, gamma ray, caliper, and both compressional and shear wave sonic. The main benefit of having these data in the laterals is to aid in completion design and to have a better way to see variation in rock properties beyond what was previously available with a simple MWD-gamma ray curve from the directional drillers, the company said.

Since its inception ThruBit has seen a steep increase in horizontal logging activities in most of the current plays. The ThruBit system provides a way to fill these data gaps and provide the critical inputs to the Schlumberger Mangrove reservoir-centric stimulation design platform.

Case study
In the Delaware Basin, the Wolfbone is the local name given to wells with comingled production from the Wolfcamp and the Bone Spring intervals. The wells are commonly drilled down to 9,500 ft to 12,500 ft with the targeted interval encompassing a thickness of up to 2,500 ft. Although the shallow intervals, like the Avalon and the first and second Bone Spring are viable targets, the majority of operators elect to initially complete the overpressured zones from the base of the Wolfcamp to the top of the third Bone Spring interval. Based on pressure management and economical considerations, the shallow horizons may be completed later on subsequent mobilizations.

Here the challenges include economic well development and controlling completion cost. The Wolfbone comprises multistacked conventional and unconventional packages resulting in the interval having highly heterogeneous lithologies and formation properties. An understanding of the spatial variability in the Wolfbone and applying the appropriate completion solutions are critical to the economic success of vertical Wolfbone well developments. Through detailed completion and production evaluation of the vertical well program, productive horizons within the Wolfbone can be identified and ranked for future horizontal well developments.

A balance must be struck between completion costs and optimal well performance to ensure project profitability. This also is true in Wolfbone developments where completion solutions must focus on applying the appropriate technologies that address the key technical challenges while controlling overall well cost and ensuring optimal production.

The Schlumberger Platform Express integrated wireline logging tool with spectroscopy measurements and the combinable magnetic resonance tools were run on the subject wells in order to construct oil shale montages. This provided petrophysical interpretations of the Wolfbone interval and allowed for improved identification of the pay targets, according to the company. The Sonic Scanner acoustic scanning platform also was run on the subject wells to derive anisotropic mechanical rock properties and stress models.

Using the oil shale montages and the anisotropic mechanical rock properties and stress models, Mangrove was used to determine treatment staging and perforation placement as well as perform hydraulic fracture simulations for optimized fracture treatment parameters. To address completion efficiency and fracture conductivity concerns, the HiWAY flow-channel fracturing technique was implemented on the subject wells.

The integrated completion optimization resulted in the vertical Wolfbone subject wells performing in the top 20% in initial oil production compared with offset wells, the company said. HiWAY also allowed for 6% in water and 30% proppant reduction when compared with conventional Schlumberger stimulation treatments, according to the company.

Completion and production evaluation provided critical input into the future drilling and completion program. Through critical petrophysical calibrations resulting from this analysis, cost savings of an average $734,000 per well were identified and implemented with regard to the drilling and completions opera-
tions. This analysis also identified high potential horizontal targets within the Wolfbone that would be targeted in future horizontal developments.

With these key Wolfbone findings in mind, Schlumberger integrated solutions were also applied to an operator’s initial horizontal Wolfcamp development in the Delaware Basin. Advanced reservoir characterization, well placement optimization using the PowerDrive X6 rotary steerable system (RSS), ShortPulse MWD and PeriScope bed boundary mapper services, as well as recommendations on wellbore configuration and stimulation design, all contributed to improvements in formation evaluation, drilling performance, and completions. As a result, the subject well was drilled and completed in a new and deeper target interval, with the well exhibiting a 60% increase in initial oil production compared to offset laterals landing in the shallower traditional target.

**Handling water logistics**

Water, a critical ingredient in all fracturing work, never has been abundant in the Permian Basin. Operators who are planning E&P work in the area face numerous questions on how they will approach water management issues. Freshwater, though always preferable, may not be readily available near the site, tipping trucking transport charges into red ink domains. Storage and disposal issues also must be considered with water management planning, especially as it concerns produced or recycled waters.

Excessive water production has long been a challenge in the Permian Basin and continues to threaten the economic viability of many wells, especially in the Wolfberry play. The Wolfberry is an oil and gas producing zone characterized by low reservoir pressure. This intertwined play combines the Spraberry, Dean, and Wolfcamp formations and is composed of interbedded sandstone, shale, and dolomite. Potentially prolific oil production in the Wolfberry wells can be nullified by water influx into wells.

A number of service companies have developed technologies to tackle water management questions and offer various approaches for operators to consider in their planning stages. Stephen Monroe, product line manager for surface water treatment for Baker Hughes’ water management group, believes the largest issue operators face in the Permian Basin is one of logistics – beginning with sourcing and ending with disposal.

“Once you find the source water, the logistics of moving that water around or even having to store it are huge. And once you use it you’ve still got a problem with produced water flowing back from those formations,” Monroe said.

An integrated approach to water management is most prudent in addressing water management questions. This includes planning for water collection and distribution while designing an infrastructure with integrated treatment options for any new development areas. Once the challenges of moving and storing water are resolved, treatment for recycling or reuse is a matter of applying the right technology to produce the desired water quality.

For its water management programs, Baker Hughes has identified four key technologies that it uses to offer a spectrum of treatment options: filtration units, electrocoagulation (EC), a chlorine dioxide
system, and a thermal evaporation system. All systems are mobile and designed to treat water as close as possible to its point of use and can move when drilling activity shifts.

“The treatment really depends on the characteristics of the water source and what the intended use of the water is,” Monroe said. “It could be something as simple as our filtration units, which filter out suspended solids. Many times that is all that is needed if you are just doing a simple slickwater frac job.

For a crosslinked application where cleaner water is needed, Monroe suggests a tool like the company’s EC system to remove heavy metals, such as iron, or chlorine dioxide for sour water or bioremediation.

When ultra-pure water is needed, Baker Hughes has a thermal evaporation system, which was released for desalination and complete dissolved solids (TDS) removal. This system will take water at 128,000 TDS and lower it to 300 TDS with up to 70% efficiency, according to Monroe.

Water treatment

Dale Pierce, development manager for National Oilwell Varco (NOV) Fluid Control, has overseen some water treatment pilot projects in Odessa and Andrews counties in Texas for recycling purposes, cleaning fracture flowback water for reuse as frac fluid. Such produced water or brine happens to be very salty. “It’s very difficult to get the saltwater out of it,” he said.

Pierce said that some of the fracturing companies prefer water without a lot of calcium, magnesium, and sulfates in it due to the scaling tendencies. Keeping the fracture fluid from gelling up and cross-linking is important. “Getting it that clean is not an easy proposition. It remains less expensive right now to use freshwater for fracturing purposes.

“I don’t think anybody has the solution to it yet, other than to go all the way to a distillation process which makes the water very expensive,” Pierce added.

NOV provides the AQUA-VES mobile membrane system, which removes suspended solids, oils, and greases. Depending on water quality, some chemical pretreatment also would remove the calcium, magnesium, and sulfates, according to Pierce.
Sand dehydration for flowback treatment
Supreme Service & Specialty Co.’s Sand Dehydration Station (SDS) also has been developed as part of the flowback system and is primarily used to contain sand and filter fluids. The sand and fluids flow into the station’s gas buster to ventilate volatile organic compounds. The fluids flowing through the filtration system then are transferred to the designated freshwater reservoir. The sand is contained within the system tank for the ensuing dehydration process. The sand’s profile then is tested and hauled to the disposal location.

According to Supreme Services, its SDS is economical and environmentally friendly. The system includes a 300 bbl tank, a vertical gas buster, a filtration system, and a transfer pump. Supreme Services can then transport the dehydrated sand to the disposal location.

Avoiding emulsions with a powdered friction reducer
The amount of water required to fracture a horizontal well may be as much as 10 times the volume of water required to fracture a vertical well, said Dennie Martin, director of engineering and technology for Universal Pressure Pumping, which specializes in horizontal fracturing. “When you get into horizontal fracturing, issues come up logistically where the fracturing process requires so much more water than on a vertical well.”

Case study: water treatment
Controlling bacteria growth in fracturing fluid is critical because bacteria downhole can lead to the corrosion of wellbore tubular, resulting in the production of sour (H2S) fluids. Bacteria also can destroy the fracturing fluid resulting in the failure of a fracturing treatment.

The CleanStream service uses a mobile unit capable of treating fracturing fluid at rates up to 100 bbl/min. Using the service enables operators to significantly reduce the volume of biocides used to treat for aerobic and anaerobic (sulfate reducing) bacteria, according to the company. If wellsite logistics permit the use of CleanStream service on-the-fly, biocide addition can be reduced to zero.

For every barrel of oil produced, approximately three barrels of water are used. Between 10% and 40% of the fluid volume used in fracturing operations flows back during the subsequent cleanup. The company’s CleanWave frac flowback and produced water treatment supports recycling of flowback and produced water at the well site. This service has a mobile electrocoagulation component that uses electricity to treat flowback and produced water at rates of up to 26,000 b/d using minimal power.

The CleanWave system destabilizes and coagulates the suspended colloidal matter in water. When contaminated water passes through the electrocoagulation cells, the anodic process releases positively charged ions which bind onto the negatively charged colloidal particles in water, resulting in coagulation. Gas bubbles, produced at the cathode, attach to the coagulated matter and cause it to float to the surface where it is removed by a surface skimmer. Heavier coagulants sink to the bottom, leaving clear water suitable for use in drilling and production operations.

(Source: Halliburton)
The company has been successfully pumping its powdered friction reducer technology – PFR-21 “A” – in the Permian Basin. This dry product demonstrates the ability to decrease surface treating pressures during a fracturing treatment on a customer’s well.

Permeability increases for fracturing

Halliburton’s 150 MaxForce FRAC is a 2¾-in., 6-shot-per-foot perforating gun system that provides positive news for the fracturing side of the drilling equation. Perforating charges traditionally have been designed for natural completions, focusing on depth of penetration but having little control concerning hole size or consistency. Oil and gas reservoirs, including unconventional in the Permian that require stimulation to be productive, can benefit from this perforating gun system, according to the company.

The charge has been designed to maximize hole size performance while providing entry hole consistency in the casing, regardless of the gun’s azimuth, orientation, and standoff. Prather pointed out that when typically perforating a hole, the gun is usually laying to one side. “When you perforate, the side of the gun that’s closest to the casing makes the biggest hole,” he said. “And the side of the gun that’s farthest away from the casing gets a very small

Penetration advances for fracturing

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almost impenetrable hole. What Halliburton has done is create a perforating charge, knowing we’re going to be laying on the casing. The charges are built so that no matter where it goes, you are virtually the same size all the way around.” These perforating charges have resulted in a lower treating pressure of 100 psi to 200 psi in fracturing treatments, according to Halliburton.

**Multistage fracturing systems**

In the Permian Basin Packers Plus provides a series of “stackable” openhole, high-pressure packers that run in conjunction with production casing for both vertical and horizontal wellbores. “The completion technique uses packers to replace the need to cement the casing in place for the purposes of fracture isolation,” said Don McLean of Packers Plus. “In between those packers, we provide what is essentially considered a ball-activated sliding sleeve.”

The purpose of the ball-activated sliding sleeve is twofold: first, it provides access to the frac zone in between those packers, thus eliminating the need to perforate the casing in between the packers. Second, by eliminating that need and using a ball-drop method, this system is able to provide a continuous pumping operation for the entire wellbore using multistage fracture stimulation without having to continually shut down to set bridge plugs in between perforation stages. “We eliminate the time and cost associated with that by providing a series of ball drops,” McLean said. “We can inject the ball while we’re still pumping and shift to the next zone up the wellbore.”

The StackFRAC multistage fracturing system is predominantly used for horizontal wells in the Permian although it can be applied vertically.

**In the field**

An operator working the Permian Basin was targeting the layered combination of the Wolfberry and Bone Spring formations, an unconventional trend that is a mix of fine sandstone and siltstone interbedded with various shale and carbonate layers. The shale and carbonate layers act as barriers to fracture growth, making well completions a challenge. As this is a well-established, mature field, new methods and technologies must be investigated to gain access to the remaining hydrocarbons.

The operator wanted to effectively complete these formations while keeping costs low. A horizontal technique was not viable due to the thickness of the pay zone and
multiple shale and carbonate barriers. In Reeves County, Texas, the operator’s pay zone for drilling was roughly 1,000 ft to 1,500 ft thick. Standard plug and perf (PNP) stimulation methods would be costly and time-consuming, so the operator wanted alternative solutions. Focus keyed on exploiting the higher porosity and permeability of the sandstone layers, as well as any existing natural fractures.

The operator chose to run StackFRAC in an openhole vertical well to maximize the total pay zone. The system was run on 5.5-in., 17 lb/ft casing with an average stage spacing of just over 100 ft, and a total of 11 stages. The tight spacing was required to effectively stimulate the entire pay zone and help to overcome the natural barriers of the formation. The stimulation was a combination of slickwater and crosslinked fluid with a maximum sand concentration of 4 lb/gal. A total of 1,000 tons of proppant was pumped into the well.

The vertical well completion design proved successful, the company said. The openhole completion allowed for contact with the entire length of the wellbore. As of November 2012, the operator completed seven wells, each with an 11-stage StackFRAC system. It took, an average of 21 hours to stimulate the 11 stages in each well. Of those 21 hours, 16 to 18 hours were spent pumping; the other hours resulted in nonproductive time (NPT) due to repairs of surface equipment. Using the PNP method would have meant a minimum of an additional 15 hours added to the stimulation time due to wireline rigup and rigdown, plus wireline trip time in and out of the hole. The system achieved time and cost savings in addition to higher production volumes compared to the standard PNP offset wells, according to the company.

**Increasing fracture conductivity**

Schlumberger’s HiWAY flow-channel fracturing technique has been designed to create open pathways inside a fracture, allowing hydrocarbons to flow through the stable channels rather than the proppant. This optimizes connectivity between the reservoir and the wellbore, resulting in better fracture conductivity, according to the company.

As the Schlumberger production and stimulation engineer Malcolm Yates sees it, the HiWAY service provides operators with measurable water and proppant savings in their hydraulic fracturing activities. “HiWAY ... uses proppant with specialized fibers and blending technology to engineer pillars within the fracture,” he said. “Between the pillars, the hydrocarbons are free to flow through the highly conductive channels.”

Yates said the company has successfully applied the technology in the Permian Basin, and had satisfactory results. “Overall in the Permian, more than 360 stages on 40 wells have been performed to date, resulting in an average 34% improvement in production versus offsets. Screenout rate has also been reduced dramatically to only 0.5% over all the stages performed. Average water savings of 6% and proppant reduction of 30% have also helped simplify logistics and reduced supply chain requirements,” he said.

**Mapping and imaging while drilling**

Schlumberger’s MicroScope resistivity- and imaging-while-drilling service provides high-resolution electrical images and laterolog resistivity measurements in conductive mud environments for advanced formation evaluation in complex and challenging reservoirs. This LWD service enables drillers to stay within their zone when placing horizontal wellbores. The tool is being implemented in the Delaware and Midland basins.

Showing a 360° view around the borehole, the MicroScope service can be used to help calculate reserve estimates, optimize completion designs, and perform an invasion profile analysis, the company said. Its real-time resistivity measurements, high-resolution borehole images, and azimuthal gamma ray measurements can be interpreted to enable critical geosteering decisions in the basins’ unconventional reservoirs.

Additionally, the PeriScope bed boundary mapper aids in greater precision of lateral placement in thin targets like the third Bone Spring Sands that range from 8 ft to 10 ft thick.

According to Irless Gene Brooks, Schlumberger PetroTechnical Services sales engineer, once a horizontal target is identified, it is becoming more critical to stay within that target. In the third Bone Spring sands, for example, Brooks said the com-
pany has drilled and steered more than 200 wells using the PeriScope deep-reading electromagnetic LWD service for optimal well placement. “We also have successfully deployed the PeriScope service in the Cline and Wolfcamp in the Midland Basin,” he added. “Once the lateral targets are identified from our key wireline measurements in a vertical pilot hole, we then model that data to identify the best tool needed for steering within the target zone.”

Schlumberger also is using MicroScope tool to identify fractures in some of the deeper Delaware Wolfcamp plays, Brooks said.

Interpretation of the technology’s images for fracture identification and porosity evaluation allows for a better understanding of fracture networks, according to the company. The service’s azimuthally focused laterolog resistivity measurements show little distortion from shoulder-bed and anisotropy effects, enabling accurate interpretation of vertical and horizontal resistivity used for evaluating production potential in unconventional reservoirs.

Petrophysical evaluations

The Baker Hughes RockView service combines geochemical data from the Spectralog service and the Formation Lithology Explore measurements. It applies the principles of gamma ray spectroscopy to provide accurate in situ mineralogical characterization of conventional and unconventional reservoirs.

The data are collected and then imported into Baker Hughes’ RockView software, which is then used to compute the lithology and mineralogy of the rock. This helps to resolve the ambiguities of traditional petrophysical evaluation methods.

“Running this service in the Permian Basin is particularly useful,” said Angie Guzman, Baker Hughes product line manager for mineralogy services, “because traditional logs do not paint an accurate picture. These formations typically have very high radioactive content, giving less than accurate [shale volume] values.”

The Feldspar content, which creates the highly radioactive signal in the gamma ray measurement, can be determined using RockView. According to the company, this method is more accurate than traditional shale volume computations.
Deep azimuthal resistivity measurement

The AziTrak deep azimuthal resistivity measurement tool from Baker Hughes is being used extensively in the Permian Basin to avoid NPT by predicting the environment using an integrated MWD/LWD response package, according to the company. The tool has real-time distance-to-bed boundary and apparent-dip calculations. It is mainly being used because the intervals being targeted are very thin and the laterals can be quite long (commonly more than 4,000 ft). The intervals being targeted generally have very little resistivity contrast, making reservoir navigation difficult without the deployment of advanced MWD/LWD tools, according to the company.

In addition to well placement, an electrical imaging tool can be run while drilling to log the complete lateral section. The images from Baker Hughes’ StrarTrak high-definition LWD imaging system covers 360° of the wellbore, the company said. In shale reservoirs the resolution of these images allow the identification of natural fractures, induced fractures, and faults. This information can be used to help optimize the stimulation program, avoiding areas where fracturing will be inefficient. According to the company, the tool reduces costs by eliminating inefficient fracturing and has been shown to increase production from a well by up to 20%.

Increasing top drive power

NOV updated its TDS-11SA top drive when it released the TDS-11SH AC. The top drive is built with more power density and torque, and as a result, the company said, deeper drilling can be achieved, both for vertical and horizontal work. Robert Goodwin, NOV’s land rig solutions Top

The intervals in the Permian Basin generally have very little resistivity contrast, making reservoir navigation difficult without the deployment of advanced LWD tools, such as AziTrak (pictured) and azimuthal gamma imaging. (Image courtesy of Baker Hughes)
Drive product line manager, said the demand for longer drilling had much to do with the development of this top drive. “We have seen a trend over the last two years in long or horizontal drilling which has put a reliance on more horsepower, more speed, and more torque used out of our top drives.”

With the operators and contractors pushing for longer wells, higher torque is an absolute. Goodwin said NOV used the TDS11SA, “And in the same package design, utilizing the majority of the components, we upgraded this top drive and updated it to be able to handle about 38 percent more torque in the same-size package.” He added that the TDS11SH can rotate and hoist at 500 tons.

The NOV TDS-11SH AC is capable of 51,000 ft-lbs of continuous drilling torque at 110 rpm, with 75,000 ft-lbs of breakout torque. Powering this top drive are two 550 HP air-cooled permanent magnet AC motors.

Accuracy demands are addressed by controlling torque and speeds using a Variable Frequency Drive control system. NOV reported that a compact integral power unit also is part of the package, eliminating downtime for hydraulic service loops, according to the company. The unit has been designed for retrofitting with existing rigs and features a rapid-installation guide beam design. Software enhancements for SoftSpeed II, Twister, and the Monkey Board collision warning system are available.

TDS11SH was just launched by NOV, with the first unit shipped in 4Q 2012. Before release, the product was heavily tested for its speed and torque at NOV’s California facility.

**Advanced drilling systems**

With the increasing demand for directional and horizontal wells in unconventional plays, Baker Hughes’ drilling systems provide precise wellbore placement in one fast run, optimizing drilling costs and maximizing reservoir exposure, according to the company.

For drilling efficiency, the company’s automated RSS offers precise steering control and near-bit inclination measurement. This helps operators drill a smoother wellbore and place it exactly in the sweet spot, thus reducing drilling risk, Baker Hughes reports.

NOV improved its TDS-11SA top drive when it released the TDS-11SH AC. The top drive is built with more power density and torque. (*Image courtesy of NOV*)
The company’s Auto-Trak Curve RSS brings better downhole economics in unconventional plays through precise wellbore placement, faster drilling, and the ability to drill the vertical curve and lateral section in one, according to the company. It has the ability to drill a high build-up rate curve up to 15°/100 ft.

Launched in March 2012, the new drilling system has been used in all major shale plays in the US. The AutoTrak Curve completed 3 million ft within 22 months after the start of the field test.

AutoTrak Curve RSS is a complete BHA, which includes a drill bit, steering unit, MWD, and a power/pulser unit. The BHA is designed to improve total operational efficiency for pad drilling operations. Operational efficiency is achieved by reducing BHA trips and by reducing flat time because the BHA comes in one piece and does not require rig-site programming.

The RSS is controlled by the slow rotating steering sleeve, which is positioned above the bit. The steering forces can be adjusted manually or automatically by means of smart control algorithms, without interrupting the drilling process. The Baker Hughes steering principle allows for continuous steering, resulting in precise 3-D steering as well as full control while drilling a straight hole, according to the company.

The motor-powered RSS helps reduce surface torque and transfer power directly to the bit so maximum penetration rates can be achieved, minimizing harmful string dynamics and BHA or casing wear for a quality wellbore in fewer runs.

**Rotary steerable systems**

The Schlumberger PowerDrive family of RSS also is enabling drillers in the Permian Basin to optimize directional drilling performance for both vertical and horizontal work. Having drilled more than 100 million ft worldwide, the technology has been deployed in unconventional formations like the third Bone Spring to help improve penetration rates and BHA performance.

In the third Bone Spring sands, Schlumberger has used the PowerDrive Archer high build-rate RSS to provide full directional control during its runs in the unconventional target. Built on PowerDrive X6 technologies, the PowerDrive Archer RSS has a unique hybrid steering unit that enables the driller to achieve maximum reservoir exposure, according to the company. The system also is fully rotational, which enables it to reduce drag and decrease the risk of sticking while drilling. Its closed-loop inclination hold mode also ensures accuracy at high drilling speeds while building high angles – from any deviation – in one run, the company said.

**Improving drilling penetration rates**

In May 2012 Halliburton introduced its new fixed cutter bits titled MegaForce, setting industry-record penetration rates. These fixed cutter drill bits have a dynamic cutting structure and matrix material with multilevel force balancing. During its press announcement, the company stated that hydraulics and shank length deliver more than a 20% improvement in drilling penetration rates for the MegaForce.

As operators drill deeper and longer wellbores in unconventionals, they will be attracted to any series of bits that can drill farther and faster.

Field work in the Permian with the MegaForce bit has drillers seeing a 50% to 70% reduction in the
number of bits that they need for drilling a horizontal well, said Halliburton’s Dean Prather. “We think that may be something that will help reduce the cost, as well.”

Case studies
Field trial data for MegaForce bits tested in Uintah County, Utah, as well as Leon, Upton, and Wheeler counties, Texas, showed penetration rate and reliability improvements over current fixed cutter bit offerings. Drilling was logged at between 18% and 31% more footage. Following each run, MegaForce bits were graded equal to or sharper than offset bits, the company said.

Remote monitoring software
The Baker Hughes Vision well-monitoring software is a web-based service that, unlike traditional SCADA systems, provides operators with prebuilt user configurable screens that are easy to learn and navigate.

Monitoring more than 3,000 electrical submersible pumps (ESPs) globally, with more than half of them located in the Permian Basin, Baker Hughes’ Vision well monitoring software continues to be successful in this region, according to the company. The company’s XPVision monitoring platform reduces an operator’s monitoring and data analysis time. Baker Hughes’ engineers analyze the operational data coming in from the field and then notify operators of any concerns and recommendations.

In the field
An operator followed a chemical treatment program by restarting a Permian Basin well but inadvertently restarted the well with the tubing and casing valves closed. The well immediately began to cycle, putting the ESP at risk of failure. A Baker Hughes engineer was remotely monitoring the ESP using XPVision monitoring software. Fewer than 16 hours after the well was restarted, exception reports generated by XPVision software identified a rise in the ESP motor temperature and a correspondingly high motor current.

The engineer analyzing the reports also noted that the pump intake pressure had a standard deviation of more than 20%. Based on this information, the engineer determined that either the well was plugged or there was a valve problem. This critical information was immediately given to the operator. A pumper sent to the field by the operator discovered the closed valves. Using the methodology and feedback of XPVision, the operator avoided an ESP failure, prevented more than eight hours of well downtime, saving significant intervention costs, according to the company.

Another customer operating a Permian Basic CO2 flood partnered with Baker Hughes to evaluate the benefits of using the XPVision monitoring platform during a four-month trial.

The XPVision software delivered a complete remote monitoring and optimization service, allowing the observation of power usage, ESP parameters, well conditions, and overall production performance. Using a standardized process, ESP engineers stayed proactive and ahead of changing conditions, ensuring optimal production and efficiency. In two months, the real-time monitoring and optimization service prevented 14 immediate failures. The quick trending features allowed analysts to view multiple wells at one time. Exception reports allowed the operator and field service technicians to prioritize work. Each well had a live AutographPC model operating in the background to reconcile data differences between the live data and software data predictions. This allowed for real-time diagnostics when systems began to operate in less-than-optimal conditions, saving the operator money. According to the company, the operator also added 104 bbl of oil by increasing overall production time.

In May 2012 Halliburton introduced its new fixed MegaForce cutter bits titled setting industry record penetration rates. (Image courtesy of Halliburton)