Fractured shale-gas systems

John B. Curtis

ABSTRACT

The first commercial United States natural gas production (1821) came from an organic-rich Devonian shale in the Appalachian basin. Understanding the geological and geochemical nature of organic shale formations and improving their gas producibility have subsequently been the challenge of millions of dollars worth of research since the 1970s. Shale-gas systems essentially are continuous-type biogenic (predominant), thermogenic, or combined biogenic-thermogenic gas accumulations characterized by widespread gas saturation, subtle trapping mechanisms, seals of variable lithology, and relatively short hydrocarbon migration distances. Shale gas may be stored as free gas in natural fractures and intergranular porosity, as gas sorbed onto kerogen and clay-particle surfaces, or as gas dissolved in kerogen and bitumen.

Five United States shale formations that presently produce gas commercially exhibit an unexpectedly wide variation in the values of five key parameters: thermal maturity (expressed as vitrinite reflectance), sorbed-gas fraction, reservoir thickness, total organic carbon content, and volume of gas in place. The degree of natural fracture development in an otherwise low-matrix-permeability shale reservoir is a controlling factor in gas producibility. To date, unstimulated commercial production has been achievable in only a small proportion of shale wells, those that intercept natural fracture networks. In most other cases, a successful shale-gas well requires hydraulic stimulation. Together, the Devonian Antrim Shale of the Michigan basin and Devonian Ohio Shale of the Appalachian basin accounted for about 84% of the total 380 bcf of shale gas produced in 1999. However, annual gas production is steadily increasing from three other major organic shale formations that subsequently have been explored and developed: the Devonian New Albany Shale in the Illinois basin, the Mississippian Barnett Shale in the Fort Worth basin, and the Cretaceous Lewis Shale in the San Juan basin.

In the basins for which estimates have been made, shale-gas resources are substantial, with in-place volumes of 497–783 tcf. The estimated technically recoverable resource (exclusive of the Lewis Shale) ranges from 31 to 76 tcf. In both cases, the Ohio Shale accounts for the largest share.

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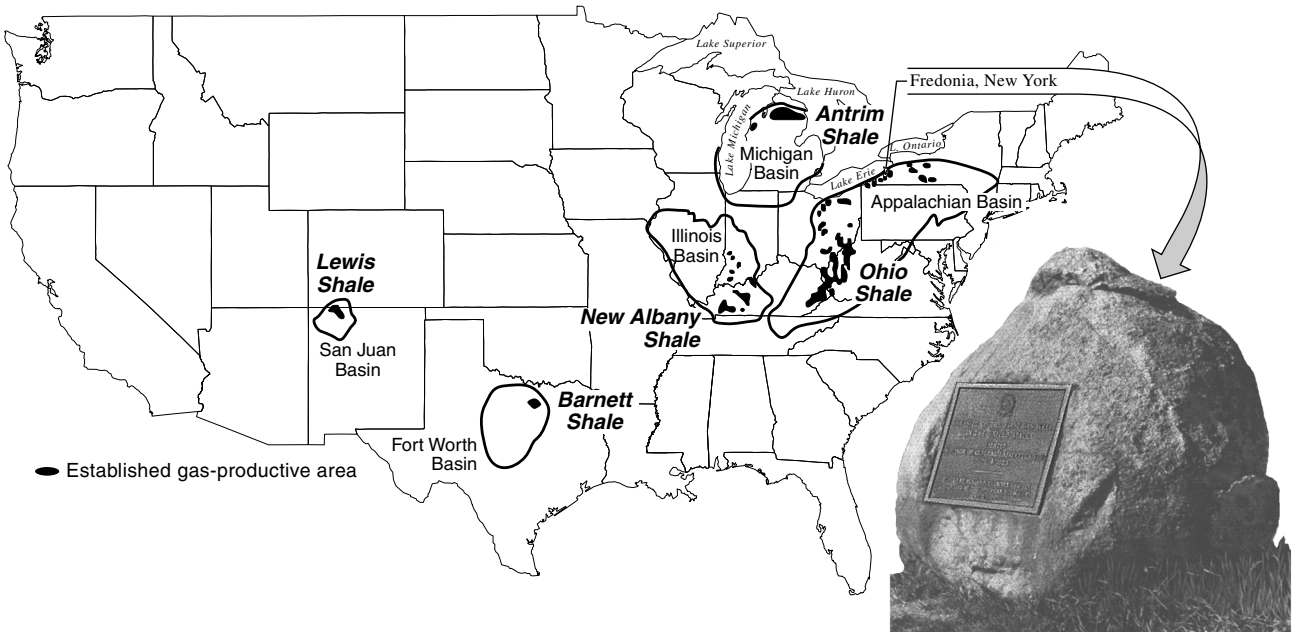

Monument at Fredonia, New York
"The Site of the First Gas Well in the United States. Lighted in Honor of General Lafayette's Visit, June 4, 1825"

Figure 1. Geographic distribution of five shale-gas systems in the lower 48 United States (modified from Hill and Nelson, 2000).

INTRODUCTION AND DEFINITION OF THE SYSTEM

Gas-productive shale formations occur in Paleozoic and Mesozoic rocks in the continental United States (Figure 1). Typical of most unconventional or continuous-type accumulations (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Curtis, 2001), these systems represent a potentially large, technically recoverable gas resource base, with smaller estimates for past production and proved reserves (Figure 2). The concept of the resource pyramid depicted in Figure 2 was first used in the late 1970s for analyzing natural gas accumulations in low-permeability reservoirs (Sumrow, 2001). If exploration and development companies are to access the gas resources toward the base of the pyramid, some combination of incrementally higher gas prices, lower operating costs, and more advanced technology will be required to make production economical. Production of gas deeper within the resource pyramid is required to fully realize the potential of this type of petroleum system.

More than 28,000 shale-gas wells have been drilled in the United States since the early 1800s (Hill and Nelson, 2000). That no gas-productive shales presently are known outside the United States (T. Ahlbrandt, 2001, personal communication) may be attributable more to uneconomical flow rates and well payback periods than to the absence of potentially productive shale-gas systems.

These fine-grained, clay- and organic carbon–rich rocks are both gas source and reservoir rock compo-

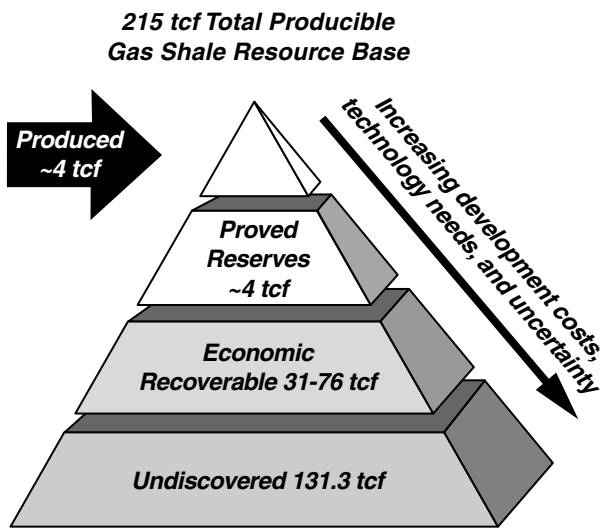

Figure 2. Resource pyramid depicting total shale-gas resource base (after Hill and Nelson, 2000, reprinted with permission from Hart Publications).

nents of the petroleum system (Martini et al., 1998). Gas is of thermogenic or biogenic origin and stored as sorbed hydrocarbons, as free gas in fracture and intergranular porosity, and as gas dissolved in kerogen and bitumen (Schettler and Parmely, 1990; Martini et al., 1998). Trapping mechanisms are typically subtle, with gas saturations covering large geographic areas (Roen, 1993). Postulated seal-rock components are variable, ranging from bentonites (San Juan basin) to shale (Appalachian and Fort Worth basins) to glacial till (Michigan basin) to shale/carbonate facies changes (Illinois basin) (Curtis and Faure, 1997; Hill and Nelson, 2000; Walter et al., 2000).

Thermogenic and biogenic gas components are present in shale-gas reservoirs; however, biogenic gas appears to predominate in the Michigan and Illinois basin plays (Schoell, 1980; Martini et al., 1998; Walter et al., 2000; Shurr, 2002).

Economical production typically, if not universally, requires enhancement of the inherently low matrix permeability (<0.001 d) of gas shales (Hill and Nelson, 2000). Well completion practices employ hydraulic fracturing technology to access the natural fracture system and to create new fractures. Less than 10% of shale-gas wells are completed without some form of reservoir stimulation. Early attempts to fracture these formations employed nitroglycerin, propellants, and a variety of hydraulic fracturing techniques (Hill and Nelson, 2000).

This article reviews the five principal shale-gas systems in the United States (Figure 1), with particular emphasis on the Antrim and Ohio shales as end members of the range of known shale-gas systems: (1) Antrim Shale, (2) Ohio Shale, (3) New Albany Shale, (4) Barnett Shale, and (5) Lewis Shale.

HISTORICAL PERSPECTIVE

The earliest references to black (organic-rich) shale units of the Appalachian basin are descriptions by French explorers and missionaries from the period 1627–1669. They noted occurrences of oil and gas now believed to be sourced by Devonian shales in western New York (Roen, 1993). The year 1821 generally is regarded as the start of the commercial natural gas industry in the young United States (Peebles, 1980). The first well was completed in the Devonian Dunkirk Shale in Chautauqua County, New York. The gas was used to illuminate the town of Fredonia (Figure 1) (Roen, 1993). This discovery anticipated the more famous Drake oil well at Oil Creek, Pennsylvania, by more than 35 yr. Peebles (1980, p. 51–52) documented this historic event as follows:

> The accidental ignition by small boys of a seepage of natural gas at the nearby Canadaway Creek brought home to the local townspeople the potential value of this "burning spring." They drilled a well 27 feet deep and piped the gas through small hollowed-out logs to several nearby houses for lighting. These primitive log pipes were later replaced by a three-quarter inch lead pipe made by William Hart, the local gunsmith. He ran the gas some 25 feet into an inverted water-filled vat, called a "gasometer" and from there a line to Abel House, one of the local inns, where the gas was used for illumination. In December 1825 the Fredonia Censor reported: "We witnessed last evening burning of 66 beautiful gas lights and 150 lights could be supplied by this gasometer. There is now sufficient gas to supply another one [gasometer] as large." Fredonia's gas supply was acclaimed as: "unparalleled on the face of the globe." This first practical use of natural gas in 1821 was only five years after the birth of the manufactured gas industry in the United States, which most commentators agree was marked by the founding of the Gas Light Company of Baltimore in 1816.

Shale-gas development spread westward along the southern shore of Lake Erie and reached northeastern Ohio in the 1870s. Gas was discovered in Devonian and Mississippian shales in the western Kentucky part of the Illinois basin in 1863. By the 1920s, drilling for shale gas had progressed into West Virginia, Kentucky, and Indiana. By 1926, the Devonian shale gas fields of eastern Kentucky and West Virginia comprised the largest known gas occurrences in the world (Roen, 1993).

The U.S. Department of Energy's Eastern Gas Shales Project was initiated in 1976 as a series of geological, geochemical, and petroleum engineering studies that emphasized stimulation treatment development. The Gas Research Institute (GRI; now the Gas Technology Institute [GTI]) built on this work through the 1980s and early 1990s to more completely evaluate the gas potential and to enhance production from Devonian and Mississippian shale formations of the United States.

The Devonian Antrim Shale of the Michigan basin, the most active United States natural gas play in the

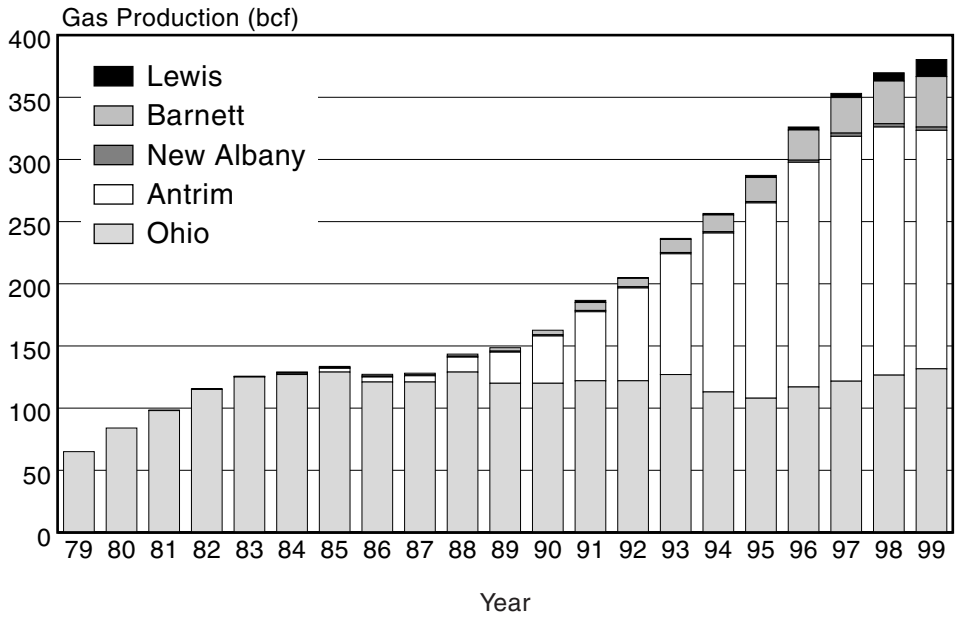

Figure 3. United States shale-gas production, in bcf, 1979–1999, for the five shale-gas systems under consideration (after Hill and Nelson, 2000, reprinted with permission from Hart Publications).

1990s, became commercially productive in the 1980s, as did the Mississippian Barnett Shale of the Fort Worth basin and the Cretaceous Lewis Shale of the San Juan basin (Figure 1) (Hill and Nelson, 2000). Shale-gas production has increased more than sevenfold between 1979 and 1999 (Figure 3). In 1998, shale-gas reservoirs supplied 1.6% of total United States dry gas production and contained 2.3% of proved natural gas reserves (Energy Information Administration, 1999).

GEOLOGICAL FRAMEWORK

Antrim Shale of the Michigan Basin

The Antrim Shale is part of an extensive, organic-rich shale depositional system that covered large areas of the ancestral North American continent in the Middle–Late Devonian (Figure 4). The intracratonic Michigan basin was one of several depocenters situated along the Eastern Interior Seaway. The basin has been filled with more than 17,000 ft (5182 m) of sediment, 900 ft (274 m) of which comprise the Antrim Shale and associated Devonian–Mississippian rocks. The base of the Antrim, near the center of the modern structural basin, is approximately 2400 ft (732 m) below sea level (Matthews, 1993).

Antrim stratigraphy is relatively straightforward (Figure 5). Wells are typically completed in the Lachine and Norwood members of the lower Antrim, whose aggregate thickness approaches 160 ft (49 m) (Figure 6). Total organic carbon (TOC) content of the Lachine and Norwood ranges from 0.5 to 24% by weight. These black shales are silica rich (20–41% microcrystalline quartz and wind-blown silt) and contain abundant dolomite and limestone concretions and carbonate, sulfide, and sulfate cements. The remaining lower Antrim unit, the Paxton, is a mixture of lime mudstone and gray shale lithologies (Martini et al., 1998) containing 0.3–8% TOC and 7–30% silica. Correlation of the fossil alga *Foerstia* has established time equivalence among the upper part of the Antrim Shale, the Huron Member of the Ohio Shale of the Appalachian basin (Figure 7), and the Clegg Creek Member

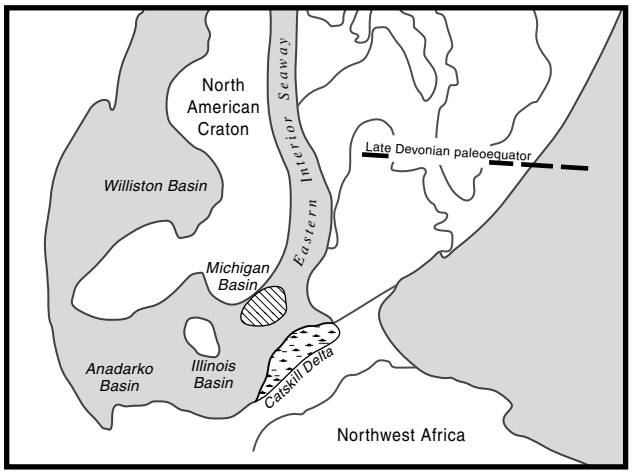

Figure 4. Reconstruction of Late Devonian paleogeography (modified from Walter et al., 1995).

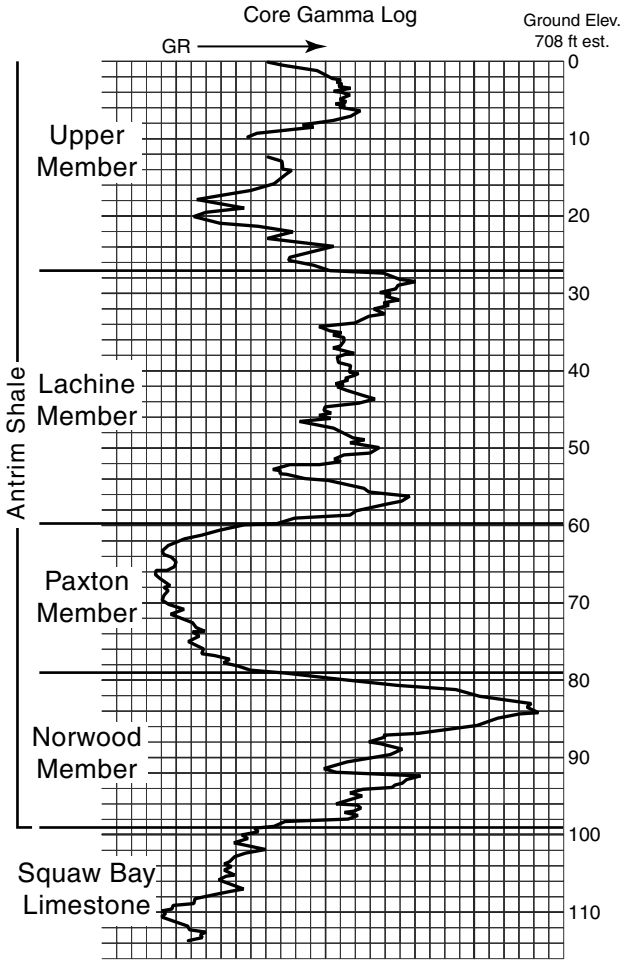

Figure 5. Antrim Shale gamma-ray log from the Paxton Quarry, Alpena County, Michigan (Sec. 30, T31N, R7E, Michigan Meridian). Figure modified from Matthews (1993) and Decker et al. (1992).

of the New Albany Shale of the Illinois basin (Roen, 1993).

The large-scale structure of the lower Antrim is relatively simple (Figure 8). Trap and seal components of the Antrim Shale petroleum system are subtle, as discussed in a following section.

Table 1 summarizes key geological, geochemical, and engineering parameters for the Antrim and the four other United States gas shale systems under discussion. The wide range of these parameters is typical of unconventional reservoirs. Specialized techniques for laboratory and field measurement of required exploration and production data and practical formation evaluation techniques for low-porosity, ultralow-permeability reservoirs were developed by the U.S. Department of Energy and Gas Technology Institute (e.g., Luffel et al., 1992; Lancaster et al., 1996; Frantz et al., 1999). Figure 9 depicts the range of values for five key parameters: (1) vitrinite reflectance (as % R_o), a measure of thermal maturity of the kerogen; (2) fraction of gas present as adsorbed gas; (3) reservoir thickness; (4) TOC; and (5) gas-in-place resource per acre-foot of reservoir. These five parameters are normalized to a maximum value of 5 and a minimum of 0 for a given basin. Inspection of Figure 9 indicates that parameters widely different from those of the Antrim Shale still permit commercial gas production from other fractured, organic-rich shales. Note that only the Antrim and New Albany shales produce significant amounts of water. This coproduced water is similar to that typical of coalbed methane production (Ayers, 2002), except that no significant reservoir dewatering is required prior to initiation of shale-gas production.

Antrim Shale gas production may have slightly leveled off, at least for the short term, in 1998 at 195 bcf (Hill and Nelson, 2000). In 1999, when 6500 wells were on production, 190 bcf were produced, approximately 2% less than the previous year. Most producing gas wells are located in the northern third of the basin, termed the northern producing trend (Figures 1, 6). The average well there produces 116 mcf/day with 30 bbl/day of water.

Two dominant sets of natural fractures have been identified in the northern producing trend, one oriented toward the northwest and the other to the northeast and both exhibiting subvertical to vertical inclinations. These fractures, generally uncemented or lined by thin coatings of calcite (Holst and Foote, 1981; Decker et al., 1992; Martini et al., 1998), have been mapped for several meters in the vertical direction and tens of meters horizontally in surface exposures. Attempts to establish production in the Antrim outside this trend have commonly encountered organic, gas-rich shale but minimal natural fracturing and, hence, permeability (Hill and Nelson, 2000).

No discrete fields are recognized for Antrim Shale production. However, as with other so-called continuous-type natural gas accumulations, shale-gas saturations exist over a relatively wide area, where commercial production is possible by stimulation enhancement of existing natural fractures (Milici, 1993; Hill and Nelson, 2000). Anecdotal evidence from deeper Antrim Shale wells drilled in the early 1990s south and east of the northern producing trend (Figure 6) encountered methane saturations but only limited permeability, which precluded production.

Antrim Shale gas appears to be of dual origin, thermogenic, resulting from thermal maturation of

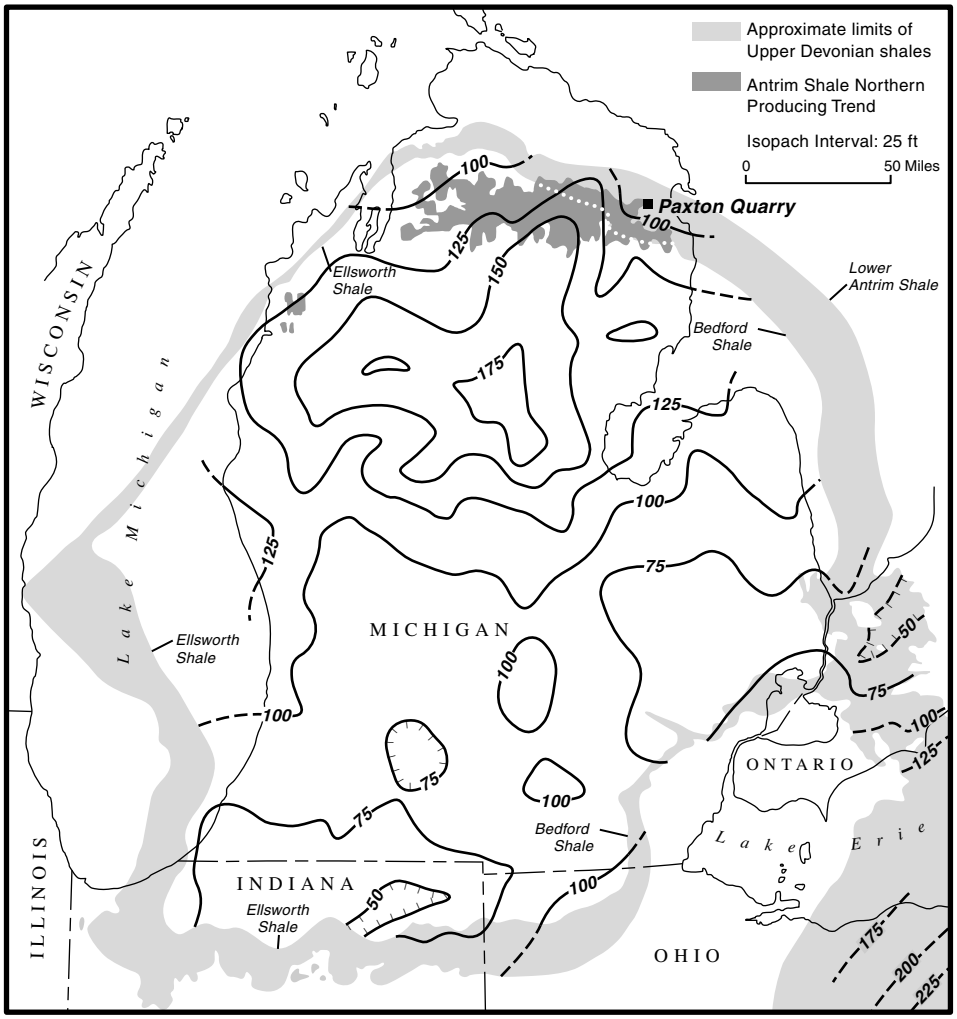

Figure 6. Isopach map of lower Antrim Shale (after Matthews, 1993).

kerogen, and microbial (or biogenic), the result of metabolic activity by methanogenic bacteria. An integrated study by Martini et al. (1998) of formation-water chemistry, produced gas, and geologic history has established the dominance of microbially produced gas within the northern producing trend; the well-developed fracture network allows not only gas and connate water transport within the Antrim Shale but also invasion of bacteria-laden meteoric water from aquifers in the overlying Pleistocene glacial drift. Deuterium isotopic compositions (δD) of methane and coproduced formation waters provide the strongest evidence for bacterial methanogenesis. A dynamic relationship was proposed by Martini et al. (1998) between fracture development and Pleistocene glaciation, wherein the hydraulic head due to multiple episodes of ice-sheet loading enhanced the dilation of preexisting natural fractures and allowed influx (recharge) of meteoric waters to support bacterial methanogenesis.

A volumetrically smaller (<20%) thermogenic gas component also was identified, based on methane:[ethane + propane] ratios and carbon isotopic ($\delta^{13}C$) composition of produced ethane. The thermogenic gas component proportionally increases basinward, in the direction of increasing kerogen thermal maturity.

Antrim Shale Petroleum System

An insightful analysis of the interplay among source rocks, reservoir rocks, traps, and seals—the traditional requirements for economical accumulations of oil or gas—can be performed by analyzing these factors as components of a petroleum system. This concept, outlined by Magoon and Dow (1994), evaluates the genetic relationship between a pod of active source rock and the resulting hydrocarbon accumulation. The essential elements of the petroleum system are source

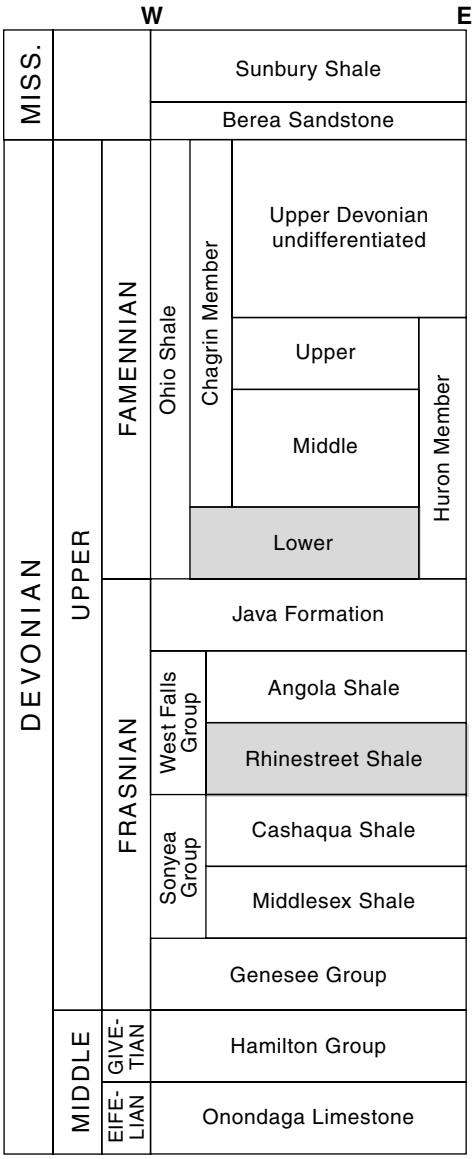

Figure 7. Middle Devonian–Lower Mississippian strata in the western part of the Appalachian basin (modified from Moody et al., 1987).

rock, reservoir rock, seal rock, and overburden rock. Processes that must be considered include trap formation and generation-migration-accumulation of hydrocarbons, all appropriately placed in time and space. Central to the application of this concept is the determination of the critical moment, that is, the time that best represents hydrocarbon generation, migration, and accumulation.

In common with other unconventional petroleum systems discussed in this volume, fractured shale-gas systems do not possess all the individual components defined by Magoon and Dow (1994). Organic-rich shale formations such as the Lachine and Norwood members of the lower Antrim Shale, for example, constitute both source and reservoir rock. Fracturing, which results in the creation or expansion of reservoir capacity and permeability, may arise from pressures generated either internally by the thermal maturation of kerogen to bitumen, or externally by tectonic forces, or by both. Furthermore, these events may occur at decidedly different times. In any event, hydrocarbon migration distances within the shale are relatively short. Conventional reservoirs situated upsection or downsection of the shale also may be concurrently charged with hydrocarbons generated by the same shale source rocks (Cole et al., 1987).

Figure 10 is an events chart (Magoon and Dow, 1994) that depicts the timing of critical events in the history of the lower Antrim Shale. Although hydrocarbon generation probably has occurred at various times in the geologic past, the gas currently produced likely is only several tens of thousands of years old (Martini et al., 1998). The thermogenic gas charge may have leaked from the shale reservoir through geologic time. The association of this more geologically recent gas generation with Pleistocene glaciation logically extends both to trap formation by the overlying till and to fracturing induced by ice-sheet loading/unloading (Martini et al., 1998; Hill and Nelson, 2000). Petroleum system preservation time, which commences after hydrocarbon generation, migration, and accumulation (Magoon and Dow, 1994), is, therefore, nearly zero, inasmuch as the system may still be generating microbial gas.

Ohio Shale

The Ohio Shale of the Appalachian basin (Figure 1) differs in many respects from the Antrim Shale petroleum system. As discussed in a preceding section, this petroleum system provided the first commercial gas production in the United States.

Figure 7 is a stratigraphic section of the Devonian shale formations in the gas-productive parts of central and western West Virginia. Locally, the stratigraphy is considerably more complex than shown here as a result of variations in depositional setting across the basin (Kepferle, 1993; Roen, 1993). The Middle and Upper Devonian shale formations underlie approximately 128,000 mi^2 (331,520 km^2) and crop out around the rim of the basin. Subsurface formation thicknesses exceed 5000 ft (1524 m), and organic-rich black shales

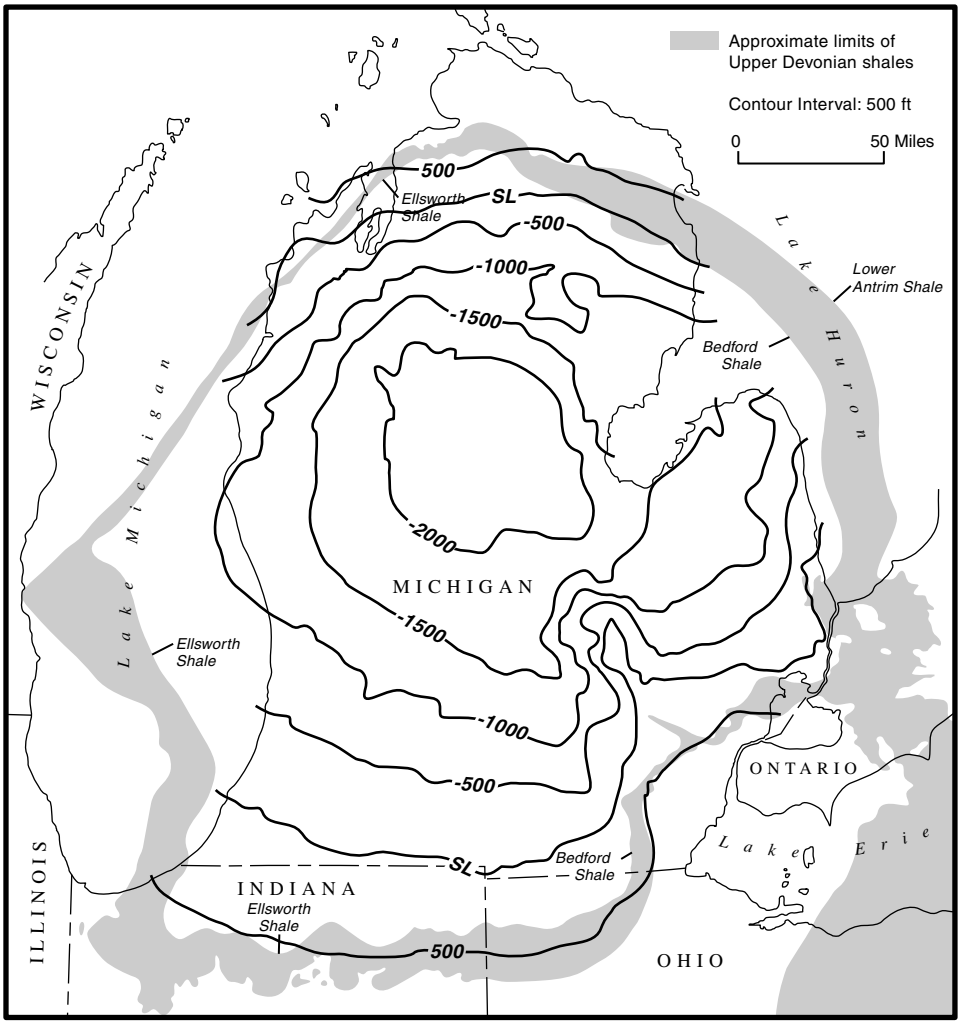

Figure 8. Structure map contoured on the base of the lower Antrim Shale (modified from Matthews, 1993).

exceed 500 ft (152 m) in net thickness (Figure 11) (deWitt et al., 1993).

The enormous wedge of Paleozoic sedimentary rocks in the Appalachian basin reflects gross cyclical deposition of organic-rich rocks (mainly carbonaceous shales), other clastics (sandstones, siltstones, and silty, organic-poor shales), and carbonates (Roen, 1993, 1984). These rocks were deposited in an asymmetrical, eastward-deepening foreland basin that evolved with the transition of the Laurentian paleocontinent from a passive-margin to convergent-margin setting. At least three major Paleozoic depositional cycles occurred, each consisting of a basal carbonaceous shale overlain by clastics and capped by carbonates. The Devonian black shale formations are part of the second youngest cycle. The shale formations themselves can be further subdivided into five cycles of alternating carbonaceous shales and coarser grained clastics (Ettensohn, 1985). These five shale cycles developed in response to the dynamics of the Acadian orogeny and westward progradation of the Catskill delta (Figure 4).

The Rome trough (Figure 12) is a complex graben system created during Late Proterozoic passive continental-margin rifting that formed the Iapetus Ocean. During the subsequent Taconic, Acadian, and Alleghanian orogenies, the faults that define the grabens were reactivated (Coogan, 1988; Shumaker, 1993), forming topographic depressions on the floor of the shallow inland sea in the Late Devonian. Curtis and Faure (1997, 1999) postulated that fault-bounded subbasins associated with these depressions controlled the preservation of alga-derived organic matter in the lower Huron Member of the Ohio Shale and in the Rhinestreet Shale Member of the West Falls Formation (Figure 7). These subbasins may have been anoxic because their poorly circulating waters limited oxygen recharge. Preservation of organic matter also was enhanced by periodic blooms of *Tasmanites* and similar algae in the

Table 1. Geological, Geochemical, and Reservoir Parameters for Five Shale-Gas Systems*

Property	Antrim	Ohio	New Albany	Barnett	Lewis
Depth (ft)	600–2400	2000–5000	600–4900	6500–8500	3000–6000
Gross thickness (ft)	160	300–1000	100–400	200–300	500–1900
Net thickness (ft)	70–120	30–100	50–100	50–200	200–300
Bottom-hole temperature (°F)	75	100	80–105	200	130–170
TOC (%)	0.3–24	0–4.7	1–25	4.50	0.45–2.5
Vitrinite reflectance (% R_o)	0.4–0.6	0.4–1.3	0.4–1.0	1.0–1.3	1.6–1.88
Total porosity (%)	9	4.7	10–14	4–5	3–5.5
Gas-filled porosity (%)	4	2.0	5	2.5	1–3.5
Water-filled porosity (%)	4	2.5–3.0	4–8	1.9	1–2
Permeability thickness [Kh (md-ft)]	1–5000	0.15–50	NA	0.01–2	6–400
Gas content (scf/ton)	40–100	60–100	40–80	300–350	15–45
Adsorbed gas (%)	70	50	40–60	20	60–85
Reservoir pressure (psi)	400	500–2000	300–600	3000–4000	1000–1500
Pressure gradient (psi/ft)	0.35	0.15–0.40	0.43	0.43–0.44	0.20–0.25
Well costs ($1000)	180–250	200–300	125–150	450–600	250–300
Completion costs ($1000)	25–50	25–50	25	100–150	100–300
Water production (b/day)	5–500	0	5–500	0	0
Gas production (mcf/day)	40–500	30–500	10–50	100–1000	100–200
Well spacing (ac)	40–160	40–160	80	80–160	80–320
Recovery factor (%)	20–60	10–20	10–20	8–15	5–15
Gas in place (bcf/section)	6–15	5–10	7–10	30–40	8–50
Reserves (mmcf/well)	200–1200	150–600	150–600	500–1500	600–2000
Historic production area basis for data	Otsego County, Michigan	Pike County, Kentucky	Harrison County, Indiana	Wise County, Texas	San Juan & Rio Arriba Counties, New Mexico

*Modified from Hill and Nelson (2000); data cited by those authors were compiled from Gas Technology Institute/Gas Research Institute research reports and operator surveys.

waters above the local basins. These algal blooms created such large concentrations of organic matter that they exhausted the supply of molecular oxygen, thereby preserving the algal material, even in sediments beyond the subbasin boundaries.

Figure 12 depicts the distribution of kerogen, as TOC, within the lower Huron Member, the main source bed of the Ohio Shale. Essentially all the organic matter contained in the lower Huron is thermally mature for hydrocarbon generation, based on vitrinite reflectance studies. The organic matter is predominantly type II (liquid- and gas-prone) kerogen (Curtis and Faure, 1997, 1999). The area enclosed by the TOC contours in Figure 12 encompasses the majority of the gas-productive areas in West Virginia, eastern Kentucky, and southern Ohio (Gas Research Institute, 2000). In the Calhoun County, West Virginia, area, the lower section of the lower Huron Member is gas productive, coinciding with maximum gamma-ray log readings, as illustrated in Figure 13, a type log from a GRI (now GTI) study well. Overall, the section contains 1% TOC; however, up to 2% TOC occurs in the gas-productive lower section.

The proportion of black shale, TOC content, and gas productivity increases to the west (Figure 12) to maxima in the Big Sandy field complex of Kentucky, near the West Virginia border. This also approximately coincides with the maximum measured TOC and resulting kerogen content. The Big Sandy field complex, which has produced shale gas since 1921 (Hunter and Young, 1953), historically is the greatest contributor of shale-gas production in the Appalachian basin.

Hunter and Young's (1953) study provides insight into the Ohio Shale petroleum system. Of 3400 wells studied, 6% were completed without stimulation. These nonstimulated wells, which presumably intercept natural fracture networks, had an average open-flow rate of 1055 mcf/day. The remaining wells did not flow appreciably after drilling, averaging only 61 mcf/day. The latter were subsequently stimulated by

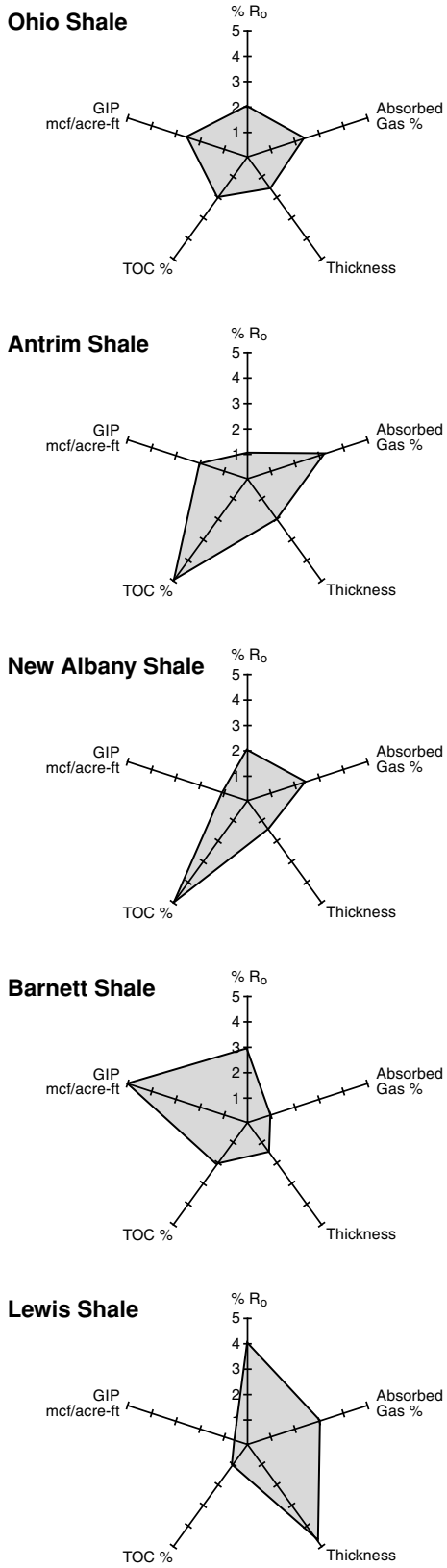

Figure 9. Comparison of gas-shale geological and geochemical properties (after Hill and Nelson, 2000, reprinted with permission from Hart Publications). GIP = gas in place.

the early oilfield technique of shooting, whereby 3000–7000 lb of nitroglycerine typically were detonated downhole. After stimulation, the wells averaged about 285 mcf/day, a greater than fourfold improvement. Hunter and Young (1953) concluded that shooting had enhanced fracture porosity and permeability, allowing commercial volumes of gas to be produced. Current stimulation practices, although not as visually impressive as shooting, are more effective and certainly less damaging to the reservoir. Today wells commonly are fracture stimulated with liquid nitrogen foam and a sand proppant (Milici, 1993).

Prior to 1994, the Ohio Shale produced the majority of United States shale gas, until the drilling boom in Michigan elevated the Antrim Shale to the top position (Figure 3).

New Albany Shale

The New Albany Shale of the Illinois basin (Figures 1, 4) is correlative in part to the Ohio Shale and Antrim Shale (Roen, 1993). New Albany Shale units range in thickness from 100 to 400 ft (30–122 m) and lie at depths of 600–4900 ft (182–1494 m) (Hassenmueller and Comer, 1994). Similar to the other black shales under consideration, gas in the New Albany Shale is stored both as free gas in fractures and matrix porosity and as gas adsorbed onto kerogen and clay-particle surfaces (Walter et al., 2000). Studies have shown that commercial production may be associated with fracturing related to faults, folds, and draping of the shale over carbonate buildups (Hassenmueller and Zuppann, 1999).

Most natural gas production from the New Albany comes from approximately 60 fields in northwestern Kentucky and adjacent southern Indiana. However, past and current production is substantially less than that from either the Antrim Shale or Ohio Shale (Figure 3). Exploration and development of the New Albany Shale was spurred by the spectacular development of the Antrim Shale play in Michigan, but results have not been as favorable (Hill and Nelson, 2000). Production of New Albany Shale gas, which is considered to be biogenic, is accompanied by large volumes of formation water (Walter et al., 2000). The presence of water would seem to indicate some level of formation permeability. The mechanisms that control gas occurrence and productivity are not as well understood as those for the Antrim and Ohio shales (Hill and Nelson, 2000) but are the subject of ongoing studies by consortia of basin operators.

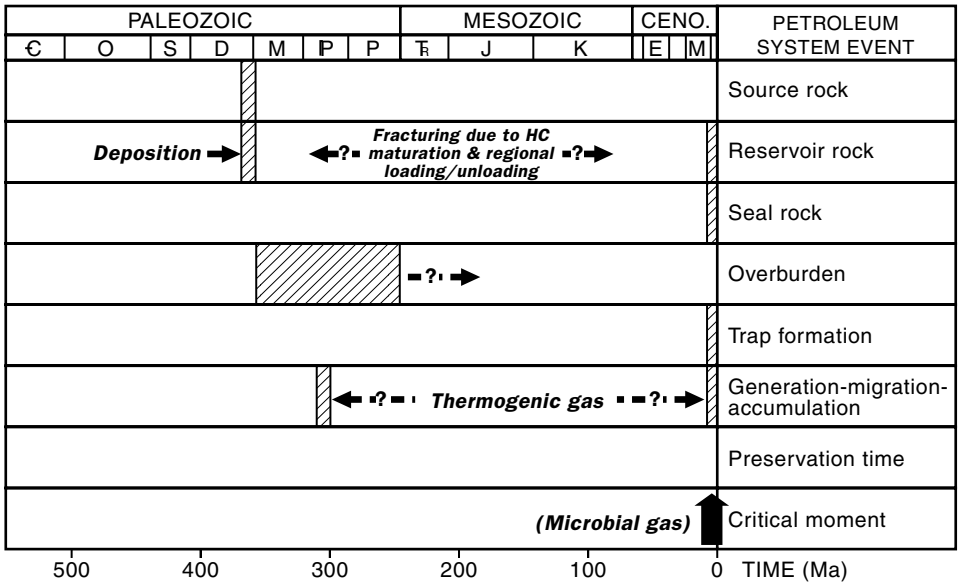

Figure 10. Antrim Shale events chart depicting the critical moment for Antrim Shale gas generation.

A GTI-sponsored consortium recently completed an investigation into natural fracturing, water production, well completion practices, and requisite economics as factors in New Albany Shale gas production (Hill, 2001). This effort included work by Walter et al. (2000) on possible hydrochemical controls on gas production. Although the potential of the New Albany Shale has not yet been realized, exploration and drilling have accelerated with recent increases in wellhead gas prices (Hill, 2001).

Barnett Shale

Mitchell Energy and Development Corporation (MEDC) initiated commercial gas production from the Mississippian Barnett Shale in the Fort Worth basin

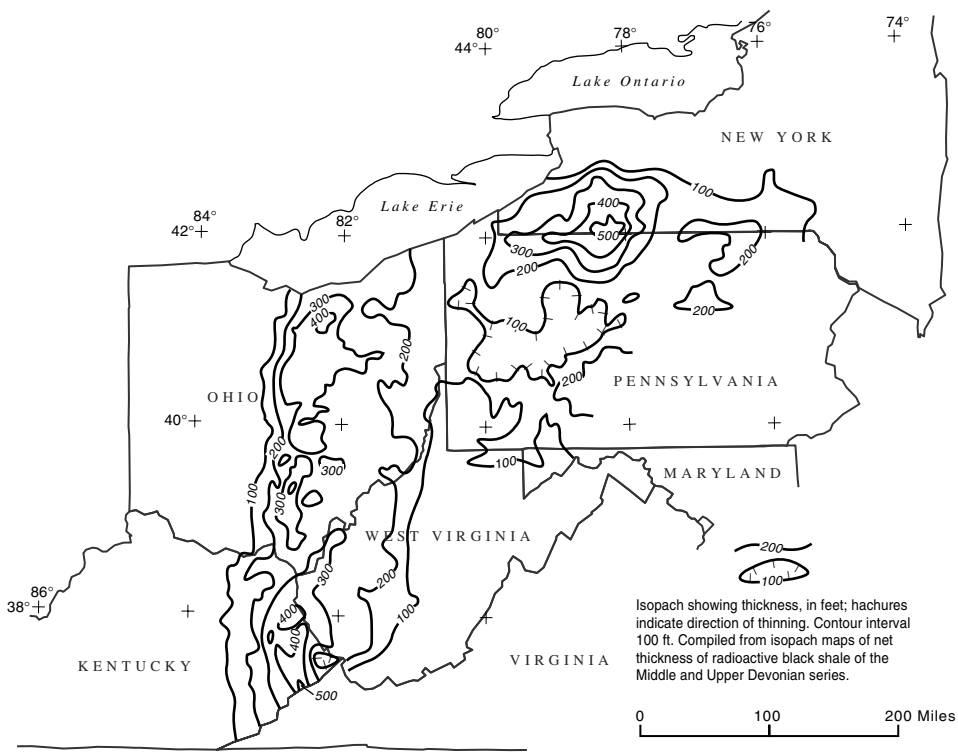

Figure 11. Total net thickness of radioactive black shale in Middle–Upper Devonian rocks (after deWitt et al. 1993).

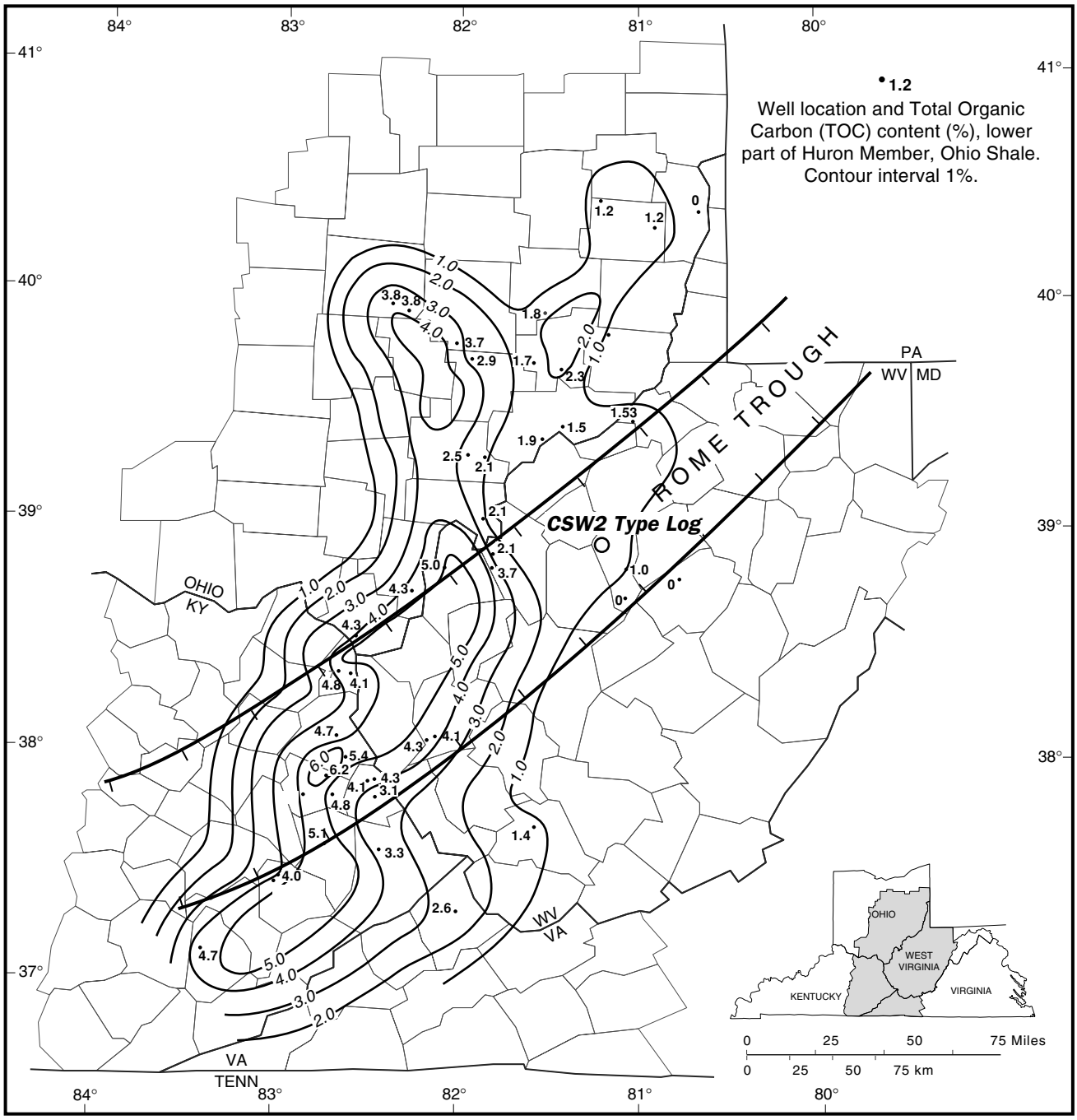

Figure 12. Distribution of total organic carbon (TOC) in the lower part of the Huron Member of the Ohio Shale (after Curtis and Faure, 1997, reprinted by permission of the AAPG whose permission is required for further use). CSW2 = Comprehensive Study Well 2 of the Gas Research Institute (now GTI).

(Figure 1) in 1981. Although Newark East field is the main producing area, MEDC (now merged with and known as Devon Energy Corporation) and other operators have expanded the commercial gas play into other areas (Hill and Nelson, 2000; Barnett Shale Home Page, 2001; Williams, 2002). The Barnett Shale in Newark East field lies at depths of 6500–8500 ft (1981–2591 m); net shale thickness ranges from 50 to 200 ft (15–61 m) (Table 1).

Geochemical and reservoir parameters for the Barnett Shale differ markedly from those of other gas-productive shales, particularly with respect to gas in place

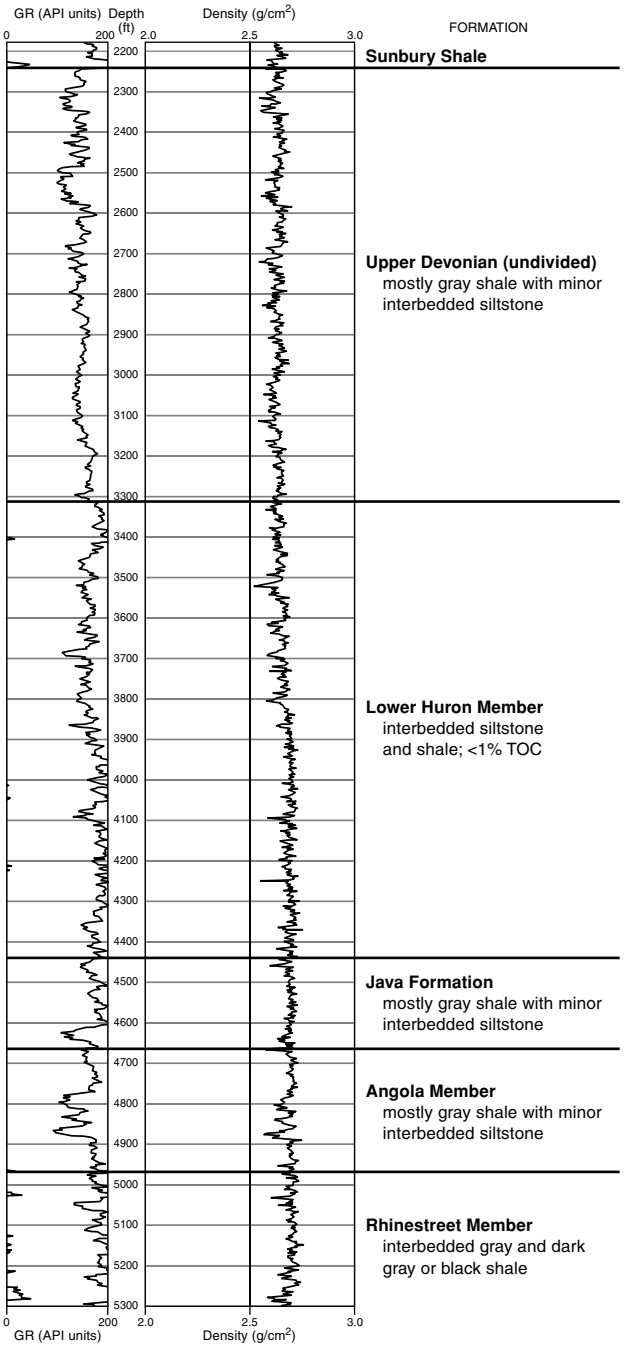

Figure 13. Type log from the GTI CSW 2 well, Calhoun County, West Virginia (after Lowry et al., 1988, reprinted with permission from the Gas Technology Institute). CSW2 = Comprehensive Study Well 2 of the Gas Research Institute (now GTI).

(Figure 9). For example, Barnett Shale gas is thermogenic in origin. According to the model depicted in Figure 14, hydrocarbon generation began in the Late Paleozoic, continued through the Mesozoic, and ceased with uplift and cooling during the Cretaceous (Jarvie et al., 2001). In addition, organic matter in the Barnett Shale has generated liquid hydrocarbons. Jarvie et al. (2001) identified Barnett-sourced oils in 13 other formations, ranging from Ordovician to Pennsylvanian in age, in the western Fort Worth basin. Cracking of this oil may have contributed to the gas-in-place resource.

Jarvie et al. (2001) also postulated that, whereas the Barnett Shale petroleum system exhibits world-class petroleum potential, two factors have combined to inhibit oil and gas productivity: (1) episodic expulsion of hydrocarbons when other elements of the petroleum system (migration paths, reservoir rocks, trap) were less than optimum in time and space and (2) periodically leaking seals.

Nevertheless, Barnett Shale gas production is on the increase; annual production exceeds 400 mcf/day from more than 900 wells (Williams, 2002). Expansion of the Barnett play beyond the historical production area is accelerating but is limited (particularly for more recent participants) by market, infrastructure considerations, and proximity to the Dallas–Fort Worth metroplex.

Lewis Shale

The Lewis Shale of the central San Juan basin of Colorado and New Mexico (Figure 1) is the youngest shale-gas play, both in geologic terms and in terms of commercial development.

The Lewis Shale is a quartz-rich mudstone with TOC contents ranging from about 0.5 to 2.5% (Table 1). It is believed to have been deposited as a lower shoreface to distal offshore sediment in the Late Cretaceous.

On the type log for the Lewis Shale, shown in Figure 15, four intervals and a conspicuous, basinwide bentonite marker are recognizable. The greatest permeability is found in the lowermost two-thirds of the section. This enhanced permeability may be the result of an increase in grain size and microfracturing associated with the regional north-south/east-west fracture system (Hill and Nelson, 2000).

Inspection of Figure 9 and Table 1 shows that the Lewis Shale has the greatest net thickness and highest thermal maturity of the five petroleum systems under discussion. Adsorbed gas content also is the highest of any of the shale-gas plays.

The late 1990s marked the startup of the Lewis Shale gas play. Operators target the Lewis as either a secondary completion zone in new wells or a recompletion zone in existing wellbores (Hill and Nelson,

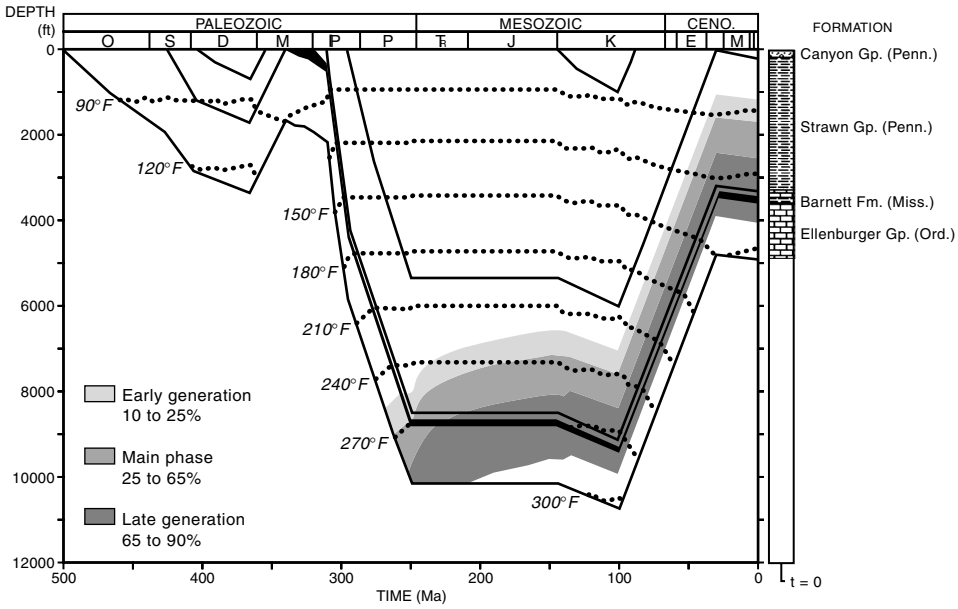

Figure 14. Burial history diagram and stratigraphic column, Fort Worth basin (after Jarvie et al., 2001, figure used with permission from D. M. Jarvie).

2000). These completion strategies result in incremental reserves-addition costs of about $0.30/mcf (Williams, 1999). Figure 3 indicates that, although still volumetrically small compared to Ohio and Antrim production, Lewis Shale gas production is increasing quickly from year to year.

This play should not be confused with the Cretaceous Lewis Shale gas play under way in the Washakie, Great Divide, and Sand Wash basins of Wyoming and Colorado. Lewis gas production in those basins comes from turbidite sands encased in marine shales, which are not age equivalent to the San Juan basin Lewis Shale.

FORMATION EVALUATION CONSIDERATIONS

A wide range of reservoir properties (Figure 9; Table 1) apparently controls both the rate and volume of shale-gas production from these five petroleum systems, notably thermal maturity, gas in place, TOC, reservoir thickness, and proportion of sorbed gas (Hill and Nelson, 2000). As discussed previously, natural fracture networks are required to augment the extremely low shale-matrix permeabilities. Therefore, geology and geochemistry must be considered together when evaluating a given shale system both before and after drilling. Several such integrated models have been developed to evaluate shale-gas systems more completely.

The Devonian Shale Specific Log model of GTI (Luffel et al., 1992) has been successfully applied to the Ohio Shale. The Antrim Shale Reservoir model of GTI-Holditch (Frantz, 1995; Lancaster et al., 1996) is a more recent development. As a result of studies of the Antrim Shale and the New Albany Shale systems, Martini et al. (1998) and Walter et al. (2000) proposed exploration models for the biogenic components of the recoverable gas.

RESOURCES AND CURRENT PRODUCTION

For the five shale-gas systems considered here, the overall magnitude of published gas-in-place resource estimates (summarized in Table 2) net of proved reserves is quite large, as high as 783 tcf, as is the range for individual systems. For comparison, in 2000 the United States produced approximately 19.3 tcf of natural gas and imported an additional 3.4 tcf, mainly from Canada (Energy Information Administration, 2001).

Additional gas resource data come from the Potential Gas Committee (PGC). Although PGC's biennial assessments are not published at the formation level, and thus are excluded from Table 2, the committee has increased substantially its estimates of technically recoverable gas in the Michigan and San Juan basins in the last 6 yr as a result of E & P activity in the Antrim and Lewis shales, respectively (Potential Gas Committee, 1995, 1997, 1999, 2001).

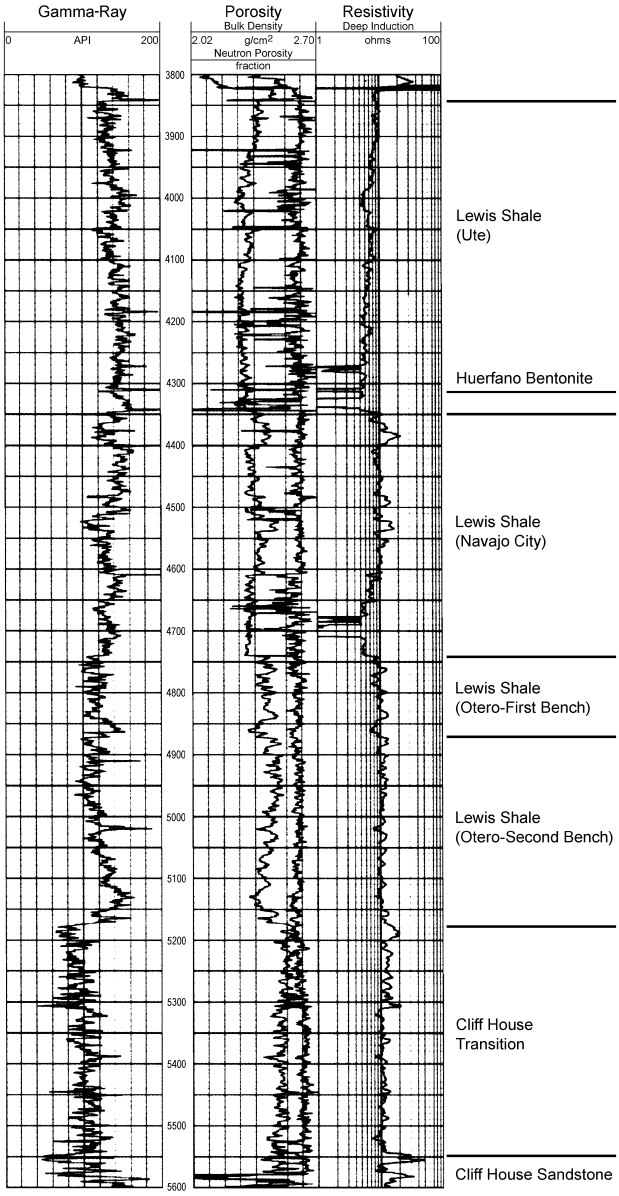

Figure 15. Lewis Shale type log, San Juan basin (after Hill and Nelson, 2000, reprinted with permission from Hart Publications).

In evaluating these estimates, consideration must be given as to whether the estimates are geologically play based (U.S. Geological Survey) or derived from sophisticated computer models that evaluate both supply and demand aspects of the gas resource base (National Petroleum Council, GTI). The latter approach tends to yield considerably larger values (Curtis, 2001). Additionally, recoverable gas resources most likely constitute only a small percentage of total gas in place (31–76 tcf out of 400–686 tcf in place for the estimates in Table 2, exclusive of the Lewis Shale). For example, Devon Energy Corporation estimates that only 8% of an estimated 147 bcf (equivalent) in place is recovered (Williams, 2002).

A comparison of Table 2 and Figure 3 indicates that whereas the Ohio Shale holds both the greatest in-place and technically recoverable resources, its share of total shale-gas production has been declining since 1994, although yearly production continues to increase. In 1994, annual production of Antrim Shale gas surpassed total Appalachian basin shale-gas production. Barnett Shale production is now approximately one-third the magnitude of Appalachian shale-gas production; note, however, that MEDC required approximately 20 yr to commercialize Barnett Shale gas. Lewis Shale gas potential is currently unknown but promising, based both on production trends in the last 4 yr and on the fact that wellhead economics do not rely solely on Lewis Shale production.

ECONOMICS OF EXPLORATION AND PRODUCTION

Table 1 compares typical well costs, completion costs, gas and water production rates, and gas reserves per well for the five shale-gas systems. Due perhaps to depth considerations, the Barnett Shale has the highest well costs. The Antrim and New Albany shales have lower well costs, and the Ohio and Lewis Shale wells are intermediate. Completion costs for the three eastern shale-gas petroleum systems are significantly lower than those for the Barnett and Lewis shales. Disposal of produced water is a consideration only for the Antrim and New Albany shales.

DOMESTIC AND INTERNATIONAL OUTLOOK

When one considers the magnitude of the resource base (Table 2), extending the production trends shown in Figure 3 out 10–20 yr strongly suggests that shale gas will become a domestic gas supply of regional, if not national, importance. Projections by industry and government researchers indicate that, to meet growing domestic natural gas demand, annual United States gas supply requirements must grow from the current 22+ to 30–35 tcf (Gas Research Institute, 2000; Energy Information Administration, 2001), which includes only 5 tcf from imports. The growth in production of total unconventional gas has been modeled through 2020 (Energy Information Administration, 2001); however,

Table 2. United States Gas-Bearing Shale Resources in Historically Productive Plays*

Basin	State(s)	Major Shale-Bearing Unit	Basin Area (mi^2)	TOC (%)	Thermal Maturity (% R_o)	Shale Gas-In-Place Resource (tcf)	Shale Gas-In-Place Resource Reference(s)	Estimated Recoverable Shale-Gas Resource (tcf)	Estimated Recoverable Shale-Gas Resource Reference(s)	Estimated Total Undiscovered Shale-Gas Resource (tcf)**
Appalachian	Ohio, Kentucky, New York, Pennsylvania, Virginia, West Virginia	Ohio Shale	160,000	0–4.5	0.4–1.3	225–248†	NPC (1980, 1992)	14.5–27.5	NPC (1980, 1992)	90.7
Michigan	Michigan, Indiana, Ohio	Antrim Shale	122,000	1–20	0.4–0.6	35–76	NPC (1980, 1992)	11–18.9	NPC (1992); USGS (1995)	40.6
Ilinois	Illinois, Indiana, Kentucky	New Albany Shale	53,000	1–25	0.4–1.0	86–160	NPC (1980, 1992)	1.9–19.2	NPC (1992); USGS (1995)	NA
Fort Worth	Texas	Barnett Shale	4,200††	4.5	1.0–1.3	54–202	Jarvie et al. (2001)	3.4–10.0	Schmoker et al. (1996); Kuuskraa et al. (1998)	NA
San Juan	Colorado, New Mexico	Lewis Shale	1,100††	0.45–2.5	1.6–1.88	96.8	1997 estimate by Burlington Resources	NA	–	NA

*Modified from Hill and Nelson (2000), with additional data from Jarvie et al. (2001) and the manuscript reviewers. NPC = National Petroleum Council; USGS = U.S. Geological Survey National Oil and Gas Resource Assessment Team.

**2000 Gas Research Institute Baseline Projection of U.S. Energy Supply and Demand to 2015 (GRI-00/0002.2) (Gas Research Institute, 2000).

†Black shales only.

††Play area only.

shale gas is not specifically projected. In terms of its recoverable resource base and production potential, shale gas probably will remain third in importance after tight sands and coalbed methane (Curtis, 2001).

Commercial shale-gas production outside the United States most likely will occur where an optimum range of values of key geological and geochemical parameters of the petroleum system (Figure 9) exists under favorable economic conditions with respect to exploration, drilling and completion costs, and proximity to a gas transmission infrastructure.

CONCLUSIONS

United States natural gas production began from organic shale formations, and, given the large, technically recoverable resource base and long life of a typical well, shale gas may represent one of the last, large onshore natural gas sources of the lower 48 states.

The occurrence and production of natural gas from fractured, organic-rich Paleozoic and Mesozoic shale formations in the United States may be better understood by considering source rock, reservoir, seal, trap, and generation-migration processes within the framework of a petroleum system. The system concept must be modified, however, inasmuch as organic shales are both source and reservoir rocks and, at times, seals. Additional consideration must be given to the origin of the gas, whether biogenic or thermogenic, in defining the critical moment in the evolution of potentially producible hydrocarbons.

The five shale-gas systems discussed in this article exhibit wide ranges of key geological and geochemical parameters, but each system produces commercial quantities of natural gas. Still, operators face considerable challenges in bringing substantially more of this gas to market. For example, the controls on gas generation and reservoir producibility must be better understood. Although fracture and matrix permeability, enhanced by application of appropriate well stimulation treatments, are key to achieving economical gas flow rates, sufficient amounts of organic matter (either for generation of thermogenic gas or as a microbial feedstock) must initially have been present to have generated the reservoired gas. Therefore, deciphering the thermal history of the organic matter within the shales and analyzing the rock mechanics response of the shale matrix and organic matter to local and regional stresses are critical steps in establishing their complex relationship to gas producibility. The poor quality of one factor (e.g., low adsorbed gas) may be compensated for by another factor (e.g., increased reservoir thickness); however, shale-gas production cannot always be achieved even where optimum combinations of geological and geochemical factors apparently are present.

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