DOMESTIC GAS and Oil INITIATIVES

DOMESTIC GAS AND OIL INCENTIVES

PAGE

I. Overview of the Gas & Oil Industry

A: Nature of the Industry

OVERVIEW OF THE OIL AND GAS INDUSTRY

The oil and gas industry has been a vital part of the United States economy for many years. In 1990, nearly $500 billion was spent on energy (8.67% of GDP) and over $300 billion was spent on oil and gas (5.5% of GDP). Over the past few decades, the industry has become increasingly internationalized, with numerous suppliers in many countries competing for market share. The worldwide search for oil and gas deposits has focused on discovering and exploiting the resources that are the 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 resources were often those first exploited, leaving relatively higher cost resources to be developed later. While the production of natural gas and crude oil often take place at the same time and place, it is instructive to examine the long-term production trends for these commodities separately.

The crude oil production industry in the United States is well established. Most of the easily obtained resources already have been or are being developed, consistent with an established natural resource extraction industry. The aggregate production of crude oil in the United States since 1970 has been a long downward trend (though price increases in the 1970's resulted in increased domestic production). Current production is at levels not seen since 1960. The downward trend in domestic production has caused many of the larger oil companies to explore for oil in other countries. Smaller oil producing firms generally do not have the capital nor the technical expertise to explore for oil outside their usual operating territory. Figure 1 indicates the post-war pattern of production of domestic crude oil.

Post-War U.S. Crude Oil Production

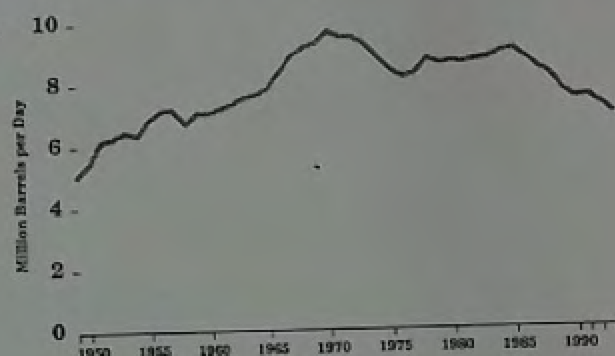


Figure 1

In contrast, the natural gas production industry in the United States still holds significant opportunities for increasing its productive capacity. Production of natural gas has not entered a long-term downward trend. In fact, the natural gas production industry has made major efforts to develop markets for natural gas and to ensure that long-term supply commitments will be fulfilled. In this sense, the industry's concern, in recent years, has not been about wellhead production as much as about ability to deliver natural gas to the ultimate consumer. Through the 1980's the U.S. had an oversupply of natural gas, the so-called "gas bubble." Figure 2 presents the post-war pattern of domestic natural gas production.

Post-War U.S. Natural Gas Production

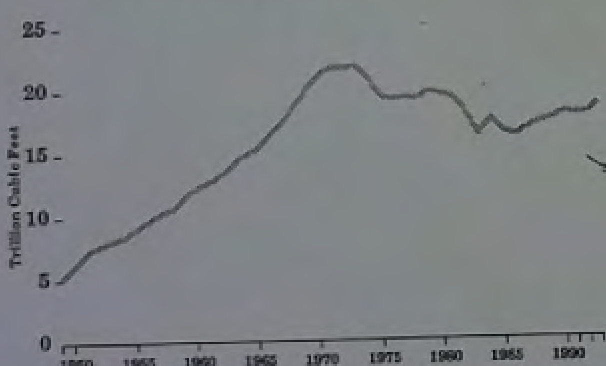


Figure 2

data provided by the Energy Information Administration

In the United States, crude oil and natural gas production take place from wells of many different productive capacities. Moreover, the capacity distribution of the wells is far from uniform. The vast majority of wells produce relatively small amounts of crude oil or natural gas. For instance, of the total 594,000 oil wells in the United States, about 300,000 produce less than 3 barrels of oil per day (over 150,000 of these 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 distribution characterizes natural gas production. Of the nearly 300,000 natural gas wells in the United States, a substantial number produce less than 18 mcf (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 increased substantially over the past half century due to economic growth and 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 fuels (e.g. coal). The trend toward increased consumption of oil and natural gas appears to have slowed in the last decade as more attention has been devoted to developing energy efficient production processes and as consumption patterns have been somewhat modified. In general, the U.S. economy has become more energy efficient. 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.

U.S. Petroleum

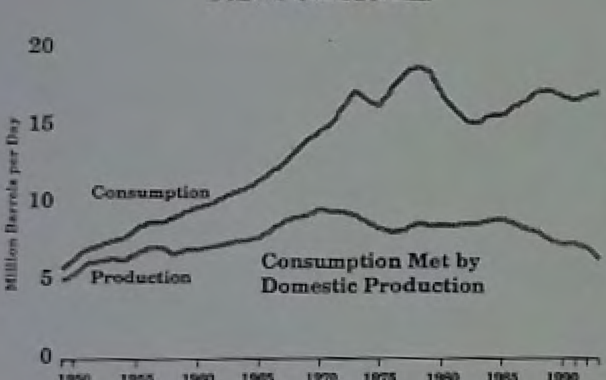


Figure 3A

U.S. Natural Gas

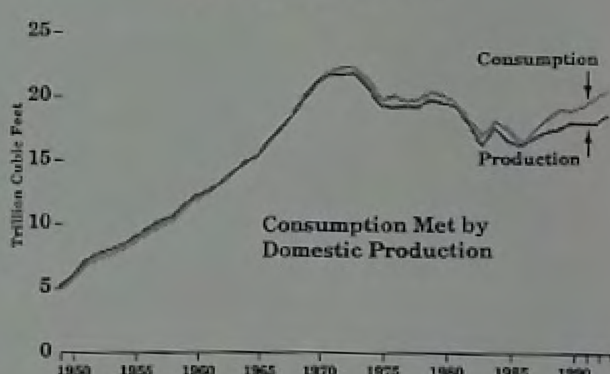


Figure 3B

One obvious trend deducible from Figure 3A is increased reliance on oil imports since 1970. 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 as 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 predetermined. Rather, like all other traded products, these levels are determined by the prices at which the commodities are traded. Many observers have noted that oil imports contribute significantly to the U.S. trade deficit. In 1993, approximately 44 percent of domestic petroleum demand was provided by imports.

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 and fallen dramatically many times. The Department of Energy reports that real prices have fallen 30 percent or more five times since 1910, (with a similar number of price rises). Many of these price shocks have been caused by threats of, or actual, foreign supply disrup-

Pattern of Crude Oil Prices in Real Terms

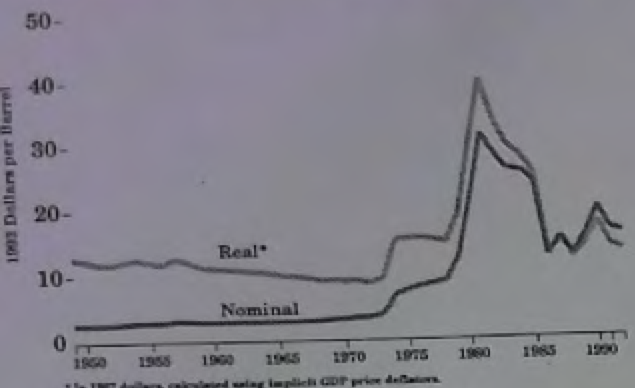


Figure 4: (1993 Dollars)

History of Real Natural Gas Prices

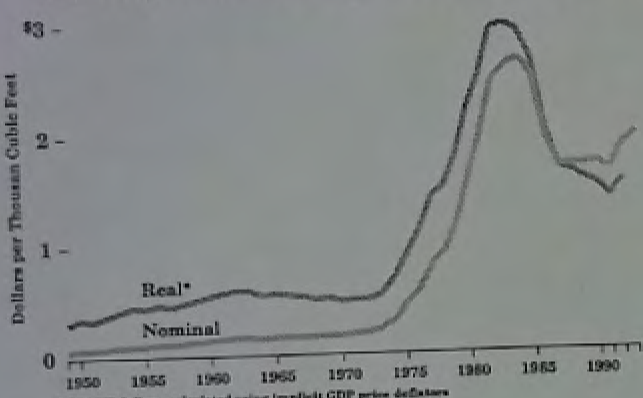


Figure 5

Employment in U.S. Energy Production

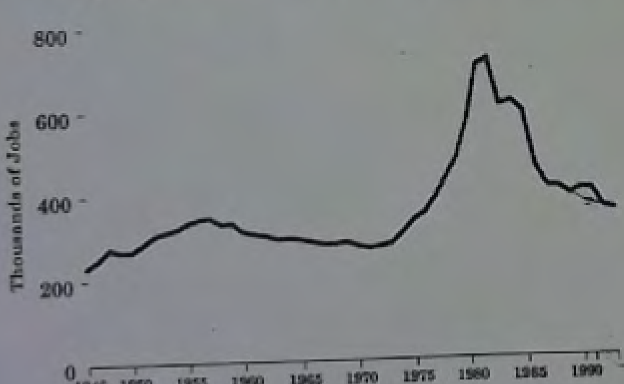


Figure 6

tions. Figure 4 shows the post-war pattern of crude oil prices in real and nominal terms.

Natural gas prices have not exhibited quite as much price volatility as crude oil prices. In part, this reflects the lack of external threats to supply. The bulk of the price volatility represents purely domestic market conditions where supply and demand were imbalanced. Many of the imbalances were caused by government regulation of the natural gas industry, much of which has since been removed. It is also important to recognize that the Fuel Use Act of 1978 also caused a dramatic decline in natural gas use in the early 1980's. That decline combined with the exploration and production stimulus of the Natural Gas Policy Act of 1978 resulted in the "gas bubble." Figure 5 shows the pattern of post-war natural gas prices in real and nominal terms.

Employment in the domestic oil and natural gas industry is related to price and production levels. At higher prices, a constant level of production activity is more profitable, which may lead to increased employment. A larger and more permanent effect on employment, though, will occur through changes in investment, exploration, and production levels. As the long-term trend in domestic crude production has been downward, exploration has declined and employment in the crude oil production industry has been falling. Post war employment in oil and gas extraction peaked at 754,000 in 1982 and has since been nearly halved to 380,000. As shown in Figure 6. This means that 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.

U.S. Natural Gas & Crude Oil Proved Reserves, 1949-1992

Figure 7

Estimates of proved oil and natural gas reserves are attempts to quantify economically recoverable quantities of these energy sources, using current technology. As prices increase, resources that were formerly too expensive to recover may become economically recoverable. Similarly, as technology advances, resources that were not economically recoverable in the past become recoverable at current prices. New discoveries will also add to reserve estimates. Of course, as production occurs, the amount of reserves correspondingly declines, unless new reserves are added to the total. As noted, reserves may be increased by changes in economic conditions, through reservoir development, and new discoveries. 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. Figure 7 shows the changing levels of domestic reserves of oil and natural gas, respectively.

The proved reserve base in the United States is small relative to foreign suppliers of oil and natural gas. The United States has about 2.3 percent of the world's known oil reserves and about 3.4 percent of the world's proved natural gas reserves. Large amounts of the world's reserves in countries other than the United States have been fairly recently discovered or determined to be economically recoverable. Accordingly, the United States share of world proved reserves in oil and natural gas has dropped since the early 1950's. This pattern is consistent with the fact that the United States is a well established producer of oil and natural gas, while other countries have yet to fully exploit their resource base. The U.S. has also prohibited exploration and development in many of its potentially productive resource areas. Figures 8A and 8B show current oil and natural gas reserve bases for the United States and for several other producing countries.

World Crude Oil Reserves, January 1, 1992

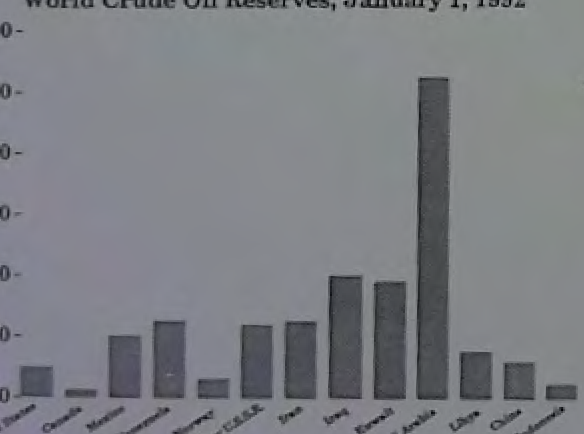


Figure 8A

World Natural Gas Reserves, January 1, 1992

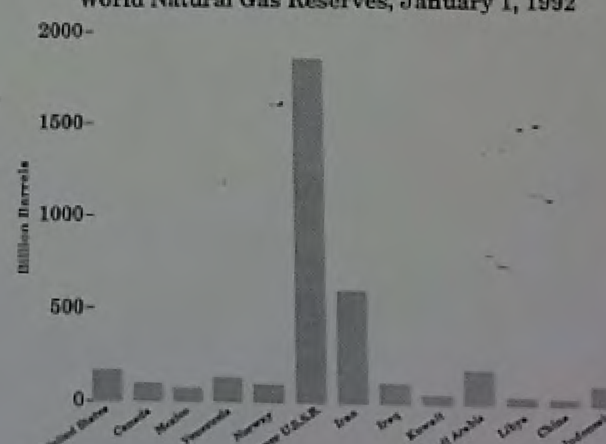


Figure 8B

I. Overview of the Gas & Oil Industry

B. Evaluating Government Policy

EVALUATING POLICIES AFFECTING OIL AND GAS PRODUCTION

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.

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 in part because oil and gas resources are finite depletable deposits which introduces 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. In addition, there is an element of irreversibility in production decisions made in oil and gas production. If a well is abandoned and production ceases, it may be prohibitively expensive to reopen the well and produce from the deposit. Accordingly, the option value of keeping a well producing should be incorporated in determining the present value of future production. Policies adopted should be those that pass a cost/benefit test on their own, where the present values of social benefits exceed the present values of social costs.

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 avoid encouraging workers from investing 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, in part, 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.

In addition, lower energy prices reduce the pressure on prices in other sectors, leading to lower inflation than would otherwise be the case. This boosts the real disposable income of consumers, providing them with the ability to purchase greater quantities of non-oil goods and services. Businesses would generally have lower energy costs, which would increase both cash flow and profit margins, potentially leading to increased investment. To the extent foreign industrial countries experience similar effects, U.S. exports could increase. All these effects would benefit the aggregate domestic economy.

The recent decline in oil prices has had a positive effect on the entire United States economy. Preliminary results from macroeconomic models (looking at the next two years) 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) by mid-1995. A price rise of similar magnitude would have effects of approximately the same size (though in the opposite direction).

If oil prices remain low for a long period of time, domestic oil consumption is likely to be higher than currently forecast. One effect of higher oil consumption levels is increased fossil fuels emissions, especially if increased oil usage displaces energy produced by natural gas or renewable sources. Thus, it is possible for low oil prices to be associated with undesirable environmental outcomes, if the low prices are passed through to energy consumers.

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. In addition, reduced levels of economic activity can place strains on the local banking industry, as happened in the mid-1980s. 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 and the threat of these disruptions may increase with regional instability. 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, 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 allies) of oil. However, if the potential level of domestic production (from current wells and from storage facilities like the Strategic Petroleum Reserve), 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).

Changes in oil markets over the last two decades generally have led the United States and other industrialized nations to adopt policies that are more market-based than those pursued in the past. Chief among these is the decontrol of domestic oil prices. These actions allow oil markets to respond to actual or potential supply disruption through relatively orderly changes in prices, rather than through quantity rationing. In addition, the creation of futures markets in oil and other fuels permits energy users to (at least partially) insulate themselves from the risk of substantial price changes.

One indication of the degree of national security concern for oil supply may be the cost of national defense measures taken to ensure an adequate supply of oil from abroad. However, it is difficult to distinguish the costs of measures taken solely to ensure supply of oil from those taken to meet other national policy goals (e.g., defending allies from aggression). In practice, there is a high degree of overlap in the security goals of the United States and its allies, often making it impossible to allocate costs incurred to individual policy objectives.

It may even be the case that national economic security is enhanced by the ability to tap a diverse set of suppliers of oil. The United States and its allies may find that mutual concerns about dependable oil supplies lead to long-term relationships that improve the prospects for meeting other policy goals.

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 the Budget Enforcement Act (BEA), 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 in determining if a legislative initiative is subject to a point of order. 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

12

administrative discretion is utilized, the results of the action are not counted for purposes of meeting the budget rules.

The Budget Enforcement Act sets annual limits on budget authority and on spending through the annual appropriations acts. If these limits are breached, appropriations are sequestered (reduced proportionally in an across-the-board manner). In addition, aggregate legislated increases in direct spending or reductions in receipts must be offset by decreases in direct spending or increases in receipts on an annual basis. If such offsets are not provided, a sequestration is required under the BEA. The Office of Management and Budget scoring determines whether such a sequester will occur.

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).

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

A: Oil and Gas Tax Incentives

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

---

[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.

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.

---

[2] Amounts disallowed as a result of this rule (65 percent of taxable income) may be carried forward and deducted in subsequent taxable years, subject to the 65-percent taxable income limitation for those years.

16

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 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

---

[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 not been 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 $14.24, 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 production will receive an additional 4 percentage point depletion allowance (to 19 percent); and qualifying 1994 production will receive an additional 5 percentage point depletion allowance (to 20 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),

---

[5]See section above on percentage depletion.

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

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

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

B: Royalty Policies

II. B Royalty Policies

<u>Royalty Rates for Outer Continental Shelf (OCS) Leases</u>

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.

(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.

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.

---

[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.

24

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.

(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 tn application from the operator is required before consideration. Approval of a royalty reduction is in recognition of the lessee demonstrating the needs for the reduction in order to continue successful operations.

<u>Stripper Property Royalty Rate Reduction</u>

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, defined as leases with average daily production of less than 15 barrels of oil per eligible well for the qualifying period). 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.

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.

<u>Royalty Collections</u>

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.

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).

f:\P&P\ELPB\NEC\ROYALTY.POL

28

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.

29

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

C: Import, export and security policies

CURRENT IMPORT, EXPORT, AND SECURITY POLICIES

IMPORT

In 1993 the U.S. relied on oil imports to meet about 49 percent of its gross crude oil needs (about 6.7 million barrels per day). The four largest suppliers of imported crude oil to the U.S. in 1993 were Saudi Arabia (19%), Venezuela (15%), Mexico (13.7%), and Canada (13.4%).

The U.S. imports a small amount of the refined petroleum product supplies it consumes. In 1992 net refined product imports accounted for five percent of U.S. refined product supply. Refined product imports have been declining for the past six years, and have declined over-all from the 1981 level of eight percent. The largest suppliers of U.S. refined product imports are Venezuela, the Virgin Islands, Canada, and Algeria.

U.S. import duties on oil and gas, with the exception of crude oil, are "bound" as a part of U.S. participation in the General Agreement on Tariffs and Trade (GATT). If the U.S. were to raise its import duties on imports of oil and gas products other than crude oil (unless done for national security reasons), countries supplying those products would have the right to ask the U.S. for duty reductions in other products as compensation. If the U.S. and another country could not agree on compensation, the other country could take retaliatory action against U.S. exports to "rebalance" the situation.

There is one qualification to this general rule. Some tariffs on products other than crude and bound subject to the reservation that the duty on that product can **in no event** be lower than the duty on crude oil. Thus, if the U.S. raised the tariff on crude oil to a level exceeding that of the current duty on the refined product, the tariff on those refined products must be raised to a level equal or greater than that on crude.

The U.S. crude oil tariff is **not** bound in the GATT. It could be raised without the compensation problems cited above. However, raising the duty would require Congressional action, unless it were done as a part of a national security action which the President has the authority to implement.

The GATT does not accept that trade restrictive actions which would otherwise be prohibited can be justified for national security purposes. However, a national security justification would be subject to review in the GATT and could be challenged by another country under GATT dispute settlement procedures. If the U.S. lost such a challenge, the U.S. would be subject to retaliation.

Under the North America Free Trade Agreement (NAFTA) the U.S. has additional bilateral commitments with Mexico and Canada. Together these two countries accounted for 27.1 percent of U.S. oil imports in 1993. Under NAFTA the U.S. could not increase tariffs on imports of oil or gas from either of these countries. The U.S. could impose a national security import fee on Mexico subject to the same right of challenge as under the GATT. With respect to Canada, U.S. ability to impose a national security fee is explicitly restricted to situations of armed conflict under NAFTA.

The U.S. has just succeeded in reaching an agreement within the new World Trade Organization (WTO) on a trade and environment work program and establishment of a Trade and Environment Committee, largely over the objections of developing countries. A major concern of the developing countries was that the U.S. objective was to eliminate developing countries' competitive advantage through "eco-dumping" taxes or other instruments. An environmental equalization fee would certainly re-ignite their apprehensions, and probably push them back to an obstructionist posture even before the WTO's work begins.

EXPORTS

Export of crude oil produced in the U.S. is tightly controlled by Federal law. Legal prohibitions on the export of domestic crude oil are included in the Export Administration Act, The Energy Policy and Conservation Act, The Mineral Leasing Act, The Naval Petroleum Reserves Production Act, and the Outer Continental Shelf Lands Act.

All of the statutory prohibitions include provisions allowing the President, or his designee, to approve export of domestically produced crude oil if export is found to be in the national interest. There have only been three national interest findings resulting in export of domestically produced oil. Since 1985, crude oil produced in the lower forty-eight states has been exported to Canada. Since 1989 under the terms of the U.S.-Canadian Free Trade Agreement 50,000 barrels per day of Alaskan north slope crude oil has been exported. Additionally, crude oil produced from fields under Alaska's Cook Inlet State waters has been exported to Pacific Rim countries since 1985. Under these exemptions the U.S. exports about 89,000 barrels of crude oil per day.

SECURITY

In order to enhance energy security, the U.S. works with partners in the International Energy Agency (IEA) to coordinate policies to reduce the risk of supply disruptions, such as increasing energy efficiency and planning for coordinated use of strategic oil stocks in a crisis. The U.S. seeks cooperative ties with moderate oil producers in the Persian Gulf, who are critical to meeting global oil needs. In order to expand the availability of oil, the U.S. promotes international efforts to remove barriers to energy trade and investment, as well as increased access for U.S. firms.

The ability of the U.S. to respond to disruptions of imported oil supplies has been strengthened over the past decade by an increasing ability to substitute other fuels for oil, increased emphasis on energy efficiency, development of financial instruments, including a crude oil futures market, that allow consumers the opportunity to hedge price risk, and strategic oil stock building.

Strategic Petroleum Reserve

The U.S. maintains the world's largest strategic stockpile of crude oil. The Strategic Petroleum Reserve (SPR) currently holds about 590 million barrels of oil; enough oil to provide ten months protection against disruption of all Arab OPEC oil imports. The SPR is a deterrent to potential oil supply disruptions and an effective instrument in minimizing damage to the economy if a disruption occurs.

The current SPR affords adequate strategic protection under the most likely disruption scenarios. Publicly held SPR stocks provide eighty days protection against complete disruption of all U.S. imports. When privately held stocks are included, the U.S. has two hundred and six days of protection from complete disruption of imported oil. Consequently, the U.S. surpasses international commitments to hold public and private stocks providing ninety days protection against complete loss of oil imports. Strategic oil stocks are also maintained by Germany (205 million barrels), and Japan (233 million barrels).

Proposed Import, Export, Security Policies

Trade Expansion Act Section 232 Investigation

The Trade Expansion Act of 1962 authorizes the President, upon petition, to impose import restrictions on products that threaten to impair national security. On March 11, 1994, the Department of Commerce received a petition from a group of domestic oil producers seeking an investigation of whether or not oil imports threaten to impair national security. The Secretary of Commerce, in consultation with the Department of Defense, must conduct an investigation and make a recommendation to the President for action or inaction within 270 days. The President has ninety days to determine what measures, if any, need to be implemented to adjust petroleum product imports.

Since 1973 there have been five crude oil and/or refined product Section 232 investigations. All of these investigations have resulted in findings that oil imports threaten to impair the national security. Remedies imposed included no action, import fees, and embargo of Libyan and Iranian oil.

The Trade Expansion Act specifies criteria the Department of Commerce must review during a Section 232 investigation. These criteria include:

o Domestic production needed to meet projected national defense requirements.

o The capacity of domestic industries to meet such requirements.

o The availability of human resources, products, and raw materials essential to national defense.

o The requirements of growth of such industries including investment necessary to assure such growth.

o The quantity, availability, and character of imports and their effect on U.S. capacity to meet national defense requirements.

Prohibition on Export of Alaskan North Slope Crude Oil

The export of Alaskan North Slope crude oil is prohibited in several laws including the Mineral Lands Leasing Act and the Export Administration Act. As part of the Domestic Natural Gas and Oil Initiative the Administration is studying lifting the current ban on export of crude oil from the north slope of Alaska. Lifting the ban would increase the demand for U.S. oil. The export ban creates jobs on U.S. flagged ships involved in transporting oil from Alaska to the West coast. If Alaskan north slope crude oil was exported on foreign flagged ships, the maritime industry would probably oppose lifting the ban. The Administration study should be completed by May.

California Heavy Crude Export Licenses

The Department of Commerce is proposing to exempt from export restrictions 25,000 barrels per day of California heavy crude oil. The Department published proposed licensing procedures on March 24, 1994. The public comment period ends on April 25, 1994.

Strategic Petroleum Reserve

The President's FY 1995 Budget proposes no new oil acquisition for the Strategic Petroleum Reserve (SPR), through 1999. Instead, the Budget proposes using oil acquisition balances to fund higher priority activities including fossil energy research and development, SPR facilities maintenance, corrective actions, and extension of the lifetime of the SPR facilities.

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

D: Regulatory policies

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 and broadened the revenue sources. 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. The Omnibus Budget Reconciliation Act (OBRA) of 1990 provided for an additional $5.1 billion and reauthorized the program for four years. OBRA also extended Superfund's tax authorities through December 31, 1995.

Water and Wetlands: The Federal Water Pollution Control Act of 1972 as amended by the Water Quality Act of 1987, commonly known as the Clean Water Act (CWA), 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 technology-based waste water treatment standards, provides for capitalization grants for state revolving funds which provide loans for construction of municipal waste treatment facilities and other water quality projects. The CWA also addresses special issues like toxic wastes and oil spills. The effluent

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 and broadened the revenue sources. 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. The Omnibus Budget Reconciliation Act (OBRA) of 1990 provided for an additional $5.1 billion and reauthorized the program for four years. OBRA also extended Superfund's tax authorities through December 31, 1995.

Water and Wetlands: The Federal Water Pollution Control Act of 1972 as amended by the Water Quality Act of 1987, commonly known as the Clean Water Act (CWA), 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 technology-based waste water treatment standards, provides for capitalization grants for state revolving funds which provide loans for construction of municipal waste treatment facilities and other water quality projects. The CWA also addresses special issues like toxic wastes and oil spills. The effluent

Ge

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 exploration and production (E&P), refining and processing, and transport often affect wetlands. Currently 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. Army Corps of Engineers jointly administer wetlands programs.

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 has proposed guidance specifying 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 gallon. 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, enhanced 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. The current policy is to use the time available to address concerns with existing leases before consideration of any new leasing within moratoria areas.

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

E. Direct Expenditures

II. E. DIRECT EXPENDITURES

The Strategic Petroleum Reserve stored about 590 million barrels of oil by the end of 1993. Assuming a cost of $18 per barrel, this reserve required an expenditure of over $10 billion between 1977 and 1993. 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 $3.2 billion over 5 years assuming an interest cost of 6 percent to the Treasury). The President's FY 1995 Budget proposes no additional crude oil acquisitions, and funds facility operation and maintenance at $244 million.

The low income housing energy assistance program, administered by the Department of Health and Human Services, and funded at $1.4 billion in FY 1994, was the largest direct federal subsidy for oil and gas products. In FY 1995, the President's Budget requests $730 million for this program.

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.

III. Current Proposals Involving Gas & Oil

A. Tax Proposals

III. A. Tax Proposals

Oil and Gas Marginal Production Tax Credits

1. Proposal

The current proposal provides for a $3 per barrel tax credit for the first 3 barrels of daily production from 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 ($3 per barrel tax credit for the first 3 barrels of oil equivalent).

For purposes of this credit, the proposal also expands the current definition of marginal oil wells for tax purposes (wells producing up to 15 barrels of oil per day plus "heavy" oil producers) to include a new category for "high water cut property" – property producing 25 barrels of oil per day or less per well, with produced water accounting for 95 percent of total production. In addition, the definition of marginal wells is also expanded for purposes of the credit to include injection and water disposal wells (non-producing wells) in the calculation of the average production per well in determining whether a property qualifies as marginal.

The tax credit is phased out ratably as prices rise between $14 and $20 per barrel of oil and between $2.49 and $3.55 per mcf of natural gas. Both the amount of the credit and the phase-out prices are indexed for inflation. The credit can be used against the alternative minimum tax and can be carried forward and back, but is not refundable.

This tax credit is nominally available to operating interests only (not royalty interests), but the portion of the tax credit that would have been attributable to the royalty interests will be made available to the operating interests.

2. Existing policy baseline

Tax credits are available under current law for certain "enhanced oil recovery" expenditures. Credits are also available through the year 2002 for the production of qualified non-conventional fuels from wells drilled before 1993 and after 1979. In addition, higher rates of percentage depletion are allowed for marginal oil and gas wells during periods of low oil prices. See the description of current law oil and gas tax incentives.

The DOE Domestic Natural Gas and Oil Initiative calls for the National Petroleum Council (NPC) to review the costs and benefits of tax incentives for maintaining production from marginal and stripper wells. DOE, Treasury, and DOI are providing staff assistance to the NPC. The study is expected to be completed in June 1994.

3. Possible variations

To reduce revenue costs, the level of the credit could be restricted to marginal production as defined in current tax law (or to a more limited group of producers identified as in the greatest danger of well abandonment), reduced from $3 per barrel, become effective at a later date, or terminate at lower price levels or as of a specific date; other restrictions could be placed on the availability of the credit, such as eliminating or reducing the offset against the alternative minimum tax.

4. Pros and cons of proposal

Pros

- Encourages some production that would not take place without the credit and forestalls shut in or abandonment of existing wells.
- Maintains domestic production and access to the resources associated with those wells for future technology advances.
- Decreases the need for additional oil imports in the future.
- Prevents some employment loss in the oil and gas industry.
- Delays and perhaps avoids potential costs to State and Federal governments to plug idle wells that have been deserted by owners.
- Provides additional supplies of natural gas to meet the Administration's goal of 24 tcf by 2010.

Cons

- Results in a significant revenue cost based on the amount of production that will qualify and the size of the credit.
- Provides windfall gains to the industry on oil and gas that would have been produced without the credit.
- Leads to the production of oil and gas that cannot be economically produced at expected market oil and gas price levels, because before-tax losses on some marginal properties can be compensated by the tax benefit of an additional credit.
- Provides an additional tax credit for those wells utilizing enhanced oil recovery methods.

- Provides benefits to over 80 percent of U.S. oil wells -- far more than are economically marginal.
- Provides windfall gains to natural gas. Unlike crude oil prices, natural gas prices are at their highest levels since 1985.

5. Legislative outlook

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

6. Costs to Federal budget

Preliminary Revenue Estimates
($millions)
Calendar-year liabilities

	5-year	10-year
Oil[1]	-3,400	-7,430
Gas[2]	-1,580	-3,370

7. Other impacts

Additional production: 123 MMBOE oil (10 years) (DOE)
47 MMBOE gas (10 years) (DOE)

Additional reserves: 500 MMBOE oil (10 years) (DOE)
191 MMBOE gas (10 years) (DOE)

*Federal revenue cost per additional barrel produced: $ oil (10 years)
$ gas (10 years)

***NOTE:** At present, revenue estimates are based on Treasury production and energy price

---

[1]Based on incomplete data. To be revised. Estimate does not include high-water cut properties or injection and water disposal wells.

[2]Based on incomplete and obsolete data, including gas well-size distribution data. To be revised, including DOE current well-size distributions. Estimate does not include high-water cut properties or injection and water disposal wells. Phase out of the credit is assumed not to take effect based on current gas prices.

47

data, while additional production and reserves are based on DOE models using DOE energy price forecasts. These may not be consistent. One cannot reliably divide the revenue cost by additional barrels of production to obtain a Federal revenue cost per additional barrel.

III. A. Tax Proposals

Oil and Gas New Production Tax Credits

1. Proposal

The current proposal provides for a $3 per barrel tax credit for the first 15 barrels of daily production for new oil wells and a $0.50 per mcf tax credit for the first 300 mcf per day for new gas wells ($3 per barrel tax credit for the first 50 barrels of oil equivalent). In each case, new wells are defined as those drilled after May 31, 1994.

The tax credit is phased out in equal increments as prices rise between $14 and $20 per barrel of oil and between $2.49 and $3.55 per mcf of natural gas. Credit and phase-out prices are indexed for inflation. The credit can be used against the alternative minimum tax and can be carried forward and back, but is not refundable.

The tax credit is available to operating interests only (not royalty interests), but the portion of the tax credit that would have been attributable to the royalty interests will be available to the operating interests.

2. Existing policy baseline

No oil or gas credits are generally available on primary production of regular oil and gas from newly-drilled wells. Credits are available through the year 2002 for the production of qualified non-conventional fuels from wells drilled before 1993 and after 1979. In addition, tax credits are available for certain enhanced oil recovery expenditures.

New wells currently receive percentage depletion, expensing of intangible drilling and development costs, and other incentives. See the description of current law oil and gas tax incentives.

3. Possible variations

To reduce revenue costs the level of the credit could be restricted to a lower quantity of daily production (or the quantity of qualifying gas could be limited to the equivalent of that for oil) and to production from operating interests only (rather than total production), reduced from $3 per barrel, restricted to wells producing less than a specified quantity of oil or gas, become effective at a later date, or terminate at lower price levels or as of a specific date; other restrictions could be placed on the availability of the credit, such as reducing or eliminating the offset against the alternative minimum tax.

4. Pros and cons of proposal

Pros

- Stimulates new drilling, increasing production.
- Encourages some production that would not take place without the credit.
- Decreases the need for additional oil imports in the future.
- Prevents some employment loss in the oil and gas industry.
- Provides additional supplies of natural gas to meet the Administration's goal of 24 tcf by 2010.

Cons

- Results in a significant revenue cost based on the amount of production that will qualify and the size of the credit.
- Provides windfall gains to the industry on oil and gas that would have been produced without the credit.
- Provides no incentive for additional production from wells with production over 15 barrels of oil per day or 300 mcf of gas per day, despite the revenue cost for these wells.
- Provides windfall gains to natural gas. Unlike crude oil prices, natural gas prices are at their highest levels since 1985.
- If combined with the Breaux deep-water production credit, as currently drafted, provides a total credit of $8 per equivalent barrel of oil to new OCS production from wells drilled after May 31, 1994. (The Congressional proposal may preclude the use of both credits.)

5. Legislative outlook

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

6. Costs to Federal budget

Preliminary Revenue Estimates
($millions)
Calendar-year liabilities

	5-year	10-year
Oil[1]	-820	-2,240
Gas[2]	-770	-2,690

7. Other impacts

Additional production: 412 Oil MMBOE (10 years) (DOE)
247 Gas MMBOE (10 years) (DOE)

Additional reserves: 885 Oil MMBOE (10 years) (DOE)
1,453 Gas MMBOE (10 years) (DOE)

*Federal revenue cost per additional barrel produced: $ oil (10 years)
$ gas (10 years)

*__NOTE:__ At present, revenue estimates are based on Treasury production and energy price data, while additional production and reserves are based on DOE models using DOE energy price forecasts. These may not be consistent. One cannot reliably divide the revenue cost by additional barrels of production to obtain a Federal revenue cost per additional barrel.

---

[1]Based on incomplete and obsolete data. To be revised, including DOE/IPAA estimated well-size distributions and expected production data.

[2]Based on incomplete and obsolete data. To be revised based on current DOE/IPAA estimates of new production by well size. Phase out of the credit between $2.49 and $3.55 per MCF indexed for inflation is assumed not to take effect based on current gas prices.

III. A. Tax Proposals

Elimination of Limitations on Deduction of Percentage Depletion

1. Proposal

The current proposal provides for (1) the elimination of the net income limitation on percentage depletion (100 percent of net income from the property, determined on a property-by-property basis); (2) the elimination of the taxable income limitation on percentage depletion (65 percent of taxable income from all sources); and (3) the elimination of the barrel-per-day limitation on percentage depletion (1,000 barrels per day per company).

2. Existing policy baseline

Percentage depletion, available only to independent (i.e., non-integrated) producers, is a deduction from taxable income of 15 percent of oil and gas revenue. (Integrated companies must use cost depletion.) Percentage depletion is limited to 365,000 barrels per year per taxpayer, may not exceed 100 percent of the net income from any property in any year, and may not exceed 65 percent of the taxpayer's overall taxable income. (Amounts disallowed as a result of the 65 percent limitation may be carried forward and deducted in subsequent taxable years, subject to the 65-percent taxable income limitation for those years.) The percentage depletion 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.

Stripper wells (15 barrels per day) and heavy oil wells are allowed an additional percentage depletion allowance on oil and gas produced, equal to one percentage point for each whole dollar when the price falls below $20 per barrel in the preceding year, up to a 25 percent maximum. Qualifying 1992 production received an 18 percent depletion allowance; qualifying 1993 production will receive a 19 percent depletion allowance; and qualifying 1994 production will receive a 20 percent depletion allowance.

See the description of current law oil and gas tax incentives.

3. Possible variations

To reduce revenue costs: (1) the additional percentage depletion could be restricted to marginal production; (2) rather than complete elimination, the 100-percent net-income limitation could be applied to all oil and gas production (rather than property-by-property); (3) additional percentage depletion could be phased out as oil prices rise; or (4) a subset of proposed eliminated provisions could be chosen (e.g., the 1,000 barrels per day cap could be maintained).

4. Pros and cons of proposal

Pros

- Provides an additional incentive to produce from marginal wells.
- Decreases the need for additional oil imports in the future.
- Prevents some employment loss in the oil and gas industry.
- Allows percentage depletion to be used for production from properties without taxable income (when properties with taxable income are held), thereby expanding the use of percentage depletion.
- Delays and perhaps avoids potential costs to State and Federal governments to plug idle wells that have been deserted by owners.

Cons

- Results in a significant revenue cost based on the amount of production that will qualify and on taxpayer's ability to shelter non-oil and gas-production income due to offsets of the increased depletion allowance against <u>all</u> other sources of income. (The Congressional proposal may be limited to avoid sheltering non-oil and gas income.)
- Removal of the barrel-per-day limitation benefits only a few of the larger independent producers, and about 0.6 percent of all domestic oil and gas production.
- Leads to the production of oil and gas that cannot be economically produced at expected oil and gas price levels, because before-tax losses on some marginal properties can be compensated by the tax benefit of an additional percentage depletion allowance.
- Allows taxpayers to "zero out" their total tax liability.

5. Legislative outlook

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

6. Costs to Federal budget

Preliminary Revenue Estimates
($millions)
Calendar-year liabilities

Elimination of net income and taxable income limitations:

5-year	10-year
[TBD] (Tres)	[TBD] (Tres)

Elimination of barrel limitation:

5-year	10-year
-510	[TBD] (Tres)

7. Other impacts

Elimination of net income and taxable income limitations:

Additional production: [TBD] (DOE)

Additional reserves: [TBD] (DOE)

Federal revenue cost per additional barrel produced: [TBD] (Tres.)

Elimination of barrel limitation:

Additional production: [TBD] (DOE)

Additional reserves: [TBD] (DOE)

Federal revenue cost per additional barrel produced: [TBD] (Tres.)

III. A. Tax Proposals

Expensing of Geological and Geophysical Expenditures

1. Proposal

The current proposal provides for the immediate expensing of all geological and geophysical (G&G) expenditures. G&G expenditures include the costs incurred for geologists, seismic surveys, gravity meter surveys, magnetic surveys, and (perhaps) the drilling of core holes.

2. Existing policy baseline

G&G expenditures are "expensed" for tax purposes when oil or gas is not found, and are amortized over the life of the field when oil or gas is located.

This treatment sometimes causes disputes between the IRS and the taxpayer in the determination of when expensing is allowed. Generally, expenditures attributable to an area of interest may be expensed when no oil or gas is found in the area, and a decision is made to terminate interest in the area. Taxpayers can increase the proportion of G&G that can be expensed by increasing the proportion of G&G attributable to areas of interest that are abandoned. See the description of current law oil and gas tax incentives.

The DOE Domestic Natural Gas and Oil Initiative calls for DOE and Treasury to review the tax treatment of G&G expenditures, and, in particular, the potential to provide incentives for the use of certain advanced exploration and production techniques, such as 3-D seismic geologic mapping. The study of this issue is scheduled to be completed in May 1994.

3. Possible variations

Revenue-neutral proposals could provide for a write-off of all G&G over a fixed period, achieving administrative simplicity; or provide a write off successful G&G over a fixed period and continue current law treatment for "dry holes". Revenue losing proposals could provide for shorter write-off periods from the revenue-neutral periods. Other possibilities for change involve accelerated write-off schedules for certain high technology G&G expenditures.

4. Pros and cons of proposal

Pros

- Encourages the exploration and finding (rather than production) of oil and gas, adding to the domestic reserve base.
- Provides administrative simplicity and reduces disputes between taxpayers and the IRS.
- For independent oil companies, that can expense intangible drilling and development costs, provides equal incentives for exploration and drilling.
- Prevents some employment loss in the oil and gas industry.

Cons

- Results in a significant revenue cost.
- Results in negligible increases in domestic oil and gas production.

5. Legislative outlook

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

6. Costs to Federal budget

Preliminary Revenue Estimates
($millions)
Calendar-year liabilities

5-year	10-year
-440	-460

7. Other impacts

Additional production:	negligible (5 or 10 years) (DOE)
Additional reserves:	230 MMBOE (5 years) (DOE)
	[TBD] (10 years) (DOE)

III. A. Tax Proposals

Deep-water Oil and Gas Production Tax Credits

1. Proposal

The proposal (S.403, introduced by Senator Breaux) provides a $5 credit per barrel of qualifying oil or energy equivalent amount of gas produced after 1995 from properties that did not produce commercial quantities of oil or gas before 1993. To qualify, domestic crude oil or domestic natural gas must be produced from a property, a portion of which is located under at least 400 meters of water. The credit can be used against the alternative minimum tax and can be carried forward but may not be carried back (to reduce taxable income in previous years).

2. Existing policy baseline

No oil or gas credits are generally available on new primary production of regular oil and gas. Credits are available through the year 2002 for the production of qualified non-conventional fuels from wells drilled before 1993 and after 1979. Tax credits are available for certain enhanced oil recovery expenditures.

See the description of current law oil and gas tax incentives.

3. Possible variations

To reduce revenue costs, the level of the credit could be restricted to marginal production (not economic at current prices), reduced from $5 per barrel, phased out as oil prices rise, become effective at a later date, or terminate as of a specific date; other restrictions could be placed on the availability of the credit, such as eliminating the offset against the alternative minimum tax.

4. Pros and cons of proposal

Pros

- Encourages production in areas of the OCS that would not have been produced without the credit. Deep water portions of the Gulf of Mexico represent one of the most promising exploration targets within the United States.
- Decreases 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.
- Prevents some employment loss in the oil and gas industry.

Cons

- Results in a significant revenue cost based on the amount of production that will qualify and the size of the credit.

- Leads to the production of oil and gas that cannot be economically produced at expected oil and gas price levels, because before-tax losses on some marginal properties can be compensated by the tax benefit of an additional credit.

- Provides windfall gains to the industry on oil and gas that would have been produced without the credit. Companies have been and are actively conducting deep-water exploration and development without the credit.

- Provides windfall gains to natural gas which comprises a substantial portion of the OCS reserves. Unlike crude oil prices, natural gas prices are at their highest levels since 1985.

- If combined with the Boren/Brewster new-well production credit, as currently drafted, provides a total credit of $8 per equivalent barrel of oil to new OCS production from wells drilled after May 31, 1994. (The Congressional proposal may preclude the use of both credits.)

- Provides an incentive to postpone development of discovered economic reserves until the credit is available.

5. Legislative outlook

The proposal has been referred to the Senate Finance Committee.

6. Costs to Federal budget

Preliminary Revenue Estimates[1]
($millions)
Calendar-year liabilities

5-year	10-year
-1,170	-4,940

[1]Based on MMS production data.

58

7. Other impacts

*Additional production: 240 MMBOE (10 years) (MMS)

Federal revenue cost per additional barrel produced: $21 (10 years)

*Based on MMS estimates that DOE believes are conservative due to lack of full knowledge of geology and potential reserves.

III. Current Proposals Involving Gas & Oil

B. Royalty Proposals

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 exceed 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

a. Microeconomic Considerations

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 increased values of remaining prospects, and in turn, higher future leasing and development.

Royalty relief represents a transfer of social benefits to the private companies. This should result in improved project economics and a greater level of private investment. Social benefits will decline to the extent that production occurs prematurely, but it will increase to the extent that the current royalty rate is larger than optimal, thereby inhibiting socially valuable investment.

---

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

The allocation of capital and labor will be efficient to the extent that the timing of resource development is efficient. 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. Macroeconomic considerations

- Incremental production helps to reduce the prices of oil and gas, though only slightly. The incremental production expected from this proposal is too small to have a discernible effect on prices.

- The oil and gas industry is a major component of the Gulf coast economy. Policies that lead to increased investment in the Gulf of Mexico OCS will result in greater economic activity within the region.

- The proposal will not inhibit free trade.

c. 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]. The analysis discussed below estimates that as much as 150 million barrels of oil equivalent (mm BOE) may be produced over the life of the analyzed fields.

An additional concern is the ability to maintain the infrastructure and skilled-labor pool 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.

d. 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.

---

[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.

- 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. However, the budget rules require that any proposal be revenue neutral in each year of the planning period (five years for Administration proposals, ten years in the Senate). Estimated "pay-go" effects are provided in section 7.

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. Recent experience with royalty rate reduction applications suggests that a complete analysis of an application takes a two-person team two to three months to conduct.

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:

  - basing the royalty suspension on production or revenues rather than on capital costs. The amount of production or revenues exempt from production could be established in advance, with several amounts corresponding to different water depths, could be established on a case-by-case basis, or could be based on a hybrid of these two approaches.

  - 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.

- In order to reduce the costs associated with granting relief to any existing leases that may already be economic, the royalty rate could increase to a level 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. At the discount rates used by industry, the higher royalty rate should have little detrimental effect on the initial investment decision. 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 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.

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.

6. Legislative Outlook

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

[illegible] [illegible]e difference between the market value and costs of production, [illegible] dollars.

7. Costs

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.

The case-by-case analysis may require additional resources. Recent experience with royalty rate reduction applications suggests that a complete analysis of an application takes a two-person team two to three months to conduct.

f:\P&P\ELPB\NEC\DW1.NEC

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 considering 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, revenue amount, production volume, or until capital costs are recovered.

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

- *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

a. Microeconomic Considerations

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.

Royalty relief represents a transfer of social benefits to the private companies. This should result in improved project economics and a greater level of private investment. Social benefits will decline to the extent that production occurs prematurely, but it will increase to the extent that the current royalty rate is larger than optimal, thereby inhibiting socially valuable production.

The evolution of industry activity in the Gulf of Mexico, including a long history of leasing, declining field sizes, and movement into deeper waters, has led MMS to reevaluate its leasing policies. 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. In deeper waters, industry confronts economic and technological challenges which may hinder development. Most forecasters expect oil prices to remain relatively stable for the foreseeable future, so many of these 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. Macroeconomic Considerations

- Incremental production helps to reduce the prices of oil and gas, though only slightly. The incremental production expected from this proposal is too small to have a discernible effect on prices.

- The oil and gas industry is a major component of the Gulf coast economy. Policies that lead to increased investment in the Gulf of Mexico OCS will result in greater economic activity within the region.

- The proposal will not inhibit free trade.

c. 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[1].

d. 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.

---

[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.

- New leases offered with attractive royalty terms will receive higher bonus bids, and more tracts will receive bids.

- Royalties will be reduced to the extent royalty rates are lower on production that would have occurred without relief.

A secondary budget consideration is the administrative burden that may be created by expanding the scope of royalty reductions for existing leases. Careful processing of requests for relief is essential to ensure that relief is granted only to production that would not otherwise occur. Failure to so limit relief could generate substantial revenue losses. In this era of government down-sizing, policies that require a substantial new workload may be difficult to implement without additional budget resources.

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

Gulf of Mexico leases in less than 400 meters of water currently have royalty rates of 16.67 percent; leases in at least 400 meters of water have royalty rates of 12.5 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:

- extend the life of mature fields; and

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

In all cases, the basis for royalty rate reductions is 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."

<u>4. Possible Variations</u>

For new leases, the regulatory 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 flexibility to tailor relief to the specific project: Three variations have been proposed:

- clarifying the Secretary's authority to reduce royalties on non-producing leases;
- allowing the Secretary to reduce royalties for a category of tracts, rather than on a case-by-case basis; and
- covering the costs of processing and analyzing applications by charging an application fee and retaining the fees within MMS to administer the program.

The first two variations listed above are contained in S. 381 (Senator Johnston's deepwater incentives bill). Legislation would be the clearest, though perhaps not the only, way to implement these variations.

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. This is particularly true as seismic technology improves, increasing interest in tracts previously thought to be marginal. For example, in the March 1994 sale in the Central Gulf of Mexico, subsalt plays received numerous and relatively high bids.
- 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.

- Royalty relief for marginal tracts affirms the notion that sooner is better, although market conditions (including price changes and technological advances) possibly could make this category of resources more valuable in the future.

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 may be sent to Congress if a regulation is developed 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. Failure to limit relief to production that would not otherwise occur could generate losses of hundreds of millions of dollars.

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. Recent experience with royalty rate reduction applications suggests that a complete analysis of an application takes a two-person team two to three months to conduct.

f:\P&P\ELPB\NEC\MARPROD2.NEC

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:**

   a. Microeconomic Considerations

   A well-designed royalty rate reduction policy can increase the ultimate recovery of resources from a producing field. Once a field stops producing, the wells are plugged and abandoned, so future recovery of resources left in the ground may be prohibitively expensive. Social benefits exceed social costs to the extent that the production is more valuable to society than leaving the resources in the ground, perhaps forever. The proposal should have little impact on the allocation of capital and labor.

   b. Macroeconomic Considerations

   The proposal should have little impact on oil and gas prices, regional economies, or free trade.

   c. Security Considerations

   To the extent that there are security benefits to the nation from increased domestic production, this proposal will provide them through increasing the ultimate recovery from developed fields.

   d. Budgetary Considerations

   The proposal could have two impacts on the budget:

   - Royalties will be collected from production that otherwise would not occur.

   - Less royalties will be collected on production that would have occurred without relief.

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.

The Bureau of Land Management (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

- lessens need for imported oil
- helps maintain a viable and healthy domestic energy industry
- helps reduce, through operator incentive, unfunded liabilities

Cons

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

6. **Legislative Outlook:** Legislation not needed.

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 Minerals Management Service (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:

Drop the currently pending legislative proposal which would 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). This legislative proposal is part of the "National Performance Review, Government Reform and Savings Act of 1993" (H.R. 3400, S. 1637), which has been passed by the House but has not yet been considered by the Senate.

Fit With Criteria:

Microeconomic considerations - Dropping this legislative initiative will not have any significant effects on the allocation of capital or labor in the gas and oil industry or on the amount or timing of production. Dropping the proposal will maintain the current situation in which companies have no strong financial incentive to pay royalties properly the first time. If retained and passed, the legislative proposal would tend to reduce government costs associated with royalty collections and possibly to reduce private costs over the long term, due to lower requirements to comply with audits and respond to audit findings. Over the short term, companies would tend to spend more on their royalty reporting activities and, when charged a penalty, would transfer money to the government (estimated to be several hundred thousand dollars per year or less) and may spend money disputing penalty assessments.

Macroeconomic considerations - No measurable effect.

Security considerations - No significant effect.

Budgetary considerations - Since MMS has not requested any additional resources to implement the legislation, dropping the provision will have no direct budgetary effect. The MMS Royalty Management Program estimates that several hundred thousand dollars of penalties or less 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, eventually reducing the costs associated with royalty collections. (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:

The Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) and the various leasing statutes authorize MMS to apply two types of incentives for companies to report and pay their royalties properly the first time:

- interest on late payments. The interest rate used (the short-term Treasury bond rate plus 3 percent) is below most companies' cost of capital internal rate of return, so that the incentive is not very strong.

- civil penalties for non-intentional and intentional violations of the regulations. For non-intentional violations, companies are allowed a 20-day cure period before the MMS assesses the penalty. Most companies correct their errors during the cure period, so the penalty does not provide a strong incentive. For intentional situations, no cure period is allowed. However, it is very difficult for MMS to prove that a violation is "knowing and willful", so MMS rarely applies this type of penalty.

The legislative proposal would provide MMS specific authority to further encourage payors to pay proper royalties the ***first time*** by providing a penalty for companies that underpay by a significant amount.

Possible Variations:

MMS has actively solicited feedback from industry associations, which generally view the legislative proposal as establishing an unfair and unworkable penalty regime. As a result of feedback, MMS is considering 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.

- Not impose the penalty if the company corrects the underreporting within a specified period of time from when the payment was due or before MMS discovers the error, whichever is later.

- Allow the company receiving written notice of a penalty for substantial underreporting to pursue an administrative appeal of the notice. Companies would not have to pay the penalty until they had received an unfavorable judgement on any appeal of MMS' determination that they had underpaid their royalties.

- Apply the penalty "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.

The proposal, with these changes, is intended to deter companies that chronically and deliberately underreport, while not penalizing those making an "honest mistake."

Pros and Cons:

<u>Pros</u>

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

- Avoids imposing additional costs on industry in the short term to improve their royalty reporting and to pay a penalty for substantial underreporting.

<u>Cons</u>

- Limits the financial incentive for paying royalties properly the first time to interest, at a relatively low rate, and the rarely-used penalties currently authorized under FOGRMA.

- Does not encourage the highest level of industry compliance, consistent with the RMP strategic plan.

- Forgoes benefits to States, Indians, and the U.S. Treasury by way of more accurate and timely collections.

Legislative Outlook:

NPR legislation has passed the House with this provision. The Senate Governmental Affairs Committee has marked up some portions of the legislation but not this provision. Other committees might amend those areas under their jurisdiction. There is a possibility for floor action in late April, at the earliest. The Senate is likely to pass a pared-down version of the House NPR legislation. However, at conference, all of H.R. 3400 would be required to be reconciled with the Senate bill.

Costs:

Federal budget - No significant impact. Could raise revenues marginally in the short term and could reduce expenditures on royalty collections over the long term.

Other Impacts:

None.

f:\P&P\ELPB\NEC\UNDRREPT3.NEC

III. Current Proposals Involving Gas & Oil

C. Import/Export/Security Proposals

ANALYSIS OF A PROPOSAL FOR A FEE ON IMPORTED GASOLINE

PROPOSAL

The objective of the proposal is to protect U.S. domestic oil refining capacity. Proponents claim protection is warranted because U.S. environment, safety, and health regulations make U.S. domestic refined product uncompetitive. A domestic refining industry is necessary for the economy and supply the U.S. military if fuel supplies are disrupted.

The proposal calls for a fee of 7¢/gallon for imported gasoline in 1994, and raise the fee by 1¢/gallon each year until it reaches 13¢/gallon in 2000. The fee would be sustained at 13¢/gallon thereafter.

The overall objective of this "environmental equalization fee" is to preserve domestic oil refining capacity. Senators Johnston and Bingaman, and Congressman Dingell have endorsed "policies such as an environmental equalization fee" in order "to hold foreign refiners to the same environmental standards as U.S. refiners." The major arguments made by the fee's proponents are:

- Cost Disadvantage. Domestic refiners, burdened by environment, safety, and health regulations and new product requirements, must absorb costs, which they cannot pass through to customers because of competition from lower cost imports. As a result many U.S. refineries will have to shutdown because they are not able to compete.

- National Security. Losses in U.S. refining capacity will threaten our ability to refine oil from the Strategic Petroleum Reserve to fuel our economy and to support defense activities.

- Macroeconomic Effects. The continued loss of U.S. refinery capacity will harm the economy. An additional decline in 10% of U.S. refining capacity will result in the loss of 570,000 jobs, reduce GDP growth, and increase inflationary pressures.

The Coalition claims that $2.3 billion in revenue could be raised from gasoline import fees collected from 1994 - 1998, *assuming* 122 million barrels are imported into the U.S. annually.

draft April 7, 1994

80

FIT WITH CRITERIA

NATIONAL SECURITY CONCERNS

Proponents of the environmental equalization fee are concerned that the loss of U.S. domestic refining capacity and the presence of refined product imports are a threat to national security. This section discusses these two important aspects of the refined products market.

<u>Gasoline imports have declined, not increased (1980-1993), and are a small portion of supply.</u>

Historical data on the gasoline and refined product trade do not support the claims that imports are currently a threat to U.S. domestic production. Based on the data, we find a five year trend toward *decreased* dependence on imports for finished motor gasoline and the aggregate of all refined products.

Energy Information Administration (EIA) volume data for the period 1980 to 1993 indicates that finished gasoline net imports have not increased, as net imports accounted for 2.1% of U.S. supply in both 1980 and 1993. Net gasoline imports rose to 5.4% of U.S. supply in 1985 and declined every year since 1989. Total imports of finished gasoline rose only 78% from 1980 to 1993, rather than the tripling claimed by the Coalition. In fact, total gasoline imports have declined 39% since 1988, and in 1993, stood at their lowest level since 1983 (see Figure 1).

EIA volume data also indicates that net imports of all refined products, as a proportion of U.S. supply, fell by 40% in the period 1980 to 1993. Net imports were 7.8% of U.S. supply in 1980, peaked at 8.6% in 1988, and declined to 4.7% in 1993. Total imports of refined products declined 22% from 1988 to 1993 (see Figure 2). Also Figure 3 shows that net imports of several refined products as percent of U.S. supply trended downward since the late 1980s.

<u>Refinery capacity has changed little in the last 11 years.</u>

From 1983 through 1993, the refining industry operated with a crude oil throughput capacity in the narrow range of 14.8 to 15.1 million barrels/day, *but with 58 fewer refineries in 1993 than in 1983*. In the last decade, refinery productivity dramatically increased due to the use of new technology and improved operational efficiencies. The industry is very dynamic. While some refineries shutdown, others expand or improve their refining capabilities.

Many, particularly small independent, refineries have shut down over the last decade largely due to competitive pressures and the prospect of making large capital investments. The smaller, less technologically sophisticated refineries face a significant disadvantage whenever they are required to upgrade. Figure 4 shows the technology gap which exists between the small and large refineries. While small, less efficient and technologically less complex refineries have had to close, the productivity and output of the larger refineries has increased.

<u>Reductions in refinery capacity resulted from market pressures and overcapacity - not imports.</u>

EIA data are consistent with the Coalition's claim that U.S. refining capacity and the number of operating U.S. refineries dropped during the period 1980 to 1993, however, this decline took place in the early 1980s. From 1980 to 1993, operating refinery capacity declined from 17.6 million to 14.8 million barrels/day, while the number of operating U.S. refineries dropped from 311 in 1980 to 175 in 1993.

Refinery capacity reductions from 1980 to 1982 shutdowns occurred, for the most part, because of market pressures to reduce excess refining capacity, not because of product imports or regulatory related costs. From 1980 to 1984, U.S. refinery utilization rates ranged from 67% to 77%, compared to a consistent historical range of 85% to 90%. Markets adjusted to bring refinery capacity in line with demand, and utilization rates went back to historical levels reaching 85% in 1989 and over 90% in 1993. U.S. refining capacity has changed little in the last 11 years.

<u>Oil from a Strategic Petroleum Reserve drawdown can be refined.</u>

With respect to the adequacy of existing capacity to refine Strategic Petroleum Reserve (SPR) crude oil in an emergency, total domestic daily refining capacity is about 14.8 million barrels of crude per day compared with SPR's maximum daily drawdown rate of 2 million barrels per day. Clearly, there is sufficient U.S. capacity to refine SPR oil. In addition, there is nothing to prevent SPR oil from being refined abroad.

<u>Refining costs outside the U.S. are expected to rise, and most domestic refiners are expected to meet the regulatory challenge.</u>

Environmental equalization fee proponents believe an import fee is needed because environment, safety, and health regulations are a severe cost disadvantage, which will result in a flood of imports as domestic refineries close. However, the National Petroleum Council concluded that "imports may be expected to play a diminishing role in U.S. light product supply" in their 1993 refinery study. The NPC found that *current foreign refinery cost advantages will not grow or will diminish in the future*. The NPC was explicit in its assessment that the U.S. market will be a formidable challenge to foreign refiners given their limited financial and operating resources:

> "First, health, safety, and environmental costs are expected to increase in all foreign locations. Second, product consumption is expected to increase outside the U.S. and product quality is expected to shift toward environmental fuels, making processing costs increase significantly more than in the U.S. Finally, the cost of moving products from foreign supply points to U.S. demand centers is expected to increase."

The cost of meeting environment, safety, and health (ES&H) regulations will be a major challenge for the U.S. refining industry. According to the NPC, U.S. refiner capital spending (per unit of capacity) will be about 17% higher (or $7.3 billion) in the 1990s than the 1980s, but 39% lower during 2001-2010 than the 1980s. Furthermore, ES&H compliance and reformulated fuels production costs will also increase refiners' operating and maintenance expenses dramatically. The NPC estimated capital expenditures by U.S. refiners for stationary source regulatory compliance and product quality would require to $37 billion during the 1990s *of which two-thirds will occur in the period 1991 to 1995*. The NPC projects that the industry will have to seek external financing to support its cash flow needs, and that this will make it more sensitive to upswings in interest rates and downturns in demand. Cash poor refiners will

82

have to decrease costs, and may have to sell, merge, partner with other firms, or go out of business. In particular, small refiners, known to be generally behind in modernizing their facilities, will carry an extra burden to upgrade their plants.

Although this level of investment will stress the industry's ability to finance the needed changes, it will also eventually affect non-domestic refiners as well. Foreign refineries will have to produce products to U.S. specifications, as well meet their own government's more stringent environment, safety and health regulations.

The profitability of domestic refining increased in 1993.

Refining and marketing profits for the 19 companies tracked by *The Oil Daily* increased 64% in 1993 over 1992, while profit margins increased 60%. Profits and profit margins of most of the member companies of the Independent Refiners Coalition also increased in 1993. Because of an improved economic climate encouraging gasoline consumption, and prices of crude oil at five-year lows, the 1994 profit picture for refining and marketing continues to look favorable.

Outlook for the refining industry and gasoline imports.

Neither the EIA nor the NPC forecasts predict a U.S. domestic refining capacity collapse. Both predict increased domestic refining capacity in the future. The EIA and NPC forecasts do differ in respect to the amount of domestic capability refiners will add in the next 15 to 20 years. The EIA projects U.S. refining capacity increasing by 0.3 million b/d between 1993 and 2010, while the NPC expects capacity for light products alone (gasoline, jet fuel, and distillate) to increase by the same amount between 1995 and 2010.

With regard to future gasoline imports, the industry NPC study differs markedly with the EIA's projections. While EIA's estimate of net finished gasoline imports in 2010 is twice that of the NPC's, the higher EIA estimate, near 1 million b/d, is relative to a total domestic market of 8.4 million b/d. As shown in Figure 5, the NPC's assumed growth and declining demand scenarios result in little or no increase in future gasoline imports. The NPC's analysis explicitly considered constraints such as the availability of capital and new regulatory demands abroad can limit foreign refiner export potential. The NPC is more optimistic than the EIA on future U.S. refinery capacity and output for light products. Also the NPC explicitly took into account that the U.S. age cohort that drives vehicles the most has peaked, that licensed drivers with access to vehicles has reached the saturation point, and that vehicle performance improvements will translate to efficiency savings.

MACROECONOMIC CONCERNS

The employment, inflation, and economic growth impact of the U.S. refining capacity losses are the Coalition's major concerns.

Between 1980 and 1992, U.S. Bureau of Labor Statistics data shows that employment in the petroleum refining industry dropped by one-quarter, from 155,000 to 116,000 workers. As mentioned previously, the industry had to adjust to a glut of capacity. After a major readjustment during 1980-1982, the number of refineries operating in the U.S. dropped by 50 *with no net change in refining capacity in the decade 1983-1992*. To a large extent, employment losses from 1983 to 1993 resulted in improved labor productivity and higher capacity utilization rates.

[We have yet to analyze the Coalition's concerns on inflation and economic growth.]

EXISTING POLICY BASELINE

Unless it is applied to domestic as well as imported gasoline, the proposed fee on gasoline would violate the GATT and NAFTA. If the U.S. determined that imported gasoline threatened the national security, a fee might be justified under GATT and the NAFTA.

Undoubtedly, such a fee would be challenged under GATT. Nothing in the GATT permits the imposition of fees on imports to equalize the economic burden borne by a domestic industry in complying with environmental or other standards that take the form of mandates, rather than taxes affecting domestic products. European governments, in particular, may argue that their environment, safety, and health requirements are becoming equivalent to U.S. requirements.

Because the national security exception in the NAFTA pertaining to energy imports from Canada (but not from Mexico) is significantly more narrowly drawn than the GATT national security exemption, it is highly unlikely that the proposed fee, if applied to gasoline imports from Canada, could be successfully defended on national security grounds. Because Canada is a our largest source of gasoline imports, an exemption would significantly reduce the intended effect of the fee. If a GATT or NAFTA dispute settlement panel were to find that the fee violated the applicable agreement, the complaining country could take trade retaliation measures against the U.S., unless the U.S. removed the measure, or offered compensation in another area in an equal amount to the trade loss suffered as the result of the fee.

POSSIBLE VARIATIONS

Extensions. Possible variations of the gasoline import fee idea include extensions of import fees to gasoline blending components, and or even to all refined petroleum products. Both extensions would be difficult to implement. Gasoline blending components are not only used for motor gasoline but for aviation fuels, which might also have to be covered by an import fee. "Refined petroleum products" would have to be defined to delineate them from organic chemical feedstocks and other products containing a high proportion of refined products. These variations are not analyzed in this paper.

Exemptions. Imports from certain countries might be exempted because of existing trade agreements or to avoid penalizing countries which have environment, safety and health standards like our own. The potential impact of exemptions is discussed in the last section of this paper.

PROS

- Provides domestic refiners of gasoline some protection from imported gasoline and would allow domestic refiners to fill gaps created from backing out up to 3 percent of domestic gasoline consumption.

- Could induce some countries to accelerate the upgrade of their environment, safety, and health rules to U.S. standards, if exemptions for such cases were allowed.

- Revenues produced through the year 2000 are likely to be no where near the Coalition's estimate. The proposed fees may make a large portion of foreign gasoline too costly to import. The Coalition's gasoline import volume is about one-qurater higher than 1993 actual imports. Exemptions for the U.S. Virgin Islands, Canada and other countries will dramatically reduce revenue potential. [Treasury will provide an analysis.]

CONS

- Reduces competition and could increase prices during high demand periods in markets where imported motor gasoline is sold. Consumers may object to another Government "tax" which could increase gasoline prices.

- Would not directly relieve the costs to smaller independent refiners of upgrading their refineries to meet higher product quality and environmental requirements unless the tax revenues from the import fee were used to subsidize their capital needs. This would be strongly opposed by the majority of the refining industry which has dramatically improved productivity and increased output.

- Increases trade tensions with nations in the Western Hemisphere and northern Europe. Exemptions would likely apply to Canada, the U.S. Virgin Islands and countries in northern Europe, limiting the intended benefits of the fee and reducing revenue potential. (See Figure 6.)

- Unlikely to provide much assistance to domestic "independent" refiners because the relatively small volume of gasoline imports would likely be replaced by major refineries, reductions in U.S. gasoline exports or increased imports from Canada.

- Exemptions of countries other than Canada (would would be justified by a GATT exception for obligations under free trade agreements) could lead to an additional ground for a GATT challenge -- denial of most-favored-nation treatment. The GATT does not permit importing countries to discriminate on the basis of the levels of health, safety, or environmental standards.

LEGISLATIVE OUTLOOK

[No legislation yet proposed. Awaiting historical information from Legislative Affairs Office on Congressional disposition of previous similar proposals.]

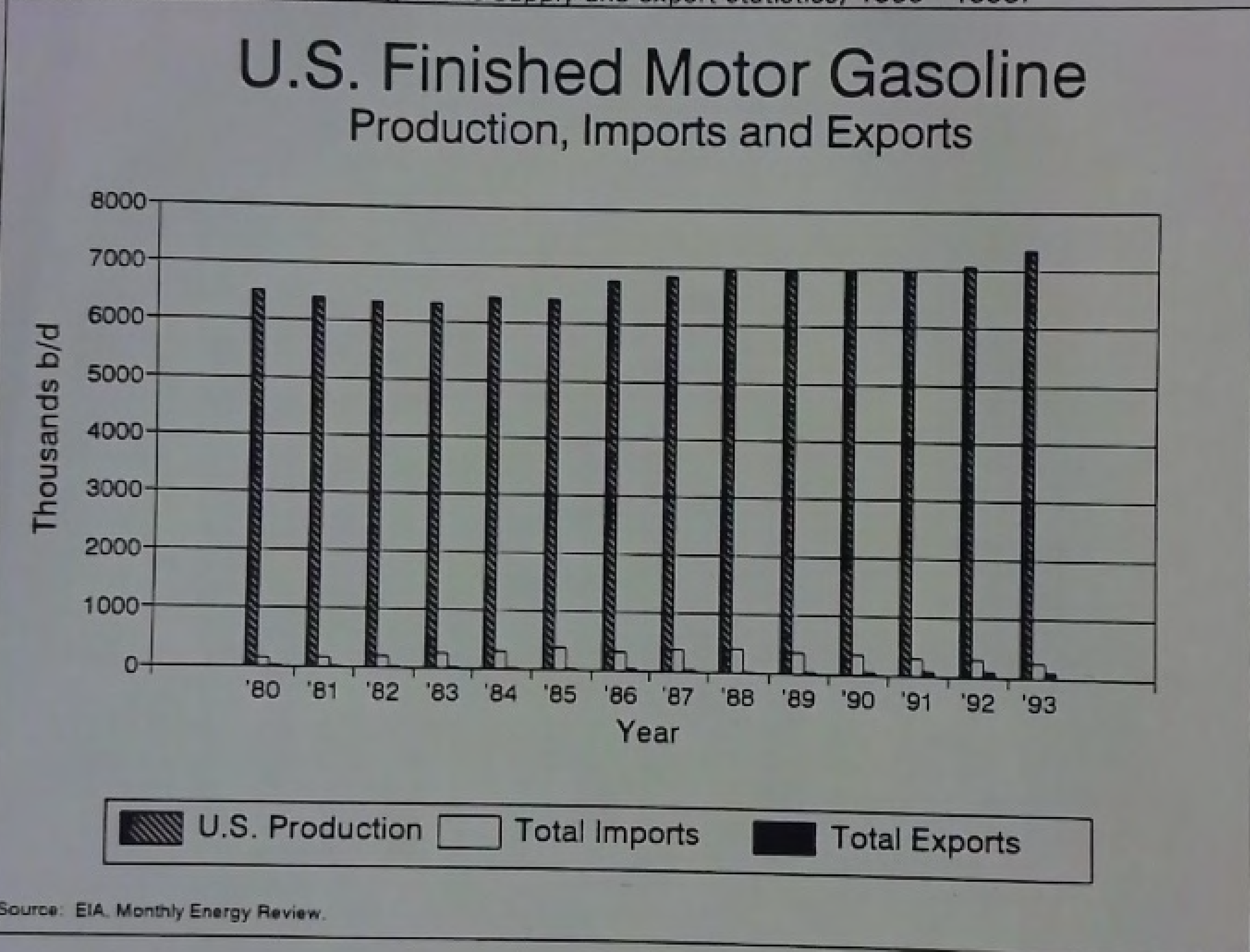
COSTS

Exemptions. Exemptions may be granted for imports from Canada, per the Canada Free Trade Act, and the U.S. Virgin Islands (comprising 41% of all 1993 imports). Imports from northwestern Europe (France, UK, Belgium, Netherlands, Norway, and Sweden comprising 10% of all 1993 imports), may be granted exemptions because these countries are not far behind the U.S. in implementing strict environment, safety, and health regulations on refining operations. Energy Information Administration (EIA) 1993 import volume data (11 months annualized) is used as the 1994 estimate. The annualized EIA 1993 import volume estimate is 26% lower than the Coalition's 1994 import estimate.

Country of Origin Assumptions. For the first 11 months of 1993, 77% of all finished motor gasoline imports were from non-OPEC countries -- principally, Canada, the U.S. Virgin Islands, and Brazil. Among OPEC countries, Venezuela and Saudi Arabia accounted for 17% and 6% of U.S. gasoline imports, respectively. (See Figure 6.) Both Venezuela and Saudi Arabia have sizable investments in U.S. refineries and retailing -- the Venezuelan state oil company stake in Citgo and Lyondell-Citgo Refining; and the Saudi Aramco stake with Texaco in Star Enterprise.

Summary. [Treasury will provide an analysis summary.]

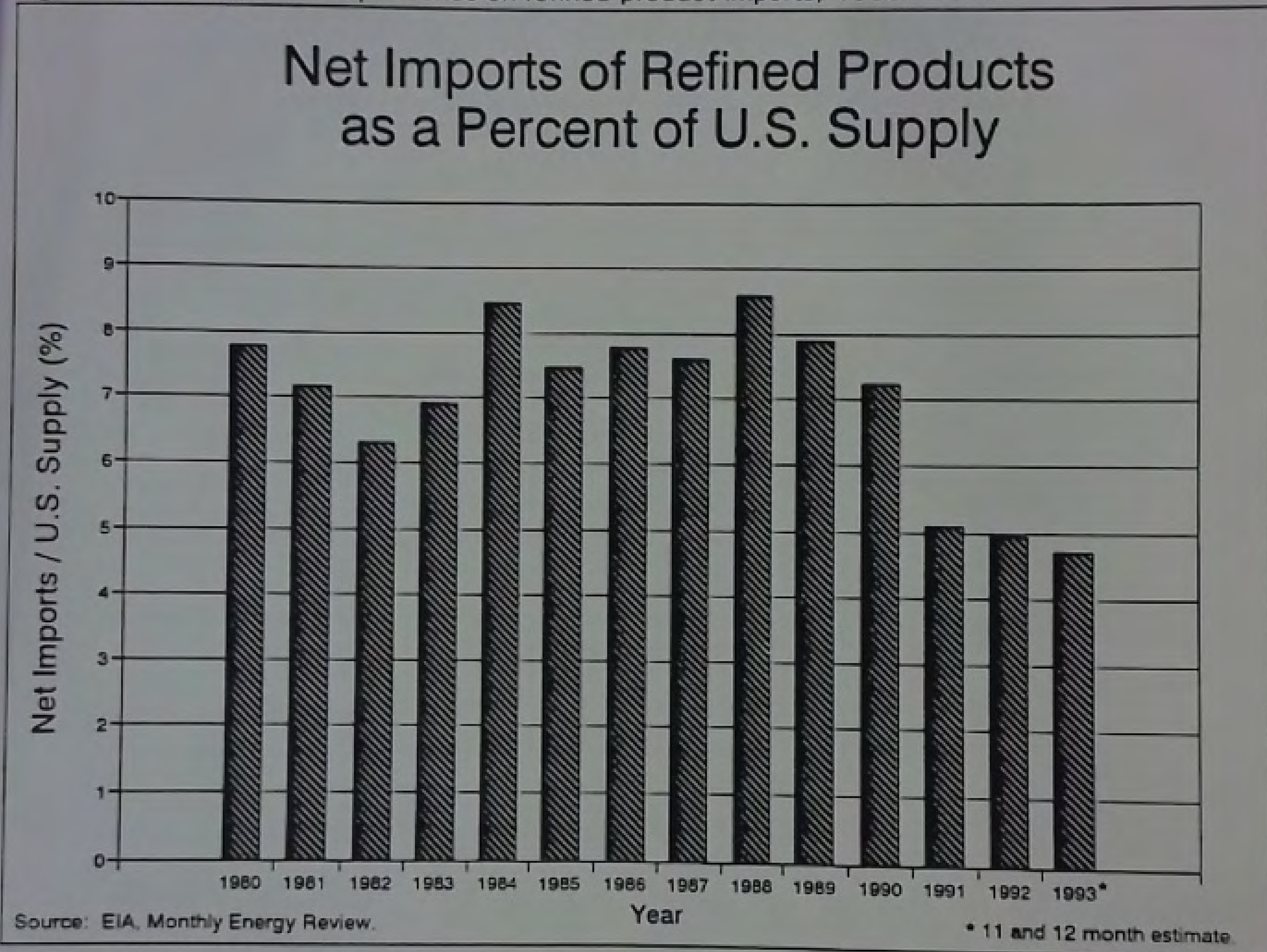
Figure 1. U.S. finished motor gasoline supply and export statistics, 1980 - 1993.



Source: EIA, Monthly Energy Review.

U.S. production of finished motor gasoline hit record levels in 1993. Imports stood at their lowest levels since 1983.

Figure 2. Reduced U.S. dependence on refined product imports, 1980 - 1993.



While it is true that the number of U.S. refineries operating between 1980 and 1993 fell by 44%, increased productivity and output at operating refineries have generally kept pace with overall domestic demand. Figure 2 shows a trend toward decreased dependence on imported refined products. Net imports, as a proportion of total supply dropped by over 50 percent in the last decade. This is true for most classes of products tracked by the EIA.

Figure 3. U.S. dependence on imports for a variety of refined products, including gasoline.

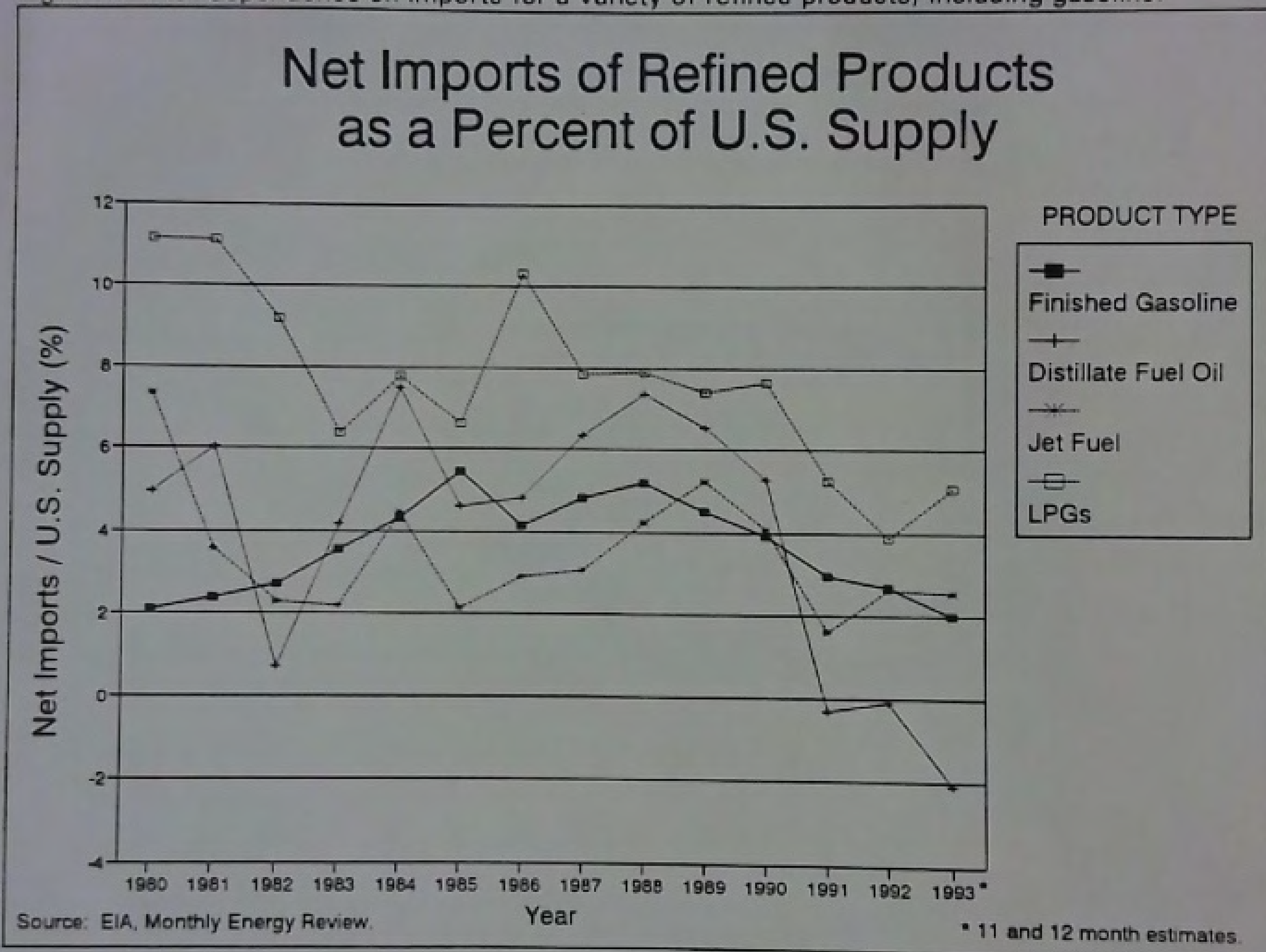
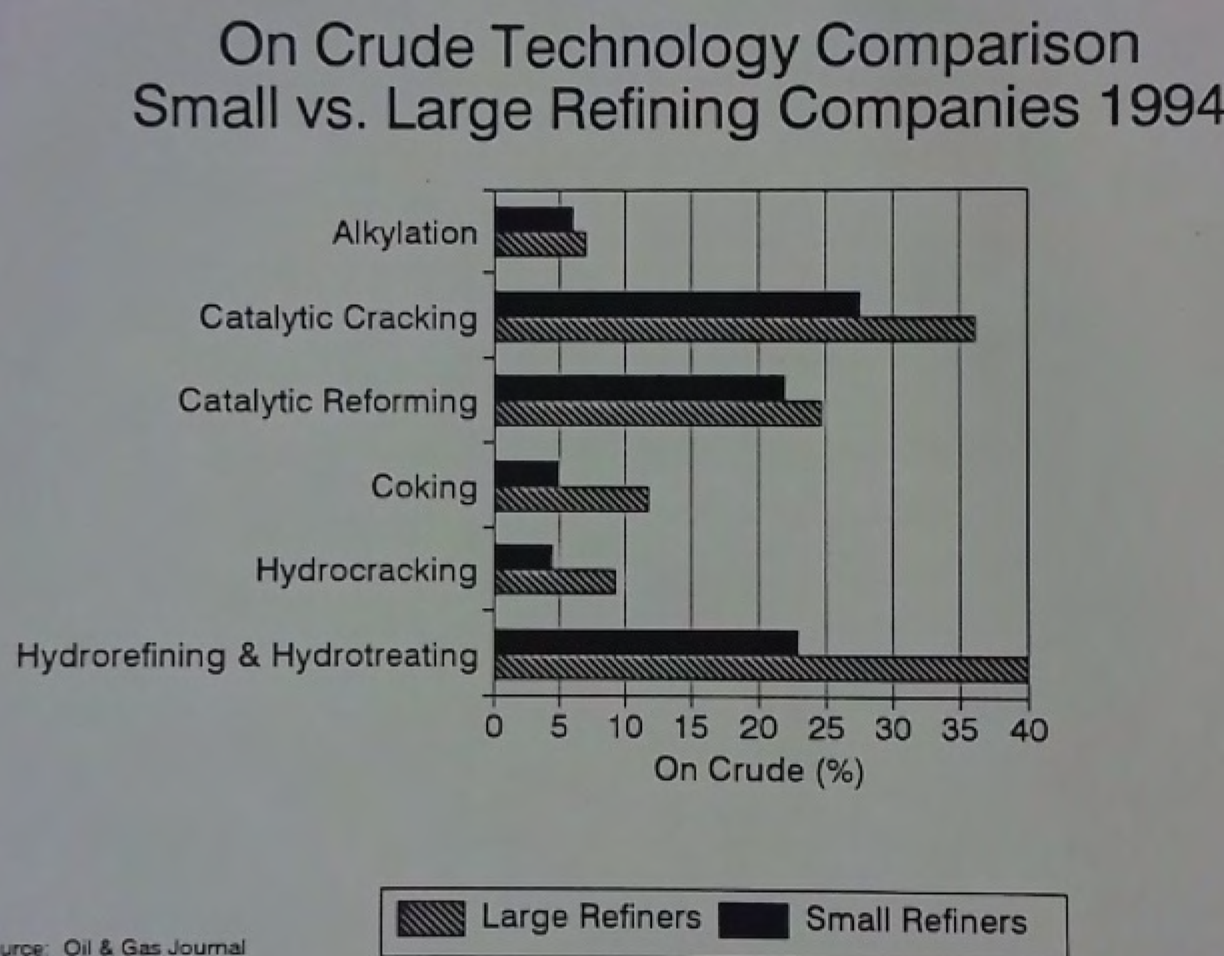


Figure 4. Technologies implemented at small and large refining companies.

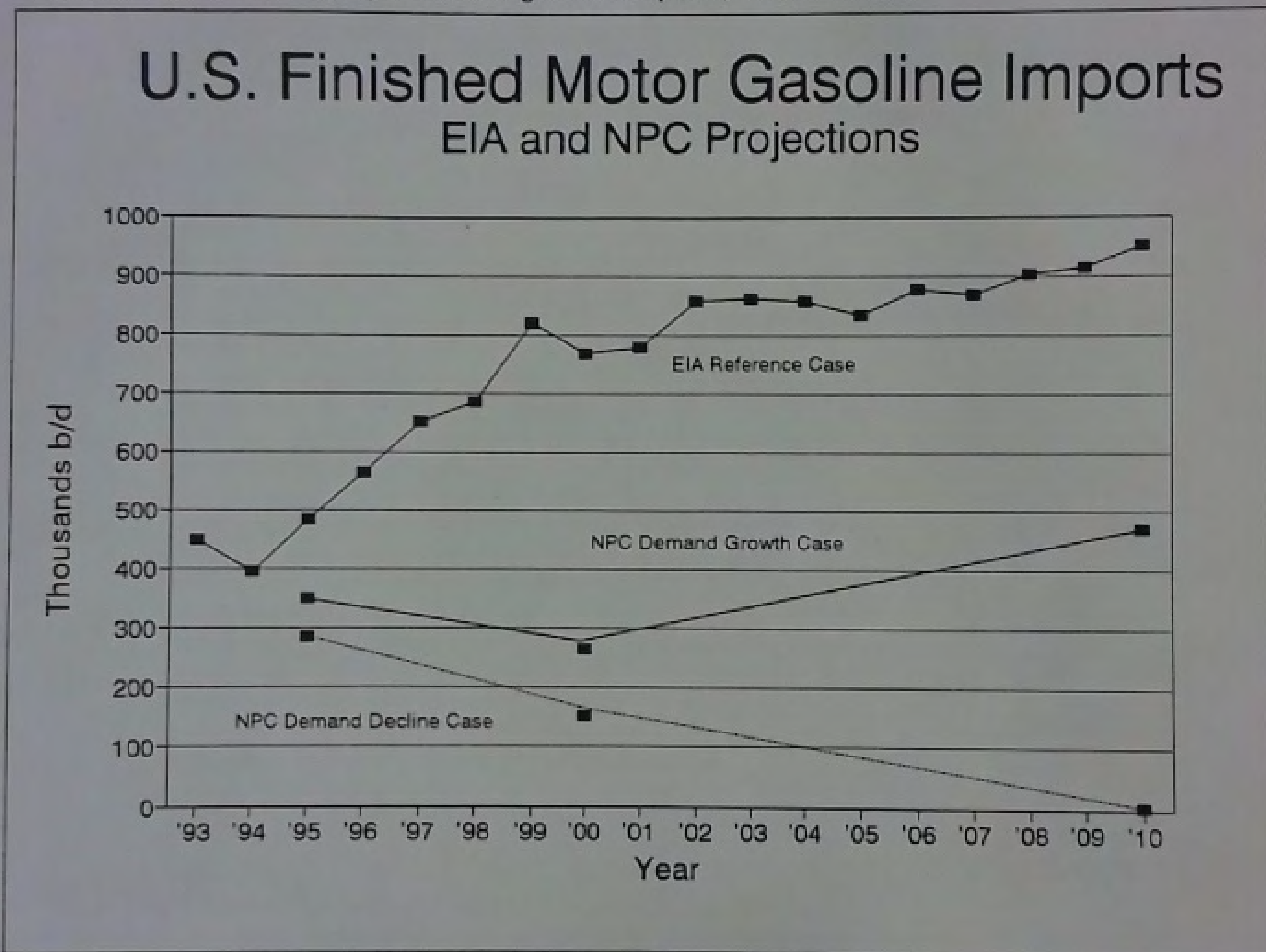


Source: Oil & Gas Journal

Companies capable of refining more than 200,000 b/d of crude oil utilize sophisticated refining technologies at a much higher level than small refiners.

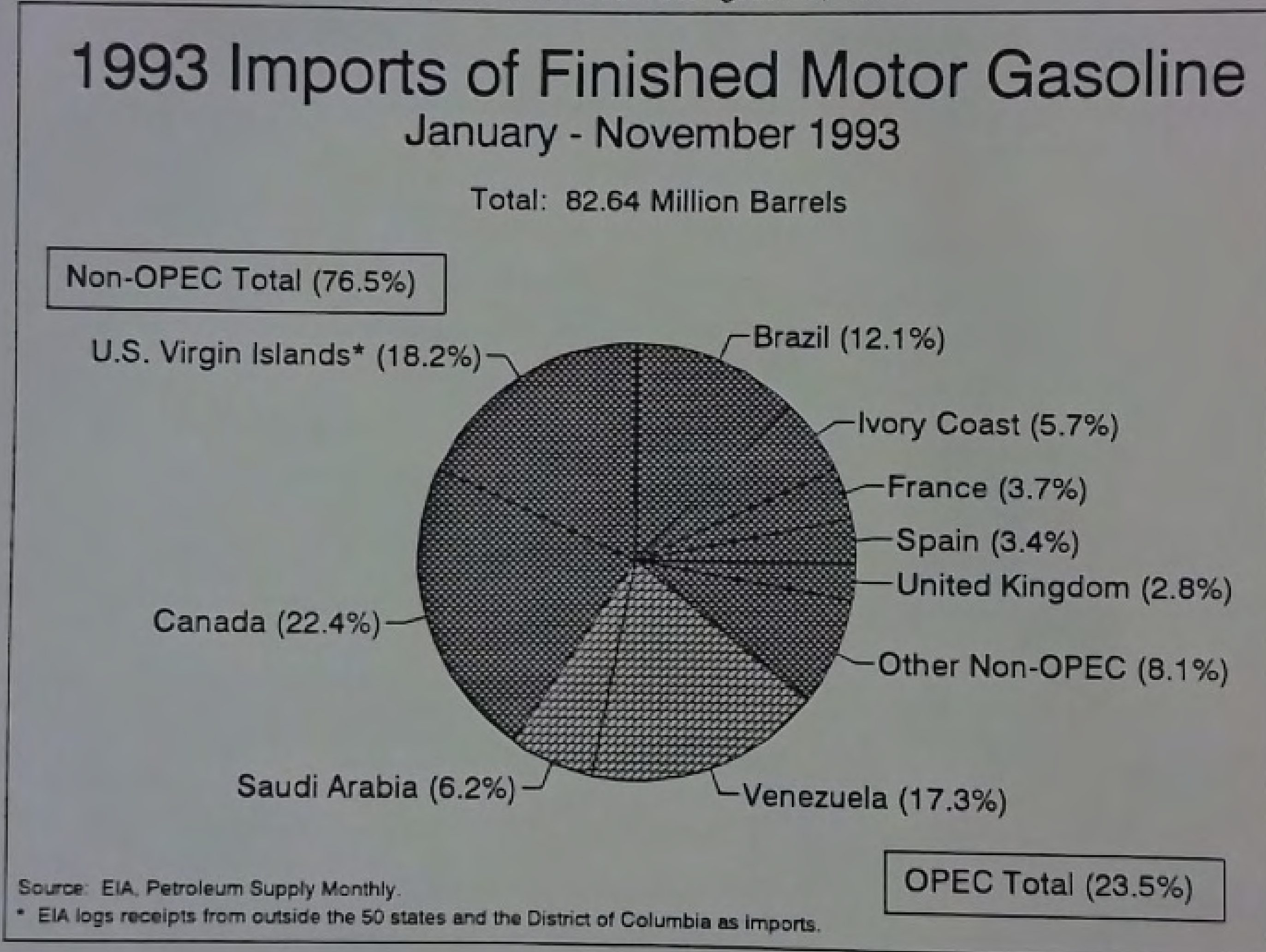
The 87 refineries owned by large refiners have an average capacity of 137,670 b/d of crude, compared to an average of 34,772 b/d for the 91 refineries owned by small refiners.

Figure 5. EIA and NPC projections for gasoline imports, 1993 - 2010.



Energy Information Administration and National Petroleum Council projections of U.S. finished motor gasoline imports differ markedly. The EIA expects U.S. refinery capacity to increase by only 0.3 million b/d between 1993 and 2010. The industry NPC expects U.S. refining capacity for light products alone (motor gasoline, jet fuel, and distallate), will increase by 0.3 million b/d between 1995 and 2010. In comparable scenarios, the NPC expects long-run refinery capacity utilization will be higher than EIA's projection. Total U.S. gasoline demand in 2010 is expected to be about 8.4 million b/d.

Figure 6. Breakdown of total imports of finished motor gasoline, 1993.



For 1993, about 70% of all finished gasoline imports orginated in the western hemisphere. Total imports accounted for about 3.3% of U.S. supply. However, with gasoline exports, net imports were only 2.1% of U.S. supply.

Of total 1993 U.S. exports, about 56% went to Mexico, 9% went to Canada, and 3% went to Puerto Rico.

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), a politically sensitive issue. 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. Domestic oil shipments must employ 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 that were suggested at recent public meetings, but not endorsed by the Administration, are:

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 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 for 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).

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. tanker fleet would be eliminated if the ban was lifted.

- o U.S. shipbuilders are counting on building replacements for ANS tankers to meet OPA-90 double-hulled requirements at the end of this decade. Fewer OPA-90 compatible ships will constructed at U.S. ship yards if foreign tankers are used to export ANS crude oil.

- 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. The revenue benefits are long-term, and do not enter into budget-scoring calculations.

8. Benefits

o Linking West Coast oil markets with Pacific Rim countries

o Would improve the trade balance with Japan (the trade balance with some oil producers would worsen)

o Making room for lighter foreign crudes on the West Coast might make it easier for <u>some</u> refiners to meet air pollution standards.

III. Current Proposals Involving Gas & Oil

D. Regulatory Proposals

Section III.D. Regulatory Proposals

Oil Pollution Act of 1990

Congress enacted the Oil Pollution Act (OPA) in August 1990 in response to the Exxon Valdez oil spill which had occurred in 1989. While much of OPA focuses on tankers, it also imposes requirements on offshore facilities (defined as "... any facility of any kind located in, on, or under any of the navigable waters of the United States..."). OPA requires parties responsible for an offshore facility or facilities to demonstrate evidence of financial responsibility in the amount of $150 million, a more than fourfold increase from the present requirement of $35 million.[1]

1. Proposal

- Limit the applicability of the OPA financial responsibility requirements to "traditional" offshore facilities, i.e., facilities in State waters and on the Outer Continental Shelf (OCS).

- Reduce the dollar limits for the certificates of financial responsibility; base financial responsibility requirements on potential oil spill risk and liability.

- Alter the guarantor status for insurers so they act as indemnitors and are not secondarily liable for all the insured's debts.

- Establish a *de minimis* exclusion for facilities which handle small volumes of petroleum and pose little risk of creating costly oil spills.

- Stagger the availability of resources since not all resources are needed immediately, but are necessary over time.

2. Fit with Criteria

Microeconomic concerns

Adoption of the proposal, either through regulatory or legislative measures, would have beneficial microeconomic effects. Imposition of a more costly and extensive oil spill financial responsibility regime (as the OPA may require) will interfere with the efficient allocation of natural gas and oil resources.

---

[1] Under current regulations issued pursuant to provisions of the Outer Continental Shelf Lands Act which were superseded by the OPA requirements, only oil and gas facilities located on the Outer Continental Shelf were required to demonstrate financial responsibility. Until new regulations are issued, the existing financial responsibility requirements ($35 million for Outer Continental Shelf facilities) will remain in place.

For many years, the major oil companies were the dominant presence on the OCS. However, production on many OCS leases, especially in the Gulf of Mexico, has declined to the point where they are no longer profitable for the majors. As a result, the majors have been selling many leases to smaller independent companies who can continue to economically produce natural gas and oil because of their generally lower operating and overhead costs. In the absence of this growing secondary market, the majors would plug and abandon the leases, leaving valuable resources in the ground forever.

These small companies cannot afford to obtain $150 million in financial guarantees and if they could, the cost of obtaining the guarantees would wipe out any potential profits from production on the leases. Thus, those parties who would otherwise place the highest value on the resources will be prevented from obtaining them. Since most spills result in clean up costs and damages much less than $150 million, requiring all companies to meet the $150 million standard will impose costs well in excess of any associated benefits.

Macroeconomic concerns

Adoption of the proposal would have a slight, but positive macroeconomic effect by avoiding the loss of domestic oil and gas production that would result from requiring all offshore operators to obtain $150 million in financial guarantees. Studies have shown that one barrel of oil produced domestically "backs out" a nearly equal amount of imported oil. About one-third of any decline in domestic gas production would have to be made up by higher oil imports. An increase in U.S. demand for world oil supplies will exert a corresponding upward pressure on world oil prices.

The regional effects of imposing high financial responsibility requirements will be more pronounced. Local economies in many areas of the Gulf of Mexico are still heavily dependent on the offshore natural gas and oil industry. If many independent producers are forced to abandon their leases, workers will lose jobs and economic activity will decline.

U.S. companies seeking to comply with the OPA requirements will have to purchase insurance from foreign sources, since insurance of this type generally is not available domestically. The cost of the insurance, together with the cost of increased oil imports needed to offset the loss of production by companies that simply cannot afford the insurance regardless of source, will worsen the United States balance of trade and payment problems.

Security concerns

Adoption of the proposal will help reduce the need for oil imports, but not to a degree as to have a significant effect on national security.

Budgetary concerns

The proposal, if adopted, would generally have no effect on government expenditures and consequently would have no PAYGO implications. If not adopted, significant additional resources will be needed to implement the financial responsibility requirements for facilities that are not now covered by existing regulations.

3. Existing Policy Baseline

The Minerals Management Service (MMS) of the Department of the Interior has responsibility for administering the OPA financial responsibility provisions for offshore facilities. The MMS issued an Advanced Notice of Proposed Rulemaking (ANPR) as an initial step in developing new regulations to implement the OPA financial responsibility requirements. The MMS is now reviewing and analyzing the 1700 comments received in response to the ANPR, as well as other materials, including a National Petroleum Council study outlining OPA's energy and economic impacts.

Until new regulations are promulgated, the existing financial certification requirements ($35 million for offshore facilities on the OCS) will remain in place.

4. Possible Variations

The provisions of OPA may require MMS to issue regulations imposing the $150 million financial responsibility requirement not only on traditional offshore natural gas and oil facilities, but also on facilities located on, in, or under inland navigable waters such as rivers and lakes. The financial responsibility requirements could even extend to oil-related facilities located on wetlands.

However, if there is sufficient latitude in OPA for alternative interpretations, regulations consistent with the proposal could be issued. This would avoid the economic hardships which would be created if all "offshore" facilities were required to obtain $150 million in financial responsibility guarantees, and would permit setting financial responsibility requirements based on a facility's potential oil spill risk and liability. Similarly, regulatory provisions could be devised to resolve the problems cited by marine insurance industry.

If it is determined that the statute does not permit such an interpretation, legislative changes would be required in order to implement the proposal.

5. Pros and Cons of Proposal

Pros

- Establishes the framework for a more manageable and enforceable oil spill financial responsibility program by limiting the application of the OPA requirements to facilities in State waters and on the OCS.

- By setting financial responsibility requirements based on potential oil spill risk and liability, industry compliance can be achieved in a cost effective manner that does not impose undue economic hardship.

- Addresses insurance and financial industry concerns over OPA provisions related to direct action.

- Avoids putting the many small and medium sized natural gas and oil producers and other oil-related firms which cannot afford to obtain $150 million in financial guarantees out of business.

Cons

- May be viewed by some as a relaxation in the Administration's commitment to ensuring that parties responsible for oil spills are able and made to pay clean up costs and damages.

- If legislative changes are required, reopening of OPA likely will be opposed strongly by some industry and environmental organizations.

6. Legislative Outlook

If the proposal can not be implemented through the regulatory process, legislative action would be required. The only known legislative proposal for amending OPA is a provision added by the Senate Energy Committee to S. 318 (Senator Johnston's deepwater incentives bill) which would allow MMS some flexibility in applying the $150 million standard. 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. MMS has not made a final determination on its interpretation of OPA and whether legislative changes are needed. Any legislative effort to amend OPA may affect other provisions of the law which the Administration may not want to have changed.

7. Costs to the Federal Budget

Revenue

Implementation of the proposal would have a negligible impact on Federal revenues. Implementation of costly financial responsibility requirements that include facilities located in State waters, on the OCS, and on inland waters would cause a significant loss of royalty and tax revenues.

Outlay

The proposal can be implemented without significant new program expenditures; if the financial responsibility requirements are imposed on oil-related facilities on inland waters, large increases in personnel and associated program resources would be necessary because of the extensive effort that would be needed to identify and ensure compliance by all eligible facilities.

8. **Benefits**

The proposal generally—

- Maintains adequate safeguards with respect to oil spill clean up costs and damages without imposing undue economic hardships which could force many firms out of business. (Based on OCS spill history, only two spills are estimated to have cost more than the current financial responsibility requirement of $35 million.)

- Allows independent petroleum companies to maintain a viable presence on the OCS and serve as a valuable secondary market for the sale of OCS leases by the majors.

9. **Other Impacts**

In contrast to the proposal, imposing a minimum financial responsibility requirement on all offshore facilities, including those on inland waters, would have major impacts on:

- Small businesses: The potential damage to a large number of small businesses—marina operators, oil storage facilities, fuel jobbers, pipelines, oil and gas operators on wetlands, etc.—is immense.

- Alaskan native communities: Many Alaskan native communities are located in wetland areas and the oil handling facilities on which they depend would be subject to this large financial burden.

- Financial community: Insurers, banks, surety companies, and other financial institutions will not want to become guarantors under the OPA provisions.

- Oil imports: A drop in oil production from the OCS could result which would have to offset by an increase in oil imports.

F:\P&P\ELPB\OPA4-5.NEC 4/5/94

Underground Injection Control Regulations

Introduction

EPA is developing a notice of proposed rulemaking (NPR) to revise existing underground injection control (UIC) regulations under the Safe Drinking Water Act (SDWA) for injection wells used in oil and gas production for the disposal of produced water and other fluids or enhanced oil recovery (Class II). This proposal which reflects the recommendations of the Federal Advisory Committee is currently in final EPA review process prior to OMB review. Publication is expected in Fall, 1994.

(1) Proposal

Senators Boren and Brewster are considering action to oppose or terminate EPA revisions to existing regulations. Similarly, in a March 2, 1994 letter to Senator Boren on tax and regulatory relief, an industry coalition representing the Independent Petroleum Association of America, the Mid-Continent Oil and Gas Association, the American Petroleum Association, and the Marathon Oil Co. expressed opposition to the revisions.

(2) Fit the Criteria

To be supplied.

(3) Existing Policy Baseline

BACKGROUND — Existing UIC regulations for Class II wells were promulgated in 1980. The SDWA requires that EPA not promulgate regulations that interfere with oil and gas production unless they are essential to the protection of underground sources of drinking water (USDWs). In addition, under SDWA Section 1425 the States do not have to adopt EPA requirements. They can instead demonstrate that their programs are equally protective. Twenty-three States have primacy to implement the UIC program for Class II wells. In eight 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 a Federal Advisory Committee (FAC) composed of representatives from environmental groups (Friends of the Earth, National Audubon Society), petroleum producing companies (ARCO, Conoco), trade associations (API, IPAA), States (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 that included 25 specific recommendations for rule revisions. All committee members endorsed the final report with the following caveats:

(1) The IPAA and 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 obligations under SDWA Section 1425 to allow States to demonstrate the effectiveness of their in-place programs (instead of adopting the regulations virtually verbatim);

(3) Kansas wanted EPA to interpret the SDWA prohibition against impeding oil and gas production, unless essential to protect USDWs, based upon local production impacts, not merely national impacts; and

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

COMPONENTS OF THE DRAFT RULE — The draft rule reflects the FAC recommendations and would modify the existing Class II regulations in three areas:

(a) Construction Standards: Newly drilled and newly converted wells must have a double containment system for injected fluids. And, as an additional "layer of protection", surface casing must 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 can meet new construction standards must be tested more frequently. The frequency of testing would be based on the level of protection afforded to these wells.

(c) Area of Review (AOR): 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 abandon wells) in the vicinity of the well (area of review). Owners and operators of existing wells would 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 would be exempt from these requirements where there is a low risk of endangering USDWs contingent upon individual States or EPA regions establishing variance plans.

REGULATORY IMPACTS ANALYSIS — EPA has estimated that the rule would result in incremental direct and indirect compliance costs of $47.1 million annually for the first five years. In addition, EPA estimates that the value of oil that would be foregone as a result of the rule would be $40 million annually. The rule would indirectly affect oil production since well owners would have to construct production wells to injection well standards to retain the option of converting the well to an injection well at a later date.

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

(5) Pros and Cons of Proposal

Pros

- Terminating the rulemaking could potentially result in cost savings for industry. EPA believes the direct and indirect compliance cost of the rule would be $47 million annually with an additional $40 million in annual foregone oil production. Preliminary DOE and industry estimates of the cost of the rule range from $500 million to $3 billion. Both DOE and industry anticipate performing more comprehensive assessments of the economic and energy impacts of the rule after it is formally proposed.

- Relatively few documented cases exist that directly implicate Class II injection wells as a source of large scale USDW contamination.

Cons

- The FAC was 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.

- The FAC was largely a "win-win" situation. Many early recommendations for changes to the regulations were not pursued. In 1989, API's worst case estimate for these proposals was $60 billion.

- API's endorsement of FAC recommendations was not unanimous. Industry continues to have conflicting opinions on whether the rulemaking should be terminated.

- Terminating the rulemaking would not address previously identified deficiencies in the UIC program and would provide less certainty that USDWs will be adequately protected.

6. Legislative Outlook

To be determined. Senators Borne and Domenici are the sponsors of the leading Senate SDWA reauthorization bill (S. 1114).

7. Costs to the Federal Budget

Revenue: Negligible

104

Outlays: None for terminating the revisions

3. Benefits

UIC regulations focus on preventing well failures that can introduce contaminants into USDWs. Potential benefits of the rule include the reduction in damage to current or future public health and protection of ecosystems. EPA believes that the costs imposed by the rule would be offset by the benefits of preventing the release of three carcinogenic contaminants contained in many injection fluids (e.g., benzene, arsenic, and radium).

In addition, the primary constituents of concern in injected fluids are sodium and chloride compounds. At high concentrations usually present in oil field brines (up to 141,000 mg/l chlorides) they can render a drinking water source totally unfit for human consumption. Treatment costs for chloride removal are high.

4. Possible Variations

(a) Issue a NPR based on FAC recommendations including preamble language reaffirming the prerogative of primacy States under Section 1425 to choose alternative approaches to protecting USDWs; and requesting comments on the measures to mitigate impacts on small operators (currently planned by EPA);

(b) Issue a NPR based upon FAC including preamble language:

(1) stating EPA's 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;

(2) requesting comments on measures to mitigate impacts on stripper and other marginally economic oil and gas production, as well as on small operators;

(3) announce a EPA/DOE partnership to assist States and EPA regions to develop AOR variance plans pursuant to the rule and encourage risk-based regulatory decision-making. (This would lessen the cost of the rule. And, it supports the Domestic Natural Gas and Oil Initiative. The DOE Office of Fossil Energy anticipates spending approximately $4 million total in FY 1994 and 1995 to refine methodologies for risk assessment and to assist States in developing AOR variance plans and improving data management for risk-based decision-making).

(c) Issue a more stringent proposed rule. This could happen if FAC participants withdraw their support for the consensus report. Some offices within EPA have called for a proposed rule that would be more stringent than FAC recommendations. Any added stringency could increase cost to industry. A more stringent proposal could lessen EPA and DOE's credibility for not substantively adhering to the "negotiated" FAC recommendations.

DOMESTIC GAS AND OIL INITIATIVES
Non-use Values of Natural Resources

Introduction

Under authority of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (CERCLA), and the Oil Pollution Act of 1990 (OPA), the Department of the Interior (DOI) and the National Oceanic and Atmospheric Administration (NOAA) are developing regulations for Natural Resource Damage Assessments (NRDA) to determine the injuries to and restoration of natural resources as a result of releases of hazardous substances and discharges of oil. In addition to liability for the costs of restoration, the responsible parties are to be liable for the diminution in value of those resources pending restoration The diminution of value is to encompass both direct use (e.g., commercial, recreational) values as well as non-use ("passive use") values that can be reliably calculated. "Passive use" values refer to the values individuals place on resources that are not linked to direct resource use by the individual, e.g., the value derived from protecting the resource for its own sake; and the value of knowing that future generations will be able to use the resource. Contingent valuation (CV), a survey-based method, is the only method available for measuring passive use values.

1. **Proposal:** The oil and gas industry has proposed that DOI/DOC exclude liability for non-use value loss from regulations on natural resource damages for discharges of oil.

2. **Fit with Criteria:** Proposal is inconsistent with the microeconomic and macroeconomic criteria since it artificially excludes lost passive values from the full cost of oil production, frustrating the "polluter pays" principle. The national security criterion may also be violated since the proposal may result in encouraging the use of foreign oil relative to domestic oil by disproportionately decreasing the cost of liability insurance for large tankers since large tanker spills represent the most likely context for use of CV under the NOAA proposed regulations. Finally, the proposal would not fully protect the value of public natural resource assets.

3. **Existing Policy Baseline:**
In the 1980s, the Department of Interior promulgated regulations interpreting the NRDA provisions of CERCLA, and was sued by a range of parties on a range of issues, including contingent valuation. The D.C. Circuit Court decision in that case [*Ohio v. Department of Interior*] clearly indicated that diminution in value is to encompass both direct use (e.g., commercial and recreational) as well as passive use values that can be reliably calculated, i.e. calculated in a manner that is trustworthy or worthy of confidence. Further, the *Ohio* decision

107

found that CV methodology could be utilized as a "valid, proven technique when properly structured and professionally applied." [The DC Circuit Court will be the court to hear the inevitable challenges to the OPA NRDA rule and the revised DOI rule.]

Due to substantial interest in the topic during its rulemaking, NOAA convened a panel of experts co-chaired by two Nobel laureates, to evaluate the reliability of CV to measure passive use values. The Blue Ribbon Panel found that contingent valuation can produce estimates reliable enough to be presented in a judicial or administrative determination of natural resource damages, including passive use value, provided that such studies adhere closely to the guidelines described in their report. Based on information in the Panel's report and on other comments, NOAA and DOI regulations follow closely the guidelines recommended by the Blue Ribbon Panel, including procedures for internal validity tests. These guidelines are also designed to meet the standard tests applied to the admissability of evidence in litigation.

After three years of an open process, involving intensive consultation with the public and with other government agencies, NOAA proposed the OPA natural resource damage assessment regulations on January 7, 1994. The comment period is open until July 7, 1994, having been extended due to numerous requests from industry.

The Department of the Interior is currently repromulgating the CV portions of the regulations in response to the judicial remand. NOAA and DOI coordinated closely in drafting and refining the CV language for the rule, and in participating in the inter-agency review process prior to proposal.

In their proposed regulations, both agencies are following the statutory and judicial mandates that "interim lost value" include both direct use and passive use values. Further, NOAA and DOI are proposing that reliable estimates of lost passive use values may be estimated using contingent valuation (CV), the only available method for determining passive use values, so long as the CV study follows the guidelines designed to produce reliable studies and to provide internal validity checks.

4. **Recommended Variations:** Launch a high level Administration-wide review of the use of contingent valuation in natural resource damage assessment by key policy makers from each interested agency to coincide with and be coordinated with development of the NOAA and DOI regulations. Representatives of the oil industry, trustees, environmentalists, and CV practitioners would be invited to present their views directly to the review panel representing all interested agencies. Carry out a special study to be presented to the review panel of the economic impact of reasonable options for CV NRDA regulations including variations in size cutoffs for using CV on different segments of the oil and gas industry, including the availability of insurance to the industry.

5. Pros and Cons of Exclusion of Non-use Values

Pros:
Would be responsive to industry's request to be relieved of part of the liability established by CERCLA and OPA.

Cons:
Destroys the integrity of the process of soliciting public comments in the rule-making process; will not allow the federal agencies to benefit from current research exploring various provisions of the NOAA/DOI regulations (research precipitated by the proposed rules).

Reflects a position that violates the *Ohio* decision (which was written by the D.C. Circuit Court, the court that will hear any challenges to the final NRDA rules), or one that is contrary to the intent of Congress for OPA.

Is not consistent with Administration position on passive use values and the use of CV to measure them, developed in an extensive interagency review process in December 1993, with technical discussions facilitated by CEA at OMB's request, prior to proposal of NOAA rule.

Trustees (states and tribes) would be more likely to choose not to use the NOAA/DOI rules, and would alternatively present damages calculated as they see fit, possibly to juries in the vicinity of the incident giving rise to the liability.

Avoid early loss of NRDA payments to Federal Government for passive use damages to Federally-managed natural resources that would result from acceptance of industry request.

6. Legislative Outlook: OPA Conference Report was very clear that "diminution in value" referred to the finding in the *Ohio* court. We are not aware of any pending legislation that would change that standard.

7. Costs: Unclear at this time; however, excluding non-use values would almost certainly result in the rules being overturned by the same court, which would mean the expense of re-drafting the rules. The variation suggested has no additional budget implications since it represents the baseline.

9. Other Impacts: Unclear at this time; however, the environmental community would be highly critical of the Administration if the proposal were adopted. In contrast to the oil and gas industry proposal, the recommended variation (following the current rulemaking process) is consistent with the criteria for evaluation. It is consistent with microeconomic principles by continuing a public process that facilitates the reliable assessment of lost nonuse values. It is consistent with the President's macroeconomic concerns by facilitating a process that accounts for previously ignored environmental costs. The variation is consistent with the national security goal in that it does not artificially lower the cost of domestic oil production below its full social cost. The variation is also consistent with the national security goal relative to the proposal in that it may encourage the use of domestic oil relative to foreign oil by increasing the insurance costs of imported oil relative to the insurance costs of transporting domestic oil. Finally, it is consistent with the goal of protecting the value of public assets by promoting a process that facilitates the reliable assessment of lost passive values.

III. Current Proposals Involving Gas and Oil

D. Regulatory Proposals

1. **Proposal:** The Oil and Gas Industry has proposed that the Bureau of Land Management (BLM) maintain its policy of multiple use management.

2. **Fit with criteria:** When making multiple use and ecosystem management decisions, a larger geographical are will be considered and political boundaries will no longer be the determining factor. All land users, including the oil and gas industry will be a part of the multiple use management decisions. This will have a negligible effect on microeconomic, macroeconomic, security, or budgetary concerns.

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.

   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.

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

<u>Pros</u>

- 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.

F:\P&P\ELPB\NEC\MULTI2