In most of the US shale plays, whether oil- or gas- or liquids-rich, the application of the latest drilling and completion technology has been the enabler of successful E&P and the primary reason for increased activity. This is particularly true in gas-prone shales during a low gas price environment. Horizontal drilling and geosteering technology has opened up regions to more successful drilling and production, creating the boom during the past few years in areas such as the Bakken, Niobrara, Eagle Ford, and Marcellus.

The Marcellus gas shale area covers about 95,000 sq miles in the Appalachian mountains of New York, Pennsylvania, and West Virginia, although most of the activity is in Pennsylvania. Depth of the Marcellus reservoir ranges from about 4,000 to 8,500 ft and has a net thickness of between 50 and 200 ft. Original gas in place totals about 1,500 Tcf, with about 262 Tcf of economically recoverable gas. However, with the application of the latest existing technologies and those under development, this figure could increase significantly as operators continually seek the most economic solutions to turning the estimated ultimate recovery (EUR) of 3.6 Bcf into technically recoverable resources.

The number of Marcellus gas shale operators has grown significantly during the past couple of years, attracting majors such as Chevron, which purchased acreage and prospects from another operator, and Statoil, which entered the play the same way as Chevron. Other companies have been active in the play since the beginning of its present popularity, including Anadarko, Range Resources, and Seneca Resources, to name a few. The region’s relatively low well cost, averaging US $3.5 million with a finding cost of about $1.19 per Mcf of gas, is attractive even in times of low natural gas prices.

As a result, many operators are aiming more of their capital expenditures toward the Marcellus play. Anadarko estimated its 2011 capital expenditures between $5.6 and $6 billion, with about 10% of that budget earmarked for the Marcellus and Eagle Ford shales. The company anticipates operating 10 rigs in Marcellus in 2011 and participating in more than 250 wells. Anadarko also said the Marcellus “will continue to be the only domestic dry natural gas field where it will be actively drilling due to the play’s proximity to premium natural gas markets that enhance the already robust economics.”

Range Resources’ 2011 capital budget is $1.38 billion. A whopping 86% of that figure is earmarked for the Marcellus. The remainder will be spent in the company’s Midcontinent, Appalachian, and Southwest divisions. The 2011 capital budget includes $1.13 billion for drilling and recompletions, $160 million for seismic, and $35 million for pipelines and facilities.

Seneca Resources said its fiscal 2012 capital budget will be in the $685 to $800 million range. This includes the planned drilling of 115 to 140 gross horizontal wells in the Marcellus, of which 80 to 95 will be operated by the company. The remainder will be operated by EOG Resources under a joint venture with Seneca Resources. In order to
concentrate its resources in its onshore prospects, Seneca sold its offshore Gulf of Mexico oil and natural gas properties for $70 million in a shift to further fund its Marcellus activities.

The company in March 2011 reached a major milestone in the Marcellus with a daily net production rate of more than 100 MMcf/d of natural gas. The company reported net production of about 120 MMcf/d from 32 operated and 27 non-operated wells.

“Longer laterals and more frac stages have allowed us to achieve outstanding results,” said Matt Cabell, Seneca Resources’ president.

That hasn’t occurred without a price. “While our well costs have increased as a result of additional frac stages and increased service company charges,” he continued, “this has been offset by higher anticipated EUR factors.

“We are now anticipating well costs of $5 to $6.4 million for wells with up to 20 frac stages and lateral lengths reaching over 6,000 ft,” Cabell said. “Taking these factors into account, we expect to see results continue to improve over time, with some of our best wells achieving EURs of 8 Bcf.”

Service companies are doing their best to make sure Seneca Resources and other operators achieve their production goals economically. Recent innovations include LWD tools and software, better geosteering capabilities to keep the bit steered in the formation’s sweet spot, “shale-specific” drill bits, greater use of electromagnetic (EM) telemetry in conjunction with MWD tools, and high build-rate rotary steerable systems (RSS) to reach the horizontal lateral quicker.

**One operator’s drilling experience**

Anadarko has been operating in the Marcellus Shale for several years, and it has used different tools and technologies to drill the most efficient and economical wells possible. Of course, sometimes a more expensive tool or technology must be used to save time. Over the last couple of years in the Marcellus, Anadarko has managed to shave off more than one-third of the time it takes them to drill a well to TD, from about 32 days to fewer than 20 days average, with current records in the 13-day range.

The company plans to drill about 120 wells in 2011 compared with about 50 wells drilled in 2010 and about a dozen wells from May through December 2009. Anadarko’s drilling operations in the Marcellus are 100% closed loop.

“We are a believer in high-performance skiddable AC drilling rigs, where we have the ability to control multiple drilling parameters from an electronic touch screen control with software and algorithms that maximize ROP,” said Steve Woelfel, Anadarko’s drilling manager in the Marcellus. “We are working to achieve more of a factory type of process in every step of the well construction process. We typically batch-drill up to six wells per pad in development mode, which allows us to capitalize on the efficiencies of repeating the same processes with the same rig team in a short period of time where learnings required for continuous improvement are applied immediately.”

The operator currently operates nine rigs in the Marcellus, including eight large drilling rigs and one rig used to spud the well and drill the top-hole section. Woelfel said he expects the company to remain at that rig level.

He added that when achieving record wells, Anadarko spent 50% to 60% of the time actually drilling. “The other 40% to 50% of the time is flat...
time, and that is where we are taking a hard look at how to reduce flat time during casing running and cementing operations and other parts of the well construction process,” he said.

Anadarko, like many other operators in the Marcellus and elsewhere, drilled several wells with RSS with and without positive displacement motors (PDMs) and used mud pulse telemetry to send downhole data to surface. However, it recently has been using EM telemetry for faster data transmission and “shale-specific” drill bits to help increase ROP. Anadarko also recently began drilling slimhole wells with significant success, and it intends to use the slimhole technique in all of its wells beginning in summer 2011, according to Woelfel.

**Drilling fluid**

In 2009, Anadarko converted to synthetic-based drilling fluid from water-based fluid, which “solved a lot of our issues and problems,” Woelfel said. “It has been a huge success for us. We can’t get anything more inhibitive or anything slicker with a better friction factor for drilling way out in the lateral.”

One of the issues synthetic-based fluid resolved was stuck pipe, a challenge to avoid when using water-based fluid due to some water-sensitive formation layers coming apart. Other challenges resolved by using synthetic-based fluid were being able to reduce rotating torque and effectively sliding far into the lateral with synthetic-based fluid.

“Synthetic-based fluid eliminated an entire casing string,” Woelfel said. “With water-based mud we had problems in a couple of formations where we had to build a curve and run 7-in. casing to proceed in the Marcellus.

“When we began using synthetic-based mud, we completely eliminated the casing string and the time associated with that,” he added.

**Rotary steerable systems**

Anadarko used RSS and still does to a certain degree, depending on the well, but Woelfel said the company can usually drill faster, particularly in the lateral section of the well, with conventional motors. Theoretically, if considerable sliding time is required to hold TVD and azimuth with a motor (a relative “tight” target window), then one ought to be able to make faster hole continuously rotating with an RSS, assuming it is capable of making the target adjustments required.

“We are in a situation where a lot of [Marcellus] exploration wells use gamma ray to steer the bit and suddenly the rock takes a 30° dip. The geology is complex; it’s truncated and faulted,” Woelfel said.

“A RSS is not very responsive to that kind of change,” he noted. “It can turn maybe 3° or 4° per 100 ft to follow the bed dip. If I have a motor in the hole, I can turn 6°, 7°, or 8° per 100 ft and chase it down before we get out of zone.”

Due to the way rotary steering is priced, Anadarko would have to save two days of drilling for RSS to break even versus a conventional motor spread, according to Woelfel. “It’s very difficult to make the economics,” he added.

Schlumberger and Baker Hughes have been developing high-angle RSS that can make 8° or higher bends, and up to about 16° in some cases. Woelfel said he has begun investigating them.

**EM telemetry**

“One of the technologies that turned out to be a big winner for us is EM telemetry instead of pulse telemetry,” Woelfel said. “We have moved to EM with our MWD.

“Instead of pulsing gamma ray and surveys up the drill pipe, we have been successful with EM technology in the Marcellus, and that is saving us a lot of time,” he explained. “This has been a game changer for us.”

One of the drilling constraints in the Marcellus has been the quality of LWD, Woelfel noted, because steering the bit is more complicated than in the Maverick Basin in the Eagle Ford Shale, where Anadarko also is extremely active. “The Marcellus geology is more complicated than Maverick,” he said. “What we found is that the level of quality of our gamma ray required to steer properly has to be significantly better than what we are using in the Maverick. EM has solved some of those problems.”

Another real plus with an EM package, Woelfel explained, is the ability to place the gamma ray and survey closer to the bit. “With one company we are running EM with gamma ray 35 ft from the bit, and our survey point is 48 ft from the bit,” he said. The
time required to take surveys also is significantly reduced with EM versus pulse technology.

Woelfel noted that gamma ray quality was a problem for the company over the past year. “We are making headway with EM because a lot of our issues with pulse telemetry were [due to] receiving distorted signals due to vibrations or other types of interference that affect pulse telemetry more so than EM,” he explained. “EM will help our team continue to make faster hole.”

Drill bits
Coupled with EM telemetry technology, Anadarko is examining new bit designs as a means to drill the curve and lateral in a single run. The company has examined and run new bit designs referred to as “shale-specific” by the bit manufacturers.

“What we have found is that the welded body bits make the fastest hole,” Woelfel said. “The matrix body bit is an alloy that is more resistant to erosion compared with steel blades that are welded together, but by the nature of the construction, you can’t build a matrix bit as aggressive as a welded blade bit.”

According to Woelfel, the bit companies are referencing the best combination between steerability and aggressiveness. When building the curve of the well, it is usually necessary to use a bit that is stable and holds tool face in order to efficiently build the curve quickly, he said. If the bit is too aggressive, it is difficult to hold the tool face and results in slow drilling of the curve.

“When you get to the lateral you want to make 2,500 ft per day, but the bit won’t drill fast if it’s overly designed to hold tool face,” Woelfel explained. “The compromise is to build a bit that is sufficiently stable to build the curve and sufficiently aggressive to drill as fast as your other drilling constraints allow.

“When the bit companies are talking about multi-purpose bits for shales, they are talking about a bit that has balance to build the curve and drill the lateral quickly, whether it is a matrix or welded blade,” he said.

The bottom line for Anadarko’s Marcellus wells: “If we don’t build the curve and drill the lateral in one run, we don’t consider ourselves successful,” Woelfel emphasized.

Slimhole drilling
Anadarko has reduced the hole size of its recent wells and has been successful to the point at which it is planning on drilling most, if not all, of its future wells in the slimhole mode. The company’s completion requirement calls for a 5½-in. production casing. Originally Anadarko was drilling 8¾-in. hole. Now with its slimhole wells, the company is drilling a 7¼-in. final section, effectively slimming everything, including the amount of cuttings from the well.

“We reduced our cuttings from our slimhole wells by 20%, and that is the cuttings that we generate from the entire well,” Woelfel said. “That reduces the number of trucks used to dispose of cuttings by 20%.”

From the top of the well, the operator now begins with a 14¾-in. top hole rather than a 17½-in. hole to about 700 ft. The next hole size from 700 to 2,000 ft is drilled with 10⁵⁄₈-in. hole rather than 12¼-in. hole. Each of these sections is drilled about 20% faster than before. When drilling the 7¼-in. curve and lateral (compared with 8¾-in. drill pipe previously), the drilling rate is constrained by other issues, although Woelfel said they drilled faster than before when building the curve and through the lateral.

“We place a premium on hydraulic horsepower from the rigs,” Woelfel explained. “We spin that pipe as fast as we can and pump as hard as we can; our annular velocities are very high, and we end up with a good clean hole, and 5½-in. production casing goes right to bottom.”

As a result, Anadarko drills wells faster, reducing the cost of cuttings disposal.

Extending productive lateral length within lease lines
RSS were considered a game changer in offshore drilling when they were developed and commercialized. RSS usually result in faster drilling, more precise placement of the well into a reservoir’s sweet spot, and a smooth wellbore that aids in casing running and completion design. RSS enable an operator to drill curves and horizontal sections in one run while also steering the bit through any dips and faults in order to remain in the target formation. A
conventional RSS has a build capability of 5° to 6°/100 ft, and as a result, the curve must begin higher in the well, requiring a long curve section and reaching the lateral section far from the vertical.

Today, service companies have been developing high-build RSS that provide all of the drilling advantages as a conventional RSS plus a few more important benefits. They include the operator’s ability to enter the lateral quicker, increasing the length of the productive horizontal section and still remaining within the lease line. Baker Hughes has been gathering experience with high build-rate RSS for some time, in different environments.

“With high build-rate RSS, an operator can kick off deeper so he can maximize his performance in the vertical, reduce torque and drag, and often minimize the intervals spent in difficult zones that don’t generate any value,” said Olof Hummes, product manager-Rotary Steerable Systems for Baker Hughes. “We have been able to achieve build rates in the relevant range of 10° to 15°/100 ft and higher.”

The high build-rate system uses expanding steering pads that push against the side of the wellbore and deflect the bit farther than the company’s standard-build rate RSS. “The steering pads are designed to work in different formations from soft to very hard or brittle,” Hummes said.

Additionally, the bottomhole assembly (BHA) is more flexible to manage the increased bending loads.

“We want to make sure that the fatigue life isn’t compromised and the tool is not running into a situation where components begin breaking,” Hummes explained.

“We are testing the high-angle RSS in different plays and have, for instance, used the system in the softer Eagle Ford and the hard Granite Wash basins to determine its capability in different formations. A large part of the testing is to be able to offer an optimized system because while it is about build rates, it also is about drilling performance,” he said.

The company designed bits for the high-build RSS that optimize ROP in the target formation environment while delivering the required directional control. At the same time, the steering is completely independent of bit hydraulics or mud pressure and is not affected by changes to the flow rate, mud properties, or bit nozzle size.

With Baker Hughes’ high-build RSS, an operator can land the bit into and potentially produce from an additional 760 ft of lateral reservoir compared with a typical RSS that delivers a dogleg severity of 5°/100 ft.

The company’s high-build RSS have reduced the number of days to drill and complete wells in different formations, resulting in significant savings of drilling and completion costs as well as significantly increasing the length of the producing horizontal lateral section.

directional bits for shales, EM technology, and BATS

Halliburton’s Drill Bits and Services business line has developed directional drill bits specifically for shale basins, including the Marcellus, and has set several performance records. Matrix body bits are used in many of the shale basins in the US because of their durability, wear, and erosion resistance, according to the company.

Halliburton’s steel body bits are run in the Haynesville and other shale basins because of the shales’ high clay content as well as high temperatures and pressures. An advantage of a steel body bit is its high blade standoff with a lot of evacuation room for cuttings such as are found in the Haynesville. The company said it has not found any other shale basin where the cuttings have exceeded the cleaning capacity of its matrix body bits.

“One issue with steel body bits is that the high flow and high-speed drilling applications cause a
lot of erosion to the bit and sometimes result in lost cutters,” said Guy Lefort, Halliburton’s US Southern Region drill bit technology manager. “We made the decision to use a more durable body material, especially for Marcellus, because it doesn’t have the stickier high clay content of other shales.

“Our shale-specific bits are our FXD series optimized for the region,” Lefort said. “They have flat, short profiles and depth-of-cut control for better steerability to minimize torque and tool face issues. To obtain the hydraulic efficiency, the blades are very narrow and tall.”

While Halliburton has been designing and manufacturing directional-specific bits for several years, the first-generation bit designs for the Marcellus have been available since early 2010, although the latest top-performing bits have been in the Marcellus Basin since earlier this year.

“We had brought in some designs from other areas in the beginning,” Lefort said, “but we really began customizing them in the middle of 2010 even though offset information was limited due to the information sharing in this ‘tight hole’ environment.

“Now they are sharing more information with us, and that resulted in improved bit performance and reduced drilling days,” he added.

For the Marcellus and other shale basins, Halliburton’s Application Design Evaluation specialists needed to design a bit that would result in higher build rates in the curve to maximize the well’s lateral length inside short lease lines. The bit designs took a four-pronged approach.
First, the bit was designed to be much more laterally aggressive and steerable than in the past. Designers used modeling systems to match the bit to the drive system to achieve the build rates they wanted. Second, bit profiles became flatter and shorter.

“We also incorporated more of what I call depth-of-cut features,” Lefort explained. “It is critical for the depth-of-cut features to be placed more accurately than we had in the past, and they had to match the drive system or steerable motor.”

Finally, the bits had to have optimized hydraulics to achieve the ROP the operators wanted.

“The new custom-designed shale bits are able to achieve the build rates operators need plus drill at very high ROP,” Lefort explained.

Case studies
Halliburton Drill Bits and Services has several case studies showing record performance bit runs with their FXD54M bits in the Bradford Field in Sullivan County, Pa. In one run, the 8½-in. FXD54M bit set a field record for ROP at 91.7 ft/hr drilling the lateral section of 3,668 ft in 40 hours with good tool face control and no downhole tool failures (DTF) or nonproductive time (NPT). The bit outperformed the offset wells, setting the benchmark in ROP and cost per ft, and was pulled out of the hole in excellent condition.

The directional drilling report showed that the bit averaged 148 hours rotating and 45.8 ft/hr sliding for an average ROP of 117.7 ft/hr without connections.

Another run established a field ROP record with a directional motor assembly in Greene County, Pa. The 7¾-in. FXD54M set the field ROP record drilling the 4,444 ft lateral section in 42.5 hrs, averaging 104.5 ft/hr on a conventional directional motor assembly with surveys and connections included. The bit had good tool face control, no DTF or NPT, and outperformed the offset wells in ROP and cost per foot. The offsets were from 8½-in. hole sections.

In another run the 7¾-in. FXD54M bit drilled the entire lateral section of 5,665 ft in 80.5 hrs for an overall ROP of 70.4 ft/hr and generated a cost per foot of $18.56. The bit provided good tool face control, resulted in no DTF or NPT, and outperformed the offset averages in footage drilled and ROP cost per foot. The bit emerged from the well in excellent dull condition.

Optimal bit placement
The company’s Sperry Drilling business line offers several tools and software to optimally place the bit, whether drilling the vertical, curve, or lateral. Some of the tools include its RSS, EM telemetry technology, and its Bi-modal Acoustic LWD Sonic tool (BAT).

The company’s EZ-Pilot RSS is being marketed as an economical system that was developed specifically for onshore applications and is being used successfully in shorter laterals typical in the Marcellus. The company also markets its full-blown Geo-Pilot RSS for longer laterals in other unconventional basins, although it also has been used in Marcellus wells.

“We are seeing some operators drill longer-length laterals to reduce their footprint,” said Patrick Connors, Northeast District operations manager for Sperry Drilling. “If you can drill six 10,000-ft laterals from one pad, you can have better access to the reservoir.”

The EZ-Pilot works by controlling orientation of the eccentric cam system that offsets the mandrel and the bit in the desired direction. Rotation of the cam system to change tool face orientation is accomplished by controlling an ultra high-torque DC motor powered by lithium batteries. The position of the outer housing is constantly monitored, and the tool automatically corrects the eccentric cam system setting as required to maintain proper toolface orientation.

The target tool face is set through rotary speed commands sent from the surface pulsed or electromagnetic telemetry.

EM telemetry
“In general, we run the bulk of our jobs across the Marcellus with EM telemetry,” Connors said. “The EM system works in most plays. Even in Marcellus there are areas that are better than others as far as EM systems are concerned.

“We generally know where those areas are, and we also developed techniques specific to Sperry that
enable us to have more access to different locations," Connors noted.

EM telemetry transmits the data signals through casing in the well or the casing of an offset well on the same pad. The technology can transmit at a higher data rate compared with mud pulse telemetry, which reduces survey time. EM telemetry transmits downhole survey data to the surface and also transmits data and commands to downhole tools such as EZ-Pilot and other tools.

EM telemetry is useful for high ROP applications where real-time logging data can be an issue, in geosteering applications with EZ-Pilot or Geo-Pilot, and in shallow TVD and extended-reach horizontal wells. A through-bore repeater system is available for increased depth range and signal strength. There are no moving parts in the system, increasing reliability and eliminating trips and NPT due to tool failure.

Sonic tools
The company’s BAT and QBAT services are used to identify stress direction, rock ductility, and brittleness. BAT and QBAT can provide porosity determination and formation mechanical properties, pore pressure determination, rock strength calculations, and borehole stability analysis.

“It essentially allows the operator to drill toward the good formation rock, doing that in real time, and being able to right-size your frac job by putting your stages in the proper areas,” Connors explained.

High-build rotary steering, bits for shale, channel fracturing, expanding cement
Service companies continually listen to and work with their clients to provide technology and solutions that result in optimal drilling, completions, and production of their wells as well as develop new technologies that can further enhance performance and economics of a well. For example, operators don’t use RSS in the Marcellus as much as in other shales, as many operators don’t consider the cost versus the reward justified in the Marcellus. Drilling operations, although complex, are not as complex as in other shale basins. However, some operators are re-examining rotary steering now that a couple of service providers have introduced high build-rate systems to get into the lateral quicker and be able to stay there. Of course, a smooth wellbore doesn’t hurt the situation, either.

High build-rate RSS
Schlumberger is one of the companies that developed a rotary steerable system that was developed and designed to drill the vertical well section, curve, and lateral in one run, eliminating flat time and improving efficiency.

“Part of the reason we developed the PowerDrive Archer, other than the advantage of drilling the well without a bit trip, which everyone cares about,” said Dale Logan, Schlumberger’s regional account manager for the Northeast Basin based in Pennsylvania, “is so operators can hit the reservoir earlier, which means more reservoir exposure and increased hydrocarbon potential.

“PowerDrive Archer was extensively field-tested in many US shale basins, drilling wells only previously possible with motors, and has achieved build rates exceeding 17°/100 ft,” he said.

Case study
In one Marcellus well, the PowerDrive Archer RSS increased ROP 170%, cut drilling time by 10 days, and saved the operator more than $1 million. To extract Marcellus gas economically, horizontal wells are drilled from multiwell pads and completed with multistage fractures of the horizontal lateral section. The operation is complex and difficult due to surface pad collision risks, 3-D profiles with planned curvature rates of 8°/100 ft, and formations that can make directional control difficult.

The hybrid PowerDrive Archer RSS combines point-the-bit and push-the-bit steering and can drill the vertical, curve, and lateral sections in one run. Traditionally, the vertical section of a Marcellus well is air-drilled; a 9¾-in. shoe is set; and the 8¾-in. hole section is kicked off, built, and landed in the Marcellus Formation with a PDM. Much of the time, however, the drill pipe and PDM are in sliding mode, which results in lower ROP, poor hole cleaning, and wellbore tortuosity. Additionally, trips were required to adjust the PDM’s bent housing when encountering geological uncertainties, resulting in increased time and cost.
The company used its PowerDrive Archer RSS when a Marcellus operator was planning a multi-well operation and wanted to improve ROP and hole quality. The first well was drilled with a PDM to establish a benchmark. All subsequent wells were drilled with the PowerDrive Archer RSS.

These wells were typically kicked off from vertical with a long turn in azimuth of 90° or more to line up with the target while simultaneously building inclination at planned rates up to 8°/100 ft. Due to geological uncertainties approaching the landing point, higher build rates up to 17°/100 ft were sometimes required to land the well.

The ability to kick off from vertical, deliver 2-D and 3-D curves with build rates up to 17°/100 ft, drill tangent sections, and land wells on target in a single run enabled the operator to reduce drilling time from 18 days with a PDM to eight days on the 10th well drilled with the PowerDrive Archer RSS, according to the company. Average ROP increased 170% compared to the benchmark ROP. Eliminating sliding with a PDM resulted in a high-quality wellbore that allowed smooth casing runs. The operator saved more than $1 million on the first 10 wells drilled with PowerDrive Archer.

Shale optimized drill bit
A couple of bit manufacturers have developed “shale-optimized bits,” application-specific bits with designs and technologies aimed at increasing performance and economics. The Spear shale-optimized steel-body PDC drill bit from Smith Bits is specifically designed for shale plays. Smith Bits’ field, design, and hydraulics engineers used proprietary design and database tools including IDEAS, an integrated drillbit design platform to predict bit and BHA performance. DBOS drillbit optimization system for rock strength analysis also
was utilized, as was YieldPoint RT drilling hydraulics and hole cleaning simulation program and DRS drilling record system, a collection of nearly 3 million bit runs.

Manufacturing the bit from steel provides more flexibility in the design criteria and allows increased blade height to optimize the blade/body configuration for shales, according to the company. Erosion to the steel body bit that could be caused by drilling mud and cuttings was alleviated by use of computational fluid dynamics that simulated at-bit flow for optimal nozzle placement and orientation. Hard facing of the bit help protect the steel from erosion.

“By combining new bit technology with new directional drilling technology, the industry can expect another leap forward in drilling efficiency,” Logan said. “The impact to the operator is that he moves to the next well quicker to drill more wells per rig per year. This is critical to operators who are under pressure to fulfill large leasehold obligations,” Logan added.

Case study
EOG Resources wanted to reduce the number of days and trips required to drill the 7¾-in. curve and lateral sections of its Marcellus wells by drilling both sections in one run. Previous bit designs were aimed primarily at either the curve or the lateral, requiring a trip to change the bit and adjust the motor bend angle at the end of the curve section. Additionally, EOG wanted to reduce NPT caused by motor and MWD failures. EOG provided BHA data, mud properties, and offset run information.

Smith Bits’ engineers needed to design a PDC bit that could be run on a PDM with a lower bend angle, allowing rotation and a high ROP in the lateral section. A the same time, however, the bit had to be capable of achieving the necessary build rates of 8° to 16°/100 ft while ensuring good directional control in the curve. Long lateral drilling in shales presents additional challenges such as cuttings accumulation at the bottom of the well, which impedes access to fresh rock and results in lower ROP, packed blades, plugged nozzles, and stick/slip.

The result was the Spear 7¾-in. SDi513 steel body PDC bit specifically designed for Marcellus shales.

The bit, in combination with a fixed bend steerable motor, drilled the 6,241 ft curve and horizontal interval in one run, eliminating trips for PDM adjustments and bit changes after landing the curve. Reduced bit and tool vibration solved the issues of PDM and MWD failures. The bit’s bullet shaped steel body and other design features alleviated buildup of cuttings in front of the bit.

In comparisons with the average offset wells, total drilling time was reduced by 2.7 days, saving EOG $175,000 in rig time and bit costs. The shortened time to production also allowed more wells to be drilled in a given period.

Channel fracturing
“One recent technology that we anticipate will have an impact in shales is a new fracturing technique that has been popular in the Eagle Ford Basin,” Logan said.

The technique, called channel fracturing, is offered by the company commercially in its HiWAY product. The technique involves mixing fibers with proppant to create channels through the fracture network to enhance conductivity of the network, Logan explained.

Rather than leaving fracture flow dependent on proppant pack conductivity, HiWAY creates stable channels for hydrocarbons to flow through, increasing the effective fracture conductivity. Operators can get better productivity from their wells, he noted, and frac jobs can be performed with less proppant. “On a typical HiWAY job we pump half as much proppant, and the amount of fibers is small,” Logan said.

The successful application of channel fracturing is very much formation-specific, and it cannot be universally applied, Logan noted.

Case study
In the Hawkville Field in the Eagle Ford Basin, Petrohawk wanted to improve production and EUR from its Eagle Ford wells. Production from the area is driven by the effective stimulated reservoir volume (SRV) and the reservoir connectivity with the wellbore that can be established with hydraulic fracturing. The field has very high fracture gradients and high bottomhole temperatures at depths between 10,000 and 13,000 ft. Since the discovery of this section of the Eagle Ford in 2008, the formation has been stimulated typically with multistage horizontal completions with high-rate slickwater treatments. Recently,
however, there has been a trend to use polymer-based crosslinked and hybrid treatments, which led to a moderate improvement in production.

Petrohawk and Schlumberger implemented the HiWAY technique in two wells to build an assessment. Results from the two wells were compared with those from valid offsets previously stimulated by conventional techniques. The results indicated that channel fracturing gave the first well fractured with the HiWAY technique a maximum initial rate of 14.5 MMcf/d, or 37% higher initial gas production than the best comparable offset well. The technique gave the second well a maximum initial rate of 820 b/d, or 32% higher initial oil production rate than the best comparable offset. Additional wells have been completed for Petrohawk using the channel fracturing technique, and all have shown production trends consistent with the initial test wells, according to Schlumberger.

Surface gas migration

“In the northeast US there is a lot of interest from the public in what the industry is doing and why we are doing it,” Logan said. “There are a lot of shallow gas zones that are not far from where people get their drinking water, and there is concern that because of the drilling activity, that gas is migrating into drinking water.”

As a result, Logan said, the industry is examining new cement systems to mitigate the risk of gas migration. Expandable cement is not a new solution, but it has not been used in the Marcellus until recently. “The cement is more flexible and makes a seal that can handle the jarring from a high-volume frac job,” Logan said. “It is more likely to maintain the isolation created during the cement job because it bends and flexes rather than breaks.”

The cement involves the use of multiple inert solids and engineered particles that provide maximum flexibility and expansion, according to the company, and provides positive linear expansion compared to most conventional cements that shrink, preserving well integrity during stimulation treatments. The cement can be engineered for use in shale gas wells, heavy oil environments, and high-temperature wells above 300°F. The cement can be used in temperatures ranging from 40 to 300°F.

During placement, the cement can provide optimized slurry viscosity and solids volume fraction suitable for effective mud removal and flat interface of fluids, according to the company. After placement, the result is low gel strength, short transition time, and fluid loss control suitable for gas migration environments. The cement can expand up to 2%.