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**Chapter 9**

**Gas From Devonian Shales**

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## INTRODUCTION

Although it is often presented as a gas source of the future, Devonian shale gas actually has a long production history: the first Devonian shale gas well was drilled in **1821**, near Fredonia, NY, and “modest” production from Devonian shale wells began around the 1920s and has continued to the present.<sup>1</sup> Cumulative production from the shales during all the years of production has been less than 3 trillion cubic feet (TCF), most from the

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<sup>1</sup>Potential Gas Agency, “Potential Gas Resources From Non-conventional Sources,” *Potential Supply of Natural Gas in the United States*, May 1981.

Big Sandy Field in Kentucky and adjacent West Virginia, and current production is only about 0.1 TCF/yr.

Because of its history, Devonian shale gas may be thought of as a “conventional” gas resource. It is also an unconventional gas resource, however, because of its complex geology and because advanced exploration and extraction technologies and higher prices may be able to transform it into an important component of U.S. gas supply from its current status as a very limited, if still locally important, gas source.

## CHARACTERISTICS OF THE DEVONIAN SHALE RESOURCE

Devonian shale gas is defined as natural gas produced from the fractures, pore spaces, and physical matrix<sup>2</sup> of shales deposited during the Devonian period of geologic time. As illustrated in figure 39, Devonian shales occur predominantly in the Appalachian, Illinois, and Michigan basins. The shales formed approximately 350 million years ago in a shallow sea that covered the eastern half of what now constitutes the continental United States. Organic-rich muds and silts were deposited in the sea and subsequently buried by younger sediments. The high pressures and temperatures that accompanied burial of the sediments resulted in the formation of natural gas from the organic material.

The gas content of the shales is proportional to the amount of organic material, and more precisely the organic carbon, present in the rock. The organic material occurs as microscopically thin layers, alternating with mineral layers. The actual physical color of the shales is indicative of their organic content: black and brown shales generally have higher organic contents and therefore more gas than gray shales.

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<sup>2</sup>That is, a portion of the gas is adsorbed, or bound, to the actual physical structure of the shale.

Other determinants of the gas content are the origin of the organic material, that is, the type of organisms (algae, pollen, woody plants, etc.) that formed the sedimentary layers which became the shale, and the physical conditions, especially the temperature, to which the organic material was exposed. For example, blooms of algae appear to be the major source of Devonian shale gas, whereas terrestrial organisms are less promising sources of gas.<sup>3</sup> And temperature conditions between 60° C (140° F) and 150° C (302° F) are optimal for the formation of petroleum (oil and gas).<sup>4</sup>

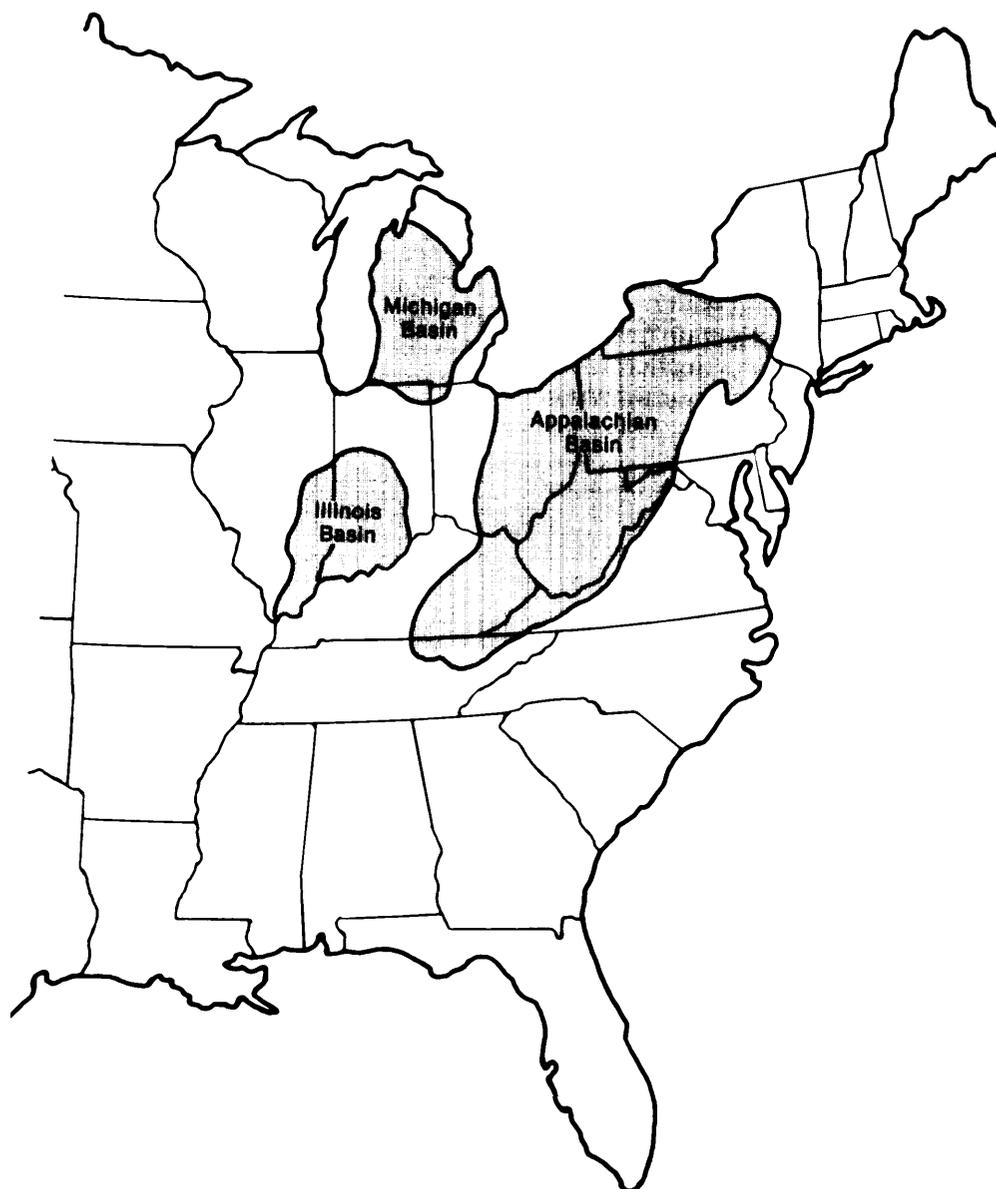
Unlike accumulations of natural gas that are considered conventional, and unlike tight sands gas, Devonian shale gas did not migrate from source rocks to reservoir rocks and accumulate in a trap. Instead, the low permeability of the Devonian shale prohibited most of the gas from escaping. As such, the shale is effectively the source, reservoir rock and trap for the gas. However, some gas originally present in the shale may

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<sup>3</sup>R. A. Struble, *Evaluation of the Devonian Shale Prospects in the Eastern United States*, U.S. Department of Energy Report DOE/MC/19143-1305, undated.

<sup>4</sup>J. M. Hunt, *Petroleum Geochemistry and Geology* (New York: Freeman, 1979), p. 617. Cited in R. A. Struble, op. cit.

Figure 39.—Primary Area of Devonian Shale Gas Potential



SOURCE: Johnston & Associates, OTA Contractor.

have migrated out of the formation, escaping to the atmosphere or forming conventional gas accumulations in nearby sandstones.

The reservoir characteristics of Devonian shale differ substantially from those of conventional reservoirs. Porosities range from 8 to 30 percent in conventional reservoirs; Devonian shale ma-

trix porosities are generally 1 to 2 percent. The permeability of the shales is also significantly lower. Conventional reservoirs have permeabilities in the range of 1 to 2,000 millidarcies (red), whereas Devonian shale matrix permeabilities generally range from  $10^{-5}$  to  $10^{-6}$  md. Even though portions of the shale contain natural fractures, fracture permeabilities tend to be low, rang-

ing from about 0.001 to 1 md; in most cases, permeabilities are less than about 0.1 md. s As suggested by these statistics, gas flows much less readily from most Devonian shale reservoirs than from conventional sandstone reservoirs.

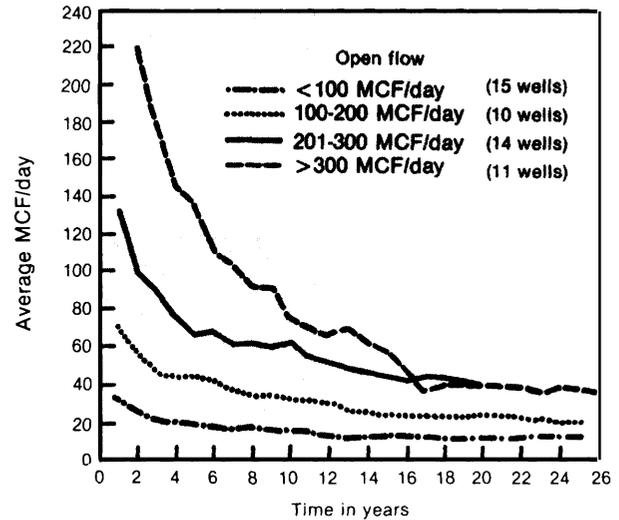
The natural fractures in the shale, which most often occur in a vertical pattern, are critical to successful production. Such production generally requires intersecting these fractures to utilize the increase in overall permeability that they promote. Because the shale fracture systems in the great bulk of the Appalachian Basin are still quite tight, however, achieving high recovery efficiencies generally also requires inducing new, propped fractures in addition to connecting with the natural system. Also, aside from their "tightness," the shale fracture systems tend to be somewhat lined up rather than being random in direction—a property called "anisotropy." Optimum fracture design and well spacing are affected by this property, e.g., a rectangular well spacing pattern aligned with the direction of anisotropy will increase gas recovery over the usual square pattern.<sup>6</sup>

Typically, production from Devonian shale wells is at first relatively high, followed by a steady decline to a base level which can remain constant for over 50 years. Four production curves representing the averaged production of multiple wells are included in figure 40. The shape of the production curves probably is a result of the multiple ways in which the gas occurs in the rock: in pore spaces, in the fracture system and adsorbed to the shale matrix. The initial production is composed primarily of the free gas contained in the fracture network immediately connected to the wellbore and that pore gas which readily migrates to the well bore. The base level then represents the rate at which the gas diffuses through and desorbs from the shale matrix. However, the relative contribution of each of the three distinct "sources" of gas in the shale is not completely

<sup>5</sup>V. A. Kuuskraa and D. E. Wicks, "Devonian Shale Gas Production Mechanisms," 1984 International Gas Research Conference; V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in Ohio*, Lewin & Associates Report for Morgantown Energy Technology Center, July 1982.

<sup>6</sup>V. A. Kuuskraa and D. E. Wicks, "Devonian Shale Gas Production Mechanisms," 1984 International Gas Research Conference.

Figure 40.—Averaged Production Decline Curves for 50 Devonian Shale Gas Wells



Lincoln, Mingo, and Wayne counties, West Virginia. Wells were metered on open flow after shooting or fracturing of the shale pay zone. MCF = thousand cubic feet. (From Bagnall and Ryan, 1976. ERDA Pub. MERC/SP-76/2. Fig 11, and W. D. Bagnall, personal communication.)

SOURCE: U.S. Congress, Office of Technology Assessment, *Gas Potential From Devonian Shales of the Appalachian Basin* (Washington, DC: U.S. Government Printing Office, OTA-E-57, November 1977).

understood, and there are alternative interpretations of the precise composition of the base production level. One interpretation is that the base level is primarily adsorbed gas that is being released by the shale matrix as the pressure drops. An alternative explanation is that the base level gas is primarily gas from other gas-bearing intervals that are connected to the primary (stimulated) interval by the vertical fracture network in the shale.

Deciphering the relative roles of these two mechanisms is critical to estimating the recoverable resource. At one extreme, if the base level of production is mostly adsorbed gas and there is little communication between gas-bearing intervals, then the intervals that are not currently being stimulated may be available for production in the future. At the other extreme, if there is little resorption of gas and the base level is due to vertical communication between intervals, then the number of targets for economic production is drastically reduced and the recoverable resource will be far less. In the latter case, the

major part of the gas-in-place (Kuuskraa and Wicks estimate that adsorbed gas represents over 80 percent of the total<sup>7</sup>) will not be available for production with currently foreseen technology.

<sup>7</sup>Kuuskraa and Wicks, op. cit.

The current available data appear to support the “resorption, little vertical communication” interpretation, but these data are limited to a very small geographical area.<sup>8</sup>

<sup>8</sup>Charles Komar, Morgantown Energy Technology Center, personal communication, 1984.

## GAS= IN-PLACE RESOURCE BASE

The Devonian shale resource is becoming increasingly well characterized as a result of recent efforts to better understand the geological characteristics of the resource and its size. Work performed as part of the Department of Energy’s (DOE) Eastern Gas Shales Project (EGSP) has provided substantive geological and geochemical data.<sup>9</sup>

### Methodologies and Results

As illustrated in table 43, several organizations have estimated the size of the Devonian shale resource base. The three most recent estimates of the in-place resource were made by the National

petroleum Council (NPC) in June 1980 and the U.S. Geological Survey (USGS) and the Mound Facility (operated by Monsanto Research Corp.) in 1982. The NPC study evaluated the Devonian shale resource in the three shale basins, whereas the other two restricted their estimates to the Appalachian Basin.

### National Petroleum Council<sup>10</sup>

The NPC estimated the gas-in-place resource for each of the three major basins. The primary variables in the in-place resource calculation were shale thickness, areal extent and gas content, with gas content assumed to be uniform throughout each basin. These parameters were established differently for each basin, depending on the type and quantity of information available.

<sup>9</sup>The results of the project are summarized in a report by R. A. Struble, *Evaluation of the Devonian Shale Prospects in the Eastern United States*, U.S. Department of Energy Report DOE/MC/19143-1305, undated. This report provides a comprehensive review of the “state-of-the-art” of Devonian shale resource analysis up to about 1982.

<sup>10</sup>National Petroleum Council, “Unconventional Natural Gas-Devonian Shales,” June 1980.

**Table 43.-Devonian Shale Resource Base Estimates (TCF)**

Organization	Year	Basin evaluated	Estimate
National Petroleum Council <sup>a</sup> .....	1980	Appalachian .....	225 to 1,861 (125 to 1040 <sup>b</sup> )
		Michigan .....	76
		Illinois .....	86
U.S. Geological Survey <sup>c</sup> .....	1982	Appalachian .....	577 to 1,131
Mound Facility <sup>d</sup> .....	1982	Appalachian .....	2,579 (1,440 <sup>e</sup> )
Lewin & Associates <sup>f</sup> .....	1980	Appalachian .....	400 to 2,000
Federal Energy Regulatory Commission <sup>g</sup> ....	1978	Appalachian .....	285
Smith <sup>h</sup> .....	1978	Appalachian	206 to 903

<sup>a</sup>National Petroleum Council, *Unconventional Gas Sources, Tight Gas Reservoirs Part 1, December 1980.*

<sup>b</sup>Considering “drillable” area only.

<sup>c</sup>R.R. Charpentier et al., *Estimates of Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin*, USGS Open-File Report 82-474, 1982.

<sup>d</sup>R. E. Zielinski and R. D. McIver, *Resource and Exploration Assessment of the oil and Gas Potential in the Devonian Shales of the Appalachian Basin*, DOE/DP/0053-1 125, undated.

<sup>e</sup>V. A. Kuuskraa and R. F. Meyer, “Review of World Resources of Unconventional Gas,” in IASA Conference on Conventional and Unconventional World Natural Gas Resources, Laxenburg, Austria, June 30-July 4, 1980.

<sup>f</sup>U.S., Department of Energy, *Nonconventional Natural Gas Resources*, Report DOE/FERC-0010, 1978.

<sup>g</sup>E. C. Smith, “A Practical Approach to Evaluating Shale Hydrocarbon Potential,” in *Second Eastern Shales Symposium, Vol. II*, U.S. Department of Energy, Report METC/SP-7816, 1978, pp. 73-87.

SOURCE: Office of Technology Assessment.

In each basin, the black and gray shale thicknesses were multiplied by their respective gas contents and their areal extents to arrive at the gas-in-place estimate for the basin.

In the Appalachian Basin, the gas-bearing zone includes the gray and black shale units that overlie the Onandaga limestone and underlie the Berea sandstone. The thickness of the black shales was determined in two ways: first, by gamma-ray well log data which detects the high radioactivity content characteristic of organic-rich shales; second, by thicknesses determined visually from core sample color. The two black shale thickness calculations yield substantially different results, which in turn yield very different gas-in-place estimates. The gas content of the shales was determined through off-gassing data from rock core samples.<sup>11</sup> Values of 0.6 and 0.1 cubic feet of gas per cubic feet of Appalachian shale were obtained for black and gray shales, respectively. The areal extent of the Appalachian shale was determined to be 111,100 square miles.

The gas-bearing unit in the Michigan Basin is the Antrim shale, which extends over 35,400 square miles and contains both black and grey shales. The thickness of the Antrim was determined strictly by well logs and is poorly defined where the Antrim grades into the barren Ellsworth shale in the western portion of the basin. Also, there were no core samples available for off-gassing experiments to determine the quantity of gas present in the unit. In the absence of these data, the gas content of the Michigan Basin shales were assumed to be the same as those of the Appalachian Basin on the basis of similarities in the well production data for the two basins.

The New Albany shale group, covering 28,150 square miles, is the gas-bearing unit in the Illinois Basin. Neither gamma-ray well log data nor core sample data were available to determine the thickness of the units, and therefore the black and gray shale thicknesses could not be differentiated. The thickness of the entire sequence was determined from USGS maps and used in a simple volumetric resource calculation. off-gassing data from cores were available to determine the gas

<sup>11</sup>Off-gassing measures the amount of gas that desorbs from a known volume of core over a specific period of time.

content. The thickness of the sampled units in proportion to the total group thickness was used to establish a weighted average of 0.62 cubic feet of gas per cubic foot of shale for the entire New Albany group.

The results of the NPC study suggest that estimates of the quantity of gas present in the Appalachian Basin are sensitive to the assumed thickness of the black shale and to the inclusion or exclusion of the lower quality gray shales. Based on thicknesses determined by gamma-ray logs, and including only the black shales, the gas-in-place is estimated to be 225 TCF. Based on black shale thickness determined visually from USGS samples and including the gray shales, 1,861 TCF is estimated to be present. (The range for the black shales only is 225 to 1,102 TCF.) If areas that are not drillable<sup>12</sup> are excluded, the gas-in-place estimate is reduced to 125 and 1,040 TCF for the log and sample thicknesses, respectively. The gas-in-place estimates for the Michigan and Illinois basins are 76 and 86 TCF, respectively, but are more uncertain because of the lack of data.

### U.S. Geological Survey<sup>13</sup>

The USGS estimate of Devonian shale gas in the Appalachian Basin recognizes three categories of shale gas: macrofracture gas, micropore gas, and that gas which is adsorbed, or attached, to the clay matrix. Unlike the early Lewin & Associates study (1978-79), the USGS attributes only a small amount of the total volume of gas-in-place to macrofractures; it assumes that most of the gas is in micropores or bound to the organic matter in the shale matrix.

The Appalachian Plateau province and a small segment of the Valley and Ridge province were divided into 19 areas, termed plays. The characteristics of each play were described in terms of physical location, unit names, thickness, organic content, maturation level and type of hydrocarbon present, tectonic or structural attributes, and, subsequently, a brief description of the produc-

<sup>12</sup>Because of difficult terrain, presence of buildings and other development, designation of the land as protected parkland, etc.

<sup>13</sup>R. R. Charpentier, et al., *Estimates of Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin*, " U.S. Geological Survey Open-File Report 82-474 (preliminary), 1982.

tion potential of the play. The volume of gas for each of the 19 different areas was calculated using Equation 1, below:

$$G = [\theta_{\text{macro}} \times TH_s \times Pr/P_s \times \frac{1}{2} \times \text{area} \times (5,280 \text{ ft/mi})^2] \text{ macrofracture} \\ + [\theta_{\text{micro}} \times TH_s \times \text{area} \times (5,280 \text{ ft/mi})^2] \text{ micropore} \\ + [SOR \times ORG \times TH_s \times \text{area} \times (5,280 \text{ ft/mi})^2] \text{ adsorbed}$$

The parameters used in the equation are explained in table 44. The volume of gas for each area was summed to obtain a total basin estimate.

The analysis explicitly recognizes two severe data problems:

- limited quantity of data for most of the assessed area, and
- large sampling errors and differences in interpretation.

Because of the limited quantity and quality of data, a range rather than a point estimate of the gas present was developed. The Monte Carlo method of estimation was employed to acquire the range.<sup>14</sup>

<sup>14</sup>Using a Monte Carlo method, appropriate variables in the equation are specified by a probability distribution rather than by a point estimate. Then, the equation is "solved" for the dependent variable—in this case, gas-in-place—a large number of times by randomly sampling the probability distributions. In this way, a probability distribution is obtained for the dependent variable (gas-in-place). The "solution" to the equation can either be expressed by the probability distribution itself, by its mean or median, or perhaps by a range defined by some probability that the actual value is within its borders (e. g., "there is an 80 percent probability that the correct value is in the range X to Y").

**Table 44.—Equation Parameters**

Symbol	Meaning
G	gas-in-place
$\theta_{\text{macro}}$	average macrofracture porosity as a fraction of total volume
$TH_s$	average thickness of organic-rich shales
$P_r$	average reservoir pressure (psi)
$P_s$	standard pressure (14.73 psi)
$T_r$	average reservoir temperature (oR)
$T_s$	standard temperature (520°R)
z	gas deviation factor (0.9)
Area	area (square miles)
$\theta_{\text{micro}}$	average content of microporosity gas at standard temperature and pressure as a fraction of rock volume
SOR	average volume ratio of adsorbed gas to inorganic content
ORG	average organic content as fraction of rock volume

SOURCE U. S. Geological Survey, "Estimates of the Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin," 1982

The data used were acquired from a variety of sources. The configuration of the gas shales was taken from geologic cross sections, isopachs (thickness maps), and other geological maps compiled by the USGS. Maps were also used to estimate thickness, organic content and average depths, which when combined with temperature and pressure gradients yielded average reservoir pressures and temperatures. Micropore gas estimates were achieved by plotting gas content—acquired from off-gassing data from canned core samples—against the amount of organic matter in the sample. The slope of the resultant curve represents the ratio of adsorbed gas to organic matter. The intercept (gas content at the point where organic matter is zero) represents the micropore gas content.

The results of the USGS study are compiled in table 45. The 95th fractile ( $F_{95}$ ) is a low estimate and signifies that there is a 95 percent chance that there is more than 577.1 TCF present. The 5th

**Table 45.—Estimates of In-Place Natural Gas Resources in the Devonian Shale of the Appalachian Basin**

Play	Natural gas resources (trillions of cubic feet)		
	Low $F_{95}$	High $F_5$	Mean
1. North-Central Ohio . . . . .	17.9	34.2	25.9
2. Western Lake Erie . . . . .	21.7	31.3	26.5
3. Eastern Lake Erie . . . . .	2.1	3.3	2.7
4. Plateau Ohio . . . . .	44.4	76.2	59.9
5. Eastern Ohio . . . . .	35.2	55.1	44.7
6. Western Penn-York . . . . .	20.4	28.2	24.3
7. Southern Ohio Valley . . . . .	19.7	36.2	27.7
8. Western Rome Trough . . . . .	38.0	74.0	56.0
9. Tug Fork . . . . .	13.7	25.9	19.7
10. Pine Mountain . . . . .	10.7	18.7	14.6
11. Plateau Virginia . . . . .	3.9	10.2	7.1
12. Pittsburgh Basin . . . . .	76.8	129.9	102.1
13. Eastern Rome Trough . . . . .	70.7	132.5	100.3
14. New River . . . . .	38.5	91.7	63.1
15. Portage Escarpment . . . . .	8.5	21.3	14.6
16. Cattaraugus Valley . . . . .	10.4	23.2	16.6
17. Penn-York Plateau . . . . .	98.1	195.2	146.0
18. Western Susquehanna . . . . .	24.1	67.7	44.9
19. Catskill . . . . .	22.1	75.8	47.6
Entire basin . . . . .	577.1	1,130.9	844.2

NOTE: All tabulated values were rounded from original numbers. Therefore, totals may not be precisely additive.  $F_{95}$  denotes the 95th fractile; the probability of more than the amount  $F_{95}$  is 95 percent.  $F_5$  is defined similarly. Because of dependency between plays, these fractiles (unlike those in many other studies) are additive.

SOURCE U.S. Geological Survey, "Estimates of the Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin," 1982

fractile ( $F_5$  is a high estimate and indicates that there is only a 5 percent chance of there being more than 1,130.8 TCF present.<sup>15</sup> The mean estimate is 844.2 TCF. Although the USGS did not estimate recoverability, it compiled a map illustrating shale gas potential (fig. 41) which qualitatively indicates the potential for recovery in each area based on gas-in-place and the presence of natural fracture systems.

### The Mound Facility<sup>16</sup>

The Mound study incorporates extensive geochemical data into its volumetric analysis of the

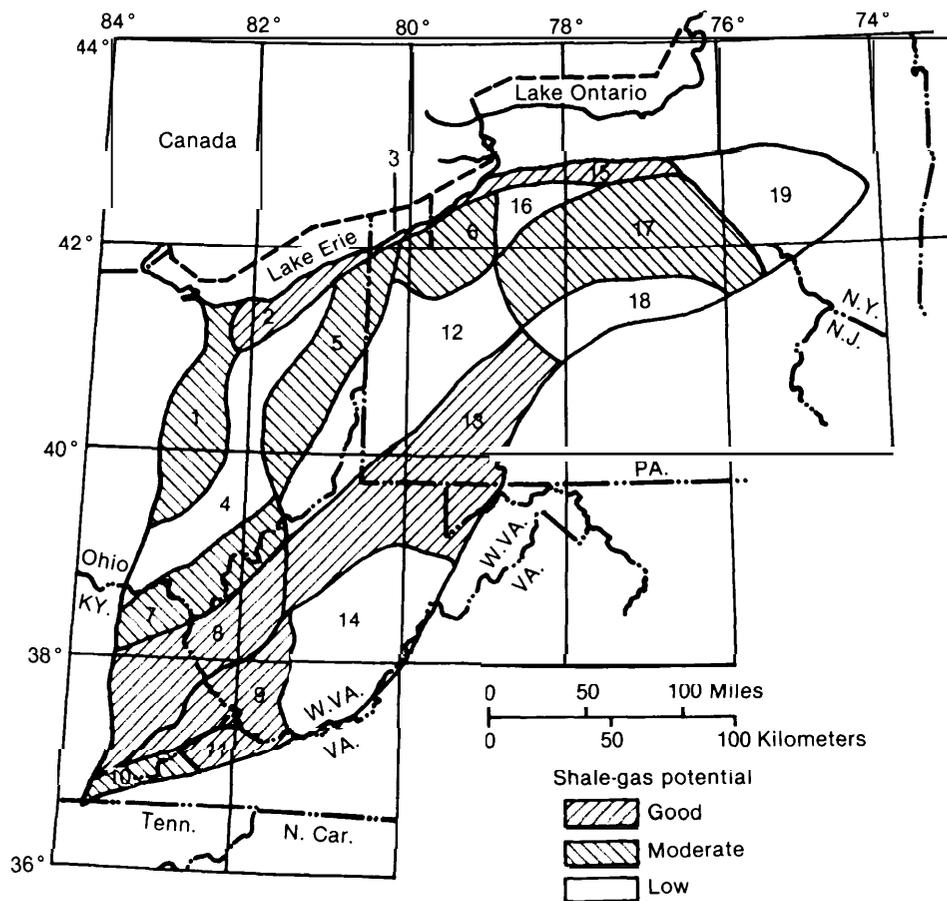
<sup>15</sup>Consequently, there is a 90 percent probability that the gas-in-place is within the range 577.1 to 1,130.8 TCF.

<sup>16</sup>R. E. Zielinski and R. D. McIver, "Resource and Exploration Assessment of Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin," 1982.

gas-in-place in the Appalachian Basin. Organic geochemical analyses were performed on over 2,000 individual core samples and on an additional several hundred well cuttings to evaluate the quality of the shale units as sources of natural gas and other hydrocarbons. In particular, the analyses focused on three primary determinants of gas content: the quantity of organic carbon present, its origin (i.e., the nature of the organic material that provided the carbon, e.g., spores, pollen, herbaceous plants, algae, etc.), and its thermal maturity.<sup>17</sup>

<sup>17</sup>Thermal maturity is the extent to which the organic matter in the rocks has been "cracked" by heat. Cracking is the process by which long hydrocarbon chains are broken to form simpler molecules such as those comprising methane gas.

Figure 41.—Shale Gas Potential in the Appalachian Basin



SOURCE USGS, "Estimates of Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin," 1982

**Several general conclusions were formulated about the resource potential of the Appalachian Basin. The most important conclusion is that the Devonian shales are exceptionally rich source rocks;** were it not for their low porosity and permeability, the shales would represent “one of the greatest oil- and gas-producing provinces of the world.”<sup>18</sup> Other conclusions point to the nonuniformity of the resource and establish where the generally rich nature of the source rocks may not apply. For example, the quantity of organic material in the basin decreased to the east. The organic-rich rocks in the extreme north-western and western portion of the basin had high potential for hydrocarbon development, but they were only slightly thermally altered and never reached their full gas-bearing potential. In the deeper portions of the basin, too much heat was generated, thereby lessening the potential for finding hydrocarbons.

The gas-in-place analysis differed from the other estimates in the way in which the gas content was determined. Mound felt that a large portion of the gas escaped during the process of obtaining the core and before the core could be sealed in the gas-tight canister. To improve the accuracy of the measurement, Mound developed a controlled off-gassing experiment where the rate of gas release from the core is measured. Data from these experiments were used in combination with other geologic and geochemical characteristics of the formations to develop equations which determined the “indigenous,” or original, gas contents of the rock. The methodology was verified by the use of a pressurized core barrel, which extracts the core under in-situ pressure, thereby limiting premature gas release. Mound thus concluded that the revised values more accurately reflected the quantity of gas originally present in the rock.

The gas-in-place estimates were determined for each of 17 separate stratigraphic intervals, or

<sup>18</sup>R. E. Zielinski and R. D. McIver, “Synthesis of organic Geochemical Data From the Eastern Gas Shales,” SPE/DOE 10793, in Proceedings of the Unconventional Gas Recovery Symposium, May 16-18, 1982, Pittsburgh, PA.

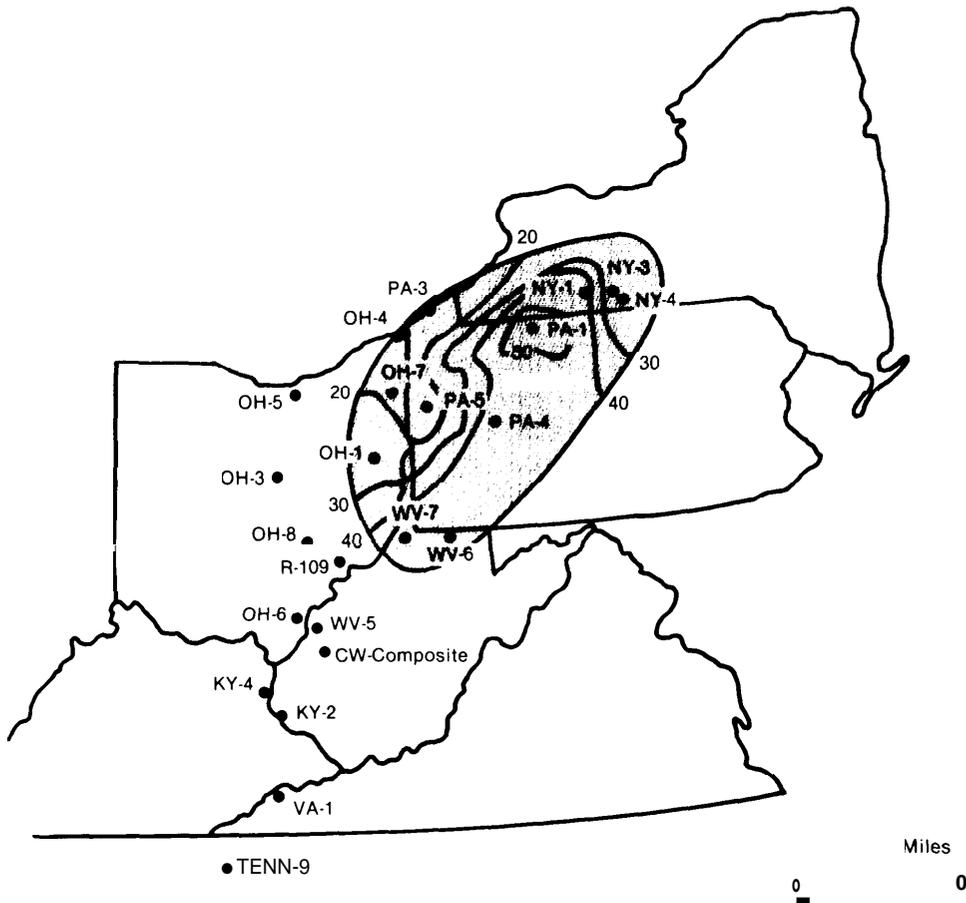
units, in the Appalachian Basin by first combining the indigenous gas contents (MCF/acre-foot) with the thicknesses of the gas-bearing shale to provide the areal distribution of the total gas in each unit. The data were contoured, as illustrated in figure 42. Next, the acreage contained within each contour area was integrated, multiplied by the appropriate gas areal density (MCF/acre), and summed to yield the total gas-in-place for the unit. This methodology resulted in a gas-in-place estimate for the 17 units composing the Appalachian Basin of 2,579 TCF.

### Estimate Comparison and Uncertainties

The methodologies used by NPC, USGS, and Mound to determine the gas-in-place are all volumetric estimates based on multiplying gas content, shale thickness, and areal extent, but they differ substantially in their computation methods and input data. The major difference appears to be in the computation of gas content. NPC used a basin-wide average based on off-gassing data available at the time. Both the Mound and USGS analyses use a more sophisticated, disaggregate approach, with USGS calculating separately the macrofracture, micro-porosity, and adsorbed (bound) gas for 19 areas in the Appalachian Basin, and Mound determining gas contents for 17 stratigraphic units in the basin using equations based on geochemical analysis, and contouring and integrating the results across the basin. Both the USGS and Mound estimates had access to new off-gassing data developed by the Eastern Gas Shales Project. The Mound approach is the most optimistic of the three because it incorporates a calculation of gas lost in obtaining and measuring the core samples, a factor not considered by the NPC and apparently not considered significant by the USGS.

**In OTA’s judgment, the physical evidence cited and calculations made in the Mound report appear plausible; the Mound estimate of 2,579 TCF gas-in-place (1,440 TCF in “drillable” areas) seems a reasonable estimate given the available data.**

Figure 42.— Distribution of Devonian Shale Gas  
 (MCF Gas/Acre  
 100 )



Stratigraphic interval: early marcellus time  
 SOURCE: Zielinski and McIver, 1982,

## TECHNOLOGY

### Fracturing

Because of the extremely low permeability of the shales, production of Devonian shale gas depends on exploiting the natural fracture network in the rock and on enhancing gas flow by artificially stimulating the well. Over 90 percent of all Devonian wells require stimulation in order to yield gas in commercial quantities, and even stimulated wells will not be successful unless

there is already a well-developed natural fracture network.

For most of the Devonian shale's production history, wells were stimulated by filling large portions of the wellbore with explosives and allowing the detonation to shatter the rock surrounding the well. This basic method was first used in 1865 and is still in use. It generally is considered less of a "fracturing" method than simply as a

means to overcome the formation damage caused by drilling in the shales. (Its primary structural effect is to fragment the rock immediately surrounding the well bore.)

As in the tight sands, hydraulic fracturing is becoming increasingly used today in the shales. The fractures being created in the shale formations are small, however, not the massive 1,000-ft fractures becoming more popular in the Western tight sands. They also generally carry less proppant than in the sands. The shales are extremely sensitive to formation damage during fracturing, especially because of the presence of water-sensitive clays in the shale that can be dislodged by the fracturing fluids and plug pores and fractures. Although formation damage is a problem with tight sands and coal seams also, Devonian shales may be the most sensitive. Devonian shales have, as a consequence, served as a testing ground for a number of new fracturing fluids.

Many of the fluids developed to minimize formation damage are foamed, using a gas phase to reduce the amount of water required. **Foamed fluids** are gas-in-water emulsions, where the surface tension of the bubbles holds the proppant-particles that become wedged in the fractures and hold them open—in suspension. Nitrogen (N<sub>2</sub>) is the most common gas used. Properties that make foam suitable for the Devonian shale include low volumes of water, high efficiency in creating fractures, high proppant-carrying capacity, low friction during pumping, and sufficient energy within the gas phase to allow recovery of most of the fluid without pumping. By 1980-81, foam technology had advanced so rapidly that it dominated fracturing in the Devonian shales.

**Pure nitrogen** has also been used as a fracturing fluid. It is not an efficient fracture fluid and can only be used to fracture small depth intervals of 10 ft or so.<sup>19</sup> In addition, it is not an effective carrier of proppants, and consequently is effective only at shallow depths where the fractures are less likely to close. However, nitrogen does not adversely affect the formation and it has proven very effective in increasing gas flow. As a re-

sult, nitrogen fracturing quickly became the preferred method for many production situations. Because of the newness of this type of treatment and its relative lack of propping effectiveness, the ability of nitrogen fracturing to maintain production levels over the long-term is uncertain.

Current trends in fracturing technology are centered on the developing of fluids that are both nondamaging, like nitrogen, and can carry proppants more effectively. possibilities include:

- **Stabilized foam.**—Although similar to the original foams, water has been reduced from 25 to 10 percent, and proppant-carrying capability is enhanced by a gelling agent that stiffens the foam. This is a high cost method that has been used only sparingly.
- **Liquid carbon dioxide.**—This method has the ability to transport proppants. As the liquid CO<sub>2</sub> warms, it reverts to the gas phase and easily flows back out of the hole with minimal damage to the formation. Liquid CO<sub>2</sub> fracturing is a relatively expensive process and somewhat more dangerous to use than foamed fluids. In addition, the casing and pumping materials must be capable of withstanding very low temperatures.
- **Shale oil.**—This method combines a nitrogen-driven fracture with the subsequent injection of shale oil—obtained from previous drilling—as a proppant-carrying agent to prevent fracture closure.
- **Water-based nonreactive solvents.**—These solvents can be used either after a fracture to clean the formation or as the fluid base of a stabilized foam fracturing treatment. This system is still experimental.

Finally, producers have attempted the use of radically improved versions of the original explosive fracturing used since the 1800s. In tailored **pulse loading**, a propellant charge is ignited to pressurize the wellbore at a much slower rate than is achieved with conventional explosives.<sup>20</sup> The loading rate, or rate at which the energy stored in the propellant is released, can be controlled to create different types of fractures. For

<sup>19</sup>For example, a nitrogen fracture might affect only the reservoir rock between 900 and 910 ft in depth.

<sup>20</sup>J. W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands," OTA contractor report, September 1983.

example, at intermediate loading rates, multiple fractures form radially around the well bore.<sup>21</sup> At slow rates, fractures form in an analogous manner to hydraulic fractures, directionally controlled by the regional stress field.

This technique has only been used on a small scale for prefracturing tests.<sup>22</sup> However, it is thought to have significant potential for use on a larger scale, especially because it causes little formation damage. Commercial application in the Devonian shales may occur in the near future.

The record of success of well stimulations in Devonian shales is mixed. Although new stimulation technologies have increased gas production from a number of wells, many have not benefited from stimulation and the specific reasons for their lack of success are not well understood.

One problem is the local variability and unpredictability of fractured zones. Wells offset short distances from producing wells may not intersect a productive fracture system.<sup>23</sup> Improved technologies or exploration strategies to locate and characterize fracture systems are critical to economic development of Devonian shales.

Another problem is the difficulty in extrapolating successful stimulation techniques from one site to another. Although some producers have been quick to try the newest in technologies, no one has yet established criteria for choosing tailored pulse loading over nitrogen or perhaps liquid CO<sub>2</sub> injection. Most stimulations appear to be conducted on a trial-and-error basis and inadequate records are kept to determine the reasons for success or failure of a particular technique.

A third problem in successful Devonian shale gas production is accurately determining the pay interval. Because many wells do not have significant gas shows prior to stimulation, it is difficult

<sup>21</sup>The radial fractures possible with tailored pulse loading may have special potential in areas where the natural fracture systems in the shale display strong directional tendencies. Radial fractures may outperform long hydraulic fractures when these tendencies (permeability anisotropies) are substantial (Kuuskraa and Wicks, 1984, op. cit.).

<sup>22</sup>Johnston & Associates, Inc., "The Status and Future of Production Technologies for Gas Recovery From Devonian Shales," OTA contractor report, 1983.

<sup>23</sup>1 bid,

to determine the interval within the shale sequence which is most likely to contain recoverable gas. Consequently, fractures may not be properly located to optimize production.

Finally, no technology now exists or is being considered to produce gas from those portions of the Devonian shales where the natural fracture system is not well developed. This severely limits the overall production potential of the resource.

## Deviated and Directional Drilling

The only other technology that currently has any potential for increasing production in unconventional reservoirs is one that allows drilling wells that either intersect more of the reservoir rock or intersect more of the natural fracture system. Thus, if reservoirs lie in an essentially horizontal plane and natural fracture systems in a more or less vertical plane, a well drilled at some angle from the vertical would intersect more gas-productive natural fractures.

Directional drilling has frequently been suggested as a technology applicable to Devonian shale gas production.<sup>24</sup> Production requires intersection of natural fractures and most of these fracture systems are vertical. The major drawback is the problem of formation damage. A drill bit drilling at an angle from the vertical encounters increased frictional resistance and, if drilling in a fractured formation, runs a greater risk of having the wellbore collapse. Drilling muds are needed to reduce friction and hold the hole open; however, drilling muds may cause considerable formation damage. One experimental deviated well has been drilled in the Devonian shale, in Meigs County, Ohio, but its intent was more to determine the natural fracture spacing than to test a new production technique.<sup>25</sup>

## Exploration

Unlike the sophisticated exploration techniques used in frontier areas such as the Western Over-

<sup>24</sup>Office of Technology Assessment, "Status Report of the Gas Potential From Devonian Shales of the Appalachian Basin," 1977.  
<sup>25</sup> Charles Komar, Morgantown Energy Technology Center, personal communication, 1984.

thrust Belt and offshore, the “exploration techniques” used for locating Devonian shale wells are often little more than near-random selection based on the availability of land. The failure to use sophisticated exploration technology reflects a number of factors. First, it is difficult to build an exploration block of any size in the Appalachian shale basin because of the diversity of land ownership. Second, leasing problems—e.g., the lack of well spacing requirements in some States in the shale area—aggravate the problem because wells on adjacent properties can get as close to a successful well as the property line allows. There is little incentive to invest in expensive seismic surveys if the costs cannot be recaptured by exclusive development of the surveyed area. Third, existing technology is not fully effective in locating the subsurface features whose understanding is critical to drilling success, and the steep terrain drives up the cost of techniques such as reflection seismology.

Aerial and satellite imagery may prove useful in Devonian shale exploration because they can identify lineaments—characteristic topographic features—which may be related to fault and fracture zones and may contain information on regional stress patterns. Concentrations of surface fractures may indicate the presence of subsurface fracture networks that could serve as potential reservoirs.<sup>26</sup> Skeptics feel that surface expression

<sup>26</sup>R. D. McIver, J. R. Kyle, and R. E. Zielinski, “Location Of Drilling Sites in the Devonian Shales by Aerial Photography,” SPE/DOE 10794, SPE/DOE Unconventional Gas Recovery Symposium, pp. 51-53.

of fractures does not accurately reflect subsurface conditions (i.e., fractures may curve at depth or may not extend to the gas-bearing rocks). To support their position, they cite failures of wells offset from producing wells along a surface lineament.<sup>27</sup>

Subsurface mapping of variations in the rock formations is also important in the shale region. A key mapping tool for the shales is well logging using a combination of gamma-ray and neutron-density logs. Induction logs, spectral logs, thermal decay logs, noise logs, and temperature logs are often run in combination with the gamma-ray and neutron-density logs. Some operators also rely on a combination of gamma-ray, bulk-density, and resistivity logs. (For a brief description of the various types of well logs, see box B-1 in app. B.) Unfortunately, current well logging techniques are not adequate to detect open fractures that do not actually intersect the boreholes, so they are only of limited use in mapping fracture patterns. Also, some States in the shale basins do not require full disclosure of well log data, and this further limits the ability to construct useful subsurface maps from the existing data.

<sup>27</sup>Johnston & Associates, inc., op.cit.

## RECOVERABLE RESOURCES AND PRODUCTION POTENTIAL

The Devonian shale gas-in-place resource in the Appalachian Basin has been estimated at between 225 TCF (the NPC low estimate) and 2,579 TCF (the Mound estimate). As discussed above, the higher end of the range appears most credible on the basis of existing data. However, much of the gas-in-place is unlikely to contribute to future gas supply, for the most part because geological conditions make the gas extremely diffi-

cult to produce. The quantity of gas likely to be produced is a function of the price of the gas, the available technology, the associated costs of production, and a variety of other factors, such as institutional barriers, that will influence decisionmaking on production. Several organizations have attempted to estimate the size of the recoverable resource. Reports have been issued which describe the resource and designate the most

favorable areas for production.<sup>28</sup> Production scenarios have also been established by further assuming drilling and development schedules. In general, the estimates of recoverable resources and future production are based on extrapolation of past production, for which there is a sizable amount of data due to the long production history of the shales. However, the production data are limited in important ways. Available production histories are for the most part limited to wells using traditional production technology, that is, “shooting” with explosives at wide well spacing. Also, these histories are affected by a variety of factors aside from the nature of the gas resource. These factors include differences in market conditions, well operating practices, production techniques, the use of workover treatments, and pipeline pressures.<sup>29</sup> Extrapolation of production data therefore should account for these variables, yet the lack of data and the complexity of the necessary analysis makes such an accounting quite difficult. None of the existing

studies of recoverable resources have attempted such an accounting. Also, it is not clear to what extent the drilling represents a true unbiased sample of what might occur on undrilled acreage if the same production techniques were used. These problems with the available data are discussed later.

### Methodologies and Results

As illustrated in table 46, several estimates of recoverable resources have been made. These include early estimates by the Office of Technology Assessment (OTA), Lewin & Associates, and the National Petroleum Council (NPC). Each estimator assumed economic and technologic parameters to establish estimates of recoverable resources in the Appalachian Basin. Both Lewin & Associates and the NPC extended their analysis to include annual production estimates or scenarios.

More recently, Pulle and Seskus of Science Applications, Inc. (SAI), Zielinski and McIver of Mound, and Lewin & Associates also estimated the recoverable resource in the Appalachian Basin. Pulle and Seskus<sup>30</sup> used past production

<sup>28</sup>Favorable areas are designated by State in DOE/METC reports 118-124 and on a play basis in the USGS report entitled, “Estimates of Unconventional Natural Gas Resources of Devonian Shale of the Appalachian Basin,” 1982.

<sup>29</sup>R. E. Zielinski and R. D. McIver, *Resource and Exploration Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin*, U.S. Department of Energy, Morgantown Energy Technology Center Report DOE/DP/0053-1125.

<sup>30</sup>C. V. Pulle and A. P. Seskus, “Quantitative Analysis of the Economically Recoverable Resource,” U.S. DOE-METC, 1981.

**Table 46.—Devonian Shale Recoverable Resource Estimates (TCF): Appalachian Basin**

Organization	Year	Estimate	Conditions
Office of Technology Assessment . . . . .	1977	15-25	After 15 to 20 years
		23-38	After 30 to 50 years
Lewin & Associates . . . . .	1978-79	2-10	At \$2 to \$3/MCF (1976), current technology (borehole shooting or hydrofracturing), 150-acre spacing
		4-25	Base case Advanced case for prices between \$1.75 to \$4.50
National Petroleum Council . . . . .	1980	traditional 3.3 - 38.9	For price levels between \$2.50 to \$9, 160-acre spacing
		advanced 15.3 - 49.9	Technically producible
Pulle and Seskus (SAI) . . . . .	1981	17-23	“Shot” wells, 160-acre spacing
Zielinski and McIver (Mound) . . . . .	1982	30-50	For States of West Virginia, Ohio, and Kentucky only, “shot” wells, 160-acre spacing
Lewin & Associates . . . . .	1983	6.2-22.5	Technically recoverable, for most promising formations in Ohio. Maximum represents 80-acre spacing, advanced technology
Lewin & Associates . . . . .	1984	19-44	Technically recoverable, for most promising formations in West Virginia. Preliminary values

SOURCE: ???

**data and Delphi estimation to compute a mean value of 20.2 TCF** for the recoverable Appalachian resource using explosive fracturing at 160-acre spacing. Zielinski and McIver<sup>31</sup> utilized SAI data to estimate the recoverable resource, also based on explosive fracturing. They felt that sufficient data were not available to make a reliable estimate, but produced a preliminary estimate of 30 to 50 TCF for the minimum recoverable gas in West Virginia, Ohio, and Kentucky. The most recent estimation effort was performed by Lewin & Associates under contract to DOE's Morgantown Energy Technology Center (METC) and was an estimate of the technically recoverable reserves in the most favorable Devonian formations in Ohio and West Virginia (the estimates for West Virginia were published only in draft form at the time of this report).<sup>32</sup> To OTA's knowledge, this estimate is the only one currently available to use reservoir simulation. Using this simulation capability, the analysis explores the ramifications of alternative fracture technologies, well spacing, and well patterns on the size of the recoverable resource.

### Office of Technology Assessment<sup>33</sup>

The OTA report was published in 1977 and was the first study that attempted to evaluate the recoverable Devonian shale gas resource in the Appalachian Basin.

OTA established production estimates based on 15 to 20 years of production data from 490 wells in three productive areas of the Appalachian Basin. Wells from Cottageville and Clendenin, WV, and Perry County, KY, were grouped according to the quantity (high, medium, or low) of gas produced. Average production rates were calculated for both shot and fractured wells in each group and used to calculate the recoverable resource assuming a productive area of 16,300

square miles— 10 percent of the entire basin area of 163,000 square miles. A well spacing of 150 acres was assumed, yielding approximately 69,000 wells. The economics were determined using an after tax net present value (ATNPV) model, a discount rate of 10 percent, and a well-head price for gas in the \$2 to \$3/MCF range (1976\$).

The findings as reported by OTA are summarized below:

- The Devonian shale resource could be produced without developing new production equipment and techniques.
- The Brown shales<sup>34</sup> (as they were called by OTA) could yield between 15 and 20 TCF during the first 15 to 20 years of production. After 30 to 50 years, cumulative production could reach 23 to 38 TCF.
- Because of the tremendous drilling effort and the time required to develop the necessary pipeline infrastructure, as many as 20 years may be required before annual production reached 1 TCF.

A critical factor in OTA's analysis is the assumption that only 10 percent of the Appalachian Basin will prove to contain gas recoverable at the assumed price using conventional technology. This assumption is based on the general argument that past drilling has not been random, but instead has been skewed to the high-quality areas—a universal tendency in resource development—and also upon observations of the clustered nature of existing development, the considerable depths and/or thinness of the shales in some undeveloped portions of the basin, the poorly developed fracture systems in other undeveloped areas, and the lack of success of drilling in some of these areas. This assumption that much of the undeveloped acreage in the basin will not prove to be productive is undoubtedly correct **qualitatively**, but there appears little quantitative basis for the choice of 10 percent as the productive fraction; it is essentially an educated guess.

<sup>31</sup>R. E. Zielinski and R. D. McIver, "Resource and Exploration Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin," 1982.

<sup>32</sup>V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in Ohio*, Lewin & Associates Report for Morgantown Energy Technology Center, July 1983; and V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in West Virginia*, Summary, 1984 (draft).

<sup>33</sup>Office of Technology Assessment, "Status Report of the Gas Potential From Devonian Shales of the Appalachian Basin," 1977.

<sup>34</sup>Brown shales are generally younger than black shales and have more hydrocarbons in the organic material. The organics in the black shales are closer to elemental carbon. (V. Kuuskraa, 1982, "Unconventional Natural Gas," in *Advances in Energy Systems and Technology*, vol. 3.) Brown and black shales are commonly referred to jointly as black shales.

### Lewin & Associates I<sup>35</sup>

Lewin & Associates addressed the gas potential of Devonian shales in a series of 1978-79 reports entitled "Enhanced Recovery of Unconventional Gas." The purpose of the Devonian shale portion of the study was to estimate the economic potential of the resource, based on empirical data such as geology, reservoir performance, and costs.

The Lewin & Associates study evaluated gas recovery potential with respect to price for base and advanced cases. The parameters assumed for each case are listed in table 47. Economic analyses were performed to determine the economically recoverable resource at \$1.75, \$3.00, and \$4.50/MCF (1977\$) for both the base and advanced cases. The base case represents the development of areas with producing characteristics similar to areas under production today, using available small-scale hydraulic fracturing techniques with design fracture lengths of 100 to 200 ft. The advanced case added a mix of strategies to the base case to increase production and enlarge the size of the recoverable resource, including:

- extension drilling into deep shales, with improved stimulation (in eastern West Virginia and Pennsylvania);
- dual completion, i.e., stimulating two separate gas-bearing intervals from one well, with improved stimulation (in Ohio), to allow economical production of marginal prospects; and
- improved recovery through advanced stimulation technologies and closer well spacing (in eastern Kentucky and western West Virginia, the center of current production).

The evaluation was confined to the Appalachian Basin. Of the entire basin area of 210,000 square miles, only 62,000 square miles were considered as potential shale gas-bearing areas. The 62,000 square mile area was divided into 12 analytical areas based on similar geologic characteristics, drilling or production histories. Approximately 5,000 square miles of that area included already proven areas or sites of previous production, leaving 57,000 square miles as probable and possible gas-bearing areas.

Actual production data from several gas companies and 250 individual wells were collected and cumulative production decline curves established for each area. The production curves were adjusted for "play out," to compensate for the fact that fields tend to produce less as drilling

<sup>35</sup>Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas*, U.S. Department of Energy reports HCP/T 2705-01, 02, and 03, 1978-79.

**Table 47.—Summary of Major Differences Between Lewin Base and Advanced Cases in Devonian Shale Analysis**

Strategy item	Base case	Advanced case
<b>Source characterization:</b>		
Eligible areas . . . . .	Probable areas	Probable and possible areas
Dry hole rates . . . . .	20%	10%
<b>Technology:</b>		
Completions . . . . .	Single	Dual where a low producer is underlain by other productive pay
Recovery efficiency per unit area . . . . .	Current levels	Improved by 20 percent in higher producing areas
<b>Economics:</b>		
Risk—reflected in discount rates <sup>a</sup> of . . .	21 %/0	160/0
<b>Development:</b>		
Start year for drilling		
Probable area . . . . .	1978	1981 (R&D effect begins)
Possible area . . . . .	1987	1987
Development pace		
Probable area . . . . .	17 years to completion	13 years to completion
Possible area . . . . .	17 years to completion	15 years to completion

<sup>a</sup>Discount rates include a constant ROR based on 10 to 150/0 and an inflation adjustment of 6<sup>7</sup>/0

SOURCE: Lewin & Associates.

moves into extension areas, and for stimulation technology improvement, to compensate for the differences between the old explosive fracturing and hydraulic fracturing. The adjusted curves were then used to estimate 30-year cumulative recovery per well for each area. These estimates were then used in the analysis of the economic potential.

The economic analysis used a discounted cash flow model. Net cash flow was calculated by subtracting investment costs, operating costs, and all other allocated costs from the cash flow acquired from production revenues. The net cash flow for the 30 years of production for each well considered in the study was discounted to arrive at the net present value. The areas with a positive net present value were assumed to be developed in accordance with the timing schedule designated for each case.

The results of the economic evaluation are summarized in table 48. The base case estimates are quite pessimistic—at \$4.50/MCF (1 977\$), or \$7/MCF (1 983\$), a very high price in today’s market, total recoverable resources are only 10.5 TCF. The somewhat more optimistic advanced case, which reaches 18 to 25 TCF at the same price, obtains most of its added recovery from the deep drilling and dual completions, with improved recovery in existing producing areas yielding only 2.1 TCF at this price.

An important consideration in this analysis is that Lewin considered there to be little difference in per well recovery efficiency between the base and advanced case, despite the more effective fracturing attainable in the advanced case. The major difference between the two cases is the

more rapid drainage attainable with the improved stimulation technology, which greatly improves the economics of recovery and moves marginal areas into the “economically recoverable” range. The source of this interpretation is the belief at the time that the primary source of producible gas is the fracture porosity.<sup>36</sup> This was thought to imply that the recovery efficiency of even borehole shooting would be quite high, in the neighborhood of so percent, with little improvement obtainable from more effective fractures. It currently is believed, however, that much of the long-term well production is from the resorption of gas bound to the shale matrix, and that the actual recovery efficiency of borehole shooting is only a few percent. Lewin’s new work, described later in this section, folds this new understanding of the source of recoverable Devonian shale gas into its analysis (see the discussion of “Lewin & Associates 11”). An important implication of this understanding is that improved fracturing should increase ultimate recovery, not just accelerate production.

### National Petroleum Council<sup>37</sup>

The NPC also estimated the quantity of producible gas in the Appalachian Basin for different levels of technology and price. Three levels of technology were considered in the analysis: traditional (borehole shooting), conventional (conventional hydraulic fracturing), and advanced (unique fracturing techniques and deviated drilling). Advanced technology was assumed to double the production increase achievable from the use of conventional technology.<sup>38</sup> Conventional technology was assumed to increase production over traditional borehole shooting by 0 to 57 percent depending on the open flow rates of the wells.<sup>39</sup>

**Table 48.- Lewin & Associates: Results of Economic Analysis, Summary Table**

Price, 1977\$ (1983\$)	Economically recoverable	
	Base case	Advanced case
\$1.75/MCF (\$2.75/MCF) . . . .	2 TCF	5 TCF
\$3.00/McF (\$4.70/MCF) . . . .	8 TCF	16 TCF
\$4.50/MCF (\$7.00/MCF) . . . .	10.5 TCF	18 to 25 TCF <sup>b</sup>

aCurrent proved reserves are 1 TCF and the following estimates represent additions to reserves.

bThe range reflects the geologic uncertainty with regard to natural fracture intensity.

SOURCE: Lewin & Associates.

<sup>36</sup>In other words, it was thought that most of the recoverable gas was free gas stored in the natural fracture systems.

<sup>37</sup>National petroleum Council, *Unconventional Gas Sources—Devonian Shales, 1980*.

<sup>38</sup>This assumption was based on experiments performed in Kanawha County, WV. Three advanced technology wells had production increases of 230 percent over wells stimulated by traditional shooting. Conventionally fractured wells showed 80 percent increases in production over traditionally shot wells.

<sup>39</sup>The advantages of fracturing over borehole shooting decline as the unstimulated flow rate increases; with flow rates above 300 MCF/D, fracturing was assumed to be no better than shooting.

The quantities of potential reserves for price levels between \$2.50 and \$9.00 (1979\$) were estimated by performing discounted cash flow analysis for 10, 15, and 20 percent after tax rates of return.

NPC's initial objective was to utilize existing production data to predictor extrapolate production in undeveloped areas. They intended to model the average well production decline of each county to the hyperbolic equation below:

$$\text{Production rate} = C_1 (1 + C_3/C_2 t)^{-1/C_1}$$

where  $C_1$ ,  $C_2$ , and  $C_3$ , were empirically derived constants for that county. When the existing production data were fit to the equation, they discovered that all the decline curves, regardless of county, could be represented adequately with the use of 3 and 2.5 for  $C_2$  and  $C_3$ , respectively. Therefore, apparently  $C_1$  can serve as an index to characterize average production decline for each county. The relation of  $C_1$  to cumulative production can be determined by integrating the hyperbolic equation over the appropriate time period. For example, 30-year cumulative production is equal to 4.43  $C_1$ .

Several parameters, such as the various thickness estimates and depth, were evaluated for correlation with the  $C_1$  values. The thickness of the black shale as determined by gamma-ray logs was the only parameter that correlated to  $C_1$ ; it did so with a linear coefficient of 0.213, that is, the average county black shale thickness as determined by logging can be multiplied by 0.213 to obtain the  $C_1$  value for each county. This value was used as the basis for the "traditional technology" case.

The results of the economic analysis are tabulated in table 49. The potential reserve is that portion of recoverable gas that is economically producible at a given price. The total producible gas is the total cumulative amount of in-place gas that

can be produced over the wells' 30-year lifetimes, under the specified technological conditions, irrespective of price.

The major findings presented in the NPC report are listed below:

- Average well production can be modelled to a hyperbolic decline curve as represented by the equation below:  

$$\text{Production rate (MCF/D)} = C_1 (1 + 5/6 t)^{-2/3}$$
 $C_1$  is an index to characterize average production decline and is linearly related (linear coefficient of 0,213) to black shale thickness as determined by log data.
- The total producible gas using conventional technology is 37.4 TCF, which is approximately 30 percent of the 125 TCF estimated gas-in-place in drillable formations assuming the lower value of shale thickness based on gamma-ray well log data (see the discussion of the NPC estimates of gas-in-place earlier in this chapter), and about 4 percent of the 1,040 TCF gas-in-place using the visually determined thickness.
- The average price requirement for production of 37.4 TCF is \$6.75/MMBtu (1979\$) at 10 percent rate of return. Approximately 15 TCF can be produced at prices up to \$3.50/MMBtu.

**Pulle and Seskus (SAI)<sup>40</sup>**

This analysis essentially extrapolates production data from 1,534 Devonian shale wells (with 10 years or more of production history) to full development of the Appalachian Basin's shales. The basin is divided into 10 subregions based on the thickness of the radioactive (black and brown)

<sup>40</sup>C. V. Pulle and A. P. Seskus, Science Applications, Inc., *Quantitative Analysis of the Economically Recoverable Resource*, DOE/MC/08216-1 57, May 1981.

**Table 49.—Summary of Producibile Gas Estimates Appalachian Basin (constant 1979 dollars and 10% ROR)**

	Cumulative potential reserves (TCF) v. price (\$/MMBtu)					Total producible gas (TCF)
	2.50	3.50	5.00	7.00	9.00	
Traditional technology . . . . .	3.3	8.5	11.4	14.9	16.6	25.3
Conventional technology . . . . .	7.3	14.5	19.5	23.5	27.0	37.4
Advanced technology . . . . .	11.8	20.1	27.2	32.9	38.9	49.9

SOURCE: National Petroleum Council.

**shales, the** drilling depth of past production, and a measure of the thermal maturity of the shale cores that have been obtained. To obtain an estimate of the recoverable resource, wells are assumed to be drilled on 160-acre spacing, using explosive shooting for stimulation. Past production histories are used to estimate 30-year cumulative production for wells in half of the subregions; for the other subregions, production is estimated by combining the opinions of four experts in a Delphi procedure. The percentages of dry holes are estimated using the same Delphi procedure.

The estimated mean recoverable gas under the 160-acre spacing is 20.2 TCF, with an estimated 95 percent probability that the total lies between 17.06 and 23.34 TCF. However, the “95 percent probability” is a statistical value based on the assumption that the distribution implied by the historical data is a perfect reflection of future production from new wells. This seemingly high level of probability should not be treated too seriously. It does not account for errors introduced by the Delphi procedure, by changes over time in well “shooting” techniques, or by the possibility that past well locations were not random but instead represent some selection on the basis of relative prospects for success.

The analysis does not include an evaluation of the effect of price on well spacing, so it is not clear what gas price corresponds to the estimated 20,2 TCF of recoverable resources. On the other hand, the authors show how total recovery is likely to vary with well spacing; table 50 shows the variation of recoverable resources with assumed well spacing. This estimate is based on a theoretical model applied to only four wells, so the results should be treated as very tentative. Also, the estimated **recovery—and revenue—per well** for 10-acre spacing is only **one-fifth of the per well recovery and revenue** for 160-acre spacing. This implies that the gas price needed for economic recovery of the 67,9 TCF resource for 10-acre spacing will be five times the price needed for recovery at 160-acre spacing, all other things being equal. A countervailing factor, however, is that gathering costs are quite high in the Appalachian region, and closer well spacing and the

**Table 50.—Effect of Spacing on the Devonian Shale Recoverable Resource**

Spacing (acres)	Relative number of wells	Ratio of increase in resource	Total recoverable resource (TCF)
160 . . . . .	1	1.00	20.2
80 . . . . .	2	1.68	34.0
40 . . . . .	4	2.44	49.3
20 . . . . .	8	3.10	63.0
10 . . . . .	16	3.36	67.9

SOURCE: C. V. Pulte and A. P. Seskus, *Quantitative Analysis of the Economically Recoverable Resource*, U.S. Department of Energy Report DOE/MC/08216-157, May 1981.

resulting higher production levels per unit area would lower these costs.

### Mound Facility (Zielinski and McIver)<sup>41</sup>

Zielinski and McIver of the Monsanto Corp.’s Mound Facility have reviewed the NPC and SAI estimates of recoverable resources in the Appalachian Basin and, using the SAI data, derived an alternative, admittedly preliminary estimate of the recoverable resource in West Virginia, Ohio, and Kentucky.

Zielinski and McIver’s review of the NPC estimates noted the following:

1. There are important numerical discrepancies between well production values reported by NPC as derived from their equations, and values actually calculated using these equations.
2. The NPC analysis derived a relationship for the initial production rate of a well by searching for correlations only with variables which have little to do with production, and picked a variable (gamma-ray log response) for the relationship only by default. Neither gamma-ray log response nor any of the other variables examined bear any relationship to the organic matter type or thermal maturation, both critical factors in determining gas potential.
3. The NPC found that a single equation could represent well production for the entire Ap-

<sup>41</sup> R. E. Zielinski and R. J. McIver, *Resource and Exploration Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin*, Mound Facility Report to U.S. Department of Energy, DOE/DP/0053-1 125, undated.

palachian Basin. This may imply that, for the shot well technology used in most of the wells in the production histories, the fairly uniform porosity and permeability values of the shale dominate average gas production. This, in turn, implies to the reviewers that closer well spacing should significantly improve recovery if shooting is the method of stimulation.

The review of the SAI estimate noted the following:

1. SAI divided the basin into 10 subregions by evaluating four variables—radioactive shale thickness, drilling depth, stress ratio, and a measure of thermal alteration. Only the latter variable has any documented relationship to gas production, and this relationship is a limited one. Consequently, the extrapolation of production data in a subregion to undeveloped portions of that region may not be valid.
2. SAI assumed that well production in each subregion would be distributed lognormally, but the actual production data in the five subregions where production data was available did not tend to indicate a lognormal distribution.

Zielinski and McIver also were concerned that neither the NPC nor the SAI estimates accounted for the effects of external influences—market forces, operating policy, production practices—on production, but instead implicitly assumed that past production was dependent only on the physical nature of the resource.

Based on the above concerns, Zielinski and McIver's conclusion was that "the two . . . studies . . . do not form a sound foundation for the estimation of recoverable resource."

Zielinski and McIver have developed a preliminary estimate of recoverable resources in Ohio, Kentucky, and West Virginia based on the observation, from **SAI** production data, that the production per unit area of the developed portions of these States follow a clear pattern, **i.e.**, Kentucky's production tends towards  $2.3 \times 10^{-3}$  TCF/mi<sup>2</sup>, Ohio's towards  $0.7 \times 10^{-3}$  TCF/mi<sup>2</sup>, and West Virginia's towards  $1.5 \times 10^{-3}$  TCF/mi<sup>2</sup>.

Extrapolating these values to prospective but undeveloped acreage yields a total recoverable resource of 30 to 50 TCF for the three States, for the same technology ("shooting") and well spacing (160 acres). This estimate is based on the assumption that different market conditions, production practices, etc., did not affect the State production averages, and also that past well siting was random. The authors consider the 30 to 50 TCF value to be a minimum for recoverable resources because improved stimulation technology, closer well spacing, or use of remote sensing techniques to improve well siting can individually or in combination increase total recovery as well as production rates. For example, Zielinski and McIver predict that halving well spacing to 80 acres will essentially double the recoverable resource.

### Lewin & Associates II<sup>42</sup>

A recent estimate by Lewin & Associates makes use of the extensive data collection and analysis effort of DOE's Eastern Gas Shales Project, e.g., the geochemical analyses of Mound, and combines this with reservoir simulation to estimate the **technically recoverable gas resource** of the Lower and Middle Huron Intervals of the Ohio Devonian shale.

The Lower and Middle Huron Intervals represent only a portion of the resource base that potentially can be exploited; they contain about **50** TCF of gas-in-place, compared to an estimated gas-in-place of 390 TCF for Ohio and 2,579 TCF for the Appalachian Basin.<sup>43</sup> The Huron Intervals have been the traditional targets for past drilling in Ohio, and the great majority of available drilling data applies only to these intervals. The recovery potential of the remaining 340 TCF in Ohio is unknown. However, nearly half of the gas-in-place in the entire basin is considered by Mound to be undrillable because of surface constraints such as roads and towns, and thus the recoverable resource for the remainder of Ohio

<sup>42</sup>V.F. Kuuskraa, et al., Lewin & Associates, Inc., *Technically Recoverable Devonian Shale Gas in Ohio*, prepared for the Morgantown Energy Technology Center, U.S. Department of Energy, July 1983.

<sup>43</sup>From the Mound Study.

is unlikely to be as large, in relationship to its gas-in-place, as in the Huron Interval. Nevertheless, **the Lewin estimates should be recognized as representing only a limited portion of Ohio's Devonian shale gas potential, although the most prospective portion.**

Selected results of the Lewin analysis are shown in table 51. The results should be interpreted carefully because they refer to the expected physical results of a specified quantity of drilling and stimulation without regard to economic feasibility. In other words, they are comparable to the "technically recoverable" or "maximum producible" resources of other estimates. The results are particularly interesting, however, because Lewin's use of reservoir simulation provides for a more credible estimate of the effects of improved stimulation technologies and smaller well spacing. As shown in the table, both methods of improving gas recovery could be extremely successful in the Appalachian Basin. According to the report, 80-acre spacing has already started to supplant the more traditional 160-acre spacing in new drilling in the basin. Accordingly, the 8.7 to 10.5 TCF projected as the result of improved but relatively conventional technology at 160-acre spacing probably represents a pessimistic estimate of actual recoverable resources assuming high gas prices. This result has interesting implications for the future potential of Devonian shale gas in view of

the limited portion of the total Appalachian resource represented by this analysis.

A more recent Lewin study, available in draft at the publication close of this report, estimates the technically recoverable Devonian shale resources in West Virginia. Table 52 summarizes the results, which apply to the Huron, Rhinestreet, and Marcellus shale intervals. These intervals represent the most promising shale prospects in the State, although only 70 TCF out of a total of 125 TCF of gas-in-place for the intervals was actually appraised. Insufficient reservoir data were available for the nonappraised portions of these intervals. In addition, hundreds of TCF exist in lower quality shale formations that may be developable at some point, but not with simple extensions of today's technology.

The results of the West Virginia assessment are even more optimistic than the Ohio results, given the estimated 25.4 to 32.7 TCF technically recoverable resource based on improved but readily attainable technology and 160-acre spacing. Coupled with the probability that Kentucky will prove to have recoverable resources somewhere in-between those of Ohio and West Virginia,<sup>44</sup> the Lewin results imply that the Devonian shale recoverable resource is considerably greater than imagined by all of the previous estimates reviewed herein.

**Table 51.—Results of Lewin Assessment of Technically Recoverable Gas in Ohio, by Stimulation Method After 40 Years**

1. Present technology, 160-acre spacing	
• Borehole shooting . . . . .	6.2 TCF
II. Improved but readily attainable technology, 160-acre spacing:	
• Small radial stimulation (30 ft radius) . . . . .	8.7 TCF
• Small vertical fracture (150 ft wings) . . . . .	10.5 TCF
III. Advanced technology, speculative, 160-acre spacing:	
• Large radial stimulation (60 ft radius) . . . . .	10.2 TCF
• Large vertical fracture (600 ft wings) . . . . .	15.2 TCF
• Large vertical fracture, 80-acre spacing (600 ft wings) . . . . .	21.0 TCF
IV. Changed well patterns (3 to 1 rectangle, taking account of permeability anisotropy) with improved or advanced technology: yields added recovery of 5 to 10 percent/well.	

SOURCE: V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in Ohio*, Lewin & Associates Report for Morgantown Energy Technology Center, July 1983.

<sup>44</sup>VelloKuuskraa, Lewin & Associates, Inc., personal communication, 1984.

**Table 52.—Results of Lewin Assessment of Technically Recoverable Gas in West Virginia, by Stimulation Method After 40 Years**

1. Present technology, 160-acre spacing:	
• Borehole shooting . . . . .	19.1 TCF
II. Improved but readily attainable technology, 160-acre spacing:	
• Small radial stimulation (30 ft radius) . . . . .	25.4 TCF
• Small vertical fracture (150 ft wings) . . . . .	32.7 TCF
III. Advanced technology, speculative:	
• Large vertical fracture (600 ft wings) . . . . .	88.4 TCF

SOURCE: V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in West Virginia*, Summary, 1984 (draft).

## Estimates Comparison and Uncertainties

OTA's examination of the several estimates of Devonian shale recoverable resources established some important concerns:

First, with the exception of the latest Lewin & Associates reports on Ohio and West Virginia, the attributes of advanced recovery technologies were described vaguely, and a reservoir simulation model that could predict the effect of longer fractures or other attributes of advanced technologies was not available. Consequently, estimates of the effects of advanced recovery technologies on recoverable resources should be considered at best either "educated guesses" or extrapolations based on quite limited evidence.

Second, several of the estimates extrapolate available data on existing production to the entire Appalachian Basin by using methods that rely on guesswork, on arguable assumptions, or on apparent relationships with variables that do not seem likely to be strongly related to resource recovery potential. For example, the early OTA study did not formally relate well production to measurable physical attributes of the areas under development, presumably because there were inadequate data. Instead, the study assumed that 10 percent of the basin will be productive in the same manner as the area now under production, and that the remainder of the basin will be unproductive; the choice of 10 percent was not explained, but is essentially an "educated guess." Both the Pulte and Seskus and the NPC estimates relied on predictive variables—in NPC's case, shale thickness as measured by gamma-ray logs—which seem likely to be only limited predictors of gas recovery. The Zielinski and McIver estimate for West Virginia, Ohio, and Kentucky, admittedly a preliminary, crude attempt, is based on the assumption that the existing wells, used for extrapolation, were randomly sited, so that their production would be representative of what would occur in the untested portions of the shale area. This type of assumption is more tenable in the Appalachian Basin than it would be elsewhere because sophisticated exploration techniques were not used to site the existing wells, the haphazard availability of land for drilling may have interfered with pattern drilling, and other

factors. In our view, however, the information gained by earlier drilling is certain to have directed subsequent drilling to better-than-average prospects, and the direct extrapolation used in this study will tend to lead to an overestimate of the resource recoverable by borehole shooting.

Third, only a very small part of the Devonian shale has been tested by drilling, and consequently the available studies focus on the resources recoverable from the producing shale intervals, or those closely resembling them, i.e., those with well-developed natural fracture systems. Much of the gas-in-place exists in intervals which are not currently productive. For the most part, the large portion of this gas probably could not be produced with current technologies and prices. However, it may be possible to economically recover much of this gas with new technology, especially at higher prices. The existing studies cannot account for this possibility, and probably there is no credible way at present to determine the true potential of these intervals. Nevertheless, it must be made clear that the existing estimates of the Devonian shale resource potential do not include this speculative portion of the resource, and that there is at least the possibility that, with further technology development, the gas ultimately recoverable from the Devonian shales may be considerably larger than currently estimated.

Fourth, all of the estimates may suffer from the problem that past production has been influenced by the market and by other external influences on production. The studies all implicitly assume either that the resource characteristics are dominant in determining production characteristics, or else that any external influences on production will remain essentially unchanged during the period of development of the resource. Zielinski and McIver have noted that these production influences might have affected the ultimate recovery of past wells, and should be taken account of when extrapolating to future production.

Comparison of the resource estimates of the various studies is made difficult by the first problem, the lack of clearly defined criteria for "advanced technologies," and also by differences in

**assumed gas prices and study areas. However, relatively clear comparisons can be made of the resources recoverable by traditional borehole shooting. Table 53 compares the resource estimates of six studies for borehole shooting at 150- to 160-acre spacing and, for three of the studies, at prices moderately higher than current market prices** for new gas. The estimates of Pulle and Seskus, Zielinski and McIver, and the recent Lewin study do not specify prices and are more in the nature of “technically recoverable gas.” They are best compared to the NPC “total producible” resource of 25.3 TCF and the 1977 Lewin estimate of 10.5 TCF for gas prices of \$4.50/MCF (\$7.00/MCF [1983\$]); the latter should be close to a “technically recoverable” limit because of the rapidly diminishing returns for further price increases apparent in the Lewin analysis.

Because there has been extensive experience with borehole shooting, the estimates for recoverable resources using this technology should be the most reliable. There are serious differences among the estimates in table 53, however, and we believe these differences reflect some of our concerns with the individual studies. The Zielinski and McIver estimate, which should be considered optimistic because it assumed that siting of past wells was random and therefore that their production experience would be representative of undrilled acreage, is in fact the highest of the estimates of technically recoverable gas. The 1977 OTA estimate is not based on a geological evaluation of the prospects of the undeveloped portion of the basin, and probably should be downplayed; it is, in fact, at considerable variance with

the NPC and early Lewin estimates, which are more pessimistic. On the other hand, the early Lewin estimates also appear to be considerably more pessimistic than the recent Lewin estimates for Ohio and West Virginia; it seems likely that a new Lewin estimate of the Appalachian gas recoverable at about \$4.70/MCF (1983\$) would be considerably higher than the 8 TCF predicted by the early study. The difference between the early and more recent Lewin studies is emphasized by the recognition that the early study includes some hydraulic fracturing in its recoverable resource estimate; presumably, its estimate for the resource recoverable with borehole shooting only would have been even lower than 8 TCF.

In conclusion, OTA's best resolution of existing resource studies is that the Devonian resource ultimately recoverable with borehole shooting at 160-acre spacing and gas priced at \$4 to \$5/MCF (1983\$) is at least 10 TCF and, based on the implications of the recent Lewin work, most probably is somewhat higher. Ultimately, if the Lewin analyses prove to be substantially correct, about 30 to 50 TCF may be recovered with this technology and spacing at very high prices. These are extremely conservative estimates of the actual gas potential of the Appalachian Basin, however, because neither the technology assumption nor the spacing assumption are realistic. Many producers in the basin have begun to use hydraulic fracturing, which increases ultimate recovery per well, and well spacing in the less permeable areas has begun to be decreased to 80 acres, which improves recovery per section. With borehole shooting as the “baseline” technology, halving

**Table 53.—Comparison of Estimated Appalachian Devonian Shale Resources Recoverable With Borehole Shooting, Well Spacing of 150 to 160 Acres**

Study (data)	Gas price (\$/MCF) study date (1983) <sup>a</sup>	Recoverable resource (TCF)	Total producible (TCF)
OTA (1976)	\$.2 to \$3 (\$3.03 to \$4.95)	23	NA
NPC (1979)	\$3.50 (\$4.70)	8.5	25.3
Lewin I (1977)	\$3000 (\$4.68)	8 <sup>b</sup>	10.5+
Pulle and Seskus (1981)	None		17-23
Zielinski and McIver (1982) (West Virginia, Ohio, Kentucky)	None		<b>30-50</b>
Lewin II (1983) (portions of Ohio and West Virginia only)	None		25.3

<sup>a</sup>The 1983 gas price is obtained by applying the GNP Price Deflators published by the Bureau of Economic Analysis, Department of Commerce. Includes hydraulic fracturing as well as borehole shooting.

SOURCE: Office of Technology Assessment.

the spacing seems likely to yield at least a 70-percent increase in recoverable resources, primarily because the area of influence of each well is smallest with this technology and thus the additional wells will interfere least with the adjacent wells. **The incremental benefit of reduced spacing will decrease for recovery technologies that contact more of the formation because of interference between adjoining wells; however, Lewin estimated that halving the spacing will still add 40 percent to the recoverable resource in Ohio even when the baseline technology achieves 600-ft fractures, which should maximize interference between wells.**

The use of conventional hydraulic fracturing and more advanced stimulation also can greatly increase the recoverable resource. The NPC estimates that conventional fracturing will yield a 50- to 70-percent increase in recovery over borehole shooting. They project an additional 40-percent increase over the conventional fracturing with the more advanced stimulation techniques, but this estimate is based on very limited experience. The recent Lewin study estimates that a stimulation achieving 600-ft fractures can more than double the recoverable resource over that obtainable with borehole shooting, and that a combination of this technology with 80-acre spacing can more than triple the resource.

These estimates imply that the recoverable resource in the Appalachian Devonian shales may prove to be quite large, perhaps 80 or 100 TCF or *even* higher with high gas prices and substantial improvements in recovery technology. **However, the current limited capability in reservoir simulation and our limited geologic understanding imply that estimates of recoverable resources using advanced technology should be viewed as having quite high uncertainty.**

Finally, as noted previously, none of the estimates consider the possibility of producing from shale intervals that do not contain well-developed natural fracture networks. This portion of the shale is a highly speculative resource, and its gas-in-place may never become recoverable. **Nevertheless, it does present some potential for future recovery.**

## Annual Production Estimates

Annual production estimates may be calculated by estimating the number of wells to be drilled and postulating a drilling schedule. The number of wells drilled is determined by the area considered to be drillable and the well spacing assumed. The larger the well spacing, the fewer the number of wells that may be drilled in a given area. The USGS argues that drainage patterns of Devonian shale wells are too variable to assume a constant spacing.

Lewin & Associates determined 1990 production estimates based on an available acreage of 57,000 square miles, a well spacing of 150 acres per well and the drilling and development schedules outlined for the base and advanced technology cases. The resulting estimates are shown in table 54.

Annual production and additions to reserves were also calculated in the NPC study. The number of wells drilled were constrained by an available acreage of 62,000 square miles, a well spacing of 160 acres per well and "low" and "high" drilling schedules. The low scenario assumed there would be initially 12 rigs drilling in Devonian shale in 1980, and a 12-percent increase each year thereafter. The high scenario assumed 15 rigs were active in 1980, with 15 rigs added each year through 2000. All rigs were assumed to drill 35 productive wells per year. The results of this analysis are included in table 55. As shown in the table, the high scenario depends on extremely high gas prices into the 1990s. Even with advanced technology, the year 2000 production rate of 1.35 TCF/yr requires gas prices above \$10.00/MCF (1983\$).

It is not clear whether or not the annual production estimates projected by the NPC and Lewin accounted for some important factors that can influence the rate at which the resource is developed. The effects of these factors are not readily quantifiable, but they can be used to qualify the production potential estimates.

One factor that definitely will affect the production rate is the availability of adequate leases for exploration and drilling. In fact, in most ac-

**Table 54.—Lewin & Associates Results for Annual Production Estimates**

Price, 1977\$ (1983\$) (\$/MCF)	Production rates (TCF/yr)	
	Base case	Advanced case
1.75 (2.75)	Peak 0.1 in 1990 declines thereafter	Peak 0.3 in 1990 declines thereafter
3.00 (4.70)	Peak 0.3 in 1990 gradual decline thereafter	0.6 in 1990, hold to 1995 declines thereafter
4.50 (7.00)	Remains constant at 0.3 through 2000	Increases to 0.7 to 0.9 in 1990

SOURCE: Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas*, U.S. Department of Energy Report HCP/T2705-01, 02, and 03, 1978-79.

**Table 55.—Potential Incremental Supply of Devonian Shale Gas in the Appalachian Basin: NPC High Growth Drilling Schedule (production and reserve volumes [BCF] and price [\$/MMBtu]) (constant 1979 dollars)**

	1980	1985	1990	1995	2000
Annual productive wells drilled	770	3,400	6,000	8,650	11,300
Cumulative wells	770	12,500	37,300	75,300	126,400
Traditional technology:					
Annual production rate	15	190	430	620	690
Annual reserve additions	200	890	1,250	1,110	720
Cumulative additions	200	3,300	8,800	14,300	18,400
Incremental price at 10%/0 ROR	<2.50	<2.50	<5.00	<7.00	<12.00
Conventional technology:					
Annual production rate	17	220	550	865	1,005
Annual reserve additions	240	1,040	1,660	1,690	1,140
Cumulative additions	240	3,800	11,000	19,600	26,100
Incremental price at 10%/0 ROR	<2.50	<2.50	<3.50	<7.00	<9.00
Advanced technology:					
Annual production rate	21	270	700	1,110	1,355
Annual reserve additions	290	1,290	2,030	2,170	1,600
Cumulative additions	290	4,800	14,000	25,100	34,500
Incremental price at 10%/0 ROR	<2.50	<2.50	<3.50	<5.00	<9.00

SOURCE: National Petroleum Council.

five areas of Devonian shale drilling, perhaps 95 percent of all wells drilled are located on the basis of the availability of land. Most of the Devonian shale in the Appalachian Basin occurs in the older, more populated areas, which over the years have been divided into small tracts (by oil industry standards). Building an exploration block of any size is difficult and expensive with many title problems. Also, a trend towards short-term leases of 1 year or less has made establishing an orderly exploration program difficult. Some States also have no well spacing requirements, making any tract capable of holding a potential drilling rig a drill site. As a result, a good well may be jeopardized by other wells that are placed too close to it.

The type of operators in the Devonian shale will also influence the development of the resource. The major oil companies have not invested in Devonian shale wells, due principally

to land problems and poor well performance. The majority of operators are small companies financed by drilling funds or direct investment groups. Although these small operators can move swiftly into "hot" acreage, their cash flows are generally not sufficient to allow much exploration. As a result, many wells are drilled with little regard to geological conditions. A lack of funds could also inhibit the use of costly yet more effective evaluation and stimulation techniques, thereby reducing the quantity of gas ultimately recovered.

Aside from these uncertainties, and the obvious uncertainty introduced by our inability to project future economic and market conditions such as gas prices, demand, and availability of capital, production projections share most of the uncertainties associated with the estimates of recoverable resources discussed previously in this chapter. Of particular interest are uncertainties

in the effects of improved stimulation technologies, since increases in fracture areas will affect production rates as well as total cumulative production. Consequently, production projections assuming the use of advanced technologies should be considered substantially more uncertain than projections assuming explosive fracturing. In the latter case, extrapolating from historic production data should be an acceptable procedure for projecting future production, although our lack of data on production practices and other factors that might have influenced past production rates requires that a substantial error band be placed around the results.

Production levels of about 1.0 TCF by the year 2000 would seem to be readily supported by the available studies: the 1977 OTA study concluded that 1.0 TCF/yr could be achieved 20 years after commencing an intensive drilling program, assuming relatively moderate prices; the first Lewin study projected a maximum production rate of 0.9 TCF/yr in 1990, with advanced technology and \$4.50/MCF gas (1977\$) (\$7.00/MCF [1983\$]); and the NPC study projected a 1.0 TCF/yr production rate in 2000 using available technology, although admittedly at a very high price (\$9.00/MCF [1979\$]). However, high production levels

of Devonian shale gas in the Appalachian Basin using currently available or moderately improved technology implies a massive expansion of drilling in an area where such an expansion is institutionally and physically difficult. Also, the production levels in the various studies were derived by assuming arbitrary drilling levels and extrapolating production data from quite limited areas to the basin as a whole. On the other hand, the recent Lewin work in Ohio and West Virginia implies that gas recovery (and production rates) per section can be increased substantially with reduced spacing, tailoring of drilling patterns to permeability anisotropy, and improved fracturing. Increased recovery per section could allow a more rapid expansion of production by easing problems of pipeline construction and land assemblage. Consequently, if gas market conditions in the Northeast improve very soon, institutional barriers to production are reduced or overcome, and exploration and production technology advances are achieved, OTA considers a production rate of 1.0 to 1.5 TCF/yr from the Appalachian Devonian shales by the year 2000 to be quite plausible. Achievement of the prerequisite conditions in the short time span involved is, however, still somewhat optimistic.