Efficient and economical oil E&P is important when prices are low but perhaps more important when prices are high. In both scenarios, operators need to drill quickly and safely with the most reliable equipment, at the surface and downhole. When it is time to stimulate the well, the operator chooses the quickest as well as the optimal techniques available.

A variety of solutions
Since acquiring Petrohawk in summer 2011, BHP has been investigating ways to increase rig, drilling, and completion performance and efficiency in the Eagle Ford and Haynesville shale plays, and in the Permian Basin. The company tested a variety of rotary steerable systems (RSS) in several of its Fayetteville, Haynesville, Eagle Ford, and Permian Basin wells with mixed results. It also is nearing the end of the process to convert its contracted land rig fleet from SCR rigs to A/C units, including about 26 rigs in the Eagle Ford as of mid-July. The newer A/C rigs are cost efficient in terms of controlling the drillstring, the feedback on drilling parameters is better, and the ability to monitor remotely is easier.
“We believe starting with good iron is the first real step to being efficient in [the drilling] process,” said Nigel Smith, president of Development for BHP Billiton Petroleum. “We have been in this program of upgrading our rig fleet the past six to eight months, moving out the under-performing SCR rigs and moving in the newer A/C rigs.”

BHP uses three primary drilling contractors, Helmerich & Payne, Nabors, and Patterson UTI, awarding them drilling contracts ranging from three to five years, trying to reach critical mass in each of its operating areas. For example, the six Patterson rigs are in the Permian Basin, most of the H&P rigs are in the Eagle Ford, and Nabors is BHP’s big rig provider in the Haynesville. Reaching critical mass with rigs in a particular region provides several advantages to BHP such as continuity of crews. A rig worker can be trained as BHP prefers, move from one H&P rig to another when necessary, and be familiar with the next rig, Smith said.

“The number of H&P rigs we have in Eagle Ford warrants them having a senior manager overseeing the rigs,” Smith explained. “We can talk with them about the supply chain, efficiencies in rig moves, and learn from experiences of the group of rigs to continuously improve our performance.”

**Downhole motors and bent subs**

The operator typically drills its Eagle Ford Formation wells with a downhole motor and bent drilling sub, although it has examined the use of RSS as well as high-build rate RSS. In the Eagle Ford, at least, the company is sticking to its typical drilling method. “We think there is a great opportunity [for RSS] if we can drill the curve and lateral in one run,” Smith said, “but they are cost prohibitive right now.”

While the company would like to use RSS because of better hole cleaning and ROP, “the benefits are not quite there to compensate for the higher cost,” Smith explained.

BHP is looking at other, more reasonably priced similar technologies, he said, that offer comparable performance if not quite at the level of rotary systems. “They are getting pretty close,” he added. “The question is, are they going to perform reliably.

“These advanced downhole drilling systems have promise so we are willing to experiment with them but they have to be controlled experiments,” Smith continued. “We aren’t going to run it everywhere, and we have to at least have the line of sight to being reliable and repeatable and cost advantageous to us.

“The advantage for us is we get to use it, test it, see it early on, and hopefully, if it works, we can replicate and adopt it. For the [service] company, they get an opportunity to use it in a well and learn from that with an operator who is interested in seeing it work,” Smith said.

BHP presently drills its directional wells with a motor and bent sub, including curves planned with build rates up to 14°/100 ft. “Whatever the rotary steerable system, it has to significantly outperform the ROP achieved by motor drilling, yield predictable and repeatable results building curves, result in more lateral footage in zone, significantly reduce circulation times required to clean the hole, and the tool’s [mean time between failure] must be extremely low for us to utilize such high-cost tools regularly on our wells,” said Mike Bloom, the company’s senior manager, Drilling and Completion.

“We look at three levels: financial, performance, and technical advantage,” Bloom said. “When these levels are aligned by the right tool, BHP will give the service company an opportunity to try the tool and more than likely will offer more than one opportunity. If we can’t see a marked improvement then motors are the way to go.”

**Streamlining completion techniques**

In Eagle Ford wells, operators case and cement the complete lateral section and install plug and perf (PNP) completion systems. However, the service industry is seeking ways to efficiently use sliding sleeve completion systems. “One of the methods Eagle Ford operators have tried from a completion optimization standpoint is cemented sleeves, but with mixed success,” said Myron Protz, senior manager, Completions Engineering, for BHP.

The challenges include the Eagle Ford’s high temperatures (300°F to 333°F) in which the tools have to operate and the debris left in the well bore from the casing running and cementing operations.

“With a cemented sleeve system we can eliminate the fracture preparation stage and save costs and time off the critical path of the well, but mainly costs,” Protz continued. “The Eagle Ford team tried...
cem ented sleeves at the toe of the well to initiate stimulation and then pump down perforating guns on wireline, but with mixed success as well.

“It’s a tool design maturity issue,” Protz said, “and one of the bigger factors is the debris mitigation has been a challenge for the tool companies.

“We are working with drillers to see if we can go with a monobore design versus a tapered string design, which will allow for a single size wiper plug versus a tapered wiper design that has been observed to have lower wiping efficiency,” he continued. “There has been some limited success there so we are pursuing that because we want to enhance operational optimization, get past the critical path, and save some costs.

“The technologies are there,” Protz said. “They are coming.”

**High-build rate RSS**

Baker Hughes launched its AutoTrak Curve high-build rate RSS in March 2012. The RSS can drill up to about 15°/100-ft doglegs compared with about 12°/100 ft to 13°/100 ft with downhole motors and 7°/100 ft with conventional RSS. “The steering unit is a new design,” said Svein Steen, Baker Hughes product line manager, Advanced Drilling Systems. “The principle is the same as our AutoTrak system. However, in order to achieve high-build rates, we have a new mechanical design, new hydraulic design, and new [steering] pad design as well.”

To enable the high-build rates, the RSS uses expanding steering pads that push against the side of the wellbore and deflect the bottomhole assembly (BHA) farther than the company’s standard RSS. The steering pads are designed to work in formations from soft to very hard or brittle. The BHA is more flexible in order to manage the increased bending loads, which is aided by building the MWD unit into the flexible BHA.

“The need for [LWD] functionality in these BHAs is limited,” Steen said, “so we didn’t build in that compatibility in order to increase reliability on the system. The benefit is that the tool now has fewer components because it doesn’t have to dock with LWD tools in the future.”
The RSS is only available with a Baker Hughes-designed bit. “It is engineered to be optimized when combined with a Baker Hughes bit from the Talon design family,” Steen said.

Directional control can be achieved with on-bottom downlink commands, which can be sent manually using rig pump controls or by using surface computers with an automated downlink system. The result is that an operator can land the bit into the target and potentially produce from an additional 750 ft of lateral reservoir compared with a typical RSS that delivers a dogleg severity of 5°/100 ft.

The company has drilled about 1,400,000 ft of hole with the high-build rate RSS between the start of field testing that began in July 2011 through the summer of 2012. This compares with three years to drill 1 million ft with its conventional AutoTrak RSS in the 1990s, Steen noted. “We have shaken out a lot of issues during the testing,” he said. He added that developing a high-temperature AutoTrak Curve is on the company’s agenda.

Case history
An operator in the Eagle Ford Shale wanted to drill an 8½-in. hole consisting of vertical, curve, and lateral sections exceeding 10,400-ft total depth (TD). The curve required an 8°/100-ft build rate. The operator needed to drill the build and turn the profile while eliminating trips to change or adjust the BHA, and wanted to stay within a 50-ft lateral window. Baker Hughes recommended its 6¾-in. AutoTrak Curve RSS with Baker Hughes bit. The RSS allowed the operator to drill out the 9-in. surface casing and drill from 2,631 ft to 13,188 ft in one run for a total of 10,462 ft in 116 total drilling hours, achieving an average on-bottom ROP of 90 ft/hr for the entire well. The RSS was able to kick off from the vertical well section and build to 88° inclination with an 8°/100-ft build rate. The RSS drilled the entire lateral section.

One BHA was used, saving two of the typically three BHA trips for changes and adjustments. The sections were drilled in six days, saving two days compared with the average for offset wells. The average spread cost for the rig was $40,000/day, saving the operator $80,000 in associated rig operating costs for the well.

Earlier this year, Halliburton launched its Geo-Pilot enhanced dogleg (EDL) high-build rate RSS for drilling up to 10°/100 ft in hole sizes 8½ in. and larger. It is offered for use mainly in areas where high-build rates are required or where soft formations typically limit build rate capability, according to the company. When drilling through interbedded formations, the RSS system can provide a more consistent build rate and help maintain higher ROP, the company said.

“Rotary steerables are used in about 10% of the wells drilled in the Eagle Ford today,” said George Sutherland, marketing manager, Global Business Development, for Halliburton’s Sperry Drilling business line. “Drilling motor technology is also improving with more torque and weight to bit, which is challenging the value proposition of rotary steerables.

“It depends on the formation but 10°/100 ft is the build rate for the 8½-in. tool,” he said. “With the Geo-Pilot EDL 5200 series system we can get up to 15°/100 ft in a 6-in. hole size.”

The company also offers its 7600 series for up to 10°/100 ft in 8-in. to 10-in. hole sizes and its 9600 series for hole sizes from 12 in. to 17½ in.

The company can use other manufacturer’s drill bits with the RSS, however, “We find that when using [a Halliburton matched system] we maximize footage and reduce the cost per foot,” Sutherland said.
When it comes to drilling performance, motors still deliver higher build rates than rotary steerable. “Doglegs in the Eagle Ford are still 8° to 10°/100 ft, but you can achieve as high as 15° to 18°/100 ft in an 8½-in. hole with the appropriate motor configuration,” Sutherland said.

He noted that the company’s new XL motor technology is resulting in more robust equipment, including ruggedized bearing packs, stronger drive shafts, and shorter bit-to-bend distances that allow for higher build rates with less sliding. “The new XL and XLS motor technologies allow more weight on bit, deliver more torque to the bit, and offer better directional control,” Sutherland said.

**Drill bits**

Since about 2008, operators in the Eagle Ford reservoir have drilled exploratory wells with a wide array of casing designs. “Operators were drilling either a 14¾-in. surface with a 9-in. intermediate size and then they went to either 8½-in. or 8¾-in. production hole sizes,” said Alan Huffstutler, South Texas Technology manager for Halliburton’s Drill Bits and Services business line. “Some operators went to 6¾-in. for their curve and lateral.”

Now that most operators are into the development phase, some involving pad drilling, the wells tend to be more standardized. “We are seeing a lot more operators going to 12¼ in. for surface and either 8½ in. or 8¾ in. for the rest of their production hole,” he explained.

Huffstutler said that most operators have wanted to drill from surface casing to TD with one BHA and drill bit. However, he sees some operators moving away from that method in search of better drilling efficiency. “In some areas significant increases in ROP are being achieved using more aggressive bits from surface casing to curve kickoff point. Frequently, the temperature range of wells creates challenges and diminishes the life of motors, which can limit the success rate of drilling the entire interval with one BHA,” he said. “PDC bits in these applications don’t typically wear out so bit life doesn’t limit the interval length. If you are drilling through the Wilcox and Olmos sands, you can destroy a PDC bit if you’re drilling with energy levels that are too high, such as high RPM, but good drilling practices should be able to eliminate that.”

Huffstutler is seeing some operators moving toward drilling the wells with two or three drillstrings, drilling from the surface pipe to the kick-off point, replacing the BHA and bit for the curve and lateral or sometimes using separate BHAs and bits for the curve and lateral.

“We are successfully designing bits for the vertical, curve, and lateral sections that not only drill as fast as possible but also include directional control capabilities required by directional drillers, such as toolface control and build rate capability,” Huffstutler explained. “You can drill the curve and lateral sections with the same BHA and bit type separate from the vertical/tangent section. It allows us to optimize ROP in the vertical section or the tangent section using a much more aggressive bit.”

The company uses its FXD55M bit in many Eagle Ford Basin wells to drill the entire production hole (vertical and lateral). However, using a dedicated BHA and bit for the vertical section has allowed the company to design and
build more aggressive bits. “We have a new bit to drill the vertical section, a 5-blade 19-mm bit designated as the FX56RM, with which we set recent ROP records,” Huffstutler said.

He said nearly all of industry can average about 150 ft/hour down to kickoff to the Austin Chalk but now the industry has bits that can drill 180 ft/hour, 250 ft/hour, and 280 ft/hour. “There are economics that justify drilling that fast and yet still pull pipe and change the BHA. And then the motor has a better chance of lasting to the end of the run,” Huffstutler added.

**Drill bit case histories**

In one well in the E agleville Field in Gonzales County, an operator was able to drill the entire 8,353-ft vertical section with an 8½-in. FX56RM bit at an average ROP of 172 ft/hr, the fastest among the direct offset runs for the operator in the field. The bit showed aggressive ROP while maintaining durability and was pulled out of the hole in excellent dull condition, according to the company.

In another E agleville well in Atascosa County, an 8¾-in. FXD55M bit drilled the vertical, curve, and lateral, a total of 10,148 ft from 5,080-ft MD to 15,228-ft MD in a single BHA run at an overall average ROP of 66.1 ft/hr. The well was drilled in fewer than 12.5 days. The bit was pulled out of the hole in excellent dull condition. Two other FXD55M bits drilled even farther, with one drilling total footage of 11,363 ft at an average ROP of 97.5 ft/hr, and another drilling 11,470 ft at an average ROP of 88.9 ft/hr.

**Freshwater drilling system**

“Lost returns can be such a major issue in Buda wells that some operators will case off and displace to a brine-type system to control the mud weight better [than an oil-based system], and because it is more economical when compared to oil-based muds,” said Scott Costner, Halliburton’s Baroid Southern Region technical manager. “Brines are more readily available to operators.”

The company formulated and tested a brine system that has been used in Wilson, Frio, Gonzales, and Karne counties where the surface section is drilled with water-based fluid and is displaced to a brine system to drill through the Escondido and Olmos formations and to the Eagle Ford Formation. Brine, however, has its drawbacks, chief of which is disposal. “Texas regulations limit the amount of chlorides that can be disposed to 3,000 milligrams per liter,” Costner said. “A saturated brine is going to be 170,000 to 180,000 parts per million, so you can eliminate diesel and other costs switching to a brine system but you can’t eliminate disposal costs.”

The company tested freshwater systems and developed its SHALEDRIL water-based drilling system for unconventional shale reservoirs. Operators using the system have been able to reduce their overall drilling fluid costs as they see reductions in areas such as cuttings disposal and rig cleanup, according to the company, while they see advantages in wellbore stability, CO₂ tolerance, and fracture sealing.
“With the SHALEDRIL system concept we’re asking operators to supply us with core and cuttings samples so we run them through x-ray diffraction to determine their mineralogy,” Costner said. “We are attempting to match chemicals to specific mineralogy in an effort to provide inhibition and stabilization for specific counties, as the Eagle Ford varies from county to county and even within counties.”

Escondido and Olmos wells still are drilled with oil-based fluids from top to bottom, according to Costner. When drilling through the Austin Chalk on the way to the Eagle Ford Formation, the company has been successful with different types of lost circulation materials in keeping losses minimized through the chalk.

### Fracture stimulation systems

The type of completion systems used most often in the Eagle Ford Basin is horizontal cemented and cased hole, and the PNP systems. The nature of the reservoirs do not necessarily dictate the cased hole completions, however. Texas is extremely particular about how zonal isolation is achieved, which has led most operators toward cemented completions.

“On a technical basis, the Eagle Ford is less naturally fractured than some of the other reservoirs that are openhole isolated completions,” said Bill Melton, sales manager, Completions, for Halliburton. “It does benefit having set entry points that perforations or some jetting of entry provides.”

According to Melton, the first few wells drilled in the Olmos reservoir were openhole isolated completions, but operators moved away from that method to cemented PNP design. The Buda reservoir just below the Eagle Ford generally is more of an openhole completion formation and some operators are running just a slotted liner and pumping acid into the well, Melton added.

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“In 2010 operators were stimulating 12 to 14 stages on average,” he said. “Last year it was probably 15 to 16 stages and this year we are seeing 18 to 20 stages. We have customers that are talking about 30 stages in the lateral. Most operators are not extending the lateral length but finding there is more value in touching more of the rock. They are not greatly increasing the amount of proppant being pumped, either.”
The RapidStart Initiator sleeve is one of Halliburton’s tools that has been gaining momentum in the Eagle Ford reservoir. “Operators have been moving away from running tubing conveyed perforating [TCP] systems for their first toe stage,” Melton said. “Six to eight months ago I would say that this type of toe initiating was used in probably less than 10% of the wells, but in the past six months it is probably used in 30% to 35% of the wells.”

The initiator sleeve can be run in cemented or unmented applications in horizontal and vertical wells. It can be used as the first-stage zone in a frac sleeve completion system such as the company’s RapidStage or RapidFrac completion systems, or more popularly to enable more efficient PNP operations.

The company’s AccessFrac fracturing service typically incorporates one or more of the following: a chemical diverter system; a proppant coating technology; a polymer alloy proppant; and a special fluid and treatment design and pumping schedule. The services are appropriate for low-permeability formations, especially shales.

The particular service used in the Eagle Ford is the AccessFrac PD service, which is designed to improve proppant distribution in multizone completions and ensuring all perforation clusters are treated. The service addresses two challenges facing operators when producing from tight formations: rapid production declines following fracture treatments, and uneven proppant distribution in PNP operations due to most of the proppant going into the fractures nearest the downhole plug.

Case history
AccessFrac PD service saved a well and cut completion time in half. An Eagle Ford well had a cased 4,000-ft horizontal section. When the completion phase began, the operator was unable to insert isolation plugs through the heel section of the lateral. A caliper log indicated the casing had been narrowed, most likely due to tectonic movement. The well bore was perforated by using a smaller-than-normal TCP system; however, because isolation plugs could not be inserted, the operator faced the possibility of plugging and abandoning the well if another completion technique was not available.

AccessFrac PD service was used to provide isolation between individual fracturing stages. During the course of 21 hours of continuous pumping, 13 frac stages were placed along the lateral, treating a total of 780 perforations. Plug setting and drillout time was eliminated, resulting in completion time being reduced by over 50%. Production from the well is equal to production from offset wells.

Long-term flow-channel productivity
The first job for the Schlumberger HiWAY flow-channel hydraulic fracturing service was pumped in 2010 for Petrohawk in the Hawkville Field. The results from that well, and hundreds of subsequent wells completed in the Eagle Ford, have proven significantly higher initial production results while reducing water and proppant requirements, according to the company.

The Eagle Ford Shale has generally been stimulated using multistage horizontal completions with high-rate slickwater treatments requiring millions of gallons of water and millions of pounds of proppant per well. The ongoing expansion of fracturing activity in the Eagle Ford constrains the availability of water and proppant.

Case history
According to a case study on the company website, one operator evaluated the flow-channel hydraulic fracturing service for the stimulation of wells in a four-well study in the Eagleville Field. Two wells were stimulated with the flow-channel hydraulic fracturing service; the other two wells were stimulated simultaneously with the conventional method. The wells treated with the service had been drilled from a single pad, in opposite directions. The other two wells had also been drilled in opposite directions from a single pad located 3,500 ft away and parallel to the first two wells. The average lateral length for each pair of wells differed by only 1%.

During the first 60 days after stimulation, the wells treated with the flow-channel service produced an average of 26,535 bbl of condensate with 30.1 MMcf of associated gas. The wells treated conventionally produced an average of 18,555 bbl of condensate with 18.7 MMcf of associated gas. The average wellhead flowing pressure for the wells treated with the HiWAY service was 2,156 psi versus 1,916 psi for the conventional
wells. The flow-channel service increased condensate and gas production by 43% and 61%, respectively, while delivering higher flowing pressures. These results were obtained while reducing the amount of water and proppant used per well by 58% and 35%, respectively. The operator saved more than 10,000,000 gal of water and 2,600,000 lb of proppant in the two wells stimulated with the flow-channel fracturing method.

Now, after about two years since the first flow-channel stimulation service was used in Eagle Ford, the company says that operators are experiencing significantly improved long-term production rates in addition to higher initial flow rates. “The decline rate in HiWAY wells is not as steep as in conventional wells,” said Alejandro Peña, Schlumberger portfolio manager, Well Production Services Chemistry and Materials. “That is leading to the growing differential in productivity over time.”

In a public 50-well study by Petrohawk (now BHP), average cumulative production from 12 flow channel-stimulated wells in the Hawkville Field was 32% higher than eight wells stimulated with conventional hybrid fluid systems and 67% higher than 30 wells stimulated with conventional slickwater systems. After 250 days, average cumulative production from 12 flow channel-stimulated wells was 37% higher than the wells stimulated with conventional hybrid fluid systems and 87% higher than the wells stimulated with conventional slickwater systems. The wells stimulated with the flow-channel service used significantly less fracture fluids and proppant than the wells stimulated with the other methods.

“With a more subtle decline rate in production, the operator can increase estimated ultimate recovery and extend the time necessary to return to the well and invest to restimulate the well,” Peña said.

Since the company performed its first Eagle Ford flow-channel stimulation in October 2010 to June 2012, 260 wells equaling 4,200 stages were stimu-
lated with the flow-channel method with zero screenouts and significant savings in water and proppant, reducing the environmental footprint. From the company’s figures, 300,000 tons of conventional proppant were saved as was 4 million bbl of water. In the Eagle Ford Basin, the flow-channel hydraulic fracturing service resulted in about 23,000 water and proppant truck trips avoided with 230,000 gal of diesel fuel saved, according to the company.

“The HiWAY service requires about 40% less proppant than a conventional fracturing treatment,” Peña said, “and in many cases about 25% less water on average. Using less water also leads to less wastewater that must be handled at the surface.”

The company continues to expand the flow-channel stimulation method’s capabilities, including using its Mangrove reservoir-centric stimulation design software for unconventional wells to design HiWAY-stimulated wells. The company has extended its pump rates from 50 to 60 bbl/min to 90 bbl/min “as we seek further proppant placement in the formation,” Peña said.

**Hydraulic fracture design**

The Schlumberger Mangrove reservoir-centric stimulation design software is a plug-in for its Petrel E&P software platform that integrates fit-for-purpose hydraulic fracture models and specialized completion algorithms with measurements relevant for unconventional reservoirs. The software enables an integrated workflow that is rooted in reservoir characterization to comprehend the unconventional reservoir heterogeneity. The completion and stimulation models can be calibrated using microseismic measurements in the context of local geology and structure. The calibrated model then is represented in a production model for forecasting and optimization. Field production data is used to calibrate the production model.
“The fundamental gap we had in the past is that the data we gathered from measurements, core and prior treatments never had the opportunity to be converted into information,” said Utpal Ganguly, Schlumberger’s Global Stimulation Software portfolio manager. “This was a result of the absence of designing and modeling capabilities in the industry for unconventional reservoirs.

“The challenge was how to pull all of the information together in one platform to enable a step-by-step workflow to increase production and ultimate recovery while minimizing cost,” Ganguly explained. “An operator can have an optimal number of perforation clusters, fewer stages if the right spot to frac is determined, and the right size job rather than going for the biggest job possible.”

The software also can work efficiently if an operator does not want to change the number of stages. In one example in the Eagle Ford reservoir, an operator wanted to pick the perforations at the best spots and keep the initial number of stages, yet gain improvement in production. “We were constrained by having to maintain the same number of stages,” Ganguly said. “We applied the Mangrove workflow to pick the sweet spots for perforating.”

The software’s workflow was applied to three new wells. Compared with six offset wells completed with conventional geometric staging, the operator saw a 33% increase in the three-month average cumulative barrels of oil equivalent production in the wells using the process.

“Based on a study of more than 100 wells in different shale plays over a period of time, we have learned that only about one-third of the perforation is contributing to 70% of the production, and that is happening because we are not contacting the sweet spots with the geometric staging technique that is widely used in the industry,” said Ganguly. “One of the key elements of Mangrove is the completion advisor that provides an optimal way of placing the perforation and grouping them in a stage.”

The completion advisor provides automated workflows for specific well orientation and has separate advisors for tight sands and shale respectively. Both advisors have been validated with improved production for the operators and minimizing the completion cost by reducing the number of treatments required, according to the company.

The Mangrove software provides rigorous and repeatable solutions for optimizing staging and
perforation design, the company said. The staging algorithms are linked to fit-for-purpose hydraulic fracture models ranging from Pseudo3D to newly developed complex fracture models, the UFM unconventional fracture model and Wiremesh. The complex fracture models are specifically developed for simulating non-planar complex fractures applicable in naturally fractured reservoirs as is common in shale.

ThruBit, a company recently acquired by Schlumberger, specializes in logging horizontal wells with a specially designed set of slimhole logging tools that are conveyed through drillpipe and the ThruBit Portal Bit. Logging measurements for openhole include resistivity, density and neutron porosities, gamma ray, caliper, and compressional and shear wave sonic. These data can aid in the completion design and provide a better way to see variation in rock properties beyond what can be obtained with MWD-Gamma Ray curve from the directional driller, according to the company.

In the Eagle Ford, some operators are seeing variations in production from adjacent horizontal wells in the same vicinity. These inconsistent production results indicate the need for more data to better understand changes in rock quality and to better tailor completion strategies. The ThruBit system fills the data gaps and provides critical inputs for the Mangrove software to further enhance stimulation and completion design.

### Zone-specific customized treatments

Among the completion tools and systems for shales and tight sands offered by Weatherford are its FracSure Multi-Zone Stimulation Technology (MZST) licensed by ExxonMobil, and the ZoneSelect suite of tools and completion methods. Weatherford is the most recent to be licensed by ExxonMobil Upstream Research to use MZST.

The two MZST methods, Just-in-Time Perforating (JITP) and Annular Coiled-Tubing Fracturing (ACT-Frac), can each provide 40 or more zone-specific customized treatments in a single well, according to the company.

The process enables multizone stimulation in a vertical, deviated, or horizontal well section using ball sealers for diversion between the frac stages.

“With JITP, a plug is set, you back up a bit with the wireline, and you frac around the wireline after you set off the first perforating gun,” said Robert Fulks, director, Unconventional Projects, for Weatherford.

“You drop sealer balls to plug the perforations and then you pump the treatment, pull up the hole, and prepare to fire the guns again.

“JITP can be mixed with other stimulation methods,” Fulks said. “You can run a standard plug and perf on the bottom, JITP in the middle, and sliding sleeves in the upper section of the completion.”

The ACT-Frac method involves frac treatments pumped down the annulus to facilitate the stimulation. This procedure, like the JITP method, involves repeating each perforation and frac treatment and enables stimulation of multiple zones with one trip. The tool assembly is conveyed on wireline in vertical wells and on coiled tubing in a horizontal section. The system sets an inflatable packer, and frac fluid is pumped down the casing annulus to the frac zone, perforating the zone. The packer is released, the tool moves up the horizontal section to the next zone, and the process is repeated as many times as necessary.

The company’s ZoneSelect modular completion system enables operators to choose from a variety of sleeve actuation options and zonal isolation methods to create the right completion for their particular formation. The completion method uses sliding sleeves that can be ball-drop actuated, mechanically shifted, or pressure activated in the case of the toe sleeve. Zonal isolation is achieved with either swellable or openhole packers or cement.

The system’s sleeves feature up to 40 drop-ball sizes that allow fracturing up to 41 zones in 5½-in. casing. The additional zone can be added by using a pressure-activated toe sleeve. A unique feature of the sleeves is that they use shear rings rather than shear screws or pins, which provides more precise opening pressures and clearer opening pressure indications, according to the company.

The completion system also is available with Multiple Array Stimulation System (MASS) sleeves in which multiple sleeves can be opened with a single ball size. The MASS sleeve allows operators to have multi-
ple points of entry for the frac within the zone, similar to PNP. Port diffusers installed in the sleeves allow preferential flow in the isolated zone during frac initiation to improve the uniformity of the pressure across the interval.

Case history
In one well in the San Miguel Formation in Dimmit County, Texas, an operator wanted to complete multiple fracture stages in a horizontal section without having to perform rigging or wireline operations on the wellhead that would expose personnel to LPG fracture fluid. The operator also wanted to be able to perform continuous fracture treatment to eliminate the need to purge the LPG from the piping systems between the fractures. Weatherford recommended using the ZoneSelect single shot sliding sleeve and ARES hydraulic openhole packers in the 6¼-in. section with 4½-in. casing liner. The extra-long packing element increases sealing capability while requiring lower packoff force, resulting in reduced stress on the formation.

The completion system was deployed to TD and the operator was able to pump the LPG frac treatment continuously with a closed system without the need for wellhead rigging operations or coiled tubing. The operator did not need to purge the LPG from the lines to fracture the next zone, which could have taken several hours, resulting in improved efficiency, reduced rig time, and lower associated costs, according to the company.