TEXAS PETROLEUM PRODUCTION

AND THE

WINDFALL PROFIT TAX

A Dissertation

by

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ABSTRACT

Texas Petroleum Production

and the

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This dissertation considers the impact of the federal windfall profit tax (WPT) on aggregate Texas petroleum production.

First, an engineering-based economic model is developed that incorporates both the geophysical aspects and economic and policy determinants of competitive petroleum production while allowing for the augmentation of the petroleum reserve base by new infill drilling, the abandonment and re-opening of individual wells extracting from that reserve base, and the effects of production prorationing by state regulatory agencies. The resulting generalized petroleum production model is then econometrically estimated using data from individual oil and gas reservoirs in Texas.

After finding that the generalized model performs adequately at the microeconomic level of the individual petroleum reservoir, it is next successfully applied to an analysis of aggregate Texas petroleum production. A simulation model of future aggregate Texas petroleum production from all sources is completed by including an econometric model of future oil production attributable to enhanced oil recovery

(EOR) methods.

This production model is then combined with an existing econometric model of petroleum drilling in Texas to fashion an integrated simulation model of aggregate petroleum production from a growing reserve base that is constantly being augmented by new reserve additions coming from drilling activity. The integrated model is used to simulate future aggregate Texas production levels from 1984 through 2003 under three alternative WPT phaseout scenarios - repeal of the WPT on 1-1-84, phaseout according to current law, and no phaseout whatsoever. The production differences and welfare effects that would result from changing the status quo phaseout schedule of the WPT to either of the two extremes of immediate repeal or indefinite extension are then determined. General conclusions and policy recommendations regarding the WPT complete the analysis.

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CHAPTER I

INTRODUCTION

On March 1, 1980, The Crude Oil Windfall Profit Tax Act was enacted by Congress in an attempt to capture some of the "windfall profits" that would arise from the decontrol of U.S. crude oil prices. From that point in time through the end of 1983, $58.3 billion in windfall profit tax liabilities have been incurred by U.S. oil producers and royalty owners (U.S. Department of the Treasury, 1984). With good reason then, federal windfall profit taxation has been called "the largest tax ever imposed in the U.S. on a single industry" (*New York Times*, June 7, 1983).

Under current law, the windfall profit tax (WPT) is scheduled to be phased out gradually over a 33 month period, which must begin no later than January 1, 1991. However, the expected persistence of high federal budget deficits for the foreseeable future has raised the possibility that the planned phaseout of the WPT will be delayed, indefinitely extending the tax into the next century. Not surprisingly, a recent editorial in an oil and gas industry newsletter voiced a specific concern over this possibility (*Oil Daily*, July 6, 1984). On the other hand, recent tax reform proposals such as the Treasury plan of November 1984 have suggested that the phaseout of the WPT be advanced by three years to begin in 1988 (*Oil*

This dissertation follows the style and format of the *American Economic Review*.

and Gas Journal, December 3, 1984). Additionally, the 1984 Republican Party platform called for the immediate repeal of the "confiscatory WPT, which has forced the American consumer to pay more for less and left us vulnerable to the energy and economic stranglehold of foreign producers" *(Oil Daily*, August 17, 1984).

In the midst of this public policy debate regarding the WPT, policy makers will need sound empirical analysis of the likely impacts involved with changing the phaseout schedule for the WPT. How would aggregate domestic U.S. petroleum production levels be affected by immediately repealing or indefinitely extending the WPT? How might U.S. crude oil imports be affected as a result? Would the corresponding changes in federal revenues be sizeable enough to warrant these changes? This dissertation will address these issues by providing quantitative assessments of these impacts on aggregate petroleum production from Texas, which is the single most important petroleum producing state in the U.S., producing 28.3% of total U.S. oil production in 1983. The impacts measured here for Texas will serve as approximate indicators of the production responses that could be expected from the nation as a whole.

A proper economic assessment of the effects to be caused by switching to a different WPT schedule will require a detailed analytical framework that incorporates all the relevant economic and policy factors influencing petroleum production by competitive Texas operators. This economic model of petroleum production should also not ignore the geophysical aspects of extraction from a petroleum reservoir, which are usually the focus of production analysis by petroleum reservoir engineers. In addition, the framework must be amenable to empirical implementation if it is to provide more than simply qualitative conclusions for policy makers as to the direction of the impact of policy changes.

In this introductory chapter, the outline of the empirical policy analysis to be performed in this dissertation will be presented. Some of the more important aspects of the analysis that will be covered by each chapter will also be discussed.

A. The Development of a Framework for Analysis

The first step in performing an empirical policy analysis is to select an appropriate modelling framework. In the case of modelling petroleum production, this selection process should begin by reviewing the existing body of literature on oil and gas production models. These models range from the decline curve methods employed by petroleum reservoir engineers for reserve estimation purposes to the purely theoretical intertemporal optimization models preferred by many economists for qualitative economic analysis. There are also several econometric petroleum production models in the literature, but they are usually specially designed for a specific quantitative analysis. The literature appears to lack detailed econometric models that consider both the engineering aspects of petroleum production and the important economic determinants of production from a base of existing reserves. As the range of existing petroleum production models are reviewed in Chapter II, the advantages and disadvantages of each as frameworks for empirical policy analysis will be noted for future use.

Chapter III will define the theoretical methodology that will be used to model production from a petroleum reserve base. The resulting framework will be an eclectic blend of the engineering and economic models reviewed in Chapter II that should reflect their strengths while avoiding their shortcomings. This hybrid engineering-economic model generalizes the basic exponential decline model of the engineering literature by adapting it to explicitly include all the relevant economic determinants of competitive petroleum production. Additionally, the resulting generalized petroleum production model will circumvent the restrictive assumptions of the basic exponential decline model by allowing for the continual augmentation of the petroleum reserve base via new infill drilling, the abandonment or re-opening of individual wells producing from the reserve base in response to economic variables, and the effects of state production prorationing on observed production rates. All this must be accomplished within a framework that will be easily amenable to empirical implementation.

Once this theoretical model has been developed, its ability to describe actual petroleum production data will be tested at a microeconomic level in Chapter IV. This analysis of individual petroleum reservoirs in Texas will be performed in order to verify the model's empirical validity at the micro level from which it was developed, before it is directly applied to a more aggregate, statewide analysis. Case studies of individual petroleum reservoirs are usually not publicly reported since they normally require access to proprietary data regarding operating costs and capacity-expanding activities. Fortunately, reservoir-specific data of this type was acquired, and will allow for the presentation of such individual reservoir studies while confirming the production modelling methodology of Chapter III at the same time.

B. Application of the Model to Aggregate Texas Data

The generalized petroleum production model that will be developed in Chapter III and empirically tested using individual reservoir data in Chapter IV will next be applied to an analysis of aggregate Texas petroleum production in Chapter V. The econometric procedures selected and utilized in Chapter IV will again be employed in Chapter V to model the aggregate production levels of conventional oil and non-associated gas in Texas, from which the aggregate production levels of associated gas and condensate in Texas will be estimated using aggregate gas-oil and condensate-gas production ratios, respectively. As a check on these estimated models' predictive power, they will be used to project remaining recoverable reserve levels as of year end 1983 for comparison with published reserve estimates.

These generalized production models will describe production from primary and secondary recovery methods, but will not capture the incremental oil production due to tertiary, or enhanced oil recovery (EOR) methods. The National Petroleum Council (NPC) projects that significant amounts of additional oil production in the U.S. will come from the application of EOR methods over the next 30 years. A large portion of this EOR activity will occur in Texas, and since the amounts of incremental EOR production levels in Texas up to this point in time have been negligible, a model of future EOR production levels cannot be estimated using historical production data. Instead, a simulation model of future EOR production in Texas will be developed from the national EOR production projections of the NPC. Once estimated, this equation describing aggregate EOR production in Texas will complete the model of aggregate Texas petroleum production from all sources.

The efforts of Chapters II through V will result in an econometric model capable of projecting aggregate Texas petroleum production from conventional petroleum reserves existing as of year end 1983. In order to simulate the future production levels that would occur if the reserve base were being constantly augmented by the new reserve additions generated from new drilling activity, this aggregate production model must be linked with an aggregate drilling model of Texas. Dale S. Bremmer (1985) has recently developed an econometric model of aggregate petroleum drilling in Texas that will be integrated with the production model developed here for joint simulation purposes.

Chapter VI examines the resulting integrated simulation model's respponse to exogenous economic or policy parameter shocks. Then, the linkages between its sectors describing exploratory and development drilling activity to the equations of the production model are outlined and explained. The integrated simulation model is then used to project the future aggregate levels of reserve additions that would augment the reserves existing as of year end 1983, as well as the future aggregate levels of production that would be forthcoming from that growing reserve base.

C. An Analysis of the Impact of the WPT

The joint simulation model of Chapter VI could then be used in Chapter VII to consider the issues raised at the start of this chapter - the impact of switching to an alternative WPT phaseout schedule. By simulating aggregate Texas petroleum production levels over the same 20 year period under each of three different WPT phaseout scenarios - immediate repeal, phaseout under current law and indefinite extension - the production effects of switching to either alternative WPT phaseout schedule from the one provided under current law can be determined. Given these production differences, it is possible to compare their value to the value of the associated changes in total WPT collections from Texas that would result from either policy switch. In this manner, the net welfare effects of either extreme case policy scenario can be estimated. The results of Chapter VII will then provide policy makers concerned with the future of the WPT with an indication of the possible range of impacts resulting from a change in its phaseout schedule as planned under current law.

The dissertation will then conclude in Chapter VIII by first summarizing the steps taken in developing the econometric model of aggregate Texas petroleum production and in applying it to an empirical policy analysis of the impact of the WPT in Texas. Second, the impacts of changing the WPT phaseout schedule that were calculated in Chapter VII will be used to consider the national policy implications for the WPT. Finally, after making some general conclusions and policy recommendations, suggestions will be made for extending the present analysis for further research.

CHAPTER II

REVIEW OF THE LITERATURE

The existing body of oil and gas production literature varies from the simple decline curve methods used by reservoir engineers to the purely theoretical intertemporal optimization techniques preferred by many economists. The reservoir engineer employs decline curve analysis to project future production rates from a petroleum property and thereby obtain an estimate of its remaining recoverable reserves. Economists usually model oil and gas as exhaustible resources, being primarily concerned with only qualitative determination of the effects on production arising from changes in current and expected future supply and demand conditions. Between these two extremes can be found either economic production models that are based on engineering decline curves, or econometric models that are especially designed for a specific quantitative policy analysis. However, what seems to be lacking in the literature are economic models that not only consider the engineering aspects of petroleum production, but also lend themselves to general examinations of policy changes within an econometric setting. The range of existing oil and gas production models will be reviewed in this chapter, carefully noting the advantages and shortcomings of each as tools for empirical analysis of policies such as the windfall profit tax.

A. Reservoir Engineering Decline Curve Models

Arthur W. McCray (1975) provides a clear presentation of the basic principles of reservoir engineering decline curve analysis as originally detailed by J. J. Arps (1945). In decline curve analysis, all production from a petroleum property is assumed to flow from a population of homogeneous wells, and can therefore be represented by the average production rate per well. Barring regulatory constraints, production rates from the representative average well are expected to decline over time, since the underground reservoir pressure that forces the oil or gas to the surface via the well bore is naturally diminished as cumulative production increases.

The most commonly used decline curve is the basic exponential model, which may be expressed as

$$q_t = q_o e^{-Dt}, \tag{2.1}$$

where q_t is the periodic production rate in time t from a petroleum property (or its average well), q_o is the initial production rate in time 0, D is the decline rate, and t is a time index.

Estimates of the remaining recoverable reserves associated with the property are made by integrating under the production path described by equation (2.1) until the point of economic exhaustion is reached. Economic exhaustion occurs when the average well's production rate has declined to the level of the economic limit, which is the rate of production at which its revenues net of royalties and taxes fail to meet the costs of its continued operation, so that it must be abandoned as unprofitable.

For any given economic limit (EL_t), the date of economic exhaustion (t^*) can be computed from (2.1) as

$$t^* = (-1/D)\ln(EL_t/q_o). \tag{2.2}$$

The amount of remaining economically recoverable reserves (hereinafter, simply reserves) associated with the property at time 0 (R_o) can then be determined by integrating (2.1) from 0 to t^* as follows:

$$R_o = \int_0^{t^*} q_t dt = \int_0^{t^*} q_o e^{-Dt} dt, \tag{2.3}$$

which yields

$$R_o = (q_o/D)(1-e^{-Dt^*}). \tag{2.4}$$

Alternatively, it may be assumed that production from the property will continue until all of the original oil or gas in place has been completely removed (i.e., until q_t approaches zero, so that physical exhaustion has occurred). This would imply that the time to that physical exhaustion would be of infinite length ($t^*=\infty$), as can be verified from (2.2) for an economic limit that approaches zero, which must be the case for production to continue indefinitely. In this instance, the amount of reserves associated with the property can be determined from (2.4) evaluated when $t^*=\infty$ as

$$R_o = (q_o/D). \tag{2.5}$$

Equation (2.5) implies that the physical amount of oil or gas in place can be estimated by only knowing the initial production rate q_o

and the decline rate D. Although (2.5) is frequently used by reservoir engineers to approximate economic reserves, the above derivation should make it clear that by doing so they ignore the role of economic factors in the decision to abandon a declining petroleum property.

In the more interesting case of a non-zero economic limit, changes in reserve estimates are brought about by changes in the economic limit for the average well, so that any production effects due to economic changes will only occur at the end of the property's economic life, either advancing or delaying the date of its economic exhaustion. Therefore, economic effects occur outside the structure of this basic model, being manifested as changes in the economic limit, which the modeller may or may not choose to overlook.

The usefulness of the basic exponential decline model as a tool for economic policy analysis depends upon the extent to which actual production conditions are approximated by the following three basic assumptions: (1) the petroleum property contains underground reserves of a known and fixed size, and this reserve base is not augmented by drilling activity; (2) all production flows from a population of homogeneous wells, and is therefore represented by the average well, so that economic exhaustion of all wells in the reserve base occurs simultaneously; and (3) there are no constraints on production from the property, or reserve base, so that all wells on the property can be operated at their maximum efficient rates

(MERs).[1] Therefore, observed production rates will exhibit a natural, unrestricted decline over time that can be estimated by the decline rate D. Unfortunately, all three of these assumptions are rarely appropriate for a petroleum reserve base of any size.

First, the amount of underground reserves associated with a petroleum property or reservoir is indeed subject to augmentation by new infill drilling activity. As the reserve base is expanded, future production rates must rise above the levels projected by earlier reserve estimates. There is no provision in the basic decline model for determining the extent to which reserve base augmentation impacts future production.

Second, the significant differences in age, depth, and strategic location among wells producing from any given reservoir will cause wide variations in average production rates per well and imply that sequential, rather than simultaneous, well abandonment and re-opening will occur with changes in the economic limit. Production effects from economic or policy changes can therefore occur at any point in the economic lifetime of the reserve base, with economic exhaustion occurring as the production rate of the last, best well has finally declined to reach the economic limit. By focusing on the average well, the basic decline model cannot reflect the heterogeneous nature of the reserve base and fails to properly capture the well-by-well abandonment decision.

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[1]The MER is defined as the highest possible rate of production that does not reduce ultimate recovery, and is based on geologic conditions rather than economics. For more see Erich W. Zimmerman (1957, p. 69).

Third and last, if there are any constraints on production, such as prorationing by regulatory agencies, observed production rates can remain virtually constant for several years. Ultimately, declining reservoir pressure will cause production rates to fall below the limits set by prorationing, so that the wells will eventually decline at their unrestricted, natural rate D. Without correcting for this prorationing effect, estimates of the natural decline rate D will be seriously biased downwards, with a corresponding bias in the estimates of remaining recoverable reserves. Reservoir engineers recognize this problem, and suggest that the decline model only be applied to production histories that have begun to show a decline (McCray, p. 312). However, this will only permit the estimation of a non-zero decline rate; it does not necessarily result in the accurate estimation of the common natural decline rate for the entire reserve base, since some of the wells in the reserve base may be constrained by their allowables even though basewide production is declining.

It must be concluded that, as it stands, the basic exponential decline model is not appropriate for the analysis of the impact of policy changes on production from a heterogeneous petroleum reserve base that has been subject to prorationing or augmented by infill drilling activity.

A simple extension of the decline curve analysis would allow the intercept term q_o or the decline rate D to vary with changes in the values of the economic parameters facing the operator of the reserve base. Referring to Figure 1, it can be seen that a change in q_o to, say, a higher level q_o' will simply shift the entire production path

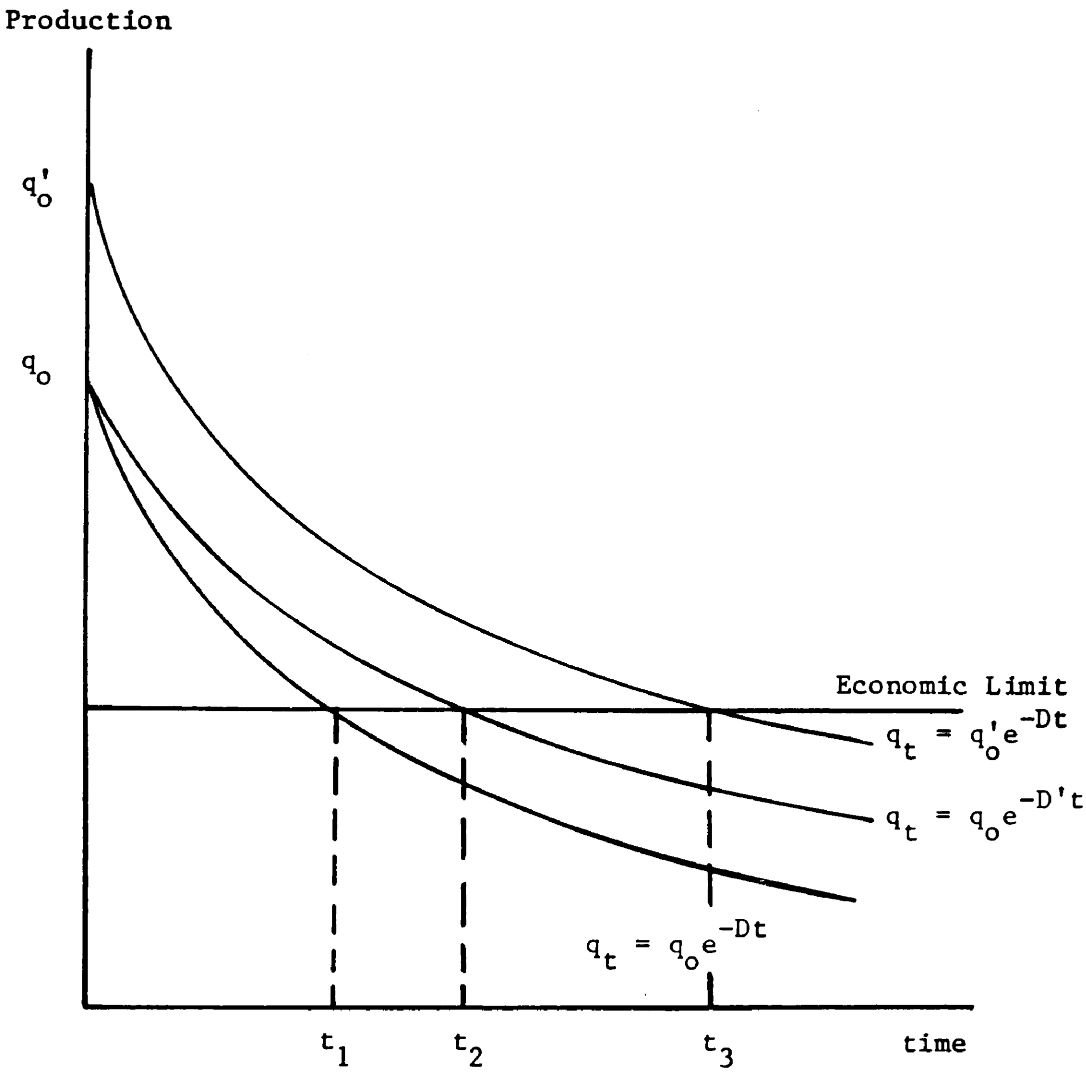

Figure 1. The Effects of Changes in the Parameters in The Basic Exponential Decline Model

upward by a constant amount. This extends the economic lifetime of the property from time t_1 to time t_3, while implied reserves are also increased.[2] Similarly, a change in D to a lower decline rate of D' will also increase production, but by an increasing rather than a constant amount, as the path rotates from the unchanged intercept q_o. The date of economic exhaustion is pushed back to time t_2 and implied total reserves are again increased.[3]

An example of one such extension is found in the work of Forrest Garb, et al. (1982), who assumed that the decline rate reacts proportionately to changes in net price to the operator. Specifically, they postulated that a new decline rate D' could be related to the previous decline rate D and the difference in net prices received by producers as

$$D' = D \exp\{-a \ln (P'/P)\}, \tag{2.6}$$

where a is a constant of proportionality, P' is the new higher net price, and P is the previous net price. The constant a was estimated

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[2] The change in implied reserves may be measured by the integral of the production path between the old and new dates of economic exhaustion. Assuming that the increase in q_o causes the date of economic exhaustion to be increased from time t_1 to time t_3, the implied change in reserves can be computed as

$$\int_0^{t_3} q_o' e^{-Dt} dt - \int_0^{t_1} q_o e^{-Dt} dt$$
$$= \{(q_o'-q_o)/-D\}(e^{-D(t_3-t_1)}-1).$$

[3] The change in implied reserves resulting from an decrease in D is computed analogously as

$$\int_0^{t_2} q_o e^{-D't} dt - \int_0^{t_1} q_o e^{-Dt}$$
$$= (q_o/D \cdot D')\{D(e^{-D't_2} -1) - D'(e^{-Dt_1} -1)\}.$$

from a closed-population stripper well analysis of production responses to increased net prices, and the resulting value of 2.12 was used to predict the production response from lower tier crude oil price deregulation. In their model, higher net prices will decrease the observed decline rate in the basic exponential model, extending the economic life of the reserve base and increasing the amount of recoverable reserves.

To conclude, as it is presently formulated in (2.1), the basic exponential decline model does not contain enough economic structure to be directly applicable to an economic analysis of the windfall profit tax. However, as the work of Garb, et al. shows, it is possible to explicitly introduce the economic determinants of petroleum production into the basic exponential decline model. In this way, the two parameters of the model - the initial production rate q_o and the decline rate D - can be affected by changes in the economic variables or tax rates facing the operator of the reserve base. As a result, estimated production rates and reserve levels would respond to changes in the economic and policy environment, thereby rendering the model more useful for policy analysis.

B. Economic Intertemporal Optimization Models

In the economics literature, oil and natural gas are usually considered to be exhaustible capital assets. Accordingly, observed production rates are assumed to be the result of an intertemporal, profit-maximizing extraction plan by the resource owner. Given the expected costs and benefits of various extraction plans, a production schedule is selected which maximizes the net present value of the exhaustible resource deposit, when discounted at the rate of return available from alternative investments of similar risk. This body of literature was pioneered by Harold Hotelling (1931), with new expositions or extensions first appearing in the 1960s (Richard L. Gordon (1967), Orris C. Herfindahl (1967), Vernon L. Smith (1968), Ronald G. Cummings (1969)). These were soon followed by a veritable avalanche of exhaustible resource-related articles that was fostered by the "energy crisis" of the 1970s. A partial listing of this recent literature includes the work of Robert M. Solow (1974), Partha S. Dasgupta and Geoffrey M. Heal (1974), Martin L. Weitzman (1976), and John M. Hartwick (1978). Excellent surveys of the exhaustible resource literature are found in Franklin M. Peterson and Anthony C. Fisher (1977) or Shantayanan Devarajan and Anthony C. Fisher (1981). A comprehensive modern treatment of the economics of exhaustible resources is given by Partha S. Dasgupta and Geoffrey M. Heal (1979).

The most fundamental principle of the exhaustible resource literature is that the net prices received by resource owners for their extracted output must grow over time in such a way as to provide them with a rate of return equivalent to that obtainable from any other capital asset of similar risk. This concept is known as "Hotelling's rule", and tells us the conditions under which extraction will occur from an exhaustible resource deposit of a known and fixed size. Under competitive ownership of the resource deposits, the net price received by resource owners, also known as the user cost of extracting one unit of the exhaustible stock, will be the market price less any taxes and marginal costs of extraction. For a monopolist, the relevant net return is the difference between marginal revenue and marginal extraction costs, or net marginal revenue. The implications for market prices depend upon the nature of the demand curve faced by resource owners and the way in which marginal extraction costs change as the resource stock is depleted. Whether the extracted output is sold competitively or by one monopolistic firm, it will always be optimal to extract from the lowest cost deposits available at each point in time (Dasgupta and Heal, 1979, p. 172; Wietzman; Hartwick).

Robert S. Pindyck's (1978) examination of the possible gains to OPEC from its monopoly position in an exhaustible resource market provides an example of the use of intertemporal optimization analysis. Pindyck treats OPEC as a monolithic monopolist that supplies all residual world oil demand that is not met by the competitive fringe of non-OPEC producers at any given world oil price. Being a monopolist, the quantity of OPEC oil demanded each year will clearly depend upon the price OPEC sets for its output. Their objective is then to select a price path (P_t, P_{t+1}, . . . , P_{t+N}) that will maximize the present value of the profits it will receive for selling what it extracts each year from its fixed amount of reserves. Formally, OPEC must choose P_t in each year to maximize the expression

(2.7) $$PV = \Sigma_{t=1}^{N} (1/(1+\delta)^t)[P_t - m/R_t]D_t,$$

where PV is the present value of its annual profits, N is the year of exhaustion of OPEC reserves, δ is the time rate of discount, m/R_t is the average production cost per barrel and D_t is the residual demand for OPEC's oil. The solution to this optimal control problem requires that prices follow the difference equation

$$P_t = (1+\delta)P_{t-1} - \delta m/R_{t-1}, \tag{2.8}$$

which reduces to Hotelling's rule when average production costs are constant. Initial price is then set to insure not only that the world oil market will clear in each year, but that OPEC's fixed reserve base will just be exhausted as the residual demand for its output goes to zero.

How useful, then is intertemporal optimization analysis for petroleum policy analysts? The answer to this question depends upon the type of policy analysis that is being performed. There are certainly many instances where an intertemporal optimization analysis of a policy change can provide valuable insights into the responses of oil and gas producers. For example, recognizing the role played by user costs in determining the timing of extraction from oil and gas reservoirs can be very helpful in analyzing the response of petroleum reserve base operators to changes in controlled price paths. This is the approach taken by Dwight R. Lee (1978) in his intertemporal examination of the impact on current oil production that could be expected from changes in controlled future oil price levels. Even though these future price control changes would not occur for several years, Lee showed how current user costs will respond to a change in future expected price levels, causing current oil extraction patterns to react accordingly, as oil producers reschedule their production to maximize their long run profits over time.

Another example of the beneficial employment of intertemporal optimization analysis is found in Geoffrey M. Heal's (1976) study of the effect of the presence of backstop technologies on current oil extraction patterns. A backstop technology is one that can provide virtually unlimited amounts of a substitute fuel for conventional oil at constant cost (e.g., nuclear fusion or shale oil). Using an optimal control framework, Heal demonstrates how conventional oil producers will plan the extraction of their initially lower cost fuel to insure that their reserves are just depleted as the market price reaches the level of unit cost for the backstop fuel. At that point, the backstop fuel industry comes into being, replacing the conventional oil industry.

The preceding discussion should make it clear that intertemporal optimization analysis can be entirely appropriate for analyzing many situations, particularly those that deal with changes in future price expectations. However, the question at hand is whether it would be appropriate for the present analysis of the impact of the windfall profit tax. Consider the competitive operator of a petroleum reserve base. His perception of both future demand conditions and future marginal costs of extraction will determine the path of user costs he will expect to receive. This expected path of user costs will play a significant role when he is making long term decisions about the level of productive capacity to install in his reserve base, whether in the form of new successful exploratory wells, new infill development wells, or secondary or enhanced recovery projects that may involve waterflooding, well fracturing or the injection of gas to increase recovery. The operator's desire to maximize his long run profits over time will influence his decisions regarding the optimal level of capacity to install at any point in time. Therefore, anyone attempting to model these long run decisions for policy analysis purposes should consider the impact of policy changes on the net present value expected from any capacity expansion project.

However, once the initial decision has been made to invest in a capacity expansion project (e.g., to drill a new well), the costs associated with the establishment of that new capacity are properly regarded as being sunk. Subsequently, the operator can only compare the marginal benefits and marginal costs of operating each component of the installed productive capacity (i.e., each well). At this point, intertemporal optimization analysis may not be very helpful in determining the optimal production schedule for an individual well. To see why not, the economic determinants of production from an individual well will now be considered in some detail.

For an individual well, real marginal operating costs per unit of output could be expected initially to remain fairly constant over a wide range of production rates. These marginal costs should rise sharply as the well's production rate approaches its maximum efficient rate (MER), giving the marginal operating cost curve (MOC) an inverted L-shape, as depicted in Figure 2. The range of possible production rates for an individual well at any point in time will be

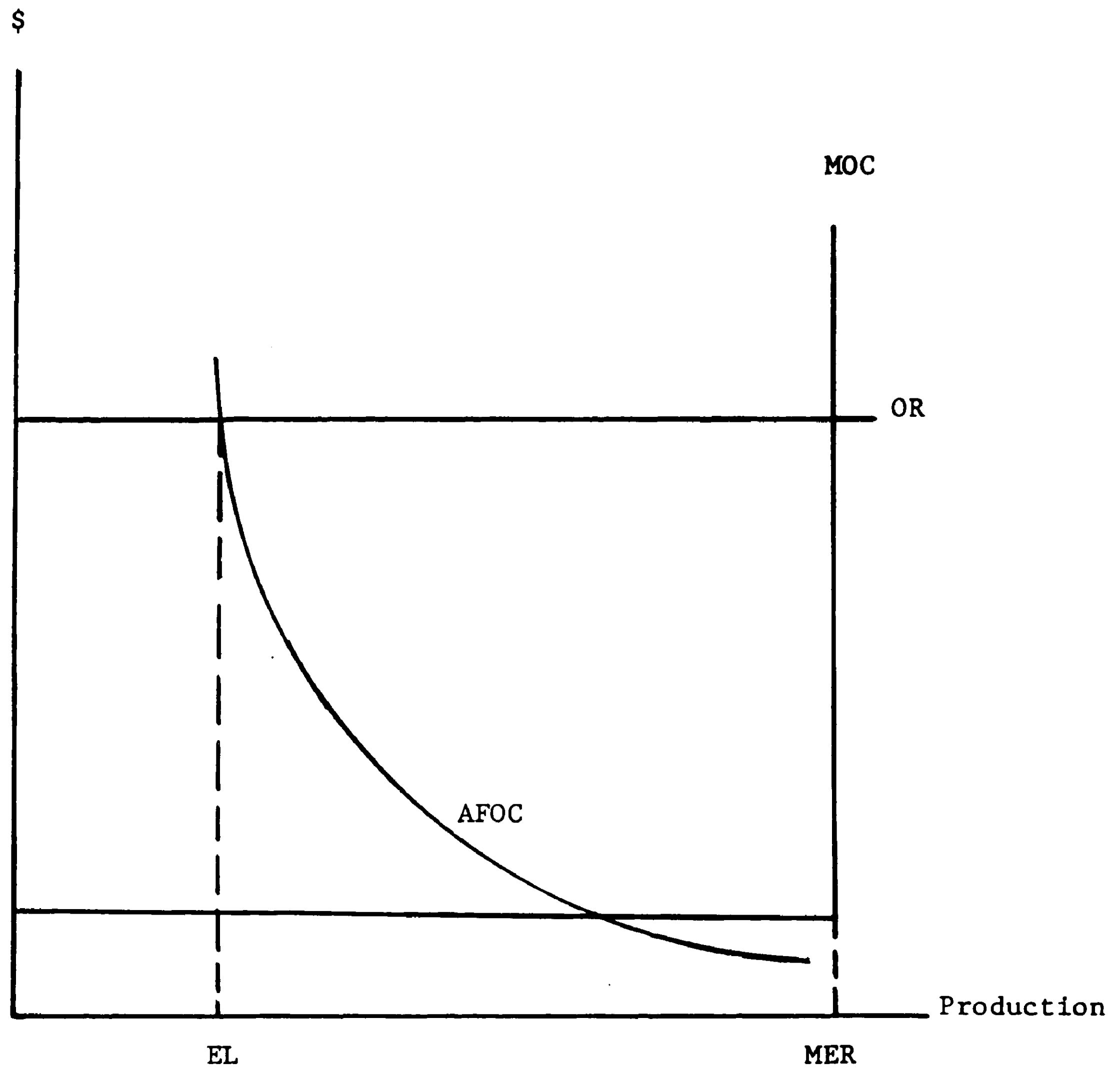

Figure 2. The Economics of Operating An Individual Well

a function of three variables: (1) the location of its MER, which defines the location of the vertical portion of the MOC curve; (2) the level of the horizontal portion of the MOC curve, which must lie at or below the level of real after-tax operating revenues per unit of output (OR) for any production to occur; and (3) the level of real average fixed operating costs of the well (AFOC), which is measured by the ratio of the real costs of operating the well that do not vary with output to the production rate of the well. Clearly, an operator of a reserve base will only be willing to install new productive capacity in the form of a new well if he expects real after-tax operating revenues per unit to be high enough to allow him to operate the well at a production rate that will cover both his fixed and variable operating costs as well as recapture his initial capacity investment and provide him with a normal profit. In terms of Figure 2, this means the OR curve must intersect the MOC curve on its vertical portion for several periods.

Assuming that the costs associated with operating a well are entirely composed of fixed costs that do not vary with the level of output as long as the well is producing below its MER, the horizontal portion of the MOC curve will coincide with the production rate axis in Figure 2. If these fixed operating costs do not change in real terms over time, the AFOC curve will have the shape of a rectangular hyperbola as depicted in Figure 2. For a competitive well operator, the OR curve should be linear and perfectly horizontal, shifting upward or downward over time as economic conditions and tax laws change. The intersection of the OR curve with the AFOC curve will then define the economic limit for the well (EL). It can quickly be seen that the economic limit will rise if the OR curve shifts downward, or fall if the OR curve shifts upward, just as intuition would suggest.

Increasing cumulative production causes reductions in the underground pressure of the reservoir from which the well is extracting, steadily reducing the well's MER over time and thereby progressively shifting the vertical portion of the MOC curve leftward. As the MER falls, the highest possible production rate of the well will also fall, causing the well to exhibit a natural decline. At any rate, production from the well will eventually decline sufficiently to reach the economic limit (EL), at which time the well will be abandoned as unprofitable to operate. The well will remain abandoned unless some change occurs in either the OR curve or the AFOC curve that causes the EL to be reduced below its previous level. In this case, the well will be re-opened and produced until its MER has once again declined to the level of the new, lower economic limit, when it will be abandoned a second time.

To reiterate, once a well has been drilled, the operator can only decide the rate at which he will extract and sell the fixed amount of reserves associated with it in each period. The optimal extraction pattern will be the one that maximizes the discounted present value of all current and future profits expected from the operation of the well, as the theory of exhaustible resources tells us. As long as the well is never operated at production rates exceeding its MER, it can safely be assumed that the total amount of recoverable reserves will be invariant to the extraction pattern selected, given enough time.

Since future profits must be discounted at a positive rate, if the well operator expects future demand or policy conditions to cause a constant or lower level for the OR curve, it will always be optimal for him to operate the well at its highest possible rate in each period, whether this is the MER or the maximum allowable rate set by the regulatory agency. However, should the well operator expect the OR curve to rise to a higher level sometime in the future, it is possible that he might be willing to defer near term production to later periods when discounted expected profits are higher. Given the assumptions about costs represented in Figure 2, it will always be optimal to operate the well at its MER if it is being operated at all, since each additional unit of output produced above the economic limit but below the MER has a positive marginal profit. Therefore, any production deferral will take the form of temporarily shutting-in the well for one or more periods as the well operator waits to begin production in the period in which the OR curve attains its new higher level.

Is such production deferral likely to occur? This issue may be considered by calculating the percentage changes in market price that would be required to make it profitable for the well operator to defer the production profile from a well. Consider the operator of a hypothetical oil well that exhibits a 10.5% decline rate, so that the fixed amount of reserves associated with the well will be essentially gone after twenty consecutive years of production at its MER.[4] For simplicity of exposition, it is assumed that he uses a real discount rate of 5%, constant real fixed operating costs are $50 per day, real marginal operating costs per barrel are negligible , there are no production or income taxes, the royalty rate is 0.125 and the real market price of oil is a constant $30 per barrel. If the operator of this mythical oil well were to expect the constant real market price of oil to increase in any one of those twenty years, he can respond in one of two ways. He can either defer commencement of the twenty year production profile to the year in which the expected price change will occur, or he can simply begin production as soon as possible.

For a fixed reserve base of 100,000 barrels of oil, the discounted present value of all real profits from this hypothetical oil well comes to $1,686,087 when no deferral of the twenty year production profile occurs (i.e., production takes place at the MER for twenty consecutive years beginning in year 1). Table 1 shows the minimum percentage increases in the constant real oil price that would have to be expected to make it worthwhile for the well operator to defer commencement of production to the year of the price change. These percentage price increases can be interpreted as those necessary to make the expected present value from the well the same, whether deferral to that year occurs or not. For example, Table 1 indicates that deferral of the twenty year production profile to the

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[4]This exponential production profile is taken from Bremmer for a representative oil well not under prorationing.

Table 1. Necessary Percentage Price Increases to Defer Production from a Hypothetical Oil Well for One to Twenty Years

Year Production Begins	Necessary Percentage Price Increase
1	0.0
2	39.0
3	42.4
4	45.8
5	49.4
6	53.3
7	57.4
8	61.7
9	66.3
10	71.1
11	76.3
12	81.7
13	87.5
14	93.5
15	99.8
16	106.6
17	113.6
18	121.1
19	128.9
20	137.0

third through the twenty-third years after year 0 would not be profitable without at least a 42.4% one-time increase in the real market price of oil being expected to occur in the third year.

Looking at the percentage price increases in Table 1, it must be asked whether oil producers can be expected to anticipate price changes of this magnitude. There is a difference between the likelihood of world oil prices rising by such magnitudes and the likelihood of oil producers anticipating such price increases. For purposes of analyzing the production decision at the level of the individual well, the latter question is the relevant one.

According to the theory of exhaustible resources, current oil prices will reflect producer's future price expectations through the path of user costs. If producers in the aggregate were to expect future price jumps of the size calculated here, some reflection of those expectations would show up in current prices as well operators held back from current production. If current prices do indeed rise in response to these future price expectations as theory suggests, then the percentage price increases of Table 1 necessary to induce well operators to temporarily shut-in their wells would not be forthcoming. This implies that well operators would not expect it to be profitable to defer commencement of their remaining production; consequently, they would begin producing their wells today at the highest possible rates.

To summarize this lengthy digression on the economics of operating an individual well, once a well has been drilled and production from it becomes possible, the well operator will commence production at the earliest possible date at the highest possible rate of production until the well eventually declines to reach its economic limit, when it is abandoned. As a result, there will be very little room for variation in individual well production rates in response to economic or policy changes, so that the operator of a reserve base containing many wells can only control his basewide production rates in the short run by abandoning or re-opening individual wells. In the long run, he can control basewide production rates by deciding whether or not to expand his productive capacity by adding new wells to his reserve base. Intertemporal optimization analysis can be useful in studying the impact of policy changes on the long run capacity decision; however, the limited possibilities for short run production re-scheduling appear to limit its usefulness in analyzing the economics of the individual well. Thus for the present purposes of analyzing the impact of the windfall profit tax on production from existing wells, an intertemporal optimization approach would only make the analysis unnecessarily complicated and more difficult to implement empirically.

C. Engineering-Based Economic Models

The oil and gas production modelling literature contains several different economic models that consider the engineering aspects of petroleum production in their theoretical frameworks, some of which are intended for quantitative policy analysis and some of which are not.

Bradley's Model

One of the first economic studies to generalize the basic exponential decline curve was Paul G. Bradley's (1967) analysis of long run supply costs for major crude-exporting regions. Using the concept of the representative well, Bradley's analysis focuses on the output of entire individual reservoirs, rather than that of individual wells, since he does not believe that the exponential decline relationship holds at the well level. He recognizes that wide variations in individual well production rates will render the basic exponential decline model inapplicable, ultimately requiring each well to be analyzed separately (Bradley, p. 48). However, Bradley feels that one should consider the output of individual reservoirs as "discrete increments", since focusing on the output of individual wells would be "vastly more cumbersome" and not clearly relevant, appealing only to the pure theorist (Bradley, p. 15). Obviously, individual well analysis is unnecessary if wells tend to homogeneous; unfortunately this is not usually the case, as was explained in the foregoing discussion of the engineering literature.

To account for the abandonment decision on existing wells, the average production rate ($\bar{q}$) of all the wells in a given reservoir is modelled as a linear function of the constant decline rate ($d>0$) with respect to cumulative reservoir output (Q) (instead of with respect to time) and the ratio (U) of the number of producing wells observed in the reservoir in each period to the maximum number of producing wells observed in the reservoir since its initial development. Formally, his model is written as

$$\bar{q} = a - dQ + gsU + htU, \tag{2.9}$$

where a is a positive constant indicating the initial average well production rate, g and h are slope coefficients, s is a dummy variable that has a value of 1 for all periods prior to the one in which the maximum number of producing wells is observed for the reservoir, and t is a dummy variable with a value of 1 for all other periods. Changes in the number of producing wells will cause this ratio to, in general, rise in the early stages of the reservoir's life, and later to fall as abandonment of the marginal wells in the reservoir occurs. By modelling the average production rate per producing well, abandonment of the least productive wells can actually increase the average rate, while re-opening of marginal wells can reduce it. Modelling total reservoir production levels with any degree of accuracy using his framework will then also require very precise estimation of the number of producing wells.

While it is important to consider the distribution of reservoir production across all producing wells, there needs to be a way to do so without introducing the additional, and possibly quite substantial margin for error in prediction suggested by Bradley's formulation. Not surprisingly, Bradley assumes that all development drilling activity is completed after the first three years of reservoir production, and simply holds the producing well population constant at the highest value observed during those first three years. This simplification eliminates much of the complexity that Bradley was trying to capture, and implicitly makes the number of producing wells an exogenous variable, rather than an endogenous variable, as it should be.

Bradley also considered the impact of capacity expansion on observed production levels. Expansion of the productive capacity of a reserve base occasioned by adding new reserves was referred to as expansion at the extensive margin, and would increase both current and future production. Capacity expansion at the intensive margin involves drilling additional wells to increase current production rates without increasing the size of the reserve base. In Bradley's view, infill drilling in producing reservoirs was strictly capacity expansion of the latter sort, although he admitted that this was not necessarily always the case (Bradley, p. 33). He felt that total recovery from a reservoir was independent of the number of producing wells that were drilled, so that capacity expansion at the intensive margin could only serve to accelerate the time to exhaustion. Observed rates of production decline were thus postulated to vary directly with the ratio of new productive capacity installed in each period to the level of known reserves in that period. As a result, augmentation of the reserve base can only arise from new discoveries due to exploratory drilling activity; development drilling activity will negatively affect future production levels in favor of increased current production. A potential objection to Bradley's model of petroleum production is that it ought to allow for augmentation of the reserve base by infill drilling as well as by exploratory drilling.

Some insights into Bradley's position that the ultimate recovery from a reservoir, and hence the amount of remaining reserves associated with it, cannot be augmented by increases in the well population or by new infill development drilling can be gained from his characterization of the exponential decline relationship at the reservoir level. Since Bradley assumes that the number of producing wells stays constant at some level N, he can delete the last two terms in (2.9), leaving a model of the form

$$\bar{q} = a - dQ, \tag{2.10}$$

where $\bar{q}$, a, d, and Q are as previously defined. Total production from the reservoir (q) can be determined by multiplying the average production rate per well ($\bar{q}$) times the number of producing wells (N) as follows:

$$q = N\bar{q} = Na - NdQ. \tag{2.11}$$

Recognizing that $q=\partial Q/\partial t$, (2.11) is seen as a first order differential equation that can be solved to obtain an expression for Q. From Alpha C. Chiang (1974), the general solution for (2.11) will be of the form

$$Q = Ae^{-Ndt} + a/d. \tag{2.12}$$

Since Q = A + a/d when t=0, the arbitrary constant A can be found equal to Q - a/d, which is substituted into (2.12) to give the definite solution

$$Q = (a/d)(1 - e^{-Ndt}). \tag{2.13}$$

Equation (2.13) provides an expression for the level of cumulative output from the reservoir since production first began, as of time t. Evaluating this expression at the time of economic exhaustion (t^*) will give an expression for ultimate recovery from the reservoir, designated as Q^*, which is

$$(2.14) \qquad Q^* = (a/d)(1 - e^{-Ndt^*}).$$

To determine the effect of changes in the constant well population on ultimate recovery, the partial derivative of Q^* with respect to N is computed as

$$(2.15) \qquad \partial Q^*/\partial N = ae^{-Ndt^*}(t^* + (\partial t^*/\partial N)N).$$

This partial derivative will only have a value of zero, as Bradley assumes that it does, when the sum $(t^* + (\partial t^*/\partial N)N)$ is exactly zero.

A necessary condition for this to occur is that an increase in the number of producing wells must reduce the value of t^*, i.e., shorten the production interval and accelerate the time to economic exhaustion, so that $(\partial t^*/\partial N)$ will be negative. This is necessary because t^* and N must be positive if production is ever to occur. Given that, a sufficient condition for ultimate recovery to remain unchanged is that the elasticity of the time to exhaustion (t^*) with respect to the number of producing wells (N) must have a value of -1. This condition can be shown from the requirement that the sum $(t^* + (\partial t^*/\partial N)N)$ be equal to zero, which can be rearranged to yield

$$(2.16) \qquad (\partial t^*/\partial N)(N/t^*) = -1.$$

It has yet to be demonstrated that the economics of petroleum production require that every one percent increase in the producing well population will decrease the production interval by one percent. Without this condition being satisfied, Bradley's production model will be inconsistent with his characterization of the impact of infill development drilling in existing reservoirs on ultimate recovery.

Bradley goes on to conclude that "any price-induced changes in the productive life of the field will only occur when output rates are already so low that the volume of crude affected is a negligible fraction of cumulative reservoir output" (Bradley, p. 26). The implication of the foregoing statement is that changes in tax rates and controlled price levels should have no significant effects on the fraction of the unextracted reserve base that will be produced. This explains why Bradley did not attempt to fully capture the impact of policy changes on existing reserves in his model.

Therefore, even though Bradley's approach was innovative in its application of the concepts of engineering decline to economic modelling of petroleum production, it would be inappropriate for an analysis of the windfall profit tax. This conclusion is reached because it fails to fully and consistently account for all the relevant economic aspects involved in operating a petroleum reserve base - specifically the impacts on production attributable to augmentation of the reserve base via infill drilling and to the abandonment or re-opening of individual marginal wells.

Kuller and Cummings' Model

Robert G. Kuller and Ronald G. Cummings (1974) were among the first economists to explicitly consider the geophysical aspects of petroleum production in an optimal control framework. They employ intertemporal optimization analysis in their dynamic model of the optimal exploitation of a reservoir of fixed size by n competitive firms. Their specification of the production path incorporates the key role played by reservoir pressure in determining both observed production rates and ultimate recovery. The amount of reservoir pressure places an upper bound on the rate of production at any point in time, and is determined by current and past rates of extraction and investment in pressure maintenance equipment. Therefore, increases in current production rates will reduce ultimate recovery, i.e., the fraction of original oil in place that is ultimately recovered, if this reduction is not at least partially mitigated by timely investment in pressure maintenance equipment.

Taking account of the cost interdependencies inherent in such a common pool situation and the user costs associated with exhausting a petroleum resource deposit makes their model theoretically complete. Unfortunately, as a result it can only provide qualitative comparisons of optimal investment and production rates for a competitively operated reservoir under various assumptions about policy variables or prices. A representative conclusion of their model is that "policies which tend to reduce marginal after-tax profits (for example, the imposition of a severance tax) may be expected to reduce production and investment rates" (Kuller and

Cummings, p. 75). Quantitative analysis of exogenous economic shocks or policy changes is not possible with their model, since even though it breaks important ground in the modelling of petroleum production in its explicit treatment of reservoir pressure as an endogenous variable to the reservoir operator, it is not easily implemented empirically.

Kalter et al.'s Model

Somewhat more helpful is the analytical framework developed by Robert J. Kalter, et al. (1975) for the quantitative examination of the effects of alternative federal leasing strategies on private petroleum production from the Outer Continental Shelf. Like Bradley, they utilize the engineering exponential decline relationship to describe the time path of production. After explicitly depicting the after-tax revenue stream to the sole producer of a reservoir of fixed and certain size, they use a computerized algorithm to determine the optimal values of q_o (the amount of productive capacity installed in time 0) and D (the observed rate of production decline) that will provide the lease operator with a desired after-tax rate of return. It is assumed that D is entirely within the control of the producer, and can be set at any rate that is necessary to earn the desired return, without any geotechnical constraints. User costs and common pool externalities are again ignored as empirically insignificant in this framework, just as they were in Bradley's work.

While the Kalter model does allow for the quantitative measurement of policy effects on the observed rate of production and the amount of the initial investment in productive capacity in new reservoirs, it does not clearly specify how the optimal values of the two parameters of the exponential decline model, q_o and D, are affected by exogenous shocks. Even though the well population is not explicitly modelled in this framework, any policy effects on basewide production are not delayed until all the wells in the reserve base are abandoned at once, since the producer is assumed to be able to completely determine the observed rate of production decline from a reserve base containing a fixed amount of productive capacity, represented by q_o. Although the operator can always reduce the production rates of his existing producing wells or even abandon some of them to reduce his total output, it may not always be possible for him to increase his total reservoir output sufficiently to maintain the desired after-tax rate of return. This is because the production rates of the individual wells are bounded from above by their MERs, and no new wells can be added to the reservoir's productive capacity by assumption. Additionally, the inevitable natural decline of all the wells that were initially installed in the reservoir as part of the fixed amount of productive capacity will reduce observed production rates in a regular manner without the addition of new reserves or new productive capacity in the form of new producing wells. The degree of flexibility in total reservoir production rates assumed by the Kalter model is not consistent with their direct application of the basic exponential decline model, suggesting that their approach be rejected for the policy analysis at hand.

D. Econometric Production Models

Petroleum production models that are representative of the primarily econometrically based frameworks can be found in the efforts of Paul A. MacAvoy and Robert S. Pindyck (1973, 1975) and Patricia Rice and V. Kerry Smith (1977). These econometric models differ widely in their specifications, illustrating that once the modeller leaves the rather narrow strictures of engineering decline curve analysis, there are few, if any structural constraints on the model, giving rise to the great diversity of the models seen in this literature.

MacAvoy and Pindyck's Model

In their analysis of alternative regulatory policies for natural gas, MacAvoy and Pindyck (1973) chose to simply model annual U.S. natural gas production (q_t) as a linear function of the natural logarithm of the average wellhead value of natural gas ($\ln(P_t)$) and the stock of reserves in year t (R_t). Their gas production model can be formally expressed as

$$q_t = a_o + a_1 \ln(P_t) + a_2 R_t. \tag{2.17}$$

In this framework, observed nationwide gas production is, in the long run, assumed to be indirectly affected by drilling activity through changes in reserve levels, while average wellhead value changes are the vehicle through which short run production from existing reserves is directly affected.

What are the economic implications of the MacAvoy-Pindyck model? From (2.17), the partial derivative of production with respect to average wellhead value, or price, is found to be

$$\partial q_t/\partial P_t = a_1/P_t. \tag{2.18}$$

Using data for the entire U.S. from 1965 to 1971 (excluding the Louisiana South region), MacAvoy and Pindyck (1973) estimated the value of a_1 to be 247,550 when production is measured in millions of cubic feet (MMCF). The 1983 level of natural gas production from this subsection of the U.S. is reported by the U.S. Department of Energy (1984) to be 11,655 billion cubic feet (BCF). Putting the two together allows for the calculation of the price elasticity of production out of reserves implied by the MacAvoy-Pindyck model as follows:

$$(\partial q_t/\partial P_t)(P_t/q_t) = a_1/q_t = 0.02. \tag{2.19}$$

This price elasticity for most of aggregate U.S. natural gas production out of reserves seems extremely low, and implies that production out of reserves would be essentially unaffected by changes in the economic limit.

Equation (2.17) also provides some information about the implied reserves-to-production (R/P) ratio for the MacAvoy-Pindyck model. As they correctly point out (1973, p. 471), the R/P ratio will be the reciprocal of the constant decline rate in the basic exponential decline model when the time to exhaustion is infinite. This is easily verified from (2.5) by rearranging it in the form

(2.20) $$q_o/R_o = 1/D,$$

which gives the R/P ratio in time 0. Since the basic exponential decline model with an infinite production horizon is the theoretical basis for their development of (2.17), their model can be examined to determine whether its implied R/P ratio is indeed essentially constant as suggested by (2.20). Dividing R_t by (2.17) yields the R/P ratio in the MacAvoy-Pindyck framework for the year t,

(2.21) $$R_t/q_t = R_t/(a_o + a_1 \ln(P_t) + a_2 R_t),$$

which does not appear to be constant over time in this formulation.

The elasticity of production with respect to reserves can provide another check on the constancy of the R/P ratio in their model. A production model that exhibits a constant R/P ratio over time implies that

(2.22) $$R_t/q_t = k,$$

where k is a positive constant. Solving (2.22) for q_t gives

(2.23) $$q_t = R_t/k,$$

from which the partial derivative of q_t with respect to R_t is easily seen to be 1/k. The elasticity of production with respect to reserves in such a model follows as

(2.24) $$(\partial q_t/\partial R_t)(R_t/q_t) = (1/k)k = 1.$$

From (2.17), the partial derivative of q_t with respect to R_t will be

(2.25) $$\partial q_t/\partial R_t = a_2,$$

which is estimated to have a value of 0.024 (MacAvoy and Pindyck, 1973, p. 479). The elasticity of production with respect to reserves in the MacAvoy-Pindyck model is then computed to be

(2.26) $$(\partial q_t/\partial R_t)(R_t/q_t) = a_2R_t/(a_o+a_1\ln(P_t)+a_2R_t),$$

which will be equal to one only if $(a_o+a_1\ln(P_t))$ should sum to zero. Using the 1983 U.S. average wellhead value for natural gas of $2.60 per thousand cubic feet (Texas Railroad Commission, 1983) and the MacAvoy-Pindyck estimates of a_o (1,905,600) and a_1 (247,550), this sum has a value of 2,142,136.86, making the elasticity's value fall below 1. Going one step further, the estimate of total gas reserves for the U.S. excluding Louisiana South for 1983 of 166,343 BCF as reported by the U.S. Department of Energy (DOE) can be used to compute a_2R_t=3,992,232. This gives an elasticity of 0.65, which indicates that their production model will not exhibit a constant R/P ratio over time. Instead, since every 10% increase in the level of reserves will only increase long run production by 6.5%, their estimated model will have an R/P ratio that rises significantly over time. Such a property for a model of a non-renewable resource is implausible, and there is no empirical support for systematically rising R/P ratios over time.

The model specification of (2.17) was undoubtedly selected for its simplicity and its ability to track observed nationwide gas production rates over the sample period. However, the structure of their production model does not allow for general policy analysis, such as the impact of tax rate changes, since it relies solely upon changes in the average wellhead value of gas, rather than the economic limit, to determine the effects on production from existing reserves. By altering the net cash flow to the well opaerator, changes in production tax rates will affect the individual well economic limit and therefore should influence the abandonment decision on existing reserves. By relying upon the average value of gas at the wellhead as the only relevant economic variable determining the rate of production from existing reserves, the abandonment decision is not fully considered, since what is most important in the determination of production from existing reserves is the individual well economic limit. Focusing on average price changes is an acceptable alternative only if one is willing to assume that all of the other components of net cash flow at the well level will remain unchanged over time. However, from the size of the average price elasticity estimated in (2.17) and examined above, it seems that even if one is only concerned with the response of production from reserves to average price changes, the MacAvoy-Pindyck framework will not indicate much of an impact. While it is desirable to employ the methods of econometrics to develop a petroleum production model that will have significant empirical validity, if the model is to be useful for policy analysis, it should retain more of the structural determinants of production and should also exhibit the engineering property of an essentially constant R/P ratio over time.

Rice and Smith's Model

Rice and Smith's econometric model of aggregate U.S. oil production differs markedly from that of MacAvoy and Pindyck. By assuming that petroleum reserve levels can be considered to be optimal holdings of a capital stock, they are able to treat the decision to maintain a desired level of reserves as being made simultaneously with the decision to produce from those reserves. Therefore, they only need to model either the production decision or the reserve level decision, since a model explaining either decision will necessarily also explain the other. This simultaneity can be seen from the following perpetual inventory accounting identity:

$$Q_t = R_{t-1} - R_t + A_t, \tag{2.27}$$

which relates annual petroleum production (Q_t) to the difference between last year's and this year's reserve levels (R_{t-1}-R_t) and any new reserve additions made during the year (A_t). Rather than modelling production from reserves directly as most modellers have done, Rice and Smith opt to model reserve levels directly and model new reserve additions by the drilling sector of their model, leaving annual oil production to be indirectly determined as the residual term in (2.27).

The level of reserves in each year (R_t) is directly modelled as a simple linear function of last period's reserve level (R_{t-1}), last period's gross revenues from the sale of the extracted reserves (S_{t-1}), and their definition of the user cost of the reserve base (U_t), which follows the investment model originated by Dale S.

Jorgenson (1963) and extended to account for tax policy by Robert M. Coen (1968). Aside from a dummy variable used to adjust for a one-time jump in the reserve data series, their equation modelling reserve levels may be written as

$$R_t = a_o + a_1 R_{t-1} + a_2 S_{t-1} + a_3 U_t. \tag{2.28}$$

Their formulation of the user cost of reserves (U_t) is presented as

$$U_t = \{r(1-tx)+h(1-tx-tv)\}/(1-t+tp), \tag{2.29}$$

where r is the interest rate, t is the tax rate, x is the depreciation rate, h is the rate of reserve depreciation that can be immediately expensed, v is the fraction of reserve investment expenditures that must be depreciated for tax purposes and p is the percentage depletion allowance rate. Since the drilling sector of their model can only explain new reserve additions, the implications of their approach for annual production levels will depend upon their model of annual reserve levels. If annual production levels are to be modelled as the residual term in (2.29), then the determinants of annual reserve levels in their model must include those variables that determine the levels of production out of those reserves. Presumably, these factors are accounted for by including last year's gross sales revenues or the user cost of reserves. These two terms in the reserve model must therefore be examined more closely to see exactly what economic determinants of production they encompass.

First of all, including last year's gross revenues from the sales of extracted reserves does not capture all of the economics regarding the production decision of the individual well. Given the geotechnical constraints on the well as represented by its MER, the production decision at the level of the individual well depends upon real after-tax operating revenues as well as real fixed and variable operating costs. There is no consideration in the lagged gross revenues term of the roles played by production taxes and costs or the MER in determining production from reserves; as a result, the abandonment decision is not properly captured by their model.

Second, it is not clear from their presentation that their formulation of the user cost of reserves adequately picks up all the economic determinants of production that are not present in the lagged gross revenues term. Their user cost of reserves is simply given in a footnote, without any justification, so that the reader can only guess as to their specification of the optimal reserve level problem that produced such a result. Although they do define the variables included in the user cost term, they fail to explain precisely how each variable is to be interpreted. This leaves some doubt whether all of the relevant economic and policy variables influencing production were properly included in the objective function and constraints of their optimal reserve level problem.

Even if it can be assumed that their user cost term does contain all the necessary economic determinants of production, it remains to be explained how the user cost of a capital stock will determine the optimal level of that capital stock. In the investment literature as developed by Jorgenson, the user cost of capital determines the optimal level of gross investment in the capital stock, not the optimal level of the capital stock. The rate of change in the capital stock over time is then determined as the difference between gross investment and replacement investment, or depreciation, in each period. In turn, this replacement investment is usually modelled as some constant fraction of the previous period's capital stock. In the Rice and Smith framework, gross investment corresponds to new reserve additions, which are modelled independently of the user cost of reserves by the drilling sector of the model. Replacement investment, or depreciation of the capital stock, should correspond to production out of reserves, but it is not modelled as a constant percentage of last year's reserve level; rather, it is modelled as the residual term in (2.27).

A more straightforward application of the investment literature would allow the user cost of reserves to directly influence the levels of new reserve additions. Production levels over time would then be separately modelled according to the relevant engineering constraints of natural decline. This approach would leave changes in the level of reserves over time to be determined as the residual term in (2.27), rather than the production level. As a result, the economic determinants of the drilling and production sectors of the petroleum industry could be directly introduced into the model and explicitly examined in a policy analysis.

As the Rice and Smith production model is currently formulated, it could only be used to analyze the impact of policy changes on production through their impact on reserve level changes; impacts on production out of existing reserves cannot be separately considered.

In other words, once the decision is made to add to reserves via drilling activity, there are no direct price effects on subsequent production from those reserves. This implies that quantitative measurement of tax effects on the abandonment decision for existing wells would not be possible using their model.

E. Summary and Conclusions

In reviewing the literature on the modelling of oil and gas production in this chapter, a variety of approaches were found, each with some appealing attributes. Nevertheless, none of the existing approaches were sufficiently well-suited to be applied directly to a quantitative analysis of the impact of the windfall profit tax. The engineering models do a good job of capturing the geophysical aspects of petroleum production, but are only completely applicable under a set of restrictive assumptions and do not fully consider the economic determinants of production. Economic models can generally capture some of the important economic aspects of the exploitation of oil and gas deposits, but they frequently ignore or slight either the technical constraints on petroleum production or the economics of the abandonment decision for individual wells, and often cannot be easily implemented for empirical policy analysis. The econometric models which were designed for quantitative analysis also failed to provide satisfactory theoretical frameworks that considered all the important economic aspects and engineering properties of petroleum production.

The next chapter will be devoted to developing an engineering-based economic model of petroleum production that will consider all the relevant technical and economic determinants of production in a framework that will be suitable for quantitatively measuring the impact of any general policy change. This framework should retain the fundamental engineering principles of petroleum production over time that are embodied in the basic exponential decline model, yet it must be more generally applicable to actual production conditions. Additionally, the model should be driven by the economic limit in order to properly capture the economics of the abandonment decision on existing wells. By drawing upon the strengths of the many different modelling approaches reviewed in this chapter, it is hoped that an eclectic methodology can be found that will have both considerable theoretical appeal and empirical validity. The empirical validity of this approach will then be considered in later chapters.

CHAPTER III

AN ENGINEERING-ECONOMIC MODEL OF PETROLEUM PRODUCTION

The purpose of this chapter is to devise a theoretical model of oil and gas production that incorporates the essential elements of petroleum engineering and economic factors yet is suitable for quantitative policy analysis. Keeping in mind the need for a framework that can be empirically estimated, this development begins with the underlying structure of the reservoir engineering models reviewed in the previous chapter. As a consequence, the model developed here will be based on generally accepted reservoir engineering principles regarding the tendency for petroleum production rates to decline as cumulative production increases. However, engineering models cannot be directly applied to economic policy analysis, since they do not allow for (i) augmentation of the installed productive capacity of the reserve base by new drilling activity, (ii) sequential abandonment and re-opening of individual producing wells in the reserve base, and (iii) exogenous restrictions on individual well periodic production rates, such as prorationing by state regulatory agencies.

In an attempt to generalize the basic exponential decline model commonly used by reservoir engineers, this chapter shows how it is possible to incorporate the effects of augmentation of the productive capacity of the reserve base, the abandonment decision, and production prorationing into the simple engineering framework of equation (2.1). Once the model has been fully developed in this chapter, it will be applied to an analysis of reservoir level data in the next chapter as a test of the empirical validity of this generalized engineering-economic approach to modelling petroleum production.

A. The Theoretical Foundation for the Model

As a starting point, the basic exponential decline model from Chapter II is restated here as

(3.1) $$q_t = q_o e^{-Dt},$$

where q_t is the periodic production rate in time t from a petroleum reservoir or property, q_o is the initial production rate in time 0, D is the decline rate, and t is a time index. For the purposes intended here, this simple engineering model will need to be modified in three main respects, so that the two structural parameters of the model, q_o and D, will be influenced by the economic determinants of petroleum production.

First, the rate at which new productive capacity is added to the reserve base will be allowed to affect the rate at which observed production from the reserve base declines over time. In this manner, the relative magnitudes of the opposing effects of augmentation and natural depletion of the reserve base will determine whether observed production rates will rise, fall, or remain constant. Allowing the rate of capacity augmentation to affect observed production rates will also provide a linkage between exploratory and development drilling activity and production for simulation purposes.

Second, the economics of the operation of individual wells in the reserve base will be explicitly incorporated into the basic exponential decline model. This will be accomplished by allowing the initial production rate q_o to change in response to changes in the single most important determinant of individual well operation, the economic limit. This also provides a way in which the percentage of installed wells in the reserve base that are profitable to operate can change as the economic limit does, effectively shifting the exponential production path upward or downward as a result.

Third, this modified production model must somehow allow for the accurate estimation of the geotechnically determined, natural decline rate D that would only be observed if all of the wells in the reserve base were being operated at their maximum efficient rates (MERs). Just as capacity augmentation can prevent observed reserve base production rates from exhibiting this natural decline, prorationing of production from individual wells by imposing a maximum allowable production rate below the MER can flatten observed production rates. Estimates of the natural decline rate D that are made without correcting for either of these effects will be biased towards zero, jeopardizing the model's ability to accurately project remaining reserves.

In the following sections, each of these three requirements will be considered separately, explaining how each can be met by relatively straightforward modifications to the basic model of (3.1). In this way, the fundamental properties of the reservoir engineering model will be retained while constructing a petroleum production model that properly responds to economic and policy changes.

B. The Effects of Augmentation of Installed Productive Capacity

The first proposed modification to the basic exponential model is to include the effects on observed reserve base production rates induced by growth in the installed productive capacity of that base. Observed production rates will be modelled as the net result of production-enhancing augmentation of the reserve base and the natural decline expected from each producing well in the base over time, rather than as a constant basewide decline rate, as in (3.1). Referring to (3.1), the exponent of the base of the natural logarithm will be changed to

(3.2) $$I_t - Dt,$$

where I_t is an index of additions of new productive capacity to the base in the form of new reserves since a specified base period, when I_t=1.0.

Inserting equation (3.2) into (3.2), the model can now be written as

(3.3) $$q_t = q_o e^{I_t - Dt}.$$

According to this formulation, a 10% growth in the capacity augmentation index I_t would just negate the effects of a 10% natural decline rate, so that observed reserve base production would not decline at all.[1]

This specification will allow for a more accurate measurement of the natural decline rate D (which is assumed to be the same for all wells in the reserve base), as it does not attribute increases in the productive capacity of the reserve base to a reduction in that natural rate. Proper estimation of the natural decline rate is crucial for correctly projecting ultimate recoverable reserves. Inclusion of the capacity augmentation index also provides a way in which projected additions to the reserve base from exploratory and development drilling activity can be integrated into the model, as will be done in Chapter VI for the policy simulations in Chapter VII.

One simple specification of the capacity augmentation index would set its value equal to 1.0 in the base period and increment that value in each period by a measure of the size of new reserve additions during each period relative to the level of reserves at the end of the previous period. Thus, I_t would be expressed as

$$(3.4) \qquad I_t = I_{t-1} + (1/n)\Sigma_{i=0}^{n} (A_{t-i}/R_{t-1-i}),$$

where A_t gives the volume of new reserve additions to the base during period t, and R_{t-1} gives, in the same units, the level of the reserve base at the end of the period t-1. The values of their ratio are then used in a moving average of length n+1 to allow current

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[1]For q_o and D constant,

$$\frac{\partial q_t}{\partial t} = q_o e^{I_t - Dt} \left(\frac{\partial I_t}{\partial t} - D\right) \{\gtreqless\} \; 0 \text{ as } \left(\frac{\partial I_t}{\partial t} - D\right) \{\gtreqless\} \; 0.$$

production rates to be gradually affected by current and previous periods' capacity augmentation, since observed periodic patterns of reserve additions are very erratic and often are not responsible for significant increases in reserve base production until several periods after their inclusion in the base. The length of this moving average will be determined empirically, in conjunction with the estimation of the entire model in later chapters.

Incorporating the effects of augmentation of the installed productive capacity of the reserve base within the basic exponential decline model was also attempted by Bradley, as may be recalled from Chapter II. Notice that the capacity augmentation index I_t proposed here is very similar to Bradley's ratio of additions to capacity during period t to the size of the reserve base at the start of time t. However, in Bradley's model that ratio helps to determine the magnitude of the overall observed decline rate he wishes to estimate; in this model, these opposing effects are separated in order to estimate the natural decline rate one would expect to observe if there were no new capacity augmentation. As a result, the model developed here will be better able to properly estimate the natural decline rate. The impact of capacity augmentation is then identified separately, so that production from existing reserves can be independently analyzed as well as production from a reserve base that responds to exploratory and development drilling activity.

C. Modelling the Abandonment Decision

Perhaps the most challenging and interesting problem in modelling petroleum production is the proper modelling of the abandonment decision. It is no accident that previous researchers have tended to overlook the abandonment process in their modelling efforts. The approach taken here is to directly introduce the abandonment decision into the model through the concept of economic capacity. This is accomplished by changing the intercept term q_o representing the initial production rate in the basic exponential decline model to

(3.5) $$q_o = q_o^* EC_t,$$

where q_o^* is simply a new constant term and EC_t is an index of the fraction of installed productive capacity of the reserve base that is economically profitable to operate, or what shall be called its *economic capacity*. This index provides a means whereby the amount of remaining reserves that are economically profitable to recover can rise or fall with changes in the economic limit for an individual well. The economic capacity of the reserve base falls as the production rates of individual wells in the reserve base decline and fall below the economic limit, causing them to be abandoned, reducing both current and future basewide production rates. For a given well population, the level of economic capacity will eventually fall to zero, as all the wells in the reserve base must eventually become unprofitable to operate and therefore be abandoned. Thus, by introducing an index of economic capacity, the level of basewide production can actually become zero, whereas in the basic exponential decline model of (3.1), production remains positive indefinitely. Using (3.3) and (3.5) the proposed model is now seen as

(3.6) $$q_t = q_o^* EC_t e^{I_t - Dt}.$$

Notice that in effect, changes in economic capacity will shift the decline curve upward or downward in the same manner as did changes in the intercept term q_o, which were analyzed in Figure 1.

The economic capacity of the reserve base in period t (EC_t) depends upon the level of the economic limit for the individual well (EL_t, which is assumed to be the same for all individual wells in the base), as well as the distribution of total reserve base production across all wells (Δ_t). This relationship can be expressed as

(3.7) $$EC_t = f(EL_t, \Delta_t).$$

To be more specific, the relevant distribution is the one that ranks the percentage contributions to total production made by each well in the reserve base according to the individual production rates, because this will identify the percentage of installed productive capacity that will be affected when the economic limit moves from one level to another. The nature of this production distribution will largely be a function of the geologic characteristics of the reserve base, and will rarely be uniform across all wells, as individual well production rates usually differ widely within any given reserve base. Accordingly, changes in the economic limit will affect only those wells whose potential production rates lie within the range of that change. The shape of this distribution must therefore be modelled so that individual wells will be affected according to their heterogeneous nature. It should also be noted that even with no change in the economic limit, the natural decline of every well in the reserve base will eventually bring each to the point of economic exhaustion. To put it another way, the distribution of production across wells will steadily shift downwards over time, implying that modelling its location will also be important if economic capacity is to be properly measured.

Modelling the Production Distribution

Properly modelling the distribution of production from a reserve base according to the productive capacities of its wells calls for the estimation of a function describing the shape of the distribution that would result if the economic limit fell to zero. This would then allow for the computation of the percentage of installed productive capacity that would be economically profitable to operate at any economic limit above a production rate of zero, by simply moving the economic limit upwards from zero to determine the level of economic capacity for any minimum production rate. Unfortunately, economic limits of zero are not observed under positive well operating costs. As will be shown, this problem may be circumvented by assuming that the shape of the production distribution does not change over time, but that its location does. The distribution may then be modelled under the economic limit of a single period, with separate consideration of the way in which its location changes over time.

The first step in modelling the production distribution is to arrange all the wells in the reserve base according to their observed production rates in a given period, going from lowest to highest. After calculating each well's percentage contribution to total reserve base production, those percentages can be accumlated to obtain the percentage of total production coming from wells producing at or below each periodic production rate. An estimated function, Δ_t, which fits this cumulative percentage distribution and relates cumulative percentages to periodic production rates will form the basis for the measurement of economic capacity.

Figure 3 shows a hypothetical production distribution (Δ_t) constructed as suggested above. The most prolific well in the reserve base has an observed production rate in period t of Q_H; the least productive well's observed rate is Q_L, which must be at least as high as the economic limit in period t, EL_0. Economic capacity, being measured relative to the installed productive capacity in period t, assumes a value of 100%, since none of the producing wells observed in period t exhibit production rates below EL_0. Should the economic limit instantaneously rise to a higher level EL_1, all wells with production rates below Q_K would be immediately abandoned as unprofitable. As a result, the lowest observed production rate moves upward along the distribution Δ_t, reducing the economic capacity to (100-K)%, since K% of the productive capacity observed to be installed in period t would now have become unprofitable to operate.

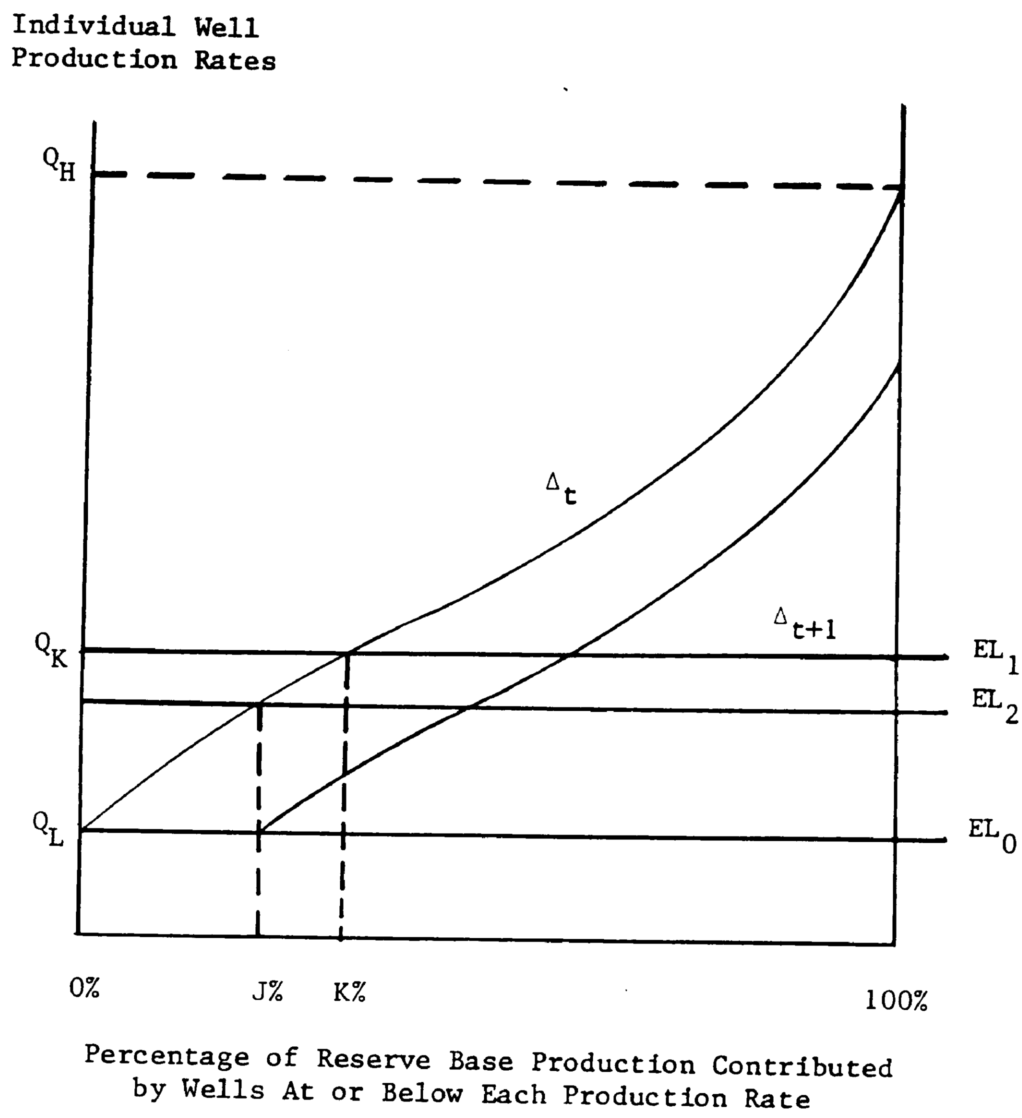

Figure 3. The Measurement of Economic Capacity

The economic capacity will change over time due to the natural decline of each well in addition to in response to changes in the economic limit. Therefore, if the economic limit does not change from period t to t+1, economic capacity does not remain unchanged, since the natural decline in each well's production during that period will imply that the distribution will shift downward to Δ_{t+1}, as seen in Figure 3, leaving only (100-J)% of the installed productive capacity profitable to operate. By knowing the natural decline rate D applicable to all the wells in the distribution, and ignoring any capacity augmentation, this downward shift in the location of Δ could be expressed as $\Delta_t = (1-D)\Delta_{t-1}$. Alternatively, this downward shift of the distribution could be treated as an upward shift of the economic limit to EL_2 along the original distribution Δ_t. If the economic limit is made to shift upward at the same rate at which the distribution Δ is shifting downward, similar results can be obtained with respect to the measurement of economic capacity.

The economic capacity index EC_t is therefore constructed by subtracting from 100% the percentage of the installed productive capacity of the reserve base that falls below the economic limit in each period. That percentage can be determined by evaluating the estimated production distribution function at the production rate associated with the economic limit, given the location of the distribution for that period. However, the individual well economic limit cannot simply be used to determine the level of economic capacity in each period. This is because the natural decline of every well in the production distribution will shift it downward at the rate D in each period, regardless of the economic limit (ignoring for the moment any prorationing constraints). Of course, this natural decline may be partially mitigated by the addition of new productive capacity to the reserve base, so the basewide production distribution will only decline at the rate $(\partial I_t/\partial t)$-D. As suggested above, this downward shift in the distribution may be treated as an upward shift in the economic limit by forcing the individual well economic limit to rise at the same rate at which the distribution should be declining.

Therefore, the basewide economic limit B_t is defined as the production rate at which the distribution will be evaluated in period t. This rate will take the form

$$B_t = EL_t e^{D(t-\bar{t})-(I_t-I_{\bar{t}})}, \tag{3.8}$$

where EL_t is the economic limit in period t, while $\bar{t}$ and $I_{\bar{t}}$ are the values of the time index and capacity augmentation index for the period in which the production distribution was estimated. The basewide economic limit in each period is determined by causing the individual well economic limit to rise at the same rate at which production from the reserve base is declining. The exponent in (3.8) is therefore the negative of the modified exponent in (3.2), I_t-Dt, except that the values of the time and capacity augmentation indexes are reduced by their levels in the period in which the production distribution was estimated. This insures that when the production distribution is evaluated in that period, the basewide economic limit will be the same as the common individual well economic limit.

However, as time passes and new productive capacity is installed, the location of the production distribution changes, and the effects of this movement in its location are captured by the addition of the exponential growth term to the individual well economic limit in (3.8).

Prior to the specification of the functional form that will be selected for the production distribution in Chapter IV, at this point the economic capacity index (EC_t) can only be expressed as a function of the basewide economic limit (B_t) and the estimated parameters (Γ) of the production distribution (Δ_t) in the form

$$EC_t = 100 - g(B_t,\Gamma). \tag{3.9}$$

This type of modelling procedure stands in marked contrast to the usual practice of assuming that all wells in the reserve base are homogeneous, having identical production rates equal to the average rate per well for the entire base.[2] As mentioned in Chapter II, the obvious implication of such an approach is that all of the wells in the base will reach the economic limit simultaneously, shutting the entire base in at once. Should the economic limit subsequently fall, all the wells would be re-opened at the same time. In terms of economic capacity, the fraction of installed productive capacity that is economically profitable to operate can only be either zero or unity under this approach, with production from the reserve base

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[2]Homogeneity of all wells in the reserve base appears to be assumed by virtually all other petroleum production models reviewed in Chapter II, with the exception of Bradley's.

being affected only at the end of the average well's economic life.

By focusing on the individual marginal well, the economics of the abandonment decision can be explicitly incorporated into an engineering-based model of production from a heterogeneous reserve base. As will be demonstrated, this proposed methodology is much less cumbersome to employ than Bradley thought it would have to be. The degree of micro-analytic detail contained in this model will provide a more complete quantitative analysis of the impact of policies such as the windfall profit tax on petroleum production.

Calculation of the Economic Limit

Before leaving this section, it is appropriate to outline the calculation of the individual well economic limit (EL_t). The economic limit is determined as the rate of production that equates net cash flow from an individual well to the incremental costs associated with its continued operation. The first step is to specify the nature of the net cash flow to the operator of an individual oil well or gas well.

For the operator of an oil well, net oil revenues per barrel of oil produced in year t (ONR_t) are defined as

$$ONR_t = P_t^o\{(1-\rho_t)(1-s_t^o)-v_t^o\}, \tag{3.10}$$

where P_t^o is the market price of oil, ρ_t is the royalty rate, s_t^o is the state oil severance tax rate, and v_t^o is the local ad valorem tax rate on oil. Net associated gas revenues per barrel of oil produced in year t ($AGNR_t$) are similarly defined as

(3.11) $$AGNR_t = P_t^g(1-\rho_t)(1-s_t^g)GOR^t,$$

where P_t^g is the market price of natural gas, s_t^g is the state gas severance tax rate, and GOR_t gives the gas-oil production ratio in thousands of cubic feet (MCF) of associated gas per barrel of oil produced. It is assumed that all local ad valorem oil well taxation is based upon gross revenues from oil alone.

Windfall profit taxes per barrel of oil produced during year t (WPT_t^o) are calculated as

(3.12) $$WPT_t^o = \omega_t(P_t^o-P^bADJ_t)(1-s_t^o)(1-\rho_t),$$

where ω_t is the windfall profit tax rate, P^b is the base price, and ADJ_t is the inflation adjustment factor. The windfall profit tax classifies crude oil and condensate production into one of three tiers, each with a separate tax rate. For this analysis, the appropriate classification is Tier 2, which includes oil produced from stripper wells (i.e., from wells producing less than 10 barrels of oil a day). It is assumed that the marginal well considered here is located on a IRS defined tax property containing other producing wells, which, for tax purposes, has an overall net income sufficiently high to exceed the 90% of net income limitation on windfall profit taxation.[3] Should the inflation adjustment factor

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[3] Should all wells be treated as separate taxable properties by the IRS, the 90% net income limitation would exempt these marginal wells from the windfall profit tax. However, the IRS definition of separate taxable properties usually includes several producing wells, especially in partially unitized reservoirs, making it unlikely that the 90% net income limitation will apply for most wells.

(ADJ_t) rise sufficiently to cause the so-called windfall profit (P_t^o-p^bADJ_t) to become non-positive, windfall profit taxes are set to zero.

Federal income taxes for an oil well in year t (FIT_t^o) will be calculated as

$$FIT_t^o = f_t\{(ONR_t+AGNR_t-WPT_t^o)q_t^o-C_t^o\}, \tag{3.13}$$

where f_t is the maximum corporate federal income tax rate, q_t^o is the average oil production rate in BPD, and C_t^o is the average daily cost of continuing to operate an oil well. It is therefore assumed that all such directly attributable operating costs could be completely avoided if the well were shut-in, and those costs are expensed and fully deducted from gross income in the year in which they occur. The percentage depletion allowance is not included in this calculation, since it cannot be taken if its value exceeds 50% of taxable income, and there is no taxable income on a marginal well producing just above its economic limit.

Finally, net cash flow from an oil well in year t (NCF_t^o) can be written as

$$NCF_t^o = (ONR_t+AGNR_t-WPT_t^o)q_t^o-FIT_t^o-C_t^o, \tag{3.14}$$

so that the economic limit for an oil well (EL_t^o) can be determined by solving (3.14) for the value of q_t^o that makes NCF_t^o=0. Substituting (3.10) through (3.13) into (3.14) yields, after some algebraic manipulation,

$$EL_t^o = \bar{q}_t^o = C_t^o/\{P_t^o((1-\rho_t)(1-s_t^o)-v_t^o) \tag{3.15}$$

$$+P^g_t(1-\rho_t)(1-s^g_t)GOR_t-\omega_t(P^o_t-P^bADJ_t)$$
$$(1-s^o_t)(1-\rho_t)\}.$$

Notice that the federal income tax rate (f_t) falls out of the solution $\bar{q}^o_t$. This makes sense in light of the fact that taxable income disappears for the marginal well.

Examining (3.15) reveals that there are a number of factors that determine the level of the economic limit for an individual oil well. The level of average daily operating costs (C^o_t) positively influences the economic limit, as it logically should; higher operating costs raise the minimum production rate needed to cover those costs. Increases in the market price of oil (P^o_t) or gas (P^g_t) or the gas-oil production ratio (GOR_t) will reduce the economic limit, all other things equal. Similarly, increases in any of the production tax rates (s^o_t, s^g_t, v^o_t, ω_t) will increase the economic limit, just as will increases in the royalty rate (ρ_t). All of the relevant economic and policy variables that affect the operation of an individual oil well are thereby included in our production model, since they appear in the individual well economic limit, which determines the level of economic capacity.

Turning to an individual (non-associated) gas well, net gas revenues per MCF of gas produced in year t (GNR_t) are

$$(3.16) \qquad GNR_t = P^g_t\{(1-\rho_t)(1-s^g_t)-v^g_t\},$$

where v^g_t is the local gas ad valorem tax rate, again assuming that all local ad valorem gas well taxation is based solely upon gross gas revenues. Net condensate revenues (if any condensate is found with the gas) per MCF of gas produced in year t (CNR_t) are

$$CNR_t = P_t^o(1-\rho_t)(1-s_t^o)CGR_t, \tag{3.17}$$

where CGR_t gives the condensate-gas production ratio in barrels of condensate per MCF of gas produced. Windfall profit taxes on the condensate and federal income taxes on the well are calculated analogously to those for the oil well so that net cash flow from a (non-associated) gas well in year t (NCF_t^g) can be written as

$$NCF_t^g = (GNR_t+CNR_t-WPT_t^g)q_t^g-FIT_t^g-c_t^g, \tag{3.18}$$

where WPT_t^g shows the windfall profit taxes on any condensate production, q_t^g is the average gas production rate in MCF per day, FIT_t^g is the federal income taxation on the gas well, and C_t^g is the average daily operating cost of the gas well.

Just as before, the economic limit for a gas well (EL_t^g) will be the q_t^g that makes $NCF_t^g=0$, or,

$$\begin{aligned} EL_t^g = \bar{q}_t^g = C_t^g/\{&P_t^g((1-\rho_t)(1-s_t^g)-v_t^g) \\ &+P_t^o(1-\rho_t)(1-s_t^o)CGR_t-\omega_t(P_t^o-P^bADJ_t) \\ &(1-s_t^o)(1-\rho_t)CGR_t\}. \end{aligned} \tag{3.19}$$

From (3.19) it can be seen that the economic limit for an individual non-associated gas well also accounts for all of the relevant economic and policy variables that determine the rate of production of the well. As before with the oil well, higher levels of operating costs (C_t^g), production tax rates (s_t^g, s_t^o, v_t^g, ω_t) and the royalty rate (ρ_t) will increase the economic limit. Likewise, higher gas or oil prices (P_t^g, P_t^o) will reduce the economic limit, just as will a higher condensate-gas production ratio (CGR_t).

This section concludes by noting that the incorporation of the individual well economic limit into the proposed petroleum production model allows the levels of production from individual previously-installed wells in the reserve base to be explicitly affected by any economic or policy changes. As a result, this model should provide a more explicit framework for an empirical analysis of the windfall profit tax.

D. Incorporating the Effects of Prorationing

The third proposed modification to the basic exponential decline model becomes necessary when production from individual wells in the reserve base is exogenously restricted below their MERs. This is the case when state regulatory agencies impose production prorationing in the form of maximum legal well production rates, or "allowables", usually in the name of conservation of the state's natural resources. The production histories from oil and gas reservoirs in Texas that will be used for estimation of the model in Chapters IV and V contain considerable evidence of such prorationing during the sample period. As a measure of the extent of prorationing of oil and gas production in Texas since 1960, Table 2 presents the market demand factors for the state as a whole for the years 1960 through 1974. These market demand factors represent the percentage of the total number of producing days in the year for which oil and gas lease operators in Texas were allowed to operate their wells. Although this factor

Table 2. Market Demand Factors in Texas for 1960 through 1974

Year	Market Demand Factor
1960	28.5
1961	27.7
1962	26.6
1963	28.0
1964	28.2
1965	28.8
1966	33.8
1967	40.7
1968	44.9
1969	52.4
1970	71.6
1971	72.5
1972	94.1
1973	100.0
1974	100.0

reached the maximum level of 100% in April 1972, never to fall below it again, this did not mean that every individual oil or gas well in the state could thereafter be operated at its MER on every producing day. After April 1972 production allowables were still assigned at the level of the individual well, and in many cases continued to fall below the MER.

The basic reason for concern over the constraining of individual well production rates below their MERs lies with the fact that such restrictions tend to flatten observed production rates. This makes it difficult to obtain an estimate of the unrestricted, natural decline rate D for a reserve base containing restricted wells.

As a solution, the reservoir engineering literature suggests that the modeller omit from his sample those wells that are known to have been constrained by their allowables diuring the sample period, or at least to restrict the sample period to periods that exhibit a decline in production. These procedures will allow for the estimation of a non-zero decline rate, but will ignore the natural decline rate of many of the wells in a highly constrained reserve base or will produce estimates that are biased towards zero.

The solution proposed here is to make a change in the way in which time is measured for a reserve base containing restricted wells. Instead of letting the time index increment by one full unit in each period as is usually done, a modified time index will be used that begins with a value of 1.0 in the base period and increments in each period by that fraction of total reserve base production that is contributed by wells unconstrained during that period. For example, should all the wells in the reserve base be constrained during a period, that fraction will be zero, and the modified time index will not increment at all, as desired, since observed production rates would be flat. If there are no constrained wells during a period, the fraction becomes unity and the modified time index increments by one full unit, just as the usual time index would. In effect, the value of the modified time index in each period will represent the number of unrestricted periods that have passed since the base period, and will thereby allow for the unbiased estimation of the natural decline rate D.

The modified time index will take the form

$$\tau_t = \tau_{t-1} + (1-\alpha_{t-1}), \tag{3.20}$$

where τ_t is the modified time index for the period t, and α_{t-1} is the fraction of total reserve base production coming from wells operating under constraint during the previous period.

Creation of the modified time index τ_t will necessitate the determination of the fraction of reserve base production in each period that comes from wells that were operating under constraint of their production allowables. The actual computation of the modified time index will be described more fully along with the estimation of the complete model in Chapters IV and V.

E. A Complete Modified Oil Production Model

The generalization of the basic exponential decline model proposed in the preceding sections yields a compact expression for the petroleum production time path that is both relatively simple to estimate and at the same time extremely rich in economic and engineering structure. The generalized model for oil production from a reserve base containing only oil wells can now be written, using (3.19), as

$$q_t^o = q_o^* EC_t^o e^{I_t^o - D\tau_t^o}. \tag{3.21}$$

This model meets all the requirements set forth at the beginning of this chapter. It accounts for augmentation of the productive capacity of the reserve base through the index of new reserve additions I_t. Implicit in the economic capacity index EC_t is an underlying production distribution (Δ_t) which recognizes the heterogeneities among wells. Also, the effects of production constraints are included through the modified time index τ_t.

The effects of changes in exogenous parameters such as price, taxes or even allowable schedules can be analyzed within this framework either through changes in the economic capacity of the reserve base (resulting from changes in the economic limit), changes in the rate at which new productive capacity is added to the reserve base (resulting from changes in the rate of new reserve additions from exploratory or development drilling activity), or changes in the rate at which natural decline affects the individual wells (resulting from changes in the fraction of production constrained by allowable, a_t).

Notice that observed basewide production rates for the complete model will be endogenous. This is because they will depend not only upon the exogenous natural decline rate for individual wells (measured by D), but also upon the degree of utilization of the installed productive capacity of the base (measured by EC_t) and the rate of growth of that capacity (measured by I_t). An operator of a petroleum reserve base is therefore assumed to be able to control his basewide production rates in such a way as to maximize his real after-tax profits, as is traditionally assumed in the exhaustible resource literature.

F. A Non-Associated Gas Production Model

Equation (3.21) is appropriate for oil production from reserve bases containing only oil wells, but modelling gas production from a reserve base containing only non-associated gas wells poses a further complication. This is because natural gas that is produced today but cannot be sold today to buyers that are connected to the seller's producing wellhead by pipeline cannot be easily stored and sold in future periods or to other buyers not connected by pipeline. Therefore, observed non-associated gas production rates will depend upon the willingness of pipeline operators or other gas buyers who are directly or indirectly connected to the wellhead to commit to purchase all or part of a gas well's potential output, known as its deliverability. As a result, the demand side of the gas market can act as a constraint on observed production rates and must be considered in modelling those rates. Furthermore, the distribution of gas purchases across all producing wells in a state is often under the control of the state oil and gas regulatory agency, which parcels out the available demand for gas along political lines. Nominations for purchases of gas not already dedicated to long-term contractual commitments are distributed to gas producers across the state to insure that every gas leaseholder in the state is able to sell some of his gas to a pipeline operator or other buyer, even under depressed demand conditions. While this procedure is followed to protect leaseholder equity as the state regulatory agency sees it, it does not guarantee that the least-cost wells will be produced first as it spreads the effects of reduced gas demand over all producers of non-dedicated gas.

As a measure of the gas market demand conditions for an individual gas well in a reserve base containing only gas wells for any given period, one could examine the percentage of basewide deliverability that is actually produced. Since this percentage will not necessarily equal 100%, the focus should be on deviations from the value it attains in periods of high gas demand, when most of the gas wells in the reserve base are being operated at their MERs. Accordingly, a gas market demand index, q_t^d, is defined to be the ratio of basewide production (q_t^g) as a percentage of basewide deliverability in period t (D_t) to the same percentage in a selected period of high gas demand (q_{high}^g/D_{high}), or

(3.22) $$q_t^d = (q_t^g/D_t)/(q_{high}^g/D_{high}).$$

This index q_t^d is then included in the theoretical model as a shift parameter similar to economic capacity.

Equation (3.21) can then be re-written for the case of gas production from a reserve base made up of non-associated gas wells as

$$q_t^g = q_o^* EC_t^g q_t^d e^{I_t^g - D\tau_t^g}. \tag{3.23}$$

G. Examination of the Model

At this point the impact of exogenous shocks on the generalized petroleum production model can be qualitatively assessed. Using (3.21) and (3.23), the production of oil or non-associated gas, respectively, changes over time as follows:

$$(\partial q_t^o/\partial t)/q_t^o = (\partial EC_t^o/\partial t)(1/EC_t^o) + \{(\partial I_t^o/\partial t) - D(\partial \tau_t^o/\partial t)\} \tag{3.24a}$$

and

$$(\partial q_t^g/\partial t)/q_t^g = (\partial EC_t^g/\partial t)(1/EC_t^g) + (\partial q_t^d/\partial t)(1/q_t^d) + \{(\partial I_t^g/\partial t) - D(\partial \tau_t^g/\partial t)\}. \tag{3.24b}$$

Equations (3.24a) and (3.24b) describe the observed proportionate rates of change in oil and gas production over time, which depend upon the level of economic capacity, the growth rate of productive capacity ($\partial I_t/\partial t$) and the rate of natural decline ($D(\partial \tau_t/\partial t)$). Note that in the basic exponential decline model of (3.1), EC_t and q_t^d have implicit constant values of unity; consequently, no growth in the productive capacity or in the size of the reserve base is allowed

$(\partial I_t/\partial t)$, and time is measured in the usual way, assuming no prorationing constraints, so that $(\partial\tau_t/\partial t)=1$. As a result, the observed proportionate time rate of change for that model simply equals D, the unconstrained rate of natural decline.

The change in economic capacity over time can be decomposed from (3.8) and (3.9) to yield

$$(3.25) \qquad \partial EC_t/\partial t = -(\partial g/\partial B_t)(\partial B_t/\partial t)$$
$$= -(\partial g/\partial B_t)(e^{D(\tau_t-\tau_{\bar{t}})-(I_t-I_{\bar{t}})}) \cdot$$
$$\{(\partial EL_t/\partial t)+EL_t(D(\partial\tau_t/\partial t)-(\partial I_t/\partial t))\}$$

where $(\partial g/\partial B_t)$ must be positive, since increases in the basewide economic limit B_t will reduce the basewide level of economic capacity EC_t. With a constant economic limit $((\partial EC_t/\partial t)=0)$, economic capacity (and therefore production) will decline unless the growth rate of productive capacity is sufficiently high to overwhelm the natural decline. Of course, an increase in the individual well economic limit (EL_t) over time will also serve to decrease the level of economic capacity.

Changes in gas market demand conditions over time are not explicitly modelled here, as they depend upon the exogenous actions of the state regulatory agency in the assignment of gas nominations across all gas wells in the state.

Equation (3.4) provides the basis for a discrete approximation to the instantaneous growth rate of the productive capacity of the reserve base for period-to-period changes:

$$(3.26) \qquad \partial I_t/\partial t \cong I_t-I_{t-1} = (1/n)\Sigma_{i=0}^{n}(A_{t-i}/R_{t-i-1}).$$

It can be seen that the incremental change in the capacity augmentation index over one period will be equal to the average of the periodic ratios of new reserve additions to previous reserve base levels for the last n periods. All other things equal, an increase in that average will increase the levels of both economic capacity and production.

The instantaneous change in the modified time index can be approximated in a similar manner for period-to-period incremental changes using (3.20),

$$\partial\tau_t/\partial t \cong \tau_t-\tau_{t-1} = (1-a_{t-1}), \tag{3.27}$$

showing that movement in τ_t is controlled by the degree of prorationing present at the well level. A decrease in the fraction of constrained production (a_t) will allow natural decline to have a greater effect, so that observed production rates will decline more rapidly.

Next, consider the change in production rates that results from a change in product price. For the case of oil production, the impact of a change in the market price of oil (P_t^o) can be expressed as

$$(\partial q_t^o/\partial P_t^o)/q_t^o = (\partial EC_t^o/\partial P_t^o)(1/EC_t^o) + (\partial I_t^o/\partial P_t^o). \tag{3.28}$$

Following the construction of (3.25), ($\partial EC_t^o/\partial P_t^o$) can be written as

$$\partial EC_t^o/\partial P_t^o = -(\partial g/\partial B_t^o)e^{D(\tau_t^o-\tau_t^g)-(I_t^o-I_t^g)} \cdot \{(\partial EL_t^o/\partial P_t^o)-EL_t^o(\partial I_t^o/\partial P_t^o)\}, \tag{3.29}$$

and using (3.15), $(\partial EL_t^o/\partial P_t^o)$ can be further decomposed to obtain

$$\partial EL_t^o/\partial P_t^o = -\{C_t^o((1-\rho_t)(1-s_t^o)(1-\omega_t)-v_t^o)\}/(ONR_t+AGNR_t-WPT_t^o)^2. \quad (3.30)$$

The partial derivative $(\partial EL_t^o/\partial P_t^o)$ will be negative as long as the ad valorem tax rate (v_t^o) is not larger than the expression $(1-\rho_t)(1-s_t^o)(1-\omega_t)$, so that economic capacity will increase when oil prices rise, as it should. Higher levels of economic capacity in turn imply higher levels of oil production over time.

The sign of $(\partial I_t^o/\partial P_t^o)$ should always be positive, implying that productive capacity expansion activity responds positively to higher prices and eventually brings about higher production levels. The magnitude of this effect of an oil price change on productive capacity additions will be determined by its effect on the expected profitability of capacity-expanding investments, such as exploratory and development drilling activity. Explicit characterization of the economics of this activity is beyond the scope of the present study; the integrated policy simulations in Chapter VII will instead rely upon an existing econometric model of petroleum drilling activity in Texas by Bremmer. For the case of non-associated gas production, the impact of a change in the market price of gas follows as

$$(\partial q_t^g/\partial P_t^g)/q_t^g = (\partial EC_t^g/\partial P_t^g)(1/EC_t^g) + (\partial I_t^g/\partial P_t^g). \quad (3.31)$$

The partial derivative $(\partial EC_t^g/\partial P_t^g)$ can be written exactly following (3.29), and $(\partial EL_t^g/\partial P_t^g)$ can be expressed as

$$\partial EL_t^g/\partial P_t^g = -\{C_t^g((1-\rho_t)(1-s_t^g)-v_t^g)\}/ \quad (3.32)$$

$$(GNR_t+CNR_t-WPT_t^g)^2.$$

As before, $(\partial EL_t^g/\partial P_t^g)$ should be negative and $(\partial I_t^g/\partial P_t^g)$ should be positive, so that higher gas prices will bring about higher levels of non-associated gas production.

Finally, the quantitative results of Chapters V and VII may be previewed by looking at the production effects of changes in the windfall profit tax rate (ω_t). For the case of oil production, this impact can be expressed as

$$(3.33a) \qquad (\partial q_t^o/\partial \omega_t)/q_t^o = (\partial EC_t^o/\partial \omega_t)(1/EC_t^o) + (\partial I_t^o/\partial \omega_t)$$

and for non-associated gas production as

$$(3.33b) \qquad (\partial q_t^g/\partial \omega_t)/q_t^g = (\partial EC_t^g/\partial \omega_t)(1/EC_t^g) + (\partial I_t^g/\partial \omega_t).$$

The effects on economic capacity can be written as

$$(3.34a) \qquad \partial EC_t^o/\partial \omega_t = -(\partial g/\partial B_t^o)e^{D(\tau_t^o-\tau_t^o)-(I_t^o-I_t^o)} \cdot \{(C_t^o(P_t^o-P^bADJ_t)(1-s_t^o)(1-\rho_t)/(ONR_t+AGNR_t-WPT_t^o)^2)-EL_t^o(\partial I_t^o/\partial \omega_t)\}$$

and

$$(3.34b) \qquad \partial EC_t^g/\partial \omega_t = -(\partial g/\partial B_t^g)e^{D(\tau_t^g-\tau_t^g)-(I_t^g-I_t^g)} \cdot \{(C_t^g(P_t^o-P^bADJ_t)(1-s_t^o)(1-\rho_t)CGR_t/(GNR_t+CNR_t-WPT_t^g)^2)-EL_t^g(\partial I_t^g/\partial \omega_t)\}.$$

Since windfall profit tax liabilities can never be negative, the signs of $\partial EC_t^o/\partial \omega_t$ and $\partial EC_t^g/\partial \omega_t$ will be strictly non-positive. Higher windfall profit tax rates should also reduce the expected after-tax present value of capacity expansion projects, causing lower levels of productive capacity augmentation, so that $\partial I_t^o/\partial \omega_t$ and $\partial I_t^g/\partial \omega_t$ will be negative. Higher windfall profit tax rates can therefore be expected to produce lower levels of economic capacity and hence, lower levels of oil and non-associated gas production.

H. Summary and Conclusions

This chapter has developed a petroleum production model that generalizes the basic exponential decline model and explicitly includes all the relevant economic and policy variables facing the reserve base operator. The three proposed modifications to the simple engineering model of (3.1) expand its applicability and give it some much needed economic structure while retaining a framework that can be easily implemented empirically for the quantitative policy analyses in Chapters V and VII. In the following chapter, equations (3.21) and (3.23) will be estimated using the production histories of individual oil and gas reservoirs in Texas in order to test the empirical validity of the model at a microeconomic level. These results should then provide some confidence in this methodology before it is applied to an analysis of aggregate Texas oil and non-associated gas production data to determine the impact of the windfall profit tax on the state as a whole.

CHAPTER IV

AN EMPIRICAL TEST OF THE MODEL USING INDIVIDUAL RESERVOIR DATA

Before applying the theoretical production model that was developed in Chapter III to an analysis of aggregate Texas oil and gas production data in Chapter V, it will first be empirically tested at the level of the individual petroleum reservoir in this chapter. There are two distinct reasons for performing this preliminary analysis of individual reservoir production data. First, a common criticism of the analysis of aggregate behavior is that in many cases, these aggregate studies are performed using theoretical models that were developed from a microeconomic perspective, without first having tested their ability to describe behavior at the micro level. This criticism will hopefully be avoided by evaluating the proposed theoretical model using micro level production data from individual reservoirs, considering its acceptable performance at the reservoir level to be a necessary condition for its application at a more aggregate level, such as statewide production. Second, the proprietary nature of the data requirements for individual reservoir studies usually precludes such work. Fortunately, access has been secured to reservoir-specific proprietary producer data on development well drilling activity and well operating costs that will enable analyses of individual petroleum reservoirs that are rarely seen in the literature. Thus the modelling efforts in this chapter will be of greater interest than merely a confirmation of methodology.

A. Description of the Data

For the purposes of this analysis, four geographically and geologically distinct oil reservoirs were selected, along with one large non-associated gas reservoir. The oil reservoirs include the giant East Texas field, a sandstone with a strong water drive located in Rusk and Gregg Counties, the Slaughter reservoir, a dolomite carbonate formation with a solution-gas drive in West Texas' Cochran County, the Neches (Woodbine) reservoir, a sandstone formation with a strong water drive in East Texas' Anderson and Cherokee Counties, and the Luling-Branyon reservoir, a limestone formation that also has a solution-gas drive,in Central Texas' Caldwell County.[1] The non-associated gas reservoir selected for analysis was the Gomez reservoir, located in Pecos County. Based on 1983 average daily production rates, East Texas ranked first among all Texas oil reservoirs at 139,851 barrels per day (BPD), while Slaughter ranked fifth at 68,359 BPD, with Neches (Woodbine) ranked fifty-first at 5,938 BPD and Luling-Branyon ranked one-hundredth with 2,931 BPD, being essentially a stripper field (i.e., one that primarily contains wells producing less than 10 BPD). Gomez ranked second among all non-associated gas reservoirs with a 1983 average production rate of 220,594 thousand cubic feet per day.[2] As is typical of most Texas oil

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[1]These geologic descriptions are taken from W. E. Galloway, et al. (1983).

[2]Average daily production rates at the reservoir level were found in various issues of the *Annual Report* of the Oil and Gas Division of the Texas Railroad Commission.

reservoirs, secondary recovery techniques have been applied to all four oil reservoirs to improve recovery efficiency. Waterflooding was used in the East Texas, Slaughter and Luling-Branyon reservoirs, and reservoir pressure-maintaining investments have been made in Neches (Woodbine) and Slaughter. Pressure maintenance for the Slaughter reservoir, unitized since 1966, has recently included the injection of carbon dioxide as an enhanced recovery technique. Finally, each oil reservoir has experienced significant infill development drilling activity, intended to increase the level of proven reserves associated with the reservoir and thereby increase its future production possibilities. The diversity of these five reservoirs should permit the assessment of the empirical applicability of the theoretical model before examining the aggregate state production data.

Before describing the actual estimation procedures that were followed, the theoretical model developed in Chapter III is briefly reviewed here. For an individual oil reservoir, the production model to be estimated will be of the form

$$q_t^o = q_o^* EC_t^o e^{I_t^o - D\tau_t^o}, \tag{4.1}$$

while the individual non-associated gas reservoir production model is

$$q_t^g = q_o^* EC_t^g q_t^d e^{I_t^g - D\tau_t^g}. \tag{4.2}$$

A sample of annual observations over the period 1973 through 1983 was selected for estimation purposes. Annual data were selected because of the considerable volatility found in monthly or quarterly production data. Even though the production data were available prior to 1973, the sample period was not started any earlier because significant statewide restrictions on production existed in Texas before 1973, causing flat or even rising production rates to be common (Recall Table 2 in Chapter III). Therefore, there would be little empirical basis in this earlier data for estimating natural decline rates, even with the modified time index.

Appendix A contains a list of all the data used in this chapter that are not of a proprietary nature. Annual production data at the reservoir level can be readily found in the forementioned *Annual Reports* of the Texas Railroad Commission. The data necessary for creation of the capacity augmentation indexes (I_t^o, I_t^g), the gas market demand index (q_t^d), the economic capacity indexes (EC_t^o, EC_t^g) and the modified time indexes (τ_t^o, τ_t^g) are not so easily obtained and utilized. The calculation of each of these indexes involved considerable effort, and will be described separately in the subsequent sections. These sections are then followed by a description and evaluation of the estimation of equations (4.1) and (4.2) for the individual reservoirs.

B. Calculation of the Capacity Augmentation Indexes

The capacity augmentation index I_t could not be calculated for the individual reservoirs exactly as presented in equation (3.4) since new reserve additions are not reported at the level of the individual reservoir. While reserve estimates are published occasionally for many of them, the timing of such revisions of reserve estimates coincides with the statistical review of the reservoir, and not with the annual activities undertaken to increase the amount of remaining reserves associated with the reservoir. A proxy for the ratio of new reserve additions to the level of reserves was computed based on the number of successful new infill development wells completed in each reservoir during each year from major producing company records, and annual producing well counts for each reservoir. The latter can be found in the *Annual Reports* of the Texas Railroad Commission. A substitute capacity augmentation index was therefore constructed as

(4.3) $$I_t = I_{t-1} + (N_{t-1}/\bar{W}),$$

where N_{t-1} gives the number of new producing wells completed in the reservoir during the previous year, $\bar{W}$ is the producing well count for the reservoir at the end of 1972, and $I_{1973}=1.0$ in the first year of the sample period.[3] Due to well spacing restrictions, there has been no recent infill drilling activity in Gomez, so the capacity augmentation index was omitted for this gas reservoir, in effect being treated as a constant. The values of I_t for 1973 through 1983 were calculated for each of the oil reservoirs using equation (4.3) and are reported in Table 3.

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[3]End of year producing well counts for 1972 found in the *Annual Reports* of the Texas Railroad Commission were 14,479 for East Texas, 2,393 for Slaughter, 126 for Neches (Woodbine), and 1,441 for Luling-Branyon.

Table 3. Capacity Augmentation Indexes for Individual Oil Reservoirs

	East Texas	Slaughter	Neches (Woodbine)	Luling-Branyon
Year	I_t	I_t	I_t	I_t
1973	1.0000	1.0000	1.0000	1.0000
1974	1.0013	1.0493	1.0160	1.0007
1975	1.0026	1.1091	1.0160	1.0125
1976	1.0035	1.1408	1.0320	1.0278
1977	1.0062	1.2027	1.0320	1.0451
1978	1.0075	1.2219	1.0710	1.0618
1979	1.0082	1.2570	1.0710	1.0687
1980	1.0098	1.3021	1.1030	1.0791
1981	1.0108	1.3293	1.1270	1.1242
1982	1.0129	1.3569	1.2140	1.1784
1983	1.0171	1.3794	1.2380	1.1936

Looking at the values of I_t presented in Table 3, it can be seen that the Slaughter reservoir has shown the greatest amount of infill drilling activity since 1973, with its installed productive capacity growing by 37.9% over the sample period. Neches (Woodbine) and Luling-Branyon have also seen significant capacity expansion during the sample period, as their capacity augmentation indexes have risen by 23.8% and 19.4% respectively. The data for East Texas shows that there has not been much capacity expansion there in the form of new infill drilling over the sample period. Much of the infill development drilling in East Texas occurred very early in its production history, when there were few, if any, enforceable restrictions on well spacing or well production rates for the reservoir. The movement of these capacity augmentation indexes suggests that for the other three oil reservoirs - Slaughter, Neches (Woodbine), and Luling-Branyon, new infill drilling could appreciably boost the productive capacity of the reservoir. Much of Texas drilling activity in the 1970s was centered around infill drilling in existing reservoirs, and the drilling activity reported for these three oil reservoirs reflects that fact.

If annual new reserve additions had been available for use in calculating the capacity augmentation indexes, every 10% increase in reserves would be completely reflected in the movement of the index I_t. However, since new producing wells were used as a proxy for new reserve additions and a 10% increase in new producing wells may result in a less than 10% increase in reserves, it may be necessary to allow for the possibility that the coefficient on the index I_t is different from 1.0. This specification will be tested statistically when estimating the complete model later in this chapter.

C. Calculation of the Gas Market Demand Index

In order to apply the non-associated gas production model of (4.2) to the Gomez reservoir, some measure of gas market demand conditions was needed for calculating the gas market demand index q_t^d for the sample period. As the percentage of fieldwide deliverability for Gomez that was actually produced in each year could not be obtained, it was not possible to follow the outline for calculation of q_t^d suggested in the theoretical development of the non-associated gas production model in Chapter III. However, data on the actual fieldwide allowables for the Gomez reservoir over the sample period were available from the Texas Railroad Commission, and should reflect the assignment of nominations for gas purchases to the reservoir.

By examining this series of actual fieldwide allowables, which is reported in Table 4 as a_t, it can be seen that softening gas market demand conditions in Texas in the latter years of the sample period caused these allowables to fall off sharply after 1980. From an average annual decline rate of 10% for 1973 through 1980, the fieldwide allowables for Gomez declined by 22% from 1980 to 1981, by 25% in 1982, and by 28% in 1983. The total reservoir production series (q_t^g) for Gomez, which is reproduced from Appendix A and is also reported in Table 4, reflects this downward dip in the allowables series. Gomez's production rates dropped by 20% from 1980 to 1981 and over 40% in 1982 before flattening out in 1983. This

Table 4. Gas Market Demand Conditions in the Gomez Non-Associated Gas Reservoir

Year	q_t^g	a_t	$\tilde{a}_t$	q_t^d
1973	1,121,340[a]	1,213,150[b]	1,213,416[c]	0.9998[d]
1974	1,056,860	1,165,753	1,049,427	1.1108
1975	893,007	959,726	1,011,308	0.9490
1976	748,162	854,794	847,254	1.0089
1977	634,554	758,904	762,041	0.9959
1978	510,646	581,096	684,029	0.8495
1979	516,120	583,014	535,928	1.0879
1980	477,620	549,863	537,538	1.0229
1981	379,864	428,219	499,346	0.8576
1982	226,110	320,548	466,846	0.6866
1983	220,594	230,137	439,044	0.5242

[a] Actual fieldwide gas production in MCF per day.

[b] Actual fieldwide allowable in MCF per day.

[c] Predicted fieldwide allowable in MCF per day.

[d] The gas market demand index, $(a_t/\tilde{a}_t)$.

abrupt downward revision in the trend of fieldwide allowables by the Texas Railroad Commission in the face of declining demand for Texas gas appears to have effectively acted as a demand side constraint on production after 1980.

This analysis can be formalized by estimating the observed downward trend in fieldwide allowables over the period 1973 through 1980 and extrapolating this trend forward to see how significant the downturn in allowables was relative to this estimated trend. Without any weakening of demand conditions, the allowable series should have continued to decline along this trend. Therefore, this estimated trend will give us a benchmark for comparison with the movement of actual allowables to discern the degree to which depressed demand conditions reduced fieldwide production in Gomez after 1980. This trend in allowables was estimated by the regression model

$$\text{(4.4)} \qquad \ln(a_t) = \delta_0 + \delta_1 \ln(a_{t-1}) + \epsilon_t,$$

where a_t is the actual fieldwide allowable for year t, measured in millions of cubic feet (MMCF), and ϵ_t is an error term that is assumed to meet the conditions for efficient and unbiased estimation.[4] Using ordinary least squares (OLS), δ_0 was estimated to be 0.478 (with a standard error of 0.899), and δ_1 was estimated to be 0.912 (with a standard error of 0.133). The coefficient of determination (R^2) was 0.903 and the standard error of the regression

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[4] In the context of the classical linear regression model, these conditions are that ϵ_t have a zero mean, a constant variance, and not be correlated with the right hand side variables.

was 0.098. The values of the fieldwide allowables predicted by this regression appear as $\tilde{a}_t$ in Table 4, extrapolating according to (4.4) to obtain the predicted values after 1980.

The index of gas market demand conditions in Gomez (q_t^d) was constructed as the ratio of the actual fieldwide allowables (a_t) to the estimated fieldwide allowables ($\tilde{a}_t$). The idea behind this ratio is that the downward trend in actual fieldwide allowables estimated for Gomez from 1973 through 1980 could be expected to continue after 1980 as long as Texas gas market demand conditions provided enough nominations for purchases of Gomez gas to support unconstrained fieldwide production there. Therefore, under strong gas market demand conditions, the value of this ratio should remain close to unity. Should gas market demand conditions weaken, fieldwide allowables for gas reservoirs across the state will be reduced by the Texas Railroad Commission, causing actual fieldwide allowables for Gomez to fall below the estimated trend, and thereby pushing the value of the ratio below unity. The values of this ratio, the gas market demand index for Gomez, are also presented in Table 4. The table indicates that gas market demand conditions remained strong in the Gomez reservoir from 1973 through 1980, as q_t^d hovered around a value of unity. However, the index drops off sharply after 1980 as the actual fieldwide allowable falls to almost half its predicted value by 1983. This result is not unexpected given the widespread natural gas glut in the U.S. since 1982. The impact on non-associated gas reservoirs such as Gomez is magnified since associated gas production is not limited by the Texas Railroad Commission according to demand conditions. Thus all natural gas supply surpluses must be corrected by cutbacks in non-associated gas production alone.

D. Calculation of the Economic Capacity Indexes

The next step in the estimation of the model using individual reservoir data was to estimate the form of the production distributions (Δ_t in equation (3.7)) to be used in the calculation of the reservoir-specific indexes of economic capacity (EC_t). Average daily production rates were collected for each producing well in each reservoir for the year 1983.[5] For oil production, this information is only available at the level of the individual oil lease, while gas production data is kept at the well level. Therefore, in order to approximate well level data for the four oil reservoirs (and for aggregate state oil in the next chapter), it was necessary to assume that all the oil wells on any given oil lease were essentially homogeneous in nature (i.e., the intra-lease production distribution was uniform across all wells on the lease). This allowed for the construction of well level oil production data by dividing the average daily production rate of each oil lease by the number of producing oil wells on the lease and using that as the well level observation for each well on that lease. This assumption of homogeneity within oil leases will be less restrictive if the degree of heterogeneity is positively correlated with the number of wells on

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[5]This production information was obtained from Petroleum Information Corporation, Houston, Texas.

the lease, so that many of the smaller leases will contain virtually homogeneous wells. This may well be the case with these four oil reservoirs and with statewide oil production, as seen by the percentages of oil leases containing no more than 1, 2, 3, or 5 producing wells in 1983. These percentages were 24.44, 41.21, 50.26, and 64.17 for the East Texas reservoir, 13.76, 22.94, 28.44, and 33.03 for Slaughter, 42.11, 57.89, 68.42, and 84.21 for Neches (Woodbine), and 27.36, 43.24, 52.70, and 66.55 for Luling-Branyon. The same percentages for all oil leases in the state are 56.72, 71.32, 77.84, and 85.05. Only Slaughter's percentages appear too low, but this is due to the high degree of unitization in that reservoir.

The well level production data was then used to rank the well production rates in each reservoir from the lowest to the highest, creating data sets for each reservoir consisting of the cumulative percentage contributions made by wells producing at or below each observed well production rate, as described in Chapter III. Thus, these data sets contained the cumulative percentages (CUM_i) of total reservoir production (q_{1983}) that were associated with each daily well production rate (q_i) observed in the reservoir during 1983 (i.e., $CUM_i = \Sigma_{k=1}^{i}(q_k/q_{1983})100$).

For each reservoir, a linear relationship was estimated between the observed daily well production rates (q_i) and the cumulative percentages (CUM_i), but only up to 20% of total production. Specifically, the regression included only those values of CUM_i at or below 20. This focused attention on the tail of the distribution that would be most affected by changes in the individual well economic limit. Visual examination of plots of these lowest 20% tails of the production distributions revealed that they were almost perfectly linear over this restricted range. This suggested that ordinary least squares (OLS) estimation of the point at which these tails intersected the horizontal axis would provide estimates of the cumulative percentages of reservoir production forthcoming at an economic limit of zero. The estimated equations were of the form

$$(4.5) \qquad CUM_i = \beta_0 + \beta_1 q_i + \epsilon_i, \qquad \text{for } CUM_i \leq 20,$$

where ϵ_i is an error term that is assumed to meet the conditions for efficient and unbiased estimation. The results of these OLS regressions are given in Table 5.

The estimated intercept terms ($\hat{\beta}_0$) of these regressions over the tails of the production distributions provided one measure of the potential productive capacity of the reservoir (beyond that observed in 1983) that would obtain at an economic limit of zero. Using this information, the entire range of the data sets of the cumulative percentages of total reservoir production was transformed to make the accumulations start at a daily production rate of zero, rather than at the lowest observed rate in 1983. Specifically, this was accomplished by using the OLS estimates of the intercept term ($\hat{\beta}_0$) to adjust the cumulative percentage contributions as follows

$$(4.6) \qquad CUMADJ_i = \Sigma_{k=1}^{i}((CUM_k+\hat{\beta}_0)/(100+\hat{\beta}_0)).$$

These adjusted well production data sets could then serve as proxies

Table 5. Linear Estimation of Equation (4.5) Using Individual Reservoir Data

Reservoir	β_0	β_1	R^2	S.E.[a]	n[b]
East Texas	-1.739 (194.8)[c]	1.415 (1091.4)	.996	0.35	4,885
Slaughter	-9.162 (48.9)	1.277 (97.6)	.905	1.82	996
Neches (Woodbine)	-4.940 (6.5)	0.641 (18.3)	.851	2.46	61
Luling-Branyon	-6.551 (85.8)	23.710 (205.7)	.979	0.83	922
Gomez	-1.613 (8.5)	0.010 (49.8)	.978	0.88	58

[a] The standard error of the regression.

[b] Number of observations in the sample.

[c] t-statistics for the null hypothesis that the parameter equals zero are given in parentheses below the estimated values.

for the unobservable potential well production data that would appear under an individual well economic limit of zero. The effect of this adjustment is to define a 100% level of economic capacity based upon a zero economic limit. Thus, it was now possible to proceed with modelling the entire range of the production distributions.

The next step was to approximate the distribution between the adjusted cumulative percentages of total reservoir production and individual well production rates. After much investigation, a simple linear function of the natural logarithm of the adjusted cumulative percentages and the natural logarithm of the average daily production rates was selected to model the production distributions. The estimated production distributions therefore took the functional form

$$(4.7) \qquad \ln(CUMADJ_i) = \gamma_0 + \gamma_1 \ln(q_i) + \eta_i,$$

where η_i is an error term that is assumed to meet the conditions for efficient and unbiased estimation. The intercept term γ_0 is replaced with $\ln|\beta_0+\beta_1(1)|$ so that the regression only estimates the value of the slope parameter γ_1. As a result, the log-linear regression line is forced to pass through the same value of CUM_i as that predicted by the earlier linear regression at an average daily production rate of 1.0. This adjustment insures that the log-linear regression using the adjusted cumulative percentages will be consistent with the linear relationship estimated using the unadjusted data from the tail of the observed production distribution.

The log-linear distribution function that was selected is very similar to the Pareto distribution commonly used to model income distributions. The Pareto distribution models the cumulative probabilities that families up to a certain income size will show up in each percentage point of the income distribution, when ranking those families from lowest to highest by their observed income levels. The Pareto law of income distribution can be restated for petroleum production distributions as: "the natural logarithm of the percentage of total reservoir output coming from wells with average production rates in excess of any given production rate q_i is a negatively sloped function of the natural logarithm of that rate". Following the presentation of Lawrence R. Klein (1962), the Pareto cumulative distribution function can be written as

$$\ln(CUM_i) = \ln(A) - \alpha \ln(q_i), \tag{4.8}$$

where CUM_i and q_i are as previously defined and A and α are the parameters of the distribution that must be estimated. In the empirical work on income distributions, the parameter A is defined to be equal to $(q_o)^{\alpha}$, where q_o is some minimum observed income level, so that the accumulation of percentages starts above this level. This definition of the intercept term is analogous to the transformation of the data sets of cumulative percentages of reservoir production per well performed above. Since the accumulation begins at a production rate of zero, the intercept term is effectively collapsed into the left hand side variable, so that equation (4.7) is estimated without a freely determined intercept. In either case, the distribution is seen to depend only upon the slope parameter, whether it is called α or γ_1.

Table 6. Log-Linear Estimation of the Adjusted Production Distributions for Individual Reservoirs

Reservoir	$\tilde{\gamma}_0$	$\tilde{\gamma}_1$	R^2	S.E.[a]	n[b]
East Texas	-1.11 (41.8)[c]	1.772 (309.3)	.951	0.67	10,977
Slaughter	2.06 (5.7)	0.504 (180.5)	.917	0.46	2,935
Neches (Woodbine)	1.46 (1.4)	0.529 (41.0)	.927	0.54	133
Luling-Branyon	2.84 (19.4)	0.733 (125.3)	.901	0.26	1,728
Gomez	0.58 (9.5)	0.319 (25.3)	.854	0.94	110

[a] The standard error of the regression.

[b] Number of observations in the sample.

[c] t-statistics for the null hypothesis that the parameter equals zero are given in parentheses below the estimated values. The standard error used to compute the t-statistic for the intercept term $\tilde{\gamma}_0$ was derived using an approximation suggested by Alexander M. Mood, et al. (1974, p. 181).

As can be seen from the results presented in Table 6, the log-linear function of (4.7) fits the adjusted production distributions for the individual reservoirs nicely. Furthermore, it has the twin virtues of being easily estimated using OLS and producing a closed-form function that was readily adaptable to the measurement of economic capacity according to equation (3.9). Other, more elaborate, distributions from the income distribution literature were considered, but either resulted in poorer fits of the data or were deemed inappropriate, being specifically designed with the intention of only estimating the means and variances of, for example, different income groups, rather than a simple closed-form function.[6]

By taking the antilogarithm of equation (4.7) after being estimated as shown in Table 6, equation (3.9) describing the economic capacity index can now be expressed more specifically as

$$EC_t = 100 - e^{\tilde{\gamma}_0}(B_t)^{\tilde{\gamma}_1}, \tag{4.9}$$

or, by also using equation (3.8), as

$$EC_t = 100 - (e^{\tilde{\gamma}_0})(EL_t e^{D(\tau_t - \tau_{1983}) - (I_t - I_{1983})})^{\tilde{\gamma}_1}, \tag{4.10}$$

where $\tilde{\gamma}_0 = \ln|\beta_0 + \beta_1|$. Equation (4.10) shows that the estimated parameters of the production distributions ($\tilde{\gamma}_0$ and $\tilde{\gamma}_1$) can be used to indicate the cumulative percentage of total installed productive

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[6] An updated critical review of the income distribution modelling literature can be found in James B. McDonald and Michael R. Ransom (1979).

capacity that is associated with any given production rate and thereby, to measure economic capacity as it was defined in Chapter III.

E. Calculation of the Reservoir-Specific Economic Limits

In order to compute the levels of the basewide economic limit needed for the measurement of economic capacity as in (4.10), values of the reservoir-specific individual oil and non-associated gas well economic limits (EL_t^o, EL_t^g) are needed for each reservoir for each year in the sample period. Calculation of these economic limits requires that annual data be gathered on the values of all of the economic variables that appear in equation (3.15) for each of the four oil reservoirs and equation (3.19) for the gas reservoir.

Observations on crude oil market prices (P_t^o) came from various editions of *Platt's Oil Price Handbook and Oilmanac*, being taken as the simple average of the annual average posted prices for West Texas Sour (API 37^o) and Gulf Coast Mixed Sweet (API 30^o), under the stripper oil category when applicable. Natural gas market prices (P_t^g) were taken as the average wellhead value for Texas as reported by the American Petroleum Institute (API) in its *Basic Petroleum Data Book*. The royalty rate (ρ_t) was assumed to be a constant 0.125 (i.e., 1/8) over the sample period. Severance tax rates (s_t^o, s_t^g) came from the Texas Comptroller of Public Accounts as reported in its publication *Oil and Gas Production Tax Laws*, while the federal income tax rate (f_t) was found in Joseph Pechman (1983, p. 309). Gas-oil and condensate-gas production ratios (GOR_t, CGR_t) were determined from Texas Railroad Commission production data, including the *Annual Report* of their Oil and Gas Division. Explanations of the appropriate windfall profit tax rates (ω_t), base price (P^b), and inflation adjustment factors (ADJ_t) for crude oil and condensate production were generously provided by various tax managers of major oil companies producing in Texas. The remaining ad valorem tax rates (v_t^o, v_t^g) and daily well operating costs (C_t^o, C_t^g) were calculated from private major oil company records on operating costs for marginal oil and gas wells. The ad valorem tax rates were calculated by assuming that all ad valorem taxes were paid based solely on either gross oil revenues or gross gas revenues, as applicable. The daily well operating costs were taken to be the simple daily averages of all observed direct operating expenses for all oil or gas wells in the marginal well sample. All of the above-mentioned information that is not proprietary in nature is listed in Appendix A, and was used to calculate the economic limits for each of the reservoirs. The calculated values of the economic limit for an individual representative well in each of the five reservoirs are presented in Table 7 for the period 1973 through 1983.

From Table 7, the patterns of the individual oil well and non-associated gas well economic limits for these five reservoirs can be traced over the sample period. All of the reservoirs experienced significant declines in their individual well economic limits from 1973 to 1974, as the impact of the energy price increases of the fall of 1973 was transmitted to the petroleum producing industry in Texas. The economic limits fell again slightly in 1975, but then tended to

Table 7. Economic Limits for Individual Reservoirs

Year	East Texas EL_t^o	Slaughter EL_t^o	Neches (Woodbine) EL_t^o	Luling-Branyon EL_t^o	Gomez EL_t^g
1973	1.48[a]	6.23[a]	4.86[a]	2.31[a]	128.72[b]
1974	1.12	4.70	3.67	1.74	91.70
1975	1.04	4.37	3.40	1.62	75.64
1976	1.13	4.76	3.69	1.78	63.54
1977	1.16	4.85	3.74	1.77	56.19
1978	1.13	4.72	3.64	1.70	58.56
1979	1.12	4.68	3.61	1.69	62.03
1980	1.15	4.81	3.70	1.74	55.93
1981	0.75	3.15	2.44	1.15	54.42
1982	0.84	3.50	2.68	1.27	62.86
1983	0.87	3.61	2.74	1.30	67.72

[a] Figures are given in BPD for an individual oil well located in the reservoir.

[b] Figures are given in MCF per day for an individual non-associated gas well located in the reservoir.

remain fairly constant for the rest of the decade. As a result of the world oil price jump in 1979-1980 and U.S. oil price decontrol in 1981, the economic limits for the oil reservoirs were once again reduced in 1981, after which time they again stabilized for the duration of the sample period. The economic limit for Gomez, the sole non-associated gas reservoir, did not receive the benefits of the 1979-1980 oil price hike, as declining demand for natural gas in the U.S. kept the average wellhead value of gas in Texas from rising at the same rate as did oil prices.

F. Calculation of the Modified Time Indexes

The last step before estimating equations (4.1) and (4.2) for each reservoir was to calculate the indexes of time (τ_t in equation (3.19)) for each year in the sample period to account for the effects of prorationing.

Creation of the modified time index τ_t requires the computation for each year of the fraction of total reservoir production (a_t) coming from individual wells that are constrained by their allowables. As it is not always clear from the available allowable and production data whether a particular well actually was or was not able to produce at its MER, it was necessary to devise a rule to use in deciding the issue based on the observed production rate of the well in each period and its corresponding allowable. Simply put, a well was considered to have become unconstrained if, in any period, its production rate was observed to fall below 95% of its allowable. That well was then considered unconstrained for the duration of its lifetime unless its production rate was seen to not only rise, but also return to within 5% of its allowable.

Using the above criteria, a_t was determined for each of the five reservoirs by a very intensive computer search performed by Petroleum Information Corporation. The comparisons were made monthly at the lease level for oil production and then aggregated to the level of the individual reservoirs. The fractions for natural gas production were similarly computed, but came from comparisons at the well level, since gas production data was available down to the level of the individual well, while oil data is kept only at the lease level, as was mentioned earlier in describing the estimation of the reservoir production distributions. Given these values of a_t, the modified time index τ_t could now be calculated for each of the five reservoirs as

$$\tau_t = \tau_{t-1} + (1-a_{t-1}). \tag{4.11}$$

The values of both a_t and τ_t for 1973 through 1983 are reported in Table 8 for each of the five reservoirs.

The values of a_t shown in Table 8 provide evidence of the degree of individual well prorationing still present in Texas oil and gas reservoirs even after the market demand factor reached 100% in April 1972. The highly competitive nature of production from the East Texas oil reservoir has forced the Texas Railroad Commission to maintain very restrictive individual well production allowables in that reservoir until the present day, with nearly 80% of its wells

Table 8. Modified Time Indexes for Individual Reservoirs

	East Texas		Slaughter		Neches (Woodbine)		Luling-Branyon		Gomez	
Year	a_t[a]	τ_t[b]	a_t	τ_t	a_t	τ_t	a_t	τ_t	a_t	τ_t
1973	0.9111	1.0000	0.1768	1.0000	0.8509	1.0000	0.1130	1.0000	0.2355	1.0000
1974	0.9015	1.0889	0.2468	1.8232	0.8757	1.1491	0.0051	1.8770	0.2674	1.7645
1975	0.8880	1.1874	0.0793	2.5764	0.7425	1.2734	0.0145	2.8819	0.2570	2.4971
1976	0.8837	1.2994	0.0649	3.4971	0.6774	1.5309	0.0008	3.8674	0.1280	3.2041
1977	0.8876	1.4157	0.1204	4.4322	0.6528	1.8535	0.0119	4.8666	0.1270	4.1121
1978	0.8766	1.5281	0.1285	5.3118	0.6167	2.2007	0.1252	5.8547	0.1291	4.9851
1979	0.8631	1.6515	0.0325	6.1833	0.5214	2.5840	0.0095	6.7295	0.2545	5.8560
1980	0.8534	1.7884	0.0379	7.1508	0.0858	3.0626	0.0627	7.7200	0.3328	6.6015
1981	0.8402	1.9350	0.0777	8.1129	0	3.9768	0.1296	8.6573	0.1398	7.2687
1982	0.8167	2.0948	0.0676	9.0352	0	4.9768	0.1677	9.5277	0.0778	8.1289
1983	0.7869	2.2781	0.0185	9.9676	0	5.9768	0.1139	10.3600	0.2996	9.0511

a The fraction of reservoir production coming from wells constrained by their allowables.

b $\tau_t = \tau_{t-1} + (1-a_{t-1})$.

still being constrained in 1983.[7] Prorationing in the Slaughter reservoir has virtually disappeared, with the degree of constraint at the well level falling from a high of 24.7% in 1974 to just under 2% by 1983. The Neches (Woodbine) reservoir has experienced an even more dramatic reduction in the production constraints on its wells. The degree of prorationing there was almost as high as that of East Texas in 1973 and 1974, but slowly fell over the next five years before abruptly vanishing in 1980.

The patterns of prorationing observed for the Luling-Branyon oil reservoir and the Gomez non-associated gas reservoir are less easily explained, since they exhibit considerable volatility over the sample period. Some of this movement in a_t for Luling-Branyon can probably be attributed to the introduction of significant numbers of new infill wells that were able to produce at or above their newly assigned allowables. However, this explanation cannot be extended to account for the Gomez reservoir, with its nearly constant producing well population. The increase in a_t for Gomez in 1983 was probably due to demand side effects that reduced its allowables but not the deliverabilty of its individual wells. This peculiar variation in a_t is not likely to be a serious problem, since for both Luling-Branyon and Gomez the year-to-year perverse fluctuations tend to be small, giving a clear picture of relatively minor prorationing constraints. As a result, the modified time index τ_t rises fairly systematically.

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[7]See Gary D. Libecap and Steven N. Wiggins (1984) for a discussion of prorationing in East Texas as a regulatory response to a breakdown in private contracting for the use of a common property resource.

Fortunately, this unusual pattern of prorationing constraints is not reflected in all of the reservoirs, nor is it found to appear in the aggregate analysis of the next chapter.

The values of τ_t reported in Table 8 give us some indication of the effects of prorationing on the observed rate of production decline from these reservoirs. Highly constrained reservoirs such as East Texas will exhibit rather low average annual production decline rates, but this does not imply correspondingly low natural decline rates that will be estimated by the parameter D in the production models. This is reflected in the value of τ_t in 1983 for East Texas of only 2.2781, which can be interpreted as the number of years it would have taken for the production decline observed over the entire eleven year sample period to occur if production had been allowed to decline at its natural decline rate. Computing the average annual rate of production decline observed for East Texas as δ in the expression $q_{1973}(1+\delta)=q_{1983}$, the average annual observed decline rate for East Texas from 1973 to 1983 is found to be only 3.8%. The natural decline rate estimated for East Texas using equation (4.1) will have to be much higher than 3.8% per year, since it will be measured using the modified time index τ_t.

With the exception of Neches (Woodbine), the degree of prorationing present in the other reservoirs over the period was not nearly so significant as it was in East Texas, so that they should exhibit lower natural decline rates, all other things equal. However, all other things are not quite equal, since oil reservoirs with a strong water drive such as East Texas or Neches (Woodbine) can be expected to have much higher natural decline rates in any case. Further discussion of these differences is better left until after the natural decline rates have been estimated in the next section.

G. Estimation of the Complete Model

At this point, all of the indexes needed to estimate both the oil and non-associated gas production models of equations (4.1) and (4.2), respectively, have been calculated for each of the five individual reservoirs. Using the functional form for the index of economic capacity that was selected in modelling the production distributions (equation (4.10)), the fully specified oil production model that will be estimated can be written as

$$(4.12a)\quad q_t^o = q_o^*\{100 - (e^{\tilde{\gamma}_0})(EL_t e^{D(\tau_t^o-\tau_{1983}^o)-(I_t^o-I_{1983}^o)})^{\tilde{\gamma}_1})\}e^{I_t^o-D\tau_t^o}.$$

The fully specified non-associated gas production model takes the form

$$(4.12b)\quad q_t^g = q_o^*\{100 - (e^{\tilde{\gamma}_0})(EL_t e^{D(\tau_t^g-\tau_{1983}^g)-(I_t^g-I_{1983}^g)})^{\tilde{\gamma}_1})\}q_t^d e^{I_t^g-D\tau_t^g}.$$

Notice that for each production model there are only two parameters to be estimated - the constant term q_o^* and the natural decline rate D. Since D enters equations (4.12a) and (4.12b) non-linearly, it cannot be estimated in the context of the classical linear regression model. Instead, an iterative procedure must be used to estimate the model.[8] Since all of the right hand side variables of the model can safely be considered to be predetermined for a price-taking petroleum producer, this iterative procedure should provide estimates that will be consistent and asymptotically efficient. Equation (4.12a) was estimated for each oil reservoir, while equation (4.12b) was estimated for Gomez, and the results of those regressions appear in Table 9. Actual average daily production rates from each reservoir are plotted against the rates predicted by the model in Figures 4 through 8.

Examination of both the results in Table 9 and the accompanying plots will indicate the degree of explanatory power of the model. All five regressions provide highly statistically significant parameter estimates with the correct signs, and the coefficients of determination (R^2) are all above .90. As percentages of 1983 production rates, the standard errors of the regressions are small for the oil reservoirs, being 1.64% for East Texas, 4.06% for Slaughter, 9.21% for Neches (Woodbine), and 4.14% for Luling-Branyon, but somewhat larger for the Gomez gas field at 18.8%. In a statistical sense then, the model does a reasonably good job of explaining historical production from these five reservoirs over the sample period.

As a check on the model's econometric specification, several variations on the functional forms of equations (4.12a) and (4.12b)

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[8]For purposes of estimation, the non-linear least squares estimation procedure LSQ found in the TSP software package designed by Bronwyn H. Hall, et al. (1981) was utilized, which employs Gauss's method to minimize the sum of squared residuals.

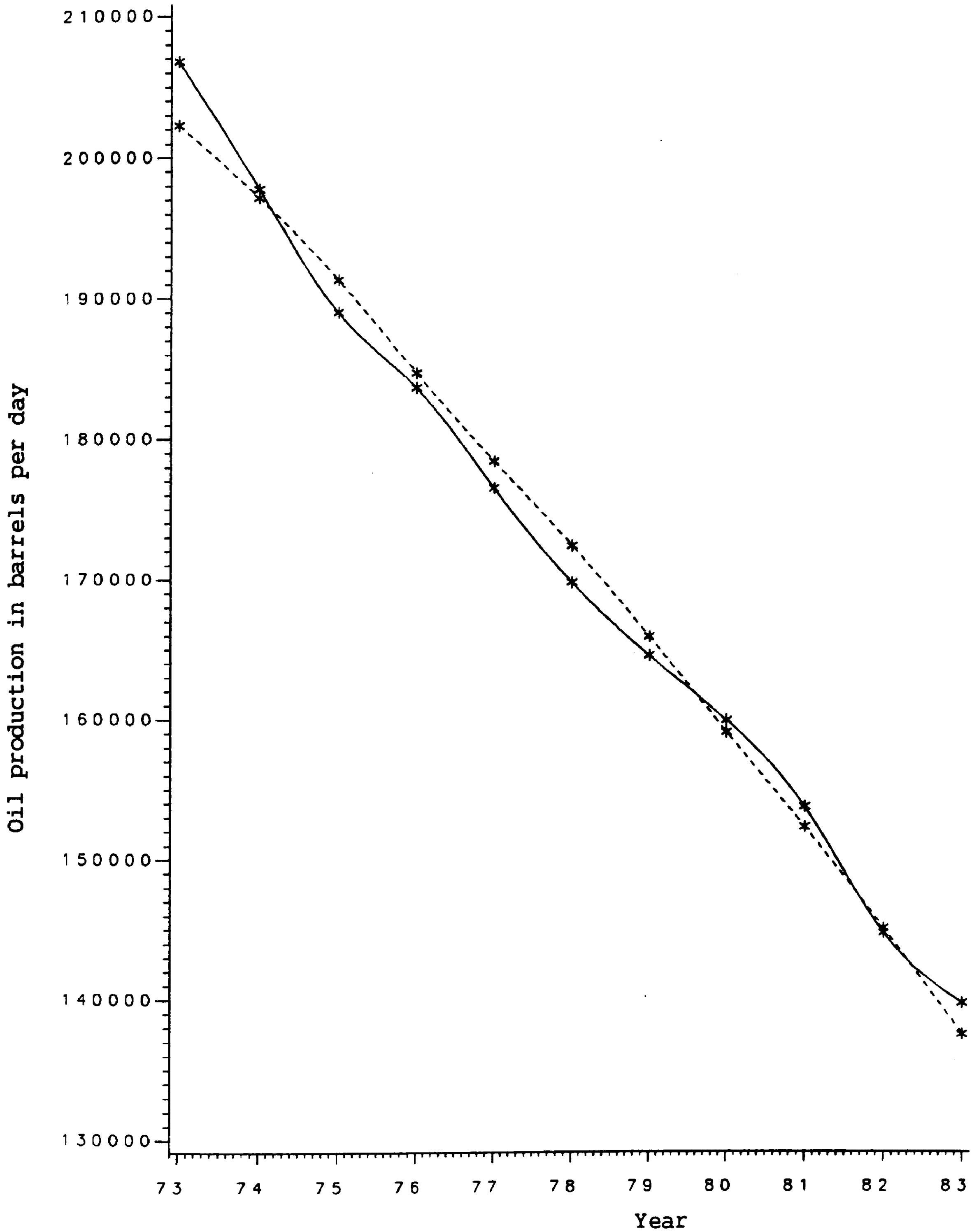

Figure 4. Actual Oil Production (solid line) vs. Predicted Oil Production (broken line) for East Texas, 1973-1983

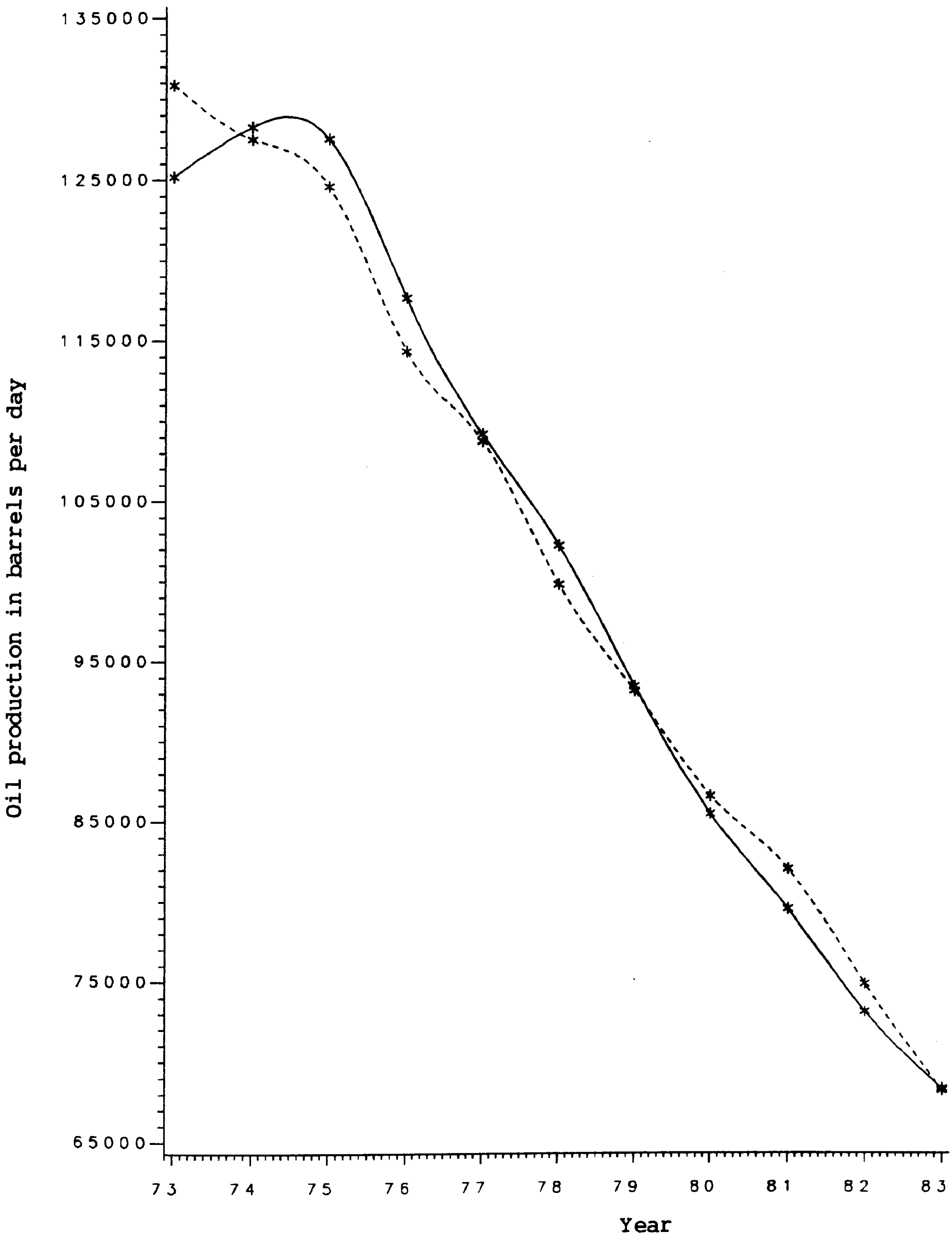

Figure 5. Actual Oil Production (solid line) vs. Predicted Oil Production (broken line) for Slaughter, 1973-1983

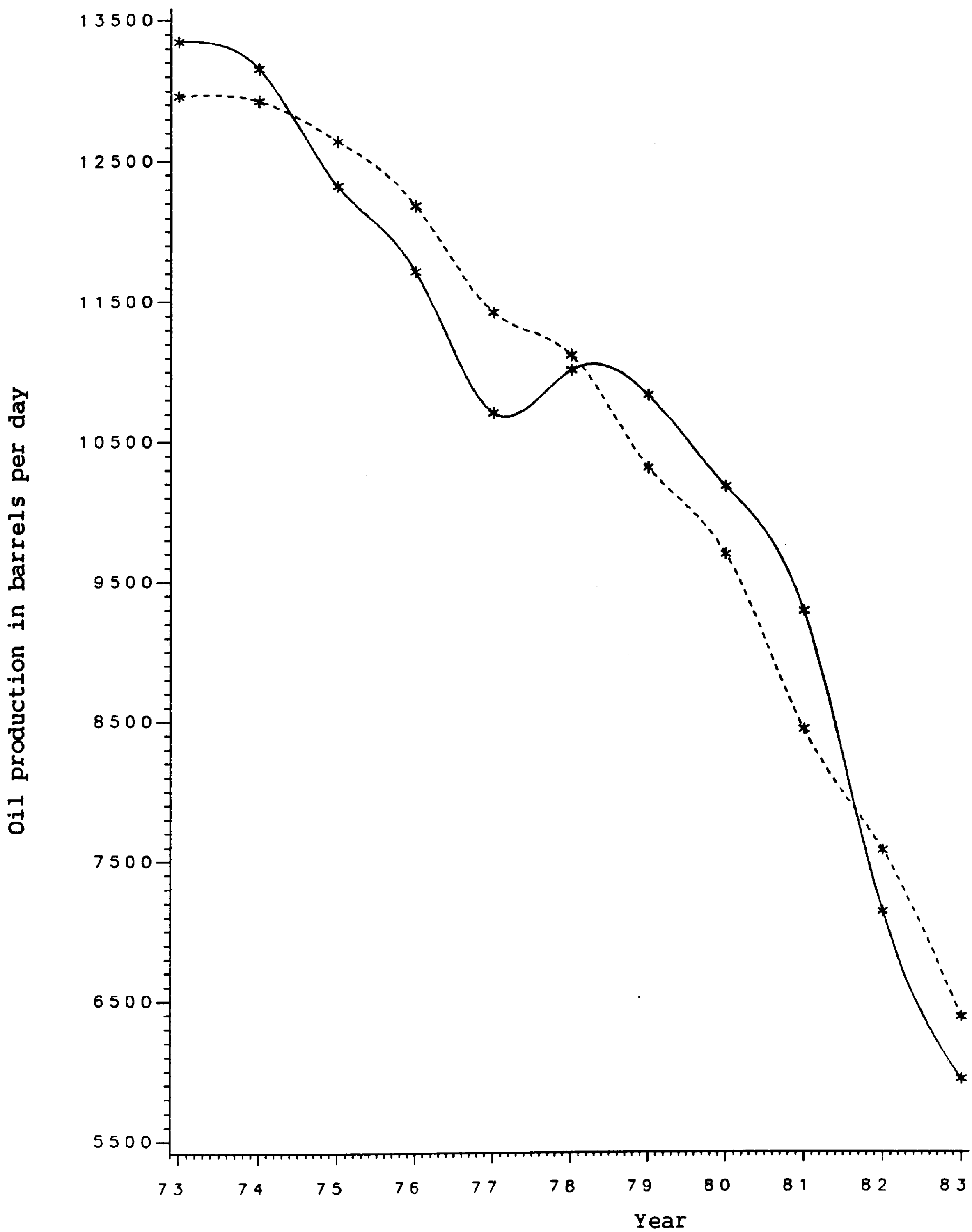

Figure 6. Actual Oil Production (solid line) vs. Predicted Oil Production (broken line) for Neches (Woodbine), 1973-1983

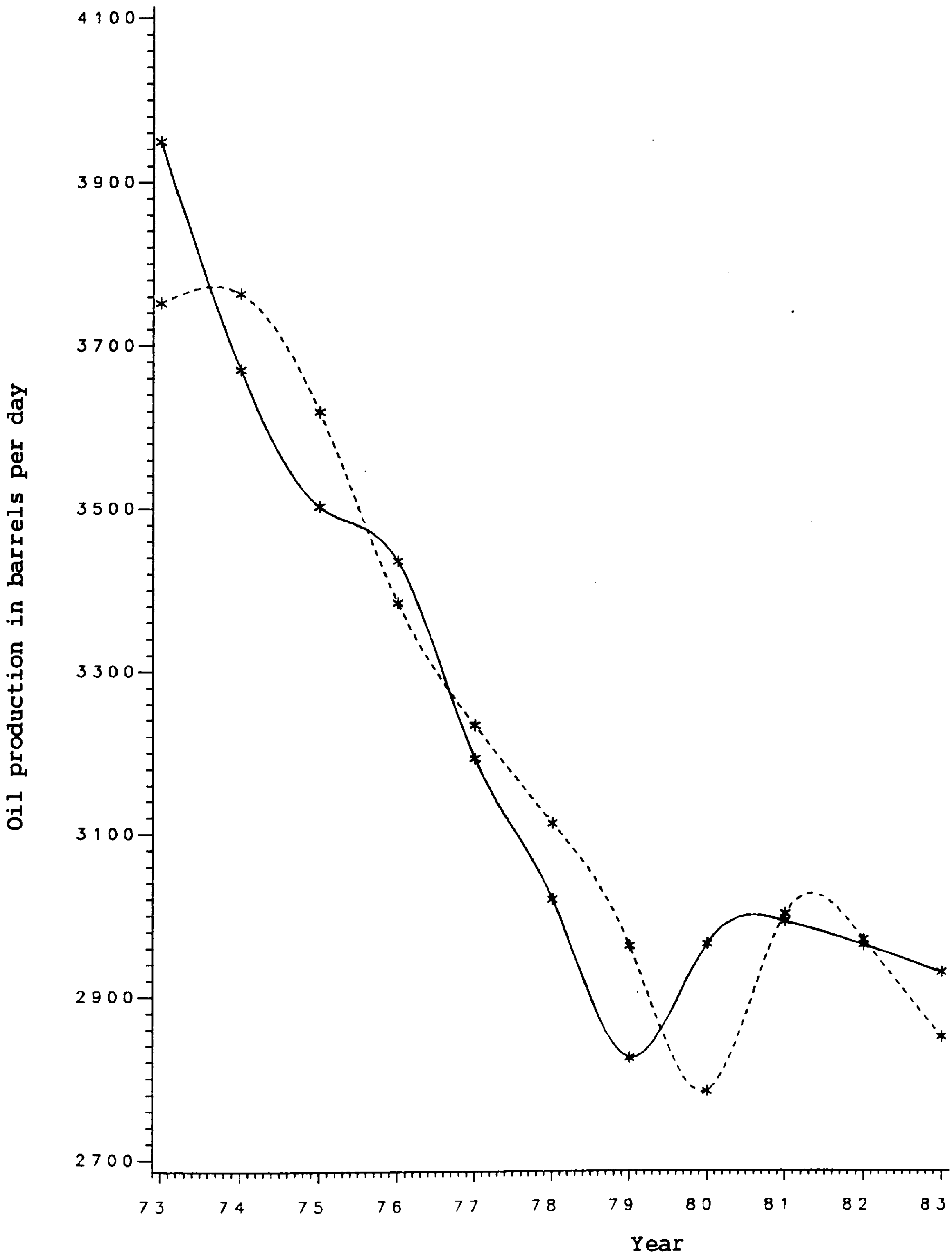

Figure 7. Actual Oil Production (solid line) vs. Predicted Oil Production (broken line) for Luling-Branyon, 1973-1983

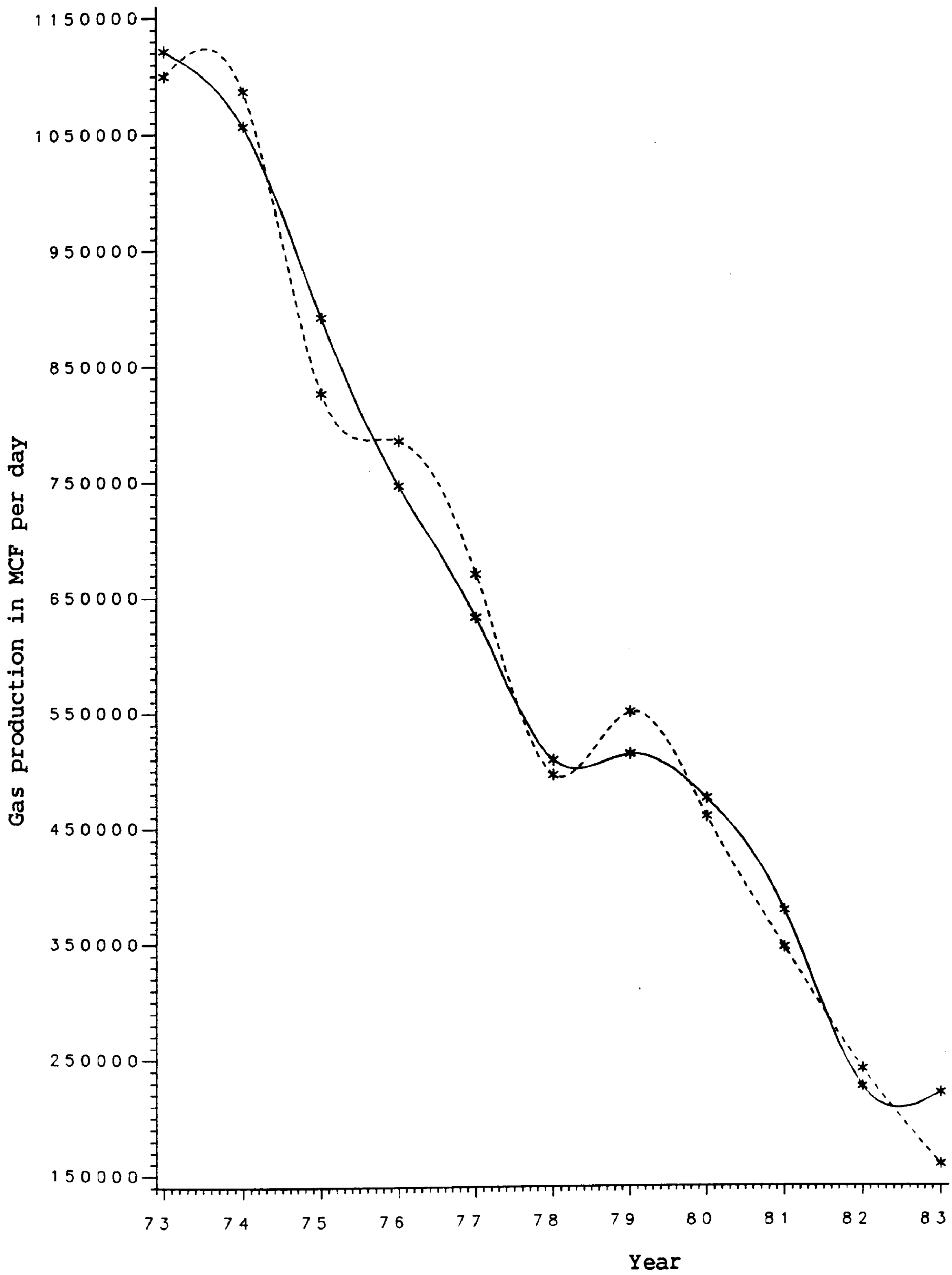

Figure 8. Actual Gas Production (solid line) vs. Predicted Gas Production (broken line) for Gomez, 1973-1983

Table 9. Non-Linear Estimation of The Model for Individual Reservoirs

Reservoir	q_o^*	D	R^2	S.E.[a]
East Texas	1023.58 (63.1)[b]	.315 (30.3)	.991	2302.27
Slaughter	629.76 (73.9)	.114 (40.0)	.987	2775.81
Neches (Woodbine)	61.82 (35.5)	.189 (15.8)	.955	546.92
Luling-Branyon	19.44 (59.6)	.056 (18.2)	.909	121.49
Gomez	13660.2 (30.9)	.159 (16.6)	.985	41489.50

[a] The standard error of the regression.

[b] t-statistics for the null hypothesis that the parameter equals zero are given in parentheses below the estimated values.

were attempted.

First, equation (4.12a) was re-estimated for each of the four oil reservoirs with a coefficient attached to the capacity augmentation index in the form of $G^*I_t^o$, to test the implicit assumption that G=1.0. This test was suggested by the fact that the capacity augmentation index (I_t^o) was constructed using the number of new infill wells as a proxy for new reserve additions. As mentioned earlier, this substitution may not guarantee that the full effect of new reserve additions on the productive capacity of the reservoir will be transmitted by the infill well data, so that the coefficient on the proxy index may not be unity.

The null hypothesis that G=1.0 was tested using the likelihood ratio test statistic $-2(\ln L_R - \ln L_{UR})$, where $\ln L_R$ is the value of the likelihood function under the restriction that G=1.0, and $\ln L_{UR}$ is the same value when G is estimated freely. Table 10 presents the value of this test statistic for each of the four oil reservoirs. Under the assumption of a normal distribution for the likelihood function, this test statistic will be asymptotically distributed as a Chi-square (X^2) random variate, so that its value can be compared to the critical values from the X^2 table for 1 degree of freedom. With the exception of Slaughter, all of the test statistics were found to exceed the critical value at the 5% significance level, implying that the null hypothesis of G=1.0 could not be rejected for those oil reservoirs at that level of significance. The estimates of the coefficients for the re-specified model of Slaughter were found to be q_o^*=286.54 (with a standard error of 100.955), D=0.149 (standard

Table 10. Likelihood Ratio Test Statistics for Specification Tests for Individual Reservoirs

Reservoir	Null Hypothesis	Test Statistic	Decision[a]
East Texas	G=1.0	0.3462	Accept
Slaughter	G=1.0	5.4772	Reject
Neches (Woodbine)	G=1.0	1.1584	Accept
Luling-Branyon	G=1.0	0.6752	Accept
Gomez	E=1.0	6.5720	Reject

[a] At the 5% level of significance.

error=0.016) and G=1.80 (standard error=0.359). The R^2 for this regression was 0.992 and the standard error of the regression was 2295.25 (only 3.36% of 1983 production).

Next, equation (4.12b) for the Gomez non-associated gas reservoir was re-estimated with a coefficient on the gas market demand index in the form of $(q_t^d)^E$ to test the implicit assumption that E=1.0. Since the gas market demand index was constructed by substituting available allowable data for the theoretically preferred measure of production as a percentage of deliverability, the null hypothesis that E=1.0 was tested, again using the likelihood ratio test. The test statistic for this hypothesis also appears in Table 10, and since it lies above the critical value for the X^2 variate with one degree of freedom at the 5% significance level, the null hypothesis was rejected. This re-estimated equation was then used for modelling non-associated gas production from Gomez for the simulations in this chapter. The new estimates of the coefficients of this model for Gomez were q_o^*=14077.2 (with a standard error of 393.031), D=0.169 (standard error=0.009) and E=0.566 (standard error=0.165). The R^2 for this regression was 0.992 and the standard error of the regression was 32644.2 (only 14.8% of 1983 production).

Finally, it might be asked whether the natural decline rates estimated by the model make any real-world sense, i.e., whether they are within the range of engineering estimates of individual well decline rates for these four reservoirs. Private communication with reservoir engineers affiliated with the companies producing from these reservoirs tended to confirm the reasonableness of these estimated natural decline rates. For sandstones with strong water drives, such as East Texas or the Neches (Woodbine), relatively high natural decline rates are to be expected, supporting the model's estimates of 31.5% and 18.9% per year, respectively. At the other end of the geological spectrum are the weaker solution-gas drive reservoirs of Central Texas represented by the Luling-Branyon, which was estimated to have a much lower annual decline rate of 5.6%. Between these two extremes lies the more moderate 14.9% annual decline rate estimated for Slaughter which is typical of the West Texas carbonates. According to industry experts, an annual decline rate of 16.9% is also reasonable to expect for a non-associated gas field that produces no condensate, such as Gomez.

H. Simulating Reserve Levels with the Estimated Equations

An additional check on the empirical validity of the model is to consider the amount of remaining recoverable reserves implied by the estimated equations. Therefore, future annual production rates were simulated for each reservoir beginning in 1984, assuming constant 1983 values of all economic variables and continuation of current tax laws, as is consistent with the reserve estimation methodology of the DOE. The capacity augmentation indexes were held constant at their 1984 values (which reflects infill drilling activity through 1983) so that the simulations would only consider the future production forthcoming from the productive capacity installed as of year end 1983. Furthermore, for Neches (Woodbine) and Slaughter no future production constraints due to prorationing were assumed, since by

1983 their fractions of production constrained by allowables (a_t) were already either zero or nearly so. In the case of East Texas, it was assumed that the fraction of constrained production would remain high indefinitely at a level of 0.80, since prorationing in this reservoir must be maintained in the interest of leaseholder equity. For Luling-Branyon, a gradual decline in a_t of 0.01 per year was assumed so that all prorationing constraints would be lifted by 1995. Similarly, a_t was assumed to drop by 0.05 each year for Gomez so that prorationing will be fully lifted there by 1989. The gas market demand index q_t^d for Gomez is gradually returned to the pre-1981 trend levels by assuming values of 0.64, 0.76, and 0.88 for 1984-1986, respectively, before reaching a constant level of 1.00 for all years after 1986.

Summing all projected future production from 1984 until the date of economic exhaustion (when economic capacity reaches zero) gives projected cumulative future production, which provides an estimate of remaining recoverable reserves. Once cumulative past production is added to projected remaining reserves, an estimate of the ultimate recovery from a reservoir is obtained. Table 11 presents the model's estimates of remaining recoverable reserves and ultimate recovery for each reservoir, along with their implied reserves-to-production (R/P) ratios for 1983. R/P ratios are commonly used by reservoir engineers to indicate the number of years of future production possible from a reservoir at the production rate of the most recent year. Of course, the reservoirs cannot continue to produce at their 1983 rates in the future without significant new development drilling activity, and even then they must eventually exhibit declining production rates. As a result, their implied dates of economic exhaustion are much farther away than is indicated by their R/P ratios, and are also shown in Table 11.

Looking at Table 11, the model predicts that the East Texas reservoir can be expected to produce approximately 724 million additional barrels of oil if current economic conditions continue, with economic exhaustion occurring in the year 2040. When added to cumulative past production of 4,082.7 million barrels as of 12-31-83, implied ultimate recovery for East Texas is in the neighborhood of 4.8 billion barrels. The *Oil and Gas Journal* annually publishes remaining reserve estimates for the largest of the oil fields in the United States that can be used for comparison with the model's predictions. Their estimate of remaining reserves for East Texas as of year end 1983 is 1,267.688 million barrels, which is considerably higher than the estimate obtained here (*Oil and Gas Journal*, January 30, 1984). Using their reserve estimate, implied ultimate recovery for East Texas will approach 5.3 billion barrels of oil, which is almost 10% higher than that predicted by this analysis. However, a separate, detailed study of major oil and gas reservoirs in the U.S. done by the Federal Energy Administration (1975) gives a much different reserve estimate for East Texas that lends support to a lower projection. The FEA study estimated remaining reserves for East Texas as of year end 1974 at 1,250.2 million barrels, which implies, after subtracting production observed from 1975 through 1983, a year end 1983 reserve estimate of only 708.8 million barrels.

Table 11. Estimated Reserves for Individual Reservoirs

	East Texas	Slaughter	Neches (Woodbine)	Luling-Branyon	Gomez
Projected cumulative future production	723.977[a]	145.182	11.239	14.244	587.840[b]
Projected ultimate recovery	4,806.7	1,116.7	94.5	152.8	4,332.0
Implied year of economic exhaustion	2040	2011	2011	2027	2034
R/P ratio for 1983	14.2	5.8	5.2	13.3	7.3

[a] Oil volumes are given in millions of barrels.

[b] Gas volumes are given in billions of cubic feet.

Such wide discrepancies in published figures exemplify the uncertainty associated with the estimation of petroleum reserves, especially at the reservoir level.

The Slaughter reservoir is predicted by the model to produce approximately 145 million barrels of oil between 1984 and 2019, in the absence of any new drilling activity. Slaughter's cumulative past production as of 12-31-83 is 926.4 million barrels, so estimated ultimate recovery for Slaughter is therefore 1,071.6 million barrels. The *Oil and Gas Journal* shows a year end 1983 remaining reserve estimate for Slaughter of 80.2 million barrels, implying an ultimate recovery of only 1,006.6 million barrels. The model's reserve estimate is substantially higher, but has to be more realistic, since the R/P ratio of 3.2 implied by the 80.2 million barrel reserve estimate is unreasonably low and implies a much faster decline rate than is possible for carbonate reservoirs of this type. Lending additional support to the model's higher reserve estimate is the projection made by Galloway, et al., who estimate Slaughter's ultimate recovery at 1,216.1 million barrels, implying remaining reserves of 289.7 million barrels.

For Neches (Woodbine), the year end 1983 published reserve estimate (also found in the *Oil and Gas Journal*) is 15.5 million barrels, compared to the model's estimate of 11.2 million barrels. Estimated ultimate recovery for Neches (Woodbine) is then 94.5 million barrels using these projections, which is 4.4% lower than the 98.8 million barrels obtained using the published estimate. Although a bit conservative, the ultimate recovery projected here is entirely plausible.

Projected remaining reserves and ultimate recovery for Luling-Branyon are 14.2 and 152.8 million barrels, respectively. As is characteristic of all reservoirs in the Austin Chalk geologic play, there are no reliable published reserve estimates available for the Luling-Branyon reservoir to compare with these estimates.

Turning to the Gomez reservoir, the non-associated gas production model estimates remaining gas reserves of about 588 BCF at year end 1983. Cumulative past production from Gomez stands at 3,744.2 BCF as of 12-31-83 for an implied ultimate gas recovery of 4,332.0 BCF. The *Oil and Gas Journal* does not publish reserve estimates for U.S. non-associated gas fields, but the FEA study estimated the ultimate recovery from Gomez at 4,370 BCF, very close to the projection made here. The FEA study also estimated remaining gas reserves for Gomez at 2,327 BCF at year end 1974, which translates into a year end 1983 reserve estimate of 646 BCF once gas production over the interim has been subtracted. The similarity in these reserve estimates implies that despite the added complexities of the non-associated gas production model, it offers an accurate method for projecting future non-associated gas production at the reservoir level.

I. Simulating Price Effects on Production and Reserve Levels

To demonstrate the flexibility of this modelling approach, an additional set of simulation runs was performed for each reservoir to determine the implied elasticities of production from existing reserves with respect to the real price of petroleum. For the four oil reservoirs, the amount of cumulative future oil production was simulated under the assumption that the market price of oil permanently increased by 10% in real terms as of 1-1-84. For the Gomez non-associated gas reservoir, it was assumed that the real market price of gas rose by 10% at the same point in time. The incremental additions to projected cumulative future production for the individual reservoirs that resulted from these real price increases are presented in Table 12. This table gives both the additional barrels of oil or cubic feet of gas produced under the higher price scenario as well as the percentage increases in cumulative future production those quantities imply for each reservoir. Dividing these percentage increases by the 10% increase in real price yields the implied price elasticities, which are also reported in Table 12.

As Table 12 indicates, the price elasticities implied by the estimated model vary considerably across the five reservoirs. East Texas and Neches (Woodbine) exhibit the smallest responses for the oil reservoirs, with price elasticities of just over 0.05. Such small elasticities of production out of existing reserves are not unreasonable for these two reservoirs, since the geologic characteristics of a strong water drive mechanism will make production from them decline rather quickly over time, whatever the level of the economic limit. By reference to Figure 1 in Chapter II, a faster natural decline rate will imply that reservoir production will drop more sharply over time, making for a very small change in

Table 12. Implied Price Elasticities for Individual Reservoirs

	East Texas	Slaughter	Neches (Woodbine)	Luling-Branyon	Gomez
Incremental cumulative future production	4.123[a]	1.599	0.057	0.434	1.980[b]
Percentage Increase In Production	0.570	1.102	0.510	3.046	0.337
Implied Price Elasticity	0.057	0.110	0.051	0.305	0.034

[a] Oil volumes are given in millions of barrels.

[b] Gas volumes are given in billions of cubic feet.

the economic lifetime of the reservoir as a result of the lower economic limit. Therefore a small price elasticity is to be expected for such reservoirs. For the less rapidly declining Slaughter and Luling-Branyon reservoirs, there are greater possibilities for increased production from the existing reserve base when the price of oil rises. Accordingly, these two oil reservoirs are found to have considerably higher price elasticities of 0.110 and 0.305, respectively. From these results, it is clear that the reservoir's price elasticity of production from a fixed reserve base will vary inversely with its natural decline rate. This general observation also holds true for the Gomez non-associated gas reservoir, which was found to have a low gas price elasticity from existing reserves of only 0.034, with its relatively high estimated natural decline rate of 16.9% per year.

This exercise shows how the generalized production model can be used to analyze the impact of any economic or policy change on production from reserve bases containing fixed amounts of productive capacity. The analysis can easily be extended to consider the impact on production from an expanding reserve base through the capacity augmentation index I_t, as will be demonstrated in Chapter VI.

J. Summary and Conclusions

It is not often that the validity of a new modelling approach proposed for an analysis of aggregate behavior can be assessed at a microeconomic level before applying it to the macroeconomic level. Fortunately, this was possible in this instance. The results presented in this chapter demonstrate that the theoretical petroleum production model developed in Chapter III performs quite adequately in both describing past production patterns and in projecting cumulative future production levels that are consistent with published reserve estimates.

However, the model's validity does not rest entirely on its explanatory and predictive power; it is also appealing in other respects. First, the structural parameters of the production model were estimated with statistical precision, and were found to have theoretically correct signs and magnitudes. Second, the detailed structure of the model was shown to make it a very flexible tool for examining the effects of price changes or tax policy changes on production from existing reserves through the abandonment decision. Third, the model incorporates a wide variety of determinants of petroleum production, including the effects of infill drilling in already producing reservoirs, the prorationing of individual wells, the natural decline phenomena associated with increasing cumulative production, and the economic factors that influence the level of the economic limit.

Given the strong microeconomic foundations for this model demonstrated in this chapter, it can now be applied to an analysis of aggregate Texas conventional oil production and aggregate Texas non-associated gas production in the next chapter, knowing that the model performs well empirically at the micro level.

CHAPTER V

AN ANALYSIS OF AGGREGATE TEXAS PETROLEUM PRODUCTION

The purpose of this chapter is to develop an econometric model that is capable of describing the aggregate levels of production of crude oil, non-associated gas, associated gas, and condensate from Texas reserves. The aggregate production levels of conventional crude oil and non-associated gas will be modelled using the generalized petroleum production model that was developed in Chapter III and empirically tested at the microeconomic level in Chapter IV. The aggregate levels of associated gas production from Texas oil wells and condensate production from Texas non-associated gas wells will be modelled using aggregate gas-oil and condensate-gas production ratios, respectively. The estimated equations will then be used to simulate future cumulative production levels in order to project aggregate Texas reserves of conventional oil and non-associated gas.

The aggregate model estimated in this chapter will also be used to simulate the impact of changes in the windfall profit tax (WPT) phaseout schedule on aggregate Texas petroleum reserve levels. These projected impacts will represent the effects of changes in the WPT on aggregate conventional oil and non-associated gas production out of existing reserves. This same WPT analysis will be repeated in Chapter VII, after the estimated model of aggregate Texas petroleum production has been integrated in Chapter VI with an econometric model developed by Bremmer that describes aggregate new reserve additions coming from the Texas petroleum drilling sector.

This chapter concludes with the development of a model of future expected enhanced oil recovery (EOR) activity in Texas, based upon the EOR projections of the National Petroleum Council's Committee on Enhanced Oil Recovery (1984). This aggregate EOR model will be needed for the windfall profit tax analysis of Chapter VII, since EOR production is expected to play a significant role in future petroleum production from the lower 48 United States, and the windfall profit tax provides special incentives for EOR projects.

A. Description of the Data

Since the results of the previous chapter verified the empirical validity of the generalized petroleum production model, it will now be applied to an analysis of aggregate Texas conventional oil production and aggregate Texas non-associated gas production. To briefly recapitulate, the equation describing aggregate conventional oil production will have the form

$$(5.1) \qquad q_t^o = q_o^*\{100 - (e^{\tilde{\gamma}_0})(EL_t e^{D(\tau_t^o-\tau_{1983}^o)-(I_t^o-I_{1983}^o)})^{\tilde{\gamma}_1})\}e^{I_t^o-D\tau_t^o},$$

while the equation describing aggregate non-associated gas production will be

$$(5.2) \qquad q_t^g = q_o^*\{100 - (e^{\tilde{\gamma}_0})(EL_t e^{D(\tau_t^g-\tau_{1983}^g)-(I_t^g-I_{1983}^g)})^{\tilde{\gamma}_1})\}q_t^d e^{I_t^g-D\tau_t^g}.$$

Once again, a sample of annual observations over the period 1973 through 1983 was selected for estimation purposes. The sources for this annual data are almost exactly the same as those for the individual reservoir data delineated in Chapter IV, and the actual data used in this chapter appears in Appendix B. Annual production data comes from the *Annual Reports* of the Texas Railroad Commission, oil prices were found in *Platt's*, and average wellhead values for gas were taken from the *Basic Petroleum Data Book* of the American Petroleum Institute (API). Aggregate annual levels of reserves and new reserve additions in Texas for the years 1973 through 1979 were found in *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada*, published by the API in association with the American Gas Association. This annual reserve series by the API/AGA terminated in 1979, but similar information began to be reported by the DOE as of 1977 in its publication *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves*, and this was the source for annual reserve and reserve addition levels data in Texas for the years 1980 through 1983. Appropriate tax rates were again found in Pechman (federal income tax rate) and *Oil and Gas Production Tax Laws* (Texas state severance tax rates). The royalty rate was again assumed to have a constant value of 1/8. Information on the appropriate windfall profit tax treatment of production from marginal wells (tax rates, base price and inflation adjustment factors) was again obtained from major petroleum producers operating in Texas, as were data on marginal well operating costs and ad valorem tax rates.

In the following sections, this data will be used to calculate each of the indexes appearing in equations (5.1) and (5.2) that are needed to estimate the model. These indexes include the statewide oil and non-associated gas capacity augmentation indexes (I_t^o, I_t^g), the statewide non-associated gas market demand index (q_t^d), the statewide oil and non-associated gas economic capacity indexes (EC_t^o, EC_t^g) and the statewide modified time indexes for oil and non-associated gas production (τ_t^o, τ_t^g). After each of these indexes has been determined, the estimation of equations (5.1) and (5.2) will be described and evaluated.

B. Calculation of the Statewide Capacity Augmentation Indexes

Since annual new reserve additions are publicly reported at the state level, the capacity augmentation indexes for aggregate Texas oil production (I_t^o) and aggregate Texas non-associated gas production (I_t^g) were calculated as originally suggested by equation (3.4). This means that the indexes took the form

$$(5.3) \qquad I_t = I_{t-1} + (1/n)\Sigma_{i=0}^{n} (A_{t-i}/R_{t-1-i}),$$

where A_t is the level of statewide new reserve additions in year t and R_{t-1} is the level of aggregate Texas reserves for the previous year, with I_{1973}=1.0. The lengths of the moving averages of the ratios of annual new reserve additions to the previous year's reserves were set at five years (i.e., n=4) for oil and two years (n=1) for non-associated gas, smoothing out the erratic patterns of annual new reserve additions observed over the sample period. The levels of annual new reserve additions to aggregate Texas oil reserves (A_t^o) and aggregate Texas non-associated gas reserves (A_t^g) for 1973 through 1983 are reproduced from Appendix B and presented in

Table 13 along with the values of the statewide capacity augmentation indexes that were calculated according to equation (5.3).

Table 13 shows how the net effect of new pool discoveries, existing field extensions and reserve estimate revisions was to create a very noisy new reserve addition series for both aggregate oil reserves and aggregate non-associated gas reserves in Texas from 1973 through 1983. The fluctuations seen in these series of new reserve additions cannot be indicative of similar variations in the actual additions to (or subtractions from) the productive capacities of the aggregate reserve bases of oil and non-associated gas in Texas over this period. For example, the large downward revisions of aggregate Texas non-associated gas reserves indicated for the years 1973 and 1978 reflect changing perceptions of the recoverable reserves rather than actual reductions in the reserve base from which production must come. The smoothing of these series by the use of moving averages allows the calculated capacity augmentation indexes to more realistically reflect the true growth in the aggregate reserve bases over the sample period. It is this steadier series of capacity-expanding activity that should be used to model annual production, not the more volatile unadjusted series, whose fluctuations do not correspond to actual changes in the size of the reserve base.

The values of the statewide capacity augmentation indexes reported in Table 13 reflect the successful aspects of the considerable amount of drilling activity that has characterized the Texas petroleum industry since 1973. Not considering the impact of

Table 13. New Reserve Additions and Capacity Augmentation Indexes for Aggregate Texas Data

	Crude Oil		Non-Associated Gas	
Year	A_t^o	I_t^o	A_t^g	I_t^g
1973	872[a]	1.0000[b]	-3,270[c]	1.0000[d]
1974	471	1.0640	1,344	0.9877
1975	254	1.1121	292	1.0014
1976	305	1.1510	1,724	1.0309
1977	339	1.1914	3,644	1.0957
1978	266	1.2237	-158	1.1319
1979	927	1.2721	3,487	1.1724
1980	796	1.3367	2,927	1.2516
1981	620	1.4102	5,160	1.3515
1982	474	1.4880	4,204	1.4638
1983	553	1.5740	3,563	1.5558

a New reserve additions of oil in millions of barrels.

b $I_t^o = I_{t-1}^o + (1/5)\Sigma_{i=0}^{4}(A_{t-i}^o/R_{t-1-i}^o)$

c New reserve additions of non-associated gas in billions of cubic feet.

d $I_t^g = I_{t-1}^g + (1/2)\Sigma_{i=0}^{1}(A_{t-i}^g/R_{t-1-i}^g)$

abandonment or re-opening of individual wells since 1973, these series show that the productive capacities of the aggregate Texas oil and non-associated gas reserve bases have grown by 57.4% and 55.6%, respectively, since 1973. As these capacity augmentation indexes were constructed using smoothed reserve additions series, they should completely reflect any movement in the size of the reserve bases. Therefore, the implicit coefficients of 1.0 for I_t^o and I_t^g will not need to be tested as they were when as a proxy for new reserve additions, new infill well data were used for the calculation of the capacity augmentation indexes of the individual oil reservoirs in Chapter IV.

C. Calculation of the Statewide Non-Associated Gas Market Demand Index

Application of the non-associated gas production model of equation (5.2) to aggregate Texas data will require the calculation of the statewide non-associated gas market demand index q_t^d. The theoretical discussion of the construction of this index in Chapter III suggested that it be calculated as the ratio of the percentage of reserve basewide deliverability that was actually produced in each year to the same percentage in a benchmark year of strong gas demand. Unfortunately, the data on statewide non-associated gas production as a percentage of deliverability were only available from the Texas Railroad Commission for the years 1981 through 1983. However, the typically strong gas market demand conditions that prevailed in Texas and the U.S. from 1973 through 1981 suggest that the percentage of deliverability actually produced in 1981 could serve as the benchmark percentage for the denominator of the ratio needed for the index. This implies that the values of the ratio from 1973 through 1981 must be set to unity. This is probably not unreasonable to assume, since the values of the gas market demand index calculated for the Gomez non-associated gas reservoir in Chapter IV also exhibited values that were practically unity over this same period (See Table 4). The values of the statewide non-associated gas market demand index for 1982 and 1983 were calculated as the ratios of non-associated gas production as a percentage of deliverability for those two years (53% and 45%, respectively) to the percentage for the benchmark year 1981 (59%).

The values of the statewide non-associated gas market demand index q_t^d for the years 1973 through 1983 are presented in Table 14. Since this index was calculated using production as a percentage of deliverability, it was not necessary to test the hypothesis that the implied exponent on the index was equal to unity, as it was necessary to do for the substitute gas market demand index constructed for the Gomez reservoir in Chapter IV.

D. Calculation of the Statewide Economic Capacity Indexes

Just as with the individual reservoir analysis in Chapter IV, application of the generalized production model of Chapter III to aggregate Texas production data will require that the forms of the statewide production distributions (Δ_t in equation (3.7)) be estimated in order to measure statewide levels of economic capacity

Table 14. Statewide Non-Associated Gas Market Demand Index

Year	q_t^d
1973	1.00
1974	1.00
1975	1.00
1976	1.00
1977	1.00
1978	1.00
1979	1.00
1980	1.00
1981	1.00
1982	0.89
1983	0.75

(EC_t^o, EC_t^g). Average daily production rates at the level of each individual well in the state were once again gathered for the year 1983 from the files of Petroleum Information Corporation. To reiterate, well level data is readily available for non-associated gas wells, but must be approximated from lease level data for oil wells.

This well level data was then organized to allow for accumulation of the percentage contributions to statewide production, going from the lowest average daily well production rate observed in the state in 1983 to the highest. These data sets, consisting of the cumulative percentages (CUM_i) of total statewide production that were associated with each average daily production rate (q_i) observed in the state during 1983, were again used in a linear regression of the form

$$(5.4) \qquad CUM_i = \beta_0 + \beta_1 q_i + \epsilon_i, \qquad \text{for } CUM_i \leq 20,$$

to estimate the intercept terms (β_0) of the tails of the two statewide production distributions. The results of the estimation of equation (5.4) using statewide oil and non-associated gas production data appear in Table 15.

Just as in Chapter IV, the estimated intercept terms ($\bar{\beta}_0$) were used to adjust the cumulative percentages of production as follows:

$$(5.5) \qquad CUMADJ_i = \Sigma_{k=1}^{i}((CUM_k+\bar{\beta}_0)/(100+\bar{\beta}_0)).$$

These adjusted cumulative percentages were then used as proxies for the cumulative percentages that would be observed under an economic

Table 15. Linear Estimation of Equation (5.4) Using Aggregate Texas Data

Reservoir	β_0	β_1	R^2	S.E.[a]	n[b]
Crude Oil	-1.24 (836.5)[c]	1.93 (7603.1)	.999	0.178484	76,783
Non-Associated Gas	-1.28 (1007.4)	.097 (7883.6)	.999	0.105569	24,953

[a] The standard error of the regression.

[b] Number of observations in the sample.

[c] t-statistics for the null hypothesis that the parameter equals zero are given in parentheses below the estimated values.

limit of zero. The same log-linear functional form selected in Chapter IV was used to model the adjusted statewide production distributions, so that the estimating equations took the form

$$(5.6) \qquad \ln(\text{CUMADJ}_i) = \gamma_0 + \gamma_1 \ln(q_i) + \eta_i .$$

The intercept term γ_0 was again replaced by the value $\ln|\beta_0+\beta_1|$ computed from the linear regressions of equation (5.5), so that only the slope parameter γ_1 was estimated by (5.6). Table 16 presents the results of these log-linear regressions using the adjusted statewide production distributions.

Once again this specification fit the adjusted production distributions nicely, yielding statistically significant estimates of γ_1 that could be used to calculate the levels of statewide economic capacity according to

$$(5.7) \qquad EC_t = 100 - e^{\tilde{\gamma}_0}(B_t)^{\tilde{\gamma}_1},$$

where $\tilde{\gamma}_0=\ln|\beta_0+\beta_1|$. Expressing the statewide economic limit (B_t) in (5.7) using equation (3.8) allows the economic capacity index to be written more specifically as

$$(5.8) \qquad EC_t = 100 - (e^{\tilde{\gamma}_0})(EL_t e^{D(\tau_t-\tau_{1983})-(I_t-I_{1983})})^{\tilde{\gamma}_1} .$$

The remaining step required for estimating the levels of statewide economic capacity using equation (5.8) was to calculate the levels of the average individual well economic limits (EL^o_t, EL^g_t) for statewide oil and non-associated gas production. For simplicity,

Table 16. Log-Linear Estimation of the Adjusted Production Distributions Using Aggregate Texas Data

Reservoir	$\tilde{\gamma}_0$	$\tilde{\gamma}_1$	R^2	S.E.[a]	n[b]
Crude Oil	-.37 (753.6)[c]	1.20 (1003.8)	.835	1.123402	198,814
Non-Associated Gas	-.29 (203.5)	.56 (1332.2)	.974	0.417129	46,899

[a] The standard error of the regression.

[b] Number of observations in the sample.

[c] t-statistics for the null hypothesis that the parameter equals zero are given in parentheses below the estimated values. The standard error used to compute the t-statistic for the intercept term $\tilde{\gamma}_0$ was derived using an approximation suggested by Alexander M. Mood, et al. (1974, p. 181).

these individual oil (gas) well economic limits were assumed to be the same for all oil (gas) wells in the state. Annual observations on all the economic and tax variables appearing in equation (3.15) for the individual oil well economic limit and equation (3.19) for the individual non-associated gas well economic limit were used to calculate these economic limits, and the resultant values are reported in Table 17.

Table 17 shows much the same pattern in individual well economic limits at the state level as were found at the individual reservoir level in Table 7. Economic limits for the average Texas oil well fell significantly in 1974 and 1975, but leveled off thereafter before falling by almost a full barrel per day after oil price decontrol in 1981. Declining oil prices caused the average Texas oil well economic limit to rise slightly in 1982 and 1983. The economic limit for the average Texas non-associated gas well dropped sharply from 1973 to 1977, and continued to decline, although more slowly, through the rest of the sample period.

E. Calculation of the Statewide Modified Time Indexes

In order to account for the effects of individual well prorationing that persisted in Texas even after the market demand factor reached 100% in April 1972, it was necessary to calculate the annual values of the modified time indexes (τ_t^o, τ_t^g) for statewide oil and non-associated gas production in Texas over the sample period.

Following the same decision rule used in Chapter IV for the individual reservoir analysis to decide whether an individual well

Table 17. Economic Limits for Aggregate Texas Data

	Crude Oil	Non-Associated Gas
Year	EL_t^o	EL_t^g
1973	4.04[a]	198.05[b]
1974	3.06	161.26
1975	2.82	115.54
1976	3.03	95.22
1977	3.05	80.33
1978	2.96	81.69
1979	2.90	74.57
1980	2.93	68.27
1981	1.90	63.81
1982	2.09	61.16
1983	2.15	58.80

[a] Production rate in BPD for an average individual oil well located in Texas.

[b] Production rate in MCF per day for an average individual non-associated gas well in Texas.

was actually constrained by its allowable in any given year, the fractions of statewide oil and non-associated production found to arise from constrained wells (a_t^o, a_t^g) were calculated and appear in Table 18. Also reported in Table 18 are the resulting values of the modified time indexes, determined as

$$\tau_t = \tau_{t-1} + (1-a_{t-1}). \tag{5.9}$$

The steadily declining values of a_t^o and a_t^g seen in Table 18 reflect the decreasing importance of individual well prorationing in Texas over the sample period. The percentage of oil wells in Texas that were constrained by their allowables fell from about 44% in 1973 to just under 15% by 1981, holding almost constant at that level for the next two years. The fraction of non-associated gas wells in Texas that were found to be constrained by their allowables similarly fell from approximately one-half to one-quarter over the sample period.

The consistent overall downward trends of these two series (a_t^o and a_t^g) make for progressively rising values of the two modified time indexes τ_t^o and τ_t^g. As can be inferred from the values of τ_t^o and τ_t^g in 1983, prorationing has effectively allowed statewide oil and non-associated gas production to naturally decline by only 8.3480 and 7.8348 years, respectively, over the 11 year sample period.

Table 18. Modified Time Indexes for Aggregate Texas Data

	Crude Oil		Non-Associated Gas	
Year	a_t^o	τ_t^o [a]	a_t^g	τ_t^g [b]
1973	0.4385	1.0000	0.4660	1.0000
1974	0.4248	1.5615	0.4194	1.5340
1975	0.3446	2.1367	0.4068	2.1146
1976	0.3409	2.7921	0.3841	2.7078
1977	0.2366	3.4512	0.2457	3.3237
1978	0.2069	4.2146	0.2381	4.0780
1979	0.1837	5.0077	0.2782	4.8399
1980	0.1808	5.8240	0.2723	5.5617
1981	0.1493	6.6432	0.2347	6.2894
1982	0.1459	7.4939	0.2199	7.0547
1983	0.1461	8.3480	0.2424	7.8348

[a] $\tau_t^o = \tau_{t-1}^o + (1-a_{t-1}^o)$

[b] $\tau_t^g = \tau_{t-1}^g + (1-a_{t-1}^g)$

F. Estimation of the Statewide Models

At this point, all of the component indexes had been calculated that were needed to estimate equations (5.1) and (5.2) using statewide production data. These two non-linear equations were then estimated using the same non-linear least squares iterative estimation procedure that was described and used in Chapter IV, and the results appear in Table 19. Actual average daily production rates for statewide oil and non-associated gas production are plotted against the rates predicted by the regressions in Figures 9 and 10.

Table 19 indicates that the parameter estimates are highly statistically significant, with the theoretically proper signs. The coefficients of determination (R^2) are similarly impressive, with values of 0.994 for the oil production equation and 0.969 for the non-associated gas equation. Additionally, the standard errors of the regressions are very low percentages of 1983 production rates, being only 1.44% for oil and 4.25% for non-associated gas. From a statistical perspective, it appears that the estimated equations possess considerable explanatory power regarding aggregate petroleum production in Texas from 1973 through 1983.

The estimated annual natural decline rate of 13.0% for statewide oil production seems to be quite reasonable when viewed as a statewide average, considering the range of annual natural decline rates estimated for the individual oil reservoirs in Chapter IV. The natural decline rate of 13.7% per year estimated as the statewide average for non-associated gas production was somewhat lower than the moderately high 16.9% rate found for the condensate-free Gomez gas

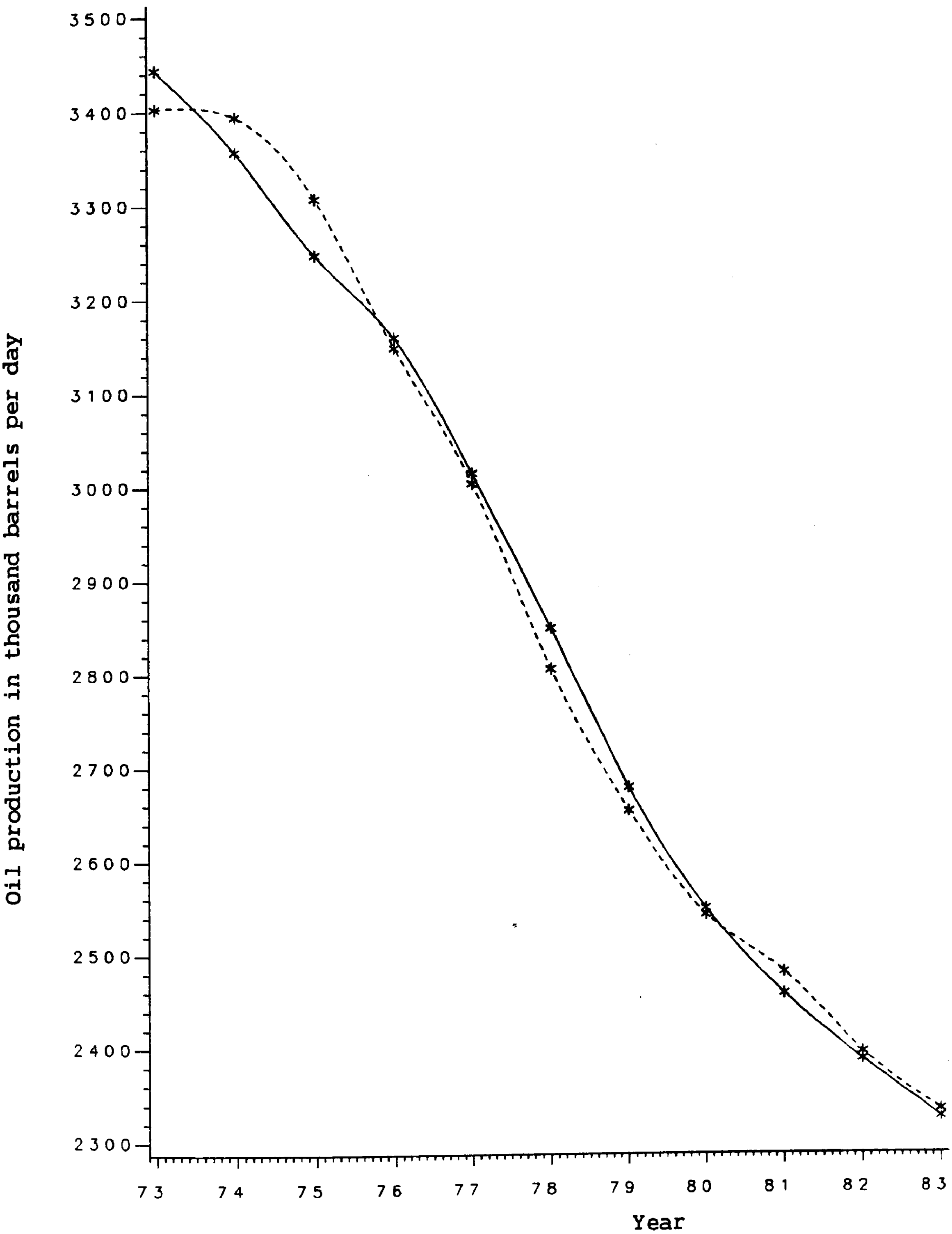

Figure 9. Actual Production (solid line) vs. Predicted Production (broken line) of Crude Oil in Texas, 1973-1983

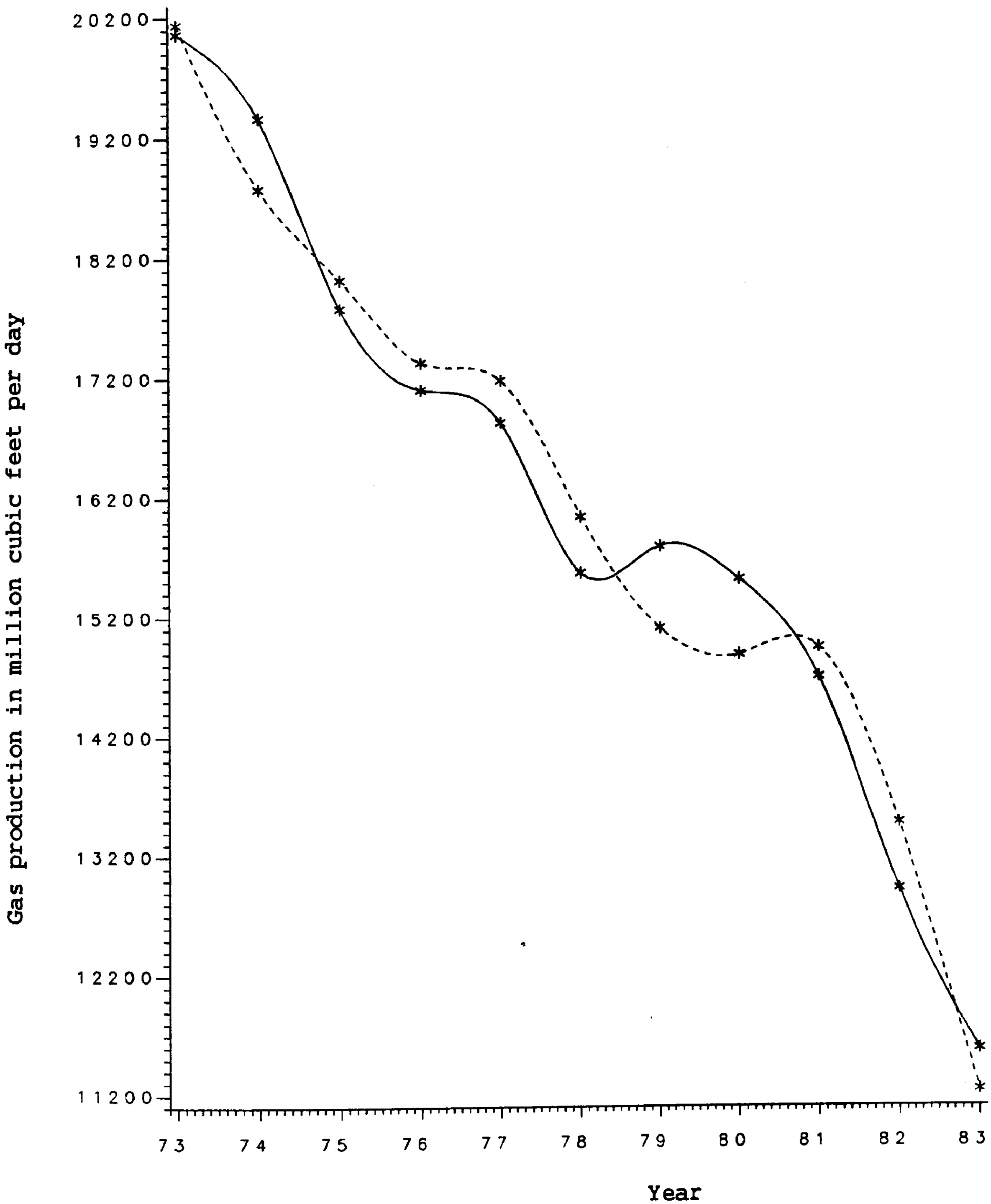

Figure 10. Actual Production (solid line) vs. Predicted Production (broken line) of Non-Associated Gas in Texas, 1973-1983

Table 19. Non-Linear Estimation of Equation (5.1) and Equation (5.2) Using Aggregate Texas Data

Reservoir	q_o^*	D	R^2	S.E.[a]
Crude Oil	12192.4 (151.9)[b]	.130 (86.1)	.994	33580.1
Non-Associated Gas	99148.2 (62.1)	.137 (34.0)	.969	492898.0

[a] The standard error of the regression.

[b] t-statistics for the null hypothesis that the parameter equals zero are given in parentheses below the estimated values.

reservoir.

It should be reiterated that these estimated annual natural decline rates are those that would only be observed if there were no prorationing constraints on all oil and gas wells in the state in addition to no further capacity augmentation from exploratory or development drilling activity. As was mentioned previously, it is essential to estimate these natural decline rates accurately in order to properly project future production rates, whether from existing reserves or allowing for capacity augmentation from the drilling sector of the Texas petroleum producing industry. As an example, if the annual decline rate for statewide oil production observed over the same sample period were estimated using the simple exponential decline model of equation (3.1), the estimated decline rate would be only 4.3%. This is because observed statewide oil production rates have declined at an average rate of 4.3% over that period. Extrapolation of production rates using this lower decline rate would not be appropriate, since doing so would imply that the prorationing and reserve additions patterns of the sample period could be expected to continue unchanged indefinitely.

Furthermore, the reserve estimate for 1983 implied by the simple exponential decline model can be calculated from the 1983 annual Texas production level of 848,990 million barrels (MMBBLS) and the 4.3% decline rate according to equation (2.5), and is found to be

$$(5.10) \qquad R_{1983} = q_{1983}/D = 848{,}990/.043 = 19{,}966.9 \text{ MMBBLS},$$

which contrasts sharply with the published estimate of Texas oil reserves at 7,539 MMBBLS as of year end 1983.

G. Modelling Statewide Production of Associated Gas and Condensate

To complete the analysis of aggregate conventional petroleum production in Texas, it was necessary to determine the projected future production levels of associated gas and condensate, which are jointly produced along with crude oil and non-associated gas, respectively. Production of these two joint products is usually modelled through the application of either the gas-oil production ratio (GOR_t) or the condensate-gas production ratio (CGR_t), as applicable. Following this methodology, aggregate Texas associated gas production levels (q_t^a) were estimated as

(5.11) $$q_t^a = GOR_t \cdot q_t^o,$$

where q_t^o is the level of aggregate Texas oil production in year t. As Appendix B shows, the statewide gas-oil production ratio has shown no definite trend over the sample period, fluctuating from a low of 1.266 MCF per barrel of oil in 1976 to a high of 1.667 in 1983. This ratio was therefore held constant at its 1983 level of 1.667 MCF per barrel of oil for simulation purposes, which was the best assumption that could be made for an indefinite period of time.

In a similar manner, aggregate Texas condensate production levels (q_t^c) were estimated by

(5.12) $$q_t^c = CGR_t \cdot q_t^g,$$

where q_t^g is the level of aggregate Texas non-associated gas production in year t. The condensate-gas production ratio was also held constant at its 1983 level of 0.0064 barrels per MCF of non-associated gas for simulation purposes.

H. Reserve Implications of the Statewide Models

The empirical validity of the estimated statewide models can be further verified by using them to project future production levels in order to compare their implied reserve levels with published reserve estimates. Future statewide production rates for both conventional oil and non-associated gas were simulated, starting in 1984 and continuing until economic exhaustion occurred (i.e., statewide economic capacity reached a level of zero). These simulations assumed continuation of current tax laws and did not allow for any further capacity augmentation from new reserve additions, so that the simulations would only project the amounts of future production forthcoming from the productive capacity installed at the end of 1983. Thus, the capacity augmentation index I_t^o became constant after 1987 and I_t^g became constant after 1984, since annual new reserve additions were assumed to be zero after 1983 and the indexes are driven by moving averages of the ratio of new reserve additions to the previous year's reserves.

The fractions of future production assumed to be constrained by prorationing (α_t^o and α_t^g) were allowed to gradually fall, declining by 0.005 each year for statewide oil production and 0.010 each year for non-associated gas. The non-associated gas market demand index was gradually raised from its 1983 level of 0.75 over the first two years of the simulation to 0.84 in 1984 and 0.92 in 1985, before returning indefinitely to its pre-1982 value of 1.00 in 1986.

Real oil and gas prices were assumed to remain constant indefinitely at their 1983 levels, when measured in 1983 dollars. This implied a constant real oil price of $29.83 per barrel and a constant real gas price of $2.31 per MCF. These assumptions resulted in reserve estimates that are consistent with the reserve estimation methodology of the DOE, making them comparable with their published figures.

Table 20 reports the simulation results under constant real 1983 prices, showing projected cumulative future production (i.e., reserves), the implied year of economic exhaustion of existing reserves, and the reserves-to-production (R/P) ratio for 1983. When assuming constant real 1983 prices, the estimated oil production equation predicts remaining, economically recoverable conventional oil reserves for Texas of 7,507 MMBBLS. The installed productive capacity supporting this projected future conventional oil production would finally be completely abandoned in the year 2016, when the last remaining oil well would no longer be economically attractive to operate. Non-associated gas reserves for Texas under constant real prices are estimated at 42,366 BCF. Economic exhaustion of the statewide non-associated gas productive capacity installed in Texas as of year end 1983 would occur in the year 2021. The R/P ratios give the number of years of future production possible from the estimated statewide reserves at 1983 production rates, being 8.8 years for conventional oil and 10.0 years for non-associated gas.

Table 20. Aggregate Texas Reserves Estimated by the Statewide Models

	Conventional Oil	Non-Associated Gas
Projected cumulative future production	7,507.0[a]	42,365.9[b]
Implied year of economic exhaustion	2016	2021
R/P ratio for 1983	8.8	10.0

[a] Oil volumes are given in millions of barrels.

[b] Gas volumes are given in billions of cubic feet.

As suggested earlier, these aggregate Texas reserve estimates made by assuming constant real prices can be compared with those made by the DOE. For aggregate Texas crude oil reserves, the DOE estimate as of year end 1983 was 7,539 MMBBLS. This figure is virtually identical to the prediction made by the estimated oil production equation of 7,507 MMBBLS. For aggregate Texas non-associated gas reserves, the DOE reserve estimate as of year end 1983 was 42,830 BCF. The prediction of the estimated non-associated gas production equation is also very close to the published DOE figure. These differences in aggregate reserve estimates are small enough to conclude that the generalized production model provides an acceptable alternative method of projecting aggregate conventional oil or non-associated gas reserves.

I. Price Effects in the Statewide Models

The sensitivity of the estimated statewide models to the assumed levels of real oil and gas prices was considered next. Therefore, future statewide production levels of conventional oil and non-associated gas were simulated under constant real oil and gas prices that were 10% higher than the 1983 values used in the preceding simulation. This implies a constant real oil price of $32.81 per barrel and a constant real gas price of $2.54 per MCF, when measured in 1983 dollars. By comparing the projected future production levels obtained when assuming these 10% higher real prices to the levels obtained previously, the price responsiveness of production from existing reserves can be estimated.

Table 21. Price Elasticities of the Statewide Models

	1 year	10 years	20 years	Long run[a]
Conventional Oil				
Projected cumulative future production under 10% higher prices	811.2[b]	5,433.8	7,135.8	7,563.0
Absolute increase	0.9	10.7	27.5	56.0
Percentage increase	0.114	0.197	0.387	0.746
Non-Associated Gas				
Projected cumulative future production under 10% higher prices	4,313.2[c]	31,246.5	40,515.3	42,702.3
Absolute increase	17.0	160.0	257.2	336.4
Percentage increase	0.396	0.515	0.639	0.788

[a] Until the point of economic exhaustion.

[b] Oil volumes are given in millions of barrels.

[c] Gas volumes are given in billions of cubic feet.

Table 21 reports the projected levels of cumulative future statewide production of conventional oil and non-associated gas forthcoming from year end 1983 reserves under 10% higher real prices. As would be expected, projected production levels are higher than those projected under 1983 prices, and the absolute and percentage increases are shown after the passage of one year, 10 years, 20 years and in the long run, when economic exhaustion has occurred. The higher real prices increase the economic lifetimes of aggregate Texas conventional oil reserves by 0.74 years (271 days), and aggregate Texas non-associated gas reserves by 1.36 years (497 days).

The percentage increase in cumulative production can be used to compute the implied price elasticities after 1 year, 10 years, 20 years or in the long run by simply dividing the percentage increase by the 10% increase in real price. Reasoning accordingly, it can be seen that the implied price elasticities of conventional oil production from existing reserves rises with time, starting at a value of 0.011 in the first year after the price change, and climbing to a value of 0.039 after 20 years. By the time economic exhaustion occurs, the elasticity has grown to a value of 0.075, and can be alternatively interpreted as a long run reserve elasticity at that point.

By way of similar logic, it can be deduced that the implied price elasticity of non-associated gas production from existing reserves also increases with time. The first year elasticity is considerably larger than that for conventional oil, being estimated at 0.040, but rises more slowly over time. It reaches a value of

0.064 after 20 years, before ending up at a value of 0.788 at the point of economic exhaustion for an implied long run reserve elasticity that is only marginally higher than that estimated for conventional oil.

While these implied price elasticities are not large, they do indicate the sensitivity of production out of existing reserves to changes in real price levels, when those changes are manifested through changes in the economic limit, which drives the abandonment decision.

J. Effects of the WPT in the Statewide Models

The price responsiveness of future production levels from existing reserves that were projected by the estimated statewide models was demonstrated in the preceding section. As a preview of the windfall profit tax (WPT) analysis that will be performed in Chapter VII, the conventional oil and non-associated gas production models were again used to simulate future production levels from existing reserves, but this time under three alternative WPT phaseout scenarios.

The first scenario considers the production levels that would occur if the WPT were immediately repealed on 1-1-84, so that there would be no WPT during the simulation period. The second scenario assumes that the 33 month WPT phaseout will begin as scheduled under current law in 1991, for a status quo projection. The third scenario assumes that the WPT would be extended indefinitely, i.e., no phaseout would ever occur. By comparing the projected statewide production levels under each of these two extreme phaseout scenarios to the levels projected to occur under continuation of the status quo, the upper and lower bounds on the impact of any proposed change in the WPT phaseout schedule can be quantitatively determined.

For these simulations, it was assumed that real oil and gas prices would follow the Middle World Oil Price Case projected by the U.S. Department of Energy (1984) through its Energy Information Administration (EIA). Expressed in 1983 dollars, real oil prices are projected by this EIA scenario to fall to \$28.48 in 1984 and \$27.48 in 1985 before bottoming out at \$26.50 for 1986 and 1987. Thereafter, they are seen to climb to \$27.48 in 1988, \$28.47 in 1989 and \$29.45 in 1990, experiencing constant 5.9% growth in real terms for all years after 1990. Similarly, real gas prices (in 1983 dollars) are expected to drop to \$2.29 in 1984 and \$2.27 in 1985, stopping their decline at a low of \$2.26 in 1986. Real gas prices are expected to subsequently rise to \$2.38 in 1987, \$2.54 in 1988, \$2.73 in 1989, and \$2.99 in 1990, after which time they will exhibit constant real growth of 7.5% per year. Using these assumptions yielded reserve estimates that portray the level of remaining recoverable reserves as economic variables that rise or fall in response to price.

Table 22 presents the simulated levels of cumulative future statewide oil and non-associated gas production in Texas that that are projected to occur under each of the WPT phaseout scenarios, when assuming the EIA real price paths. Under current law, phaseout of the WPT will begin in 1-1-1991 as the tax rates for all three tiers

Table 22. Aggregate Texas Reserves Estimated Under Alternative WPT Phaseout Scenarios

	Conventional Oil	Non-Associated Gas
Assuming WPT Repeal on 1-1-84		
Projected cumulative future production	7,965.4[a]	44,602.3[b]
Absolute change[c]	+ 18.0	+ 13.4
Percentage change	0.23	0.03
Year of exhaustion	2043	2060
Assuming WPT Phaseout Under Current Law		
Projected cumulative future production	7,947.4	44,588.9
Year of exhaustion	2043	2060
Assuming No Phaseout of WPT		
Projected cumulative future production	7,815.4	44,568.4
Absolute change	- 131.9	- 20.6
Percentage change	1.66	0.05
Year of exhaustion	2031	2059

[a] Oil volumes are given in millions of barrels.

[b] Gas volumes are given in billions of cubic feet.

[c] Relative to that projected under current law.

are reduced by 3% each month so that the rates will become zero after 33 months, which will be 9-1-93. When assuming this status quo phaseout schedule, projected future statewide oil production from existing reserves comes to 7,947.4 MMBBLS, with an implied economic exhaustion in the year 2043. When the WPT is assumed to be immediately repealed on 1-1-84, that projected total rises by 18 MMBBLS, or 0.23% of the amount projected under current tax law. The projected increase in cumulative future statewide production from existing non-associated gas reserves in Texas is 13.4 BCF, an almost negligible difference of 0.03% relative to the projection under the staus quo. The production effect of immediate WPT repeal is significantly smaller for statewide non-associated gas production from existing reserves because the impact of the WPT on condensate net revenues has very little effect on overall net cash flow from a non-associated gas well, and hence, little effect on its economic limit. For example, at 1983 prices, the amount of WPT paid per barrel of oil produced from a marginal oil well in Texas averages $4.51, while the amount of WPT paid on the amount of condensate that is jointly produced, on the average, with every MCF of gas from a marginal non-associated gas well in Texas is only $0.03. Since current law provides for the WPT to be completely removed by 1993, there is no difference in the implied years of economic exhaustion for either product.

Alternatively, when the WPT is assumed to continue indefinitely, the projected levels of cumulative future statewide production from existing reserves decline as expected. Aggregate Texas oil production from existing reserves is projected to fall by a cumulative amount of 131.9 MMBBLS over the economic lifetime of those reserves. This represents a reduction of 1.66% below the level of cumulative oil production projected when assuming a complete WPT phaseout by 1993. The higher WPT tax rates after 1991 reduce net cash flow to Texas oil well operators in all years thereafter, causing the individual oil well economic limit (EL_t^o) to rise. As a result, the implied date of the economic exhaustion of aggregate Texas oil reserves is reduced by 11.32 years. Aggregate Texas non-associated gas production from existing reserves is similarly projected to drop, but only by the cumulative amount of 20.6 BCF, which is once again only a small (0.05%) percentage of implied reserves under current law. The small effect of reduced condensate net revenues on the individual non-associated gas well economic limit (EL_t^g) makes aggregate Texas non-associated gas production rather insensitive to the timing of the WPT phaseout. The economic lifetime of Texas' non-associated gas reserves is only projected to decrease by 0.63 years, or 230 days.

It must be re-emphasized that the simulation results in Table 22 pertain only to the impact of the WPT on production from existing reserves through the effect on the abandonment decision. The total impact of the WPT includes not only the effect on production from existing reserves but also the effect on the additional production levels engendered by new exploratory and development drilling activity. These three alternative WPT scenarios will again be considered in the policy analysis of Chapter VII, where aggregate

Texas oil and gas future production levels will be simulated from a reserve base that is constantly being augmented by drilling activity.

K. Modelling Future Statewide Oil Production from Enhanced Oil Recovery Activity

The oil production equation used for the simulation of statewide oil production from existing Texas oil reserves was estimated using historical production data that contained negligible amounts of incremental oil production attributable to enhanced oil recovery (EOR) activity. Consequently, it was not possible to use the generalized production model to simulate the expected future levels of incremental Texas oil production attributable to EOR.

Modelling the levels of EOR production in Texas is important, because the amounts of incremental EOR oil production in the U.S. are projected to be very significant in the future by the National Petroleum Council's Committee on Enhanced Oil Recovery (1984). In their report, EOR activity is defined to include production techniques that are intended to improve the ultimate recovery from an oil property or reservoir beyond that which is possible using only primary and secondary recovery techniques of oil production. Primary oil recovery is accomplished via the natural drive mechanism of the reservoir, while secondary recovery normally implies waterflooding of the field or the injection of gas to replace the reservoir pressure naturally lost during primary recovery. EOR activity encompasses recovery methods that are more technologically advanced, and thus, more expensive than those employed in primary and secondary recovery.

The three types of EOR activity found by the NPC to be the most promising for the U.S. in the near future are chemical flooding, miscible flooding and thermal recovery methods. Chemical flooding involves the injection of polymers, surfactants and alkaline chemicals, rather than simply using water, as in secondary recovery. Miscible flooding methods also replace water in a flooding operation, but use carbon dioxide, nitrogen, or hydrocarbons. Thermal recovery methods primarily involve the underground injection of steam, but also include some *in situ* combustion techniques.

The NPC projects significantly rising levels of total U.S. oil production from EOR, as may be seen in Figure 11, which is taken from Figure 28 of their report. Assuming a 10% required real rate of return, the figure shows the annual U.S. EOR production rates that can be expected to occur over the next 30 years, given one of four constant real oil prices (expressed in 1983 dollars). The appreciable differences in the projected EOR production paths associated with each of the four assumed constant real price paths reflect the sensitivity of most EOR projects to oil market conditions. At higher real market prices for oil, the number of EOR projects that will satisfy the required 10% real rate of return is naturally higher, and falls as the real market price of oil does.

This sensitivity is also reflected in the NPC's estimates that at a $20 constant real oil price, 60% of incremental EOR production in the U.S. will come from the less expensive thermal recovery projects, 27% will come from miscible flooding projects, and the remaining 13% will come from chemical flooding projects. These

Figure 11. Projected U.S. EOR Production Levels by the NPC Under Alternative Real Price Paths, 1984-2013

percentages change under a $50 constant real oil price, as more of the miscible and chemical flooding projects become profitable to develop, increasing their percentages of total U.S. EOR production to 41% and 21%, respectively, while the contribution made by thermal projects declines to 38%. Most of the thermal projects considered by the NPC would take place outside of Texas; chemical flooding, and in particular the injection of carbon dioxide in miscible flooding projects in West Texas would be the most feasible types of EOR projects for Texas oil reserves.

As the NPC report represents the U.S. petroleum industry's best and most current projections of future EOR production in the U.S., it was the logical foundation for projecting the future levels of EOR production in Texas. Industry participants in the NPC's Committee on EOR recommended that Texas EOR production levels be approximated as percentages of the national projections, and also graciously provided the necessary percentages for each of the four constant real oil price paths. Table 23 shows the NPC's projections of additional ultimate recovery of oil expected from EOR activity, both at the national level and for Texas, using the percentages appropriate for each of the four assumed real oil price levels. This table indicates just how important EOR activity can be for Texas; at a constant $30 real oil price, 4.6 billion barrels of new oil reserves would ultimately be added to Texas' existing conventional oil reserves of 7.5 billion barrels by EOR activity.

The annual levels of future statewide oil production expected from EOR activity in Texas were determined by applying the Texas

Table 23. NPC Projections of EOR Activity Under Alternative Constant Real Oil Prices

Oil price (1983$ per barrel)	20.00	30.00	40.00	50.00
Ultimate recovery from EOR (billions of barrels)				
Total U.S.	7.4	14.5	17.5	19.0
Texas	1.5	4.6	5.2	5.7
Percentage of total U.S. produced in Texas	20.6	31.7	29.7	30.0

percentages to the annual production levels projected by the NPC for the U.S. as a whole shown in Figure 11. Unfortunately, this will only provide annual EOR production projections for Texas under any one of the four different real oil price assumptions used by the NPC. Some method was needed to model the expected statewide levels of EOR production in Texas so that the impact of real oil price or tax rates on those levels could be determined.

The EOR production paths of Figure 11 are seen to follow rather smooth, unimodal curves, suggesting that a good mathematical approximation to them could be provided by a second degree polynomial of the form

$$q_t^e = a_0 + a_1 t + a_2 t^2, \tag{5.13}$$

where q_t^e is the level of incremental EOR production in Texas during year t, and t is an ordinary time index. Equation (5.13) could be estimated using the NPC data for any one of the four constant real oil price paths - \$20, \$30, \$40, or \$50. However, the estimated coefficients that would result would differ depending upon which price path was assumed. What would be preferable is a specification that will allow the coefficients of the polynomial to depend upon the level of the real oil price that is being assumed, without constraining that price to be constant over time.

Thus, the coefficients of the polynomial were specified to be linear functions of the real market price of oil (P_t^o), changing equation (5.13) to

$$q_t^e = (b_0+b_1 P_t^o) + (c_0+c_1 P_t^o)t + (d_0+d_1 P_t^o)t^2, \tag{5.14}$$

which can be rearranged to the form

$$q_t^e = (b_0+c_0t+d_0t^2) + (b_1+c_1t+d_1t^2)P_t^o. \tag{5.15}$$

Equation (5.15) shows that annual EOR production levels can be modelled as a linear function of the real market price of oil, where the intercept and slope terms of the linear function are themselves simple second degree polynomials in time. This specification is capable of modelling the Texas EOR production levels that could be expected for any given constant real market price of oil, but does not take into account the possibility of real oil price changes in any given year.

To account for this complexity, equation (5.15) was extended as

$$q_t^e = a_0(t) + a_1(t)P_t^o + \Sigma_{i=1}^{t-1}a_1(t-i)(P_{i+1}^o-P_i^o), \tag{5.16}$$

where $a_0(t)=b_0+c_0t+d_0t^2$, $a_1(t)=b_1+c_1t+d_1t^2$, and $a_1(t-i)=b_1+c_1(t-i)+d_1(t-i)^2$. If the real market price of oil is assumed to stay constant, then the year-to-year price differences $P_{i+1}^o-P_i^o$ will always be zero, and equation (5.16) reduces to equation (5.15). If, on the other hand, the real market price of oil is assumed to rise in any given year, then the year-to-year price difference will be positive in that year. As a result, the level of EOR production that was projected to occur under the earlier, lower price ($a_0(t)+a_1(t)P_t^o$, the same as equation (5.15) would predict) will continue as before, but will be augmented by a polynomial describing the new, incremental EOR production that was engendered by the price increase, with the time index for the new polynomial starting at a value of one in the year of the price change. Similarly, if the real market price of oil were assumed to decline in any given year, the negative year-to-year price difference would reduce the level of EOR production below what it would have been if prices had not fallen, by subtracting the incremental EOR production that was not forthcoming under the new, lower price in the form of another polynomial whose time index started in the year of the price decrease.

Although the NPC's EOR projections only considered the impact of changes in the assumed value of the constant real market price of oil, the functional form of equation (5.16) allows their analysis to be extended to consider the levels of EOR production that would be forthcoming under a real oil price path that was not constant. However, in order to consider the impact of changes in the WPT phaseout schedule on EOR activity, the real market price of oil in equation (5.16) was replaced with the real price, net of all production taxes, received per barrel of EOR oil. This real net price (P_t^n) can be expressed as

$$P_t^n = P_t^o\{(1-s_t^o)(1-\rho_t)-v^o{}_t\} \\ -\omega_t(P_t^o-P^b ADJ_t)(1-s^o{}_t)(1-\rho_t), \tag{5.17}$$

where s_t^o is the Texas severance tax rate on oil production (4.6%), ρ_t is the royalty rate (assumed to be a constant 1/8, or 0.125), and v_t^o is the ad valorem tax rate (assumed to be 2%). The WPT taxes applicable to EOR production are represented by the second term in (5.17), where ω_t is the Tier 3 WPT tax rate (22.5% through 1987, falling to 20% in 1988 and 15% in 1989, before being phased out over

33 months starting in 1991, under current law), P^b is the base price for Tier 3 oil in Texas ($17.10) and ADJ_t is the inflation adjustment factor for Tier 3 oil (composed of an inflation index plus an additional 2% increase per year). Using this real net price in place of the real market price when modelling the expected EOR production levels in Texas will permit the analysis of the impact of the WPT on those estimated levels.

The EOR model that was estimated using the Texas percentages of the NPC projections under each of the four assumed real market price paths can be written as

$$(5.18) \qquad q_t^e = a_0(t) + a_1(t)P_t^n + \Sigma_{i=1}^{t-1}a_1(t-i)(P_{i+1}^n - P_i^n) + \epsilon_t,$$

where ϵ_t is an error term assumed to meet all the requirements for unbiased and efficient estimation. According to equation (5.18), changes in the projected levels of EOR production in Texas will be driven by changes in the real net price of a barrel of EOR oil (P_t^n), which can occur in any given year. Equation (5.18) was estimated using OLS, yielding the following estimates:

$$(5.19) \qquad \tilde{a}_0(t) = \underset{(2.71)}{120.963} - \underset{(2.63)}{16.242t} + \underset{(1.56)}{0.289t^2}$$

and

$$\tilde{a}_1(t) = \underset{(0.75)}{1.326} + \underset{(6.26)}{1.457t} - \underset{(5.42)}{0.037t^2}.$$

The t-statistics for the null hypothesis that each estimated coefficient equals zero are given in parenthesis below each one. The coefficient of determination (R^2) was 0.926 and the standard error of the regression was 38.0927.

This estimated EOR model was then used to simulate the future expected levels of incremental EOR production in Texas from 1984 through 2013. Assuming a constant real oil price of $30 per barrel, the cumulative amount of EOR production projected by the estimated EOR model for the 30 year period was 2,995.7 MMBBLS. In order to examine the sensitivity of the EOR model's projections to the real market price of oil, an additional simulation was then performed using a constant $33 real oil price. Under this 10% higher real oil price, projected cumulative EOR production was forecast to be 3,631.3 MMBBLS, an increase of 635.6 MMBBLS over that projected under a $30 price above.

This percentage increase of 21.2% in projected cumulative EOR production arising from a 10% increase in the real oil price implies a 30 year price elasticity for EOR production of 2.12. Such a high price elasticity is consistent with the NPC's contention that EOR projects only become profitable to producers when real oil prices climb above $30. Therefore, a sizeable price elasticity is to be expected over this range. The magnitude of this price response for EOR suggests that, all else equal, the impact of changes in the WPT phaseout schedule should be much greater than those for conventional oil or non-associated gas seen above.

The responsiveness of EOR production levels to the WPT was then directly examined by performing 30 year simulations under the same three alternative WPT scenarios considered earlier when using the

Table 24. Projected Cumulative EOR Production in Texas Under Alternative WPT Phaseout Scenarios

Assuming WPT Repeal on 1-1-84	
Projected cumulative EOR production	8,114.9[a]
Absolute change[b]	+ 14.3
Percentage change	0.18
Assuming WPT Phaseout Under Current Law	
Projected cumulative EOR production	8,100.6
Assuming No Phaseout of WPT	
Projected cumulative EOR production	7,656.7
Absolute change	- 643.9
Percentage change	7.95

[a] In millions of barrels.

[b] Relative to that projected under current law.

statewide conventional oil and non-associated gas models. Once again assuming the EIA real oil price path, the cumulative totals of EOR production were projected under each of the scenarios of the continuation of current tax law, immediate repeal of the WPT and its indefinite extension. These results appear in Table 24, along with the percentage changes in the amount of cumulative EOR production projected under current law that would result from either of the changes in the WPT phaseout schedule.

If the WPT were to expire by 1993 according to current law, 8,100.6 additional MMBBLS of oil would be produced in Texas over the next 30 years from EOR methods, given the EIA real oil price projections. This cumulative total would be increased by 14.3 MMBBLS, or 0.18% if the WPT were repealed on 1-1-84. Alternatively, indefinite extension of the WPT would reduce the amount of cumulative EOR production in Texas over the next 30 years by 7.95%, a loss of 643.9 MMBBLS. These results underscore the sensitivity of EOR activity to the real net price received per barrel of EOR oil, and demonstrate the insignificant degree of relief that immediate repeal of the WPT would imply for EOR projects, as well as the strong impact that indefinite extension would imply.

This sensitivity can also be seen at the level of the real net price of a barrel of EOR oil. At a real oil price of $30, the real net price of a barrel of EOR oil in 1984 can be calculated using equation (5.17) to be $23.51. Immediate repeal of the WPT would increase this net price by only $0.93 in 1984, or about 4%. However, this percentage would fall quickly after 1984, as the declining real oil prices assumed by the EIA would cause the "windfall profit" (the difference between the market price of oil and the adjusted base price, which grows at the rate of inflation plus 2% each year) to become negative. At negative values, the windfall profit is set to zero, so that repeal during a period of falling real oil prices would have little positive effect on the real net price. Using the real oil price of $52.35 projected by the EIA for the year 2000, indefinite extension of the WPT would reduce the real net price in that year by $2.24, or 5.25%. This decrease would not evaporate over time, since the EIA real oil price path is growing quickly enough to maintain a positive windfall profit. Therefore, indefinite extension of the WPT beyond 1993 would have proportionately greater cumulative effects than would its repeal today, because real oil prices are expected to rise at a rate of 5.9% after 1990.

This estimated model of EOR activity will be integrated with the estimated models of statewide conventional oil and non-associated gas production to fashion a complete model of aggregate Texas petroleum production in the next chapter.

L. Summary and Conclusions

The preceding sections of this chapter have presented the development and estimation of three econometric equations that are capable of modelling the aggregate levels of oil and gas production in Texas under any given set of assumptions regarding real oil prices or tax rates.

The generalized petroleum production model developed in earlier chapters was used to model the aggregate levels of conventional oil and non-associated gas production in Texas. The resulting estimated equations were found to have considerable explanatory power, and demonstrated their accuracy in predicting aggregate reserve levels. While most previous research efforts have considered production from existing reserves to be unresponsive to price, simulation with these estimated statewide models revealed that such was not the case here, with implied long run price elasticities of 0.075 with respect to cumulative conventional oil production and 0.079 with respect to cumulative non-associated gas production. This sensitivity of aggregate conventional oil and non-associated gas production from existing reserves was also demonstrated in an analysis of the impact of changes in the WPT phaseout schedule. The simulation model of Texas petroleum production was then completed by modelling the aggregate levels of the joint products of associated gas and condensate as constant proportions of the aggregate levels of conventional oil and non-associated gas production, respectively.

The aggregate levels of EOR production in Texas were modelled from the NPC projections as a function of the real net price received from a barrel of EOR oil. By simulating this estimated EOR model under two different constant real oil price paths, the 30 year price elasticity of cumulative EOR production was found to be 2.12. This large price response by EOR producers was also reflected in an analysis of the impact of changes in the WPT phaseout schedule on cumulative EOR production from Texas.

As the model of aggregate petroleum production from all sources in Texas has now been completed, it will be combined in the next chapter with an econometric model of aggregate petroleum drilling developed by Bremmer that will describe the annual levels of new reserve additions in Texas. This will allow for the extension of the analysis performed in this chapter to consider the aggregate levels of Texas petroleum production forthcoming from a growing reserve base.

CHAPTER VI

AN INTEGRATED MODEL OF AGGREGATE TEXAS PETROLEUM PRODUCTION

In this chapter, the econometric equations developed in Chapter V that describe the aggregate levels of production of oil and gas in Texas will be integrated with a system of econometric equations developed by Bremmer that describe the aggregate levels of new oil and gas reserve additions in Texas. The resulting model will therefore be capable of simulating future levels of statewide oil and gas production in Texas from a petroleum reserve base that is continually being augmented by the activities of the drilling sector.

The first part of this chapter provides a brief explanation of the several econometric equations in the Bremmer drilling model of Texas. Each of the estimated equations that describe the aggregate levels of exploratory and development drilling and the resultant aggregate levels of new oil and gas reserve additions will be presented and explained. Then, the linkages between the drilling model and the aggregate production model of Chapter V will be discussed. The drilling side of the model will project aggregate new reserve additions in each year, which will in turn affect the annual aggregate levels of production predicted by the production side of the model. The simulated levels of aggregate production will feed back into the drilling model, and estimate annual reserve levels as last year's reserves plus new reserve additions, minus production.

Given a common set of assumptions regarding the future levels of the exogenous variables needed for each sector of the model, the integrated model will be used to simulate aggregate Texas petroleum production levels over the 20 year period 1984 through 2003. This integrated model will then be used to determine the sensitivity of aggregate production from a growing reserve base to price changes before it is applied to an analysis of the windfall profit tax in the next chapter.

A. An Econometric Model of Petroleum Drilling in Texas

This section describes the component equations of the Bremmer model of petroleum drilling in Texas that will be used to generate the aggregate levels of new reserve additions in Texas. The Bremmer drilling model is based on the methodology pioneered by Franklin M. Fisher (1964) that models new reserve additions in year t (A_t) as a function of the total number of new wells drilled in year t (N_t), the fraction of those new wells that find new reserves (S_t/N_t, where S_t is the number of new successful wells) and the average size of the new reserves added per new successful well (S_t/A_t). This framework may be succinctly expressed by the so-called "Fisher identity":

$$(6.1) \qquad A_t = N_t \cdot (S_t/N_t) \cdot (A_t/S_t).$$

By estimating separately each of these three components of the Fisher identity, Bremmer develops an econometric model of new reserve additions in Texas that is rich in economic structure. His model is capable of determining how exogenous shocks in prices or tax rates will affect the decisions to drill either an exploratory or development well, the success ratios associated with those wells and the average size of the reserves added by each new successful well.

The equations in Bremmer's model may be classified in one of three categories: (i) the exploration sector, which considers aggregate drilling activity in unproven areas; (ii) the development sector, whcich considers aggregate drilling activity in areas that are already known to be productive; or (iii) the revision sector, which considers the annual revisions to aggregate reserve levels arising from new information or secondary oil recovery activity. The exploration sector is made up of six equations which describe the aggregate level of exploratory drilling activity, the number of successful exploratory oil and non-associated gas wells and the average size of new oil and gas reserves associated with each new successful exploratory well, which are called discoveries. The development sector is made up of six equations which describe the aggregate level of development drilling activity, the number of successful development oil and non-associated gas wells and the average size of new oil, associated gas and non-associated gas reserves associated with each new successful development well, called extensions. The revision sector has two equations describing the aggregate volumes of reserve estimate revisions of oil and associated gas.

Table 25 contains a list of the variables that appear in the estimated equations of the Bremmer model. All oil volumes are in millions of barrels and all gas volumes are in billions of cubic feet. All dollar values are in 1972 dollars, but will be converted to 1983 dollars for joint simulation purposes.

Table 25. Variable List for the Bremmer Drilling Model

Variable	Definition
XW_t	Number of exploratory wells drilled in year t
XO_t	Number of successful exploratory oil wells in year t
XG_t	Number of successful exploratory non-associated gas wells in year t
XP_t	Total number of successful exploratory wells in year t (XP_t=XO_t+XG_t)
DW_t	Number of development wells drilled in year t
DO_t	Number of successful development oil wells in year t
DG_t	Number of successful development non-associated gas wells in year t
R_t^o	Aggregate oil reserves at end of year t
OD_t	Volume of aggregate oil discoveries in year t
OX_t	Volume of aggregate oil extensions in year t
OR_t	Volume of aggregate oil revisions in year t
R_t^g	Aggregate non-associated gas reserves at end of year t
ND_t	Volume of aggregate non-associated gas discoveries in year t
NX_t	Volume of aggregate non-associated gas extensions in year t
R_t^a	Aggregate associated gas reserves at end of year t
AD_t	Volume of aggregate associated gas discoveries in year t
AX_t	Volume of aggregate associated gas extensions in year t
AR_t	Volume of aggregate associated gas revisions in year t

Table 25 Continued

Variable	Definition
GD_t	Volume of aggregate total gas discoveries in year t
Δq^o_{t-1}	Change in aggregate oil production from year t-2 to year t-1 ($\Delta q^o_{t-1}=q^o_{t-1}-q^o_{t-2}$)
KQO_t	Cumulative oil production in Texas since 1866
KQG_t	Cumulative non-associated gas production in Texas since 1935
$OWELL_t$	Aggregate number of producing oil wells at the end of year t
$GWELL_t$	Aggregate number of producing non-associated gas wells at the end of year t
DNP^o_t	Discounted net price of a barrel of oil reserves added in year t
DNP^g_t	Discounted net price of an MCF of gas reserves added in year t
$RELPRI_t$	Discounted net price of oil relative to that for gas ($RELPRI_t=DNP^o_t/DNP^g_t$)
DC_t	Average drilling cost per well
f_t	Maximum corporate federal income tax rate
$X\Pi_t$	Discounted value of after-tax profits expected from drilling an exploratory well
$D\Pi_t$	Discounted value of after-tax profits expected from drilling a development well

Four of the variables in Table 25 require some additional explanation. The first of these are the two discounted net prices of a barrel of oil (DNP_t^o) and an MCF of gas (DNP_t^g), which represent the present values of a barrel of oil reserves or an MCF of gas reserves that is found in year t, but is only gradually recovered over the production horizon of the well. For oil wells, this production horizon was assumed to be 20 years, while it was assumed to be 30 years for non-associated gas wells. These discounted net prices are calculated by first computing the return from the production and sale of a barrel of oil or an MCF of gas, net of all production costs and taxes, for each year of the assumed production horizons. The fractions of a barrel of oil reserves or an MCF of gas reserves found in year t that will be extracted in each year of the production horizon (which starts in year t) are determined from a simple exponential decline model. After multiplying these fractions by the after-tax net returns computed for each year, the resulting products are discounted back to year t. The present values obtained by summing these annual discounted values over the production horizons are defined to be the discounted net prices of a barrel of oil reserves or an MCF of gas reserves found in year t.

Given these two discounted net prices, it is possible to calculate the other two variables that need to be explained - the discounted values of the after-tax profits expected from the drilling of an exploratory well ($X\Pi_t$) or a development well ($D\Pi_t$). Considering the expected profit from a exploratory well first, $X\Pi_t$ is computed as

$$(6.2) \qquad X\Pi_t = [(XO_t+XG_t)/XW_t]\{DNP_t^o[OD_t/(XO_t+XG_t)] \cdot + DNP_t^g[GD_t/(XO_t+XG_t)]\} - (1-f_t)DC_t.$$

The discounted net price of a barrel of new oil reserves (DNP_t^o) is multiplied by the average size of the new oil reserves discovered per successful exploratory well ($OD_t/(XO_t+XG_t)$) and then added to the product of the discounted net price of an MCF of new gas reserves (DNP_t^g) and the average size of the new gas reserves discovered per successful exploratory well ($GD_t/(XO_t+XG_t)$). This sum is then weighted by the probability that an exploratory well will be successful ($(XO_t+XG_t)/XW_t$) before subtracting the after-tax cost of drilling a well ($(1-f_t)DC_t$).

For a development well the expected profit term $D\Pi_t$ is similarly computed as

$$(6.3) \qquad D\Pi_t = (DO_{t-1}/DW_{t-1})\{DNP_t^o(R_{t-1}^o/OWELL_{t-1}) + DNP_t^g(R_{t-1}^a/OWELL_{t-1})\} + (DG_{t-1}/DW_{t-1}) \cdot \{DNP_t^g(R_{t-1}^g/GWELL_{t-1})\} - (1-f_t)DC_{t-1}.$$

In this instance, the amount of aggregate reserves per producing well in the previous year is used as a proxy for the average size of new reserves found per new successful development well. These average extension sizes are multiplied by the appropriate discounted net prices for year t and then weighted by the probabilities observed in year t-1 that the development well will be either a successful oil well (DO_{t-1}/DW_{t-1}) or a successful non-associated gas well (DG_{t-1}/DW_{t-1}). The sum of these expected net revenue terms is reduced by the after-tax cost of drilling a well last year to obtain the expected profit per development well drilled in year t.

The Exploration Sector

The first of the six equations comprising the exploration sector of the Bremmer model of drilling in Texas describes the total number of exploratory wells drilled in year t (XW_t) as

$$(6.4) \quad \ln(XW_t) = 0.0446 + 0.8278\ln(XW_{t-1}) + 0.1196\ln(X\Pi_{t-1}).$$

The natural logarithm of the total number of exploratory wells is modelled as a linear function of the same value for the previous year and the natural logarithm of the discounted value of after-tax profits expected from an exploratory well. The log-linear specification of equation (6.4) is typical of most of the equations in the model, allowing easy interpretation of the estimated coefficients as elasticities. The short run elasticity of the number of exploratory wells with respect to the expected profit term is seen to be 0.1196, so that every 10% increase in expected profit will only bring about an increase of 1.2% in the number of exploratory wells drilled in year t. In the long run, this elasticity grows to a value of 0.6945 (=0.1196/(1-0.8278)), making the long run response to a 10% increase in expected profits be an increase in exploratory wells of 6.9%.

The number of successful exploratory oil wells drilled in year t (XO_t) is modelled as

$$(6.5) \quad \ln(XO_t) = -5.2769 + 1.3520\ln(XW_t) + 0.1132\ln(RELPRI_t).$$

According to equation (6.5), every 10% increase in the number of exploratory wells drilled brings about an increase in the number of successful exploratory oil wells of 13.2%. Directionality in drilling is explicitly accounted for by this specification, which shows that every 10% increase in the relative discounted net price of oil will increase the number of successful oil wells by 1.13%.

Analagous to equation (6.5) is the equation describing the number of successful exploratory non-associated gas wells in year t (XG_t),

$$(6.6) \quad \ln(XG_t) = -4.7050 + 1.4969\ln(XW_t) - 0.5578\ln(RELPRI_t).$$

Again it can be inferred that every 10% increase in the number of exploratory wells drilled in year t results in an increase in the number of successful exploratory non-associated gas wells of 14.97%. As expected, a 10% increase in the relative price of oil reduces the number of successful exploratory non-associated gas wells by 5.57%.

The remaining three equations of the exploration sector describe the aggregate volumes of oil and gas discovered by successful exploratory wells. The aggregate volume of new oil reserves discovered in year t (OD_t) is estimated by the equation

$$(6.7) \qquad \ln(OD_t) = 2.8977 + 0.3766\ln(XO_t) - 0.0651t,$$

where t is an ordinary time index used to account for depletion of the stock of undiscovered oil reserves. This depletion effect alone causes the aggregate volume of oil discoveries to fall by 6.51% each year. Otherwise, aggregate oil discoveries in year t increase by

3.77% for every 10% increase in the number of successful exploratory oil wells in that year.

The aggregate volume of new gas reserves discovered by successful exploratory wells in year t (GD_t) is estimated as

$$(6.8) \qquad \ln(GD_t) = 6.9167 + 0.2542\ln(XP_t) - 0.0511t,$$

where t again denotes a time index, implying that depletion of the stock of undiscovered gas reserves reduces the aggregate gas discoveries by 5.11% each year. Since new gas reserves may be discovered either from successful exploratory non-associated gas wells or in conjunction with new oil reserves as associated gas from successful exploratory oil wells, they are modelled as a function of the total number of successful exploratory wells (XP_t). Every 10% increase in successful exploratory wells will increase aggregate gas discoveries by 2.54% in year t, all else equal.

Since equation (6.8) only models total new gas discoveries (GD_t), it is necessary to distinguish between those new gas reserves that are found by successful exploratory non-associated gas wells (ND_t) and those that are found by successful exploratory oil wells (AD_t). This distinction is made according to the weighting procedure

$$(6.9) \qquad GD_t = (0.95025)GD_t + (1-0.95025)GD_t = ND_t + AD_t.$$

Equation (6.9) splits total natural gas discoveries (GD_t) between non-associated gas discoveries (ND_t) and associated gas discoveries (AD_t), assigning 95.025% of the total to the former according to the average of the percentages observed from 1966 through 1983.

Equations (6.4) through (6.9) constitute the exploration sector of the Bremmer model, and can be used to generate the aggregate volumes of new oil and gas reserves discovered by exploratory wells in Texas each year.

The Development Sector

The next sector of the Bremmer model describes the development drilling activity in Texas, which involves drilling new wells in areas that are already known to be productive. The first equation in this sector models the number of development wells drilled in year t (DW_t) as

$$(6.10a) \quad \ln(DW_t) = -0.2383 + 0.2021\ln(D\Pi_t) + \Sigma_{j=1}^{8} a_j \ln(XP_{t-j}),$$

where the a_j's are coefficients in an Almon polynomial distributed lag structure, with values of

$$(6.10b) \quad \begin{array}{lll} a_1=0.2461, & & a_2=0.2122, \\ a_3=0.1791, & & a_4=0.1470, \\ a_5=0.1158, & & a_6=0.0855, \\ a_7=0.0561 & \text{and} & a_8=0.0276. \end{array}$$

Equations (6.10a) and (6.10b) show that every 10% increase in the expected profit from drilling a development well ($D\Pi_t$) results in a 2.02% increase in the number of development wells drilled. The number of development wells drilled also increases by 2.46% in the first year following a 10% increase in the number of successful exploratory wells. Since the a_j's sum to a value of 1.0694, after eight years that percentage response rises to a maximum of 10.69%, implying that in the long run, any increase in the number of successful exploratory wells will lead to an almost equiproportional increase in the number of development wells that are subsequently drilled.

The number of successful development oil wells (DO_t) in year t is modelled as

$$(6.11) \quad \ln(DO_t) = -0.9104 + 1.0206\ln(DW_t) + 0.1125\ln(RELPRI_t).$$

This equation is entirely analogous to equation (6.5) describing the number of successful exploratory oil wells. Every 10% increase in the number of development wells increases the number of successful development oil wells by 10.21%. Directionality in drilling is also seen in the development sector, where every 10% increase in the relative price of oil increases the number of successful development oil wells by 1.13%, all else equal.

The number of successful development non-associated gas wells in year t (DG_t) is similarly modelled as

$$(6.12) \quad \ln(DG_t) = -0.4816 + 0.9780\ln(DW_t) - 0.5210\ln(RELPRI_t).$$

The number of successful development non-associated gas wells increases by 9.78% with every 10% increase in the number of development wells, and decreases by 5.21% for every 10% increase in the relative price of oil.

The development sector concludes by describing the aggregate volumes of oil, non-associated gas and associated gas reserves found by successful development wells, known as extensions. Aggregate oil extensions in year t (OX_t) are modelled as

(6.13) $\ln(OX_t) = 1.4923 + 0.6556\ln(DO_t) - 0.2210\ln(KQO_t)$.

For the development sector, the depletion of undiscovered reserves in known producing areas is captured by increasing cumulative production. This depletion effect on aggregate oil extensions is to reduce them by 2.21% with every 10% increase in cumulative oil production (KQO_t). Since aggregate oil extensions come from successful development oil wells (DO_t), every 10% increase in the latter results in a 6.56% increase in the former.

Aggregate non-associated gas extensions in year t (NX_t) are modelled as

(6.14) $\ln(NX_t) = 32.4912 + 0.6930\ln(DG_t) - 2.4845\ln(KQG_t)$.

The depletion effect reduces aggregate non-associated extensions by 24.85% for every 10% increase in cumulative non-associated gas production (KQG_t). Aggregate non-associated gas extensions are also increased by 6.93% for every 10% increase in the number of successful non-associated gas development wells.

Finally, aggregate associated gas extensions in year t (AX_t) are modelled as a simple linear function of aggregate oil extensions in year t (OX_t), since they are found together. The estimated equation is

(6.15) $\ln(AX_t) = 0.5193 + 1.0410\ln(OX_t)$, which shows that aggregate associated gas extensions increase by 10.41% for every 10% increase in aggregate oil extensions.

Equations (6.10) through (6.15) comprise the development sector of the Bremmer drilling model, and can be used to generate the aggregate volumes of new oil and gas reserves found by development wells in Texas each year.

The Revision Sector

The last source of new reserve additions in Texas each year is the revision sector, which describes the annual positive or negative adjustments in aggregate reserve estimates for Texas. These revisions arise from new information on the ultimate recovery possible from existing reservoirs, which includes adjustments from secondary oil recovery projects.

Aggregate oil revisions in year t (OR_t) are modelled as a linear function of year-to-year differences in aggregate conventional oil production levels (Δq^o_{t-1}). The estimated equation is

$$\text{(6.16)} \qquad \ln(OR_t) = 5.9339 + 5.2570\ln(\Delta q^o_{t-1}),$$

where $\Delta q^o_{t-1}=q^o_{t-1}-q^o_{t-2}$ is used to reflect the information about conventional oil reserves contained in observed annual rates of change in conventional oil production. Every 1% increase in the observed year-to-year conventional oil production difference increases aggregate oil revisions by 5.25%.

Aggregate associated gas revisions (AR_t) are modelled as constant proportions of aggregate oil revisions (OR_t) by using the aggregate gas-oil production ratio (GOR_t). This equation is

$$AR_t = GOR_t \cdot OR_t, \tag{6.17}$$

where the gas-oil production ratio is assumed to remain constant at its 1983 value of 1.667 for purposes of simulation.

Aggregate non-associated gas revisions are assumed to be zero by the Bremmer model. This is because they have exhibited such extreme positive and negative fluctuations that they are not easily modelled, showing no recognizable trend and averaging about zero over time.

Equations (6.16) and (6.17) make up the revision sector of the Bremmer drilling model, and can be used to generate the aggregate volumes of oil and associated gas revisions expected in Texas each year.

Aggregate New Reserve Additions

The aggregate levels of new reserve additions in Texas from all sources can be determined from the three sectors of the Bremmer model as the sum of discoveries, extensions and revisions for conventional oil, non-associated gas or associated gas. For conventional oil, new reserve additions in year t (A_t^o) can be computed as the sum of oil discoveries in year t (OD_t), oil extensions in year t (OX_t) and oil revisions in year t (OR_t):

$$A_t^o = OD_t + OX_t + OR_t. \tag{6.18}$$

Aggregate non-associated gas new reserve additions in year t (A_t^g) can be similarly computed as

$$A_t^g = ND_t + NX_t, \tag{6.19}$$

where only discoveries (ND_t) and extensions (NX_t) are used in the sum, since revisions are assumed to be zero for simulation purposes. Finally, aggregate associated gas new reserve additions in year t (A_t^a) are found to be

$$A_t^a = AD_t + AX_t + AR_t, \tag{6.20}$$

where all three sources of reserve additions are included - discoveries (AD_t), extensions (AX_t) and revisions (AR_t). Aggregate new additions to condensate reserves are not modelled by the Bremmer model, owing to data limitations and the relative insignificance of condensate reserves and production to total oil reserves and production in Texas.

B. Integration of the Drilling and Production Models

The previous section described how the exploration, development sectors of the Bremmer drilling model can be used to simulate the aggregate levels of new reserve additions in Texas in each year. This section describes the linking of the estimated equations of that drilling model with the estimated model of aggregate Texas petroleum production developed in Chapter V for the purposes of simulation. The drilling sector of the integrated model will simulate the aggregate levels of new reserve additions for each year and feed those values to the production sector. In turn, the production levels simulated by the production sector of the joint model will feedback into several equations of the drilling sector. The

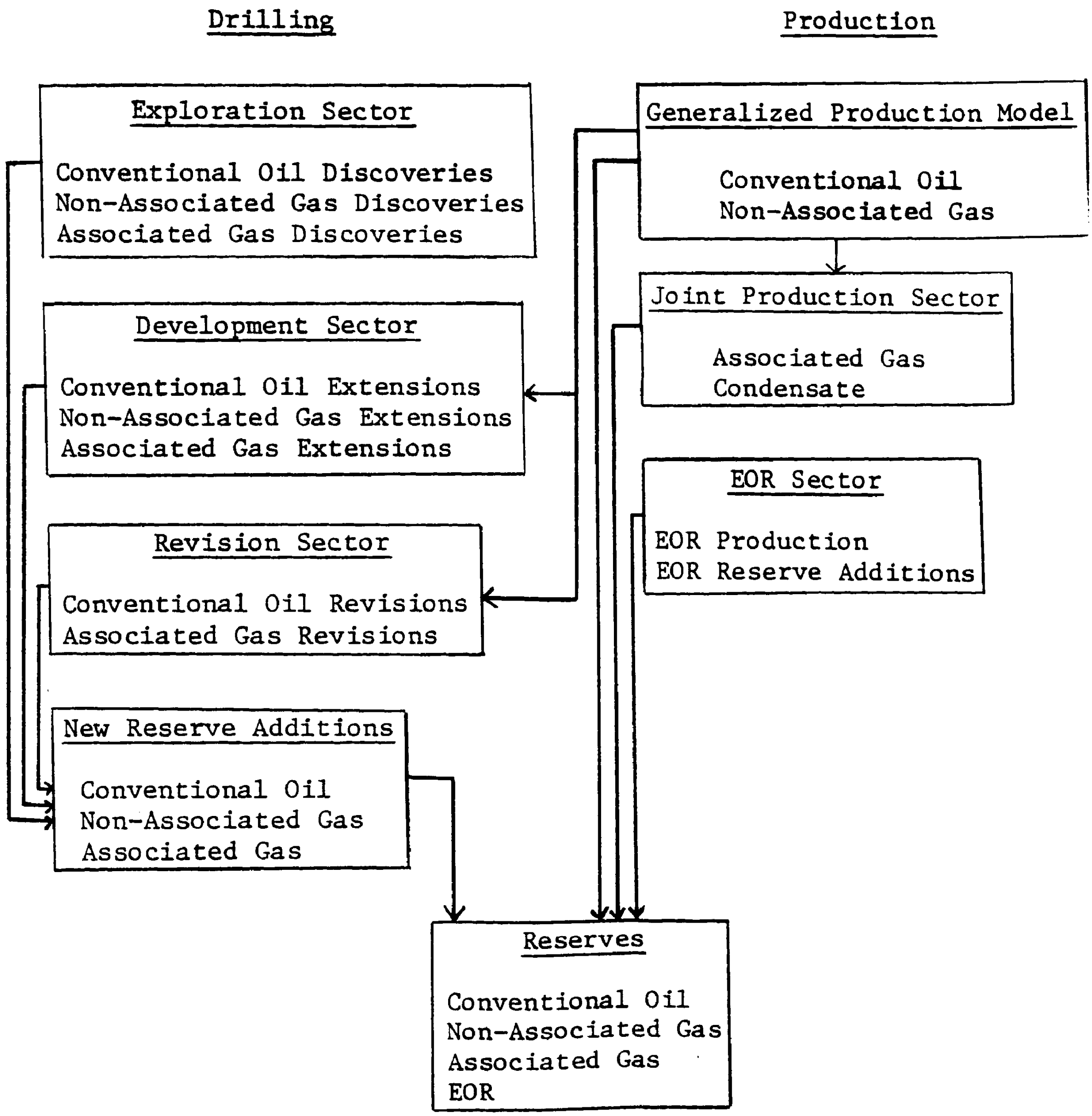

Figure 12. Flowchart of the Integrated Model

flowchart provided in Figure 12 shows the directions of the interrelationships between the various sectors of the joint model and should serve as a useful reference for the reader in this section.

From The Drilling Sectors to Production

Of all the linkages from the drilling sectors to the production sector, the most important is the provision of projected aggregate levels of new reserve additions to be used for the calculation of the annual values of the capacity augmentation indexes I_t^o and I_t^g in the estimated equations describing conventional oil and non-associated gas production, respectively. As a first step, the annual reserve levels of conventional oil (R_t^o) and non-associated gas (R_t^g) are calculated according to the perpetual inventory equations

(6.21) $$R_t^o = R_{t-1}^o + A_t^o - q_t^o$$

and

(6.22) $$R_t^g = R_{t-1}^g + A_t^g - q_t^g.$$

The annual values of I_t^o and I_t^g can then be calculated as

(6.23) $$I_t^o = I_{t-1}^o + \Sigma_{i=0}^{4}(A_{t-i}^o/R_{t-1-i}^o)$$

and

(6.24) $$I_t^g = I_{t-1}^g + \Sigma_{i=0}^{1}(A_{t-i}^g/R_{t-1-i}^g).$$

The resulting values of the two capacity augmentation indexes I_t^o and I_t^g are then inserted into the estimated equations describing aggregate production of conventional oil and non-associated gas so that they can be used to simulate future production levels from growing reserve bases. Those two estimated equations are recalled from Chapter V to be

(6.25) $$q_t^o = 12192.4EC_t^o e^{I_t^o - 0.130\tau_t^o}$$

and

(6.26) $$q_t^g = 99148.2EC_t^g q_t^d e^{I_t^g - 0.137\tau_t^g},$$

where

$$EC_t^o = 100 - 0.690(EL_t^o e^{-(I_t^o - 1.7542) + 0.130(\tau_t^o - 8.348)})^{1.204}$$

and

$$EC_t^g = 100 - 0.747(EL_t^g e^{-(I_t^g - 1.5558) + 0.137(\tau_t^g - 7.8348)})^{0.560}.$$

Simulation of the aggregate levels of associated gas and condensate production does not require simulated levels of new reserve additions for the computation of capacity augmentation indexes for those two outputs, since their production levels were modelled as constant proportions of the simulated levels of conventional oil and non-associated production, respectively. Assuming that the aggregate gas-oil production ratio (GOR_t) and the aggregate condensate-gas production ratio (CGR_t) remain constant at their 1983 values over the simulation period, the equations that will be used to simulate aggregate associated gas production (q_t^a) and aggregate condensate production (q_t^c) are

$$(6.27) \qquad q_t^a = 1.667 \cdot q_t^o$$

and

$$(6.28) \qquad q_t^c = 0.0064 \cdot q_t^g,$$

where 1.667 is the 1983 value of GOR_t and 0.0064 is the 1983 value of CGR_t.

The simulated levels of new reserve additions of associated gas (A_t^a) will be useful in keeping track of aggregate levels of associated gas reserves (R_t^a) according to the perpetual inventory equation

$$(6.29) \qquad R_t^a = R_{t-1}^a + A_t^a - q_t^a.$$

Since the Bremmer model does not consider the small and relatively insignificant levels of condensate reserve additions, the annual levels of condensate reserves in Texas cannot be determined by the integrated model. This slight omission is of little consequence to the overall conclusions of the model as to the aggregate levels of production and reserves of oil and natural gas in Texas.

The remaining source of petroleum production in Texas comes from EOR activity, and the EOR model developed in Chapter V will be used to simulate annual EOR production levels. The estimated EOR production model is recalled to be

$$(6.30) \qquad q_t^e = \tilde{\alpha}_0(t) + \tilde{\alpha}_1(t)P_t^n + \Sigma_{i=1}^{t-1}\tilde{\alpha}_1(t-i)(P_{i+1}^n - P_i^n),$$

where

$$\tilde{\alpha}_0(t) = 120.963 - 16.242t + 0.289t^2,$$

$$\tilde{\alpha}_1(t) = 1.326 + 1.457t - 0.037t^2,$$

and

$$\tilde{\alpha}_1(t-i) = 1.326 + 1.457(t-i) - 0.037(t-i)^2.$$

The aggregate levels of EOR production simulated by this equation imply the existence of some annual new reserve additions to an aggregate EOR reserve base that supports that production. Those implied EOR reserve additions (A_t^e) are modelled as

(6.31) $$A_t^e = R_t^e - R_{t-1}^e + q_t^e,$$

where R_t^e is the aggregate level of EOR reserves in year t. Annual levels of EOR reserves are modelled as

(6.32) $$R_t^e = q_t^e/D,$$

where D is the natural decline rate estimated for conventional oil production (0.130). Equation (6.32) is derived from the engineering property of a constant reserves-to-production (R/P) ratio over time, which was seen earlier in equation (2.20) for an exponential decline model with an infinite production horizon.

From Production To The Drilling Sectors

The foregoing discussion explained how the output of the drilling sectors fed into the equations of the production sector. The results of the production sector in turn impact the simulations of the drilling sector in several respects.

First, the aggregate reserve levels of conventional oil (R_t^o), non-associated gas (R_t^g) and associated gas (R_t^a) simulated by equations (6.21), (6.22) and (6.29) are used by the development sector to calculate the average amount of reserves per well in its computation of the expected after-tax profit from drilling a development well ($D\Pi_t$) as seen in equation (6.3). The development sector also uses the simulated levels of aggregate oil and non-associated gas production to update the levels of cumulative oil production (KQO_t) and cumulative non-associated gas production (KQG_t). These two cumulative totals are used as depletion measures in equations (6.13) and (6.14) describing the aggregate volumes of oil and non-associated gas extensions (OX_t, NX_t).

Lastly, the revision sector is driven by year-to-year differences in the aggregate levels of conventional oil production (Δq_{t-1}^o) as seen in equation (6.16) describing aggregate oil revisions (OR_t).

As should now be clear, simulation of the drilling model requires some kind of a production sector to update and feed its development and revision sectors. On the other hand, simulation of the production arising from a growing reserve base that is constantly being augmented by drilling activity requires simulated values of the annual levels of new reserve added in each year. When integrated as described in this section, the resulting joint model can be used for purposes of simulating future aggregate production and reserve levels in Texas under any given set of exogenous assumptions regarding prices or tax rates.

C. Joint Simulation Under Constant Prices

The integrated model could now be used to simulate the aggregate production and reserve levels of oil and natural gas in Texas over the 20 year period 1984 through 2003.

The first simulation that was performed assumed that real oil and gas prices were held constant at their 1983 levels. Just as in Chapter V, the statewide non-associated gas market demand index q_t^d was slowly raised back to its pre-1982 level of 1.00 by increasing it to 0.84 in 1984, 0.92 in 1985 and 1.00 thereafter. All tax rates were held constant, with the exception of the windfall profit tax rates, which were assumed to be gradually phased out beginning in 1991 as provided under current law. The results of this simulation will therefore demonstrate how the integrated model projects future aggregate production and reserve additions when assuming continuation of the status quo.

Tables 26 through 31 present the basic results of this benchmark simulation for conventional oil, non-associated gas, associated gas, EOR and combined total oil (conventional and EOR) and combined total gas (non-associated and associated gas). Each of these tables present: (i) the levels of aggregate new reserve additions (A_t)

simulated by the drilling side of the model according to equations (6.18) through (6.20) and by equation (6.31) for EOR; (ii) the levels of aggregate production (q_t) simulated by the production side of the model according to equations (6.25), (6.26), (6.27), (6.28) and (6.29); (iii) the implied aggregate reserve levels (R_t) determined from equations (6.21), (6.22), (6.29) and (6.31); and (iv) the implied reserves-to-production ratios ($(R/P)_t$) for each year, determined as R_t/q_t. In addition, these tables present the totals of new reserve additions and production over the 20 year simulation period.[1]

Looking first at the results for conventional oil in Table 26, it can be seen that the levels of aggregate new reserve additions (A_t^o) generated by the drilling sectors fall monotonically over time, as would be expected in a geologically mature region such as Texas. The annual level of new conventional oil reserve additions falls by 21.7% from 1984 through 2003. Over the 20 year simulation period, these additions total 9,966.5 MMBBLS, about 32% higher than the level of aggregate conventional oil reserves in 1983 of 7,539.0 MMBBLS.

The annual production levels (q_t^o) forthcoming from these new reserve additions are generated by the conventional oil production model of equation (6.25) and are also seen to decline monotonically in this constant price simulation, totalling 12,723.1 MMBBLS over the

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[1] The simulations of conventional oil, non-associated gas and associated gas required the use of one-time constant adjustments to the initial 1983 reserve levels of -400 MMBBLS, +2,250 BCF and -950 BCF, respectively, to calibrate the integrated model and obtain stable R/P ratios.

Table 26. Simulated Conventional Oil Production and Reserve Levels

Year	A_t^o	q_t^o	R_t^o	$(R/P)_t^o$
1984	582.6[a]	824.0	6,897.6[b]	8.37
1985	558.0	791.7	6,663.9	8.42
1986	537.6	761.4	6,440.2	8.46
1987	530.3	735.8	6,234.7	8.47
1988	528.0	712.8	6,049.9	8.49
1989	521.0	691.8	5,879.0	8.50
1990	513.0	672.2	5,719.8	8.51
1991	505.0	654.7	5,570.0	8.51
1992	499.4	638.8	5,430.6	8.50
1993	494.1	624.1	5,300.6	8.49
1994	488.6	610.0	5,179.0	8.49
1995	482.1	596.8	5,064.3	8.49
1996	477.4	584.6	4,957.1	8.48
1997	473.5	573.4	4,857.2	8.47
1998	469.9	563.0	4,764.1	8.46
1999	466.6	553.5	4,677.3	8.45
2000	463.6	544.8	4,596.2	8.44
2001	461.0	536.9	4,520.3	8.42
2002	458.6	529.7	4,449.2	8.40
2003	456.4	523.3	4,382.3	8.37
Totals	9,966.5	12,723.1		

[a] Oil volumes are given in millions of barrels.

[b] Includes a one-time constant adjustment of -400 MMBBLS in 1984.

Table 27. Simulated Non-Associated Gas Production and Reserve Levels

Year	A_t^g	q_t^g	R_t^g	$(R/P)_t^g$
1984	3,749.3[a]	4,496.0	44,333.3[b]	9.86
1985	3,402.6	4,807.5	42,928.4	8.93
1986	3,201.8	5,059.8	41,070.4	8.12
1987	2,960.0	4,880.4	39,150.0	8.02
1988	2,792.2	4,688.5	37,190.7	7.93
1989	2,511.5	4,486.8	35,215.3	7.85
1990	2,315.2	4,278.6	33,251.9	7.77
1991	2,139.7	4,067.5	31,324.1	7.70
1992	1,983.8	3,856.4	2,9451.6	7.64
1993	1,843.8	3,647.3	27,648.1	7.58
1994	1,718.3	3,441.6	25,924.8	7.53
1995	1,604.7	3,241.1	24,288.3	7.49
1996	1,501.5	3,047.0	22,742.8	7.46
1997	1,406.9	2,859.9	21,289.7	7.44
1998	1,319.8	2,680.3	19,929.3	7.44
1999	1,239.4	2,508.3	18,660.4	7.44
2000	1,164.5	2,344.0	17,480.9	7.46
2001	1,095.3	2,187.3	16,388.9	7.49
2002	1,031.0	2,038.3	15,381.5	7.55
2003	971.2	1,896.7	14,456.0	7.62
Totals	39,889.2	70,513.1		

[a] Gas volumes are given in billions of cubic feet.

[b] Includes a one-time constant adjustment of +2,250 BCF in 1984.

Table 28. Simulated Associated Gas Production and Reserve Levels

Year	A_t^a	q_t^a	R_t^a	$(R/P)_t^a$
1984	1,082.6[a]	1,373.6	9,732.0[b]	7.09
1985	1,033.8	1,319.7	9,446.2	7.16
1986	999.2	1,269.2	9,176.3	7.23
1987	983.9	1,226.6	8,933.6	7.28
1988	976.0	1,188.3	8,721.4	7.34
1989	959.5	1,153.2	8,527.6	7.39
1990	941.4	1,120.6	8,348.5	7.45
1991	923.4	1,091.3	8,180.6	7.50
1992	910.1	1,064.9	8,025.7	7.54
1993	897.5	1,040.4	7,882.8	7.58
1994	884.6	1,016.9	7,750.6	7.62
1995	870.7	994.9	7,626.4	7.67
1996	859.9	974.6	7,511.7	7.71
1997	850.6	955.8	7,406.5	7.75
1998	842.0	938.5	7,309.9	7.79
1999	833.9	922.6	7,221.3	7.83
2000	826.5	908.1	7,139.7	7.86
2001	819.8	894.9	7,064.5	7.89
2002	813.5	883.0	6,995.0	7.92
2003	807.7	872.3	6,930.3	7.94
Totals	18,066.8	21,209.4		

[a] Gas volumes are given in billions of cubic feet.

[b] Includes a one-time constant adjustment of -950 BCF in 1984.

Table 29. Simulated EOR Production and Reserve Levels

Year	A_t^e	q_t^e	R_t^e	$(R/P)_t^e$
1984	588.8[a]	67.9	520.9	7.67
1985	118.7	73.7	565.9	7.67
1986	122.0	79.3	608.6	7.67
1987	125.0	84.6	649.1	7.67
1988	129.8	89.8	689.1	7.67
1989	133.8	94.9	728.0	7.67
1990	132.1	99.1	760.9	7.67
1991	134.3	103.2	792.0	7.67
1992	134.5	106.8	819.7	7.67
1993	131.9	109.7	841.9	7.67
1994	129.7	112.0	859.5	7.67
1995	127.9	113.8	873.6	7.67
1996	125.6	115.2	884.0	7.67
1997	122.9	116.1	890.9	7.67
1998	119.7	116.5	894.1	7.67
1999	116.0	116.4	893.7	7.67
2000	111.9	115.9	889.6	7.67
2001	107.3	114.9	882.0	7.67
2002	102.2	113.5	870.7	7.67
2003	96.6	111.5	855.9	7.67
Totals	2,910.7	2,054.8		

[a] Oil volumes are given in millions of barrels.

Table 30. Simulated Total Oil Production and Reserve Levels

Year	A_t^O	q_t^O	R_t^O	$(R/P)_t^O$
1984	1,171.4[a]	920.6	7,418.5[b]	8.06
1985	676.7	896.2	7,229.8	8.07
1986	659.6	873.1	7,048.8	8.07
1987	655.4	851.6	6,883.7	8.08
1988	657.8	832.6	6,739.0	8.09
1989	654.7	815.3	6,607.0	8.10
1990	645.0	798.7	6,480.7	8.11
1991	639.2	783.9	6,362.0	8.12
1992	633.8	770.3	6,250.3	8.11
1993	626.0	757.2	6,142.4	8.11
1994	618.2	744.0	6,038.6	8.12
1995	610.0	731.4	5,937.9	8.12
1996	603.0	719.3	5,841.1	8.12
1997	596.4	707.8	5,748.1	8.12
1998	589.6	696.6	5,658.2	8.12
1999	582.7	686.0	5,570.9	8.12
2000	575.5	675.7	5,485.8	8.12
2001	568.3	665.8	5,402.3	8.11
2002	560.8	656.2	5,319.9	8.11
2003	553.1	647.0	5,238.1	8.10
Totals	12,877.2	15,229.2		

[a] Oil volumes given in millions of barrels.

[b] Includes a one-time constant adjustment of -400 MMBBLS in 1984.

Table 31. Simulated Total Gas Production and Reserve Levels

Year	A_t^G	q_t^G	R_t^G	$(R/P)_t^G$
1984	4,831.9[a]	5,869.5	54,065.4[b]	9.21
1985	4,436.4	6,127.1	52,374.6	8.55
1986	4,201.0	6,329.0	50,246.6	7.94
1987	3,944.0	6,106.9	48,083.6	7.87
1988	3,705.2	5,876.7	45,912.1	7.81
1989	3,470.9	5,640.0	43,742.9	7.76
1990	3,256.6	5,399.1	41,600.4	7.70
1991	3,063.1	5,158.8	39,504.7	7.66
1992	2,893.9	4,921.9	37,477.4	7.62
1993	2,741.3	4,687.7	35,530.9	7.58
1994	2,602.9	4,458.5	33,675.3	7.55
1995	2,475.5	4,236.1	31,914.8	7.53
1996	2,361.4	4,021.6	30,254.5	7.52
1997	2,257.5	3,815.7	28,696.2	7.52
1998	2,161.8	3,618.8	27,239.2	7.53
1999	2,073.4	3,430.9	25,881.7	7.54
2000	1,991.0	3,252.1	24,620.7	7.57
2001	1,915.1	3,082.3	23,453.4	7.61
2002	1,844.4	2,921.3	22,376.5	7.66
2003	1,778.8	2,769.0	21,386.3	7.72
Totals	58,006.0	91,722.3		

[a] Gas volumes are given in billions of cubic feet.

[b] Includes a one-time constant adjustment of +1,300 BCF in 1984.

20 year period. For comparison, the simulation of future conventional oil production coming from existing reserves that was performed in Chapter V projected cumulative conventional oil production from 1984 through 2003 of only 7,108.3 MMBBLS. This implies that the 9,966.5 MMBBLS of new conventional oil reserves added since 1984 led to 5,614.8 MMBBLS of additional conventional oil production by the year 2003. In other words, 56.3% of the new conventional oil reserves added during that period were extracted as of 2003.

By the end of the simulation period in 2003, the declining levels of new reserve additions and aggregate production have reduced the remaining conventional oil reserves (R_t^o) in Texas to 4,382.3 MMBBLS, or about 58% of the reserve level in 1983. Finally, the virtual constant pattern of the R/P ratio ($(R/P)_t^o$) indicates the stable characteristics of the integrated model for conventional oil, hovering around a value of 8.5 years.

Table 27 presents the simulation results for non-associated gas under constant real 1983 prices. Again, the projected levels of aggregate new reserve additions (A_t^g) decline in every year of the simulation period, demonstrating the increasing difficulty of finding new non-associated gas reserves in Texas. This annual decline is even more pronounced than it was for conventional oil, as annual new reserve additions in 2003 have fallen to approximately 25% of the level in 1984. The sum of new reserve additions over the period 1984-2003 is 39,889.2 BCF, which is 93.1% of the level of non-associated gas reserves in Texas as of year end 1983 of 42,830.0 BCF.

Annual production levels of non-associated gas (q_t^g), which are projected by equation (6.26), are stimulated by these new reserve additions and are expected to rise until the statewide non-associated gas market demand index returns to 1.00 in 1986. After that, the production series declines monotonically, totaling 70,513.1 BCF over the 20 year period. The cumulative amount of non-associated gas production predicted to come from existing reserves over the same period in Chapter V only comes to 40,258.0 BCF. Therefore, it can be concluded that the 39,889.2 BCF of new non-associated gas reserves added from 1984 through 2003 increased non-associated gas production by 30,255.1 BCF, so that 75.8% of the new reserves were extracted by the year 2003.

The level of aggregate non-associated gas reserves (R_t^g) in Texas is projected to stand at 14,456.0 BCF in 2003, or at about 1/3 of the level in 1983. Table 27 also shows the projected return of the R/P ratio for non-associated gas ($(R/P)_t^g$) to its pre-1982 level of approximately 7.5 years after the statewide non-associated gas market demand index returns to its pre-1982 value of 1.00.

The simulated levels of associated gas production and reserve levels are reported in Table 28. By virtue of the close correlation between aggregate associated gas revisions and aggregate oil revisions expressed in equation (6.17), aggregate associated gas new reserve additions (A_t^a) do not decline as rapidly as do those for non-associated gas. Even though aggregate associated gas discoveries and extensions are projected to fall considerably over the simulation period, annual revisions slightly increase, making the net effect on aggregate new reserve additions a decline of only 25.4% from the 1984 level by the year 2003. The sum of aggregate associated gas new reserve additions over the simulation period is 18,116.8 BCF, or 65.1% higher than the level of aggregate associated gas reserves in 1983 of 10,973.0 BCF.

Aggregate associated gas production levels (q_t^a) are predicted by equation (6.27) to fall regularly over the simulation period at the same rate as aggregate conventional oil production (q_t^o). The cumulative total of aggregate associated gas production as of 2003 is 21,209.4 BCF, almost double the 11,849.6 BCF predicted to come from existing reserves over the same period. The additional production of 9,359.8 BCF exhausts 51.7% of the new associated gas reserves added since 1984.

By the year 2003, aggregate associated gas reserve levels (R_t^a) are projected to have fallen to 6,930.3 BCF, which is 63.2% of the level in 1983. The R/P ratio for associated gas ($(R/P)_t^a$) shows a slight upward trend over the simulation period due to the assumption of a constant gas-oil production ratio (GOR_t) in equation (6.27).

Simulated levels of EOR production and reserves appear in Table 29. The manner in which EOR reserves (R_t^e) are calculated (see equation (6.31)) insures a constant R/P ratio ($(R/P)_t^e$) for EOR of 7.67 years, and requires a large upward revision of EOR reserves from 0 to 588.8 MMBBLS in 1984. Subsequent levels of EOR reserve additions (A_t^e) follow the parabolic path that is characteristic of EOR activity under constant real prices, rising from 118.7 MMBBLS in 1985 to a high of 134.5 in 1992 before falling back down to 96.6

MMBBLS by 2003. New reserve additions of EOR total 2,910.7 MMBBLS as of 2003.

Annual levels of EOR production (q_t^e) also follow a parabolic path, peaking at 116.5 MMBBLS in 1998. This pattern is to be expected under a constant real price of oil, as seen in Figure 11 of Chapter V. Cumulative EOR production for the 20 years comes to 2,054.8 MMBBLS, leaving 855.9 MMBBLS of the new EOR reserves added since 1984 to be produced after 2003.

The results of Table 26 (conventional oil) and Table 29 (EOR) are combined in Table 30 to represent the levels of total Texas oil production and reserves from all sources. The total oil production levels (q_t^O) in Table 30 include the annual levels of condensate production projected using equation (6.28), but the total oil new reserve additions (A_t^O) and reserve levels (R_t^O) do not include condensate reserves, since these were not projected by the Bremmer model.

After the initial upward revision of EOR reserve estimates in 1984, the pattern of total oil annual new reserve additions shows a steady decline over the simulation period, with the annual level in 2003 being 19.3% lower than the level in 1985. Annual total oil new reserve additions sum to 12,877.2 MMBBLS by the year 2003. In spite of EOR, total oil annual production levels also decline monotonically, although more slowly, with an observed average decline rate of 1.8% per year. Cumulative total oil production over the simulation period is projected to be 15,229.2 MMBBLS.

When including EOR reserves, total oil reserves in Texas are not projected to drop as much as conventional oil reserves, only falling by 29.4% in 20 years, to a level of 5,238.1 MMBBLS as of year end 2003. As a result, the R/P ratio for total oil ($(R/P)_t^O$) stays in a rather tight band around 8.1 years over the simulation period.

Finally, Table 31 combines the results of Table 27 (non-associated gas) and Table 28 (associated gas) to obtain results for total gas production and reserves from all sources in Texas.

Total gas new reserve additions (A_t^G) show a rather dramatic decline over the simulation period, with the annual level in 2003 being only 36.8% of the level in 1984. Annual total gas new reserve additions sum to 58,006.0 BCF by the year 2003. Total gas production (q_t^G) declines significantly more slowly than total gas new reserve additions do, but more quickly than total oil production does, with an observed average decline rate of 3.9% per year. Cumulative total gas production over the period is projected to be 91,722.3 BCF.

Total gas reserves in Texas (R_t^G) are not supplanted by future EOR activity as total oil reserves are, and accordingly are projected to fall to about 40% of the level in 1983 by the year 2003. Since non-associated gas production usually makes up about 3/4 of total gas production in Texas, the R/P ratio for total gas ($(R/P)_t^G$) is heavily influenced by the R/P ratio for non-associated gas. Therefore, $(R/P)_t^G$ is seen to stabilize at a value of just over 7.5 years after the statewide non-associated gas market demand index returns to 1.00 in 1986.

D. Price Effects in the Integrated Model

In order to determine the sensitivity of the integrated model to price changes, another simulation was performed, but this time using constant real prices that were 10% higher than the 1983 levels. By comparing the resulting higher cumulative totals of new reserve additions and production, the implied 20 year price elasticities of the drilling and production sectors can be ascertained. The magnitudes of these price elasticities will give some indication of the magnitudes of the impact of the windfall profit tax that will be examined in Chapter VII.

This higher price simulation was performed by increasing only the assumed values of the real prices of oil and gas used by the model. No other exogenous variables were changed from the benchmark simulation performed above using 1983 prices, thereby allowing for the direct comparison of these higher price results with those earlier results. The results of the 10% higher real price simulation are summarized in Table 32, which reports the differences in the simulated levels of new reserve additions and production that are solely attributable to the price increases.

For conventional oil, the 10% real price increase led to a 2.32% increase in new reserve additions, implying a 20 year price elasticity of 0.232 over the 20 year period. This 2.32% increase in reserves caused conventional oil production to rise by 1.27% over the simulation period for an implied 20 year price elasticity of 0.127. The production increase will be smaller than the increase in new reserve additions since a barrel of new oil reserves added today is

Table 32. Differences in Simulated Reserve Additions and Production Under 10% Higher Real Prices

	ΔA_t	Δq_t
Conventional Oil	+ 231.7[a]	+ 161.1
Percentage change	2.32	1.27
EOR Oil	+ 592.2	+ 381.0
Percentage change	20.35	18.54
Total Oil	+ 823.9	+ 552.7[b]
Percentage change	6.40	3.63
Non-Associated Gas	+ 1,467.8[c]	+ 1,673.5
Percentage change	3.68	2.37
Associated Gas	+ 472.9	+ 268.5
Percentage change	2.61	1.27
Total Gas	+ 1,940.7	+ 1,942.0
Percentage change	3.35	2.12

[a] Oil volumes are given in millions of barrels.

[b] Includes condensate production.

[c] Gas volumes are given in billions of cubic feet.

not fully extracted for many years thereafter. EOR activity is considerably more sensitive to price, as demonstrated by the 18.54% increase in EOR production from 1984 through 2003. This increase implies a large 20 year price elasticity of 1.85 for EOR production, and caused the implied levels of EOR new reserve additions to rise by 20.35%. Together, new reserve additions for conventional oil and EOR rose by 6.40% over the 20 year period, exhibiting a price elasticity of 0.64. Cumulative total oil production rose 3.63% by 2003 for an implied 20 year price elasticity of 0.363.

Turning to natural gas, the 10% increase in real prices caused the drilling side of the model to project new reserve additions that were 3.68% higher, for a 20 year price elasticity of 0.368. Non-associated gas production rose by 2.37% over the simulation period, showing slightly more responsiveness to price than did associated gas production, which was linked to conventional oil production and therefore exhibited the same percentage response of 1.27%. The corresponding 20 year price elasticities are 0.237 and 0.127, respectively. Associated gas reserve additions rose by 2.61%, yielding a 20 year price elasticity of 0.261. When taken together, total gas reserve additions increase by 3.35% for a 20 year elasticity of 0.335, while total gas production rises by 2.12% for a 20 year elasticity of 0.212.

These 20 year price elasticities for conventional oil and non-associated gas production from a growing reserve base can be compared to the 20 year price elasticities computed in Chapter V for production from existing reserves. This comparison will indicate the contribution made by the abandonment process to the full production response to the 10% higher real prices. For conventional oil production, the 20 year price elasticity from existing reserves is recalled from Chapter V to be 0.039, which is 30.7% of the broader elasticity measured here. The magnitude of the 20 year price elasticity for non-associated gas production from existing reserves was estimated in Chapter V to be 0.064, which is 27% of the 20 year price elasticity estimated from a growing reserve base. It can be concluded that the abandonment or re-opening of individual wells that are extracting from existing reserves can make a significant contribution to the production response to an exogenous shock such as a price change.

These results demonstrate the sensitivity of the integrated model to exogenous shocks in prices or tax rates. The higher real prices increased the discounted net prices of oil and gas (DNP_t^o, DNP_t^g) used to compute the expected profit per exploratory or development well ($X\Pi_t$, $D\Pi_t$). As a result, the number of exploratory and development wells drilled in each year went up, causing discoveries and extensions to rise and thereby increasing the projected levels of new reserve additions of conventional oil and non-associated gas (A_t^o, A_t^g).

The higher levels of new reserve additions then increased the values of the capacity augmentation indexes (I_t^o, I_t^g) used to determine the projected levels of conventional oil and non-associated gas production (q_t^o, q_t^g). In addition, the higher prices themselves reduced the economic limits (EL_t^o, EL_t^g) which determine the levels of economic capacity (EC_t^o, EC_t^g) driving the conventional oil and non-associated gas production models. The projected levels of associated gas and condensate production (q_t^a, q_t^c) were also increased along with the levels of conventional oil and non-associated gas production, since they were projected as constant proportions of them. A higher real oil price will, of course, also increase the projected levels of EOR production, as shown earlier in Chapter V.

E. Summary and Conclusions

In this chapter, the model of aggregate Texas petroleum production developed in Chapter V was integrated with a model describing aggregate new reserve additions in Texas developed by Bremmer.

First, the individual estimated equations of the Bremmer model of petroleum drilling activity were presented and explained. This drilling model, rich in economic structure, is capable of analyzing the impact of any exogenous shocks to prices or tax rates on the levels of drilling activity and the resultant new reserve additions. Just as in the production sector developed here, Bremmer's model is driven by economic variables that fully incorporate the effects of prices, tax rates, operating and drilling costs and regulatory constraints. Thus the two models share a similar economic structure and can be easily integrated for joint analysis.

Next, the interrelationships between the drilling sectors of the Bremmer model and the production models were outlined, showing how each sector could be integrated into a single simulation model. The integrated model was then used to simulate the future levels of production that would be forthcoming from the reserves that were constantly being augmented by the new reserve additions generated by the drilling sectors of the model.

The 20 year cumulative totals of reserve additions and production that resulted from a benchmark simulation using constant real 1983 prices were compared with the same values from a simulation assuming real prices that were 10% higher in order to estimate the price responsiveness of the integrated model. The 20 year price elasticities of conventional oil and non-associated gas found in this manner were 0.127 and 0.237, respectively. These estimates are considerably larger than the 20 year price elasticities of 0.039 and 0.064 computed for conventional oil production and non-associated gas production from existing reserves in Chapter V, indicating that the abandonment process can account for about 25% to 30% of the full production response to an exogenous price or tax rate shock.

Using this integrated simulation model, the next chapter will consider the impact of changes in the windfall profit tax phaseout schedule on aggregate Texas petroleum production from a growing reserve base. After the aggregate production impacts of the windfall profit tax have been quantitatively determined, estimates will be made of the net federal budgetary effects resulting from the changes in the phaseout schedule. In this way, the magnitude of the marginal benefits associated with a windfall profit tax policy change can be compared with its associated marginal costs to determine if the policy change is beneficial on the whole.

CHAPTER VII

AN ANALYSIS OF THE IMPACT OF THE WPT ON AGGREGATE TEXAS PETROLEUM PRODUCTION

This chapter is devoted to a quantitative analysis of the impact of the windfall profit tax (WPT) on aggregate Texas petroleum production. The fate of the WPT remains uncertain and will surely generate considerable debate among public policy makers in this decade. Is the WPT likely to be a significant source of federal revenues? How would those revenues change if the WPT were extended or repealed before its planned phaseout in 1991-1993? Would removing or extending the WPT significantly affect exploration and production activity? To the economist, these questions can best be answered within the context of a welfare analysis that can provide the basis for rational and well-informed policy formulation.

As a first step, the integrated simulation model developed in the preceding chapter will be used to estimate the production effects arising from changes in the WPT phaseout schedule. Estimation of the effects on aggregate Texas petroleum production levels will simply be a matter of making the appropriate assumptions when simulating with the integrated model. Gains or losses in total oil and gas production that result from the immediate repeal or the indefinite extension of the WPT can be easily calculated by comparing the simulated production levels under those two alternative phaseout scenarios with the levels projected to occur under a status quo scenario that assumes phaseout of the WPT according to current law.

Once these production effects have been determined, the next step will be to estimate the resultant changes in the federal revenues collected from the WPT on Texas oil production. Estimation of the federal budgetary effects of the WPT will require the development of several equations that are capable of simulating the aggregate WPT collections for Texas. In doing so, it will be necessary to determine the appropriate percentages of Texas oil production that will fall into each tier classification under the WPT, since each tier has a different tax rate and adjusted base price.

Finally, the value of the estimated production effects will be compared to the estimated changes in the amounts of WPT collected in Texas to determine the net welfare effects of the alternative WPT phaseout scenarios.

A. Simulation of Reserves and Production Under Alternative WPT Phaseout Scenarios

The integrated model of aggregate Texas petroleum production from Chapter V was used to simulate future levels of new reserve additions and production under each of three alternative WPT phaseout scenarios for the 20 year period 1984 through 2003. These same three WPT phaseout scenarios were examined in Chapter V when considering the future production levels from reserves existing as of year end 1983. To repeat, the first scenario assumes that the WPT will be phased out according to current law, which provides for a 33 month phaseout beginning in 1991. The second scenario assumes that the WPT was completely repealed on 1-1-84, so that there is no WPT throughout the 20 year simulation period. The third scenario assumes that the WPT phaseout scheduled to begin in 1991 is postponed, thereby indefinitely maintaining the WPT rates in place as of 1990.

The production increases arising from full WPT repeal should represent the upper bound on additional production forthcoming under any diminuation of the WPT rates or phaseout schedule. Similarly, the losses in production resulting from indefinite extension of the WPT should give an indication of the "worse case" impact from any expansion of the duration of the WPT, short of making substantial increases in the tax rates on all the tiers. Since the actions of policy makers concerned with the WPT cannot be predicted with any degree of certainty, there is no guarantee that these two comparisons will cover all cases. However, they should provide some guidance for policy makers as to the range of possible impacts of the WPT on the single most important petroleum producing state in the nation, and hence on a substantial portion of national petroleum production levels.

Just as in Chapter V, the simulations of these three WPT scenarios assumed that real oil and gas prices would follow the paths projected by the EIA in its Middle World Oil Price Case. The statewide non-associated gas market demand index q_t^d was again assumed to take on the values of 0.84 in 1984, 0.92 and 1984 and 1.00 thereafter. All other tax rates were assumed to remain constant.

Assuming WPT Phaseout Under Current Law

Table 33 reports the cumulative 20 year totals of aggregate new reserve additions (A_t) and production (q_t) projected to occur in Texas when assuming phaseout of the WPT according to current law. Aggregate new reserve additions of conventional oil sum to 10,389.8 MMBBLS, and help to generate 12,862.1 MMBBLS of aggregate conventional oil production over the 20 year simulation period. Aggregate EOR production adds up to 3,280.0 MMBBLS by the the year 2003, implying aggregate new reserve additions of EOR oil of 5,909.1 MMBBLS over the same timespan. Combining the aggregate conventional oil results with the EOR projections gives the estimated levels of aggregate total oil new reserve additions and, after including condensate, aggregate total oil production. Total oil new reserve additions are therefore projected to reach 16,298.9 MMBBLS by 2003, supporting 16,610.0 MMBBLS of crude oil production from all sources.

Aggregate new reserve additions of non-associated gas sum to 42,446.7 BCF over the 20 year simulation period, giving rise to 73,116.9 BCF of aggregate non-associated gas production. Aggregate associated gas reserves are projected to grow by 18,974.3 BCF from 1984 through 2003. Closely following the production path of aggregate conventional oil production, aggregate associated gas production comes to 21,441.1 BCF. When taken together, total natural gas reserves in Texas are seen to grow by 61,421.0 BCF during the simulation period, while being depleted by 94,557.8 BCF of production at the same time.

Table 33. Simulated Reserve Additions and Production Assuming WPT Phaseout Under Current Law

	A_t	q_t
Conventional Oil	10,389.8[a]	12,862.1
EOR Oil	5,909.1	3,280.0
Total Oil	16,298.9	16,610.0[b]
Non-Associated Gas	42,446.7[c]	73,116.9
Associated Gas	18,974.3	21,441.1
Total Gas	61,421.0	94,557.8

[a] Oil volumes are given in millions of barrels.

[b] Includes condensate production.

[c] Gas volumes are given in billions of cubic feet.

Assuming WPT Repeal on 1-1-84

Table 34 reports the cumulative 20 year totals of aggregate new reserve additions (A_t) and production (q_t) projected to occur in Texas when assuming repeal of the WPT on 1-1-84, the start of the simulation period. The results under this WPT phaseout scenario therefore represent a world in which there is no WPT and should estimate the highest possible aggregate petroleum production levels that could be forthcoming in Texas without some additional tax reform or real price increases. To aid in the comparison of the results under this scenario to those obtained under current law as presented in Table 33, Table 34 also reports the absolute and percentage changes in the cumulative levels of new reserve additions and production that result from the repeal of the WPT on 1-1-84.

Aggregate new reserve additions of conventional oil increase by 7.4 MMBBLS under WPT repeal to a level of 10,397.2 MMBBLS, an increase of only 0.07%. This relatively small upturn in reserve additions can be attributed to the fact that newly discovered oil production falls into Tier 3 for purposes of the WPT. In addition to having the lowest WPT rate, Tier 3 also has the highest base price, and that base price is allowed to grow at the rate of inflation plus 2% each year. The EIA real price path assumes that real oil prices will remain depressed below the 1983 level of $29.83 until the year 1991. As a result, the legally defined "windfall profit" - the difference between the market price and the adjusted base price - will be very small for Tier 3 production until just about the time the WPT phaseout is scheduled to begin under current law, which is

Table 34. Simulated Reserve Additions and Production Assuming WPT Repeal on 1-1-84

	A_t	q_t
Conventional Oil	10,397.2[a]	12,892.9
Absolute change	+ 7.4	+ 30.8
Percentage change	0.07	0.24
EOR Oil	5,925.9	3,295.4
Absolute change	+ 16.8	+ 15.4
Percentage change	20.35	18.54
Total Oil	16,323.1	16,656.3[b]
Absolute change	+ 24.2	+ 46.3
Percentage change	0.15	0.28
Non-Associated Gas	+42,424.2[c]	73,118.4
Absolute change	- 22.5	+ 1.5
Percentage change	0.05	0.002
Associated Gas	18,986.9	21,492.5
Absolute change	+ 12.6	+ 51.4
Percentage change	0.07	0.24
Total Gas	61,411.1	94,610.7
Absolute change	- 9.9	+ 52.9
Percentage change	0.02	0.06

[a] Oil volumes are given in millions of barrels.

[b] Includes condensate production.

[c] Gas volumes are given in billions of cubic feet.

1-1-91. Therefore, the repeal of the WPT would have little effect on the discounted net price of a barrel of new oil reserves (DNP_t^o). This implies an even smaller effect on the expected profits from drilling exploratory or development wells ($X\Pi_t$, $D\Pi_t$), which drive the levels of exploratory and development drilling activity and hence, the volumes of new conventional oil reserve additions.

Aggregate conventional oil production is driven by the economic limit for the marginal oil well (EL_t^o), whose production is classified under Tier 2 for WPT purposes. Tier 2 has a lower base price than does Tier 3, and its base price is only increased by the rate of inflation each year, making the windfall profit larger for a barrel of oil produced under Tier 2 than under Tier 3. Along with the larger windfall profit, Tier 2 production is taxed at a higher WPT rate, so that repeal of the WPT would have a significant impact on the economic limit for the individual marginal oil well. Accordingly, aggregate conventional oil production rises under WPT repeal by 30.8 MMBBLS, an increase of 0.24%, mainly as a result of lower economic limits, rather than due to a larger reserve base.

The greater sensitivity of EOR production levels to the net price received per barrel of EOR oil resulted in considerably larger percentage increases than those projected for conventional oil production. Cumulative EOR production is projected to rise under repeal of the WPT by 15.4 MMBBLS, for an increase of 0.47%, nearly twice the response for conventional oil production. Since the implied levels of EOR reserve additions are driven by the projected levels of EOR production, they are seen to rise by 16.8 MMBBLS, an increase of 0.28%. Although larger than the responses for conventional oil, the percentage increases for EOR are still rather small, because EOR production also falls under Tier 3 for WPT purposes.

Total oil production, including condensate, is projected to rise by 46.3 MMBBLS should the WPT be repealed on 1-1-84. This is an increase of 0.28%, bringing total oil production to 16,656.3 MMBBLS over the 20 year simulation period. Aggregate oil reserves are projected to be augmented by 24.2 MMBBLS, an increase of 0.15%.

Aggregate new reserve additions of non-associated gas are projected to fall under repeal of the WPT on 1-1-84, but only by 22.5 BCF, or 0.05%. This result is explained by the directionality present in the drilling sectors of the integrated model. The repeal of the WPT on oil and condensate production has a much greater impact on the discounted net price of oil (DNP_t^o) than it does on the discounted net price of gas (DNP_t^g). As a result, the relative price of oil ($RELPRI_t$) - which drives the oil and gas success ratios of exploratory and development wells drilled each year - rises, causing drilling firms to seek out more new oil reserves vis-a-vis new gas reserves. This directionality in drilling efforts is sufficiently strong to actually reduce the cumulative total of new non-associated gas reserves added over the simulation period.

Aggregate non-associated gas production is projected to rise marginally in response to repeal of the WPT, in spite of the slightly smaller levels of new reserve additions. The total amount of non-associated gas produced over the simulation period is higher under repeal by 1.5 BCF, a scant increase of only 0.002%. The removal of the WPT on the condensate jointly produced with non-associated gas causes the economic limit for the marginal non-associated gas well (EL_t^g) to fall slightly. This small decline stimulates aggregate non-associated gas production enough to just barely overcome the effects of slightly reduced levels of new reserve additions on the non-associated gas capacity augmentation index (I_t^g).

Aggregate new reserve additions of associated gas are projected to rise under repeal of the WPT by 12.6 BCF, which is the same percentage increase as that projected for conventional oil new reserve additions of 0.07%. This result is not surprising in comparison to the projected decline in non-associated gas reserve additions once it is recalled that associated gas extensions and revisions are driven entirely by conventional oil extensions and revisions.

Aggregate associated gas production levels are projected to rise by 51.4 BCF, or 0.24%, which is the same percentage increase as that for conventional oil production. Again, this is a direct result of the way in which associated gas production is modelled as a constant proportion of conventional oil production.

Total new reserve additions of natural gas in Texas are projected to fall by 9.9 BCF over the simulation period because the drop in non-associated gas reserve additions exceeds the upturn in associated gas reserve additions. The net percentage decrease in total gas reserve additions is only 0.02%. Conversely, since both non-associated and associated gas production rise, cumulative total natural gas production in Texas is projected to rise by 52.9 BCF, for a percentage increase of 0.06%.

The small magnitudes of these production responses indicate the relatively small benefits that would result from advancing the phaseout of the WPT during a period of declining or constant real oil prices.

Assuming No Phaseout of the WPT

Table 35 reports the cumulative 20 year totals of aggregate new reserve additions (A_t) and production (q_t) projected to occur in Texas when assuming that the gradual phaseout of the WPT phaseout scheduled to begin in 1991 does not occur. These simulation results therefore represent the lowest aggregate production levels possible under the WPT as it is currently formulated, without some downward revision of the computation of the adjusted base prices or an increase in the tax rates for the three WPT tiers. Just as in Table 34, Table 35 also reports the absolute and percentage changes in cumulative reserve additions and production that would result if the current phaseout schedule of the WPT were indefinitely postponed.

Under a permanent WPT, aggregate new reserve additions of conventional oil would fall by 22.6 MMBBLS below that which is projected to occur over the simulation period under current law. This is a decrease of 0.22%, over three times the impact of repeal of the WPT. This response is significantly higher than the response under repeal because real oil prices are assumed by the EIA to rise by 5.9% each year after 1990, when the extension will begin to take

Table 35. Simulated Reserve Additions and Production Assuming No Phaseout of the WPT

	A_t	q_t
Conventional Oil	10,367.2[a]	12,825.0
Absolute change	- 22.6	- 37.1
Percentage change	0.22	0.29
EOR Oil	5,530.3	3,118.6
Absolute change	- 378.8	- 161.4
Percentage change	6.41	4.92
Total Oil	15,897.5	16,411.7[b]
Absolute change	- 401.4	- 198.3
Percentage change	2.46	1.19
Non-Associated Gas	+42,560.2[c]	73,151.1
Absolute change	+ 113.5	+ 34.2
Percentage change	0.27	0.05
Associated Gas	18,933.8	21,379.2
Absolute change	- 40.5	- 61.9
Percentage change	0.21	0.29
Total Gas	61,494.0	94,530.2
Absolute change	+ 73.0	- 27.6
Percentage change	0.12	0.03

[a] Oil volumes are given in millions of barrels.

[b] Includes condensate production.

[c] Gas volumes are given in billions of cubic feet.

effect. In a world of rising real oil prices the windfall profit for Tier 3 oil production will also rise, making the impact of extension be felt more strongly than that of repeal, which occurs during a period of falling or constant real oil prices.

These reduced levels of new reserve additions would, in turn, help to reduce the cumulative total of conventional oil production. Of course, the extension of the WPT after 1991 would increase the oil well economic limit (EL_t^o), and this would also cause conventional oil production to decline in all years after 1990. The net effect is a projected decline in cumulative conventional oil production of 37.1 MMBBLS, a drop of 0.29%.

As might have been expected, the responses projected for EOR activity are considerably larger than those for conventional oil. The decline in cumulative EOR production that extension of the WPT would bring totals 161.4 MMBBLS, over four times the drop in cumulative conventional oil production over the same period. This represents a decrease of 4.92% below the level projected under current law. Again, it must be noted that extension of the WPT during a period of rising real oil prices will have a significantly greater effect than if real oil prices were expected to fall. This explains why the percentage decrease in cumulative EOR production due to extension is 10 times the size of the percentage increase expected under repeal. The implied levels of EOR new reserve additions that are calculated from the projected EOR production levels show a similar decline of 378.8 MMBBLS, or 6.41%.

Cumulative total oil production from all sources, including condensate, is projected to drop by 198.3 MMBBLS over the 20 year simulation period due to extension of the WPT, a decrease of 1.19% below that projected under current law. Aggregate new oil reserves added over the period fall by a total amount of 401.4 MMBBLS, or 2.46%.

Turning to natural gas, the cumulative amount of non-associated gas reserve additions is projected to rise due to extension by 113.5 BCF, or 0.27%. This result is again due to the directionality contained in the drilling sectors of the model, indicating that the relative price of oil ($RELPRI_t$) has fallen, making new gas reserves more attractive to find than new oil reserves. Cumulative non-associated gas production rises by 34.2 MMBBLS because of these new reserves, an increase of 0.05%. The directionality effect is stronger in this scenario because the WPT change occurs in the latter half of the simulation period, when real oil prices are assumed to be rising.

Associated gas is affected in the opposite direction as non-associated gas, but in the same direction as conventional oil. This is to expected, given the high degree of correlation between associated gas reserve additions and production and those of conventional oil. Cumulative associated gas new reserve additions fall by 40.5 BCF, a decrease of 0.21%, which is just slightly smaller than the percentage decrease of 0.22% projected for conventional oil new reserve additions. The difference arises because associated gas discoveries are modelled as a constant percentage of total gas discoveries, just as non-associated gas discoveries are, and both are projected to rise in this case. The difference is small (0.01%) because associated gas discoveries make up a small proportion of associated gas new reserve additions. Cumulative associated gas production falls by 61.9 BCF, the same percentage response as that for conventional oil production of 0.29%.

The total amount of new gas reserves added during the 20 year simulation period rises by 73.0 BCF, or 0.12%, when the WPT is indefinitely extended. As a seeming paradox, cumulative total gas production falls by 27.6 BCF, a drop of 0.03%. This paradox is resolved by realizing that non-associated gas reserve additions and production respond most strongly to real gas prices, while associated gas reserve additions and production occur in conjunction with conventional oil reserve additions and production, which respond most strongly to real oil prices.

B. Decomposition of Total Oil Production by WPT Tier

Having determined the magnitudes of the production effects projected to arise under alternative WPT phaseout scenarios, the next objective was to estimate the changes in total WPT collections that would accompany these production differences. In order to properly estimate those WPT collections changes, total Texas oil production levels projected for each year must be decomposed according to the WPT tier classification scheme, since each tier has a different base price for determining the windfall profit as well as a different tax rate on that profit.

All incremental EOR production and new oil production from reserves discovered after 1979 falls into Tier 3 of the WPT, with a base price of \$17.10 that rises with inflation plus 2% per year and a tax rate of 22.5% in 1984 through 1987 that falls to 20% in 1988 and 15% in 1989. All oil production coming from stripper wells falls into Tier 2, with a base price of \$15.71 that only rises with inflation and a tax rate of 60% for majors and 30% for independents. After 1-1-84, the Tier 2 tax rate for independents was reduced to zero by law. All remaining oil production falls into Tier 1, which has a base price of \$12.81 that only rises with inflation and a tax rate of 70% for majors and 50% for independents.

The annual percentages of total oil produced in Texas that fall into each of these three tiers were determined from the integrated simulation model, when assuming the EIA real price paths. As a first step, the annual projected levels of conventional oil (q_t^o), condensate (q_t^c) and EOR production (q_t^e) were summed to obtain total oil production (q_t^O) in each year,

(7.1) $$q_t^O = q_t^o + q_t^c + q_t^e.$$

The share of total oil production (q_t^O) contributed by EOR production in year t (S_t^e) can be calculated as

(7.2) $$S_t^e = q_t^e/q_t^O.$$

The share contributed by conventional oil production from new reserves discovered after 1979 (S_t^n), or the new oil share in year t, is similarly calculated as

(7.3) $$S_t^n = q_t^n/q_t^o,$$

where q_t^n denotes the amount of new oil produced from those recently discovered reserves. These two shares will sum to give the share of total oil production falling into Tier 3 for WPT purposes (S_t^3) in year t,

(7.4) $$S_t^3 = S_t^e + S_t^n.$$

The share of EOR production (S_t^e) was quickly calculated, since the integrated model projects annual EOR production and total oil production levels. Calculating the share of new oil production (S_t^n) was accomplished with the help of the estimated conventional oil production equation. New reserve additions of conventional oil (A_t^o) were set to zero after 1979, so that the capacity augmentation index (I_t^o) in the conventional oil production equation reached a maximum value of 1.5883 in 1983. The future conventional oil production levels projected by holding I_t^o constant at 1.5883 were representative of the "old" oil levels forthcoming from reserves discovered before 1980. These old oil production levels were then subtracted from the conventional oil production levels projected by the integrated model (q_t^o) to obtain estimates of the incremental oil production coming from reserves added since 1979, or new oil production (q_t^n).

Table 36 shows the calculated shares of EOR and new oil production and their sum, the share of total Texas oil production falling into Tier 3.[1] The share of total oil production contributed

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[1]The shares reported in Table 36 were calculated under the

Table 36. Breakdown of Projected Shares of Total Oil Production in Tier 3

Year	EOR Oil	New Oil	Tier 3[a]
1984	0.07	0.29	0.36
1985	0.08	0.33	0.41
1986	0.08	0.37	0.45
1987	0.09	0.40	0.49
1988	0.10	0.44	0.54
1989	0.11	0.47	0.58
1990	0.12	0.50	0.62
1991	0.13	0.52	0.65
1992	0.15	0.53	0.68
1993	0.17	0.55	0.72
1994	0.19	0.56	0.75
1995	0.21	0.56	0.77
1996	0.23	0.57	0.80
1997	0.25	0.57	0.82
1998	0.27	0.57	0.84
1999	0.29	0.57	0.86
2000	0.32	0.56	0.88
2001	0.34	0.56	0.90
2002	0.35	0.55	0.90
2003	0.37	0.54	0.91

[a] EOR share plus new oil share.

by EOR is projected to grow more than five-fold over the 20 year simulation period, rising from 7% in 1984 to 37% by 2003. This growth reflects the tremendous importance EOR production will have in the future, as conventional oil production continues to decline. The share contributed by new oil is also projected to grow as old oil reserves are depleted, starting at 29% in 1984, peaking at 57% in 1996, and then falling back slightly to 54% by 2003. Taken together, these two components sum to make the share of total oil production falling into Tier 3, and that share is projected to have an increasingly large role over the simulation period, rising from 36% in 1984 to 91% by 2003.

The share of total oil production in Texas that will fall into Tier 2 for WPT purposes was estimated with the help of the concept of economic capacity. The percentage of total oil production coming from stripper wells that are producing less than 10 barrels per day (BPD) was determined by subtracting from 100% the level of economic capacity for an economic limit of 10.0. This stripper well percentage, S_t^s, was therefore calculated as

(7.5) $$S_t^s = 100 - EC_t^o(10.0),$$

where $EC_t^o(10.0)$ is the value of the conventional oil economic capacity index when evaluated at an individual oil well economic limit of 10.0 BPD. This stripper well percentage was then applied to

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status quo WPT phaseout schedule provided for by current law, but these shares were found to be invariant to the WPT phaseout scenario being assumed, out to the third decimal place.

the amount of total oil production not already classified as falling into Tier 3, so that the share of total oil production falling into Tier 2 (S_t^2) was calculated as

$$S_t^2 = (S_t^s/100)\cdot(1 - S_t^3), \tag{7.6}$$

where S_t^3 is the share classified as Tier 3.

The remaining portion of total oil production in Texas that was not already classified as falling into Tiers 2 or 3 was designated as falling into Tier 1. Since all the shares must sum to unity, the share of production falling into Tier 1 (S_t^1) was calculated as

$$S_t^1 = 1 - S_t^2 - S_t^3. \tag{7.7}$$

The projected shares of total oil production falling into each tier of the WPT are reported in Table 37.[2] The projected growth in the share falling into Tier 3 suggests that the way in which Tier 3 oil production is taxed will be most important in determining future WPT collections from Texas. Starting at 35.9% in 1984, the Tier 3 share soon comes to dominate the shares of the other two tiers, passing Tier 1's share in 1987 and passing both Tier 1's and Tier 2's shares taken together by the next year, 1988.

As the levels of production forthcoming from old reserves discovered before 1980 decline over time, the amount of total Texas oil production falling into Tier 1 also declines. From an initial

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[2] Again, these shares do not vary significantly with the WPT phaseout scenario being assumed, so that only the projections for the status quo phaseout schedule are reported in Table 37.

Table 37. Projected Shares of Total Oil Production in Tiers 1, 2 and 3

Year	Tier 1	Tier 2	Tier 3
1984	0.568	0.074	0.359
1985	0.523	0.072	0.406
1986	0.481	0.070	0.449
1987	0.440	0.067	0.493
1988	0.401	0.063	0.536
1989	0.364	0.060	0.576
1990	0.329	0.057	0.614
1991	0.297	0.053	0.650
1992	0.266	0.049	0.684
1993	0.238	0.046	0.716
1994	0.212	0.042	0.746
1995	0.188	0.038	0.773
1996	0.167	0.035	0.798
1997	0.147	0.031	0.821
1998	0.130	0.028	0.842
1999	0.114	0.025	0.861
2000	0.100	0.022	0.861
2001	0.088	0.020	0.892
2002	0.077	0.017	0.906
2003	0.068	0.015	0.917

level of 56.8% in 1984, Tier 1's share is cut in half after 10 years, yet falls even more dramatically thereafter to a level of only 6.8% by 2003. As the wells producing from those old reserves decline, their average daily production rates eventually fall below 10.0 BPD, making the remaining production from those wells eligible for Tier 2 status as stripper production. As the Tier 1 share is projected to decline over time, the Tier 2 share must also decline, since Tier 2 production is simply that portion of Tier 1 production coming from stripper wells. This is reflected in the decline of Tier 2's share from 7.4% in 1984 to 1.5% by 2003.

C. Projecting Future WPT Collections in Texas

Given the shares of total oil production that are projected to fall into each of the three WPT tiers, it was a simple matter to calculate the amount of windfall profit taxes to be collected from Texas producers in each year. Using equation (3.12) describing the WPT levied per barrel of oil, the amount of WPT that producers must actually pay in year t (WPT_t^i) can be calculated as

$$WPT_t^i = \omega_t^i(P_t^o - P_i^b ADJ_t^i)(1-s_t^o)(1-\rho_t)(1-f_t), \tag{7.8}$$

where i=1,2,3 to denote the WPT tier. The WPT liabilities have been reduced by $(1-f_t)$ to account for the deduction of WPT liabilities in computing corporate federal income tax liabilities, where f_t is the maximum federal corporate income tax rate.

Using equation (7.8), Table 38 reports the estimated levels of WPT collections, in millions of 1983 dollars, by WPT tier and for the

Table 38. Projected WPT Collections by Tier Under the Status Quo Phaseout Schedule

Year	Tier 1	%[a]	Tier 2	%	Tier 3	%	Total
1984	1,765.5[b]	89.5	91.9	4.7	115.2	5.8	1,972.6
1985	1,530.6	90.9	78.7	4.8	71.2	4.3	1,653.5
1986	1,271.3	93.8	66.0	4.9	17.7	1.3	1,354.9
1987	1,181.5	94.8	64.3	5.2	0.0	0.0	1,245.7
1988	1,212.4	93.2	73.3	5.6	14.6	1.1	1,300.3
1989	1,234.5	92.0	81.7	6.1	25.5	1.9	1,341.8
1990	1,247.0	90.6	89.3	6.5	40.6	2.9	1,376.9
1991	848.4	85.1	82.2	8.2	66.3	6.6	997.0
1992	392.3	79.0	51.1	10.3	53.0	10.7	496.4
1993	147.1	87.0	9.3	5.5	12.6	7.5	169.1
Totals	10,803.7		687.7		416.8		11,908.2

[a] Percentage of total WPT collections.

[b] In millions of 1983 dollars.

state as a whole under the status quo phaseout schedule. The table stops at 1993 since the WPT will be expired at that point under current law.

Table 38 shows that even though the Tier 1 share is projected to decline, the amount of WPT collected on Tier 1 production is projected to continue to make up a significant portion of total WPT collections from Texas until phaseout is complete in 1993. This would be possible because the size of the windfall profit on Tier 1 production is calculated using the lowest base price ($12.81), which is only increased by the rate of inflation each year, and then is taxed at the highest rates (70%, 50%). Tier 1's share of total WPT collections stays near 90% for most of the simulation period, only dropping below that after phaseout begins in 1991.

Tier 2's share of total WPT collections is projected to grow from about 5% in 1984 to over 10% by phaseout, even though its share of total production is declining over this period. Again, this is possible because the relatively large windfall profit for Tier 2 - calculated using a base price of $15.71 that rises with inflation - is taxed at the high rate of 60% for majors, who are assumed to always produce 62.7% of total Texas oil production each year, just as they did in 1983.

The pattern of Tier 3's share of total WPT collections is considerably different from those of Tier 1 or Tier 2. Its share is seen to fall from 5.8% in 1984 to zero in 1987 before rebounding to surpass the share for Tier 2 by the end of phaseout in 1992-1993. This pattern arises as a result of the much higher base price of

$17.10 for Tier 3 production that is increased at the rate of inflation plus 2% each year, causing the windfall profit for Tier 3 to fall all the way to zero by the year 1987, since real oil prices are falling from 1984 to 1987. As real oil prices begin to rise in 1998, the windfall profit for Tier 3 rises back above zero. Tier 3's shares of total WPT collections are able to eventually surpass those of Tier 2 in 1992, in spite of the lower tax rate on Tier 3 (15% at that point) and the smaller windfall profit, because of the rapid increase in Tier 3's share of total production.

This procedure was then repeated for the two other alternative WPT phaseout scenarios to project the levels of total WPT collections forthcoming under each scenario. The changes in these projected total WPT collection levels that would result from the immediate repeal or the indefinite extension of the WPT could then be easily calculated. The levels of total WPT collections reported in Table 38 were simply subtracted from the levels projected to occur under the WPT repeal scenario and the WPT extension scenario to find the net changes in total WPT collections each year.

Since the WPT repeal scenario involves setting all WPT tax rates to zero as of 1-1-84, there would be no further WPT collections and the changes relative to the status quo phaseout scenario would simply be the negatives of the values reported in Table 38. Under the WPT extension scenario, there would be higher total WPT collections during the phaseout period 1991 through 1993, and positive WPT collections thereafter. Table 39 reports these total projected differences relative to the status quo phaseout scenario for the

Table 39. Projected Differences in Total WPT Collections Due to Indefinite Extension of the WPT

Year	Change in Total WPT Collections
1991	+ 513.3[a]
1992	+ 1,147.9
1993	+ 1,608.9
1994	+ 1,914.6
1995	+ 2,056.0
1996	+ 2,202.9
1997	+ 2,356.3
1998	+ 2,519.7
1999	+ 2,671.0
2000	+ 2,883.2
2001	+ 3,088.1
2002	+ 3,312.4
2003	+ 3,556.2
Totals	+ 29,830.5

[a] In millions of 1983 dollars, relative to that projected under current law.

period 1991 through 2003, since there are no differences in tax rates from 1984 through 1990. These differences rise over time and sum to a total increase in WPT collections due to extension of $29,830.5 in millions of 1983 dollars.

D. Welfare Effects of Changes in the WPT Phaseout Schedule

The preceding sections of this chapter have established the effects on total oil production and real WPT collections in Texas that would result from changes in the WPT phaseout schedule provided by current law. The question at this point is whether the marginal costs of changing the WPT phaseout schedule are met or exceeded by the associated marginal benefits to society as a whole. This question can be answered by a straightforward calculation of the welfare effects of changing to each alternative WPT phaseout scenario from current law following the methods of welfare analysis as outlined by James M. Griffin and Henry B. Steele (1979).

Adapting either of the two alternative WPT phaseout scenarios - repeal or extension - would cause a change in the prices Texas oil producers would receive for each barrel of oil they brought to market. These changes in the net price path expected by Texas producers would be equal to the changes in the average amount of WPT paid per barrel of oil produced in each year. The average amount of WPT paid per barrel of Texas oil produced in year t ($\overline{WPT}_t$) is simply total WPT collections ($\Sigma_{i=1}^{3} WPT_t^i$) divided by total Texas oil production (q_t^O) for that year, or

(7.9) $$\overline{WPT}_t = \Sigma_{i=1}^{3} WPT_t^i / q_t^O.$$

The change in net price in year t (ΔP_t^n) can be calculated as

$$\Delta P_t^n = \overline{WPT}_t^1 - \overline{WPT}_t^0, \tag{7.10}$$

where $\overline{WPT}_t^0$ and $\overline{WPT}_t^1$ are the average amounts of WPT paid per barrel of oil in year t under two alternative WPT phaseout scenarios.

Figure 13 presents a simplified graphical depiction of the impact of extending the WPT into some year t on total Texas oil output in that year (q_t^0). The demand curve for Texas oil in year t can be represented by the horizontal line D_t, whose location depends upon the world oil price in year t. The location of the supply curve of Texas oil producers in year t (S_t) depends upon the net price they can receive in year t (P_t^n), which drives production out of reserves existing as of year t, and the net prices that were received in years past, which drove the exploratory and drilling activity that provided those reserves. If the WPT is extended, the net price path is reduced in each year of the extension by the change in the average amount of WPT paid per barrel of Texas oil. This net price change causes the supply curve for production in year t to shift upward from $S_{t,0}$ to $S_{t,1}$, which reduces production in year t from $q_{t,0}^0$ to $q_{t,1}^0$. Not only is current production reduced, but future production levels will also be lower due to the reduced levels of exploratory and development drilling in year t that would be caused by the lower net prices. These annual production changes (Δq_t^0) were measured at the start of this chapter for the period 1984 through 2003 under both alternative WPT phaseout scenarios - extension and repeal.

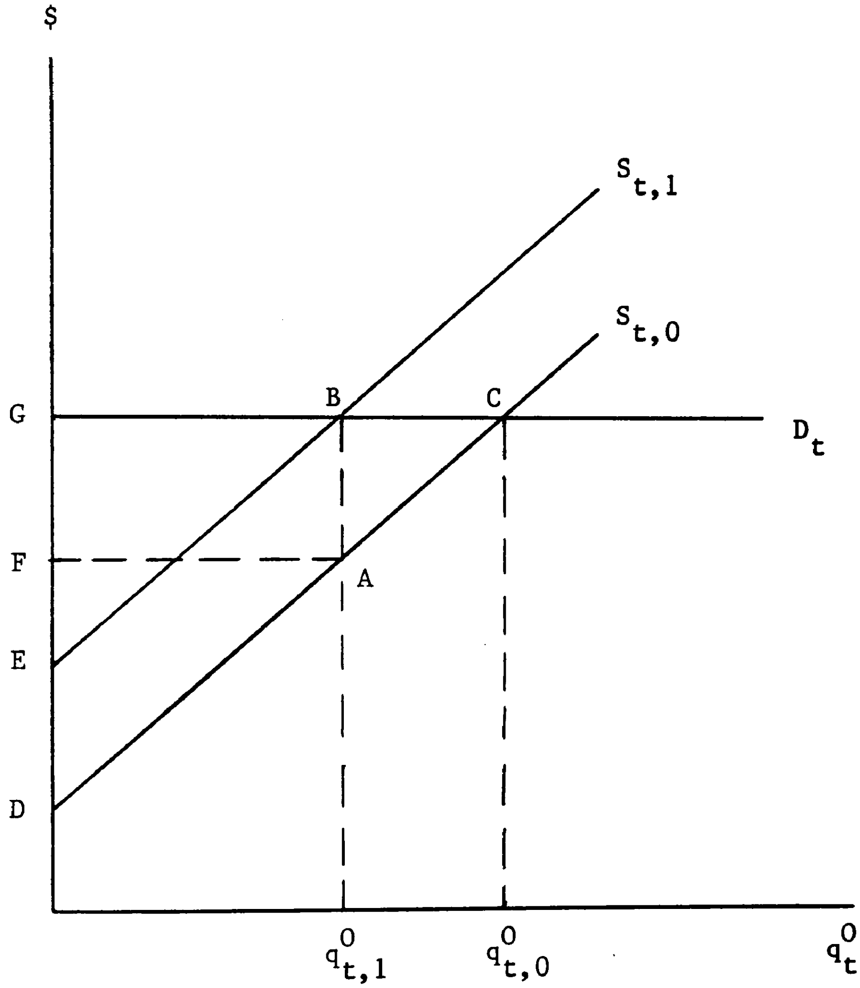

Figure 13. The Impact of WPT Extension on Texas Oil Production

The change in government surplus (Δgs_t) resulting from the extension would be equal to the area FGBA in Figure 13, measured as the change in the average amount of WPT paid per barrel of Texas oil, which is the same as the change in net price (ΔP_t^n), times the new output level ($q_{t,1}^o$), so that

$$\Delta gs_t = \Delta P_t^n \cdot q_{t,1}^o. \tag{7.11}$$

The net welfare change (Δw_t) would be the area of the triangle ABC, which can be measured as the change in net price (ΔP_t^n) times the change in output (Δq_t^o) divided by 2, or

$$\Delta w_t = (\Delta P_t^n \cdot \Delta q_t^o)/2. \tag{7.12}$$

The change in producers surplus (Δps_t) would be the area DEBA, which is not so easily measured. However, since the change in producers surplus and the change in government surplus must sum to equal the net welfare change, the amount of producers surplus can instead be determined as

$$\Delta ps_t = \Delta w_t - \Delta gs_t. \tag{7.13}$$

The welfare effects of indefinitely extending the WPT were calculated for the years 1984 through 2003 following the procedure outlined above. Table 40 reports the annual changes in current year net price (ΔP_t^n) induced by the extension, calculated according to equation (7.10) for the years 1991 through 2003. The value of ΔP_t^n is zero prior to 1990, since the extension did not affect current year net prices until 1991, the first year of the gradual WPT phaseout

Table 40. Welfare Effects Due to Indefinite Extension of the WPT

Year	ΔP_t^n	Δq_t^o	Δw_t	Δgs_t	Δps_t
1991	- 0.66[a]	- 0.8[b]	- 0.264[c]	+ 513.3[d]	- 513.6[e]
1992	- 1.48	- 2.8	- 2.072	+ 1,147.9	- 1,145.8
1993	- 2.08	- 5.6	- 5.824	+ 1,608.9	- 1,614.7
1994	- 2.48	- 7.7	- 9.548	+ 1,914.6	- 1,924.1
1995	- 2.65	- 9.6	- 12.720	+ 2,056.0	- 2,068.7
1996	- 2.82	- 11.8	- 16.638	+ 2,202.9	- 2,219.5
1997	- 2.99	- 14.3	- 21.379	+ 2,356.3	- 2,377.7
1998	- 3.15	- 16.8	- 26.460	+ 2,519.7	- 2,546.2
1999	- 3.29	- 19.3	- 31.749	+ 2,617.0	- 2,648.7
2000	- 3.48	- 22.4	- 38.976	+ 2,883.2	- 2,922.2
2001	- 3.65	- 25.7	- 46.903	+ 3,088.1	- 3,135.0
2002	- 3.83	- 29.0	- 55.535	+ 3,312.4	- 3,367.9
2003	- 4.01	- 32.6	- 65.363	+ 3,556.2	- 3,621.6
Totals		-198.3	-333.431	+29,830.4	-30,163.8

[a] Changes in average amount of WPT paid per barrel of oil in 1983 dollars.

[b] Changes in total oil production in Texas in millions of barrels.

[c] Changes in net welfare in millions of 1983 dollars.

[d] Changes in total WPT collections in millions of 1983 dollars.

[e] Changes in producers surplus in millions of 1983 dollars.

under current law. The annual changes in total Texas oil production (Δq_t^o) are taken from the production analysis in Section A of this chapter. The annual changes in net welfare (Δw_t) were calculated according to equation (7.12). The annual changes in government surplus (Δgs_t) were simply the changes in total WPT collections reported in Table 39. Finally, the changes in producers surplus (Δps_t) were determined according to equation (7.13).

The totals reported in Table 40 indicate the sizeable costs to society that would occur over the period 1991 through 2003 from the indefinite extension of the WPT on Texas oil production. The total reduction of 198.3 MMBBLS in Texas oil production over this period leads to rather significant total net welfare losses of 333.431 million 1983 dollars. The federal government would gain almost 30 billion 1983 dollars in WPT collections from Texas over this period if the WPT were extended. Texas oil producers would suffer a loss in producers surplus totaling some $30,163.8 million 1983 dollars, with most of that total simply being transferred to the federal tax coffers. Thus the WPT appears to be able to do a good job of capturing producers surplus for redistribution by the federal government, but only at the cost of a deadweight welfare loss totaling one-third of a billion 1983 dollars from 1991 through 2003 in Texas alone. Additionally, the indefinite extension of the WPT would continue to reduce total oil production after 2003, generating even more net welfare losses and losses of producers surplus than are calculated here.

Table 41. Welfare Effects Due to Repeal of the WPT on 1-1-84

Year	ΔP_t^n	Δq_t^O	Δw_t	Δgs_t	Δps_t
1984	+ 2.15[a]	+ 3.3[b]	+ 3.546[c]	- 1,972.6[d]	+ 1,976.1[e]
1985	+ 1.86	+ 3.0	+ 2.786	- 1,653.6	+ 1,656.4
1986	+ 1.57	+ 2.4	+ 1.886	- 1,354.9	+ 1,356.8
1987	+ 1.49	+ 2.1	+ 1.560	- 1,245.7	+ 1,247.3
1988	+ 1.58	+ 2.7	+ 2.136	- 1,300.3	+ 1,302.4
1989	+ 1.67	+ 3.1	+ 2.587	- 1,341.8	+ 1,344.4
1990	+ 1.74	+ 3.5	+ 3.043	- 1,376.9	+ 1,379.9
1991	+ 1.27	+ 3.8	+ 2.421	- 997.0	+ 999.4
1992	+ 0.64	+ 3.1	+ 0.988	- 496.4	+ 497.4
1993	+ 0.22	+ 1.8	+ 0.194	- 169.1	+ 169.3
1994	+ 1.85	+ 1.5	+ 1.388	0.0	+ 1.4
1995	+ 1.96	+ 1.4	+ 1.372	0.0	+ 1.4
1996	+ 2.08	+ 1.4	+ 1.456	0.0	+ 1.5
1997	+ 2.20	+ 1.4	+ 1.540	0.0	+ 1.5
1998	+ 2.33	+ 1.5	+ 1.748	0.0	+ 1.7
1999	+ 2.46	+ 1.7	+ 2.091	0.0	+ 2.1
2000	+ 2.62	+ 1.9	+ 2.489	0.0	+ 2.5
2001	+ 2.77	+ 2.0	+ 2.770	0.0	+ 2.8
2002	+ 2.94	+ 2.3	+ 3.381	0.0	+ 3.4
2003	+ 3.11	+ 2.6	+ 4.043	0.0	+ 4.0
Totals		+ 46.3	+ 43.425	-11,908.2	+11,951.7

[a] Changes in average amount of WPT paid per barrel of oil in 1983 dollars.

[b] Changes in total oil production in Texas in millions of barrels.

[c] Changes in net welfare in millions of 1983 dollars.

[d] Changes in total WPT collections in millions of 1983 dollars.

[e] Changes in producers surplus in millions of 1983 dollars.

The welfare effects of immediately repealing the WPT on 1-1-84 were similarly calculated for the years 1984 through 1993 and are reported in Table 41. After 1993 there would be no difference in current net price, although the higher net prices from 1984 through 1993 would have generated enough additional new reserves to increase annual total oil production in Texas for many years thereafter. In order to estimate the net welfare gains associated with each of these additional barrels of oil produced after 1993, the average percentage change in net price caused by repeal from 1984 through 1993 was used to calculate a net price change for the years 1994 through 2003.

The results in Table 41 indicate the relatively small benefits that would be obtained by advancing the phaseout of the WPT to 1-1-84. As seen in Section A, repeal would cause total Texas oil production to rise by a cumulative amount of 46.3 MMBBLS from 1984 through 2003. This additional production would only generate net welfare gains of 43.425 million 1983 dollars over the same period.

The federal government would lose 11,908.2 million 1983 dollars in total WPT collections from Texas under repeal. Total producers surplus in Texas would rise by 11,951.7 million 1983 dollars over 1984 through 2003 when the WPT is repealed. Of the total reduction in government surplus, only 0.36% occurs as a net welfare gain; the rest is simply transferred from the federal government to Texas oil producers.

E. Summary and Conclusions

The analysis in this chapter considered the inpacts of changing the phaseout schedule for the WPT on Texas oil production. Two alternative WPT phaseout scenarios were examined - the immediate repeal of the WPT on 1-1-84 and the indefinite extension of the WPT beyond 1990 - for comparison with the gradual WPT phaseout over 1991-1993 provided under current law.

The first step in the analysis was to estimate the production effects of switching to either of these two alternative WPT phaseout scenarios. It was found that immediate repeal of the WPT would provide an additional 46.3 MMBBLS of oil production in Texas from 1984 through 2003. Over the same period, indefinite extension of the WPT would reduce total Texas oil production by 198.3 MMBBLS.

Given these production scenarios, the associated changes in total WPT collections from Texas that repeal or extension would bring were calculated. After projecting the shares of total Texas oil production that would fall into each tier of the WPT, total WPT collections from Texas were estimated to fall by $11,908.2 million 1983 dollars under repeal, but rise by $29,830.4 in millions of 1983 dollars under extension.

Finally, the net welfare effects of changing to either alternative WPT phaseout scenario were calculated over the same period. Repeal was found to provide a relatively small net welfare gain of $43.4 in millions of 1983 dollars, while extension was projected to cause a rather large net welfare loss of $333.4 in millions of 1983 dollars. The next and final chapter of this dissertation will consider the policy implications for the WPT, based upon the results of the analysis in this chapter.

CHAPTER VIII

CONCLUSIONS

This dissertation began by developing an engineering-based economic model capable of determining the production effects of the federal windfall profit tax (WPT) on aggregate Texas petroleum production. After it had been econometrically estimated, the model was integrated with an econometric model of aggregate petroleum drilling in Texas developed by Bremmer to produce a joint simulation model of aggregate Texas petroleum production from a growing reserve base. This integrated simulation model was then used to project future production levels in Texas under three different WPT phaseout scenarios - immediate repeal, current law and indefinite extension. Finally, the projected impacts on aggregate Texas production of switching away from the status quo WPT phaseout schedule were compared to the associated changes in total WPT collections to determine the net welfare effects of changing to the two alternative WPT phaseout scenarios. Thus, not only were the problems involved with properly modelling petroleum production for policy analysis considered by this dissertation, but the resulting analytical framework was rigorously tested and applied to an examination of the impact of a major policy instrument - the WPT - on a major producing region in the U.S., specifically Texas.

In this final chapter, some general conclusions will be made regarding the policy implications of changing the WPT phaseout schedule, and then some suggestions will be made for further research.

A. Summary of Projected Impacts for Texas

By way of a quick review, the basic results of the analysis in Chapter VII are repeated here. The integrated simulation model of Chapter VI was used to project future aggregate Texas petroleum production levels from a growing reserve base under each of three WPT phaseout scenarios - immediate repeal, phaseout under the status quo and indefinite extension. Immediate repeal of the WPT on 1-1-84 was found to imply only 46.3 million additional barrels of total Texas oil production over the period 1984 through 2003. On the other hand, the indefinite extension of the WPT beyond its planned phaseout in 1991-1993 under current law would reduce total oil production in Texas by 198.3 MMBBLS over the same period. In return for these production impacts, total WPT collections from Texas over this period were projected to fall by almost 12 billion 1983 dollars under immediate repeal, but rise by nearly 30 billion 1983 dollars under indefinite extension.

The net welfare effects of these two alternative WPT phaseout scenarios were then determined for the 20 year simulation period. The net welfare gains of the increased production under immediate repeal were found to be slight - only $43.4 in millions of 1983 dollars. Indefinite extension was found to be much more distorting, producing nearly one-third of a billion 1983 dollars in deadweight welfare losses by the year 2003.

B. The Role of Price and Policy Expectations

It should be emphasized that the projected magnitudes of the impacts of changing the WPT phaseout schedule will depend greatly upon the assumptions that are made regarding future real oil prices and producers' tax policy expectations.

Probably most important is the nature of the path of future real oil prices that is assumed. The analysis of Chapter VII followed the EIA's projections that real oil prices would fall from 1984 through 1987, and then slowly rise back to just below the real price level of 1983 by the year 1990. Thereafter, real oil prices are projected to rise by 5.9% each year. However, it should be recalled that the adjusted base prices that are used to compute the size of the windfall profit that is to be taxed under each tier of the WPT will not follow this same pattern, since they are mandated to rise annually with the national rate of inflation (plus 2% for Tier 3). As a consequence, the amount of WPT paid per barrel of oil is depressed from 1984 through 1990, making the WPT have a relatively light impact from 1983 through its planned phaseout in 1991-1993.

This explains why the immediate repeal of the WPT was found to provide very little in the way of additional production and net welfare gains, while only slightly reducing federal revenues. For similar reasons, the assumption that real oil prices would rise by 5.9% each year after 1990 led to the conclusion that the indefinite extension of the WPT would cause significant net welfare and production losses through the year 2003.

If real oil prices were instead assumed to experience a substantial one-time increase shortly after 1984 as a result of a world oil supply shock (caused, say, by military conflict or embargo), the magnitudes of the impacts of immediately repealing the WPT that would be projected to occur would be considerably larger than those projected in Chapter VII. By the same token, should real world oil prices be assumed to continue to decline throughout the rest of the century, the net welfare and production losses projected under the indefinite extension of the WPT would be reduced.

In addition to the assumed path of future real oil prices, U.S. petroleum producers' expectations regarding the future tax environment must also be considered when evaluating the impact of the WPT.

The nature of the tax environment that U.S. petroleum producers expect to face in the future, when they will be extracting and selling their petroleum reserves, has a clear impact on the amount of reserves they are willing to add today. The analysis of Chapter VII assumed that Texas petroleum producers base their long run capacity investment decisions, such as whether or not to drill a well and whether or not to engage in an EOR project, on the expectation that the future tax environment in Texas would be that which is scheduled to occur under current law. In reality, petroleum producers could be expected to attach probabilities of less than one to the event of the continuation of current tax law, so that they would base their current drilling and EOR decisions on their rational perceptions of what the future might bring in the way of tax policy changes.

It was mentioned earlier that some U.S. petroleum producers fear that the WPT will be extended indefinitely. If those fears are indeed reflected in their analyses of prospective drilling and EOR projects, then perhaps it would have been more appropriate to compare the immediate repeal scenario with the indefinite extension scenario, rather than with the status quo scenario which assumed that producers expected the WPT to be phased out according to current law. Of course, such a comparison would greatly increase the magnitudes of the production and net welfare gains projected to result from the immediate repeal of the WPT, as well as the production and net welfare losses projected to result from its indefinite extension.

C. The Effects on Oil Import Levels and World Oil Prices

To this point, the projected impacts of changing the WPT phaseout schedule have focused solely on the possible net welfare and production effects for Texas. Since Texas plays such a significant role in total U.S. petroleum production, any substantial changes in aggregate Texas petroleum production levels induced by a WPT policy change would surely also be reflected in national production levels. Any gains or losses in domestic oil production in the U.S. that resulted would then be transmitted into lower or higher foreign crude oil import levels, respectively, assuming no change in U.S. crude oil demand. Ultimately, the resulting changes in U.S. oil imports could affect world oil price levels.

Should the WPT be extended indefinitely, the decreased domestic oil production in the U.S. would almost certainly lead to an increase in the nation's dependence on foreign crude oil supplies. The 198.3 MMBBLS of domestic oil production projected to be lost from 1991 through 2003 from Texas alone translate into an increase in average daily U.S. crude oil imports over this period of 41,791 BPD, which is 0.84% of the 4,988 thousand BPD imported by the U.S. in 1983. Since Texas currently produces only about 1/4 of total U.S. oil production, this percentage increase in oil imports due to the WPT in Texas could easily be four times as large for the U.S. as a whole, implying a non-trivial percentage increase of 3.35% in the 1983 level of average daily U.S. crude oil imports under a permanent WPT, or about 167,000 BPD. At a price of $30 per barrel, this would increase the U.S. oil import bill by about $1,830 million each year.

An increase in U.S. crude oil imports of this magnitude would have a even greater impact on the total U.S. oil import bill if it provided OPEC with the opportunity to raise world prices as a result. According to the Energy Modeling Forum's (1982) sixth study of the world oil market, national policies which increase world oil import demand can significantly affect the path of world oil prices. The Energy Modeling Forum (EMF) estimated that each 1 million BPD reduction in OECD oil import demand can be expected to reduce world oil prices by anywhere from $0.99 to $2.65 in 1983 dollars. If these estimates also hold for an increase in oil import demand, then an increase in U.S. oil imports of 167,000 BPD could conceivably increase world oil prices by $0.17 to $0.44 in 1983 dollars. At 1983 import levels, any such increases in the world oil price would imply an increase in the annual U.S. oil import bill in the range of 300 to

800 million 1983 dollars, which would be in addition to the $1,830 million increase caused by higher import levels.

Turning to the other extreme, immediate repeal of the WPT was projected to provide, on the average, an additional 6300 BPD of domestic oil production from Texas over the next 20 years. Again assuming that the national production response could be approximately four times as large, this implies an average reduction in annual U.S. oil imports of only about 25,000 BPD, which is only 0.50% of the 1983 level. This small reduction in imports would save the U.S. about $273.75 million each year, but could not be expected to reduce the world oil price by more than $0.07 at the most (using the estimates of the EMF), leaving the annual U.S. oil import bill essentially unchanged.

D. General Conclusions and Policy Recommendations

Given the results of the WPT analysis of Chapter VII and the additional comments made in this chapter, some general conclusions and policy recommendations can now be made.

Assuming the stagnant path of real oil prices from 1984 through 1990 projected by the EIA, it appears that the WPT would act as a relatively benign tax until its planned phaseout in 1993-1993. While it would not greatly reduce domestic production levels over the next 20 years, the WPT would also not bring in a great deal of federal revenues - only about 12 billion in 1983 dollars from 1984 through 1993. In addition, it does not appear that removing the WPT during this period of depressed real oil prices would materially reduce either the level of U.S. oil imports or the annual oil import bill, although it would provide some marginal assistance in reducing the size of federal budget deficits.

Under such circumstances, simply letting the WPT die a slow death as planned could be seen as a reasonable policy action. However, such a conclusion is only warranted if it can safely be assumed that U.S. petroleum producers do not base their long run drilling and investment decisions on the expectation that the WPT will be a permanent fixture of the federal tax code. If U.S. producers do indeed assume that the WPT will never be phased out, as they very well might, then both current and future domestic oil production will continue to be negatively affected as long as the WPT is still in existence. An immediate repeal of the WPT would send a positive signal to U.S. petroleum producers that the tax was not a permanent one, and would thereby result in increases in the levels of drilling and production in excess of those projected here.

Since the very presence of the WPT, even with a legislated phaseout schedule, can cause producers to act today as if the WPT has already been extended indefinitely, the impact of the WPT can be more clearly evaluated by comparing the production and drilling levels projected to occur under immediate repeal with those projected to occur under a permanent WPT. From this perspective, the role of future real oil price projections becomes even larger, since the rate at which real oil prices recover and grow over the 1990s will, in large part, determine the magnitudes of the net welfare, production and import effects that indefinite extension of the WPT would entail.

For the path of real oil prices assumed in this analysis, the indefinite extension of the WPT was found to produce deadweight welfare losses totaling at least one-third of a billion 1983 dollars from Texas alone by the year 2003. Over the same period, the level of U.S. foreign crude oil imports could increase by as much as 3.35% each year, giving OPEC the opportunity to raise world oil prices as a result and increasing the vulnerability of the U.S. economy to a sudden world oil supply reduction. The magnitudes of these welfare and production losses and the increased national risks associated with a permanent WPT make its indefinite extension difficult to justify. While a permanent WPT would provide significant amounts of federal revenues for funding government programs and reducing the national debt, such large negative impacts as those projected here suggest that the continued direct taxation of the U.S. petroleum industry is not the best way to obtain those funds.

E. Suggestions for Further Research

As a final note, the generalized petroleum production model developed in this dissertation could be profitably applied to the analysis of petroleum production from any geological region, from the level of the individual reservoir to the nation as a whole. The data requirements do not appear to be too restrictive for studies of an aggregate nature, and the estimation of the production equations would be possible with almost any iterative estimation procedure. Extending the present analysis to consider the impact of the WPT on aggregate U.S. petroleum production levels would seem to be a worthwhile venture, but would require a companion aggregate drilling model for joint simulation purposes. Extension of the Bremmer drilling model could probably be accomplished in a straightforward manner to fill this gap, so that the nice economic structure of the integrated model could be retained.

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APPENDIX A

DATA FOR CHAPTER IV

Table 42. Annual Average Daily Production Rates for Individual Reservoirs

	East Texas	Slaughter	Neches (Woodbine)	Luling-Branyon	Gomez
Year	q_t^o [a]	q_t^o	q_t^o	q_t^o	q_t^g [b]
1973	206,791	125,183	13,346	3,939	1,121,340
1974	197,813	128,284	13,158	3,671	1,056,860
1975	189,108	127,613	12,329	3,503	893,007
1976	183,800	117,807	11,729	3,437	748,162
1977	176,707	109,331	10,725	3,195	534,554
1978	169,987	102,435	11,039	3,021	510,646
1979	164,792	93,634	10,864	2,826	516,120
1980	160,139	85,602	10,214	2,966	477,620
1981	153,854	79,646	9,317	2,944	379,864
1982	144,887	73,176	7,149	2,965	226,110
1983	139,851	68,358	5,938	2,931	220,594

[a] In barrels per day.

[b] In MCF per day.

Table 43. Prices and Tax Rates

Year	Nominal Oil Price ($/BBL)	Nominal Gas Price ($/MCF)	Price Deflator (1983=100)	State Severance Tax Rates On Oil	Gas	Federal Income Tax Rate
1973	6.52	0.20	49.04	0.046	0.075	0.48
1974	10.28	0.31	53.37	0.046	0.075	0.48
1975	12.05	0.52	58.34	0.046	0.075	0.48
1976	11.47	0.72	61.37	0.046	0.075	0.48
1977	11.16	0.90	64.95	0.046	0.075	0.48
1978	12.15	1.00	69.76	0.046	0.075	0.48
1979	13.14	1.23	75.79	0.046	0.075	0.46
1980	14.31	1.57	82.74	0.046	0.075	0.46
1981	35.33	1.87	90.50	0.046	0.075	0.46
1982	32.19	2.17	95.94	0.046	0.075	0.46
1983	29.83	2.31	100.00	0.046	0.075	0.46

Table 44. Windfall Profit Tax Rates and Base Prices

	WPT Tax Rates					Adjusted Base Prices		
	Tier 1		Tier 2		Tier 3	Tier	Tier	Tier
Year	Major	Ind.	Major	Ind.	Both	1	2	3
1980	0.700	0.500	0.600	0.300	0.300	14.05	17.23	18.79
1981	0.700	0.500	0.600	0.300	0.300	15.38	18.87	20.67
1982	0.700	0.500	0.600	0.300	0.275	16.28	19.97	22.02
1983	0.700	0.500	0.600	0.300	0.250	16.97	20.82	23.12

Table 45. Gas-Oil Production Ratios for Individual Oil Reservoirs

	East Texas	Slaughter	Neches (Woodbine)	Luling-Branyon
Year	GOR_t [a]	GOR_t	GOR_t	GOR_t
1973	0.340	0.350	0.904	0.018
1974	0.340	0.325	0.882	0.013
1975	0.336	0.318	0.783	0.016
1976	0.328	0.338	0.745	0.034
1977	0.330	0.391	0.755	0.481
1978	0.331	0.400	0.759	0.617
1979	0.328	0.397	0.707	0.579
1980	0.329	0.406	0.702	0.534
1981	0.339	0.414	0.792	0.473
1982	0.337	0.420	0.819	0.494
1983	0.339	0.429	0.939	0.595

[a] MCF of associated gas produced per barrel of oil.

APPENDIX B

DATA FOR CHAPTER V

Table 46. Annual Average Daily Production Rates and Ratios for Aggregate Texas Petroleum

	Crude Oil		Non-Associated Gas	
Year	q_t^o	GOR_t	q_t^g	CGR_t
1973	3,444[a]	1.605[b]	20,062[c]	0.0037[d]
1974	3,357	1.501	19,365	0.0038
1975	3,248	1.316	17,786	0.0040
1976	3,161	1.266	17,116	0.0040
1977	3,017	1.285	16,849	0.0044
1978	2,852	1.332	15,591	0.0046
1979	2,681	1.370	15,824	0.0049
1980	2,551	1.420	15,550	0.0052
1981	2,459	1.512	14,729	0.0058
1982	2,388	1.597	12,936	0.0064
1983	2,326	1.667	11,583	0.0064

[a] Thousands of barrels of oil.

[b] MCF of associated gas produced per barrel of oil.

[c] Millions of cubic feet of non-associated gas.

[d] Barrels of condensate produced per MCF of non-associated gas.

Table 47. Ad valorem Tax Rates and Average Daily Well Operating Costs for Aggregate Texas Petroleum

	Crude Oil		Non-Associated Gas	
Year	v_t^o	c_t^o	v_t^g	c_t^g
1973	0.020[a]	22.51[b]	0.025[c]	51.45[d]
1974	0.020	26.76	0.025	61.15
1975	0.020	29.23	0.025	66.81
1976	0.020	30.57	0.025	69.86
1977	0.020	30.58	0.025	69.90
1978	0.020	32.46	0.025	74.17
1979	0.020	34.98	0.025	79.95
1980	0.020	39.38	0.025	89.99
1981	0.020	44.93	0.025	102.67
1982	0.020	49.03	0.025	112.06
1983	0.020	50.04	0.025	114.36

[a] Statewide average ad valorem tax rate on oil production; assumed to remain constant at its 1983 value.

[b] Statewide average daily operating costs for oil wells in 1983 dollars.

[c] Statewide average ad valorem tax rate on non-associated gas production; assumed to remain constant at its 1983 value.

[d] Statewide average daily operating costs for non-associated gas wells in 1983 dollars.

Table 48. Annual Levels of Reserves and New Reserve Additions of Aggregate Texas Petroleum

	Crude Oil		Non-Associated Gas	
Year	R_t^o	A_t^o	R_t^g	A_t^g
1973	11,757[a]	872[b]	60,530[c]	-3,270[d]
1974	11,002	471	55,724	1,344
1975	10,080	254	50,638	292
1976	9,226	305	48,047	1,724
1977	8,467	339	46,465	3,644
1978	7,690	266	41,340	-158
1979	7,636	927	39,455	3,487
1980	8,347	796	41,107	2,927
1981	8,093	620	42,382	5,160
1982	7,616	474	42,058	4,204
1983	7,539	553	42,830	3,563

[a] Year end oil reserves in millions of barrels.

[b] Annual new oil reserve additions in millions of of barrels.

[c] Year end non-associated gas reserves in billions of cubic feet.

[d] Annual new non-associated gas reserve additions in billions of cubic feet.