DOMESTIC GAS AND OIL INCENTIVES

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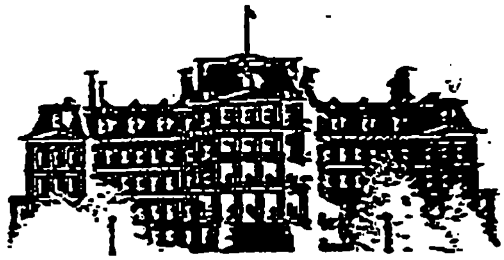

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MESSAGE:

Overview of the Oil and Gas Industry

[To the Working Group -- This is a very rough first draft. Your comments are necessary to make this into a reasonable work product and will be greatly appreciated. -- Mark]

[Please note that the figures contained below have not been checked for accuracy. These were obtained mainly from recollection and certainly will have to be corrected. They are provided for illustration only.]

The oil and gas industry has been a vital part of the United States economy for many years. Over the past few decades, the industry has become increasingly internationalized, with numerous suppliers competing for market share. The worldwide search for oil and gas deposits has focused on discovering and exploiting the reserves that are least costly to develop. These generally are found in areas that have not been extensively prospected in the past. In more mature areas, the cheapest reserves were often those first exploited, leaving the relatively higher cost reserves to be subsequently tapped.

The crude oil production industry[1] in the United States is a mature industry, with most of the easily obtained resources already exploited. Consistent with a mature industry, the aggregate production of crude oil in the United States has been on a long downward trend. Figure 1 indicates the post-war pattern of production of domestic crude oil.

[Figure 1 will be a chart of crude oil production from 1946 to the present]

The natural gas production industry in the United States has yet to reach the degree of maturity that characterizes the crude oil production industry. Production of natural gas has not entered a long-term downward trend. In fact, most of the concern in the natural gas production industry has been with developing markets for natural gas and with ensuring that long-term supply commitments will be fulfilled. In this sense, industry concern has not been with wellhead production as much as with the ability to deliver natural gas to the ultimate consumer. Figure 2 presents the post-war pattern of production of natural gas.

[Figure 2 will be a chart of natural gas production from 1946 to the present]

In the United States, crude oil and natural gas production take place from wells of all sizes. However, the size distribution

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[1] While the production of natural gas and crude oil often take place at the same time and place, it may be instructive to examine the long-term production trends for these commodities separately.

of these wells is far from uniform. In fact, the vast majority of wells produce relatively small amounts of crude oil or natural gas. For instance, of the total 580,000 oil wells in the United States, about 300,000 produce less than 3 barrels of oil per day (and about 250,000 produce less than one barrel per day). Wells producing less than 3 barrels per day are responsible for about three percent of total United States oil production. A similar size distribution characterizes natural gas production. Of the total 300,000 natural gas wells in the United States, about 180,000 produce less than xxx thousand cubic feet of natural gas per day (the energy equivalent of 3 barrels of oil). These relatively small wells are responsible for about 2 percent of total United States production of natural gas.

United States consumption of both oil and natural gas has increased substantially over the past half century. This has resulted from economic growth and the associated increased incomes available to consumers. In many cases, energy use has replaced labor and/or physical capital in production processes. In other cases, oil and natural gas have been substituted for other, less useful, fuels. The trend toward increased consumption of oil and natural gas appears to have slowed in the last decade, however, as more attention has been devoted to developing energy efficient production processes and as consumption patterns have been somewhat modified. Figures 3A and 3B show United States post-war consumption of oil and natural gas, respectively.
These charts provide a breakdown of the portions of domestic consumption provided from domestic production and from imports.

[Figure 3A will be a chart of US oil consumption from 1946 to present, with the domestic and imports portions labelled. Figure 3B will be the same chart, except for natural gas.] ✓

One obvious trend visible in Figure 3A is the increased reliance on oil imports over the past several decades. The United States exports very little in the way of crude oil or natural gas, and so it is appropriate to think of domestic production supplying a portion of domestic consumption, with the balance made up by imported oil. Of course, the observed levels of consumption and production are not pre-determined. Rather, like all other traded products, these levels are determined by the prices at which the commodities are traded.

The history of oil and natural gas prices is replete with episodes of price volatility. In real terms, the price of crude oil has risen dramatically, fallen, risen again, and fallen yet again. Many of these price shocks have been caused by threats of supply disruption by foreign producers or actual disruption. Figure 4 shows the post-war pattern of crude oil prices in real terms (1993 dollars).

[Figure 4 will be a chart of oil prices from 1946 to the present deflated using the consumer price index or the GDP deflator. Maybe ✓

emergence of natural maturing
[illegible] future outlook to 2010 EIA

we should use a constant grade of crude oil, if possible; otherwise, we could use the refinery acquisition price]

Natural gas prices have not exhibited quite as much price volatility as crude oil prices. In part, this reflects the lack of external threats of supply disruption. Rather, the bulk of the price volatility represents purely domestic market conditions where supply and demand were imbalanced. Many of these imbalances were caused by governmental regulation of the natural gas industry, which has since been removed. Figure 5 shows the post-war history of natural gas prices in real terms.

[Figure 5 will be a chart of natural gas prices from 1946 to the present deflated using the consumer price index or the GDP deflator. We should use something like wellhead price to provide an indication of what the producer receives.] ✓

Employment in the domestic oil and natural gas industry is related to price and production levels. At higher prices, a constant level of production is more profitable, which may lead to increased employment. A larger effect on employment, though, will occur through production levels. Higher production generally leads to increased employment. As the long-term trend in domestic crude oil production is downward, employment in the crude oil production industry will also follow a downward trend. Moreover, technological advances in oil and natural gas production have made workers in these industries more productive. This means a given level of production can be achieved with a smaller work force. Increased productivity combined with decreased production implies that employment in the crude oil industry will decrease faster than production, in the long term. If natural gas production begins to decline, then increased productivity of these workers will also exacerbate the trend toward lower employment in this industry. Figure 6 shows the post-war pattern of employment in the oil and natural gas industry.

[Figure 6 will show the pattern of employment in the oil and gas industry from 1946 to the present. It might make sense to show employment in production separately from that in refining and other activities.] ✓

Estimated oil and natural gas reserves are attempts to quantify economically recoverable quantities of the energy sources, using current technology. As prices increase, reserves that were formerly too expensive to recover may become economically recoverable. Similarly, as technology advances, reserves that were not economically recoverable in the past may become recoverable at current prices. Of course, as production occurs, the amount of reserves correspondingly declines. By comparing current production levels with the amount of economically recoverable reserves, one may get an indication of how long current production rates may last.[2] However, it should be noted that reserve estimates may be somewhat volatile, since new information may have large effects on previous determination of the size of particular reserves and the determination of whether these reserves are recoverable. Figures 7A and 7B show the changing levels of domestic reserves of oil and natural gas, respectively.

[Figure 7A will be a chart of oil reserves in the US from 1946 to the present. The chart may include short explanations of any large reserve increases or decreases. Figure 7B will be a similar chart for natural gas.]

The reserve base in the United States is small relative to other world suppliers of oil and natural gas. In particular, the United States has about X percent of the world's known oil reserves and about Y percent of the worlds natural gas reserves. Large amounts of the world's reserves in countries other than the United States have been recently discovered or determined to be economically recoverable. Accordingly, the United States share of world reserves in oil and natural gas has dropped over the last Z (20?) years. This pattern is consistent with the fact that the United States is a mature producer of oil and natural gas, while other countries have yet to fully exploit their resource base. Figures 8A and 8B show the current oil and natural gas reserve bases for the United States and for several other producing countries.

[Figure 8A will show US oil reserves and compare them to those of other countries for 1993. Figure 8B will provide similar information for natural gas.]

[This is the end of the overview section. The next section (forthcoming) will cover the ways in which government policies will be evaluated -- microeconomic, macroeconomic, security, budgetary.]

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[2] Similarly, one might compare current consumption levels with current domestic reserves to gauge the ability of domestic resources to service domestic demand. By this measure, oil reserves in the United States are sufficient to support X years and the natural gas reserves are sufficient to support Y years of current consumption.

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DOMESTIC GAS AND OIL INCENTIVES

Materials received for meeting on Friday, March 25 at 10:00am
Treasury

Outline Sections

II. Current U.S. Policies toward the Gas and Oil Industry

A. Tax Policies

B. Royalty Policies

C. Import, export and security policies

D. Regulatory Policies

E. Direct Expenditures

III. Current Proposals Involving Gas and Oil

A. Tax Proposals

II. A. OIL AND GAS TAX INCENTIVES

Introduction

Preferential tax treatment is the principal source of assistance provided by the federal government to the domestic oil and gas industry. These subsidies, known as "tax expenditures", total in excess of $17 billion over 5 years. Tax expenditures that benefit the oil and gas industry are considerably larger than direct Federal expenditures. Direct expenditures are projected to total $7 billion over 5 years.[1] (To be superceded by DOE's direct expenditures information.)

Tax expenditures are intended to encourage the exploration and production of domestic oil and gas. These incentives are generally justified on the ground that they increase U.S. energy security by reducing vulnerability to an oil supply disruption through increases in production, reserves, and exploration and production capacity. However, these various means of achieving energy security gains are not equally cost effective, nor are the security and economic considerations relating to oil the same as those relating to natural gas. For example, in contrast to oil, natural gas production is expected to continue to increase, gas prices are at their highest levels since 1985, and, in addition, natural gas production will surpass crude oil in value and energy content within two or three years.

Oil and Gas Tax Expenditures

Under current law, six tax expenditures are specifically targeted for the oil and gas industry. These are noted below in order of the size of the associated tax expenditure, with a brief description of the tax provision and its effectiveness. (See attached Schedule 1 of recent oil and gas tax legislation.)

The tax expenditures discussed below are measured on an "outlay equivalent" basis, i.e., they show the amount of outlay that would be required to provide taxpayers the same after-tax income as are received through the tax preference. The outlay equivalence measure allows a direct comparison of the cost of a tax expenditure and a direct federal outlay.

Percentage Depletion

A taxpayer other than an integrated oil company (an oil company that engages in substantial refining or marketing) may, as an option under Section 613A (c), deduct from taxable income a percentage of oil and gas revenue known as "percentage depletion." The cost of the property may be first amortized through cost depletion reflecting the decline in

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[1] The largest direct expenditures involve HUD energy assistance outlays projected to be $3.6 billion over 5 years and $3.1 billion over 5 years of forgone interest on purchases of oil for the Strategic Petroleum Reserve. Figures extrapolated from data in Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets, November 1992, EIA Service Report SR/EMEU/92-02.

property value with oil and gas extraction. When percentage depletion exceeds cost depletion the taxpayer may continue percentage depletion, generally at a 15 percent rate, as long as production continues. This deduction may cumulate to exceed the original cost of the property i.e., the taxpayer is able to recover as a deduction more than his or her original costs. Percentage depletion is limited to 365,000 barrels per year per taxpayer, may not exceed 100 percent of the net income from that property in any year (the "net income limitation") and may not exceed 65 percent of the taxpayer's overall taxable income (determined before such deduction and adjusted for certain loss carrybacks and trust distributions).[2] Estimated tax expenditures for percentage depletion total about $7.5 billion over 5 years.

Although percentage depletion is considered an incentive to maintain production from economically marginal wells, it may not be efficient. When operating costs approach the value of production, the percentage depletion allowed declines to zero, as it is limited to not exceed the net income from the property. Since percentage depletion is not allowed when there is no net income, it provides little incentive to produce from wells that are marginal, despite the substantial cost of percentage depletion to the Federal budget. The net income limitation, however, was designed to preclude any taxpayer from using percentage depletion attributable to production from one property to shelter income from another property or to shelter non-oil or gas-production income.

don't want to produce beyond this margin

Non-Conventional Fuels Credit

The "non-conventional" fuels (or Section 29) credit provides a $3 per barrel of oil equivalent tax credit for gas production from "tight" formations and about a $6 per barrel credit (due to an inflation adjustment) for other qualified energy production. More specifically, fuels eligible for the credit are: (1) oil produced from shale and tar sands; (2) gas produced from tight formations, Devonian shale, coal seams, geopressured brine, and biomass; and (3) liquid, gaseous or solid synthetic fuels produced from coal. The credit generally applies to wells drilled before 1993, and credits extend for production through 2002. [Certain facilities qualify through 2007.] Qualifying gas well drilling grew rapidly in the last few years, particularly in 1992, to beat the 1993 deadline. The estimated tax expenditure for the Section 29 credit is about $6.7 billion over 5 years.

The Section 29 credit was effective in encouraging drilling and production in these formations. However, the size of the credit is sufficiently large that it likely reduced gas prices and harmed gas drilling and production from formations that do not qualify for the credit. Partly due to controversy in the industry about the wisdom of this provision and partly due to the cost, the credit was not extended for new wells drilled after 1992.

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[2] Amounts disallowed as a result of this rule (65 percent of taxable income) may be carried forward deducted in s[illegible] ta[illegible] le [illegible] subject to the 65-percent taxable income limitation for [illegible] s.

Alternative Minimum Tax Relief

Oil and gas activities have largely been eliminated from the alternative minimum tax[3] (AMT), which was significantly strengthened in 1987. The Energy Policy Act of 1992 removed oil and gas percentage depletion and intangible drilling and development cost (IDC) expensing as preferences in the taxpayer's calculation of AMT beginning in years after 1992. Therefore, the taxpayer's potential alternative minimum tax is greatly reduced.[4]

The annual cost of the AMT relief is about $2.5 billion over 5 years. Little effect on production is expected (given the relaxation of the AMT for oil and gas), as the alternative minimum tax affects the timing of regular taxes rather than the total amount of tax eventually paid. (The AMT was designed to ensure that corporations with economic income would pay some tax. This may no longer be the case for oil and gas extraction.) The cost to the Federal budget of AMT relief for oil and gas is the time value of money.

Intangible Drilling and Development Costs

An integrated oil company can expense 70 percent and an independent oil company can expense 100 percent of intangible drilling and development costs (IDC). Intangible drilling and development costs are expenditures necessary for the drilling and preparation of wells for production that have no salvage value. Such expenditures include wages, fuel, repairs, hauling, supplies, etc. In practice, a number of companies have amortized a substantial portion of IDCs over 5 years. For the next five years the tax expenditure for this provision is expected to total $380 million. Calculated on a present value basis and recent levels of activity, future tax expenditures from continuing the practice is about three times this amount ($0.8 billion).

Expensing is equivalent (in the absence of debt financing) to providing an exemption from tax for the income from the investment. Thus, IDCs provide a substantial incentive for oil and gas drilling.

Enhanced Oil Recovery Credit

The enhanced oil recovery credit (Code Section 43) provides a 15 percent credit for qualified tertiary recovery expenditures which generally involve injecting substances into the reservoir to increase oil production (defined in Code Section 193). The credit was established in the Omnibus Budget Reconciliation Act of 1990 (OBRA) for expenditures after

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[3] A taxpayer is subject to an alternative minimum tax to the extent that the taxpayer's minimum tax exceeds the taxpayer's regular income tax liability.

[4] Repeal of the excess IDC preference may not reduce the taxpayer's alternative minimum taxable income (AMTI) by more than 40 percent (30 percent in 1993) of the amount it would have been if the IDC preference had repealed.

1990. The 15 percent credit provides benefits in excess of expensing, i.e., the benefits are more favorable than tax exemption. Thus, this credit encourages use of tertiary methods in situations where it would not be profitable before tax. Based on 1991 corporate data, tax expenditures are expected to be about $750 million over 5 years. While the credit provides a substantial incentive, the expense of tertiary methods is sufficiently high that the increase in production from the credit is not expected to be substantial.

Increased Percentage Depletion for Stripper Wells

Oil and gas produced from stripper wells, defined as wells producing less than 5,475 barrels of oil per year (15 barrels per day) or producing heavy oil (mostly from California), are allowed an additional percentage depletion allowance equal to one percentage point for each whole dollar by which $20 exceeds the reference price for crude oil for the calendar year preceding the calendar year in which the taxable year begins. This provision was introduced in OBRA 1990 and it is limited to a 10 percentage point increase in the standard 15 percent percentage depletion rate. The growth in the depletion rate fully maintains percentage depletion allowances when oil declines in price from 20 to 15 dollars per barrel (as $20 times 15 percent equals $15 times 20 percent). It also offsets a large portion of reductions in percentage depletion allowances from oil price declines to $9 per barrel by raising the percentage depletion allowance by another 5 percentage points.

Based on 1991, 1992, and 1993 oil prices ($16.50, $15.98, and approximately $15.40, respectively), this provision gives rise to tax expenditures for 1992, 1993, and 1994. Qualifying 1992 production received an additional 3 percentage point depletion allowance over the standard 15 percent. Qualifying 1993 and 1994 production will receive an additional 4 percentage point depletion allowance (to 19 percent). The associated annual additional revenue cost will be less than $20 million. The incentive effect on production is small, as wells without net income are not eligible for percentage depletion[5]. Also, the one year lag between oil prices and the subsidy suggests that production may be encouraged in years of high oil prices and not encouraged in years of low prices. As the Administration does not forecast current low oil prices to continue, future tax expenditures are uncertain.

Other Provisions

Other recent provisions have affected the oil and gas industry. OBRA 1990 increased the net income limitation on oil and gas percentage depletion (i.e. the provision that restricts the percentage depletion allowance to not exceed 50 of net income) to 100 percent of net income from the property (valued at about $300 million over 5 years). Also, taxpayers who have working interests in oil and gas properties (rights to oil or gas income from a property), were exempted from passive loss limitations ($250 million over 5 years), and percentage depletion was allowed on properties transferred from integrated oil companies, which was not

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[5]See section above on percentage depletion.

permitted under prior law (valued at about $160 million over 5 years).

II. B. Royalty Policies

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II. A. Royalty Policies

Royalty Rates for Outer Continental Shelf (OCS) Leases

Congress established in 1978 the following guidance for the administration of offshore Federal oil and gas leases:

- to make resources available to meet the Nation's energy needs as rapidly as possible;
- to balance orderly development with protection of the environment;
- to insure the public a fair and equitable return on the OCS resources; and
- to preserve and maintain free enterprise competition.

The Department of the Interior's Minerals Management Service (MMS) sets OCS lease terms, including royalty rates, based on this guidance. At the same time, MMS strives to achieve other Congressionally-set objectives, including meeting national economic and energy goals, assuring national security, reducing dependence on foreign sources, and maintaining a favorable balance of payments in world trade.[1]

The OCS Lands Act authorizes the Secretary of the Interior to use various systems for leasing the rights to develop offshore resources and to ensure a fair financial return to the public. The system MMS uses today consists of sealed-bid auctions of specified offshore tracts. Before each auction (lease sale), MMS announces the royalty rates that it will apply to production from those tracts (typically 16.67 percent of gross revenues from tracts in water depths of 400 meters or less, and 12.5 percent in deeper water or in certain frontier areas). Companies then bid for the tracts, which are awarded to the highest bidder, subject to a minimum bid of $25 per acre and a bid review process whereby MMS can reject high bids that do not meet certain criteria (e.g., level of competition, comparison to MMS' estimate of value).

MMS may reduce the royalty rate on any previously-issued lease in order "to promote increased production from the lease area." Relatively few lessees have ever applied for such royalty rate reductions. MMS has applied this authority only to leases that are already in production. MMS has granted reductions to fields where a reduction is needed either to:

(1) allow for continued production from a lease that is near the end of its productive life; or

[1] OCS Lands Act Amendments of 1978, 43 U.S.C. 1802.

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(2) make economic additional investments that would increase or maintain production from the lease.

As authorized and directed by Congress, MMS has used several other bidding and royalty systems for offshore leases. The list below shows some of the systems previously tried and the basic reasons why MMS has opted to use the current system instead of these alternatives:

- variable royalty bidding, with a small fixed bonus payment. This system brings in minimal revenues to the Government except when and if production occurs. Furthermore, the high royalty rates that often resulted from such bidding provided a disincentive for the company to produce any resources found.

- cash bonus bidding with relatively high royalty rates (e.g. 33.3 percent). This system is similar to the current system, but it results in lower up-front bonus payment and less interest in marginal tracts. Furthermore, higher royalty rates tend to discourage producers from developing marginal prospects and from recovering the marginal resources remaining near the end of a field's productive life.

- cash bonus bidding with a sliding royalty rate which increases proportional to the lease production rate. This system has the potential to share risk between the lessor and lessee more effectively than the current system, since it charges higher royalties for larger discoveries than for smaller ones. The difficulty with such systems has been to define the sliding scales so that they are actually effective (particularly given the 12.5 percent statutory minimum discussed below) and do not distort lessees' production decisions.

- cash bonus bidding with a fixed share of net profits (typically 50 percent) associated with production from the lease. Net profit share leases have the advantage of effectively sharing risks between the lessor and lessee. However, the large accounting burdens associated with determining how much profit is attributable to a specific lease -and the difficulties in auditing such accounting— have discouraged MMS from using this approach.

The OCS Lands Act sets a minimum royalty rate of 12.5 percent for all royalty-based systems. However, it allows the Secretary of the Interior to employ systems otherwise not allowed by the Act, provided that the Secretary submits to Congress the planned bidding system and neither the Senate nor the House passes a resolution disapproving the proposal within 30 days. Before using any new bidding system, MMS also would have to modify its regulations.

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MMS' goals in designing it's bidding and royalty systems, in conformance with its Congressional mandate, can be summarized by two basic rules:

- maximize the net social value obtained from developing offshore leases. This goal implies letting companies explore and develop leases when and if the expected benefits of production (generally expressed by the production quantity times its market price) exceed the costs (primarily the exploration, development, and production costs)[2]. MMS' bidding and royalty policies generally are designed to be neutral with respect to the timing of leasing and development—companies may bid whenever they think a tract has a positive net value.

- ensure that the public receives a fair return on the resource. The current system is designed so that, on average, the government should receive a large portion of the economic "rent" resulting from development of offshore leases, while companies should be able to earn a reasonable return on their investment. The system shares much of the risk between the lessor and the lessee—the up-front bonus payment is risky for the lessee, who often does not discover sufficient resources to allow for production, while the relatively low royalty rate can allow for high rewards to those lessees who discover large, low-cost oil or gas reserves. (The Federal Government reaps additional economic benefits from offshore production operations in the form of income taxes collected on company profits. Higher royalty rates tend to reduce income tax collections by discouraging production of some otherwise profitable resources and by increasing company costs—royalties are tax-deductible costs—thereby reducing their profits.)

Changes in the oil and gas industry, such as lower oil prices than previously predicted, movement into deeper waters of the Gulf of Mexico, and declining discovery sizes, have led MMS to reevaluate it's current leasing policies. MMS issued a Federal Register notice on December 7, 1993, requesting input from the public on this issue. Based on comments received and on its own internal analyses, MMS is considering changes to make for its 1995 Gulf of Mexico lease sales, which could involve changing the royalty terms for new leases in deepwater and for certain types of new leases in shallow water. MMS also has evaluated and provided comments on legislative proposals for providing royalty incentives for deepwater production, and MMS is refining its policies for evaluating lessee's applications for lower royalty rates on existing leases.

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[2] These costs and benefits are adjusted for external considerations not reflected in the market system, such as environmental advantages or disadvantages of developing certain leases.

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Royalty Rates for Onshore Federal Leases

Royalty rates for onshore Federal oil and gas leases are set by the Department of the Interior's Bureau of Land Mangement (BLM). Prior to the enactment of the Federal Onshore Oil and Gas Reform Act of 1987, royalty rates ranged from 12.5 percent to 25 percent, depending on the average production level from the lease. The royalty rate is now 12.5 percent for almost all leases issued after passage of the Act. The royalty rate is 16.67 percent for noncompetitive leases reinstated after a single failure to pay penalty (plus a two percentage point increase for each additional reinstatement).

Authority for Reducing Royalty Rates--Case-by-Case Applications

The Act of August 8, 1946 amended Section 39 of the Mineral Leasing Act of 1920 to state, "The Secretary of Interior, for the purpose of encouraging the greatest ultimate recovery of coal, oil, or gas and in the interest of conservation of natural resources, is authorized to waive, suspend, or reduce the rental, or minimum royalty, or reduce the royalty on an entire leasehold, or on any tract or portion thereof segregated for royalty purposes, whenever in his judgement it is necessary to do so in order to promote development, or whenever in his judgement the leases cannot be successfully operated under the terms provided therein. In the event the Secretary of Interior, in the interest of conservation, shall direct or shall assent to the suspension of operations and production under any lease granted under the terms of this Act, any payment of acreage rental or of minimum royalty prescribed by such lease likewise shall be suspended during such period of suspension of operations and production; and the term of such lease shall be extended by adding any such suspension period thereto."

The regulations implementing these laws are found at 43 CFR 3103.4-1(a), and state, "In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development or that the leases cannot be successfully operated under the terms provided therein may waive, suspend, or reduce the rental or minimum royalty or reduce the royalty on the entire leasehold, or any portion thereof.

(b)(1) An application for the above benefits on other than stripper oil well properties shall be filed in the proper BLM office. It shall contain the serial numbers of the leases, the names of the record title holders, operating rights owners (sublessee), and operators for each lease, the description of the lands by legal subdivision and a description of the relief requested.

(2) Each application shall show the number, location and status of each well drilled a tabulated statement for each month covering a period of not less than 6 months prior to the date of filing the application of the aggregate amount of oil or gas subject to royalty,the number of wells counted as producing each month and the average production per well per day.

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(3) Every application shall contain a detailed statement of expenses and costs of operation of the entire lease, the income from the sale of any production and all facts tending to show whether the wells can be successfully operated upon the fixed royalty or rental. Where the application is for a reduction in royalty, full information shall be furnished as to whether overriding royalties payments out of production, or similar interests are paid to others than the United States, the amounts so paid and efforts made to reduce them. The applicant shall also file agreements of the holders to a reduction of all other royalties or similar payments in excess of one-half the royalties due the United States.

The practical implementation of this reduction for successful operations is quite difficult to manage as it is designed to be at the judgement of the Authorized Officer to review and approve these requests on the merit of each individual case. The information required to conduct an evaluation of economic viability can require a large amount of detailed data from the operator. It should be noted that under this royalty reduction provision that an application from the operator is required before consideration. Approval of a royalty reduction is in recognition of lessee demonstrating the needs for the reduction in order to continue successful operations.

Stripper Property Royalty Rate Reduction

In addition to the case-by-case royalty reduction authority discussed above, BLM also has authority for a more automatic reduction for leases with low production rates (stripper properties). In a final rule published in the Federal Register on August 11, 1992, BLM amended 43 CFR section 3103.4-1 relating to waiver, suspension, or reduction of rental, royalty, or minimum royalty. BLM alerted the field offices of these changes in responsibility through WO IM No. 92-310 dated August 12, 1992. The purpose of the amendment was to establish conditions under which an operator or an owner of a stripper oil well property can obtain a reduction in the royalty rate. This action was necessary in order to encourage operators of Federal stripper oil properties to place marginal or currently uneconomical shut-in oil wells back in production and to provide the economic incentive to increase production by reworking such wells, drilling new wells, and/or by implementing enhanced oil recovery projects. The rule contains information and procedures for operators to follow in determining whether a property qualifies and in calculating the royalty rate.

Further program guidance to clarify appeals was forwarded to the field offices in WO IM No. 93-55 dated November 13, 1992. Additional guidance concerning well classification, critical definitions and determinations were sent to the field on November 20, 1992 in WO IM No. 93-64.

It should also be noted that under this royalty reduction provision that no formal application is necessary. Royalty reductions are considered on the basis of promoting development. The attached Appendix provides more detail on the program.

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Through reinvestment of the differential savings from royalty reduction numerous valid industry benefits can occur including:

- Encourage new and continued development of Federal lands
- Improve ultimate recovery of finite resources
- Reduce abandonment rate for marginally economic wells
- Return shut-in wells to production
- Increase domestic reserve base
- Lessen exposure to foreign imports
- Help maintain a viable and healthy domestic energy industry

BLM is coordinating with MMS to develop a list of operators taking advantage of royalty rate reduction, in both hard copy and automated format. BLM will use this list to conduct a program review by sending a letter to operators evaluating accomplishments and reinvestment which will help in the 5 year program review required within the regulation.

DRAFT March 24, 1994

Royalty Collections

MMS collects royalties and related payments due on production from Federal onshore and offshore leases and distributes these payments to appropriate accounts in the U.S. Treasury and to certain states and counties that receive a share of these revenues. In fulfilling this function, MMS follows the mandates of the various leasing statutes mentioned above as well as the provisions of the Federal Oil and Gas Royalty Management Act.

MMS' basic policy is that lessees are responsible for:

- measuring the amount of oil and gas they produce from Federal leases and the revenues they receive for this production;

- reporting this information to MMS; and

- paying all royalties and related payments due on such production.

After companies submit their reports and payments, MMS uses computerized routines to properly account for and verify the submissions and follows up with comprehensive audits of selected leases and time periods. Where MMS finds that lessees have not reported or paid properly, MMS requires them to correct the reporting problems and pay any additional royalties due, plus interest (the short-term Federal bond rate plus three percentage points—a rate that is below many companies' cost of borrowing).

MMS has three ways for discouraging companies from inaccurate reporting and paying:

- assessments for filing reports that are late or that have errors. These assessments are set at relatively low amounts intended to cover the additional costs that MMS incurs as a result of improper reporting.

- civil penalties for "non-intentional" violations of its regulations. Before MMS can assess such penalties, companies are allowed a 20-day cure period, allowing them to correct the problem and avoid the penalty.

- civil penalties for "knowing and willful" violations. In these cases, companies are not allowed a cure period. However, it is difficult to prove that violations are "knowing and willful," so MMS very rarely exercises this authority.

DRAFT **March 24, 1994**

The general policy for royalty collections is to efficiently and accurately collect the amount of revenues properly due under the applicable statutes, regulations, and lease terms. The goal is to receive more accurate payments in the first place and to catch any problems earlier and resolve them faster than in the past. MMS tries to encourage timely and accurate reports and payments through a variety of methods:

- simplifying and clarifying regulations and procedures;

- identifying, resolving, and implementing policy issues so as to provide industry with timely and clear guidance on how to report and pay properly;

- providing comprehensive training to industry; and

- applying incentives to promote accuracy and timeliness, including assessments for improper reporting.

In response to prior strategic planning efforts and the National Performance Review process, MMS has launched a number of efforts to work with industry and states to simplify reporting requirements, revise regulations to make it easier for companies to determine their royalty liability, develop systems for MMS to detect problems efficiently and early, resolve policy issues faster, and institute more meaningful incentives for reporting and paying properly the first time (including proposed penalties for substantial underreporting).

DRAFT March 24, 1994

Appendix
Stripper Program Summary

The definitions for the stripper royalty rate reduction program are:

Stripper Well Property: A Federal lease or portion thereof segregated for royalty purposes, a communitization agreement, or a participating area of a unit agreement, operated by the same operator, that produces an average of less than 15 barrels of oil per eligible well per well-day for the qualifying period.

Eligible Well: An eligible well is an oil well that produces or an injection well that injects and is integral to production for any period of time during the qualifying or subsequent 12-month period.

Oil Well: An oil completion from which the energy equivalent of the oil exceeds the energy equivalent of the gas produced or any completion producing oil and less than 60 MCF of gas per day.

Injection Well: An injection well is a well that injects a fluid, including gas, for secondary or enhanced oil recovery, including reservoir pressure maintenance operations.

Calculation of Average Daily Production: Total oil production for the subject period from the eligible wells on the property is totaled and then divided by the total number of well days. Average production is always rounded down to the next whole number.

Qualifying Periods:

Initial: August 1, 1990 through July 31, 1991

Shut-in for 12 consecutive months: 12-month production period immediately prior to the shut-in.

Does not qualify During Initial Period: First 12-month consecutive period beginning after September 1, 1990.

Qualifying Royalty Rate Calculation:
0.5% + (0.8 x average daily production rate) = royalty rate

Effective Date: First day of the month after the Regulations are effective or after MMS receives notification whichever occurs later.

Oil Technology Program

The Oil Technology Program attempts to counter the forces of premature abandonment by supporting the development and dissemination of improved and advanced technology to the industry to facilitate maximum, cost-effective and environmentally sound production of the domestic oil resources.

Because abandonment of high value, light oil reservoirs is proceeding at a recent rate of 3%/year -- upwards of 40% of our remaining resources are effectively abandoned -- and the 1994 abandonment rate is projected as high as 5% (if the $14 to 15 per barrel oil prices continue) Time is growing short for the program is to have a meaningful impact. This is the reason behind FE's request for a 42% increase in Oil Technology funds in FY 1995 above FY 1994's: $107 million compared to $75.3 million last year. The Program has four sub-programs:

1. <u>Exploration and Production Supporting Research.</u> About 45% of the Oil Technology funds in FY 1995 will be directed to the development of improved and advanced geoscience and extraction technology (including work with the National Labs); the transfer of program as well as non-program improved technology to the oil producing industry, particularly independents; and field management and direction of both the supporting research efforts and the field demonstration activities. (FY 1994 budget is $25.3 million; FY 1995 request is $47.9 million)

2. <u>Recovery Field Demonstrations.</u> Forty of the Oil Technology FY 1995 budget will be earmarked to support cost-shared field demonstrations of improved and advanced reservoir characterization techniques, oil production methods, and oil recovery processes within the various geologic classes of reservoirs. These demonstrations are designed to further practical transfer of technology to operators within the respective reservoir classes, as well as to better define optimum approaches to secure additional recovery above that obtainable with current technology. (FY 1994 budget is $42.0 million; FY 1995 request is $43.1 million)

3. <u>Exploration and Production Environmental Research.</u> Approximately six percent of the Oil Technology funds in FY 1995 will support development of accurate environmental impact information to support the development and implementation of streamlined, risk-based environmental regulation of our producing oil industry on the part of federal, state, and local governing bodies. Additional support is directed for the development of more cost-effective E&P compliance technologies. (FY 1994 budget is $3.7 million; FY 1995 request is $6.0 million)

4. <u>Processing Research and Downstream Operations.</u> About nine percent of the Oil Technology funds in FY 1995 will support research directed to more efficient and environmentally compliant upgrading and related refining technology needed to convert our substantial heavy oil reserves (and heavy ends of our lighter, domestic nd imported crudes) to t light, nvironmentally preferred liquid fuels essen to our economy. (FY 1994 budget $4.3 million; FY 1995 request is $10.0 million)

II. C. Import, Export, and Security Policies

[not yet received]

II. D. Regulatory Policies: Environmental and Others

EPA

Domestic Gas and Oil Incentives

Section II, D

Regulatory Policies: Environmental and Other

The Environmental Imperative

The interrelationship between energy and the environment is complex. The ways in which natural gas and oil are produced, transported, and consumed help determine our quality and style of life. Yet we are often reminded that fossil fuel consumption brings its own problems, sometimes undercutting the quality of life that it has made possible. Energy production, transportation, and use have significant adverse impacts on air, water, land use, and larger global environmental systems. Energy-related environmental accidents, such as oil spills, are notorious and very visible reminders of the potential risks we take to enjoy the benefits of fossil fuels. Air and water pollution are well known adverse side effects of fossil fuel use. The land use impacts of energy production, transportation, and consumption have also become of greater concern in recent years. The potential for climate change due to heightened concentrations of carbon dioxide has served to renew and heighten concern regarding energy's pervasive effect on the environment. Energy production and consumption are responsible for the bulk of air pollutants that comprise or cause urban air pollution, acidic deposition, air toxins, and greenhouse gases.

Since enactment of the Clean Air Act of 1970, increasingly stringent federal and state regulations have reduced or stabilized emissions of several energy-related pollutants. Other key pieces of environmental regulations enacted in the 1970s, 1980s, and 1990s have helped control the growth in pollution and produced numerous environmental success stories: volatile organic compounds and carbon monoxide from mobile sources have been reduced; lead emissions have been reduced dramatically. However, the rising awareness of the ubiquity and persistence of an industrial society's environmental impacts challenges policy makers to find effective and efficient ways to mitigate adverse environmental effects. Environmental policy makers will increasingly need to examine alternatives that help ensure that energy is produced and consumed efficiently so as to minimize adverse environmental impacts. Market-based strategies that create economic incentives to reduce adverse environmental impacts can help provide society the flexibility to maximize its diverse goals. In addition, a credible and efficient long-term mitigation strategy will recognize the importance of regional, state and local action, as well as promote the economically efficient goals of sustainability, waste minimization, and recycling.

Specific Environmental Regulations

A wide range of environmental regulations affect the domestic gas and oil industries. Environmental protection is provided for at all stages: exploration and production, transportation and transmission, refining and processing, and end use. It is often convenient to break down a discussion of environmental controls by medium. The discussion below highlights the key environmental laws and regulations affecting the domestic gas and oil industries.

SOLID WASTES: The Resource Conservation and Recovery Act (RCRA) is intended to provide a cradle-to-grave regulatory framework to monitor and control the production, storage, transportation, and eventual disposal of wastes that pose a risk to health and the environment. Amendments to RCRA in 1984 added regulation of petroleum and hazardous wastes stored in underground tanks. However, wastes associated with oil and gas operations were exempt from Federal regulations pending further review by EPA. **[Discuss current status of proposed changes to definition definition of Solid Waste. Discuss Hazardous Waste Identification Rule. Discuss Land disposal Restriction Regulations.] [State regulations of oil and gas wastes.]**

[Discuss Superfund.]

WATER AND WETLANDS: The Federal Water Pollution Control Act of 1972 and the Clean Water Act (CWA) of 1977 set as a goal "to restore and maintain the chemical, physical, and biological integrity of the nation's waters." The CWA establishes a system of effluent standards by industrial category, provides for a permitting system, sets waste water quality standards, provides for grants for municipal waste treatment, and addresses special issues like toxic wastes and oil spill. The effluent limitation standards and the National Pollutant Discharge Elimination System (NPDES) permit program are the primary regulatory tools under the CWA. Within the domestic gas and oil sector, CWA requirements primarily affect offshore drilling and refinery activity.

Section 404 of the CWA provides authority for the protection of wetlands. **[Fuller discussion.]**

The Safe Drinking Water Act of 1984 (SDWA) established the Underground Injection Control (UIC) program to protect drinking water aquifers from contamination by subsurface injection fluids. SDWA requires EPA to establish minimum requirements for state programs or for Federal primacy in the absence of state programs. The UIC affect all underground injection associated with oil and gas exploration and production activities. A Federal Advisory Committee composed of representatives of the petroleum production industry, environmental groups, states, and Federal agencies issued a final report recommending a requirement for double containment systems for injected fluids. In addition, surface casing would be required to extend to the base of aquifers containing less than 3,000 mg/l total dissolved solids and be cemented to the surface. Virtually all wells drilled by the major oil producers already employ these construction standards. The rule would require existing injection wells that do not meet the new construction standards to be tested more frequently. The frequency of testing would be based on the level of protection offered by these wells.

The Oil Pollution Liability and Compensation Act of 1990 raised liability limits for oil tankers. The Act allows unlimited liability against tanker owners where gross negligence or willful misconduct is involved, and does not preclude states from imposing their own unlimited liability requirements. In addition to the liability provisions, the Act requires that, over a 15 year phase-in period, double hulls be used for all new tankers and for vessels trading with the United States.

[Discuss Great Lakes Water Quality Initiative.]

Air: The 1970 Clean Air Act (CAA) produced notable environmental gains. Two key parts of the CAA affecting the oil refining industry were related to end-products: the lead phase-out in gasoline and the requirements for low sulfur distillate and residual fuel use at electric utilities. The CAA established a schedule for reducing lead additives and required automobile manufactures to design and construct vehicles that could run on low-lead and unleaded fuel. The legislation required that all gasoline stations of specific sizes offer at least one grade of unleaded gasoline. The allowable lead in gasoline was reduced to 1.1 grams per gallon in 1982, and a system of waivers was established that allowed refiners to build up lead credits. Further reductions in 1986 brought the allowable lead to a maximum of 0.1 grams per gallons. All grades of gasoline must be completely lead-free as of January 1, 1996. The lead regulation resulted in a greater than 90% reduction in airborne lead emissions.

The 1990 Clean Air Act Amendments (CAAA) expanded the effort to reduce harmful emissions from auto fuels, putting new requirements on refineries. As of November 1, 1992, the oxygenate fuels program requires that gasoline sold in the 39 areas of the country designated as carbon monoxide nonattainment areas to contain a minimum of 2.7% oxygen by weight during at least 4 winter months. As of October 1, 1993, the sulfur content of highway diesel fuel must be reduced from the current maximum of 0.25% to 0.05% by weight. Finally, as of January 1, 1995, reformulated gasoline will be required in the nine metropolitan areas with the worst ozone problems. The reformulated gasoline requirements will control VOC and NO_x emissions, as well as benzene and other toxic air pollutants. **[Discuss Ethanol/ETBE mandate for reformulated gasoline.]** Earlier regulations to combat urban smog precursors control the summertime volatility of motor gasolines. **[Discuss testing of fuels and fuel additives for motor vehicles.]**

In addition to environmental requirements for products sold by refiners, the refineries themselves must meet standards for emissions of VOCs, NO_x, and air toxins. **[Add detail]** **[Discuss Enhanced Monitoring.]**

Reporting required by the Superfund Amendments and Reauthorization Act (SARA) identified approximately 1.4 million tons of toxic air pollutants released in 1987 by a wide range of chemical and other manufacturing facilities. EPA estimates that facilities in 37 states, primarily in those states along the Atlantic, Gulf, and Pacific coasts, are associated with toxic releases that pose high individual cancer risks. Energy-related sources of toxic air emissions include oil-and coal-fired utility boilers, petroleum refineries, and oil and gas exploration and production operations. In addition, VOC emissions from the transportation sector are among the largest sources of toxic air emissions in many urban areas. **[Discuss MACT for hazardous air pollutants.]**

Natural gas and oil pipelines are subject to CAA requirements for NO_x and VOC controls. New pipeline compressor stations will be required to have the most efficient, clean-burning prime movers technology available, and existing stations my be required to undergo extensive retrofitting or replacement. In non-attainment areas along with advanced controls, enhance emission offset requirements will be required for permitting of new or modified facilities.

LAND USE IMPACTS AND PUBLIC LANDS ACCESS: Much of the land within the United States is public property subject to Federal control. Wilderness areas, parks and monuments, and some wildlife refuges are not available for oil and gas E&P. National forests and other public lands, however, may be available. Actions by Federal agencies likely to have a significant environmental impact, such as leasing land or granting right-of-ways, require a formal Environmental Impact Assessment (EIA). States and other levels of government have similar requirements for EIAs. In addition, the Endangered Species Act may place severe constraints on economic activity in sensitive areas. These protections can affect gas and oil E&P and pipeline construction permitting.

OUTER CONTINENTAL SHELF MORATORIA: The Outer Continental Shelf is subject to the jurisdiction and control of the United Sates by Authority of the OCS Lands Act and the Submerged Lands Act. The OCS is made available for oil and gas E&P through a bonus bid leasing system. Leasing activity is planned and announced in a 5-year OCS leasing program schedule specifying the proposed size, timing, and location of each lease sale. Since 1982, Congress has used the appropriations process to adjust the 5-year program schedule through "moratoria" blocking the DOI from conducting lease sales in certain OCS planning areas. **[discuss why]**

II. E. Direct Expenditures

DOE materials supplemented by Treasury materials

II. E. DIRECT EXPENDITURES

The Strategic Petroleum Reserve had stored 575 million barrels of oil by the end of 1992. Assuming a cost of $18 per barrel, this reserve required an expenditure of over $10 billion between 1977 and 1992. The additional demand may have had a small effect in increasing domestic oil prices and sales benefiting domestic producers. Given that this oil is available for emergencies, the true cost of the reserve is perhaps better measured by the interest cost of holding the reserve, rather than the direct expenditure for its purchase (about $3.1 billion over 5 years assuming an interest cost of 6 percent to the Treasury).

The low income housing energy assistance program by the Department of Housing and Urban Development, which totaled $1.1 billion in FY 1992, was the largest direct federal subsidy for oil and gas products. About 63 percent of this amount is used for winter heating assistance that would primarily affect gas and oil demand. The total revenue cost is about $3.6 billion over 5 years for oil and gas products.

Synthetic fuels grants, which guarantee a minimum price to producers, cost about $70 million a year. While the Synthetic Fuels Corporation was abolished in 1986, two price guarantees remain in effect. Dow Chemical's Syngas project, with $622 million in guarantees expiring in 1997, and the Forest Hills heavy oil project in Texas, with $60 million in price guarantees expiring in 1995, were transferred to Treasury's "Energy Security Reserve" account. Treasury outlays for these residual obligations were $72 million in FY 1992, primarily for the production of gas from western coal. The total cost is about $0.3 billion through 1997.

Also, DOE attributes $96 million in R&D expenditures to oil and gas and a further $307 million for the cost of regulation. Additional amounts could be imputed from the Tennessee Valley Authority expenditures and DOE Technical Assistance programs but would be difficult to allocate to oil and gas.

Department of Energy
Washington, DC 20585

OFFICE OF THE
DEPUTY SECRETARY

March 30, 1994

DOMESTIC GAS & OIL INCENTIVES WORKING GROUP

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This fax includes a "work in progress" analysis of the core group of proposals.

Please send your comments back by fax to Len Coburn at 586-4341. We will endeavor to incorporate as much as we can by the Friday meeting.

Kyle Simpson
586-5500

2 #389

March 29, 1994

MEMORANDUM FOR KYLE SIMPSON

FROM LEN COBURN

SUBJECT Boren Incentive Proposal

Pursuant to our meeting on Friday, I am providing you with write ups in the format proposed by the NEC of several of the options in the Boren Incentive Proposal.

Policy was responsible for the following:

- Limitation on Exports
- OCS Deep Water and Frontier Area Production
- Oil Pollution Act of 1990
- Royalty Reduction
- Royalty Collection
- Natural Resources Damage Assessment
- Oil and Gas Leasing on Public Lands

Fossil was responsible for the following:

- Marginal Well Tax Credit
- Geological and Geophysical Costs
- Net Income Limitation
- Underground Injection Control

For the Policy write ups, we have drafted new papers for everything but the royalty reduction and royalty collection, for which we have recycled the papers prepared by MMS.

cc: Sue Tierney
Jack Riggs

Tax Credits for Existing Marginal Wells (BOREN)

0. Introduction

Stripper oil wells and marginal gas wells are currently defined as those wells producing less than 15 barrels of oil equivalent (BOE) per day. Given current low oil and gas prices, these marginally economic wells are at risk of abandonment, potentially foregoing future reserves and production potential.

1. Proposal

This proposal will establish a tax credit for existing marginal wells. The provision will allow a $3 per barrel tax credit for the first 3 barrels of daily production from existing marginal oil wells and a $0.50 per Mcf tax credit for the first 18 Mcf of daily natural gas production from marginal gas wells.

The proposal will also expand the current definition of marginal wells to include a new category for "high water cut property" — producing 25 barrels per day or less per well, with produced waters accounting for 95 percent of total production. In addition, techniques such as waterflooding and disposal, cyclic gas injection, horizontal drilling, and gravity drainage could be encouraged to enable domestic producers to capture more of the oil in a given marginally economic property.

The tax credit will be phased out in equal increments as prices for oil and natural gas rise. The phaseout prices, which are based on BTU equivalence, are as follows:

- Oil-phase out between $14 and $20 per bbl.
- Gas-phase out between $2.49 and $3.55 per mcf.

The tax credit is creditable against regular tax and AMT, but is not refundable.

2. Fit with Criteria

[to be supplied]

3. Existing Policy Baseline

Currently, the only incentive applied to marginal oil and gas wells is to allow higher rates of percentage depletion during periods of low oil prices.

4. Possible Variations

Possible variations on this specific proposal would be to:

- limit the credit to a more limited group of producers identified as in the greatest danger of well abandonment,
- and/or limit the size of the credit to something less than $3/barrel,
- and/or limit the credit to oil stripper wells only.

5. Pros and Cons of Proposal

Pros

- Stimulates the further production and forestalls abandonment of existing wells, maintaining domestic production and access to the resources associated with those wells for future technology advances.

- Tax credits can be structured such that its impact can be optimized, allowing for the maximum amount of benefit (in terms of delayed abandonments) at minimum cost to the Federal Treasury.

Cons

- If improperly structured, the incentive could result in substantial costs to the Federal Treasury, without a commensurate benefit to the nation in terms of foregone abandonment and access to future reserves potential.

6. Legislative Outlook

This proposal has not, as yet, been introduced as proposed legislation in Congress.

7. Costs to Federal Budget

	5-Year Costs ($ MM)		10-Year Costs ($ MM)	
	Nominal	Real	Nominal	Real
Crude Oil	2,225	2,057	3,974	3,494
Natural Gas	889	822	1,639	1,437
High Water Cut	26	24	45	39
Total	3,140	2,903	5,658	4,970

Note: Assumes only 56% of existing marginal wells can use the credit; the remaining 44% have no Federal tax liability, and therefore cannot use the credit (source: IPAA).

8. Benefits

	5-Year Benefits (MMBOE)		10-Year Benefits (MMBOE)	
	Reserves Add's	Production	Reserves Add's	Production
Crude Oil	500	55	500	123
Natural Gas	191	21	191	47
High Water Cut	negligible	negligible	negligible	negligible
Total	691	76	691	170

Note: Reserve additions are the same for both the 5-year and 10-year projections of benefits for existing marginal wells because it is the same population of wells receiving the credit, and the reserve additions are projected for the remaining lives of those wells.

9. Other

Tax Credits for New Wells (BOREN)

0. Introduction

Given today's low oil and gas prices, many domestic oil and gas producers are reluctant to explore for and develop new oil and gas prospects. Until prices begin to rebound, incentives may be required to stimulate new drilling to assure that future production is sufficient to meet the demands of the marketplace.

1. Proposal

The proposal will establish a tax credit for production from new wells that have been drilled after June 1, 1994. The provision will allow a $3 per barrel tax credit for the first 15 barrels of daily production for oil wells (only for new oil wells originally producing 50 bbls./day, or less) and a $0.50 per Mcf for the first 300 Mcf per day for gas wells.

As with the credit for existing marginal wells, the tax credit will be phased out in equal increments as prices for oil and natural gas rise. Moreover, the tax credit is creditable against regular tax and AMT, but is not refundable.

2. Fit with Criteria

[to be supplied]

3. Existing Policy Baseline

Currently, there are no major incentives for new well drilling.

4. Possible Variations

Possible variations for this proposal are similar to those described for tax credits on existing marginal wells.

5. Pros and Cons of Proposal

Pros

- Stimulates new drilling, increasing production and reserve additions.

Cons

- Unless carefully structured, tax credits on new wells could result in a substantial drain on the U.S. Treasury, without stimulating any substantial incremental drilling activity.

6. Legislative Outlook

This proposal has not, as yet, been introduced as proposed legislation in Congress.

7. **Costs to Federal Budget**

Outlay equivalent tax expenditure

	5-Year Costs ($ MM)		10-Year Costs ($ MM)	
	Nominal	Real	Nominal	Real
Crude Oil	1,588	1,439	4,879	4,131
Natural Gas	5,566	5,046	16,480	13,973
Total	7,154	6,485	21,359	18,104

Note: Assumes only 56% of existing marginal wells can use the credit; the remaining 44% have no Federal tax liability, and therefore cannot use the credit (source: IPAA).

8. **Benefits**

	5-Year Benefits (MMBOE)		10-Year Benefits (MMBOE)	
	Reserves Add's	Production	Reserves Add's	Production
New Oil Wells	442	133	885	412
New Gas Wells	362	91	1,453	247
Total	804	224	2,338	659

9. **Other**

Expensing of Geological and Geophysical Costs

0. Introduction

Geological and geophysical (G&G) expenditures include the costs incurred for geologists, seismic surveys, gravity meter surveys, magnetic surveys, and (perhaps) the drilling of core holes.

The vast majority of oil and gas fields yet to be found in the U.S. will be small and/or subtle traps. One implication of this is that the proportion of total finding costs attributable to geological and geophysical (G&G) expenses and lease acquisitions is rising. Further, such small fields are typically economically marginal. An incentive that reduces the negative impact on potential prospect net cash flow, especially tied to this increasingly large component of exploration costs, would stimulate exploration for marginal prospects.

Currently, G&G costs associated with successful exploration drilling are generally capitalized and recovered through cost depletion, usually in proportion to the ratio of annual production to ultimate recovery. G&G costs associated with unsuccessful drilling can be expensed in the year incurred.

1. Proposal

Immediate expensing of all G&G.

2. Fit with Criteria

[to be supplied]

3. Existing Policy Baseline

G&G expenditures are expensed for tax purposes when oil or gas is not found and amortized over the life of the well when oil or gas is located according to rules set forth in Rev. Rul. 77-188 and amplified by Rev. Rul. 83-105.

These regulations are somewhat complex and are a source of dispute between the IRS and the taxpayer as to when expensing is allowed. Generally, expenditures may be expensed when no oil or gas is found and a decision is made to terminate interest in the property. Gaming the tax system can take place when "areas of interest" are narrowly defined to increase the proportion of G&G that can be expensed under the regulations.

The DOE Domestic Natural Gas and Oil Initiative (DNGOI) calls for DOE and Treasury to review the tax treatment of G&G costs, and in particular, the potential to provide incentives for the use of advanced computational technologies such as 3-D seismic geologic mapping.

4. Possible Variations

Several variations of G&G proposals are possible.

5. Pros and Cons of Proposal

Pros

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- Encourages companies to take advantage of the incentive to more aggressively explore for domestic oil and gas resources, adding to the domestic reserve base.
- Solves a serious accounting problem that exists currently where the industry, and the IRS, expend considerable time and money debating what costs, for a successful well, are G&G, and therefore must be amortized, and what costs are "intangible drilling costs that can be expensed in the year incurred.

Cons

- Although relatively low cost, this incentive will likely not result in major additions in domestic reserves, since capitalized G&G expenditures make up a relatively small portion of the total costs of finding, developing and producing new field discoveries.

6. Legislative Outlook

This proposal may be achieved by an administrative change to the regulations rather than through a new legislative initiative.

7. Costs to Federal Budget

Outlay equivalent tax expenditure

5-Year Costs ($ MM)		10-Year Costs ($ MM)	
Nominal	Real	Nominal	Real
420	391	529	428

8. Benefits

5-Year Benefits (MMBOE)		10-Year Benefits (MMBOE)	
Reserves Add's	Production	Reserves Add's	Production
230	negligible	TBD	negligible

9. Other

Limitations on Percentage Depletion

0. Introduction

Percentage depletion is the expensing of a percentage of gross income (after rents and royalties) from oil and gas production revenue. This allowance reflects the fact that production diminishes (depletes) the physical asset represented by a universal deposit. Percentage depletion is available only to independent producers (i.e., non-integrated) and amounts to 15% of net revenue for most oil and gas wells up to 1,000 barrels of oil equivalent per day per company. (Integrated companies must use cost-based depletion.)

Many operators, and in particular small and/or marginal operators, are not able to use all, or some, of the depletion allowance in the current environment of low prices due to the added limitations that the percent depletion claimed cannot exceed 100% of net income earned from the property, or 65% of net income earned by the company.

1. Proposal

- Raise the 1,000 BOE/d per company limitation.
- Expand the net operating income limitation above 100%.
- Expand the limit for deductions from all properties to above 65%.

2. Fit with Criteria

[to be supplied]

3. Existing Policy Baseline

Percentage depletion is available only to independent producers (i.e., non-integrated) and amounts to 15% of net revenue for most oil and gas wells up to 1,000 barrels of oil equivalent per day per company. (Integrated companies must use cost-based depletion.) Relaxation of the 1,000 BOE/d per company limitation would make the incentive available to larger independents.

The total that can be claimed for each property is limited to 100% of net taxable income, while deductions from all properties cannot exceed 65% of net taxable income. Increasing the net income limitation would increase the net cash flow from operations, and could result in extending the life of marginal wells. Note that for marginal oil and gas wells (less than 15 BOE/d), the rate is 15%, plus one percent per dollar the price falls below $20/Bbl in the preceding year, up to 25% maximum.

4. Possible Variations

- Possible variations associated with this proposal primarily pertain to the production limit for which depletion is allowed, or the percentage of net operating income, both for the property and in total, to which it can apply.

5. Pros and Cons of Proposal

Pros

- Extends the life of marginal production (and marginal producers) until oil prices rise, maintaining access to domestic resources for future recovery.

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- Removal of the net income limitations allows marginal producers to make greater use of the depletion allowance.

Cons

- Removal of the 65% of company-wide net revenues may allow the percentage depletion allowance to shelter income from non-petroleum sources.

6. Legislative Outlook

There is no legislative proposal on this at this time.

7. Costs to Federal Budget

Outlay equivalent tax expenditure

	5-Year Costs ($ MM)		10-Year Costs ($ MM)	
	Nominal	Real	Nominal	Real
Remove 1,000 BOE/d Limit	1,328	1,228	2,799	2,428
Add Removal of Net Income Limit for Lease and Total	4,863	4,496	10,245	8,889

8. Benefits

	5-Year Benefits (MMBOE)		10-Year Benefits (MMBOE)	
	Reserves Add's	Production	Reserves Add's	Production
Remove 1,000 BOE/D Limit	TBD	TBD	TBD	TBD
Add Removal of Net Income Limit for Lease and Total	TBD	TBD	TBD	TBD

9. Other

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Limitations on Percentage Depletion

0. Introduction

Percentage depletion is the expensing of a percentage of gross income (after rents and royalties) from oil and gas production revenue. This allowance reflects the fact that production diminishes (depletes) the physical asset represented by a universal deposit. Percentage depletion is available only to independent producers (i.e., non-integrated) and amounts to 15% of net revenue for most oil and gas wells up to 1,000 barrels of oil equivalent per day per company. (Integrated companies must use cost-based depletion.)

Many operators, and in particular small and/or marginal operators, are not able to use all, or some, of the depletion allowance in the current environment of low prices due to the added limitations that the percent depletion claimed cannot exceed 100% of net income earned from the property, or 65% of net income earned by the company.

1. Proposal

- Raise the 1,000 BOE/d per company limitation.
- Expand the net operating income limitation above 100%.
- Expand the limit for deductions from all properties to above 65%.

2. Fit with Criteria

[to be supplied]

3. Existing Policy Baseline

Percentage depletion is available only to independent producers (i.e., non-integrated) and amounts to 15% of net revenue for most oil and gas wells up to 1,000 barrels of oil equivalent per day per company. (Integrated companies must use cost-based depletion.) Relaxation of the 1,000 BOE/d per company limitation would make the incentive available to larger independents.

The total that can be claimed for each property is limited to 100% of net taxable income, while deductions from all properties cannot exceed 65% of net taxable income. Increasing the net income limitation would increase the net cash flow from operations, and could result in extending the life of marginal wells. Note that for marginal oil and gas wells (less than 15 BOE/d), the rate is 15%, plus one percent per dollar the price falls below $20/Bbl in the preceding year, up to 25% maximum.

4. Possible Variations

Possible variations associated with this proposal primarily pertain to the production limit for which depletion is allowed, or the percentage of net operating income, both for the property and in total, to which it can apply.

5. Pros and Cons of Proposal

Pros

- Extends the life of marginal production (and marginal producers) until oil prices rise, maintaining access to domestic resources for future recovery.

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- Removal of the net income limitations allows marginal producers to make greater use of the depletion allowance.

Cons

- Removal of the 65% of company-wide net revenues may allow the percentage depletion allowance to shelter income from non-petroleum sources.

6. **Legislative Outlook**

There is no legislative proposal on this at this time.

7. **Costs to Federal Budget**

Outlay equivalent tax expenditure

	5-Year Costs ($ MM)		10-Year Costs ($ MM)	
	Nominal	Real	Nominal	Real
Remove 1,000 BOE/d limit, and remove net income limitations	5,160 to 7,425	4,768 to 6,860	11,428 to 16,550	9,879 to 14,299

8. **Benefits**

	5-Year Benefits (MMBOE)		10-Year Benefits (MMBOE)	
	Reserves Added	Production	Reserves Added	Production
Remove 1,000 BOE/D limit, and remove net income limitations	258 to 407	33 to 51	341 to 490	111 to 147

9. **Other**

OCS DEEP WATER AND FRONTIER AREA PRODUCTION

Introduction

Deep water production on the Outer Continental Shelf (OCS) usually is considered to be in depths of 400 meters or more. Substantial gas and oil resources are located in deep water; however, in many instances these resources are not economic to produce under current oil prices.

1. Proposal

A tax credit for production of gas or oil in deep water is proposed to encourage deep water and frontier production. While no dollar amount is specified in the proposal, discussion in the past focused upon a production tax credit of $5.00 per barrel proposed by Senator Breaux in S.403.

2. Criteria

3. Existing Policy Baseline

There is currently no tax credit for production of oil or gas in deep water OCS.

The Domestic Natural Gas and Oil Initiative indicates that the OCS contains substantial oil and gas reserves. In 1991, the OCS contained 10.6% of all oil reserves and 17.7% of all gas reserves. The deep water portion of the OCS represents a significant portion of these reserves as well as additional resources not yet proved. The Initiative recognizes that the deep water portions of the Gulf of Mexico represent one of the most promising exploration targets within the United States, but the economic and technological development challenges are substantial. Legislation has been proposed that would encourage development in deep water areas.

The Initiative supports production incentives for OCS areas available for leasing. The Initiative's support was directed towards royalty incentives and not necessarily tax credits for production.

4. Possible Variations

Tax credits for production can be of any amount deemed necessary to make deep water production economic. Thus, Senator Breaux has suggested a $5.00 tax credit per barrel of production. The credit could be a lesser amount.

-The tax credit could be phased out as oil prices increase. For example, the full amount of the tax credit could be available at prices less than $15.00 per barrel. As prices increase above $15.00 a phase out could occur so that by the time the price of oil was $20.00 per barrel or greater, the tax credit would be zero.

The tax credit also could contain a sunset provision, that is, it would be in effect for a specific period of time and then terminate. Since it takes a very long period of time to bring deep water production on line, a termination date of 2010 or thereafter probably makes the most sense.

5. Pros and Cons of Proposal

Pros

- Encourages production in areas of the OCS that are not economic under present oil prices. According to Breaux/DRI, two billion BOE of reserves have been discovered that otherwise would not be developed, with the prospects of an additional 7-9 billion BOE to be discovered and developed.

- Adds to the national security by decreasing the need for additional oil imports in the future.

- Provides additional supplies of natural gas to meet the Administration's goal of 24 Tcf by 2010.

- Can be revenue neutral or low if a five year window is considered and production occurs outside the five year window. According to DRI, expenditures start in 1999 at $1 billion per year and increase thereafter to $6 billion in 2010 and $17 billion in 2017. If only existing reserves are developed, the cost is much lower, increasing only to $4 billion in 2017.

Cons

- Overall, likely to be the most expensive of the tax proposals due its size and the amount of production that likely will qualify. MMS estimated that the cost of the tax credit would be $6.4 billion in current dollars.

- Development and production is likely to occur in the future anyway without the tax credit if oil prices increase or stabilize at levels that make development economic. MMS estimated that the tax credit includes a present value cost to the federal government of $5.2 billion for fields that currently are profitable.

6. Legislative Outlook

7. Cost to Federal Budget

Revenue
Cumulative through 1998: $6-10 billion (DRI)
Cumulative through 2017: $330-375 billion (DRI)

Outlay
Cumulative through 1998: $1-2 billion (DRI)
Cumulative through 2010: $17-? billion (DRI)
Present value expenditures: $6.4 billion (MMS)

8. Benefits

New Jobs: 56,000-105,000 by 1998 (DRI)
Sustain new jobs of 63,000-80,000 through 2017 (DRI)
Increase annual read GDP by $4-8 billion in 1998 increasing to $20 billion in 2017 (DRI)
Reduce federal debt $5-9 billion by 1998 with total debt reductions reaching between $213-234 by 2017 (DRI)
Improve annual foreign trade balance by about $23 billion in 2017 (DRI)

9. Other Impacts

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III. Current Proposals Involving Gas and Oil

B. Royalty Proposals

1. Proposal: Deep Water Royalty Suspension

Senator Johnston's "Outer Continental Shelf (OCS) Deep Water Royalty Relief Act" (S. 318) would suspend royalties on each "new production" project in water depths greater than 200 meters until the project's gross revenues exceeded capital investments for exploration and development. The original bill was limited to the Central and Western Gulf of Mexico and mandated the suspension for all new production. Recent amendments to the bill expanded it to include the OCS offshore Alaska and the deep-water portions of the eastern Gulf of Mexico offshore Alabama. Also, the Secretary would have 90 days to review applications, on a case-by-case basis, and could deny relief to projects that were already economic. In the absence of a determination within 90 days, the relief would be automatically granted.

2. Fit with Criteria *[Author's note: NEC is drafting the "criteria" section of the package. Since we don't know exactly how they will frame the issues, this draft simply relates some relevant arguments. Results of MMS analyses are presented in the "Pros & Cons" section.]*

a. Economic Criteria

At any one time, there is an array of geologic prospects, with associated development costs, in which companies may choose to invest. While some prospects are economic to produce now, others may be left in the ground until sometime in the future when higher prices or lower production costs make them economic. The government may want to accelerate development of these resources if there are public benefits of production that are not accounted for in the decision-making process of private companies.

Most forecasters expect oil prices to remain relatively stable for the foreseeable future. Thus, the future development of marginal oil discoveries may depend on reducing costs[1]. However, the ability to reduce development costs in deep waters may depend on the availability of infrastructure and experience gained operating in those depths. Encouraging some development earlier than it would otherwise occur may help to develop this infrastructure and experience, leading to higher future leasing and development.

[1] Gas prices, however, are expected to increase, which may provide sufficient incentive for gas prospects to be developed.

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Other economic considerations include:

- Price effect: Incremental production helps to reduce the prices of oil and gas, though by only a fraction of a cent per barrel or mcf. The incremental production expected from this proposal is too small to have a discernible effect on prices.

- Employment: Bureau of Labor Statistics data indicate that each $1 billion invested in the petroleum extraction industry supports 20,000 job-years (direct and indirect). Large deep-water discoveries have development costs of about $1 billion.

b. Security Considerations

Energy security arguments focus on the preferability of domestic gas and oil production over imported oil. A recent analysis of the OCS program shows that imported oil is the primary substitute for OCS production. Specifically, 86 percent of lost OCS production would be replaced by imported oil, and 34 percent of OCS gas production would be replaced by oil, mostly imported residual fuel[2].

An additional concern is the ability to maintain the infrastructure necessary to develop resources as they become economic. As the shallow water Gulf matures as a producing region, more of the infrastructure will be removed as fields reach the end of their economic life. In addition, a rising share of the industry's capital ~~has been~~ invested overseas. Thus, if the economics of deep-water prospects improve in the future, development could be hindered by the lack of supporting infrastructure.

c. Budgetary Considerations

The proposal could have several direct impacts on the budget:

- Royalties will be forgone from any fields that would be developed without the incentive. Case-by-case review could reduce this impact.

- Royalties will be collected from some fields that otherwise would not have produced for the foreseeable future.

- New leases offered with the royalty suspension will receive higher bonuses and more tracts will receive bids.

Up-front incentives--like royalty suspensions--could have negative budget impacts in the short run, while increasing the long term present value of federal receipts and economic benefits.

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[2] ICF Resources Inc., February, 1991, "Comparative Analysis of Energy Alternatives," Final report submitted to the Minerals Management Service, U.S. Department of the Interior.

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However, the budget rules require that any proposal be revenue neutral in each year of the planning period.

A secondary budget consideration is the administrative burden created by the proposal. In this era of government down-sizing, policies that require a substantial workload may be difficult to implement.

3. Existing Policy Baseline

The Administration supports the concept of deep-water incentives in the Central and Western Gulf of Mexico. However, any incentive should strike a careful balance between encouraging production and ensuring a fair return to the public.

MMS has concerns with certain provisions of S. 318, as amended:

- The capital cost approach is administratively burdensome. By requiring that royalties be suspended until gross revenues are equal to actual capital costs for exploration and development, the bill would place a large reporting, accounting, and auditing burden on both industry and the Minerals Management Service (MMS).

- The case-by-case review approach involves a substantial new workload on the part of the Interior Department. Also, given the large number of potential applications, the 90-day time limit may preclude careful evaluation of each application on its merits.

- By suspending royalties until each production project recovers all of its capital costs, the bill may provide greater royalty relief than is necessary to encourage development and production. MMS analysis suggests that of the set of discovered deep-water fields, the largest ones could be produced without any royalty relief, while some others could be profitably produced with an incentive smaller than that offered by S. 318.

4. Possible variations

Several variations have been proposed to address the concerns addressed above:

- The administrative burdens associated with the capital costs provision could be reduced by:

    - establishing fixed amounts of production or revenues for which royalties would be suspended (several amounts could be set corresponding to different water depth intervals); or

    - allowing the Secretary to set a schedule of allowable capital costs in regulation, rather than use actual lease-specific costs.

- The costs of processing and analyzing applications could be covered by charging an application fee and retaining the fees within MMS to administer the program.

- In addition to determining whether the royalty suspension should be granted, the Secretary could have the authority to vary the size of the incentive based on the economics of individual projects. A small fixed suspension could be granted automatically, with a case-by-case review used to determine if a larger suspension amount is warranted.

- Set the royalty rate higher than the current rate after the suspension period ends. This policy may discourage requests by lessees with large discoveries that do not need relief. It also allows the government to recover some portion of forgone royalties from larger discoveries; marginal fields will not produce for very long after the suspension period ends. Finally, existing royalty rate reduction authority can be used to avoid premature abandonment.

- For new leases, case-by-case review may not be necessary, especially where a higher post-suspension royalty is in place. Companies should incorporate the value of the incentive into their bid-determination process and MMS' tract evaluation procedures can reject bids deemed too low.

5. Pros & Cons

MMS reviewed over 150 discoveries in deep-water Central and Western Gulf of Mexico and analyzed 30 fields that were large enough to merit consideration for development. The pros and cons discussed below are based on that analysis.

Pros

- S. 318 might encourage the development of two additional fields, containing 150 million barrels of oil equivalent (mm BOE). The fields would add $250 million in net economic value[3]. The bill would also encourage development of some future discoveries on both new and existing leases.

- The up-front nature of the suspension increases the value of an incentive due to the time value of money and the more rapid recovery of capital.

- If the Secretary can effectively identify undeserving fields in the 90-day period, there will be no revenue losses.

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[3] Net economic value is the difference between the market value and costs of production, expresses in discounted (8%) real dollars.

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Cons

- At least seven fields appear to be profitable to produce without any incentive. Experience with those fields might lead to improved economics of deep-water production in the future without any additional incentive.

- Substantial additional resources would be needed to manage the administrative burdens of the proposal. The capital cost provision is unnecessarily burdensome on both government and industry.

- The size of the royalty suspension cannot be varied according to project economics, so some fields will receive a larger incentive than necessary to encourage production.

- If the applications cannot be accurately analyzed in 90 days, there could be substantial revenue losses.

<u>6. Legislative Outlook</u>

The Senate Energy and Natural Resources Committee has passed S. 318, but it has not been scheduled for debate on the floor. The OCS subcommittee of the House Merchant Marine and Fisheries Committee held a hearing last summer, but no further action has been taken or scheduled.

<u>7. Costs</u>

There will be no budget impacts if the Secretary can accurately determine whether relief is warranted in the proposed 90-day review period. Assuming the Secretary can correctly identify the largest discoveries (project value greater than $25 million), but may not be as successful with smaller projects, the "pay-go" costs (gross royalty losses in nominal dollars for the next five years) may be as much as $164 million, and long term revenue losses (present value of net royalties) could be as much as $209 million. Insufficient time to correctly identify the largest discoveries could add "pay-go" costs of up to $500 million.

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Permitting Export of Alaskan North Slope Crude Oil

0. Introduction

This initiative would reduce or remove the barriers to exporting oil produced on the Alaskan North Slope (ANS). If ANS production falls as projected in the late 1990s, PADD V will again become permanently dependent on imported crude oil. Permitting ANS exports may raise crude oil prices in California, stimulate investment, and ultimately help offset some of the imported oil.

A study of the effects of exporting ANS crude oil is now underway and should be completed in late April 1994.

1. Proposal

Modify the Export Administration Act (EAA) to remove barriers to exporting ANS crude oil. Amendments to the EAA must also modify language in several other statutes that prohibit ANS exports.

2.

3. Existing Policy Baseline

Banning ANS crude oil exports was part of a deal struck in the early 1970s in order to pass the Trans Alaska Pipeline Act that authorized building the pipeline to open the North Slope. U.S. flag shipping interests and labor unions supported the bill when exports were banned because it meant that oil shipments from Valdez would remain domestic and must be transported on U.S. tankers per the Jones Act.

This issue has been studied repeatedly, and generally produces net positive economic gains from lifting the ban. The negative effects on the domestic tanker fleet, however, have been sufficiently persuasive politically to undercut all efforts to remove the ban.

4. Possible Variations

Usually, removing the ban is interpreted to be synonymous with allowing ANS oil to be exported in foreign tankers (some has always been shipped to the Virgin Islands in foreign flag tankers). Two variations have been discussed recently:

a. Export with Jones Act tankers--Previous analyses have suggested employing U.S. flag vessels would make ANS oil prohibitively expensive in the Far East. One potential exporter-producer believes that is no longer so. That company's calculations indicate that profits might rise $0.50 per barrel even if domestic shipping is used.

b. Government guarantee of union pension funds--Since the U.S. flag tanker fleet is fast declining with or without ANS

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exports, some maritime unions might support lifting the ban if the Federal Government underwrites pension funds.

5. Pros and Cons of proposal

Pros

- o Alaska benefits most if exports are permitted since it receives at least $0.25 of every dollar the ANS wellhead crude oil price increases. If prices rose $1 per barrel for all ANS production, Alaska would net at least $146 million per year.

- o Better production margins for ANS producers might stimulate additional North Slope investment, resulting in some subsequent incremental production.

- o California independent producers argue that exporting ANS crude oil will reduce the West Coast "glut" and raise their prices (independents produce about 25% of California's crude oil in low-margin operations).

- o Federal revenues might increase due to higher income taxes and royalties in both Alaska and California. The income tax revenues might be slight, however, if producers reinvest their incremental revenues in production activities.

Cons

- o Over 60% of the U.S. flag tanker fleet subsists on the ANS trade. It is likely that 10-20% of the total U.S. fleet would be eliminated if the ban was lifted.

- o U.S. shipbuilders are counting on replacements for ANS tankers being constructed to meet OPA-90 double-hulled requirements at the end of this decade. That will not be the case if foreign tankers can enter the trade.

- o Removing the ban might be politically expensive.

6. Legislative outlook

[To be supplied by others?]

7. Costs to the Federal Budget

Estimates are premature at this point, pending the outcome of the ongoing study. It is likely that this initiative will be revenue positive, however.

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8. Benefits

- Linking West Coast oil markets with Pacific Rim countries
- Would improves trade balance with Japan (trade balance with Persian Gulf oil producers would worsen)
- Making room for lighter foreign crudes on the West Coast might make it easier for <u>some</u> refiners to meet air pollution standards.

OIL POLLUTION ACT OF 1990

Introduction

The Oil Pollution Act (OPA) was enacted in 1990 in response to the Exxon Valdez oil spill that occurred in 1989. While much of OPA is focused on requirements for tankers, a portion of OPA 90 targets offshore facilities. OPA 90 requires offshore facilities to provide a certificate of financial responsibility for each operator of a facility or facilities for $150,000,000. This is an increase from the present requirement of $35,000,000.

1. Proposal

The proposal includes a number of provisions:

- Reduce the dollar limits for the certificates of financial responsibility.
- Alter the guarantor status for insurers so that they act as indemnitors and are not secondarily liable for all the insured's debts.
- Stagger the availability of resources since not all resources are needed immediately, but are necessary over time.
- An incident involving de minimis quantities should be excluded from the financial requirement.
- The applicability of the financial requirement should be limited to offshore facilities and not applied to onshore facilities on navigable waters.

2. Criteria

3. Existing Policy Baseline

While OPA 90 was enacted in 1990, the existing certificate of financial responsibility regulations remain in place, requiring certificates for $35 million.

The Minerals Management Service of Interior has been delegated the responsibility for implementing Section 1016, the financial responsibility requirements for offshore facilities.

The MMS has issued an Advanced Notice of Proposed Rulemaking and is in the process of reviewing about 1,700 comments. Included among those comments is a National Petroleum Council study requested by the Secretary of Energy outlining economic and other impacts.

4. Possible Variations

A strict interpretation of the requirements would mean that both offshore and onshore facilities would be subject to the $150 million requirement. This means extending the impact beyond offshore facilities to onshore facilities such as marinas, pipelines, storage facilities, refiners, and any facility located on a navigable waterway or wetland that handles oil. For example, most of Alaska is considered a wetland and any storage facility on a wetland in Alaska would be affected, including Native Alaskan power facilities that run on diesel.

A more flexible interpretation would limit the requirements to offshore facilities avoiding the impact upon onshore facilities. Flexibility would limit the hardship on a variety of small companies or small operators in no position to meet the $150 million requirement. Flexibility also would imply that there are alternative methods for the affected operators to meet the financial requirements.

A legislative change could limit the exposure and impact of the present financial requirement.

5. Pros and Cons of Proposal

Pros

- Reduces OPA 90 to a manageable program, while eliminating the adverse impact on small operators located onshore.
- Sets financial responsibility requirements that industry can comply with without causing undue economic hardship.
- Avoids putting many small and medium sized operators out of business thereby decreasing domestic production and the nation's reliance upon imports.
- Addresses concerns of the insurance and financial industries over the OPA 90 provisions related to direct action.

Cons

- May be viewed by some as a relaxation in the Administration's commitment to ensuring that parties responsible for oil spills are made to pay for those spills.
- Opens up legislation that Congress and various interested parties do not want to deal with now.

6. Legislative Outlook

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7. Costs to Federal Budget

Revenue

Decrease in federal royalty collections due to elimination of small and medium sized operators and the shut in of their production.

Outlay

Increase in program expenditures to implement program, especially if strict interpretation of law is implemented.

8. Benefits

- Maintains production from a number of small and medium operators.
- Provides opportunities for the independent sector to continue operations on the OCS and to be a source for sale of marginal properties by the majors.

9. Other Impacts

- Other industries: potential damage to a large number of small companies is immense. These include marina operators, oil storage facilities, fuel jobbers, oil and gas operators on wetlands, etc.
- Alaska native communities: Many Alaska native communities are located in wetland areas.: Their oil handling facilities would be subject to this onerous requirement.
- Financial community: Insurers, banks, surety companies will not want to become guarantors under OPA 90.
- Oil imports: A strict interpretation of OPA 90 could reduce domestic production and increase oil imports.

DRAFT March 24, 1994

Section III.D.

OPA 90 Financial Responsibility

I. Proposal: Reduce the adverse economic impacts associated with OPA 90 financial responsibility provisions relating to offshore facilities, restrict jurisdiction to the open waters of the OCS and the territorial sea, and preserve current insurance market for certifications of evidence of financial responsibility by addressing direct action and state statute preemption criteria. This might be done through regulatory interpretation of the statutory provisions or through legislative amendment of OPA 90.

II. Fit with criteria:

a. Economic Considerations

Implementation of OPA 90 Financial Responsibility based on a "narrow" interpretation of the statute would impose significant economic burdens on a wide range of industries, including:

- oil and gas producers.
- oil refiners.
- oil pipelines.
- oil storage terminals.
- marinas and others facilities located on navigable waters that handle oil.

Imposing a $150 million financial responsibility on many of these industries could make it impossible for small operators to remain in operation, causing significant effects on industry output and on competition within these industries. There could be large effects on employment.

Implementation of the proposal would minimize these adverse effects.

b. Security Considerations

Many small producers of oil and gas from offshore facilities could be driven out of business by a requirement to demonstrate $150 million in financial responsibility. This would lead to higher oil imports, with associated effects on security. The proposal could minimize these effects.

c. Budgetary Considerations

Significant losses in royalty and tax revenues could result from a "narrow" interpretation of OPA 90. The proposal would minimize these losses.

III. Existing policy baseline:

- Continuation of existing COFR regulations at 33 CFR 135 for OCS ($35 million per facility) implementing Title III of OCS Lands Act Amendments of 1978 (OCSLAA 78) requirements.

- The OPA 90 Statute and Executive Order 12777/Department of the Interior Manual, 2 DM 218, delegated Section 1016 financial responsibility requirements for "offshore facilities" to MMS.

- The Minerals Management Service (MMS) is reviewing 1,700 comments received in response to an Advance Notice of Proposed Rulemaking (ANPR) concerning implementation of the OPA 90 financial responsibility provisions. Based on this review, it will be determined whether a regulatory proposal can be developed to implement the provisions without causing undue economic hardship. If this cannot be done, a legislative change may be needed.

IV. Possible variations:

- "Narrow" interpretation of OPA 90 requirements. Implements the letter, if not the intent, of the law but has corollary effect of causing undue hardship on marinas, fuel jobbers, small oil producers on wetlands, and virtually any other class of oil handler.

- OPA 90 flexibility. It may be possible to interpret OPA 90 more broadly in order to reduce its economic effects on small oil and gas producers and other facilities located on navigable waters that handle oil. However, there must be a strong justification for such interpretation if it is to survive any future legal challenges.

- Phased implementation. It may be possible for MMS to phase in the traditional OCS facilities at $150 million and postpone regulation of other potential "offshore facilities." However, many small offshore owners/operators would not be able to comply with financial responsibility requirements that can't be made consistent with risk, particularly if the insurance market doesn't materialize. Also, some parties may not consider this to be a full implementation of the law and may challenge it legally.

- Legislative change. The Administration could work with the Congress to change the OPA 90 provision in order to avoid undue economic hardships while ensuring that the basic purposes of the Act are fulfilled.

V. Pros and Cons

<u>Pros</u>

- Reduces OPA 90 to a manageable program utilizing anticipated financial responsibility program resources, while avoiding the costly complexities for facilities located on inland waters.

- Sets financial responsibility requirements that industry can comply with without causing undue economic hardship.

- Avoids putting many small and medium sized enterprises, including oil and gas producers, remote municipalities, drilling companies, and oil transporters, out of business.

- Addresses concerns of Insurance/Guarantor industry over the OPA 90 provisions related to direct action and multiple venues for liability claims.

- May be viewed by some as an exemption of facilities on inland navigable waters from responsibility for oil spill cleanup and damages.

<u>Con</u>

- May be viewed by some as a relaxation in the Administration's commitment to ensuring that parties responsible for oil spills are made to pay for spills from their facilities.

VI. Legislative outlook:

If the proposal could not be implemented during the regulatory process, legislative action would be required. At the present time there is no known movement towards a revision of OPA 90. However, in response to the ANPR, MMS has received comments from a number of concerned members of Congress, both in support of and against a legislative fix. Until MMS makes a final determination on its interpretation of OPA 90, the outlook for a legislative fix remains unclear.

VII. Costs: Federal budget; gross and net; 5 yr. and 10 yr.

Adoption of the proposal would not require a significant increase in budgetary resources. However, if a narrow interpretation of the OPA 90 financial provisions is implemented, a substantial increase in program resources will be required. Furthermore, implementation of a narrow interpretation will result in the loss of OCS bonus and royalty revenues as well as the loss of tax revenues.

VIII. Other impacts

- Other industries - Potential for any regulation of inland navigable waters to inadvertently economically damage large numbers of small-volume oil handlers.

- Alaska native communities - Already having great difficulty meeting U.S. Coast Guard requirements for unsafe storage tanks, no resources for OPA 90 financial responsibility requirements.

- Financial community - Insurers, banks, and surety companies do not appear likely to become OPA 90 "Guarantors."

- Oil imports - Implementation of a narrow interpretation of OPA 90 financial responsibility requirements could reduce domestic production and increase imports.

Section III.B. Royalty Proposals

Royalty Rate Reductions for Federal Leases--Offshore

1. Proposal:

Relief for marginal properties can be placed in two categories:

- *New Leases:* The Minerals Management Service (MMS) is preparing regulations for modified bidding systems. These modifications would allow the Secretary to offer new leases with more attractive royalty terms, including:

  1. Fixed rates below 12.5 percent.

  2. Sliding scale royalties with a floor rate below 12.5 percent.

  3. Royalty suspensions for a specified time period or production volume, or until capital costs are recovered.

  These systems would be used selectively to target marginal tracts in shallow waters, such as tracts with discoveries that were relinquished without production.

- *Existing Leases:* The Secretary has the authority under the OCS Lands Act to reduce royalty rates to "promote increased production" from a lease. MMS proposes to develop guidelines to provide industry with information on how to apply for reductions and the conditions under which reductions will be granted.

2. Fit with Criteria *[Author's note: NEC is drafting the "criteria" section of the package. Since we don't know exactly how they will frame the issues, this draft simply relates some relevant arguments.]*

a. Economic Criteria

At any one time, there is an array of geologic prospects, with associated development costs, in which companies may choose to invest. While some prospects are economic to produce now, others may be left in the ground until sometime in the future when higher prices or lower production costs make them economic.

In the shallow water Gulf of Mexico, most of the unleased marginal prospects are small fields which cannot be profitably produced under current financial terms and market conditions. Production technology is well established for these fields, so major cost reductions that will make them economic are unlikely to occur. Most forecasters expect oil prices to remain relatively stable for the foreseeable future, so many of these small fields may not enter production without some incentive. Gas prices, however, are expected to increase, which may provide sufficient incentive for gas prospects to be developed.

For existing leases, a well-designed royalty rate reduction policy can increase the ultimate recovery of resources from a producing field. Extension of production at the end of field life and production from small pools of oil located by in-fill or step-out drilling often would not occur without royalty relief. Once a field stops producing, the wells are plugged and abandoned and the platforms removed, so future recovery of resources left in the ground may be prohibitively expensive.

b. Security Considerations

Energy security arguments focus on the preferability of domestic gas and oil production over imported oil. A recent analysis of the OCS program shows that incremental OCS production would displace imports. Specifically, 86 percent of lost OCS production would be replaced by imported oil, and 34 percent of OCS gas production would be replaced by oil, mostly imported residual fuel[1].

c. Budgetary Considerations

The proposal could have several direct impacts on the budget:

- Royalties will be collected from production that otherwise would not occur for the foreseeable future.
- New leases offered with attractive royalty terms will receive higher bonus bids.
- Royalties will be reduced from production that would have occurred without the relief.

A secondary budget consideration is the administrative burden that may be created by the proposal to reduce royalties on existing leases. In this era of government down-sizing, policies that require a substantial workload may be difficult to implement.

<u>3. Existing Policy Baseline</u>

Leases in the shallow water (< 400 meters) Gulf of Mexico currently have royalty rates of 16.67 percent. Under current law and regulations, new leases cannot be offered with royalty rates below 12.5 percent.

MMS uses its authority to grant royalty reductions on existing leases to:

- o extend the life of mature fields; and

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[1] ICF Resources Inc., February, 1991, "Comparative Analysis of Energy Alternatives." Final report submitted to the Minerals Management Service, U.S. Department of the Interior.

o encourage investments for in-fill and step-out drilling and for well workovers.

In all cases, the basis for royalty rate reductions are to promote beneficial production that would not otherwise occur.

The traditional interpretation of this authority limits the Secretary to reducing royalties, as appropriate, only on leases that are already producing. S. 318, Senator Johnston's deep water royalty relief act, contains language that allows the Secretary to reduce royalties on existing, non-producing leases to "encourage production of marginal resources."

4. Possible Variations

For new leases, the proposal is designed to increase the flexibility of the Secretary to set royalty terms to reflect market conditions. As such, the Secretary would be able to set the royalty terms for each lease at the time of a lease sale. Thus, variations are built into the proposal.

For existing leases, the Secretary has the authority to reduce or eliminate royalties to promote increased production. Again, this provides the Secretary sufficient flexibility to tailor relief to the specific project. Two variations have been proposed:

- clarifying the Secretary's authority to reduce royalties on non-producing leases; and
- allowing the Secretary to reduce royalties for a category of tracts, rather than on a case-by-case basis.

5. Pros & Cons

Pros

- Encourages production of OCS gas and oil that would otherwise not be produced for the foreseeable future.
- Promotes increased ultimate recovery from producing fields.
- Increases government revenues, to the extent that the production would not otherwise occur.

Cons

- Many of the tracts considered marginal continue to be acquired in MMS lease sales. Thus, any definition of tracts that will receive reduced royalty terms will probably include tracts that do not need relief.

- Current and expected future natural gas prices have resulted in increased activity on the OCS, without any additional royalty incentive.

- Case-by-case reviews of applications for royalty rate reductions for existing leases could require substantial resources.

6. Legislative Outlook

New legislation is not required.

Under section 8(a)(1)(H) of the OCS Lands Act, the Secretary may modify authorized bidding systems or propose new systems, subject to the disapproval of the House or Senate within 30 days. The proposal to reduce the minimum royalty rates in the authorized bidding systems will be sent to Congress after developing a regulation that defines the modifications.

The Secretary has authority to reduce royalties on existing leases. As noted above, S. 318 contains language that clarifies this authority. The Senate Energy and Natural Resources Committee has passed S. 318, but it has not been scheduled for debate on the floor.

7. Costs

No formal cost estimates are available. However, to the extent that the proposals meet the goal of offering reduced royalty terms to marginal production that would not otherwise occur for the foreseeable future, revenues should increase.

The program for reducing royalty rates on existing leases could require significant resources to process, depending on the nature of the final guidelines and the number of lessees that apply.

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Section III.B. Royalty Proposals

Royalty Rate Reductions for Federal Leases--Onshore

1. **Proposal:** A number of proposals are being considered to provide a royalty rate reduction for oil and gas producers for purposes of conservation of resources, improving ultimate recovery of finite resources and increasing the domestic reserve base.

2. **Fit with criteria:** [This section will be completed when the NEC has finalized their criteria for evaluating Government policy]

3. **Existing policy baseline:** The proposals will build upon the existing stripper property royalty reduction as delineated in CFR 3103.4-1 (for a detailed discussion of these regulations, see II.B. of this report). However, while the stripper reduction is a function of average rate of production, other proposals are keyed to such diverse criteria as the American Petroleum Institute (API) degree of gravity, water cut and environmental compliance. In every case, the goal is to keep marginally profitable wells and fields on-line and producing. The alternative is abandoned or shut-in wells and the concomitant lost resources.

   BLM believes that authority for this action comes from the Mineral Leasing Act of 1920 (as amended), which states "The Secretary of the Interior, for the purpose of encouraging the greatest ultimate recovery of coal, oil or gas and in the interest of conservation, is authorized to waive, suspend or reduce the rental, or minimum royalty... whenever in his judgement it is necessary to promote development, or whenever in his judgement the leases cannot be successfully operated under the terms provided therein."

4. **Possible variations:** Royalty rate reductions are being considered for:

   a. wells/properties with high lifting costs associated with producing heavy (high gravity) oil;

   b. stripper (marginal) gas wells/properties on the edge of economic viability;

   c. operators with good records of compliance with environmental laws and regulations;

   d. wells/properties with a high water-cut percentage (i.e., a high amount of water produced per barrel of oil); and,

   e. new wells/wells using new technology to enhance recovery/wells testing new formations (royalty holiday)

5. **Pros and cons:** The advantages and disadvantages are similar for each of the variations proposed above:

<u>Pros</u>

- o encourages new and continued development of Federal lands
- o improves ultimate recovery of finite resources
- o reduces the abandonment rate for marginally economic wells
- o returns shut-in wells to production
- o increases domestic reserve base
- o lessens need for imported oil
- o helps maintain a viable and healthy domestic energy industry
- o helps reduce, through operator incentive, unfunded liabilities

<u>Cons</u>

- o may be perceived by the public as a "give-away" to industry
- o may significantly reduce states' share of royalties
- o may increase administrative burden to industry and the federal government

6. **Legislative Outlook:** [Unaware of any pending legislation regarding royalty rate reductions for economically marginal oil and gas properties]

7. **Costs:** For each of the royalty rate reduction variations listed above, no formal application process is envisioned. This reduces the administrative burden to both private industry and the BLM. Some additional burden will accrue to the MMS, however, as they work to process these reductions in a timely fashion.

Section III.B. Royalty Proposals

Penalty for Substantial Underreporting of Royalty

Proposal:

Provide the Minerals Management Service (MMS) with the authority to assess penalties for royalty underreporting (similar to the authority residing with the IRS for tax liability).

Fit With Criteria:

Economic considerations - This legislative initiative will not impact domestic production. This will increase the incentive to pay royalty properly the first time bringing private and social marginal cost more into line. There are no macroeconomic implications.

Security considerations - No impact on national security.

Budgetary considerations - No additional resources will be requested to implement the legislation. The Royalty Management Program estimates that several hundred thousand dollars of penalties may be assessed each year. The legislation is not proposed to enhance revenue, but rather to focus more attention on the correct and timely payment of royalty due. (We understand the CBO has scored the penalty language using their own estimates. OMB, however, did not score the penalty language prior to forwarding to Congress.)

Existing Policy Baseline:

Proposed legislation (H.R. 3400; S. 1637) provides MMS the specific authority that is currently lacking in the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) and the various leasing statutes. This legislation is designed to further encourage payors to pay proper royalties the ***first time*** by providing a penalty for companies that underpay by a significant amount. For many companies, it is currently cheaper to underpay and wait for MMS to bill for additional royalty due since the only sanction is late payment interest and the interest rate used to calculate late payment charges is well below the current cost of capital and most companies' internal rate of return. MMS seeks to make it "unattractive" to underpay.

Possible Variations:

MMS has actively solicited feedback from industry associations, which generally view the MMS reinventing government legislative proposal as establishing an unfair and unworkable penalty regime. As a result of feedback, MMS is proposing the following changes to the Senate bill:

- Limit the penalty to "substantial" underreporting scenarios (i.e., greater than 10 percent difference between the value of production and the value reported). Current language calls for penalties for any underreporting of royalty.

- DOI will not impose the penalty if the company corrects the underreporting prior to receiving a specific "written notice" from MMS that an underreporting may have occurred or within specified time period after the original report was due, whichever is later.

- Allow the company receiving written notice of a substantial underreporting to pursue an administrative appeal of the notice.

- The penalty provision would be applied "prospectively"--i.e., only to underreporting occurring after the date of enactment of proposed legislation.

- The legislation as originally introduced includes several circumstances under which the penalty can be waived by the Secretary. Some of those will be clarified:

    - As introduced, the penalty can be waived if the person has "substantial authority" for reporting as they are. There was concern about the ambiguity of the term "substantial authority." A definition will be included in the legislation to clarify what it means.

    - The waiver concerning notification to the Secretary of a difference in interpretation of a law or regulation will be clarified and language suggested by industry incorporated into the legislation.

Pros and Cons:

<u>Pros</u>

- Provides authority currently lacking in FOGRMA.

- Encourages highest level of industry compliance, consistent with the RMP strategic plan.

- Will benefit States, Indians, and U.S Treasury by way of more accurate and timely collections.

- Deters companies that chronically and deliberately underreport, while not punishing those making an "honest mistake."

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Cons

- Industry and some members of Congress feel MMS already has adequate penalty authority, and that this is not a widespread problem warranting additional authority.

Legislative Outlook:

NPR legislation has passed the House, but is not currently under active consideration by the Senate.

Costs:

Federal budget -

Gross and net -

5-yr and 10-yr -

Other Impacts:

Administrative/Regulatory Initiatives

Underground Injection Control Regulatory Revisions

0. Introduction

EPA is developing revisions to existing underground injection control (UIC) regulations under the Safe Drinking Water Act (SDWA), and has reportedly considered issuing a proposal that would be more stringent than recommendations made by a Federal Advisory Committee (FAC) that consisted of environmental, industry, State, and Federal agency representatives. Depending on their final content and implementation, the revised regulations could be costly to industry without significantly improving the environment.

1. Proposal

Senator Boren and others are considering action to oppose or terminate EPA revisions to the existing regulations.

2. Existing policy baseline

Background -- In 1980, EPA promulgated regulations for injection wells used in oil and gas production operations for the disposal of produced water or enhanced oil recovery (Class II). Twenty-three States have primacy to implement the UIC program for Class II wells. In other States, EPA implements the program.

Several efforts over the last five years have identified deficiencies in the Class II UIC regulations. In 1991, EPA formed an Advisory Committee under the Federal Advisory Committee Act composed of representatives from environmental groups (Friends of the Earth, National Audubon Society), petroleum producing companies (ARCO, Conoco), trade associations (American Petroleum Institute, Independent Petroleum Association of America), and State (California, Kansas, Ohio and Texas) and Federal agencies (EPA, DOE, and DOI/BLM) to develop recommendations for revising the regulations.

The Advisory Committee issued a final report in March 1992. All committee members endorsed the final report with the following caveats:

(1) The Independent Petroleum Association and the State of Ohio did not endorse a provision to require annual mechanical integrity testing for injection wells with only one layer of protection;

(2) Ohio and Kansas reminded EPA of its obligation under SDWA Section 1425 to allow States to demonstrate the effectiveness of their in-place programs (instead of adopting the regulations virtually verbatim);

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(3) Kansas wanted EPA to interpret the SDWA prohibition against impeding oil and gas production, unless essential to protect underground sources of drinking water (USDW), based on local production impacts, not merely national impacts; and

(4) DOE and DOI expressed concerns that a specified schedule of mechanical integrity testing may be overly stringent when frequent monitoring can be equally protective, and the Committee's recommendations provided no incentive for EPA regions to establish AOR variance programs in those States whose programs are administered by EPA.

Briefly stated, the Advisory Committee recommended the following:

a) **Construction Standards:** Newly drilled and newly converted wells should have double containment systems for injected fluids. Surface casing should extend to the base of aquifers containing less than 3,000 mg/l total dissolved solids and be cemented to the surface. (Virtually all wells drilled by major oil producers already employ these construction standards.)

b) **Increased Monitoring:** Existing wells that do not meet the new construction standards should be tested more frequently. The frequency of testing should be based on the level of protection afforded to these wells.

c) **Area of Review:** The existing regulations require owners or operators of new injection wells to assess the potential for contamination of USDWs by fluids migrating through open conduits (i.e., improperly plugged abandoned wells) in the vicinity of the well (area of review). Owners and operators of existing wells should be required to conduct the same area of review. (These changes respond specifically to recommendations by the Government Accounting Office in a 1989 study requested by Representative Synar.) New and existing wells should be exempted from these requirements where there is a low risk of endangering USDWs, contingent upon individual States or EPA regions establishing variance plans.

<u>EPA Regulatory Impact Analysis</u> -- EPA has estimated that revisions based on FAC recommendations would result in incremental direct and indirect compliance costs of $47.1 million annually for the first five years. In addition, the value of oil that would not be produced as a result of the revisions is estimated to be $40 million annually.

Direct compliance costs for injection wells would average $19.3 million annually for the first five years. Annual indirect compliance costs for production wells are estimated at $27.8 million. The proposed rule would indirectly affect oil production since well owners would have to build production wells to injection well standards to retain the option of converting the well to an injection well at a later date.

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The proposed rule may severely affect stripper production in some States. EPA is concerned about the potential impact on small operators and plans to request comment in the preamble of the proposed rule on possible mitigation measures.

Industry and DOE are concerned that EPA has significantly underestimated the costs of the regulatory revisions. Industry estimates the economic impact of these revisions to be more than $1 billion over five years -- perhaps as much as $3 billion -- depending on their final form. The costliest aspect of the revisions is the requirement to perform AORs for the thousands of injection wells which were constructed prior to 1982. API members were not unanimous in supporting the FAC recommendations, and some companies have particular concerns with the AOR requirements.

Benefits -- Injected fluids can contain different chemical contaminants depending on geographic and geologic factors. Primarily the contaminants fall into three categories -- hydrocarbons, metals, and radionuclides. The regulatory revisions focus on preventing well failures which can introduce contaminants into USDWs. Potential benefits include reduction in damage to current or future public health and protecting ecosystems. Because Class II injection projects rarely feature ground water monitoring systems and most incidents of USDW contamination occur in rural areas and are settled directly with the landowner, relatively few documented cases exist that directly implicate Class II injection wells as a source of large-scale USDW contamination.

The primary constituents of concern in injected fluids are chlorides an sodium compounds. Their introduction into a USDW at the high concentrations usually present in oil field brines (up to 141,000 mg/l Cl) can render it totally unfit for human consumption. Treatment costs for chloride removal are high.

EPA believes that the costs imposed by an FAC-based rule are likely to be offset by the benefits as depicted in scenarios developed for the RIA. The scenarios examined the potential carcinogenic effects of three contaminants in injected fluids -- benzene, arsenic and radium. The benefits analysis in the RIA only compared the benefits with the direct costs to injection wells.)

4. Possible variations

The Administration's response to proposals to terminate the UIC rulemaking could include: (1) EPA reaffirming its intent to support the FAC recommendations and the prerogative of primacy States under Section 1425 to choose alternative approaches to protecting underground sources of drinking water, and (2) EPA pledging its intent to implement the regulations in the most cost-effective manner consistent with statutory intent and Administration policies to avoid burdensome, unnecessary regulations such as described in Executive Order 12866 on

Regulatory Planning and Review.

Other options include:

a) Making the response described above with an added commitment that EPA and DOE will continue to work cooperatively with States, EPA regions, industry, and others to ensure that variance plans to AOR requirements -- the most costly portion of the proposed rule -- are established to the maximum extent possible;

b) Allowing for alternative regulatory compliance schedules or approaches for small operators and injection wells associated with stripper wells or other marginally economic operations;

c) EPA issuing a more stringent proposed rule. (This could have a devastating impact on industry.)

5. Pros and cons of proposal

Pros

- Terminating the revisions to the regulations could potentially result in cost savings for industry up to $3 billion based on preliminary industry estimates; EPA believes the cost of the revisions would be considerably less.

Cons

- The FAC was viewed as a "negotiated" rulemaking. If the revisions were terminated, adverse reaction, particularly from environmental groups, could be severe and prove detrimental to other cooperative efforts on topics related to the domestic oil and gas industry such as the regulation of oil and gas wastes.

6. Legislative outlook

To be determined. Senators Boren and Domenici are the sponsors of the leading Senate SDWA reauthorization bill.

7. Costs to Federal budget

Revenue: None.

Outlays: None for terminating the revisions. Assuming that EPA issues a rule consistent with FAC recommendations, the DOE Office of Fossil Energy anticipates spending approximately $3 million total in FY 1994 and 1995 to assist States and industry in developing AOR variance plans.

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Number of pages to follow: 3

Comments: MIC - latest version — we have attempted to incorporate DoE comments.

Mike S.

Underground Injection Control--Class II (Oil & Gas) Wells

Status

The proposed rule is currently undergoing final EPA review.

About to publish as proposed rule for comment?

Background

Several efforts over the last five years have identified deficiencies in the Class II (oil and gas well) UIC regulations. EPA formed a FACA advisory committee composed of representatives from environmental groups (Friends of the Earth, National Audubon Society), petroleum producing companies (ARCO, Conoco), trade associations (American Petroleum Institute, Independent Petroleum Association of America), and state (Kansas, Ohio, California, Texas) and federal agencies (EPA, DOE, BLM) to develop recommendations for revisions to the regulations to correct those deficiencies.

The Advisory Committee issued a final report in March 1992. All committee members endorsed the final report with the following caveats: 1) The Independent Petroleum Association and the state of Ohio did not endorse the provision requiring annual mechanical integrity testing for injection wells with only one layer of protection; 2) Ohio and Kansas reminded EPA of its obligation under §1425 of the Safe Drinking Water Act (SDWA) to allow states to attempt to demonstrate the effectiveness of their in-place program (instead of adopting the regulation virtually verbatim); and 3) Kansas wanted EPA to interpret the SDWA prohibition against impeding oil and gas production, unless essential to protect underground sources of drinking water (USDW), based on local production impacts, not merely national impacts; 4) The Department of Energy expressed concerns that a specified schedule of mechanical integrity testing may be overly stringent when frequent monitoring can be equally protective; and that the Committee's recommendations provided no incentive for EPA regions to establish area of review variance programs in those States whose programs are administered by EPA.

Components of the Rule

The proposed rule reflects the Advisory Committee's recommendations and proposes modification to the Class II regulations in three areas.

a) **Construction Standards:** The rule would require double containment systems for injected fluids. In addition, it would require that the surface casing be extended to the base of aquifers containing less than 3,000 mg/l total dissolved solids and be cemented to the surface. (Virtually all wells drilled by the major oil producers already employ these construction standards.)

b) **Increased Monitoring:** The rule would require existing injection wells that do not meet the new construction standards to be tested more frequently. The frequency of testing would be based on the level of protection afforded by these wells.

c) **Area of Review:** The current regulations require owners or operators of new injection wells to assess the potential for contamination of USDWs by fluids migrating through open conduits (i.e. improperly plugged abandoned wells) in the vicinity of the well (area of review). The proposed rule would require owners or operators of existing wells to conduct the same area of review. New and existing wells could be exempted from these requirements through a variance procedure proposed in the rule, based on the absence of risk to USDWs.

Regulatory Impact Analysis

Costs: The RIA estimates the total direct and indirect compliance costs at $47.1 million annually for the first five years. In addition, the value of the oil that will not be produced as a result of this rule is estimated at $40 million annually.

Direct compliance costs for injection wells average $19.3 million annually for the first five years. Annual indirect compliance costs for production wells are estimated at $27.8 million. The proposed rule would indirectly affect oil production since well owners would have to build production wells to injection well standards to retain the option of converting the well to an injection well at a later date.

The value and percentage of the foregone production is negligible from a national perspective. The RIA estimates a decline in oil production from existing projects of up to 0.05 percent to 0.005 percent nationally, depending on the price of oil.

The proposed rule may severely affect stripper production in some states. For example, 85% of stripper wells in Kentucky and 78% of stripper wells in Arkansas would not be drilled. In contrast, only 7% of the stripper wells in Oklahoma would not be drilled (97 wells). EPA is concerned with the potential impact on small operators and is therefore requesting comment in the preamble on possible mitigation measures.

Benefits: Injected fluids can contain many different chemical contaminants depending on geographic and geologic factors. Primarily the contaminants fall into three categories--hydrocarbons, metals, and radionuclides. The proposed rule focuses on preventing well failures which can introduce contaminants into USDWs. The benefits include reduction in damage to current or future public health and protecting ecosystems. Because Class II injection projects rarely feature ground water monitoring systems and most incidents of USDW contamination occur in rural areas and are settled directly with the land owner, relatively few documented cases exist that directly implicate Class II injection wells as the source of large-scale USDW contamination.

The primary constituents of concern in injected fluids are chloride and sodium compounds. Their introduction into a USDW at high concentrations usually present in oil field brines (up to 141,000 mg/l Cl) can render it totally unfit for human consumption. Treatment costs for chloride removal are high.

The costs imposed by the rule are likely to be offset by the plausible benefit scenarios developed in the RIA. The scenarios examined the potential carcinogenic effects of three contaminants in injected fluids--benezene, arsenic, and radium. (The benefits analysis in the RIA only compared the benefits with the direct costs on injection wells.)

REGULATORY POLICIES

DRAFT

Exclusion of Non-Use Values In Natural Resource Damage Assessments

0. Introduction

Under authority of CERCLA and the Oil Pollution Act of 1990, the Department of Interior and the National Oceanic and Atmospheric Administration (NOAA) are developing regulations for Natural Resource Damage Assessments (NRDA) to govern the scope and level of liability for injuries to natural resources caused by discharges of hazardous substances and oil.

In addition to corporate liability for the costs of environmental restoration measures and reduction in use values (i.e. compensation for hikers, recreational fisherman, birdwatchers who actually use the injured natural resource), both Interior and NOAA are considering including damage estimates for "non-use" values of natural resources in the determination of liability. Non-use values are broad concerns the public may have about the environment. An example of a non-use value is "existence value," which refers to the value that the public attaches to the knowledge that a natural resource exists, even though they do not actually see it or use it.

1. Proposal

Exclude liability for non-use value losses in NRDA.

2. Fit With Criteria

[To be determined]

3. Existing Policy Baseline

Under CERCLA and the Oil Pollution Act, state and federal government officials are authorized to recover from responsible parties natural resource damages. When the Interior Department first published the CERCLA NRDA regulations in 1986, they were immediately challenged in the D.C. Circuit by a coalition of ten states and three public interest groups.

In two separate decisions, the D.C. Circuit struck down the Interior Department's rule. Among other things, the court ordered the Department to issue a rule that would permit trustees to include reliably calculated use and non-use values in Natural Resource Damage Assessments.

There is significant controversy regarding the inclusion of compensation for non-use losses in the NRDA process. The only method currently available to measure non-use values is the Contingent Valuation Method (CVM). CVM estimates non-use losses from survey responses to hypothetical questions regarding how much money one would be willing to pay to prevent certain natural resource injuries or to preserve certain environments. Average dollar responses are multiplied by the size of the relevant population to calculate liability.

CVM as a reliable method to establish liability has been seriously questioned by many analysts. A Blue Ribbon Panel created by NOAA to address the reliability of CVM concluded that the method can be used to produce estimates reliable enough to serve as the starting point for an assessment of non-use values. However, the NOAA Panel was not able to identify any study conducted to date which satisfied its stated criteria of reliability.

Industry is concerned that inclusion of CVM-based estimates of non-use losses in the NRDA process could have a substantial economic impact on many companies, and even result in the uninsurability of parties that handle petroleum and petroleum products. They argue that final regulations for NRDA should not include liability for non-use value losses as measured by CVM.

4. Possible Variations

One alternative to a determination that CVM is not reliable would be to structure the NOAA/DOI NRDA regulations so that CVM is applied in a manner that minimizes its potential for overstating actual losses. This could be done by building on several elements already included in NOAA's proposal.

- Maintain the CVM "calibration" procedure as proposed by NOAA. Recognizing that in cases where actual willingness to pay significantly exceeds hypothetical willingness to pay as expressed in survey responses in all studies where they have been directly compared, NOAA's current proposal applies a 50% calibration factor to the former unless it can be demonstrated that a different calibration factor should be used. This will reduce damage assessments both directly and by spurring research on key calibration issues.

- Reflect public's "prior knowledge" of resource and damage in estimates of non-use losses by adjusting CVM-based estimates to reflect zero losses for that proportion of the survey population unaware of a resource or damage to it. While participants in a CVM survey may actually be willing to pay to avoid damages to resources that they learn about during the survey process, it is their pre-survey state of knowledge that is truly representative of the general population. Without such an adjustment, non-use loss estimates that are supposedly representative for the general public would be the same whether 0% or 100% of the survey population knew about the resource and/or the damage. The prior knowledge adjustment, which is included in NOAA's proposed rule as a discussion issue but is not proposed, could be especially important in cases that do not receive massive press attention.

- Apply a credible "split sample" test to increase confidence in CVM studies used for NRDA purposes. NOAA's proposal already includes a requirement that CVM studies use a split-sample test to demonstrate that willingness to pay for a distinctly better environmental outcome is higher than for an inferior environmental outcome. However, the proposed rules for applying this test require that the two environmental outcomes to be compared be recognized as having distinctly different values by 95% (i.e. 19 out of 20) of a pre-survey focus group. A more credible test to screen out bad CVM studies would set a 70% threshold in the focus group based on ability to differentiate environmental outcomes rather than values. This test would present a high, but realistic, hurdle for CVM studies.

5. Pros and Cons of Proposal

Pros

- Consistent with other standards for litigation.
- Avoids slippery slope of trying to "improve" CVM.

Cons

- Environmental community lobbied heavily for the inclusion of non-use values in the damage assessment.
- Adoption of industry position by DOE would require a change in earlier DOE position as expressed in comments to NOAA.

6. Legislative Outlook

[To be determined]

7. Costs to Federal Budget

[To be determined]

8. Benefits

[To be determined]

9. Other Impacts

[To be determined]

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Minerals Management Service

Facsimile Transmission

	FAX	Phone
To: Domestic Gas and Oil Incentives Working Group		
From: Carolita Kallaur	(202) 208-7242	(202) 208-3500

COMMENT: Attached is a paper on Multiple Use Management which is included in Section III.

Date: 29 March 94 Number of Pages (including cover): 4

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DOMESTIC GAS AND OIL INITIATIVES

MULTIPLE USE MANAGEMENT FOR OIL AND GAS

III. [Section 3]

1. Proposal: The Oil and Gas Industry has proposed that BLM maintain its policy of multiple use management.

2. Fit with criteria: [This section will be completed when the NEC has finalized their criteria for evaluating Government policy.]

3. Existing policy baseline: The Federal Land Policy and Management Act of 1976 (FLPMA) established policy to retain the public lands under Federal ownership, to inventory and identify their resources, including oil and gas resources, and to provide for the multiple use and sustained yield management of public lands and resources through land use planning. As a result of this planning, areas are made available for oil and gas exploration, development, and production. The BLM has recently formally adopted the principles of ecosystem management to guide its management of the public's lands and resources.

   In the 1960's, before enactment of FLPMA, the BLM began using a multiple use philosophy when concerns for wildlife, recreation, soil and water resources were integrated into traditional programs such as range, forestry, lands, and minerals through a land use planning process.

   By the 1970's, systematic land use planning was implemented in the field by preparation of Management Framework Plans (MFP's) which considered resource inventories with economics and social information to develop and compare alternatives.

   The passage of the National Environmental Policy Act of 1970 (NEPA) made protection of the environment a national priority by requiring all Federal agencies to assess the impacts of their actions on the environment and to mitigate adverse effects. Environmental Impact Statements (EIS's) became BLM's primary tool for analyzing resources, impacts, and management alternatives on the ground.

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Section 202 of FLPMA required BLM to develop a more comprehensive land use planning system for developing, displaying, and assessing management alternatives and to strengthen the Bureau's coordination with State and local governments. Therefore, in 1977, the BLM began developing Resource Management Plans (RMP's) which were prepared in the field in conjunction with EIS's.

The RMP process includes public participation, identifies issues, develops planning criteria, gathers information and inventories resources, analyzes the management situation, formulates alternatives and estimates the effects of the alternatives, then selects a preferred alternative and publishes a draft and final RMP. Once this plan has been completed, the BLM can identify areas acceptable for oil and gas development, allow exploration, and if the resource is discovered in commercial quantities, allow oil and gas production. At each stage, NEPA compliance is adhered to with supplemental NEPA documents being tiered from the initial EIS prepared for the land use plan.

The FLPMA mandate for multiple use management has been the BLM's basic tool for reconciling the various demands and viewpoints about how public lands are to be administered. This allowed for development and production of oil and gas as well as other resources in a compatible manner that contributed to the nation's economy and provided for a safe and viable environment. The RMP's are flexible and reflect the conditions of the land. They are effective because of the close relationship BLM has established with public land users.

The BLM is currently adapting ecosystem management concepts within multiple use practice. As a foundation for multiple use, ecosystem management presupposes an understanding of ecosystems that will minimize unacceptable damage to the environment and its resources. Multiple use policy is fundamental to land management. Many land uses have conflicting interests, however, successful ecosystem management requires an understanding of all the components and an analytical resolution of conflicts. In this more sophisticated system, as at present, oil and gas development will continue to be considered equally with other resources.

4. Possible variations: Ecosystem management has just been adopted and specific variations in policy have not been developed.

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5. Pros and cons: [Pros and Cons of Multiple Use Management and Ecosystem Management.]

Pros

- Multiple use is analogous with the guiding principles for ecosystem management.

- Geology and minerals, including oil and gas, will be an important part of ecosystem management as ecosystem management includes the biotic, abiotic, social, and economic considerations. Oil and gas have a place on public lands; the task is to strike a balance for a healthy ecosystem.

- Multiple use and ecosystem management will prevent conflicts at later stages of development after time and money have been spent by the oil and gas companies.

Cons

- In ecosystem planning, as when BLM was implementing multiple use management, in some situations, lands will be preserved to fill a need such as to provide a return of a certain species to the land. (Once the ecosystem becomes healthy, development including exploration and production should be allowed to continue.)

6. Legislative Outlook: [We are not aware of any pending legislation in regard to either ecosystems or multiple use. Future legislation regarding NEPA may be forthcoming.]

7. Costs: This is undetermined at present.

8. Other Impacts: It's too early to tell.

19/389

RECENT TAX INCENTIVES FOR OIL AND GAS PRODUCTION

Technical and Miscellaneous Revenue Act of 1988

- extended Sec. 29 credit expiration date (for facilities placed in service or wells drilled) from 1/1/90 to 1/1/91

OBRA 1989

- reduced period of elective amortization for intangible drilling costs from 10 years to 5 years

OBRA 1990

- extended Sec. 29 credit expiration date (for facilities placed in service or wells drilled) from 1/1/91 to 1/1/93 and expiration date (for sale of qualified fuels) from 1/1/2001 to 1/1/2003

- reinstated Sec. 29 credit for tight sands gas

- provided enhanced oil recovery tax credit

- enhanced percentage depletion by: (a) increasing net income limitation from 50 percent to 100 percent of the net income from the property; (b) permitting independent producers to claim percentage depletion on properties transferred from integrated firms (who are unable to claim percentage depletion); (c) providing bonus rates of percentage depletion for production from marginal wells (defined as either stripper wells (wells on a property with average production of less than 15 barrels per day per well) or heavy oil wells)

- provided special energy deduction for alternative minimum tax (AMT) purposes

Energy Policy Act of 1992

- repealed AMT and adjusted current earnings (ACE) preference for excess intangible drilling costs (IDC) and percentage depletion deductions for independent producers; use of excess IDC deductions cannot reduce alternative minimum taxable income (AMTI) by more than 40 percent of the level before taking this item into account; special energy deduction (see OBRA 1990) was repealed

Department of the Treasury
Office of Tax Policy
October 15, 1993

Domestic Gas and Oil Incentives

Section II, D

Regulatory Policies: Environmental and Other

The Environmental Imperative

The interrelationship between energy and the environment is complex. The ways in which natural gas and oil are produced, transported, and consumed help determine our quality and style of life. Yet we are often reminded that fossil fuel consumption brings its own problems, sometimes undercutting the quality of life that it has made possible. Energy production, transportation, and use have significant adverse impacts on air, water, land use, and larger global environmental systems. Energy-related environmental accidents, such as oil spills, are notorious and very visible reminders of the potential risks we take to enjoy the benefits of fossil fuels. Air and water pollution are well known adverse side effects of fossil fuel use. The land use impacts of energy production, transportation, and consumption have also become of greater concern in recent years. The potential for climate change due to heightened concentrations of carbon dioxide has served to renew and heighten concern regarding energy's pervasive effect on the environment. Energy production and consumption are responsible for the bulk of air pollutants that comprise or cause urban air pollution, acidic deposition, air toxins, and greenhouse gases.

Since enactment of the Clean Air Act (CAA) of 1970, increasingly stringent federal and state regulations have reduced or stabilized emissions of several energy-related pollutants. Other key pieces of environmental regulations enacted in the 1970s, 1980s, and 1990s have helped control the growth in pollution and produced numerous environmental success stories: volatile organic compounds and carbon monoxide from mobile sources have been reduced; lead emissions have been reduced dramatically. However, the rising awareness of the ubiquity and persistence of an industrial society's environmental impacts challenges policy makers to find effective and efficient ways to mitigate adverse environmental effects. Environmental policy makers will increasingly need to examine alternatives that help ensure that energy is produced and consumed efficiently so as to minimize adverse environmental impacts. Market-based strategies that create economic incentives to reduce adverse environmental impacts can help provide society the flexibility to maximize its diverse goals. In addition, a credible and efficient long-term mitigation strategy will recognize the importance of regional, state and local action, as well as promote the economically efficient goals of sustainability, waste minimization, and recycling.

Specific Environmental Regulations

A wide range of environmental regulations affect the domestic gas and oil industries. Environmental protection is provided for at all stages: exploration and production, transportation and transmission, refining and processing, and end use. It is often convenient to break down a discussion of environmental controls by medium. The discussion below highlights the key environmental laws and regulations affecting the domestic gas and oil industries.

SOLID WASTES: The Resource Conservation and Recovery Act (RCRA) is intended to provide a cradle-to-grave regulatory framework to monitor and control the production, storage, transportation, and eventual disposal of wastes that pose a risk to health and the environment. Amendments to RCRA in 1984 added regulation of petroleum and hazardous wastes stored in underground tanks. However, wastes associated with oil and gas operations were exempt from Federal regulations pending further review by EPA. EPA has issued a proposed rulemaking that will modify the "mixture" and "derived from" rules, clarifying when hazardous wastes streams that have been mixed with other wastes (or otherwise managed) can be determined to be no longer hazardous.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or "Superfund" was enacted in 1980. CERCLA authorized $1.6 billion over five years for a comprehensive program to clean up the worst abandoned or inactive waste sites in the nation. CERCLA funds used to establish and administer the cleanup program are derived primarily from taxes on crude oil and 42 different commercial chemicals. The reauthorization of CERCLA is known as the Superfund Amendments and Reauthorization Act of 1986 (SARA). These amendments provided $8.5 billion for the cleanup program and an additional $500 million for cleanup of leaks from underground storage tanks. Under SARA, Congress strengthened EPA's mandate to focus on permanent cleanups at Superfund sites, involve the public in decision processes at sites, and encourage states and tribes to actively participate as partners with EPA to address these sites. In the process of amending CERCLA, Congress passed the Emergency Planning and Community Right-To-Know Act, known as Title III. Title III was enacted to promote the public's awareness of hazardous or toxic chemicals used or produced by industry.

WATER AND WETLANDS: The Federal Water Pollution Control Act of 1972 and the Clean Water Act (CWA) of 1977 set as a goal "to restore and maintain the chemical, physical, and biological integrity of the nation's waters." The CWA establishes a system of effluent standards by industrial category, provides for a permitting system, sets waste water quality standards, provides for grants for municipal waste treatment, and addresses special issues like toxic wastes and oil spill. The effluent limitation standards and the National Pollutant Discharge Elimination System (NPDES) permit program are the primary regulatory tools under the CWA. Within the domestic gas and oil sector, CWA requirements primarily affect offshore drilling and refinery activity.

Wetlands are among the most productive of all ecosystems. Gas and oil E&P, refining and processing, and transport often affect wetlands. Currently no comprehensive Federal law for protecting wetlands exists. The major Federal regulatory program for wetlands stems from Section 404 of the CWA which provides authority for the protection of wetlands. EPA and the U.S. Corps of Engineers jointly administer wetlands regulations.

The Safe Drinking Water Act of 1984 (SDWA) established the Underground Injection Control (UIC) program to protect drinking water aquifers from contamination by subsurface injection fluids. SDWA requires EPA to establish minimum requirements for state programs or for Federal primacy in the absence of state programs. The UIC affect all underground injection associated with oil and gas exploration and production activities. A Federal Advisory Committee composed of representatives of the petroleum production industry, environmental groups, states, and Federal agencies issued a final report recommending a requirement for double containment systems for injected fluids. In addition, surface casing would be required to extend to the base of aquifers containing less than 3,000 mg/l total dissolved solids and be cemented to the surface. Virtually all wells drilled by the major oil producers already employ these construction standards. The rule would require existing injection wells that do not meet the new construction standards to be tested more frequently. The frequency of testing would be based on the level of protection offered by these wells.

The Oil Pollution Liability and Compensation Act of 1990 raised liability limits for oil tankers as well as other onshore and offshore facilities. The Act allows unlimited liability against tanker owners where gross negligence or willful misconduct is involved, and does not preclude states from imposing their own unlimited liability requirements. In addition to the liability provisions, the Act requires that, over a 15 year phase-in period, double hulls be used for all new tankers and for vessels trading with the United States.

The Great Lakes are a valuable national resource, with unique environmental problems. In 1990, the Great Lakes Critical Programs Act was enacted requiring states to adopt minimum water quality standards for the protection of the Great Lakes. EPA is to issue guidance specify minimum water quality standards, anti-degradation policies, and implementation procedures to protect human health, aquatic life, and wildlife.

AIR: The 1970 Clean Air Act (CAA) produced notable environmental gains. Two key parts of the CAA affecting the oil refining industry were related to end-products: the lead phase-out in gasoline and the requirements for low sulfur distillate and residual fuel use at electric utilities. The CAA established a schedule for reducing lead additives and required automobile manufactures to design and construct vehicles that could run on low-lead and unleaded fuel. The legislation required that all gasoline stations of specific sizes offer at least one grade of unleaded gasoline. The allowable lead in gasoline was reduced to 1.1 grams per gallon in 1982, and a system of waivers was established that allowed refiners to build up lead credits. Further reductions in 1986 brought the allowable lead to a maximum of 0.1 grams per gallons. All grades of gasoline must be completely lead-free as of January 1, 1996. The lead regulation resulted in a greater than 90% reduction in airborne lead emissions.

The 1990 Clean Air Act Amendments (CAAA) expanded the effort to reduce harmful emissions from auto fuels, presenting new challenges for refineries. As of November 1, 1992, the oxygenate fuels program requires that gasoline sold in the 39 areas of the country designated as carbon monoxide nonattainment areas to contain a minimum of 2.7% oxygen by weight during at least 4 winter months. As of October 1, 1993, the sulfur content of highway diesel fuel must be reduced from the current maximum of 0.25% to 0.05% by weight. Finally, as of January 1, 1995, reformulated gasoline will be required in the nine metropolitan areas with the worst ozone problems. The reformulated gasoline requirements will control VOC and NO_x emissions, as well as benzene and other toxic air pollutants. EPA has also issued a separate proposal that seeks to assure a 30% market share for renewable fuels, in particular ethanol and ethyl tertiary butyl ether (ETBE) in the reformulated gasoline program. Earlier regulations were promulgated to combat urban smog precursors to control the summertime volatility of motor gasolines.

In addition to environmental requirements for products sold by refiners, the refineries themselves must meet standards for emissions of VOCs, NO_x, and air toxins. The 1990 CAAA require EPA to promulgate regulations for enhanced monitoring and compliance certification for major stationary source of air pollutants.

Reporting required by the Superfund Amendments and Reauthorization Act (SARA) identified approximately 1.4 million tons of toxic air pollutants released in 1987 by a wide range of chemical and other manufacturing facilities. EPA estimates that facilities in 37 states, primarily in those states along the Atlantic, Gulf, and Pacific coasts, are associated with toxic releases that pose high individual cancer risks. Energy-related sources of toxic air emissions include oil-and coal-fired utility boilers, petroleum refineries, and oil and gas exploration and production operations. In addition, VOC emissions from the transportation sector are among the largest sources of toxic air emissions in many urban areas. The 1990 CAAA require that sources of hazardous air pollutants install maximum achievable control technology (MACT) to reduce such emissions. As defined by the CAAA, MACT represents the average emission limitation achieved by the best performing 12% of existing sources in a source category. EPA is presently developing regulations that will specify MACT requirements for several petroleum industry operations (refineries, gasoline marketing terminals, and marine loading).

Natural gas and oil pipelines are subject to CAA requirements for NO_x and VOC controls. New pipeline compressor stations will be required to have the most efficient, clean-burning prime movers technology available, and existing stations my be required to undergo extensive retrofitting or replacement. In non-attainment areas along with advanced controls, enhance emission offset requirements will be required for permitting of new or modified facilities.

Land Use Impacts and Public Lands Access: Much of the land within the United States is public property subject to Federal control. Wilderness areas, parks and monuments, and some wildlife refuges are not available for oil and gas E&P. National forests and other public lands, however, may be available. Actions by Federal agencies likely to have a significant environmental impact, such as leasing land or granting right-of-ways, require a formal Environmental Impact Assessment (EIA). States and other levels of government have similar requirements for EIAs. In addition, the Endangered Species Act may place severe constraints on economic activity in sensitive areas. These protections can affect gas and oil E&P and pipeline construction permitting.

Outer Continental Shelf Moratoria: The Outer Continental Shelf (OCS) is subject to the jurisdiction and control of the United States by authority of the OCS Lands Act and the Submerged Lands Act. The OCS is made available for oil and gas E&P through a bonus bid leasing system. Leasing activity is planned and announced in a 5-year OCS leasing program schedule specifying the proposed size, timing, and location of each lease sale. Since 1982, Congress has used the appropriations process to adjust the 5-year program schedule through "moratoria" blocking the DOI from conducting lease sales in certain OCS planning areas.

I.B

EVALUATING POLICIES AFFECTING OIL AND GAS PRODUCTION

[Working Group -- this is the second part of the overview section. I would appreciate any comments you might have on this material. As I said earlier, the quality of the final product will depend, to a large extent, on your comments. -- Mark]

While market allocations of resources generally lead to an efficient distribution of resources, there are circumstances where the operation of a free market leads to resource allocations that can be improved upon through well-chosen government policies. These circumstances include situations where: (i) market prices do not reflect all the social costs and benefits of production and/or consumption (situations where this occurs are called externalities); (ii) buyers or sellers are able to exercise market power to limit quantities produced or to increase prices above those that would prevail in a competitive market; (iii) national security concerns remain unaddressed by market transactions. In these cases, it is important to evaluate whether the proposed (or existing) market intervention is likely to lead to a better resource allocation and whether the proposed intervention is more desirable than alternative interventions.

There are at least four separate dimensions on which the performance of government interventions can be evaluated. These dimensions incorporate microeconomic concerns; macroeconomic concerns; national security concerns; and budgetary concerns. Proposed and existing interventions may look more or less desirable depending on which dimension is used to perform the evaluation. These dimensions are explained below, with some of the critical components described in detail.

Microeconomic concerns

The most important consideration in using a microeconomic framework is whether the resources involved are efficiently allocated. Microeconomic issues often revolve around whether the parties most able to efficiently utilize particular resources have access to those resources. In general, this means that the parties placing the highest value on a resource should be able to obtain it and put it to its best use. For instance, the owners of a natural resource should be able to exploit it using the most productive technology or to freely transfer ownership interests to others. Policies that interfere with the efficient allocation of resources are generally undesirable.

In the case of oil and gas properties, production decisions should be made on a cost/benefit basis, with the costs and benefits ideally being the complete social costs and benefits of production (not just the private costs and benefits). Social costs and benefits include both marketed and non-marketed items. These non-marketed items include recreational opportunities, health and safety, and overall environmental quality.

Oil and gas production is different from that of many other goods and services because there is an implicit time element involved. That is, present production of an amount of oil or gas precludes future production of that same amount. Therefore, current production must be appropriately valued relative to future production. This is generally accomplished by projecting future prices and then discounting future costs and revenues using a market interest rate to place all items on a present value basis. Policies adopted should be those that both pass a cost/benefit test on their own and that do not interfere with the cost/benefit analysis used by private parties for making their efficient production decisions.

One indication of there being sufficiently profitable opportunities in an industry (either now or in the future) is the flow of private capital into that industry. When market participants view the prospects for an industry as being favorable, the market response is generally to bid up the price of assets in the industry (e.g., to increase the price of share of corporations in the industry) or to provide capital to new ventures in the industry (e.g., to support new issues of stock). When markets work reasonably well (including adequate information flow to potential investors), the test provided by capital flows is generally a good, though indirect, way to determine market expectations for the industry. Desirable policies generally would not unduly interfere with the decisions of capital market participants to move capital to industries with better economic prospects.

Moving capital to its most productive uses is one concern, and its complement is the efficient allocation of labor resources. This is not measured by the flow of workers into an industry (or the stock of workers employed in an industry). Rather, the efficient allocation of labor is a matching process, where the skill levels of workers are matched to the skill needs of firms. Firms may choose to hire workers with the necessary skill levels or else invest in training workers to provide a labor force with the appropriate set of skills. In either case, desirable government policy would ensure that workers can obtain the skills demanded by employers either through basic or job-specific education or training. Similarly, government should try to ensure that workers do not invest in obtaining skills with low future demand.

Macroeconomic Concerns

When evaluating various economic interventions, usual practice holds the macroeconomy fixed. Therefore, unless strong reasons to the contrary are present, individual policy changes are assumed to have no effect on GDP, employment, price levels, interest rates, etc. Only in very rare cases do the policy interventions being considered have such widespread economic effects that it is appropriate to adjust the macroeconomic baseline.

Generally, the United States economy is made better off when energy prices (particularly oil prices) are low. This occurs because the United States is essentially a debtor nation in terms of oil. Consumption of oil in the U.S. substantially exceeds domestic production. The domestic economy requires oil imports, and pays for this need by issuing claims on U.S. goods and services. When the price of oil declines, the size of the claim on U.S. goods and services by oil-exporting nations also declines. This is exactly the same effect that an interest rate decline has for borrowers.

The recent decline in oil prices has had a positive effect on the entire United States economy. Macroeconomic models indicate that a drop in the world oil price from $20 per barrel to $15 per barrel would: increase real GDP growth in the U.S. by 0.3 - 0.5 percent annually; reduce domestic inflation by about 0.8 percentage points in the first year after the price drop occurs; and reduce the U.S. unemployment rate by about 0.5 percentage points or more (over 500,000 jobs). A price rise of similar magnitude would have effects of approximately the same size (though in the opposite direction).

Of course, the generally positive national economic effects mask significant regional variation. In areas that are dependent on oil production, low prices can result in substantially reduced economic activity. However, recent economic development activities have generally succeeded in diversifying local economies in many areas of the country, including those characterized by production of natural resources (including oil). This diversification reduces the regional economic impact of changed oil prices, but does not eliminate it entirely.

Finally, the international trade position of the nation may be affected by various policy interventions. In these cases, the general presumption is that interventions which inhibit free and voluntary trade have the effect of reducing worldwide (and domestic) welfare levels. Moreover, policy interventions placing constraints on trade flows may have ancillary effects if they impinge on the credibility of the United States to live up to its trade commitments and discredit its free trade rhetoric.

Security Concerns

In general, national security concerns focus on the threat of supply disruptions for necessary goods. Such disruptions can be either temporary or permanent. These disruptions often cannot be insured against using conventional means, because the potential disruption would affect all trading partners or because the disruption would be used strategically to cause maximum harm.

In these cases, the cost of disruption may exceed the nominal reduction in trade flows, because the disruption affects the Nation's ability to provide for its defense. The threat of disruption in certain commodities, then, can result in a social premium being put on these commodities. That is, reliable supplies (e.g., domestic production) may have a social value that exceeds the market price (which is set in world markets, including those suppliers who threaten market disruption).

In the case of oil and natural gas, the threat of supply disruption has been carried through on a few occasions. Since supply of oil is concentrated in a relatively few countries, it is possible for these suppliers to act in concert and reduce aggregate supply (or supply to certain nations) by large enough quantities to affect overall levels of economic activity. Given this threat, it is possible to assign a premium to domestic production (and production of trusted allies) of oil. However, if the potential level of domestic production (from current wells and from storage), along with the production of allies, is sufficiently large to meet domestic demands for the likely period of disruption, then the premium associated with domestic production is likely to be very small (and may actually be zero).

Budgetary Concerns

The budget implications of government interventions are important in computing the "cost" elements for the cost/benefit computations described in the section on microeconomic concerns. But there are other implications, as well. Under current budget rules, all initiatives must be "paid for" before they are enacted into law (this is called the PAYGO requirement). Budgetary outlays are divided into two groups: discretionary and mandatory spending. Total discretionary spending is subject to an annual cap, limiting it to a specified nominal amount. Additional discretionary spending must be "paid for" with reductions in other discretionary spending. Mandatory spending is not subject to specific spending caps. However, any increase in mandatory spending must be offset with either a decrease in some other form of mandatory spending or an increase in revenues (generally either raising a tax explicitly or else reducing the size of a tax expenditure). Congressional budget figures determine if legislation complies with the budget rules. Therefore, the Congressional Budget Office and the Joint Committee on Taxation (for tax proposals) are responsible for calculating the budgetary effects of legislative proposals. It is important to note that these budget rules apply only to legislative initiatives. If administrative discretion is utilized, the results of the action are not counted for purposes of meeting the budget rules.

In the case of natural gas and oil production incentives, industry preference is to provide these through the Tax Code.

Therefore, any legislative proposal to reduce the tax burden on gas and oil producers would have to be accompanied by offsetting revenue raising proposals. These could be: increased general taxes; reduced tax expenditures (either in the gas and oil industry or elsewhere); or reduced mandatory spending (e.g., entitlement reduction).

MEMORANDUM

ROUGH DRAFT

Date: July 22, 1993

From: Bill White

To: Sue Tierney
Jack Siegel
Len Coburn
Don Juckett
Kyle Simpson

Subject: Thoughts on Domestic Energy Initiative

In preparation for the meeting that we are having next week to narrow the options, I am writing to outline some ideas that most intrigue me concerning the Domestic Energy Initiative. This is not exhaustive.

1. Advanced seismology research designed to increase the probabilities of finding gas by at least 10 percent within 5 years.

2. Peril point legislation authorizing the Secretary of Energy to implement several direct import-restriction strategies if imports of crude and refined products remained over 50 percent for a period of 12 months or more. The actions could be subject to a legislative veto within 90 days. Build this on Senator Bentsen's Bill.

3. Requiring a contribution to the Strategic Petroleum Reserve for importers who refined more than 300,000 to 500,000 barrels per day of oil (imported oil?). The contribution, or payment in lieu of contribution, would be made based on a very small percentage of the oil imported. The Secretary of Treasury would immediately sell futures contracts expiring in the year 2000 for half or more of the oil. The revenue from the sale of futures contracts would be used to fund an annual program of tax incentives spread between marginal oil production and new exploratory drilling.

4. An announcement by the Secretary of Energy that it is the energy policy of the United States that various state utility commissions should not second-guess the prudency of long-term gas contracts.

5. An advisory group shall be created based on nominations from the EPA, Secretary of Interior, Department of Energy, and the Department of Justice, to formulate a pilot program for alternative dispute resolution for certain types of

recurring environmental disputes concerning the oil and gas industry. The Committee should be asked to make a recommendation should be due by the end of the year.

6. Some recommendation to facilitate natural gas pipeline construction.

7. A plan to be implemented by the end of 1995 to enhance the transparency and liquidity of gas markets, making them more accessible to small producers. Such a plan would include: (1) more and more reliable market hubs with greater storage; (2) a real time computer network showing current bid and ask price for gas available in the field nationwide, along with current transportation rates; (3) gas storage information; and (4) real time information concerning how product flows and pipeline capacity at any time.

8. I am interested in some recommendation concerning how the OMB might reserve bonus payments for offshore tracts whose drilling has been delayed if not precluded by the moratorium.

9. Something on cogeneration.