Shale gas developments: enabled by technology

Andrew Jennings* reviews some exploration and development technologies employed by Schlumberger that have supported the economic production of shale gas in the US and are now being applied to resources in Europe and around the world.

The generally accepted theory of the origins of oil and gas is that they are derived from organic materials that sank to the bottom of seas or lakes in conditions short of oxygen, as commonly found when such materials become buried by fine mud, which later hardens into shale. Burial under increasing thicknesses of mud and other sediments leads to an increase in pressure and temperature that converts the organic material to kerogen, the primary ingredient of hydrocarbons. Further increases in pressure and temperature led to conversion of the kerogen to oil and gas. Some of this oil and gas migrates into adjacent rocks, but much of it is likely to remain behind, trapped within the remaining kerogen and between the mineral matrix of the shale (Fig 1.).

Most global gas production has, until now, been from sandstones and limestones with high permeability related to well-connected granular porosity or natural fractures that allow the easy flow of gas into a well. While many shales around the world contain large volumes of gas, they have until recently generally been considered uneconomic for commercial production due to their low permeability. Increases in global gas prices, coupled with the development of several new technologies, are making economic gas production from shale increasingly viable. Technologies to optimize exploration and development of shale gas are now well-proven in the US, and continuous improvements in efficiency are significantly reducing the cost of well construction. Several operators are now leveraging experience from the US to develop shale gas reservoirs in Europe and elsewhere.

Hydraulic fracturing

Natural fractures can improve permeability, but in gas shales they are frequently mineralized, and usually do not provide sufficient pathways for the flow of hydrocarbons into a well to support economic levels of production. Most gas shales therefore require hydraulic fracturing to increase the rate at which hydrocarbons can be produced from the rock formation. Fluids are pumped into a well at high pressure, causing the formation to crack. Solid proppant materials – typically sieved round sand grains or man-made ceramic spheres – are added to the fracture fluid. These solids hold the fractures open after the injection stops, and are higher in permeability than the surrounding formation, so the propped hydraulic fracture becomes a conductive path through which fluids can flow from the rock formation to the well.

Horizontal drilling

Shale gas reservoir components are typically just 10s of metres thick vertically but extend laterally over several kilometres. One of the major examples in the US is the Middle Devonian Marcellus shale, which extends over areas of Ohio, West Virginia, Maryland, Pennsylvania, and New York. It is believed to hold in excess of 1000 tcf of natural gas, of which an estimated 500 tcf is considered recoverable (Engleder, 2009).

In common with many other shale gas reservoirs, the Marcellus play was initially developed using vertical wells, but these delivered low production rates. To extract the hydrocarbons at more economically viable rates, horizontal wells are now widely used, providing contact to long producing reservoir sections. Experience from the Barnett Shale in Texas suggests that horizontal wells in this play attain approximately three times the estimated ultimate recovery of vertical wells for only about twice the cost.

Typically, several horizontal wells are drilled from one surface installation, or ‘pad’. The wells are challenging to drill due

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Figure 1 Example gas shale micro-image. Black is pores, dark grey is kerogen, light grey is shale minerals.
to risk of collision close to the pad; complex 3D profiles with planned curvature rates in excess of $8^{\circ}/100$ ft; more geological uncertainty; and formations that make directional control difficult. The wells are often completed with multi-stage perforating and fracturing. Multi-stage completions require long sections of equipment to be installed from the surface into the whole of the lateral producing section. A smooth borehole improves the likelihood of successfully running the completions equipment to the bottom, particularly in extended reach laterals.

**Steerable motors**

Typical conventional directional drilling systems utilize a positive displacement mud motor with a $1.5^{\circ}$ bend about 5 ft behind the bit. This bend tilts the bit face and cutting structure from the bottomhole assembly (BHA) axis. The whole assembly rotates when drilling in a straight trajectory. When it is necessary to change trajectory, drillstring rotation is stopped and the bit is turned by pumping mud through the motor. The bend points the bit in a direction different from the axis of the wellbore. This is called ‘sliding mode’. Wellbore trajectory control is achieved by controlling the amount of hole drilled in the sliding versus the rotating mode.

When the drillstring is not rotating, there is an increased risk of equipment sticking in the wellbore, leading to stress, equipment fatigue, and the possibility of having to abandon the BHA downhole. When in rotating mode, because of the bend in the drilling assembly, the bit rotates off-centre from the BHA axis and drills a slightly enlarged and spiral shaped borehole. The resulting rough sides of the wellbore can cause problems, especially in long lateral sections, on account of increased torque and drag when running complex completion equipment into the hole.

**Rotary steerable systems**

A rotary steerable system (RSS) is an improved method of controlling the trajectory of vertical and deviated wells, and usually delivers a higher rate of penetration (ROP) compared with a steerable motor system. With the latest generations of RSS technology, all external components rotate, a feature that reduces the risk of mechanical or differential sticking and improves wellbore quality and consistency of hole diameter for easier well completion (Fig. 2). High build-rate RSS technologies have recently been developed that can deliver complex well profiles. Recent field trials confirm the system can deliver high build rates in many formations (some wells exceeding $17^\circ/100$ ft) from any inclination, and in a single shoe-to-shoe run with no flat time for trips to change the BHA.

**Drill bits designed for shale**

The 20th century saw the development of rotating, rolling cone, steel drill bits that could quickly cut through soft rocks. Unprotected steel can be worn down rapidly, so it is often covered with inserts of tungsten carbide, which is more brittle than steel but has greater resistance to erosion. In other cases the entire bit body is made from tungsten carbide. The early 1970s saw the development of a process to create small crystals of synthetic diamond that bond together to become polycrystalline diamond compact (PDC). These PDC inserts, typically 11–16 mm in diameter, are incorporated into the cutting faces of bits, where they drill by digging into the formation and gouging out rock. The PDC cutters are usually arranged at the ends of blades that extend from the bit body. This arrangement facilitates the rapid flow of drilling mud to cool the cutting edges and carry away rock cuttings.

Based on experience with drilling horizontal wells in sandstones and limestones, shale gas wells have typically been drilled with tungsten carbide PDC bits; however, field and laboratory analysis has indicated several inefficiencies when drilling through these soft formations. Long lateral drilling with conventional PDC bits in shale plays was found to result in premature bit failure and short runs because of bit balling, poor directional behaviour, and loss of tool face control. Lack of hydraulic energy at the drill bit meant that cuttings accumulated at the bottom of the well and could not efficiently move around the bit or escape up the annulus. This impeded access to fresh rock and dramatically reduced ROP. Packed blades and plugged nozzles were other consequences, together with drillstring stick/slip, which is detrimental to directional control.

A new shale-optimized steel body PDC bit has been developed (Fig. 3), specifically designed to efficiently drill a curve and long lateral hole section for faster well construction in low hydraulic energy environments. The low abrasiveness of shale means that steel is durable enough to drill these soft formations. Because it is less brittle than tungsten carbide, steel allows for the cutting blades to extend further from the bit body without suffering forces that would lead them to fail and break off. The bit enables high ROP through a combination of tall and thin blades, which provide a large area for cuttings flow. A special hydraulic design directs flow towards the cutter faces, keeping them sharp, and also helps sweep cuttings away from the bottom of the hole and around the bullet-shaped body into the annulus.
The new shale-optimized steel body PDC drill bit has been used successfully in the Bakken, Barnett, Marcellus, Haynesville, and Eagle Ford shale formations of North America. In the Marcellus application, the target ROP goal for drilling the horizontal leg with an 8 1/2 in bit was 50 ft/hr. The new bit achieved ROPs in excess of 65 ft/hr, a 30% improvement over the operator-set target. In the Haynesville area, a 6 5/8 in the bit has been consistently drilling the horizontal section in one run at ROP’s 10–20% faster than the best offset performance.

**Azimuthal LWD imaging**

Shale reservoir rock quality can be highly variable within narrow vertical and horizontal sections, and shale zones often tend to undulate. Real-time acquisition, interpretation, and integration of measurements made while drilling can help prevent unexpected drilling events and keep the wellbore in the most productive zones or sweet spots.

Most shale plays exhibit high natural gamma ray activity, so gamma ray logs are typically run in the vertical evaluation wells that are usually drilled early during field development to delineate the reservoirs. The resulting data are commonly used for correlation with gamma-ray measurement-while-drilling (MWD) when placing the horizontal production wells. These wells are typically steered within a defined target window using non-azimuthal, averaged gamma ray measurements. While gamma ray measurements can be effective for correlations in vertical and high-angle wells, using this measurement alone for structural modelling can potentially provide non-unique solutions in a horizontal well environment. Inconsistent and inaccurate reservoir interpretations are likely to result in variable production rates, not only between hydraulic fracturing stages but also from well to well.

Resistivity measurements complement gamma ray data as they provide extra information for correlation. Further improvements in the accuracy of the modelled structure can be provided through estimates of dip along the well trajectory based on azimuthal images from real-time logging-while-drilling (LWD) density measurements. A validated structural model enables a higher level of confidence in real-time steering decisions. An accurate structural model is also an effective tool to aid completion designs, correlate formation properties, refine target delineation, and provide a foundation for evaluating production logs and hydraulic fracture monitoring observations.

In the Woodford Shale in Oklahoma, standard non-azimuthal representation of resistivity, density, and porosity MWD data were shown to provide very little steering information or contrast across prominent gamma ray changes observed along the lateral (Kok et al., 2010). Differing independent models built using the same non-azimuthal data illustrated the capacity for non-unique structural solutions. Additional measurements, such as resistivity and density images, were shown to provide insight to remove incoherent interpretations, refine the structural model, and improve its accuracy. Having high confidence in the structural model promotes accurate steering decisions. This mitigates out-of-zone drilling that may lead to expensive and unnecessary sidetracks or poor producing intervals. During real-time drilling operations, azimuthal images can help steer horizontal wells for precise well placement within narrow target windows. Target windows less than 10 ft have been effectively steered within various shale plays using density images.

**Multipole sonic-while-drilling**

A new sonic LWD service is available that provides multipole measurements to consistently and reliably deliver compressional and shear data. It also offers a dedicated mode for acquiring Stoneley waveforms while drilling, which ensures high quality data before washouts can develop. In a fast formation, a monopole tool can deliver shear slowness since its shear slowness (1/velocity) is lower than the slowness of the drilling mud. When shear slowness is higher than mud slowness, a quadrupole tool is needed to provide the shear measurement. The new service combines high quality monopole and quadrupole measurements to deliver robust compressional and shear slownesses – along with enhanced Stoneley data – in a wide range of applications, regardless of formation slowness. Completely reassessed strategies for handling and processing acoustic data, coupled with extensive modelling, ensure a predictable response in almost any environment.

The Stoneley borehole wave is sensitive to open permeable fractures, and can be evaluated using a forward modelling technique. In water-based mud, Stoneley for fracture analysis

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**Figure 3** Shale optimized steel body PDC drill bit with sleek profile, thin high steel blades, and wide junk slots.
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can be combined with while-drilling high-resolution imaging to completely describe the fracture network. The combination of acoustic measurements provided by the new service enables the assessment of rock mechanics and characterization of fractures, which is crucial for designing complex completions to optimize production from tight formations. The technique can be applied to highly deviated and horizontal wells, where running wireline logs may be challenging.

Seismic: the key to large-scale shale gas exploration
Shale gas fields often extend over very large areas, and these unconventional plays are frequently not in traditional oil and gas producing regions, so there is likely to be limited existing seismic or well data. This is particularly true for new gas development regions such as the Baltic shale of Poland, a 100,000 km² area with, until recently, only five wells, none of which have modern log data. The first of two planned exploration wells in the area, specifically designed to evaluate the potential of shale gas production, reached total depth in August 2010, including coring operations of the target shales. Further possible complications in undeveloped areas include higher drilling costs, greater environmental concerns and restrictions, and access limitations. In many countries, the rights of land owners do not extend to underground resources, so there is little incentive to allow access for exploration.

An accurate geological understanding, including the presence of faults and natural fractures, is an essential prerequisite for the successful economic development of a shale gas play. Seismic plays a fundamental part in this process, not only for reservoir characterization and production modelling, but also through the use of seismic-derived properties such as stress maps to support drilling and surface infrastructure decisions. The integrity of the seismic data is particularly important for understanding and developing shale gas, because in addition to imaging horizons and faults, high fidelity acquisition, followed by careful processing and analysis, can provide information about lateral and vertical variation within the reservoir compartments, help establish reservoir quality (RQ) and completion quality (CQ), and optimize hydraulic fracturing strategies. Factors contributing to good RQ include high gas saturation and kerogen content, high matrix permeability and porosity, and high pore pressure. Factors contributing to good CQ include strong fracture containment (large reservoir contact), fracturable formations (resulting in large surface area), and low rock-fluid sensitivity (low loss of surface area). While seismic data alone cannot confirm all of these factors, when combined with other measurements, it can provide an indication of the most prospective well locations.

Point receiver acquisition and inversion
Feasibility tests have been performed to investigate the extent to which point-receiver acquisition and modern processing technologies can improve the temporal and spatial resolution of imaging for shale gas reservoirs relative to conventional seismic systems.

The Bakken resource of the Williston Basin, which covers parts of Montana, North Dakota and South Dakota, produces oil from thin heterogeneous reservoir zones with rapidly varying lithology in a complex shale setting. A 19.2 km 2D test line, passing close to three well locations, was acquired in the area during 2009 using a lightweight, portable, version of a high channel-count point-receiver central recording system (El-Kaseeh et al., 2010). To put more low-frequency energy into the ground, the seismic source used the maximum displacement sweep (MD Sweep). The broadband seismic signal was recorded by geophone accelerometers (GACs), which are designed to preserve signal with less distortion of low frequencies compared with velocity geophones that are typically used for surface seismic recording. The GACs were deployed at 3 m spacing, with the data from each accelerometer recorded as a separate trace. The results indicated that point receiver systems can deliver

Figure 4 Example from Marcellus Shale test line: Seismic attributes from inversion compared with those of well-derived data.
data with broader bandwidth and higher signal fidelity than conventional acquisition methods. Estimations of rock properties from the inverted test data correlated with measurements from the three producing wells close to the test line. Rock physics models enabled dynamic Young’s modulus to be computed, an indication of the brittleness of the reservoir rocks. Brittle rocks are more prone to natural fracturing, and more conducive to artificial fracturing than ductile rocks. They are therefore likely to deliver higher permeability.

Two intersecting 2D test lines were acquired in 2010 using the point-receiver system in an area of New York State where the Marcellus formation is known to exist (Koesoemadinata et al., 2011). All processing was applied in the single sensor domain, maintaining 5 ft midpoint spacing. Curves from a nearby well, including gamma ray, sonic and shear, and bulk density measurements, were available for use in pre-stack inversion. Inversion was also performed on a 0–10° angle stack. Inversion results showed excellent agreement with the well data (Fig. 4). Pre-stack inversion results were used to compute Poisson’s ratio and Young’s modulus attributes, both critical elastic parameters for reservoir quality and completion quality estimation.

As discussed by Banik et al. (2010), Young’s modulus in these low-porosity and low-permeability formations can also be estimated from acoustic impedance. A comparison between the two methods of estimation showed acoustic impedance-based estimation to be superior in this dataset to that from the combined shear impedance, Poisson’s ratio, and density. Both Poisson’s ratio and Young’s modulus were found to vary considerably over the line length. High Young’s modulus and low Poisson’s ratio are zones of interest to drillers, as they indicate high-grade reservoir potential and completion quality for hydraulic fracturing. Combining the two can provide an indication of reservoir and completion quality (Fig. 5).

Lithofacies classification of the thin Marcellus formation clearly differentiated shale-dominated facies from sands, limestone, and dolomites. Results from the test will be formally presented during 2011. Results to date indicate that the inversion workflow is appropriate for a full 3D point-receiver survey, and is likely to provide valuable information about shale gas reservoirs. This information includes anisotropy which should be addressed in any shale gas study, even in the absence of in-situ fractures.

**Spreading the knowledge**

Experience in the US has provided a broad range of advanced technologies and workflows that are continuously being refined to further enhance the economics of shale gas production. In addition to the technologies discussed in this article, there have been advances in geochemical analysis techniques to assess the organic content, thermal maturity, and potential productivity of core samples. Our understanding of natural fractures, reservoir anisotropy, and stress profiles continues to improve: this is essential when predicting the effectiveness of hydraulic fracturing and the resulting fracture geometry.

Knowledge gained in the US in the last few decades is now being used to help guide an increasing interest in shale gas around the world. In Europe, shale gas is being explored in several countries, including Austria, England, France, Germany, Hungary, Poland, and Sweden. As technology advances and knowledge continues to grow, shale gas reserves can be expected to make an increasing contribution to diversifying the global sources of natural gas and supplying the individual energy demands of countries throughout Europe and the rest of the world.

**References**


