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Federal Income Taxation of the United States Petroleum Industry and the Depletion of Domestic Reserves

Final Report

Silvio J. Flaim
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A Division of Midwest Research Institute

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FEDERAL INCOME TAXATION OF THE U.S. PETROLEUM INDUSTRY AND THE DEPLETION OF DOMESTIC RESERVES

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SILVIO J. FLAIM
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PREFACE

This report was prepared in compliance with Contract Number EG-77-C-01-4042 for the U.S. Department of Energy. It marks completion of Economics and Market Analysis Branch Task 5203 of the Solar Energy Research Institute.

This analysis is based on a model developed at Cornell University as part of S. Flaim's doctoral program under the direction of Professor T. D. Mount. Substantial revisions in the model and data updates to account for post oil embargo changes warrant the duplication of model description found within. The results of the following analysis provide an unsubsidized price of oil for comparisons with renewable energy sources.

All other work on this task has been reported in Progress Reports filed during January, April, and July 1978.

Silvio J. Flaim, Project Leader

Dennis Costello, Branch Chief
Economics and Market Analysis

Approved for:

Solar Energy Research Institute

Melvin K. Simmons
Assistant Director
Analysis and Assessment

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ABSTRACT

Silvio Joseph Flaim
and T. D. Mount*

This paper models in a dynamic framework the production activities of the United States petroleum industry in an attempt to measure the effects of the federal income tax on reserve depletion. This model incorporates general corporate taxes, including the capital subsidies, excess depreciation and the investment tax credit, and taxes unique to the industry: drilling subsidies and percentage depletion. Because corporate response to tax incentives depends on market power and behavior, three behavioral assumptions are tested for consistency with the 1960 to 1974 data period before the tax policies are simulated. These assumptions are perfect competition, profit monopoly, and sales monopoly. The tax policies simulated at the end of this paper present six possible alternatives for future petroleum industry taxation.

Sales monopoly is selected as the behavioral assumption that best describes petroleum industry behavior. Tax simulations under sales monopoly reveal that historical income tax policies have kept oil prices articially low, stimulating (subsidizing) reserve depletion.

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FEDERAL INCOME TAXATION OF THE UNITED STATES PETROLEUM INDUSTRY AND THE DEPLETION OF DOMESTIC RESERVES

I. INTRODUCTION

Macroeconomic fiscal policy has long recognized the impact of taxation on corporate investment. Economists generally agree that a reduction in corporate tax liability stimulates investment which in turn increases employment. Investment tax credits and accelerated depreciation are two instruments employed for this purpose.[1] Microeconomics recognizes that corporate response to tax incentives (disincentives) depends on market power and behavior. Although monopolists may respond to tax incentives in a much different manner than perfect competitors, tax policy is generally evaluated under the assumption of perfect competition. This analysis determines how the petroleum industry responds to changes in tax schedules given the objectives of the industry. Three behavioral assumptions are tested in an optimal control framework and compared with actual industry output, pricing, and investment policies. These assumptions are (1) perfect competition, (2) profit maximizing monopoly, and (3) sales monopoly. The following simulations reveal that the industry's historical pricing and production policies are closely approximated by the assumption of sales monopoly. The sales monopoly assumption requires the existence of market power to

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[1]This analysis will also include the drilling subsidies; intangible expensing, dry hole allowances, exploration expensing, the effect of limited partnership involvement in drilling programs; and percentage depletion. For a detailed discussion of foreign and domestic taxes on oil, see: Silvio J. Flaim, Federal Income Taxation of the Petroleum Industry and the Depletion of Domestic Reserves (unpublished Ph.D. dissertation) Cornell University, Ithaca, New York, 1978.

subsidize high-cost production, Alaska and offshore, with low-cost production, Texas and Oklahoma.[2]

The principal objective of this analysis is to determine how changes in tax policies affect the price of oil and domestic reserve depletion. To facilitate this analysis, the production activities of the petroleum industry are modeled and then optimized subject to single representation of demand for all refined products. These production activities are reserve acquisition, production, transportation, and refining. Marketing activities are not modeled because of their complexity, but marketing costs are accounted for in the industry model and are assumed to equal marketing revenues. The production functions for the above activities include measures of capital and labor as inputs for determining output at that stage of production. Other variables in these functions are included to represent changes in technology caused by recent industry activity in Alaska. These variables imply that different levels of inputs are required to produce the same quantity of oil for different years. In addition, these variables incorporate the effects of reserve depletion on new reserve acquisitions.

The tax simulations under the assumption of sales monopoly allow the tax subsidies to be ranked in order of the magnitude of impact on production. Ranked from smallest to largest, elimination of the investment tax credit had the smallest effect, followed by interest deductibility, percentage depletion, and excess depreciation. The largest impact on production occurred when

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[2]The existence of market power, particularly through cooperative production and exploration practices, is conclusively documented in, T. A. Flaim, <u>The Structure of the U.S. Petroleum Industry: Concentration, Vertical Integration and Joint Activities</u> (unpublished Ph.D. dissertation) Cornell University, Ithaca, New York, 1977.

drilling subsidies were eliminated and limited partnership participation in drilling programs was curtailed. The conclusions of this analysis reveal that the historical federal income tax policies and objectives of the industry have maintained the price of oil at artificially low levels, stimulating reserve depletion.

The format for the remainder of this report is as follows: Section II is an analysis of domestic oil production; Section III shows how the industry model was optimized; and Section IV presents simulation results under different income tax policies.

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II. AN ANALYSIS OF THE DOMESTIC PETROLEUM INDUSTRY

A. INTRODUCTION

This chapter describes the main activities of the United States petroleum industry relating to the finding, producing, transporting, and refining of oil and natural gas. The description of each activity includes an introduction to historical production practices and technological response to reserve depletion. In certain cases, ownership of production facilities affects the manner in which oil is produced and transported. Although ownership questions are important when examining the behavior of the industry, its discussion is omitted except where it affects physical production relationships.

Following the description of each activity, production functions are estimated for each stage of the production process. Although the petroleum industry consists of thousands of firms engaged in exploring, drilling, producing, transporting, refining, and marketing oil and natural gas, the following model treats the domestic industry as a single firm. Production functions for (1) reserve acquisition, (2) production and transportation to refineries, and (3) refining are defined. These three production functions form a system of equations which describe petroleum industry activities from reserve acquisition through refining. Because of its complexity, the marketing function is not modeled as a production function. Marketing costs are incorporated in the industry model as a fixed markup of refinery price. In addition, the quantities of imported crude oil and refined products are treated as though they are determined exogenously from the industry model. The price received for marketed oil, which includes imported petroleum products, is determined by a single demand relationship for all refined products sold domestically.

The production activities modeled in this chapter form a system of equations related in the following manner. Domestic reserves (Q_1) are used as an input for domestic production (Q_2). Refinery output (Q_3) equals domestic production plus net imports of crude oil (Q_{IC}). Total refined product sold domestically equals refinery output plus net imports of refined products (Q_{IR}). By assuming that imports and exports are determined exogenously, the total amount of oil sold domestically (Q_4) is determined as soon as the level of domestic production (Q_2) is chosen. The model as postulated in this chapter is summarized in Figure 2-1 with values for 1971 included. It is immediately obvious that the model has no provisions for changing inventories of refined products. Inventories are important when making investment and production decisions, but this model requires that all production must be sold.

Each of the three production activities discussed below is represented by a production function which includes measures of capital and labor as inputs for determining the associated quantity of oil (and natural gas) at that stage of production. Other variables in these functions are used to represent changes of technology, implying that the same quantity of oil requires different levels of inputs for different years in the sample period. The form of the typical production function is,

$$Q = Q[K,L,f(\Gamma)] \tag{2-1}$$

where Q presents output, K is a measure of capital stock, L is a measure of labor use, and $f(\Gamma)$ is a function of measured variables defining the appropriate technology. The production of nonrenewable resources will eventually exhibit diminishing returns as cumulative production approaches the limit of extractable reserves. As stocks of reserves are depleted, one would expect greater capital and labor requirements per unit of output. Hence, $f(\Gamma)$ is generally made a function of the depletion of reserves.

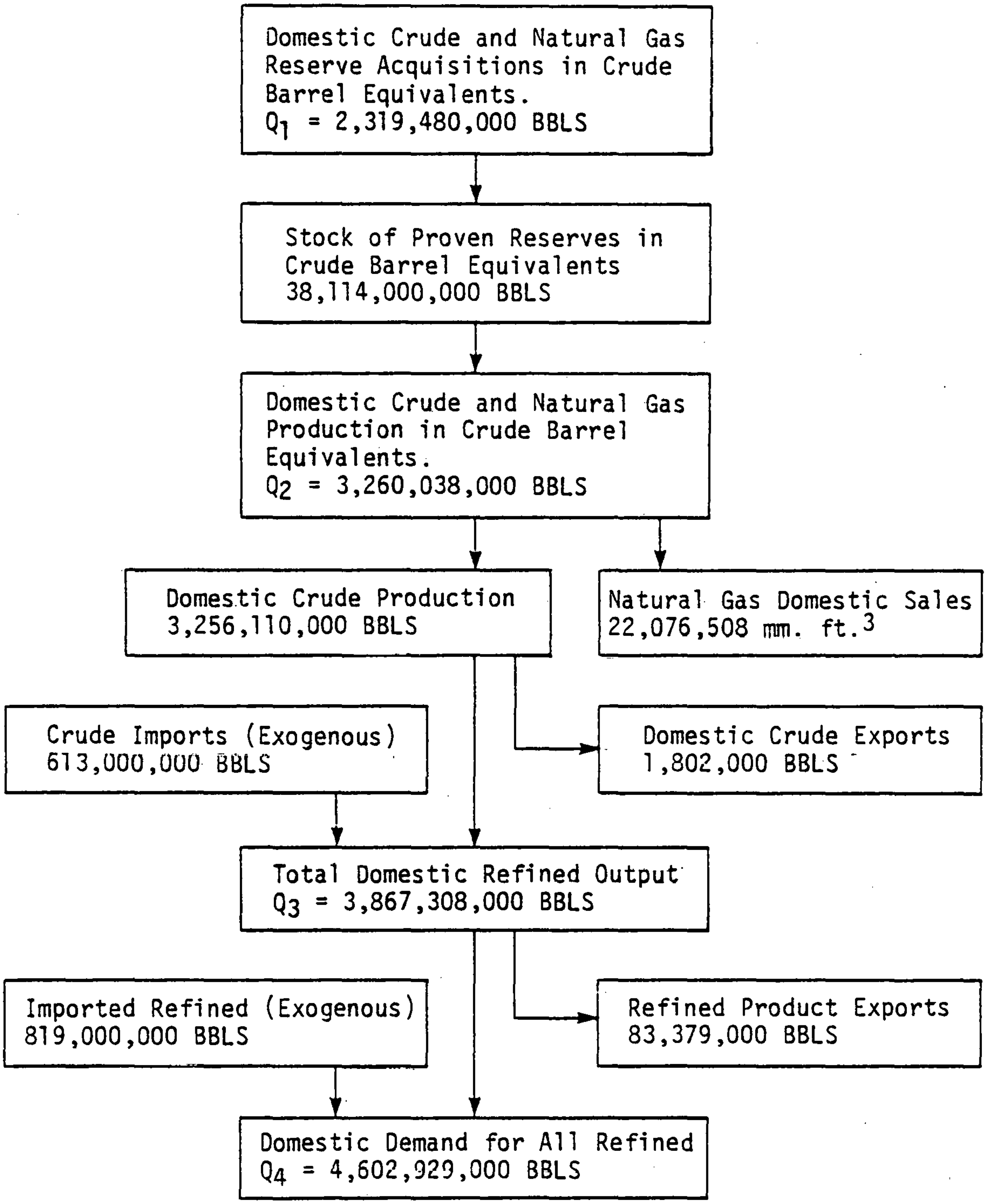

Figure 2-1. Flowchart of Domestic Oil Production, 1971

The production activities modeled below are characterized by high capital investment per employee[1] and very specialized technology during the sample period 1947 to 1974. For example, pipelines are built with specific operating and maintenance labor requirements. With an economic life of 25 to 30 years, pipeline companies have little flexibility to substitute capital for labor no matter how high wages rise. As a consequence, this author suspected relatively low capital labor substitutability in each of the production activities.[2] J. Kmenta has devised a convenient means of estimating the elasticity of substitution for production functions in a linear regression framework.[3] A two input constant

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[1]Fortune magazine has compiled 1975 capital asset per employee ratios from the Fortune Directory of the 500 Largest United States Industrial Corporations ranked by sales. Compared to an average of $38,000 invested per employee for all industries, petroleum refining and crude oil production asset per employee ratios are $197,000 and $115,000, respectively. See: "The Fortune Directory of the 500 Largest United States Industrial Corporations," Fortune (May 1976), reproduced in Duane Chapman, Energy Conservation, Employment, and Income, Cornell University Staff Paper, Agricultural Economics Research 77-6 (Ithaca: Cornell University Press, [1977]), p. 58.

[2]For a given output level, the elasticity of subsitution, , is defined as the proportionate rate of change of the input ratio divided by the proportionate rate of change of the rate of technical substitution (-dK/dL, with Q fixed):

$$\sigma = -\frac{d \log (L/K)}{d \log (dK/dL)}$$

See: James N. Henderson and Richard E. Quandt, Microeconomic Theory: A Mathematical Approach, 2nd ed. (New York: McGraw-Hill, 1971), p. 62.

[3]J. Kmenta, "On Estimation of the CES Production Function," International Economic Review 8, No. 2 (June 1967): 180-189.

elasticity of substitution (CES) production function can be written in the form

$$Q = \alpha[\delta K^{-\rho} + (1 - \delta)L^{-\rho}]^{-v/\rho} \qquad (2\text{-}2)$$

The parameters of the CES function can be characterized as follows: α is the scale parameter denoting the efficiency of technology; δ is a measure of capital intensity; v is the degree of homogeneity of the function or the returns to scale; and $\frac{1}{1-\rho}$ is the elasticity of substitution between labor and capital. Taking the logarithm of (2-2) and using the first two terms of a Taylor's expansion around $\rho = 0$, Kmenta's approximation is,

$$\text{Ln } Q = \text{Ln } \alpha + v\delta \text{ Ln } K + v(1 - \delta) \text{ Ln } L$$

$$- \frac{\rho v \delta(1 - \delta)}{2} [\text{Ln } K - \text{Ln } L]^2 \qquad (2\text{-}3)$$

This approximation to the CES function can be separated into two parts. The first three terms on the right-hand side correspond to the Cobb-Douglas form (elasticity of substitution = 1), and the last term represents a correction for the amount that differs from zero. The appropriateness of the Cobb-Douglas form may be tested by examining whether the coefficient for $[\text{Ln } K - \text{Ln } L]^2$ is significantly different from zero.

A standard assumption of neoclassical theory is that production functions exhibit constant returns to scale.[4] Since this assumption simplifies the subsequent analysis, each of the

[4]Returns to scale describes the output response to a proportionate increase of all inputs. If output increases by the same proportion, returns to scale are constant for the range of input combinations under consideration. See Henderson and Quandt, Microeconomic Theory: A Mathematical Approach, p. 79.

production functions was also tested for linear homogeneity. Although several different measures of capital and labor were tried for each production activity, the returns to scale for all three production functions were very close to one. These results were probably due to the fact that the production functions are aggregates for the whole industry. When doubling industry output, for example, it is not necessary to double the capacity of every plant; it is also possible to double the number of plants. For individual plants, however, it is likely that the production functions would exhibit increasing returns to scale.

The restricted version of (2-3) with constant returns to scale and an elasticity of substitution of one can be written,

$$\frac{Q}{L} = e^{\beta_0} \left(\frac{K}{L}\right)^{\beta_K} f(\Gamma) \tag{2-4}$$

Since this restricted form implies imposing two linear restrictions on the parameters of (2-3), it is possible to use a standard F-test to determine if the restrictions are appropriate.

The production functions and demand equation are estimated on data from overlapping periods. Production function data are available only through 1974, but the demand equation is estimated through 1977 to capture post oil embargo effects.

B. PRODUCTION ACTIVITIES

The Acquisition of Domestic Reserves

Historical Background

Total reserves of oil and natural gas (proven and inferred) existing within a given geographical area or basin are determined by the forces of nature over long periods of time. Using various exploratory techniques, men are able to find a portion of total reserves. The portion extractable at current prices and technology is termed proven reserves. Past production estimates of reserves reflect measured (proven) reserves of about 32% of the oil in place.[5] Some portion of the remaining oil in place is recoverable through enhanced recovery techniques.

The process of finding and proving reserves follows an information flow based on petroleum formation. Since petroleum is entrapped in sedimentary basins of significant porosity (15%-20% pore volume to total volume), geologists look for oil by examining the age and type of subsurface strata. Oil is most commonly found in shale, limestone, and sandstone formations.[6]

Exploration methods include seismic, gravimetric, and magnetic testing. In addition, aerial surveying is used to examine large tracts of land for oil bearing characteristics. When exploratory testing is completed, exploratory drilling crews will drill wells in anticlines and look for structural or stratigraphic traps. Oil is forced to these traps by subsurface pressures of heat and water intrusion. Drilling may be the most important activity in exploration since the existence of oil is rarely proven by testing alone.

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[5]The extractable portion of oil in place may soon exceed this average with the 1975 deregulation of stripper production. Price for stripper oil is now set at the world price, approximately $15.50 per barrel as of the January 1976 OPEC price increase. Domestic proven reserves have increased by eight billion barrels since deregulation went into effect. Even though some wells produce less than one barrel per day, this rate can gross over $5,000 per year per well. For more information about recent stripper activities, see Wall St. Journal, 7 January 1977, p. 1.

[6]M. King Hubbert, "Energy Resources," in Resources and Man: A Study and Recommendations, ed. Committee on Resources and Man (San Francisco: W. H. Freeman and Company, 1969), p. 170.

The greatest advances in exploration methods may be summarized by developments in the science of geophysics. Once the principal forces in reserve formation were understood, exploration techniques were devised to use the new theories.

The effect of exploration on reserve acquisition is difficult to evaluate empirically. No systematic relationship between reserve acquisitions and exploration expenditures is known to exist. Exploration costs vary widely depending on geographic location and the availability of support services for crews. Further, there are no common physical units among exploration methods. Exploration is also difficult to assess because there is no indication when or how newly acquired information will be used. Generally, exploration services are used for either bidding (speculative) or developing (proving) purposes.

Drilling

The drilling industry performs two separate functions. The first of these is exploring for new reserves. New field wildcat exploratory wells are drilled in untested areas to indicate whether or not new reserves exist. If reserves are found in significant quantities and if these reserves can be extracted profitably given current prices and technology, the new field will probably be developed. Drilling and equipping development wells is the second function of the drilling industry. Development wells actually measure (prove) reserves although wildcat wells find them.

Drilling technology in the post-World War II period may be summarized by refinements in rotary and offshore drilling techniques. Directional drilling, hole surveying, electrical well logging, and the use of the torsion balance have increased drilling successes. The practices of well cementing and putting additives in drilling mud have significantly reduced drilling costs. Other technological advancements have been in the area of reducing materials' costs. In particular, the use of smaller and lighter casing has reduced total well costs by nearly 20%.[7]

The technological history of the drilling industry is closely tied to domestic reserve depletion. Drilling technology and practices have advanced as new reserves have become more difficult to access. Onshore, the use of rotary drilling rigs clearly illustrates this fact. Percussion type drills were used extensively throughout the shallow reserve areas of the northeastern United States. As these reserves were depleted, exploration moved to the Mid-Continent area (Texas, Oklahoma, and Louisiana) where new reserves were deeper. Rotary drilling rigs were used almost exclusively by the end of World War II.[8] Offshore, technological advancements arising to meet declining reserve accessibility are reflected by increasing water depth capabilities for exploration and drilling. The ability to drill in increasing water depths developed gradually. Each step further offshore required new drilling techniques. Advancements in offshore technology may be summarized by drilling first from piers, second from barges, and third from platforms. Platform depth capabilities now exceed 700 feet.

The major effect of reserve depletion on reserve acquisition is to force drilling and exploration activities to ever more remote areas. The history of the drilling industry reveals movement from

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[7]U.S., Department of the Interior, Bureau of Mines, Engineering Cost Study of Development Wells and Profitability Analysis of Crude Oil Production, by T. M. Garland and W. D. Dietzman (Washington, D.C.: Government Printing Office, 1972), p. 13.

[8]Edward L. Beard, Jr., The Rotary Drilling Industry and Related Bank Financing (Tulsa: National Bank of Tulsa, 1954), p. 25.

the northeastern United States to the Mid-Continent area and California by 1930. Simultaneously, new fields were being developed further and further offshore. The most recent geographic shift in domestic petroleum industry production activities has been movement to Alaska. These shifts lead to increasing transportation costs for input materials and outputs[9] as well as to higher levels of inputs for drilling because low-cost reserves are usually developed first.[10]

To obtain a perspective of reserve depletion in the United States, a few facts may be revealing. First, cumulative production from domestic sources in December 31, 1976, exceeded 110 billion barrels. Remaining reserves, both proven and inferred, were estimated to be about 200 billion barrels in 1975.[11] Second, over two million oil and gas wells have been drilled in the continental United States, approximately one well per square mile. As Alaska and the outer-continental shelf are explored, the United States is

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[9]Drilling costs are heavily influenced by costs of building roads to wellsites. See: U.S., Department of the Interior, Bureau of Mines, Engineering Cost Study of Development Wells and Profitability Analysis of Crude Oil Production, p. 13.

[10]Technological advances in drilling and equipping offset increasing costs and diminishing returns to drilling outputs. Franklin M. Fisher found that costs per well during the late 1950s actually declined despite increases in average well depths. See: Franklin M. Fisher, "Technological Change and the Drilling Cost-Depth Relationship, 1960-66," in The Energy Question: An International Failure of Policy, ed. Edward W. Erickson and Leonard Waverman (Toronto: University of Toronto Press, 1974), pp. 225-266.

[11]U.S., Department of the Interior, U.S. Geological Survey News Release, New Estimates of Nations Oil and Gas Reserves (Washington, D.C.: Goverment Printing Office, 1975), and American Petroleum Institute, Basic Petroleum Data Book (Washington, D.C.: American Petroleum Institute, 1975), Section VI.

clearly approaching its geographical limits of exploration and development. Barring unforeseen technology that increases recovery of oil in place, the United States is also approaching its geographical limit in the search for new reserves.[12]

The Model for Reserve Acquisition

Reserves of oil and natural gas extractable at current prices and technology are termed proven reserves. Reserve discoveries and extensions are proven only when drilling confirms the existence of oil. Since the proportion of reserves that can be profitably extracted is price dependent, reserve revisions must be made when the price of oil increases. Reserve revisions are adjustments in reserve discoveries which are credited to the year of discovery. Reserve acquisitions in this analysis are defined by the price and technology for January 1, 1975.

Several different variables were employed as potential measures of capital and labor inputs in reserve acquisition. The first attempt involved using drilling cost data. Drilling costs, however, are highly variable since they depend on well location and well depth. Consequently, drilling costs did not accurately reflect the number of wells being drilled. To further complicate matters, drilling costs were not disaggregated enough to separate actual drilling costs from transportation and equipping costs. In short, no systematic relationship between drilling costs and reserve acquisition was found.

A second attempt to measure capital inputs was based on drilling statistics, such as well completions, total footages drilled, and

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[12] Technological advances and price increases for oil could conceivably add oil shale to domestic proven reserves. This appears unlikely, however, in the near future.

success ratios for wildcat exploratory and development wells, and were tried without success. These drilling statistics did not reveal where reserves were sought. In some years, particularly when oil was abundant, it is quite likely that new drilling was confined to tested areas already under development. However, using the number of rotary drilling rigs operating to measure capital, and the number of drilling and equipping employees as the corresponding measure of labor gave better results. Apparently drilling intensity is better measured by the number of rigs operating than the number of wells drilled.

An additional variable measuring expenses for other exploratory methods such as gravimetric, magnetic, and seismic tests and aerial surveying was deleted from the equation for three reasons. First, there appears to be no systematic relationship (including various lag structures) between exploratory efforts, measured in crew months, and reserve acquisitions. Second, there is no way to ascertain whether the information acquired will be used for lease bidding or drilling. In addition, use of the results of such exploratory efforts may be delayed for years depending on the strategy of the particular holder of the test results. The third reason is that reserve acquisitions (the dependent variable in this equation) increase only when drilling confirms the existence of oil. No matter how likely a geological formation appears from the exploratory evidence, there is no way to tell how much, if any, oil exists until wells have been drilled.

To capture the effects of reserve depletion on reserve acquisition, three technology variables were included. The first accounts for declining domestic reserves, and the latter two account for specific changes in production technology caused by movement to Alaska. The reserve decline variable, $1/R_u$, is defined as the inverse of undiscovered reserves. The denominator of this variable is the difference between ultimate recoverable and proven reserves at the beginning of each year in the data series.[13] As undiscovered reserves decrease, new proven reserves become more difficult to acquire.

Movement to Alaska created special problems in estimating reserve acquisitions. A technology variable, A, was included for Prudhoe Bay discoveries nearly three times larger than any other observation in the sample period. Movement to Alaska also required new drilling and production techniques. To account for these changes, a post-Alaska variable, PA, was also included.

Specifically, the model postulates that reserve revisions, extensions, and discoveries of crude oil and natural gas in equivalent British thermal unit (Btu) crude barrels, Q_1, are a function of the number of rotary drilling rigs in operation, K_1; the average annual number of employees in drilling and equipping, L_1; a technology variable to account for drilling in Alaska, A; a reserve decline variable to account for decreasing reserve accessibility, $1/R_u$; and a post-Alaska variable, PA, to account for technology change in reserve acquisition.

The reserve acquisition model is

$$\text{Ln}\,\frac{Q_1}{L_1} = \beta_{10} + \beta_{1K}\,\text{Ln}\,\frac{K_1}{L_1} - \beta_{1R}\,\text{Ln}\,\frac{1}{R_u} + \beta_{12}PA + \beta_{13}A \qquad (2\text{-}5)$$

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[13] Ultimate recoverable reserves are the sum of total domestic proven reserves plus probable reserves onshore and offshore. The Interior Department's estimate was 299 billion barrels in 1974. See: U.S., Department of the Interior, U.S. Geological Survey News Release, New Estimates of Nations Oil and Gas Reserves, p. 1. (Water depth to 200 meters.)

An F-test comparing (2-5) with its more general form (2-3), which allows for nonconstant returns to scale and elasticities of substitution different from one, did not suggest significant explanatory power was lost by imposing the two restrictions on the model. The computed value of the F statistic was 1.65, and the critical value for $F_{2,22}$ is 3.44 at the 5% level of significance. In the general model, estimated returns to scale were .992.

Regression results are presented in Table 2-1. All variables have the expected signs and acceptable t-values, and the Durbin-Watson statistic shows no serious problem of first-degree autocorrelation. The multiple coefficient of determination for this model was .924.

Table 2-1

Domestic Reserve Acquisitions of Crude Petroleum and Natural Gas, 1947-1974

Variable	Output Elasticity	t-Value
Rotary drilling rigs/man	.627	4.86
$1/R_u$	-.981	-3.51
1970 variable	1.644	11.86
Post-Alaska variable	.240	2.59
Constant	-13.800	
R^2 = .924[a]		
D-W = 2.155		

[a] This R^2 is the proportion of total variation of the orginal dependent variable, Ln Q_1, explained by the model. This is not the R^2 reported for the final model (3-5) because this is computed in terms of the variation $Ln(Q_1/L_1)$.

Figure 2-2 presents a plot of actual and predicted domestic reserve acquisitions from 1947 to 1974. It is obvious by

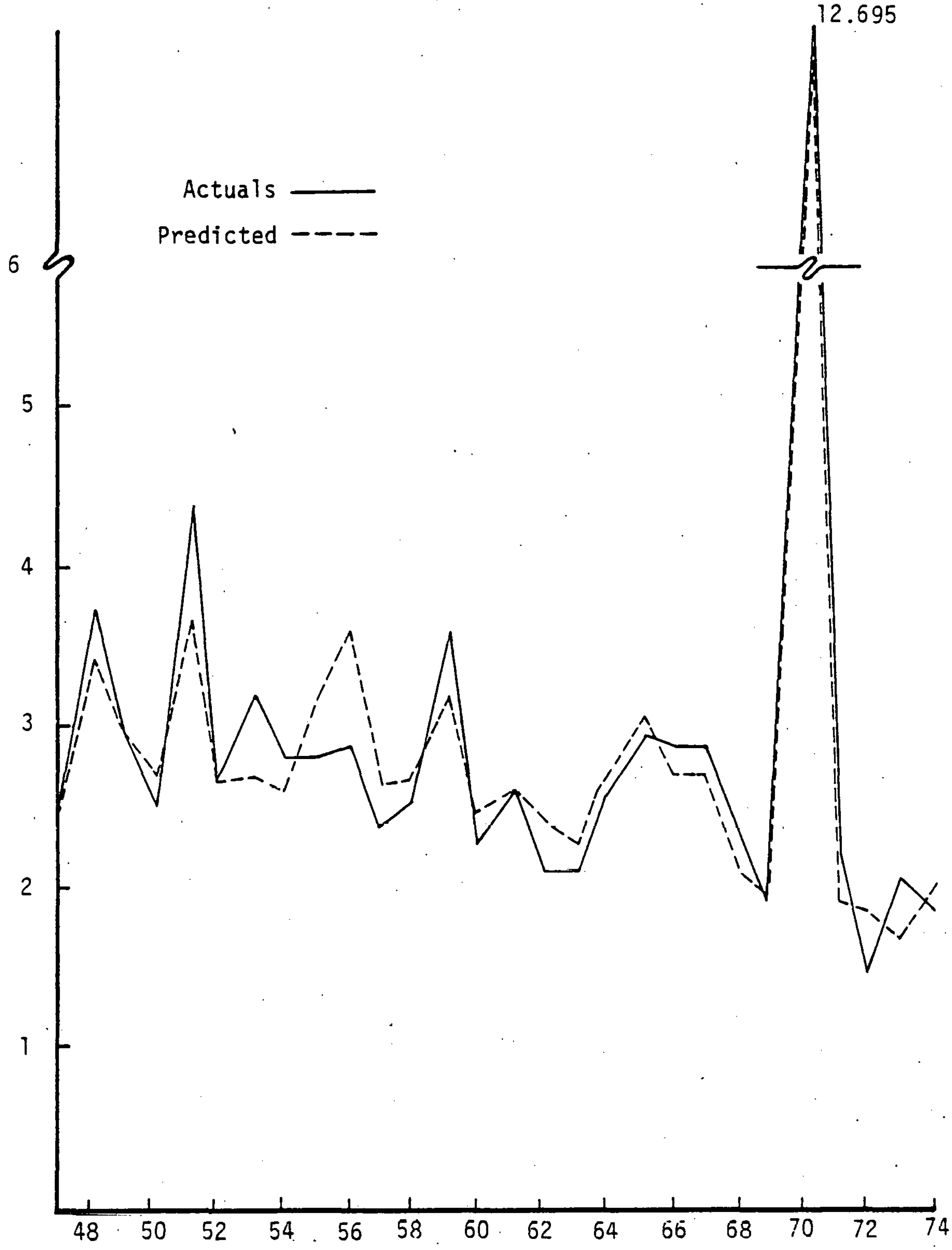

Figure 2-2. Domestic Reserve Acquisitions, Crude and Natural Gas, in Billions of Equivalent Barrels, 1947-1974

inspection that reserve acquisitions have fluctuated widely over the data period. Prudhoe Bay discoveries in 1970 are nearly three times larger than any other observation. Except for 1970, the plot reveals a general downward trend of reserve acquisitions, perhaps suggesting declining domestic accessibility. The predictive ability of this equation appears greater than the simple R^2 would suggest. Only two turning points are incorrectly predicted, 1972 and 1973. Deviations from actual values are highest in 1951, 1954, and 1956. Noting the random nature of new reserve discoveries, the equation does a surprisingly good job of predicting reserve acquisitions.

Production and Transportation

Production

Successful development wells are equipped and set for production by the rigs and crews that drill them. Producing wells require production casing, producing equipment, gathering lines, and lease equipment. Producing equipment includes a wellhead with fittings, tubing, rods, pumps, and pumping equipment. The gathering system consists of flowlines and a manifold. Lease equipment, which is usually connected to a number of wells for separating crude, natural gas, and water, includes a production separator, test separator, heater-treater, tanks, and water disposal system. Once this equipment is in place, labor, fuel, and supplies are required to operate the well.

Approximately 90% of United States producing wells are artificial lift or stripper wells.[14] Pressure in these wells is not sufficient to lift the oil and gas to the surface, so pumping is

[14]American Petroleum Institute, Basic Petroleum Data Book, p. 50.

required. Although flowing wells are few in number relative to strippers, they constitute over 70% of annual domestic production.[15]

Crude and natural gas are produced as joint products from some oil wells although many gas wells produce no crude at all. Field gathering equipment collects the product from flowing and artificial lift wells. In general, collection lines are connected with pipelines after water, gas, and crude are separated.

Production technology from 1947 to 1974 has remained relatively constant. Most efforts to increase production efficiency have centered on enhanced oil recovery. Water and gas injection are two techniques that have been used to increase subsurface pressure and percentage yield, but both procedures are expensive. Another technique is fracturing producing formations. Underground blasting cracks impermeable layers of strata which allows oil to flow unimpeded towards the well.

One production practice, unitization, has increased production efficiency by requiring the cooperative development and production of domestic reserves. Prior to the early 1930s, the law of capture allowed individuals on a single property to produce oil without regard to the mineral rights of individuals on adjacent properties. Oil belonged to the person who extracted it. The law of capture encouraged overdevelopment of oil fields and wasteful production techniques. Unitization makes all firms owning oil wells in the same oil field partners even if the wells were drilled independently. This practice provides a means of increasing production efficiency and total extractable reserves by preventing overdevelopment and regulating production. Since

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[15] Wall St. Journal, 7 January 1977, p. 1.

production from each well is regulated, independent firms in effect jointly own reserves. Approximately 80% of domestic oil and natural gas proven reserves are jointly owned.[16]

Transporation

Crude oil and natural gas must be transported and processed after being produced. Natural gas requires only separation from associated materials and water, but crude oil must be refined before it is marketable. The following discussion relates primarily to movement of crude from the wellhead to processors to wholesale consumers. About 75% of all crude transported moves through pipelines.[17] Tankers carry an additional 20%, but most of this is from foreign sources. The remaining portion of crude and natural gas is transported by trucks, railroad cars, and barges. However, the number of tons transported per mile by pipeline may be understated because trucks and railroads are not used to move crude over long distances. Pipelines are used so extensively because pipeline transportation costs are about one-fifth the cost of the next cheapest alternative.[18]

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[16]For a discussion of ownership see: U.S., Congress, Senate, Special Subcommittee on Integrated Oil Operations of the Committee on Interior and Insular Affairs, The Structure of the U.S. Petroleum Industry: A Summary of Survey Data, by D. Chapman, T. Flaim, J. Locken, K. Cole, and S. Flaim (Washington, D.C.: Government Printing Office, 1976), pp. 39-57.

[17]American Petroleum Institute, Petroleum Facts and Figures (Washington, D.C.: American Petroleum Institute, 1971), p. 272.

[18]Melvin G. de Chazeau and Alfred E. Kahn, Integration and Competition in the Petroleum Industry (New Haven: Yale University Press, 1959), p. 320.

Technological innovations in pipeline transportation are most evident in construction. Automatic welders, specialized pipe equipment, and construction techniques have facilitated some economies of scale. One interesting innovation not related to construction technology has been the development of gas turbine centrifugal compressor systems for pipelines. Cooper Industries, Incorporated, has adapted the common jet engine to increase yields of oil and natural gas by more efficient pressurization.[19] If piston engines are used, gas is often burned off as waste because the value of the gas saved is less than the cost of pressurization.

The effects of reserve depletion on petroleum transportation activities are twofold. First, as production moves to more inaccessible fields, pipelines are built offshire and across continents. Underwater pipelines are estimated to be five times more expensive than onshore pipelines of comparable size.[20] The Alaskan pipeline has also been very expensive. Special compressors, heaters to keep the crude from freezing, and arctic construction methods have nearly doubled pipeline costs.[21]

The second effect of reserve depletion is revealed by examining the ratio of annual production from a field to the total reserves in that field. Ideally, reserves should be sufficient to last the economic life of physical plant and equipment. This is more difficult to achieve in more inaccessible fields.

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[19] Wall St. Journal, 11 December 1976, p. 18.

[20] Ibid., p. 8.

[21] Ibid.

The Model for Production and Transportation

Several different specifications were tried for this activity; however, the more successful attempts concerned different definitions for pipelines. Only one labor variable was tried: average annual production plus pipeline employees. Alternative definitions of K_2 included capacity equivalents for trucks, tank cars, and barges; however, these definitions of K_2 suggested highly unrealistic returns to scale, $\beta_K + \beta_L$ greater than 7.5. In addition, the t-ratio for K_2 was less than one. Other pipeline definitions did not yield such widely varying results. Nevertheless, domestic crude and natural gas field gathering and trunk pipeline miles most clearly describe transportation of domestic production from wellhead to refineries. Additional costs for truck, tank car, and barge transportation were included in the industry model as an additional per barrel cost of production.

A reserve decline variable was originally included for production and transportation. This variable was the inverse of unproduced reserves or ultimate recoverable reserves less cumulative production to the preceding period. Unlike the reserve decline variable estimated in the reserve acquisition equation, the inverse of unproduced reserves was positively related to output. Instead of reflecting decreasing accessibility and increasing remoteness, this variable suggested that production became easier as reserves were depleted. This result was caused by the Prudhoe Bay discovery in Alaska. The small changes in the reserve decline variable during most of the sample period were outweighed by the large increase in reserves in 1970. Movement to Alaska also required new production-transportation technology. The Alaska pipeline is just one example. To account for these changes, a post-Alaska variable, PA, was included. Hence, this variable is the only one that reflects the increased inaccessibility of reserves.

The model postulates that United States production of crude and natural gas, Q_2, is a function of domestic crude and natural gas field gathering and trunk pipeline miles, K_2, average annual production labor plus pipeline labor, L_2, proven reserves, and a post-Alaska variable to account for movement to Alaska. The production-transportation model is

$$\mathrm{Ln}\ \frac{Q_2}{L_2} = \beta_{20} + \beta_{2K}\ \mathrm{Ln}\ \frac{K_2}{L_2} + \beta_{21}\ \mathrm{Ln}\ R_p + \beta_{22}PA \qquad (2\text{-}6)$$

An F-test was used to compare (2-6) with the general CES production function in (2-3) which allows nonconstant returns to scale and elasticities of substitution from one. The sums of squared error for the models were identical to four digits, yielding a computed F-test value less than .0002. Compared to the critical value for $F_{2,23}$ of 3.40 at the 1% level, the F-test did not suggest that significant explanatory power was lost by imposing the double restriction. Returns to scale estimated from the unconstrained version of (2-6) were .999.

Regression results for (2-6) are presented in Table 2-2. All variables have the correct sign and acceptable t-values. The R^2 is .968, and the Durbin-Watson statistic shows no serious problem of first degree autocorrelation.

Figure 2-3 presents a plot of predicted and actual domestic crude and natural gas production levels from 1947 to 1974. It is obvious by inspection that domestic production does not provide a very interesting set of observations to explain. The first really significant turning point does not occur until 1972 when the historical upward trend reverses. Because the actual and predicted values are so similar (never differing by more than 200 million barrels per year), it is difficult to discuss turning points. Except for 1948, predicted values are exceptionally well-behaved.

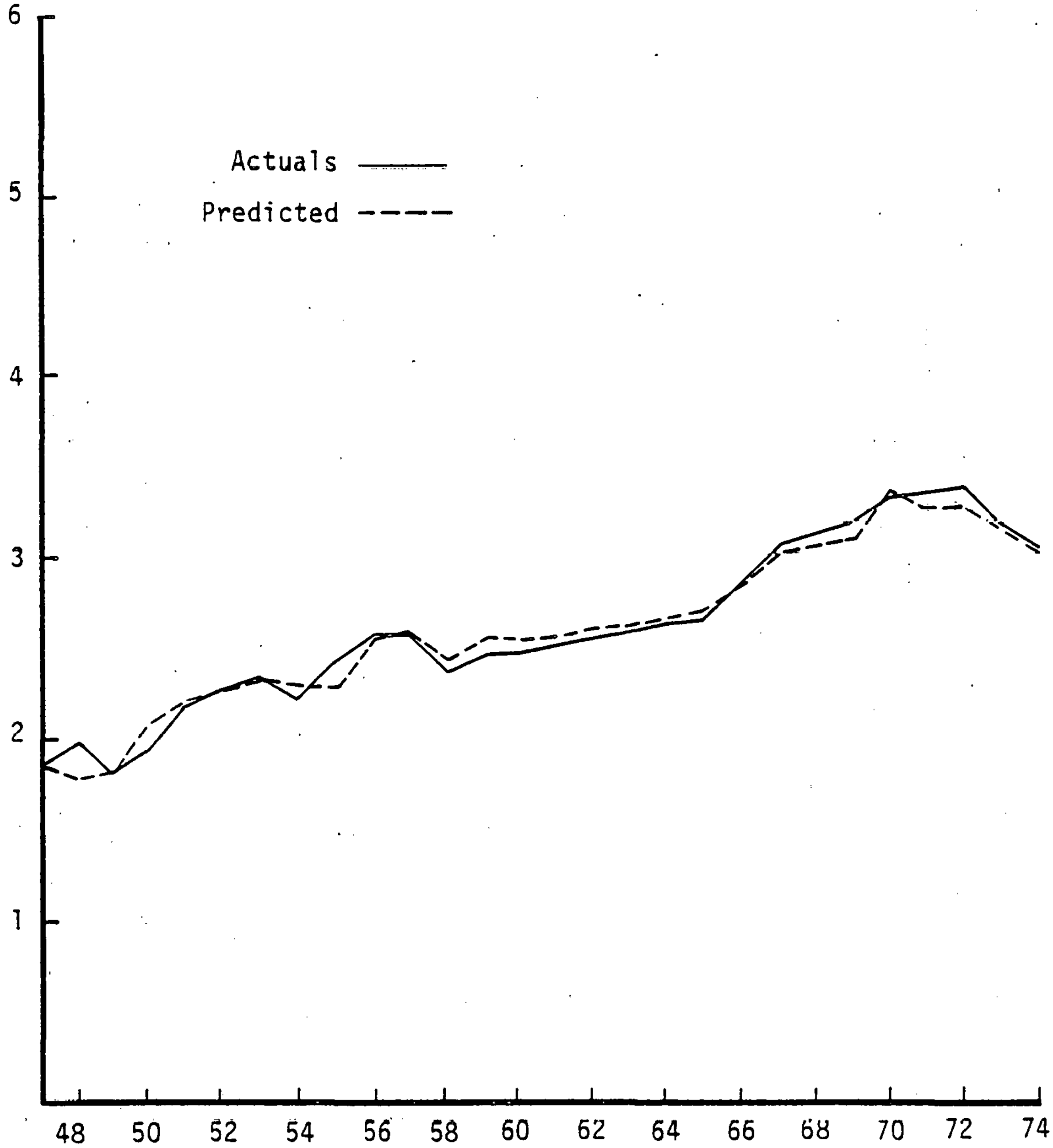

Figure 2-3. Domestic Production, Crude and Natural Gas, in Billions of Equivalent Barrels, 1947-1974

Table 2-2

Domestic Crude and Natural Gas Production, 1947-1974

Variable	Output Elasticity	t-Value
Pipe miles/man	.987	8.770
Reserves	.248	3.044
Post-Alaska variable	-.017	-.670
Constant	3.080	
R^2 = .968[a]		
D-W = 1.976		

[a] This R^2 is the proportion of total variation of the original dependent variable, Ln Q_2, explained by the model.

Refining

Refining Technology and History

Hydrocarbon processing is a capital-intensive high-technology activity that transforms crude into usable products. Refining resembles a simple manufacturing process more than any other petroleum industry production activity. Feedstocks are subjected to heat, pressure, and combined with catalysts to separate fuels, lubricants, and residual oil.

Since World War II, gasoline has constituted nearly 45% of all refinery output. Domestic refining technology has been directed at increasing gasoline yields per barrel of feedstock. A brief review of major technological developments reveals attempts to meet increasing domestic demand for gasoline. Before 1900, most petroleum was refined by simple distillation. Feedstocks were boiled, and separation occurred as the gases cooled at different points along a condensation tube. William Burton invented the process of thermal cracking by the turn of the century. This process increased gasoline yields by combining heat with pressure. The most important technological innovation in refining, however, was the process of catalytic cracking. This process allows total chemical reformation by combining heat and pressure with catalysts. Theoretically, it is possible to change any hydrocarbon feedstock into any output mix.

In addition to process technology, refiners responded to the increasing use of automobiles by putting lead additives in gasoline by 1923. Tetraethyl lead lengthened engine life and increased engine efficiency and power without increasing the cost of automobiles. High-octane gasolines were developed by 1935, which increased engine performance and decreased the operating costs of automobiles.

Refining Ownership of Feedstocks

Refining requires total capital outlays second only to drilling and exploration.[22] Operating with such high fixed costs, refiners find it necessary to operate as near maximum capacity as possible, and this requires guaranteed supplies of feedstocks. To avoid input squeezes, refiners have moved into pipeline transportation, production, and marketing. Kahn observes:

> Fully integrated majors have been content to run their refinery and distribution operations on a break-even basis in order to generate volume supporting profits made on crude oil production.[23]

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[22]de Chazeau and Kahn, Integration and Competition in the Petroleum Industry, p. 287.

[23]U.S., Congress, Senate, Subcommittee on Antitrust and Monopoly, "Economists Views," by Alfred E. Kahn, Hearings on Government Intervention in the Market Mechanism: The Petroleum Industry, Part 1 (Washington, D.C.: Government Printing Office, 1969), p. 136.

Exchanges by refiners are one means of meeting supply demands for feedstocks. T. Flaim has summarized the effects of exchanges on refining and merits quoting at length.

> Basically, an integrated refiner can obtain crude oil for processing in one of four ways: (1) by producing crude oil, (2) by purchasing crude oil, (3) by exchanging crude oil with another firm or (4) by processing oil for another firm. Similarly, a refiner can dispose of refined products in several ways: (1) by marketing products directly, through company-owned or dealer-owned branded service stations, (2) by selling to other refiners, resellers of large direct users, (3) by delivering product to another firm, in exchange for either crude oil, the same product or some combination of products, or (4) by delivering product to firms for which crude oil was processed.[24]

Exchanges and processing agreements in finished petroleum products occur for the same reasons they occur in crude oil: to minimize transport costs and keep refineries operating at full capacity.

Flaim further notes that

> The five majors reporting data exchanged 228 million barrels of gasoline with other firms, an amount equivalent to . . . 42 percent of their combined national gasoline sales for 1973, as reported in the National Petroleum News.[25]

Exchanges by major petroleum firms are extensive but not necessarily undesirable since these agreements minimize transportation costs.

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[24]Theresa Flaim, "The Structure of the United States Petroleum Industry: Concentration, Vertical Integration, and Joint Activities" (Ph.D. dissertation, Cornell University, 1977), p. 191.

[25]Flaim, "The Structure of the United States Petroleum Industry," p. 192.

The effects of reserve depletion on refining are not as evident as on reserve acquisition and transportation. Since refining closely resembles simple manufacturing, costs of refining are most dependent on fixed input costs and oil quality. Quality is usually measured by the amount of impurities in crude. Pennsylvania light crude, for example, has few impurities, costs less to refine, and has higher gasoline yield. Alaskan reserves, on the other hand, have much higher sulphur content and require special processing. High sulphur modification for Alaskan crude for one refinery may cost as much as $100 million.[26] To this extent, depleting reserves can lead to higher costs of refining, but such changes were relatively small during the sample period.

The Refining Model

After crude and natural gas are separated at the wellhead, crude is transported to refineries, and natural gas is sold to wholesale consumers.[27] It is convenient and logical to assume refinery output equals domestic refinery input for two reasons. First, domestic refinery feedstocks, domestic crude production plus net imported crude must equal output because hydrocarbon processing is essentially a closed system with small leakages. Second, refiners consumed less than 1% of feedstocks for fuel and power in 1971.[28] Since the various and sundry refinery products embody

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[26] Wall St. Journal, 10 October 1976, p. 1.

[27] Refiners are wholesale consumers of natural gas although most is consumed as a fuel, not as a feedstock. Refineries purchased 1,291 billion cubic feet of natural gas for fuel in 1971 at a cost exceeding $350 million. See: U.S., Department of Commerce, Bureau of Census, Census of Manufacturers: Fuel Purchases for Heat and Power, 1971 (Washington, D.C.: Government Printing Office, 1972), Table 7-A.

[28] Ibid.

practically the same quantity of British thermal units (Btu's), the model assumes that refinery throughput equals refinery input.

The model postulates that refinery output is a function of domestic refining capacity and average annual number of refinery employees. Because refining resembles a simple manufacturing process more than any other petroleum production activity, no reserve decline variables were included in this production function. The only other capital variable tried was domestic operating capacity. The output elasticity and t-value were identical to three digits for this K_3. Total capacity was preferred since the definition of operable capacity excluded technologically obsolete capacity even if potentially operable. In addition, total capacity is a more appropriate economic measure of the stock of capital in refining. The refinery production function is,

$$\text{Ln}\,\frac{Q_3}{L_3} = \beta_{30} + \beta_{3K}\,\text{Ln}\,\frac{K_3}{L_3} \tag{2-7}$$

An F-test was used to compare (2-7) with the general CES production function in (2-3). The computed F-test value of 4.51 suggests that relaxing the double restriction is marginally significant. This value lies between the critical values for $F_{2,24}$ of 3.40 and 5.61, corresponding to the 5% and 1% levels of significance, respectively. Since the Kmenta variable had a t-value of 2.96, it suggests that the elasticity of substitution may be different from one. The estimate of returns to scale is 1.019 which is close to one. However, the regression coefficients for K_3 and for L_3 on the general model were poorly determined due to multicollinearity, and as a result, the restricted version of the model was chosen.

The refinery production function exhibited first degree autocorrelation since the Durbin-Watson (D-W) statistic was 0.90. Consequently, a correction for autocorrelation was introduced by transforming the original observations. The estimate of the degree of serial correlation was (1 - 1/2 D-W).[29]

The results for the refinery equation are presented in Table 2-3. The output elasticities for the corrected and uncorrected equations were similar. Figure 2-4 presents a plot of predicted and actual values for domestic refined product throughput from 1947 to 1974. Inspection reveals that the estimated equation did not capture the downward turning points in 1948, 1953, 1957, and 1973. Instead, the equation predicts nearly continuous upward trend except in 1959 to 1962. Since the main explanatory variable is total domestic refining capacity, not operating capacity, production intensity is not really captured.

Table 2-3

Domestic Refined Throughput, 1947-1974
Uncorrected and GLS Estimates

Variable	Uncorrected	GLS
Domestic refining capacity/man	.926	.931
t-Value	32.924	24.606
Constant	7.180	-.521
R^2 [a]	.977	.950
D-W	.905	1.828

[a] This R^2 is the proportion of the total variation of the original variable, Ln Q_3, explained by the model.

[29] For a detailed description of these procedures and the properties of the corrected parameter estimator, see: J. Johnston, Econometric Methods, 2nd ed. (New York: McGraw-Hill, 1972), pp. 260-261.

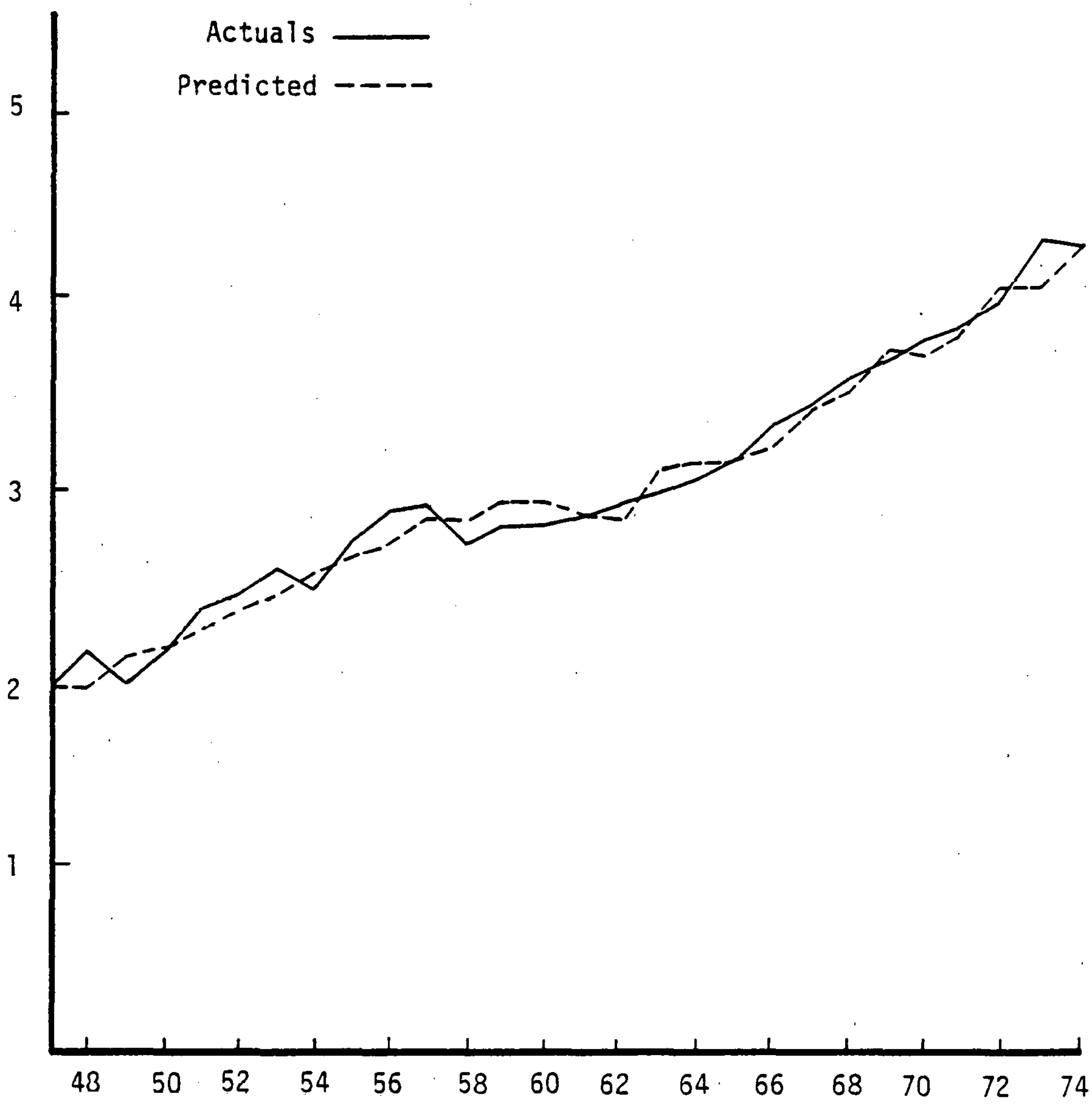

Figure 2-4. Domestic Refined Product Throughput, in Billions of Barrels, 1947-1974

C. DEMAND

The total quantity of refined products sold in the United States is the sum of domestic refinery output and net imported refined products. Imports of crude and refined have risen from 8.5 to nearly 100% of domestic production between 1947 and 1977. Domestic per capita consumption of refined products has also risen from 14.79 to 25.8 barrels from 1947 to 1973, decreased to 24.7 barrels after the Arab oil embargo, and then increased to 28.1 barrels in 1977. The post-embargo decrease reflects adjustments to foreign oil price increases by substitution of other fuels; substitution of energy efficient appliances; and also direct reductions of consumption by, for example, turning down thermostats and by restrictions on the sale of gasoline.

Five causal factors are included in the determination of domestic per capita demand for refined petroleum products, Q_{4P}. The first of these is deflated per capita income, G. As per capita income increases, one would expect per capita consumption of refined petroleum products to increase. The deflated prices of coal, P_C, and natural gas, P_G, were included to allow for substitution of alternative fuels. To account for post-embargo conservation effects, a variable defined as $\frac{1}{T-E}$ (where the denominator represents the number of years past the embargo) was included to represent the declining importance of the embargo on oil consumed. In addition, a deflated weighted retail price for all refined products, P_R, was included. Electricity was considered as another substitute for refined products but was deleted because the resulting model was unsatisfactory. This omission is not unreasonable, however, since electricity is, to a large extent, coal and oil energy in another form. Hence, this model represents substitution among primary fuels.

In linear form, the demand equation estimated is

$$Q_{4P} = \beta_{40} + \beta_{41}\dot{G} + \beta_{42}P_C + \beta_{43}P_G + \beta_{44}P_R + \beta_{45}\frac{1}{T-E} \qquad (2-8)$$

The results for the demand equation are presented in Table 2-4. All variables have expected signs and acceptable t-ratios. The single largest problem with the model is that the sum of the substitute elasticities is greater than the absolute value of its own price elasticity.

Table 2-4

Demand for All Refined Product
Sold Domestically, 1948-1977

Variable	Regression Coefficient (t-Ratio)	Long-Run Elasticity
Deflated per capita income	0.0017 (3.2300)	.29
Deflated price coal	2.8730 (13.3000)	.82
Deflated price gas	1.0820 (11.7900)	.83
Deflated retail price all refined	-1.8060 (-6.2300)	-1.09
Weighted post-embargo $\frac{1}{T-E}$	-3.6250 (-2.3120)	
Constant	2.7960	
R^2 = .98		
D-W = 1.47		

A plot of predicted and actual levels of per capita consumption for 1947 to 1977 is presented in Figure 2-5. Significant turning points in this data period occur in 1949, 1953, 1957, and 1973, when reversals from upward trend are experienced. The model captures these turning points.

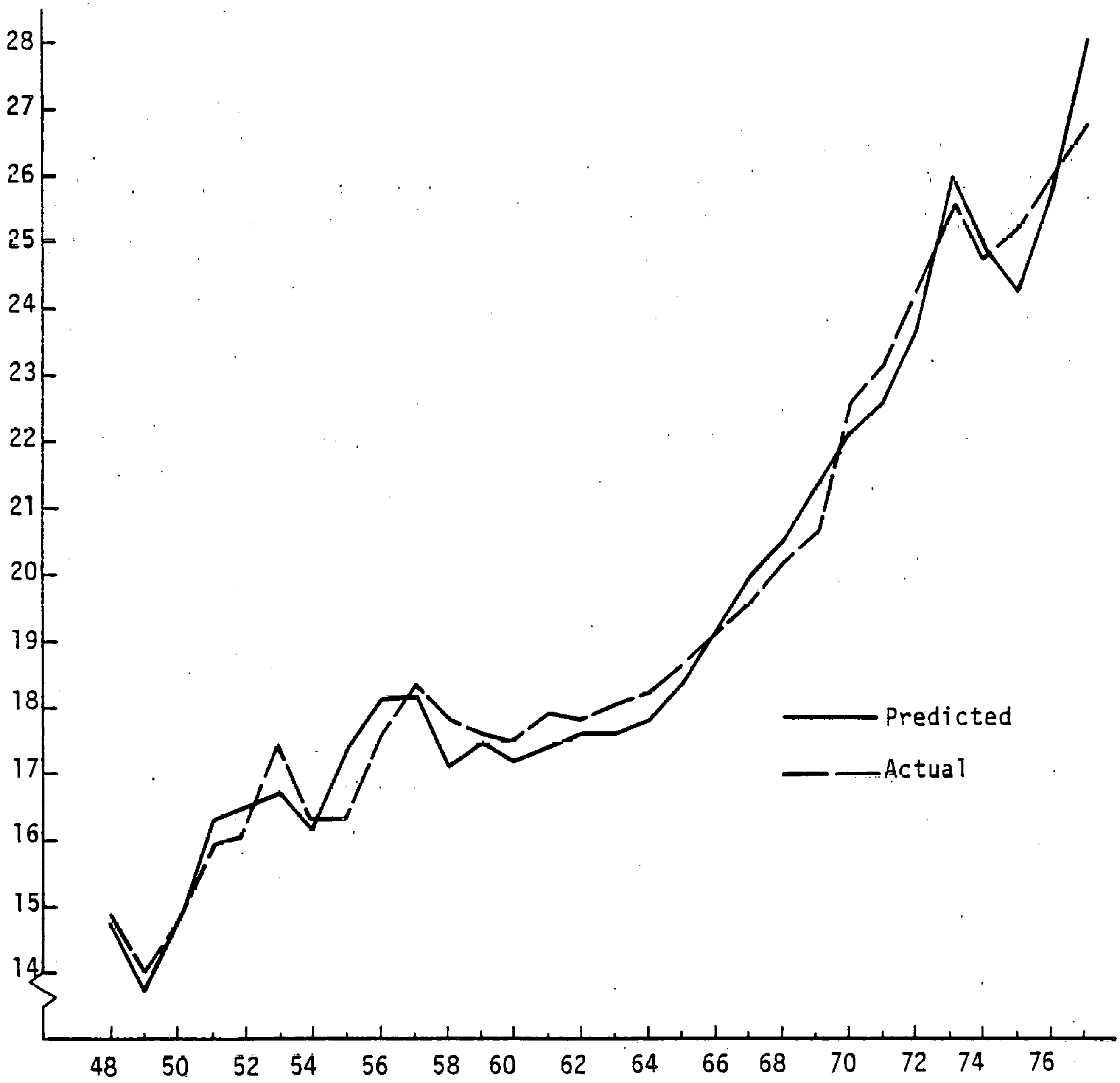

Figure 2-5. Domestic per Capita Consumption All Refined Product Delivered to Final Demand, 1948-1977

III. OPTIMIZATION OF THE PETROLEUM INDUSTRY PRODUCTION MODEL

A. INTRODUCTION

Empirical models of investment behavior typically attempt to explain observed changes in investment through two contrasting approaches. First, the direct approach involves regressing the level of investment against a set of explanatory variables, such as the price of capital equipment, the interest rate, and the previous level of production, without specifiying a formal theoretical structure. Alternatively, optimum behavior patterns for investment can be derived by assuming the firms follow criteria like profit or sales maximization. This structural approach imposes additional restrictions on the form of the model, but generally requires more data than the direct approach. With profit maximization, it is usually assumed that firms maximize the discounted flow of net receipts.[1] This objective is consistent with utility maximization and provides a convenient means of testing whether actual investment behavior corresponds to the optimum since at the optimum level the marginal value product of each input is equated to its price.

Two important additions to investment theory are the inclusion of taxes and investment dynamics. Taxes can be treated straightforwardly as an additional deduction from revenues although in certain situations taxes may reduce the cost of

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[1]The neoclassical theory of optimal capital accumulation suggests that the objective of the firm is to maximize the discounted flow of net receipts. Managers need not worry about the specific character of the owners' utility functions or indifference curves. By maximizing the present value of the productive enterprise, the highest possible budget constraint will be reached and owners' utility optimized. This topic is developed more extensively in William H. Branson, Macroeconomic Theory and Policy (New York: Harper & Row, 1972), pp. 198-203.

specific inputs such as capital equipment. Investment dynamics are generally incorporated under the direct approach by the flexible accelerator theory, which states that growth in past output induces investment.[2] Empirical applications usually involve regressing current investment against lagged output, lagged input prices, and lagged investment. Investment dynamics are automatically incorporated in the structural approach because the objective function is the present value of future returns. This implies that the objective is to derive an optimum path for investment through time, and this generally involves the use of calculus of variations or optimal control techniques.[3] One of the more successful attempts to incorporate taxes in a dynamic model of investment has been developed by Hall and Jorgenson.[4]

B. THE NEOCLASSICAL MODEL OF INVESTMENT BEHAVIOR

Hall and Jorgenson use a simple dynamic model of a competitive firm, assuming that the objective of the firm is to maximize the present value of net returns after taxes for a two-input production process: capital, K, and labor, L. The production function is represented by:

$$Q = f(K,L) \tag{3-1}$$

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[2] J. M. Clark, "Acceleration and the Theory of Demand," Journal of Political Economy 25 (March 1917): 130.

[3] See: Michael D. Intriligator, Mathematical Optimization and Economic Theory (Englewood Cliffs: Prentice Hall, 1971), pp. 306-315.

[4] R. Hall and D. Jorgenson, "Tax Policy and Investment Behavior," American Economic Review 57 (June 1967): 391-414.

where Q is output. The level of gross investment I is represented by

$$I = \dot{K} + \delta K \qquad (3\text{-}2)$$

where $\dot{K} = dK/dt$, by definition, is net investment, and δK is replacement investment, determined by the depreciation rate, δ, which is assumed to equal the inverse of the useful life of capital.[5] If the firm is perfectly competitive, it faces fixed prices for output, denoted P_Q, and for the inputs, P_L and P_K for labor and capital, respectively. If, in addition, profits are discounted at a constant rate r (assumed equal to the interest rate on borrowed capital), then the objective function may be written:

$$\max \int_0^{\infty} W_t dt = \int_0^{\infty} [P_Q Q - P_L L - P_K I - T] e^{-rt} dt \qquad (3\text{-}3)$$

where

$$T = u[P_Q Q - P_L P - v\delta P_K K - wrP_K K + x\dot{P}_K K] \qquad (3\text{-}4)$$

represents corporate income taxes. Reviewing this notation: u is the corporate tax rate, v is the allowable proportion of replacement costs, w is the allowable proportion of interest on capital stock, and x is the proportion of capital gains charged as income. Substituting for Q, I and T implies that the objective function can be rewritten as follows:

$$\max \int_0^{\infty} W_t dt = \int_0^{\infty} \{(1-u)(P_Q f(K,L)) - P_L L - P_K \dot{K}$$

$$+ P_K [uv\delta + uwr + ux \frac{\dot{P}_K}{P_K} - \delta]K\} \, e^{-rt} dt \qquad (3\text{-}5)$$

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[5]Depreciation schedules are defined in Hall and Jorgenson, "Tax Policy and Investment Behavior," p. 394.

Using Euler's Theorem, one may determine the necessary conditions for the optimum time paths of inputs if the prices are known. In general:

$$\frac{\partial W}{\partial X} = \frac{d}{dt} \quad \frac{\partial W}{\partial \dot{X}} \tag{3-6}$$

where X = K or L. The necessary condition for labor is:

$$\frac{\partial f}{\partial L} = \frac{P_L}{P_Q} \tag{3-7}$$

Similarly, the necessary condition for capital is,

$$\frac{\partial f}{\partial K} = \left\{ P_K \left[\delta \, \frac{(1 - uv)}{(1 - u)} + r \, \frac{(1 - uw)}{(1 - u)} \right] - \frac{(1 - ux)}{(1 - u)} \dot{P}_K \right\} \Big/ P_Q$$

$$= \frac{c}{P_Q}, \text{ by definition.} \tag{3-8}$$

Hall and Jorgenson interpret (3-8) as determining the expression for the cost to the business firm of employing capital assets. This implicit rental cost of capital, c, depends on the discount rate, the price of investment goods, and the tax treatment of business income. Under the assumption of profit maximization and perfectly competitive markets, the firm's desired level of capital can be derived by equating the marginal value product of capital to its implicit rental price. For empirical applications, Hall and Jorgenson further assume a distributed lag model to allow a gradual adjustment of actual investment to the desired level. This assumption implies that the empirical model departs from the strict logic of the theoretical framework. The actual expression estimated is, in fact, very similar to a flexible accelerator model since output is used as an explanatory variable.

C. DYNAMIC OPTIMIZATION OF THE PETROLEUM INDUSTRY PRODUCTION MODEL

The following model of the petroleum industry is a variant of the Hall-Jorgenson approach although the objective criterion is not restricted to profit maximization. Three different behavioral assumptions are considered. These are: (1) profit monopoly, (2) perfect competition, and (3) sales monopoly. The petroleum industry production model, which is based on the three production functions presented in Section II, replaces the simple production relationship in the Hall-Jorgenson approach. In addition, the final price is not determined exogenously, but instead varies inversely with output through the demand relationship for all refined products sold domestically.

The petroleum industry production model is more complicated than the single equation production functions optimized by Hall and Jorgenson. Optimization requires equating the marginal returns to inputs in all three stages of production as well as between the two inputs at each stage. Rather than burden the reader with unnecessary details, the following presentation will use the same notation used for Hall and Jorgenson's model developed in the introduction of this chapter. A complete presentation of objective functions and optimum conditions may be found in Appendix A.

The outline of the remainder of this chapter is as follows. First, alternative objective functions of the industry will be presented in the Hall-Jorgenson framework. Necessary conditions for optimum levels of the inputs are derived. Second, the model of the petroleum industry is outlined, and a short discussion of costs and taxes is included to show how they are incorporated in the model. Third, the alternative behavioral assumptions for the industry are used with historical levels of imports, prices of inputs, and tax schedules to simulate the levels of domestic production, reserve acquisition, input use, and the price of refined products for the sample period 1960 to 1977. (Cost data, in a consistent form, were not available before 1960.) Finally, the preferred behavioral assumption is selected by determining which simulation most closely follows actual experience.

Behavioral Assumptions

Profit Monopoly

The first behavioral assumption to be examined is profit monopoly. Economic theory dictates that monopolists maximize profits by equating marginal revenue (MR) to marginal cost (MC). The objective of profit monopolists from (3-5) is

$$\max \int_0^\infty [P_Q(Q) - P_L L - P_K I - T]e^{-rt}dt \tag{3-9}$$

where the only difference from (3-3) is that the price of the product now depends on the quantity produced. The necessary conditions for optimum levels of labor and capital, replacing (3-7) and (3-8), are:

$$\frac{\partial f}{\partial L} = \frac{P_L}{MR} \tag{3-10}$$

and

$$\frac{\partial f}{\partial K} = \frac{c}{MR} \tag{3-11}$$

where $MR = \partial P_Q(Q)/\partial Q$ is marginal revenue, which replaces price, P_Q. Since for any level of production MR is less than P_Q, the optimum level of production for monopolists is smaller than in the competitive model of Hall and Jorgenson.

Perfect Competition

The second behavioral assumption to be investigated is perfect competition. Perfectly competitive firms also maximize profits by equating marginal revenue and marginal cost, but unlike monopolists, they have no control over price so that price is the firm's marginal revenue. In Hall and Jorgenson's specification, price is given exogenously, but for an industry model, the demand relationship between price and output must be accounted for. This can be achieved by replacing the revenue term in the objective function by the corresponding area under the demand curve. The objective function can now be written

$$\max \int_0^\infty \left[\int_0^Q P_Q(q)dq - P_L L - P_K I \right] e^{-rt}dt \qquad (3\text{-}12)$$

The necessary conditions for determining optimum levels of labor and capital are now identical to those given for the Hall and Jorgenson model (3-7) and (3-8), except that all tax parameters are now assumed to be zero.

Perfect competition is generally regarded as the societally optimal organization of production. Welfare optimums are Pareto optimal if production cannot be reorganized to increase the utility of one or more individuals without decreasing the utility of others. In the absence of external effects on production, Pareto efficiency will be achieved under perfect competition.[6]

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[6]The actual conditions for Pareto optimality are somewhat more stringent. Three additional conditions must be met. First, consumers must have decreasing marginal utility. Second, no consumer can be satiated, and third, consumers' utility functions must be independent. See: James M. Henderson and Richard E. Quandt, Microeconomic Theory: A Mathematical Approach (New York: McGraw-Hill, 1971), p. 256.

This textbook ideal implies that marginal costs of production equal societal marginal cost. The objective function for perfect competitiors in this case (PCNT) is (3-12).

The economists' ideal organization of production, perfect competition, breaks down in the presence of external costs. If social externalities exist in production, then an appropriate tax can be imposed to account for these extra costs.[7] Taxes can alternatively be treated as a measure of external costs or as a way of changing production price and the costs of inputs. When taxes are treated as a measure of social costs, the objective function for perfect competitors (PCSC) is

$$\max \int_0^{\infty} \left[\int_0^{Q} P_Q(q)dq - P_L L - P_K I - T \right] e^{-rt}dt \qquad (3\text{-}13)$$

which is identical to (3-12) except taxes are now included. The necessary conditions for optimum levels of input use include P_Q from the first term in the objective function and marginal revenue (MR) from the tax term, T.

The Hall and Jorgenson approach effectively treats taxes as a way of changing production price and the cost of inputs. This objective function (PCPD) is

$$\max \int_0^{\infty} \left[\int_0^{Q} (1-u)P_Q(q)dq - P_L L - P_K I + P_K[uv\delta + uwr + ux \frac{\dot{P}_K}{P_K} - \delta]K \right] e^{-rt}dt \qquad (3\text{-}14)$$

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[7]F. M. Bator, "The Simple Analytics of Welfare Maximization," American Economic Review 47 (March 1957): 22-59.

where notation is defined as in (3-4). The necessary conditions for optimum levels of input use are identical to (3-7) and (3-8).

The use of petroleum is known to have external effects such as pollution, pollution related cancer deaths, and automobile accidents. Moreover, heavy energy use may have adverse effects on urban geography, employment, and economic stability. The petroleum industry is an anomaly to those who would tax the industry to achieve societally optimal marginal cost. Tax simulations below reveal that historical taxation of the United States petroleum industry has accelerated reserve depletion by maintaining artificially low oil prices. Consequently, external costs are greater, since output is higher, when the industry is taxed than it would be without the historical subsidies. Because historical taxes have actually reduced costs to the industry, perfect competition without taxes (PCNT) is arbitrarily chosen as the normative standard in all the tax policy simulations that follow. Under the assumption of no taxes, however, societal costs are not compensated for. Consequently, no tax perfect competition may be viewed as an upper limit to socially optimal output. Since reserves contribute to the ease of production, PCNT output is further biased upward because the actual stock of reserves held at the beginning of the simulation period was larger than those stocks held by no tax perfect competitors.

Sales Monopoly

An alternative theory of industry behavior when firms can exert monopoly power is sales maximization. Rather than maximize profits, sales revenues are maximized subject to some specified minimum level of profit.[8] This profit level may be expressed as

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[8]William J. Baumol, Business Behavior, Value and Growth, Revised ed. (New York: Harcourt, Brace, and World, 1967), Ch. 6.

an absolute level or as a percentage rate of return to capital. The objective function for a sales maximizing monopolist may be written

$$\max \int_0^{\infty} \{P_Q(Q)Q + \xi\,[(P_Q(Q)Q - P_L L - P_K I - T) - i\psi P_K K]\}e^{-rt}dt \quad (3\text{-}15)$$

where i is the specified rate of return on own capital which is defined as a fixed proprotion of the value of capital stock, $\psi P_K K$, and ξ is a Lagrangian multiplier. Necessary conditions for optimum levels of input use are analogous to those under profit maximization. By redefining the implicit rental cost of capital, c, and the price of labor, L, to include the new constraint, ξ, the necessary conditions for optimum input use are,

$$\frac{\partial f}{\partial L} = \frac{P_L\,\xi}{MR(1 + \xi)} \quad (3\text{-}16)$$

$$\frac{\partial f}{\partial K} = \frac{(c + i\psi P_K)\,\xi}{MR(1 + \xi)} \quad (3\text{-}17)$$

Since $0 \leq \xi \leq 1$ at the optimum, production is greater than it is with profit maximization. If i is sufficiently low, production will also be greater than under perfect competition. In the following simulations, i was assumed to equal the prime rate of interest paid by major corporations.

Measurement of Costs

Costs of the petroleum industry are determined from input requirements of capital and labor and per unit costs associated with imports and output. Capital costs are based on the replacement cost of capital, and labor costs are annual average wages paid within each production activity. Import costs are simply the average per barrel price paid for crude and refined product imports. Output costs are defined differently for each production activity. In reserve acquisition, exploration costs are assumed to be determined exogenously and are equal to actual exploration expenditures paid by the industry in each year. In production-transportation and refining, per unit costs associated with output are nonlabor variable costs of production: fuel, materials, state and local taxes, administration, and overhead.

The production functions presented in Section II already include costs for capital and wages. The following discussion completes the specification of costs for the petroleum industry.

Reserve Acquisition Costs

Additional costs of reserve acquisition not incorporated by the cost of drilling rigs, P_{K1}, and the wages paid drilling crews, P_{P1}, may be separated into two categories, exploration, C_1, and well equipping, P_{K12}, from Table 3-1. Because no systematic relationship was found between exploration and reserve acquisition, total exploration costs were assumed to be determined exogenously. Actual exploration costs were subtracted from oil industry revenues each year whether or not reserves were acquired.

Well equipping costs are not as easily defined, and many simplifying assumptions had to be made. Rotary drilling rigs are capable of drilling approximately 12 average depth wells (4,000 to 6,000 feet) and equipping 10 of them per rig year.[9] Based on a national average of 10 successes and two dry holes for all types

[9] Most drilling and equipping costs from U.S., Department of the Interior, Bureau of Mines, Engineering Cost Study of Development Wells and Profitability Analysis of Crude Oil Production, by T. M. Garland and W. D. Dietzman (Washington, D.C.: Government Printing Office, 1972), Table 7-A.

Table 3-1

Notation for Petroleum Industry Model

Variable	Units	Explanation
W_t		The objective function of the firm
Quantities		
Q_{4P}	BBLS	Per capita refined product sold domestically
Q_4	BBLS	All refined products sold domestically
Q_3	BBLS	Domestic refined throughput
Q_2	BBLS	Domestic crude and natural gas production in BTU equivalent BBLS
Q_1	BBLS	Domestic reserve acquisition crude and natural gas in BTU equivalent BBLS
Q_{IC}	BBLS	Imported crude
Q_{IR}	BBLS	Imported refined
R_u	BBLS	Ultimate recoverable domestic reserves
R_P	BBLS	Stock of proven reserves
Capital Inputs		
K_3	BBLS/day	Total domestic refining capacity
K_2	Miles	Crude and natural gas gathering and trunk pipeline miles in U.S.
K_1	Rigs	Rotary drilling rigs in operation in the U.S. (technologically equivalent)
K_{12}	Well	Producing wells--crude and natural gas
Labor Inputs		
L_3	Men	Average annual number of employees--refining
L_2	Men	Average annual number of employees--production and transportation
L_1	Men	Average annual number of drilling and equipping employees
Investment		
I_3	BBLS/day	Gross investment--refining
I_2	Miles	Gross investment--production-transportation
I_1	Rigs	Gross investment--drilling
I_{12}	Wells	Gross investment--equipping

Table 3-1 (continued)

Variable	Units	Explanation
Prices--Outputs--Substitutes--Income		
P_4	\$/BBL	Weighted average price all refined products sold domestically
P_3	\$/BBL	Average price domestic refined throughput
P_2	\$/BBL	Average wellhead price domestic crude production
P_{IC}	\$/BBL	Average price imported crude
P_{IR}	\$/BBL	Average weighted price imported refined
P_G	¢/000 ft.^{3}	Average deflated price domestic natural gas
P_C	\$/ton	Average deflated price domestic bituminous coal (F.O.B.)
γ_4	\$/BBL	$P_4 - P_3$
γ_3	\$/BBL	$P_3 - P_2$
G	\$	Per capita gross national product--deflated
Prices--Capital Inputs		
P_{K3}	\$/unit capacity	Replacement cost one unit of BBL/day refining capacity
P_{K2}	\$/mile	Replacement cost one mile pipeline
P_{K1}	\$/rig	Replacement cost one rotary drill rig size = 3,000 - 6,000 ft. depth class
P_{K12}	\$/well	Average casing and equipping costs per well
Prices--Labor Inputs		
P_{L3}	\$/year	Average annual wage all refining employees
P_{L2}	\$/year	Average annual wage all production pipeline employees
P_{L1}	\$/year	Average annual wage drilling and equipping employees
Direct Operating Costs--Including administration, overhead, state and local taxes, lease acquisition, and least rental costs		
C_3	\$/BBL	Direct operating costs--refining
C_2	\$/BBL	Direct operating costs--production-transportation
C_1	\$/BBL	Exploration costs--reserve acquisition

Table 3-1 (continued)

Variable	Units	Explanation
Direct Operating Costs (cont.)		
E_1	$\$/K_1$	Direct operating costs--drilling
r_B	%	Interest expense--borrowed capital which is assumed to equal the prime rate
r_P	%	Interest expense--borrowed capital--partnership rates
r	%	Industry discount rate for future revenues and costs which is assumed to equal the prime rate
Exogenous Parameters		
z_1	%	Drilling successes, all holes drilled domestically
z_2	Wells	Average depth wells capable of being drilled by one rotary rig for one year
z_{33}	%	Proportion of investment expense qualifying for investment credit--refining
z_{32}	%	Proportion of investment expense qualifying investment credit--production and transportation
z_{31}	%	Proportion of investment expense qualifying for investment credit--drilling
θ	%	Crude/gas production ratio in BTU equivalents
ϕ	%	Proportion of capital borrowed from banks for refining and production-transportation
ψ_B	%	Proportion of capital borrowed from banks for drilling
ψ_P	%	Proportion of capital borrowed from limited partners for drilling
ψ_1	%	Drillers' portion of drilling costs
i	%	Rate of return on own capital, assumed to equal the prime rate of interest.
Taxes		
a_0	%	Corporate statutory tax rate
a_1	%	Percentage depletion allowance
a_2	%	Interest expense write-off
a_3	%	Dry hole expensing write-off

Table 3-1 (continued)

Variable	Units	Explanation
<u>Taxes</u> (cont.)		
a_4	%	Intangible drilling expense write-off
a_5	%	Exploration expense write-off
a_6	%	Investment tax credit
δ_1	%	Real depreciation--rotary drilling rigs
δ_{12}	%	Oil well abandonment rate
δ_2	%	Real depreciation--pipeline production
δ_3	%	Real depreciation--refining
δ_{Ei}	%	Depreciation in excess of straight-line
δ_{Ti}	%	Real depreciation plus excess depreciation in production activity i

of oil and gas wells drilled, variable costs associated with rotary drilling, E_1, may be determined by the number of rigs operating each year, K_1, or the number of wells drilled, z_2K_1. Direct operating expenses for rotary drilling include fuel, rig transportation, drill bits, drilling mud, cement, engineering and geological services, as well as road building, wellsite preparation, surveying, and pit digging among other costs. These intangible drilling and development costs are incurred whether or not wells are dry holes or producers.

For each producing well, additional capital costs are incurred for surface, intermediate, and production casing. Groups of producing wells require producing equipment; wellheads and fittings, tubing, rods, pumps and pumping equipment; a gathering system including flowlines and manifold; and lease equipment consisting of a production separator, test separator, heater-treater, tanks, water disposal system, and fence.

The number of producing wells is determined in a manner similar to depreciation in (3-2). The number of producing wells is

$$K_{12\ t} = z_1 z_2 K_{1\ t} + (1 - \delta_{12})K_{12\ t-1} \tag{3-18}$$

where z_1 is the proportion of drilling successes, z_2 is the number of wells drilled per rotary rig year, and δ_{12} is the well abandonment rate from Table 3-1.

Reserve acquisition costs now include all costs in drilling and equipping except lease acquisition costs for drilling rights. Since these costs are usually paid as a proportion of wellhead income, they were deleted unless the royalty payment was paid to state or local governments. Royalties paid within the industry are costs to one party and revenues to the other and provide no net contribution to industry revenues.

Production-Transportation Costs

The production-transportation activity models the movement of crude and natural gas to wholesale consumer or refinery gate. Capital and labor costs are attached directly to capital and labor inputs. The replacement cost per pipeline mile of crude and natural gas gathering and trunk line, P_{K2}, includes right-of-way expenses and rents from land usage. Labor expenses, P_{L2}, are annual average wages paid production and transportation labor. Additional capital costs for truck, tank car, and barge transportation are included as an additional charge per unit of production.

Direct operating expenses for production-transportation, C_2, are based on national averages of production and are assumed to be a fixed charge per barrel of output.[10] Direct operating expenses in production-transportation include field office overhead, auto use, chemicals, fuel, power, water, supplies, special services, remedial services, and equipment repair. Administration and overhead expenses, state and local taxes including property and severance taxes, royalties, and rents are also assumed to be a fixed per unit charge.

Refining Costs

Costs not associated with labor, P_{L3}, and capital, P_{K3}, in refining are incorporated in the industry model as an exogenous

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[10]Most production cost data from U.S., Department of the Interior, Bureau of Mines, Engineering Cost Study of Development Wells and Profitability Analysis of Crude Oil Production, by Garland and Dietzman, various tables. Most pipeline transport costs from U.S., Department of Transportation, Interstate Commerce Commission, Transport Statistics in the United States, for Selected Years, Part 6 Petroleum Pipelines (Washington, D.C.: Government Printing Office, selected years).

per barrel cost of production, C_3.[11] These costs include administration and overhead, chemicals, catalysts, power, water, repair services, state and local taxes, containers, and refining materials. State and local taxes including income and property taxes are also assumed to be a fixed per unit charge.

Measurement of Taxes

The following discussion of taxes applies to each behavioral assumption. Tax deductions are set by the Internal Revenue Service and may be directly attached to the cost of inputs, per unit costs associated with production, and revenues from sales. A summary of these provisions may be found in Table 3-2.

Inspection of Table 3-2 reveals that while revenues are simply taxed at the corporate statutory rate, costs are treated differently in each state of production. In drilling and exploration, all costs may be expensed as incurred except for production equipping expenses, which are depreciated or recovered through cost depletion. In production-transportation and refining, production costs, including rents, royalties, state and local taxes, and administration and overhead expenses, may be expensed as incurred. Capital investment costs in all three activities are reduced by the investment tax credit but may be recovered through depreciation only. An additional factor is the depletion allowance on wellhead revenues.

[11] Most refining cost data from U.S., Department of Commerce, Bureau of Census, Census of Manufacturers: Fuel Purchases for Heat and Power, 1971 (Washington, D.C.: Government Printing Office, 1972).

Table 3-2

Tax Accounting Treatment of Expenditures and Revenues in Finding, Developing, and Producing Crude Oil and Natural Gas

Expenditures[a]	Tax Treatment
1. Dry hole costs	1. Expensed as incurred[b]
2. Lease rentals	2. Expensed as incurred
3. Lease acquisition	3. Capitalized upon acquisition, charged to depletable asset account
a. Leases later proved unproductive	a. capitalized cost charged-off as loss upon surrender of lease[c]
b. Leases later proved productive	b. Capitalized cost recoverable as such only through cost depletion
4. Other exploration expense (such as geophysics, geology)	4. Capitalized if on an area of interest,[d] otherwise expensed as incurred, charged to depletable asset account
a. Areas later proved unproductive	a. Capitalized costs charged-off as a loss upon surrender of property[c]
b. Areas later proved productive	b. Capitalized cost recoverable as such only through cost depletion
5. Intangible drilling costs of producing wells	5. Option of expensing as incurred or capitalizing and recovering through cost depletion[d]
6. Tangible equipment on producing wells	6. Capitalized charged to depreciable assets account and recovered through depreciation
7. General lease equipment on producing properties	7. Capitalized charged to depreciable assets account and recovered through depreciation
8. Production costs including rents and royalties	8. Expensed as incurred
9. Qualifying investment costs	9. Credited against tax bill at investment tax credit rate
10. Interest expense on borrowed capital	10. Expenses as incurred.
11. Taxes including state, local, production, and severance taxes	11. Expensed as incurred

Table 3-2 (continued)

Revenue	Tax Treatment
12. Wellhead revenues	12. Taxed at corporate statutory rate, but the effective rate of tax is reduced by percentage depletion
13. Other revenues	13. Taxed at corporate statutory rate

Source: Commerce Clearing House, 1977 Federal Tax Course (Chicago: Commerce Clearing House, 1977).

[a] Limited partners' proportions of all costs are deductible or creditable against each partner's personal income tax. Industry costs of drilling decrease as limited partners' shares increase. Limited partners in effect purchase drilling expenses to reduce their own personal income tax.

[b] Taxpapers electing to capitalize intangible drilling costs have the additional option of either expensing or capitalizing dry hole costs. The option to capitalize intangibles is almost never used.

[c] Or upon final determination of worthlessness of mineral rights without immediate surrender of the property.

[d] An area of interest is one in which further exploratory work is at least conditionally contemplated.

[e] Capitalized intangible costs incurred in the installation of casing and equipment and in the construction on the premises of derricks and other physical structures are recoverable through depreciation.

Incorporating taxes and costs into the different objective functions typically involves specifying net receipts after taxes, which may be expressed as

$$[A_3P_3Q_4 - (1-a_0)P_{IC}Q_{IC} - (1-a_0)P_{IR}Q_{IR} - c_1Q_1 - b_1L_1 - e_1K_1$$
$$- d_1(\dot{K}_1 + \delta_1K_1) - f_1 \int_0 e^{-\delta_{12}s}(z_1z_2K_{12t-s})ds - c_2Q_2$$
$$- b_2L_2 + {}_2P_2Q_2 - e_2K_2 - d_2(\dot{K}_2+\delta_2K_2) - c_3Q_3 - b_3L_c$$
$$- e_3K_3 - d_3(\dot{K}_3+ \delta_3K_3)] \qquad (3\text{-}19)$$

where the coefficients for revenues and inputs are consolidations of the expressions presented in Table 3-3. All taxes, costs, and revenues affecting production or any input may be obtained by summing down down the corresponding column of this table.

Inspection of Table 3-3 reveals the complicated nature of petroleum industry taxation when limited partnerships are introduced. Drilling and production equipping expenses are divided among three groups. The industry's portion of drilling costs, Ψ_1, is reduced as limited partners', Ψ_p, and financial institutions' shares, Ψ_B, increase. Limited partners' direct purchases and loans from banks (usually through nonrecourse loans), are paid two different rates of return, denoted r_p and r_B, respectively.

Outputs and Prices at Different Production Stages

The petroleum industry production model, which includes the three production functions presented in Section II, is optimized subject to a single representation of demand for all refined products sold domestically. As output increases, price received by the industry decreases. The industry's production functions are related

Table 3-3

Measurement of Taxes for the Petroleum Industry Model[a]

		Drilling and Production Equipping Expense				
		Q_1	L_1	K_1	$\dot{K}_1 + \delta_1 K_1$	W
Direct Operating Costs						
(1) Intangibles			$-z_1\psi_1 P_{L1}$	$-z_1 z_2 \psi_1 E_1$		
(2) Dry Holes			$-(1-z_1)\psi_1 P_{L1}$	$-(1-z_1)z_2\psi_1 E_1$		
(3) Exploration		$-\psi_1 C_1$				
Interest Costs of Borrowed Capital				$-[r_B\psi_B + r_P\psi_P]P_{K1}$		
(1) Intangibles			$-[r_B\psi_B + r_P\psi_P]z_1 P_{L1}$	$-[r_B\psi_B + r_P\psi_P]z_1 z_2 E_1$		$-[r_B\psi_B + r_P\psi_P]z_1 z_2 P_{K12}$
(2) Dry Holes			$-[r_B\psi_B + r_P\psi_P](1-z_1)P_{L1}$	$-[r_B\psi_B + r_P\psi_P](1-z_1)z_2 E_1$		
(3) Exploration		$-[r_B\psi_B + r_P\psi_P]C_1$				
Investment Costs					$-\psi_1(1-z_{31})P_{K1}$	$-\psi_1 z_1 z_2 P_{K12}$
After Tax Revenues						
Tax Deductions						
(1) Deductible Direct	a_0					
(2) Deductible Interest	$a_0 a_2$			$[r_B\psi_B + r_P\psi_P]P_{K1}$		$[r_B\psi_B + r_P\psi_P]z_1 z_2 P_{K12}$
(1) Intangibles	$a_0 a_2$		$[r_B\psi_B + r_P\psi_P]z_1 P_{L1}$	$[r_B\psi_B + r_P\psi_P]z_1 z_2 E_1$		
(2) Dry Holes	$a_0 a_2$		$[r_B\psi_B + r_P\psi_P](1-z_1)P_{L1}$	$[r_B\psi_B + r_P\psi_P](1-z_1)z_2 E_1$		
(3) Exploration	$a_0 a_2$	$[r_B\psi_B + r_P\psi_P]C_1$				
(3) Depreciation	a_0				$\psi_1\delta_{T11}(1-z_{31})P_{K1}$	$\psi_1\delta_{T12}P_{K12}$
(4) Investment Tax Credit	a_6				$\psi_1 z_{31} P_{K1}$	
(5) Exploration Expense	a_0	$a_5\psi_1 C_1$				
(6) Intangible Drilling	a_0		$a_4\psi_1 z_1 P_{L1}$	$a_4\psi_1 z_1 z_2 E_1$		
(7) Dry Hole Allowances	a_0		$a_3\psi_1(1-z_1)P_{L1}$	$a_3\psi_1(1-z_1)z_2 E_1$		
(8) Depletion	a_0					
Consolidated Parameter Notation		c_1	b_1	e_1	$\dot{c}_1$	f_1

[a] Notation is presented in Table 4-1.

Table 3-3 (continued)

		Production and Transport Expense				Refining Expense				Revenues	
		Q_2	K_2	L_2	$\dot{K}_2 + \delta_2 K_2$	Q_3	K_3	L_3	$\dot{K}_3 + \delta_3 K_3$	P_2	P_3
Direct Operating Costs		$-C_2 - P_2$		$-P_{L2}$		$-C_3$		$-P_{L3}$			
(1) Intangibles											
(2) Dry Holes											
(3) Exploration											
Interest Costs on Borrowed Capital			$-\phi r_B P_{K2}$				$-\phi r_B P_{K3}$				
(1) Intangibles											
(2) Dry Holes											
(3) Exploration											
Investment Costs					$-(1-z_{32})P_{K2}$				$-(1-z_{33})P_{K3}$		
After Tax Revenues	$(1-a_0)$									Q_2	Q_4
Tax Deductions											
(1) Deductible Direct	a_0	$C_2 + P_2$		P_{L2}		C_3		P_{L3}			
(2) Deductible Interest	$a_0 a_2$		$\phi r_B P_{K2}$				$\phi r_B P_{K3}$				
(1) Intangibles											
(2) Dry Holes											
(3) Exploration											
(3) Depreciation	a_0				$\delta_{T2}(1-z_{32})P_{K2}$				$\delta_{T3}(1-z_{33})P_{K3}$		
(4) Investment Tax Credit	a_6				$z_{32}P_{K2}$				$z_{33}P_{K3}$		
(5) Exploration Expense	a_0										
(6) Intangible Drilling											
(7) Dry Hole Allowances											
(8) Depletion										$a_0 a_1$	
Consolidated Parameter Notation		c_2	e_2	b_2	d_2	c_3	e_3	b_3	d_3	A_2	A_3

through imports, assumed to be determined exogenously from the system. Refining throughput, Q_3, is linked to domestic sales by

$$Q_3 \equiv Q_4 - Q_{IR} \tag{3-20}$$

where Q_{IR} represents imported refined products. Domestic production of oil and natural gas, Q_2, is related to refining throughput by

$$\theta Q_2 \equiv Q_3 - Q_{IC} \tag{3-21}$$

where Q_{IC} represents imported crude, and θ is the proportion of production in the form of oil.

The prices per barrel at each production level are related to final price through two exogenous price markups γ_3 and γ_4. These exogenous markups are based on national averages observed in the 1960 to 1977 data period. Price per barrel at the refinery gate, P_3, is related to the retail price by

$$P_3 \equiv P_4 - \gamma_4 \tag{3-22}$$

and the wellhead price, P_2, is defined as

$$P_2 \equiv P_3 - \gamma_3 \tag{3-23}$$

The price at the wellhead is necessary for optimization because of the depletion allowance.

The retail price, P_4, is determined by the quantity of oil sold, Q_4, and by a number of exogenous factors. These are the delfated prices of the substitute fuels, coal, P_C, and natural gas, P_G, which are based on national averages of their final price, deflated per capita income, G, population, and a post embargo variable, $\frac{1}{T-E}$, to account for conservation effects. It should be noted, however, that the behavioral assumptions are optimized in terms of refinery price, P_3, since it is assumed that marketing does not provide any net revenues for the industry.

Deriving the Optimum Solutions

At this point, all the requirements for deriving optimum solutions have been explained. To review briefly, the estimated functions decribing demand and production are incorporated with one of the objective functions, profit monopoly, perfect competition, or sales monopoly. The appropriate expressions for costs, revenues, and taxes are determined, and in addition, the exogenous variables affecting demand, production technology, and imports of oil are specified.

The optimum solution under each behavioral assumption is completely determined for the industry if the optimum time paths for the three different capital and labor variables are known. Since there is an identity linking domestic production to refinery output, there are only five optimum paths that determine the solution. The results are presented in terms of final sales of oil, reserve acquisitions, and the three capital-labor ratios. Selection of the preferred behavioral assumption is primarily in terms of final sales of oil and reserve acquisition. However, the model can also be used to determine final price, gross investment, and employment within the industry.

With linear homogeneous Cobb-Douglas production functions, the optimal solutions for the inputs are simple to derive. However, the role of reserves in production complicates the problem. In addition, even though technology is defined in terms of the initial conditions for estimation, this must be modified for simulation since continuous time is used in the objective function. In production-transportation, unused reserves, R_P, increase as reserve acquisitions, Q_1, increase, and decrease as production, Q_2, increases. Similarly in reserve acquisition, undiscovered reserves, $R_u - R_P$, decrease as Q_1 increases, since Q_1 appears in both equations. The two production functions are now interdependent implicit functions relating outputs, Q_1 and Q_2, to inputs. The optimum solution must be obtained by solving the total differential of both equations.

The above discussion implies that the optimum solution for each input is nonlinear, and some iterative scheme must be employed. The procedure used involved searching over different Q_1 and Q_2 levels until the optimum was found. The optimum solutions were found by equating the value of marginal products of a dollars expenditure at all three stages of production. A complete presentation of the objective functions and optimum conditions may be found in Appendix A.

D. SIMULATION OF THE PETROLEUM INDUSTRY MODEL

The petroleum industry model determines price, quantities, levels of input use, and gross investment. Each of these endogenous variables can be used to compare the performance of the model under a particular behavioral assumption with the industry's historical record. The most important criterion for comparison is total refined product delivered to final demand. Once the production decision is made, all quantities (except Q_1) from (4-20) and (4-21) and prices from (4-22) and (4-23) are determined. Final price is not as important as production since Q_2 determines P_4 automatically.

Simulation results for the petroleum industry production model under the behavioral assumptions of (1) profit monopoly, (2) perfect competition, and (3) sales monopoly are presented in the following tables. To put these analyses in perspective, historical outputs and price for all refined product sold domestically are presented in Table 3-4. Simulation results for gross investment are expressed in terms of replacement costs and are noncomparable with actual investment data. Hence, gross investment estimates are not presented.

Total Refined Product Sold Domestically

Simulation results of the petroleum industry model for total refined product sold domestically are presented in Table 3-5. In addition to the other behvavioral assumptions, the normative standard, perfect competition with no taxes (PCNT), is also presented. A plot of these output levels is presented in Figure 3-1.

Examination of Figure 3-1 reveals that output levels vary widely under the different behavioral assumptions. As expected, profit monopoly output is substantially less than all other alternative behavioral assumptions tested. Profit monopoly output is about one-half of historical industry output. PCNT is one-half to one billion barrels less than historical levels for each year. When taxes are treated as a measure of social costs (PCSC) perfect competitors' output is 500 million to 2 billion barrels less than historical output. Perfect competition when taxes act as price distancers (PCPD) is 500 million to 1 billion barrels less each year. Of the behavioral assumptions tested, sales monopoly constrained to zero profits is most similar to historical output. Sales monopoly differs from actual output by less than 220 million barrels for every year until 1974. The oil embargo increased prices and the zero profit level beyond the conservation adjustment was made by consumers. The reduction in oil consumption, concervation, was accounted for in the demand relationship as variable $\frac{1}{T-E}$.

Table 3-4

Historical Quantities and Price for All Refined Product
U.S. Petroleum Industry
(Quantities in 000,000's BBLS, Price in $/BBL)

Year	Q_1	Q_2	Q_3	Q_4	P_4
1960	2,367	2,473	2,844	3,137	11.23
1961	2,660	2,514	2,895	3,213	11.46
1962	2,184	2,552	2,963	3,311	11.69
1963	2,177	2,595	3,007	3,369	11.59
1964	2,668	2,646	3,084	3,472	11.42
1965	3,051	2,689	3,141	3,589	11.48
1966	2,967	2,867	3,314	3,806	11.36
1967	2,966	3,080	3,491	4,005	11.37
1968	2,457	3,127	3,599	4,163	11.26
1969	2,121	3,198	3,712	4,353	11.43
1970	12,695	3,323	3,806	4,571	11.90
1971	2,319	3,260	3,873	4,692	12.64
1972	1,559	3,285	4,096	5,020	13.55
1973	2,147	3,189	4,372	5,472	14.63
1974	1,995	3,047	4,316	5,269	17.69
1975	1,318	2,981	4,479	5,191	19.46
1976	1,805	2,883	4,812	5,544	21.40
1977	1,403	2,905	5,301	6,083	23.55

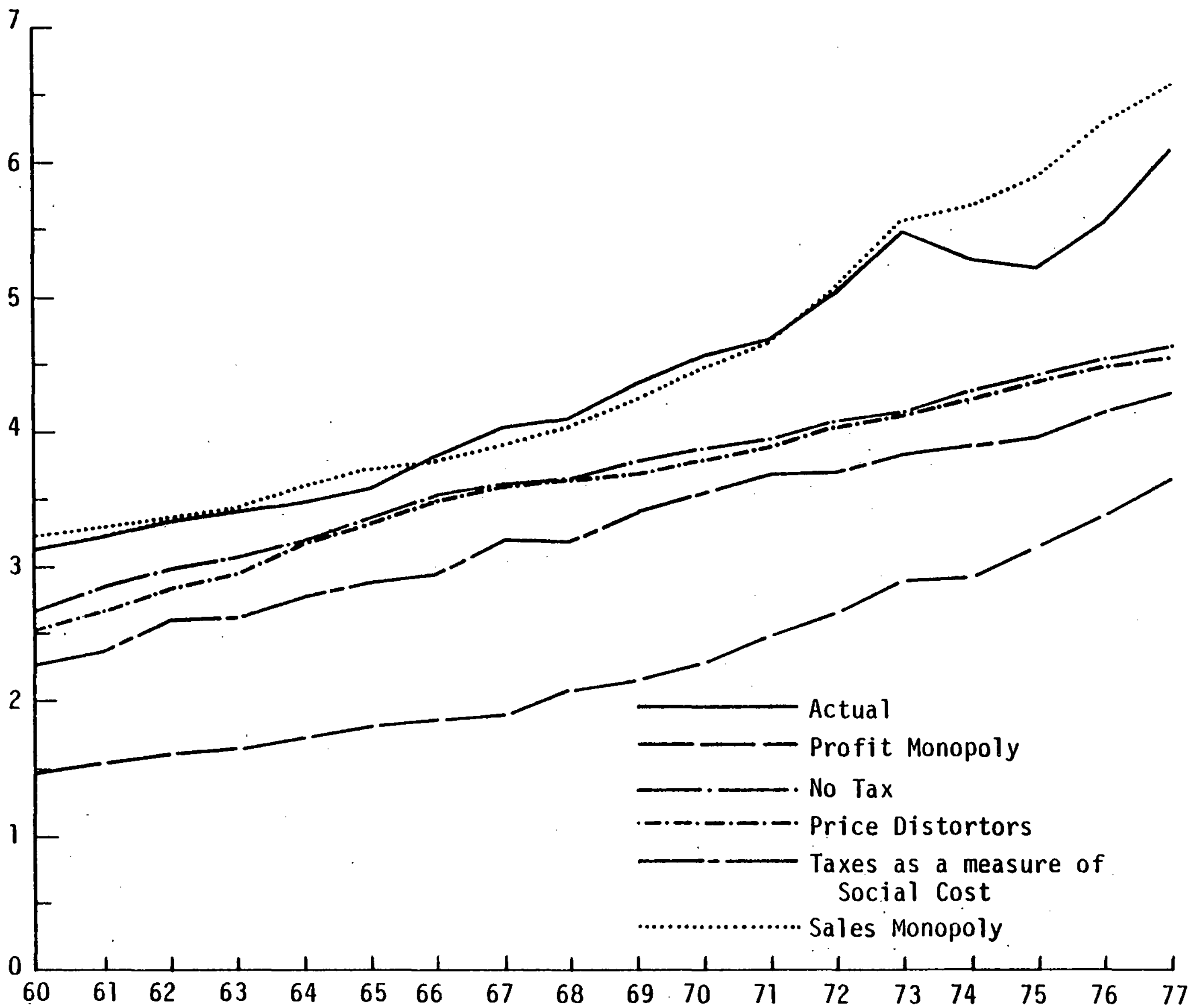

Figure 3-1. Simulation of Petroleum Industry Model Under Alternative Behavioral Assumptions, 1960-1977, Total Refined Product Delivered to Final Demand in Billions of Barrels

Table 3-5 presents the total refined product delivered to final demand over the 15-year data period. These column totals reveal the very accurate performance or sales monopoly in predicting industry output. Noting the importance of the output decision in determining prices, and input use, these criteria will further substantiate the selection of sales monopoly as most accurately reflecting actual industry behavior.

Price per barrel of all refined product sold domestically is presented in Table 3-6. Since price is a function of exogenous income and prices and endogenous per capita consumption, price per barrel may be viewed as a function of a number exogenous factors and domestic production. Deviations from actual prices simply reflect variation in output caused by the pecularities of the behavioral assumption employed, the optimization procedure, and the assumptions of instantaneous adjustment. Prices are presented for completeness and to further reaffirm the superiority of sales monopoly in explaining petroleum industry behavior.

Ranked in order of magnitude, monopoly price is significantly greater than price under any other behavioral assumption. Price under perfect competition with taxes as price distorters charge the next highest price, followed by perfect competition with taxes as a measure of social cost. No tax perfect competitors charged prices higher than actual but lower than profit monopoly. Sales monopoly price, however, is close to actual price in every year until 1974. Sales monopoly output is higher than actual output in the post embargo period requiring that price be lower.

Reserve Acquisitions

Before discussing reserve acquisition results under each behavioral assumption, a brief review will illuminate how Q_1 is

Table 3-5

Simulation of Petroleum Industry Model under
Alternative Behavior Assumptions, 1960-1977
Total Refined Product Sold Domestically in Millions of Barrels

			Perfect Competition			
Year	Actual	Profit Monopoly	No Tax	Price Distorters	Taxes as a Measure of Social Cost	Sales Monopoly
1960	3,137	1,499	2,661	2,517	2,291	3,247
1961	3,213	1,547	2,839	2,659	2,371	3,292
1962	3,311	1,601	2,964	2,821	2,598	3,366
1963	3,369	1,636	3,070	2,943	2,615	3,416
1964	3,472	1,727	3,176	3,165	2,771	3,585
1965	3,589	1,808	3,371	3,276	2,892	3,716
1966	3,806	1,849	3,518	3,487	2,920	3,787
1967	4,005	1,870	3,564	3,556	3,192	3,865
1968	4,163	2,091	3,619	3,534	3,169	4,021
1969	4,353	2,163	3,783	3,646	3,391	4,229
1970	4,571	2,275	3,858	3,772	3,545	4,421
1971	4,692	2,496	3,931	3,868	3,663	4,675
1972	5,020	2,620	4,075	4,037	3,675	5,144
1973	5,472	2,887	4,146	4,113	3,796	5,552
1974	5,269	2,926	4,290	4,211	3,887	5,669
1975	5,191	3,135	4,415	4,369	3,926	5,892
1976	5,544	3,386	4,522	4,489	4,138	6,312
1977	6,083	3,638	4,616	4,506	4,231	6,546
Totals	78,260	41,154	66,418	64,969	59,071	80,735

Table 3-6

Simulation of Petroleum Industry Model under Alternative Behavioral Assumptions, Price per Barrel All Refined Product Sold Domestically, 1960-1977

			Perfect Competition			
Year	Actual P_4	Profit Monopoly	No Tax	Taxes as Price Distorters	Taxes as a Measure of Social Cost	Sales Monopoly
1960	$11.23	$14.11	$12.19	$14.66	$14.26	$11.05
1961	11.46	14.55	12.83	14.83	14.69	11.52
1962	11.69	14.67	13.67	15.02	14.98	11.60
1963	11.59	15.09	13.81	14.91	14.80	11.65
1964	11.42	15.55	13.94	15.04	14.93	11.23
1965	11.48	15.89	14.12	15.38	14.96	11.21
1966	11.36	17.10	14.63	15.46	15.05	11.40
1967	11.37	17.59	14.86	15.68	15.41	11.52
1968	11.26	18.12	14.90	15.94	15.81	11.44
1969	11.43	18.78	15.25	16.21	16.14	11.30
1970	11.90	19.07	16.71	18.62	18.33	12.63
1971	12.64	19.39	17.72	19.79	19.19	13.13
1972	13.55	19.77	18.38	21.38	20.63	13.34
1973	14.63	21.12	19.08	22.47	22.40	14.16
1974	17.69	22.23	21.23	24.75	23.79	16.12
1975	19.46	24.59	22.72	25.18	24.81	17.64
1976	21.40	25.72	23.02	26.95	25.61	18.92
1977	23.55	28.89	25.52	27.29	27.01	21.03

determined in the model. Reserve acquisitions are a function of drilling rigs, drilling employees, a reserve decline variable, and technology shifters. Reserves are more difficult to acquire as proven reserves increase, except when drilling in Alaska. A technology shifter to account for movement to Alaska makes reserve acquisition easier. When simulated cumulative discoveries over the period equal actual cumulative discoveries in 1970, Alaska acquisitions are permitted but do not exceed 15 billion barrels.

The model is optimized by generating shadow prices for reserves, production, and refining throughput. Equating these shadow prices forces returns to investment in each activity to converge. Reserves are, of course, necessary for production; but in addition, reserves contribute to the ease of production. As the stock of reserves increases, fewer capital and labor units are required for production. Apart from the contribution to ease of production, reserves have no other value in the model. Since reserves embody the capital and labor necessary to prove them, the cost of holding reserves is the discounted investment embodied in the reservoir. Costs of acquiring reserves like other costs in the model are reduced by income tax treatments and limited partnerships.

Reserve acquisitions under the assumptions of perfect competition, profit monopoly, and sales monopoly are presented in Table 3-7. Perfect competition is again run under three assumptions: (1) taxes as a measure of social costs (PCSC), (2) taxes as price distorters (PCPD), and (3) perfect competition with no taxes (PCNT). Actual reserve acquisitions are presented to provide a comparative base.

It is obvious by inspection that monopoly and perfect competition PCSC perform poorly in describing domestic reserve acquisitions.

Table 3-7

Simulation of Petroleum Industry Model under
Alternative Behavioral Assumptions, Reserve Acquisitions
in Millions of Barrels, 1960-1977

			Perfect Competition			
Year	Actual Q_1	Profit Monopoly	No Tax	Taxes as Price Distorters	Taxes as a Measure of Social Cost	Sales Monopoly
1960	2,367.80	0	0	0	0	0
1961	2,560.62	0	0	0	0	0
1962	2,184.36	0	0	0	0	858
1963	2,177.34	0	0	0	0	0
1964	2,668.37	0	0	0	0	3,585
1965	3,051.87	0	0	0	0	2,486
1966	2,967.57	0	0	0	0	762
1967	2,966.02	0	0	0	0	3,787
1968	2,457.07	0	1,026	0	0	2,430
1969	2,121.52	0	2,871	1,878	0	5,202
1970	12,695.54	0	760	695	0	3,254
1971	2,319.48	0	2,920	1,710	0	3,417
1972	1,559.56	0	0	0	0	15,000
1973	2,147.04	0	3,354	1,952	0	0
1974	1,995.11	0	1,695	1,603	0	1,171
1975	1,318.00	0	2,320	1,678	0	4,266
1976	1,805.00	0	1,192	1,925	0	2,809
1977	1,403.00	0	1,168	1,861	0	1,314
Totals	50,855.27	0	17,306	13,302	0	50,341

Domestic production is so low for these behavioral assumptions, reserve stocks are not depleted enough to make new reserves very valuable. Reserves are sought, however, by sales monopolists, perfect competition with taxes as price distorters (PCPD), and no tax perfect competitors (PCNT).

Although Table 3-7 reveals a superior performance of sales monopoly in explaining domestic reserve acquisitions, reserves are not acquired in a smooth investment pattern. This discrepancy may have occurred for two reasons. First, reserve extensions and revisions that are price dependent are not credited to the year of discovery as they have been historically. This is particularly apparent in the early years of the simulation. Second, the model optimizes by equating shadow prices at the margin. Unlike actual drilling activity which takes significant lead time to acquire drilling materials, contracts, and drilling rights, the model assumes instantaneous investment response.

The performance of the model under perfect competition and monopoly may be in part due from nonmarket value of holding reserves. Reserve acquisitions by the U.S. petroleum industry are difficult to explain in terms of shadow prices. Oversupply may be due to chance, not overinvestment. In addition, competitors may view reserve acquisitions as a means of preventing other competitors from developing reserves known to exist. In terms of developing a field, unitization requires production to be prorated by the number of wells owned, not who developed the field first. Another nonmarket value given the nonrenewable nature of petroleum is backward vertical integration to guarantee reserves for future development. Future market shares could conceivably be determined by reserve holdings.

Despite the limitations of the reserve acquisition model, sales monopoly meets historical output levels by acquiring nearly the same total number of barrels of reserves. Table 3-7 reveals that over the 15-year data period, sales monopoly is less than one-half billion barrels short of actual reserve acquisitions. PCPD perfect competition is 35 billion barrels short of actual acquisitions. PCNT is 33 billion barrels less than actual acquisitions. In terms of explaining reserve acquisitions, sales monopoly more closely resembles actual industry behavior than any other assumption. Sales monopoly differs most in the manner in which reserves are acquired, not in the quantity acquired.

Input Use

Table 3-8 presents capital labor ratios for the petroleum industry production activities under sales monopoly and no tax perfect comeptition. Since sales monopoly is clearly the preferred behavioral assumption for explaining historical patterns of production and reserve acquisition, this analysis is directed at comparing sales monopoly results with the normative base case, no tax perfect competition. Historical capital labor ratios are included, but capital labor ratios for other behavioral assumptions are not presented.

Inspection of Table 3-8 reveals the model's bias towards capital in production and refining. This is equivalent to overestimating the cost of labor relative to capital; however, performance of sales monopoly is reasonably good for reserve acquisition and refining.

In spite of many historical capital subsidies, imposing no tax on the industry actually results in more intensified use of

Table 3-8

Capital Labor Ratios in Petroleum Industry Production Activities Actuals, No Tax Perfect Competition and Sales Monopoly

	Reserve Acquisition			Production-Transportation			Refining		
Year	Actual, K_1/L_1	No Tax Perfect Competition	Sales Monopoly	Actual, K_2/L_2	No Tax Perfect Competition	Sales Monopoly	Actual, K_3/L_3	No Tax Perfect Competition	Sales Monopoly
1960	.011	0	0	1.370	4.273	2.838	55.545	129.680	85.293
1961	.013	0	0	1.358	4.172	2.896	59.373	128.861	86.621
1962	.014	0	.008	1.370	3.862	2.830	62.511	127.955	88.003
1963	.014	0	0	1.359	3.923	3.424	65.132	128.613	97.730
1964	.014	0	.007	1.370	4.468	3.068	68.888	123.048	95.095
1965	.016	0	.007	1.365	4.711	3.176	70.356	129.901	88.098
1966	.016	0	.007	1.371	4.618	3.655	70.133	127.715	102.883
1967	.015	.018	.007	1.357	4.931	3.619	72.064	128.104	104.813
1968	.011	.018	.007	1.362	5.014	3.811	75.638	127.773	112.313
1969	.013	.021	.007	1.358	5.011	3.438	80.872	129.652	93.256
1970	.009	.020	.007	1.362	5.016	3.551	78.212	130.340	101.006
1971	.013	.025	0	1.357	4.645	3.626	84.218	131.858	104.429
1972	.013	0	.008	1.361	4.817	3.590	87.278	134.878	98.527
1973	.012	.022	.009	1.358	4.193	3.409	91.203	129.372	77.659
1974	.016	.020	.009	1.357	4.916	3.492	92.416	121.517	83.381
1975	.014	.019	.010	1.359	4.261	3.480	93.618	124.620	92.676
1976	.015	.023	.011	1.361	4.376	3.590	93.721	128.768	93.244
1977	.017	.024	.010	1.363	4.892	3.760	95.976	130.915	98.720

capital.[12] This surprising result is probably a consequence of the current deductibility of labor costs. When taxes are eliminated, labor costs per man nearly double. Capital costs also increase but only to the extent of the investment tax credit and the present value of depreciation deduction.

E. SELECTION OF THE PREFERRED BEHAVIORAL ASSUMPTION

The petroleum industry production model has been simulated for three behavioral assumptions: (1) profit monopoly, (2) perfect competition, and (3) sales monopoly. Each assumption has imposed different market power and pricing behavior patterns on the industry's objective function. These assumptions will be discussed in turn.

Profit monopolists' necessary conditions for optimum levels of input use require equating marginal cost and marginal revenue. Input use requires marginal value product to be equated with input price. Although perfect competitors also equate MR and MC for determining optimum output levels and input use, market power allows monopolists to charge a higher price because competitive entry is deterred. Simulation of the petroleum industry model under profit monopoly generates output levels about half historical levels and final prices $3 to $4 more per barrel. Reserves are not sought under this behavioral assumption, contrary to the actual behavior of the industry. In short, profit monopoly does not accurately reflect industry behavior in the 1960 to 1977 data period.

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[12] This result is not dependent on the behavioral assumption employed. A similar reduction in labor use is observed when sales maximization is simulated under the no tax assumption.

Perfect competition was simulated under three different assumptions: (1) perfect competition with taxes as price distorters (PCPD), (2) perfect competition with taxes as a measure of social costs (PCSC), and (3) perfect competition subject to no federal taxes (PCNT). No tax perfect competition was not tested as a behavioral assumption that best described petroleum industry behavior. All perfect competitors charged a higher price and produced less than historically observed output and price. Cumulative reserve acquisitions did not exceed 25% of actual acquisitions for any of the perfectly competitive cases.

Selection of sales monopoly as the preferred behavioral assumption is based on output, reserve acquisition, and pricing behavior. Although capital and labor use in production-transportation is slightly biased towards the use of capital, outputs and price are very similar to those actually observed. Sales monopoly results in higher output and lower price than perfect competition because the former accepts a lower rate of return to the industry's own capital. (Capital invested by other financial institutions in the industry is paid the same rate of return among behavioral assumptions.) Sales monopoly constrained to zero profits (including a return to own capital) is also preferred because it is logically consistent for a highly regulated industry concerned with antitrust litigations to keep profits low by increasing sales. The economic implications of sales monopoly in a nonrenewable resource industry will be discussed in the conclusions.

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IV. TAXES AND THE DEPLETION OF DOMESTIC RESERVES UNDER SALES MONOPOLY

A. INTRODUCTION

Federal income taxation of the United States petroleum industry from 1960 to 1977 has had three separate effects. First, the costs of exploration, extraction, and production have been reduced by the deductibility of drilling and capital subsidies. Second, a large part of these drilling subsidies have been purchased by high income limited partners seeking tax shelters. Third, percentage depletion has increased the industry's after tax income through an output subsidy. In this section, the industry model is optimized under the assumption of sales monopoly to determine the effects of eliminating capital and drilling subsidies and percentage depletion. In conclusion, six tax policies are considered: (1) elimination of capital subsidies and percentage depletion, (2) elimination of drilling subsidies, (3) imposition of an externality tax as a fixed percentage of final price, (4) removal of all federal income taxes (no taxes), (5) elimination of capital and output subsidies in conjunction with an externality tax, and (6) elimination of all tax subsidies.

B. TAX POLICY SIMULATIONS

Six income tax strategies are considered as possible alternatives for taxation of the United States petroleum industry. The first to be considered is elimination of all drilling subsidies. This policy would reduce limited partnership involvement in domestic reserve acquisition activities and, in addition, limit drilling costs to depreciation or amortization. Second, capital subsidies, including excess depreciation, deductible interest and investment tax credits, are eliminated together with percentage depletion. These preferences are considered together because all are effectively production subsidies that reduce the optimum price of petroleum. Third, the alternative of no taxes is considered as a case to determine the direction of net transfers between the government and the industry. Fourth, an externality tax is imposed like a sales tax to represent social costs that are not paid by the industry. Fifth, an externality tax is imposed in conjunction with eliminating capital and output subsidies. Sixth, all tax subsidies are eliminated. Tables 4-1, 4-2, 4-3, and 4-4 present six tax policy simulations for reserve acquisitions, total refined product delivered to final demand, final price, and total employment, respectively.

Elimination of Drilling Subsidies

The elimination of drilling subsidies increases the costs of reserves in two ways. First, limited partnership purchases of drilling costs decrease, and, second, drilling costs are limited to depreciation or amortization. As a consequence, the industry's cost of acquiring reserves increases sharply. Reserves become so expensive when drilling subsidies are eliminated that the industry does not seek reserves until 1972 when the stock of reserves is reduced from historical levels near 31 billion to 4.5 billion barrels (Table 4-1). Although the industry has historically maintained stocks at levels 10 times greater than annual production, this tax assumption makes reserves too expensive.

Under the assumption of no drilling subsidies, the industry reduces output delivered to final demand to the third lowest level simulated under any tax policy alternative. Cumulative output is reduced by 10 billion barrels, nearly 20% of simulated output in 1977 (Table 4-2). Price per barrel reflects higher costs and lower output for the industry. Simulated weighted average price for all refined product delivered to final demand is from \$0.50 to \$3.50 per barrel more expensive than actual price observed during the 1960 to 1977 period (Table 4-3).

Table 4-1

Tax Policy Simulation of the Petroleum Industry Model under Sales Monopoly, Reserve Acquisitions in Millions of Barrels, 1960-1977

Year	Actuals Q_1	No Tax Perfect Competition	Sales Monopoly: As Taxed	No Drilling Subsidies	No Capital Subsidies or Percentage Depletion	No Taxes	Externality Tax	No Capital Subsidies or Percentage Depletion Plus an Externality Tax	No Tax Subsidies
1960	2,367	0	0	0	0	0	0	0	0
1961	2,660	0	0	0	0	0	0	0	0
1962	2,184	0	858	0	1,843	1,824	0	0	0
1963	2,177	0	0	0	1,871	1,769	0	910	0
1964	2,668	0	3,585	0	2,869	4,125	2,160	2,263	0
1965	3,051	0	2,486	0	1,495	2,693	2,073	1,006	0
1966	2,967	0	762	0	706	1,685	4,880	286	0
1967	2,966	0	3,787	0	2,567	3,693	3,338	2,051	0
1968	2,457	1,026	2,430	0	2,069	3,026	2,086	1,564	0
1969	2,121	2,871	5,202	0	1,747	4,009	4,732	1,348	0
1970	12,695	760	3,254	0	3,442	4,221	2,911	2,894	0
1971	2,319	2,920	3,417	0	4,027	15,000	3,044	3,397	0
1972	1,559	0	15,000	1,824	2,969	0	3,649	2,408	0
1973	2,147	3,354	0	2,765	3,406	1,575	4,564	2,718	0
1974	1,995	1,695	1,171	2,178	15,000	2,863	15,000	1,627	0
1975	1,318	2,320	4,266	2,740	0	3,901	0	2,797	283
1976	1,805	1,192	2,809	2,666	0	2,075	0	2,016	1,603
1977	1,403	1,168	1,314	2,477	0	1,391	839	15,000	1,506
Totals	50,895	17,306	50,341	14,650	44,011	53,850	49,276	42,285	3,392

Table 4-2

Tax Policy Simulation of the Petroleum Industry Model under Sales Monopoly, Total, Refined Product Delivered to Final Demand in Millions of Barrels, 1960-1977

			Sales Monopoly						
Year	Actuals Q_4	No Tax Perfect Competition	As Taxed	No Drilling Subsidies	No Capital Subsidies or Percentage Depletion	No Taxes	Externality Tax	No Capital Subsidies or Percentage Depletion Plus an Externality Tax	No Tax Subsidies
1960	3,137	2,661	3,247	3,100	3,165	3,361	3,143	3,071	2,961
1961	3,213	2,839	3,292	3,045	3,128	3,500	3,111	2,967	2,843
1962	3,311	2,964	3,366	3,034	3,149	3,642	3,119	2,916	2,779
1963	3,369	3,070	3,416	3,024	3,119	3,705	3,124	2,841	2,681
1964	3,472	3,176	3,585	3,078	3,156	3,843	3,222	2,844	2,643
1965	3,539	3,371	3,716	3,148	3,204	3,957	3,330	2,865	2,640
1966	3,806	3,518	3,787	3,196	3,229	4,040	3,387	2,864	2,627
1967	4,005	3,564	3,865	3,195	3,230	4,095	3,450	2,844	2,571
1968	4,153	3,619	4,021	3,304	3,352	4,257	3,601	2,945	2,642
1969	4,353	3,783	4,229	3,404	3,495	4,437	3,808	3,073	2,741
1970	4,571	3,858	4,421	3,504	3,717	4,680	3,994	3,266	2,882
1971	4,692	3,931	4,675	3,637	3,969	5,053	4,246	3,497	3,062
1972	5,020	4,075	5,144	3,966	4,283	5,304	4,579	3,797	3,333
1973	5,472	4,146	5,552	4,544	4,760	5,731	5,074	4,268	3,794
1974	5,269	4,290	5,669	4,628	4,966	5,913	5,321	4,324	3,786
1975	5,291	4,415	5,892	4,801	5,086	6,051	5,466	4,443	3,802
1976	5,544	4,522	6,312	5,326	5,553	6,342	5,952	4,917	4,281
1977	6,083	4,616	6,546	5,798	6,017	6,646	6,408	5,526	4,780
Totals	78,260	66,418	80,735	67,732	70,578	84,557	74,335	63,168	56,848

Table 4-3

Tax Policy Simulation of the Petroleum Industry Model under Sales Monopoly, Price per Barrel All Refined Product Delivered to Final Demand, 1960-1977

			Sales Monopoly						
Year	Actuals P_4	No Tax Perfect Competition	As Taxed	No Drilling Subsidies	No Capital Subsidies or Percentage Depletion	No Taxes	Externality Tax	No Capital Subsidies or Percentage Depletion Plus an Externality Tax	No Tax Subsidies
1960	11.23	12.19	11.05	11.45	11.27	10.74	11.33	11.53	11.83
1961	11.46	12.83	11.52	12.19	11.96	10.95	12.01	12.40	12.74
1962	11.69	13.67	11.60	12.50	12.19	10.86	12.27	12.82	13.19
1963	11.59	13.81	11.65	12.70	12.44	10.87	12.43	13.19	13.62
1964	11.42	13.94	11.23	12.59	12.38	10.53	12.20	13.22	13.76
1965	11.48	14.12	11.21	12.74	12.59	10.56	12.25	13.51	14.12
1966	11.36	14.63	11.40	13.02	12.93	10.70	12.50	13.93	14.58
1967	11.37	14.86	11.52	13.39	13.29	10.88	12.67	14.37	15.13
1968	11.26	14.90	11.44	13.50	13.36	10.76	12.64	14.53	15.40
1969	11.43	15.25	11.30	13.79	13.51	10.68	12.57	14.78	15.78
1970	11.90	16.71	12.63	15.52	14.85	11.81	13.98	16.27	17.48
1971	12.64	17.72	13.13	16.51	15.43	11.90	14.53	16.97	18.39
1972	13.55	18.38	13.34	17.28	16.22	12.80	15.23	17.85	19.40
1973	14.63	19.08	14.16	17.70	16.94	13.53	15.84	18.67	20.34
1974	17.69	21.23	16.12	20.16	18.85	15.17	17.47	21.34	23.42
1975	19.46	22.72	17.64	22.21	21.02	16.97	19.42	23.71	26.40
1976	21.40	23.02	18.92	23.25	22.06	18.92	20.50	25.05	27.84
1977	23.55	25.52	21.03	24.49	23.47	21.03	21.66	25.75	29.20

Table 4-4

Tax Policy Simulation of the Petroleum Industry Model under Sales Monopoly, Total Employment in Thousands, 1960-1977

			Sales Monopoly						
Year	Actuals $L_1+L_2-L_3$	No Tax Perfect Competition	As Taxed	No Drilling Subsidies	No Capital Subsidies or Percentage Depletion	No Taxes	Externality Tax	No Capital Subsidies or Percentage Depletion Plus an Externality Tax	No Tax Subsidies
1960	713.2	163.2	228.7	216.5	270.9	160.6	220.0	261.3	250.0
1961	706.1	165.4	228.8	208.0	261.6	165.4	213.6	245.1	232.5
1962	658.3	168.8	357.7	106.4	524.0	354.2	213.6	238.9	229.3
1963	649.2	212.2	119.7	171.8	520.4	336.0	179.2	354.3	210.2
1964	698.7	221.6	903.6	195.3	695.7	603.5	516.1	566.7	221.6
1965	715.3	237.9	617.5	202.2	502.5	471.7	518.1	389.7	220.8
1966	698.4	239.8	330.1	178.9	358.4	352.2	260.2	259.1	196.6
1967	733.4	242.6	806.6	181.6	642.9	575.7	694.3	516.8	188.8
1968	725.1	456.8	590.6	177.4	562.3	503.6	500.5	439.1	184.1
1969	672.7	517.9	1,084.6	209.2	517.6	640.7	952.8	409.7	184.9
1970	747.2	432.5	775.1	205.9	789.6	676.0	672.3	644.8	186.4
1971	661.4	453.5	801.6	212.5	908.7	470.2	692.8	740.7	206.4
1972	637.1	167.6	653.9	393.0	753.1	194.9	797.7	600.7	220.0
1973	635.3	289.8	309.8	517.7	857.6	378.6	976.1	678.1	261.8
1974	636.9	291.3	470.4	469.5	717.6	504.4	654.0	523.5	271.4
1975	634.1	264.6	919.3	544.6	373.0	625.0	304.5	720.8	318.8
1976	641.7	462.6	746.1	565.1	400.1	454.2	326.7	639.1	458.2
1977	642.2	468.8	538.1	566.7	423.0	386.6	456.5	733.7	474.8
Total Man-Years	12,205	5,426.8	10,482	5,322.2	10,079	7,853.5	9,149	8,962.1	4,516.6
Total Man-Years per Thousand Barrels of Refined Product Delivered to Final Demand	.156	.020	.129	.078	.142	.092	.123	.141	.079

The elimination of drilling subsidies substantially reduced total final output (Table 4-2). As a consequence, labor necessary to meet these lower output levels was also reduced. Although sales monopoly underpredicted actual total employment by about 15%, total employment when drilling subsidies were eliminated was even lower (Table 4-4). This sharp reduction in labor requirements was primarily due to the absence of reserve acquisitions in the optimum solution. In addition, since imports are assumed to be determined exogenously, domestic production decreases by the same amount as the reduction in Q_4, also reducing production labor requirements.

Elimination of Capital Subisidies and Percentage Depletion

Elimination of production subsidies included eliminating percentage depletion in conjunction with capital subsidies, excess depreciation, the investment tax credit, and deductible interest. Simulation of industry activity under the assumption of no production subsidies was really a simulation of industry activity when it must bear the total costs of its own production (except reserve acquisition costs.) This tax policy alternative did not have as large an impact on reserve acquisitions as the removal of drilling subsidies because drilling costs were still being shared with limited partners. Total reserves acquired by sales monopoly with no production tax subsidies were only 5 billion barrels less than actual reserve acquisitions for 1960 to 1977 (Table 4-1).

Total refined product delivered to final demand (Table 4-2) was reduced on average by 500 million barrels below actual levels for each year. This reduction in output, caused by increased production costs, in turn increased final price by as much as $2 to $3 per barrel by 1973 (Table 4-3).

Elimination of capital subsidies and percentage depletion did not have a substantial impact on total employment although total production was about 5% of sales monopoly total output. The 10 billion barrel reduction in total output (Table 4-2) reduced total labor requirements by approximately one-half million man years. Removing cpaital subsidies and percentage depletion substantially reduced total output without seriously reducing the number of people employed.

No Federal Corporate Income Tax

The alternative of no corporate income tax is presented as a case to compare present and possible tax strategies. Under this assumption, the industry pursued an active reserve acquisition policy (Table 4-1) even though all drilling costs were borne by the industry. Total refined product delivered to final demand under the no tax assumption was slightly higher than actual historical output, but only by six billion barrels in total (Table 4-2). This suggests that subsidies transferred to the industry under historical tax policies were slightly less than revenues collected.[1]

The increase in output under the assumption of no income taxes was reflected in final price (Table 4-3). Price per barrel decreased approximately $1 for most of 1960 to 1977. Removing corporate income taxes had a substantial impact on reducing labor

[1]This conclusion limits the findings of Cox and Wright who studied the cost-effectiveness of federal income taxation of the petroleum industry. However, their analysis did not incorporate limited partnerships--an important factor when estimating production costs. See: James C. Cox and Arthur R. Wright, "The Cost Effectiveness of Federal Tax Subsidies for Petroleum Reserves: Some Empirical Results and Their Implications," in Studies in Energy Tax Policy, ed. Gerard M. Brannon (Cambridge: Ballinger Publishing Company, 1975), chapter 8.

requirements (Table 4-4). Total employment was about one-third less than sales monopoly employment for the 18-year period.

Externality Tax

Imposition of an externality tax assumes that the social costs of using petroleum (pollution, automobile accidents, etc.) can be approximated by a fixed proportion of final price. Industry response can be observed when costs of petroleum use increased to consumers. Social costs for these simulations were arbitrarily assumed to equal 10% of final price.

Simulation results under an externality tax suggested: a reduction in total reserve acquisitions by 1 billion barrels less than actual acquisitions (Table 4-1), a decrease in cumulative output by approximately 3 billion barrels (Table 4-2), and a slight increase in final price. Imposition of an externality tax had a small impact on employment. Total man-years per 1,000 barrels of refined product delivered to final demand was reduced by about 5% of the labor requirements simulated under sales monopoly.

An imposition of an externality tax indicated a smooth adjustment in prices and outputs in all three stages of industry production. Price increases were absorbed by consumers and led to a reduction in per capita consumption with no serious reductions in investment, production, or reserve acquisitions by the industry.

Elimination of Production Subsidies and an Imposition of an Externality Tax

The effects of eliminating capital subsidies and percentage depletion in conjunction with an externality tax are summarized as follows: The industry acquired reserves but at a slower rate than under sales monopoly; output was lower and final price higher than any other alternative considered except the elimination of all subsidies. Total employment per 1,000 barrels of Q_4 was higher than sales monopoly labor requirements.

Elimination of all Tax Subsidies

The effects of eliminating all tax subsidies may be summarized as follows: reserve acquisitions and total refined product delivered to final demand were lower than any other tax alternative considered and did not exceed the output levels of no tax perfect competition, the normative standard. Prices were highest and employment levels lowest under this assumption.

C. SUMMARY AND CONCLUSIONS

Summary of Tax Simulations

The public policy implications of petroleum tax preferences go far beyond the tax losses to the Treasury that can be measured in this model. Externality costs of pollution and automobile accidents are only a small portion of the social costs associated with the overexploitation of domestic petroleum reserves. Recent economic research indicates that overinvestment in petroleum and energy in general may stimulate capital-energy substitution for labor, thus creating long-run unemployment.[2]

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[2]This topic is further developed in: Duane Chapman, Energy Conservation, Employment, and Income, Cornell University Staff Paper, Agricultural Economics Research 77-6 (Ithaca: Cornell University Press, [1977]), and E. R. Berndt and D. Wood, "Technology, Prices, and the Derived Demand for Energy," Review of Economics and Statistics 57 (August 1975): 259-268.

If the use of petroleum has these uncompensated social costs, the question of what constitutes overexploitation may then be raised. In terms of the economists' textbook standard, the societally optimal organization of production is perfect competition, however, because historical tax policies have actually subsidized the industry almost to the extent of the taxes it paid, it seems societally preferable to remove these subsidies and reduce social costs. Using perfect competition not subject to corporate income tax (PCNT) as an upper limit to the normative standard, Table 4-5 presents a comparison of actual to simulated outputs, reserves, price, per capita consumption, and employment under the six tax policies simulated above.

Under PCNT, refined product delivered to final demand in 1977 was about 30% less than actual output levels, and the 15-year total (1960-1974) was about one-sixth less than the actual total. PCNT output was not exceeded when all subsidies were eliminated. Output was highest under the assumption of no corporate income tax and second highest under sales monopoly as historically taxed.

Reserves were acquired under PCNT, the normative standard but were less than one-fourth of actual acquisitions. When corporate income taxes were eliminated, the industry lost the lucrative drilling subsidies that attracted limited partners. However, reserve acquisitions when corporate taxes were eliminated were higher than actual and sales monopoly acquisitions. Reserve acquisitions were lowest when all tax subsidies were removed.

The stock of proven reserves held under each tax policy simulation similarly reflected the relative burden of drilling costs. Stocks were lowest when drilling subsidies were removed, when all subsidies were removed, and PCNT. Ultimate recoverable reserves left for future development reflected the extent that final product delivered to final demand came from domestic production.

Table 4-5

Comparison of Simulated Outputs, Reserves, Prices, per Capita Consumption, and Employment under Six Alternative Tax Policies, 1977

			Sales Monopoly						
	Actual	No Tax Perfect Competition	As Taxed	No Drilling Subsidies	No Capital Subsidies or Percentage Depletion	No Taxes	Externality Tax	No Capital Subsidies or Percentage Depletion Plus an Externality Tax	No Tax Subsidies
(1) Refined product to final demand (Q_4) in millions of barrels, 1977	6,083	4,616	6,546	5,798	6,017	6.646	6,408	5,526	4,780
(2) Total refined product to final demand in millions of barrels, 1960-1977	78,260	66,418	80,735	67,732	70,578	34,557	74,335	63,168	56,848
(3) Reserve acquisitions (Q_1) in millions of barrels in 1977	1,403	1,168	1,314	2,477	0	1,391	839	15,000	1,506
(4) Total reserve acquisitions in millions of barrels, 1960-1977	50,859	17,306	50,341	14,650	44,011	33,850	49,276	42,285	3,392
(5) Stock of proven reserves in millions of barrels, 1977	31,620	5,963	29,964	4,359	33,571	38,695	30,237	23,661	3,938
(6) Ultimate recoverable domestic reserves left for future development in millions of barrels, 1977	180,192	218,955	183,918	221,782	189,944	181,496	189,910	206,670	232,069
(7) Ultimate recoverable reserves left for future production in millions of barrels, 1978	211,812	224,918	213,882	226,141	223,515	210,191	220,147	230,331	236,007
(8) Price per barrel in 1978	23.55	25.52	21.03	24.49	23.47	21.03	21.66	25.75	29.20
(9) Per capita consumption in barrels	28.12	21.34	30.03	26.59	27.60	30.03	29.39	25.35	21.92
(10) Total man-years of labor in thousands	12,235	5,426.8	10,482	5,322.3	10,079	7,835.5	9,149	8,962.1	4,516.6

Ultimate recoverable reserves left for future development were highest under no tax subsidies; the next highest were no drilling subsidies and PCNT. These alternatives depleted their reserve stocks without replacing them with new reserves. Ultimate recoverable reserves left for future production reflected this fact. This variable measured unproduced ultimate recoverable reserves. Stocks of undepleted reserves were highest when all subsidies were removed. Stocks of undepleted reserves were lowest under actual and simulated sales monopoly (no tax) assumptions.

Price per barrel in 1974 was highest under sales monopoly with no subsidies. Sales monopoly price was lowest, closely followed by sales monopoly not taxes and sales monopoly with an externality tax. Similarly, per capita consumption also reflected the quantity of refined product delivered to final demand since output was divided by the same number, population. Per capita consumption in 1977 was lowest under PCNT, followed by elimination of all subsidies.

Although the petroleum industry model slightly favored the use of labor, substantial reductions in total employment were experienced under PCNT. The shut down in domestic reserve acquisition activity in conjunction with lower production levels reduced total employment to 50% of the simulated level for sales monopoly. Production and refining labor were reduced because a one barrel reduction in Q_4 requires a one barrel reduction in Q_2. This was due to the fact that imports were assumed to be determined exogenously. Total employment was about one-third actual employment when all subsidies were eliminated for the same reasons.

In summary, elimination of all subsidies reduced output to a level that did not exceed no tax perfect competition. Final output in the latest years of the simulation period closely approximated PCNT, after PCNT stocks of less expensive reserves were depleted.

Conclusions

This paper has attempted to quantify the effects of the federal corporate income tax on domestic reserve depletion. Because industry response to tax incentives depended on market power and behavior, three behavioral assumptions were tested for consistency with the 1960 to 1977 period. This paper concludes that the recent historical past indicates that the behavior of the United States petroleum industry most resembled that of an industry pursuing maximum growth by means of sales maximization.

The conclusions of the tax simulations under sales monopoly may be summarized by a few points. First, the net effect of federal corporate income tax policies during the 1960 to 1977 period has left the industry with a small tax burden. Because limited partners were allowed to deduct from their personal income taxes drilling expenses that were in excess of their "at risk" investment, a substantial portion of drilling and development costs were purchased for tax shelter purposes.

Second, increases in petroleum production costs caused by the elimination of capital subsidies and percentage depletion would not have serious or adverse effects on reserve acquisition or employment. Third, eliminating excess depreciation had a greater impact on reducing production than removing percentage depletion. Fourth, an externality tax could be imposed on domestic petroleum consumption without imposing serious adjustment problems on the industry. Fifth, removing all subsidies is the preferred means of achieving socially optimum output and final price in the petroleum industry. Finally, the societal price of all petroleum products is understated by the federal income tax system by more than 20%. If societal costs are compensated for, actual prices may be further understated. These low prices accelerate reserve depletion and inhibit the deployment of renewable resources.

APPENDIX A

MATHEMATICAL APPENDIX

Overview of the Optimization Procedure

This mathematical appendix presents the complete set of necessary conditions for optimum levels of input use for the industry model under the behavioral assumptions of (1) profit monopoly, (2) perfect competition, and (3) sales monopoly. This presentation omits a discussion of taxes and costs which may be found in Section III. However, taxes are incorporated by Table 3-3 where all after tax costs and revenues affecting an output or an input may be obtained by summing down each column vector. The following optimum conditions are expressed in terms of the sum of each column vector represented by the consolidated parameter notation of Table 3-3. All notation is explained in Table 3-1.

To review briefly, the industry model, which includes the three production functions presented in Section II, is optimized subject to a single representation of demand for all refined products sold domestically. The industry's production functions are related through the identities (3-20) and (3-21) where imports are assumed to be determined exogenously from the industry model. Similarly, prices between the production stages are related through the identities (3-22) and (3-23) where the markups between prices are also assumed to be determined exogenously and are based on national averages for prices received at that stage of production.

The optimum solution under each behavioral assumption is completely determined if the optimum time paths for the three different capital and labor variables are known. With linear homogeneous production functions, the optimal solutions for the inputs are simple to derive. However, this is only true for refining since the role of reserves in production, (2-6), complicates the problem. In addition, even though technology is defined in terms of the initial conditions for estimations, this must be modified for simulation since continuous time is used in the objective function. Proven reserves, R_p, increase as reserve acquisitions, Q_1, increase and decrease as production, Q_2, increases. Similarly, in reserve acquisition (2-5), undiscovered reserves decrease as Q_1 increases. Consequently, the production functions are now implicit functions relating output to inputs. In order to derive the optimum solutions, it is necessary to determine the marginal products of the input variables. For reserve acquisition and production, this can be achieved by solving the total derivative for each equation. Taking the total derivative of (2-6) gives

$$dQ_2 = \beta_{2K} \frac{Q_2}{K_2} + (1-\beta_{2K}) \frac{Q_2}{L_2} dL_2 + \beta_{21} \frac{Q_2}{(R_p + Q_1 - Q_2)} dQ_1$$

$$- \beta_{21} \frac{Q_2}{(R_p + Q_1 - Q_2)} dQ_2 \qquad \text{(A-1)}$$

Similarly, taking the total derivative of (2-5) gives

$$dQ_1 = \beta_{1K} \frac{Q_1}{K_1} dK_1 + (1-\beta_{1K}) \frac{Q_1}{L_1} dL_1 + \beta_{1R} \frac{Q_1}{R_u - Q_1} dQ_1 \qquad \text{(A-2)}$$

These two equations can be solved so that dQ_1 and dQ_2 are expressed in terms of dK_1, dL_1, dK_2, and dL_2.

The simultaneous determination of Q_1 and Q_2 implies that the optimum solution for each input is nonlinear and some iterative scheme must be employed. The procedure involved searching over different Q_1 and Q_2 levels until an optimum was found. These optimums were found by equating the value of marginal products of a dollar's expenditure at all three stages or production.[1] This procedure will become apparent as the optimum solution for profit monopoly is derived. The solutions for the other objective functions will then be compared with these results.

Profit Monopoly

The objective function for profit monopoly for the petroleum industry model is

$$\begin{aligned} \max \int_0^{\infty} W_t dt = \int_0^{\infty} e^{-rt} [& A_3 P_3 Q_4 - (1-a_0) P_{IC} Q_{IC} - (1-a_0) P_{IR} Q_{IR} \\ & - c_1 Q_1 - b_1 L_1 - e_1 K_1 - d_1 \, (K_1 + \delta_1 K_1) \\ & - f_1 \int_0^{\infty} e^{-\delta_{12} s} (z_2 K_{12t-s}) ds - c_2 Q_2 - b_2 L_2 + A_2 P_2 Q_2 \\ & - e_2 K_2 - d_2 (K_2 + \delta_2 K_2) - c_3 Q_3 - b_3 L_3 - e_3 K_3 \\ & - d_3 (K_3 + \delta_3 K_3) + \eta (Q_3 - Q_{IC} - \theta Q_2)] dt \end{aligned} \qquad \text{(A-3)}$$

where η is a Lagrangian multiplier for the identity relating Q_3 to Q_2. Euler's theorem can be used to derive necessary conditions for the six input variables. The following expressions can be derived.[2]

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[1]Since Q_3 and Q_2 are related by an identity the solution is defined in terms of five optimum paths.

[2]Note that $\partial P_4 / \partial Q_3 = 1/\beta_{44}$, where β_{44} is the coefficient for price in the demand equation.

$$\frac{\partial Q_1}{\partial L_1} = \frac{(A_2P_2 - c_2 - \eta\theta)\frac{\partial Q_2}{\partial L_1} + b_1}{-c_1} \tag{A-4}$$

$$\frac{\partial Q_1}{\partial K_1} = \frac{(A_2P_2 - c_2 - \eta\theta)\frac{\partial Q_2}{\partial K_1} + e_1 + (r + \delta_1)d_1 + f_1 z_2}{-c_1} \tag{A-5}$$

$$\frac{\partial Q_2}{\partial K_2} = \frac{(r + \delta_2)d_2 + e_2 + c_1 \frac{\partial Q_1}{\partial K_2}}{A_2P_2 - c_2 - \eta\theta} \tag{A-6}$$

$$\frac{\partial Q_2}{\partial L_2} = \frac{b_2 - c_1 \frac{\partial Q_1}{\partial L_2}}{A_2P_2 - c_2 - \eta\theta} \tag{A-7}$$

$$\frac{\partial Q_3}{\partial K_3} = \frac{(r + \delta_3)d_3 + e_3}{A_3P_3 - c_3 + \eta + \frac{A_2Q_2}{\beta_{44}} - \frac{a_0Q_4}{\beta_{44}} + \frac{Q_3 + Q_{IR}}{\beta_{44}}} \tag{A-8}$$

$$\frac{\partial Q_3}{\partial L_3} = \frac{b_3}{A_3P_3 - c_3 + \eta + \frac{A_2Q_2}{\beta_{44}} - \frac{a_0Q_4}{\beta_{44}} + \frac{Q_3 + Q_{IR}}{\beta_{44}}} \tag{A-9}$$

The marginal products for inputs into reserve acquisition and production can be expressed by solving the two total derivatives discussed above. These can be evaluated if Q_1 and Q_2 are known. (The expressions for refining are straightforward.) The iterative strategy is to search over values of Q_1 and Q_2 until the three solution values for the Lagrangian multiplier, η, corresponding to the three production functions are identical. This is equivalent to equating the value of a dollar's expenditure at each production stage. Denoting each η with a subscript from its respective production activity, the expressions are

$$\eta_3 = \frac{b_3}{\frac{\partial Q_3}{\partial L_3}} - A_3P_3 + c_3 - \frac{A_2Q_2}{\beta_{44}} + \frac{a_0Q_4}{\beta_{44}} - \frac{Q_4}{\beta_{44}} \qquad \text{(A-10)}$$

$$\eta_2 = \frac{-b_2}{\frac{\partial Q_2}{\partial L_2}} + A_2P_2 - c_2 \frac{1}{\theta} \qquad \text{(A-11)}$$

$$\eta_1 = \frac{\frac{\partial Q_1}{\partial L_1} c_1 + b_1}{-\frac{\partial Q_2}{\partial L_1}} + A_2P_2 - c_2 \quad \frac{1}{\theta} \qquad \text{(A-12)}$$

Perfect Competition

The objective function for perfect competitors differs from profit monopoly because competitors maximize profit with respect to output price, not marginal revenue. Since the only difference between perfect competition and profit monopoly objective functions is the revenue term, the necessary conditions for inputs into reserve acquisition and production activities are the same. The expressions for refining are different

$$\frac{\partial Q_3}{\partial L_3} = \frac{b_3}{A_3P_3 - c_3 + \eta + \frac{A_2Q_2}{\beta_{44}} - \frac{a_0Q_4}{\beta_{44}}} \qquad \text{(A-13)}$$

$$\frac{\partial Q_3}{\partial K_3} = \frac{(r + \delta_3)d_3 + e_3}{A_3P_3 - c_3 + \eta + \frac{A_2Q_2}{\beta_{44}} - \frac{a_0Q_4}{\beta_{44}}} \qquad \text{(A-14)}$$

The above expressions are for perfect competition with taxes as price distorters. The expressions for no tax perfect competition are exactly the same except a_0 in Table 3-3 equals zero. The expressisons for taxes as a measure of social cost are similarly analogous except the conditions are optimized with respect to final price, P_3, not A_3P_3 which is after tax final price. Rewriting the conditions for refining the denominator is the only term that changes and it is $(P_3 - c_3 + \eta)$.

Sales Monopoly

For sales monopoly, the minimum profit level is expressed as a percentage rate of return to cpaital, i, which is assumed to equal the prime rate. The objective function may be written

$$\begin{aligned}
\max \int_0^\infty W_t dt = \int_0^\infty e^{-rt} \; & P_3Q_4 + \xi \;\; P_3Q_3 - (1-a_0)P_{IC}Q_{IC} \\
& - (1-a_0)P_{IR}Q_{IR} - c_1Q_1 - b_1L_1 - e_1K_1 - d_1(\dot{K}_1 + \delta_1K_1) \\
& - f_1 \int_0^\infty e^{-\delta_{12}s}(z_2K_{12t-s})ds - c_2Q_2 - b_2L_2 - e_2K_2 \\
& - d_2(\dot{K}_2 + \delta_2K_{2)} - c_3Q_3 - b_3L_3 - e_3K_3 - d_3(\dot{K}_3 + \delta_3K_3) \\
& + A_2P_2Q_2 - i(1-\phi)(P_{K3}K_3 + P_{K2}K_2) - i\psi_1(P_{K1}K_1 + P_{K12}K_{12}) \\
& + a_0(\delta_{E11}P_{K1}K_1 + \delta_{E12}P_{K12}K_{12} + \delta_{E2}P_{K2}K_2 + \delta_{E3}P_{K3}K_3) \\
& + \eta(Q_3 - Q_{IC} - \theta Q_2) \quad dt
\end{aligned} \tag{A-15}$$

where ξ is the Lagrangian multiplier for the profit constraint. The necesary conditions for sales monopoly are

$$\frac{\partial Q_1}{\partial L_1} = \frac{A_2P_2 - c_2 + \dfrac{A_2Q_2}{\beta_{44}} - \dfrac{\eta\theta}{\xi} \quad \dfrac{\partial Q_2}{\partial L_1} + b_1}{-c_1} \tag{A-16}$$

$$\frac{\partial Q_1}{\partial K_1} = \quad A_2P_2 - c_2 + \frac{A_2Q_2}{\beta_{44}} - \frac{\eta\theta}{\xi} \; \frac{\partial Q_2}{\partial K_1} + e_1$$

$$+ \quad r + \delta_1 + \frac{\dot{\xi}}{\xi} \; d_1 + f_1 z_2 + (i\psi_1 - a_0\delta_{E11})P_{K1}K_1$$

$$+ (i\psi_1 - a_0\delta_{E12})P_{K12}K_{12} \quad / -c_1 \tag{A-17}$$

$$\frac{\partial Q_2}{\partial L_2} = \frac{}{A_2P_2 - c_2 + \frac{A_2Q_2}{\beta_{44}} - \frac{\eta\theta}{\xi}} \tag{A-18}$$

$$\frac{\partial Q_2}{\partial K_2} = \frac{e_2 + (r + \delta_2)d_2 + (1-\phi)P_{K2} - a_0\delta_{E2}P_{K2} + \frac{\dot{\xi}}{\xi}d_2}{A_2P_2 - c_2 + \frac{A_2Q_2}{\beta_{44}} \quad \frac{\eta\theta}{\xi}} \tag{A-19}$$

$$\frac{\partial Q_3}{\partial L_3} = \frac{b_3}{P_3 + \frac{Q_3}{\beta_{44}} \quad \frac{1}{\xi} + 1 - a_0 \quad + \frac{\frac{Q_{IR}}{\beta_{44}}}{\xi} - c_3 \quad + \frac{A_2Q_2}{\beta_{44}} + \frac{\eta}{\xi}} \tag{A-20}$$

$$\frac{\partial Q_3}{\partial K_3} = \frac{e_3 + (r + \delta_3)d_3 + i(1-\phi)P_{K3} - a_0\delta_{E3}P_{K3} - \frac{\dot{\xi}}{\xi}d_3}{P_3 + \frac{Q_3}{\beta 44} \quad \frac{1}{\xi} + 1 - a_0 \quad + \frac{\frac{Q_{IR}}{\beta 44}}{} - c_3 + \frac{A_2Q_2}{\beta\ 44} + \frac{\eta}{\xi}} \tag{A-21}$$

The only additional complication with deriving the solution for sales monopoly is that the marginal products of capital depend on the rate of change of the Lagrangian multiplier, ξ. The initial solution for the first year in the simulation period is determined by assuming that $\dot{\xi} = 0$.

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