Coalbed- and Shale-Gas Reservoirs

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Introduction

Annual natural-gas production from coalbed- and shale-gas reservoirs in the US is approximately 2.7 Tscf, which represents 15% of total natural-gas production. Approximately 1.7 Tscf of this gas comes from more than 40,000 coalbed gas wells completed in at least 20 different basins. The remaining 1.0 Tscf comes from more than 40,000 shale gas wells completed in five primary basins. While the pace of coalbed-gas drilling is starting to slow, shale gas continues to be one of the hottest plays in the US, and drilling is expanding rapidly, especially in the south-central US (the Barnett shale and its equivalents), the Appalachian basin, and numerous Rocky Mountain basins.

Outside the US, more than 40 countries have investigated the potential of coalbed gas, resulting in commercial projects in Australia, Canada, China, and India. No commercial shale-gas projects currently exist outside of the US, but work continues to identify both new shale-gas reservoirs and to add incremental shale-gas production in existing reservoirs. Given that worldwide coalbed-gas resources are estimated to exceed 9,000 Tscf and shale-gas resources are estimated to exceed 16,000 Tscf, it is clear that tremendous potential exists for future growth (Kawata and Fujita 2001).

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Reservoir Fundamentals

Coals are sedimentary rocks containing more than 50 wt% organic matter, whereas shales contain less than 50 wt% organic matter. Methane is generated from the transformation of this organic matter by bacterial (biogenic gas) and geochemical (thermogenic gas) processes during burial. The gas is stored by multiple mechanisms including free gas in the micropores and sorbed gas on the internal surfaces of the organic matter. Nearly all coalbed gas is considered to be sorbed gas, whereas shale gas is a combination of sorbed gas and free gas.

Coalbed-gas reservoirs contain an orthogonal fracture set called cleats that are oriented perpendicular to the bedding and provide the primary conduit for fluid flow. Gas diffuses from the matrix into the cleats and flows to the wellbore. In shale-gas reservoirs, gas is sometimes produced through more-permeable sand or silt layers interbedded with the shale, through natural fractures, or from the shale matrix itself. In some cases, natural fractures are healed by a mineral filling and must be forced open by hydraulic-fracture stimulation. It also is possible to have both shales and coals interbedded in a single reservoir, resulting in gas contributions from both lithologies.

In coalbed-gas reservoirs, the key parameters controlling the amount of gas in place include coalbed thickness, coal composition, gas content, and gas composition. Coal composition refers to the amount and type of organic constituents in the coal, which has a significant effect on the amount of gas that can be sorbed. Gas contents in coal seams vary widely (<1 to >25 m^3/tonne) and are a function of coal composition, thermal maturity, burial and uplift history, and the addition of migrated thermal or biogenic gas. Gas composition generally is greater than 90% methane, with minor amounts of liquid hydrocarbons, carbon dioxide, and/or nitrogen.

Gas productivity from coalbed reservoirs is controlled primarily by permeability and the gas-saturation state. Permeability in producing areas typically ranges from a few millidarcies to a few tens of millidarcies, although permeabilities exceeding 1 Darcy have been reported. Absolute permeability increases with time as gas desorbs from the coal, causing the matrix to shrink and the cleats to widen, although this may be offset by a reduction in cleat aperture because of increased net stress caused by reservoir-pressure depletion.

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TABLE 1—SUMMARY OF CRITICAL DATA USED TO APPRAISE COALBED- AND SHALE-GAS RESERVOIRS	
Analysis	**Results**
Gas Content	Provides volumes of desorbed gas (from coal samples placed in canisters), residual gas (from crushed coal), and lost gas (calculated). The sum of these is the in-situ gas content of a given coal seam.
Rock-Evaluation Pyrolysis	Assesses the petroleum-generative potential and thermal maturity of organic matter in a sample. Determines the fraction of organic matter already transformed to hydrocarbons and the total amount of hydrocarbons that could be generated by complete thermal conversion.
Total Organic Carbon	Determines the total amount of carbon in the rock including the amount of carbon present in free hydrocarbons and the amount of kerogen.
Gas Composition	Determines the percentage of methane, carbon dioxide, nitrogen, and ethane in the desorbed gas. Used to determine gas purity and to build composite desorption isotherms.
Core Description	Visually captures coal brightness, banding, cleat spacing, mineralogy, coal thickness, and other factors. Provides insights about the composition, permeability, and heterogeneity of a coal seam.
Sorption Isotherm	A relationship, at constant temperature, describing the volume of gas that can be sorbed to a surface as a function of pressure. Describes how much gas a coal seam is capable of storing and how quickly this gas will be liberated.
Proximate Analysis	Provides the percentage of ash, moisture, fixed carbon, and volatile matter. Used to correct gas contents and sorption isotherms to an ash-free basis, correct the isotherms for moisture, and determine the maturity of high-rank coals.
Mineralogical Analyses	Determines bulk mineralogy using petrography and/or X-ray diffraction, and clay mineralogy using X-ray diffraction and/or scanning electron microscopy.
Vitrinite Reflectance	A value indicating the amount of incident light reflected by the vitrinite maceral. This technique is a fast and inexpensive means of determining coal maturity in higher-rank coals.
Calorific Value	The heat produced by combustion of a coal sample. Used to determine coal maturity in lower-rank coals.
Maceral Analysis	Captures the types, abundance, and spatial relationships of various maceral types. These differences can be related to differences in gas-sorption capacity and brittleness, which affect gas content and permeability.
Bulk Density	Relationships between bulk density and other parameters (such as ash content and gas content) can be used to establish a bulk-density cutoff for counting coal and shale thicknesses using a bulk-density log.
Conventional Logs	Self-potential, gamma ray, shallow and deep resistivity, microlog, caliper, density, neutron, and sonic logs. Used to identify coals and shales, and to determine porosity and saturation values in shales.
Special Logs	Image logs to resolve fractures and wireline spectrometry logs to determine in-situ gas content.
Pressure-Transient Tests	Pressure buildup or injection fall-off tests to determine reservoir pressure, permeability, skin factor, and to detect fractured-reservoir behavior.
3D Seismic	Used to determine fault locations, reservoir depths, variations in thickness and lateral continuity, and coal/shale properties.

Coals that are gas-saturated will produce gas immediately, whereas undersaturated coals will not produce gas until the pressure in the reservoir is reduced below the saturation pressure of the coal, which could require years of dewatering.

Controls on resource volume and productivity in shale-gas reservoirs are similar to those in coalbed-gas reservoirs. However, shale-gas reservoirs typically are thicker (30 to 300 ft), have lower sorbed-gas content (<10 m^3/tonne), and contain a much larger volume of free gas in the pore space. In addition, shale-gas reservoirs usually have much lower permeabilities than coalbed-gas reservoirs, with values commonly in the nano- to microdarcy range. To obtain commercial gas rates at such low permeabilities, a long completion interval often is opened (to maximize the permeability-thickness value) and hydraulic-fracture stimulation is required.

Both coalbed-gas and shale-gas reservoirs are continuous gas accumulations. These reservoir systems have gas-bearing strata that are not density-stratified, do not contain a gas/water contact, and persist over a very large geographic area. The challenge in these accumulations is not to find the gas, but rather to find those areas that will produce gas commercially. This challenge can be difficult given the vertical and areal variability and the requirement that sufficient core, log, seismic, and well-test data be obtained to characterize reservoirs. **Table 1** provides a summary of the most critical data needed to evaluate these reservoirs.

Drilling, Completion, and Production Methods

Historically, most drilling activity in coalbed- and shale-gas reservoirs has consisted of vertical wells. Shallow wells (150 to 1000 m deep) commonly are drilled using

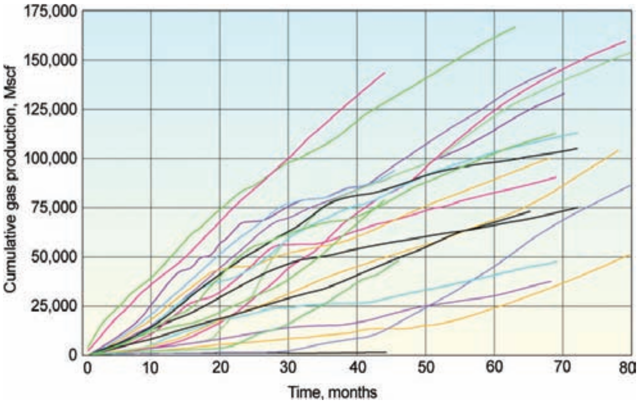

Fig. 1—Variability in coalbed-methane well performance from a 23-well field in the Black Warrior basin, Alabama, USA (courtesy of Schlumberger).

underbalanced rotary-percussion methods that result in rapid drilling rates (up to 15 m/h) and minimal formation damage. Conventional rotary drilling with lightweight-mud systems (balanced to underbalanced) are used at deeper depths (1000 to 2500+ m) in which higher reservoir pressures, excessive water flows, and/or wellbore-stability problems are expected.

With recent improvements in downhole technology and associated reductions in cost, horizontal drilling has become an attractive alternative. The first large-scale application of single-wellbore horizontal wells in a coalbed reservoir was in the mid-1990s in the Arkoma basin of Oklahoma, USA. Subsequently, a multilateral technique was developed in the central Appalachian basin of West Virginia, USA, consisting of an initial vertical well followed by a horizontal well steered to intersect the vertical well in the coal seam of interest (Von Schoenfeldt et al. 2004). From the horizontal wellbore, multiple laterals then are drilled to generate a pinnate pattern, similar to the vein pattern on a leaf. Typically, the horizontal laterals are completed openhole, and a pump is placed in the vertical well. Other multilateral configurations have evolved since the pinnate system was introduced and are being tested in several basins. The use of horizontal and multilateral techniques in shale-gas reservoirs also has been expanding rapidly, especially in the Barnett shale in which more than 90% of all new wells are horizontal.

A wide variety of fracture-stimulation designs are used in coalbed reservoirs. In the Raton basin of New Mexico, USA, multiple cased-hole, coiled-tubing fracture stimulations are conducted on thin individual seams by use of gelled fluids, with sand as proppant. In the Powder River basin of Wyoming, USA, where coal-seam permeability is high, wells are completed openhole and coals are flushed with water at rates of <5 bbl/min to flush out coal fines, open the cleats, and effectively connect the wellbore to the coal reservoir. The Horseshoe Canyon coals in Alberta, Canada, which produce no water, are stimulated with nitrogen-only fracturing treatments to keep liquids from damaging the coals by clay swelling, fines migration, or other mechanisms. Overall, cased and perforated wellbores with single- or multistage hydraulic fractures are the most common form of completion in coalbed wells.

Shale-gas wells almost universally rely on hydraulic fracturing to connect natural fractures to the wellbore. Although several horizontal openhole wells have been attempted in the New Albany shale of the Illinois basin, USA, most shale-gas horizontal wells are cased, cemented, and perforated with multistage treatments pumped along the length of the horizontal section. To monitor these treatments and adjust the fracture-stimulation pumping schedule in real time, new technologies, including tiltmeters and microseismics, are used. These technologies are especially important in the Barnett shale, in which it is critical to avoid fracture growth into the underlying wet rocks of the Ellenburger group.

Most coalbed- and some shale-gas reservoirs (such as the Antrim shale in the Michigan basin, USA) are water-saturated, and initial production is dominated by water with small amounts of gas. As this water is produced from the natural-fracture system, the reservoir pressure declines, gas desorbs from the matrix, and gas production increases while water production decreases. Gas production eventually reaches a peak or plateau for some period of time before declining at a rate controlled by key reservoir parameters (especially permeability) and interference effects from adjacent wells. Conversely, dry-coalbed- and shale-gas reservoirs typically perform like conventional gas reservoirs, with a peak initial production and slow decline thereafter as gas desorption replenishes the natural-fracture system.

One production characteristic common to all coalbed-and shale-gas reservoirs is a high variability in productivity. An example is a 23-well coalbed-gas development in a 1-sq mile area of the Black Warrior basin of Alabama, USA. All of the wells were drilled and completed in essentially the same way in a single coal seam, but there was still significant variation in gas productivity **(Fig. 1).** Local changes in permeability, as a result of both fracture intensity and fracture-aperture width, are thought to be the primary causes of this variability (Weida et al. 2005).

Resources and Reserves

Accurate determination of gas-in-place values in coalbeds and shales can be a difficult and time-consuming process because of the heterogeneous nature of these reservoirs and the uncertainties inherent in data collection and analysis. In coalbed-gas reservoirs, the gas-in-place value generally is assumed to be sorbed gas. Gas in place (m^3) is the product of coal thickness (m), areal extent (m^2), density (tonne/m^3), and gas content (m^3/tonne). To determine coal thickness, a conservative density limit of 1.75 g/cm^3 often is applied, although this should be increased to 2.5 g/cm^3 to capture any gas-prone shales that are interbedded with the coals. The average in-situ coal density can be estimated from a density log or from core measurements. Traditionally, gas-content values are obtained by desorbing core samples in the laboratory and then correcting these values for lost and residual gas. Alternatively, a recently introduced downhole laser spec-

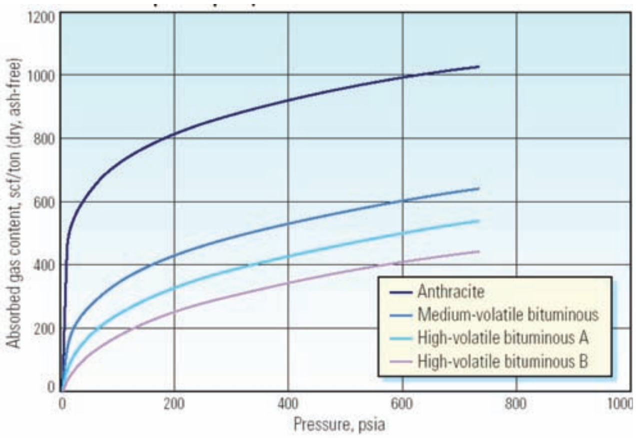

Fig. 2—Langmuir isotherm for coal showing the variation in methane-sorption capacity for different-rank (-thermal-maturity) coals. Note that the shape of the isotherm results in much more gas being liberated for a given pressure drop at low pressures than at high pressures (courtesy of Schlumberger).

trometer can be used to make in-situ measurements of the sorbed-gas content.

In shale-gas reservoirs, it is important to determine both the sorbed-gas component (by use of the same techniques applied in coalbed-gas reservoirs) and the free-gas component. The amount of free gas can be estimated from conventional-log data, but this method is complicated by low matrix porosities, a large bound-water fraction, and potentially long transition zones. Core measurements, especially porosity and drainage capillary pressure measurements, are important for estimating the storage characteristics of the matrix. Fracture porosity also can be an important component of gas storage. Even though it generally is low (less than 2% of the bulk reservoir volume), fracture porosity can account for 10% or more of the storage volume given the low matrix porosity of shales.

Assigning proved reserves to coalbed- and shale-gas reservoirs requires gas production at economic rates. In general, this is possible only if there is sufficient gas in place, adequate permeability, successful dewatering, a high enough gas price, and cost-effective drilling, completions, and production operations. Proved reserves also require a production profile, which can be difficult to predict during the dewatering phase when gas production is increasing. Some operators use well-production profiles from analogous reservoirs for this prediction, while others rely on more-sophisticated techniques, including numerical simulation.

Numerical simulation is a powerful tool that integrates core, log, and well-test data to help quantify well behavior by assessing the effects of variations in key reservoir parameters, incorporating unique components such as directional permeability and the contributions of free gas and sorbed gas, and evaluating the effects of various development strategies including well spacing, well pattern, and fracture-stimulation design. Once constructed, the model can be updated with production data, static reservoir pressures, and producing bottomhole pressures obtained on a regular basis to better understand and predict future well performance.

After the reservoir has been dewatered, or if dewatering is not needed, production performance and reserves can be estimated with conventional techniques such as material balance and decline-curve analysis. An important element in maximizing reserves in these reservoirs is minimizing the abandonment pressure. The storage characteristics of sorbed-gas reservoirs are such that larger volumes of gas are liberated at lower reservoir pressures. **Fig. 2** shows, for coals of various maturities, that if the average reservoir pressure is reduced from 100 to 50 psia, much more gas will be liberated than with a comparable 50-psia reduction in pressure from 200 to 150 psia.

Evaluation Strategies and Commercial Aspects

The challenge in evaluating coalbed- and shale-gas accumulations is to identify the most-prospective areas and to appraise and develop them efficiently. Successful projects have many similarities, including access to technology and gas markets, concentrated gas resources, and favorable reservoir characteristics **(Tables 2 and 3).**

The first step in analyzing a new area is to collect existing information from conventional wells, geological studies, and geophysical surveys. An important, but often overlooked, source of information is data from the mining industry including subsurface maps, coal characteristics, and mining-corehole data. These data can be used to identify coals and shales with sufficient thermal maturity, organic richness, thickness, depth, and areal extent to be a potential reservoir. Widely spaced vertical appraisal wells then can be drilled to quantify gas content, gas saturation, organic-matter characteristics, and permeability. Drilling a sufficient number of appraisal wells is critical for quantifying variations in reservoir properties, especially permeability, which can vary by several orders of magnitude even among closely spaced wells.

If appraisal-well characteristics are encouraging, then several options can be pursued including placing the appraisal well on production, which may yield significant gas if the reservoir does not have to be dewatered; drilling horizontal or multilateral wells to dewater the reservoir quickly and produce gas; or drilling a set of vertical pilot wells. Historically, a multiwell pilot project has been the most common approach because most reservoirs require dewatering and horizontal wells may not be appropriate at the beginning of a project. This is especially true if there are multiple reservoirs to evaluate and numerous uncertainties to consider such as faulting, lateral facies changes, and wellbore stability.

Most multiwell pilot tests consist of closely spaced wells drilled as part of a five- or nine-spot configuration. The primary purpose of a pilot test is to demonstrate that commercial gas rates can be achieved and that full-scale development will be economic. As a general rule, pilot wells should be drilled at a well spacing of less than 80 acres and produced for a minimum of 6 to 12 months. As part of operating the

TABLE 2—COMPARISON OF CHARACTERISTICS FROM SELECTED COMMERCIAL COALBED-GAS PROJECTS

Basin	Field	Area (sq miles)	Coal Thickness (ft)	Coal Rank	Gas Content (scf/ton)	Permeability (md)	Well Spacing (acres)	Well Count	Gas Rate/ Well (Mscf/D)	OGIP (Bscf)	RF (%OGIP)	Reserves (Bscf/well)
San Juan (US)	Ignacio Blanco	60	40–70	Bituminous	300–600	5–50+	60–320	130	1,500	1,760	66	3–15
Uinta (US)	Drunkard's Wash	120	4–48	Bituminous	425	5–20	160	450	500	1,571	57	1.5–4
Black Warrior (US)	Cedar Cove	65	25–30	Bituminous	250–500	1–25	80	520	100	809	53	0.5–1.5
Powder River (US)	Recluse Rawhide Butte	75	40–90	Subbituminous	30–70	5+	80	600	150	288	62	0.2–0.5
Western Canadian Sedimentary (Alberta)	Horseshoe Canyon	620	35–110	Subbituminous	55–110	0.1–100	80–160	3,300	45	4,393	28	0.25–0.5
Bowen Basin (Australia)	Fairview	430	50–100	Bituminous	200–400	100	250	80	700	450	60	2.5–3.5
Qinshui Basin (China)	Yangcheng-Qinshui	22	20–40	Anthracite	300–900	<1–5	80	40	70–140	100	20	0.4–0.8

pilot, data (e.g., produced-fluid volumes, pressures, and fluid-entry surveys) should be collected routinely.

Not all coalbed-gas reservoirs need multiwell pilot tests. Some reservoirs, such as those in the Appalachian basin of the USA, consisting of thick, shallow, continuous coal seams, can be developed at the outset with horizontal wells. Dry coals, such as the Horseshoe Canyon coals in Alberta, Canada, do not require dewatering and have been developed on the basis of appraisal-well gas rates. The same is true for the Barnett, Ohio, and Lewis shales, which do not have to be dewatered.

Whether pilot wells are needed or not, the technical evaluation of any coalbed- or shale-gas prospect is a multistage activity that requires a comprehensive strategy coupled with clearly defined success and exit criteria. Many companies "walked away" from projects that now are commercial because they failed to conduct a thorough evaluation or lacked the persistence to continue investing. Further, once a project becomes commercial, there is a tendency for companies to regard continued development as a "gas-manufacturing process" the primary objective of which is to minimize costs. This strategy fails to gather additional critical data and to test technical innovations that can increase profitability.

Strategies to quantify and reduce the financial risk associated with a coalbed- or shale-gas project should proceed simultaneously with work to minimize the technical risk. These strategies include taking advantage of financial incentives offered by host governments or using international capital resources from the World Bank or other entities. Another important aspect of reducing risk is to develop partnerships to minimize exposure, create economies of scale, and provide operational synergies. For example, exchanging an interest in a coalbed-gas project for an equivalent interest in a conventional-gas project might ensure that the combined gas stream provides a plateau rate for 25 years. The conventional project would provide the majority of the gas in the early years, and the coalbed-gas project would provide most of the gas in later years.

Because the commercialization of unconventional gas is still a novel process in many countries, foreign companies face several issues that can increase financial risk. There may be rivalries between various licensing and regulatory agencies, numerous hurdles in negotiating production-sharing contracts, and the absence of reliable oilfield services or a daily (spot) market for gas. These risks make it critical to partner with a company that has experience in the country of interest.

Coalbed- and Shale-Gas Project Summaries

Fruitland Coalbed Gas, San Juan Basin, USA. This area in northwestern New Mexico and southeastern Colorado is the most prolific coalbed-gas basin in the world, producing more than 2.5 Bscf/D from coals of the Cretaceous Fruitland formation and accounting for approximately 60% of the annual US coalbed-gas production. From a reservoir, completions, and production standpoint, the basin can be divided into two distinct regions: "fairway" and "nonfairway" productive areas. The fairway represents approximately 15% of the total productive area, yet it produces more than 75% of the total

Shale Play	Basin	Net Thickness (ft)	Gas Content (scf/ton)	*kh* (md-ft)	Reservoir Pressure (psia)	Well Spacing (acres)	Gas Rate/ Well (Mcf/D)	Water Rate/ Well (B/D)	OGIP (Bscf/ sq mile)	RF (%OGIP)	Reserves (Bscf/ well)
Antrim	Michigan	70–120	40–100	1–5,000	400	30–160	20–550	5–1,500	5–35	20–60	0.2–1.8
Ohio	Appalachian	30–100	60–100	0.2–50	500–2,000	40–160	30–500	0	5–10	10–20	0.15–0.6
New Albany	Illinois	50–150	40–80	1–1,800	300–700	80	30–100	5–1,000	7–10	10–20	0.15–0.6
Barnett	Fort Worth	50–200	150–350	0.01–2	3,000–4,000	80–160	100–3,000	0	30–40	5–20	0.5–3.0
Lewis	San Juan	200–300	15–45	6–400	1,000–1,500	80–320	100–500	0	8–50	5–15	0.6–2.0

TABLE 3—COMPARISON OF CHARACTERISTICS FROM SELECTED COMMERCIAL SHALE-GAS PROJECTS IN THE US [MODIFIED FROM CURTIS (2002)]

coalbed gas from the basin. Coal reservoirs are thickest in the fairway (locally exceeding 100 cumulative ft), which has high permeabilities (20 to 100 md) and overpressured reservoirs. Outside the fairway, coals are generally thinner (20 to 40 ft), with lower permeabilities (1 to 30 md) and normal- to underpressured conditions.

Within the fairway, more than 90% of the wells are completed with a cavitation technique. This technique alternately pressures up then rapidly depressures an openhole completion that is top-set with casing. This process causes the coal to fail, which enlarges the open hole and creates a donut-shaped area of enhanced permeability, both of which increase productivity. Outside the fairway, conventional hydraulic fracturing is the norm. Typical production from a fairway well is 6 MMscf/D, with peak rates reported at more than 25 MMscf/D. Nonfairway production is typically 100 to 400 Mscf/D. Production operations are characterized by wellhead compression to minimize the bottomhole flowing pressure and maximize desorption and water disposal into deep wells. Development in the basin continues, with more than 700 wells being drilled in 2006, in part to take advantage of a reduced well-spacing allowance of 80 acres vs. the previous 160 acres.

Fort Union Coalbed Gas, Powder River Basin, USA. The Powder River basin in northeastern Wyoming and southeastern Montana currently is the most active coalbed-gas play in the US, with an estimated 3,000 wells drilled in 2006. Because the Paleocene Fort Union coals have such low gas content (<100 scf/ton), activity in this basin was delayed for many years. As of April 1999, only 848 wells were producing a combined 135 MMscf/D, but by the end of 2005, more than 16,000 wells were producing a combined 900 MMscf/D. The combination of shallow drilling depths (250 to 1,500 ft), thick coal seams (up to 300 ft cumulative), high permeability (100 md to 2+ darcies), and low drilling and completion costs (<USD 100,000/well) compensates for the low gas content and results in reserves of 100 to 500 MMscf/well, which are recovered in 5 to 8 years at a 40- to 80-acre well spacing.

The vast majority of wells are completed openhole in a single coal seam, and it is common to have multiple wells on a single site targeting individual coal seams. Each seam is underreamed or jetted to enlarge the borehole, and water is injected at low rates to clean up any near-wellbore damage. Operators only recently have begun completing wells in multiple coal seams with commingled production. Wells take less than 1 week to drill and complete, and they reach highly variable peak gas rates of 30 Mscf/D to greater than 1 MMscf/D within 1 year. Initial water rates are very high and may exceed 1,000 B/D. Fortunately, the water quality is such that it can be inexpensively discharged at the surface, which helps reduce lease operating costs to less than USD 0.30/Mscf. Wells commonly retain their peak gas rate for 9 to 12 months before declining at a rate of approximately 20%/yr. Total recovered gas to date is approximately 2 Tscf, with estimates of total recoverable gas ranging from 20 to 40 Tscf.

Barnett Shale Gas, Fort Worth Basin, USA. The Mississippian Barnett shale is the largest gas-producing field in Texas, with more than 6,600 wells producing a combined 2.1 Bscf/D. Mitchell Energy drilled the first wells in the early 1980s, and there were only approximately 450 producing wells in 1999. Several factors are responsible for the drilling boom that has occurred since that time, including the use of horizontal wells, which now comprise approximately 25% of all wells drilled to date (>90% of all new wells); application of slick-water fracture stimulations and restimulations, which are more cost-effective than earlier gel-based fracture treatments; and successful expansion outside the initial core area of the play. This expansion continues westward, with more than 100 companies involved and potential reserves estimated at more than 30 Tscf.

Gas in the Barnett shale is thermogenically derived, and the shale is gas-saturated, so there is no initial water production. The majority of the gas exists in the pore space (free gas) instead of being sorbed to the rock, and the wells exhibit a normal decline with production. In many places, the Barnett shale contains few naturally open fractures and, therefore, is considered fracturable shale instead of fractured shale. As such, nearly all wells are fracture stimulated. The Barnett shale is found at depths of 6,500 to 8,500 ft, and vertical wells cost USD 700,000 to USD 1.5 million. Horizontal wells, with laterals varying from 500 to 3,500+ ft in length, cost approximately twice as much as vertical wells, but their

TABLE 4—CRITICAL TECHNOLOGY NEEDS AND APPLICATIONS FOR COALBED- AND SHALE-GAS RESERVOIRS		
Primary Technology Areas	Technology Needs	Technology Applications
Reservoir Characterization	Quantify fracture systems and variability Identify areas with high permeabilities	3D and 4D seismic
		Wellbore imaging tools
		Surface geochemistry
	Sorbed-gas content measurements	Downhole spectroscopic analysis
		Geochemical logging
	Permeability measurements	Pre- and post-closure minifrac analysis
		Wireline-conveyed isolation/injection systems
	Identification of behind-pipe reservoirs	Through-casing analysis
		Improved interpretive algorithms
Drilling Operations	Rapid, reduced-cost drilling	High-pressure, jet-assisted coiled-tubing systems
		Telemetric and composite drillpipe
		Nondamaging, environmentally benign fluids
	Reduced drilling “footprint”	Multilateral wells
		Below-reservoir extraction
	Horizontal-well stability	Combination drill and liner systems
		Mechanical liner systems
Completion Operations	Nondamaging cementing	Ultralightweight cement
	Formation access	Jet-assisted hydrojetting
		High-energy laser perforating
	Increased hydraulic-fracturing effectiveness	Coiled-tubing-conveyed systems with horizontal-well application
		Fracture diagnostics, including microseismic and tiltmeters
		Environmentally benign fluids
		Ultralightweight proppants
Production Operations	Artificial lift/water disposal	Downhole gas/water separation and reinjection
		Improved filtration and/or sequestration of contaminants
		Surface-modification agents
		Smart-well and expert systems
	Enhanced production	Carbon dioxide or nitrogen injection
		Enhanced horizontal-wellbore configurations
		Microbial-enhanced gas generation

gas rates and recoveries are 2 to 4 times those of a vertical well. Initial gas rates for horizontal wells typically range from 1 to 3 MMscf/D, with reserves of 1.5 to 3 Bscf/well based on a 30-year well life.

Antrim Shale Gas, Michigan Basin, USA. The Devonian Antrim shale provides a unique contrast to the Barnett shale. Production comes from two black-shale intervals in the Lower Antrim: the Lachine (80 to 120 ft thick) and the Norwood (10 to 30 ft thick), which are separated by the gray Paxton shale (20 to 50 ft thick). Gas in the Antrim is of biogenic origin and is primarily sorbed gas with a concentration ranging from 50 to 100 scf/ton. Productivity depends largely on the development of well-connected natural fractures that initially are water-saturated. This water must be removed to reduce the reservoir pressure and allow gas to desorb from the matrix, in a manner similar to coalbed-gas reservoirs.

The Antrim play saw rapid development from 1990 through 1992, spurred by a US federal-tax credit. Annual gas production peaked in 1998 at 200 Bscf. In 2005, more than 8,300 wells produced a combined 150 Bscf of gas and 75 million bbl of water; the average per-well rate was approximately 50 Mscf/D and 25 BWPD. Per-well gas rates are highly variable, ranging from 5 to more than 500 Mscf/D/well, with the gas stream averaging 10 to 20% carbon dioxide. Drilling continues, with more than

400 new wells completed within the past year. Total gas production to date is approximately 2 Tscf, with estimates of technically recoverable gas resources ranging from 5 to 10 Tscf.

Antrim shale wells are 400 to 2,000 ft deep, and gas production typically is 125 to 200 Mcf/D after 6 to 12 months of dewatering, during which time water rates can exceed 500 BWPD. A peak gas rate is reached in approximately 2 years, followed by an average decline of approximately 8%/yr for 20 years, resulting in a cumulative gas production of 400 to 800 MMscf. Well spacing varies from 30 to more than 160 acres/well, with initial gas-in-place estimates ranging from 5 to more than 35 Bscf/sq mile. Although wells initially were completed open hole, most operators now use cased-hole operations and two-stage nitrogen-foam hydraulic-fracturing treatments. The cost to drill and complete a well is less than USD 250,000, and there is increasing interest in trying horizontal wells in the Antrim shale. Operating costs are relatively high because of the need to lift water and inject it into disposal wells.

Technology and Future Trends

Both the coalbed- and shale-gas industries have experienced rapid growth over the past 20 years caused, in large part, by significant advances in upstream technologies. These technologies include horizontal drilling, specialized completion techniques, and novel water-disposal methods. Given this dependence on technology, it is clear that future innovations will exert a great influence on both the degree of development and the rate of growth in development.

The overall technology needs for both coalbed- and shale-gas development fall into the same basic categories as conventional reservoirs: reservoir characterization, drilling, completions, and production operations, as shown in **Table 4.** But the critical suite of technologies needed for any given coalbed- or shale-gas reservoir depends on the degree of reservoir heterogeneity, the mechanical properties of the rocks, and the types of fluids present. In addition, gas rates and reserves play a role in the selection process because certain technologies that could be very useful, such as 3D seismic, may currently be cost-prohibitive.

The expansion of coalbed-gas development to countries outside the US continues to be slow because of various factors including unfavorable reservoir characteristics, inadequate infrastructure, and competition with conventional-gas reservoirs. In some cases, leases changed hands several times before an operator with the right combination of corporate size, technical know-how, and contractual terms achieved a successful project. However, recent increases in gas prices have encouraged investments in projects that would not have been funded a decade ago.

Although currently there are no commercial shale-gas projects outside the US, intensive work is under way by many companies to identify the most-prospective basins and collect the data necessary for decision development. The most promising opportunities appear to be in western Canada, where basins with strata similar to those in the western US are thought to contain shale-gas resources of more than 1,000 Tscf. It seems clear that it will not be long before shale gas is produced commercially outside the US.

A future trend is the coupling of coalbed- and shale-gas development with the injection of carbon dioxide. Coal and the organic constituents in shale will release sorbed methane in preference to carbon dioxide, which enhances methane recovery and sequesters carbon. Although this is not without technical problems—for example, the coal swells as it sorbs carbon dioxide, resulting in reduced permeability—there are numerous combined enhanced-recovery and sequestration projects planned or under way in several countries.

Conclusions

Compared to conventional-gas reservoirs, coalbed- and shale-gas reservoirs are characterized by greater heterogeneity, multiple gas-storage mechanisms, and unique attributes that control productivity. Advances in understanding these complexities over the past 20 years have been accompanied by substantial improvements in drilling, completion, and production technologies. The result is faster dewatering, earlier and higher peak gas rates, more-accurate resource and reserves estimates, and improved economics.

These successes have encouraged many companies to pursue international opportunities. As a result, many small- to moderate-sized coalbed-gas reservoirs have been developed outside the US during the past decade, and a significant investment has been made to identify the world's most-prospective shale-gas basins. Assuming that the pace of technological innovation can be maintained and that gas prices remain favorable, there is every reason to believe that significantly more coalbed- and shale-gas reservoirs will be developed in the near future and that their gas-production stream will become an increasingly important component of the world's energy supply.

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Nomenclature

kh = permeability-thickness product, md-ft
OGIP = original gas in place
RF = recovery factor

JPT