The Future of Natural Gas

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Role of Technology in Unconventional Gas Resources

Abstract

Unconventional gas resources play an increasingly important role in supplying low carbon fuel for a growing energy demand. They can be classified into three categories: tight gas, coalbed methane and shale gas. Although there are differences between production behavior and the transport mechanisms governing it, common characteristics of all unconventional resources are: low permeability (less than 1 md); advanced technology is necessary for economic development; and low recovery factors (less than 10%), relative to conventional resources.

Technology development has focused on increasing the amount of contact between the reservoir and the wellbore. Advances in directional drilling and hydraulic fracturing have moved low quality, unconventional gas resources to economically viable sources of natural gas. Basic scientific questions regarding transport mechanisms in these reservoirs exist. Research into understanding properties governing flow and interplay between geochemistry, rock fabric and flow will facilitate the development of technologies to reduce uncertainty in assessing the size of the resource, leading to viable science based energy policies. Through improved understanding of the subtleties of the physics governing transport in unconventional gas resources, technologies tailored to the unique production characteristics of each type of resource can be developed to improve recovery efficiency. Environmental concerns surrounding water resources and development footprint can be reduced as an additional benefit of the technologies gains associated with appropriate deployment of technology.

Introduction

Production performance and recovery from unconventional reservoirs are highly variable between basins and within individual plays. Due to the interdependence of geology, geochemistry, geomechanics and petrophysics on productivity and recovery, an integrated understanding of geologic controls (such as mineralogy, rock textures, depositional environment, present day and paleo stresses) is required for interpreting production behavior and predicting future success. Unconventional gas resources are considered technological plays, where successful economic development of these resources requires advanced technology (such as advanced drilling or massive hydraulic fracture treatments) to improve recovery factors and reduce costs, increasing the economic viability of the resource.

This paper reviews the production characteristics of the three categories of unconventional gas resources: tight gas, coalbed methane and gas shale, and the current state of technology application in these plays. A wide range of resource types is included in this definition, making production mechanisms and recovery efficiencies between the types of unconventional plays significantly different. Successful application of the appropriate technology to improve recovery from unconventional resources requires an understanding of the differences in reservoir type and flow mechanisms between the categories. The level of development of a particular resource is dependent on both the natural potential of the rock and the price that the market can support. Technologies that improve the understanding of mechanisms which govern flow behavior in the reservoir and increase operational efficiency present opportunities to increase recovery from these resources. Environmental benefits of technology applications are discussed, and research areas which offer the potential to increase recovery from unconventional gas reservoirs are identified.

Unconventional Gas Resources

Unconventional gas resources constitute a large component of the remaining gas resource in North America. While unconventional resources do not play as large a role in the resource base in the rest of the world, it is expected that they will play a larger role as understanding of these resources improves and as operators become more proficient at deploying advanced technologies necessary for economic development. As the conventional gas resource base matures and output declines, unconventional resources will play a more prominent role in supplying a growing energy demand.

Tight Gas Reservoirs

Tight gas refers to natural gas reservoirs with very low permeability and porosity (Table 1). They are defined as reservoirs with permeability less than 0.1 md. Rock fabric and texture of low permeability reservoirs are significantly different from those of conventional reservoir rocks (Soeder and Chowdiah 1990). These differences in petrophysical character, lead to a unique production behavior relative to conventional gas resources. Initial production is marked by a steep decline, followed by a stable production period with a slow rate of decline that can last for decades. Figure 1 compares a thin section from a conventional sandstone with that of a tight sandstone. In the conventional sand (Figure 1a), pore space (blue) is interconnected and the size of the pore throats relative to pore bodies are similar, allowing gas to flow easily through the rock. In the tight sand (Figure 1b), pores are distributed irregularly throughout the sample. Pore throats are reduced to narrow slots, creating a more tortuous path through which the gas must flow.

The low permeability of tight gas reservoirs is attributed to the complex diagenetic history which formed the present day fabric of the reservoir. Understanding these processes is critical to predicting production response and develop well designs and completion strategies which exploit existing reservoir characteristics. Tight gas sands are often deeply buried and subject to large compressive stresses, altering the original depositional fabric of the rock. Effects, such as grain dissolution and mineral growth, produce a complex pore network. Soeder and Randolph (1987) evaluated petrophysical properties of cores from the Mesaverde group of the Piceance Basin. They categorize the internal pore geometry of tight gas sandstones into three main groups:

- Grain-supported primary porosity: Primary intergranular pores are supported by contact points between individual rounded quartz grains. These contact points bear the weight of the grains above, providing support to the formation once fluids are depleted from the pore space. Pore throats are plugged by authigenic clay, calcite or quartz cements to reduce permeability. Permeability in this type of pore geometry ranges from 10 to 100 µd.

- Intergranular slot pores connecting secondary solution pores: Primary porosity is reduced to narrow, slot-like pores along the boundaries of quartz overgrowths. Secondary porosity is well developed and comprises the majority of the pore space. Slot porosity provides the flow paths connecting secondary porosity. Fluid flow between the larger sized pores of the secondary porosity system is restricted, resulting in a lower permeability than reservoirs comprised of grain-supported porosity. Permeability in this type of pore geometry ranges from 0.1 to 10 µd.
- Matrix-supported grains: Sand sized quartz grains are supported in a matrix composed of detrital clay. In contrast to grain-supported porosity, pore volume compressibility in matrix supported rocks is high due to the lack of strong quartz-to-quartz grain contacts. Permeabilities in these types of sands are less than 0.1 µd and can decrease significantly upon gas production.

Characterization

One of the challenges in developing low permeability resources is the ability to accurately evaluate rock properties (such as permeability, porosity and capillary pressure). This information is necessary to quantify resource potential and predict production behavior; essential information required for developing viable energy policies and making sound investment decisions for field development. Due to the complex structure of the pore network, simple relationships relating permeability to porosity are not representative. The low permeability of these rocks makes the standard steady-state techniques, widely applicable in evaluating conventional gas reservoirs, inadequate and virtually impossible to implement. Application of these techniques to low permeability rocks yield unrepresentative results. Conventional methods for assessing in-situ reservoir properties (such as shut in pressure build up tests) are not practical due to the very long times required for the reservoir to reach pressure equilibrium and the delay of production (or income from the well) as a consequence of the shut in.

Effect of Overburden Stress

Permeability and porosity measurements of conventional, high permeability reservoirs are normally performed at low pressures and are not representative of in-situ conditions. Due to the well-cemented nature of the rock, there is little change in porosity with increased pressure (Lorenz *et al*. 1984, Soeder and Randolph 1987). Low permeability reservoirs are sensitive to confining pressure (Vairogs *et al.* 1971, Thomas and Ward 1972, Wei *et al.* 1986, Morrow *et al.* 1991). In stressed core experiments, low permeability cores exhibited a decrease in permeability with increasing stress. Brouwer and Morrow (1985) attributed this behavior to the sensitivity of high aspect ratio pore structures to stress. In stressed core experiments, low permeability cores exhibited a decrease in permeability with increasing stress. This explanation for permeability reduction is in agreement with the findings of Davies and Davies (1999) who observed that the greatest response to stress in low permeability reservoirs was found in those dominated by slot pores and pore throats. As stress is increased, the high aspect ratio of slot-like pore structures dominating conductive pathways are compressed and ultimately closed off, restricting fluid flow and increasing tortuosity of flow pathways.

Multiphase Flow Effects

Effective permeability is the permeability of a porous media to a fluid in the presence of one or more additional phases. When another phase is present in the pore space, such as water, less space is available for the gas phase to flow unimpeded in the reservoir, reducing the mobility of the gas phase. The degree of interference is dependent on properties of the fluids, interactions between fluid phases with the solid phase, and the geometry of the pore throats. Presence of partial saturation in the pore space can have a dramatic effect on low permeability reservoirs. In these reservoirs, gas permeability is significantly reduced at water saturations greater than 50% (Cluff and Byrnes 2010), Figure 2. Above this saturation, gas production is effectively zero. Ward and Morrow (1987) measured relative permeabilities Mesaverde Group cores. Effective permeabilities to gas in the presence of water were reduced. When subjected to confining pressures, these were reduced even further (Figure 3).

Basin Centered Gas Accumulations

A class of tight gas reservoirs is basin centered gas accumulations (BCGA), or continuous-gas accumulations. BCGAs are believed to be a unique hydrocarbon system, with characteristics distinct from conventional oil and gas accumulations. They were initially characterized by Masters (1979), and over time, these descriptions have increased in complexity to encompass many members of the unconventional gas category (Law 2002). They are characterized by regionally pervasive gas accumulations, with areal extents covering tens to hundreds of square kilometers. They may occur as single isolated reservoirs a few feet thick, or multiple stacked reservoirs comprising thousands of feet of thickness. Reservoirs are abnormally pressured; overpressured and underpressured rocks are both common in these systems. Many BCGAs are believed to be in close proximity to reservoir rocks, reducing the importance of conventional petroleum systems components of stratigraphic and structural traps on these types of accumulations (Law and Spencer 1993). Controls on these types of accumulations are poorly understood. As a consequence, characteristics of what differentiates a basin centered accumulation from other unconventional gas accumulations are poorly defined. This lack of clarity has led to inefficient exploration and production strategies.

Like most unconventional gas reservoirs, porosities and permeability are low: 5-15% and less than 0.1 md. Water saturations are moderate, ranging from 20-40%. Water production is typically low or absent. Buoyancy is not a significant factor in BCGAs. Some accumulations lack downdip water contacts (Cretaceous Mesaverde sands in Colorado and the Lower Cretaceous Cadotte Member in Alberta), while others may have updip water accumulations where higher density water is found overlying low density gas within a stratum. Masters (1979) introduced the concept of a “water block” to explain the presence of water bearing sands above gas within a lithologically continuous unit. In this interpretation, the relative permeability of gas becomes effectively zero at high water saturations, rendering the rock incapable of production. Extending this to explain production behavior from very low permeability sands, the concept of a “relative permeability jail” is introduced (Figure 4). As the absolute permeability of the reservoir decreases, gas-water relative permeability curves separate. The crossover point where gas is no longer the preferentially mobile fluid decreases. Cluff and Byrnes (2010) define a threshold relative permeability to delineate a range of water saturations where neither fluid flows. In a conventional reservoir, both water and gas would be produced. If conventional relative permeability relationships are applied to assess the viability based on water saturation measurements obtained from well logs, gas and water production would be expected from a range of moderate to high water saturations. In a tight gas BCGA, there would be no fluid production, even at very high water saturations, highlighting the importance of an integrated understanding of petrophysics and multiphase flow in the successful exploration and development of these reservoirs.

Production from BCGAs is associated with areas of improved productivity or rock quality (sweet spots). The exploration strategy focuses on identifying these areas for optimal well placement. Figure 5 compares the differences in exploration strategy employed in a BCGA and a conventional gas accumulation. Because gas saturation is pervasive, it is believed that any well drilled in the region will encounter gas, making exploration risk low (Figure 5a). Development is performed on a statistical basis, assuming that all wells drilled would have similar distributions of reservoir properties, drainage areas and ultimate recoveries. Economic development of BCGAs is dependent on improvements in drilling and completion technology and gas price.

Controversy exists over the concept of BCGAs, and how it can be applied to resource assessment and development. Shanley *et al.* (2004) assessed the petrophysical properties of low permeability gas fields in the Greater Green River basin. They contend that the basin is not regionally gas saturated; rather, these fields are merely conventional accumulations in structural, stratigraphic or combination traps (Figure 5b). They believe that an integrated understanding of how petrophysical properties vary with water saturation and overburden stress is essential to correctly explain fluid distributions in the basin and parameters influencing well performance. This interpretation that gas saturation is not pervasive across the basin suggests that resource assessments based on a continuous accumulation concept substantially overstate the size of resource base and understate the risk associated in developing these reservoirs. From this perspective, resource assessments in low permeability basin centered regions should also consider the traditional petroleum systems framework associated with discreetly distributed conventional gas accumulations.

Coalbed Methane

Coal reservoirs are both source rock and reservoir. Coals are formed in low energy sedimentary deposits composed of organic and inorganic material (peat). Rapid burial and a low oxygen environment are required for coalification of the peat to occur. As the peat is compacted, water is driven out and the material is converted into sedimentary rock. Pressure and temperature increase with burial depth, further compacting and dewatering the system. Coalification converts the plant material into coal (Levine 1993). During this process, two important features of coal reservoirs are created: natural gas is generated and cleats (high permeability pathways) are formed.

Coal is a complex porous medium, consisting of a high permeability fracture network and a low permeability matrix. The majority of the gas resides in the matrix, while the cleats (natural fracture network) provide conduits for production. Production in coals is a multistep process, and is frequently modeled using a dual porosity representation (Warren and Root 1963). In the low permeability matrix, transport is controlled by diffusion, where the rate of transport is dependent on concentration gradients. In the high permeability fracture network, advection dominates and flow is controlled by pressure gradients (Cervik 1969). For coals that are diffusion limited, an additional porosity system may be required to accurately capture production behavior (Reeves and Pekot 2001, Shi and Durucan 2003). Multi-porosity systems are characterized by transfer coefficients which control the rate of mass transfer between the systems. Good representation of production behavior can be achieved with these multi-porosity systems, however, determining values representative of the coefficients is a challenge.

Most of the gas exists in an adsorbed state, with a small amount present as a free gas phase in the micropores and cleats (De Bruin and Lyman 1999). Adsorption capacity is a function of pressure and temperature (Figure 6). Gas is adsorbed on the surface as a monolayer, and Langmuir and extended Langmuir isotherm models are sufficient to describe adsorbed gas capacity in these systems (Yang 1987, Arri *et al.* 1992, Yee *et al.* 1993). In general, the percentage of adsorbed methane is proportional to pressure, coal rank and deeper depths. Shallower coals with good cleat development contain significant amounts of free gas. Although higher gas content coals are expected at deeper depths, coals are sensitive to effective stress (McKee *et al.* 1988). Very low permeabilities result at greater reservoir depths. Due to the interplay between mechanical properties, overburden pressure and permeability, it is estimated that production from coal may be limited to depths less than 1524-1829 m if structural permeability enhancements, such as massive hydraulic fractures, are not performed (Scott and Tyler 2000).

Gas is produced through a reduction of reservoir pressure during coalbed methane production. If the coal is water saturated, pressure reduction is achieved by dewatering the reservoir. During the primary stage, large volumes of water are produced. Small volumes of gas may be coproduced at this stage. Stable production occurs once the pressure has decreased sufficiently such that gas desorbs from the matrix and accumulates to form a free gas phase. Figure 7 shows a schematic of the production stages associated with conventional coalbed methane production.

Gas Shales

Gas shales are continuous-type resources (Schmoker 2002). Unlike conventional gas accumulations which exist in discrete fields, gas saturations in shales exist over a wide area, making exploration risk associated with these plays very low. They are characterized by low porosity (less than 10%) and low permeability (micro- to nanodarcy range). Recovery factors are low; average recovery factors for the Barnett Shale, one of the most prolific shale gas plays, are 8% (Williams 2002). Shales were once considered marginal resources. However, advancements in directional drilling, fracture stimulation and seismic have made gas shales an increasingly important source of natural gas in the United States. Although there are several gas shale formations currently being produced economically, many basic scientific questions pertaining to their mechanical properties, adsorption behavior and flow mechanisms remain unanswered.

Gas shales refer to any very fine-grained rock that is capable of storing significant amounts of gas. These fine-grained sediments were deposited in a low energy environment, such as a tidal flat or a deepwater basin. Gas may be present as free gas stored in the natural fractures and macroporosity, adsorbed onto the kerogen and internal surfaces, or dissolved in the kerogen and bitumen. They range from the organic rich, fine-grained rocks of the Antrim Shale in the Michigan Basin to the variable facies rocks of the Lewis Shale in the San Juan Basin. The shale gas play is almost exclusively limited to onshore United States; however, there has been some activity in Canada (Ross and Bustin 2008).

This ambiguous definition of shale resources has led to uncertainty in defining controlling factors which are used to predict an economic development. Key parameters used in evaluating the potential of shale resources include thermal maturity, sorbed gas fraction, reservoir thickness, total organic content, gas in place and ability to fracture. Values for these parameters vary widely between basins (Curtis 2002), making it difficult to apply analogues and expand shale exploration and development outside established basins.

Production in shale reservoirs is a multi-scale, multi-mechanistic process. Similar to coalbed methane, fractures provide the permeability for gas to flow, but contribute little to the overall storage capacity. The micro- and mesoporosity of the matrix provides most of the storage capacity, but have very low permeability. Flow in the fractures is controlled by advection and is modeled using Darcy's Law. At the nanometer scale encountered in the matrix, the no-slip condition breaks down and Darcy's Law is no longer applicable. Flow in the matrix is controlled by diffusion (Schettler *et al.* 1989, Javadpour *et al.* 2007, Bustin *et al.* 2008). At this scale, conventional continuum descriptions of gas transport do not apply. Molecule-molecule and molecule-pore wall interactions must be considered.

Production behavior is marked by a steep initial decline. Initial gas production is dominated by free gas depleted from the fractures and the macroporosity. This is followed by a long term, nearly flat decline. As the pressure is lowered, gas desorbs from the organic matter in the matrix and diffuses into the fracture system. During this stage, desorption and diffusion through the matrix drive production. The long-term production behavior of a shale gas well is dependent on the time scale of diffusion from the matrix relative to flow of gas in the fracture network.

Rock Fabric

Pore structure controls both gas in place and long-term deliverability in shales. This is controlled by mineralogy, which is dependent on depositional environment and post-depositional diagenetic processes. Understanding how mineral composition controls rock fabric, gas in place and the mechanical properties of the shale is critical to accurately assessing its potential. Pore throats in shales range from 0.1 to 0.005 µm (Nelson 2009). Throat size controls permeability of the rock, affecting the gas flow rate. Porosity controls the distribution of free gas and adsorbed gas in the shale. Surface area is inversely proportional to pore diameter. In shales with smaller pores, a larger amount of surface area is available for gas to be adsorbed, and a larger fraction of the gas may be present in the adsorbed state than in the free state.

Understanding the depositional history of the shale is important in predicting long-term production behavior. Soeder (1988) analyzed the microscopic structure of Devonian Shales of the Appalachian Basin. These could be divided into two categories: black shales and grey shales. Texture of the shales was controlled by oxygen availability in the depositional environment. Black shales had a high organic content. Clay flakes were oriented in a laminar fashion. The pore structure of black shales consisted of narrow, slot-like openings between clay flakes. These sediments were deposited in an anoxic environment, containing anaerobic bacteria and few other microorganisms. Absence of biological activity preserved the laminar orientation of the clay flakes, as well as the organic matter in the sediments. In contrast, grey shales were deposited in an oxygen rich environment. Burrowing organisms fed off the organic matter. Their activity disturbed the sediments, churning up the clays, resulting in random orientations of the minerals, creating the basis for the structure which produced the modern day rock fabric. Davies *et al*. (1991) found that black shales had lower permeabilities (less than 1 μd) than grey shales (greater than 1 μd). This was due to the depositional orientation of the clays minerals. The parallel orientation of clays created a highly laminated and anisotropic system, restricting gas movement in the horizontal direction in unfractured black shales. The random orientation of clay minerals created by biological activity in the grey shales produced a chaotic fabric and an isotropic system for gas flow.

Diagenetic modification is also commonly observed in shales. These processes may alter rock fabric in a positive or negative manner. Precipitation of new materials or recrystallization of detrital grains reduce pore space. These changes may also affect permeability, increasing the tortuosity of the pore network and the number of isolated and disconnected pores. Secondary porosity may be created. Dissolution of minerals or maturation of the kerogen may create secondary porosity, enhancing permeability and increasing volume available for gas storage. Understanding the level of diagenetic modification is important for assessing the long term production behavior of the shale.

Characterization

Specialized methods to characterize pore structure, storage capacity and flow characteristics have not been developed for shales. Techniques currently applied to assess shale properties are a mixture of methods developed for coals and conventional reservoir rocks, implicitly assuming that the same transport and storage mechanisms occur in shales. As discussed previously, gas shales have a rock fabric unique from coals and tight gas reservoirs. Many of the techniques employed to characterize porosity are at or close to the limit of resolution encountered in shale reservoirs (Figure 8). Helium is routinely used to characterize the pore structure in shales because of its accessibility to small pores and its low affinity for adsorption. The kinetic diameter of helium is smaller than the kinetic diameter of methane. Helium has greater access to smaller pores than methane. This small difference has the potential to yield a higher porosity than if larger molecules were used, overestimating the amount of gas in place. Most methods for characterization require pre-drying of the samples, causing the clay to shrink and alter rock fabric. As a consequence of pretreatment, the sample and the properties determined from it are no longer representative of in-situ production conditions. Small errors in porosity or gas storage capacity can translate to large errors in gas volumetrics because of the large areal extent of shale reservoirs. This can lead to unsustainable energy policies and poor investment decisions. Understanding the limitations of current characterization techniques and the adjustments that are required to calibrates these measurements to shale are important for accurate assessment of the resource base.

Adsorbed Gas Content Measurement

Canister desorption tests are frequently used to assess adsorbed gas in place. This technique was originally devised for assessing adsorbed gas in coals. Gas content measured from the canister is assumed to be solely from the sorbed portion of gas in the reservoir. Canister tests represent an integrated response of several different gas release processes, each with their own characteristic time scale. The relative contribution of each process is dependent on a number of factors, such as sample recovery time, reservoir pressure and temperature, and rock fabric. Samples that are retrieved quickly may not allow sufficient time for free gas to flow from the core during the recovery process. Free gas and solution gas may be captured along with the sorbed gas, overestimating the amount of sorbed gas associated with the shale. Shales that have abundant microfractures may yield more representative gas content measurements than shale without microfractures. As the pressure decreases when the sample is brought to surface, gas expansion may create fractures in the sample, allowing gas deep in the matrix to be transported outside of the sample increasing the amount of gas that would be attributed to the sorbed component. Shales that fracture more readily may result in overestimation of total gas in place.

Gas distribution may change significantly when in-situ conditions are considered. Higher reservoir temperatures reduce the ability of the gas to adsorb. Ross and Bustin (2008) reported a significant decrease in adsorbed gas capacity in Liard Basin shales when adsorption isotherms were corrected to reservoir temperatures. Understanding the distribution of gas between free and adsorbed phase will determine the development strategy. If the majority of the gas is present as adsorbed gas, the shale will behave more like a coalbed methane reservoir and a depressurization phase is required to release the gas from the shale surface. If the majority of the gas is present as free gas, like in the Barnett (Gas Research Institute 1991), the shale will behave more like a tight gas reservoir and the completion strategy should focus on maximizing the amount of reservoir contact with the wellbore through directional drilling and hydraulic fracturing.

Mechanical Properties

Fractures are necessary for creating high permeability pathways for gas migration from the matrix to the wellbore due to the extremely low permeability of shale. Key to optimizing fracture stimulation treatments is a thorough understanding of the mechanical properties of the shale. The ability of a shale to fracture and maintain an open fracture is influenced by mineralogy and lithology. Poisson's ratio is a measure of the shale's ability to fail under stress. Young's modulus reflects its ability to maintain a fracture. Silica rich shales, like the Barnett and Woodford, have a high Young's modulus and low Poisson's ratio and tend to fail in a brittle manner. These types of shales will respond well to hydraulic fracture treatments. Calcite and clay rich shales, like the Caney Shale, fail in a ductile manner, tending to deform internally and resist fracturing.

Within a play, mineralogy can be very heterogeneous. Mineralogy of the middle grey facies of the Lower Antrim Shale is highly variable with respect to calcite content (Manger *et al*. 1991). Lithology varies from a slightly carbonaceous rock with a shaley texture to a fossiliferous, calcareous shale. In some instances, the middle grey facies serve as barriers to fracturing, while in other instances, it is conducive to fracturing. Changes in mineralogy and lithology result in a variable response of the Lower Antrim Shale to stimulation treatments. Integration of these differences permits optimization of stimulation treatments.

Natural Fractures

There are mixed views regarding the role of natural fractures in the success of shale plays. In the Barnett, natural fractures do not appear to be essential for production (Montgomery *et al.* 2005, Bowker 2007). Wells located in areas where natural fractures are expected, such as structural flexures, adjacent to local faults or in sites surrounded by karst-related collapse structures, did not produce as well as those situated in flat and undisturbed areas. Moreover, core analysis indicates that most of the fractures are sealed with calcite and are nonconductive.

Gale *et al.* (2007) proposed that natural fractures are important for the development of the Barnett through the enhancement of the effectiveness of hydraulic fracture treatments. The calcite fill is not in crystallographic continuity with the shale fracture face. Tensile strength of the contact between calcite and shale is low. The cemented fractures act as planes of weakness. Elevated fluid pressure from hydraulic fracture treatments results in failure at these interfaces, reactivating the natural fractures to create a complex fracture network and a large simulated rock volume extending far into the reservoir.

Because shales are both source and reservoir, open natural fractures can act as migration pathways for gas out of the shale and into overlying strata. At discovery, free gas would be depleted in areas with open natural fractures, and the majority of the remaining gas in place in these areas would be in the adsorbed state. A production strategy in these areas would focus on enhancing gas desorption. In contrast, an area of a shale play without natural fractures would have a larger total gas content because the free gas phase would not have access to high conductivity migration pathways out of the source rock. A production strategy in this setting would focus on developing flow pathways through artificial stimulation.

Technology in Unconventional Gas Resources

Technology is a critical factor in the economic development of unconventional gas reservoirs. Advances in technology make development of these resources competitive with conventional gas through increasing the recovery efficiency and improving the economics of the development.

Improved Recovery

Due to the low permeability of unconventional resources, conventional development strategies recover gas at rates that are too slow for economic recovery. Advances in directional drilling and fracture stimulation technologies have improved recovery in these types of resources through increased reservoir contact with the wellbore and augmentation of pathways for the gas to flow. Enhanced recovery through gas injection has the potential to significantly improve recovery through more efficient local recovery of methane from the pore space. Because of the large areal extent of unconventional gas reservoirs, small improvements in recovery efficiency can lead to large gains in the overall volume of gas recovered.

Drilling

Advances in directional drilling have led to increased development of unconventional gas in two ways: increased reservoir contact and improved access to the reservoir from surface locations. Well productivity is proportional to the permeability and the length of net productive reservoir in contact with the wellbore. A horizontal well provides greater wellbore contact with the reservoir than a vertical well. In a vertical well, the amount of reservoir thickness in contact with the wellbore is limited by the thickness of the formation. In a horizontal well, the length of reservoir contact is limited by the length of the lateral, which is determined by the mechanical ability to extend the drill bit along the lateral. Multiple lateral lengths can be drilled off of a single wellbore, further increasing well productivity. When horizontal wells are drilled perpendicular to the dominant fracture orientation in a naturally fractured reservoir, reservoir contact may be enhanced by increasing the probability of intersecting the additional high conductivity fractures.

Many unconventional gas plays are located under environmentally sensitive (Greater Green River Basin in Wyoming and Piceance Basin in Colorado) or heavily populated areas (Barnett Shale in the Dallas-Fort Worth metropolitan area and Marcellus Shale, which underlies major population centers in the Northeastern United States). Directional drilling and extended reach wells decouple the surface location from the subsurface location, allowing producers to access high quality resources from drill sites removed from these sensitive areas. Surface features, such as steep slopes and large boulders, may prevent vertical wells from being deployed in a manner that efficiently drains the reservoir. Optimal drainage spacings in the subsurface, which maximize recovery in a field by promoting uniform depletion of the reservoir, can be maintained with directional drilling technology.

Advances in directional drilling have enabled pad development. In this configuration, multiple wells are drilled from the same surface location, minimizing the amount of surface disturbance and reducing the development footprint caused by multiple vertical well locations at the surface. In the Piceance Basin, as many as 22 wells are drilled from the same surface location (Tolman *et al.* 2009). Multi-well pad developments also yield operational efficiencies. Because the multiple wells are drilled from the same surface location, drilling rig and completion equipment can move easily from one well to the next, reducing the time required for mobilization and set up. Operating costs are also reduced due to efficiency gains and consolidation of production infrastructure created by a centralized production location. Efficiency gains will also be realized through less manpower required to operate and maintain the development. Relative to a development with an equivalent number of vertical wells, transportation time associated with monitoring and servicing the well will be significantly reduced for a pad development. A centralized location for multiple wells allows more frequent monitoring, which can lead to more efficient operations. Operational adjustments can be made to multiple wells during a single visit out to a well pad, allowing production anomalies to be resolved more quickly than in a more disperse vertical well development.

Hydraulic Fracturing

In low permeability reservoirs that do not have natural fractures, hydraulic fracturing is required to connect the reservoir with the wellbore to achieve economic rates of production. Hydraulic fracturing technology to enhance well productivity has been applied since the 1950s. Early stimulation treatments in tight gas sands during the 1980s used crosslinked polymer gel systems. Most of these treatments were unsuccessful due to the inability of the reservoir to clean up residues from the gels, which impaired or damaged flow pathways and reduced productivity. These treatments were also expensive relative to the incremental and accelerated production that would result. Slickwater fractures were first introduced in late 1990s, in the Cotton Valley Field, a low permeability, depleted sandstone reservoir in the East Texas Basin. In this application, production enhancements from slickwater treatments were comparable to those from conventional gel treatments. However, slickwater treatments were significantly less, 30 to 70% less expensive (Walker *et al.* 1998), allowing widespread application of fracture stimulation in the field at a fraction of the cost.

Slickwater fracture treatments use a low viscosity water based fluid. Additives include friction reducers, surfactants, biocides and clay stabilizers. High pressure injection of large volumes of fluid into the formation fractures the rock and pushes the reservoir open to create a high conductivity pathway between the reservoir and the wellbore. To prevent fractures from closing and reducing the conductivity of the pathway after the fracture fluids are returned, proppants are required. Multiple fracture stages on a single lateral increase reservoir contact, further enhancing productivity and improving the economics of the well (Lohoefer *et al.* 2006). Wells drilled in the Woodford Shale are completed with as many as 20 fracture stages.

Fracture growth is influenced by the stress state in the formation. Effectiveness of subsequent fracture stages along a lateral are influenced by the stress changes resulting from the open, adjacent fractures created during the treatment. As a consequence, fracture growth in later stages of the fracturing operations may not be as extensive as fractures performed in the initial, unperturbed stress state. Optimization of hydraulic fracturing operations to the changing stress state, such as simultaneous fracturing of two or more offset parallel horizontals (Matthews *et al*. 2007), can create a more uniform degree of interwell fracturing to maximize the extent of the fracture network generated and increase recovery.

Large volumes of water are required during hydraulic fracturing operations. Approximately 40% of the water injected is recovered. Water retained by the formation may be trapped in the pore throats, resulting in a loss of productivity. Low permeability formations have very high capillary pressures. Drawdowns generated during production may not be sufficient to overcome threshold capillary pressures required to remove water from the small pore throats, permanently blocking flow pathways and rendering the rock non-productive. Use of CO_2 miscible fluids may reduce phase trapping and improve fluid load recovery (Taylor *et al.* 2006).

As fracture designs become more complex, the simplified modeling of fractures and proppant transport in low viscosity systems are inadequate for designing appropriate stimulation treatments and predicting recovery enhancements (Gadde *et al.* 2004, Dayan *et al.* 2009). The ability to more accurately predict fracture network formation allows optimization of fracture treatments, informing operational parameters such as fluid and proppant volume and selection, maximizing the potential of the development. Optimization of fracture treatment parameters to the shale formation in which the treatment is applied can reduce costs and improve economic recovery, facilitating access to reserves that were previously uneconomic.

CO_2 enhanced recovery

Increasing atmospheric concentrations of CO_2 and concerns about climate change present a synergy between enhanced gas recovery in unconventional reservoirs and stabilization of CO_2 levels. Depleted natural gas reservoirs and deep unminable coal seams have been identified as candidates for geological storage of CO_2 (IPCC 2007). Simultaneous recovery of natural gas while sequestering CO_2 is an attractive option because it addresses increasing atmospheric CO_2 concentrations while offsetting some of the costs associated with capture, storage, compression and transportation of CO_2 by the production of gas. Replacement of high carbon intensity coal and oil with low carbon intensity gas provides additional reductions in atmospheric CO_2.

In enhanced coalbed methane production (ECBM), gas is injected to reduce the partial pressure of methane in the coal. Reservoir pressure is maintained, preserving high production rates. When CO_2 is injected, CO_2 preferentially adsorbs onto the surface, displacing CH_4 from the coal. Replacement ratios of CO_2:CH_4 vary from 2:1 to 10:1 (Stanton *et al.* 2001). When N_2 is injected, CH_4 is still the preferentially adsorbed species. Reduction of partial pressure of CH_4 provides the driving force for desorption in N_2 displacements. Pilots of both CO_2-ECBM and N_2-ECBM have successfully demonstrated enhanced recovery (Reeves 2001).

Organic matter in shales have large surface areas, and sorption capacities, similar to coal reservoirs. Nuttall *et al.* (2005) investigated the feasibility of CO_2 enhanced recovery in gas shales. CO_2 and CH_4 adsorption isotherms were measured from drill cuttings and sidewall cores from the Devonian Shales of the Appalachian Basin. At reservoir conditions, CO_2 adsorption exceeded CH_4 adsorption by a factor of five, suggesting that CO_2 enhanced recovery from shale gas could serve as a promising source of carbon neutral energy. On a strictly volumetric basis, gas shales have the potential to sequester large amounts of CO_2, provided that CO_2 can diffuse deep into the matrix. Research into the dynamic interactions between flow, gravity and heterogeneity are required to assess the feasibility of CO_2 enhanced recovery and sequestration in gas shales. Sidewall cores were used to investigate the dynamics of CH_4 displacement in the presence of CO_2. Permeability of the samples was too low to respond to conventional permeability tests and pulse decay measurements. Results of these tests were inconclusive. Sufficient injectivity to deliver CO_2 into the reservoir is a concern. Injection pressures must be maintained below fracture pressures to ensure that the integrity of the reservoir remains intact and a fracture is not induced during injection, preventing formation of a pathway for CO_2 leakage.

Permeability changes have been observed by a number of researchers (Harpalani and Schraufnagel 1990, St. George and Barakat 2001, Lin *et al.* 2008) as gases adsorb onto and desorb from the coal surface. Matrix shrinkage occurs when gases desorb from the surface, enhancing permeability, while matrix swelling occurs when gas adsorb onto the coal, decreasing permeability. Reductions in permeability would have a negative impact on injectivity and reduce the ability to sequester CO_2 in the formation. Hydraulic fractures may be necessary to facilitate injection of material volumes, required to impact rising atmospheric CO_2 levels, into the shale.

Operational Efficiency

Technologies that reduce upfront exploration and development costs make unconventional gas developments more economically attractive. Those that reduce the time required for drilling and completion improve the discounted cash flow of the project by reducing the upfront capital costs associated with drilling and completion operations. Because of the long term, stable, low rate production behavior characteristic of unconventional gas wells, technologies that accelerate production that would be accessed late in the life of the well to the initial production stages also improve the discounted cash flow and economic performance. Many of the technologies which have made unconventional gas developments so successful were originally developed for high cost offshore environments. As operators became more comfortable deploying the technology, costs decreased and widespread application of these technologies to increasingly marginal resources became economic.

Rotary steerable technologies were developed in the 1990s for offshore Norway and deepwater Gulf of Mexico. Application of this technology in the Woodford Shale, has led to reduced drilling time (drilling times were reduced by more than five days) and well trajectories which optimize drainage patterns in the reservoir (Janwadkar *et al.* 2009). Improved bottom hole assembly designs allow better control over the well trajectory in the curve and the lateral. Improvements in transfer of weight on bit, reduced torque and drag, permitting faster drilling rates, reducing the time required to drill the well and associated rig costs. Steerable technology, coupled with the expanding capabilities of real time data acquisition technologies, such as measurement while drilling, logging while drilling or wired pipe technology (Manning *et al.* 2008), allow for real time adjustment of well trajectory and operating parameters in accordance with observed geological and petrophysical data, permitting precise navigation of the wellbore within the targeted zone.

In conventional well construction, the diameter of the well gradually decreases due to the use of smaller diameter tubing strings used to assist in stabilizing the wellbore as the well approaches the reservoir. This telescoping effect of wellbore diameter with depth limits the types of tools that can be employed in logging and completing the well. Developments in expandable tubular technology have led to efficiency gains in unconventional gas operations. Expandable tubular were initially used as a contingency liner during unplanned drilling problems but has found applications in standard drilling operations. These have facilitated the drilling of deep wells by reducing the tapering effect that the wellbore diameter experiences as it is drilled and cased from surface to reservoir depth. This allows larger completion and evaluation tools, which are more reliable and less expensive, to be run in the wellbore. Tubbs and Wallace (2006) estimate that overall drilling costs were reduced by 15 to 20 % with expandable tubular technology relative to conventional well designs. These gains were attributed to faster drilling rates (36% enhancement) and improved drilling performance with expandable tubulars.

During multistage fracturing, zonal isolation is required to ensure that fracture fluids are injected in the intended location at each fracture stage. This is achieved by setting a bridge plug in the tubing that hydraulically isolates a section of the wellbore. Once a fracture stage is finished, these plugs are drilled out and new ones are set for the next stage. In long multistage laterals, the time and expense required to set and drill these plugs add cost and non-productive rig time to the operation. Swellable elastomers in expandable systems can be used to achieve zonal isolation and facilitate accurate placement of fractures along a lateral without the need for bridge plugs, eliminating the rig time required for tripping in and out of the wellbore to drill out the plugs once a fracture stage is completed.

Coil tubing technology is a promising technology for re-entering old wellbores to extend the life of a well and increase recovery. Coiled tubing drilling has been applied in mature developments like Alaska and has demonstrated potential in the Cleveland formation (Dietrich *et al.* 2009). Peak *et al.* (2007) estimate that coiled tubing deployed fracturing technologies reduce cycle times to bring a well on production by as much as factor of ten. Efficiencies come largely from the result of making a single trip into the wellbore for both perforation and stimulation operations. Costs for coil tubing rigs are lower than drilling rigs. Additionally, coil tubing technology separates drilling and completion activities from fracturing operations. This allows drilling and fracturing operations to occur in parallel over a multi-well development instead of in serial. Decoupling these activities can allow for optimization of drilling and completion resources over the multi-well drilling campaign and reduce the overall costs of the development.

Optimization

Advances in geophysical techniques have led to the development of more sophisticated techniques to infer reservoir properties. This information can be used to identify regions with high natural fractures or favorable geomechanical properties to optimize well location and ultimately increase gas recovery.

Multicomponent seismic

Because fractures play such an important role in producing economic gas rates in unconventional resources, multicomponent seismic, 3-component (3-C) seismic, is uniquely positioned for fractured reservoir characterization. It is conducted in the form of either 3-C surface seismic or 3-C vertical seismic profiling (VSP). Analysis of the behavior of components of the seismic signal provide valuable information about the density and orientation of the fractures in a reservoir, allowing optimization of drilling location and orientation of the well bore in the reservoir. Prior knowledge of the fracture system during the well planning stage improves the chance that a well will intersect fractures, and ultimately increase gas recovery.

The influence of vertically aligned fractures on seismic waves has been well documented (Crampin 1985). The major two effects are shown in Figure 9. The first is related to shear wave propagation. When a shear wave enters an anisotropic region, such as a fractured reservoir, it undergoes shear-wave birefringence or splitting. The shear wave splits into two vertically propagating shear waves with the fast shear wave polarized parallel to the fractures (S1) and the slow shear wave polarized perpendicular to the fractures (S2). The fast shear polarization direction can be used to determine fracture orientation. The magnitude of shear-wave birefringence, the travel time difference between the fast (S1) and slow (S2) waves, can be used to infer fracture density (Lynn 1986, 1996).

The second effect pertains to the compressional wave. Small amounts of gas over water in open fractures will produce a compression-wave amplitude-versus-offset (AVO) anomaly when the compression-wave ray paths are oriented perpendicular to the fractures (Crampin 1985). As shown in Figure 9, when the orientation of the compression wave is parallel to the fractures, the wave mode converts to the fast shear direction SV1. When the compression wave orientation is perpendicular to the fractures, the wave converts to the slow shear direction SV2. The compression wave reflection coefficient, as a function of source-receiver offset, is sensitive to the fracture orientation, density and gas saturation. Compression wave anisotropy provides another method to assess fracture orientation. When this information is integrated with other types of information, such as regional stress, outcrops and analogues, compression wave anisotropy can reduce uncertainty in fracture orientation interpretation and risk by determining whether a well will intersect natural fractures.

In contrast to shear wave anisotropy studies where a single wave path can be used to determine the magnitude of splitting, compression wave analysis requires travel paths through different rock sections. This can introduce uncertainty by including other potential causes of amplitude variations such as heterogeneity in the rock or pore-fill type into the interpretation. The use of compression waves for fracture analysis is that the cost is less expensive relative to shear wave techniques (Bates *et al.* 1999).

Microseismic

Understanding fracture geometry is key to developing effective stimulation treatments and improving economics of drilling and completing a well. Microseismic fracture mapping provides a way to image the geometry of a hydraulic fracture to accurately measure fracture geometry and assess the volume of rock enhanced by the fracture treatment.

During a hydraulic fracture, the resulting stress perturbations often reactivate faults and open or close fracture sets. Earthquakes generated in manner are often referred to as micro-earthquakes or microseismic events (Jupe *et al.* 2000). These events often occur in large numbers. Their source locations can form clusters that can reveal the location of fractures and faults in the subsurface. Because of the low magnitude of most microseismic events, passive seismic monitoring of reservoirs is usually done using well-based seismic arrays rather than surface arrays. By placing the detection array closer to the source, detection of more events as well as better data quality is ensured. Microseismic information permits mapping of active faults in the area that have the potential to affect drilling and production operations. It is also useful for reservoir modeling because it can indicate directions of increased permeability and/or porosity (Shapiro *et al.* 2002). Microseismic source locations also reveal zones of mechanical instability, which is useful information for planning and designing new wells (Kristiansen *et al.* 2000). Time-dependent variations and trends in the clustering of microseismic sources also have been used to monitor the growth and to determine the orientation of injection-induced fractures (Maxwell and Urbancic 2002), allowing optimization of fluid injection parameters during the hydraulic fracturing operation.

Microseismic data can also be used to determine the mechanisms of observed microseismic events, such as shear or tensile failure. This information can be further used to quantify stress changes resulting from microseismic events and constrain geomechanical models (Eisner and Sileny 2004) used in fracture design and reservoir simulation models. Microseismic monitoring offers precise data on hydraulic fracture systems to increase understanding of the fracturing process. This increased understanding during operations improves recovery from unconventional gas resources by reducing well stimulation costs, optimizing field development plants and allowing modification of drilling and completion plans in real time with the most up to date data, tailoring the well to the observed geomechanical characteristics specific to that location.

Logging

Well logging is conducted both during drilling and completion of a well. It entails the use of a variety of geophysical tools, typically run on a wireline, to attain indirect information about the rock properties and the presence of hydrocarbons. Models are required to transform measurements, such as rock resistivity, into the properties of interest, such as porosity. Logging plays an important role in all four stages of exploring and developing the unconventional gas resources: evaluating source-rock potential, evaluating gas in place, evaluating reservoir potential, producing from the reservoir (Boyer *et al.* 2006).

In stage 1, logs from previously drilled wells have been used in conjunction with geochemical analysis of core samples to evaluate the source-rock potential. Shales properties, like high gamma ray activity, high resistivity, low bulk density and low photoelectric effect can be estimated from well logs. Well logs are also used to ascertain the complex mineralogy of the shale and to quantify the amount of free gas in the pore space. Geochemical logs can give additional information on the organic carbon content, types of clays and their respective volumes. Mineralogy and clay content can be used to assess the ability of the shale to fracture and predict the effectiveness that hydraulic fracturing could have on the shale prior to exploration. All information derived from well logging, combined with core analysis, can help geoscientists characterize variability in kerogen maturity and explore for locations where commercial gas accumulations may exist. In stage 2, log analyses (when calibrated to actual measurements of reservoir properties supplied through core analysis) provide the basis for reliable predictions of gas in place through porosity and gas-saturation calculations. Log-based models can also be used to predict properties in adjacent wells across regions of limited lateral extent, thus facilitating the evaluation of basin-scale heterogeneity. Shale gas reservoirs have a high degree of heterogeneity. In stage 3, well logs are used to evaluate this heterogeneity at a wellbore scale together with core analysis. Wellbore imaging can also help here to provide direct information on the distribution and orientation of fractures and faults encountered at depth, which will be illustrated in the following section. At the production stage, logging tools can provide structural, stratigraphic and mechanical-property information for optimizing subsequent well drilling and completions.

Current logging tools are best suited for conventional porous high permeable media, and new methods are needed to provide well based measurements of permeability, effective porosity, organic content, gas content (adsorbed or otherwise), gas saturation, water saturation, clay mineralogy, pressure, temperature, bulk density and other physical, chemical and geomechanical properties. Core retrieval and analysis to determine these properties is expensive and may be difficult in friable shales. The ability to infer reservoir properties through well logs can reduce development cost. Because logging is a less expensive operation than core retrieval and analysis, more wells can be measured from logs than from core operations. Data can be gathered from a larger fraction of the system, reducing uncertainty and exploration risk. Accurate permeability measurement tools capable of characterizing natural fracture or cleat volume, length and orientation will assist in identifying pay zones.

Rock physics models for unconventional reservoirs

Rock physics models relate measurable geophysical signatures to the microstructure and composition of the rock. Because of the long production history and large catalogue of production from many different types of conventional gas reservoirs, rock physics models developed for porous permeability sandstone reservoirs are well characterized and there is a strong confidence associated with applying these models to new developments. However, reliable models have not been developed for shales. Two major reasons are because shales were not considered to be viable reservoir rocks, and laboratory measurements on representative shale samples are extremely difficult and time-consuming. Recent developments in unconventional gas reservoirs, especially on low-permeability gas shales, calls for an extension of rock physics relationships to enable property prediction in low permeability unconventional reservoirs. The ability to define and categorize in situ the complex lithofacies associated with shale gas plays according to kerogen content, mineralogy and geomechanical properties has the potential reduce costs involved in hydraulic fracturing while improving hydrocarbon recovery (Jacobi *et al.* 2008).

Effective medium theories were developed for establishing the elastic properties of dry and saturated rocks containing pores and cracks of different aspect ratios. These theories can be divided into two groups: self-consistent (Kuster and Toksoz 1974) and scattering (Avseth *et al.* 2005). These models play an important role in interpreting field measurements from logs and seismic, and inverting rock microtexture from geophysical signatures. Recently some modified effective medium theories have been developed to model shale and sandy shale (Mukerji and Mavko 2006). However, almost all models based on effective medium theory assume a relatively homogeneous, isotropic background medium, no crack-crack interaction, and a long-wavelength approximation where the characteristic scales of grains, pores and cracks are much shorter than wavelength.

Gas shales are highly heterogeneous and anisotropic due to clay mineral alignment and appearance of micro-cracks in both the micro-scale and the macro-scale. Modeling attempts have had limited success when it comes to shale. This poses a large challenge for interpreting geophysical measurements from shale reservoirs. Hornby *et al.* (1994) and Jakobsen *et al.* (2003) address the anisotropic background medium and moderate crack-crack interaction by using a preliminary multi-scale modeling approach. Ortega *et al.* (2009) extend this approach to a multiscale, micromechanics model to address the strong heterogeneity problem on macro-scale models. Initial tests of these models show a strong influence of clay-mineral alignment and microcracks on seismic/sonic anisotropy. The results also indicate a strong influence of kerogen content on both velocity and anisotropy of shales. These findings provide a way to infer microstructure and composition of shales from seismic or acoustic velocity data available through increasingly sophisticated well logging tools and seismic measurements.

Geomechanical wellbore imaging and fracture analysis

Wellbore imaging has been demonstrated to be a reliable method for assessing reservoir geomechanics (Barton *et al.* 2009). Two most well known wellbore imaging tools are ultrasonic borehole televiewer (BHTV) and formation electrical imaging device. These tools measure the smoothness of the wellbore wall and infer the apparent aperture of fractures where they are intersected by a wellbore. BHTV measures the amplitude and travel time of the reflected pulse, which contains information on formation stiffness, wellbore smoothness and the wellbore radius. Electrical imaging device monitors the contact resistance with an array of electrodes in direct contact with the wellbore wall. It can identify fractures at higher resolution than borehole televiewers, however, it provides less useful information about the size and shape of the well. Empirical relations have been proposed that attempt to relate fracture length to aperture (Gudmundsson 2000), making wellbore imaging useful in analyzing natural fractures and cleats.

High-resolution image data can also yield direct observations of stress-induced wellbore breakouts. This information can be used to develop a geomechanical model of the shale, which can be used to design the well trajectory and fracture treatments. Advanced LWD imaging technologies provide operators with immediate information to continuously update geologic and geomechanical data for real-time well planning and monitor wellbore integrity during drilling operations (Barton *et al.* 2009). The geomechanical data derived from wellbore images can be used to establish a predictable relationship between in-situ stress and permeability, which in turn makes it possible to determine the best wellbore trajectory to maximize intersection with permeable fractures and minimize the risk of instabilities resulting from drilling-induced slip on the same features.

Recommendations for research

Key scientific questions regarding transport mechanisms in unconventional gas reservoir exist. As a consequence, these resources are not being developed at their maximum potential. A research program for addressing these concerns should focus on three key areas: 1) understand transport and flow in unconventional reservoirs, 2) develop a unified understanding of controls on production through wide scale petrophysical analysis of existing unconventional gas reservoirs, and 3) develop tools for predicting flow behavior in these systems, specific to shales, coalbed methane and tight gas.

Traditional continuum models describing flow in porous media that are widely applicable in conventional gas reservoirs are not applicable in unconventional gas resources due to the small pore size and very low permeability of unconventional reservoirs. Although there are similarities between coalbed methane, tight gas and shale resources, there are fundamental differences in gas transport between the types. This leads to very different production behaviors. Research efforts should focus on increasing our understanding of the transport mechanisms unique to each category of unconventional gas. Improved understanding of flow in these systems benefits both exploration and development activities associated with increasing recovery from these resources. Understanding the fundamental physics governing transport in these types of rocks will facilitate the development of analytical techniques for evaluating reservoir flow properties, specific to unconventional gas. Because of the high degree of interdependence between rock fabric, gas transport and recovery in unconventional reservoirs, better delineation of transport processes will lead to improved insights into how gas is distributed in the reservoir, assisting exploration efforts of new unconventional plays. This will provide a more representative estimate of reservoir properties such as porosity, permeability and gas in place, reducing uncertainty in determining the potential of the resource. Incorporating this knowledge into tools for predicting flow behavior and upscaling pore scale transport to reservoir scale flows will reduce uncertainty in estimating production behavior from the wells. Accurate tools can be used to plan drilling and completion strategies and develop development plans to optimize production from the resource.

Unconventional gas development is relatively immature compared to conventional resources. As a consequence, there is not as extensive a knowledge base regarding the expected range of properties and flow behaviors of unconventional reservoirs. Because of this, the categories for unconventional gas cover a range of sediments, resulting in a wide spectrum of production behavior. A unified understanding of the interaction of the effects of geochemistry, geomechanics, multiphase flow, depositional history and heterogeneity on production is poor. There is little data available to develop a complete understanding of the controls on production that are responsible for production differences between fields. In 2005, the Department of Energy funded a study with the Kansas Geological Survey to advance understanding of the reservoir properties of the Mesaverde tight gas sandstone. Detailed petrophysical analysis was performed on 150 rock samples, capturing the range of facies present in the Mesaverde group. This study improved understanding on the range of variability in flow parameters in the reservoir. Expanding this effort to other unconventional basins will enhance our understanding of the range of heterogeneity within a field and between basins. This knowledge will reduce uncertainty in developing unconventional resources and reduce risk in extending unconventional gas exploration strategies to new areas.

Existing commercial simulators were originally developed for predicting flow in high permeability reservoirs. Modifications have been made to accommodate models representing transport phenomena associated with unconventional gas production, such as diffusive transport, dual porosity and adsorption. Underlying these simulators is the assumption that Darcy flow describes the dominant flow mechanism. Long term production behavior of flow in the matrix is governed by diffusion. Accurate representation of this process is essential for providing confident predictions of long term production, upon which sound, science based policies for sustainably maximizing benefit of the resource for all stakeholders can be made.

Environmental Benefits from Technology Application

Although natural gas production has a long history in the United States, the intensity of development associated with unconventional gas compared to conventional resource development and extension of the petroleum industry into areas unfamiliar with drilling and completion practices have raised a number of concerns about water resources and surface impact (US Department of Energy 2009).

Water resources

The largest environmental concerns surrounding unconventional gas development are focused on water resource issues and hydraulic fracturing practices in shale gas plays. Substantial amounts of water are required in shale developments. Average water usage for drilling and completion operations in four active shale plays is summarized in Table 2. Water is used for drilling, to carry rock cuttings produced during the drilling process to the surface, and to cool and lubricate the drill bit. Water is also used for hydraulic fracturing. As the economics support drilling of longer wellbores with an increasing number of fracture stages and a more intensive well spacings in the reservoir, the demand for water will only grow. Because of the large number of wells required to effectively recover gas from a shale play within a reasonable period of time, adjustments in the lateral length and completion strategy can translate to material reduction in the volume of water required. Technology that provides information on shale properties and allows optimization of lateral length and fracture treatments, such as well logs and fracture analysis, can reduce the impact of shale operations on water resources.

Concerns about water resources include supply of water to operations without disruption of local water resources to established users, degradation of watersheds and streams by surface erosion due to mobilization of large amounts of heavy equipment, contamination of fresh water resources and disposal of large quantities of contaminated fluid from wells. Prior to development, an operator must file plans for drilling, water supply and disposal with the state agency that regulates development. Good oilfield drilling practices, economic incentives to reduce the volume of water to properly treat and dispose of and an integrated coordination of water resources with all stakeholders mitigate concerns of supply, freshwater contamination and disposal capacity associated with water usage in shale development.

Proper well design mitigates the risk of contamination of overlying freshwater aquifers. Surface casing and casing to the bottom of the aquifer provides hydraulic isolation from the reservoir. In very sensitive areas where contamination of the freshwater aquifer is a concern, air drilling is performed in order to prevent infiltration of drilling mud into the aquifer. As drilling progresses towards the shale formation, a series of telescoping casings are installed and cemented into place. These provide stability to the well and reduce the risk of wellbore collapse. They also create multiple barriers of hydraulic isolation between the aquifer and the production tubing, preventing contamination of the aquifer by fluids in the production string. Prior to the start of production, cement bond logs are run in the well to confirm the integrity of the cement between the casing and the formation. This provides additional confidence that reservoir fluids will not flow up along the outer side of the casing.

Shale reservoirs are separated from freshwater aquifers by hundreds to thousands of feet of alternating layers of siltstones, sandstones and shales. Fracture growth into adjacent aquifers is detrimental to gas recovery. If communication is established between the water bearing formation and the wellbore, the higher mobility water will be preferentially produced, significantly reducing gas production and can cause the well to prematurely cease production. Loss of production and the unnecessary cost associated with injecting excess fluids for creating fracture growth out of the formation create economic incentives for producers to restrict fracture formation to the reservoir. Technologies that can characterize the geomechanical stress states and simulate fracture growth in the reservoir facilitate optimal design of hydraulic fracture treatments. Microseismic allows real time monitoring of fracturing operations. Fluid injection volumes can be adjusted during operations, ensuring that the critical fracture pressure that could result in fracture growth out of the formation is not exceeded, safeguarding overlying freshwater resources.

Surface runoff and infiltration into shallow, high permeability aquifers is another potential pathway for contamination. In some areas of the Marcellus Shale where aquifers are close to the surface and recharged by precipitation and runoff, properly designed surface impoundments (such as double lined pits) prevent infiltration of drilling fluids into the drinking aquifers. Pennsylvania and New York require erosion and sedimentation controls and plans for storm water management prior to drilling. If a leak were to occur, monitoring downstream water quality during drilling operations can reduce the extent of contamination through timely detection of leaks.

In 2005, total water demand for Barnett Shale operations was 7200 acre-feet, less than 1% of total water usage in the area. Approximately 60% was supplied by groundwater from the Trinity and Woodbine aquifers. It was estimated that the amount of groundwater used for gas well development accounted for approximately 3% of the total groundwater usage in the area (R. W. Harden and Associates 2007). In rural areas, such as Cooke County in the Barnett Shale development, where groundwater provides 85% of the total water supply, shale development competes with local needs which have limited options for water supply. Local stresses on water resources may be created by shale development needs. Coordination of water resources amongst all stakeholders and diversification of water supply through water management measures, such as surface runoff catchments and seasonal storage, can alleviate stresses on supply.

Local gas operations may represent a higher percentage of water usage, depending on drilling density and seasonal conditions, which may put additional stress on water demand, particularly in drought prone areas such as West Texas and Wyoming. Although municipal water usage, irrigation and power generation consume a larger fraction of the total water usage in an area, the intensity of shale gas development may place local and seasonal stresses on water demand. Seasonal suspension of hydraulic fracturing activities analogous to seasonal moratoria of rig mobilization operations in northern locations, as the ground thaws between winter and spring, or drilling activities, to accommodate wildlife migration patterns, could be introduced to accommodate seasonal variability of water supply. Prior to approval of a development, water management plans submitted by operators prior to development detail where water required for operations is sourced and how it will be disposed of, alleviating concerns of supply and disposal.

Another concern pertaining to water resources is the chemicals used in hydraulic fracturing operations. Table 3 lists commonly used additives found in fracturing fluids. The exact composition of chemical additives used in fracture operations is viewed as propriety property. However, many of these chemicals are found in common household products. Small amounts of chemical additives, less than 0.5% by volume (Table 4), are present. Although the volumes of additives represent a fraction of the fluid, by virtue of the large volumes of slickwater used in these operations (millions of gallons per well in a development with thousands of wells) results in a large volume of chemicals (on the order of thousands of gallons) that must be treated and properly disposed of. Completion fluids are in close contact with the reservoir. Minerals (heavy metals, radionuclides and organics) may leach from the formation into the slickwater and will be brought to surface as the fracture fluids are returned prior to the start of production. Options for disposal are re-injection into underground formations of suitable permeability, evaporation ponds, land farming and reuse.

Water disposal is expensive and may represent a substantial cost in future operations as municipalities enact more stringent limits on total dissolved solids and capacity at disposal facilities becomes more scarce. In areas unaccustomed to handling and disposal of oil field waste, the infrastructure for treating drilling waste may not be adequate. Water treatment plants designed without oil field waste in mind may not be able to handle produced fluids from hydraulic fracturing operations. Pilot projects in the Barnett Shale are investigating technologies for onsite treatment and recycling of fluids for reuse in fracturing operations. Mobile water purification units can be used to treat a portion of the returned fluids for reuse. Technologies being developed for onsite recycling are distillation, separation and filtration, and reverse osmosis (Janks and Cadena 1992, Atlas 2002, Lee *et al.* 2002, Welgemoed *et al.* 2002, Horn 2009). Additional benefits associated with recycling flow-back water in a 50 well project in southeast Alberta were realized through reduced trucking and chemical additive costs (Gupta and Hlidek 2009). On site units also reducing road damage and air quality associated with transportation of such large volumes of fluid because of the reduced truck traffic. Pilot tests indicate that recycling technologies could allow reuse of 10 to 80% of the returned fluids, further reducing water demand. Research into efficient separation techniques, durable, high throughput membranes and development of technology to create valuable co-products from the separated solid phase will promote the development of cost effective onsite treatment options. Support for field scale demonstration will allow onsite recycling to be more widely adopted in the industry, reducing transportation costs and stresses on supply.

Water disposal is also a concern in coalbed methane operations (Table 5). Prior to production of gas, coalbed methane wells require a dewatering period to reduce reservoir pressure sufficiently for gas to desorb and form a free gas phase. Large amounts of water may be produced during the early stages of production. This can have a large impact on the hydrological system of the basin. Between 1996 and 2003, water production in the Powder River Basin increased from 100 000 bbl/day to 1.6 million bbl/d (WOGCC 2004). In some areas of the Powder River Basin, water levels have been drawn down by more than 600 ft. In many coalbed methane plays, produced water volumes are so large that disposal wells are not feasible. In Wyoming, water disposal methods include discharge to streams following treatment, evaporation, livestock watering, crop irrigation, water enhancement refracs in existing wells and constructed wetlands (USGS 2000). While produced water is typically less saline than produced water from oil and gas wells, it may still contain levels of salts or solids that exceed state water quality standards, requiring treatment prior to disposal.

Proper completion strategies can reduce water production in coalbed methane wells. In different locations in the Powder River Basin, the least principal stress switches between the minimum horizontal stress and the overburden (Colmanares and Zoback 2007). Both vertical and horizontal hydraulic fractures are present in the basin. It was inferred that excessive water production occurred in wells with vertical hydraulic fractures. If a vertical fracture extends into overlying aquifer, much of the water produced from the dewatering phase of a coalbed methane well is from the overlying aquifer, resulting in inefficient depressurization of the coal and excess water production. A better understanding of the stress state in the basin through wellbore imagery and fracture analysis would lead to completion designs that minimize the formation of out of zone fracture growth and reduce water production.

Footprint reduction

Due to the low permeability of the rock, unconventional gas reservoirs are developed with densely spaced wells to optimally recovery gas within a reasonable period of time. As a consequence, unconventional developments surface land usage is intensive relative to conventional fields. In many of these plays, the development is limited by the state regulatory requirements. As the development matures, applications for more dense well spacing are made to access areas of the reservoir that are inefficiently being drained and reduce overall production decline from the field. Table 6 lists spacing requirements by state. Densely developed areas of the Permian have well spacings as small as 10 acres, corresponding to 64 wells per section (1 section is equal to 640 acres). In 2005, Ultra Petroleum petitioned the State of Wyoming to reduce well spacing to as little as five acres in some areas of the Jonah-Pinedale Field. Figure 10 shows the surface footprint of a 40-acre development. Conventional gas developments are typically drilled on spacings of one section or greater.

The US Department of the Interior (2008), estimates surface disturbance for a vertical shale gas well would be 4.8 acres/well (2 acres for the well pad, 0.1 miles of road disturbance, 0.55 of utility corridor). Horizontal wells are estimated to disturb 6.9 acres. Due to the longer length of reservoir contact in horizontal wells, horizontals have the potential to drain a much larger reservoir volume than a vertical well. Fewer horizontal wells are required for a comparable amount of reservoir contact than in a vertical well development. Directional drilling has enabled pad developments. Drilling multiple wells from a single pad further reduces surface disturbance associated with field operations. In addition to reducing the number of well sites, horizontal wells and pad drilling also reduce surface disturbance by reducing the number of access roads and utility corridor associated with well sites and reduce disruption of native species habitats.

Conclusions

Technology plays a key role in the development of unconventional gas resources. Advanced drilling and completion technologies have enabled successful development of unconventional gas reservoirs, transforming a marginal resource into an increasingly important source of domestic natural gas. Because of the interdependence of rock fabric, mineralogy and geomechanics on production behavior, an integrated understanding of how these factors influence production can optimize the deployment of directional drilling and hydraulic fracturing, driving down development costs and increasing recovery from this unique class of resources.

Research and development into understanding the basic physics governing flow in unconventional gas reservoirs and the differences governing production behavior amongst shale gas, tight gas and coalbed methane is necessary for optimal deployment of technology. Improved understanding of processes governing gas distribution and production behavior will facilitate the development of analysis techniques and technologies tailored to the unique characteristics of each, providing more representative estimates of reservoir properties, reducing uncertainty in assessments of the size and potential of the resource.

Technology application has also reduced the environmental impact of unconventional gas developments. Geophysical techniques to identify areas of high fracture density and geomechanical properties of the reservoir allow optimization of well design parameters, such as lateral length, wellbore trajectory and number of fracture stages, reducing surface disturbance and water demand. Advances in technologies for water recycling and reuse have lessened impact on water resources while also reducing water acquisition and disposal costs, improving the economics of a development.

Unconventional gas resources will play a role in meeting the growing demand for natural gas. Because of the low recovery factors relative to conventional resources, continued technology development and application in these types of reservoirs is essential in maximizing the potential of unconventional gas in a safe and sustainable manner.

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