The Impact of Environmental Regulation on U.S. Petroleum Production

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Contents

Chapter 1

General Introduction

The U.S. oil and gas industry is among America's largest and most important industries. Domestic petroleum production and petroleum imports in 1994 were each worth about $45 billion. Since oil and gas are the largest sources of energy and among the largest sources of corporate profits in the U.S. economy, policy makers have often concerned themselves with the domestic production of oil and gas and with the increasing reliance upon imported oil. Regulatory measures have frequently had conflicting or contradictory effects, presumably because of unintended consequences of the regulations. Some policies have been designed to benefit the domestic oil and gas industry. Some such policies have, at least ostensibly, attempted to increase oil and gas production. Others have restricted production, on the theory that oil and gas should be saved for the future. This type of regulation has often allowed the domestic oil industry to gain monopoly power and, presumably, increase profits. Policies adverse to the industry have been designed either to reduce consumer prices for refined petroleum products and natural gas or to protect the environment, and in doing so have reduced domestic oil and gas production. This paper examines the effects which environmental regulation[1] has had on costs and production of petroleum in the United States.

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[1]The term "regulation" as used in this paper in some cases includes both statutory law and regulations of the executive branch. Moreover, the term "regulations" is sometimes used to refer to a group of regulatory measures in the aggregate.

The History of Petroleum Regulation

The domestic petroleum industry has faced regulation almost since its inception. This regulation tended to benefit the industry until the 1970's, when the regulation took on a heightened importance and generally hindered the industry. The first regulation of the petroleum industry was the Hepburn Act (1906), which regulated petroleum pipelines and directed the Interstate Commerce Commission to set pipeline rates. This act was intended to reduce the monopoly power of the pipelines and the Standard Oil Company, rather than to regulate the petroleum industry as a whole. During World War I, the federal government established the United States Fuel Administration and gave it the power to regulate the prices and distribution of petroleum and other fuels. This power was never exercised, however.

During the 1920's, the Federal Oil Conservation Board (FOCB) was created to reduce the inefficiencies which had resulted from applying the rule of capture, which gave the rights to oil to the first person to extract it from the ground. This policy created inefficiently high production in fields where more than one party was producing oil. Production was inefficient because each party had an incentive to pump as quickly as possible, before competitors extracted more of the limited amount of oil. However, since pumping quickly diminishes the natural pressure in the oil field, the total amount that can be extracted from the field is reduced. This was a negative externality by which production decisions of one producer raised costs for others and was correctly recognized as wasteful. In response to pressure from the FOCB, the states enacted laws allowing parties producing in a field to collude and reduce production. With this privilege, the oil producers were able not only to reduce costs within a field but also to take advantage (with federal-level FOCB assistance) of coordination to reduce total output and gain monopoly profits. In addition, as a result of the efforts of the FOCB, the petroleum industry began to receive special federal tax treatment in the form of a depletion allowance. This special tax treatment has continued to the present day.

The New Deal brought increased federal regulation in many sectors of the U.S. economy, but there was little increased regulation of the petroleum industry. The first major regulation of the gas industry occurred in 1938 with the passing of the Natural Gas Act. This act gave the Federal Power Commission (FPC) the authority to regulate the rates of interstate natural gas pipelines. A 1954 Supreme Court decision extended the FPC's authority to regulate the wellhead prices for interstate natural gas.

After World War II the petroleum industry was no longer able to meet all domestic demand at the world price, which resulted in ever increasing oil imports. The combination of these imports and the friendly attitude of the federal government towards the oil industry led to oil import quotas, which became mandatory in 1959. In 1971 the regulation of the oil industry changed from being generally beneficial to being generally unfavorable when President Nixon instituted wage and price controls, including price controls on oil. Most of these controls were allowed to expire in 1973, but the price controls on oil were continued. They became important when the price of oil rose dramatically during the 1973-74 and 1979-80 OPEC oil embargoes.

The primary purpose of the price controls during the 1970's was to reduce the prices consumers paid for refined petroleum products. If price controls had been imposed only on domestic crude oil, the result would have been to reduce domestic production and increase imports. Thus, despite the price controls, at the margin the cost of crude oil faced by refiners would have remained at the world price. Therefore refiners' marginal costs and production decisions would not have changed as a result of the controls.

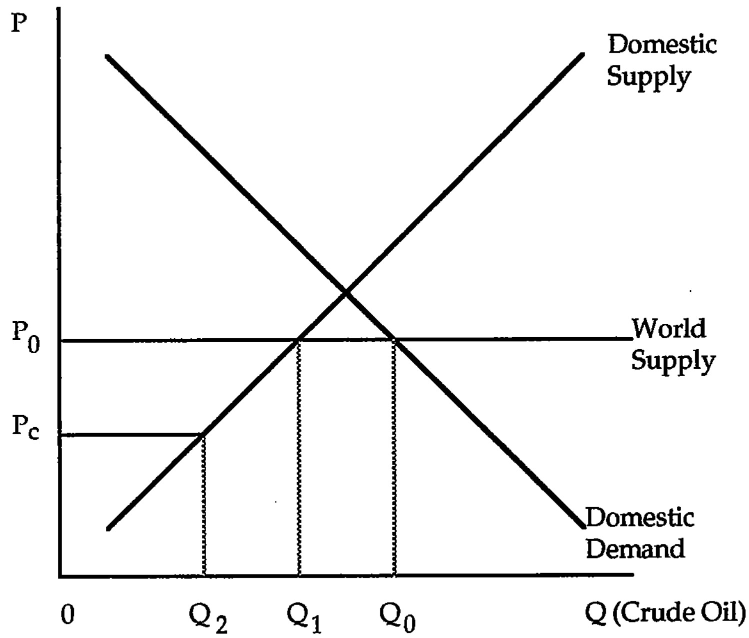

Figure 1.1

Figure 1.1, in which domestic producers are assumed to be price takers and foreign producers are willing to offer ample supply at P_0, illustrates the effect of price controls. Initially the domestic price of crude oil equals the world crude oil price P_0. At that price, oil consumption is Q_0 and domestic production is Q_1, with imports accounting for the difference, $Q_0 - Q_1$. If a price control on domestic oil is instituted at price P_c, the quantity of oil produced domestically decreases to Q_2 and imports increase to $Q_0 - Q_2$. Total consumption and the world price remain the same. For crude oil producers, total producer surplus decreases, while those refiners that have access to the price controlled oil are benefited.[2]

The regulation, however, went beyond price ceilings. Through the entitlements system, the ratio of price controlled oil to imported oil for each refiner was equalized. The price of oil to each refiner was therefore a

[2]As long as imports are substantial, the domestic price is effectively the same as the world price. Price controls increase the volume and importance of imported crude but do not affect its price.

weighted average of the controlled domestic price and the world (import) price. This system made the marginal cost of oil to a refiner equal to the average cost, which was lower because of the price controls, and reduced refined product prices.

In the 1980's the price controls on oil were removed, as was most of the direct regulation of the oil industry. However, growing concern about the environment led to a series of laws and regulations which forced oil producers to comply with procedures intended to reduce the damage to the environment from petroleum production. These laws include the National Environmental Policy Act, the Resource Conservation and Recovery Act, the Clean Water Act, and the Comprehensive Environmental Response, Compensation, and Liability Act (usually called CERCLA or Superfund). As a result of the regulations authorized under these acts, the costs of petroleum extraction increased, which discouraged domestic production during the 1980's, in spite of and in conflict with the general movement towards a reduction in petroleum regulation.

Goals of the Paper

Although there has been extensive research on the oil and gas industry, most of the research on the regulation of the industry examines the price control regulation of the 1970's. Little of the previous research examines the effects of environmental regulation on total domestic petroleum production. I propose to examine the effect of current and potential future environmental regulation on domestic petroleum production in the aggregate. The current environmental costs are taken from American Petroleum Institute environmental cost estimates; the potential future regulatory costs are taken from Department of Energy cost estimates. The goals of this paper are primarily positive, to determine if such regulation has caused significant changes in the production of oil.

Subsequent Chapters

This paper has seven chapters. Chapter 2 summarizes previous economic studies of oil and gas. In January, I interviewed five oil industry executives. Chapter 3 summarizes these executives' views on the environmental regulation of petroleum production and how the current regulatory environment has affected production. In chapter 4 I develop an economic supply model of domestic petroleum production. Chapter 5 develops a price leadership model of the U.S. petroleum market, with a provision for regulatory costs. Chapter 6 describes the estimation of the parameters used in the price leadership model and the predictions made by the model. Chapter 7 uses the supply and price leadership models to estimate how current and potential future regulatory costs affect domestic petroleum production.

Chapter 2

Previous Work in the Area

The energy crises of 1973 and 1979 put the petroleum industry in the national spotlight. The petroleum industry in the 1970's has been intensively studied. Most of this research examines the effects of the oil price controls and the entitlements system of the 1970's. In the 1980's President Reagan reduced the regulation of the oil industry, and in the process fired approximately 1,800 of the 2,000 federal oil bureaucrats. In addition, oil prices fell by nearly 50% in 1986, and a lack of future energy resources was seen as less of a threat to the nation's economic future. Because of these changes, government research and government-sponsored research were greatly reduced. Insofar as government research continued at all, it shifted toward environmental issues. The focus of non-government research has shifted away from domestic supply and responsiveness toward particular techniques and locations associated with environmental risk.

Studies of Regulations in the 1970's

Joseph Kalt makes a rigorous theoretical and empirical study of the effects of the price controls and entitlements program of the 1970's in The Economics and Politics of Oil Price Regulation (1981). His general findings are that the federal government's shift from pro-producer policies before 1971 to anti-producer policies transferred income from producers to intermediate and final consumers of crude oil and crude oil products in the range of $14-$50 billion per year from 1974 through 1980 (Kalt, 1981, p. 286). In addition, the price controls and entitlements programs caused deadweight losses ranging from \$0.8-\$5.7 billion (p. 216). Kalt estimates that the entitlements program subsidized 10%-20% of the cost of imported crude oil from 1974 through 1980, which increased the U.S.'s dependence upon imported oil and exacerbated the disruptions caused by the 1979 oil embargo (p. 287). Kalt also speculates on the negative consequences for economic efficiency of the Windfall Profits Tax, which was enacted under President Carter to replace the oil price controls and entitlements system. This tax never had a large impact on the domestic petroleum industry because of the fall in world petroleum prices in the 1980's.

W. David Montgomery, of the Department of Energy, discusses the effects of the price controls from a theoretical standpoint in "Decontrol of Crude Oil Prices" (1981). Montgomery states that the price controls functioned as a stepped marginal revenue curve. Because of the stepped nature of the marginal revenue curve, the marginal cost curve of an oil-producing property could intersect this demand curve at several points (see figure 2.1).

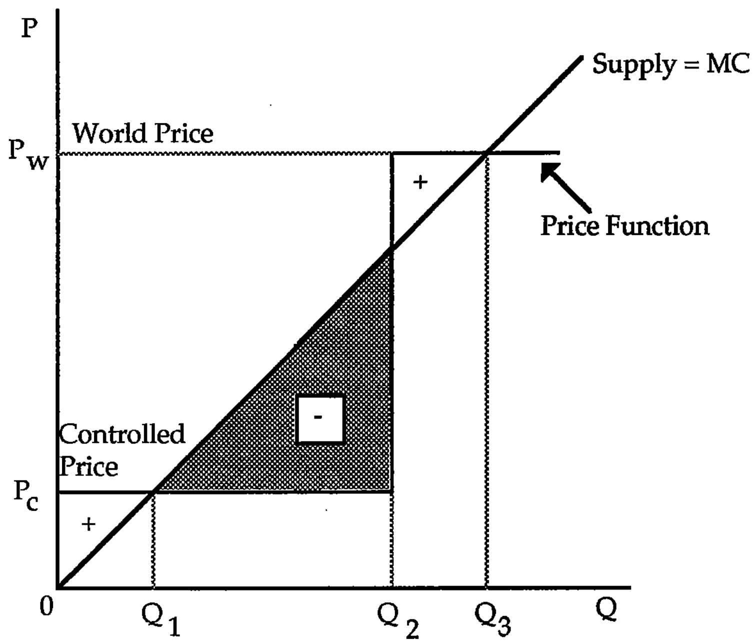

Figure 2.1

Figure 2.1 shows the marginal cost and price function for an oil producing property with price controls. For the firm in question, P_c is the price it receives for each unit of production up to Q_2. For additional production beyond Q_2 the firm's marginal revenue is P_W, the world price. If all output must be sold at the controlled price, P_c, the profit-maximizing output for the firm is Q_1. At production levels higher than Q_1, marginal cost is greater than P_c; thus profits would be reduced by producing more than Q_1.

Production would always be Q_1 except that P_c is effective only up to a limit (Q_2). If the quantity produced exceeds Q_2, the marginal revenue for units in excess of Q_2 is P_W. The firm would produce Q_3 if and only if total profit is greater at Q_3 than at Q_1. In the figure, since the gains are clearly not as large as the losses in moving from Q_1 to Q_3, production would be only Q_1. If Q_2 were moved to the left the firm could be induced to produce Q_3.[1]

Since the placement of Q_2 was different for different fields, firms would produce at different levels from different fields even if the fields' costs were the same. Montgomery states that, in order to reduce the average crude oil price as much as possible without affecting the production decision, the price function should have many steps and be close to the supply function, but should intercept the supply function only at the world price. In addition, the price control system mandated that properties which had produced below their "base level of production" had to make up this deficiency by selling oil produced above the base level at the low, controlled price before they could begin to sell oil at the higher prices allowed for production in excess of the base production. Because of this rule, owners of properties which fell deeply in arrears below their base level of production had reduced incentives to

[1] The price controls actually had two price levels, rather than the one shown here. The amount of production from a particular field which was sold at each level depended on the production in some base year. The base year changed as the legislation was modified.

produce additional oil, as they could receive only the base price even with additional production above base level (Montgomery, 1981, pp. 193-196).

In "Petroleum Regulation and Public Policy" (1986), R. Glenn Hubbard and Robert Weiner discuss the petroleum price controls of the 1970's and domestic petroleum policy in the first half of the 1980's. Hubbard and Weiner estimate that the annual deadweight losses of the entitlements subsidy for 1975-1980 were small if the elasticity of import supply was very low but that such losses may have been as much as $1.038 billion. In addition, the entitlements subsidy transferred as much as $12.5 billion annually from domestic oil producers to foreign oil producers whose exports reached the domestic market (pp. 126-127). Hubbard and Weiner argue that there is a negative externality associated with consumption of imported oil since high oil imports make our economy vulnerable to massive damage in the event of an oil embargo. They suggest that an import tariff would be one way to make the market price of imported oil equal its marginal social cost and thereby eliminate the externality. However, a tariff would transfer wealth from domestic consumers to producers and would be politically difficult. Hubbard and Weiner also discuss the strategic petroleum reserve (SPR) and state that having an SPR would have "significant benefits in terms of reduced oil prices during shocks" (p. 130).

The consensus of the studies of the price control and entitlements regulation of the 1970's is that this regulation was successful in reducing the overall price of crude oil, but at the cost of massive market disruptions. In addition, the price controls made the U.S. more dependent on crude oil imports, primarily from OPEC, and exacerbated the economic disruptions of the 1979 oil embargo.

Studies of Offshore Oil and Gas

Constance Helfat develops a portfolio choice model for offshore oil investments in "Investment in Offshore Oil by Diversified Petroleum Companies" (1989) and then applies this model to explain the drop in offshore lease prices after the 1973-1974 oil embargo. Helfat's model has the firm minimize the variance of cash flows from investments, subject to a return on investment requirement. Helfat then develops a sub-model for the present discounted value of cash flows from an offshore oil tract, which includes as variables the preparation costs of the site, the marginal tax rate, a discount factor, output, price of oil, price growth rate, and operating costs. Helfat estimates her model and then compares the results to actual prices paid for offshore oil leases in the 1970's. This comparison shows that oil companies overpaid for offshore leases prior to the 1973 oil embargo but paid only the predicted amounts after the embargo. Helfat concludes that this drop occurred not as a result of the oil embargo (which should have actually raised lease prices, since the higher oil prices increased the expected returns on an oil investment), but because of a consistent overestimation of tract returns in the early 1970's. This overestimation stopped after the 1973 embargo. Helfat does not provide a clear causal link between the cessation of overestimation and the oil embargo.

Di Jin and Thomas Grigalunas develop a model of offshore oil and gas investment and production in "Environmental Compliance and Energy Exploration and Production: Application to Offshore Oil and Gas" (1993). In their basic model, an oil and gas firm maximizes the present value of profits from oil and gas development and production. The model includes exploration costs, development costs, and production costs as variables; Jin and Grigalunas also have sub-models to determine each of these costs. Each of these sub-models includes many variables which affect costs, including variables relating to environmental regulation. The model assumes that a firm will not explore a field unless the expected after tax net present value is positive.

Using their model, Jin and Grigalunas reach many conclusions, among them that (1) stricter regulations have a proportionately greater impact on smaller fields and therefore hurt smaller independent producers disproportionately; and (2) the environmental regulation that would have the greatest negative impact on the profitability of exploration and development would be a rule which forced offshore producers to have no discharge of drilling muds. Other regulations would have negative impacts of varying degrees of severity. The magnitudes of the production decreases predicted by Jin and Grigalunas' model are quite large; in one case the model predicts a 51% decrease in production for the strictest possible regulations on a medium-sized offshore field.

Studies of the Tax Treatment of the Oil and Gas Industry

Contrary to its initial conception, this paper does not examine how federal tax provisions affect petroleum production. Nevertheless, to preserve my research on the subject, this section includes a selection of the many economic studies of how taxation affects petroleum production. These studies illustrate that government policies affecting the oil industry do not always place burdens on production; on the contrary, some tax policies have strongly encouraged domestic production.

In "Assessing the U.S. Federal Tax Burden on Oil and Gas Extraction" (1987), Robert Lucke and Eric Toder examine the tax treatment of the oil and gas (O&G) industry and how this treatment changed under the Tax Reform

Act of 1986 (TRA86). In comparison to other sectors, they find that the O&G industry clearly receives special tax treatment because of the favorable rules for capital cost recovery (p. 51). TRA86 scaled back some of the tax advantages for domestic O&G production. In addition, TRA86 made changes which are unfavorable to the O&G industry in the alternative minimum tax (AMT) provisions. Ironically, Lucke and Toder conclude that TRA86, in spite the adverse changes in O&G taxation, actually made O&G investments relatively more favorable than other investments, because other industries received significantly less favorable capital recovery provisions under TRA86 (p. 54).

The article then examines the effective marginal tax rates on crude oil investments. A discounted cash flow (DCF) model is used, which takes into account the present discounted value of expected revenues, costs, and taxes for an investment. Lucke and Toder's simulation finds that the effective marginal tax rates on new oil investments range from 7% to 14% for integrated oil companies and from minus 8% (a subsidy) to plus 2% for independent oil companies. These rates are slightly lower than the rates which would have applied under pre-TRA86 tax law[2] and are slightly higher than those that would apply to an oil company using the AMT.

Lucke and Toder also consider the effect of the present tax law on past investments made by many industries in the U.S. economy. These results were determined by using a weighted average of the taxes that would have been imposed on investments in each of these industries as they were made from 1939 through 1984, if post-TRA86 tax law had been in effect; hence, they differ from those reported using the DCF model. They conclude that the petroleum industry faces a different marginal tax rate from that applying to

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[2]This result is not explained by Lucke and Toder, but presumably the lower statutory marginal tax rates under TRA86 more than offset the slower capital recovery for the O&G industry.

any other major industry. Lucke and Toder report that effective marginal tax rates for other industries range from a low of 24% for the communications industry to a high of 33% for several industries. The overall average effective marginal tax rate for all industries excluding petroleum is 31%. The effective marginal tax rate for crude oil production by integrated companies ranges from 7% to 24%, averaging 17%, and the rate for independent companies ranges from minus 8% to plus 2%, averaging 0% (p. 61).[3] These results do not include the windfall profits tax (appropriately, since it has been repealed) nor the AMT. If the AMT is included, the marginal rates are slightly higher for both types of producers.

The General Accounting Office (GAO) examines the tax treatment of the petroleum industry and the potential for increasing domestic petroleum production by additional tax incentives in Additional Petroleum Production Tax Incentives Are of Questionable Merit (1990). This paper outlines the special tax treatment which the petroleum industry currently receives. The paper then discusses the current marginal effective tax rates for new petroleum production. The statutory rate for marginal income increases is 35% for all large companies in all industries including the petroleum industry. The GAO advocates "tax neutrality" for business investments, in order that marginal investments be determined by relative rates of return and risk and not by differential tax treatment among industries, and states that tax neutrality would generally require equal marginal tax rates across industries. However, the GAO notes that sometimes it may be necessary to meet "more complicated objectives" such as "other distributional and efficiency goals." These objectives may necessitate different marginal tax rates across industries (p. 54) and therefore apparently do not always support tax neutrality among

[3]The average rates are given in the GAO's 1990 discussion of this study; see below.

business investments. The GAO summarizes the Lucke and Toder study discussed above.

To determine whether Lucke and Toder's results were flawed because of modeling assumptions, the GAO commissioned Jane Gravelle of the Congressional Research Service to estimate the tax rates applicable to various industries both in the standard manner and while considering R&D and advertising expenditures as capital expenditures. The results of Gravelle's study were essentially the same as those of the Lucke and Toder study, with the marginal tax rate for integrated petroleum firms' production being 17%[4] and the rates for other industries averaging about 28%. The inclusion of intangible assets in capital had no effect on the petroleum industry's marginal tax rate and had only small effects on the tax rates of other industries (pp. 58-59). The GAO finds that, because the petroleum industry already receives uniquely favorable tax treatment, additional tax incentives would have only small production effects. Tax incentives would increase domestic petroleum production by about 0.2% to 0.3% (i.e., about 20,000 barrels per day) while reducing tax revenues by $3 to $14 per barrel of additional production (p. 34). The GAO also finds that the current tax incentives already provide incentives for inefficient investments within the petroleum industry and that the U.S. tax structure does not usually give domestic producers an incentive to invest in foreign projects (p. 3).

Studies of Oil and Gas Regulation and Production of the 1980's

The literature discussed in this section examines the effects of various forms of regulation on the oil and gas industry during the 1980's. Conspicuously absent from all of this research is the inclusion of "user cost"

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[4]Independent firms were not considered in this study.

in the examination. User cost is the opportunity cost of the production of a non-renewable resource. The concept of user cost was originally proposed by Harold Hotelling in 1931. In theory, a firm equates marginal revenue with the marginal cost of production plus user cost; thus, user cost could explain a gap between marginal revenue and the marginal cost of production. Since the U.S. oil industry today is a competitive industry and is a price taker in world oil markets, the marginal cost of production should equal the price of oil. On the other hand, the gap between price and marginal cost for oil from the Middle East is so large at present[5] that it is virtually inconceivable that the difference is explained by user cost. The more likely case is that OPEC uses its market power to increase the world price of oil above its marginal cost of production. In any event, none of the recent research considers user cost to be a significant factor.

A recent study concludes that user cost is insignificant: "Petroleum Producing and Consuming Countries: A Coalescence of Interests" (1988). Munkirs and Knoedler, the authors, argue that the greatest threat facing the petroleum industry is that greater production will reduce prices and profits. Production in the Persian Gulf countries could more than double in less than 10 years, which would greatly reduce prices. Munkirs and Knoedler argue that Hotelling's theory of depletable resources does not explain the high prices in the industry,[6] since reserves are constantly expanding as technology improves.

Turning to a different subject, M.A. Adelman studies the changes in oil development costs after 1986 in "U.S. oil/gas production cost: recent changes"

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[5]One estimate puts the marginal cost of production for a barrel of Persian Gulf oil as low as 25 cents (Griffin and Steele, 1986, p. 70).
[6]Munkirs and Knoedler estimate the marginal cost of production for a barrel of Middle Eastern oil to be between 30 and 60 cents (p. 18).

(1991). Adelman assumes that new reserves are a function of oil prices and exhibit diminishing returns with higher prices. This model correctly predicts the reduction in new reserves after the 1986 price declines. Adelman finds that the reduction occurred not only because of the lower prices but also because of an increase in the exponential coefficient of the model, which represents the diminishing returns. This indicates that the supply curve for oil reserve additions has moved unfavorably inward since 1986 and that lower oil prices are not the only reason for falling domestic production.

In United States Energy Policy 1980-1988 (1988), the Department of Energy (DOE) discusses the energy policy of the 1980's and makes recommendations for changes in energy policy and regulation, with the general goals of increasing or at least maintaining domestic production and reducing reliance on imported oil. The DOE recommends that research in enhanced oil recovery techniques be intensified so that more of the oil in the ground can be extracted. In addition, the DOE calls for exploration and development of more offshore oil tracts (especially tracts not in the Gulf of Mexico) and more Arctic oil fields. Two tax relief proposals are made: one would allow integrated oil companies to use percentage depletion for properties which they purchase from independent oil companies (which are the only companies currently allowed to use percentage depletion), and the other would allow percentage depletion deductions to increase from 50% to 100% of a property's net income (p. 23). The DOE states that these tax proposals would allow more marginal oil properties to remain in production. The DOE also concludes that there is no need to subject oil and gas production wells to the strict hazardous waste disposal regulations adopted under subtitle C of the Resource Conservation and Recovery Act (RCRA).

In a rather different approach, Carl Schwobel interviewed producers operating in the outer continental shelf (OCS) to determine which regulations they find most burdensome (The Gulf of Mexico: OCS Operator Concerns, Issues, and Problems, 1994). This study is useful because those regulations which industry executives believe to be the most burdensome are presumably those that have had the greatest effect on production. Mr. Schwobel found that the greatest regulatory problems facing OCS operators are environmental regulations. The two regulations mentioned most often are the Oil Pollution Act of 1990 (OPA) and the National Pollution Discharge Elimination System (NPDES). OPA mandates that all offshore operators must have a minimum of $150 million available to pay cleanup costs in the event of an oil spill. This requirement eliminates many independent oil companies from consideration for OCS leases. In addition, operators complain that OPA makes them liable for environmental resources with "nonuse values" (for example, plankton) which are damaged in an oil spill, and they are concerned about how nonuse values would be determined in the event of a lawsuit.

Operators dislike the NPDES, which governs the disposal of produced water, because they contend that the EPA is continually increasing the strictness of the standards without considering the costs associated with reducing the pollution in the produced water or even whether the technology to reduce the pollution is available. Throughout his interviews, Mr. Schwobel noted that operators continually complain about the lack of cost-benefit analyses when new environmental regulations are drafted and that the EPA has a "zero-pollution" mentality which results in ever stricter emission standards. The EPA seems to pursue the goal of totally eliminating emission of pollutants, even if to achieve it companies must be driven out of the Gulf.

Susan Zachos examines the application to O&G production in Texas of the Clean Air Act of 1977 (CAA), the 1990 amendments to the CAA, and the Texas Clean Air Act (TCAA) and its 1991 amendments in "Air Pollution Requirements Applicable to Oil & Gas Operations" (1994). She finds that, in general, this legislation has had little effect on O&G production, since nearly all O&G production operations are given special exemptions from the regulations in the original acts (p. 5). The legislation does have important effects on the petroleum refining industry, which does not receive special exemptions and is a major source of pollution. The one area of O&G production which could be affected by the 1990 amendments to the CAA is outer continental shelf production, which is regulated for the first time under these amendments. However, the act specifically exempted all OCS O&G production off the coast of Texas, and the new regulations promulgated under the authority of the act by the EPA are currently the subject of a lawsuit (p. 10).

The Department of Energy discusses the effects on production of various proposed changes in environmental regulations in <u>Potential Cumulative Impacts of Environmental Regulatory Initiatives on U.S. Crude Oil Exploration and Production</u> (1990). This paper considers proposed changes to four different environmental laws: RCRA, the Safe Drinking Water Act, the Clean Water Act, and the CAA. For each law, three different regulatory scenarios are considered: low, medium, and high. The low scenario assumes minimal changes to the regulations, the medium scenario assumes moderate regulatory changes, and the high scenario assumes extensive regulatory changes. All of the changes would cause the regulations to be more burdensome to producers and to reduce production. The costs of compliance with each aspect of the regulations which is changed are estimated; for example, the DOE estimates that the requirement that all emergency pits be lined (a change in RCRA under the low regulatory scenario) would cost $355 per pit. These costs are then totaled for all regulatory changes in each scenario.

The costs are broken out into initial costs, which would be incurred by producers when the regulations were promulgated (the lining of emergency pits would be an initial cost), and annual costs, which would be the new costs associated with continuing compliance with the regulations. The total initial cost estimates for the regulations range from $15 billion for the low scenario to $79 billion for the high scenario, and the total annual cost estimates range from $2 billion to $7 billion (DOE, 1990, p. 24). The annual costs, which would affect the marginal cost of production, could therefore exceed $2 per barrel. These results are used in my paper to estimate the effect which the proposed regulatory changes would have on domestic petroleum production costs. Since these results are used extensively, a description of the proposed regulatory changes to RCRA under the medium scenario is given in Appendix A. This appendix is provided only to illustrate the detail of the potential regulatory changes which the DOE examines.

The DOE study then goes on to determine the effects of the regulatory changes on oil production in nine states. These states represented approximately 30% of U.S. production in 1990. The DOE finds that, under the medium regulatory scenario with an oil price of $20/barrel, production in these states would be 12% below the reference level (no new regulations) ten years after the promulgation of the regulations (p. 44). The study does not consider the effects of the proposed regulatory changes on overall national production.

General Commentary on Previous Economic Studies of Petroleum

There are many other economic studies of the petroleum industry. Most of the studies, however, focus on the regulation of the industry which took place in the 1970's. Few studies at any time have dealt explicitly with determinants of domestic production, which is the issue addressed by this paper. Moreover, while the studies described above are a representative sample of the literature, those studies, with the exception of the DOE study of future regulatory costs, were generally not very helpful for this paper.

Chapter 3

Interviews with Individuals Working in the Oil Industry

During January I was able to interview five individuals in the oil industry about the topics covered in my thesis. I spoke with four individuals at Pennzoil Company, an integrated oil company, and with an individual who owns and runs an independent oil production company. At Pennzoil I spoke with Lance C. Vinson, Environmental Counsel; Sarosh J. H. Manekshaw, Director, Environmental, Safety and Health Affairs; David Soza, Senior Environmental Engineer; and Bruce T. Maughs, Assistant Director of Tax. I spoke with Mr. Vinson, Mr. Manekshaw, and Mr. Soza about the environmental regulation of petroleum production and of the petroleum industry in general. I spoke with Mr. Maughs about the tax treatment of petroleum companies and other issues affecting investments in petroleum properties. I also spoke with Mr. John Kirby Ewing of Ewing Oil Company, an independent oil producer operating in the southwest, about the environmental regulations to which his company is subject. Mr. Ewing also discussed the economics of a single stripper well and the physical aspects of oil production. Below are detailed summaries of and commentary for each of the interviews.

Mr. Lance C. Vinson, Environmental Counsel, Pennzoil Company

Mr. Vinson spoke about a variety of environmental regulations affecting the oil industry. Before coming to work at Pennzoil, Mr. Vinson worked at the EPA. In general, Mr. Vinson believes that federal environmental regulations have not had a large direct impact on domestic oil production and that no specific federal regulation has been particularly onerous for production. He has a generally favorable view of the EPA, stating that many EPA regulators are overworked and are trying to do what they think is right.

Mr. Vinson first discussed the Resource Conservation and Recovery Act (RCRA) and its 1984 amendments. One aspect of the 1984 amendments was to require far stricter standards for underground storage tanks (USTs). By 1987 the new UST regulations resulting from the 1984 amendments to RCRA began to take effect. These regulations had major impacts on the retail and refining side of the industry but had little effect on production, as oil production was given an exemption from the new regulations. The new RCRA regulations affected refiners by changing the methods of dealing with refining wastes and by requiring that a refinery which had any wastes in the ground must clean up these wastes in order to get new permits. Mr. Vinson stated that regulation like RCRA, which imposed major costs on integrated producers on the "downstream" (i.e., refining and marketing) side of the business, would have some effect upon production by an integrated producer. The limited capital must be divided between "upstream" (production) and downstream operations; when downstream operations become more expensive, less capital is available for upstream operations. Mr. Vinson believes that regulations probably do divert capital away from production and therefore reduce production but that this is a very subtle effect.

Mr. Vinson then also discussed the Clean Water Act (CWA). The most important effects of the CWA for oil production have been the effects upon offshore oil production. The first regulations issued under the CWA for offshore oil were promulgated in 1981 and dealt with produced water. Produced water is the water which is extracted in combination with the oil in a well. Nearly all wells have some produced water, and in some wells there can be more produced water than oil. The regulations limited the amount of oil and grease which produced water may contain when it is discharged into the ocean. They were not very stringent in 1981, although they have been subsequently tightened. Louisiana recently banned the discharge of produced water for offshore production, and this should have a large impact on production. For onshore production, produced water discharges have been banned since 1981. Producers are required to reinject produced water, which typically means that produced water is fed back into a well which is no longer producing. This regulation had almost no impact on production by major oil producers, since most of them were already reinjecting.

The CWA has also regulated the content and discharge of drilling muds. Drilling muds are the material which is circulated through the well during drilling to extract the cuttings and lubricate the drill bit. Muds typically contain barite mixed with water, mineral oil, or diesel fuel. When an offshore well is drilled, the muds are usually discharged into the ocean; since 1979, there has been a prohibition against the discharge of muds containing diesel. For part of the 1980's muds containing mineral oil could be discharged, but today only water-based muds can be discharged. Water-based muds are the least effective of the muds. Mr. Vinson stated that some marginal offshore wells are probably not drilled today since they would be economical only if diesel muds were used in drilling them.

Mr. Vinson briefly discussed the Superfund Amendments and Reauthorization Act of 1986 (SARA). Petroleum received an exemption in the original Superfund legislation; since this exemption continued in SARA, SARA had little impact on oil production. In addition, an oil spill is subject to the SARA regulations only when there is overflow or seepage off of the firm's property, whereas most other materials which are spilled or released are always subject to reporting and cleanup regulations. The Superfund legislation is similar in its effects to RCRA, as it has cost larger companies "billions," but only on the refining and marketing side of the business. Mr. Vinson stated that the Superfund legislation has had no effect on independent oil production and little direct effect on production by integrated companies. Mr. Vinson strongly dislikes the Superfund and stated that it is "grossly unfair" and has caused greater expenditures on lawyers and consultants than on cleanup.

In conclusion, Mr. Vinson stated that uncertainty is the most important factor affecting oil production and the drilling of new wells. The most important source of uncertainty is world oil prices. Environmental costs in the aggregate are high for downstream operations and moderate for upstream operations, but they can be planned for, whereas oil prices cannot. Since environmental costs can be planned for and since oil production has received exemptions from most environmental regulations, environmental costs have had little effect on domestic oil production.

Mr. Sarosh J. H. Manekshaw, Director, Environmental, Safety and Health Affairs, Pennzoil Company

Mr. Manekshaw also discussed the environmental regulation of the petroleum industry, with an emphasis on the genesis of the regulations and their cost effectiveness. Mr. Manekshaw stated that most of the environmental laws which affect petroleum production were enacted in the 1970's but that the petroleum industry was initially exempted from most of the major requirements of the laws. In the late 1980's a series of scathing articles was published in the Wall Street Journal concerning the environmental damage that petroleum production was causing in Louisiana and the lax enforcement of environmental laws there. Thereafter the environmental regulations on petroleum production became stricter. Before these articles were published only refining had been subject to strict environmental laws, and the environmental regulations for petroleum production were not strictly enforced when they existed at all. Mr. Manekshaw thinks that most of the environmental regulation of the petroleum industry has been driven by disasters, such as the Exxon Valdez spill, rather than by careful analysis of the costs and benefits of the regulation.

One problem with the environmental regulation of the industry is that it is generally "media specific," meaning that the regulations apply only to one medium, such as air or water, which can carry pollution. Often the laws require that a set amount of pollution be removed from one medium when the same amount could be removed from another medium at a much lower cost. There has been some movement in newer regulations to allow a "multi-media" approach to pollution control, where pollution can be removed from whichever medium the polluter selects. This will lead to more cost effective pollution control.

In general, there has been little cost-benefit analysis in the promulgation of new environmental regulations. Most of the regulations are concerned only with the perceived benefits of the regulation and do not consider the costs of compliance. This is ironic, since the costs of the regulations are easily determined (at least by the companies which are complying with them), but the true benefits of the regulations are much harder to determine. Mr. Manekshaw believes that surveys of public opinion are not reliable indicators of the public's desire for environmental regulations since the public often does not understand that the costs of compliance will eventually be passed on to them. He cites the recent public uproar over the requirement in the Clean Air Act that individual passenger vehicles be tested for emissions as evidence that the public does not favor new regulations when they are directly aware of (and personally liable for) the costs of compliance. Mr. Manekshaw expects that the new Republican-controlled congress will require cost-benefit analysis for new regulations.

The current environmental regulations on production are often loosely enforced by the EPA. Inspectors rarely come out to the fields to inspect. There is therefore a perception in the industry that some independent producers do not always comply with the regulations. This is not the case for the integrated oil companies, which are inspected more regularly and generally do comply with the regulations. Although the inspections, especially of the independents, are infrequent, they can be quite burdensome when they occur, as the inspectors will often come up with obscure regulations which are not being complied with. As Mr. Ewing mentions (discussed below), there is at times an element of harassment in the EPA inspections.

The EPA is not always hostile to the oil industry. Mr. Manekshaw believes that the high ranking officials in the EPA understand that there may be frivolous regulations and that the costs of some regulations exceed the benefits. However, the rank and file EPA workers do not seem to understand this and generally try to enforce the regulations as strictly as possible.

Mr. Manekshaw's final comments dealt with the overall cost of environmental regulations in petroleum production. He discussed "life cycle analysis," where the cost of the regulations takes into account not only the direct cost of the regulation to petroleum production, but all of the indirect costs of the regulation as well. Mr. Manekshaw compared the current set of environmental regulations to a value added tax, where the regulations impose a cost at each level of production. Although the regulations may not impose many direct production costs for petroleum, the indirect cost of the regulations is high: the equipment which is used in petroleum production is significantly more expensive as a result of regulations applicable to the equipment manufacturers. While these cost are quite high in the aggregate, they are not particularly burdensome at any one level of production, which may explain why they are allowed to persist.

Mr. David Soza, Senior Environmental Engineer, Pennzoil Company

Mr. Soza discussed how federal and state environmental regulations have affected the petroleum industry. Before coming to Pennzoil, Mr. Soza worked as an environmental regulator in California. Mr. Soza said that most of the impact on production from environmental regulations comes from state regulations rather than federal regulations. The petroleum industry has managed to get exemptions from most federal regulations for production. One reason that state regulations are inevitably more stringent than federal regulations is that a state environmental regulation is required to be at least as stringent as any relevant federal regulation.

In some states, the state environmental regulations probably have had major effects on production. California has extremely strict regulations, especially as a result of the Toxic Pits Cleanup Act. California also has strict environmental regulations for offshore production. Louisiana has recently begun to have stricter regulations. These have encouraged the closure of production pits, which are used to separate oil from produced water. Closing these pits has been very costly for production.

One reason that environmental regulations have not had a major impact on production is that they rarely have a large impact on marginal cost. The initial compliance cost of a new regulation can be high; however, since the maintenance costs associated with a new regulation are usually fairly low, the regulation has little impact on marginal cost.

Mr. Soza stated that the indirect costs of regulations are often high, even when the direct costs are not. One of the indirect costs of environmental regulations is the costs of hiring lawyers for oversight. Mr. Soza thinks that the legal costs associated with complying with environmental regulations are far higher than the costs of measures which are implemented in the field. He says that everything that he does must be checked by an attorney before it is put into practice. The legal costs are especially high for the Superfund and RCRA legislation.

Lawsuits are generally not a major problem for petroleum production and are currently not too costly. Lawsuits have recently become more expensive and may become a major cost in the future. Mr. Soza states that part of the reason that lawsuits are not a major problem is that companies usually compensate the injured party before the party sues; he gave the example of a farmer with an injured cow. The threat of lawsuits probably causes some change in behavior by petroleum companies and presumably makes them more cautious. Mr. Soza thinks that regulations are preferable to lawsuits as a method of maintaining environmental quality since regulations give all companies a "level playing field," where the rules and the cost associated with breaking them are known.

Cleanup costs associated with SARA can be very expensive. SARA is particularly important for a company that is acquiring a property: the company can be responsible for all cleanup costs of any contamination on the site, even if the previous owners created the contamination. These cleanup costs can exceed the costs of producing the oil. However, federal regulators do not always force companies to clean up contaminated sites, even when SARA would require such cleanup.

In conclusion, Mr. Soza stated that federal environmental regulations do not have a major impact on petroleum production. Some state environmental regulations may affect production. The reason that much of the production by U.S. companies has moved to other countries is not U.S. regulations but the lower cost of extracting oil in other countries, which results from superior geology. The most important factor determining petroleum production is the price of oil. Often a company will wait to produce, hoping that the price of oil will rise.

Mr. John Kirby Ewing, Ewing Oil Company

Mr. Ewing owns and runs the Ewing Oil Company, an independent oil producer. He discussed the environmental regulation of petroleum production and many of the problems and concerns of an independent. Mr. Ewing's attitude towards environmental regulations can be summed up best by one of the first things that he said: the regulations are "well meaning but uninformed." An example of this type of regulation is the regulation of the disposal of produced water; Mr. Ewing stated that produced water is usually pure water, once it has been separated from the oil, and that it is therefore not a threat to the environment. The EPA requires that produced water be reinjected (i.e., put back into the ground through an old well); this is extremely expensive and difficult for a smaller producer to do. In addition, Mr. Ewing emphasized that oil is an organic compound and that oil does not do permanent damage to the environment. As proof of this, Mr. Ewing pointed out that there are many areas in Texas, some of which are in the city limits of Houston, where oil used to be produced and much oil was spilled onto the ground. Today those areas are at least as fertile as other areas which were not covered in oil.

Regulators today are extremely concerned about contamination of drinking water, and many of the most onerous regulations for a petroleum producer are a result of this concern. Mr. Ewing believes that this concern is overstated. Oil is generally extracted at a level far below that of drinking water; on the other hand, good drinking water is far enough below the surface that surface contamination is extremely unlikely to reach it.

Mr. Ewing also discussed the differences between an independent producer and an integrated producer. Independent producers usually produce from old, marginal fields and often pick up marginal production skipped by the larger producers. Today most onshore fields have been depleted nearly to the limits of profitable extraction. Most of the new oil finds today in the United States are offshore; however, because of the higher costs and capital needs of offshore production, only larger producers can produce offshore. There are still large gas reserves left onshore, which can be drilled by smaller producers. A smaller producer faces great risks and cannot spread these risks over many fields and wells, as a large producer does. The single greatest cost for a well is mechanical failure, which also introduces a large degree of risk for a small producer. Small producers do not get many of the economies of scale that a larger producer does; for example, a workover rig (used for servicing a well) is necessary for production, but an operator must own at least 100 wells to make owning a workover rig economical.

Mr. Ewing does not find any specific environmental laws to be particularly onerous but finds all of the laws in the aggregate to be onerous.

One problem is that, although the laws and regulations may not be onerous as written, the EPA inspectors are often extremely picky and require expensive procedures to be followed for relatively minor problems. For example, the inspectors once required an intense cleanup effort for an "oil spill" that amounted to two gallons of oil accidentally dropped on the ground next to a storage tank. The regulators at times seem to be bent on harassment rather than on environmental quality and often invoke and then enforce obscure regulations.

The greatest environmental threat which the industry poses is in the transport of oil rather than in production. There is a constant threat of spills from tankers, especially while they are being loaded or unloaded. As is well-known from the Valdez disaster, the consequences can be devastating.

Unlike the Pennzoil officials, Mr. Ewing thinks that current environmental regulations do reduce domestic production. Mr. Ewing said that the regulations are extremely costly for Ewing Oil Company. Messrs. Vinson, Manekshaw, and Soza generally believed that environmental regulations impose some additional costs on production but that these costs are not high in comparison with the cost of extracting the oil from the ground. They did think that the environmental costs could rise in the future and become more important.

Mr. Bruce T. Maughs, Assistant Director of Tax, Pennzoil Company

Mr. Maughs discussed the current tax treatment of the oil industry and how the tax laws applicable to petroleum changed during the 1980's. Mr. Maughs emphasized the difference in the tax treatment of independent and integrated producers. Independent producers receive many tax benefits which integrated producers do not receive. Since tax is not a focus of this paper, part of what Mr. Maughs said will not be reported here, but the following is a summary of his essential conclusions. As will be seen, the concepts introduced by Mr. Maughs apply to production decisions as a whole, not just those decisions which are tax driven.

In general, tax provisions are often favorable to oil production, especially for smaller producers and for nonconventional fuels, which receive a tax credit. The tax consequences of a new oil investment are critical in deciding if the investment will be made. All new investments must meet a "hurdle" rate of return in order to receive funding. Taxes have a major impact on rates of return and therefore are often the governing factor in determining which projects meet the hurdle rate.

Because of preferential tax treatment and some lower operating costs, independent producers are able to continue production on marginal properties, where production would not be profitable for larger companies. Since many independent oil companies get investor money only because of the tax benefits that the companies receive, the tax law apparently affects capital allocation and skews it towards independent producers. Without special tax benefits, Mr. Maughs thinks that many independents would not exist.

The oil industry as a whole does receive more favorable tax treatment than most other industries. However, more capital has not necessarily flowed into oil production in order to equalize after tax returns across industries; this is demonstrated by the fact that the p/e ratios for oil companies are not higher than those of other industries. Mr. Maughs thinks that, before 1986, the special tax treatment probably caused excessive investment in oil production, especially for independent producers.

Mr. Maughs cautioned that it will be difficult to identify changes in production which result from changes in the tax law. He estimates that the lag between a tax law change and a change in production would be five years for onshore production and ten years for offshore production. With lags of this duration, isolating the effects on production of a change in the tax law might be very difficult.

In conclusion, Mr. Maughs emphasized the differences in the tax treatment of independent and integrated producers. Petroleum production does receive preferential tax treatment, but the amount of this preference has decreased steadily for more than two decades.

Summary

The interviews revealed certain common threads. Current environmental regulations apparently do not have a major impact on production, according to these executives, but the regulations may have a disproportionately negative impact on smaller producers. Changes which made environmental regulation of production more strict could have a much greater effect on production. The tax law generally benefits petroleum producers relative to other industries, and especially benefits smaller producers, possibly offsetting their greater regulatory burden. Finally, since petroleum investments take a long time to bear fruit, any regulatory, tax, or (presumably) price change would take a long period to be reflected in changes in the level of production.

Chapter 4

Econometric Supply Model

I have developed and estimated a model of U.S. domestic oil supply as a function of price. This model uses a regression of total domestic production on the wellhead price of oil. Oil production adjusts slowly to price changes because increasing production may require the development of new fields. Development of a new field can take five to ten years. When prices drop, oil production falls slowly, because decreasing production generally requires shutting in some wells, which effectively prevents them from ever producing in the future. In order for a profit-maximizing firm to shut in a well, the revenue from the well must be below the variable cost of operating the well. Since most of the costs of a well are fixed costs rather than variable costs, a well is rarely shut in.

These physical realities of oil production cause the supply of oil to be very inelastic in the short run. In the long run this is not the case, as capital adjustments can be made; accordingly, price is a primary determinant of the production level of oil over the long run. Since some adjustments to price changes take a long time, it is reasonable, indeed necessary, to include lagged prices in the regression so as to make it possible to capture and distinguish short-run and long-run effects of price changes. Because production responses to price change take a long time, the depth of the lagged price structure must also be long.[1] This causes some problems of interpretation for the totally unrestricted null model. In addition, a null model loses many

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[1]The data used in this study are monthly; modeling a 5 year lag (the minimum lag recommended by Mr. Maughs of Pennzoil) therefore requires 60 lagged variables.

degrees of freedom in the regression. For these reasons a polynomial distributed lag model is used. A polynomial distributed lag model treats the coefficients of the lagged variables as related through a polynomial function of the length of the lag. This reduces the problems with multicollinearity and degrees of freedom.

Production and price data were taken from the Petroleum Supply Monthly, published by the Department of Energy. The wellhead price is the average price paid at the wellhead for domestically produced oil. In the data series, the exact definition of wellhead price changed in minor ways, but these changes did not significantly change the reported prices, which are average prices paid to petroleum suppliers during a particular month. Ordinarily, the use of average price presents no special problem; price varies from day to day over the month but at any one time is essentially the same for all producers.[2] However, during the era of price controls (before October 1981), the use of average price could be expected to cause possibly important distortions, since the average price at a given time does not necessarily represent the price being received by most producers; some producers received the low, controlled prices for their older wells, whereas other producers received high, uncontrolled prices if their wells were new. It may be that no single well or field had a marginal revenue equal to the average reported price. In the period after price controls, most production was sold at a price near the average reported price, with adjustments for the quality of the oil sold and transportation costs, which are generally low. The production reported is the average daily production, in thousands of barrels per day, for all domestic

[2]There are price differences related to crude oil quality, but presumably the quality mix of crude production does not change significantly over time.

petroleum production, including Alaskan and offshore production. Alaskan and offshore production are also reported separately.

The price data have been adjusted using the producer price index, published by the Bureau of Labor Statistics. For convenience, all prices were converted to May 1994 prices, since May 1994 is the month for the most recent data used in this study. Since the price of oil relative to other production inputs and intermediate goods seems a relevant consideration, I have used the PPI to represent changes in that relative price. The relative price adjustment is made so that the results will reflect petroleum producers' supply response to changes in the real price of petroleum. During the period covered in the study the PPI more than doubled, and without this adjustment the price response results could be skewed.

The Petroleum Supply Monthly begins these data series in 1974. In this study the data from 1974 to May 1994 (the most recent available) are used. One possible problem with the earliest data is that the price data from 1974 are not reported in the same manner as the later price data. The 1974 price data report the wellhead prices for "old" and "new" oil; in 1974 old oil was sold at the controlled price of $5.25 and new oil was sold at uncontrolled prices ranging from $9.82 to $11.08. The price data for 1975 to the present report a single price for the average wellhead price for domestic oil. In order to determine monthly average wellhead prices for 1974, I calculated averages of the old and new oil prices weighted by reported production of oil and new oil.[3] This construction causes the average wellhead prices for 1974 to be comparable to the price data from 1975 to the present.

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[3]For example, in June 1974, 63% of production was sold at the controlled, "old oil" price, and 37% was sold at uncontrolled prices. The old oil price was $5.25, and the uncontrolled price was $9.95. The weighted average price is therefore 0.63 x 5.25 + 0.37 x 9.95 = $6.99.

There is another issue concerning price data. In 1974 and 1975 there were market disruptions which resulted from the imposition of oil price controls. From 1973 through 1975 four different oil price control schemes were alternately implemented and discarded. On February 1, 1976 a new price control scheme, which included higher allowed prices and more incentives for new production, was implemented. This regimen of controls remained until price controls were removed in 1981. I thought that the more steady system of price controls after 1976 would give more meaningful results. However, the results for using all the data from 1974 to the present are nearly identical with those obtained when 1974 and 1975 are excluded. I have therefore used the results from the longer period 1974-1994, since inclusion of these data allows for more degrees of freedom in the regression and therefore allows longer lags to be used. The results both with and without the 1974 and 1975 data are reported below.

Regression Results and Discussion

The regression is performed using the PDL model. A polynomial of degree 5 is used, so as not to unduly or arbitrarily restrict the lag pattern of supply response.[4] The length of the lag was determined by repeatedly running the regression with different lag lengths until the coefficients in the final periods approach 0 and become insignificant at the 5% level of significance. The length chosen is 94 periods, or seven years and ten months. No near constraint is used. A near constraint forces the coefficient for the next period ahead (i.e., a lag of -1 period) to be zero. This has the practical effect of forcing the coefficients in the early periods lower. Since, in this case, there is no conceptual reason to force the coefficients in the earlier periods to

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[4]The choice of the degree of the polynomial is discussed further below.

be lower, no near constraint will be used. There does not appear to be a need for or any advantage in using a far constraint since the coefficients naturally converge to 0 for the final periods of the lag. Nevertheless, I did perform the regression with a far constraint for comparison purposes.

A summary of the results of the regressions is given in table 4.1. Six different regressions were performed. The null model uses simple lagged coefficients for 94 months. The PDL models all use a degree 5 polynomial. The standard PDL model (B.1 in the table) has a 94 month lag period. There are also a PDL model which includes a far constraint and a PDL model which does not use the 1974 or 1975 data. In addition, there are two PDL models with different lag lengths, one with a 72 month, or six year, lag period and one with a 120 month, or ten year, lag period. The total response is reported in thousands of barrels per day. For convenience of comparison, in part C of the table the PDL 94 model results are repeated, on line C.2.

Table 4.1: Regression results for equation Production = Constant + PDL(Price)

Model	Total Response	Adjusted R^2	F-statistic	Degrees of Freedom
A. Null	173.845	0.982231	88.27825	55
B. 1. PDL 94	**178.343**	**0.976489**	**1039.349**	**144**
2. PDL - far	178.569	0.976649	1255.767	145
3. PDL x74,75	178.515	0.977757	924.127	120
C. 1. PDL 72	139.213	0.830146	141.1057	166
2. PDL 94	178.343	0.976489	1039.349	144
3. PDL 120	121.424	0.982244	1144.289	118

Several observations can be made about the results shown in table 4.1. The three PDL models with 94 month lag lengths have nearly identical results for the adjusted R^2 and estimated total response. All have high F-statistics, showing that the null hypothesis that all of the coefficients are 0 can be rejected at any level of significance. These results show that imposing a far constraint has almost no effect and is therefore unnecessary, and that including the 1974 and 1975 data has not distorted the results in any way. The null model's estimated total response is very close to that of the standard PDL model, as is the null model's adjusted R^2. These results might at first suggest that the null model is equivalent to the PDL model; however, the coefficients of the null model are difficult to interpret: only two of the estimated coefficients are significant at the 5% level of significance, and they repeatedly shift from being positive to negative. On the other hand, the coefficients of the PDL model decline smoothly and uniformly (with the exception of one tiny wrinkle) over the entire lag period and are all significant except for those for the last three periods.[5] The coefficients of the models will be discussed further below. In addition, the PDL model has a higher F-statistic than the null model; however, in both cases the F-statistic is high enough to be significant at nearly any level of significance.

The results of the PDL models with different lag lengths show that reducing or increasing the lag length reduces the estimated response. The 72 month lag is clearly too short; its adjusted R^2 and F-statistics are markedly lower than those for the 94 month lag. In addition, the coefficients in the 72 month lag model are negative for 10 of the months, which is an implausible result. The 120 month lag appears to be too long; its estimated total response

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[5]Graphs of the coefficients of the standard PDL model and the null model are given later in this chapter. In addition, the values of the coefficients for these models are given in Appendix B.

is much lower than that of the 94 month lag. This occurs because the coefficients for every period after 94 are negative, which is also implausible. The 120 month lag model gives only relatively minor increases in adjusted R^2 and F-statistics. Although there is nothing patently wrong with the results for the 120 month lagged model, the 94 period lagged model does not have any negative coefficients and has a higher estimated total response and will therefore be used.

The results for the standard PDL model show that price changes, when lagged over a period of seven years and ten months, determine over 97% of the change in domestic oil production. These results are significant at any level of significance. The total daily average production change for a $1 increase in the price of oil is 178,000 barrels, with a standard error of approximately 4,000 barrels. If the price of oil were $20, which is the approximate average price over this time period, a $1 increase in the price of oil would cause the total annual value of domestic oil production to increase by approximately $1.3 billion.

Coefficients of the Regressions

Since these are lagged regressions, the speed of the response to price changes by petroleum producers can be determined by examining the values of the lagged coefficients. For example, if the sum of the lagged coefficients were 178 and the sum of the first six coefficients were 58, the results would imply that 32.6% of the price response occurs within the first six months after a price change. I have calculated the percentage of the total response of the 94 period PDL which occurs after set periods of time for each of the regressions performed above; the results are given in table 4.2. I have reported the percentage of the 94 period PDL response rather than the percentage of the total response for each model to show how the total response of each other model relates to the total response of the preferred 94 period model. In addition, the results for the 72 month lag model are not shown, since this lag period is clearly too short, as discussed above.

Table 4.2: Percentage of total response

	Depth of Lag in Months						
Model	6	12	24	48	72	94	120
Null	17.4%	22.5%	46.2%	75.8%	71.6%	97.5%	
PDL 94	**23.5%**	**35.7%**	**50.3%**	**70.5%**	**87.9%**	**100%**	
PDL 120	26.0%	40.9%	55.3%	59.5%	73.2%	84.9%	68.1%
PDL-far	23.4%	35.7%	50.4%	70.5%	88.0%	100.1%	
PDL x74,75	18.6%	29.1%	44.7%	70.4%	85.8%	100.1%	

Table 4.2 reflects several interesting results. The results for the standard and far constraint PDL models are virtually identical. In both cases about a quarter of the effect occurs within six months and about half of the effect occurs within two years after a price change. As mentioned above, in both cases the coefficients smoothly decline over the lag periods, and this result causes the total lag effect to rise at a declining rate over the lag period. Not using the 1974 and 1975 data changes the results somewhat, but not to a large degree.

The null model appears to have plausible results through the first four years, but shows the strange result of having a decline between four and six years in the percentage of the total price effect. The declining percentage results from the many negative coefficients in the null model for the middle lag periods. A negative coefficient implies that a price rise causes production to fall, which is illogical. The fact that the null model has many negative coefficients reveals a major problem with the results in the model and is the primary reason that the PDL model was chosen over the null model.

The 120 month lagged model shows that percentage of total response peaks at the 94th period and falls for subsequent periods. This result occurs because all of the coefficients after the 94th period are negative. The fact that the coefficients for the longest lags are negative indicates that a 120 month lag is too long and that the 94 month model properly accounts for all of the effects of a price change on production.

Choice of the Degree of the Polynomial and Comparison of PDL and Null Models' Coefficients

As stated above, a fifth degree polynomial was used for all of the PDL models. Choosing the degree of the polynomial involved balancing two factors, degrees of freedom and the allowance for the lagged effects to be shown in the coefficients. As the degree of the polynomial is increased, the coefficients have greater freedom to vary, but degrees of freedom are lost. For example, a polynomial of degree 2 would save 3 d.f. over one of degree 5, but such a polynomial would force the coefficients to assume an inverted u-shaped pattern, which would not necessarily represent the true values of the coefficients. A polynomial of degree 5 allows the coefficients to exhibit several "kinks" in the lag pattern, should these kinks exist. If the lag pattern had shown distinct kinks, I would have performed the PDL regressions with a higher degree polynomial, but there were no kinks. The coefficient pattern is shown in figure 4.1.

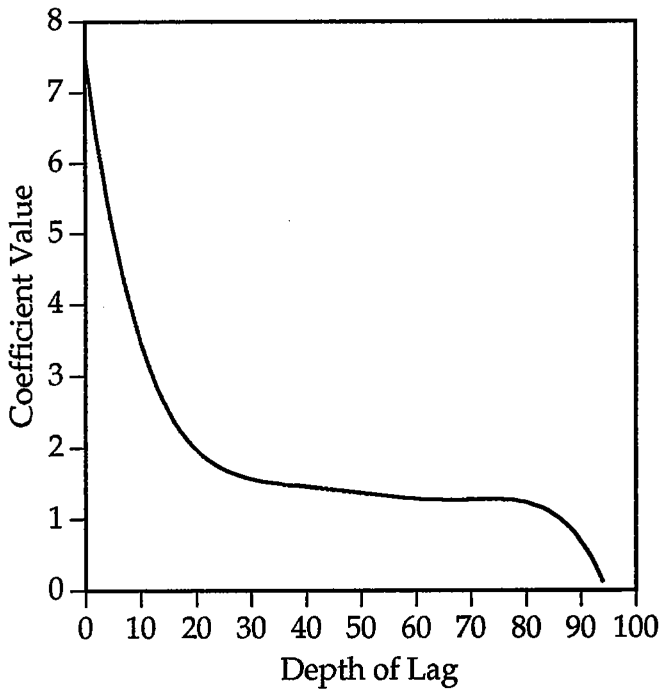


Figure 4.1

The coefficients of the PDL model using a fifth degree polynomial decline smoothly. Since the graph shows that there are only two inflection points in the coefficient pattern, it is possible that this model could have been performed equally as well with a third degree polynomial. In view of the fact that the coefficients do not appear to need the additional freedom to vary which a higher degree polynomial would give, a higher degree polynomial is not needed and would unnecessarily sacrifice degrees of freedom.

For comparison purposes, I prepared a graph of the coefficients of the null model. That graph is shown in figure 4.2.

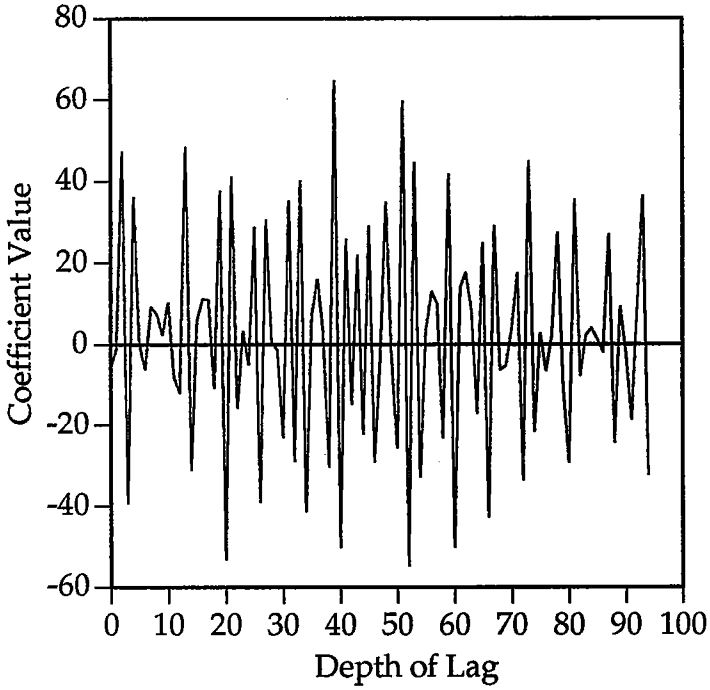


Figure 4.2

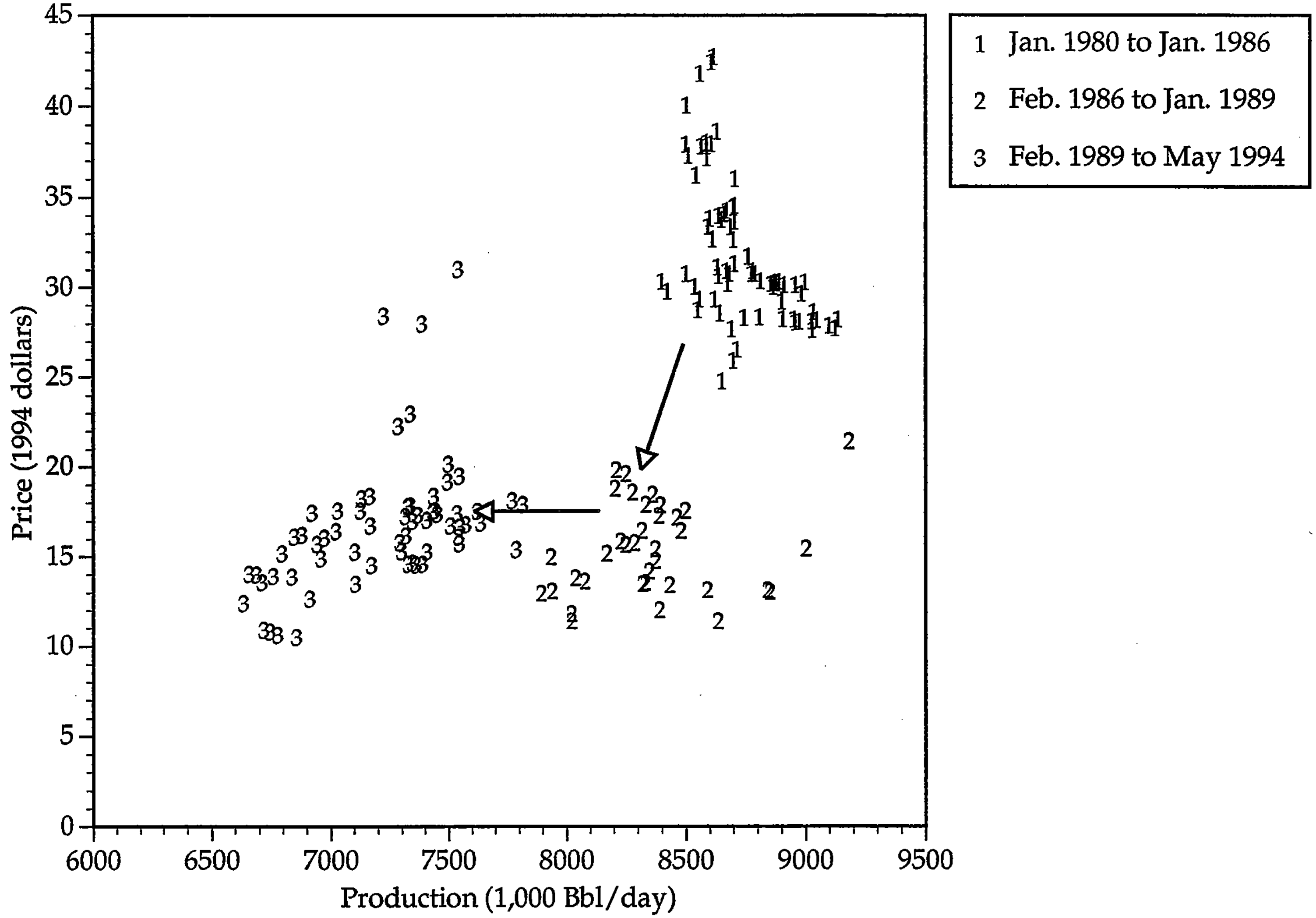
The coefficients of the null model do not smoothly descend as those of the PDL model do. In addition, nearly half of the coefficients are negative. The coefficients and associated standard errors for the PDL and null models are given in appendix B.

Causality

In estimating the supply parameters, it was assumed that changes in the price of oil caused changes in production rather than vice versa. The results do show a strong correlation between price and production, but these results do not prove causality.

In my initial examination of causality, I looked at the price and production points over a period of time. The precipitous drop in the price of oil in 1986 provides a good way to examine causality. Figure 4.3 graphs the monthly price and production points from January 1980 to May 1994.

Figure 4.3: Price and Production Relationship for 1980-1994



As the legend in the figure notes, the points from January 1980 to January 1986 are symbolized by a "1;" the points from February 1986 to January 1989 are symbolized by a "2;" and the points from February 1989 to May 1994 are symbolized by a "3." Before 1986, the price of oil was relatively high, and production was steady in the range of 8,500-10,000 Bbl/day. From 1986-1989, the price fell, but production was in about the same range, falling only slightly. After 1989, the price stayed steady and relatively low, but production fell to a range of 6,500-8,000 Bbl/day. The figure provides evidence that price changes cause changes in production, since production fell after price fell. Since production took several years to drop, the graph also shows that production reacts slowly to price changes.

A statistical test of causality is the Granger causality test. The Granger causality test first regresses the dependent variable on lagged values of itself and on the lagged values of an independent variable. This is the unrestricted model. A restricted model is then created, in which the coefficients of the dependent variable are assumed to be zero. An F-test is performed to determine if the unrestricted model is significantly different from the restricted model. If the models are significantly different, the independent variable is said to Granger-cause the dependent variable (Ramanathan, 1992, p. 530).

The logic of the Granger causality test is fairly simple. One assumes that previous values of the dependent variable will predict the current value of the variable. This is certainly the case for oil production, as production levels do not change substantially from month to month. A regression is performed which regresses production on lagged values of production. Then, the lagged values of an independent variable, petroleum price in this case, are added. If the past values of price and the past values of production explain production levels significantly better than the past values of production alone, price changes must be causing production changes.

The equation for a general unrestricted Granger causality regression is as follows:

$$Y_t = C + \sum_{i=1}^{p} \alpha_i Y_{t-i} + \sum_{j=1}^{q} \beta_j X_{t-j} + u_t$$

C is the constant. Y is the dependent variable, and X is the independent variable. u_t is the residual, p is the order of the lag for Y, and q is the order of the lag for X. In the restricted model, all β_j are assumed to be equal to 0. The restricted model is therefore:

$$Y_t = C + \sum_{i=1}^{p} \alpha_i Y_{t-i} + u_t$$

I performed this test using production as the dependent variable (Y) and price as the independent variable (X). For production, I used 36 lag periods. The production variable in this case does not need to be lagged for an extremely large number of lags. I chose 36 periods as a medium lag. Using a greater or smaller number of lags, such as 24 or 48, has only a tiny effect on the results, but using less than 24 periods (two years) begins to cause problems because of seasonal production variations. The value of p is therefore 36.

Rather than using a null model for the lagged values of X, I again used a PDL model with a fifth degree polynomial and a 94 period lag. The reason for using the PDL is similar to the reasons discussed above for using a PDL for the production model: a PDL saves degrees of freedom and gives more plausible results. A PDL can be used since doing so is conceptually identical to using regular lagged values of the coefficient. In this case, the PDL method uses all 94 lags to generate six variables, each of which is a function of all 94 lagged variables. The PDL model then estimates coefficients for the six variables using ordinary least squares. The final step is to combine these six coefficients into 94 separate coefficients, corresponding to the 94 lagged variables. This third and final step is done by inverting the functions by which the six variables were created from the 94 variables in the first step. No new statistical estimates are made in this final step. Since six independent variables are used in this PDL model, the value of q is six. The process of generating these six variables, instead of using 94 values, saves 88 degrees of freedom in the PDL model.

The unrestricted Granger causality test equation which I tested is as follows:

$$production_t = C + \sum_{i=1}^{36} \alpha_i production_{t-i} + \sum_{j=1}^{6} \beta_j price^*_{tj} + u_t$$

Price has an * because the price variables used are not the actual lagged price values, but instead the price variables from combinations of all 94 lagged price variables. The restricted model is:

$$production_t = C + \sum_{i=1}^{36} \alpha_i production_{t-i} + u_t$$

I performed each of these regressions, and then performed an F-test to determine if the null hypothesis that all $\beta j = 0$ can be rejected. In each case, t begins with the 95th observation, corresponding to December 1981, since the first period is February 1974. The F-statistic is 10.80, with 6 d.f. in the numerator and 108 d.f. in the denominator. This F-statistic is significant at the 1% level of significance,[6] indicating that the null hypothesis should be rejected. Since the null hypothesis is rejected, all values of βj cannot be assumed to be equal to 0. Therefore, price has been shown to Granger-cause production.

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[6]The F-statistic for 6, 60 d.f. is 3.12 at the 1% level of significance, and the F-statistic for 6, 108 d.f. is slightly below this value.

I also performed a Granger causality test to determine if production Granger-causes price. The test was performed using a 36 period lag for both price and production. A PDL model was not used, since the lag used (36 periods) is much shorter than the 94 period lag used above. The F-statistic for this test is 1.11, with 36 d.f. in the numerator and 136 d.f. in the denominator. This F-statistic is not significant at the 5% level of significance,[7] indicating that the null hypothesis cannot be rejected. These results indicate that production does not Granger-cause price.

These tests show that price changes cause changes in production, but that production changes do not cause price changes. These results indicate that the supply model is reasonable in regressing production on price and in assuming that price changes cause production changes.

[7]The F-statistic for 40, 120 d.f. is 1.39 at the 5% level of significance, and the F-statistic for 36, 136 d.f. is slightly above this value.

Chapter 5

Any environmental regulation of petroleum production will increase the costs of production for firms subject to the regulation. A cursory examination might suggest that these costs will be borne by the petroleum producers' shareholders, but this is not necessarily the case. It is possible for regulatory costs to be borne almost entirely by producers or almost entirely by consumers. The incidence of regulatory costs depends on several factors, including the competitiveness of the industry, the elasticity of demand, and whether the regulation affects all producers' marginal costs equally. To examine the incidence of regulatory costs, I have formulated a model of the domestic petroleum market which takes new regulatory costs into account.

A Price Leadership Model of the U.S. Petroleum Market

The structure of the U.S. oil market is unusual. The many U.S. producers supply slightly less than half of the oil consumed, with the remaining demand being met by imports.[1] Most of these imports come from OPEC. Since the U.S. petroleum market has many relatively small domestic producers and since most imports are controlled by an oligopoly, the characteristics of the U.S. petroleum market suggest the use of a price leadership model, with OPEC acting as the price leader and domestic producers acting as the competitive fringe.

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[1]U.S. producers in this paper are companies which produce oil domestically for domestic consumption; nearly all domestic production is consumed domestically. Many U.S. producers also produce in other countries; most of this production is in OPEC countries and is closely regulated and heavily taxed by the OPEC countries. "OPEC production" refers to production regulated and controlled by OPEC countries, even when the oil is actually extracted from the ground by a U.S. corporation.

Although U.S. producers supply most of the oil produced in the United States, they have little pricing power. There are numerous U.S. producers, and they are modeled as price takers in the U.S. market. For a firm to be a price taker, it must assume that its actions have no effect on the market price. The largest domestic producers together account for a significant portion of the market,[2] but no single producer dominates the market; in fact, domestic production of the largest domestic producer is less than 6% of the total oil consumed. Compared to other industries, oil production is relatively unconcentrated. In addition, domestic producers apparently do not collude to set oil prices. Given this relatively unconcentrated industry, it seems likely that domestic producers do act as price takers and set their marginal costs of production equal to the world oil price, which is their marginal revenue.

Several characteristics of U.S. petroleum producers support the assertion that they act as price takers. The U.S. producers fit the following criteria: there are many firms, the product is homogeneous,[3] prices are known to all market participants, and the costs of effecting transactions are low. Since the domestic market fits these criteria, the U.S. producers should act as price takers and should behave as if their actions will not affect the market price. Acting as price takers, the U.S. producers are the competitive fringe in the price leadership model.

The price of oil is set on the world oil market, and the members of OPEC have sufficient market power to hold the price well above their marginal cost of production, which is low relative to the marginal cost of domestic production in the United States. OPEC's marginal cost is generally

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[2]The three largest domestic producers produce 17% of domestic oil consumed (Arthur Andersen, 1994, p. 17)

[3]Crude oil differs in sulfur content and quantity of lighter distillates, but these differences are reflected in long established price differentials between crude oil grades. The price difference between the "best" and "worst" domestic crude rarely exceeds 7%.

acknowledged to be in the range of twenty cents to two dollars per barrel, far below the world oil price.

Given these characteristics, the U.S. market can be modeled using the price leadership model, with OPEC (or Saudi Arabia) acting as the price leader, and U.S. producers acting as the competitive fringe. The market can be represented graphically, as shown in figure 5.1:

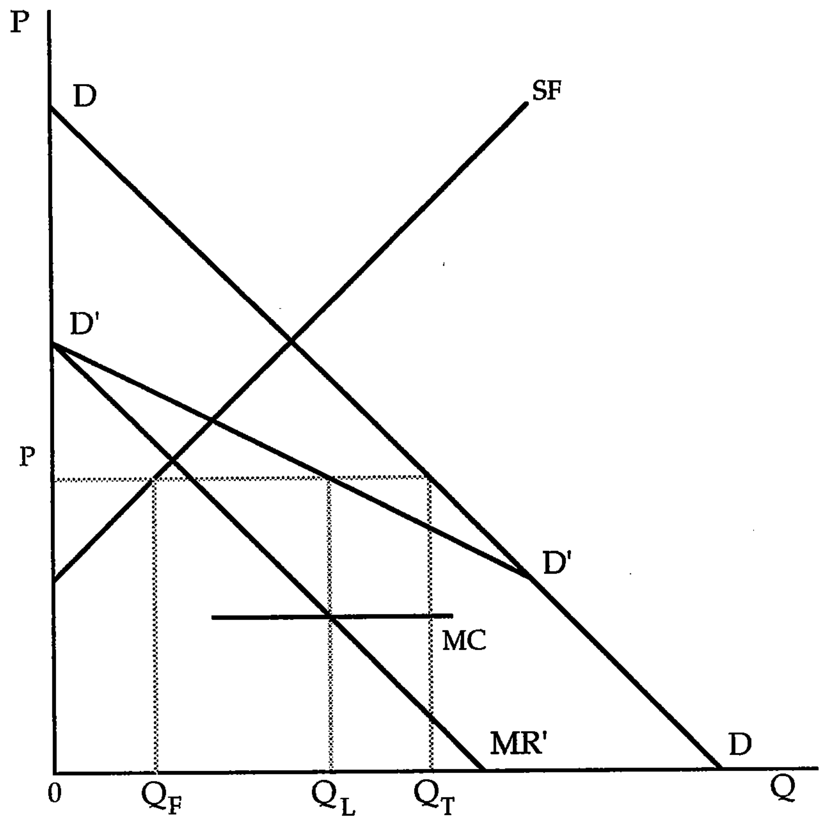

Figure 5.1

In figure 5.1, OPEC acts as price leader in the large U.S. market. As the U.S. price leader, OPEC faces the effective demand curve D'D', which is the residual demand and is equal to the difference between the total U.S. demand (DD) and the U.S. domestic supply (SF) [F for fringe]. OPEC acts a monopolist and determines its marginal revenue curve (MR') from its demand function (D'D'). OPEC then chooses the output level where MR is equal to MC. OPEC does this in order to maximize profits. Once OPEC has determined its output level (Q_L) [L for leader], OPEC sets its oil price (P) so that its output equals the difference between the quantity demanded at that price and the quantity supplied by U.S. producers at that price. Once OPEC has set the U.S. oil price, U.S. producers accept this price and behave as price takers. As a result, U.S. producers produce Q_F, at the intersection of the oil price (set by OPEC) and the domestic supply curve, which represents the domestic marginal cost of production at various output levels.

Effects of Regulation on the Market

Suppose a regulation is adopted which increases the marginal production cost uniformly for all domestic producers. The marginal cost of production will rise for all output levels. The regulation is assumed to cause marginal costs to rise by the same amount for all output levels. This regulation can be modeled using the price leadership model of the U.S. petroleum market. If the regulatory cost increases domestic marginal costs of production by value R, the fringe supply line in the price leadership model will rise by an amount R for all output levels. The rise in the fringe supply line will cause the residual demand faced by OPEC to rise, which will cause OPEC to increase the world oil price.

At a higher world oil price, OPEC's production will rise, but total U.S. consumption will fall. Since OPEC's production is higher yet consumption is lower, production by U.S. producers must fall. These effects can be represented graphically by introducing a regulatory cost which causes the fringe supply curve in the price leadership graph shown above to rise by R, the value of the regulatory cost. The rest of the graph, except for the demand curve, must be redrawn to reflect this change, and the effects of the regulatory cost on price and production can then be seen. The graph is shown in figure 5.2.

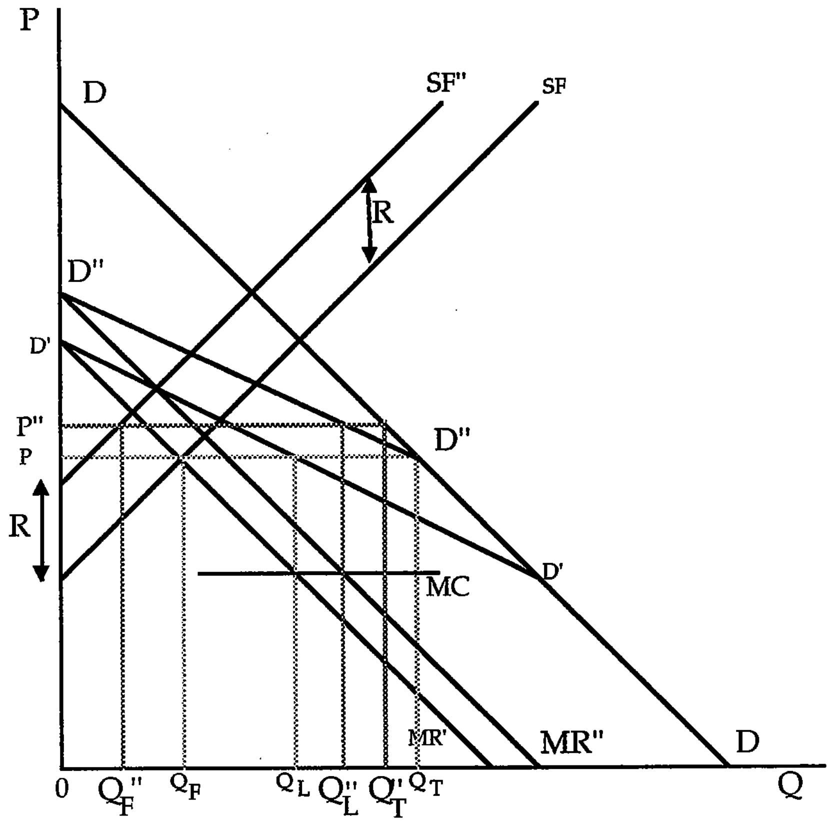

Figure 5.2

As may be seen in the graph, the price of oil rises and total production falls when a regulation is introduced, but the price does not rise by as much as the regulatory cost. In addition, OPEC's production level also rises. The burden of the regulatory cost is borne mainly by domestic producers; since total consumption falls and OPEC production rises, the loss in domestic production may be quite substantial. The effects of a regulatory change would not necessarily be felt immediately. This model attempts to determine how, *ceteris paribus*, a regulatory cost would affect domestic petroleum production in the long run.

The Incidence of Regulatory Costs

The situation described above occurs if the regulatory cost applies equally to all firms. If the regulatory cost applies only to some firms, as is the case for Superfund cleanup costs, the firms which must pay the costs will not be able to pass them on to consumers. In a competitive market where some producers do not have these costs and therefore will not raise prices, none of the costs could then be passed on to consumers.

The regulation must affect marginal cost in order to have an impact on production; many regulations impose large capital costs which have little impact on marginal costs. Since a firm determines its output level by producing at the level where marginal cost equals marginal revenue, regulations that do not affect marginal cost will not affect production.

I have assumed that the regulatory cost will increase marginal cost by the same amount for all levels of output. This is an approximation, but it should apply at the current and long-run average production levels. The increase in marginal cost caused by a regulation might not be the same for all output levels, but, in the output range considered in this study, the increase in marginal cost should be approximately constant.

Most environmental regulatory costs are borne by all firms across-the-board. For example, all petroleum producers bear additional production costs arising from the regulations under the Clean Water Act. Since all producers must pay these costs, all producers can raise their prices and pass some of the costs on to the consumers. Thus, if the market were perfectly competitive with no barriers to entry, all regulatory costs would be fully passed on to the consumers, as shown in figure 5.3.

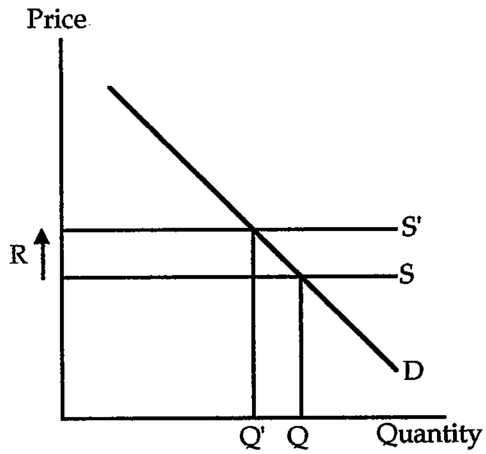

Figure 5.3

When a regulatory cost R is imposed, the long-run supply curve in the perfectly competitive market, which is effectively horizontal, rises by R, the quantity supplied drops from Q to Q', and the price rises by the full value of R.

This would not be the case, however, if the regulation applied only to some producers and not others. Such a regulation would cause the marginal costs for the affected producers to rise, but the marginal costs for other producers would not rise. The firms affected by the regulation will not be able to raise their prices to pass on the costs of the regulation. The unaffected firms will not raise their prices, and, in a commodity market like the oil market, a unilateral price increase by a single firm or group of firms is impossible, since all purchasers would simply purchase oil from those unaffected firms whose price is lower. The firms which must pay the regulatory costs will lose profits and reduce production, rather than raising prices. The lost production will be made up by increases in production by the firms unaffected by the regulation, or perhaps by market entry, which is relatively free for petroleum production. Eventually, the costs of the new regulation will be borne by the shareholders of the firms whose costs rise because of the regulation.

This analysis indicates that seemingly similar regulations can have very different economic effects. A regulation that affects all producers equally will have a large impact on product prices and a small impact on producers' profits. On the other hand, a regulation which affects only some producers or affects producers differently will have most of its effects on the profits of the firms, rather than on the product prices. In the U.S. petroleum market this analysis is not completely applicable; no U.S. environmental regulation will affect all producers, since OPEC and other foreign producers are not subject to U.S. environmental regulations on petroleum production. This fact is accommodated readily in the price leadership model, allowing us to determine how the burden of a regulatory cost is distributed.

Assumptions and Derivation of the Price Leadership Model

The price leadership model, as shown above, is used to model the U.S. petroleum market. In this model, OPEC sets the world oil price, the domestic producers equate their marginal cost to this price to determine the domestic supply, and OPEC supplies oil for any remaining U.S. demand at the same price. Because of this supply relationship, the demand curve which OPEC perceives is the difference between the domestic demand and the domestic supply curves.[4] OPEC determines the world oil price by equating the marginal revenue (determined from its perceived demand curve) with its marginal cost, by determining its quantity supplied at that point, and by

[4]The perceived demand curve is labeled D'D' on the graph.

setting the price where the quantity supplied intersects OPEC's perceived demand curve.

For the purposes of quantitative analysis, the demand and supply curves in the U.S. petroleum market are treated as straight lines. There are two implications of assuming that the demand curve is a straight line. The first is that the U.S. demand for petroleum would be 0 at some "reasonable" price.[5] It seems likely that, although the quantity demanded for petroleum could become significantly smaller were oil prices higher, the quantity demanded would always be positive and significant unless the price were far higher than ever in the past; even though the price of imported oil has ranged from $12 to $48 in the past,[6] total consumption of petroleum has never fallen below a monthly average of 10 million Bbl/day.[7] Even if the price of oil rose to $100/Bbl, which is unlikely given the technologically feasible production of synthetic oil at a lower cost,[8] it seems likely that there would still be significant demand for petroleum (either synthetic or natural) in the United States. The second implication of a straight demand curve is

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[5]A reasonable price is a fairly low price, such as a price below $100. The quantity demanded would be 0 with linear demand at such a price, given the historical price and quantity ranges and possible slopes which would be consistent with estimates of demand elasticity for oil.
[6]These and all subsequent prices, unless otherwise noted, are in May 1994 dollars.
[7]All subsequent Bbl/day amounts are for monthly average Bbl/day.
[8]There are several possibilities for the production of synthetic fuels. The most promising current possibility is the extraction of petroleum from tar sands. Already (as of 1986; these facilities may have subsequently shut down) there are a few facilities in Canada converting tar sands to synthetic petroleum, and these facilities are able to operate competitively with normal petroleum production. Tar sands petroleum reserves in the U.S. and Canada are estimated to be more than 30 times current U.S. petroleum reserves. In addition, in the future it may become technologically feasible to produce synthetic petroleum from oil shales. Synthetic petroleum was produced from oil shales in the late 1970's by Exxon and Arco, but these facilities were not economically feasible without subsidies, even with the high oil prices at the time. However, were the price of oil to rise substantially, oil shale production of synthetic petroleum could also become economical. If oil shale were converted to petroleum, reserves within the United States would be sufficient to supply U.S. petroleum demand at current levels for more than 300 years. Finally, in the more distant future, it might become technologically feasible to convert coal to petroleum and natural gas at economically viable costs. (Griffin and Steele, 1986, pp. 341-348.)

that the price elasticity of demand varies widely over the historical price range, being higher at higher prices. Although the elasticity of demand probably does vary as oil prices change, it is unlikely that the elasticity varies by a factor of 2 or more, as the historical price and quantity ranges would imply given a linear demand function.[9]

A more realistic demand function would be a convex curve, which would not imply that the quantity demanded will go to 0 and would allow for a constant or mildly varying elasticity of demand. However, over a moderate range of quantities, a straight line can approximate a convex demand function closely, as shown below:

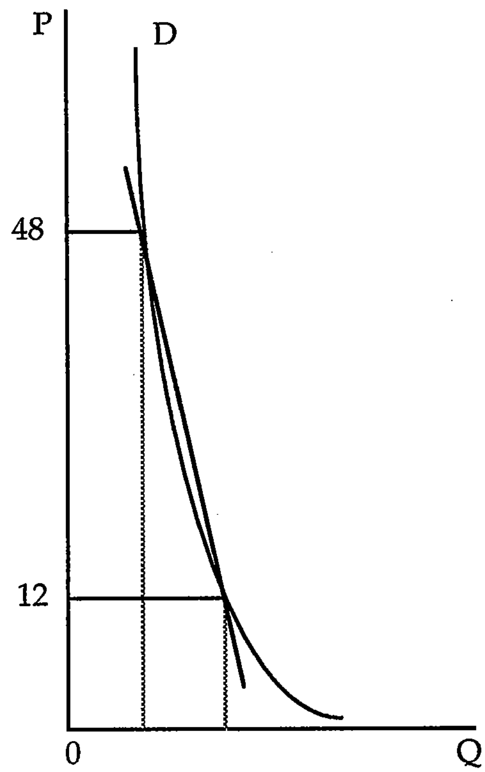

Figure 5.4

[9]The elasticity of demand = (dQ/dP) (P/Q). If demand is a line, dQ/dP is constant and equals the slope of the line. Over the historical period considered in this study, the price range varies by a factor of 4 (48/12 = 4), and the quantity demanded varies by a factor of about 1.5. Therefore, price varies 4 times while quantity varies only 1.5 times, implying that elasticity varies by about 2.7 times.

Over the range of quantities in the graph, a straight line closely approximates the demand curve. Since total U.S. petroleum consumption has ranged from 10.8 million to 15.6 million Bbl/day over the last 20 years, consumption has varied moderately relative to the total amount, and demand can therefore be accurately approximated by a straight line.

The supply curve for the U.S. producers is also assumed to be linear. For U.S. producers, it appears that this assumption is sufficiently accurate that it will not distort the results of this study. The supply curve represents the horizontal sum of the marginal cost curves for all U.S. producers. For petroleum production, by far the most important factor in determining the marginal cost of production is the quality of the oil field. For a field with a high natural gas pressure on the oil, the marginal cost of production of oil can be very low, since the company has only to store the oil as it is forced out of the ground. On the other hand, in some fields oil is extracted using tertiary recovery techniques, such as injecting chemicals into the oil-bearing strata to force the oil out; these techniques can have a high marginal cost (high enough, in fact, that they are often not used and the oil is instead left in the ground).

A straight-line supply curve therefore implies that the distribution of oil field quality is equal across all reasonable marginal costs of production from the producing fields. This assumption breaks down at the lower and higher ends of the marginal cost range: there are few extremely low marginal cost fields available in the United States, and there is no benefit in extracting oil from an extremely high cost field, since synthetic petroleum can be produced at a lower cost. For the middle range of quantities, a straight line is a close approximation of the domestic supply curve, even though over a wider range of quantities a straight line might not be a good approximation. This can be shown on a graph similar to the demand graph provided above.

The OPEC marginal cost is approximately constant. The marginal cost at the wellhead for OPEC production is low and is certainly below $2 (Griffin and Steele, 1986, p. 106). This is a small fraction of the domestic price of oil, which has averaged about $20 for the last 20 years. These figures might suggest that the marginal cost of OPEC should be placed near zero. However, over the last 20 years, the price of imported oil for refiners has always been higher than the wellhead price of domestic oil. This result is reasonable since there are small costs associated with transporting the domestic oil from the production fields to refineries, but these transport costs are almost negligible relative to the price of oil.[10] It would be expected that imported oil would be more expensive than domestic oil if imported oil were of higher quality than domestic oil, but this is not the case; if anything, imported oil is of lower quality than domestic oil.[11]

Finally, the price discrepancy could be explained by price controls, which, when in effect, held down the price of domestic oil yet did not affect the price of imported oil. In fact, the price differences did tend to be larger in the period of price controls, but they have continued to exist after the price controls were eliminated. In addition, this study examines the behavior of domestic oil producers for a period which includes part of the era of price controls; therefore, the price difference which will be used is the difference

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[10]Transport costs for oil in the 1960's were estimated to be around 10% of the price of oil (Jones, 1993, p. 689) and presumably have fallen because of technological improvements. In addition, the price of oil has risen sharply since the 1960's. Therefore, transport costs for the period covered in this study are probably far below 10% of the price ($2.08).

[11]An oil's "quality" is determined by the ease with which it may be refined into high value refined products. A lighter crude oil is therefore of higher quality since when refined it produces more high value products (such as gasoline) as a fraction of its total volume than does a heavy crude. An additional factor in the quality of crude is its sulfur content. A "sour" crude has a higher sulfur content and is therefore more expensive to refine.

averaged across the entire period of the study. Since there is a persistent difference in price between imported and domestic oil, this difference will be considered in estimating the marginal cost for OPEC as discussed in chapter 6.

Algebraic Development of the Model

The price leadership model discussed above can be represented algebraically. The graph, the model and the parameters used to describe it are shown in figure 5.5.

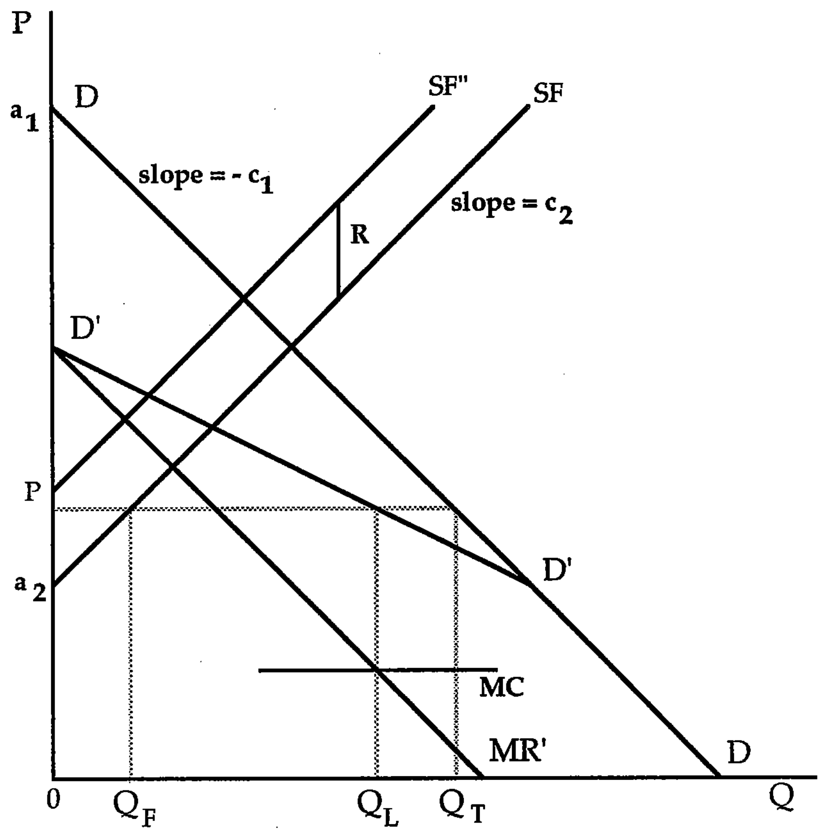

Figure 5.5

The model's parameters, as described below, are shown in bold in figure 5.5. In order to describe the model algebraically, the demand curve, the domestic supply curve, the OPEC marginal cost curve, and the regulatory cost must be given equations.

The equations are as follows:

Domestic demand: $P = a_1 - c_1 Q$
Domestic (fringe) supply: $P = a_2 + c_2 Q$
OPEC marginal cost: $P = MC$
Regulatory cost is R[12]

These equations can be solved to determine the price, domestic production, and OPEC production before and after the imposition of a regulatory cost R. In appendix C the solution of the equations is shown in detail.

[12]The regulatory cost is added to the intercept of the domestic supply curve, since it represents an across-the-board increase in domestic marginal cost.

Chapter 6

Derivation of Parameters of Price Leadership Model and Results

In order to determine how a regulatory cost will affect petroleum production, the demand and supply lines must be estimated. In addition, an estimate of OPEC's marginal cost must be made. To estimate the demand and domestic supply lines, several parameters must be estimated. The parameters which are estimated are the slopes of the supply and demand lines and the long-run average price, production, and consumption.

Estimation of Supply Elasticity and the Domestic Supply Line

The total effect of a $1/Bbl price increase is to increase production by 178,000 Bbl/day,[1] as shown in the results of the PDL supply model in chapter 4. Using this result, the slope of the supply curve (c_2) should be 1/178 or 0.0056. The supply line can be estimated by using this slope and a point. The point used is the long-run average price and production point, which must be on the long-run supply line. The average price of oil from 1974 through 1994 is $20.77 per barrel, and the average domestic production level over this period is 8,203 Bbl/day. At the point of the means, the long-run elasticity of supply implied by a slope of 0.0056 is 0.45. The supply line can now be determined and is shown in figure 6.1.

[1]The price leadership model will use figures in thousands of Bbl/day. All subsequent figures in this chapter for Bbl/day are in thousands, unless otherwise noted.

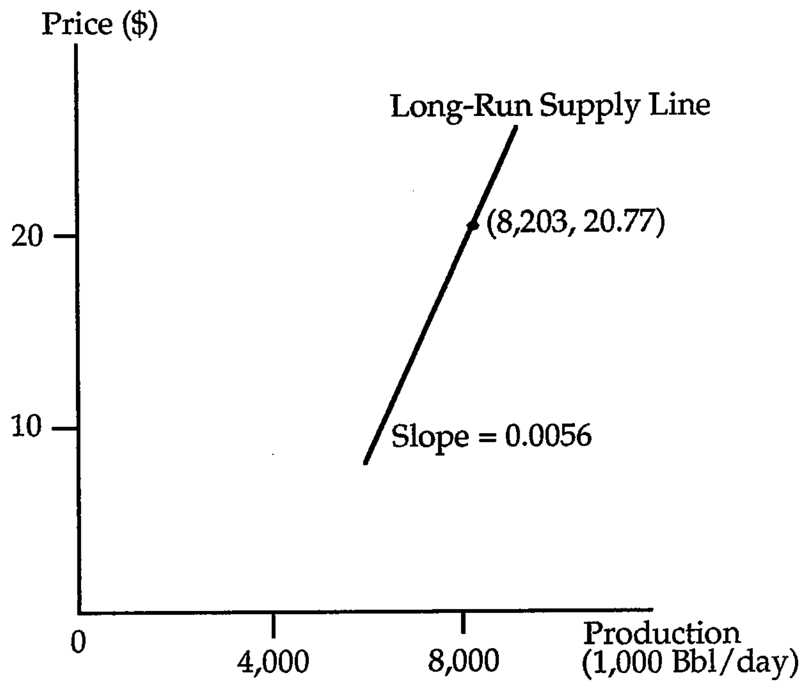

Figure 6.1

Figure 6.1 demonstrates the determination of the long-run supply line from the long-run average price and production point and the slope. Over a larger range of prices, the supply function might be curved, but, in the neighborhood of the period average, the supply curve may be closely approximated by a line.

Estimation of Demand Elasticity and the Demand Line

Estimating the slope of the demand line is more difficult than estimating the slope of the supply line. I attempted a regression using a PDL model with consumption regressed on price. In this regression, the crude oil consumption and price data were taken from the Monthly Energy Review. The price data used were not the same price data used in the supply regression. In the supply regression the wellhead price of oil was used. For the consumption regression, a weighted average crude oil price was used. This was done in order to account for the higher price of imported oil, especially during the 1970's when domestic oil prices were controlled.[2] For this regression, the price used is not the wellhead price of oil but is a weighted average price of oil, in order to account for the higher price of imported oil. The largest value found for the sum of the lags in this regression is -108.043, which occurs with a lag length of 41 months. Having a lag period for the response in demand to an increase in the price of petroleum is reasonable, since individuals' short-term consumption patterns may be fixed; for example, an individual who has a fuel-inefficient car and must drive to work will not be able to make immediate changes in his gasoline consumption when the price increases, but over a period of years he may choose to purchase a new, fuel-efficient car, which will in the long term reduce his gasoline consumption.

In the demand regression, the coefficients between the 23rd and 37th period are insignificant at the 5% level of significance, and the coefficients for the first three periods are positive; this result therefore suggests the unlikely result that an increase in the price of oil increases oil consumption for three months after the price increase. The sum of the coefficients seems to be too small, indicating that a $1/Bbl increase in the price of oil will cause a reduction in consumption of only about 108 Bbl/day. Were this result correct, the price of oil could go to $50, yet consumption would only drop from 13,136 Bbl/day to 9,977 Bbl/day, even over the long run. The result implies that the long-run demand elasticity for oil is 0.185,[3] which also seems low and does not conform to estimates of demand elasticities from other studies, as reported by Jones (1993), discussed below.

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[2]The weighted average price is a weighted average of the domestic wellhead price and the imported crude oil refiner acquisition cost.

[3]The elasticity value is actually -0.185. Since all demand elasticities for normal goods are negative (indicating that, as price rises, quantity demanded falls), all demand elasticities will be reported as positive numbers for convenience.

The problem with the PDL-consumption regression is that the equation probably should include additional independent variables, since demand for petroleum should not depend solely on the real price of crude oil. Demand for petroleum should be affected by real GDP, since, *ceteris paribus*, more oil should be consumed when GDP rises. To examine the possibility of the existence of other independent variables, regressions were performed which regressed consumption on real GDP and/or an industrial production index (IP) in addition to price. These regressions yielded more plausible results than the regression using price alone. The results for various combinations of these variables are given in table 6.1.[4] The standard errors for the coefficients are given in parentheses below the coefficient values.

Table 6.1: Results of supply regressions

	(1)	(2)	(3)	(4)
Price	-108.043	-166.741	-168.948	-167.175
	(8.513)	(6.739)	(10.25)	(9.839)
IP		-69.678		122.10
		(4.387)		(48.61)
GDP			-1.1617	-3.0843
			(0.1081)	(0.7723)
R^2	0.502	0.783	0.846	0.863
F-statistic	32.94	100.5	45.67	44.41

These results show that including either the GDP or industrial production variables increased the predicted long-run price effect and the R^2; however, even the largest price effect estimates a consumption decrease of only 169 Bbl/day for a $1/Bbl increase in petroleum prices, which implies a long-run demand elasticity of 0.267. This demand elasticity is at the very

[4]The GDP data are quarterly rather than monthly. For the regressions including GDP as a variable, the consumption, price, and IP data were converted to quarterly data by averaging the monthly data from each quarter. The lag on the PDL for price was 14 quarters, which is equivalent to 42 months.

bottom of the range of demand elasticities reported for the U.S. petroleum market in recent studies. In addition, the coefficients for GDP are negative, implying that, as GDP increases, petroleum consumption drops. This is not a logical result and probably reflects the increased energy efficiency in the U.S. economy which occurred as a reaction to the energy crises of the 1970's. I do not have much confidence in these results, since they imply low long-run demand elasticities, and since the coefficients for the GDP and IP variables are difficult to interpret.

Because of these concerns, I chose in this study to use an estimate of the demand elasticity for petroleum from another study to determine the slope of the demand line. In "A Single-Equation Study of U.S. Petroleum Consumption: The Role of Model Specification" (1993), Clifton Jones reports that various studies place the long-run demand elasticity in the U.S. petroleum market between 0.25 and 0.56. Jones estimates that elasticity to be 0.487 (p. 694). A demand elasticity of 0.487 implies a slope for the demand line in the price leader model of -0.00262. With this slope for the demand line, a \$1/Bbl increase in the price of oil will cause the demand for oil to fall by 382 Bbl/day over the long run. I performed a simple regression of consumption on price, which yielded a slope of -0.0025, thus providing support for Jones' elasticity estimate, although the R^2 for this regression was only 0.1.

The long-run average price of oil is \$20.77. The long-run average consumption is 13,136 Bbl/day. Using -0.00262 as the slope of the demand line and the historical average values for price and consumption, the demand line can be determined. The demand line is shown in figure 6.2.

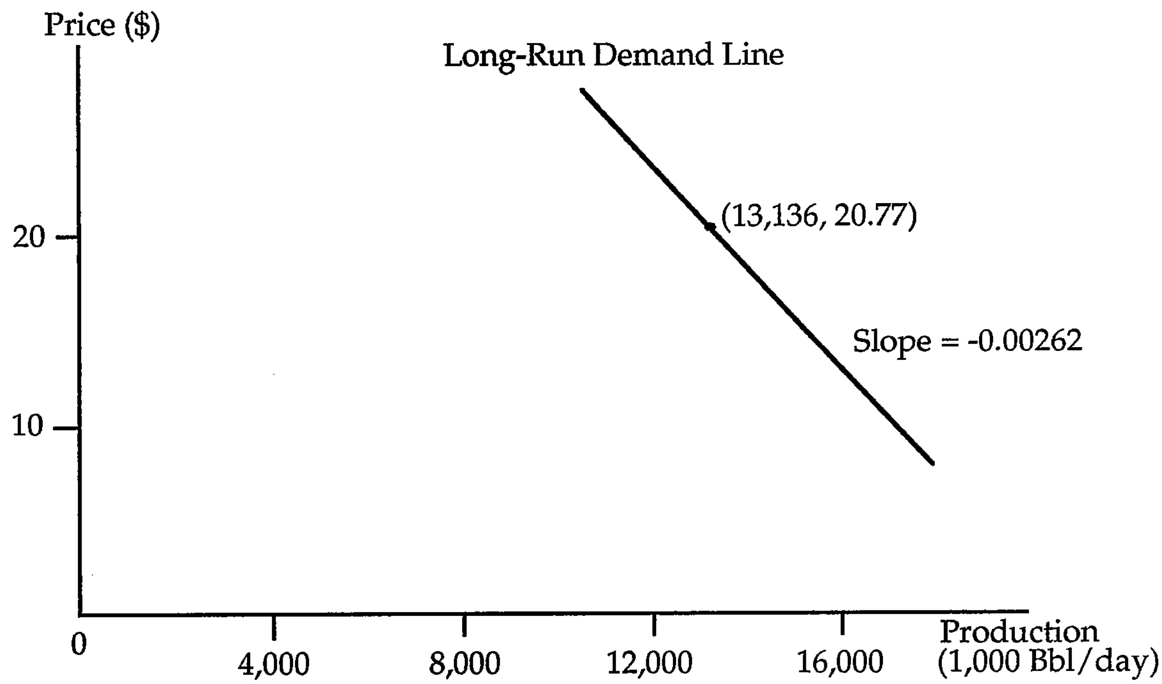

Figure 6.2

The long-run demand line is derived as the supply line was, using the long-run average price and consumption values as a point and the slope determined above. Again, this line is an approximation of the true demand function, which may be curved over a wide range of values.

Estimation of OPEC's Marginal Cost

The remaining parameter needed in the price leadership model is the marginal cost for OPEC. The goal of the study is to determine how various regulatory costs would affect domestic petroleum prices and production. For this reason, the regulatory cost will be given various values which depend on different estimates of regulatory costs. This will be the focus of the following chapter.

The estimate of the marginal cost for OPEC used in this model is not an estimate of the marginal cost at the wellhead for OPEC; instead the OPEC MC needs to be the marginal cost for OPEC to supply crude oil to the U.S. market, including all transportation costs. As discussed in chapter 4, there has been a persistent price differential between imported oil and domestically produced oil, which I cannot explain. Since I cannot strongly support the use of the price differential as OPEC's MC, I instead tried various values for MC until the model's prediction of OPEC's production was close to the historical average production for OPEC. I found that using $12 as the estimate of MC causes the model to predict OPEC's production closely. Therefore, I have used this value. I cannot explain why the value is this large. In any event, the value should be greater than the marginal cost at the wellhead, since the oil must be transported to the United States. Since the model that I am using is a simplification of a part of the extremely complex worldwide petroleum market, other factors which are beyond the scope of this model may be involved.

Results and Tests of Algebraic Price Leadership Model

A summary of the parameter estimates for the parameters of the price leadership model is given in table 6.2.

Table 6.2: Parameter estimates for price leadership model

Description	Parameter	Estimated Value
Negative of Slope of Demand Line	c_1	0.00262
Slope of Fringe Supply Line	c_2	0.0056
Long-run Average Price		$20.77
Long-run Average Production		8,203 Bbl/day
Long-run Average Consumption		13,136 Bbl/day
OPEC's Marginal Cost	MC	$12/Bbl

Basic Results

The price leadership model has now been developed and all of its parameters have been reasonably estimated. These parameters are used with the algebraic formulas derived from the model (shown in Appendix C) to estimate long-run price and quantities produced by domestic producers and OPEC. The results of the model and the average reported results for these variables over the period studied are shown in table 6.3.

Table 6.3: Comparison of model's and actual results

	Model's Prediction	Average Result
Price	$20.79	$20.77
OPEC Production	4,923 Bbl/day	4,936 Bbl/day
Domestic Production	8,206 Bbl/day	8,203 Bbl/day
Total Consumption	13,129 Bbl/day	13,136 Bbl/day

As the table shows, the model's results are close to the long-term averages. This should not be surprising, since part of the calibration of the model comes from the long-term average price, production, and consumption data.

Results with the Addition of a Regulatory Cost

Suppose a regulatory cost of $1/Bbl is imposed on domestic production so as to raise the domestic supply curve by $1. The resulting changes as predicted by the price leadership model are shown in table 6.4.

Table 6.4: Effect of regulatory cost in price leadership model

	Pre-Regulation	Post-Regulation	Absolute Change	Percent Change
Price	$20.79	$20.94	+$0.16	0.77%
OPEC Production	4,923 Bbl/day	5,012 Bbl/day	+89 Bbl/day	1.81%
Domestic Production	8,206 Bbl/day	8,056 Bbl/day	-150 Bbl/day	-1.83%
Total Consumption	13,129 Bbl/day	13,069 Bbl/day	-60 Bbl/day	-0.46%

A $1/Bbl regulatory cost is borne mainly by the domestic producers. The price of oil rises by 16¢, or 16% of the regulatory cost. Total consumption falls by 60 Bbl/day, only 0.46% of the original level, while OPEC production rises by 89 Bbl/day, equal to 1.81% of its original level. As a result, domestic production falls the most, by 150 Bbl/day, or 1.83%. If domestic production today fell by 1.83%, the total lost production each year would be worth approximately $850 million.[5] Regulatory costs greater than $1 would have proportionately larger effects; for example, a $2/Bbl regulatory cost would decrease domestic production by 300 Bbl/day or 3.66%.

Sensitivity Analysis of the Model

The model can be tested to see how the results change when parameter estimates are varied. This test is performed to determine whether the results are particularly sensitive to the estimates of any particular parameters, and to determine how sensitive the results are to the estimates of the parameters in general. To test sensitivity, we fix the regulatory cost shift at $1/Bbl and vary

[5]This estimate is made using the May 1994 production data and the current (March 1995) domestic oil price.

each parameter estimate in turn by 25%.[6] Each parameter is first varied by 25% up and 25% down. Twenty-five percent is chosen as a convenient percentage variation. The results of this initial analysis are shown in table 6.5.[7]

Table 6.5: Effect of parameter changes on domestic production

Percent Change in Domestic Production		
Parameter	Parameter +25%	Parameter -25%
Base	**-1.83%**	**-1.83%**
Demand Slope	-1.75%	-1.93%
Dom. Supply Slope	-1.50%	-2.37%
OPEC MC	-1.77%	-1.89%

These results show that the model's predictions of the change in domestic production which results from the imposition of a regulatory cost are fairly stable, even as the individual parameters used to estimate the model are varied. The model is apparently most sensitive to changes in the slope of the domestic supply line, but this slope was estimated the most carefully of any of the parameters and is therefore the least likely to be wrong.

To further test the model, I combined variations in the estimates in the parameters of 25% in such a manner as to cause the greatest rise and fall in the estimate of the change in domestic production which results from the regulatory cost. To achieve the lowest change in domestic production, 25% is added to the estimates of the slopes and of the OPEC MC. When these changes in the parameters are made, the domestic supply change estimate is

[6]The domestic production changes are discussed in detail since the focus of this study is the determination of how domestic production has changed because of environmental regulations.
[7]The long-run price, production, and consumption parameters are not varied in this sensitivity analysis, since these values are not estimates but are historical values.

-1.40%. When the opposite changes are made in the parameters, in order to get the largest possible domestic supply change, the supply change estimate is -2.64%. These results show that if the estimates of the parameters are all incorrect in a manner which minimizes the impact of the regulatory costs, domestic supply should fall by 1.40% rather than by the original estimate of 1.83%. On the other hand, if the parameters have been misestimated in a manner which maximizes the regulatory impact, domestic supply should fall by 2.64% rather than by the original estimate of 1.83%. These results imply that the estimate of the domestic supply change is only moderately affected by different parameter estimates.

Since the OPEC MC parameter may have been misestimated, variations in the MC parameter estimate were examined more closely. The initial estimate of MC is $12, which predicts a 1.83% drop in domestic production with the regulatory cost added. If MC is set to $0.05, far below any conceivable value for OPEC's true MC, the model predicts a 2.10% drop in domestic production with the regulatory cost. On the other hand, if MC is set to $29, the highest value which would permit OPEC to export petroleum to the United States at all (as predicted by the model), the regulatory cost causes domestic production to drop by 1.54%. This analysis shows that the predictions of the model are not at all sensitive to the value of OPEC's MC, and a misestimation of the MC parameter would have only a tiny effect on the results.

This sensitivity test shows the price leadership model to be fairly robust, in that its estimates of the domestic supply change resulting from the imposition of a regulatory cost do not vary widely when the parameters are varied. It is likely that at least some of the parameters have been misestimated, but this analysis shows that it is reasonable to use -1.83% as the change in domestic supply which results from the imposition of a \$1/Bbl regulatory cost.

Chapter 7

Effects of Environmental Regulation on Production

Effects of Recent Regulatory Compliance Actions

This section uses the supply and price leadership models to estimate the effects of current environmental regulatory costs on domestic petroleum production. The estimates of environmental regulation compliance costs come from Petroleum Industry Environmental Performance, published by the American Petroleum Institute.[1] The environmental compliance costs are broken out by sector (i.e., exploration and production, refining, etc.), by media (i.e., air, water), and by whether the expenditures were capital expenditures or ongoing expenses. For this study I consider only compliance costs associated with exploration and production (E&P), since my focus is on the effects of the regulatory costs on production.

In addition, only the ongoing expenses associated with environmental compliance are considered, since these expenses affect marginal cost. Capital expenditures associated with compliance are not considered. Capital expenditures are sunk costs which should not affect marginal cost and therefore should not affect current production decisions; capital expenditures necessitated by regulation will, of course, still affect profits and stock prices of petroleum producers. The ongoing expenditures for E&P environmental compliance, in millions of May 1994 dollars, are given in table 7.1. In the table, "Wastes" refers to solid wastes.

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[1]This book was provided by Mr. Manekshaw.

Table 7.1: Environmental regulatory costs by medium, 1990-1992

Medium	1990	1991	1992
Air	$114 million	$115 million	$74 million
Water	$610 million	$411 million	$413 million
Wastes	$104 million	$131 million	$184 million
Other	$157 million	$235 million	$194 million
Total	$985 million	$892 million	$865 million

Source: American Petroleum Institute

Table 7.1 shows that total ongoing environmental compliance expenses for E&P averaged somewhat below $1 billion per year from 1990 through 1992. Most of the expenses relating to air pollution resulted from compliance with the Clean Air Act (CAA). Most of the expenses relating to water pollution resulted from compliance with the Clean Water Act (CWA), and most of the expenses relating to solid waste pollution resulted from compliance with the Resource Conservation and Recovery Act (RCRA).

For E&P, the CWA clearly has the highest compliance costs. Air compliance costs fell in 1992 as compared to 1991. Although for the entire petroleum industry the 1990 amendments to the CAA sharply raised costs,[2] the amendments apparently reduced the costs for E&P. Solid waste compliance costs rose by over 75% for this period, although no major new laws regarding solid waste pollution were enacted. Possibly, the EPA issued more stringent regulations under the authority of the 1984 amendments to

[2]Total industry expenditures for compliance with environmental regulations regarding air pollution nearly doubled from 1990 to 1992.

RCRA, since the promulgation of regulations authorized by an act can take many years.[3]

Using the production data from 1990-1992, the per barrel expense can be determined. I determined only the average per barrel expense for all three years, since this study examines the long-term production impact of environmental costs. The results are given in table 7.2.

Table 7.2: Per barrel environmental regulatory costs, average for 1990-1992

Medium	Expense per barrel
Air	$0.04
Water	$0.18
Wastes	$0.05
Other	$0.07
Total	$0.34

The environmental compliance expenditures per barrel are fairly low relative to petroleum prices, which today are about $19/Bbl.[4] That these costs are low makes sense, since the Pennzoil executives generally did not feel that current environmental regulations have a large impact on petroleum production.

I shall treat, as seems reasonable, the per barrel incremental expense as an increase in marginal cost. The production impact of a 34¢ increase in marginal cost for domestic producers can be determined using the supply model and the price leadership model. To apply the supply model, I assume that the 34¢ increase in marginal cost is equivalent to a drop in oil prices of

[3]In fact, an important reason for the 1984 amendments to RCRA was that the EPA by the early 1980's had still not promulgated regulations under the authority of several sections of the original RCRA, which was enacted in 1976.
[4]This is the wellhead price for West Texas Intermediate Crude on March 28, 1995.

34¢, since oil producers' expenses will rise by 34¢/Bbl, and profits will therefore drop by 34¢/Bbl. The effect is the same as if oil prices dropped by 34¢/Bbl, in which case producers' profits would also drop by the same amount. I further assume that OPEC has little monopoly power and in effect treats the world petroleum market as competitive. Since this regulation affects only U.S. producers, the U.S. producers must absorb all of the regulatory cost. The case where OPEC does have significant monopoly power is better represented by the price leadership model, discussed below.

In the long run, the supply model predicts that for each increase of \$1/Bbl in the price of oil, domestic production will rise by 178,000 Bbl/day. In this case, since the regulatory cost is equivalent to a price decrease of 34¢, production will fall by 0.34 x 178,000 Bbl/day, or 61,000 Bbl/day. This is a 22 million Bbl/year drop in production, which would reduce the revenues of the petroleum industry by approximately \$420 million. In percentage terms, this is a 0.9% drop in production for 1994.

On the other hand, the price leadership model assumes that OPEC is a successful monopolist, and that an increase in U.S. regulatory cost will not be fully borne by U.S. producers, since the price of oil will rise. Therefore, if OPEC is a successful monopolist, the price leadership model predicts that a 34¢ regulatory cost will cause domestic production to fall by 0.62%. This decrease in production would reduce the industry's revenues by approximately \$290 million.

Although the models rest on different assumptions regarding OPEC's monopoly power, both models predict that current environmental regulatory costs are responsible for only relatively small changes in production by U.S. producers. The supply model predicts more of a production response, primarily because it assumes that the regulatory cost is borne completely by domestic producers, whereas the price leadership model allows some of the regulatory costs to be borne by consumers and therefore predicts less of an impact on domestic producers. These results conform to the general sense of the Pennzoil executives, who did not feel that current environmental regulations have much of an impact on domestic production.

Effect of Potential Future Regulations on Production

As discussed in Chapter 2, the DOE has made estimates of the additional costs which potential new regulations would impose on petroleum E&P. The DOE study limits itself to RCRA, the CWA, the CAA, and the Safe Drinking Water Act (SDWA). For each of these acts, amendments have been considered by Congress which would make the acts more stringent. The increased strictness of the amendments would bring with it additional costs for petroleum E&P. Three different regulatory scenarios are postulated by the DOE. Each of the three scenarios contains a group of regulatory changes for each of the acts considered; the "low" scenario assumes only a few additional regulations, the "high" scenario assumes the promulgation of many stringent new regulations, and the "medium" scenario strikes a balance between the other two. Not surprisingly, as the scenarios include more stringent new regulations, compliance becomes more expensive.

In each case, none of the new regulations has been promulgated. In the current political climate, it is unlikely that any of these new regulations will be promulgated in the near future; however, all of the regulations have been previously considered, and it is likely that at some time in the future they will again be considered.

The DOE study divides the new regulatory costs for each scenario into initial and annual costs. The initial costs are costs which would be borne immediately with the promulgation of the new regulations, in order to bring current facilities up to the more stringent emissions standards. The annual costs are costs that would be borne continuously during production, such as costs associated with transporting offshore drilling muds to the shore to be disposed of.

As in the examination of current regulatory costs, only the ongoing (annual) costs of the regulations are used, since only ongoing costs affect marginal cost and production decisions. The costs of the proposed regulatory changes in each act for each scenario are given in table 7.3.

Table 7.3: Annual costs to production of new regulations, by DOE scenario

	Low Scenario	Medium Scenario	High Scenario
RCRA	$1,903 million	$3,351 million	$3,655 million
SDWA	$87 million	$493 million	$595 million
CWA	$85 million	$1,024 million	$2,684 million
CAA	$278 million	$325 million	$1,177 million
Total	$2,353 million	$5,193 million	$8,111 million

Source: Department of Energy

Several observations can be made about the numbers in table 7.3. Clearly, amendments to RCRA would increase costs for E&P by the greatest amount, even if RCRA were only slightly amended. In addition, extensive amendments to the CWA would also be extremely expensive. Minor changes to the SDWA and the CWA would increase costs only slightly and would have only a very small production effect.

Table 7.4 shows the per barrel increase in costs which these regulatory changes would cause at current production levels.

Table 7.4: Per barrel regulatory costs, by DOE scenario

	Low Scenario	Medium Scenario	High Scenario
RCRA	$ 0.79	$ 1.40	$ 1.52
SDWA	$ 0.04	$ 0.21	$ 0.25
CWA	$ 0.04	$ 0.43	$ 1.12
CAA	$ 0.12	$ 0.14	$ 0.49
Total	$ 0.99	$ 2.18	$ 3.38

The total impact on production of these regulatory costs can be estimated using both the supply model and the price leadership model, in the same manner as the estimate of the impact of the current regulatory costs. The estimated percentage decreases in production from each of these models are given in table 7.5.

Table 7.5: Domestic production decrease under DOE regulatory scenarios

	Low Scenario	Medium Scenario	High Scenario
Supply Model	2.66%	5.87%	9.17%
Price Leadership Model	1.79%	3.97%	6.18%

Again, the supply model predicts a greater production response to regulatory costs than does the price leadership model; both models' predictions are in the same broad range, but the supply model predicts about a 40% greater response. The dollar value of the lost U.S. production, in billions of 1994 dollars, which would partially be made up by greater petroleum imports, is given in table 7.6.

Table 7.6: Lost U.S. production

	Low Scenario	Medium Scenario	High Scenario
Supply Model	$1.21 billion	$2.67 billion	$4.18 billion
Price Leadership Model	$0.81 billion	$1.81 billion	$2.81 billion

The estimates of lost production from the supply and price leadership models can be compared to the DOE's estimates of the reduction in domestic production from the implementation of these regulatory schemes. The DOE estimates of the percentage decline in domestic production from each of these regulatory scenarios is given in table 7.7. These estimates assume an oil price of $20/Bbl and a ten year adjustment period.

Table 7.7: DOE estimated production changes, by scenario

	Low Scenario	Medium Scenario	High Scenario
Percentage decrease in production	1%	12%	21%

Source: Department of Energy

For the low scenario, the DOE predicts almost no decrease in production; however, for the medium and high scenarios the DOE predicts that the regulatory costs will have a much larger impact on production than do the supply and price leadership models. Part of the difference is that the DOE considers not only the ongoing costs of the regulations but also the capital expenditures necessary for initial compliance with the regulations (i.e., the initial costs). Although these capital expenditures should not affect the marginal cost of production, they could conceivably have a large impact on production over the long term, as they would substantially increase the costs of bringing new wells on stream. This, in turn, would decrease the expected return of a new well and could push its expected return below the "hurdle rate" mentioned by Mr. Maughs, which would cause the firm not to develop the well.

The capital expenditures associated with complying with the potential new regulations are estimated to be very high, at $36 billion for the medium scenario and $79 billion for the high scenario. If these expenditures are amortized over the 10-year period used in the DOE study, the cost per year would be $3.6 billion for the medium scenario and $7.9 billion for the high scenario. If these costs are then added to the ongoing costs discussed above, the percentage decline in production predicted by the supply and price leadership models can be recalculated. The results of this recalculation are given in table 7.8.

Table 7.8: Estimated production changes assuming capital expenditures affect marginal cost

	Medium Scenario	High Scenario
Supply Model	9.94%	18.11%
Price Leadership Model	6.72%	12.22%

These results, especially for the supply model, conform more closely to the DOE's predictions. Although it is possible that the capital expenditures should be considered to be comparable to increases in marginal cost, there is no compelling argument for doing so, except perhaps that the results then better conform to those of the DOE. Another possible reason why the predictions of my models do not agree with those of the DOE is that the DOE's study examined production in only nine states, whereas my models examine aggregate production. It is possible, albeit unlikely, that the particular states chosen for the DOE study have petroleum production which is particularly sensitive to regulatory costs.

The potential new regulations could have a much greater effect on production than the current environmental regulations, and the value of lost production could run into the billions of dollars. Nevertheless, in no case does my model predict that production will drop by more than 10% over the long run as a result of environmental regulations.

Conclusion

The U.S. petroleum industry has been regulated almost from its inception. The most stringent constraints were the price controls of the 1970's, but the history of regulation has continued to the present day in the form of environmental regulation. There have been many economic studies of how regulation has affected the industry. Most of these studies, however, have focused on the price controls of the 1970's and the massive market disruptions which those price controls engendered. Since the 1970's, far fewer studies have been undertaken, and the studies which were made generally focused on very specific aspects of regulation, such as the regulation of offshore production.

This study examined how environmental regulations in the aggregate affect domestic oil production. The fundamental conclusion is that current environmental regulations have only a minor impact on production, reducing it by less than 1%. As has been demonstrated, proposed and potential future regulations could have a much larger impact, resulting in a reduction as large as nearly 10%. Such a reduction would occur only if new environmental regulations are far more stringent than any current regulations. Although more stringent regulations have been proposed, as discussed in the DOE future regulatory changes study and by the Pennzoil executives, it is doubtful that they can or will be enacted or implemented.

These results confirm the general consensus of the Pennzoil executives whom I interviewed. The executives felt that current environmental regulations do not have a major impact on petroleum production, primarily because the industry has been able to obtain exemptions for production from the most onerous provisions of the regulations. The executives also repeatedly expressed concern that future regulations would impose much greater burdens on production, as the empirical results of this study suggest is possible even if not likely.

Several factors mentioned by the individuals whom I interviewed must be considered when interpreting these results. Mr. Manekshaw pointed out the importance of life cycle analysis in evaluating the cost of a regulation. Life cycle analysis considers not just the cost of the regulation at a particular stage of production, such as extracting petroleum from the ground, but the costs which the regulation imposes at all levels of production. For example, the Clean Air Act might increase the costs of smelting steel, which then increases the costs of manufacturing oil rigs. These increased costs are added to the increased costs at the production level, which were examined in this study. Then, all of these costs are added to increased transport costs, and so forth. The regulatory costs compound since they apply at all levels of production. For this reason, the real cost of environmental regulations to the petroleum industry could be much higher than the direct costs of the regulations on production. In any event, the regulations directly increase production costs by only a minimal amount.

It is also possible that the cost statistics provided by the API and the DOE understate the ongoing compliance costs of environmental regulations. Mr. Ewing noted that much of the compliance costs arise not from complying with any specific regulation, but from the many small compliance efforts which EPA inspectors often require. It is conceivable that the API statistics, for example, missed these costs, since these statistics looked at the cost for complying with regulations affecting different media, rather than overall compliance costs. If the API or DOE statistics were underestimated, the impact of environmental regulations on production could be greater than predicted by this paper.

Although as noted there are methodological reasons to believe that the API and DOE estimates may be low, compelling practical reasons support a contrary conclusion. Certainly the API, an organization funded by the industry, would seek to maximize the reported environmental compliance costs, so that these statistics could be used by the industry when Congress is considering new environmental laws or the repeal of current laws. The DOE, although theoretically neutral, displayed some pro-industry bias during the Reagan-Bush era, and therefore might be presumed to bias cost estimates upwards, if there were any bias at all.

On the basis of Mr. Ewing's interview, it seems that regulatory costs are relatively higher for smaller producers than larger producers. This is plausible, as many regulations have costs which are fixed and which would therefore be much higher per barrel for a smaller producer. Accordingly, environmental regulations which reduced overall production by less than 1% (as predicted by the supply and price leadership models) might reduce production by smaller firms by a much greater percentage, while barely affecting production by larger firms. Were this the case, an argument could be made for relieving smaller producers of some of the more onerous provisions of these regulations.

Smaller producers, however, have in the past and still today receive many benefits which are not available to larger producers, especially in the form of special tax treatment; it is possible that this special tax treatment more than compensates for the regulatory burdens. Probably many smaller domestic producers are inefficiently small and exist only because of governmental policies favoring them. It would seem that governmental policies should be evenhanded with respect to size, in order to encourage efficiency in production. There is no good case for biasing policy in favor of small producers.

Mr. Soza mentioned that many of the costs to companies of environmental regulations are indirect, particularly legal oversight costs. He said that legal costs might exceed the cost of complying with regulations in the field. If this is the case, environmental regulations might be much more expensive than the API estimates, since the API compliance cost estimates apparently reflect only the cost of complying with the regulations in the field. Nevertheless, even on the assumptions that indirect costs equal direct costs, that indirect costs were not included in the API estimates, and that indirect costs affect marginal cost, regulatory costs would reduce production by less than 2%.

Since environmental regulations apparently do not have a major impact on domestic production of petroleum, why does the industry complain about the regulations? There are several explanations. First, the initial costs of the regulations, which reduce industry profits, are often extremely high, running into the tens of billions of dollars. These costs, however, do not greatly affect production since they do not affect marginal cost.[1] Second, the major impact of regulatory costs is on the refining sector of the petroleum industry; the API estimates the ongoing costs of regulatory compliance for refining to be about three times as large as for E&P. In addition, this paper considered only regulation which affects the cost of production. Some regulation, especially the regulation of offshore production in California, precludes production in certain areas. Although

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[1]Mr. Soza said that the regulations often do not have a major impact on marginal cost, even when they are expensive in the start-up phase.

this type of regulation theoretically could have a large effect on production, it is unlikely that it does, since production is prohibited in only a small number of potential producing areas.

The current environmental regulatory environment for the petroleum industry is surprisingly rational,[2] if one assumes that the government is attempting to maximize environmental quality while avoiding decreases in employment. E&P receives many exemptions from regulations. These exemptions allow it to compete with imported oil and avoid the loss of U.S. jobs which would accompany reduced domestic production and increased imports. Refining, which currently has little international competition since few refined products are imported, is heavily burdened with environmental regulations. These regulations undoubtedly reduce refiners' output. The reduction in output, however, is lower than it would be were there significant international competition, since most of the costs can presumably be passed on to consumers, thus minimizing the impact on employment.

Since environmental regulations have only a small impact on production, it is entirely possible that the benefits of the regulations to society outweigh the costs. An examination of the benefits of the regulations is beyond the scope of this study, but this study has shown the costs of the regulations to be small.

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[2]It is surprising considering how irrational the regulatory scheme appears on an initial examination.

Appendix A

Assumed regulatory changes in RCRA under the medium scenario described in the 1990 DOE study (p. 7):

Regulatory Category	Compliance Requirements
1. Management and disposal of drilling waste	Oil-based muds use closed systems Salt water-based muds disposed into lined pits
2. Disposal of associated wastes into central disposal facilities	Liquid wastes into off site disposal well; solid wastes into hazardous waste landfill
3. Upgrading emergency pits	Existing emergency pits must be lined; new pits must be replaced with tanks
4. Replace workover pits with portable rig tanks	Required on all rigs
5. Organic toxicity characteristic test	Applied to all facilities and new wells
6. Corrective action (soil remediation only)	Excavation of salt water contamination at 100% of SWD wells and 75% of EOR projects and tank batteries Land treatment of hydrocarbon contamination at 50% of tank batteries and EOR projects

Appendix B

The values of the coefficients for the PDL supply model and the null supply model are as follows:

	PDL Model		Null Model	
Period	Coefficient	Stand. Error	Coefficient	Stand. Error
0	7.51	0.63	-5.92	11.67
1	6.93	0.51	-1.18	23.83
2	6.40	0.40	47.27	27.59
3	5.90	0.30	-39.34	28.48
4	5.45	0.23	36.13	28.76
5	5.04	0.17	0.15	29.03
6	4.66	0.13	-6.03	29.45
7	4.32	0.12	9.09	29.90
8	4.01	0.13	7.48	29.77
9	3.72	0.15	2.25	28.63
10	3.46	0.16	10.33	28.19
11	3.23	0.18	-8.17	28.32
12	3.02	0.19	-12.03	28.49
13	2.83	0.19	48.37	28.44
14	2.66	0.20	-31.14	28.88
15	2.51	0.20	5.93	29.58
16	2.37	0.20	11.15	30.04
17	2.25	0.19	10.90	30.51
18	2.15	0.19	-10.75	30.50
19	2.05	0.18	37.60	30.49
20	1.97	0.17	-53.20	30.61
21	1.90	0.16	41.07	30.43
22	1.84	0.15	-15.75	29.34
23	1.78	0.14	3.17	28.08
24	1.74	0.13	-5.05	27.55
25	1.69	0.13	28.76	27.55
26	1.66	0.12	-39.00	27.57
27	1.63	0.11	30.54	27.72
28	1.60	0.11	0.50	28.33
29	1.58	0.10	-1.36	28.49
30	1.56	0.10	-23.10	28.55
31	1.54	0.10	35.18	28.54
32	1.53	0.10	-28.92	28.74
33	1.52	0.09	40.14	29.64
34	1.50	0.09	-41.47	30.61
35	1.49	0.09	7.15	30.67

	PDL Model		Null Model	
Period	Coefficient	Stand. Error	Coefficient	Stand. Error
36	1.49	0.09	15.98	30.93
37	1.48	0.09	3.04	30.85
38	1.47	0.09	-30.43	30.74
39	1.46	0.09	64.74	30.73
40	1.45	0.08	-50.20	30.63
41	1.44	0.08	25.75	30.91
42	1.43	0.08	-14.86	31.18
43	1.43	0.08	21.94	31.41
44	1.42	0.08	-22.20	31.58
45	1.41	0.08	28.99	31.58
46	1.40	0.08	-29.18	32.37
47	1.39	0.08	-3.90	34.05
48	1.38	0.08	34.79	34.19
49	1.37	0.08	-2.90	34.21
50	1.36	0.08	-25.64	34.55
51	1.35	0.08	59.66	34.49
52	1.34	0.08	-54.82	34.22
53	1.33	0.08	44.67	33.93
54	1.33	0.09	-32.81	33.72
55	1.32	0.09	3.43	34.06
56	1.31	0.09	12.86	33.83
57	1.30	0.09	9.86	33.74
58	1.30	0.09	-23.25	33.49
59	1.29	0.09	41.69	33.26
60	1.28	0.09	-50.34	33.84
61	1.28	0.09	13.89	34.13
62	1.28	0.09	17.61	33.76
63	1.27	0.09	8.39	33.78
64	1.27	0.09	-17.12	33.95
65	1.27	0.08	24.83	33.47
66	1.27	0.08	-42.79	33.05
67	1.27	0.08	28.99	31.87
68	1.27	0.08	-6.32	31.14
69	1.27	0.08	-5.24	30.83
70	1.27	0.08	3.79	30.13
71	1.27	0.09	17.57	30.18
72	1.27	0.09	-33.56	29.91
73	1.28	0.10	44.94	29.89
74	1.27	0.11	-21.63	30.28
75	1.27	0.11	2.76	30.43
76	1.27	0.12	-6.53	29.90

	PDL Model		Null Model	
Period	Coefficient	Stand. Error	Coefficient	Stand. Error
77	1.26	0.13	1.82	29.57
78	1.25	0.14	27.43	29.42
79	1.24	0.14	-10.62	28.57
80	1.23	0.14	-29.22	27.09
81	1.21	0.14	35.42	24.52
82	1.18	0.14	-7.87	23.70
83	1.15	0.14	2.18	23.39
84	1.11	0.13	3.86	23.47
85	1.07	0.13	1.22	23.46
86	1.01	0.12	-2.01	23.86
87	0.95	0.13	27.08	23.89
88	0.87	0.14	-24.50	24.15
89	0.78	0.17	9.34	24.05
90	0.68	0.21	-2.15	23.80
91	0.57	0.27	-18.72	23.52
92	0.44	0.35	9.40	23.03
93	0.29	0.44	36.39	22.00
94	0.12	0.54	-32.44	12.67
Sum of Coefficients	178.3	3.987	173.8	-

Appendix C

The price leadership model can be derived algebraically in the following manner:

The basic equations are:

Domestic demand: $P = a_1 - c_1 Q$
Domestic (fringe) supply: $P = a_2 + c_2 Q$
OPEC marginal cost: $P = MC$
Regulatory cost is R

a_1 and a_2 are determined from the slope of the demand and supply lines, respectively, and the historical average price and production values, which provide a point on the line.

The equation of the D'D' line (the demand curve for OPEC) is:

$$P = a_1 - c_1 \left(\frac{a_1 - a_2}{c_1 + c_2} \right) + Q \left(\frac{a_1 - c_1 \left(\frac{a_1 - a_2}{c_1 + c_2} \right) - a_2}{\frac{a_2 - a_1}{c_1}} \right)$$

From this equation the marginal revenue for OPEC can be determined. This marginal revenue is then set equal to OPEC's marginal cost (MC), and the equation is solved to determine the quantity supplied by OPEC, Q_L. The equation for Q_L is:

$$Q_L = \frac{1}{2} \left(\frac{\frac{a_2 - a_1}{c_1}}{a_1 - a_2 - c_1 \left(\frac{a_1 - a_2}{c_1 - c_2} \right)} \right) \left(MC - a_1 + c_1 \left(\frac{a_1 - a_2}{c_1 + c_2} \right) \right)$$

The price is then determined by substituting Q_L for Q in the D'D' equation given above. Once price is known, Q_T and Q_F can be determined:

$$Q_T = \frac{a_1 - P}{c_1} \text{ and } Q_F = Q_T - Q_L$$

I now assume that a regulation is imposed on domestic producers which adds an additional marginal cost R at all output levels for the domestic producers. The new basic equations are:

Domestic demand: $P = a_1 - c_1 Q$
Domestic (fringe) supply: $P = a_2 + R + c_2 Q$

The new D'D' line equation is:

$$P = a_1 - c_1\left(\frac{a_1 - a_2 - R}{c_1 + c_2}\right) + Q\left(\frac{a_1 - c_1\left(\frac{a_1 - a_2 - R}{c_1 + c_2}\right) - a_2 - R}{\frac{a_2 + R - a_1}{c_1}}\right)$$

The new Q_L equation is:

$$Q_L = \frac{1}{2}\left(\frac{\frac{a_2 + R - a_1}{c_1}}{a_1 - a_2 - R - c_1\left(\frac{a_1 - a_2 - R}{c_1 - c_2}\right)}\right)\left(MC - a_1 + c_1\left(\frac{a_1 - a_2 - R}{c_1 + c_2}\right)\right)$$

Again, the price is determined by substituting Q_L in the D'D' equation, and, from price, the total quantity consumed and fringe production can be determined.

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