CBO MEMORANDUM

WAIVING ROYALTIES FOR PRODUCERS OF OIL AND GAS FROM DEEP WATERS

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CONGRESSIONAL BUDGET OFFICE

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The Congressional Budget Office (CBO) has prepared this analysis of the economic and budgetary effects of reducing royalties on oil and gas production from the deep waters of the federal offshore region at the request of the House Committee on Natural Resources. Richard Farmer of CBO's Natural Resources and Commerce Division prepared the report under the supervision of Roger Hitchner and Jan Acton. Pete Fontaine of CBO's Budget Analysis Division provided assistance on budgetary issues. The report was edited by Leah Mazade. Christian Spoor provided editorial assistance, and Donna Wood prepared the memorandum for production.

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SUMMARY AND INTRODUCTION

The Congress is considering proposals that would require the Secretary of the Interior to exempt businesses from paying royalties on new production of oil and gas from parts of the federal offshore region. The House of Representatives has yet to consider any specific legislation for reducing royalty levels, but the Senate Committee on Energy and Natural Resources has approved a bill, the Outer Continental Shelf Deep Water Royalty Relief Act (S. 318). That legislation would temporarily suspend the requirement to pay royalties on new production from waters deeper than 200 meters until a business had recouped the capital costs associated with bringing the new production on line.

In this memorandum, the Congressional Budget Office (CBO) investigates the likely economic and budgetary effects of reducing royalties on oil and gas production from deep waters. The memo reviews the data on the resource potential of deep waters and some of the arguments put forth by proponents of government support for deep water development. Without considering any specific proposals for changing royalties, CBO concludes that the likely effect of lower royalty rates on the new production of offshore oil and gas would be very small. The probable budgetary impact would be negligible as well, mainly because of the constraints of the competitive process for issuing leases for offshore drilling and production rights. However, to the

extent that any policy establishing different royalty rates for producers working in different regions or using different technologies succeeded in increasing activity by those producers, basic distortions in economic activity could occur that would eventually raise the cost of production for other producers.

BACKGROUND

The great resource potential of the deep waters makes them a natural focus for policies aimed at increasing the nation's production of oil and gas. The federal offshore waters contributed 14 percent of the United States' total production of crude oil in 1993 and 26 percent of its natural gas.[1] Texas, Louisiana, and southern California are the principal sources of offshore production. Production from deep waters--200 meters and greater--of the Gulf of Mexico represents a large and growing part of the current supply from the offshore region. In 1993, 4.6 percent of all Gulf of Mexico production of crude oil and 1.8 percent of natural gas came from the deep waters--up from 1.0 percent for oil and 0.2 percent for gas 10 years earlier.

1. Based on conversations with staff of the Department of the Interior, Minerals Management Service, Resource Evaluation Division.

The general policy objectives of the U.S. government in developing oil and gas resources located in the offshore regions are straightforward. Those resources "should be available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs."[2] To that end, the federal government awards leases on a competitive basis for the rights to look for and produce crude oil, natural gas, and natural gas liquids from offshore lands. Specific legislative proposals to encourage greater oil and gas production from deep waters have sought changes in the royalties associated with these leases.

Royalties and the Competition for Offshore Resources

In the most common competitive process, qualified businesses submit bids specifying cash bonuses that they are willing to pay up front for leases granting them exclusive rights to explore for and extract mineral deposits from individual tracts of submerged land. The government awards leases to the highest bidders. The leases are subject to diligence requirements (dictating how much time the leaseholder may take to explore for and develop the

2. 43 U.S.C. 1332 (3).

resources); they also require the payment of royalties of at least 12.5 percent on the gross proceeds from oil and gas sales.

Currently, a royalty rate of 16.7 percent applies to production from shallow waters. A rate of 12.5 percent applies to deep water and frontier areas, such as Alaska and parts of the Atlantic coast. The Secretary of the Interior now has discretion to reduce or eliminate royalties in order to promote increased production from existing leases.[3]

The law also allows the Secretary of the Interior to conduct other types of competitive sales, such as the bonus bid with a fixed share of net profits (instead of a royalty) from future production. The government introduced net-profit-share leases in the early 1980s, but only a few have ever become profitable and paid revenues to the federal government. Accordingly, this memorandum concentrates on fixed-royalty leases.

The Resource Potential of Deep Waters

The continental slope is the offshore region encompassing water depths of between 200 meters and 2,500 meters. As recently as 1975, the U.S.

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3. 43 U.S.C. 1337 (3).

Geological Survey (USGS) assumed that the cost of producing oil from those depths would be prohibitive and decided to exclude resources from the continental slope in its estimates of undiscovered resources. The government's delineation of offshore leasing areas also recognized this early supposed barrier, establishing a clear distinction between regions on the continental shelf (less than 200 meters) and those on the slope. As oil prices rose throughout the 1970s, however, oil companies moved their operations into deeper waters.

In a revised resource appraisal only six years later, USGS reported a 50 percent likelihood that undiscovered crude oil located under waters with depths of between 200 meters and 2,500 meters and developable with conventional technologies might total at least 2.5 billion barrels.[4] This quantity represented nearly 40 percent of the total undiscovered resources of oil in the Gulf of Mexico. Undiscovered, producible volumes of natural gas in these regions might be as much as 26.5 trillion cubic feet--or about 35 percent of the Gulf total. The same resource appraisal also indicated a significant production potential for the deep waters offshore of the mid-Atlantic states.

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4. U.S. Geological Survey, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, USGS Circular 860 (1981), Appendixes A and D. Later estimates prepared jointly by USGS and the Minerals Management Service (*Estimates of Undiscovered Conventional Oil and Gas Resources in the United States--A Part of the Nation's Energy Endowment*, 1989) do not distinguish resources by depth, although the mean undiscovered, conventionally recoverable figure for the entire Gulf is comparable to the 1981 USGS figure.

Today, there are 24 active fields producing oil and gas from 85 leases on the continental slope of the Gulf of Mexico.[5] At the beginning of 1993, remaining proved reserves in these deep water areas stood at 791 million barrels of crude oil and 3.39 trillion cubic feet of natural gas. (Proved reserves are resources that have been discovered and developed and can be completely and profitably produced, given today's prices and technologies.) These figures represent nearly 40 percent of the crude oil and 15 percent of the natural gas reserves located in the Gulf of Mexico.

Pointing to even greater deep water production, the Department of the Interior (DOI) also reports 27 fields on 1,611 leases in deep water areas where companies are actively searching for or developing oil and gas resources. These leases account for over 40 percent of the unproved active leases in the Gulf. Moreover, technological capabilities are now sufficient to allow installation of production facilities and pipelines in water over 800 meters deep. The current record for deep water drilling in the Gulf of Mexico is 2,500 meters.

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5. Department of the Interior, Minerals Management Service, *Estimated Proved Oil and Gas Reserves, Gulf of Mexico, December 31, 1992* (August 1993), Tables 1 and 2. Totals are for western slope and central slope areas.

Some Arguments for Reducing Royalties on Deep Water Production

Proponents of royalty waivers offer several justifications for such action. Special support for exploration and development in deep waters may fit in with the nation's goal of expeditious development of oil and gas resources. These resources are more costly to locate, require more time and money to develop, and may be subject to greater capital risk than other prospects. Appropriate government support may help to offset these drawbacks to production from deep waters.

Some proponents of waiving royalties may also see it as a means of aiding a declining industry. Waivers may provide some economic stimulus for deep water exploration and production, helping to restore profits, jobs, and tax revenues for local economies. To this end, the Senate proposal (S. 318) would clarify the Secretary of the Interior's current authority to reduce royalty rates to promote increased production by specifying that this authority also applies to new production--from anywhere in the offshore regions, not just from deep waters.

Other advocates may see the lowering of royalties as a way to help support the nation's energy security goals. By increasing the profitability of offshore production, royalty waivers may increase domestic oil and gas

production (and reduce oil imports). And waivers may help the industry maintain an infrastructure it will need in responding to future oil crises. (The later section on economic efficiency suggests that the government's policy on royalties may better promote energy security if royalty rates are flexible, allowing the government to lower them on an emergency basis during an oil price shock.)

The following section raises concerns that may challenge arguments for royalty waivers.

THE PROMISE OF GREATER PRODUCTION: CAN LOWER ROYALTY RATES REALLY HELP?

A temporary reduction in royalties for deep water producers of oil and gas would probably have little direct impact on the nation's production of oil and gas or on employment in related industries. For existing offshore leases, the reasons behind this statement are rooted in the basic cost structure of the industry; for new leases, they can be found in the design of the competitive process for leasing exploration and production rights for offshore resources. A small indirect boost to development in shallow waters may result from incentives meant for deep water producers alone if the laying of new pipelines to deep waters enhances the profitability of some shallow water prospects

along the route. This benefit would come, however, at the cost of raising the initial transport expenditures of deep water producers.

The Cost Structure of the Industry and Production from Existing Leases

As a general statement, offshore production activities differ from their onshore counterparts in three ways. First, the capital costs of production and pipeline facilities are higher offshore. For example, in 1990, the average costs for drilling an oil well offshore were about $300 per foot, compared with costs of about $50 per foot onshore.[6] Second, the delay from signing a lease to starting production is longer offshore (from 5 to 10 years offshore versus from 1 to 2 years onshore). The time needed for making changes to existing facilities is longer offshore as well. The third difference reverses the pattern of the first two--the operating costs per unit of oil or gas production are lower offshore because field sizes tend to be larger. For example, average reserves for offshore oil and gas fields are more than 10 times larger than for onshore fields.[7] All of these differences are more accentuated for production activities in deep waters.

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6. American Petroleum Institute data reported by the Energy Information Administration, *Petroleum--An Energy Profile*, DOE/EIA-0545 (1991), Figure 14.

7. Energy Information Administration, *Geologic Distributions of U.S. Oil and Gas*, DOE/EIA-0557 (1992), Figures 12, 60, and 61.

For production from existing facilities, the economic implication of higher capital costs, lower operating costs, and longer and less certain paybacks is straightforward: changes in royalty rates (or oil and gas prices) will have a smaller effect on optimal production levels offshore than onshore. Businesses operating both onshore and offshore design production, processing, and transportation facilities to handle a certain flow of oil or gas. But the costs of subsequently increasing capacity by even a small amount are much higher offshore. Conversely, because operating costs are relatively low offshore, a drop in oil or gas prices would have much less impact on the profitability of continuing production offshore than it would onshore.

As an example, for operators of existing facilities contemplating expansion, waiving a 12.5 percent royalty rate would be equivalent to raising oil or gas prices by about 14 percent.[8] A permanent lowering of royalty rates by this amount would clearly enhance the profitability of offshore production. But this incentive would be much weaker if the royalty waiver were temporary--tied, for example, to recouping expenditures made to increase production. Issuing temporary waivers in an environment in which oil and gas price movements from year to year are often in the range of 10 percent to 20 percent is likely to have little discernible effect on production levels.

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8. In very basic terms, the net cash flow (*NCF*) from an oil lease would equal the price (*P*) net of royalty payments ($P * R$, for royalty rate *R*) minus operating costs (*O*), all net of taxes (for tax rate *T*), or $NCF = [P * (1 - R) - O] * (1 - T)$. From this formula, the equivalence between a change in the royalty rate (dR) and a percentage change in price that yields the same changes in net cash flow would be $-dR = (1 - R) * (dP/P)$ or, for a royalty rate of 12.5 percent, $0.125 = (1 - 0.125) * 0.143$.

The Competitive Process and Production from New Leases

Changing the royalty rate is not likely to affect total payments to the government or total production from new exploration prospects that otherwise appear to be profitable. Because of the competitive nature of the bidding process for new leases, businesses would respond to a drop in the royalty requirement by bidding a higher bonus. A lower rate might induce a business to increase the size of its initial development of a prospect, but the ultimate cumulative flow of oil or gas would not change very much.

Pipeline Economics and the Boost to Shallow Water Development

In the case of the U.S. offshore regions, the economics of shallow and deep water operations are closely linked because of their common use of extensive networks of undersea pipelines and platform-mounted pumping stations. These networks, which bring crude oil and gas to shore by the least expensive route, have extended slowly outward from the shorelines over the past four decades. The prospective profitability of new operations in deep waters, which are more distant from shore, is greatly enhanced by the existence of pipelines that already serve producers in shallow waters nearby.

Government incentives that successfully encourage deep water production on new leases could cause operators to extend pipelines directly to those facilities. Deep water incentives that cause oil and gas companies to leapfrog over shallower prospects may have the effect of improving the profitability of some prospects in shallow waters that lie close to a new pipeline extension. Thus, the possibility exists that a small boost to new development in shallower waters could accompany royalty waivers for deep water producers. However, any benefit in the form of lower transport costs for future development in shallow waters would necessarily come at the cost of higher initial transport costs for the new deep water facilities. The net benefit over time is likely to be nil.

POTENTIAL BUDGETARY IMPACT

Legislation providing for the temporary waiver of royalties on new oil and gas production from deep waters, or, indeed, any water depths, would probably have little budgetary consequence. There is, however, some risk of loss to the government, depending on how the legislation defines "new" and the precise preconditions for granting the waivers.

No Adverse Budgetary Impact in Most Cases

In at least four specific cases, waiving royalties would have no adverse budgetary impact. First, if DOI waived royalties only for production from existing leases that would otherwise be unprofitable and would shut down anyway, the government would not lose receipts. The waivers could be temporary or permanent, or could apply to all or only a part of the production from those leases, without affecting receipts.

Second, if DOI waived royalties only for new production from existing leases, the government would not lose receipts in instances in which that new production resulted from some specific expenditures (for example, capital costs, as in S. 318) that the company could not profitably make without the waiver. Again, whether the waivers were temporary or permanent would have no effect on receipts.

Third, if DOI waived royalties only for new leases that firms in the industry would bid on even in the absence of waivers, bonus bid payments (which are categorized as offsetting receipts) would be likely to rise commensurate with the drop in the present value of future royalty payments. Hence, the net budgetary effect over time would be neutral. Regardless of the duration of the waivers or whether they were tied to recouping capital

costs (as in S. 318) or to some other mechanism, the bonus bid would likely rise to offset all or part of the drop in royalties.

A fourth case of no adverse budgetary impact would arise if DOI waived royalties for new leases that would otherwise be unprofitable for companies to bid on. In other words, without a waiver of royalties, these additional lease sales would not occur under current law because potential bidders would view the lease properties as uneconomic. In such cases, the government would receive additional bonus bid receipts relative to current law, but those receipts would be the proceeds of nonroutine asset sales. Hence, the net budgetary impact would be zero for pay-as-you-go purposes under Congressional scorekeeping rules.[9]

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9. Section 257(e) of the Congressional Budget and Impoundment Control Act of 1974 (the Budget Act), as amended in 1987 and 1990, sets out the rules on asset sales:

> The sale of an asset or prepayment of a loan shall not alter the deficit or produce any net deficit reduction in the budget baseline, except that the budget baseline shall include asset sales mandated by law before September 18, 1987, and routine, ongoing asset sales and loan prepayments at levels consistent with agency operations in fiscal year 1986.

CBO considers the continuing lease of federal lands under leasing provisions in law before 1987 as "routine" under the Budget Act. In contrast, new offshore oil leases that may occur directly as the result of legislation providing for royalty relief in deep waters would be "nonroutine." Hence, the receipts from such sales could not be counted toward reducing the deficit under section 257(e).

Possible Budgetary Costs: Waivers That Do Not Add Production

The federal government could experience a significant loss of receipts relative to current law if the legislation set conditions that resulted in the granting of royalty waivers for all or most existing leases. (Currently, the federal government receives about $2.4 billion a year in offshore royalties.) The concern here is with waivers that do not "promote increased production," as required by current law. Losses could occur in several ways.

Among the more obvious examples, the prospect of budgetary costs would be great if the legislation required the extension of waivers to all production from any facilities that have recorded some new production. Costs could also occur if the legislation simply defined any production resulting from additional investment as new production, regardless of whether that investment would have been profitable without waivers.

But large costs could also occur inadvertently if the legislation required DOI to determine whether production would be profitable without a waiver but did not allow sufficient time for the agency to collect the necessary company data and thoroughly evaluate all waiver applications. The result would be that many otherwise ineligible leases would receive waivers.

One other way legislation may lead to budgetary costs is by broadly defining new production as any additional production coming from some management unit larger than the individual lease. For example, legislation could define a unitized property, encompassing all leases that tapped the same reservoir. In that case, a company might be able to receive royalty waivers for higher levels of production from several existing leases (that would have been profitable without waivers) on the strength of some investment on one new lease.

Legislation Versus Current Law: Does Anything Change?

Part of any legislation addressing royalty waivers may be redundant with current law, which states that the Secretary of the Interior "may, in order to promote increased production on the lease area, through direct, secondary, or tertiary recovery means, reduce or eliminate any royalty or net profit share set forth in the lease for such area."[10] Legislation that neither provides additional authority nor mandates further actions would have no budgetary impact because it would not change anything. Thus, if new legislation merely restates or clarifies the existing authority quoted above, CBO would not estimate any budgetary impact from it. If, however, new legislation required

10. 43 U.S.C. 1337 (3).

the Secretary of the Interior to grant waivers, the budgetary effects would depend on what conditions were required for granting the waivers.

SELECTIVE ROYALTY WAIVERS AND ECONOMIC EFFICIENCY

The bottom line of the preceding sections was that reducing offshore royalties would have little effect on production. Nevertheless, in some very narrow circumstances, it may still be possible to gain some economic benefits from lowering royalties. At the same time, some other perverse and unexpected changes in offshore activity may occur. This section briefly describes some potentially valid economic arguments for waivers, investigates some basic distortions in economic activity that may occur, and reviews some basic considerations in designing waivers that may also affect economic activity.

An Economic Rationale for Waivers

The economic benefits from lowering royalties would be greatest if the waivers applied to production from older, depleted reservoirs--especially if production would halt altogether without the reduction. The public has a financial stake in sustaining a flow of income from these leases, and a small

cash flow (from any royalty greater than zero) would be better than no flow at all.

In a broader sense of economic efficiency, it might also be worthwhile to reduce royalties in this situation if the costs of restarting production after a production facility had closed would be very high. This asymmetry in costs is a common problem in the oil and gas industry--as in many other industries--and is especially acute for low-volume, high-cost wells in the nation's oldest onshore producing regions. Redrilling expenses can be so high that a facility that becomes unprofitable and closes when prices drop cannot profitably reopen when prices return to their original levels. Examples of facilities shutting down in response to only small price changes are harder to find offshore, however, because the costs of plugging wells and removing platforms are themselves so high.

Establishing some policy discretion for lowering royalties may also make sense from the perspective of enhancing energy security. In general, policies that help the nation to reduce oil imports in response to rising oil prices can help minimize economic losses attributable to disruptions of world oil supplies. Lowering royalties as an emergency response to an oil price shock may magnify the incentive to increase offshore production, thereby contributing further to reducing imports and economic losses. This type of

emergency royalty management would complement other energy security policies, such as the release of oil from the Strategic Petroleum Reserve, that try to reduce oil imports in response to disruptions of world oil supplies. (In contrast, any policy that would increase royalty rates in response to rising oil prices--akin to proposals for variable import fees on crude oil--would have the opposite effect, dampening the oil supply response to the price shock and adding to oil imports.)

As previously noted, DOI already has the authority to reduce or eliminate royalties. (The agency exercised this authority for stripper wells--those producing 10 barrels per day or less--on public lands onshore during the Persian Gulf War.) Yet production from the offshore region is even less sensitive to changes in prices than production from the onshore regions. Thus, it is not likely that significant additional security benefits would be forthcoming from such flexibility regarding royalties.

Economic Disincentives to Other Producers

It is frequently difficult to establish an economic incentive for one activity that does not have the effect of simultaneously discouraging other activities. This situation would likely be the case for royalty waivers for deep water

production as well. Most clearly affected would be operators in the shallower waters of the offshore regions. Royalty waivers, if successful in stimulating deep water production, could lead to higher demand for offshore drillships, platform construction, specialized personnel, and so forth. The result would be that the costs for that equipment and those services would rise for shallow water producers. Costs would remain low only under conditions of excess supply of equipment and services.

Even though the current demand for drilling and production services in U.S. waters is low by historical standards, the demand worldwide for such services is high. Thus, conditions may exist today whereby shallow water producers could be adversely affected by any new incentives offered by the government that succeeded in boosting deep water activity.

Efficiency Considerations in Designing Royalty Waivers

One key issue in extending royalty waivers to new production may be in deciding what is meant by "new." The preceding section on the budgetary impact of waivers discussed different ways in which legislation might extend waivers to production that is not new, in the sense of being made profitable

by the waivers. This section considers the effect of defining "new" in different ways.

The prospect of a reduction in royalties may enhance the profitability of certain types of expenditures to sustain or increase production. Examples include specific types of capital investment, such as drilling new development wells or installing secondary recovery equipment (pumping water into a reservoir to increase pressure). Other expenditures may be more in the nature of operating costs, such as repairing pumping equipment, replacing tubing in existing wells, or otherwise reworking wells to increase product flow. But lower royalty payments may also make it profitable simply to continue producing a little longer than would have been possible otherwise.

Thus, it would matter whether "new" referred to production associated with some specific classes of capital expenditure, with any expenditure, or with any increase in production relative to some baseline projection of output.

Even within the narrow class of capital expenditures, an issue remains as to what expenditures are relevant. The policy choices are many. The total costs of installing or expanding production capacity offshore would include drilling and equipping wells, constructing and installing platforms and associated on-platform equipment, laying undersea pipelines and pumping

equipment, and constructing onshore processing plants for separating and storing products. Oil companies operating offshore may make their own capital expenditures or, especially in the case of pipelines and onshore facilities, pay others for those services.

How legislation defines the particular expenditures that would qualify production as new may be relevant for determining the duration of royalty waivers, as well as whether they are granted at all. For example, if offshore operators could waive royalties until they recouped the qualified expenditures, legislative definitions that had the effect of including bigger dollar expenditures would yield a longer period of zero royalties. Similarly, if legislation allowed operators to adjust the qualified expenditures for inflation, the period of zero royalties would be longer--regardless of the expenditure basis for the waiver.

To the extent that choices among ownership modes and technologies were available, offshore operators would prefer to make production-increasing expenditures that would qualify them for waivers. With waivers based on capital expenditures, for example, a firm might build its own pipeline rather than pay for transportation on some other company's line or drill a new development well rather than rework an existing well. To the extent that

government regulations distorted business choices about where or how to produce, the total costs of producing oil and gas would rise.

All businesses are operating on the margin of expected profitability in developing their last unit of output. The economic rationale for helping one marginal group over another is weak unless some significant external benefits exist for that assistance. In the case of deep water production, it is not clear where that external benefit resides.

A further issue related to how the Congress might define new production concerns the administrative burden that different definitions could place on the Minerals Management Service and the industry. The Minerals Management Service is the government agency that administers the offshore leasing program and collects royalties. Confirming whether companies actually make certain types of expenditures to add production capacity at certain locations or whether production levels represent an increase over some baseline could be time-consuming at best. The data burden on offshore operators would certainly increase.

Aside from any considerations of efficiency, such as how much production or costs would change, any proposal to alter federal royalties may benefit (or disadvantage) one group over another. This would be particularly so for royalty waivers for deep water production. Equity considerations in designing royalty waivers may be of particular importance to small oil and gas producers and small petroleum refiners.

The companies that dominate operations in the offshore waters deeper than 200 meters tend to be the large, integrated oil companies. These companies produce, refine, and market oil and gas worldwide. Smaller companies working offshore tend to concentrate their efforts in shallower waters. Thus, deep water royalty waivers would benefit large international companies over smaller domestic companies.

One other group that royalty waivers might affect adversely is small and independent refiners. Current law on the management of offshore resources specifies that leaseholders must offer 20 percent of their oil and gas production subject to federal royalties to small or independent refiners.[11] This may be a minor point, since the Minerals Management Service has not reserved production under this provision for several years. In any case, if the

11. 43 U.S.C. 1337 (7).

production subject to royalties declined, so would the amount that the Congress intended to reserve for this group.