RELEASED

REPORT BY THE U.S.

General Accounting Office

Problems Identified In FERC's Incentive Pricing Program For Natural Gas From Tight Formations

Under the Natural Gas Policy Act of 1978, the Federal Energy Regulatory Commission established a program to provide an incentive price to producers of natural gas from tight geologic formations. A tight formation contains gas that generally seeps out slowly, under normal conditions. The incentive price--which is twice the price otherwise generally available--was designed to encourage producers to develop and produce natural gas from locations determined to present extraordinary risks or costs.

GAO found that in the states and geologic formations it reviewed (1) tight formations were not extraordinarily risky or costly to develop, (2) FERC's criteria for designating formations were difficult to apply, and (3) much of the program activity occurred outside high-potential areas. Further, GAO found that little program activity occurred in undeveloped tight formations identified by FERC as having the greatest potential for increasing gas reserves.

Because of the decontrol of certain natural gas prices as provided by the act and a related FERC ruling, the tight formation program will have limited application in the future. Therefore, GAO is not recommending any program changes.

127393

GAO/RCED-85-49
JUNE 13, 1985

532281

Request for copies of GAO reports should be sent to:

U.S. General Accounting Office
Document Handling and Information
Services Facility
P.O. Box 6015
Gaithersburg, Md. 20877

Telephone (202) 275-6241

The first five copies of individual reports are free of charge. Additional copies of bound audit reports are $3.25 each. Additional copies of unbound report (i.e., letter reports) and most other publications are $1.00 each. There will be a 25% discount on all orders for 100 or more copies mailed to a single address. Sales orders must be prepaid on a cash, check, or money order basis. Check should be made out to the "Superintendent of Documents".

UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

RESOURCES, COMMUNITY, AND ECONOMIC DEVELOPMENT DIVISION

B-216769

The Honorable Philip R. Sharp
Chairman, Subcommittee on Fossil and Synthetic Fuels
Committee on Energy and Commerce
House of Representatives

The Honorable Max Baucus
United States Senate

The Honorable Howard M. Metzenbaum
United States Senate

This report responds to your separate, but similar, requests for information on certain aspects of the Federal Energy Regulatory Commission's incentive pricing program for natural gas from tight formations.

As arranged with your offices, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from the date of the report. At that time, we will send copies of this report to the Chairman, Federal Energy Regulatory Commission; the Secretary of the Interior; the Commissioner of Internal Revenue; and other interested parties. We will also make copies available to others upon request.

J. Dexter Peach
Director

GENERAL ACCOUNTING OFFICE REPORT

PROBLEMS IDENTIFIED IN FERC'S INCENTIVE PRICING PROGRAM FOR NATURAL GAS FROM TIGHT FORMATIONS

DIGEST

The Natural Gas Policy Act of 1978 authorized the Federal Energy Regulatory Commission (FERC) to provide special incentives for the production of natural gas which presented extraordinary risks or costs. In August 1980 the Commission established an incentive price for natural gas from tight formations--geological formations from which gas generally seeps out slowly, under normal conditions--and criteria which formations must meet to qualify for the incentive price. The incentive price--in April 1985 about $5.96 per million British thermal units (a measure of heat content)--is generally twice the amount that a producer could otherwise charge for the gas. It is a ceiling price only, however, and a producer can charge that price only if the purchaser has agreed, by contract, to pay it.

Before a producer can charge an incentive price, two steps are required: (1) a jurisdictional agency recommends that a formation be designated as tight to the Commission, which approves or disapproves the recommendation, and (2) the jurisdictional agency determines whether individual wells are located within an approved formation. Jurisdictional agencies are generally state agencies for non-federal lands and the Department of the Interior for federal lands. (See pp. 2 to 4.)

From the beginning of the program through December 1984, the Commission received 234 tight formation recommendations. Of these, 195 were approved in whole or in part, 36 were awaiting Commission action, and 5 were withdrawn or returned to the jurisdictional agency for additional data (the figures include two recommendations, which were approved in part and were pending in part). The approved formations cover portions of 17 states. According to the Commission, natural gas produced from these approved formations accounts for up to 8 percent of domestic production. (See p. 4.)

GAO made this review in response to separate requests from the Chairman, Subcommittee on Fossil and Synthetic Fuels, House Committee on Energy and Commerce, and Senators Max Baucus and Howard M. Metzenbaum. As agreed with the requesters' offices, GAO addressed the following questions:

--Did the tight formations approved under the incentive pricing program prove to be extraordinarily risky and costly to develop, as had been assumed by the Commission?

--Were the jurisdictional agencies able to apply the Commission's qualifying criteria in recommending tight formations for incentive pricing?

--To what extent did the incentive price stimulate drilling activity in formations having the greatest potential for development? (See p. 7.)

To answer these questions, GAO obtained data on selected formations and states, as explained below. The number of formations and states was not the same for each question, due to data limitations and other factors. (See pp. 8 to 10.)

In summary GAO found that tight formations were not extraordinarily risky or costly to develop; that problems in interpreting available data, the lack of appropriate data, and other factors created problems for the jurisdictional agencies in applying the Commission's criteria; and that much of the program activity occurred outside high-potential areas. Also, relatively few of the qualifying wells were located in the areas identified by the Commission and others as having the greatest potential for development.

TIGHT FORMATIONS WERE NOT EXTRAORDINARILY RISKY OR COSTLY TO DEVELOP

In the rulemaking process leading to the establishment of the incentive pricing program, the Commission invited public comments on the risks, costs, and other aspects of producing and pricing natural gas from tight formations. The other aspects included the costs of other fuels and the expected rate of production from tight formation wells. The Commission acknowledged in the rulemaking that an acceptable measure of risk had not been developed during the rulemaking. It also indicated that most of the gas-producing companies and others commenting on the proposed rulemaking had asserted, without substantiating information, that the costs of developing tight formation wells were twice as high as for conventional gas wells. Nevertheless, based on this and other information submitted, the Commission established the incentive price at twice the price for conventional wells.

GAO did not attempt to evaluate the basis for the Commission's tight gas pricing decisions when it established the program. Instead, GAO reviewed program activity to determine whether the selected approved formations were extraordinarily risky or costly. As agreed with the requesters' offices, GAO did not review program activity with respect to the other aspects.

To determine to what extent tight formations proved to be more risky to develop than conventional formations, GAO reviewed results for 7 of the 195 approved tight formation recommendations. Although these formations were not selected randomly, they accounted for more than one-half of the wells qualified under the program. (As a measure of risk, GAO used the number of successful wells as a proportion of all gas and oil wells drilled in an area because separate gas well data were not available.) GAO found that it was not extraordinarily risky to drill wells in these seven formations. During the period 1976 to 1982, six of the seven tight formations' annual success rates ranged from 68 to 100 percent. In comparison, the national success rate for all drilling activity during the same years ranged from 66 to 71 percent.

To determine the additional costs of drilling tight formation wells, GAO contacted industry officials and officials from three states (Colorado, Ohio, and Texas). The three states accounted for about 75 percent of the tight formation wells that have been drilled under the program. (As a measure of cost, GAO obtained information on the cost of developing a tight formation well versus the cost of developing a conventional gas well.) From its discussions with state officials and review of data, GAO concluded that it was not extraordinarily costly to develop tight formation wells in the three states. Developing tight formation wells increased well costs by 18 to 50 percent over the cost of developing a conventional gas well, rather than costing twice as much, as the Commission had anticipated. (See pp. 12 to 24.)

JURISDICTIONAL AGENCIES ENCOUNTERED PROBLEMS IN APPLYING THE COMMISSION'S CRITERIA

The Commission specified physical (or geological) criteria which were supposed to limit incentive pricing to formations that were substantially more risky and costly to develop than conventional gas wells. The two key criteria related to the maximum average allowable level of permeability--the ease with which gas can migrate through sand or rock--and a sliding scale of expected production. The Commission used these criteria as indirect measures of risks and costs. The Commission permitted, but did not require, applications to include financial data; only 7 of the 234 recommendations to the Commission were based on financial data.

The Commission's physical criteria for qualifying tight formations depended heavily on being able to collect and measure well permeability and the expected production rate. However, according to the jurisdictional agencies GAO contacted, they encountered problems in applying these criteria.

First, permeability testing was not as common as the Commission assumed and was not done with the degree of accuracy implied by the standard. The several techniques used to measure permeability produced varying results and were subject to varying interpretations of key data elements, such as the thickness of the producing area. Second, test data on well production rates were often not available. Such data were often not available because operators routinely treated tight formation wells to improve their production, rather than hold up production for up to 2 years in order to obtain test data to meet the Commission's gas production criterion. Third, because the Commission's standard for "average" permeability did not specify how to compute the average, jurisdictional agencies had to decide which wells or areas within a formation to include and which of several mathematical methods they should use to compute an "average." (See pp. 25 to 31.)

MUCH OF THE PROGRAM ACTIVITY OCCURRED OUTSIDE HIGH-POTENTIAL AREAS

The program's objective was to encourage development of high-potential formations. However, GAO found that much of the program activity occurred outside areas that the Commission considered to have high potential for development. GAO's analysis shows that, while about 60 percent of the program's production activity (representing 17 percent of the qualifying wells) occurred in high-potential developing areas, almost 40 percent of the production activity (representing about 83 percent of the qualifying wells) occurred outside the high-potential areas. Furthermore, the undeveloped tight formation gas basins with the greatest potential accounted for a small proportion of program activity.

To determine if the program was encouraging development of selected formations which had little or no development at prevailing prices, GAO analyzed drilling trends in 11 approved tight formations between 1973 and 1979, the year before the program started. The 11 formations accounted for about 87 percent of the wells that qualified for incentive pricing under the program at the time of GAO's review in December 1982. GAO found that 9 of the 11 formations had substantial annual growth in drilling at prevailing prices, as measured by the compounded annual rate of increase in drilling, which ranged from 27 to 67 percent. (See pp. 32 to 42.)

THE FUTURE OF THE TIGHT FORMATION PROGRAM

According to the Department of Energy, about 50 to 60 percent of the natural gas produced in this country was deregulated and no longer subject to federal price ceilings effective January 1, 1985, under the provisions of the Natural Gas Policy Act of 1978. About 75 to 80 percent of the natural gas will be deregulated by 1990. Because of phased price deregulation under the act and a related November 1984 Commission ruling that tight formation gas will be included in phased deregulation, the tight formation program will have limited application in the future. For this reason, GAO is not recommending any program changes. (See pp. 42, 43, and 45.)

AGENCY COMMENTS AND GAO's EVALUATION

GAO obtained written comments from the Commission, the Department of the Interior, and the Internal Revenue Service. (See apps. V, VI, and VII.) The Department of the Interior and the Internal Revenue Service offered some technical clarifications and updated information. These comments were incorporated, where appropriate, in the report.

The Commission agreed with GAO's conclusion that jurisdictional agencies had encountered problems in applying the Commission's qualifying criteria. The Commission also agreed with GAO's conclusion that the tight formations which have undergone development generally have not been extraordinarily risky or costly to develop. However, the Commission explained that the incentive price was available for several types of tight formation gas drilling and that, in establishing the price, it had expected the less costly and risky sources to be developed first. It explained further that it had expected the more costly and risky sources to be developed later, but that--because of declining oil prices and other factors--these sources were not developed.

In response to GAO's conclusion that there was little program activity in high-potential areas as evidenced by the program's drilling activity, the Commission said that it believed the program had encouraged considerable activity in the high-potential areas. The Commission suggested that gas production is another method of measuring program activity in high-potential formations. GAO agrees that this method is also valid, but believes that, even using this method, the Commission somewhat overstated the extent of program activity in high-potential formations. GAO revised its report to recognize the method proposed by the Commission and made its own estimate according to this method. (See pp. 45 and 46.)

Contents

APPENDIX

ILLUSTRATIONS

Table

ABBREVIATIONS

bcf	billion cubic feet
Btu	British thermal unit
DOE	Department of Energy
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GAO	General Accounting Office
Mcf	thousand cubic feet
Md.	millidarcy
NPC	National Petroleum Council
NGPA	Natural Gas Policy Act of 1978

CHAPTER 1

INTRODUCTION

As existing supplies of natural gas are used up, new supplies must be found. Otherwise, current levels of reserves (inventories) and production cannot be maintained. Federal regulation of natural gas prices recognizes the increasing costs and difficulty of developing new supplies by allowing higher prices for them. This was one of the goals of the Natural Gas Policy Act (NGPA) of 1978 (15 U.S.C. 3301) which established a series of maximum prices which may be paid for gas, depending on such factors as when and where the gas is found.

Natural gas provided about 25 percent of the nation's energy in 1983. About 95 percent of this gas was produced domestically, with the remaining 5 percent imported from Algeria, Canada, and Mexico. Gas is used throughout the economy. Nationwide, industry accounted for about 38 percent of all gas used in 1982, more than any other sector. Residences accounted for 26 percent with gas being the most widely used fuel for home heating. Other end-users were electric utilities (18 percent), commercial establishments (14 percent), and miscellaneous uses (3 percent).

The natural gas industry is comprised of three main sectors--production, transmission, and distribution--which are physically interconnected by a network of pipes throughout the United States. Companies in the various sectors may also be related through corporate affiliations.

Producers include thousands of small, medium, and large firms which explore for, drill for, and produce gas. Texas, Louisiana, Oklahoma, New Mexico, and Kansas--in descending order--accounted for 86 percent of production in 1983. All domestic production is subject to federal price regulation, administered by the Federal Energy Regulatory Commission (FERC).[1] In addition, producing states may regulate production volumes, spacing of wells, and other aspects. Producers explore for new reserves of natural gas, develop them to determine their size, and extract the gas from the reserves. Having determined that a reserve is large enough to warrant marketing, the producer will often negotiate to sell the gas--usually to a transmission or pipeline company. (Producers also sell gas directly to distributors or end users.)

Pipeline companies generally purchase the gas--under negotiated contracts--from producers in the field, transport it to market, and sell it either to distribution companies or directly

---

[1]Certain natural gas prices were decontrolled on January 1, 1985, as discussed further on pp. 42 and 43.

to large industrial and electric utility end users.[2] FERC regulates 129 interstate pipeline companies, and intrastate pipeline companies in the producing states are generally subject to state regulation.

Finally, there are almost 1,600 distribution companies nationwide. They are usually local public utilities serving a specific market area and are under the jurisdiction of state or local regulatory entities.

NATURAL GAS FROM APPROVED TIGHT FORMATIONS CAN RECEIVE AN INCENTIVE PRICE

Natural gas is not found in vast underground lakes and caverns but rather is contained in porous rock masses composed of individual beds or units with similar physical characteristics or origins. The rate at which these formations will release the gas they contain depends upon geological conditions in the area and specifically to the petrophysical properties of the formation rock. One key property of a formation is permeability--the degree of interconnection among void spaces which permit gas, oil, or other fluids to migrate through the rock. Certain formations are called tight formations because they exhibit low permeability; in other words, under normal conditions, the gas these formations contain generally seeps out slowly.

Recognizing that it is especially difficult to produce gas under some conditions, the Congress provided additional price incentives for so-called high-cost gas under section 107 of the NGPA. The act identifies four sources of high-cost gas.[3] In addition, the act provides that FERC may establish incentive prices for additional subcategories which are produced "under such other conditions as the Commission determines to present extraordinary risks or costs." The act does not mention gas from tight formations, but such gas was identified as a potential subcategory in the Conference Report on the act and elsewhere.[4]

---

[2]Pipeline companies may produce some gas themselves and purchase gas from and resell to other pipelines. Some pipelines also provide a transportation service for customers that have their own gas supply.

[3]Designated high-cost natural gas that is produced from geopressured brine, coal seams, Devonian shale, or from wells drilled below 15,000 feet after February 19, 1977.

[4]This was noted in FERC's "Notice of Proposed Rulemaking and Public Hearing on High Cost Natural Gas Produced from Tight Formations," 44 Fed. Reg. 52253, 52254 (1979).

FERC began implementing this provision in June 1979 by requesting comments from interested parties on the types of gas which should receive incentive prices. Few of the ensuing comments suggested tight formations, but FERC's attention was drawn to this source by former President Carter's specific mention of tight formation gas in a July 16, 1979, speech. The Department of Energy (DOE) also emphasized tight formations in its response to FERC's June 1979 request.

FERC issued a proposed rulemaking on August 29, 1979. The rulemaking listed 27 formations that would qualify as tight formations and established a procedure for expanding the list. After holding public hearings and receiving written comments, FERC made substantial changes in the rule and put it into effect on an interim basis on March 21, 1980. On August 15, 1980, FERC issued its final rule, Order No. 99, which established procedures and criteria for qualifying tight formation gas that differed considerably from those in the proposed rulemaking. FERC also established an incentive price for such gas.

NGPA established a series of maximum prices for eight major price categories, covered by sections 102 through 109,[5] and additional subcategories depending on when a well is drilled, how deep the well is, when and where the gas was contracted for, and other criteria. The act also allows gas that qualifies under more than one category to be treated under the section that could result in the higher price for the producer. The tight formation incentive price provides a substantial increase over the maximum price that would otherwise apply. In April 1985 gas produced from wells in approved tight formations qualified for about $5.96 per million British thermal units (Btu). If the tight formation had not been approved, the gas otherwise generally may qualify for a price from about $2.98 or $3.93 per million Btu's.

In a letter commenting on this report, the Chairman, FERC, said that the incentive price authorized in Order No. 99 is a ceiling price only, and such a price could be charged only if the producer had specific contractual authority to do so. FERC said that this safeguard was intended to ensure that the price was deemed necessary by a purchaser to elicit development of the tight formation gas.

---

[5]This report deals with three of the price categories: Section 102 which covers gas from new onshore reservoirs, new wells at a minimum distance or depth from an existing well, and certain Outer Continental Shelf reservoirs; section 103 which covers gas from new wells less than a minimum distance or depth from an existing well; and section 107 which covers high-cost natural gas from wells at a depth of 15,000 or more feet and three other sources specified in the act or from other sources determined by FERC to present extraordinary risks or costs. The definitions are general descriptions only.

Quantities of natural gas may be measured on the basis of heat content (Btu's) or quantity (cubic feet). A thousand cubic feet (Mcf) typically contains somewhat more than 1 million Btu's. Price ceilings under the 1978 act are generally stated on a Btu basis. Production estimates are often stated on a cubic-feet basis, for example, Mcf or billion cubic feet (Bcf). In this report, prices are stated in terms of million Btu's, while quantities are stated in terms of cubic feet.

FERC regulations provide guidelines for formally designating tight formations and for determining which wells drilled into such formations will qualify for the incentive price. The regulations provide that, to designate a tight formation, a jurisdictional agency is to submit a written recommendation to FERC. The jurisdictional agency is generally a state agency for nonfederal lands and the Department of the Interior for federal lands. After receiving such a recommendation, FERC is to publish a proposed rulemaking in the Federal Register, requesting comments on the proposal. After receiving comments and, if warranted, conducting its own review, FERC approves or disapproves the recommendation.

Once FERC designates a tight formation, any well completed for production in the formation on or after July 16, 1979, becomes eligible for the higher ceiling price. The operator must apply to a jurisdictional agency for a determination that the wells are in the designated area and are completed at the appropriate depth. Jurisdictional agencies forward their well determinations to FERC. The determination is applicable unless FERC, within 45 days, reverses the determination because it was not supported by substantial evidence.

FERC and the jurisdictional agencies have different roles in tight formation designations and in well determinations. For designations, jurisdictional agencies have essentially an advisory role. They submit applications to FERC, and FERC must prescribe a rule approving or disapproving the designation of the recommended tight formation. For well determinations, jurisdictional agencies make a final determination as to whether a well in an approved formation qualifies under the defined requirements.

Through December 1984 FERC received 234 tight formation recommendations. It approved 195 in whole or in part. One was remanded to the jurisdictional agency for further consideration, 4 were withdrawn by the jurisdictional agencies, and the remaining 36 were awaiting FERC action. The numbers do not sum to the total because two recommendations were approved in part and were pending in part. The approved formations cover a portion of 17 states. Further, FERC had received well determinations covering 28,570 wells in tight formations through October 1984 (the latest data available as of December 1984).

The National Petroleum Council (NPC)--an industry advisory group to DOE--estimated that tight formations in the United States contain more than 500 trillion cubic feet of gas. This would constitute about 33 percent of the nation's total gas reserves, which NPC estimated at about 1,500 trillion cubic feet. According to FERC the sum of the annual tight formation gas production for fiscal years 1981 through 1983 totaled about 1.5 trillion cubic feet of gas.[6] This represents up to 8 percent of total annual gas production.

TIGHT FORMATION GAS MAY BE ELIGIBLE FOR A TAX CREDIT

Under the Crude Oil Windfall Profit Tax Act of 1980 (Public Law 96-223, 94 Stat. 268), as amended, producers of alternative energy sources, including tight formation gas and other gas classified in accordance with section 503 of the NGPA as high-cost, nonconventional gas eligible for incentive pricing (geo-pressured brine, coal seams, and Devonian shale), are eligible for a tax credit. The following discussion relates specifically to tight formation gas.

The credit provides producers an incentive to continue developing alternative energy sources if the average wellhead price for uncontrolled domestic crude oil decreases significantly. Since natural gas frequently competes with crude oil, the tax credit may provide a greater benefit than the incentive price if demand for natural gas declines in response to the reduced crude oil prices. The tax credit is available when the price of oil is below $29.50 per barrel (in 1979 dollars adjusted for inflation).

A given quantity of gas is not eligible for both the incentive price and the tax credit. Therefore, the tax credit does not apply to any gas for which the producer elects to receive the incentive price under Order No. 99.

The credit is an amount equal to $3 multiplied by the barrel of oil equivalent of the natural gas on the basis of its energy content (as measured in Btu's). This equates to a maximum tax credit of about $0.52 per million Btu's for tight formation

---

[6]See FERC's 1983 Annual Report, dated May 1, 1984, p. 16. FERC receives initial production estimates with most applications for well determinations under NGPA. However, FERC cautions that these estimates do not represent actual gas production. Tight formation wells represent a particular problem for initial estimates because their production drops markedly in the first year and they often take 2 years to settle into a fairly stable rate. Hence, we are using these production estimates for trend analysis only.

natural gas. The tax credit begins to apply when the average wellhead price of uncontrolled domestic crude oil drops below \$29.50 and is fully phased in when such price drops to or below \$23.50 (the entire range of prices is adjusted for inflation). According to an engineer in the Internal Revenue Service's Corporate Tax Division, a tax credit was not available in calendar year 1980. He said that the tax credit per million Btu's was \$0.21 in 1981 and \$0.52 in 1982, 1983, and 1984.

The tax credit, provided in section 29 of the Internal Revenue Code, is available for the domestic production and sale of gas to unrelated users. The tax credit applies to gas which (1) is produced from wells drilled after December 31, 1979, and before January 1, 1990, and (2) is sold after December 31, 1979, and before January 1, 2001.

To qualify for the credit, gas produced from tight formations must be subject to federal price regulation. Although some tight formation gas remains regulated under NGPA phased deregulation provisions, the credit terminates if that gas is deregulated. Also, the maximum lawful price for such gas must be at least 150 percent of the current NGPA section 103 price. This requirement is met under the provisions of Order No. 99 which has a ceiling price set at 200 percent of the NGPA section 103 price.

An Internal Revenue Service legislative affairs officer told us in January 1985 that a negligible number of taxpayers have claimed the tax credit. He said that this information was based on data through the 1982 tax year--the most recent for which complete information was available.

TERMINOLOGY RELATED TO PRODUCTION OF TIGHT FORMATION NATURAL GAS

Virtually all of the natural gas ever discovered has been found in sedimentary basins--low areas in the earth's crust most likely to contain the organic-rich rocks required for oil and gas formation. Commercially recoverable quantities of natural gas occur in porous underground formations called reservoirs, or pools, which are formed where geological conditions have resulted in the formation of traps which block migration and cause accumulation of gas and oil. Reservoirs may contain only natural gas or both natural gas and crude oil. An interval containing one or more reservoirs is called a zone.

Once a gas well has been drilled, generally a test must be made to determine the well's performance. Two of the more common tests are core analysis and pressure buildup. In a core analysis, a core bit is attached to the end of a drill pipe which in turn cuts a column of rock from the formation being penetrated. The core is then removed and tested for evidence of oil or gas, and its characteristics (such as porosity and permeability) are determined. In a pressure buildup test, a pressure gauge is lowered into the well to measure the well's reservoir pressure at a specific depth during the producing interval. This type of test has several variations, such as "flowing bottom-hole pressure test," which is a measurement taken while the well continues to flow, and "shut-in bottom-hole pressure test," which is a measurement taken after the well has been shut in for a specified length of time. A series of bottom-hole pressure tests conducted at scheduled time periods will provide information about the decline or depletion of the zone in which the well has been producing.

Wells often must be treated, or stimulated, to improve the drainage pattern and therefore increase the production rate. The most common stimulation technique for tight formation wells has been hydraulic fracturing. This process involves pumping a mixture of fluid and a proppant (sand or some other solid substance) into the well at high pressure. Cracks are opened in the formation and extend outward as pumping continues. The sand remains in the cracks after the fluid retreats, keeping them open as channels through which gas can escape and flow into the well.

OBJECTIVES, SCOPE, AND METHODOLOGY

We initiated this review in response to separate requests from the Chairman, Subcommittee on Fossil and Synthetic Fuels, House Committee on Energy and Commerce, and Senators Max Baucus and Howard M. Metzenbaum. As agreed with the requesters' offices, we addressed the following questions:

--Did the tight formations approved under the incentive pricing program prove to be extraordinarily risky and costly to develop, as had been assumed by FERC?

--Were the jurisdictional agencies able to apply FERC qualifying criteria in recommending tight formations for incentive pricing?

--To what extent did the incentive price stimulate drilling activity in formations having the greatest potential for development?

We addressed these questions by

--reviewing FERC's rulemaking process leading to the issuance of Order No. 99 but not attempting to evaluate the basis for FERC's tight gas pricing decisions when it established the program;

--reviewing the record of formation approvals and comparing it to drilling activity in areas considered by FERC and others to have the greatest potential for development;

--analyzing the development history of 11 approved formations in 6 states to assess their need for incentive pricing. (The basis for selecting these 11 formations is discussed below.);

--examining the risks and costs associated with developing tight formation wells in selected states and formations to determine if the approved formations were extraordinarily risky or costly. (As agreed with the requesters' offices, we did not review other aspects of producing tight formation gas, such as the expected rate of production from tight formation wells.); and

--examining selected tight formation proposals and discussing their review and approval with officials of FERC, the Department of the Interior, and state jurisdictional agencies.

To analyze actual formation designations, we obtained a listing from FERC showing the status of recommended formations through January 14, 1983, which was the latest data available at the time of our review. We compared the list with (1) a list of proposed formations published in FERC's proposed rulemaking, (2) recommendations from DOE and the U.S. Geological Survey submitted in response to the rulemaking, and (3) a list compiled by NPC for its appraisal of tight gas reservoirs published in 1980.

Identifying approved formations was somewhat complex because names and classification systems vary from state to state. We contacted officials in the 19 states which had recommended formations to FERC in order to distinguish between the formations included in the original list and those that were approved. When we were uncertain of the relationship of specific formations to those listed in FERC's proposed rulemaking, we assigned them to the list in the proposed rulemaking in order not to overstate the additions which have occurred. Appendixes I and II show our breakdown of recommended formations into those included and those not included in the proposed rulemaking.

We used FERC's computerized data base on well determinations[7] to tabulate the number of wells which have qualified for

---

[7]We discussed data quality control procedures with FERC staff and also performed certain edit checks during our analyses of the data. We concluded that the data were sufficiently accurate to support our findings and conclusions.

incentive pricing from the original expected formations and from additional approved formations. FERC's data base was somewhat difficult to use because formation names were missing from many of the records. To the extent possible, we used field and reservoir names which we could associate with approved formations. Again, we asked state officials to help resolve uncertainties. Overall, we were able to classify 99 percent of all the wells which had qualified for incentive pricing through December 22, 1982, which were the latest data available at the time of our review.

We reviewed data on selected formations and states to determine if the program was achieving its objective of encouraging drilling activity in undeveloped areas and if it was extraordinarily risky and costly to drill tight formation wells. We selected 11 approved tight formations in 6 states to analyze both drilling activity before the program started and the degree of risk and cost involved in their development. These 11 formations accounted for 87 percent of the wells qualified for incentive pricing under Order No. 99 through December 22, 1982. These formations include the formations on FERC's original list and additional ones approved.

The number of formations and states varied for the three factors that we analyzed due to data limitations and our desire to concentrate on selected formations and states which accounted for a relatively large share of program activity. We obtained drilling activity data on all 11 formations, risk data on 7 formations (accounting for over half the qualified tight formation wells), and cost data from 3 states in different sections of the nation (accounting for 75 percent of the qualified tight formation wells).

To determine the extent of drilling activity in tight formations identified by FERC as having the greatest potential, we reviewed all 14,593 tight formation well determinations received by FERC at the time of our review.

To review the process by which the formations were designated, we examined application material submitted for these formations and discussed the material with federal and state officials who reviewed the applications in Colorado, New Mexico, Ohio, Pennsylvania, Texas, and Wyoming. We discussed the adequacy and interpretation of test data submitted, the usefulness of the criteria provided in Order No. 99, and decisions to include or exclude from proposed designations those areas which could be drilled economically without the incentive pricing.

We used statistics from the Ohio Division of Oil and Gas to compile drilling history on Ohio formations. For Colorado, New Mexico, Pennsylvania, and Wyoming, we compiled the data by formation from well completion reports. Texas did not have drilling statistics classified by formation, so we made a computer analysis using the Texas Railroad Commission's[8] data base on gas fields and gas wells.

We used drilling statistics to determine both the trend of development in tight formations and the risk of drilling non-commercial wells (dry holes). We also discussed the cost of drilling in tight formations, especially the additional cost required to stimulate wells for commercial production, with engineers and geologists at three state jurisdictional agencies and three well service companies--Dowell, Halliburton, and Western Company of North America. Well service companies provide drilling, testing, and other services for oil and gas concerns. We selected these companies because they were reportedly active in areas with approved tight formations.

To obtain information on the tax credits available to producers of tight formation gas, we reviewed the Crude Oil Windfall Profit Tax Act and section 29 of the Internal Revenue Code, pertaining to a tax credit for producing gas from a nonconventional source.

Finally, we obtained published information from DOE's Energy Information Administration (EIA); the American Petroleum Institute, a trade association; and NPC.

We did not attempt to independently verify the accuracy of data obtained from FERC, states, and other sources. Dollar amounts used in the report were not adjusted for inflation. Also, we did not review the effectiveness of the tax credit.

Our review was conducted between May 1982 and September 1984 in accordance with generally accepted government auditing standards.

The remainder of this report is organized as follows:

--Chapter 2 details the development of FERC's rulemaking on tight formation gas, highlighting the major changes made and the key assumptions behind those changes. It also presents the results of our analysis of the risks and costs of developing selected tight formations.

--Chapter 3 explains how jurisdictional agencies were hampered in applying FERC's criteria because of a lack of permeability and production test data, difficulties in interpreting available permeability test data, and difficulties in selecting the proper method of averaging test results.

---

[8]The Texas Commission is the state agency which regulates oil and gas production. We discussed quality control with Commission staff and concluded that their data base was sufficiently accurate to support our findings and conclusions.

--Chapter 4 demonstrates that much of program activity under Order No. 99 occurred outside high-potential areas. Conversely, other undeveloped tight formations that FERC and others considered to have the greatest potential for development received relatively little attention under the program.

--Chapter 5 presents our conclusions, agency comments, and our evaluation.

CHAPTER 2

TIGHT FORMATIONS WERE NOT EXTRAORDINARILY RISKY OR COSTLY TO DEVELOP

When FERC issued its proposed rule for tight formations in August 1979, it attempted to ensure that both the formations designated and the wells approved for incentive pricing would be those needing the higher price for commercial development. To qualify tight formations, FERC's proposed rule contained two types of criteria: (1) physical criteria (such as the gas permeability of the formation) which were designed to limit incentive pricing to formations and wells that were substantially more expensive to develop than conventional ones and (2) financial criteria (such as the need for expensive well stimulation techniques to enhance production).

In response to comments from interested parties, however, FERC made it easier to qualify formations and wells by

--substantially changing the procedures and physical criteria for designating tight formations,

--eliminating the financial criteria except in specified circumstances, and

--making rules less restrictive for qualifying wells to receive the incentive price.

As finally written, Order No. 99 contained physical criteria but eliminated financial criteria except in certain cases in which a formation is recommended under an alternative standard for qualifying formations. In such cases, a formation not meeting FERC's permeability criteria, but having low permeability characteristics, could still qualify for incentive pricing if supporting financial data were provided to demonstrate that the formation is high risk and high cost.

FERC raised the ceiling price of tight formation gas from an originally proposed 150 percent of the new onshore production price to 200 percent of such price based primarily on the assumption that the combined factors of risk, cost, and other aspects warranted a ceiling price that was twice that of conventional gas. However, we found in our review of selected states and formations that tight formations were not extraordinarily risky or costly to develop.

PROCEDURES AND CRITERIA FOR DESIGNATING TIGHT FORMATIONS WERE SUBSTANTIALLY CHANGED

FERC initially tried to target incentive pricing to certain formations considered to be important potential sources of tight formation gas. It listed these formations in the proposed rule and established fairly strict criteria for adding to the list. After receiving comments from interested parties, FERC decided not to designate tight formations and relied instead on jurisdictional agencies to recommend them. It relaxed the criteria by which proposed formations would be evaluated and settled on physical criteria involving the permeability and productivity of the formations.

FERC proposed an initial list of 27 formations in 10 geographic areas or "basins" (see app. I) and solicited comments on whether the formations would be appropriate for incentive pricing. It left open the possibility of expanding the list if potential formations could satisfy four physical criteria.

The first criterion was intended to characterize a formation as tight. It called for the average *in situ* (in place) gas permeability throughout the producing section to be 0.03 millidarcies (md.) or less.[1] The second criterion was intended to confine the program to formations where natural gas production was very low. The criterion stated that wells drilled into the formation must not be expected to produce more than 200 Mcf of gas per day without stimulation treatment. These two criteria were retained in the final rule but were less stringent.

With the third criterion, FERC tried to ensure that designated formations represented high-cost gas by requiring that the formations generally be subject to expensive well stimulation techniques which substantially increase production. Finally, with the fourth criterion, FERC wanted to limit incentive pricing to fields with little prior development. The criterion would

[1] The millidarcy is the standard unit of measurement for permeability and represents 1 one-thousandth of a darcy. The darcy is the rate of flow in milliliters per second of liquid with a certain viscosity through a cross section of one square centimeter of rock under a specified pressure.

have required that formations would be eligible only if field rules covering well spacing[2] had not been issued.

On February 20, 1980, FERC issued an interim rule which accommodated many of the comments made by oil- and gas-producing companies. FERC decided not to focus incentive pricing on predesignated formations. Instead, the interim rule deferred to jurisdictional agencies the responsibility to review and recommend proposed formations, using guidelines which were less restrictive than those originally proposed. In addition, the permeability standard was raised from 0.03 to 0.1 md., which FERC stated was the lowest permeability which could be reasonably measured without having producers carry out expensive and imprecise pressure build-up or drawdown tests. FERC also proposed an alternative standard for formations with low permeability but not as low as 0.1 md. In such cases, the formation could qualify if the state agency could show that the high risk and high cost of producing the formation made the incentive price necessary for development.

FERC retained the gas-production standard in the interim rule but modified it to a sliding scale based on formation depth rather than the limit of 200 Mcf per day for each well. FERC agreed with comments that the gas-production standard should be higher than 200 Mcf per day for deeper wells because they must have higher production rates to justify the higher drilling costs. The revised gas-production standard was a sliding scale which allows production to range from 44 Mcf per day at depths up to 1,000 feet to 2,557 Mcf per day at an average depth interval between 14,500 and 15,000 feet. FERC derived the scale using a formula which reflected the increased effect of depth on drilling costs.

FERC also added a guideline that wells in a proposed formation could not be expected to produce more than 5 barrels of crude oil per day. The purpose of the oil-production guideline was to ensure that the gas is not produced with any more than a

---

[2]Well spacing regulates the number and location of wells over an oil or gas reservoir to promote effective and efficient drainage of the reservoir. Well spacing is normally accomplished by order of the state regulatory conservation division. The order may be statewide or it may be entered for each field after its discovery. Some well-spacing orders allow one well to be located on every 40 acres. Other well-spacing orders prohibit drilling a well closer than x feet from another well or closer than y feet to any surface boundary line. The existence of well-spacing rules for a given reservoir would generally suggest that commercial development of the reservoir had begun or was expected.

minimum amount of oil because production of oil in greater quantities could, in itself, create incentives for developing the formation.

FERC's interim rule eliminated its proposed guidelines regarding production stimulation techniques and well-spacing rules which were aimed at restricting incentive pricing to largely underdeveloped formations that needed it. These two guidelines were eliminated because FERC decided that they were not helpful in determining whether a formation could be economically developed without an incentive price. FERC did not substitute any specific financial criteria but instead cautioned agencies to exclude formations (or portions thereof) which could be developed without the incentive price.

In Order No. 99 FERC added an infill drilling guideline to clarify the uncertainty regarding the appropriateness of recommending formations or portions of formations that were being developed by infill drilling programs. Infill drilling is defined as drilling that occurs in a substantially developed field for which the agency has allowed a smaller drilling area or drilling of additional wells in order to promote more effective and efficient drainage of the reservoir. Under this guideline an agency may not recommend a formation or portion thereof if the formation or portion was authorized to be developed by infill drilling prior to the date of the recommendation and the agency has information which indicates that the formation can be developed without the incentive price. Once a formation has been approved by FERC, future infill wells are eligible to receive the incentive price.

RULES FOR QUALIFYING WELLS WERE MADE LESS RESTRICTIVE

In addition to the rules for designating formations, FERC proposed guidelines for qualifying wells drilled in the designated formations. In the proposed rulemaking, these well-determination rules were intended to ensure that the incentive price was justified by special cost considerations. Producers would have had to document that a well had been subjected to an appropriate "production enhancement technique" to qualify it for incentive pricing. An appropriate technique is one which is expected to substantially increase the rate of natural gas production. Such a technique must also be substantially more expensive than those techniques used for a typical well which does not produce from a tight formation. Some commenters pointed out that in choosing production enhancement techniques, this requirement could limit flexibility and make the incentive for drilling in tight formations less certain. After considering these comments, FERC dropped the provision from its interim and final rules. It required only that (1) wells be completed in approved tight formations, (2) drilling had begun on or after July 16, 1979, and (3) the gas qualifies as new natural gas or is produced through new, onshore production wells (e.g., that meet well-spacing requirements).

FERC originally proposed that incentive pricing be available only for wells on which drilling started on or after August 17, 1979, the date FERC approved the proposed rule. FERC chose this date to ensure that producers would not profit unduly from wells they had started drilling under previously existing ceiling prices. Some commenters asked for an earlier date, particularly for wells drilled through a tight formation to other producing zones but not completed in the tight formation because of the high production stimulation costs. FERC decided that a significant amount of gas could be produced from recompletions in such wells and changed the program accordingly. It moved the effective date back to July 16, 1979 (the date of President Carter's speech) and provided that wells drilled earlier but not completed for production in a designated tight formation could qualify as recompletion wells.

CEILING PRICE FOR TIGHT FORMATION GAS WAS RAISED

FERC originally proposed that the incentive ceiling price be set at 150 percent of the new onshore production gas price because it corresponded to the prevailing energy-equivalent price of Saudi Arabian crude oil ($18 per barrel). Before fixing the final price in Order No. 99, FERC considered several approaches without clearly choosing any particular one. Although FERC staff concluded that it could only justify a price set at 175 percent of the new onshore production gas price, FERC raised the price from 150 percent to the 200-percent level in line with its assumptions about risk, cost, and other aspects. The other aspects included the costs of other fuels and the expected rate of production from tight formation wells.[3]

Many commenters on the proposed rule suggested that the ceiling price for tight formation gas be indexed to the price of imported oil or gas instead of the 150-percent proposal. However, the price of imported oil was rising rapidly in early 1980, and FERC maintained its 150-percent proposal in its interim rule. FERC pointed out that its statutory authority was limited to setting a ceiling price at the level necessary to provide reasonable incentives for the production of high-cost gas. FERC

---

[3]Based on the assumption that tight formation wells have lower production rates and therefore a longer payback period over which revenues are collected.

also said that if it allowed tight formation gas to command a price too much higher than other NGPA categories, it might cause a diversion of capital and drilling equipment from conventional gas development. Such "perverse incentives," FERC said, could depress gas supplies by encouraging development of less productive wells at the expense of more productive ones.

FERC concluded in the interim rule that it should be cautious about using oil prices to determine the appropriate price for tight formation gas. It specifically requested further comments on what price ceiling was necessary to promote development. FERC said that it was disappointed by the response. It noted in the preamble to Order No. 99 that most commenters asked for a higher price without submitting data or empirical information to show that it was necessary and acknowledged in the order that an acceptable quantitative estimate of risk exposure had not been developed during the rulemaking. However, the FERC staff had done an analysis based on projections of NPC, which was studying tight gas reservoirs for the Secretary of Energy. The FERC staff concluded that it could support 175 percent of the new onshore production gas price for tight formation gas. The staff believed any higher price would result in small incremental production increases and might cause a diversion of capital from conventional drilling.

FERC decided in Order No. 99 to set a ceiling price for tight formation gas at 200 percent of the new onshore production gas price. Its decision was accompanied by a lengthy discourse on numerous alternative criteria, which only narrowed the decision to a range of prices from $3.50 to $5 per million Btu's.

FERC's choice was related to its assumption that the combined factors of risk, cost, and other aspects warranted a ceiling price that was twice the price of conventional gas. FERC said that the rulemaking record indicated that the additional risk of an unsuccessful fracturing job provided the basis for arguing that tight formation production is more risky than conventional gas production. FERC noted, however, that neither the record nor its staff's analysis had yielded an acceptable quantitative estimate of the extent to which the risk of tight formation drilling exceeded conventional drilling. Regarding cost, FERC stated in its rulemaking that several commentors argued without substantiating data that the average cost of drilling and completing a tight formation well was roughly twice the cost of a conventional well because the additional cost of fracturing a well can be equal to the cost of drilling a well.

At that time (August 1980), the 200-percent level meant a ceiling price of $4.55 per million Btu's; by April 1985 inflation adjustments brought the price to about $5.96.

Table 1 summarizes FERC's key rulemaking changes from the proposed rule to Order No. 99.

Table 1

Summary of Key Rulemaking Changes By FERC

Issue	Proposed rule (Aug. 1979)	Order No. 99 (Aug. 1980)
Qualifying formations	27 formations were listed. Producers and states could apply to FERC for additional designations.	No formations listed. Producers apply to state and federal agencies, which review and recommend formations to FERC.
Permeability	Tight formations defined as those with average permeability of 0.03 md. or lower.	Permeability standard raised to 0.1 md.
Productivity	Tight formations defined as those with expected pre-stimulation production of 200 Mcf per day or less.	Production standard became a sliding scale based on depth.
Well stimulation requirement	Tight formation defined as requiring expensive well stimulation techniques to enhance production.	Criterion eliminated.
Alternative standard for qualifying formations	No alternative standard provided for qualifying formations.	Optional economic standard provided for formations not meeting permeability standard.
Qualifying wells	A well would qualify if it was completed in a designated tight formation and was stimulated with an appropriate technique.	A well would qualify if it was completed in a designated tight formation.
Effective date	Wells drilled on or after Aug. 17, 1979.	Wells drilled on or after July 16, 1979, or recompletion wells completed for production on or after July 16, 1979.
Price	150 percent of new, onshore production gas price, (NGPA sec. 103 ceiling price).	200 percent of NGPA sec. 103 ceiling price.

TIGHT FORMATIONS WERE NOT EXTRAORDINARILY RISKY TO DEVELOP

In Order No. 99 FERC assumed that developing tight formations was more risky than conventional drilling because tight formation wells usually require massive hydraulic fracturing to stimulate production and there exists an additional risk of unsuccessful fracturing operations. However, FERC noted in the final rulemaking that neither the record nor its staff's analysis had yielded an acceptable quantitative estimate of the extent to which the risk of tight formation drilling exceeded conventional drilling. Nevertheless, this was one of the factors upon which FERC based its decision to establish an incentive ceiling price for tight formation gas at 200 percent of the price for conventional gas.

In the absence of a specific risk factor identified by FERC in Order No. 99, we attempted to compile data on the riskiness of drilling gas wells for the nation and for selected states and formations. (As a measure of riskiness, we used the drilling success rate--the number of successful wells as a proportion of all wells drilled in an area.)

We found that such data were not available on a national level for gas wells only. The drilling success rate data published by EIA include both oil and gas wells drilled and do not permit the calculation of success rates for gas wells only. Rather, the calculation of drilling success rates from EIA's data provides a combined drilling success rate for oil and gas wells. EIA's data show that the national combined drilling success rate for oil and gas wells averaged 66 to 71 percent between 1976 and 1982.

Also, we compiled drilling success rates between 1973 and 1982 for seven tight formations which accounted for over half of the wells qualified under Order No. 99. As with the national data, the success rates include both oil and gas wells because we could not obtain data for gas wells only. We did not attempt to determine if all gas wells in these formations were fractured. However, wells in these tight formations are routinely fractured, according to state jurisdictional agency officials and our review of tight formation applications. As shown in table 2, we found that it was not extraordinarily risky to drill tight formation wells in the seven formations. Between 1976 and 1982, six of the seven tight formations' annual success rates averaged 68 to 100 percent.

We did not compare year-by-year drilling success rates for the nation and the seven formations because the data may not be comparable. Because the success rates for oil and gas drilling may differ, the combined success rate for an area could depend on the proportion of oil and gas wells in that area. For the nation in 1982, 68 percent of the successful wells were oil and 32 percent were gas. Because we could not obtain data regarding the proportion of oil and gas wells in each formation, we believe it could be misleading to compare the seven tight formations' success rates with the national success rates.

In response to our analysis of success rates for seven approved tight formations which showed no increase in risk between 1976 and 1982, FERC said that an analysis of success rates before and after the effective date of Order No. 99 would be more indicative of how the incentive price has operated in those areas. FERC said the unweighted[4] combined success rate for the seven formations was 71 percent before the start of the program (1973-78) and the success rate increased to 91 percent after the program started (1980-82). In addition, FERC said that the tight formation incentive price program apparently worked well in the areas we selected for comparison precisely because the program decreased the economic risk (or conversely compensated producers for accepting the risk) and brought a greater percentage of wells into the realm of "successful."

FERC's comments regarding the combined success rate for seven tight formations before and after the program started suggest that the rate increased from 71 to 91 percent as a direct result of the tight formation incentive pricing program. The unweighted combined success rates for these formations, however, showed a steadily upward trend throughout the period 1973 to 1982 and reached 89 percent in 1979, the year before tight formation gas incentive pricing became available. We believe this increasing success rate is generally consistent with the increasing prices that natural gas received throughout the 1970's. Further, we believe our analysis shows that it was not extraordinarily risky to develop the seven formations prior to the incentive pricing program; and it is unclear whether the minimal increase in success rates that occurred after 1980 is a direct result of FERC's tight formation incentive pricing program, as opposed to the higher prices that were available for such gas even without the incentive price.

---

[4]An unweighted average treats the rate for each formation equally, instead of giving greater importance (weight) to formations with more wells.

Table 2

Commercially Productive Wells as a Percent of Total Wells Drilled[a]

Formation and state	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Abo (New Mexico)	11	50	57	-	47	59	84	81	87	90
Mancos B (Colorado)	53	62	79	94	88	97	94	95	96	87
Dakota (Colorado)	67	83	100	100	71	83	87	100	98	100
Mesaverde (Wyoming)	35	53	61	76	68	72	86	89	84	75
Frontier (Wyoming)	36	48	81	78	69	80	81	82	88	92
Clinton (Ohio)	92	93	93	94	95	93	97	98	95	94
Berea (Ohio)	79	85	87	87	95	91	95	98	92	93
Combined success rate (unweighted)	53	68	80	76	76	82	89	92	91	90

[a]Available data for gas and oil wells. Separate gas well data were not available.

Source: FERC well completion reports analyzed by GAO. For Ohio, statistics compiled by the Ohio Division of Oil and Gas.

TIGHT FORMATIONS WERE NOT EXTRAORDINARILY COSTLY TO DEVELOP

In Order No. 99 FERC assumed that developing tight formations was more costly than conventional drilling because of the additional cost of massive hydraulic fracturing. However, FERC acknowledged that this was based on the views of several commentors who had argued, without substantiating data, that fracture treatments may double the average total cost of drilling and completing a tight formation well compared to a conventional well. We examined FERC's assumption about well completion costs by interviewing engineers from well service companies and officials from three state agencies (Colorado, Ohio, and Texas) which represent about 75 percent of the wells that have qualified for incentive pricing. We also reviewed documents filed with tight formation applications. While this information is not complete or definitive, it does suggest that the extent of fracturing required varies extensively among formations and that not all tight formations require the massive fracturing that FERC assumed.

The formations which qualified most of the wells under Order No. 99 did not exhibit the cost characteristics that FERC assumed. For the formations in three states that we studied, tight formation wells were typically stimulated with fracture treatments that were not massive. Therefore, fracturing costs did not double total well costs as FERC anticipated, but rather increased well costs by 18 to 50 percent over what would have been incurred with no fracture treatment.

Without stimulation, most tight formation wells would not be economical to produce. In cases where tests were run before stimulation, gas flow was often reported as too small to measure. For example, in its application for the Cotton Valley Group in east Texas, Amoco Production Company submitted prestimulation test data on 75 wells. Nearly half had production rates that were too small to measure, while the average for the remainder was about 30 Mcf per day. After stimulation, many of these wells produced over 500 Mcf per day, and some more than 1,000 Mcf per day.

The scale of fracturing operations, however, varies enormously, depending on reservoir characteristics and the effect desired. A wide range of operations exists, and the large operations are referred to as massive hydraulic fracturing. In Order No. 99, FERC mentioned massive hydraulic fracturing as the technique usually applied to tight formations. The environmental assessment for Order No. 99 characterized a massive fracturing job as requiring 300,000 to 500,000 gallons of fluid. The assessment also suggested as a rule of thumb that such a fracturing job might require 600,000 to 1 million pounds of proppant.

Hydraulic fracturing is not peculiar to tight formations but is commonly used in conventional well completions. In its environmental assessment for Order No. 99, FERC estimated that more than 600,000 fracturing operations had been done since the technique was introduced commercially in 1949. Engineers at the Texas Railroad Commission and Dowell, Inc. (a well service company) told us that hydraulic fracturing is often used in conventional wells to achieve more effective reservoir drainage.

Some formations are typically stimulated with fracture treatments that are not massive. For example, in Ohio, fracture operations in the Clinton Formation used 25,000 to 100,000 gallons of fracturing fluid and 30,000 to 90,000 pounds of proppant. Operations in Ohio's Berea Formation were even smaller.

Similarly, Colorado tight formation wells were typically stimulated with fracture treatments that were not massive. Representatives of well service companies in Colorado told us that typical fracturing jobs in tight formations there used 40,000 to 60,000 gallons of fluid and 120,000 to 150,000 pounds of proppant. Testimony submitted in support of the Canyon Sandstone in Texas indicated that typical wells were treated with 35,000 to 50,000 gallons of fluid and 45,000 to 142,500 pounds of sand. The Cotton Valley Formation in Texas, on the other hand, was often the subject of massive fracturing. Data submitted by Amoco Production Company on 75 wells showed that 67 were fractured with more than 200,000 gallons of fluid.

FERC agreed with our conclusion that most of the tight formations that have undergone development have not been extraordinarily risky or costly to develop. FERC said, however, that in establishing the incentive price for tight formations, it had no illusions concerning which gas would be first developed and produced. FERC noted that Order No. 99 stated that the estimated amount of tight formation gas included developing formations and formations that are known but undeveloped. FERC said Order No. 99 provided an incentive price for gas produced from several types of drilling programs: (1) infill wells drilled into certain developed tight formations; (2) recompletion of wells that are already producing from formations that are vertically situated to the designated tight formations; and (3) new wells drilled and completed in undeveloped tight formations.

FERC explained that producers of this type of commodity are going to make decisions which result first in the least costly and least risky production of that commodity. In addition, FERC said the total energy situation of the United States over the last few years, including declining oil prices and oversupply of gas, precluded the necessity for advancing into undeveloped tight formations that require the risks and costs thought in 1979 to be necessary to mobilize the full productive capability of the more-difficult-to-find-and-produce gas. FERC said a prime example of this is the Northern Great Plains/Williston Basin, estimated to have approximately 30 percent of the nation's total tight formation gas, which has only had one formation in the basin recommended for the incentive price. FERC said that for a variety of reasons, including low permeability, producers have not attempted development of these seemingly vast resources because the expected return on investment does not warrant commitment of resources when easier, more profitable opportunities are available.

CHAPTER 3

JURISDICTIONAL AGENCIES HAD DIFFICULTY IN APPLYING FERC's QUALIFYING CRITERIA

Selected jurisdictional agencies had difficulty in applying FERC's criteria because of (1) a lack of test data on permeability and production, (2) difficulties in interpreting available permeability test data, and (3) difficulties in selecting the proper method of averaging test results. These problems hampered jurisdictional agencies in applying FERC's criteria.

APPLICATION OF FERC's PERMEABILITY STANDARD WAS HAMPERED BY DATA SPARSENESS AND INTERPRETATION DIFFICULTIES

In the jurisdictional agencies we contacted, problems arose in applying FERC's 0.1 md. permeability standard because permeability testing is not as common as FERC assumed and is not done with the degree of accuracy implied by the standard. Engineers use various techniques for estimating permeability; however, only core analysis involves actual measurement. All other approaches are indirect and do not always yield consistent results because of the judgments which are needed to interpret the results.

During the rulemaking process for Order No. 99, DOE and the U.S. Geological Survey advised FERC not to rely on a specific permeability standard as a criterion for designating tight formations. For instance, DOE recommended instead a number of factors, including economic analysis, to determine whether incentive pricing was justified. DOE commented that the thickness of the productive zone--or pay zone--from which pressure readings are taken is a critical variable in estimating permeability. The formula for interpreting pressure buildup tests requires division by the estimated thickness. Thus, if the thickness is underestimated, permeability will be overestimated. DOE also commented that estimates of pay zone thickness are imprecise; and so, therefore, are estimates of permeability. In fact, DOE said that there can easily be a considerable difference in values determined by different analysts.

Also, according to FERC records, staff of the Texas Railroad Commission, which regulates oil and gas production in Texas, told FERC staff that many formations have highly variable characteristics and would be difficult to evaluate using an average permeability standard. The Texas commission staff favored a well-by-well approach because a total formation approach might disqualify many low-production areas.

In Order No. 99 FERC said that it believed most tight formations were relatively homogeneous and the average in situ permeability of the total formation could be reliably estimated. FERC did make some concessions to critics of its proposed 0.03 md. permeability standard. As mentioned in chapter 2, FERC raised the permeability standard to 0.1 md. so that applicants could avoid expensive well pressure tests. Furthermore, FERC included an alternative criterion in Order No. 99 which provided that a low-permeability formation not meeting the physical criteria could be qualified if a financial analysis showed the incentive price was needed.

FERC's inclusion of an alternative financial criteria in Order No. 99 had little impact. Only 7 of the 234 applications recommended to FERC through December 1984 were based on this standard. The other 227 applications were recommended using the permeability standard.

Application of FERC's permeability standard was hampered by sparse data

Order No. 99 does not specify the amount of well test data required for estimating whether the average permeability of a formation meets FERC's standard. Thus, states had to decide how much data were needed to draw a reasonable conclusion. The states we contacted were hampered in their application of FERC's permeability standard because permeability testing was not common in tight formations. Therefore, these states generally depended on the applicant to provide whatever data were available.

Officials in the six states we visited told us that they relied on applicants to compile whatever data they had available to estimate permeability. In Ohio--the state with the largest number of tight formation wells--the Division of Oil and Gas tried to arrange pressure testing of Clinton Formation wells to provide a basis for its first recommendation. It encountered problems finding test equipment and wells which could be tested and finally obtained results from eight wells. The division decided that future recommendations from Ohio would be based on data compiled and submitted by the applicants.

According to state jurisdictional agencies and well service companies included in our review, permeability testing is not common in tight formations. Companies often complete wells and put them into production without testing permeability because the tests take time and the operators do not expect to gain anything from them. Core tests are expensive to retrieve and pressure buildup tests require that wells be shut in for several days. A service company representative in Ohio said that his company rarely does the tests unless a problem well does not produce as expected.

Because permeability testing is not common in the states we contacted and the states generally relied on available data, formations were approved with relatively little well test data and, in some cases, based on only one well. For example, based on pressure build-up data from one test well and production curve data and other related information from other wells in the formation, the Colorado Oil and Gas Conservation Commission recommended to FERC in August 1980 that the Colorado-2 Formation (covering over 195,000 acres) be designated as a tight formation. On November 14, 1980, FERC issued Order No. 111 which approved the formation for incentive pricing.

Different permeability tests yield varying results

In applying FERC's permeability standard, which provides that the average permeability of the test data must be 0.1 md. or less, the principal problem in the states we contacted was the inconsistent results derived from the various testing procedures for estimating permeability. The kind of testing procedure would not be a problem if different procedures could be counted on to yield consistent results. However, the tests are not very consistent when applied to tight formation reservoirs.

As previously stated, permeability testing is not common in the states we reviewed. Nevertheless, we were able to identify several tight formation wells for which the permeability had been estimated by more than one procedure. For example, in Ohio's recommendation for a portion of the Berea Sandstone Formation, four wells were shown with permeability estimates derived from both pressure tests and another method--type curve matching, whereby permeability can be estimated by using production data from wells in the formation.

Well number	Pressure buildup	Type curve
	---------------(md.)-------------	
7	0.11	0.07
9	.32	.12
11	1.63	.23
17	.01	.01

All the results indicate a low-permeability reservoir, but some are not low enough to meet FERC's standard. A well service company engineer told us that specific estimates, such as Order No. 99 requires, are not needed in the field. He said that only a reasonable range of permeability values is needed. It should be noted that having one or more test results above FERC's permeability standard does not automatically disqualify a formation because FERC's standard is met if the average of the test results falls within its criterion.

In another case, the permeability of one well in the Canyon Sand Formation of Texas was estimated according to three different procedures, and the measured permeability ranged from 0.01 to 0.48 md.

<u>Permeability test data are subject to interpretation</u>

Most techniques for estimating permeability involve measuring other well conditions such as pressure and temperature. Permeability is then estimated using mathematical equations or curve matching. These methods involve judgments in the choice of analytical techniques and the interpretation of data. An engineer at the Texas Railroad Commission told us that errors in any variable can seriously distort the final permeability estimate.

Ohio's recommendation of the Clinton Formation illustrated some of the interpretive problems in the estimation of pay zone thickness which involve considerable judgment. Ohio officials calculated permeability from pressure buildup tests performed on 19 wells, 8 under state supervision and 11 from well service company files. Calculating permeability from a pressure buildup test requires using a complex equation in which the final step is dividing by the thickness of the productive or pay zone.

Ohio officials told us that they first calculated pay zone thickness using an industry rule of thumb and found that more than half the wells were above FERC's 0.1 md. permeability standard. Lawyers for the applicants contended that this approach was too restrictive, and state officials agreed to recompute the figures using a more liberal estimate of pay zone thickness. This approach left only 5 of the 19 wells above the standard. The alternate test results are shown in appendix IV. We did not attempt to determine if similar problems occurred elsewhere.

FERC agreed with our conclusion that jurisdictional agencies encountered problems in applying FERC's criteria. FERC said that in many cases the jurisdictional agencies had to make difficult judgmental decisions concerning permeability estimates and pre-stimulation production rates in deciding whether a formation met FERC's guidelines for designation as a tight formation. FERC said that, as a general rule, it is not difficult to determine that a formation exhibits low permeability and will produce limited quantities of gas. However, it is extremely difficult to determine with any degree of precision the permeability values of the formation at the low ranges involved. FERC said that the measurement of these parameters is a subjective and imprecise exercise subject to differing interpretations and general lack of agreement, even among experts. Finally, FERC acknowledged that jurisdictional agencies, in many cases, had to make decisions based on generally inconclusive and minimal data.

APPLICATION OF FERC's PRODUCTION STANDARD WAS HAMPERED BY SPARSE DATA

In applying FERC's gas production standard, which allows a sliding scale of production based on formation depth, the states we contacted were hampered because stabilized prestimulation production rate test data were generally not available. FERC's standard for stabilized prestimulation production rates allows graduated increases in gas production based on the formation depth. For example, allowable gas production ranges from 44 Mcf per day at depths up to 1,000 feet to 2,557 Mcf per day at a depth interval between 14,500 and 15,000 feet. However, according to state jurisdictional agencies and well service companies included in our review, this type of test data was generally unavailable because operators routinely fractured wells and saw no need to hold up operations for prestimulation production tests.

In Pennsylvania, which tried to collect prestimulation production rates on well completion reports, less than 20 percent of those from the Medina Formation show any gas flow measurements.

Lacking stabilized prestimulation test data, applicants reported other data instead but pointed out that these were not the stabilized rates called for by FERC's standard. These other data included nonstabilized, prestimulation data and/or nonstabilized, post-stimulation data. Tight formation wells often take 2 years or more to stabilize, so it may not be possible to directly measure the rate FERC specified unless an operator postpones fracturing a well for up to 2 years. For instance, in the Texas applications for the Cotton Valley Group and Canyon Sandstone, which had some prestimulation flow data but not the stabilized rates, applicants used complex engineering equations to project stabilized production rates.

APPLICATION OF FERC's PERMEABILITY AND PRODUCTION STANDARDS WAS HAMPERED BY UNCERTAINTY ABOUT AVERAGING TEST RESULTS

FERC's tight formation criteria require that the estimated average permeability throughout the recommended formation be 0.1 md. or less, and the stabilized prestimulation production rate of wells completed in the formation not exceed maximum production rates based on the formation's depth. However, FERC's criteria do not specify the proper methodology for calculating the average permeability or productivity, so states have to decide on the method of averaging test results.

In estimating average permeability or production rates, states have generally used the arithmetic average[1] of test results. Sometimes the average permeability or productivity of test wells in a formation exceeded FERC's standards because a small number of test results were much higher than the rest. Rather than disqualify entire formations, FERC has permitted states to exclude areas where average permeability or production rates exceed the standard. (Any wells drilled into these excluded areas would not qualify for incentive pricing.)

For instance, Ohio excluded Knox County and a portion of Coshocton County from its recommendation of the Clinton Formation, bringing the average permeability of the remaining areas below 0.1 md. Similarly, Texas excluded portions of the first application for the Wilcox Formation because the permeability test data results exceeded the allowable level. In addition, Pennsylvania drew small circles around test wells (each representing an area within 1,320 feet radius around each well) that were above the standard and excluded the areas within these circles from its recommendation of the Medina Formation.

Rather than excluding areas with unusually high test results, several states have recommended tight formation applications using other methods for averaging results. These methods were a median[2] and a geometric mean[3]--each of which could

---

[1]The arithmetic average method simply adds the recorded values of all wells and divides the total by the number of wells measured.

[2]The median is the permeability or production value, M, such that at least half of the wells measured had values which equalled or exceeded M, and at least half the wells had values which equalled or were less than M.

[3]The geometric mean G of a set of N numbers $X_1, X_2, X_3, \ldots X_n$ is the Nth root of the product of the numbers.

$$G = \sqrt[n]{X_1 \ X_2 \ X_3 \ \ldots X_n}$$

The geometric mean of a set of positive numbers is less than or equal to their arithmetic average. For example, the geometric mean of the numbers 1, 1, 2, 2, 8 is 2; the arithmetic average is 2.8; and the median is 2.

reduce the effect of a few high-permeability wells on the overall result. On November 12, 1982, FERC held a hearing on the Louisiana-3 Addition application and eight other consolidated applications with a similar issue. Despite voluminous testimony by expert witnesses, FERC said that the issue of the proper methodology need not be addressed because Louisiana's subsequent alternative recommendation (which excluded certain areas) satisfied FERC's criteria under any of the proposed methodologies for averaging test results. As of December 1984, this issue was still unresolved in five of the other consolidated applications.

CHAPTER 4

MUCH OF THE ACTIVITY UNDER ORDER NO. 99 OCCURRED OUTSIDE HIGH-POTENTIAL AREAS

In the rulemaking process for Order No. 99, FERC tried to ensure that the incentive price for qualifying tight formations would encourage producers to develop the nation's untapped sources of high-risk and high-cost tight formation gas. However, much of the gas that qualified for incentive pricing was in areas under development at previously available prices. Drilling activity was increasing at a rate of 27 percent or more each year, at the prices available prior to the incentive pricing program, in 9 of the 11 formations included in our review (accounting for about 87 percent of the qualified tight formation wells at the time of our review work).

Much of the program activity occurred outside areas that FERC and others considered to have high potential for development. Program activity can be measured in two ways--drilling activity and production activity. Our analysis shows that about 40 percent of the production activity (83 percent of the qualifying wells) occurred outside the high-potential areas, while about 60 percent of the production activity (17 percent of the qualifying wells) occurred in high-potential areas. Moreover, some undeveloped tight formation basins, considered to have the greatest potential, accounted for a small proportion of program activity.

On January 1, 1985, phased natural gas price deregulation substantially reduced the amount of tight formation gas that is eligible for either incentive pricing or tax credits. Under the NGPA's phased deregulation, price ceilings on gas from wells deeper than 5,000 feet were generally lifted as of January 1, 1985, while gas from wells 5,000 feet or less will generally remain under price regulation until July 1, 1987. Much of the tight formation gas is deeper than 5,000 feet and, therefore, was deregulated on January 1, 1985.

In a September 1984 proposed rulemaking regarding price deregulation issues, FERC sought comments on whether producers of tight formation gas, which qualifies for both a regulated and a deregulated category, should be given the option to remain under regulation and collect the regulated price.[1] On November 16, 1984, FERC issued Order No. 406 which stated that producers of dual-category gas would not be given an option. Instead tight formation and other such gas would be considered deregulated effective either January 1, 1985, or July 1, 1987.

ORDER NO. 99 FAVORED FORMATIONS WITH HISTORIES OF PRIOR DEVELOPMENT

Even though Order No. 99 did not limit the incentive price to particular formations, it remained FERC's objective to confine incentive pricing to formations and areas which had (1) little or no commercial development at prevailing prices and (2) high potential for development. However, most of the formations that we reviewed had histories of increasing development before Order No. 99. In addition, much of the program activity occurred outside high-potential areas. Further, some undeveloped formations originally identified by FERC and others as having the greatest potential accounted for a small proportion of program activity.

Formations were approved which had increased drilling activity before Order No. 99

During its rulemaking process, FERC attempted to encourage drilling of tight formation wells in undeveloped or little-developed areas. However, 9 of the 11 formations that we reviewed had histories of increasing development before Order No. 99. When FERC issued its proposed rule in August 1979, it tried to exclude developed areas from the program by requiring that proposed tight formations should not have been the subject of field rules for well spacing.[2] But the comments on the proposed rule convinced FERC that it should not exclude developmental drilling, that is, drilling additional wells in producing reservoirs. For instance, DOE, responding to the proposed rule, contended that such a requirement was impractical and recommended instead that no well qualify for incentive pricing unless it was at least a mile from the nearest marker well--a well from which natural gas was produced in commercial quantities at any

---

[1]In its rulemaking FERC noted there may be instances in which a producer may find it more advantageous to claim a contractual right to receive a higher price if the gas can remain under a regulated category than if the gas is deregulated. Also, the tax credit is not available if the gas is deregulated.

[2]Normally, states issue well-spacing orders which regulate the number and location of wells in a reservoir to promote effective and efficient drainage of the reservoir.

time after January 1, 1970, and before April 20, 1977. Other commenters argued that a number of partially developed tight gas reservoirs had reached their limit of commercial development at prevailing prices. In Order No. 99 FERC added a standard concerning infill drilling that was authorized prior to the date of recommendation. Under this standard, the jurisdictional agency was to exclude that portion of a formation that it determined could be developed without the incentive price.

Nevertheless, formations were approved which had substantial increases in drilling activity before Order No. 99 was issued. As shown in table 3, we analyzed drilling trends in 11 approved tight formations between 1973 and 1979, the year before FERC issued Order No. 99. We did not use data beyond 1979 because such drilling trend data may have been influenced by the potential availability of incentive pricing. The 11 formations accounted for about 87 percent of the wells qualified for incentive pricing under Order No. 99 through December 22, 1982.

The table shows that between 1973 and 1979, 9 of the 11 formations exhibited substantial growth in drilling--as measured by the compounded annual rate of increase in drilling. The nine formations' compounded annual rate of increase ranged from 27 to 67 percent.

The other two formations had lower growth rates. The Canyon Formation's compounded annual growth rate was about 2 percent, and it is possible that incentive pricing could have accelerated drilling in such an area. The Clinton Formation's compounded annual growth rate was about 12 percent. However, the large number of wells already drilled and the low-risk factor, discussed on pages 19 to 21, indicate that the Clinton Formation was being developed at prevailing gas prices.

Table 3

Wells Completed In Selected Tight Formations by Year, 1973-79[a]

Formation and State	1973	1974	1975	1976	1977	1978	1979	Compounded annual rate of increase (percent)
Abo (New Mexico)	9	4	7	3	15	17	37	27
Berea (Ohio)	76	91	62	165	389	329	511	37
Canyon[b] (Texas)	231	281	331	250	336	284	258	2
Clinton (Ohio)	1,342	1,585	1,102	1,630	2,081	2,163	2,680	12
Cotton Valley[b] (Texas)	14	34	31	75	131	238	303	67
Dakota (Colorado)	3	6	3	3	14	14	16	32
Frontier (Wyoming)	11	25	37	45	64	69	68	35
Mancos B (Colorado)	17	21	24	70	113	67	80	29
Medina (Pennsylvania)	19	24	17	26	60	199	222	51
Mesaverde (Wyoming)	17	19	49	58	94	130	123	39
Wilcox[b] (Texas)	8	22	51	43	54	58	61	40

[a]For formations in Pennsylvania and Texas, drilling data are for completed gas wells. For formations in other states, available drilling data are for completed gas and oil wells.

[b]Only counties included in tight formation designations were analyzed.

Source: For Texas, GAO analysis of Texas data base on gas wells. For Ohio, statistics compiled by the Ohio Division of Oil and Gas. For other states, GAO analyses of FERC data on wells completed.

Formations outside high-potential areas accounted for much of the program activity

During its rulemaking process, FERC attempted to encourage drilling of tight formation wells in formations with high potential for development. However, several formations proposed by FERC (in its initial notice of proposed rulemaking) were never approved, while states recommended many formations that were not listed in the proposed rule. Even among the formations listed in the proposed rule, those estimated to have the greatest potential have received relatively little attention despite the incentive price. (We did not attempt to determine what factors other than the incentive price may have affected activity in these formations.)

As mentioned in chapter 2, FERC's proposed rule included a list of 27 formations considered to be important sources of tight formation gas. These formations were identified in 10 basins extending over 12 states, all west of the Mississippi River. The list closely resembled one compiled by NPC, which had identified 30 formations in 9 basins.[3]

In response to FERC's proposed rule, DOE recommended that FERC direct its incentive program to 10 formations in three western states--Colorado, Utah, and Wyoming. DOE also discussed a number of other basins in a band running from Montana down through Texas and Louisiana which were known to contain low-permeability reservoirs. DOE pointed out that these other basins were either little known or contained areas of commercial production under prevailing prices. DOE recommended that action on these basins be deferred until federal agencies could compile better information on their development problems and the incentives needed for production.

As previously noted, however, FERC changed its approach during the rulemaking, giving up its attempt to target incentive pricing to specific formations. Under Order No. 99 FERC relies on jurisdictional agencies to recommend formations.

---

[3]We made some consolidations of the basins and formations in FERC's list based on discussions with both FERC and state officials. The effect of these consolidations on the analysis in this chapter is to give the benefit of the doubt to FERC's original list. Therefore, to the extent that any of the wells were not actually in formations on the original list, the amount of activity under Order No. 99 which can be attributable to the original list would tend to be overstated. To be consistent, we treated NPC's list the same way. See appendixes I and II for these lists.

As shown in table 4, we analyzed 14,593 tight formation well determinations received at FERC through December 1982,[4] to assess whether the program was reaching the high-potential formations identified by FERC and others. (As noted on p. 32, this is one way to measure program activity. Another way is discussed below, beginning on p. 38.) Even though FERC's final rule did not include a listing of the tight formations with high potential, FERC retained the objective of providing incentives to those formations that could not be commercially developed at otherwise available prices. Therefore, we believe it is reasonable to compare drilling activity in approved tight formations to (1) FERC's originally proposed list, (2) NPC's list, and (3) DOE's recommended list.

The results of these comparisons are shown below.

--Results for the FERC list and the NPC list were similar. Formations proposed by both organizations accounted for about 17 percent of the total (2,507 and 2,460, respectively, of the 14,433 wells identified). In both cases, of the 13 states with approved formations, 2 states (Colorado and Texas) accounted for the majority of the wells, while 4 other states had some wells, and 7 states had no wells.

--Formations identified by DOE accounted for 3 percent of the total (484 of 14,433). Of the 13 states, 3 (Colorado, Utah, and Wyoming) contained all the 484 wells, while 10 states had no wells.

Conversely, formations not listed in both FERC's original list and NPC's list accounted for 83 percent of the wells (11,926 and 11,973, respectively, of the 14,433 total). The Appalachian Basin states of Ohio and Pennsylvania accounted for most of these wells although a significant number also came from Louisiana, New Mexico, New York, and Texas. Formations not listed by DOE accounted for 97 percent of the wells (13,949 of 14,433).

FERC's aggregate data for the period through October 1984 (the most recent data available as of December 1984) show a similar pattern. Three states which had no formations listed in the proposed rule--Ohio, New York, and Pennsylvania--accounted for 20,347 wells or about 71 percent of the qualifying wells.

---

[4]We were unable to identify formations for 160 wells included in FERC's data base of 14,593 wells, leaving 14,433 wells. Our original analysis was supplemented with October 1984 aggregate data to demonstrate that the original results are still valid.

Table 4

Number of Wells Qualified for Incentive Pricing from Initially Identified Formations Compared with Those Not Listed in the Proposed Rule

State	Total wells	From formations: Identified by DOE	NPC	Listed in proposed rule	Not listed in proposed rule	Number of wells in formations not identified in FERC data base
Colorado	653	218	318	456	123	74
Louisiana	285	-	17	20	254	11
Mississippi	3	-	-	-	3	-
New Mexico	525	-	38	38	477	10
New York	697	-	-	-	697	-
Ohio	8,523	-	-	-	8,523	-
Oklahoma	4	-	-	-	4	-
Pennsylvania	1,354	-	-	-	1,354	-
Texas	2,131	-	1,758	1,732	367	32
Utah	158	140	140	140	-	18
Virginia	34	-	-	-	34	-
West Virginia	14	-	-	-	14	-
Wyoming	212	126	189	121	76	15
Total	14,593	484	2,460	2,507	11,926	160

Source: GAO analysis of FERC data base on tight formation well determinations through December 22, 1982.

FERC did not explicitly agree or disagree with our statement that only 17 percent of the qualifying wells were drilled in high-potential formations. However, it proposed that gas production is another method of measuring the program's results. FERC estimated that 85 percent of the production from qualifying wells come from high-potential formations.

FERC also commented that much of the tight formation program economic activity, as measured by cost and risk factors, took place in the higher potential areas (northeastern Texas, Utah, and Wyoming) rather than in the Appalachian region (New York, Ohio, Pennsylvania, and West Virginia). FERC estimated in comparing high potential west areas to east areas that it cost nine times as much to drill a well that had two thirds as great a chance of being successful. However, it estimated that such a well will produce 27 times as much gas if successful. FERC estimated that twice the capital was invested in successful tight formation wells in the western areas compared to the eastern areas ($5.979 billion versus $2.977 billion) and six times the volumes of gas was produced (500 Bcf versus 80 Bcf). Finally, FERC said this kind of activity indicates that the program encouraged activity in the higher potential areas, with the expected result of increase in reserves.

We agree with FERC that gas production is a valid way of measuring program activity. Based on FERC comments, we recalculated program activity based on estimated tight formation gas production in high-potential formations and estimated production outside high-potential formations. We believe that FERC's estimate of 85 percent overstates the amount of program activity in high-potential formations. A branch chief in FERC's Division of Producer Audits and Pricing told us that FERC derived its estimate by adding up all tight-gas production in the Appalachian states and three western states that had high-potential formations (see p. 60). This method credits all gas production in the western states to high-potential formations, even though some production may have occurred elsewhere in the state. For example, as shown in table 4, of the 2,099 qualifying wells in Texas,[5] 1,732 wells, or 83 percent, were in high-potential formations, and 367 wells, or 17 percent, were outside those formations. Our recalculation shows that about 60 percent (470.3 of 788.8 Bcf) of the tight formation gas production was from high-potential formations (see table 5). This figure is lower than the 85-percent figure stated by FERC because the tight formation gas production from each state was apportioned between high-potential formations and other formations.

Conversely, our recalculation shows that about 40 percent (318.5 of 788.8 Bcf) of the tight formation gas production under the program did not occur in high-potential formations. Furthermore, as FERC said in its comments, most of the production in high-potential formations was in areas already under development and not in those tight formation areas, such as the Northern Great Plains/Williston Basin, considered to have the greatest potential for increasing tight formation gas reserves.

---

[5]The 2,099 total includes 2,131 wells in Texas minus 32 wells that were in formations not identified in FERC's data base.

Table 5

Estimated Annual Tight Formation Gas Production in High-Potential Formations and Outside High-Potential Formations

State	Number of wells[a]	Percentage of wells estimated to be in high-potential formations[b]	Total estimated annual production[c]	Estimated annual production in high-potential formations[d]	Estimated annual production outside of high-potential formations
			--------(billion cubic feet)	--------	--------
Colorado	1,474	79	51.9	41.0	10.9
Louisiana	722	7	27.4	1.9	25.5
New Mexico	967	7	92.5	6.5	86.0
New York	2,244	-	12.1	-	12.1
Ohio	15,866	-	68.2	-	68.2
Oklahoma	35	-	3.2	-	3.2
Pennsylvania	2,237	-	14.3	-	14.3
Texas	4,185	83	447.4	371.3	76.1
Utah	232	100	16.8	16.8	-
West Virginia	100	-	1.2	-	1.2
Wyoming	424	61	53.8	32.8	21.0
Other[e]	84	-	[f]	-	-
Total	28,570		788.8	470.3	318.5

[a]FERC well determination statistics through October 1984.

[b]Calculated from data shown in table 4.

[c]Production per well computed from Drilling and Production Under Title I of the Natural Gas Policy Act (DOE/EIA-0448, June 1984, pp. 49-50). Total estimated annual production is equal to the number of wells multiplied by production per well.

[d]Total estimated annual production multiplied by the percentage estimated to be in high-potential formations.

[e]Kentucky, Mississippi, Tennessee, and Virginia.

[f]Production data not available.

We also analyzed tight formation wells that qualified for incentive pricing to assess whether the program was reaching formation basins considered to have the greatest potential. We based our analysis on NPC data because NPC had developed estimates of maximum recoverable gas in nine formations.

As shown in table 6, among the nine basins, those with the greatest potential accounted for a disproportionately small number of wells. The four basins with the greatest potential accounted for about 88 percent of the potentially recoverable gas supplies (258.3 of 292.6 trillion cubic feet). However, they accounted for only 527 wells, which represent 21 percent of the wells in the high-potential areas and 4 percent of all wells. The other five high-potential basins accounted for 1,933 wells, which represent 79 percent of the wells in the high-potential areas and 13 percent of all wells.

Instead, as discussed earlier, some areas in Texas (such as the Cotton Valley and Val Verde Basins), which were already under development before Order No. 99, accounted for substantial drilling under the program.

Table 6

NPC's Estimates of Potentially Recoverable Tight Gas Compared to Drilling Activity Under Order No. 99

Basin	NPC's estimate of maximum recoverable gas	Number of wells qualified under Order No. 99[a]
	(trillion cu. ft.)	
Northern Great Plains/ Williston	100.2	-
Greater Green River	86.5	189
Uinta/Piceance	48.3	338
Wind River	23.3	-
Cotton Valley	12.8	979
Edwards Lime	8.6	26
Denver	7.9	120
Val Verde	2.8	770
San Juan	2.2	38
Total	292.6	2,460[b]
Formations not appraised by NPC		11,973[b]

[a]These are wells from formations included in the NPC's study.

[b]These totals do not include 160 wells that were in formations not identified in FERC's data base.

Source: National Petroleum Council, Tight Gas Reservoirs, Part I, 1980, pp. 39-43. GAO analysis of FERC data base on tight formation well determinations through December 22, 1982.

THE TIGHT FORMATION GAS PROGRAM UNDER PHASED DEREGULATION

Under the NGPA's phased deregulation of natural gas, price ceilings on gas from wells deeper than 5,000 feet were generally lifted as of January 1, 1985, while gas from wells 5,000 feet or less will generally remain under NGPA price controls until

July 1, 1987.[6] On January 1, 1985, the scope of the tight formation gas program was substantially reduced because much of the gas was deregulated. Similarly, the scope of the tax credit was reduced because the credit is not available if the gas is deregulated.

To prepare for NGPA price deregulation, FERC issued a proposed rulemaking on September 13, 1984,[7] which considered, among other issues, whether producers of tight formation gas should be given the option to continue collecting the regulated price even though the gas could qualify for the deregulated price. On November 16, 1984, FERC issued Order No. 406 stating that gas, such as tight formation gas, which qualified for both a regulated and a deregulated price category would be deregulated.[8]

Under provisions of the 1978 act, much of the natural gas was or will be deregulated. According to a DOE report,[9] under phased deregulation federal price ceilings ceased to apply to about 50 to 60 percent of domestic natural gas production on January 1, 1985, and deregulated gas will increase to about 75 to 80 percent by 1990.

---

[6] Natural gas categorized as new natural gas or new onshore production wells under the NGPA was generally decontrolled on January 1, 1985. However, some gas volumes under the above two categories was not decontrolled. This includes gas from reservoirs discovered after July 27, 1976, on old offshore (Outer Continental Shelf) leases and wells that were producing gas from acreage dedicated to interstate commerce before April 20, 1977.

[7] Docket No. RM84-14-000, "Deregulation and Other Pricing Changes on January 1, 1985, Under the Natural Gas Policy Act," 49 Fed. Reg. 36399 (1984).

[8] 49 Fed. Reg. 46874 (1984).

[9] The First Report Required by Section 123 of the Natural Gas Policy Act of 1978 (DOE/PE-0054, July 1984, p. 6-3).

CHAPTER 5

CONCLUSIONS

The Natural Gas Policy Act authorized FERC to prescribe a ceiling price in excess of the otherwise maximum lawful price to provide reasonable incentives for the production of high-cost natural gas. The act defines "high-cost natural gas" to mean, among other things, gas which is produced "under such other conditions as the Commission determines to present extraordinary risks or costs."

In Order No. 99 FERC determined that natural gas produced from tight formations was produced under conditions which presented extraordinary risks or costs and that an incentive price of up to 200 percent of the new, onshore production price was necessary to provide reasonable incentives to produce such gas. In addition, producers of such natural gas may also qualify for a tax credit.

FERC sought to establish an incentive price that would lead to the development of high-risk and high-cost areas that could not be commercially developed at otherwise available prices. We found in our review of selected states and formations that most of the qualifying wells drilled were not in tight formations that were extraordinarily risky or costly to develop. During the period 1976 to 1982, formations included in our review had annual success rates which ranged from 68 to 100 percent. In comparison, the national success rate for all drilling activity during the same years ranged from 66 to 71 percent. Also, discussions with state officials and review of data suggest that developing a tight formation well did not double a well's cost as FERC had anticipated, but instead added 50 percent or less in the three states which have accounted for a substantial number of qualified tight formation wells.

FERC's program objective was to encourage development of formations which had little or no commercial development and those which had high potential. However, drilling trends in 11 approved tight formations, which have accounted for a significant number of qualified wells under the program (87 percent as of December 1982), indicate that substantial development occurred at previously available prices. Nine of the 11 formations had a compounded annual growth in drilling which ranged from 27 to 67 percent (between 1973 and 1979) before the program started. (However, we did not attempt to determine what factors other than the incentive price may have affected activity in these formations.) Furthermore, although over 28,000 tight formation wells qualified for incentive pricing through October 1984, the majority were not in the high-potential formations identified by FERC, NPC, and DOE.

FERC's physical criteria for designating areas eligible to receive tight formation incentive pricing depended heavily on being able to collect and measure test data on well permeability and the expected production rate. However, jurisdictional agencies, given the responsibility to review and recommend tight formation applications, experienced difficulties in applying FERC's qualifying criteria. The principal problems which jurisdictional agencies encountered in evaluating proposed tight formations related to the availability and interpretation of data on permeability, availability of production test data, and the proper method for averaging permeability and production test data.

Even though we found that FERC's qualifying criteria did not limit the incentive price to high-potential formations and were difficult to apply in selected states, we are not recommending any changes to the program because it will have limited application in the future. This limited application is due to the combined effects of the 1978 act and a November 1984 FERC rulemaking.

According to a DOE report, under provisions of the 1978 act, federal price ceilings ceased to apply to about 50 to 60 percent of domestic natural gas production on January 1, 1985. Deregulated gas will increase to about 75 to 80 percent by 1990. To consider how to treat gas (such as tight formation gas) that could qualify for both a deregulated price and a regulated price, FERC initiated a rulemaking in September 1984. A key question was whether or not the producer of such gas should have a choice of price category--for example, could a producer assert a claim to collect the tight formation price even after January 1, 1985? In November 1984, FERC issued a final rulemaking, which stated that all such gas would be considered deregulated; and, therefore, a producer would not be able to choose.

Together with the act's provisions, the rulemaking means that much tight formation gas was deregulated on January 1, 1985, and the remainder will be deregulated on July 1, 1987. Thus, the program will have limited application in the future. For this reason, we are not recommending any program changes.

AGENCY COMMENTS AND OUR EVALUATION

The entire report was sent to FERC and the Interior Department, and a section regarding tax credits for tight formation gas was sent to the Internal Revenue Service for comment. Their comments are included as appendixes V, VI, and VII. We have incorporated agency comments in the report, where appropriate.

FERC comments

FERC generally agreed with our conclusion that tight formations which have undergone development have not been extraordinarily risky or costly to develop. However, FERC explained that the program provided an incentive price for various types of tight formation drilling programs in developing and undeveloped areas, some of which are more risky and costly than others. Also, FERC provided a variety of reasons why the least risky and costly gas was the first gas produced under the program (see pp. 20 to 24).

FERC also agreed with our conclusion that jurisdictional agencies encountered problems in applying FERC's qualifying criteria. FERC acknowledged that making the needed measurements is a subjective and imprecise exercise and that jurisdictional agencies, in many cases, had to make decisions based on generally inconclusive and minimal data (see pp. 28 and 29).

FERC did not explicitly agree or disagree with our conclusion that a small proportion of drilling activity occurred in high-potential formations. However, it proposed that gas production is another criterion for measuring program effectiveness. FERC stated that, when gas production is taken into consideration, the program encouraged considerable activity in high-potential formations. Also, FERC explained that a comparison of program activity, as measured by cost and risk factors, indicates that the program encouraged activity in the higher-potential areas and increased gas reserves.

We agree that gas production is a valid method of measuring program activity, and revised the report accordingly. However, we believe that FERC overestimated gas production in high-potential formations and we made our own estimate--60 percent versus FERC's estimate of 85 percent. Thus, we still believe that much of the program activity took place outside high-potential formations (see pp. 38 to 40).

In addition, FERC said the incentive price authorized in Order No. 99 is a ceiling price only, and such price could be charged only if the producer had specific contractual authority to do so. FERC said this safeguard was intended to ensure that the price was deemed necessary by a purchaser to elicit development of tight formation gas (see p. 3).

Department of the Interior comments

In commenting on a draft of this report, Interior generally agreed with the report's findings. Interior also provided technical clarifications.

Internal Revenue Service comments

The Internal Revenue Service generally agreed with the information presented on tax credits and provided some technical clarifications and updated information.

TIGHT FORMATIONS FROM FERC's ORIGINAL LIST[a]

STATUS OF ACTION BY STATES AND FERC

(THROUGH JANUARY 14, 1983)[b]

Basin	Formation	States that recommended area including formation	FERC approval
Northern Great Plains/ Williston	1. Greenhorn	Montana	Pending
	2. Frontier	Not recommended	-
	3. Judith River	Not recommended	-
	4. Eagle	Not recommended	-
	5. Carlile	Not recommended	-
Greater Green River	6. Fort Union	Wyoming	Yes
	7. Mesaverde (including Almond, Erickson, Rock Springs, Blair)	Wyoming	Yes
Wind River	8. Frontier	Wyoming	Pending
	9. Muddy	Not recommended	-
Big Horn	10. Mesaverde	Not recommended	-
Uinta/Piceance/ Douglas Creek Arch	11. Fort Union	Colorado	Yes
	12. Wasatch	Colorado	Yes
		Utah	Yes
	13. Barren	Not recommended	-
	14. Coaly	Not recommended	-
	15. Mesaverde (including Corcoran, Cozzette, Castlegate)	Colorado	Yes
		Utah	Yes
	16. Mancos	Colorado	Yes
		Utah	Pending
	17. Dakota	Colorado	Partial
		Utah	Pending

[a]This appendix is GAO's interpretation of FERC's list of proposed formations in the August 1979 proposed rule. We consolidated some of the basins after discussions with state officials. We also concluded that some of the geologic units mentioned by FERC were actually parts of a larger formation (such as the Mesaverde). We were able to classify wells better as a result of the interpretation made in this appendix. It also resulted in crediting more drilling activity under Order No. 99 to FERC's original list of formations.

[b]Latest data available at the time of our review.

APPENDIX I

Basin	Formation	States that recommended area including formation	FERC approval
Denver	18. Niobrara	Colorado	Yes
		Nebraska	Partial
		Kansas	Pending
	19. Sussex	Colorado	Yes
	20. Dakota	Colorado	Partial
San Juan	21. Dakota	Colorado	Yes
		New Mexico	Partial
Val Verde	22. Canyon	Texas	Yes
Cotton Valley Trend	23. Cotton Valley	Texas	Yes
		Louisiana	Partial
	24. Bossier	Texas	Yes
	25. Haynesville/Gilmer/	Louisiana	Yes
	Cotton Valley Lime	Texas	Yes
	26. Smackover	Louisiana	Partial
Quachita	27. Stanley	Not recommended	-

TIGHT FORMATIONS NOT ON FERC's ORIGINAL LIST

THAT HAVE BEEN RECOMMENDED BY THE STATES

(THROUGH JANUARY 14,1983)[a]

Basin	Formation	States that recommended area including formation	FERC approval
Northern Great Plains/ Williston	1. Phillips	Montana	Pending
	2. Bowdoin	Montana	Pending
Greater Green River	3. Frontier	Wyoming	Yes
	4. Fox Hills	Wyoming	Yes
	5. Bear River	Wyoming	Yes
	6. Lewis	Wyoming	Yes
	7. Nugget	Wyoming	Yes
Wind River	8. Lance	Wyoming	Yes
	9. Dakota	Wyoming	Pending
	10. Meeteetse	Wyoming	Yes
Uinta/Piceance/ Douglas Creek Arch	11. Morrison	Utah	Partial
Denver	12. Wattenberg "J" Sand	Colorado	Partial
	13. Codell	Colorado	Yes
San Juan	14. Fruitland	New Mexico	Yes
	15. Mesaverde	Colorado	Yes
		New Mexico	Partial
	16. Pictured Cliffs	New Mexico	Yes
	17. Chacra	New Mexico	Yes
Val Verde	18. Strawn-Detrital	Texas	Partial
	19. Devonian	Texas	Pending
Edwards Lime Trend	20. Edwards Limestone	Texas	Partial
Cotton Valley Trend	21. Arkadelphia	Louisiana	Yes
	22. Travis Peak/Hosston	Mississippi	Yes
		Louisiana	Pending
		Texas	Partial

[a]Latest data available at the time of our review.

 APPENDIX II

Basin	Formation	States that recommended area including formation	FERC approval*
Cotton Valley Trend (continued)	23. James Lime	Louisiana	Yes
		Texas	Partial
	24. Pettit Lime	Texas	Pending
Anadarko	25. Atoka	Oklahoma	Partial
	26. Cleveland	Oklahoma	Pending
		Texas	Pending
	27. Cherokee Group	Oklahoma	Pending
	28. Granite Wash	Texas	Pending
Western Gulf Coast	29. Vicksburg	Texas	Partial
	30. Rea Sand	Mississippi	Yes
	31. Frio	Texas	Yes
	32. Navarro	Texas	Yes
	33. Olmos	Texas	Yes
	34. Georgetown	Texas	Pending
	35. Garza Sand	Texas	Pending
	36. Anacacho	Texas	Pending
	37. Wilcox	Texas	Partial
Appalachian	38. Clinton/Medina	New York	Yes
		Ohio	Yes
		Pennsylvania	Yes
	39. Queenston	New York	Pending
	40. Berea	Kentucky	Yes
		Ohio	Partial
		Virginia	Yes
		West Virginia	Partial
	41. Second Berea	Ohio	Partial
	42. Mauch Chunk	West Virginia	Yes
	43. Greenbriar	West Virginia	Pending
	44. Chemung	West Virginia	Pending
	45. Catskill	West Virginia	Pending
Black Warrior			
	46. Pottsville	Alabama	Yes
	47. Hartselle	Alabama	Yes
Permian			
	48. Austin-Mississippian	New Mexico	Yes
	49. Atoka	New Mexico	Partial
	50. Abo	New Mexico	Yes
	51. Wolfcamp	New Mexico	Pending
	52. Canyon/Cisco	New Mexico	Yes
	53. Clearfork	Texas	Yes
	54. Fusselmann/Montoya	Texas	Pending
Other			
	55. Morrow	Colorado	Yes
	56. Tarkio	Kansas	Pending

TIGHT FORMATIONS ON THE NATIONAL PETROLEUM COUNCIL'S LIST[a]

STATUS OF ACTION BY FERC

(THROUGH JANUARY 14, 1983)[b]

Basin	Maximum recoverable gas (Tcf)	Formation	States in which FERC has approved
Northern Great Plains/ Williston	100.2	1. Judith River	Not recommended
		2. Niobrara	Not recommended
		3. Eagle	Not recommended
		4. Carlile	Not recommended
		5. Greenhorn	Not recommended
		6. Mowry	Not recommended
Greater Green River	86.5	7. Fort Union	Wyoming
		8. Mesaverde (including Almond, Ericson, Rock Springs, Blair)	Wyoming
		9. Lance	Not recommended
		10. Lewis	Wyoming
		11. Frontier	Wyoming
Wind River	23.3	12. Fort Union	Not recommended
		13. Lance	Wyoming
		14. Lower Mesaverde	Wyoming
		15. Frontier/Muddy	Not recommended
Uinta/Piceance	48.3	16. Wasatch	Utah Colorado
		17. Barren	Not recommended
		18. Coaly	Not recommended
		19. Mesaverde (including Castlegate, Corcoran, Cozette)	Colorado Utah
		20. Fort Union	Colorado
		21. Dakota	Colorado
		22. Morrison	Colorado Utah
Denver	7.9	23. Wattenberg "J" Sand	Colorado
		24. Dakota	Colorado

[a]We made some interpretations of NPC's list in order to be consistent with appendix I. See the explanatory footnote to appendix I.

[b]Latest data available at the time of our review.

Basin	Maximum recoverable gas	Formation	States in which FERC has approved
	(Tcf)		
San Juan	2.2	25. Dakota	Colorado New Mexico
Val Verde (Ozona/Sonora)	2.8	26. Canyon Sandstone	Texas
Edwards Lime	8.6	27. Edwards	Texas
Cotton Valley	12.8	28. Cotton Valley Sand	Louisiana Texas
		29. Bossier Shale	Texas
		30. Cotton Valley Lime/ Haynesville/Gilmer Lime	Texas Louisiana
Total	292.6		

PERMEABILITY OF TEST WELLS ACCORDING TO TWO METHODS OF ESTIMATING PRODUCTIVE ZONE THICKNESS IN OHIO'S CLINTON FORMATION

Well no.	County	First method (md.)	Second method (md.)
1.	Portage	0.015	0.012
2.	Guernsey	.015	.011
3.	Geauga	.021	.030
4.	Tuscarawas	.053	.027
5.	Tuscarawas	.059	.057
6.	Tuscarawas	.069	.057
7.	Ashtabula	.078	.096
8.	Tuscarawas	.082	.065
9.	Tuscarawas	.096	.053
10.	Muskingum	.120[a]	.047
11.	Tuscarawas	.123[a]	.095
12.	Tuscarawas	.137[a]	.088
13.	Guernsey	.149[a]	.090
14.	Tuscarawas	.202[a]	.094
15.	Coshocton	.219[a]	.377[a]
16.	Wayne	.308[a]	.139[a]
17.	Noble	.321[a]	.276[a]
18.	Coshocton	.372[a]	.251[a]
19.	Knox	2.804[a]	1.630[a]
	Average	.276	.184
	Median	.120	.088
	Average without wells 15 and 19	.139	.094

[a]Values above the 0.1 md. threshold.

Source: Ohio Division of Oil and Gas, Supplemental Geological Report on the Clinton Formation.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

MAR 18 1985

J. Dexter Peach, Director
Resources, Community, and Economic Development Division
U.S. General Accounting Office
Washington, DC 20548

Dear Mr. Peach:

Thank you for giving us the opportunity to review the General Accounting Office's (GAO) draft report entitled "Problems Identified in FERC's Incentive Pricing Program for Natural Gas from Tight Formations."

In this report, the GAO addressed the following three questions:

1) Did the tight formations approved under the incentive pricing program prove to be extraordinarily risky and costly to develop, as had been assumed by the Commission?

2) Were the jurisdictional agencies able to apply the Commission's qualifying criteria in recommending tight formations for incentive pricing?

3) To what extent did the incentive price stimulate drilling activity in formations having the greatest potential?

In summary, GAO found that:

1) Tight formations were not extraordinarily risky or costly to develop;

2) Jurisdictional agencies encountered problems in applying the Commission's criteria; and

3) Little program activity was found in high potential areas.

GAO did not recommend any program changes, however, since the tight formation program will have limited application due to the deregulation of certain natural gas on January 1, 1985, and July 1, 1987, under the Natural Gas Policy Act of 1978.

I have enclosed for your review the Commission staff's comments on the draft report. I believe these comments are valid and should be considered in the preparation of your final report.

In addition to these specific comments, I believe the following general comments are pertinent. The incentive price authorized in Order No. 99 is a ceiling price only, and such rate could only be charged if the producer had specific contractual authority which referenced the Commission's authority under section 107 of the NGPA to establish incentive rates. This safeguard was built into the collection requirements to insure that the price was deemed necessary by a purchaser to elicit development of the tight formation gas. The purchaser is not required to pay a price higher than necessary to elicit production of tight formation gas.

Sincerely,

Raymond J. O'Connor

Raymond J. O'Connor
Chairman

Enclosure

Staff Comments on GAO Report

GAO Draft Report

GAO's draft report concludes that tight formations were not extraordinarily risky or costly to develop.

FERC Staff Response

The criticisms leveled in GAO's analysis of this question are not a total surprise. Most of the tight formations which have undergone development have not been extraordinarily risky or costly to develop.

We note, however, that in 1980, the Commission stated in Order No. 99:

"The estimated amount of tight formation gas includes formations that are presently being developed as well as formations that are known but undeveloped. This rule will provide an incentive price for the production of gas produced from several types of drilling programs: (1) Infill wells drilled into certain developed tight formations; (2) recompletion of wells that are already producing from formations that are vertically situated to the designated tight formations; and (3) new wells drilled and completed in undeveloped tight formations." 1/

This illustrates that in establishing the incentive price for tight formations, the Commission had no illusions concerning which gas would be first developed and produced. Producers of any commodity in a situation that demands optimization of profit and minimization of risk, combined with the decreasing value of a monetary unit over time, are going to make decisions which result first in the least costly and least risky production of that commodity. Moreover, the total energy situation of the United States over the last few years -- declining oil prices, oversupply of gas, relatively flat energy consumption, worldwide economic stagnation -- precluded the necessity for advancing into undeveloped tight formations which require the amount of risk taking or investment thought in 1979 to be necessary to mobilize the full productive capability of the more-difficult-to-find-and-produce gas. A prime example of this is the Northern Great Plains/Williston Basin, an area of approximately 120,000 square miles with estimated resources of natural gas in place in excess of 100 trillion cubic feet (TCF), or approximately 30 percent of some estimates of all tight formation gas available in the U.S. However, only one formation in this basin has been recommended for the incentive price,

---

1/ FERC Order No. 99, [Reg. Preambles 1977-1981] FERC Stats. and Regs. ¶ 30,183 (1980).

the Greenhorn in Montana. For a variety of reasons, primarily little concentration of gas in producible quantities, lack of availability of transportation, and low permeability (ease of extraction), producers have not attempted development of these seemingly vast resources because the expected return on investment does not warrant commitment of resources when easier, more profitable opportunities are available.

Finally, in examining whether those tight formations approved under the program proved extraordinarily risky or costly to develop, we note that GAO compares a success ratio of all oil and gas wells between 1976 and 1982 to the success ratio for seven approved tight formations during the same time, and determined that the comparison of 66-71 percent for the national average for combined oil and gas wells and 68-100 percent for six of the seven tight formations' wells revealed no increase in risk. The GAO report admits that success for oil and gas well drilling may differ, and that it could be misleading to compare the seven tight formations' success rates with national success rates for all oil and gas wells. A comparison of "success rates" in the tight formations chosen by GAO for analysis before and after the effective date of Order No. 99 would be more indicative of how the incentive price has operated in those areas. The (unweighted) combined success rate for 1973-1978 was 71 percent. The success rate for the 1980-1982 period for the same seven formations increased to 91 percent.

It must be realized that the terms "successful well" and "commercially productive" are first and foremost economic terms. All geologic depositions contain natural gas. However a commercially productive formation must have sufficient producible quantities to justify the investment required to extract the desired resource. Therefore if one accepts that the term "success rate" is an economic term, it would seem that the tight formation incentive price program worked well in the areas selected for comparison by GAO, precisely because it decreased the (economic) risk (or conversely compensated producers for accepting the risk) and brought a greater percentage of wells into the realm of "successful," as comments by the House Ad Hoc Committee of Energy indicated was desirable when they stated that the incentive price is extended to provide the "fullest practicable development" of our gas reserves. 2/

2/ H. Rep. No. 95-543 (Vol. I), 95 Cong. 1st Sess. 46 (1977).

GAO Draft Report

GAO concludes that the jurisdictional agencies encountered problems in applying the Commission's criteria.

FERC Staff Response

In many cases the jurisdictional agencies had to make difficult judgmental decisions concerning permeability estimates and pre-stimulation production rates in deciding whether a formation met the Commission's guidelines for designation as a tight formation. As a general rule, it is not difficult to determine that a formation exhibits low permeability and will produce limited quantities of gas, but it is extremely difficult to determine with any degree of precision the permeability values of the formation at the low ranges involved. The measurement of these parameters is a subjective and imprecise exercise subject to differing interpretations and general lack of agreement, even among experts. The jurisdictional agencies, in many cases, had to make decisions based on generally inconclusive and minimal data.

GAO Draft Report

GAO concludes that most of the wells qualifying for the incentive price were located in formations not identified as high potential areas.

FERC Staff Response

The report concludes that there was little tight formation activity in high potential areas, finding that only 17 percent of the qualifying wells were drilled into formations identified as having the greatest potential. This 17 percent however, represents 85 percent of the total estimated tight formation gas being produced. 3/

Instead of comparing number of wells drilled, as GAO did, we believe a comparison of some of the risk factors reveals a different picture of where program activity has occurred.

Table 1 (following) compares an estimated cost per well and total investment in the Appalachian region (Ohio, New York, West Virginia, Pennsylvania) and those same parameters in Wyoming, Utah, and Texas (Railroad Commission Districts 5 & 6, 47 counties in northeastern Texas).

Making a conservative assumption that the average cost of a tight formation well is the same as others in the examined regions, and that 1983 is a representative year from which to draw these averages, the following is revealed. Through FY 1984, $2.977 billion was invested in 20,822 tight formation wells ($143,000 per well) in Appalachia. These had a 96 percent success rate, and produced an average of 4 MMcf per year each for a total of about 80,000 MMcf, or 80 Bcf. In the western region (Utah, Wyoming, Texas RRC Districts 5 & 6), $5.979 billion was invested in 4722 tight formation wells ($1,266,000 per well) with a 65 percent success rate, producing 107 MMcf per year each, or 500 Bcf. Thus, comparing west to east, it costs 9 times as much to drill a well that has 2/3 as great a chance of being successful but will produce 27 times as much gas if successful. Twice the capital was invested in successful tight formation wells in the indicated areas of the west and six times the gas was produced. In terms of analysis of economic activity, instead of counting the number of holes in the ground, far more activity took place in the areas identified as high potential by FERC in the rulemaking. This kind of analysis of the activity indicates that the program has encouraged activity (economic activity, not drilling activity as measured by completed wells) in the higher potential areas, with the expected result of increase in reserves.

3/ DOE/EIA-0448, Drilling and Production under Title I of NGPA, p. 49, Table 15.

Table 1

All tight formation wells.
1979 - 1984

	1	2	3	4	5	6
	1983 % Successful 3/	1983 3/ $000/T.F. well	Total # of TF wells 4/	Total TF-$ ($000,000) 5/	Avg. Annual TF Production per well MMcf 6/	Total Annual T.F. Production BCF 7/
Appalachia 1	96.2	143	20822	2977.5	4	83.3
Texas 2/	69.7	1184	4133	4893.5	107	442.2
Wyoming	60.0	2136	358	764.7	127	45.5
Utah	65.1	1391	231	321.3	72	16.6
Total TX, WY, UT	65.3	1266	4722	5979.5	107	504.3

1/ Ohio, New York, Pennsylvania, West Virginia.

2/ Texas Railroad Commission Districts 5 and 6.

3/ All wells drilled, from API 1983 Joint Association Survey on Drilling Cost.

4/ FERC NGPA determination statistics through October 1984

5/ Column 2 x Column 3

6/ DOE/EIA - 0448, Drilling and Production under Title I of NGPA, p. 49, Table 15.

7/ Column 3 x Column 5

APPENDIX V

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

MAR 19 1985

Mr. J. Dexter Peach
Director
United States General Accounting Office
Washington, D.C. 20548

Dear Mr. Peach:

Your letter of February 14, 1985, requested that this Department review and comment on your draft report entitled "Problems Identified in FERC's Incentive Pricing Program for Natural Gas From Tight Formations."

The conclusions reached are fairly concise and we basically agree with the findings of the draft report, as presented. We, however, suggest the following technical corrections in the report.

1. Page "i" of the Digest, second paragraph, first sentence, item (1): "tight formation" changed to read "formation to be designated as tight."

2. Chapter 1, Introduction, page two, last paragraph, first sentence: "soaked into sand, porous rock, and other natural formations --" be replaced with "contained in porous."

3. Chapter 1, Introduction, page three, first incomplete paragraph, first complete sentence: replace "particular set of geological conditions" with "petrophysical properties of the formation."

4. Chapter 1, Introduction, page three, first incomplete paragraph, second complete sentence: "characteristic of such natural structures" changed to read "petrophysical property of the formation" and the words "sand or" deleted.

5. Chapter 1, Introduction, page three, first incomplete paragraph, third complete sentence: the word "structures" changed to "formations" in both instances.

We appreciate the opportunity to review and provide comments on the draft report, and trust that our comments will be of assistance to you in preparing the final report.

Sincerely,

Deputy Assistant Secretary - Land and Minerals Management

GAO note: Page references for comments 2 through 5 are contained in the second paragraph of page 2 in this final report.

COMMISSIONER OF INTERNAL REVENUE
Washington, DC 20224

MAR 0 8 1985

Mr. William J. Anderson
Director,
United States General Accounting Office
Washington, D. C. 20548

Dear Mr. Anderson:

This is in regard to your letter of February 14, 1985, which forwarded a section of the GAO draft report entitled Problems Identified in FERC's Incentive Pricing Program for Natural Gas From Tight Formations.

Suggestions to enhance the clarity of that section have been provided, informally, to Mr. Dishmon and Mr. Marwick, GAO. Assuming the final report reflects these suggestions, we concur in that report.

With kind regards,

Sincerely,

Roscoe Egger

(308542)

Department of the Treasury Internal Revenue Service

31430

AN EQUAL OPPORTUNITY EMPLOYER

UNITED STATES
GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

OFFICAL BUSINESS
PENALTY FOR PRIVATE USE $300

BULK RATE
POSTAGE & FEES PAID
GAO
PERMIT No. G100