BY THE U.S. GENERAL ACCOUNTING OFFICE

Report To The Chairman, Federal Energy Regulatory Commission

Need To Revise Eligibility Criterion For One Natural Gas Price Category And Eliminate Backlog In Refund Control Work

The Natural Gas Policy Act of 1978 created eight price categories for natural gas and set the criteria for charging each price. GAO found that the Commission's implementing regulations for one higher priced category included natural gas that the Congress did not intend to include.

The Commission had over a 3-year backlog at the end of fiscal year 1982 in its program to detect and require refunds of overcharges in various categories and has been slow in reducing that backlog. A large continuing backlog could adversely affect the orderly completion of the compliance program when price controls end.

GAO recommends that the Commission revise its criterion for the one category and eliminate the refund control backlog.

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

RESOURCES, COMMUNITY,
AND ECONOMIC DEVELOPMENT
DIVISION

B-203111

The Honorable Charles M. Butler III
Chairman, Federal Energy Regulatory
Commission

Dear Mr. Butler:

This report discusses the Federal Energy Regulatory Commission's administration of price controls under the Natural Gas Policy Act of 1978.

This report contains recommendations to the Commission on pages 17 and 29. As you know, 31 U.S.C. § 720 requires the head of a Federal agency to submit a written statement on actions taken on our recommendations to the House Committee on Government Operations and the Senate Committee on Governmental Affairs not later than 60 days after the date of the report and to the House and Senate Committees on Appropriations with the agency's first request for appropriations made more than 60 days after the date of the report.

We are sending copies of this report to the other Commissioners; the Director, Office of Management and Budget; the Chairmen, House Committee on Government Operations, Senate Committee on Governmental Affairs, House and Senate Committees on Appropriations, House Committee on Energy and Commerce, and the Senate Committee on Energy and Natural Resources; and the Secretary of Energy.

Sincerely yours,

J. Dexter Peach
Director

GENERAL ACCOUNTING OFFICE
REPORT TO THE CHAIRMAN,
FEDERAL ENERGY REGULATORY
COMMISSION

NEED TO REVISE ELIGIBILITY
CRITERION FOR ONE NATURAL GAS
PRICE CATEGORY AND ELIMINATE
BACKLOG IN REFUND CONTROL WORK

D I G E S T

The Natural Gas Policy Act of 1978 (NGPA), administered by the Federal Energy Regulatory Commission, established eight categories of natural gas sold from domestic wells. The act provides a maximum lawful price and the criteria for each of the categories. State and Federal agencies make category determinations for wells within their jurisdiction, which are then reviewed by the Commission. (See pp. 1 to 3.)

GAO made this review to assess the accuracy of well determinations for NGPA incentive priced categories. GAO specifically wanted to determine whether (1) prices received by producers and ultimately paid by consumers are in agreement with the prices prescribed by the act and (2) procedures are sufficient for making accurate pricing determinations. (See p. 4.)

FINDINGS

Most of the wells GAO reviewed were correctly categorized under NGPA's and the Commission's implementing criteria. However, the Commission's criterion for certain natural gas stripper wells did not meet NGPA requirements. Consequently, consumers are charged higher prices for this natural gas. (See p. 7.)

The Commission has developed a huge backlog in its program to detect and require refunds of overcharges in various categories by natural gas producers. This backlog and associated processing timelag may allow overcharges to increase, and the eventual refunds may not reach the consumers that paid them. This backlog may also present difficulties in effecting an orderly completion of the compliance program when price controls end. (See p. 18.)

NGPA REQUIREMENTS NOT INCLUDED IN THE COMMISSION'S CRITERIA FOR STRIPPER WELL NATURAL GAS

The Congress intended that wells of marginal production and low revenues qualify as natural gas stripper wells. However, the Commission's interpretations allow wells which subsequently begin earning a higher economic return to retain their qualification for this higher price category. (See p. 7.)

NGPA allows only nonassociated natural gas (not produced in conjunction with crude oil) to receive stripper prices. Associated gas was not included on the assumption that revenues from crude oil production would obviate the need for incentive prices for the low volume of natural gas produced. (See p. 7.)

However, NGPA's conference report provides that associated natural gas may qualify if the oil production is minor. The Commission's criterion (in consonance with the act) allows oil production up to an average of three barrels per day during a 90-day qualifying period. However, the Commission consciously avoided placing a limit on oil production after the qualifying period. GAO believes that the Commission's basis for not placing such a limit was not sound and has provided producers a loophole for receiving the higher prices without meeting NGPA requirements. (See pp. 7 to 10.)

At two companies it visited, GAO found that 27 of the 146 stripper wells it reviewed were producing oil exceeding the Commission's criterion and continued to receive stripper pricing. However, the sampling method was too limited to project the results to the universe of domestic stripper wells. (See p. 11.)

GAO does not know the extent to which this situation affects revenues for all domestic producers, but the price differences between stripper well and other categories are substantial. The January 1982 price for stripper well natural gas was $3.217 per thousand cubic feet (Mcf)--over 1,100 percent above the lowest regulated price of $0.265. (See pp. 10 to 12.)

REFUND REPORT PROCESSING BACKLOG SHOULD BE ELIMINATED

The Commission's NGPA Compliance Division has developed a huge backlog of refund cases and reports for processing because (1) the staff was unable to keep current with the cases being received and (2) a surge of cases was created by closing a loophole in the NGPA regulations. Producers may immediately begin charging the category price when they apply for approval of the well category but must refund overcharges if the well is found ineligible for that category. Producers are required to file the refund reports which are the principal means the Commission uses to ensure compliance with NGPA and the prompt refunding of overcharges. (See p. 18.)

Although the Division had taken some measures to expedite case processing, it had not been able to process the fund reports and cases in a timely manner. As of September 30, 1982, the actual backlog was 9,929 cases, or 3.1 caseload years, and GAO projects a backlog representing 2.4 caseload years at the end of fiscal year 1983. (See pp. 21 to 27.)

Actual refunds through July 1982 were slightly over $34 million and were associated with 1,133 wells. However, because not all cases result in refunds (and therefore result in "no refund due" refund reports), GAO has no estimates of the potential refunds represented by the backlog. (See p. 18.)

Almost half of the natural gas being produced will be decontrolled after January 1, 1985. GAO is concerned that refunds may not reach the consumers who paid the overcharges earlier, and as price controls end, there may not be an orderly completion of the Commission's refund program. (See pp. 27 to 29.)

RECOMMENDATIONS TO THE FEDERAL ENERGY REGULATORY COMMISSION

GAO recommends that the Commission revise the NGPA regulations to prohibit continued stripper status for wells with subsequent oil production exceeding its sliding-scale criterion. (See p. 17.)

GAO also recommends that the Commission take timely and aggressive action to identify the actual size and types of the work backlog and the procedural or staffing problems causing the backlog in the refund control program and use this information to eliminate the backlog of refund reports and cases and keep caseload processing current through the end of NGPA price controls. (See p. 29.)

AGENCY AND COMPANY COMMENTS AND GAO EVALUATION

The Commission Chairman provided extensive comments on GAO's report. (See app. I.) The Chairman disagreed with GAO's conclusions that the Commission's regulations do not conform to NGPA requirements and that the regulations should be amended. However, GAO found no basis in the comments for significantly revising its conclusions with respect to associated natural gas. (See p. 12.) A finding and recommendation concerning an exemption for recognized enhanced recovery techniques was deleted from the report after consideration of the Chairman's comments. (See p. 16.)

The Chairman expressed general agreement with the GAO recommendation for reducing the refund backlog and discussed recent steps (including assigning additional staff) that had been taken to expedite processing and to reduce the backlog. GAO believes that assigning additional staff was a good step, but the Commission needs to carefully monitor and study the situation to assure that the backlog is eliminated when the price control program ends. (See p. 30.)

The three companies whose wells are discussed in GAO's report provided comments which GAO considered in preparing its final report. (See apps. II and III.) The comments resulted in minor technical corrections to the report.

Contents

ABBREVIATIONS

Btu	British thermal unit
FERC	Federal Energy Regulatory Commission
GAO	General Accounting Office
Mcf	thousand cubic feet
MMBtu	million British thermal units
NGPA	Natural Gas Policy Act of 1978
USGS	U.S. Geological Survey

CHAPTER 1

INTRODUCTION

Natural gas provides over 25 percent of the U.S. energy supply. Residential, commercial, and industrial consumers use about 20 trillion cubic feet of natural gas a year, principally for heating, producing consumer goods, and generating electricity.

Natural gas first came under Federal regulation with the passage of the Natural Gas Act of 1938. This act declared that interstate pipeline companies were public utilities and empowered the Federal Power Commission and later its successor agency, the Federal Energy Regulatory Commission (FERC), to establish just and reasonable rates which the interstate pipelines could charge for natural gas. Price regulation was limited to interstate pipelines until a Supreme Court ruling in 1954 extended the Commission's responsibility to include interstate natural gas producers.[1] Regulation of natural gas in intrastate commerce--produced, transported, and consumed within a State--was left to the States until the Natural Gas Policy Act (NGPA) of 1978.

NGPA PRICING PROVISIONS

NGPA, which became effective November 9, 1978, replaced the dual market for natural gas with a single market by expanding Federal price jurisdiction to encompass sales in both the interstate and intrastate markets. Title I (wellhead pricing) of NGPA created eight categories of natural gas which cover every natural gas producing well in the United States. These categories are listed in the following table.

NGPA Pricing Categories

Section	Type of gas
102	New natural gas
103	New onshore production wells
104	Interstate gas
105	Intrastate gas under existing contracts
106	Rollover contracts
107	High-cost natural gas
108	Stripper well natural gas
109	Other categories of natural gas

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[1]Phillips Petroleum Company v. Wisconsin, 347 U.S. 672.

NGPA also specified the initial ceiling prices for each category and how those prices would be escalated each month. The ceiling prices vary by category and escalate each month on the basis of an annual inflation adjustment factor, plus a growth factor for all categories except section 103. Since the same annual inflation adjustment factor is applied to all the categories, the proportional differences stay about the same.

The Congress intended that the comparatively high ceiling prices for sections 102, 103, and 107 provide producers an incentive to locate and develop new sources of natural gas. The Congress intended section 108 to encourage continued production from marginal wells. The prices in the base months are compared to January 1982 prices in the table below. Because of the higher prices that can be charged for gas in these four categories, producers have an incentive to qualify their wells under these categories, if possible. Therefore, we initially directed our attention to these categories.

Ceiling Price per MMBtu[a]

	Section	Base month	Base price	January 1982 price
102	New	4/77	$1.75	$3.003
103	New onshore	4/77	1.75	2.572
107	High cost (tight sands)	4/77	1.75	[b]5.144
108	Stripper	5/78	2.09	3.217

Other regulated prices were as low as $0.265.

[a]MMBtu stands for 1 million British thermal units (Btu's). A thousand cubic feet (Mcf) of natural gas provides approximately 1,021,000 Btu's. However, for this report a Mcf equals a MMBtu.

[b]The prices for the four other subcategories under section 107 were deregulated 1 year after NGPA became effective.

To establish entitlement for ceiling prices under any of these categories, producers/operators must apply for a well category determination. NGPA authorizes a Federal or State agency having regulatory jurisdiction over natural gas production to make determinations as to the category for which a well qualifies. These jurisdictional agencies are

--the Department of the Interior, for wells located on Federal lands, Indian lands, and the Outer Continental Shelf;

--the Department of Energy, for wells located on the Naval Petroleum Reserves; and

--State agencies, for all other wells.

A well determination is made on the basis of documentation provided by the producer that a well meets the qualification requirements defined in NGPA and in FERC's regulations. FERC prescribes minimum documentation, and the jurisdictional agencies can supplement them to cover local conditions.

Well determinations made by the jurisdictional agencies are subject to FERC's review. FERC has overall responsibility for implementing NGPA and for assuring that prices producers receive do not exceed the prices prescribed in the act.

The criteria for each category is summarized below.

Section 102--the well must have been drilled on or after February 19, 1977, and must be 2.5 miles from an existing "marker well" defined in NGPA.

Section 103--the well must be drilled on or after February 19, 1977, and must not be within an existing "Proration unit" defined in NGPA.

Section 107--deep high cost; the well must be drilled on or after February 19, 1977, and must be completed at a depth of more than 15,000 feet. The price of this gas is deregulated.

Section 107--tight formations; the well must be drilled on or after February 19, 1977, and present extraordinary risks or costs. The price is not deregulated.

Section 108--the well must produce at a rate that does not exceed an average of 60 Mcf per day during a 90-day production period. Once qualified as a stripper well, production may exceed the 60 Mcf per day criterion and still qualify for stripper pricing if the increase in production is the result of the application of recognized enhanced recovery techniques. In addition, FERC regulations provide that natural gas produced in association with crude oil may also qualify for stripper pricing if the production of oil and gas meets the following sliding-scale criterion during a 90-day qualifying production period.

If the average production of natural gas per production day during such production period was:	The average crude oil production per day may not exceed:
50 Mcf or more but not more than 60 Mcf	1 barrel
30 Mcf or more but less than 50 Mcf	2 barrels
Less than 30 Mcf	3 barrels

OUR PRIOR REPORT

In a report entitled, "FERC Should Improve the Natural Gas Well Determination Process" (EMD-81-88, July 30, 1981), we evaluated whether the well determination process was working effectively and efficiently.

We found, among other things, that FERC field auditors did not review producer records when necessary to verify the accuracy of supporting evidence and resolve questions of wells' eligibility for the price categories. We recommended that the Chairman, FERC, encourage the jurisdictional agencies to validate supporting evidence as part of their well determination process and direct that the NGPA Compliance Division

--provide guidance to the jurisdictional agencies for use in implementing validation procedures and

--coordinate its overall compliance activities with the jurisdictional agencies and review producer records when they are the only source of the supporting evidence.

The Chairman was in general agreement with the recommendations and has taken steps to implement them.

In this follow-on review, as noted below, we examined the supporting evidence contained in producer records. As detailed in the following chapters, we found that, in certain cases, FERC was not following the criteria set by the Congress.

OBJECTIVES, SCOPE, AND METHODOLOGY

We made this review to assess the accuracy of well determinations for NGPA incentive-priced categories (sections 102, 103, 107, and 108). Our objectives were to determine (1) whether prices received by producers, and ultimately paid by consumers, are in agreement with the prices prescribed by the act and (2) whether existing procedures for determining the price for which a well qualifies are sufficient for making accurate pricing determinations. This was done primarily through an evaluation of whether producers' records supported the evidence they presented in their applications.

To assess the accuracy of pricing determinations, we visited three jurisdictional agencies responsible for making category determinations, four natural gas producers, and FERC. We selected the jurisdictional agencies for the States of Oklahoma and New Mexico because they are major natural gas producing States and have a large number of stripper wells. The third jurisdictional agency, the U.S. Geological Survey (since redesignated as the Minerals Management Service), Department of the Interior, has jurisdiction over Federal and Indian lands within both States. The natural gas producers were selected on the basis of operating in these States and for having wells in the high price categories.

The producers were:

El Paso Natural Gas Company, El Paso, Texas.

Mitchell Energy Corporation, The Woodlands, Texas.

Phillips Petroleum Company, Bartlesville, Oklahoma.

We also visited Mesa Petroleum Company, Amarillo, Texas, because, unlike the other three, it has a large number of section 107 high-cost natural gas wells in so-called tight formations. Because we found nothing of a reportable nature, this company is not discussed further in this report.

We examined filings for wells which had been approved by a jurisdictional agency and FERC for collection of NGPA prices. The wells reviewed were selected at random from within the four pricing categories. The basis for selection is discussed in conjunction with our description of our findings in chapter 2.

Three major factors influenced the scope of our work. The first factor was the types of each producer's wells. For example, one had a significant number of deep wells and another had a high number of old, nearly depleted wells which were in the stripper category. Therefore, the types of wells included in our selection varied at each company, depending on the number of wells qualifying for a specific category. We did not address all price categories at all of the producers we visited.

The second factor was that the criteria for sections 102, 103, and 107 are well defined, and the proof of qualification is through physical evidence and dates of specific actions. In contrast, the criteria for section 108 are open to some interpretation.

The third factor was that, with respect to stripper wells, the detailed information we obtained on individual wells highlighted the difference between the criteria contained in NGPA and in FERC's regulations. Therefore, we had no need to expand our initial sample of two States and three of the four natural gas producers to document this difference because the same criteria apply in all States and to all producers. This report, therefore, addresses this difference in criteria for section 108 stripper wells. We consulted with industry, government, and academic experts concerning whether the enhanced recovery techniques accepted by FERC were recognized as such by the industry. The information about specific wells was obtained in 1981, but the findings are still valid because FERC has not changed its criteria for section 108 stripper wells.

Except as noted, this report was prepared in accordance with generally accepted government auditing standards.

CHAPTER 2

NGPA REQUIREMENTS NOT INCLUDED IN FERC'S CRITERIA

FOR STRIPPER WELL NATURAL GAS

NGPA states that wells of marginal production and low revenues qualify for stripper prices, but FERC's interpretations allow wells which, subsequent to qualification, earn a high economic return to retain their qualification for this higher price category. As a result, consumers are paying higher prices than NGPA intended. FERC should revise its regulations to reflect NGPA's requirements.

Because the stripper price is higher than the other incentive price categories, producers have an incentive to seek such pricing. For one producer, the difference in January 1982 prices was $2.44 per Mcf, or 315 percent above the amount set by NGPA for the alternative category. However, if the lowest regulated price had been the alternative price category, the difference would have been $2.952, or 1,113 percent above the alternative category. Another measure of significance is that, for 1981, stripper well natural gas was estimated to be 4.33 percent of total natural gas production.

NGPA REQUIREMENTS

The Congress, in NGPA, provided only for natural gas wells (nonassociated) to qualify for stripper well prices. Associated natural gas--produced in conjunction with crude oil--was not included, on the assumption that the revenues from crude oil production would obviate the need for incentive prices for the low volume of natural gas produced.

NGPA allows only nonassociated natural gas to receive stripper pricing, but the act's conference report provides that natural gas produced in association with crude oil may qualify if the oil production is "de minimis."

The NGPA incentive-priced categories were intended to encourage natural gas production. In particular, stripper prices were designed to encourage production from marginal wells to prevent these low-production wells from being plugged and abandoned.

IMPROPER IMPLEMENTATION BY FERC PROVIDES A LOOPHOLE FOR CHARGING HIGHER PRICES

FERC observed the Congress' intent in limiting the oil production when setting the criteria for stripper well natural gas. However, FERC consciously avoided placing a limit on oil production beyond the initial 90-day qualifying period. FERC's basis for this position was not sound and has provided a loophole for producers to receive the higher price without meeting NGPA's requirements. NGPA does not authorize the continued collection of stripper well prices when more than a de minimis amount of oil is produced.

FERC provided a loophole in its regulations

In establishing its regulations, FERC recognized that it had no authority to allow more than a de minimis amount of oil production for stripper well qualification. The preamble to the regulations states

> "* * * we are mindful that Congress provided in section 108(b)(3)(c) of the NGPA that nonassociated natural gas means natural gas which is not produced in association with crude oil. While the above-cited Statement of Managers and other legislative history makes it clear that Congress intended a minimal amount of crude oil production to be permitted, we feel constrained to keep crude oil allowances to a de minimis standard." 44 Fed. Reg. at 49657 (Aug. 24, 1979).

The regulations state that the well must produce at a rate that does not exceed an average of 60 Mcf per day during a 90-day production period. The regulations also provide that natural gas produced in association with crude oil may also qualify for stripper pricing if the production of oil and gas meets the following sliding-scale criteria during a 90-day qualifying production period.

If the average production of natural gas per production day during such production period was:	The average crude oil production per day may not exceed:
50 Mcf or more but not more than 60 Mcf	1 barrel
30 Mcf or more but less than 50 Mcf	2 barrels
Less than 30 Mcf	3 barrels

In December 1982 the stripper price was $3.51 per Mcf. The following chart uses the sliding-scale qualifying criteria and December 1982 prices to show the maximum combined monthly revenues from oil and natural gas that a producer could have received during the 90-day qualifying period for a well.

Allowable average daily production Natural gas	Oil	Computation of income	Maximum revenues
(Mcf)	(Barrels)	(rounded to nearest dollar)	
50-60		60 x $3.51 = $210.60	
	1	1 x 27.95 = 27.95	$238.55
30-49		49 x 3.51 = $171.99	
	2	2 x 27.95 = 55.90	227.89
Less than 30		29 x 3.51 = $101.79	
	3	3 x 27.95 = 83.85	185.64

In the preamble to the regulations, FERC also responded to comments that the regulations should require that written notice be given if the production of crude oil, after qualification, exceeds the amount allowed under the sliding scale. FERC expressed concern about the practical difficulties inherent in monitoring oil production and the administrative burden it would impose. FERC assumed that in a situation where oil production increases, as a general matter gas production would also increase. Consequently, the increased natural gas production would disqualify the well as a stripper well. FERC stated that, should a situation come to its attention wherein this general proposition did not apply and wherein crude oil production exceeded the limits of the sliding scale, it would take whatever measures it deems appropriate to resolve the matter. [44 Fed. Reg. at 44660 (Aug. 24, 1979).]

However, when notices of withdrawals were filed by producers because oil production, after qualification, exceeded the sliding-scale criterion, FERC's then General Counsel notified the producers that withdrawal applications and corresponding decreases in price were unnecessary. In an October 27, 1980, letter to the Mobil Oil Corporation, FERC's then General Counsel stated that the regulation recognizes the Commission's expressed concern for the practical difficulties and administrative burdens inherent in monitoring oil production. The then General Counsel stated that a well which satisfies the definition of nonassociated natural gas in the sliding scale will continue to qualify as a stripper well even if oil production subsequently increases above the limits after the 90-day qualifying period. The then General Counsel also stated that the views expressed were his, as General Counsel, and do not bind the Commission.

The position FERC's former General Counsel took is still being followed in FERC's administration of stripper pricing. As indicated below, we found that monitoring oil production would require little administrative burden and oil production can significantly increase without natural gas production exceeding the stripper limits.

FERC assumptions not sound

Neither of the assumptions which formed the basis for FERC's decision to not limit the amount of subsequent oil production while retaining the natural gas stripper well status was valid. The then General Counsel apparently continued to rely on these assumptions in his letter to Mobil, cited above.

Monitoring oil production is not burdensome

While we share FERC's concern for administrative burden, we found that monitoring oil production created little, if any, additional burden to producers. Two primary reasons are that (1) producers routinely monitor oil production from wells producing associated natural gas to assure maximum efficient production and (2) the sliding-scale criterion makes it necessary for producers to have a system in place which will identify those wells meeting the sliding-scale criterion.

If natural gas production exceeds an average of 60 Mcf per day, the well must be withdrawn regardless of its oil production. However, the well may requalify if production again drops below an average of 60 Mcf per day and the corresponding oil production does not exceed the sliding scale. Therefore, producers must have a continuing system to monitor both oil and gas production so that determinations of qualification, withdrawal, and requalification are readily available. Accordingly, the producers we visited had systems in place which readily reported both oil and gas production.

Oil production can increase without concurrent increase in natural gas production

FERC believes that concurrent increases in crude oil and natural gas may be the most common occurrence. However, as discussed in the following section of this chapter, it is not unusual for significant increases in oil production to occur while natural gas production remains within the stripper sliding scale.

Moreover, when natural gas production no longer fits the definition of "stripper well natural gas," NGPA authorizes the continued collection of stripper prices in only one instance--when the increased production is due to the application of "recognized enhanced recovery techniques." Neither the statutory language nor the conference report suggests a similar exception when a stripper well produces more than a *de minimis* amount of oil.

THE EFFECT OF THE LOOPHOLE ON PRODUCERS AND CONSUMERS

We examined the issue of excess oil production, after qualification, at the Phillips Petroleum Company and Mitchell Energy Corporation. (El Paso Natural Gas Company did not acknowledge that "liquids" produced from its natural gas wells was crude oil.) We found that after the initial qualifying period, 33 of the 146 stripper wells we reviewed had been producing oil in excess of the sliding-scale criterion and continued to receive stripper pricing. In addition, our review of 1980 production data in a New Mexico State report identified six stripper wells having oil production above the sliding-scale criterion, after qualification. Average production from these six wells over a 6-month period ranged from 4.5 to 40.7 barrels per day. Such amounts of oil production remove these wells from the economically marginal category, but the higher prices for natural gas from them continue to be passed on through the transportation and distribution companies to the ultimate consumers.

Phillips Petroleum Company had 1,564 natural gas stripper wells with oil production in Texas and Oklahoma. We randomly selected 64 of these wells and found that 9 (or 14 percent) had subsequently produced oil above the sliding-scale criterion. Company officials told us that natural gas produced from three of the nine wells was not being sold; rather it was being reinjected from two wells to maintain reservoir pressure and was being vented from the other for economic reasons. The oil production from the other six wells ranged from 3.6 to 28.6 barrels per day. If the sliding scale limit were a continuing requirement, these six wells would be disqualified from stripper pricing and their monthly average production of 2,817 Mcf would have qualified only under section 104 and would have sold for 0.774 cents per Mcf in January 1982, rather than $3.22, a difference of $2.44. FERC's criterion, therefore, increases this company's natural gas revenues from these six wells by approximately $6,873 per month or $82,476 per year.

Mitchell Energy Corporation had 484 natural gas stripper wells, of which 62 had oil production. We found that 18 of the 62 (or 29 percent) subsequently produced oil above FERC's sliding-scale criterion for qualification. Of the 18, in May 1981, the average daily production of

--11 exceeded the criterion by up to 1 barrel.

--4 exceeded the criterion by 1 to 2 barrels.

--3 exceeded the criterion by 3.1 or more barrels.

At the State agency in New Mexico, we identified six stripper wells with oil production of 4.5 to 40.7 barrels per day by examining the State's annual report on oil and gas production. The wells were not randomly selected, and we did not attempt to quantify the total number of stripper wells having oil production, subsequent to qualification, above the sliding scale criterion.

We do not know the extent to which all domestic producers are receiving unwarranted revenues from wells that do not qualify for stripper prices. Nevertheless, such revenues represent a higher cost to consumers that should be remedied by FERC. The Federal and State regulation of rates charged by natural gas transportation and distribution companies provides for the wellhead price to be included in the total price charged to consumers. In January 1982 the difference between the stripper well price ($3.217) and the lowest regulated price ($0.265) was $2.952; therefore, the consumers could be charged as much as 1,113 percent above the price the Congress intended. Another measure of significance is that for 1981, stripper well natural gas was estimated to be 4.33 percent of total natural gas production.

AGENCY AND COMPANY COMMENTS AND OUR EVALUATION

The Mitchell Energy Corporation and Phillips Petroleum Company commented on a draft of this report on October 22 and 25, 1982. (See apps. II and III.) We have considered their comments in preparing this final report.

The FERC Chairman provided us comments by letter dated November 3, 1982. (See app. I.) The Chairman disagreed with our conclusions that FERC's regulations implementing section 108 of NGPA do not conform to the requirements of the statute and that the regulations should be amended. The Chairman's comments and our evaluation of them are presented below.

The Chairman characterized our concern by stating that:

> "What GAO chiefly objects to is the Commission's decision to make the nonassociated test stringent initially and to make continuing qualification less burdensome once the initial qualification hurdle is passed, calling this a 'loophole.'"

FERC did not make continuing qualification as nonassociated gas less burdensome--it eliminated the burden altogether. Also, we are not as concerned about the original regulation as we are about FERC's lack of action when it was put on notice by Mobil

Oil Corporation's inquiry (see p. 12) that its assumptions may not have been correct.

The Chairman stated that FERC chose to apply the sliding scale for oil production to the 90-day qualifying period only and not to subsequent periods. This was done because of FERC's concern with the practical difficulties inherent in monitoring oil production as well as administrative burdens which such a requirement would impose. Although not explicitly acknowledged in the Chairman's comments, FERC also relied on the assumption that most wells which come to exceed the oil limit will, at the same time, exceed the gas limit and be disqualified as strippers on the basis of the latter.

The Mobil Oil Corporation, in its April 30 and June 26, 1980, letters, put FERC on notice of two facts:

--First, oil production could increase to the point where it exceeded the sliding-scale criterion without an accompanying increase in natural gas production which would disqualify a well as a stripper.

--Second, without being required to do so by the regulation, Mobil was monitoring the oil production. Thus, continuing the sliding-scale requirement beyond the 90-day qualifying period would not impose an additional burden on Mobil.

The Deputy Director, NGPA Compliance Division, told us that similar inquiries were received informally from other firms. We believe that this provided FERC sufficient indications that its assumptions were not correct and should have prompted FERC to follow through on its promise to "undertake whatever measures we deem appropriate to resolve the matter." Also, from a strictly legal viewpoint, we find no basis in the statutory language or legislative history of the NGPA for any appropriate measure other than disqualification for natural gas produced with more than the de minimis amounts of oil permitted by FERC's regulations. In only one instance has the Congress provided for natural gas which no longer fits the statutory definition of stripper well natural gas to continue qualifying for stripper prices. This exception, Section 108(b)(2) of NGPA, concerns gas produced in excess of an average daily rate of 60 Mcf due to the application of recognized enhanced recovery techniques.

The Chairman stated that "merely calculating price and revenue differences does not really address the issue of the legality or appropriateness of the Commission's rule." It was not intended to; it merely demonstrated that FERC's regulation has a direct and measurable effect on the prices that consumers pay for natural gas.

The Chairman raises a doubt that the sliding scale is often exceeded beyond what could have been set as a de minimis limit--10 barrels average per day. Of the 33 wells we found with subsequent production above the sliding scale, 3 were producing an average of 22.44, 31.62, and 43.7 barrels per day. Our small sample does not permit a projection concerning the number or production of all stripper wells exceeding the sliding scale. However, we believe that the information we obtained does raise a problem that FERC should resolve, rather than dismiss without further investigation.

The Chairman also states that FERC could have set the de minimis standard higher--up to 10 barrels per day. Nevertheless, FERC chose to adopt a more stringent standard in its regulations and must enforce that standard. Also, while FERC could have set the de minimus level at 10 barrels a day, we believe that it would have been hard to justify, considering the circumstances behind a comment provided by Phillips Petroleum Company. Phillips said that the natural gas being produced from one of its stripper wells was not being sold, but was being vented because it was not economical to connect the well to a pipeline. We inquired further and found that this well was producing an average of 5.92 barrels of oil per day while venting an average of 32.48 Mcf of natural gas per day between June 1980 and May 1981. This indicates that it would be difficult to justify setting the de minimus level at 10 barrels average per day, because production of nearly 6 barrels of oil per day can make it economical to produce the well, rather than shut it in.

The Chairman's comments attempt to show a substantial burden for both the industry and FERC to monitor oil production. He stated that the stripper well category accounts for over 38 percent of NGPA filings at FERC, with over 67,000 filings received as of August 1982. He also states that 50 percent of the stripper wells are located in States which require reports on an annual or lease basis only, if reports are required at all. Both of these statements overstate the potential burden.

First, not all 67,000 filings are for wells with associated natural gas. Second, there are ways of minimizing the burden of monitoring associated natural gas wells. For example, FERC has an alternative procedure for qualifying wells whose natural gas production is affected by seasonal variations in demand. The procedure allows the average production per day to be calculated on the basis of annual production, rather than for a 90-day period. A similar alternative could be used for monitoring subsequent production from wells in those States which require only annual production reports. Also, FERC could set higher de minimis production limits on subsequent production to avoid the disqualification/requalification problem when the original sliding-scale criterion is barely exceeded.

The Chairman also claimed that the practical difficulties in monitoring oil production and the administrative burden of keeping records provide an adequate legal justification for not establishing a notice procedure in the regulations to disqualify wells in such circumstances. He alleges that FERC has broad administrative authority under NGPA to make such judgments.

FERC does have authority under section 501 to implement the provisions of NGPA through regulations and to define the technical terms of the statute in a manner consistent with the definitions provided in this act. But, these authorities do not authorize FERC to allow stripper well prices to be collected for wells which exceed the *de minimis* levels prescribed by FERC. Even though the range of *de minimis* oil production might have been set at higher levels (but was not), this fact does not permit FERC to violate its own regulations. If FERC wanted to continue the qualification of wells producing higher amounts of oil than set out in its regulations in the first place, it should have amended them to prescribe such higher limits.

As we have previously stated, in only one instance has the Congress prescribed an exception for exceeding the requirements for stripper well qualification under section 108, and that is section 108(b)(2), which involves enhanced recovery techniques. The Congress has not granted FERC discretion under NGPA or any other statute to provide any additional exceptions. Such authority also can not be implied from FERC's responsibility to administer the statute. We are aware of no theory of administrative law which would support the Chairman's interpretation.

The Chairman dismisses our objection to the position taken by the former FERC General Counsel in his October 21, 1980, letter to Mobil Oil Corporation on the basis that we were merely "second-guessing" a matter entrusted to FERC's judgment. However, we disagree with the former FERC General Counsel's views in his letter to Mobil Oil and with the Chairman's statement.

First, it is evident from the basic statutory and regulatory authority that stripper well status is a continuing status that can be lost if the conditions for qualification are no longer met. For example, regarding to excess gas production, FERC recognized this in adopting the "continuing qualification" section of its regulations (18 C.F.R. 271.805) and rejecting the approach of "once a stripper, always a stripper." In the preliminary comments to its final regulations implementing section 108 of NGPA, FERC stated that it would "undertake whatever measures we deem appropriate to resolve the matter" (44 Fed. Reg. 49660) (Aug. 24, 1979), if oil production should exceed the de minimis amount permitted but gas production remained the same. Thus, the de minimis limits of oil production also continue to apply after the initial production period.

Second, FERC's failure to adopt a notice requirement when oil production exceeds the de minimis limits in no way means that these limits are not relevant after the initial production period or that disqualification does not result when the limits are exceeded. As discussed previously, FERC merely concluded that affirmative monitoring of compliance with the de minimis limits would be impracticable and unnecessary.

The draft of this report which the Chairman commented on contained a preliminary finding concerning the exemption in the stripper well regulations which allows continued eligibility for stripper prices when the production exceeds the limit if recognized enhanced recovery techniques had been applied to the well. This preliminary finding and a related proposed recommendation have been deleted from this report.

In reviewing the Chairman's comments, it became apparent that the real issue was not whether FERC had accepted well completion or well maintenance actions as recognized enhanced recovery techniques. Rather, the issue was in whether the well completion or well maintenance actions were "normal" and thus not acceptable under FERC's regulations. We did not have enough evidence to clearly show that the examples we cited were "normal" rather than "abnormal;" therefore, the matter has been deleted from this report. Because the comments from El Paso Natural Gas Company addressed only this matter, its comments are not appended to this report.

CONCLUSION

FERC, in its regulations implementing NGPA, has not followed the NGPA requirements regarding the criterion for receiving the higher prices for associated natural gas produced from stripper wells. Consequently, natural gas produced in association with oil from economically viable oil wells has improperly been allowed to retain qualification for stripper prices.

The higher costs incurred by this facet of FERC's NGPA regulations are borne by the consumers. We did not perform the work that would have allowed us to estimate

--the total volume of natural gas sold by all producers that is priced higher than intended by the Congress or

--the cost to consumers of the higher prices being charged.

However, the price differences between stripper well and other categories are substantial. One case we examined had a price difference of $2.44 per Mcf, 315 percent above the amount set by NGPA. Also, producers have become aware of the situation.

The FERC Chairman disagreed with our recommendations for amending FERC regulations with respect to associated natural gas. We evaluated the arguments he presented in support of his position and found no basis for changing our conclusions and recommendation. We believe FERC should revise its regulations to bring its criteria for receiving incentive prices into conformity with the NGPA requirements.

RECOMMENDATION TO FERC

We recommend that FERC revise the NGPA regulations to prohibit continued stripper status for wells with subsequent oil production exceeding its sliding-scale criterion.

CHAPTER 3

REFUND REPORT PROCESSING

BACKLOG SHOULD BE ELIMINATED

FERC's NGPA Compliance Division has developed a huge backlog of refund cases and reports for processing because the staff assigned has never been able to keep current with the cases being received and a surge of cases was created by closing a reporting loophole in the NGPA regulations. The Division has taken measures to expedite case processing, but it has been unable to process the refund reports and cases in a timely manner and decrease its backlog. This backlog could eventually result in the failure to refund overcharges to consumers when NGPA price controls are ended. Also, the Division has been understating its refund backlog in reports to FERC's upper management. When it began keeping current statistics properly, Division officials said that they did not have the staff available to correct prior statistics. These backlog statistics are useful as a management tool for measuring performance and identifying problems that need attention.

We have no estimates of the potential refunds represented by the backlog since

--not all cases result in refunds,

--the Division only began in February 1981 to keep records associating inquiries (based on various sources of information) with the eventual refunds shown on refund reports, and

--some refund reports are filed by the firms without inquiries from FERC.

These refunds through July 1982 were slightly over $34 million and were associated with 1,133 wells.

REFUND REQUIREMENTS

Subject to certain filing requirements, producers may begin collecting the ceiling price when they apply for a well determination. However, if the well is found ineligible for the price category, the producer is obligated to promptly refund any amount above the price that is determined to be applicable. Also, producers are required to file refund reports with FERC to ensure compliance with NGPA and prompt refunding of excess amounts.

The Division's General Reports Branch is responsible for processing these reports. Refunds result from

--disapproval of well determination applications by jurisdictional agencies,

--FERC reversal of approvals by jurisdictional agencies,

--producer withdrawal of well determination applications,

--producer reports of stripper well disqualifications and those identified by FERC, and

--FERC staff audits indicating overcharges.

FERC regulations require that refunds be made within 60 days after (1) the date of a final determination that a well is ineligible for the price category stated in the application for determination or (2) the date an application was withdrawn. A refund report is due at FERC within 90 days from the date of either of these two events. Also, when no refunds are due following either of these two events, sellers are required to file a statement with FERC to that effect.

FERC is assured that proper refunds have been made when it receives a statement of concurrence from the purchaser. If the seller's refund report does not contain such a statement from the purchaser, the seller must so indicate. The purchaser is required to submit to FERC a statement of concurrence or the reason for refusing concurrence within 30 days after the seller files the refund report.

Refunds are computed by subtracting the price actually due from the price that was paid and adding the appropriate interest. The high interest rates--18.27 percent for the quarter beginning July 1, 1981; and 20.31 and 18.46 percent for the succeeding quarters, for example--encourage the seller to make the refunds as soon as possible.

FERC's manual system for processing refund reports is labor intensive. A routine case can be completed within a day, but the more complicated ones can take several weeks. In cases where the sellers have withdrawn their applications from FERC or the jurisdictional agencies, letters of inquiry are sent to the sellers to determine whether refunds are due. This process is also very time consuming because the sellers do not readily respond to the letters. In this report the statistics for cases, refund reports, applications, etc., are in numbers of wells.

We have no basis for estimating the potential refunds represented by the backlog.

--Not all cases result in refunds. For example, a FERC inquiry to a company may be based on a disapproval of a well determination application. The producer's response may be that no refund was due because no sales were made.

--Also, producers commonly file refund reports without prompting from FERC.

--FERC, in June 1981, began keeping records associating letters of inquiry with refund reports.

Cumulative refunds through July 1982 were slightly over $34 million and were associated with 1,133 wells.

LOOPHOLE IN REGULATIONS CREATED EARLY PROBLEMS

The loophole in FERC's refund regulations was that they initially required only first sellers who actually made refunds to file refund reports with FERC. This oversight allowed producers that received negative determinations or withdrew their applications from FERC or the jurisdictional agencies to avoid filing refund reports. FERC eliminated this loophole in February 1981 by amending the regulations to require the filing of refund reports within 90 days after the well determination application is rejected or withdrawn from FERC or the jurisdictional agencies. Although the withdrawals may not require a refund, each case represents a potential refund until it is resolved.

By the time the loophole had been closed, over 2,950 applications had been withdrawn from FERC and the jurisdictional agencies. The Division's workload at the end of fiscal year 1980 was already up to 5,274 cases. The refund reports resulting from the revised regulation contributed to a surge in workload which helped increase the backlog to 9,388 cases at the end of fiscal year 1981.

The Chairman, in commenting on a draft of this report, stated that:

> "The surge in receipts to which GAO refers resulted not from the issuance of Order No. 131 but rather from the identification of applications for determination which had been withdrawn by the applicants from the jurisdictional agencies. The high level of JA-level withdrawals resulted from the fact that this was the first time this information had been reported to the Commission since enactment of the NGPA and, as such, reflected a catch-up count."

Order No. 131, issued in February 1981, required for the first time that producers file either a refund report or a no refund due report if their well determination application is rejected or withdrawn from the jurisdictional agency. FERC had also recently encouraged the jurisdictional agencies to notify them of any well determination applications that had been withdrawn. The important point is that the surge in cases that followed these two events increased the Division's case workload and backlog. FERC statistics do not reveal the extent to which the change in the regulation also prompted some producers to file delinquent no refund due reports with FERC.

REFUND STAFF UNABLE TO ELIMINATE BACKLOG AND UNDERREPORTS ITS SIZE

The processing of refund reports and cases is done manually, and the General Reports Branch has not been able to process them in a timely manner. This is primarily because of staff reassignments and cutbacks in hiring. Also, the Division, in its workload reporting to FERC upper management, has been significantly underreporting the size of the backlog, thus not drawing attention to the magnitude of the problem. When we brought this to upper management's attention, the staff was increased by 25 percent.

Refund backlog understated

The refund workload backlog was being understated because cases received or identified were not counted until someone started processing them. While obtaining updated refund backlog information at the conclusion of our review, we discovered that as of July 31, 1982, the Division's actual refund workload backlog of 9,935 cases had been understated by 4,176 cases. Specifically, the Division had been reporting as received, only the cases that it had actually started processing, as opposed to reporting all of the potential refund cases it had either identified or received.

Division officials are aware that this method does not accurately reflect its actual workload and told us that beginning in August 1982 the workload statistics will reflect everything they receive or identify during that month. However, the statistics will not include those 4,176 potential refund cases received or identified during previous months that they have not began processing. Thus, at the present rate of completing cases, all of those unreported cases would not enter the statistics for over 2 years (see table on p. 22).

Refund Workload Processing for Fiscal Years 1979-84[a]

	Actual				Projections using FERC estimates[c]		Our projections[d]	
	1979	1980	1981	1982[b]	1983	1984	1983	1984
In process, start of period	0	443	5,274	9,388	9,929	8,034	9,929	9,660
Received	443	5,127	5,506	3,780	1,600	1,600	3,780	3,780
Total workload	443	5,570	10,780	13,168	11,529	9,634	13,709	13,440
Completed	0	-296	-1,392	-3,239	-3,495	-4,500	-4,049	-4,049
In process, end of period	443	5,274	9,388	9,929	8,034	5,134	9,660	9,391
Staff assigned		23	16	16	20	20	20	20
Caseload years (backlog divided by cases completed)		17.8	6.7	3.1	2.3	1.1	2.4	2.3
Productivity (cases completed divided by staff assigned)		12.9	87	202	175	225	202	202

[a] Workload is in numbers of wells.

[b] To avoid distortions, one company's refund report covering 650 wells with no refunds due was deleted from the table because of its unusual nature and the comparatively low workload burden.

[c] FERC estimates of cases "received" and "completed."

[d] Projections based on the actual cases received and completed in fiscal year 1982. Completions uses 1982 productivity, but the higher 1983 and 1984 staff

When the program was inaugurated, Division management was aware that the statistics were not accurate and would have to be eventually corrected. However, when the Division began correcting the statistics, it began keeping only the current statistics properly because the Division did not have the staff available to correct prior statistics, according to Division management. The refund workload/backlog statistics used in this report are the actual figures.

Further discussions disclosed that FERC's upper management was not aware of how the Division was measuring its workload or the extent of the refund case backlog. After we brought it to management's attention, four additional professional staff were assigned to this work, thus increasing the professional staff by 50 percent and the total staff by 25 percent.

Refund staff unable to eliminate backlog

In fiscal year 1980 about 25 persons were assigned to the General Reports Branch to process refund reports. Since the refund process was just developing and there was a lag until the regulated companies began filing the refund reports, 18 of the 25 people were reassigned to other work. In late fiscal year 1980 the staff increased to 23 because over 2,500 cases had been received from the agencies; this staff level is shown in the table on page 22 because it is more closely related to the workload and backlog in subsequent years.

By the end of fiscal year 1980 about 296 cases had been processed, showing that about $4.5 million had been properly refunded, but that was only about 5 percent of the total workload of 5,570 cases, leaving a backlog of 5,274 cases. The table on page 22 identifies the actual annual refund workload processing for fiscal years 1979 to 1982.

In fiscal year 1981 the General Reports Branch functioned with a staff of about 16 because in March 1981, 6 persons were reassigned within the Division and 1 was transferred to another branch. As the table on page 22 shows, during fiscal year 1981 FERC received about 5,500 cases and completed about 1,400 of them (or about 25 percent). The 1,400 cases involved refunds totaling about $10.8 million. However, the 1,400 completed cases were only about 13 percent of the total workload of about 10,780 cases.

In fiscal year 1981 the shortage of staff for processing refund reports and cases resulted in a case backlog of about 6.7 years. That is, at that staffing level and productivity, it would take 6.7 years to process the backlog. Although FERC officials indicated more people would be needed to alleviate the backlog, the fiscal year 1981 FERC budget cuts and subsequent hiring freeze did not allow the Division to hire up to its ceiling or replace those individuals who retired or left the agency.

The fiscal year 1982 budget did not allow the Division to hire new staff or replace staff lost due to reassignment. However, the staff productivity rose significantly and the year end case backlog dropped to about 3.1 years. A FERC official attributed the increase in productivity to an increase in the numbers of letters of inquiry sent, with a corresponding increase in responses which closed cases.

The Chairman disagreed with our statistics concerning the workload (see app. I). He said that beginning in October 1982 the FERC report will include all cases for which a "refund potential event" has occurred. He also said that, even considering this adjustment, we still overstated the Division's backlog at the end of fiscal year 1982 by 2,470 cases because we included data concerning "Buyers' Own Production." (Gas produced by a pipeline company and taken into its own system.) He further said that FERC does not include this data in its workload figures because these wells, in large measure, are cost-of-service wells and do not involve refunds. We disagree with the Chairman's statement for two reasons.

First, the Chairman's statement that actual fiscal year 1982 receipts totaled 3,288 cases was based on a projection for September 1982, not actual data. Actual September workload and backlog were 269 cases less than the Chairman estimated. According to the Division's staff member responsible for compiling the refund workload summary, 3,019 refund cases were actually received and the backlog was 8,234 cases.

Second, Buyers' Own Production cases were included in our statistics, but the number totaled 1,633 cases and not 2,470 as the Chairman stated. Further, there is a difference of 62 cases which Division officials could not identify or resolve because of problems with their data for fiscal year 1980 and 1981. In summary, the difference between our total of 9,929 and the Chairman's total of 8,234 for the fiscal year 1982 ending backlog consists of the 1,633 Buyers Own Production cases and 62 cases the Division could not account for.

Furthermore, we believe that Buyers' Own Production wells should be included in the refund workload because such wells are among those that FERC has identified as having potential overcharges. Through September 30, 1982, the Division identified 1,633 wells in the Buyers' Own Production category which have potential refunds. However, it had sent only four letters covering 242 wells to determine whether refunds were owed and had been made. Five working-interest owners (co-owners) filed refund reports covering 11 wells and involving $73,000.

According to the Division's Deputy Director, the response to those letters showed that about 96 percent of the wells involved did not have other co-owners and therefore no refunds were due. Additionally, based on the results of that response, the Division concluded that the Buyers' Own Production category was not a likely area for refunds and does not plan to follow-up on those cases until its backlog of other cases is eliminated. We do not believe the response to the four letters provided FERC a valid basis for drawing conclusions about the potential refunds due from all wells in this category. We do not agree that this workload should not be counted until FERC decides to begin working on it. Whether the work is performed now or later, it is work to be performed. To delay this work would exacerbate the problem we discuss beginning on page 27 of the smaller probability that consumers who paid the overcharges will receive the refunds.

We are also concerned about the low priority being given this portion of the workload because of the absence of an arms-length transaction between the producer and the pipeline. If the natural gas is being overpriced, the pipeline (as the producer) has no incentive to correct the pricing and make refunds because it is the entity profiting from the overcharge.

The projections of workload processing for fiscal years 1983 and 1984, using FERC estimates of cases received and completed, as shown in the table on page 22, may be low. The FERC estimates were used as a basis for the fiscal year 1983 appropriation request. The projections show further decreases in the yearend backlog to 8,034 and 5,134, respectively, at the end of the fiscal years 1983 and 1984.

The Chairman said that, using productivity estimates shown in FERC's statistics, he expects the Division to get current by the end of fiscal year 1984 (which could coincide with deregulation) because the number of cases received will decrease and completions will increase significantly. According to a Division official, "get current" means that by the end of fiscal year 1984, there will be less than a year's work remaining and it will be current year work.

However, FERC's refund case workload is understated by 1,695 cases (1,633 Buyer's Own Production and 62 unaccounted for) and its "actual" fiscal year 1982 data includes projections for September 1982 which were 269 cases over the actual. Therefore, FERC's refund workload projections are based on inaccurate data.

Also, FERC's rationale for estimating fewer refund cases in fiscal years 1983 and 1984 (1,600 cases per year) is that requests for determinations that are withdrawn from the jurisdictional agency would decrease significantly because they would be receiving current cases instead of "catch-up" cases since the NGPA was enacted. The jurisdictional agency withdrawals may decrease; however, beginning in fiscal year 1981, the Division has consistently underestimated refund case receipts in its budget justifications. It has been estimating 1,600 cases per year, but actual receipts have exceeded the estimates by over 50 percent.

Additionally, over the last 3 fiscal years, cases other than jurisdictional agency withdrawals have averaged 2,440 annually, and the jurisdictional agency withdrawals have averaged 2,365 annually. If during fiscal years 1983 and 1984 the Division receives only 25 percent (591 cases) of its past average jurisdictional agency withdrawals, the Division's total workload would be over 3,000 cases per year.

FERC's rationale for estimating that 3,495 and 4,500 cases would be completed in fiscal years 1983 and 1984, respectively, is based on its belief that the increase in professional staff by four (or 50 percent) will result in a 50-percent increase in completions. However, this increase in completions can only be realized if the refund reports and no refund due statements have been received and thus allow the cases to be completed.

Although the regulations require producers to file refund reports or no refund due statements when they become aware that their wells have become ineligible for a NGPA price category, many are delinquent in filing those reports. In fact, as of September 30, 1982, the Division had identified 9,929 wells involving potential refunds for which no reports had been received from the producers.

The Division, in an effort to get producers to file the reports, has sent letters of inquiry concerning potential refunds to producers covering 2,735 wells through September 1982. (This includes letters covering about 400 wells and follow-up letters covering 455 wells that were sent in fiscal year 1982.) However, these letters covered only about 28 percent of the 9,929 wells.

Of the 3,239 cases completed in fiscal year 1982, only 983 (or 30 percent) involved cases in which producers had filed refund reports without prompting from FERC. It is apparent, then, that the completion of refund cases has been dependent on receiving refund reports from producers, which, in turn, has been primarily dependent on mailing the inquiry letters. Therefore, the addition of staff will increase the completion rate to the level FERC has projected only if there is a greater emphasis on sending letters of inquiry.

FERC also attributes its estimates of increasing productivity in fiscal year 1984 to the effect of a proposed regulation which would involve the pipeline companies in the refund seeking process. Because of the uncertainty of whether the proposed regulation will be adopted (either in its present form or revised) or its effect on the workload, we did not consider it in making our projection.

Therefore, using the actual workload received and completed through fiscal year 1982 and assuming that four people will be permanently added to the refund staff, we project that the backlog will only decrease to 9,660 and 9,391 in fiscal years 1983 and 1984, respectively.

ACTIONS TAKEN TO ALLEVIATE THE BACKLOG NOT EFFECTIVE

Near the end of November 1981 about eight field auditors from the Review and Compliance Branches were sent to the General Reports Branch to temporarily assist in processing refund reports. The auditors were available because travel fund cuts prevented them from making field trips. FERC officials indicated that the auditors performed well after they learned the system.

This was not the first time the General Reports Branch has received assistance from one of the other branches. In the past, it has received several staff persons for much shorter periods of time. However, the additional staff have not been sufficient to substantially eliminate the backlog.

POTENTIAL PROBLEMS THAT SHOULD BE AVOIDED

The backlog of refund cases presents several potential problems. One is that the longer that refunds due remain unidentified, the larger the refund grows and the smaller the probability that the end consumers who were overcharged will receive the refund. Another is that, as price controls end, both the executive and legislative branches could attempt to reduce personnel and funding for NGPA compliance and enforcement activities before FERC has effected an orderly completion of its refund program, particularly if there is a 2.3-year backlog of cases to close.

Effect of decontrol

Almost half of the natural gas being produced will be decontrolled after January 1, 1985. On January 1, 1985, and

July 1, 1987, certain categories of natural gas will be decontrolled pursuant to NGPA. According to DOE's Energy Information Administration, about 8 trillion cubic feet of natural gas will have no price ceiling on January 1, 1985.

Probability of refunds reaching consumers

Our concern over whether the ultimate consumer will benefit from refunds if the refund report backlog remains is derived from a situation we reported on in 1976. In that report we disclosed the lack of assurance that municipal retail customers would receive refunds from electric rate cases with potential refunds of about $8.7 million which took up to 5 years for FERC's predecessor, the Federal Power Commission, to process. The States, in 1983 as in 1976, control retail sales of both electricity and natural gas.

In that report, "Management Improvements Needed in the Federal Power Commission's Processing of Electric-Rate-Increase Cases" (EMD-76-9; Sept. 7 1976), we stated that the Commission took over 5 years to process a Boston Edison Company wholesale electric-rate-increase case and that three additional Edison rate cases were still in process. Edison may have collected about $8.7 million in potential overcharges, which were subject to refund with interest, under three of the four cases.

We noted that municipals generally passed wholesale rate increases, including potential overcharges, on to their retail customers. However, they may or may not choose to pass overcharge refunds to their retail customers. The Massachusetts Department of Public Utilities did not require the pass-on and the Commission had no authority in the matter. An official of one municipal estimated that about 89 percent of one refund had been returned to retail customers, but the municipal was having problems locating some customers.

Problems similar to those described above would appear to be applicable to the current administration of NGPA price controls. FERC has no authority over the retail natural gas industry which is generally regulated by the States. Also, we estimate that the NGPA refund report processing backlog will be 2.3 caseload years at the end of fiscal year 1984. Therefore, we are concerned that the potential refunds may not reach all who were overcharged.

Orderly program completion

The other potential problem concerns orderly program completion after the natural gas price controls expire. Our concern is derived from a parallel situation we examined when the crude oil price controls were ended.

In our report, "Department of Energy Needs To Resolve Billions in Alleged Oil Pricing Violations" (EMD-81-45, Mar. 31, 1981), we stated that, as of January 1981, DOE had alleged over $13 billion in oil pricing violations. However, only $4.2 billion had been resolved. Because petroleum pricing had been decontrolled and most alleged violations had not been settled, DOE needed to pursue its enforcement efforts to bring those violations to a fair and orderly resolution.

DOE prepared a 5-year plan for phasing out the compliance programs after deregulation. However, the Office of Management and Budget had proposed major reductions in DOE's personnel and funding requirements for fiscal year 1982 which would have seriously impaired the effectiveness of DOE's compliance program.

We are concerned that a similar situation could develop in the natural gas price regulation program under NGPA. To avoid, or at least minimize the potential problem, we believe that action should be taken to eliminate the refund report backlog and to keep the caseload processing current through the end of price regulation and until all cases are resolved.

According to FERC officials, refund reports and cases on file before deregulation will continue to be processed after deregulation. Also, natural gas refund cases subject to control after the deregulation dates will be processed. However, we believe that if there is a large backlog at the time of deregulation, both the executive and legislative branches could attempt to reduce FERC's personnel and funding. Such reductions could seriously impair FERC's ability to effect an orderly completion of its natural gas price regulation program under NGPA.

CONCLUSION AND RECOMMENDATION TO FERC

We believe that FERC should identify the actual size and types of backlog refund cases and work to eliminate the backlog to prevent large refunds which may not reach consumers and to avoid problems with orderly completion of the compliance and enforcement programs when NGPA price controls expire.

We recommend that FERC take timely and aggressive action to identify the actual size and type of backlog work and the procedural or staffing problems causing the backlog in the refund control program and use this information to eliminate the backlog of refund reports and cases and keep caseload processing current through the end of NGPA price controls.

AGENCY COMMENTS AND OUR EVALUATION

The FERC Chairman was in general agreement with our recommendation for reducing the refund backlog (see app. I) and stated that four additional people had been assigned to expedite processing and to reduce the backlog. This is a good step, but FERC needs to carefully monitor and study the situation to assure that the backlog is eliminated when the price control program ends. The Chairman also provided updated and revised information concerning the size and nature of the workload which we considered in preparing our final report.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

IN REPLY REFER TO:

NOV 3 1982

Mr. J. Dexter Peach
Director, Energy & Minerals Division
U. S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Peach:

On September 29, 1982, the United States General Accounting Office (GAO) forwarded its draft report entitled "FERC's Administration of NGPA Price Controls" for our review and comment.

The draft report concludes that, although most of the wells reviewed by GAO were properly categorized under the NGPA, the Commission's criteria for stripper wells under Section 108 of the NGPA do not meet the statutory requirements because higher incentive prices can be charged for natural gas which Congress did not intend to receive an incentive price. Specifically, the draft report first asserts that the Commission's definition for "nonassociated" natural gas should be applied after the qualifying 90-day production period because the current criteria do not reflect the requirements of the NGPA. GAO asserts that even after a well is qualified as a stripper well, an increase in the production of oil from that well should disqualify that well as a natural gas stripper well although its gas production remains under the statutory limit. Second, the draft report asserts that the Commission's definition of "recognized enhanced recovery techniques" is also "inconsistent with NGPA requirements." Here GAO argues that the Commission's interpretation of the term "recognized enhanced recovery technique" is too broad and enables operators to collect the stripper well price when production exceeds the statutory limit, as a result of routine well maintenance. In addition, the draft report finds that the backlog of NGPA refund cases has been underreported to upper level management and that the size of the backlog may allow refund amounts to increase and result in substantial refunds not reaching the consumers that paid the overcharges.

We are in general agreement with the GAO recommendation concerning the refund backlog and, as explained in the detailed response in Attachment A, have taken steps to expedite processing and to reduce the backlog. We disagree, however, with GAO's conclusion that the Commission's regulations implementing Section 108 of the NGPA do not conform to the requirements of the statute and that the regulations should be amended.

GAO note: Page references in this appendix have been changed to conform to page references in the final report.

The Commission has broad administrative authority under the NGPA to refine definitions of terms such as "nonassociated natural gas" and "recognized enhanced recovery techniques." In defining the parameters of such terms, the Commission has not only the authority but the obligation to consider administrative burdens which would be imposed by its regulations. Thus, as the draft report notes, the Commission consciously chose to apply the sliding scale for oil production to the 90-day qualifying period only and not to subsequent periods in view of its concern with the practical difficulties inherent in monitoring oil production as well as administrative burdens which such a requirement would impose. GAO's draft report, based on its review of two producers with stripper wells in two states, concludes that there would be no additional administrative burdens imposed by requiring continued monitoring of oil production. Although the two states involved in GAO's review do require monthly reporting of oil production, 50% of the stripper wells are located in states which require reports on an annual or lease basis only, if reports are required at all (see Table 1 to Attachment B). Thus, monitoring oil production for any 90-day production period is simply not possible in many states under current reporting requirements. Additionally, since production from stripper wells amounts to approximately 4% of total annual production, it is questionable whether the administrative burdens attendant with the monitoring of oil production are justifiable.

The Statement of Managers regarding enhanced recovery techniques states that the objective of recognizing enhanced recovery techniques is to insure that the producer does not have a built-in incentive to limit production from a given well to the statutory limit. Thus, in its regulations implementing Section 108 of the NGPA, the Commission established a strong disincentive to delay normal well completion techniques solely to qualify a well as a stripper well by prohibiting <u>normal</u> well completion operations which are performed within two years of the initial completion from qualifying as a recognized enhanced recovery technique but permitted a broad range of production enhancement activities to qualify in order to provide producers with an incentive to continue or to increase production from marginal wells without jeopardizing their stripper well status. If the incentive had not been provided, producers would be unwilling to expend monies to increase production and the result would be premature abandonment of wells. It would have been contrary to the Congressional intent to promulgate regulations that would cause a producer to lose the stripper well price as a result of increased production due to production enhancement work performed on a well. This perverted logic would discourage producers from performing production enhancement work on a well if the reward for the additional expenditures and increased production were a lower price and reduced revenues. As of August 1, 1982, the Commission had received 66,927 notices of determination under Section 108 but only 432 notices of recognized enhanced recovery determinations, an indication that normal or routine well maintenance is not being qualified as recognized enhanced recovery techniques. GAO's recommendation that the Commission define the term "recognized enhanced recovery techniques" is impractical since there is no consensus in the oil and gas industry about what such a definition should be, the term was not generally used with respect to a reservoir producing nonassociated gas prior to the NGPA, and initial completion operations differ greatly from state to state and what is normal in one area may not be considered normal in another. Upon review of the Commission's regulations and the NGPA itself, I conclude that the Commission's interpretations of "nonassociated natural gas" and "recognized enhanced recovery techniques" are reasonable within the Commission's broad administrative authority under the statute (see Attachment B for a detailed response on the legality of the Commission's stripper well regulations). The draft report data regarding nonassociated natural gas "loopholes" do not clearly show that the de minimis standard intended by Congress has been exceeded. GAO's marshalling of experts to challenge the Commission's "recognized enhanced recovery technique" procedures is not compelling so long as the substantial evidence test is met. In light of the clear exclusion in the regulations of "normal well maintenance" and the conferees' deference to jurisdictional agency expertise in interpreting what are "recognized enhanced recovery techniques" for their locale, the Commission's practice in this area is eminently reasonable and properly implements the NGPA.

Sincerely,

C. M. Butler III
Chairman

Enclosures

ATTACHMENT A

GAO Draft Report and Recommendation

GAO's draft report states that the Division of NGPA Compliance has developed a huge backlog of refund cases and reports for processing. GAO is concerned that the backlog situation could eventually result in the failure to refund overcharges to consumers when NGPA price controls are ended. The report further contends that the Division has been understating its refund backlog in reports to FERC's upper management.

GAO recommends that timely and aggressive action be taken to identify the actual workload backlog and to eliminate the backlog of refund reports to be processed and to keep caseload processing current through the end of price controls.

FERC Response

Since the August 1982 Red Book, the Division has been counting receipts as the universe of potential refund cases on a well basis. Completions continue to be wells for which staff has completed its analysis.

In attempting to determine the best method for counting NGPA refund workload, staff was originally concerned that the figures not be inflated by the large percentage of cases involving no refunds due. Although no refund due reports represent 60-70% of the NGPA refund documents received by FERC, we now believe a well-by-well count of cases with a refund potential is a more accurate measure of staff efforts since staff must review all refund cases to verify, in fact, that no refunds are due or that the appropriate amount, with interest, has been refunded.

While this appears to be the best method for counting receipts, we are still concerned that the workload may be understated. Most wells have numerous working interest owners whose refund obligations may not be covered by the well's operator. On the average, wells may involve 3-5 working interest owners; however, it is not unusual for some wells to have as many as 12-15.

For workload purposes, the well is the basic unit and therefore represents one receipt (and correspondingly one completion) regardless of the number of working interest owners or whether refunds were actually involved. For these reasons NGPA refund figures cannot precisely represent the complexity or breadth of the workload but can only serve as a general indicator of the caseload.

In order to assure that all wells that would have been counted as receipts had this new system been in effect for the preceding year, staff will adjust summary workload levels reported in the October 1982 Red Book for FY81 and FY82 to reflect all cases for which a refund potential event has occurred. Thus, receipts would be reported consistently for all years shown in the Red Book. Staff will not, however, attempt to allocate receipts back on a monthly basis to the month in which the refund potential event occurred since this would be an extremely time consuming and difficult task. The revised workload figures are shown on Table I. The revised pending end of FY82 figure is 8,503 refund cases or 2,163 cases more than had been shown previously in the Red Book.

Once staff adjusts the workload numbers, there are still discrepancies with the workload shown in the chart on page 22 of the draft GAO report. The GAO chart shows 10,973 cases pending at the end of FY82, while staff's revised figure is 8,503 cases. Assuming that GAO used only data contained in the Monthly Status Reports and the NGPA Summary Sheets which were provided by staff, it would appear that GAO has included data concerning buyers' own production (gas produced by a pipeline company and taken into its own system). The NGPA Compliance Division does not include this in its figures because these wells, in large measure, are cost of service wells and, as such, do not involve refunds. Additionally, these cases are more appropriately handled through routine field audits conducted by the Pipeline Rates Division's Purchased Gas Adjustment audit staff. Therefore, GAO has overstated the NGPA Compliance Division's workload pending at the end of FY82 by 2,470 cases. (Similarly, the statement on page 21 of the draft report that as of July 31, 1982 the Division's actual refund workload backlog of 9,935 cases has been understated by 4,176 cases is also inaccurate.)

Furthermore, Division, OPPR and FERC management have been aware of the growing backlog of NGPA refund cases for some time, and various alternatives for expediting processing of this workload have been explored. The most recent action taken by the Division Director involved the transfer of four Review & Compliance employees to the General Reports Branch as of October 1, 1982. Because these employees are already knowledgeable of the NGPA, it is anticipated that they will require only a minimal training period before becoming fully productive in the refund area. Using productivity estimates shown in the Red Book, staff expects to get current by the end of FY84 (see Table I to Attachment A) which would coincide with deregulation timetables.

Several other comments in the draft report require clarification.

On page 20 of the draft report, GAO refers to a loophole in the FERC's refund regulations which only required first sellers who actually made refunds to file refund reports with FERC. GAO further states that this loophole was eliminated in FY 1980 and the surge in workload from the revised regulation helped the increase in backlog to 9,388 cases at the end of FY81. We presume that the loophole to which GAO refers was the lack of a reporting requirement in cases where no refunds were due under Part 273 of the Commission's regulations (allowing for interim collections) as a result of receiving a negative determination or withdrawing the application for determination. This situation was amended when the Commission issued Order No. 131 on February 9, 1981 (in Docket No. RM80-54). Order No. 131, among other things, required that producers file either a refund report or a no refund due statement, whichever is appropriate, within 90 days of receiving a negative determination or withdrawal, by the applicant, of an application for determination.

The existence of a reporting requirement has never been a criteria for determining NGPA refund workload. In fact, refunds owed under the General Refund Obligation in Part 270 of the Commission's regulations (like those as a result of disqualification of stripper wells) are beyond the scope of interim collection regulations. However, Part 270 refunds have always been included in the NGPA refund workload.

The surge in receipts to which GAO refers resulted not from the issuance of Order No. 131 but rather from the identification of applications for determination which had been withdrawn by the applicants from the jurisdictional agencies. The high level of JA-level withdrawals resulted from the fact that this was the first time this information had been reported to the Commission since enactment of the NGPA and, as such, reflected a catch-up count. For the most part, the JA's have been subsequently reporting withdrawals to the FERC on a routine basis.

Attachment A

Table I

Revised NGPA Refund Processing Workload for FY79 - FY84

	Actual				Estimated	
	1979	1980	1981	1982	1983	1984
In process, start of period	0	443	4,135	8,454	8,503	6,608
Received	443	3,988	5,711	3,288	1,600	1,600
Total Workload	443	4,431	9,846	11,742	10,103	8,208
Completed	0	296	1,392	3,239	3,495	4,500
In process, end of period	443	4,135	8,454	8,503	6,608	3,708

ATTACHMENT B

GAO Recommendation

On September 20, 1982, the United States General Accounting Office (GAO) forwarded to the Federal Energy Regulatory Commission (Commission) its draft report to the Congress entitled: "FERC's Administration of NGPA Price Controls." This response is intended to support the Commission's interpretation of the statute and the lawfulness of the current regulations thereunder in response to the assertions of the draft report.

The draft report makes two assertions with regard to the legality of the Commission's regulations implementing section 108 of the Natural Gas Policy Act of 1978 (NGPA). First, the draft report asserts that the Commission's criteria for making the determination whether natural gas from a given well is "nonassociated" should be revised because the current criteria allegedly do not reflect the requirements of the NGPA. GAO asserts that even after a well is qualified as a stripper well, and its gas production remains under the statutory limit, an increase in the production of oil in that well should disqualify that well as a natural gas stripper well. Second, the draft report asserts that the Commission's definition of "recognized enhanced recovery techniques" is also somehow "inconsistent with NGPA requirements." Here GAO argues that the Commission's interpretation of the term "recognized enhanced recovery technique" is too broad and enables operators to perform routine maintenance work on a well which then has production in excess of the statutory limit, and to retain the well's status of a stripper well.

FERC Response

The starting point for resolving any issue of statutory construction is the language of the statute itself. Consumer Product Safety Commission v. GTE Sylvania, Inc., 447 U.S. 102, 108 (1980); International Brotherhood of Teamsters v. Daniel, 439 U.S. 551, 558 (1979). The starting point here is section 108 of the NGPA which defines stripper well natural gas in relevant part as follows:

> ...the term "stripper well natural gas" means natural gas determined in accordance with section 503 to be nonassociated natural gas produced during any month from a well if --
>
> (A) during the preceding 90-day production period, such well produced nonassociated natural gas at a rate which did not exceed an average of 60 Mcf per production day during such period; and
>
> (B) during such period such well produced at its maximum efficient rate of flow...

NGPA section 108(b)(1) (emphasis supplied).

There is also an exception provided if production from a previously qualified stripper well exceeds 60 Mcf per production day:

> ...such natural gas may continue to qualify as stripper well natural gas if the increase in nonassociated natural gas produced from such well was the result of the application of recognized enhanced recovery techniques.

NGPA section 108(b)(2) (emphasis supplied).

The GAO draft report takes issue with the Commission's interpretation of what the statutory terms "determined in accordance with section 503 to be nonassociated natural gas" and "recognized enhanced recovery techniques" mean. The following discussion explains and supports the Commission's interpretation of these terms.

DISCUSSION

I. "Determined In Accordance With Section 503 To Be Nonassociated Natural Gas."

If the term "nonassociated natural gas" were to be applied as strictly as it is defined in section 108(b)(3)(C) of the NGPA, there would be very few qualifying stripper wells since even a trace of crude oil would be grounds for disqualification. Section 108(b)(3)(C) states:

> The term "nonassociated natural gas" means natural gas which is not produced in association with crude oil.

However, the NGPA in section 501 makes a broad grant of authority to the Commission to administer the Act, including the authority to define terms:

> Except where otherwise expressly provided, the Commission is authorized to define, by rule, accounting, technical, and trade terms used in this Act. Any such definition shall be consistent with the definitions set forth in this Act.

NGPA section 501(b) (emphasis supplied).

The Conference Report adds a final gloss, confirming that "the Commission shall have authority to define what constitutes non-associated gas," and adds that "the Commission could allow a de minimis amount of oil to be produced from the well without disqualifying the well as a natural gas stripper well." (H.R. Rep. No. 1752, 95th Cong., 2d Sess. 89 (1978)).

The Commission exercised its authority to define "non-associated" in Order No. 44, Docket No. RM79-73, issued August 22, 1979. (FERC Stat. & Reg., Regulations Preambles ¶ 30,079). The order specifically refers to the Conference Report language and states, with respect to the initial qualification of a stripper well: "...we feel constrained to keep crude oil allowances to a de minimis standard." (FERC Stat. & Reg., Regulations Preambles ¶ 30,079 at 30,502). The Commission, as the GAO draft report indicates, published a sliding-scale ratio of natural gas to crude oil production to determine whether a well produced "non-associated natural gas" during the 90-day qualifying period.

Faced with many commenters favoring a flat limitation on the crude oil allowance of up to 10 barrels per day (Id.), the Commission instead set a relatively stringent sliding-scale for the initial qualifying period as follows:

If the average production of natural gas per production day during such production day during such production period was:	Then average crude oil production per day may not exceed:
50 Mcf or more but not more than 60 Mcf	1 bbl.
30 Mcf or more but less than 50 Mcf	2 bbl.
Less than 30 Mcf.	3 bbl.

18 C.F.R. § 271.803(b).

At the same time it issued the sliding scale above, the Commission issued a less stringent guideline for continuing qualification based on considerations of administrative feasibility, and the fact that gas production will generally increase commensurate with increases in oil production, so that disqualification would generally occur due to increased gas production. Aware of its authority to set the parameters of the term "nonassociated natural gas," the Commission consciously made continuing qualification less stringent and rejected a proposal that would require that written notice be given if production of crude oil exceeds the amount allowed under the sliding-scale, saying:

> The Commission has not adopted this proposal because of our concern about both the practical difficulties inherent in monitoring oil production and the administrative burden it would impose. In a situation where oil production increases, we believe that as a general matter gas production will also increase. Consequently, most wells which come to exceed the oil limit will at the same time exceed the gas limit and be disqualified as strippers on the basis of the latter. Should a situation come to the Commission's attention wherein this general proposition does not apply and wherein crude oil production is in excess of the prescribed limits of § 271.803(b), the Commission will undertake whatever measures we deem appropriate to resolve the matter.

FERC Stat. & Reg., Regulations Preambles ¶ 30,079 at 30,508.

What GAO chiefly objects to is the Commission's decision to make the nonassociated test stringent initially and to make continuing qualification less burdensome once the initial qualification hurdle is passed, calling this a "loophole." (Draft report at 8). The GAO presents some general data -- in the form of "ranges" of oil production -- to show that some stripper wells now have oil production in excess of the sliding scale. The draft report notes that in January 1982, the stripper well maximum lawful price of $3.217 was 1,113 percent above the lowest possible regulated price of $0.265. The report states that 27 of the 146 stripper wells GAO reviewed were producing oil in excess of the sliding scale. Another measure of "significance" GAO explains is that 4.33 percent of total natural gas production in 1981 was stripper well gas. (Draft report at 13-14).

Before addressing the real issue here -- the discretion of the Commission to define "nonassociated" as it did -- a word should be directed to GAO's calculations of price and revenue differentials, and its "ranges" of excess oil production data.

First of all, merely calculating price and revenue differences does not really address the issue of the legality or appropriateness of the Commission's rule. It assumes that the § 271.803(b) regulation is inappropriate, thereby begging the question. If an operator is entitled to the stripper well price, the fact that this price is several times higher than the price that would otherwise be applicable is simply part of the bargain struck in the NGPA. The issue is whether the "line-drawing" being done by the Commission in § 271.803(b) is within its discretion.

Another point is that "ranges" of oil production in excess of the sliding scale criteria do not give a clear picture of the situation. In reviewing the GAO data, one should keep in mind that the Commission could have set a higher flat rate as long as it was de minimis. A rate of 3-10 bbls., e.g., would still arguably be within the de minimis standard. The draft report at 14 indicates that at one company 18 wells were found that exceeded the sliding scale criteria in these amounts:

- -- 11 exceeded the criteria by amounts up to 1 barrel.
- -- 4 exceeded the criteria by 1 to 2 barrels.
- -- 3 exceeded the criteria by 3.1 or more barrels.

While these wells exceed the initial qualifying criteria of § 271.803(b), it is arguable that the crude oil production from these wells is still de minimis. At another company the draft report cites 9 wells where excess production "ranged" from 3.6 to 28.6 barrels per day. Yet there is no indication whether most of these wells clustered near the de minimis end of this range, were evenly distributed, or clustered at the high end. Similarly, the report states that New Mexico records show 6 wells where oil production exceeded the sliding scale criteria by 4.5 to 40.7 barrels, without any detailed break-out of amounts within that range. Thus, it is possible that few of the wells referred to exceed amounts that are arguably de minimis.

The point is this: the Commission struck a balance when it set the standard for initial and for continuing qualification in Order No. 44. It could have set any standard as long as only de minimis associated oil production was permitted. We believe the Commission could have chosen initial qualifying criteria that permitted greater oil production than the criteria actually chosen, and that this hypothetically higher standard would have been easily defensible. A 5 barrel, or even a 10 barrel per day limit is still arguably de minimis. The Commission obviously intended to adhere to the de minimis standard and said as much in Order No. 44 (see p.3, supra), but the Commission struck a balance, making initial qualification more stringent than it had to in order to ease the administrative burden attendant on subsequent monitoring.

The draft report at 11-12 makes little of the administrative burden that the Commission sought to ease by the continuing qualification procedures of Order No. 44. We note, however, that although stripper wells account for only approximately 4.33 percent of U.S. production (GAO's figure), the stripper well category accounts for over 38 percent of NGPA filings at the FERC, with over 67,000 filings received as of August 1982. Although the monitoring burden the Commission eased by the continuing qualification system it adopted in Order No. 44 may be considered small in individual cases, the cumulative reduction in unnecessary paperwork both on the industry and on the agency is greater. Considerations of administrative necessity may be a basis for finding implied authority for an administrative approach not explicitly provided in a statute. Alabama Power Co. v. Costle, 636 F.2d 323, 358 (D.C. Cir. 1979). Further, the draft report at 12 concurs with the Commission that concurrent increases in crude oil and natural gas are the most common occurrence. Thus, both bases for the system adopted in Order No. 44 -- the administrative burden consideration and the belief that increased oil production will usually trigger disqualification because of increased gas production -- are eminently reasonable.

An agency's construction of a statute which it implements is entitled to judicial deference, and its construction should be followed unless there are "compelling indications" that it is wrong, CBS, Inc. v. F.C.C., 453 U.S. 367, 382 (1981), and its construction should be overturned only if clearly wrong or unreasonable. E.g. Red Lion Broadcasting Co. v. F.C.C., 395 U.S. 367, 381 (1969). The Commission's section 108 regulations are clearly not unreasonable. Also, when the administrative interpretation, as here, "involves a contemporaneous construction of a statute by the men charged with setting its machinery in motion, of making the parts work efficiently and smoothly, while they are yet untried and new," this deference is especially due. Power Reactor Co. v. Electricians, 367 U.S. 396, 408 (1961), quoting from Norwegian Nitrogen Products Co. v. United States, 288 U.S. 294, 315 (1933). This rule has been equally well established with respect to the Commission's interpretation of the various provisions of the NGPA, and the same deference is due the Commission's interpretation of section 108 in Order No. 44. See, e.g., Ohio Association of Community Action Agencies v. F.E.R.C., 654 F.2d 811, 822 (D.C. Cir. 1981), Ecee, Inc. v. F.E.R.C., 645 F.2d 339, 360 (5th Cir. 1981), Petrolite Corporation v. F.E.R.C., 667 F.2d 664, 666 (8th Cir. 1981), Columbia Gas Development Corp. v. F.E.R.C., 651 F.2d 1146, 1155 (5th Cir. 1981), Falcon Petroleum v. F.E.R.C., 642 F.2d 780, 783, n.3 (5th Cir. 1981).

Moreover, the Commission based its regulations on the assumption that increased oil production would almost always be accompanied by an increase in gas production, which would cause a well to lose its stripper well status. This is not an unreasonable assumption. The regulation is not unreasonable, therefore, simply because the assumption on which it is based does not prove true in some cases.

The draft report also takes issue with an interpretation letter of the Commission's General Counsel to Mobil Oil Corporation, dated October 27, 1980. The letter at page 2, however, merely interprets § 271.803(b) which defines non-associated natural gas as:

> ...gas produced from a well which a jurisdictional agency determines produced an average number of barrels of crude oil per production period upon which the determination is based, which does not exceed the number of barrels in accordance with the following table.

(Emphasis supplied; See table of sliding scale criteria, supra, at 3).

The General Counsel advised Mobil that his interpretation of Order No. 44 and § 271.803(b) was that withdrawal applications were not necessary if oil production subsequently exceeded the sliding scale criteria used for the initial qualification. This is what is objectionable to the authors of the draft report. Yet as we have seen, the objection amounts to little more than second-guessing a matter entrusted to the Commission's discretion. Stripper well gas is natural gas "determined in accordance with section 503 to be nonassociated..." (emphasis supplied) NGPA Section 108(b)(1). Section 503 focuses on the determination process and the Commission's authority to reverse and review jurisdictional agency determinations by a finding that they were not supported by substantial evidence. (Section 503(b)). In keeping with this focus on the determination process in the statute, the sliding scale criteria in § 271.803(b) is only applied to the 90-day production period in which the stripper well determination is based, as the General Counsel advised Mobil.

The Commission acted within its discretion to focus the initial stringent criteria on the determination stage. The administrative efficiency concern and the fact that increased gas production is a usual concomitant to increased oil production are reasonable bases for the Commission's rule.

II. "Recognized Enhanced Recovery Techniques."

When production from a stripper well exceeds an average of 60 Mcf per production day, NGPA section 108(b)(2) requires that the Commission shall, by rule, provide that such natural gas may continue to qualify if the increase was the result of the application of recognized enhanced recovery techniques.

The Conference Report explains that the objective of the "enhanced recovery" language is "to insure that the producer does not have a built-in incentive to limit the production from a given well to an average of 60 Mcf per day." (H.R. Rep. No. 1752, 95th Cong., 2d Sess. 89 (1978)). Other than this gloss in the Conference Report, there is no indication in the NGPA of how to define or interpret the term "recognized enhanced recovery technique." There is a corollary to the rule that one must listen attentively to what a statute says: One must also listen attentively to what it does not say. (Frankfurther, Some Reflections on the Reading of Statutes, in 3 Sutherland, Statutory Construction 409, 419 (1974)). Since the NGPA is silent regarding the definition of "recognized enhanced recovery techniques," the broad authority expressly granted in section 501 empowers the Commission to define this term.

The Commission exercised its definitional authority in Order No. 44 by providing that:

> ...any enhanced recovery techniques which increase the rate of production of gas from a well shall generally qualify as recognized enhanced recovery

GAO note: The subject of recognized enhanced recovery techniques has been deleted from the final report. See page 16.

> techniques...normal completion operations performed within two years of the initial completion do not qualify as recognized enhanced recovery techniques...

The Commission also stated that:

> With respect to what constitutes a "normal well completion operation,"...such operations may differ from State to State due to geological differences in the producing reservoirs. For this reason...the jurisdictional agency shall define the term "normal well completion operation"...

FERC Stat. & Reg., Regulations Preambles ¶ 30,079 at 30,501.

This is codified at § 271.803(a) of the Commission's regulations.

The draft report at page 15 asserts that "FERC's definition, however, allows normal well maintenance actions -- which... experts do not recognize as enhanced recovery techniques -- to qualify..." The Commission's regulations expressly state, however, that "[n]ormal well maintenance, repair, or replacement of equipment or facilities does not qualify as enhanced recovery techniques." 18 C.F.R. § 271.803(a).

The draft report at pages 16-17 lists certain actions which have been submitted as enhanced recovery techniques and which "experts" contacted by GAO have indicated were only normal well maintenance. The list includes acidization, fracturing, installation of gas line compressor, removal or replacment of tubing, pumping unit installation to remove hydrocarbons, use of surfactant, installation of intermitter, and wellbore and tubing cleanout. What the GAO report ignores is that a determination whether an action is an enhanced recovery technique or a normal well maintenance technique is not ordinarily made in the abstract as a matter of academic expert judgment outside of the context of a jurisdictional agency determination. Rather it is a concrete practical call made by the appropriate jurisdictional agency experts in the context of their local situation.

Section 503 of the NGPA authorizes the jurisdictional agency to make initial well determinations at the local level. In Order No. 44-A, the Commission stated that section 503 makes it clear that:

> because of the many factors indigenous to each locale, determinations of normal well completion operations should be done on a state by state basis.

> The Commission is of the position that the jurisdictional agency may reach its determination of what constitutes a "normal completion operation" either by adopting a general definition of the term based on factors indigenous to that state or by determining what constitutes a normal completion operation on a case-by-case basis for each particular well. In either case as long as the determination is based upon substantial evidence the Commission will defer to the jurisdictional agency's exercise of its expert judgement.

Rather than engaging in a kind of "battle of experts" with GAO experts in one camp, and jurisdictional agency experts in another, the key to assessing the legality of the Commission's review of "enhanced recovery" determinations is to determine whether they are based on substantial evidence in the record. Although the draft report at 15 alleges that "FERC's definition of recognized enhanced recovery techniques [is] inconsistent with NGPA requirements," this allegation is misdirected because the §271.803(a) definition expressly excludes normal well maintenance. GAO's allegation should have been that Commission review of jurisdictional agency determinations of recognized enhanced recovery techniques is flawed because the determinations were made on less than substantial evidence.

The substantial evidence test is found at NGPA section 503(b)(1)(A) and requires the Commission to reverse a jurisdictional agency determination if:

> (A) it makes a finding that such determination is not supported by substantial evidence in the record upon which such determination was made...

The substantial evidence test has been borrowed from the courts and there are various refinements of what it means. It has variously been described as something less than the weight of the evidence, Consolo v. Federal Maritime Commission, 383 U.S. 607, 620 (1966); more than a mere scintilla of evidence, Bray v. U.S., 515 F.2d 1383 (Ct. Cl. 1975); and such relevant evidence as a reasonable mind might accept as adequate to support a conclusion, John W. McGrath Corp. v. Hughes, 264 F.2d 314 (2d Cir.), cert. denied, 360 U.S. 931 (1959).

For our purposes, the Conference Report Statement on the subject should be given great weight:

> The conferees have followed the traditional definition of substantial evidence review; that is there is

> no intention to allow the Commission to "second guess" the agency by independently weighing the evidence and reversing the agency's determination as if the initial responsibility to make the determination were placed within the Commission.

H.R. Rep. No. 1752, 95th Cong., 2d Sess. 118 (1978).

Thus, the conference report suggests great weight should be given the jurisdictional agency's assessment of the evidence. When coupled with the fact that "substantial evidence" does not have to be a preponderance of the evidence but simply adequate to support a conclusion, the Commission's treatment of recognized enhanced recovery technique determinations is seen to be reasonable and appropriate. When a jurisdictional agency, fully aware of the factors indigenous to its locale, makes an enhanced recovery determination, its expertise, even if it is a minority view, may well constitute substantial evidence, since the substantial evidence test does not require that the weight of the evidence support that view. See Consolo, supra.

Finally, the Commission's system of defining and implementing the "recognized enhanced recovery technique" exception in section 108 is entitled to deference and can be overturned only if clearly wrong or unreasonable. See, e.g., Red Lion Broadcasting Co., supra. It is eminently reasonable for the Commission to rely on the expertise of those familiar with factors indigenous to their locale, particularly since the conference report points in this direction. The test does not turn on finding more experts to support one side rather than the other. Instead, one must focus on whether, given indigenous factors affecting the well or the locale, the jurisdictional agency's determination was based on substantial evidence. This draft report does not focus on this test.

In an analogous discussion regarding the proper interpretation of "recognized conservation practices" the Fifth Circuit U.S. Court of Appeals has stated:

> Congress declared that the stripper well's average daily production must be at its maximum efficient rate of flow, determined in accordance with recognized conservation practices... This is a clear directive to respect and rely on state agency determinations of what constitutes recognized conservation practices.

Ecee, Inc. v. F.E.R.C., 645 F.2d 339, 356 (1981). (emphasis in original).

This further supports the Commission's practice, consistent with its section 501 and 503 authority, of deferring to jurisdictional agency expertise in weighing recognized enhanced recovery technique determinations for a particular locale.

Attachment B

Table I

State	Number of §108 wells	% of §108 wells in U.S.	Avg. Daily 1/ Oil Prod-1980 (BP W/D)	Reporting Requirements for Oil Production
Kentucky	1,928	2.7	1.1	Monthly on lease basis
New York	967	1.3	0.5	Annual on lease basis
Ohio	8,107	11.4	1.7	Annual on well basis
Pennsylvania	7,000	9.8	0.3	No mandatory reports
West Virginia	17,523	24.7	0.4	Annual on well or lease basis

1/ From The Oil and Gas Compact Bulletin, Volume XL, Number 2, December 1981

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004 918 661-6600

GAS AND GAS LIQUIDS GROUP

October 22, 1982

United States General Accounting Office
Resources, Community and Economic
Development Division
Washington, DC 20548

Attention: F. Kevin Boland
Senior Associate Director

Re: GAO's Draft Report
Entitled: "FERC's
Administration of NPGA
Price Controls"

Gentlemen:

Your office, by letter dated October 12, 1982, forwarded to Phillips Petroleum Company a paragraph from the subject report and invited comments thereon.

We would like to point out that of the nine wells discussed in the paragraph, the production from two of the wells is not sold but is returned to the lease for pressure maintenance. The gas from another of the nine wells is being vented, inasmuch as an economical connection to the sales line could not be made even at stripper prices. Therefore, we cannot agree with the revenue figures stated therein. Further, any sales prices would be on the basis of cents or dollars per MMBtu rather Mcf.

We think the report language should recognize the wells in question fully qualified as stripper wells and that the increase in the oil production occurred only after the qualifying period. While it is recognized that such an increase may occasionally occur, we believe that continued monitoring after the qualifying period of the sliding scale limit would be an unwarranted burden on the industry and the state and federal jurisdictional agencies. Apparently, the FERC recognized this burden in its Order No. 44 declining to impose such a requirement.

Very truly yours,

PHILLIPS PETROLEUM COMPANY

By
W. B. Gaul

WBG:lr

Alan W. Nash
Vice President-Regulatory Affairs

October 25, 1982

Mr. F. Kevin Boland
Senior Associate Director
Resources, Community and
Economic Development Division
U. S. General Accounting Office
Washington, D.C. 20548

Re: Draft of a Proposed Report
"FERC's Administration of NGPA Price Controls"

Dear Mr. Boland:

Thank you for your letter of October 12, 1982, in which you requested Mitchell Energy Corporation to review and comment on an excerpt from a General Accounting Office draft report entitled "FERC's Administration of NGPA Price Controls". Mitchell appreciates being afforded the opportunity to comment on this excerpt and I hope that the following will be of assistance to you in finalizing your report.

The statistics shown in the excerpt, although accurate, tend to be very misleading in two respects. First, as written, the excerpt leads the reader to believe that 29 percent of Mitchell's stripper wells exceeded the FERC's sliding scale criteria for the oil production applicable for initial qualification. In fact, as of May 1981, Mitchell had 484 stripper wells, only 62 (12.8%) of which had any crude oil production. Of these 484 wells, only 18 (3.72%) had crude oil production that exceeded in that reporting month the initial sliding scale criteria established by the FERC.

It should be noted that an examination of our most recent data on these 62 wells reveals that only 8 (1.65% of the May 1981 total of 484 stripper wells) currently have oil production that exceeds the FERC sliding scale criteria. Further, 6 of these wells (75% of the 8) were over the initial criterion by less than one barrel per day.

Second, the excerpt from the draft report leads the reader to assume that, because 18 wells exceeded the FERC sliding scale criteria for oil production, some violation of the FERC regulations may exist. This is not the case.

MITCHELL ENERGY CORPORATION 2001 TIMBERLOCH PLACE
P.O. BOX 4000 THE WOODLANDS, TEXAS 77380
A Subsidiary of Mitchell Energy & Development Corp

In its Final Rule - Order No. 44 (issued August 22, 1979, in Docket No. RM79-73), the FERC stated that it would not adopt recommendations that written notice be given if oil production exceeded the sliding scale criteria "because of [its] concern about both the practical difficulties inherent in monitoring oil production and the administrative burden it would impose." With this statement, subsequently confirmed in an October 27, 1980 Office of General Counsel letter opinion to Mobil Oil Corporation, the FERC recognized that the amount of oil produced in conjunction with natural gas fluctuates both up and down and in no way can be considered as a constant flow. Had the FERC required notices of disqualification each time a well exceeded the criteria, producers would have had to disqualify, requalify, disqualify, etc., every time the oil production fluctuated the other way. The burden of this amount of potential paperwork is clearly unjustified, particularly in view of the fact that, in Mitchell's case, only 1.65% of its stripper wells fall into this category.

§271.82(b) of the Commission's regulations incorporates this policy through a definition of "nonassociated natural gas" which limits use of the sliding scale criteria to the initial 90-day qualifying period. Although oil production may increase beyond the FERC sliding scale criteria from time to time subsequent to qualification as a stripper well, such criteria is not then applicable.

Accordingly, we recommend that the excerpt be revised to read as indicated in the attachment to this letter. Should you require any additional information, please do not hesitate to contact me.

Very truly yours,

Alan W. Nash
Attachment
AWN:nw

Proposed Revision

At the second company we examined all 62 of its stripper wells with oil production (the company's total stripper well inventory being 484 wells). We found at the time of our audit that 18 (29 percent of stripper wells with oil production and 3.7 percent of all stripper wells) had oil production in excess of FERC's sliding scale criteria applicable for initial qualification. Of the 18, the average daily production of

-- 11 exceeded the criteria by amounts up to 1 barrel.

-- 4 exceeded the criteria by 1 to 2 barrels.

-- 3 exceeded the criteria by 3.1 or more barrels.

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