VI. Economics of Brown Shale Gas Production

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There are three principal areas of uncertainty in evaluating the commercial potential of natural gas production from the Devonian shales. These basic uncertainties are:

- economic
- technological, and
- geologic.

The economic uncertainties involve primarily expected well head prices and the tax treatment of income from natural gas production, but economic uncertainty also intersects technological uncertainty. The areas of intersection involve possible progress in drilling technology and the effects of stimulation techniques on production. The principal geologic uncertainty involves the Brown shale resource base, i.e., how much of the Brown shale is a high-quality, gas-productive resource, how much is medium quality, and how much is low quality? As natural gas prices increase to reflect the value of this resource more closely, it is reasonable to expect that relatively large amounts of shale gas might become economically attractive. What is not now adequately known, and can only be determined from actual drilling and production experience over a wide geographic area, is the quantity of high-, medium-, and low-quality areas of Brown shale. [1]

The approach used here is to deal with economic uncertainty by considering a range of wellhead prices and tax treatments. These ranges of price and tax cases are used to evaluate the after-tax net-present values (ATNPV—Current worth of a flow of income after taxes); of gas wells drilled into the Brown shale in three geographic localities in the Appalachian Basin. The drilling costs, dry-hole experience, and production profile information used in the ATNPV calculations are the actual data for each of the three localities,[2] and each locality is evaluated separately.[3] The three were chosen as examples of high-, medium-, and lower-quality resources for which adequate data were available on a consistent basis to support ATNPV calculations under alternative assumptions concerning the price and tax determinants of economic incentives. It must be realized that these three localities are situated in a small area of the Appalachian Basin which is known to be gas productive. Therefore, the terms high-quality, medium-quality, and low-quality resource are relative to each other only, and production data from these three localities cannot be extrapolated directly to the entire 163,000-square-mile extent of the Appalachian Basin.

Production data from 490 shale wells in the gas-productive area of the Appalachian Basin were used to estimate the potential production from other areas of the Appalachian Basin where shale gas production might be economically feasible. This part of the analysis is the point of most crucial interest and the weakest link in the overall analysis, Until substantially more drilling has been done over a wide area, the amount of the Brown shale resource with economic potential will not be known with any more confidence than the judgmentally plausible estimates used in

[1] See the section titled *Extent of the Economically Producible Area* for rationale used to estimate the quantity of commercially productive Brown shale in the Appalachian Basin,

[2] The after tax net-present value (ATNPV) calculations were made with the aid of a computerized routine developed by Drs. Robert Kalter and Wallace Tyner. This ATNPV calculation routine is described in Wallace E. Tyner and Robert J. Kalter, "A Simulation Model for Resource Policy Evaluation, " Cornell Agricultural Economics Staff Paper No. 76-35, November 1976.

[3] These individual localities are not homogeneous in terms of either the quality of the resource base or the stimulation technique used. As a result, seven types of Brown shale gas production in the Appalachian Basin are actually evaluated on an ATNPV basis.

this analysis. q The assumptions used here are explicit, and are subject to sensitivity variation and revision as more actual drilling results become available.

The general result of the analysis is relatively optimistic:

- if 10 percent of the total Appalachian Basin shale is as attractive as the higher quality resources examined here;[5]
- if there" is no improvement in drilling technology or stimulation techniques; and
- if current tax treatment of income from natural gas production continues; then,
- at wellhead prices for natural gas in the $2.00 to $3.00 per Mcf range, it is not unreasonable to conclude that the Brown shale of the Appalachian Basin may have a production potential in the neighborhood of 1 trillion cubic feet (Tcf) per year for a considerable future period.

Such a level of production would require a substantial effort (69,000 wells), but the additional supply is not inconsequential in the context of the current and prospective U.S. natural gas situation. One trillion cubic feet (Tcf) per year of Brown shale gas would be equivalent to about 5 percent of current U.S. production.

Price, Tax, and Other Economic Assumptions

In recent years, wellhead gas prices have increased substantially and the tax treatment of income from gas production has become less generous. In this analysis, four alternative prices for prospective Brown shale gas and four tax cases are considered, The basic price and tax assumptions are firmly rooted in the current facts of interstate and intrastate gas markets and internal Revenue Service (IRS) treatment of income from gas production. The additional price alternatives and tax cases are designed to cover a broader range of possibilities for enhanced economic incentives and to test the sensitivity of the ATNPV of shale gas potential to such possibilities.

Price Assumptions

The four alternative assumed prices are:

- $1.42 per Mcf,
- $2.00 per Mcf,
- $2.50 per Mcf, and
- $3.00 per Mcf.

The current Federal Power Commission (FPC) wellhead ceiling price for sales of natural gas in interstate commerce is $1.42 per Mcf.[6] This price is subject to a 1 -cent escalation every 3 months. It also contains a provision for an upward proportional adjustment if the gas sold contains more than 1,000 Btu's per cubic foot.[7] Much of the gas from the Devonian shale of the Appalachian Plateaus has a substantially greater Btu content than the FPC standard upon which the $1.42 per Mcf new-gas ceiling rate is based—it is not uncommon for gas from Brown shale to have a Btu content as high as 1,350 Btu's per cubic foot. In addition, although a considerable part of the area of Brown shale potential, particularly in West Virginia, is served by interstate pipelines subject to FPC ceiling price regulation, much

[4] There are approximately 10,000 wells producing gas from the Brown shale. But data for many of these wells are not readily available, a large fraction of the wells are in a relatively small area, and for many wells production from the Brown shale is commingled with production from other zones. It is possible that careful screening and analysis of these data would significantly improve our current knowledge of the Brown shale resource, but such an effort was beyond the scope of this assessment.

[5] The rationale for considering 10 percent of the Appalachian Basin as higher-quality resources is presented in the section of this report titled, *Extent of the Economically Producible Area.*

[6] Federal power Commission, opinion No.770-A, p. 181.

[7] Ibid, pp. 186-187.

prospective shale gas may be sold in intrastate commerce. prices in intrastate markets are typically higher than those in interstate markets.[8] For these two reasons—Btu adjustment and intrastate market sales—the current $1.42 Mcf ceiling price may be considered a lower-limit base case on wellhead prices, which will be a determinant of the economic feasibility of Brown shale production.[9] In addition, there are the prospects of higher FPC ceilings for new gas or of congressional deregulation of new gas sales. Both of these later possibilities support treatment of $1.42 per Mcf as a lower limit base case.

The weighted average price per Mcf for national natural gas sales in intrastate commerce for new contracts signed in the second quarter of 1976 was $1.60 per Mcf. Many contracts were in the neighborhood of $2.25 per Mcf. Prices in this range can be considered the leading edge of the intrastate gas market. Intrastate sales of gas from Brown shale in Ohio and Kentucky have brought prices of over $2.00 per Mcf, The recent trends of both interstate and intrastate wellhead prices have been upward. Current shortages suggest these trends will continue. Leasing, drilling, and well-completion decisions on the basis of price expectations of $2.00 per Mcf or more for Brown shale gas in various areas are therefore not an unreasonable assumption. The second alternative price is $2,00 per Mcf.

The third and fourth alternative prices are $2.50 and $3.00 per Mcf. The prices of alternative fuels such as fuel oil, propane, synthetic natural gas (SNG), or liquefied natural gas (LNG) are either at or substantially above these values on a Btu basis. Use of prices in this range is therefore appropriate in the ATNPV calculations in order to test the potential sensitivity of natural gas production from the Brown shale to substantially enhanced economic incentives. It must be emphasized, however, that these values are not price projections or forecasts. For the purposes of the calculations reported herein, they are merely elements of the sensitivity analysis.

All prices are specified in constant 1976 dollars. In each of the ATNPV calculations reported below, if a price of $1.42 per Mcf (or $2.00, $2.50, or $3.00) is specified that price is assumed to hold in constant 1976 dollars for the life of production. Drilling, well-completion, and operating costs are also specified in constant 1976 dollars. These cost components are discussed in more detail in the section on cost and technological considerations.

Tax Assumptions

Four cases for the tax treatment of income from gas production are considered in the ATNPV calculations reported below. These are:

- zero percentage depletion allowance and no investment tax credit;
- 22-percent depletion allowance and no investment tax credit;
- zero percentage depletion allowance and a 10-percent investment tax credit; and,
- 22-percent depletion allowance and a 10-percent investment tax credit.

The assumption of zero percentage depletion allowance and no investment tax credit is consistent with the current treatment of income from natural gas production for producers with average daily output in excess of 2,000 barrels of oil or 12 MMcf of natural gas. Relative to typical lease output for Devonian shale production, these are large amounts of natural gas. But most U.S. oil and natural gas output is produced by the very large number of operators (whether corporations, partnerships, or sole proprietorships, etc.) with production above these cutoff levels. If economic incentives are sufficient to make Brown shale prospects an attractive investment opportunity, and if the Brown shale resource is

[8] See Federal Power Commission form 45 data.

[9] Wellhead prices also reflect unit transportation costs to end-use markets. Unit transportation costs are a decreasing function of the volume of shipments. Shale gas output per producing area may sometimes be small enough that relatively high unit transportation costs have an adverse effect on the wellhead netback from end-use markets. For the purposes of the analysis here, we assume that the high-quality Btu characteristics of Brown shale, its proximity to major markets, the possibility of intrastate sales, the form of pipeline and distribution company regulation, and the cost of alternative supplies all operate to make the $1,42 per Mcf value a lower-limit base case.

extensive enough to allow significant volumes of production, then this tax treatment is relevant for many potential Brown shale operators. Together with the $1.42 per Mcf price assumption, this tax treatment defines the lower-limit base case considered here.

The 22-percent depletion allowance and zero investment tax credit is the tax treatment relevant to many, perhaps most, current Brown shale operators. The small-producer exemption phases down, on an allowable output basis over the period 1976-80, to 1,000 barrels of oil or 6 million cubic feet of gas per day. Beginning in 1981, the applicable percentage depletion allowance rate begins to decrease on a phased basis from 22 percent until it reaches 15 percent in 1983. However, a 22-percent depletion allowance rate for production not in excess of 1,000 barrels of oil per day or 6 million cubic feet of natural gas per day will be allowed for production which results from enhanced or tertiary recovery. Because of the following reasons:

- eligibility of small Brown shale operators for 22-percent depletion allowance until 1981,
- importance of the early years' receipts in the net present value calculations, and
- possible classification of Brown shale operations as tertiary or enhanced recovery production;

the second tax case is a relevant component of the sensitivity analysis for the economic feasibility of Brown shale gas supplies.[10]

The third tax case considered puts the tax treatment of income from gas production on more of an equal footing with the tax treatment of other nonextractive investment opportunities in the U.S. economy. In this third case, percentage depletion is set at zero and an investment tax credit of 10 percent is assumed.

The fourth tax case is a liberalized tax treatment of income from gas production. Percentage depletion is assumed at 22 percent and a 10-percent investment tax credit is allowed.

In all four tax cases considered, no change is assumed in the tax treatment for expensing of intangible drilling costs.

State income and severance taxes are assumed to be equivalent to an average State income tax of 12 percent. Actual income and severance tax rates in the Appalachian Basin States in which increased Brown shale production may become a factor are typically lower.[11] However, experience in Gulf Coast and Southwestern States, where severance taxes have been converted from a unit to an ad valorem basis, suggests that it is prudent to use conservative State tax rates for the sensitivity analysis reported below,

Other Economic Assumptions

The ATNPV calculations are also sensitive to a number of other factors. These include:

- the discount rate;
- the lag between initial investment costs and the commencement of sales;
- the time profile of production;
- the amount of recoverable reserves per unit of investment cost; and
- operating costs.

The discount rate used in the ATNPV calculations reported below is 10 percent in real terms after taxes. ("Real terms" means in constant dollars adjusted for inflation.) Many individual entrepreneurs and corporate decision makers now require rates-of-return for project evaluation which are substantially in excess of 10 percent, but these higher rates are expressed in current

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[10] Consideration of this tax case is not an implicit recommendation for differential tax treatment by size or status of operator. Rather, it is simply a recognition of the current law and the fact that different categories of operators focus their activities in different areas and on different types of prospects.

[11] The highest marginal rate for corporate income tax is 5.8 percent in Kentucky, 8 percent in Ohio, and 6 percent in West Virginia. Ad valorem and severance taxes for these States are approximately 2,2 percent for Kentucky, 2.6 percent for Ohio, and 10 percent for West Virginia of typical gross revenues expected for a Brown shale well.

dollar terms and include an inflationary adjustment. In addition, there is often substantial process or outcome risk associated with the projects in question.[12] There is considerable evidence that the petroleum industry has been willing to commit substantial investment funds on an ongoing basis in situations in which the realized rate-of-return was in the neighborhood of 10 percent after taxes.[13] For this reason, and also because the lower-limit base case overstates the after tax costs of smaller operators, a 1 O-percent after-tax discount factor is used.

There is commonly a lag between the time when initial investment expenses are incurred and actual production commences. In many cases, for example offshore production, this lag may be measured in years. In proven onshore areas connecting a well to a pipeline network where no unusual drilling, well-completion, or production problems arise, the lag may be relatively short. There are instances in which the lag between the time when an Appalachian Basin well to the Brown shale is spudded in and the start of production has been as short as 1 week. The critical determinants of the lag between initial investment and the commencement of the revenues (if any) which justify the commitment of the funds are:

- the distance from an existing pipeline;
- the expected volume of production for the area;
- the ease or difficulty of acquiring pipeline right of way; and
- the costs per well of pipeline construction.

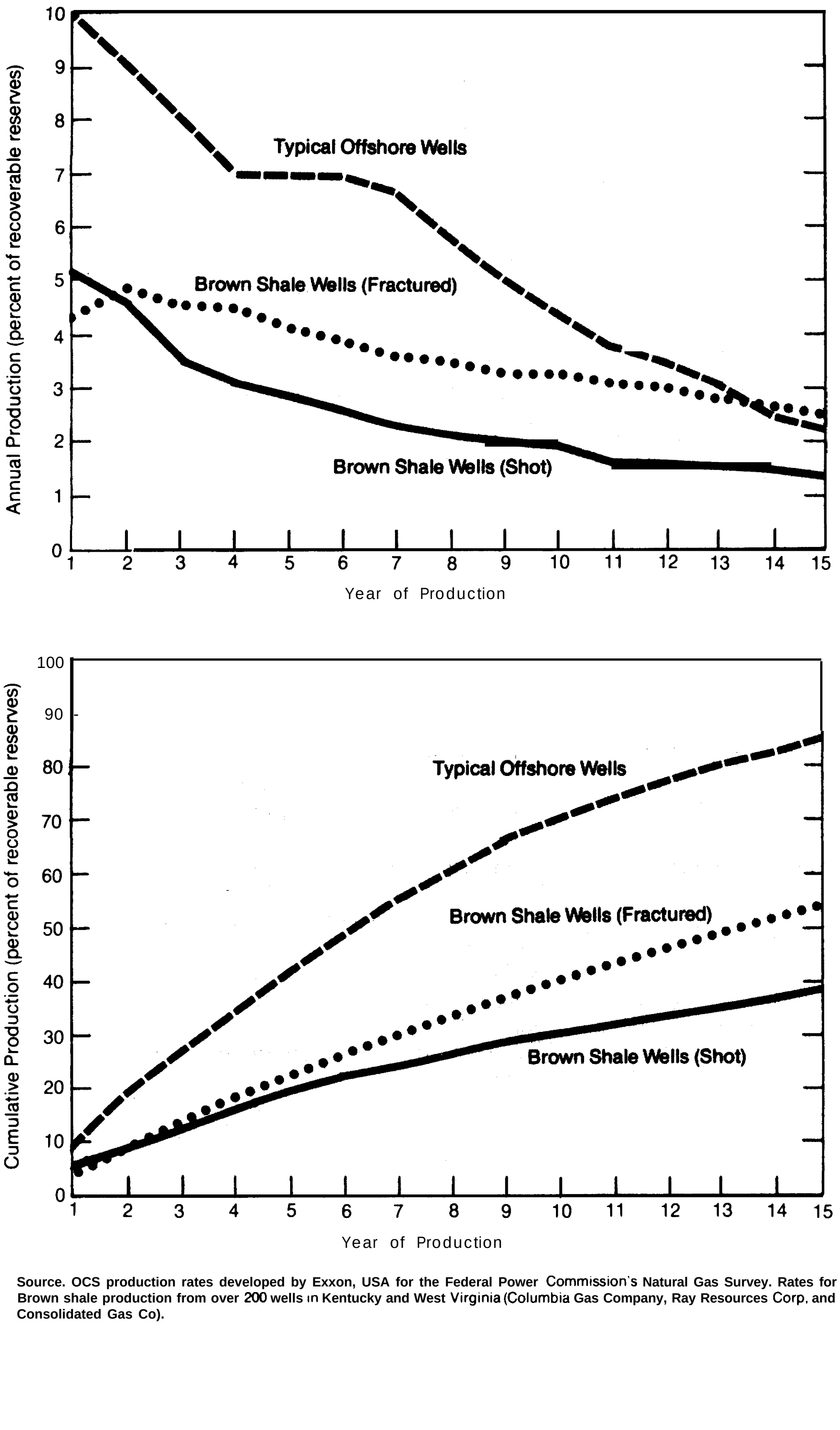
Existing Brown shale production has generally been developed in areas close to an existing pipeline network. Under these circumstances, lags between the initial investment costs and the realization of production revenues have been relatively short-on the order of a few weeks. On a prospective basis, the average lag may be expected to increase. But if Brown shale development taps a significant resource base, the pipeline network will follow it and the lag can be expected to close. In the ATNPV calculations reported below, the average lag assumed between the initial investment expenditure and the realization of production revenues is 1 year. This is considerably greater than current experience, but is not inconsistent with a prudent approach to possible future lags.

One of the most critical factors concerning Brown shale gas is the time profile of production. A typical shale reservoir is relatively small and has a very stretched-out production profile. Flow rates are currently being accelerated by artificial stimulation through hydrofracturing or shooting the well bore with explosives. But even under the best circumstances, a relatively small fraction of total recoverable reserves is produced in the earlier years of the life of the reservoir. [n figure 11, the production profile of a typical offshore

I [2]See, for example, *Enhanced Oil Recovery,* the National Petroleum Council, Washington, D. C., pp. 19-62, 1976.

ı [3]There have been a number of studies of the rate of return to offshore activity. These studies indicate that in general, oil companies have earned rates of return in offshore activity which are consistent with effective competition. These studies include: T.D. Barrow, "Economics of Offshore Development, " *Exploration and Economics of the Petroleum Industry,* Bender, New York, N. Y., 1967; "Post Appraisal of Recent Sales, " op. cit., Vol. 7, pp. 69-89; Walter J. Mead, estimates contained in Nossaman, Waters, Scott, Kreuger, and Riordan, "Study of Outer Continental Shelf Lands of the United States, " Public Land Law Commission, U.S. Department of Commerce/National Bureau of Standards, pp. 521-527, revised 1969; "The Role of Petroleum and Natural Gas From the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas, " U.S. Department of the Interior, Bureau of Land Management, Technical Bulletin No. 5, May, 1970; L.K. Weaver, H.F. Pierce, and C.J. Jirik, "Offshore Petroleum Studies: Composition of the Offshore U.S. Petroleum Industry and Estimated Costs of Producing Petroleum in the Gulf of Mexico, " U.S. Department of the Interior, Bureau of Mines, Information Circular 8557, Washington, D. C., 1972; "Rates of Return on the OCS," U.S. Department of the Interior, Office of the OCS Program Coordination, May 7, 1975; Jessee W. Markham, "The Competitive Effects of Joint Bidding by Oil Companies for Offshore Lease Sales, " op. cit.; and E.W. Erickson and R.M. Spann, "An Analysis of the Competitive Effects of Joint Ventures in the Bidding for Tracts in OCS Offshore Lease Sales, " in hearings before the Special Subcommittee on Integrated Oil Operations of the Senate Committee on Integrated Oil Operations of the Senate Committee on the Interior and Insular Affairs, *Market Performance and Competition in the petroleum Industry,* Washington, D.C., pp. 1691-1745, 1974. The best interpretation of these studies is that there is a substantial body of evidence which unanimously supports the conclusion that in oftshore activity 011 companies have not, in general, earned rates of return in excess of the competitive normal level,

Figure 11. Comparison of Gas Production from Brown Shale Wells and a Typical Offshore Gas Well



Source. OCS production rates developed by Exxon, USA for the Federal Power Commission's Natural Gas Survey. Rates for Brown shale production from over 200 wells in Kentucky and West Virginia (Columbia Gas Company, Ray Resources Corp, and Consolidated Gas Co).

natural gas well is compared with those of two typical Brown shale wells. In the first 15 years of production, only 38 to 54 percent of total recoverable shale gas reserves are produced, but about 85 percent of the reserves in the offshore reservoir are produced. Production which is weighted toward the later years in the production profile has a weaker positive effect upon the ATNPV of the prospect. This production profile, together with the relatively small volume of reserves per unit of investment cost, has been the principal reason that, until recently, Brown shale gas production has been economically submarginal.

Cost and Technological Characteristics of Brown Shale Production in Three Localities

Production data have been obtained from three gas-productive locations in the Appalachian Basin, These localities, in descending order of general investment attractiveness, are Cottageville, W.Va. (high quality); Clendenin, W.Va. (medium quality); and Perry County, Ky. (lower quality). The quality designations reflect geologic and economic characteristics of each region and are not intended to reflect any differences in the actual Btu content of the natural gas in the fields. The 15-year production profiles are given in table 4. In the high-quality area, production data were available only from shot wells. These figures are the averages of actual production data for 13 wells in this field for the 15-year period.

In the medium-quality shale, data were available for both shot and hydrofractured wells, but only for 5 years. The rest of the profiles were extrapolated using production decline curves for Brown shale wells developed for the region.[14]

[14]Bagnall and Ryan, "The Geology, Reserves and Production Characteristics of the Devonian Shale in Southwestern West Virginia," figure 11, *Devonian Shale-Production and Potential,* ERDA, 1976.

Table 4
Production Statistics of Natural Gas From Brown Shale in Three Localities

(Mcf Per Year)

Locales:	High Quality	Medium Quality		Lower Quality			
				Good		Bad	
Stimulation:	Shot	Frac *	Shot	Frac	Shot	Frac	Shot
Year							
1	36,318	17,989	17,858	21,250	18,750	11,400	6,800
2	29,490	20,227	16,053	20,850	15,880	10,900	5,000
3	23,883	17,978	12,342	20,600	13,600	9,200	5,600
4	20,071	18,570	11,001	17,700	11,480	9,600	5,100
5	17,439	17,000	10,000	18,350	1-1,170	8,300	5,400
6	15,980	16,000	9,000	17,290	11,080	7,500	5,300
7	14,879	15,000	8,200	17,000	10,000	6,900	5,000
8	13,464	14,500	7,500	16,300	9,300	6,300	4,950
9	12,772	13,800	7,000	15,600	8,700	5,800	4,900
10	12,498	13,500	6,500	15,000	8,200	5,050	4,800
11	11,661	12,700	6,100	14,500	7,800	4,750	4,700
12	11,304	12,200	5,800	13,800	7,500	4,500	4,600
13	11,131	11,700	5,500	13,300	7,200	4,250	4,550
14	10,842	11,300	5,200	12,800	7,000	4,050	4,450
15	9,766	10,800	5,000	12,300	6,800	3,850	4,400

Source: Production and cost data on Brown shale operations are averages from over 200 wells in Kentucky and West Virginia (Columbia Gas Co., Ray Resources Corp., and Consolidated Gas).

*Hydrofracturing is commonly referred to as "frac " which will be used as an abbreviation in tables in this report, Because of great, variability in the production from the wells in the lower-quality location, the wells were separated into two groups-good and bad-based solely on their production rates. Shot and hydrofractured wells fell into both groups. Fifty-nine percent of the wells in this locality fell into the good group, while the remaining *41* percent were in the bad group. One might be misled by looking only at the good groups in this locality for comparison with the high- and medium-quality locality, because one assumes a risk of having a bad well in this locality 41 percent of the time. So, while one can get a good well from the lower-quality locality, the investment potential on average is less attractive than in the other localities.

In judging the investment potential of the localities, there is concern regarding the costs associated with the production: the initial costs for drilling and stimulating the wells, the annual operating costs, and the indirect cost from the risk of drilling a "dry hole. " Table 5 shows the average of the direct initial costs for drilling and stimulating wells in the localities. The differences in drilling costs reflect differences in depth of the wells in the various portions of the Appalachian Basin and in the drilling costs per foot, which are a function of the geologic and topographic characteristics of the localities. Detailed cost figures are presented in tables 13 through 17 at the end of this chapter.

Table 5
Direct investment Costs for Producing Wells in Brown Shale

(Dollars in thousands, 1976 constant)

Locality	Stimulation Technique	Average Cost: Intan-gible	Average Cost: Tan-gible	Total
High Quality	Shot	$80.5	$23.9	$104.4
Medium Quality	Frac	121.7	38.7	160.4
	Shot	98.9	20.8	119.7
Lower Quality	Frac	115.9	40.0	155.9
	Shot	94.3	27.4	121.7

Drilling costs in the lower-quality locality were taken to be about $10 per foot, whereas they were about $9 per foot in the other localities. It is recognized that in some other areas these costs may be as low as $6.50 per foot, but these areas are readily accessible and have easily worked geologic formations. In light of the potential for technological advances in the drilling process, a low estimate is given in table 6, approximately reflecting a 10-percent reduction in actual drilling costs.[15] The effect of lower drilling costs or of cheaper stimulation techniques on the investment decision in the localities can be examined by comparing the reduction in average and low estimates with the ATNPV for the different scenarios as displayed in tables 8 through 11.

The effect of progress in drilling technology or of improvement in stimulation procedures, which reduces the initial investment cost per unit of reserves, will be to extend the economically feasible portion of the Devonian shale resource. A 10-percent decrease in real drilling costs, such as that assumed for purposes of example in table 6, would make some of the prospects in tables 8

[15] See, for example, Franklin M. Fisher, "Technological Change and the Drilling Cost-Depth Relationship, 1960 -66," in E.W. Erickson and L. Waverman, editors, *The Energy Question, Vol. 2, North* America, University of Toronto, 1974.

Table 6
Effect of Reduction in Initial Investment Cost

(Dollars in thousands, 1976 constant)

Locality	Stimulation Technique	Average Cost	Low Estimate	Change in ATNPV as a Result of Reduced Costs*
High Quality.	Shot	$104.4	$ 90.4	+$6.5
Medium Quality	Frac	158.4	137,4	+ 9,6
	Shot	119.7	102.6	+ 7.8
Lower Quality	Frac	155.9	144.3	+ 5.3
	Shot	120.5	110.8	+ 4.4

● The only change in tax effect considered is in the first-year writeoff of intangibles.

through 11, which have small negative ATNPV values, economically attractive.[16]

The average costs are separated into intangible and tangible items because of the impact of the different tax treatment as to expensing and capitalizing these costs. The intangible costs were set to include a management fee of about 15 percent and a contingency fee of 6 percent. While these figures may be high for some operators at some locations, they are typical of current charges and are representative of anticipated costs if an extensive effort to develop the Brown shale should occur.

The annual operating costs are set at $1,800 per well. While some operators may use a substantially cheaper well-tending service, this figure provides a cushion for expenses resulting from equipment repair.

An additional cost to be considered is that associated with the risk of a "dry hole. " This risk is difficult to assess because of the difficulty in determining which wells are in fact "dry holes." Of course, the clearest case is the hole which produces no natural gas at all. The problem arises when there is some gas but the flow is not sufficient to make the well profitable based on its own operations. The decision to continue the final casing of the well would be based on the additional cost of finishing the well rather than the amount already invested. However, it is complicated not only by the uncertainty of the price to be received for the gas but also by its usefulness to the investors as a tax shelter for other income. In addition, under syndication, not only do marginal tax rates vary among investors and operators, but which costs are sunk and which are incremental may be different to investors and operators. Hence, wells which would be economically unattractive on a total basis may be brought into production for personal financial reasons of a key decisionmaker. This effect may also work in the opposite direction. Since it is almost impossible to determine the impact of these incentives on the number of "dry holes, " and some external incentives are likely to continue to affect the "produce or plug" decision, the number of dry holes is taken to be those which presently are not in actual production regardless of the basis for the decision.

As evident from table 7 there is great variability among the localities in the share of dry-hole costs for each producing well. This variability does not arise solely from the actual costs of a dry hole as shown in column 1, but rather in the ratio of number of dry holes to the number of producing wells in each locality. This

Ibsen-le of the wells with negative ATNPV values in tables 8-11 would nevertheless be producers because drilling costs are already committed and the returns on incremental out-of-pocket completion, stimulation and production costs are adequate to induce production. But these wells would not return 10 percent after taxes on total Investment.

Table 7
Effect of Dry Holes on the Cost of Producing Wells
(Dollars in thousands, 1976 constant)

Locality	Column 1 Cost of a Dry Hole	Column 2 Cost of Dry Hole-Net of Tax Writeoff*	Column 3 No. of Dry Holes	Column 4 No, of Producing Wells	Column 5 Share of After-Tax Dry-Hole Cost for Each Producing Well
High Quality.	$ 86.9	$34.7	15	72	$7.2
Medium Quality					
Frac	97.9	29.6	1	27	1.5
Shot.	96.1	38.4	1	150	0.3
Lower Quality	101.1	40.4	49	241	8.2

● This calculation is based on a 48 percent marginal Federal tax rate and a 12 percent average State tax rate. It also is based on the assumption that the taxpayer has at least this much income which would otherwise be taxable at these rates. To the extent the taxpayer is not at the marginal Federal and State tax rates, the average State tax rate is less than 12 percent, or the taxpayer does not have income which would otherwise be taxable, the after-tax cost of dry holes increases heterogeneity probably arises not just from geologic differences but also from the operators' aggressiveness in drilling to the boundaries of the resource pool. The values of table 7 are included as negative components of the ATNPV calculations reported in tables 8 through 11.

Analytical Results for After-Tax Net-Present Values Under Alternative Price and Tax Assumptions

The basic analytical results are presented in tables 8 through 11. In each table, the four alternative price assumptions are the column headings. The resource quality examples are the row headings. For the medium-quality resource base example, two alternative stimulation techniques are displayed. For the lower-quality resource base example, two stimulation techniques and two internal quality distinctions are displayed. Each table refers to a specific tax case:

- Table 8; depletion allowance = zero, investment tax credit = zero,
- Table 9; depletion allowance = 22 percent, investment tax credit = zero,
- Table 10; depletion allowance = zero, investment tax credit = 10 percent,
- Table 11; depletion allowance = 22 percent, investment tax credit = 10 percent.

The entries in the bodies of the tables are the after-tax net-present values (ATNPV; in thousands of dollars) based on the actual investment and operating costs and production profiles in the three localities under the assumed price and tax conditions and at a 10-percent discount factor. if the entry is positive, the investment has an internal rate of return in excess of 10 percent. If the entry is negative, the investment has an internal rate of return of less than 10 percent.

For example, in table 8 (depletion and investment tax credit both equal to zero), only the high-quality resource has a calculated ATNPV per well which is positive at an assumed price of $1.42 per Mcf. All the other situations have per-well ATNPVs which are negative. This may appear anomalous because the actual localities upon which these illustrative ATNPV calculations are based are all being developed. " This continuing development is presumably based on private business decisions involving expectations of positive after-tax net present values. The fact that

[17]It will be recalled that the high-quality case is based on operating experience in the Cottageville, W. Va., area; the medium-quality case on Clendenin, W. Va.; and the lower-quality case on Perry County, Ky.

Table 8
After-Tax Net-Present Value of Brown Shale Natural Gas Wells in Three Locations-Case A*

(Dollars in Thousands, 1976 constant)

Location	Stimulation	Wellhead Price per Mcf			
		$1.42	$2.00	'$2.50	$3.00
High Quality	Shot	+21	+57	+84	+114
Medium Quality	Frac	−16	+10	+33	+56
	Shot	−19	−1	+13	+28
Lower Quality					
Good	Frac	−16	+13	+38	+63
Good	Shot	−22	−3	+13	+28
Bad	Frac	−55	−42	−31	−20
Bad	Shot	−48	−40	−32	−25

"Assumptions:
Depletion Allowance 0
Investment Tax Credit 0

Table 9
After-Tax Net-Present Value of Brown Shale Natural Gas Wells in Three Locations-Case B*

(Dollars in Thousands, 1976 constant)

Location	Stimulation	Wellhead Price per Mcf			
		$1.42	$2.00	$2.50	$.3.00
High Quality	Shot	+43	+86	+123	+160
Medium Quality	Frac	+1	+34	+63	+91
	Shot	–8	+14	+33	+51
Lower Quality					
Good	Frac	+2	+39	+70	+102
Good	Shot	–lo	+14	+35	+52
Bad	Frac	–50	–31	–17	–3
Bad	Shot	–45	–33	–23	–13

● **Asumptlons:**

Depletion Allowance	**220/0**
Investment Tax Credit	0

Table 10
After-Tax Net-Present Value of Brown Shale Natural Gas Wells in Three Locations-Case C*

(Dollars in Thousands, 1976 constant)

Locations	Stimulation	Wellhead Price per Mcf			
		$1.42	$2.00	$2.50	$3.00
High Quality . . . .“.	Shot	+23 “	+57	+86	+116
Medium Quality	Frac	–13	+13	+36	+59
	Shot	–17	0	+15	+30
Lower Quality					
Good.	Frac	–13	+16	+41	+66
Good	Shot	–20	– 1	+15	+32
Bad ., ...	Frac	–52	–39	–28	–17
Bad , ...	Shot	–46	–38	–30	–23

“Assumption:

Depletion Allowance	0
Investment Tax Credit	**10“/0**

Table 11
After-Tax Net-Present Value of Brown Shale Natural Gas' Wells in Three Locations-Case D*

(Dollars in Thousands, *1976* constant)

Location	Stimulation	Wellhead Price per Mcf $1 .42	$2.00	$2.50	$3.00
High Quality	Shot	+45	+37	+125	+162
Medium Quality	Frac	+4	+37	+66	+94
	Shot	–6	+16	+34	+53
Lower Quality					
Good	Frac	+6	+42	+74	+105
Good	Shot	–8	+16	+37	+58
Bad	Frac	–46	–28	–13	+1
Bad	Shot	–43	–31	–21	–11

● **Assumption:**

Depletion Allowance **220/0**
Investment Tax Credit **10"/0**

the lower-limit base case has negative ATNPVS for most situations is attributable to a number of factors:

- there is no Btu adjustment in the assumed prices;
- some of the gas is sold in intrastate markets at higher prices;
- the assumed tax treatment is more severe than that actually experienced by many operators;
- the assumptions concerning investment and operating costs and well lives were generally slightly tilted in the direction of adverse results; and
- the poorer situations in the lower-quality resource area are legitimate losers. " "

The lower-limit base case for $1.42 per Mcf in table 8 reflects the conservative nature of the assumptions on which the ATNPV calculations are based in all the price and tax cases analyzed.

The particular ATNPV figures reported in tables 8 through 11 are all of interest,[18] but what is of special interest is the general pattern of results. As the wellhead price of gas increases from $1.42 per Mcf to $2.00 per Mcf, it becomes economically feasible to produce shale gas from some of the medium- and lower-quality sites of the gas-productive area. The price change of $1.42 per Mcf to $2.00 per Mcf appears to have a greater effect on making shale locations economically feasible than does the change from $2.00 to $2.50 per Mcf, or a change from $2.50 to $3.00 per Mcf.

For example, in table 8, under the most severe tax assumptions, at an assumed price of $2.00 per Mcf, the pattern of ATNPV results is such that the high-quality resource area is a prime candidate for development, the medium-quality resource area is marginally attractive, and the best situation in the lower-quality resource area is economically rewarding. At $2.50 per Mcf, both situations in the medium-quality area become economically attractive and the good locations in the lower-quality area have a positive ATNPV. Because the areal extent of each of these gas-productive quality areas is not known, the actual impact on potential production cannot be determined.

It is instructive to compare table 8 with table 11. Table 8 is the most severe tax case examined. Table 11 is the most liberal (in terms of the

[18]If economic incentives are such that there is substantial Devonian shale development under conditions of positive ATNPV per well, it can be expected that royalty payments, lease bonuses, and lease rentals will absorb the major portion of the difference between prospective expected wellhead prices and costs.

generosity with which income from gas production is treated) tax case examined. At $2.00 per Mcf, two additional situations achieve positive ATNPV values in table 11 which did not achieve positive ATNPV values in table 8. These are shot wells in the medium-quality resource area and shot wells in the good area in the lower-quality resource area. Note that the liberal tax treatment does not increase the area of potential gas production, but does make shot wells economically feasible in the medium- and lower-quality good areas. A well head price of $2.50 per Mcf does not increase the potentially productive area of the shale resource but it does increase the value of the wells and, like the $2.00 price, makes shot wells economically feasible. A wellhead price of $3.00 per Mcf under the most liberal tax treatment makes shale gas production from all three localities in the gas-productive area economically feasible.

A comparison of data in table 8 with that in table 9 shows that a 10-percent investment tax credit would have little positive impact on shale gas development. However, a comparison of data in table 8 with that in table 10 shows the positive impact of a 22-percent depletion allowance. At $1.42 per Mcf, in addition to increasing the value of wells in the high-quality locations, a 22-percent depletion allowance makes hydrofractured wells in the medium- and lower-quality good areas economically feasible. Basically, the 22-percent depletion allowance has about the same positive effect as a $.50 per Mcf increase in wellhead price.

Extent of the Economically Producible Area

As indicated in an earlier section, estimates of the natural gas in the Brown shale are subject to great variability. The question involves not only the total resource present but also the portion that can be economically produced. Until the Brown shale resource of the Appalachian Basin is more fully characterized, there will continue to be great uncertainty in any attempt to estimate the extent of the Appalachian Basin which might sustain commercial development of shale gas production.

The ATNPV analyses indicate that under many of the price and tax scenarios, drilling for and producing shale gas from localities in the known shale gas productive area is economically feasible. However, it is unrealistic to assume that the current gas-productive area is representative of the whole Appalachian Basin. A number of general observations about resource deposits are relevant. First, the distribution of resource deposits in nature tend to be highly skewed, i.e., there are fewer very high-quality resource deposits than medium-quality deposits, and fewer medium-quality deposits than low-quality deposits.[19,20] Second, the better-quality resources tend to be developed first.[21] There being no strong evidence to the contrary, OTA assumes that these principles apply to gas-bearing shales of the Appalachian Basin.

In a marginal resource base such as the Brown shale, the definition of "better-quality resource" includes, as a determinant, location relative to existing production and pipelines. Until recently, the Brown shale have not been a primary target of drilling except in the Big Sandy area. The current areas of shale development were initially

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[19] J. W. McKie, "Market Structure and Uncertainty in Oil and Gas Exploration, " Quarterly *Journal of Economics,* Vol. 74, pp. 543-571, November, 1960.

[20] G. Kaufman, "Statistical Decision and Related Techniques in Oil and Gas Exploration, ' Prentice Hall, Englewood Cliffs, N. J., 1973, and J. Aitchison and J.A. C. Brown, "The Lognormal Distribution, " Cambridge University Press, New York, N. Y., 1957.

[21] G. Kaufman, Y. Bulcer, and D. Kryt. "A Probabilistic Model of Oil and Gas Discovery, " *Studies in Geology,* Vol. *1,* American Association of Petroleum Geologists, *Tulsa,* Okla, pp. 113-142, 1975.

byproducts of other activity. While it might appear that this fact would blunt the operation of the principle that the better prospects are drilled first, this is not the case. Even if the initial knowledge of Brown shale prospects was developed as a byproduct of other activity, the better Brown shale prospects (byproducts or not) are developed first. "Better" here, however, involves a strong element of location relative to existing pipelines. This is particularly true for historical wellhead price levels. Evidence of this is that much of the Brown shale production in West Virginia is served by existing interstate pipelines.

All of this suggests that there may be other areas which are geologically as promising as the three localities examined here. These other areas, although more remote relative to existing pipelines, may become economically feasible at the $2.00 to $3.00 per Mcf price levels examined in the sensitivity analysis reported herein.

There might be a temptation to extrapolate the production results from the three sample locations in the currently productive, area directly to the entire Appalachian Basin. Results of such an extrapolation are not likely to be valid primarily because:

- the existing wells are not located randomly in the Appalachian Basin, but rather are clustered in a known producing area;
- the gas-productive area sampled (98.6 square miles) is less than 0.06 percent of the 163,000-square-mile Appalachian Basin;
- the 490 sample wells are but a very small (5 percent) portion of the 10,000 producing wells in the Appalachian Basin, and do not represent a random sample; and
- average production data from producing wells are biased because dry holes and plugged and abandoned wells are not included in the "average production. "

OTA assumed that the production potential in the currently producing area is much higher than is characteristic of the Appalachian Basin as a whole.

Based on the following information, OTA estimates that about 10 percent of the 163,000-square-mile extent of the Appalachian Basin might be of high enough quality to produce shale gas economically at a price of $2.00 to $3.00 per Mcf.

1. *Production History.*—The wells which have a potential of producing more than 240 to 300 Mcf of shale gas over a 15- to 20-year period tend to be clustered in a few locations in the Appalachian Basin. This type of distribution of commercially productive wells indicates that not all of the Appalachian Basin is composed of the same resource quality. No doubt additional locations exist which have commercial potential, but it is unlikely that these areas will comprise a significant portion of the 163,000-square-mile extent of the Appalachian Basin.

2. *Shale Depth.*—The Brown shale outcrops at the surface in central Ohio and is 12,000 feet below the surface in northeastern Pennsylvania. Because drilling and stimulation costs increase with depth, commercial production of shale gas in the volumes encountered in the best wells to date is generally limited to depths less than 5,000 feet. A considerable extent of the Brown shale of the Appalachian Basin is deeper than 5,000 feet and is therefore unlikely to sustain commercial shale gas production under the economic conditions and technology considered in this assessment.

3. *Shale Thickness.*—The total thickness of the gas-productive Brown shale sequence in the Devonian rocks varies from less than 100 feet to more than 1,000 feet across the Appalachian Basin (figure 3). It is not generally economical to stimulate Brown shale layers which are less than 100 feet in thickness unless multiple layers in one well can be treated. The Brown shale resource in a significant portion of the Appalachian Basin consists of thin layers of Brown shale which may not be amenable to modern hydrofracture techniques.

4 *Fractures.—The* fracture system (number, length, openness, and direction of fractures or joints) in the Brown shale is not uniform across the Appalachian Basin. The much-fractured areas of the Brown shale tend to be more gas-productive than the less-fractured areas. Extensive areas of the Appalachian Basin have limited fracture systems and therefore are potentially poorer areas for shale gas production even with modern stimulation techniques than the much-fractured areas.

5 *Drilling* Experience. -Drilling and production records of independent operators in the Appalachian Basin have reflected vast areas where shale gas production is uneconomic unless new stimulation techniques can more than double shale gas production rates without significant increases in cost. Poor shale gas production experience over extensive areas probably is a result of a combination of the circumstances outlined above.

An Estimate of Readily Recoverable Reserves

The Appalachian Basin has an areal extent of about 163,000 square miles. If 10 percent of this area is of high enough quality to be economically attractive for shale gas production at prices of $2.00 to $3.00 per Mcf, it provides a potential production area of 16,300 square miles. (The present gas-productive area is less than 5 percent of the 163,000-square-mile area.) With a spacing of 150 acres per well, this area would support approximately 69,000 wells. Production data presented in table 4 show that wells economically feasible at **$2.00** per Mcf will produce approximately 240 million cubic feet of shale gas per well over a 15-year period, and about 290 million cubic feet per well over 20 years.[22] Readily recoverable reserves were determined by multiplying the number of potential wells by the average production per well as follows:

15-year *readily recoverable reserve*
69,000 wells x 240 MMcf/well = 16.6 Tcf

20-year readily recoverable reserve
69,000 wells x 290 MMcf/well = 20.0 Tcf

If the entire undeveloped gas-productive area were a medium-quality resource and all wells were shot treated, the 15-year readily recoverable reserve would be 9 Tcf; use of hydrofracturing rather than shot treatment would increase this figure to 15 Tcf. The 20-year readily recoverable reserves would approximate 11 and 19 Tcf, respectively. If 10 percent of the 163,000-square-mile (1 6,300 square miles) gas-productive area were all high-quality resource and all wells were shot treated, the readily recoverable reserve would be about 17 Tcf over a 15-year period and about 20 Tcf over a 20-year period. Assuming that hydrofracturing results in a 50-percent increase in shale gas production (as is suggested by production data in table 4), 69,000 hydrofractured wells on high-quality Brown shale sites might produce 26 Tcf of gas over a 15-year period, and approximately 30 Tcf over a 20-year period.

It is highly unlikely that all of the undeveloped gas-productive Brown shale resource will be high quality, and also unlikely that all of it will be medium or low quality. For this reason, a 15 to 25 Tct estimate of readily recoverable shale gas reserves appears justified until the Brown shale resource base is more thoroughly characterized. This range clearly indicates that the Brown shale do in fact have a potential for making a significant contribution to the U.S. natural gas supply.

Because of the great uncertainty in the quality distribution of the shale resource, no attempt was made to undertake price elasticity studies in this assessment. The impact of a specific price change on shale gas production will be impossible to assess accurately until extensive resource characterization studies are completed, This will require a large amount of drilling throughout the region.

[22]In a similar analysis for a smaller producing area, ultimate recoverable reserves were used at levels of 300, 350, and 400 MMcf per well, P. J. Brown, "Energy From Shale—A Little Used Natural Resource. " Natural Gas *From Unconventional Geologic Sources,* National Academy of Sciences, J 976.

Some estimates of the total amount of gas-in-place in the Brown shale range in the hundreds of Tcf.[23] However, such estimates of the resource base should be distinguished from estimates of readily recoverable reserves, which represent the fraction of the total resource whose recovery is feasible under reasonable assumptions about costs, taxes, and geologic formations. OTA's 15 to 25 Tcf estimate of readily recoverable reserves is consistent with a total resource estimate of hundreds of Tcf because of the fact that under present technology the average shale well recovers only 3 to 8 percent of the calculated gas in place.[24]

General Observations and Findings

it appears that under plausible economic, geologic, and technological assumptions, the Brown shale of the Appalachian Basin contain as much as 15 to 25 Tcf of readily[25] recoverable natural gas. This reserve would be producible **in the first 15 to 20 years of the production profile of typical reservoirs. Because one of the characteristics of Brown shale gas production is a slow flow rate over a very long period of time, ultimate recoverable reserves** over the life of production would be greater. This 15 to 25 Tcf estimate critically depends on the price and cost assumptions used, the total extent of the Brown shale resource, and the distributions of resource quality.

The price assumptions ($2.00 to $3.00 per Mcf) realistically reflect the current opportunity value of additions to the U.S. natural gas supply and are consistent with general market conditions for both interstate and intrastate sales. Estimates of drilling, well completion, stimulation, and production costs are based on actual operating experience.

The estimate of 15 to 25 Tcf of readily recoverable reserves is based on the assumption that about 10 percent of the 163,000-square-mile Appalachian Basin has Brown shale of high enough quality to permit the production of shale gas economically at prices of $2.00 to $3.00 per Mcf.

From table 12 one sees the important role that the Brown shale could play in national natural gas supply, If annual production were at 1.0 Tcf,[26] the region would match some of the larger gas-producing States and make up almost 5 percent of current national production.

Table 12
Estimated Gross Production of Natural Gas of the five Largest Producing States, 1976

State	Gross Production (Tcf/annum)
Texas	7.7
Louisiana	7.1
Oklahoma	1.8
New Mexico	1.2
Kansas	0.8
Total U.S.	20.9

Source: Gas *Facts* 1976, American Gas Association (1977), p. 24.

The estimates presented in this report are based on the analysis of 490 producing wells in three gas-productive localities. These 490 wells were drilled by a large number of operators with different financial situations and technical capabilities. There are some data available from a smaller number of wells drilled by a single operator.[27] If these single-operator data are, in fact, representative of the potential of the Brown shale of the Appalachian Plateaus, this resource might

[23] *Natural Gas From Unconventional Geologic Sources,* p. *113,* National Academy of Sciences, 1976.

[24] Ibid., p. 86.

[25] "Readily recoverable reserves" is not a category in either the American Gas Association or United States Geological Survey nomenclature. In the present context, "readily recoverable reserves" are resources which can be converted to proved reserves and actually produced in a 15- to 20-year time frame.

[26] The 1.0 Tcf is a central estimate based on the 15 to 25 Tcf range; therefore, one should keep in mind the variability associated with the point estimate.

[27] K.I. Brooks, R.M. Forrest, and W.I. Morse, 1974. "Gas Reserves in the Devoniain Shale in the Appalachian Basin the Operating Territory of the Columbia Gas System. " (Mimeographed Report in the files of Columbia Gas System Service Corporation, Columbus, Ohio.)

account for more than 1.0 Tcf per year of additional U.S. supply in the next 20 years. This larger production could result from either or both (1) greater average productivity per well, or (2) a larger resource base which would permit a greater number of wells of average productivity. However, even under an optimal combination of circumstances (1 5-percent higher average production per well and a 50-percent increase in the areal extent of the quality shale resource), only about 30 to 35 Tcf of readily recoverable reserves would be producible over 15 to 20 years. For the reasons cited previously, however, OTA considers such an optimal combination to be unlikely.

The 1.0 Tcf figure is a judgmental estimate based on the facts that: (1) much potential shale gas production is likely to spread over a wide area without immediate access to pipeline connections, and (2) a large amount of drilling is required to generate is to 25 Tcf of readily recoverable reserves.

Based on production data from the three localities analyzed, creation of 15 to 25 Tcf of readily recoverable reserves will require drilling 69,000 wells. In 1975, 38,498 wells were drilled in the United States.[28] If drilling 69,000 wells with the Appalachian Basin Brown shale as the target pay zone were spread over 20 years, this number of new wells would average 3,450 wells per year. This drilling alone would represent a 9-percent increase in drilling activity over the total U.S. 1976 **level.** The U.S. drilling industry has shown considerable ability to respond to increased economic incentives. Between 1971 and 1975, total wells drilled increased by 45 percent (9 percent per year), from 26,532 to 38,498. Between 197l and 1975, total rotary-drilling rigs in operation increased by 70 percent (15 percent per year), from 976 to 1,660. Because Brown shale production is relatively well-intensive, and because it is likely to be scattered over extensive areas, it is prudent to assume that shale gas development will proceed at a gradual pace, possibly spreading the required drilling effort over 15 to 20 years.

The fact that potential shale gas production is likely to be scattered over extensive areas contributes to a relatively slow pace of development because of the requirement that natural gas be shipped by pipelines. This suggests that the economically feasible expansion of the gas-pipeline network required to serve new shale development and production will be on an incremental basis. This in turn suggests that location relative to potential pipeline connections (in addition to geologic promise) will continue to bean important determinant of the economic quality of shale drilling prospects. As a result, gradual development is a prudent assumption.

The magnitude of the required drilling effort does, however, have an important aspect. The drilling of 3,450 wells per year in the Appalachian Basin would be a significant addition to total U.S. drilling activity. There has been an impressive record of technological progress in the U.S. drilling industry.[29] This progress has been associated with deeper target horizons in the gulf coast and the Southwest. It is possible that a drilling effort of the magnitude required to develop Brown shale gas resources would sufficiently focus the attention of the drilling industry so that substantial technological progress in reducing shale drilling costs and improved deliverability would result. A comparison of table 6 with tables 8 through 11 indicates the potential of such progress to extend the margin of economic feasibility for Brown shale development. The possibility of improved drilling and completion technology is not included in the 15 to 25 Tcf estimate.

The comparison of table 6 with tables 8 through 11 is relevant to any technological advance which improves the ratio of productive capacity to investment cost, All Brown shale gas production is artificially stimulated through either hydrofracturing or shooting.[30] An improvement in stimulation technology would have an effect similar to that of an improvement in drilling technology. The possibility of an improvement in stimulation technology is not included in the 15 to 25 Tcf estimate.

[28] Drilling statisties are from the *Oil and Gas Journal*, Review and Forecast Issues, 1972 and 1976, pp. 91 and 114.

[29] See F.M. Fisher, op cit.

[30] It is noteworthy that hydrofracturing itself was developed in response to the post World War II Increase in U.S. crude oil prices,

If improvements in drilling or stimulation technology are developed by drilling or well-service contractors who can patent the techniques, it is possible that the socially optimal amount of effort to develop such technology will be forthcoming. But it is likely that much drilling, well stimulation, and production will be done by operators who do not have a very large share of total shale production. In addition, many technical improvements may not be readily patentable. Under these circumstances, the Congress may wish to consider the desirability of some publicly supported research and development activity directed toward improvements in shale drilling and stimulation technology.

The possible effect of either (1) dramatically improved technology, or (2) improvements in economic incentives beyond those examined here, must be considered with caution. This is because of the likelihood that the development effort which such possibilities would encourage would be working against an increasingly marginal resource base. If economic incentives were to be twice as good as those associated with current tax treatment and wellhead prices of $2.00 to $3.00 per Mcf; or, alternatively, if drilling and stimulation technology were to improve so that these operations cost only half as much as they do now, it is unlikely that twice as great a quantity of reserves would become economically feasible. This is because the additional development efforts which such economic or technological improvements would induce would be pressing further and further into the margin of poorer and poorer sites and geologic prospects. In addition, because poorer resource quality in the Brown shale is very much associated with slower flow rates per unit of ultimately recoverable reserves, the contribution to yearly output would be apt to increase relatively less than the increase in reserves. For example, on a purely illustrative basis, if a doubling of economic incentives or technical productivity were to result in a 50-percent increase in ultimate recovery, average output in the first 20 years might increase by only 25 percent.

The 15 to 25 Tcf of readily recoverable reserves and approximately 1.0 Tcf of yearly production reported here are based on the following assumptions:

- no significant changes in real drilling, well stimulation, or production costs;
- the economic and production characteristics of the three localities analyzed represent the more promising sources of natural gas from the Brown shale;
- wellhead prices for natural gas in the $2.00 to $3.00 per Mcf range;
- continuation of current tax treatment of income from natural gas production; and
- approximately 10 percent of total now undeveloped Appalachian Basin Brown shale resource is of high enough quality to permit commercial development.

It is a well-known axiom that there is no sure proof of gas or oil production potential other than the drillbit. It is possible that all of the undrilled resource potential of the Devonian shale has economic and production characteristics similar to those of the bad situations in the lower-quality resource area. In this case, there would be no incremental Brown shale gas production which would be economically feasible, at wellhead prices in the range of $2.00 to $2.50 per Mcf. This appears unlikely, given the geographic dispersion of Brown shale resources. There appears to be no practical way short of creating the economic incentives necessary to induce an extensive drilling effort, to ascertain whether the Appalachian Basin shale might actually contribute more, or less, than 5 percent of the total U.S. natural gas supply.

Table 13
Typical Well Costs (1976 Constant Dollars)
High-Quality Brown Shale Well

Cottageville Area, Jackson County, W.Va.

Total Depth-4,300 feet
Completion Method-Shooting 450 feet of Gross Pay Section

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 300	$ 300
Stake location	300	300
Drilling permit & bond	350	350
Other legal expenses	200	200
Right-of-way expenses	100	—
Road & location costs	2,000	2,000
Hauling (all except cement)	3,500	3,500
Well logs (open hole)	3,000	3,000
Centralizers & float equipment	1,800	1,800
Cementing surface & conductor	3,500	3,500
Shooting 450 feet	5,000	—
Geologic & engineering service	2,800	1,400
Drilling 4,200 feet @ $8/ft	34,400	34,400
Rig charges	2,600	—
Install 2,000 feet flow line	1,730	—
Reclaim road & location	2,000	2,000
Subtotal	63,580	52,750
Contingency (6% of intangibles)	3,815	3,165
Management overhead (1 50/0 total well costs excluding contingency)	13,115	10,917
Total Intangibles	80,510	66,832
Tangible Costs:		
Conductor casing:		
30 feet of 13"@$l4.45/ft	430	430
500 feet of 9-5/8 ''@$9 .36/ft	4,700	4,700
2,500 feet of 7"@$5.96/ft.	14,900	14,900
Christmas tree	1,000	—
Valves & fittings	1,000	—
2,000' of 2-3/8" flow line @$.91/ft.	1,820	—
Total Tangibles	23,850	20,030
Total Well Costs	$104,360	186,862

Table 14
Typical Well Costs (1976 Constant Dollars)
Medium-Quality Brown Shale Well

Blue Creek Area, Kanawha Co., W.Va.

Total Depth-500 feet
Completion Method-Hydrofracture (1,000 bbl)

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 300	300
Stake location	350	350
Well permit & bond	350	350
Other legal expenses	200	200
Right-of-way expenses	100	—
Road & location costs	4,000	4,000
Hauling (all except cement & 4-1/2" casing)	3,500	3,500
Hauling 4-1 /2" casing & line	520	—
Well logs (open hole)	3,200	3,200
Centralizers & float equipment	1,800	1,800
Cementing conductor & surface	3,500	.3,500
Cementing 4-1 /2" casing	3,300	—
Hydrofrac-1,000 bbl, 60,000# sd, 75,000 cu. ft. nitrogen	9,020,	—
Perforate & CBL log	2,000	—
Tool and equipment rental	500	—
Frac tank rental (5 x 250-bbl@$l50/tank)	750	—
Pump or haul water @ 40/bbl x 1,000	400	—
Completion rig 140 hrs@ $55/hr	7,700	—
Geologic & engineering service	3,000	500
Drilling 5,000 feet @ $9/ft	45,000	45,000
Rig charges	2,600	—
Install 2,000 feet flow line	1,730	—
Reclaim road & location	2,000	2,000
Subtotal	95,820	64,700
Contingency (6°/0 of intangibles)	5,749	3,882
Management overhead (1 50/0 of total well costs excluding contingencies)	20,176	12,260
Total Intangibles	121,745	80,842
Tangible Costs:		
Conductor casing:		
30 feet of 13" @ $14.45/ft,	430	430
500 feet of 9-5/8" @ $9.36/ft	4,700	4,700
2,000 feet of 7" @ $5.96/ft	11,900	11,900
Production casing: 5000 feet of 4-1 /2" @ $3.12/ft	15,600	—
Christmas tree	1,000	—
Valves & fittings	1,000	—
2,000 feet of 2-3/8" flow line @$.91/'ft	1,820	—
Separator & tank	2,000	—
Valves & fittings, drips	235	—
Total Tangibles	38,685	17,030
Total Line & Well Costs	$160,430	97,872

Table15
Typical Well Costs (1976 Constant Dollars) Medium-Quality Brown Shale Well

Blue Creek Area, Kanawha Co., W.Va.

Total Depth-5,000 feet
Completion Method-Shooting 1,000 feet of Gross Pay Section

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 300	$ 300
Stake location	350	350
Drilling permit & bond	350	350
Other legal expenses	200	200
Right-of-way expenses	100	—
Road & location costs	4,000	4,000
Hauling (all except cement)	3,500	3,500
Well logs (open hole)	1,500	1,500
Centralizers & float equipment	1,000	1,000
Cementing conductor & surface	3,500	3,500
Shooting 1,000 feet	10,000	—
Geologic & engineering service	3,000	1,500
Drilling 5,000 feet @$9/ft.	45,000	45,000
Rig charges	2,600	—
Install 2,000 feet of flow line	1,730	—
Reclaim road & location	2,000	2,000
Subtotal	79,150	63,200
Contingency (6°/0 of intangibles)	4,749	3,792
Management overhead (1 5°/0 of total well costs excluding contingency)	15,000	12,034
Total Intangibles	98.899	79.026
Tangibla Costs:		
Conductor casing:		
30 feet of 13" @ $14.45/ft.	430	430
500 feet of 9-5/8 ''@$9 .36/ft.	4,700	4,700
2,000 feet of 7"@$5.96/ft.	11,900	11,900
Christmas tree	1,000	—
Valves & fittings	1,000	—
2,000 feet of 2-3/8" flow line @ $.91/ft	1,820	—
Total Tangibles	20,850	17.030
Total Well & Line Costs	$119,749	$96,056

Table 16
Typical Well Costs (1976 Constant Dollars) Lower-Quality Brown Shale Well

Hazard Area, Perry County, Eastern Kentucky

Total Depth-3,900 feet
Completion Method-Hydrofracture (1,000 bbl)

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 400	$ 400
Stake location	350	350
Well permit & bond	350	350
Other legal expenses	300	300
Right-of -way	100	—
Road & location costs	5,500	5,500
Hauling (except 4-1 /2" cement)	3,500	3,500
Hauling 4-1 /2" & line pipe	500	—
Well logs (open hole)	3,000	3,000
Centralizers & float equipment	1,800	1,800
Cementing conductor & surface	3,500	3,500
Cementing 4-1 /2" casing	3,000	—
Hydrofrac-1,000 bbl, 60,000# sd, 75,000 cu. ft. nitrogen	9,020	—
Perforate & CBL log	2,000	—
Tool and equipment rental	500	—
Pump or haul 1,000 bbl water	400	—
Frac tank rental (5 x 250-bbl@$150)	750	—
Completion rig 140 hrs @ $55/hr	7,700	—
Install 2,000 feet of flow line	1,730	—
Geologic & engineering service	2,800	1,400
Drilling 3,900 feet @$ 10/ft.	39,000	39,000
Rig charges	2,600	—
Reclaim road & location	2,000	2,000
Subtotal	90,800	61,100
Contingency (6°/0 of intangibles)	5,448	3,666
Management overhead (1 5°/0 of total well & line costs excluding contingencies)	19,621	12,705
Total Intangibles	115,869	77,471
Tangible Costs:		
Conductor casing:		
30 feet of 13"@$l4.45/ft	430	430
500 feet of 9-5/8 ''@$9 .36/ft.	4,700	4,700
3,100 feet of 7"@$5.96/ft.	18,476	18,476
Production casing: 3,900 feet of 4-1/2''@$3.l2/ft	12,168	—
Christmas tree	1,000	—
Valves & fittings, drips	1,235	—
Separator & tank	2,000	—
Total Tangibles	40,009	23,606
Total Well & Line Costs	$155,878	$101,077

Table 17
Typical Well Costs (1976 Constant Dollars)
Lower-Quality Brown Shale Well

Hazard Area, Perry County, Eastern Kentucky

Total Depth-3,900 feet
Completion Method-Shooting 450 feet of Gross Pay Section

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 400	$ 400
Well permit & bond	350	350
Stake location	350	350
Other legal expenses	300	300
Right-of-way	100	—
Road & location costs	5,500	5,500
Hauling (except 4-1/2" casing & cement)	3,500	3,500
Well logs (open hole)	3,000	3,000
Centralizers & float equipment	1,800	1,800
Cementing conductor & surface	3,500	3,500
Shooting 450 feet	5,000	—
install 2,000 feet of flow line	1,730	—
Geologic & engineering service	2,800	1,400
Drilling 3,900 feet @$10/ft.	39,000	39,000
Rig charges	5,200	—
Reclaim road & location	2,000	2,000
Subtotal	74,530	61,100
Contingency (6% of intangibles)	4,472	3,666
Management overhead (1 50/0 of total well & line costs excluding contingencies)	15,293	12,705
Total Intangibles	94,295	77.471
Tangible Costs:		
Conductor casing:		
30 feet of 13"@$l4.45/ft	430	430
500 feet of 9-5/8 ''@$9 .36/ft.	4,700	4,700
3,100 feet of 7"@$5.96/ft.	18,476	18,476
Christmas tree	1,000	—
Valves & fittings	1,000	—
2,000 feet of 2-3/8" flow line @$.91/ft	1,820	—
Total Tangibles	27,426	23,606
Total Well & Line Costs	$121,721	$101,077