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INVESTMENT AND RETURNS IN EXPLORATION AND THE IMPACT ON OIL AND NATURAL GAS SUPPLY

by

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ABSTRACT

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An econometric model is developed to explain the investment in exploratory activity and the resulting accumulation of proved reserves of oil and natural gas in the continental United States. The model explicitly takes into account therole of geological uncertainty as well as the effect of depletion in the context of a finite resource base.

The model for reserve additions describes the process of generating new discoveries of oil and natural gas in two stages. The first stage describes investment in exploration under conditions of geological uncertainty and a continuing process of depletion of the hydrocarbon resource base. Exploratory companies are assumed to choose a level of investment that maximizes the firm's value after balancing expected returns against the risks involved in exploration and the corresponding costs. Combined with a characterization of costs of exploration and development, this analysis leads to an expression for the total amount of exploratory drilling in each production district in terms of estimates of anticipated returns and anticipated risk. In the second stage, the model predicts the parameters of the size distribution of alternative drilling prospects, and updates them from period to period to reflect the continuing process of depletion of prospects as well as new information on geological and economic variables. The amount of drilling activity can then be translated into actual discoveries of oil and natural gas through the estimates of success fractions and sizes of discovery (conditional on a success), which depend on these parameters. Structuring the model in this way enables us to take account of possible shifts in the relative proportions of <u>extensive</u> and <u>intensive</u> drilling as a result of changes in economic variables.

Additions to proved reserves can also occur as a result of extensions and revisions of existing fields and pools. Extensions and revisions are modelled as functions of previous discoveries, exploratory wells drilled, existing levels of accumulated reserves and production, and an index of geological depletion.

An important aspect of the model is that it gives explicit consideration to the process of long term geological depletion as well as the role of risk in determining the amount of exploratory activity. It also accounts for the fact that on the level of new

discoveries oil and natural gas are in fact joint products, and must be treated symmetrically. Finally, the model allows for shifts in the relative proportions of intensive and extensive drilling in response to changes in economic incentives.

The model is estimated and simulated to verify its predictive validity over a historic period. It is then used to examine the influence of alternative regulatory policies on the oil and natural gas reserves and production. Combined with an existing model of demand for oil and natural gas (the MacAvoy-Pindyck Model), this provides a basis for estimating future shortages and increases in economic incentives needed to ameliorate them.

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CHAPTER I

INTRODUCTION

1.1 Historical Background and Setting of the Study

The economics of the oil and natural gas industry in the United States has been a subject of much controversy in recent years. This is not surprising when one keeps in mind the dramatic changes that have occurred in the domestic and world petroleum markets over the last three decades.

As late as in 1946, the United States was shipping more oil overseas than it was importing. With the advent of the flourishing low-cost production of the Middle East and Venezuela, this positive balance was never to be realized again. Imports from overseas increased fourfold by 1955 (even though prices were already at twice the levels of the early post-war years) and continued in this trend in the face of the seemingly unlimited supply potential of the Middle East. By 1959, concern about the survival of a healthy domestic petroleum industry and related issues of national security became very significant. In March 1959 the mandatory Oil Import Program went into effect to provide incentive for increased domestic exploration and to protect the domestic producers. The controversial import controls were in effect until they were discontinued in April 1973 in the face of sharply rising import prices. By the fall of 1973, Persian Gulf prices had far surpassed controlled U.S. prices. Firm action by the Oil Cartel (OPEC) led to increases in Persian Gulf export prices of about $3.10 in September, 1973 to $8.30 per barrel in January, 1974, as well as a threat of a total Arab oil embargo.

The natural gas market presents a history of equally interesting changes. Prior to World War II there was no economical way of transporting gas more than moderate distances. Extensive venting and flaring of natural gas was a common occurrence in the surplus Gulf states in the United States because markets were confined to the immediate producing areas. With the development of economical long-distance pipelines, the large natural gas reserves discovered in the search for oil became available nationwide. Subsequently, exploration for natural gas had become worthwhile in its own right. The production of gas had risen from about 5 trillion cubic feet in the early fifties to more than 20 trillion cubic feet by the early seventies. Natural gas differs dramatically from crude oil with respect to governmental price regulation. Oil prices were not regulated at the well-head or the refinery (until the August 1971 general price "freeze"). In contrast, producer prices of natural gas at the well-head have been under regulation by the Federal Power Commission (F.P.C.). Following the Supreme Court decision in the Phillips Petroleum case in 1954,[1] the F.P.C. has been using "Area Rate Regulation", i.e., "just and reasonable" price ceilings are set for a specified geographic area on the basis of estimated costs and returns averaged over that entire area.[2]

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[1]Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954).

[2]For detailed accounts of how the "Area Rates" are set, see, for example, U.S. Federal Power Commission, "Hugeton-Anadarko Area Rate Proceeding," Annual Report of the Federal Power Commission, 44 FPC 761, 1970; or U.S. Federal Power Commission, "Southern Louisiana Area Rate Proceeding," Annual Report of the Federal Power Commission, 46 FPC 86, 1971.

The basis for regulating well-head prices (as distinct from regulation of pipeline and distribution companies which may be considered natural monopolies in case of natural gas) has always been a controversial and puzzling matter, evoking much debate among legislators, industry spokesmen and academicians.[1] In any case, the natural gas industry has been transformed from a relatively free market of the late fifties (when price ceilings set by F.P.C. were close to or higher than the prevailing market clearing prices) to one of strict regulation by the middle sixties. By somewhere between 1968 and 1970,[2] shortages were beginning to affect consumers and led first to cutting off supplies in peak periods to industry and eventually (by 1972) to curtailments to all classes of customers.[3,4] The Federal Power Commission shows that natural gas distributors were 3.7 percent short of meeting consumption demands of communities and industries in 1971, and are expected to be 10 percent short of demands in 1974 [45]. During the period 1960-1973, the reserves-to-production ratio of natural gas dropped from 20 to nearly 11 .

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[1] See, for example, Hawkins [17], Garfield and Lovejoy [13], MacAvoy [27, 28], and MacAvoy and Pindyck [29].

[2] See Mitchell [33].

[3] See [46].

[4] Note that shortages were evident in the reserves markets (as opposed to production market) much earlier. Demand for proved reserves exceeded the supply of new additions to reserves by 1965.

Interest in the workings of the natural gas and oil industry in the United States is further enhanced most recently by the declared policy of independence from foreign supplies of energy. Under the name "Project Independence," goals have been set which call for complete self-sufficiency by the end of the decade, to free the nation from the threat of sharp price increases and import cut-downs from sources abroad.[1]

As one might expect in the face of this background, much of the debate and discussion centers around the responsiveness of the supply of oil and natural gas reserves to economic incentives.[2] For example, in defending the oil depletion allowance, industry spokesmen had asserted that crude oil discoveries were quite sensitive to price incentives. The case for either stronger regulation[3] or deregulation[4] of natural gas field prices also rests on arguments of price-sensitivity or price-insensitivity. The question of the sensitivity of exploration and discovery to economic incentives is the question that this study is mainly addressed to. However, answering a policy question of this kind requires building of a relatively sophisticated econometric policy model that takes into account all the geological and economic inter-relationships

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[1] New York Times, May 8, 1974, p. 72.

[2] See, for example, Gonzales [15].

[3] See testimony of Alfred E. Kahn, The Permian Basin Area Rate Proceeding, U. S. Federal Power Commission Docket AR61-1, 1960.

[4] See Erickson and Sapnn [10], MacAvoy and Pindyck [29] and Spann and Erickson [38].

of the oil and natural gas industry. In the next three chapters of this thesis, such a model is therefore built, tested, and applied to examine alternative policies.

Chapter II gives the theoretical basis for the present model of exploration and discovery. Structural relationships are derived in this chapter on the basis of a consideration of the physical (geological) as well as economic aspects of exploratory drilling. The model so specified is econometrically estimated in Chapter III. The choices on data used and econometric procedures are discussed in detail in that chapter. In Chapter IV, the econometric model is first simulated over a historical period of time to check its predictive validity and then used to examine the price responsiveness of oil and natural gas supply under alternative regulatory and economic conditions. Chapter V summarizes the major conclusions from this study.

1.2 Previous Studies

The pioneering study of supply response of oil and gas reserves has been that of Fisher [12] in 1964. He used a three-stage model with estimating equations for total wildcat wells, success ratio and the average size of discovery. New discoveries are then computed as the product of these three estimates. His contribution was important in that it illustrated the distinction between the response of wildcat drilling to economic incentives and that of discoveries. When economic incentives are increased, not only total exploratory activity goes up, but the average characteristics of the prospects drilled change because it now becomes worthwhile to drill poorer prospects. Thus it should be expected that discoveries of reserves would be less sensitive than wildcat drilling to price changes. The problem with the Fisher study is that the specification of his structural equations had no theoretical basis, other than expected direction of the effects of different explanatory variables. This leads to many difficulties in the interpretation of his results as well as possible econometric biases.

There has been surprisingly little improvement in the structural specification of supply models over the next decade. Erickson and Spann [10, 11, 38] extend the basic Fisher framework to include considerations of joint costs of exploration for oil and natural gas. Since oil and natural gas are joint products from the viewpoint of exploration, they should be treated as such. This point was very well illustrated by Erickson and Spann (E-S). They derive constraints that must be obeyed by own-price and cross-price elasticities in the joint-product case and impose these constraints in estimating their econometric equations. Their model was a definite step in improving the specification, but continues to have some of the same problems as Fisher's. Some of their price elasticity estimates came out to be unreasonably large[1] and may be the result of the remaining problems in the specification - especially a lack of explicit consideration of the depletion of the finite natural resource base.

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[1]For example, an own-price elasticity of more than 3.0 was reported for natural gas discoveries in [38].

Khazzoom [21,23] visualizes the discovery of natural gas reserves as a response to a signal (gas or oil price) through a "black box" which includes such factors as the number of wildcats drilled, success in drilling and directionality. He concedes that the price signal triggers the drilling decision which determines simultaneously the number of wildcats drilled, the success ratio, directionality and the average size of discoveries. He nevertheless proceeds to estimate the output of the black box directly in terms of the inputs and stresses the lagged distributive effects of prices rather than structural aspects of natural gas industry. The structural specification of this model should therefore be considered inferior to both the Fisher and E-S models. Much of the explanatory power in his estimated equations derives from the lagged endogeneous variables. There are well-known problems of econometric bias associated with using lagged endogeneous variables as an explanatory variable.

The MacAvoy-Pindyck (M-P) model treats simultaneously the field market for reserves (gas producers dedicated new reserves to pipeline companies at the well-head price) and the wholesale market for production (pipeline companies selling gas to public utilities and industrial users). The linking of the two markets for purposes of policy simulation is the innovation of the M-P approach. On the field market side (the supply side), they study the exploratory process in two stages - exploratory drilling and average size of discoveries per exploratory well. This avoids the difficulties of modelling the success ratio, admittedly the weakest link in the Fisher-ES estimations, but difficulties with the structural specification still remain.

In the present study, an attempt is made to derive structural relationships that reflect more closely the geological and economic interrelationships in the exploration and discovery process. In particular, available empirical evidence [4, 19, 42] on the geological size distributions of reservoirs and the physics of the evolution of a play [18, 20] was incorporated into the structural specification of the equations determining the characteristics of the average prospect drilled. In addition, the relationship determining the total exploratory wells is derived from an explicit characterization of the individual explorer's preferences. Finally, explanatory variables are introduced to represent resource depletion and geological uncertainty associated with exploration.

A caveat is probably appropriate for the benefit of a potential researcher in this field. Supply models in the area of oil and natural gas exploration are faced with serious data problems. Some of the most interesting (disaggregated) information on wells as well as reserves happens to be confidential information of the producing companies and is not available publicly. Also, the geographic data are frequently aggregated by political units (e.g., states or F.P.C. production districts) rather than by geologically meaningful areas. The challenge lies in formulating reasonable economic and technical relationships in the face of these formidable data problems.

CHAPTER II

A THEORY OF EXPLORATION AND DISCOVERY OF NATURAL GAS AND OIL RESERVES

2.1 Nature of the Exploratory Process

The goal of exploration is to gain information on whether a certain structure is productive of oil or natural gas and if productive, the probable size of the reserve underground. Thus the chief product of exploratory activity is knowledge, which can be exploited by consequent developmental drilling activity, building of surface facilities to withdraw the hydrocarbon and delivering to an oil refinery or a natural gas pipeline company as the case may be. The primary component of reserves additions resulting from exploratory activity are "new discoveries." These may later be added to by "extensions" which result from further exploratory drilling in the neighborhood of a newly discovered field or pool. Estimates of both new discoveries and extensions may be revised from time to time as new geological and other technical information arrives. This leads to the last category of reserves additions called "revisions."

The process of exploration and discovery, and the resulting accumulation of new reserves, are probably the parts of the oil and gas industry that are the most difficult to capture in a conceptual model. Much of the current controversy over regulatory policy centers, however, on this process--whether or not reserve additions have been "too low" as a result of past regulatory policy. Although the exploration and discovery process is a complicated one, involving many geological and technological factors, structural econometric relationships can be formulated to link economic, geological and technological variables that govern reserve additions and describe in a simple manner the effects of regulatory policy.

2.2 Summary of the Model

The model for reserve additions describes the process of generating new discoveries of oil and natural gas in two stages. The first stage describes investment in exploration under conditions of geological uncertainty and a continuing process of depletion of the hydrocarbon resource base. Exploratory companies are assumed to choose a level of investment that maximizes the firm's value after balancing expected returns against the risks involved in exploration and the corresponding costs. Combined with a characterization of costs of exploration and development, this analysis leads to an expression for the total amount of exploratory drilling in each production district in terms of estimates of anticipated returns and anticipated risk.

As has been mentioned earlier, producers engaged in exploratory activity have a portfolio of drilling options available, and must make a trade-off between risk and return (i.e., extensive versus intensive drilling) in choosing among these options. The set of prospects relevant to the individual explorer's decision-making process are those lying on the current "efficient frontier"[1] of the inventory of prospects. The second

[1] This term is explained more elaborately in a later part of this chapter.

stage of the model predicts the parameters of the size distribution of the currently efficient drilling prospects and updates them from period to period to reflect the continuing process of depletion of prospects as well as new information on geological and economic variables. Structuring the model this way enables us to take into account possible shifts in the relative proportions of "extensive" and "intensive"[1] drilling as a result of changes in economic variables. The amount of drilling activity can then be translated into actual discoveries of oil and natural gas through the estimates of success fractions and sizes of discovery (conditional on a success), which depend on these parameters.

Additions to proved reserves can also occur as a result of extensions and revisions of existing fields and pools. Extensions and revisions are modelled as functions of previous discoveries, exploratory wells drilled, existing levels of accumulated reserves and production, and an index of geological depletion.

An important aspect of the model is that it gives explicit consideration to the process of long term geological depletion as well as the role of risk in determining the amount of exploratory activity. It also accounts for the fact that on the level of new discoveries oil and natural gas are in fact joint products, and must be treated symmetrically. Finally, the model allows for shifts in the relative proportions of intensive and extensive drilling in response to changes in economic incentives.

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[1] These terms are explained more elaborately in a later part of this chapter.

2.3 Investment in Exploration and A Valuation Model for Exploratory Activity

The aggregate industry supply function for exploratory wells drilled is, of course, the composite of the individual drilling decisions of several explorers (typically small and large exploratory companies) operating simultaneously. The individual driller makes his decisions after taking into account all of the currently available information that can help him ascertain expected return and risk in exploratory drilling, as well as the relevant costs.

Our analysis is based on the assumption that individual exploratory firms have a range of drilling options available, each with its own expected risk and expected return, and that a set of options are chosen that will maximize the present value of the certainty equivalent cash flow resulting from exploration. We also assume that risk can be represented by the variance of the cash flow. Then following the theoretical framework suggested in the Sharpe-Lintner-Mossin[1] capital asset pricing

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[1]This is based on the single-period mean-variance model for pricing of capital assets under uncertainty developed by Sharpe [37], Lintner [25] and Mossin [34]. Consider a single-period world in which all investors are risk-wise expected utility maximizers whose investment decisions can be characterized by the maximization of a preference function $U_i(W_i, e_i, v_i$ where W_i is the individual's wealth at the beginning of the period, e_i is the expected value of the cash flow to be generated one period hence by the investor's portfolio, and v_i is the variance of this cash flow. If one assumes that $\partial U_i/\partial W_i > 0$, $\partial U_i/\partial e_i > 0$ and $\partial U_i/\partial v_i < 0$, and that all investors have homogeneous expectations and that transactions costs and taxes are zero, then equation $(1)_a$ holds. In that equation the certainty equivalent of a random cash flow $\tilde{\Pi}_i$ is expressed as its expectation minus a risk discount equal to the product of the price per unit risk λ and the risk of the firm given by the sum of its variance and covariances with all other firms.

model, we can write the value of the j^{th} firm will be given by

$$V_j = (1/r)(\overline{\Pi}_j - \lambda\sigma_{jm}) \qquad (1)_a$$

where $\tilde{\Pi}_j$ is the total end-of-period cash flow to firm j, $\overline{\Pi}_j = E(\tilde{\Pi}_j)$ is the expected value of $\tilde{\Pi}_j$, σ_{jm} is the covariance of $\tilde{\Pi}_j$ with $\tilde{\Pi}_m$, the total cash flow to all firms in the economy, and λ is an average index of risk aversion.

The traditional version of the capital asset pricing model assumes that each investor actively participates in the entire market for capital assets and that all capital assets are infinitely divisible. This leads to the restriction λ should equal the market price of unit risk as determined by equilibrium in the entire capital market. In case of the market for oil and natural gas prospects, we avoid the above two assumptions in view of the fact that a majority of wildcatters are "small-time" operators--either individuals or small privately held companies whose owners have a major portion of their portfolios invested in the activity of petroleum exploration. Moreover, it is generally agreed that most explorers consider the geological unpredictability, rather than other economic factors as the main source of uncertainty in exploration. Geological uncertainty is specific to the particular prospect being considered: we would expect little correlation between the amounts of oil or natural gas discovered from a given and the economic returns for the rest of the firms in the economy. The measure of risk σ_{jm} can therefore be replaced in this case by $var(\tilde{\Pi}_j)$, the own variance of the cash flows to the j^{th}

exploratory firm.[1] Taken together, these considerations lead us to drop the restriction that λ must equal the price per unit risk as determined by the entire capital market. Instead it represents an average index of risk aversion among individuals engaged in petroleum exploration. Thus we modify $(1)_a$ to

$$V_j = (i/r)(\overline{\Pi}_j - \lambda \, \mathrm{Var}(\tilde{\Pi}_j)) \qquad (1)_b$$

Now let us examine how each firm can choose drilling options that will maximize V_j. At any point in time there is an inventory of undrilled prospects about which some information is available. Depending on which geological sub-population they belong to, the prospects vary in expected return after correcting for the costs involved, and the corresponding risks are measured by the variances of these returns. The utility maximizing behavior on the part of several risk-averse explorers operating simultaneously leads them to always strive for prospects that yield the highest expected return for a given level of risk, or, conversely, prospects that have the lowest level of risk for a specified mean return, i.e., prospects that are on an <u>efficient frontier</u> which may be represented as an upward sloping curve in the risk-return plane, as shown in Figure 2.1.

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[1] One might expect significant positive correlations between size of discoveries from one prospect and from an adjacent prospect. This means some of the covariance terms in σ_{jm} will not equal zero. However, when two or more prospects are likely to exhibit high correlations in terms of geological returns, the drillers are likely to treat the whole "package" as a single prospect. The individual driller would drill only one prospect out of the package and wait for information to flow from this before he even considers drilling the other prospects in the package. This preserves the "geological independence" assumption.

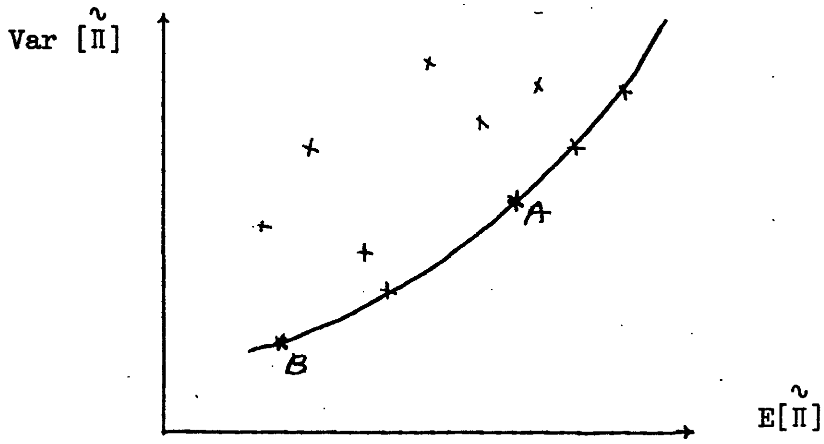

Figure 2.1 - Efficient Frontier

Prospects lying on this frontier are efficient in the sense that they dominate the rest of the prospects currently in the inventory in a risk-return sense, and at any point in time an individual driller need only consider these prospects in making his drilling decisions. The frontier would include small and relatively certain prospects such as point B as well as large but less certain prospects such as point A. The particular prospect chosen, if any, would depend on the individual preference function--more specifically, its degree of risk-aversion. The more risk-averse the explorer, the more likely it is that he will choose prospects yielding small but relatively certain returns--i.e., that he will drill intensively.

This might be related to the traditional distinction between the extensive and intensive modes of drilling behavior. Extensive drilling corresponds to points such as A in Figure 2.1 where relatively few wells are drilled, but those that are drilled usually go out beyond the frontiers of recent discoveries to open up new geographical locations or previously neglected deeper strata at old locations. Typically, this would include drilling farther offshore, or onshore but at very great depth. The probability of discovering oil or natural gas in these cases is small, but the size of discovery in case of success is expected to be large. On the other hand, when drilling is done intensively, many wells are drilled in an area which had already proven to be a more likely source of hydrocarbon discovery. Points such as B on the frontier correspond to intensive drilling. Typically the probability of discovering new hydrocarbon deposits is large in these cases, but the size of discoveries is likely to be relatively small.

2.4 The Number of Exploratory Wells Drilled

Either or both of natural gas and oil may be discovered as a result of exploratory well drilling. Suppose that in a given period the j^{th} explorer is considering drilling a set of independent prospects which are expected to yield mean dollar receipts $\overline{RW}_j$ per exploratory well from oil and gas discoveries. Let $\check{(RW)}_j$ represent the corresponding variance of dollar receipts per exploratory well. The expected net return $E(\tilde{\Pi}_j)$ from drilling W_j wells may then be expressed in terms of $\overline{RW}_j$ and $C^e(W_j)$, the expected total costs of exploration and development of W_j wells are drilled:

$$E(\tilde{\Pi}_j) = W_j \cdot \overline{RW}_j - C^e(W_j) \tag{2}$$

If $\overline{RWG}_j$ and $\overline{RWO}_j$ are the mean sizes of discoveries respectively of natural gas and oil per exploratory well, $\check{(RWG)}_j$, $\check{(RWO)}_j$ the corresponding variances, and PG^e and PO^e the expected prices of natural gas and oil respectively, then we may write

$$\overline{RW}_j = k \cdot (\overline{RWG}_j \cdot PG^e + \overline{RWO}_j \cdot PO^e) \tag{3}$$

and

$$E(\tilde{\Pi}_j) = k(W_j \cdot \overline{RWG}_j \cdot PG^e + W_j \cdot \overline{RWO}_j \cdot PO^e) - C^e(W_j) \tag{4}$$

Where k is a multiplicative factor that accounts for the fact that discoveries may be extended or revised at a later time.

Probably the largest source of uncertainty in returns from exploration is geological unpredictability, i.e., the randomness of discovery size. For simplicity the economic parameters will therefore be assumed to be known with certainty so that

$$\mathrm{Var}(\tilde{\Pi}_j) = W_j \cdot (RW)^{\vee}_j \tag{5}$$

or

$$\mathrm{Var}(\tilde{\Pi}_j) = k^2[W_j \cdot (RWG_j)^{\vee} (PG^e)^2 + W_j(RWO_j)^{\vee} \cdot (PO^e)^2] \tag{6}$$

if no significant correlations exist between oil and gas discoveries.

Let us now examine the components of total expected costs, $C^e(W_j)$. This is composed of the cost of exploration C_E and the cost of subsequent development activity C_D. Although there is little theory establishing a functional relationship between explorations costs and wells drilled, we can observe that (1) costs vary in total and at the margin from one production district to another, depending on average well depth, rock permeability and other geological conditions, and (2) costs per well in a given drilling district seem to rise with the total number of wells drilled in that district within a specific period, i.e., average costs are increasing. The second observation is analagous to the popular assumption, found in many studies of investment behavior,[1] that the costs per unit of investment

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[1]See, for example, Eisner and Strotz [10], Gould [16], Lucas [26] and Treadway [4].

are positively related to the rate of investment. In the case of exploratory activity, this may arise due to (a) rapidly rising installations and reorganization costs when a firm is forced to adjust to a new capacity within a shorter period of time, and (b) higher purchase costs of items in limited supply such as drilling rigs and wire products required for drilling and skilled labor. We will model exploration costs by a quadratic cost function, so that the cost of drilling W_j wells is:

$$C_E(W_j) = \alpha + \beta W_j + \gamma(W_j)^2 \tag{7}$$

Data on historical average drilling costs ($\overline{ATC}$) in each district provide one index of the geological factors affecting costs in a particular district, so that we posit:

$$\beta = \beta_o + \beta_1 \cdot \overline{ATC}$$

which gives us

$$C_E(W_j) = a_o + a_1 W_j + a_2\,\overline{ATC} + a_3(W_j)^2 \tag{8}$$

where a_o, a_1 a_2 and a_3 are constant parameters.

The cost of subsequent development activity is governed partly by the same geological factors that affect exploratory costs (e.g., depth, rock permeability, shape of the decline curve, type of drive, etc.) and also by the amount of reserves withdrawn from ground. This leads us to assume

$$C_D(W_j) = k_o + k_1 W_j \cdot \overline{RW}_j + k_2\,\overline{ATC} \tag{9}$$

Substituting expressions (8) and (9) into (2), we obtain an expression for expected net return of the form

$$E(\tilde{\Pi}_j) = b_o + b_1 W_j + b_2 (W_j \cdot \overline{RW}_j) + b_3 \cdot W_j \cdot \overline{ATC} + b_4 (W_j)^2 \qquad (10)$$

Now we can substitute equation (5) for Var $(\tilde{\Pi}_j)$ and equation (10) for $\overline{\Pi}_j$ in equation $(1)_b$. Then, differentiating the resulting expression with respect to the number of exploratory wells drilled (so as to maximize V_j), we obtain the following expression for WXT_j, the total number of exploratory wells drilled by firm j:

$$WXT = c_0 + c_1 \overline{RW}_j + c_2 \cdot \overline{ATC} + c_3 (RW_j)^{\vee}$$

Aggregating over all firms in the district, we therefore expect to find a relationship of the form

$$WXT = c_0 + c_1 \cdot \overline{RW} + c_2 (RW)^{\vee} + c_3 (\overline{ATC}) \qquad (11)$$

Here $\overline{RW}$ and $(RW)^{\vee}$ stand for the values of the mean and variance of dollar receipts averaged over all the exploratory wells drilled in the district.

Notice that because of our one-period formulation, the riskless interest rate r cancels out and does not appear in the final expression for total exploratory wells drilled. This would be correct only if costs and corresponding revenues occurred in the same period. Since there are in fact considerable lags between investment outlays for exploration and accrual of revenues from reserves discovered, we include an interest rate term as an additional explanatory variable in equation (11). Since an adjustment for the risk in exploration has already been made, the appropriate rate of interest to use would be the AAA bond rate (INTA). Adding this term, and substituting for $\overline{RW}$ and $(RW)^{\vee}$ the aggregate average values of the parameters $\overline{RWG}$, $\overline{RWO}$, $(RWG)^{\vee}$ and $(RWO)^{\vee}$, we obtain the estimating equation for exploratory wells to be:

$$WXT = c_0 + c_1\,(\overline{RWG} \cdot PG^e + \overline{RWO} \cdot PO^e) + c_2\,[(RWG)^{v}(PG^e)^2 + (RWO)^{v} \cdot (PO^e)^2] + c_3\,(\overline{ATC}) + c_4\,(INTA) \tag{12}$$

2.5 The Geological Environment and the Process of Depletion

A single production district will in general contain reservoirs of distinctly different geological types. However, following Kaufman et al. (1974) we shall assume that reservoirs can be classified into a finite number of geologically homogeneous "sub-populations." A play begins when an exploratory well leads to the discovery of the first reservoir in a sub-population. Drilling then continues into the sub-population until the economic returns from drilling no longer compensate for the associated costs and risks.

Our description of the physical evolution of a play and the related process of geological depletion relies on the following three postulates suggested by Kaufman et al. (1974), and supported by several earlier empirical studies including Arps and Roberts (1958), Kaufman (1963) and Uhler and Bradley (1970):

I. The size distribution (in barrels of oil or Mcf of natural gas) of petroleum deposits in reservoirs within a sub-population is lognormal.

II. Within a sub-population of deposits the probability that the next discovery will be of a given size is proportional to the ratio of that size to the sum of sizes of as yet undiscovered reservoirs within the sub-population.

III. Conditional on a play beginning within a sub-population, the probability that an exploratory well will discover a new reservoir is proportional to the ratio of the sum of volumes of the as yet undiscovered reservoirs to the total unexplored volume of potentially hydro-carbon bearing sediment.

Postulates I and II together can be used to determine the probabilistic behavior of the amounts of oil or gas discovered by each successful well in the order of discovery. Postulate II implies that on the average the larger reservoirs will be found first, and that as the discovery process continues, sizes of discovery tend to decline. The third postulate is related to the behavior of success ratios once a play has begun. Postulates I, II and III can be used together to show that <u>within a given sub-population</u>, as the play unfolds, the probability of success tends to decrease, as does the average size of discovery. The result, then, of geological depletion, is to shift the efficient frontier of Figure 2.1 towards the left. This may in part be compensated for by addition of some new, hitherto unknown, prospects to the <u>efficient</u> set, but these additions are the result of new geological information acquired during the activity of exploratory drilling in the previous period, and are relatively unpredictable.

2.6 Influence of Economic Variables on the Distribution of Size of New Discoveries

So far we have confined ourselves to the dynamics of the average sizes of new discoveries and probabilities of success within a given sub-population of reservoirs. However, a single production district may contain more than one sub-population with varying geological characteristics. For example, the geological types of some sub-populations might be such that the average size of reservoirs in them is quite large, but drilling for these prospects involves high risk (low probability of success). Just the reverse (small reservoir sizes but high success probabilities) might be true for other sub-populations within the same district. This fact is relevant to the influence of shift in the economic incentives on the size distribution of discoveries.

A change in economic incentives (e.g., a price rise) may have two effects on the pattern of drilling in a given district. First, it may accelerate the rate of drilling within individual sub-populations, and this would hasten the process of depletion. However, following our three postulates, it is reasonable to assume that the physical process of depletion as well as the process of acquiring new geological knowledge within a subpopulation will remain unaltered, <u>if it is measured on a scale of cumulative successful wells drilled</u> into it. That is, economic variables may influence the rate of exploratory drilling within a sub-population while not altering size distribution or probabilities of discovery when plotted on a scale of cumulative wells.

Secondly, shifts in economic incentives may lead to shifts in the relative proportions of drilling in the different sub-populations within a district. For instance, a large price rise may increase exploratory drilling in a high-risk sub-population at a substantially higher rate than that in a low risk sub-population. This means drilling in the district would, on the average, shift towards a more extensive mode. More intensive drilling would be the result if a price rise had the opposite effect.

In order to separate the physical process of discoveries from the influence of economic variables, we shall use the number of successful exploratory wells as the scale of measurement of elapsed duration within a play. This leads to substantial simplifications in modelling the discovery and depletion process. With this structure, once the number of exploratory wells drilled in a given time interval is known, the model automatically generates a description of the associated depletion process.

2.7 New Plays

The discussion so far has dealt with the evolution of a play, once it has begun. The task of articulating the conditions under which a new play begins is a much more formidable one. New geological knowledge is generated by fresh geophysical surveys as well as from information arising out of exploratory well drilling in adjacent areas. Most of the potentially oil- or gas-bearing land in the onshore district has already undergone at least some amount of geophysical survey. In view of this, and in the absence of a better theory, we assume that new increments in geological knowledge (that may eventually lead to beginning of new plays) are proportional to the number of successful exploratory wells drilled in that region in the recent past.[1] Admittedly, this is a crude measure of

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[1] Dry wells too may contribute some new geological information, but most of the useful information arrives from an analysis of the characteristics of a newly-found reservoir.

new geological knowledge, but knowledge does improve as more wells are drilled and more of the surrounding areas are explored.

Exploratory drilling activity with an intention of generating a new play (i.e., discovering a brand new sub-population of reservoirs) may be thought of as an extreme form of extensive drilling. This is the approach taken in this model. As long as <u>some</u> information is available about such prospects, they may be plotted on the graph of the efficient frontier in Figure 2.1 and thus enter the individual explorer's decision in the same ways as all the other prospects.

2.8 The Dynamics of Discovery Size

Having described the physical laws governing the evolution of the discovery and depletion process, we can now develop the dynamics of the size distribution of reservoirs as drilling continues. Let δ_k represent the mean rate of decline in the size of new reservoirs discovered in the k^{th} sub-populations. For reasons discussed in sections 2.5 and 2.6, the mean rate of decline is expressed in units of proportional decline per successful exploratory well drilled. Let $\mu_k(t)$ be the true mean size of the subset of reservoirs discovered at time t in the k^{th} sub-population and $\tilde{s}_k(t)$, a random variable representing the anticipated size of the next reservoir discovered in this sub-population. Based on the postulates and evidence cited in section 2.5, $\tilde{s}_k(t)$ may be assumed to be lognormally distributed, at least to a reasonable approximation.[1] Then if WXS $[t_1; t_2]$ denotes the total number of successful exploratory

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[1](See following page for footnote.)

wells (gas <u>or</u> oil) drilled into the k^{th} sub-population during the time interval $[t_1, t_2]$, the anticipated size of the next reservoir discovered as at time $(t + h)$ would be lognormally distributed with

$$E[\tilde{s}_k\ (t + h)] = \mu_k\ (t) - \delta_k \cdot \mu_k\ (t) \cdot WXS_k\ [t;\ t + h] = \mu_k\ (t + h) \quad (13)$$

and

$$Var[\tilde{s}_k\ (t + h)] = \mu_k^2(t + h)\ \sigma_k^2 \approx \mu_k^2(t)\sigma_k^2 \quad \text{for small } h \quad (14)$$

(see previous page)

[1]Strictly speaking, if the original size distribution of reservoirs in nature was lognormal, the distribution of the "sampled" reservoirs at any point during the evolution of a play would not be exactly lognormal. This is so as a result of the natural process of sampling without replacement and proportional to random size. However, most of the empirical studies on size distributions of reservoirs themselves were based on distributions of sample observations. The only promising approach to determine the empirical size distributions of reservoirs after correcting for this bias in sampling has been that of Kaufman <u>et al</u>. (1974). Based on highly disaggregated data on wells drilled and sizes of reservoirs found in order of their discovery in the Alberta Province (Canada), they have concluded that in most cases the lognormal assumption is still reasonable for reservoir size distributions <u>in nature</u>. After developing a mathematical description of a play based on the postulates very similar to the ones we are using, they used the mathematical model to simulate the size distribution of reservoirs already "sampled out" as well as that of the as yet undiscovered reservoirs under various assumptions of total number of reservoirs in the population and number in the observed sample. The findings of this study indicate that lognormal approximation would be reasonable for the set of sampled reservoirs as long as the number of reservoirs already discovered is only a small fraction of the total number of reservoirs in the original sub-population. This condition is not unreasonable to assume because, as a general rule, only the largest 5 percent or fewer of the deposits can actually be recovered before making the exploratory activity economically untenable.

where σ_k^2 is the variance parameter associated with the lognormal density governing $\tilde{s}_k$. The parameters δ_k and σ_k are characteristics of the k^{th} sub-population and are assumed to remain constant over the range of geological depletion we are concerned with. Thus over a small interval of time h, the mean rate of decline in the size of discovery per successful well drilled is

$$E\{\frac{1}{WXS\ [t;\ t+h]} \quad \frac{(\tilde{s}_k(t+h) - \mu_k\ (t))}{\mu_k\ (t)}\} = \delta_k \tag{15}$$

and the variance of the rate of decline per successful well (for small h) is

$$Var\{\frac{1}{WXS_k[t;\ t+h]} \quad \frac{\tilde{s}_k\ (t+h)}{\mu_k(t)}\} = \sigma_k^2 \tag{16}$$

Since the error variance in (16) is constant over time, we can estimate δ_k by a simple ordinary least squares regression of the relationship in (15) without the expectation operator on the left-hand side. The standard error of regression in this estimation would <u>directly give us a consistent estimate of the variance parameter σ_k^2</u>.

Note that under our set of assumptions, as long as an estimate of the mean size of reservoirs μ_k at some initial point in time is available, knowledge of the values of the two parameters δ_k and σ_k is sufficient to describe fully for our purposes the dynamics of the probability distribution of discovery sizes on a scale of lagged cumulative successful wells in the following sense: Given an estimate of the mean size of $\mu_k(t_0)$ at some initial point in time t_0, we can predict (using the relations (15) and (16) repeatedly) the mean size of discoveries as well as the variance of the discovery sizes at any subsequent point in time t_1 as long as we know the number of successful wells drilled into this sub-population WXS $[t_0; t_1]$ during the interval between t_0 and t_1. In this way determination of δ_k and σ_k^2 describes fully, at least for the purpose of our analysis, the discovery and depletion process in the k^{th} sub-population.

The above procedure for determining discovery size distributions will now be modified in four ways--with a goal partly to improve the specification of the model and partly to facilitate a better and more convenient econometric procedure.

First, in the above discussion it has been assumed that it is possible to observe values of $\tilde{s}_k$, the size of individual discoveries. In reality this data is confidential information of the producing and is not available, and for estimation purposes we must use the average $\tilde{\bar{s}}_k[t-\theta, t+\theta]$ of the sizes of all reservoirs discovered in a specified small interval of time $[t-\theta, t+\theta]$.

Second, referring to the estimating equation (15), the term $(\bar{s}_k(t + h) - \mu_k(t)/\mu_k(t)$ denotes an estimate of the percentage change in average size during the time interval $[t; t + h]$, and will be replaced by $\Delta(\log \bar{s}_k)$.[1] We can now estimate equation (15) in the more convenient form

$$\log (\bar{s}_k(t + h)) = \log (\mu_k(t)) - c_0 \cdot WXS_k[t; t + h] \tag{17}$$

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[1] It is easy to verify that for small values of h, the approximation is very close. The replacement leads to substantial convenience in econometric estimation and simulation.

The value of c_0 estimated from this regression gives an estimate of δ_k.

Third, we have thus far assumed that the parameter δ_k representing the mean rate of decline in size is constant throughout the evolution of a play. This may not be a bad assumption during the earlier stages of the evolution when the size of as yet unexploited resource base is very large relative to the amount of incremental depletion occurring in one period (say, a year). However, in cases where the accumulated geological depletion of the resource base in the region has reached more advanced levels, the finiteness of the resource base becomes a factor to be reckoned with. The rate of decline in discovery sizes is likely to be steeper where the exploratory firms are operating at levels close to the operating at levels close to the total exhaustion of resource base. A large percentage of the reservoirs found in these cases will not even be economically recoverable.

To capture this effect, we define the following index of accumulated depletion (or exhaustion) of the resource base:

$$\mathrm{DEP} = \left\{ \frac{\begin{array}{l}\text{Estimate of total}\\ \text{original oil (or}\\ \text{natural gas) in place}\end{array} - \begin{array}{l}\text{Cumulative}\\ \text{production}\\ \text{to date}\end{array} - \begin{array}{l}\text{Current estimate}\\ \text{of proved}\\ \text{resources}\end{array}}{\begin{array}{c}\text{Estimate of original oil}\\ \text{(or natural gas) in place}\end{array}} \right\}$$

i.e., $\mathrm{DEP}_k(t)$ at any point in time t is the index of estimated potential reserves still left in sediments of the k^{th} geological type at time t expressed as a fraction of the total reserves originally in place. δ_k may then be expressed as a function of this index:

$$\delta_k(t) = f(\mathrm{DEP}_k(t) \tag{19}$$

A reasonable postulate would be

$$\delta_k(t) = c_0 + c_1 \cdot DEP_k(t) \qquad (20)$$

where c_0 and c_1 are parameters to be estimated.

Finally, each production district as defined by the Federal Power Commission might well contain more than one sub-population, and shifts in drilling across populations might occur in response to changes in prices of natural gas or oil. Since the data on size of discoveries are aggregated by production districts, observed average size of discoveries might change in response to price changes because of shifts from one sub-population to another. For instance, if a given price change motivates explorers, on the average, to increase the proportion of extensive drilling (i.e., drilling in high risk sub-populations which also have larger deposits), the observed average size of discoveries aggregated over all the sub-populations might actually show an increase.

The magnitude of such shifts in aggregate average size in response to price changes would be positively related to the amount of new geological knowledge received regarding deposits in the district, which in turn has been conjectured to be proportional to the number of successful exploratory wells drilled in the region in the recent past.

Since the estimate of δ occurs multiplicatively with the number of successful wells drilled (WXS) in the estimating equations (15) and (17), a natural way to capture the price effects on the aggregated average sizes would be to use the specification $\delta = f(DEP, PG, PO)$. Thus, the estimating equation (17) may now be modified to:

$$\log(\overline{s}(t + h)) = \log(\mu(t)) + f(DEP, PG, PO) \cdot WXS[t; t + h] \qquad (21)$$

where the function f( ) represents the mean decline rate δ of discovery sizes aggregated over an entire production district.

2.9 The Success Ratio

The discussion in the previous section is relevant conditional upon an exploratory well striking oil or natural gas. In order to estimate expected returns and risks from an exploratory well before the drilling begins, these figures must be modified to take into account the probability that the exploratory well will result in a success. Postulate III of Section 2.5 describes the behavior of success ratios as the play evolves. The factor of proportionality between the probability of success and the ratio in III is a constant for any given geological type, and may be thought of as an index of difficulty of discovery of reservoirs in that geological type once the play has started. It varies from one sub-population to another (and one production district to another) depending on the complex interaction of a number of geological variables.

Using postulates I, II and III (of Section 2.5) together, it can be shown that once a play has begun, the probability of a success tends to decrease monotonically throughout the evolution of the play in a pattern similar to that derived for the average discovery size. This leads us to specify the following type of relationship between probability of success SR and average discovery size (s) within a given sub-population:

$$SR = a_1 s/R_{max} \tag{22}$$

where R_{max} is the estimated total reserves originally in place and a_1 is a geological index describing the difficulty of finding a reservoir in this sub-population. Written in terms of the corresponding aggregate variables $\overline{SR}$ and $\overline{s}$ for all the wells drilled in this sub-population,

$$\overline{SR} = a_1 \overline{s}/R_{max} \tag{23}$$

This says that as more exploratory drilling takes place in a given sub-population, we expect to find proportional changes (declines) in average discovery size and success ratio. Once again, to the extent that we are forced to use size and success ratio data aggregated by production district rather than by sub-population, we expect to see some price effects on the mean success ratios reflecting shifts in the relative proportion of extensive and intensive drilling in response to price changes. Combining this observation with the specifications in (21) and (22), we expect a relationship of the form

$$\log \left(\frac{\overline{SR}(t)}{\overline{SR}(t_0)} \right) = \log \left(\frac{\overline{s}(t)}{\overline{s}(t_0)} \right) + f'(PG,PO) \tag{24}$$

where f' ( ) is a function of the current and/or lagged prices of oil and natural gas. The observed price coefficients in the success ratio equations (unlike the average size equations) would also reveal any shifts in "directionality"[1] in response to changes in the relative prices.

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[1]"Directionality" is a term that became popular during and after the Federal Power Commission's Permian Area Rate Hearing. It refers to the capability of the explorers to predict ahead of time if the well will strike oil or gas conditional on its being a successful well. There is empirical evidence (see, for example, Khazzoom (1968)) to support the hypothesis of high directionality. A high directionality implies the capability of an operator to conduct search, if he so desires, oriented specifically for either oil or natural gas.

For instance, if directionality is strong, a higher oil price might result in an increase in the tendency to "drill for oil" rather than gas, which in turn would increase the fraction of successful oil wells out of total exploratory wells.

2.10 New Discoveries of Natural Gas and Oil

The size of discoveries per exploratory well SW is defined as the product of the success ratio SR and the size of discovery conditional on a success, S, i.e., SW = (SR)(s). It can be shown that under our assumptions,

$$\mathrm{Var}(SW) \simeq (\overline{SW})^2 \cdot 4\sigma^2 \tag{25}$$

where σ^2 is the variance of the distribution of s, the size per successful well. This relation will later be used in computing the parameters $(RWG)^{v}$ and $(RWO)^{v}$ of the exploratory wells equation (12).

Once the estimates of total exploratory wells drilled, fraction of successful wells and average size of discovery per successful well are known, new discoveries of natural gas and oil are simply given by

$$\left\{\begin{matrix}\text{New} \\ \text{discoveries} \\ \text{of gas}\end{matrix}\right\} = \begin{pmatrix}\text{total} \\ \text{exploratory} \\ \text{wells}\end{pmatrix} \times \begin{pmatrix}\text{fraction} \\ \text{of} \\ \text{gas wells}\end{pmatrix} \times \begin{pmatrix}\text{average} \\ \text{size of gas} \\ \text{discoveries}\end{pmatrix} \tag{26}$$

$$\left\{\begin{matrix}\text{New} \\ \text{discoveries} \\ \text{of oil}\end{matrix}\right\} = \begin{pmatrix}\text{total} \\ \text{exploratory} \\ \text{wells}\end{pmatrix} \times \begin{pmatrix}\text{fraction} \\ \text{of} \\ \text{oil wells}\end{pmatrix} \times \begin{pmatrix}\text{average} \\ \text{size of oil} \\ \text{discoveries}\end{pmatrix} \tag{27}$$

2.11 Extensions and Revisions

Additions to oil and gas reserves can also occur as a result of extensions and revisions of existing fields and pools. Extensions are adjustments to the estimates of proved recoverable reserves that result from changes in the estimates of the productive limits. Following the discovery of a reservoir, a producer would normally drill additional wells (extension as well as development wells) to delineate the productive limits of the reservoir. In general a substantial portion of extensions are realized within a year or two following the reservoir discovery. This provides the following working hypothesis for the specification of the extensions equation:

$$\text{Extensions} = g_1 \text{ (lagged discoveries, lagged exploratory wells)} \qquad (28)$$

As the basin is depleted of the richer prospects, it is reasonable to expect the size of extensions to drop. The index of accumulated depletion DEP may therefore be added as an additional explanatory variable on the right-hand side. However, it is likely that depletion effects on extensions are already reflected in the functional relationship of (28) through its effects on discoveries and exploratory wells. This is a matter to be resolved on the basis of empirical evidence from econometric estimation. Similarly, an argument may be made to include the price of natural gas (or oil) as an additional explanatory variable on the grounds that incentive to gain more extensions is influenced by price expectations. This too must be resolved empirically, since some price expectations are already embedded in lagged discoveries and wells drilled.

Revisions are the least predictable category of reserve additions. They refer to adjustments in oil and natural gas reserves estimates brought about by new geological and engineering information on reservoir characteristics such as porosity, permeability and interstitial water.

Sometimes they also result from improved geological techniques of estimating the sizes of previously known reservoirs. Finally, and unfortunately, the American Gas Association and American Petroleum Institute have historically followed the convention of including negative extensions in the category of revisions.

Needless to say, we do not expect to find too much of an economic explanation for the observed size of revisions. Since the total amount of proved recoverable reserves at the end of the previous year represents the size of the reserves base susceptible for revision in any given year, we expect this to serve as the main explanatory variable for explaining revisions. Secondly, new information that leads to revisions comes from exploratory drilling which makes lagged exploratory wells a second candidate for explaining revisions. New information can also arrive from new developmental drilling. Lagged incremental production of natural gas (or oil) is therefore included as a third explanatory variable. Finally, the index of exhaustion of the resource base DEP may be included to capture depletion effects. The specification for the revisions equation is therefore of the form

$$\text{Revisions} = g_2\left(\begin{array}{l}\text{lagged}\\ \text{year-end}\\ \text{reserves}\end{array},\ \begin{array}{l}\text{lagged}\\ \text{exploratory}\\ \text{wells}\end{array},\ \begin{array}{l}\text{incremental},\\ \text{production}\end{array}\ \begin{array}{l}\text{depletion}\\ \text{index}\end{array}\right) \quad (29)$$

It is not expected that all of the variables on the right-hand side will figure prominently, but a priori, year-end reserves is expected to have a significant effect.

CHAPTER III

ESTIMATION OF THE MODEL

The discussion of Chapter II provides the basis for the specification of an econometric model to predict the supply of natural gas and oil reserves in the Continental United States. Such a model will now be formulated and estimated, with a goal to use it later for forecasting reserves under alternative economic and regulatory environments.

3.1 Structure of the Model

The overall structure of the model is shown schematically in the block diagram of Figure 3.1. The dashed line on this diagram indicates the boundaries of the model presented here. The inter-relationships and neutral dependence among the various blocks are indicated by the arrows. There is one block to represent each of the main categories of additions to reserves viz. new discoveries, extensions and revisions of oil and natural gas. New discoveries are computed by multiplying together the estimates of total exploratory wells, success fractions and average sizes of new discoveries conditional on success. Extensions and revisions are estimated as functions of new discoveries, exploratory wells and year-end reserves. As can be seen in the block diagram, additions to gas reserves are formed from the sum of new discoveries, extensions, and revisions, and, aside from changes in underground storage, the only major subtraction from gas reserves occurs as a result of production. Similarly, additions to oil reserves are the sum of new discoveries of

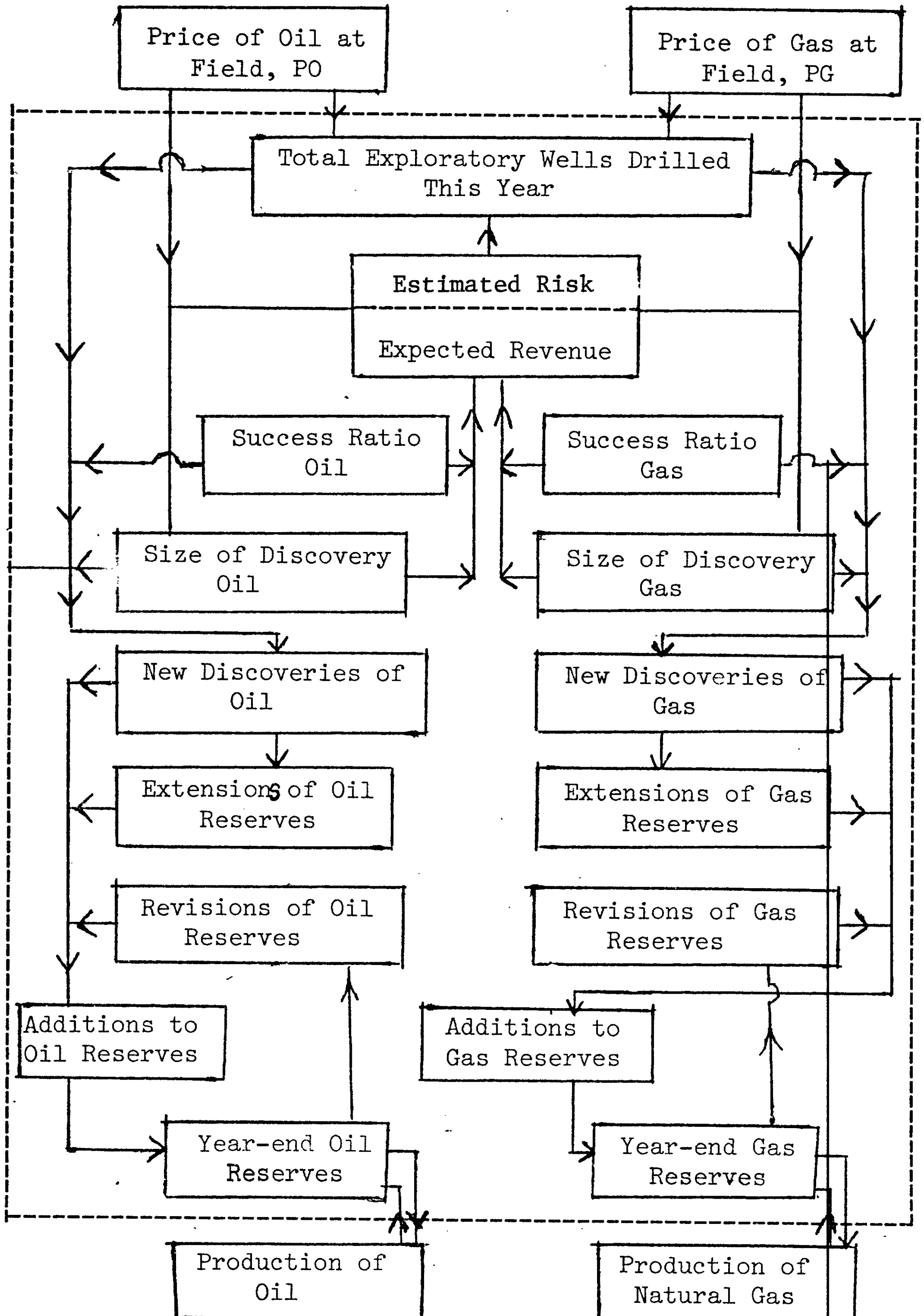

FIG. 3.1 <u>BLOCK DIAGRAM OF</u>

<u>THE ECONOMETRIC MODEL</u>

oil, extensions, and revisions. Thus, to close the model of supply of oil and natural gas reserves, we need estimates of the production out of reserves. These are obtained from a separate model (in case of natural gas) or by making a suitable assumption (in case of oil).

This chapter will therefore describe the steps in estimating a set of nine equations that explain additions to reserves for natural gas and oil. One equation is estimated to explain the total number of exploratory wells drilled (WXT), one equation each is estimated to explain the average sizes of new discoveries per well of natural gas (SZG) and oil (SZO), and one equation each is estimated to explain the fraction of wells drilled that are successful in finding gas (SRG) and in finding oil (SRO). Finally, four equations are estimated that explain extensions of natural gas (XG), extensions of oil (XO), revisions of natural gas reserves (RG), and revisions of oil reserves (RO).

3.2 Variable Definitions and Data Sources

The variables used in estimating the model, together with the sources of data and units of measurement, are listed below. The list is arranged under four sub-groups, representing the four categories of variables used.

WELLS	Exploratory wells data are from the Joint Association Survey of Drilling Statistics, for 18 FPC (Federal Power Commission) production districts, for the years 1963-1972.
WXT:	Total number of exploratory wells drilled.
WXG:	Number of successful exploratory gas wells.

WXO:	Number of successful exploratory oil wells.
WXTM:	A time-average of WXT over the period 1963-1972.
SRG:	Ratio of successful gas wells to total exploratory wells, SRG = WXG/WXT.
SRO:	Ratio of successful oil wells to total exploratory wells, SRO = WXO/WXT.
$\hat{SRG}$, $\hat{SRO}$:	Fitted values of the above two variables using the estimated success ratio equations.

<u>RESERVES</u> All data are from American Gas Association/American Petroleum Institute/Canadian Petroleum Association, <u>Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas</u>, for 18 FPC production districts,[1] for the years 1964-1972. Units are millions of cubic feet for natural gas, and thousands of barrels for oil. Exceptions to this are explicitly stated.

DD1:	Dummy variable for Louisiana South District.
DD2:	Dummy variable for Permian District.
DD3:	Dummy variable for Kansas, Oklahoma, TRRC Districts 1, 2, 3, 4, and 10.
DD4:	Dummy variable for Colorado-Utah, and Wyoming Districts.
DG:	Total new discoveries of natural gas.
DO:	Total new discoveries of oil.
RG:	Total revisions of natural gas.
RO:	Total revisions of oil.
XG:	Total extensions of natural gas.
XO:	Total extensions of oil.
XRG:	Natural gas extensions plus revisions, XRG = XG + RG.

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[1]Oil reserves data are available for twenty FPC districts, and were used in the estimation of equations, whenever feasible.

YG: Year-end reserves of natural gas.

YO: Year-end reserves of oil.

SZG: Average size of gas discoveries per successful gas well, SZG = DG/WXG.

SZO: Average size of oil discoveries per successful oil well, SZO = DO/WXO.

$\hat{SZG}$, $\hat{SZO}$: Fitted values of the above two variables, obtained from the estimated size of discovery equations.

$\hat{\sigma}_G^2$, $\hat{\sigma}_0^2$: Estimates of the variance over time of the size distributions of gas and oil discoveries respectively. These are obtained from the estimated size of discovery equations.

PGC_G: Estimate of the total potential gas reserves in each district as of 1963. From Potential Supply of Natural Gas in the U.S., published by the Potential Gas Association, Mineral Resources Institute, 1971.

PGC_0: Estimate of the original oil-in-place in the district.

DEPG: Index of depletion of the natural gas resource base in the production districts,

$$DEPG = (PGC_G - YG - CQG^1)/PGC_G$$

DEPO: Index of depletion of the oil resource base in the production district,

$$DEPO = (PGC_0 - YO - CQO^1)/PGC_0$$

PRODUCTION: Data are from AGA/API/CPA, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas, for 18 FPC production districts, for the years 1963-1972. Units are 10^6 cubic feet for gas and 10^3 barrels for oil.

QG: Total production of natural gas.

QO: Total production of oil.

CQG: Cumulative production of natural gas,

$$CQG = \sum_{t'=1963}^{t} QG_{t'}$$

CQO: Cumulative production of oil,

$$CQO = \sum_{t'=1963}^{t} QO_{t'}$$

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[1]See list of production variables for definition.

PRICES AND ECONOMIC VARIABLES

PG: New contract price of interstate sales of gas at the wellhead, in cents per Mcf, by production district for 28 FPC production districts, for the years 1952-1972. Compiled by Foster Associates, Inc.

PW or $\overline{PG}$: Average wellhead price, in cents per Mcf, by production district for 18 FPC production districts, for the years 1962-1971, from Table F, FPC, Sales of Natural Gas.

PO: Wellhead price of oil, in dollars per barrel, by production district from 20 FPC production districts, for the years 1954-1972, from Bureau of Mines, Minerals Yearbook.

INTA: AAA bond interest rate (percent per annum), from Federal Reserve Bulletin.

ATCM: Index of average drilling costs for exploratory drilling per well, by production district for 18 FPC production districts, from AGA/API/CPA's Joint Association Survey. This is a time average over the period 1963-1971.

Note that in all the estimations, new contract prices of natural gas are used rather than average wellhead prices because they are likely to represent much more closely the expectations with regard to future prices on the part of the producers. No long term contracts analogous to those between producers and the pipeline companies are written in case of oil. That is, at least for purposes of our estimation, all sales of crude oil at the wellhead may be considered to be at spot prices. Accordingly, the oil prices used in estimating the exploration and discovery equations are the average wellhead prices.

3.3 Modification of Theoretical Forms for Purposes of Econometric Specification

Some of the theoretical relationships for the exploration and discovery of natural gas and oil that were derived in Chapter II must be modified for purposes of econometric estimation. We begin by re-examining Equation (12) of Chapter II that defines the specifications for the total number of exploratory wells drilled. Note that the equation includes the mean and variance of RWG and RWO, the average sizes of gas discoveries and oil discoveries per well drilled. Using Equation (25) of Chapter II we can write:

$$(\mathrm{RWG})^{v} = 4\hat{\sigma}_G^{\,2}(\overline{\mathrm{RWG}})^2 = 4\hat{\sigma}_G^{\,2}(\widehat{\mathrm{SZG}})^2(\widehat{\mathrm{SRG}})^2 \tag{1}$$

$$(\mathrm{RWO})^{v} = 4\hat{\sigma}_0^{\,2}(\overline{\mathrm{RWO}})^2 = 4\hat{\sigma}_0^{\,2}(\widehat{\mathrm{SZO}})^2(\widehat{\mathrm{SRO}})^2 \tag{2}$$

where $\hat{\sigma}_G^{\,2}$ and $\hat{\sigma}_0^{\,2}$ are estimated values of the variances of the error terms associated with the equations that determine the sizes of gas and oil discoveries respectively.

Our theoretical specification for the number of exploratory wells drilled also includes the <u>expected</u> prices at the field of natural gas and oil. Since it is impossible to observe expected prices, we will use as proxy variables a three-year moving average of past prices.

The theoretical specification also contains the mean values of oil and gas discovery sizes, and we will use the <u>estimated</u> values of these variables (obtained from the estimated forms of the size of discovery equations) in our exploratory wells estimating equation. Finally, dummy variables will be introduced (DD1, DD2, DD3, and DD4) to account for heterogeneity between broadly-defined field markets in the United States. This gives us the following estimating equation for exploratory wells drilled:

$$\begin{aligned} WXT &= c_o + a_1 DD1 + a_2 DD2 + a_3 DD3 + a_4 DD4 \\ &+ c_1 [\hat{SZG} \cdot \hat{SRG})(PG_{-1} + PG_{-2} + PG_{-3})/3 \\ &+ (\hat{SZO} \cdot \hat{SRO})(PO_{-1} + PO_{-2} + PO_{-3})/3] \\ &+ c_2 [(\hat{SZG})^2 (\hat{SRG})^2 (PG_{-1} + PG_{-2} + PG_{-3})^2/9 \\ &+ (\sigma_0{}^2/\sigma_G{}^2)(\hat{SZO})^2(\hat{SRO})^2(PO_{-1} + PO_{-2} + PO_{-3})^2/9] \\ &+ c_3 ATCM + c_4 INTA_{-1} \end{aligned} \tag{3}$$

Note that this equation cannot be estimated until the size and success ratio equations for both oil and gas have also been estimated, since the equation includes the estimated values for sizes and success ratios, as well as the estimated error variances of the oil and gas size equations.

The theoretical specification for the average size of discovery appears in Equation (21) of Chapter II, and it determines the average discovery size at a point in time (t + h) given the average discovery size at some previous time t. For purposes of estimation, we must choose some interval of time (which we shall call the "reference period") for which we can make observations of changes in discovery size. We will use as a reference period for changes in discovery size the two-year interval immediately preceding the middle of the previous year's observation. The reference value of discovery size will therefore be the average of sizes over the past three years. We thus define:

$$SZG_{REF} = (SZG_{-1} + SZG_{-2} + SZG_{-3})/3 \quad (4)$$

and

$$SZO_{REF} = (SZO_{-1} + SZO_{-2} + SZO_{-3})/3 \quad (5)$$

for natural gas and oil respectively. Consistent with this, the appropriate variable to be used in place of WXS[t; t + h] would be an index of the number of successful wells drilled from the reference period through the end of the previous year. The number of successful gas wells drilled from the middle of the reference period to date can be approximated by $(1/2)WXG_{-3} + WXG_{-2} + (1/2)WXG_{-1}$. We therefore define the following indices proportioned for numerical convenience:

$$WXG_{REF} = (WXG_{-1} + 2WXG_{-2} + WXG_{-3})/40 \quad (6)$$

$$WXO_{REF} = (WXO_{-1} + 2\ WXO_{-2} + WXO_{-3})/40 \quad (7)$$

Since the theoretical specification includes expected gas and oil prices, we will again use three-year moving averages of these prices as explanatory variables. This three-year moving average also corresponds to the time interval between the reference point (middle of reference inkwell) and beginning of the current period. We thus obtain the following estimating equations for the size of gas discoveries and size of oil discoveries:

$$\begin{aligned}\log(SZG) = \log(SZG_{REF}) + \\ WXG_{REF} \cdot f_1(DEPG_{-1}, (PG_{-1} + PG_{-2} + PG_{-3})/3, \\ (PO_{-1} + PO_{-2} + PO_{-3})/3)\end{aligned} \quad (8)$$

$$\log(SZO) = \log(SZO_{REF}) +$$

$$WXO_{REF} \cdot f_2(DEPO_{-1}, (PG_{-1} + PG_{-2} + PG_{-3})/3,$$

$$(PO_{-1} + PO_{-2} + PO_{-3})/3 \qquad (9)$$

The theoretical specification for the success ratio equations appears in Equation (24) of Chapter II, and applying the same notion of a reference period we obtain the following equations for the gas and oil success ratios:

$$\log(SRG) = \log(SRG_{REF}) + WXG_{REF} \cdot f_3(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) \qquad (10)$$

$$\log(SRO) = \log(SRO_{REF}) + WXO_{REF} \cdot f_4(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) \qquad (11)$$

where SRG_{REF} and SRO_{REF} are defined by

$$SRG_{REF} = ((SRG_{-1} + SRG_{-2} + SRG_{-3})/3) \cdot \left(\frac{\hat{SZG}}{\hat{SZG}_{REF}}\right) \qquad (12)$$

$$SRO_{REF} = ((SRO_{-1} + SRO_{-2} + SRO_{-3})/3) \cdot \left(\frac{\hat{SZO}}{\hat{SZO}_{REF}}\right) \qquad (13)$$

One problem with equations (12) and (13) is that they provide no guarantee that the estimated success ratios will take on values between 0 and 1. In order to guarantee that we do not obtain success ratios that are smaller than 0 or larger than 1, we will use the following logit specification for our estimating equations:[1]

[1] To elaborate, referring to equations (10) and (11), the dependent variable is by definition constrained to take only positive values whereas the function on the right hand side is completely unconstrained. There are econometric biases as well as simulation difficulties associated with estimation of such equations directly. The logit form avoids this difficulty by modifying the dependent variable into a form that is not constrained. For small values of success fractions (say, <0.2), log (SRG/(1-SRG)) should closely approximate log(SRG).

$$\log\left[\frac{SRG}{1 - SRG}\right] = \log\left[\frac{SRG_{REF}}{1 - SRG_{REF}}\right] + WXG_{REF} \cdot f_3(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) \quad (14)$$

$$\log\left[\frac{SRO}{1 - SRO}\right] = \log\left[\frac{SRO_{REF}}{1 - SRO_{REF}}\right] + WXO_{REF} \cdot f_4(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) \quad (15)$$

It is important to stress that Equations (3), (8), (9), (14), and (15) must be estimated in sequential order. First, the size equations (8) and (9) are estimated and the resulting equations are used to generate size estimates for the reference variables in the success ratio equations. In addition, the estimated standard errors of the size equations $\hat{\sigma}_G$ and $\hat{\sigma}_0$ will be used in the estimation of the wells equation. Equations (14) and (15) for the success ratios are estimated next, and the results are used to generate estimated success ratios. Finally, the wells equation can be estimated, using estimated sizes, estimated success ratios, and the estimated ratio of size variances $(\hat{\sigma}_0^2/\hat{\sigma}_G^2)$.

3.4 Estimation Method

All the equations in the model are estimated by using pooled time series - cross-section data from eighteen Federal Power Commission districts over the years 1964 to 1972. In choosing a time horizon, it is important to choose a period over which the structure of the industry and environment is reasonably stable. The regulation of the wellhead prices of natural gas by the Federal Power Commission (FPC) and the mandatory import quotas imposed on the U.S. crude oil market (beginning March, 1959) provided a period where price expectations were very stable.[1]

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[1]See, for example, evidence presented in Table 8-2 of E. Erickson and R. Spann, "Price, Regulation and the Supply of Natural Gas in the United States" [10].

Exploratory firms can therefore be assumed to act like price-takers operating in a competitive market. However, FPC regulation of natural gas prices did not become effective (i.e., no excess demand was observed in reserves markets) for all the producing regions until 1964. Hence, no data prior to 1964 was used in the case of natural gas. The crude oil market was influenced by the secondary and tertiary effects of natural gas regulation. In addition, the major producing states imposed restrictions on production of oil (withdrawal of proved reserves of oil) on the producing companies. This, too, had an indirect influence on the supply of oil reserves.[1] Since the production restrictions varied from year to year, oil reserves data used in the estimation was restricted to even a narrower time range of 1966 to 1972. To the extent that available geophysical information on the petroleum fields in the United States underwent any significant change in the previous decade, estimation over the shorter time period is likely to provide more relevant estimates of the parameters. Table 3.1 summarizes the exact groupings of the production districts as well as the time bounds used for estimating the different equations in the model.

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[1]For instance, it is alleged that the way these production restrictions were administered amounted to discrimination against large discoveries in favor of small discoveries and against deeper wells relative to shallower wells.

Table 3.1

SUMMARY OF CROSS-SECTIONS AND TIME BOUNDS FOR THE ESTIMATING EQUATIONS

EQUATIONS	DISTRICTS POOLED	TIME BOUNDS
WELLS (WXT)	18 FPC DISTRICTS*	69-72
DISCOVERY SIZE FOR GAS (SZG)	" " " *	67-72
SUCCESS RATIO FOR GAS (SRG)	" " " *	68-72
EXTENSIONS FOR GAS (XG)	" " " *	65-72
REVISIONS FOR GAS (RG)	" " " *	65-72
DISCOVERY SIZE FOR OIL (SZO)	" " " *	69-72
SUCCESS RATIO FOR OIL (SRO)	" " " *	69-72
EXTENSIONS FOR OIL (XO)	20 " " **	67-72
REVISIONS FOR OIL (RO)	" " " **	69-72

*These include Texas 1, 2, 3, 4, 6, 9, 10, California, Colorado + Utah, Kansas, Louisiana North, Louisiana South (onshore), Mississippi, New Mexico North, Permian (= New Mexico South + Texas 7C + Texas 8 + Texas 8A), Oklahoma, West Virginia + Kentucky, Wyoming.

**These include the above eighteen plus Montána and Pennsylvania.

3.5 Econometric Procedures

In estimating the equations using least squares, attention must be paid to the characteristics of the additive error terms assumed in each of the equations. The appropriate econometric procedure to be used will be a function of these characteristics. Consider an equation to be estimated of the form:

$$Y_{jt} = \beta_1 X_{jt,1} + \beta_2 X_{jt,2} + \ldots + \beta_k X_{jt,n} + \varepsilon_{jt} \tag{16}$$

Let m = number of cross-sections

t = number of time periods

n = number of independent variables (ncluding constant term).

Then (16) can be written in the matrix form:

$$\underline{Y} = \underline{X}\,\underline{\beta} + \underline{\varepsilon} \tag{17}$$

If the error terms ε_{jt} are all homoscedastic and uncorrelated both across time and cross-sections, the covariance matrix will be of the form:

$$\underline{\Omega} = \underline{E}[\underline{\varepsilon}\,\underline{\varepsilon}'] = \sigma^2 \underline{I} \tag{18}$$

But this would probably be an unreasonable assumption in our case. In some cases there are theoretical reasons to expect the error terms to have different variances for different districts. For example, since the average size is computed as the mean of the sizes of several independent new discoveries in a given time period, we would expect the variance of the corresponding terms to vary inversely as the number of successful wells drilled in that period. Similarly, it is reasonable to expect at least a first order autocorrelation across time in these specifications. The reason behind this is usually related to the set of omitted variables whose effect is expressed by the disturbance term ε_{jt}. Frequently many of these variables (especially economic variables) are characterized by some inertia so that a large value this year is followed by a large value next year. This leads us to expect a time-wise autocorrelation in the error terms. We shall assume for simplicity that the error terms are cross-sectionally independent. The specification of the error terms may then be expressed by the following properties of the covariance matrix Ω:

$$E(\varepsilon_{jt}^{2}) = \sigma_{jt}^{2} \tag{19}$$

$$E(\varepsilon_{jt}, \varepsilon_{it}) = 0 \text{ for } j \neq i \tag{20}$$

$$\varepsilon_{jt} = \rho_k \varepsilon_{j,t-1} + u_{jt} \tag{21}$$

where u_{jt} is serially uncorrelated. Since the omitted variables are likely to be of the same nature for all the cross-sections, we shall assume that the individual ρ_j do not differ significantly from each other so that ρ_j can be replaced by ρ.

In the case of the average size and success ratio equations, estimates of the relative values of σ_{jt} can be derived from theoretical considerations. The heteroscedasticity in the error terms is thus avoided by simply applying a weight of $(1/\hat{\sigma}_{jt})$ to the observations of Y_{jt} and $X_{jt,n}$ in estimating equation (17) and then applying ordinary least squares to the transformed equation, i.e., to the equation:

$$\underline{Y}^* = \underline{X}^* \ \underline{\beta} + \varepsilon^* \tag{22}$$

where $$Y^*_{jt} = Y_{jt}/\hat{\sigma}_{jt} \tag{23}$$

$$X^*_{jt,i} = X_{jt,i}/\hat{\sigma}_{jt} \quad (i = 1, \ldots n) \tag{24}$$

and $$\varepsilon^*_{jt} = \varepsilon_{jt}/\hat{\sigma}_{jt} \tag{25}$$

To correct for the serial correlation, first an ordinary least squares regression is performed on (22) and the residuals are used to calculate an estimate of the first order serial correlation coefficient given by :

$$\rho = \frac{\sum_{j=1}^{m} \sum_{t=2}^{t} \tilde{\varepsilon}^{*}_{jt}, \tilde{\varepsilon}^{*}_{j,t-1}}{\sum_{j=1}^{m} \sum_{t=2}^{t} (\tilde{\varepsilon}^{*}_{j,\,t-1})^2} \tag{26}$$

with $\tilde{\varepsilon}^{*}_{jt} = \varepsilon_{jt} - \bar{\varepsilon}$

where $\bar{\varepsilon}$ is the mean of ε_{jt} over all t and j. This can be shown[1] to be a consistent estimate of ρ. We can now transform the variables autoregressively as:

$$Y^{**}_{jt} = Y^{*}_{jt} - \rho\, Y^{*}_{j,t-1} \tag{27}$$

$$X^{**}_{jt} = X^{*}_{jt} - \rho\, X^{*}_{j,t-1,i} \tag{28}$$

$$\varepsilon^{**}_{jt} = \varepsilon^{*}_{jt} - \rho\, \varepsilon^{*}_{j,t-1} \tag{29}$$

Ordinary least squares is then applied to the transformed equation

$$\underline{Y}^{**} = \underline{X}^{**}\, \underline{\beta} + \varepsilon^{**} \tag{30}$$

to obtain unbiased, consistent and efficient estimates of the parameter vector $\underline{\beta}$.

In the case of the exploratory well equation, no theoretical estimates of $\hat{\sigma}_{jt}$ are available and so a slightly modified procedure is used under the assumption that σ_{jt} are constant over time and vary only across districts. This consists of a generalized least squares estimation procedure[2] involving three steps. First, an ordinary least squares

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[1] See Theil [40], Section 6.3.

[2] This procedure was suggested by Robert S. Pindyck of the Sloan School of Management, M.I.T.

regression is performed, and the residuals are used to calculate first-order serial correlation coefficients for each district pooled in the sample. These coefficients are used to perform an autoregressive transformation on the data, a second OLS regression is performed, and the resulting residuals are used to calculate estimated error term variances for each district. Finally, these variances are used to perform a weighted least squares regression. For a more complete and technical description of this procedure, see MacAvoy and Pindyck [30].

In the case of extensions and revisions equations, an autoregressive correction is applied as described earlier and ordinary least squares is performed on the transformed equations. The step involving the heteroscedasticity correction is omitted in view of certain data considerations. Instead the geological dummies are expected to remove most of the heteroscedasticity effect.

3.6 Statistical Results

3.6.1 Exploration and New Discoveries

The estimated versions of the five equations that determine new discoveries of natural gas and oil are shown below, with t-statistics in parentheses. Also listed for each equation are the number of observations N, the R^2, F-statistic, standard error or regression and the Durbin-Watson statistic.

Exploratory Wells*

$$\mathrm{WXT} = \underset{(6.01)}{796.16} - \underset{(-0.03)}{20.74}\mathrm{DD1} + \underset{(2.61)}{294.12}\mathrm{DD2} - \underset{(-0.02)}{1.49}\mathrm{DD3} + \underset{(0.53)}{234.29}\mathrm{DD4}$$

$$+ \underset{(7.074)}{0.00367}[\hat{\mathrm{SZG}}\cdot\hat{\mathrm{SRG}}(\mathrm{PG}_{-1} + \mathrm{PG}_{-2} + \mathrm{PG}_{-3})/3)$$

$$+ \hat{\mathrm{SZO}}\cdot\hat{\mathrm{SRO}}\cdot((\mathrm{PO}_{-1} + \mathrm{PO}_{-2} + \mathrm{PO}_{-3})/3]$$

$$- (\underset{(-2.49)}{2.04\mathrm{x}10^{-8}} - \underset{(0.51)}{1.74\mathrm{x}10^{-8}}\mathrm{DD1}^{*})[\hat{\mathrm{SZG}}^2\cdot\hat{\mathrm{SRG}}^2((\mathrm{PG}_{-1} + \mathrm{PG}_{-2} + \mathrm{PG}_{-3})/3)^2$$

$$+ \frac{\sigma_0^2}{\sigma_G^2} \cdot \hat{\mathrm{SZO}}^2 \cdot \hat{\mathrm{SRO}}^2 \cdot ((\mathrm{PO}_{-1} + \mathrm{PO}_{-2} + \mathrm{PO}_{-3})/3)^2$$

$$- \underset{(-1.36)}{0.00204}\mathrm{ATCM} - \underset{(-5.85)}{64.15}\mathrm{INTA}_{-1} \qquad (31)$$

$N = 54$ $\quad R^2 = 0.81$ $\quad F = 20.84$

S.E. = 1.781 $\quad$ D.W. = 1.52

where

$$\left(\frac{\sigma_0^2}{\sigma_G^2}\right) = \frac{(\text{S.E. of SZO regression})^2/(\text{Average value of WXG})^{**}}{(\text{S.E. of SZO regression})^2/(\text{Average value of WXO})}$$

$$= \frac{(5.46)^2}{(3.52)^2} \cdot \frac{1}{2.38} = 1.01$$

---

*An additional dummy variable is used for Louisiana South (onshore) on the coefficient for the variance term . This is because the average size of discoveries in this district is much higher than that in any of the other production districts; the squared size term therefore falls beyond the range of values over which (3) can be expected to hold without any modification.

**Estimated error variances are divided by average values of the number of successful gas and oil wells to account for the heterscedasticity correction used in the estimation of the size equations.

Size of Gas Discoveries
(For Successful Gas Wells)

$$\frac{1}{WXG_{REF}} \log\left(\frac{SZG}{SZG_{REF}}\right) = \underset{(-1.21)}{-0.0717} + \underset{(1.92)}{0.02687DD1} + \underset{(1.53)}{0.0638DD2} + \underset{(0.0255)}{0.03825DD3}$$

$$+ \underset{(1.60)}{0.1146DEPG_{-1}} + \underset{(1.21)}{0.00285}\ ((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$- \underset{(-0.95)}{0.0241}\ ((PO_{-1} + PO_{-2} + PO_{-3})/3) \qquad (32)$$

N = 107 $\qquad R^2 = 0.95 \qquad F = 295.6$

S.E. = 3.519 $\qquad$ D.W. = 1.68

where

SZG_{REF} = size of gas discoveries in the reference period immediately preceding the current period

$= (SZG_{-1} + SZG_{-2} + SZG_{-3})/3$

WXG_{REF} = index of number of successful gas wells completed in the reference period immediately preceding the current period

$= (WXG_{-1} + 2WXG_{-2} + WXG_{-3})/40$

Size of Oil Discoveries
(For Successful Gas Wells)

$$\frac{1}{WXO_{REF}} \log\left(\frac{SZO}{SZO_{REF}}\right) = \underset{(-1.10)}{-0.08228} + \underset{(1.22)}{0.02074DD1} + \underset{(0.66)}{0.00464DD2} + \underset{(0.37)}{0.00233DDC}$$

$$+ \underset{(0.35)}{0.02820DEPO_{-1}} - \underset{(-2.08)}{0.00195} ((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$+ \underset{(2.37)}{0.02932} ((PO_{-1} + PO_{-2} + PO_{-3})/3) \qquad (33)$$

N = 72 $\quad R^2 = 0.84 \quad$ F = 55.92

S.E. = 5.46 $\quad$ D.W. = 1.68

where

SZO_{REF} = size of oil discoveries in the reference period immediately preceding the current period

$= (SZO_{-1} + SZO_{-2} + SZO_{-3})/3$

WXO_{REF} = index of number of successful oil wells completed in the district in the reference period immediately preceding the current period

Since the variance of the discovery size averaged over n independent discoveries is proportional to (1/n), multiplicative weights proportional to $(WXG_{REF})^{1/2}$ were applied in estimating (32). Similarly weights proportional to $(WXO_{REF})^{1/2}$ were used in estimating (33). Using the same logic, weights proportional to the square root of total exploratory wells drilled in the reference period in estimating the following equations for the fractions of successful wells.

Fraction of Successful Gas Wells

$$\log\left(\frac{SRG}{1-SRG}\right) = \log\left(\frac{SRG_{REF}}{1-SRG_{REF}}\right) + WXG_{REF}\ [\underset{(-0.902)}{-0.04653} - \underset{(-2.60)}{0.02706DD1} - \underset{(-1.88)}{0.02502DD2}$$

$$- \underset{(-2.382)}{0.02891DD3} - \underset{(-2.21)}{0.00312}\ ((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$+ \underset{(2.14)}{0.04384}\ ((PO_{-1} + PO_{-2} + PO_{-3})/3)] \qquad \ldots\ldots \quad (34)$$

$N = 90 \qquad R^2 = 0.76 \qquad F = 55.59$

$S.E. = 4.32 \qquad D.W. = 1.61$

where

$$SRG_{REF} = ((SRG_{-1} + SRG_{-2} + SRG_{-3})/3)\ \frac{\hat{SZG}}{\hat{SZG}_{REF}}$$

Fraction of Successful Oil Wells

$$\log\left(\frac{SRO}{1-SRO}\right) = \log\left(\frac{SRO_{REF}}{1-SRO_{REF}}\right) + WXO_{REF}\ [\underset{(0.98)}{0.05521} + \underset{(1.09)}{0.02815DD1} + \underset{(0.73)}{0.02571DD2}$$

$$+ \underset{(0.69)}{0.0138DD3} + \underset{(0.80)}{0.00208}\ ((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$- \underset{(-1.27)}{0.0378}\ ((PO_{-1} + PO_{-2} + PO_{-3})/3)] \qquad \ldots\ldots \quad (35)$$

$N = 54 \qquad R^2 = 0.43 \qquad F = 2.88$

$S.E. = 3.7 \qquad D.W. = 1.48$

where

$$SRO_{REF} = ((SRO_{-1} + SRO_{-2} + SRO_{-3})/3)\ \frac{\hat{SZO}}{\hat{SZO}_{REF}}$$

The following observations can now be made about the estimated equations. First, although some of the explanatory variables are not significant at the 95% level, the signs of all of the coefficients are consistent. For example, in equation (31) expected return per exploratory well appears with a positive coefficient while expected risk, drilling costs, and the interest rate all appear with negative coefficients as expected.

Referring to the average size equations (32) and (33), the constant term is negative in both cases, which means that on the average, discovery size does decline as more successful wells are drilled into it. This is a reflection of the "sampling without replacement" or the "non-Bernoulli Urn" effect. Note also that the positive coefficients of the index of accumulated depletion DEP in the site equations are also correct, since this index decreases in size as depletion ensues. Finally, in both the size equations and success ratio equations the price variables for gas and oil appear with opposite signs, and this would be expected if we believe that there is some directionality in oil and gas drilling.

The estimated equations provide us with some important empirical results. First, the estimates of the constant terms in equations (32) and (33) can be used to compute the average rate of decline in the size of new discoveries as drilling progresses. Some simple computations will show that[1] on the average, after filtering out the effects

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[1]Consistent with the scale constant of (1/80) applied in the definitions of WXG_{REF} and WXO_{REF} in (6) and (7), the estimated constant term should be divided by 80 to give an estimate of percentage rate of decline in the size per successful well drilled in the reference period.

of other economic and geological variables, size of new gas discoveries from the next gas well drilled in a given district should be expected to drop by nearly 0.09%. Similarly the size of oil discoveries are expected to drop by 0.103% for each additional oil well drilled into the district. This is not an insignificant rate of decline considering that more than 400 gas wells and 500 oil wells have been drilled in the United States (i.e., about 20 gas wells and 25 oil wells in the "average" production district) in the last reported year (1972).

Secondly, the estimations show that as field prices increase additional drilling is done on the extensive margin. If price of natural gas is increased, the size of gas discoveries per successful well will increase (from equation (32)), while the success ratio for gas wells will decrease (from equation (34)), indicating that additional drilling is being done in regions with lower probabilities of success but higher size of gas finds. Increases in the price of oil will also result in additional drilling on the extensive margin, with the size of oil discoveries increasing and the success ratio for oil wells decreasing. In general, the net effect of moving to a more extensive margin is seen to be an increase in the discoveries per exploratory well. That is, for instance, when price of gas goes up, the average size of gas discoveries increases more than enough to compensate for the decrease in success ratio.[1]

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[1] To see this, note that the values of SRG_{REF} and SRO_{REG} go up in proportion with SZG_{REF} and SZO_{REF} when prices are increased.

Further, an increase in price of gas in the success ratio for oil wells and a decrease in the size of oil discoveries. This indicates that as gas becomes more profitable relative to oil, producers shift to more extensive exploration for gas and more intensive exploration for oil. This means that the new discoveries of oil per exploratory well drilled will probably go down, but the total oil discoveries may nevertheless increase. This is because the total exploratory drilling increases (from equation (31)) in response to the added economic incentive. Similarly, an increase in the price of oil, while resulting in a large increase in oil discoveries, will also probably result in some increase in gas discoveries, since although there is a shift towards more extensive oil drilling, the total amount of drilling has also increased so that we can expect more gas to be discovered as well.

This symmetric behavior of gas and oil discovery sizes in response may be contrasted with the empirical findings of Erickson and Spann [11]. Based on their estimations for the 1946 to 1959 period, they conclude that increases in gas price increased the average size per successful well of both gas and oil discoveries in that period. They explained this phenomenon as arising out of a situation where even potentially large gas prospects were shelved in the inventory of undrilled prospects since gas discoveries were not marketable (in the absence of pipeline connections). Over a period of time this led to the build-up of an inventory of undrilled gas prospects whose average size (in B.T.U. terms) was much larger than that of the oil prospects. When the construction of large pipeline networks began in the fifties, they were willing to pay a premium for gas in large discoveries. These two facts, combined with the lack of certainty as to whether a prospect is likely to yield gas or oil, and a positive correlation between the chance of finding a large oil discovery and that of finding a large gas discovery caused the cross-elasticity of gas price on size of oil discoveries to be positive. The negative cross-elasticity in our estimations may be interpreted as evidence that the effects of inventory of gas prospects discussed above are exhausted by the middle sixties. This must have been a direct result of the advent of an integrated network of long-distance pipelines which made natural gas just as marketable (if not more) as oil.

Alternative Estimations

Referring to the estimations in (32) and (33), it is seen that the dummy variables for Louisiana South (DD1) and Permian (DD2) appear with significantly positive signs in the two average size equations. This indicates that the average rate of decline in size per successful well drilled is somewhat lower in these two districts relative to the others. One possible reason for this might be that they are the two largest production districts and, hence, have a proportionately much larger number of reservoirs in the ground so that size does not decline with continued drilling as steeply as for smaller districts. This suggested the possibility of modifying the indices of successful wells WXG_{REF} and WXO_{REF} to reflect differences (across districts) in the total number of reservoirs in the ground. An index of the average amount of exploratory activity in the district (WXTM) was thought to be a possible surrogate. Two new indices WXG'_{REF} and WXO'_{REF} are therefore defined:

$$WXG'_{REF} = WXG_{REF}/WXTM \tag{36}$$

$$WXO'_{REF} = WXO_{REF}/WXTM \tag{37}$$

The estimations in (32) to (35) were then repeated using these new indices in place of WXG_{REF} and WXO_{REF} . The results of these estimations are presented in equations (38) to (41).

$$\begin{aligned} \frac{1}{WXG'_{REF}} \log\left(\frac{SZG}{SZG_{REF}}\right) = & -24.84 + 9.518DD1 + 14.461DD2 \\ & \;(-1.29)\quad(1.582)\quad\;(1.012) \\ & + 12.852DD3 + 29.995DEPG_{-1} \\ & \;\;(1.610)\qquad(1.377 \\ & + 0.887\ ((PG_{-1} + PG_{-2} + PG_{-3})/3) \\ & \;(1.158) \\ & - 6.052\ ((PO_{-1} + PO_{-2} + PO_{-3})/3) \\ & \;(-0.684) \end{aligned} \tag{38}$$

N = 107 $\quad$ $R^2 = 0.943$ $\quad$ F = 279.3

S.E. = 3.5594 $\quad$ D.W. = 1.67

$$\frac{1}{WXO'_{REF}} \log\left(\frac{SZO}{SZO_{REF}}\right) = \underset{(-1.715)}{-37.78} + \underset{(1.566)}{9.724DD1} + \underset{(0.305)}{0.935DD2} + \underset{(0.240)}{0.621DD3}$$

$$+ \underset{(0.705)}{11.179}\ DEPO_{-1}$$

$$- \underset{(-2.258)}{0.865}\ ((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$+ \underset{(+2.319)}{13.96710}\ ((PO_{-1} + PO_{-2} + PO_{-3})/3) \tag{39}$$

N = 72 $\quad R^2 = 0.841 \quad F = 57.466$

S.E. = 5.48 $\quad$ D.W. = 1.51

$$\log\left(\frac{SRG}{1-SRG}\right) = \log\left(\frac{SRG_{REF}}{1-SRG_{REF}}\right) + WXG'_{REF} \cdot [\underset{(1.868)}{25.731} - \underset{(-1.030)}{6.105DD1}$$

$$- \underset{(-0.756)}{6.585DD2} - \underset{(-1.512)}{6.621DD3}$$

$$- \underset{(-1.20)}{0.677}\ ((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$- \underset{(-0.367)}{1.316}\ ((PO_{-1} + PO_{-2} + PO_{-3})/3)] \tag{40}$$

N = 90 $\quad R^2 = 0.72 \quad F = 45.67$

S.E. = 4.48 $\quad$ D.W. = 1.64

$$\log\left(\frac{SRO}{1-SRO}\right) = \log\left(\frac{SRO_{REF}}{1-SRO_{REF}}\right) + WXO'_{REF}\ [\underset{(1.118)}{28.043} + \underset{(0.969)}{14.339}DD1$$

$$+ \underset{(0.505)}{8.765}DD2 + \underset{(0.370)}{3.249}DD3$$

$$+ \underset{(0.717)}{0.750}\ ((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$- \underset{(-1.341)}{16.97}\ ((PO_{-1} + PO_{-2} + PO_{-3})/3)] \qquad (41)$$

$N = 54$ $\quad R^2 = 0.38$ $\quad F = 2.67$

S.E. = 3.654 $\quad$ D.W. = 1.43

The results of these alternative estimations are not satisfactory. Although the signs of the various coefficients are in general the same as for the first set of estimations (except in the case of coefficient of oil price in (40), their statistical significance is much lower. This leads us to the conclusion that the heterogeneity among districts with regard to the number of reservoirs is not very large and can be adequately taken account of by the geological dummies of equations (32) to (35). The results of these alternative estimations are therefore rejected in favor of those in (32) to (35).

3.6.2 Extensions of Natural Gas and Oil

As we saw in Section 2.11, we would expect extensions of both natural gas and oil to depend on lagged discoveries and the number of exploratory wells drilled in the previous years. The equations implied by (28) of Chapter II were estimated in linear form using these explanatory variables, and the results are shown below.

Natural Gas Extensions

$$XG = \underset{(-0.34)}{-38213} + \underset{(2.72)}{1.1307x10^6 DD1} + \underset{(6.18)}{1.9595x10^6 DD2} + \underset{(0.11)}{16080.9DD3} + \underset{(2.38)}{0.2942DG_{-1}}$$

$$+ \underset{(2.17)}{440.2WXT_{-1}} \tag{42}$$

N = 144 $\quad R^2 = 0.44 \quad$ F = 22.05

S.E. = $2.87x10^5$ $\quad$ D.W. = 1.84

Oil Extensions

$$XO = \underset{(0.79)}{4096.05} + \underset{(10.31)}{1.7852x10^5 DD1} + \underset{(3.06)}{44092.7DD2} - \underset{(-0.81)}{5192.72DD3} + \underset{(+0.93)}{0.09243DO_{-1}}$$

$$+ \underset{(2.86)}{33.928WXT_{-1}} \tag{43}$$

N = 120 $\quad R^2 = 0.69 \quad$ F = 50.80

S.E. = $1.9x10^4$ $\quad$ D.W. = 1.90

Alternative forms for these equations were estimated to determine whether the depletion variables and prices would offer any additional explanatory power. Alternative regression equations for extensions of natural gas are shown below in equation (44), which includes the index of accumulated depletion DEP and the year-end reserves YG, and equation (45), which includes the gas price.

$$XG = 1.85x10^5 + 2.15x10^6 DD1 + 2.16x10^6 DD2 + 1.69x10^5 DD3$$
$$(0.72) \quad (2.40) \quad (5.81) \quad (0.91)$$

$$+ 0.315PG_{-1} + 463.75WXT_{-1} - 2.7x10^5 DEPG_{-1} - 0.015YG_{-1} \quad (44)$$
$$(2.64) \quad (2.41) \quad (-0.74) \quad (-1.25)$$

$N = 144$ $\quad R^2 = 0.45$ $\quad F = 18.2$

S.E. $= 2.73x10^5$ $\quad$ D.W. $= 1.85$

$$XG = 2.02x10^6 + 1.18x10^6 + 1.92x10^6 DD2 - 6412.0DD3$$
$$(0.64) \quad (2.94) \quad (5.76) \quad (-0.04)$$

$$+ 0.289DG_{-1} + 409.0WXT_{-1} - 1.04x10^5 DEPG_{-1} - 8490.0PG_{-1} \quad (45)$$
$$(2.41) \quad (2.06) \quad (-0.30) \quad (-0.87)$$

$N = 144$ $\quad R^2 = 0.46$ $\quad F = 17.5$

S.E. $= 2.8x10^5$ $\quad$ D.W. $= 1.82$

Note that both the depletion variable and the price variable are statistically insignificant and appear with the wrong signs. The year-end reserves also has the unexpected negative sign.

Alternative estimations for extensions of oil reserves are shown in equations (46) and (47) below.

$$
\begin{array}{lllll}
XO = & -15853.0 & + 1.56\text{x}10^{5}DD1 & + 2989.6DD2 & - 3593.9DD3 \\
 & (-1.24) & (8.58) & (0.14) & (-0.65) \\
 & + 0.105DO_{-1} & 30.52WXT_{-1} & 21447.0DEPO_{-1} & + 0.0065YO_{-1} \\
 & (1.02) & (2.89) & (1.31) & (2.44)
\end{array}
\qquad (46)
$$

$N = 120 \qquad R^2 = 0.76 \qquad F = 51.4$

$S.E. = 1.88\text{x}10^{4} \qquad D.W. = 1.81$

$$
\begin{array}{lllll}
XO = & 33743.0 & + 1.85\text{x}10^{5}DD1 & + 45438.0DD2 & - 2908.3DD3 \\
 & (1.38) & (10.78) & (3.45) & (-0.48) \\
 & + 0.098DO_{-1} & + 26.72WXT_{-1} & + 8065.0DEPO_{-1} & - 10748.0PO_{-1} \\
 & (0.95) & (2.30) & (0.49) & (-1.68)
\end{array}
\qquad (47)
$$

$N = 120 \qquad R^2 = 0.74 \qquad F = 44.8$

$S.E. = 1.9\text{x}10^{4} \qquad D.W. = 1.84$

We see that the price variable appears with the wrong sign, and the depletion variable is insignificant.

3.6.3 Revisions of Natural Gas and Oil Reserves

As we saw in section 2.11, revisions of natural gas and oil reserves tend to be rather erratic and difficult to explain and predict in an econometric framework. Equations are estimated for these variables according to the specification in (29) of Chapter II. We expect that the explanatory variables would include past year-end reserves, the number of exploratory wells drilled in the previous year, changes in production, and the depletion index. When these equations were actually estimated, it was found that the number of exploratory wells drilled did offer any explanatory power, although all of the other variables did. The final regression equations, again estimated in linear form, are shown below. No dummy variables are used in these estimations because it was felt that there is no characteristic size for revisions in a particular district.

Revisions of Natural Gas Reserves

$$\underset{(-2.42)}{RG = -712950} + \underset{(3.21)}{0.02007YG_{-1}} + \underset{(0.52)}{0.3142\Delta(QG_{-1})} + \underset{(2.07)}{930610DEPG_{-1}} \tag{48}$$

$N = 144$ $\qquad R^2 = 0.14$ $\qquad F = 7.3$

$\qquad S.E. = 5x10^5$ $\qquad D.W. = 1.98$

Revisions of Oil Reserves

$$\underset{(-2.38)}{RO = -133450} + \underset{(5.80)}{0.0483YO_{-1}} + \underset{(2.92)}{3.501\Delta(QO_{-1})} + \underset{(2.33)}{188210DEPO_{-1}} \tag{49}$$

$N = 72$ $\qquad R^2 = 0.56$ $\qquad F = 28.3$

$\qquad S.E. = 1.02x10^5$ $\qquad D.W. = 1.75$

Note that the equation for revisions of natural gas reserves has a rather poor statistical fit, with an R^2 of only 0.14. The results of (48) could not be improved upon. We must simply recognize that natural gas revisions are likely to provide a certain amount of noise in our simulation results.

CHAPTER IV

SIMULATION OF THE MODEL

The model estimated in Chapter III will now be tested for predictive validity over a historical period of simulation and later used to predict the response over time of the supply of natural gas and oil reserves under alternative assumptions regarding the future economic and regulatory environments. The predictions will then be used in conjunction with existing models of production supplied out of known reserves and wholesale demand of natural gas and oil to study the behavior of these markets under the various assumptions. The results obtained are very relevant to the current controversy over the field price regulation of natural gas as well as the feasibility of "Project Independence" or complete energy self-sufficiency of the United States by the end of the decade.

Before we can proceed to these applications, certain additions must be made to the model to facilitate policy simulations.

4.1 Additions to the Supply Model for Simulation Purposes

The nine estimated equations of Chapter III can be used to forecast additions to proved reserves of natural gas and oil under alternative assumptions. These additions modify the estimates of total proved reserves of gas and oil, i.e., reserves which can be committed by the producers for sale to oil refineries or natural gas pipeline companies. The accumulated amounts of proved reserves in the producing reservoirs limit the quantities of oil and natural gas that can be supplied to buyers as "production." The annual production supplied out of the reserves is restricted (sometimes purely by technical efficiency considerations and other times enforced by the various state regulatory agencies) to some fixed percentage of proved reserves. Faster rates may reduce the economic value of the remaining reserves by "channelling" or sealing off parts of the reservoir. But up to that limit, more production in a given period can take place, although the marginal costs of such incremental production will be rising. This might be justified if prices offered are higher. Thus, for both technical and economic reasons, the supply of production out of reserves will be greater the larger the total volume of proved reserves in the ground and the higher the prices offered by the buyers at the field. Production supply should therefore be modeled as a function of the well-head price and the quantity of proved reserves.

Such a model has been constructed and verified by MacAvoy and Pindyck [30] for the case of natural gas. We will use this model in conjunction with the model for supply of proved reserves for purposes of simulation.[1] The task of building an analogous model for crude oil production is a much harder one. It is complicated by the fact that state regulatory agencies (the most well-known of them being the Texas Railroad Commission) have been periodically changing their production

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[1] For more details of the model for production out of reserves, see MacAvoy and Pindyck [29 ,30].

restrictions, not for reasons of technical efficiency, but to maintain a domestic price of crude oil that is most advantageous to their producing states. State-imposed restrictions rather than other economic considerations have often been the factor limiting oil production. In the absence of a more satisfactory model in the literature to explain supply of oil production, it will be assumed that production in the future will be a constant fraction of the proved reserves. To reflect the differences among the prevailing regulatory conditions in the different states, the inverse of the latest year's reserves-to-production ratio in the production district is used as an estimate of this fraction in the future years.[1]

Secondly, a separate "sub-model" developed by Sussman [39] is added to explain natural gas reserves additions and the production of gas from reserves in off-shore Louisiana. Certain off-shore data that is needed for the exploratory and discovery equations of Chapter III is not available for the offshore region (e.g., successful exploratory wells). Furthermore, offshore exploration and production depend partly on variables unique to this region (e.g., the number of acres leased out by the Federal Government and the number of off-shore drilling rigs available). Thus, using a separate model for off-shore region not only improves the specification of the model, but permits us to examine the

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[1]When simulating over a historical period of simulation, this assumption is removed and the actually observed values of crude oil production is used as an exogeneous input to the model for reserves additions.

the effect of an additional policy variable; namely, the acreage of off-shore lands leased out every year to explorers. The Sussman model predicts the number of wildcats drilled in offshore land and the new discoveries of natural gas for wildcats which together yield an estimate of new gas discoveries. Extensions and revisions of natural gas are then modeled as functions of lagged discoveries and field wells.[1,2]

---

[1]For a more detailed exposition of this sub-model, see P. N. Sussman, "Supply and Production of Offshore Gas Under Alternative Leasing Policies," Master's thesis submitted to Sloan School of Management, M.I.T., June, 1974.

[2]The Sussman model does not predict the addition to reserves of oil from off-shore because of non-availability of some of the required data in case of oil. However, oil tends to occur in reservoirs at much smaller depths than natural gas. The characteristics of an off-shore reservoir are much closer to those in the adjacent on-shore region if it it happens to be an oil reservoir rather than a gas reservoir. Hence, the estimates obtained for the discoveries of oil per exploratory well in on-shore Louisiana South are assumed to hold for the off-shore district as well.

The number of exploratory wells in the off-shore region are then estimated as a constant factor times the number of wildcats as estimated by the Sussman model. The value of the multiplicative factor is estimated on the basis of the most recent historical data. Finally, the new discoveries of oil from the entire Louisiana South district (on-shore and off-shore) are computed by multiplying the total exploratory wells in the district with the average size and fraction of successful wells.

Extensions and revisions are then estimated using (42) and (48) of Chapter III as in the case of other districts. The procedure admittedly involves an approximation, but fared quite satisfactorily when applied over a historical period simulation. In any case, oil discoveries are much less significant than gas discoveries in the off-shore region.

Finally, two accounting equations of the following form (one each for natural gas and oil) are added to close the model for reserves and production:

$$\begin{pmatrix}\text{Year-end}\\ \text{Reserves}\end{pmatrix}_t = \begin{pmatrix}\text{Year-end}\\ \text{Reserves}\end{pmatrix}_{t-1} + \begin{pmatrix}\text{New}\\ \text{Discoveries}\end{pmatrix}_t + \left(\text{Extensions}\right)_t + \left(\text{Revisions}\right)_t + \left(\text{Production}\right)_t$$

4.2 Simulation of the Model Over An Historical Time Period

The model is first used to predict the response of reserves and production supply over an historic period of time. This will help us judge the predictive validity of the model and apply suitable corrections if necessary. For instance, if this simulation revealed an increasingly upward bias in discoveries, this can be taken into account when predictions for the future are interpreted.

Tables 4.1 to 4.7 report the results of the simulation over the period 1967-1972. In addition to the simulated, actual values and the errors for each variable, the mean and root-mean-square (RMS) simulation errors are presented in these tables.

The predicted number of total exploratory wells is quite close to the actual values with a mean error of about 5% of the mean number of wells over the period (see Table 5.1). The mean errors of successful oil and gas wells are approximately 11.5% and 20% of the corresponding averages. These may appear relatively large, but as we have seen earlier, some amount of chance variation in the fraction of success and average size of discoveries must be expected due to geological uncertainty.

Table 4.1: Comparison of Actual and Simulated Number of Total Exploratory Wells, Gas Wells and Oil Wells, 1967-1972

Year	(1) Simulated Total Wells	(2) Actual Total Wells	(3) Wells Error (1) - (2)	(4) Simulated Successful Gas Well	(5) Actual Successful Gas Well	(6) Gas Wells Error (4) - (5)	(7) Simulated Successful Oil Wells	(8) Actual Successful Oil Wells	(9) Oil Wells Error (7) - (8)
1967	7964	6754	1211	361	316	45	813	858	- 45
1968	7760	6621	1139	349	263	86	855	672	183
1969	6748	7113	- 365	284	367	- 83	588	883	- 295
1970	5759	5590	169	236	369	- 133	520	622	- 102
1971	4665	4990	- 325	194	318	- 124	395	499	- 104
1972	5415	5163	252	218	422	- 204	422	533	- 111

MEAN TOTAL WELLS ERROR = 347	MEAN SUCCESSFUL GAS WELLS ERROR = -69	MEAN SUCCESSFUL OIL WELLS ERROR = -79
RMS ERROR = 718	RMS ERROR = 123	RMS ERROR = 161
MEAN ACTUAL = 6038	MEAN ACTUAL = 343	MEAN ACTUAL = 678

Table 4.2: Comparison of Actual and Simulated New Discoveries of Natural Gas and Oil, 1967-1972

Year	(1) Simulated Gas Discoveries (Trillions cu.ft.)	(2) Actual Gas Discoveries (Trillions cu.ft.)	(3) Gas Discoveries Error (1) - (2)	(4) Simulated Oil Discoveries (Billions of brls.)	(5) Actual Oil Discoveries (Billions of brls.)	(6) Oil Discoveries Error (4) - (5)
1967	5.5	5.2	0.3	0.34	0.28	0.06
1968	7.5	2.7	4.8	0.36	0.27	0.09
1969	6.1	3.7	2.4	0.19	0.24	- 0.05
1970	4.8	5.6	- 0.8	0.21	0.31	- 0.10
1971	5.5	5.9	- 0.4	0.17	0.14	+ 0.03
1972	6.9	4.7	2.2	0.18	0.27	- 0.09

MEAN GAS DISCOVERIES ERROR = 1.4

RMS ERROR = 2.4

MEAN ACTUAL = 4.6

MEAN OIL DISCOVERIES ERROR = -0.01

RMS ERROR = 0.08

MEAN ACTUAL = 0.25

Table 4.3: Comparison of Actual and Simulated Extensions of Natural Gas and Oil Discoveries, 1967-1972

Year	(1) Simulated Gas Extensions (Trillions cu.ft.)	(2) Actual Gas Extensions (Trillions cu.ft.)	(3) Gas Extensions Error (1) - (2)	(4) Simulated Oil Extensions (Trillions cu.ft.)	(5) Actual Oil Extensions (Billions of brls.)	(6) Oil Extensions Error (4) - (5)
1967	10.0	10.9	- 0.9	0.55	0.59	- 0.04
1968	10.0	8.0	0.2	0.57	0.58	- 0.01
1969	10.1	5.2	4.9	0.56	0.58	- 0.02
1970	9.1	7.5	1.6	0.51	0.57	- 0.06
1971	8.0	5.6	2.4	0.48	0.38	0.10
1972	7.7	6.0	1.7	0.44	0.41	0.03

MEAN GAS EXTENSIONS ERROR = 2.0

RMS ERROR = 2.6

MEAN ACTUAL = 7.2

MEAN OIL EXTENSIONS ERROR = 0.0

RMS ERROR = 0.05

MEAN ACTUAL = 0.52

Table 4.4: Comparison of Actual and Simulated Revisions of Natural Gas and Oil Reserves, 1967-1972

Year	(1) Simulated Gas Revisions (Trillions cu.ft.)	(2) Actual Gas Revisions (Trillions cu.ft.)	(3) Gas Revisions Error (1) - (2)	(4) Simulated Oil Revisions (Billions of brls.)	(5) Actual Oil Revisions (Billions of brls.)	(6) Oil Revisions Error (4) - (5)
1967	2.0	4.4	- 2.4	1.96	1.82	0.14
1968	1.7	1.0	0.7	1.34	1.27	0.07
1969	1.5	- 0.9	2.4	1.39	1.21	0.18
1970	1.2	- 2.1	3.3	1.14	1.87	- 0.73
1971	0.9	- 1.0	1.9	1.05	1.51	- 0.46
1972	0.6	- 1.9	2.5	0.91	0.66	0.25

MEAN GAS REVISIONS ERROR = 1.4

RMS ERROR = 2.3

MEAN ACTUAL = -0.1

MEAN OIL REVISIONS ERROR = -0.09

RMS ERROR = 0.38

MEAN ACTUAL = 1.39

Table 4.5: Comparison of Actual and Simulated Additions to Proved Reserves of Natural Gas and Oil, 1967-1972

Year	(1) Simulated Gas Additions to Reserves (Trillions cu.ft.)	(2) Actual Gas Additions to Reserves (Trillions cu.ft.)	(3) Gas Additions to Reserves Error (1) - (2)	(4) Simulated Oil Additions to Reserves (Billion brls.)	(5) Actual Oil Additions to Reserves (Billion brls.)	(6) Oil Additions to Reserves Error (4) - (5)
1967	17.6	20.6	- 3.0	2.85	2.69	0.16
1968	19.2	11.6	7.6	2.27	2.11	0.16
1969	17.8	8.0	9.8	2.14	2.03	0.11
1970	15.1	11.0	4.1	1.87	2.76	- 0.89
1971	14.4	10.5	3.9	1.70	2.04	- 0.34
1972	15.3	8.8	6.5	1.53	1.35	0.18

MEAN GAS ADDITIONS TO RESERVES ERROR = 4.8

RMS ERROR = 6.3

MEAN ACTUAL = 11.8

MEAN OIL ADDITIONS TO RESERVES ERROR = -0.10

RMS ERROR = 0.41

MEAN ACTUAL = 2.16

Table 4.6: Comparison of Actual and Simulated Year-end Reserves of Natural Gas and Oil, 1967-1972

Year	(1) Simulated Gas Reserves (Trillions cu.ft.)	(2) Actual Gas Reserves (Trillions cu.ft.)	(3) Gas Reserves Error (1) - (2)	(4) Simulated Oil Reserves (Billions brls.)	(5) Actual Oil Reserves (Billions brls.)	(6) Oil Reserves Error (4) - (5)
1967	285	289	- 4	29.5	24.0	5.5
1968	285	282	3	29.2	28.4	0.8
1969	282	269	13	28.9	27.5	1.4
1970	276	259	17	28.3	27.2	1.1
1971	269	246	23	27.7	26.3	1.4
1972	261	234	27	26.9	24.6	2.3

MEAN GAS RESERVES ERROR = 13

RMS ERROR = 17

MEAN ACTUAL = 263

MEAN OIL RESERVES ERROR = 2.1

RMS ERROR = 2.6

MEAN ACTUAL 26.3

Simulated gas wells tend to be lower than their actual numbers towards the end of the simulation period, indicating a greater predicted proportion of extensive drilling than was actually observed. However, the structure of the model is such that errors in the success fraction arising from observational errors in economic variables are in part cancelled by corresponding errors in the average size of discovery, thus yielding an estimate of new discoveries that is less sensitive to random observational errors. For example, if the observed gas price is larger than the true price to which producers react, an unduly large shift towards extensive drilling will be predicted, i.e., the predicted fraction of successful gas wells will be too low and the predicted average size of discovery too high. The percentage errors in the predicted new discoveries will probably be less than either of the above two errors. This is what we see from the simulation results for total new discoveries (Table 4.2). The simulated new discoveries of natural gas do not reveal any significant under-predictions towards the end of the period. The predicted new discoveries of gas in 1968 and 1969 are actually too high, but this appears to be due to a rather unusual drop in discoveries that cannot be explained by smoothly varying economic or geological variables.

Note that the model tracks the extensions and revisions of oil much more accurately than those of natural gas over the historic period of simulation (see Tables 4.3 and 4.4). It is possible to explain this finding in terms of producers' anticipations of future natural gas prices. By about 1968, the first signs of a natural gas shortage to consumers began to show. Indication of a disequilibrium condition in the market for reserves led many producing companies to anticipate a review and upward revision of the natural gas ceiling prices.

A natural reaction of a producing company to this set of circumstances would be to search less keenly for extensions as well as to adopt somewhat more conservative procedures for estimating the sizes of proved reserves. This does not necessarily imply a deliberate attempt by the producers to mislead the public. For example, since proved reserves are by definition the amount of natural gas that can profitably be produced from a reservoir "at the existing economic and operating conditions" [3], producing companies facing restrictive price regulation can quite legitimately base their estimates of proved recoverable reserves on the prevailing artificially low prices. Thus, part of the explanation behind the overly conservative estimates by the industry of natural gas extensions and revisions might be the uncertainties generated by the regulatory process itself. Since the definitions of the different categories of reserves additions are ambiguous, other possibilities of misclassifying reserves present themselves as well.

In any case, if it is true that industry estimates of extensions and revisions tend to be more conservative under a restrictive regulatory policy, we would expect these categories of reserves additions to increase more than proportionately (relative to new discoveries) if and when regulation is liberalized.

The predicted supplies of natural gas production for the historical period are shown in Table 4.7. Although total reserves additions (in Table 4.5) of natural gas are somewhat overestimated by the model, no significant over-prediction of production supply is observed. This is

Table 4.7: Comparison of Actual and Simulated Supply of Production of Natural Gas, 1967-1972

Year	(1) New Contract Field Prices (Cents/Mcf.)	(2) Simulated Production Supply (Trillions of cu.ft.)	(3) Actual Production (Trillions of cu.ft.)	(4) Supply Error [(1) - (3)]
1967	17.75	18.9	18.9	0.0
1968	18.17	20.1	19.9	0.2
1969	19.04	20.9	21.3	- 0.4
1970	21.79	21.8	22.6	- 0.8
1971	24.68	22.8	22.8	0.0
1972	31.37	23.6	23.3	0.3

MEAN SUPPLY ERROR = -1.02

RMS SUPPLY ERROR = 0.39

MEAN ACTUAL PRODUCTION = 21.5

understandable because production supply is a function of year-end reserves. There are long lags built into the process of development; hence, a percentage change in reserves additions is fully translated into a corresponding change in production supply only after several years.

Judged on the whole, the results of the historical simulation are quite satisfactory. Although the predicted additions to reserves of natural gas do not track the actual values as closely as those of oil, the deviations can be explained in terms of the producers' reaction to regulatory uncertainties.

Finally, results of an additional "experiment" conducted by MacAvoy and Pindyck[1] for the historical period (1967-1972) are of some interest in evaluating the behavior of reserves additions in the past. They used the supply model to evaluate the impact of the restrictive regulatory policies during 1967-1972 on reserves additions of natural gas and compared it with the reserves additions that would have been achieved in the absence of field price regulation. The latter condition was simulated by using hypothetical "unregulated prices," chosen such that a reserves to production ratio of 15 to 1 (the lowest ratio actually experienced in the early and middle 1960's) is maintained.[2] The results

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[1]See Chapter 5 of [30] for more detail.

[2]If it can be assumed that demands for reserve backing by final consumers was constant throughout the decade, this ratio is the lowest in keeping with equilibrium of demand and supplies of <u>reserves</u> as well as <u>production</u> throughout the period.

of these simulations are shown in Table 4.8. The simulated total additions to reserves, at regulated prices on new contracts ranging from 17 to 31 cents per Mcf, declined over the period from 17 trillion cubic feet in 1967 to 15 trillion cubic feet in 1972 (with a low of 14 in 1971). In contrast, the hypothetical "unregulated" prices would have maintained reserve additions at 16 to 19 trillion cubic feet. This illustrates clearly the process through which the field price regulation of natural gas led to progressively lower reserves-to-production ratios (see Fig. 4.9).

4.3 Simulation of Supply Response to Future Economic and Regulatory Environments

The chief utility of the model developed in this thesis is to help evaluate relevant future policy alternatives. The model can be used to study the response of exploratory activity and the resulting additions to reserves to alternative regulatory policies and economic environments. Combined with models of demand for oil and natural gas, it can help us analyze the behavior of oil and gas markets under various assumptions.

The current controversy over what natural gas regulatory policy is to be used over the rest of the decade provides an ideal opportunity for such an application. It is widely believed that low wellhead ceiling prices over the past decade have led to the beginning of a shortage in natural gas production. If the demand for gas grows as expected during the 1970's, and if ceiling prices remain low as a result of restrictive regulatory policy, this shortage could grow significantly.

Table 4.8: Simulated Additions to Reserves of Natural Gas Under Actual and Hypothetical Ceiling Prices, 1967-1972

Year	(1) New Contract Field Prices (Cents/Mcf.)	(2) Total Additions to Reserves (Trillions of cu.ft.)	(3) Hypothetical "Unregulated" New Contract Field Prices (Cents/Mcf.)	(4) Hypothetical "Unregulated" Total Additions to Reserves (Trillions of cu.ft.)
1967	17.7	17.6	23.8	17.6
1968	18.0	19.2	30.2	19.6
1969	18.9	17.8	36.6	18.7
1970	21.6	15.1	43.0	16.3
1971	24.7	14.4	49.7	15.9
1972	31.4	15.3	56.2	16.8

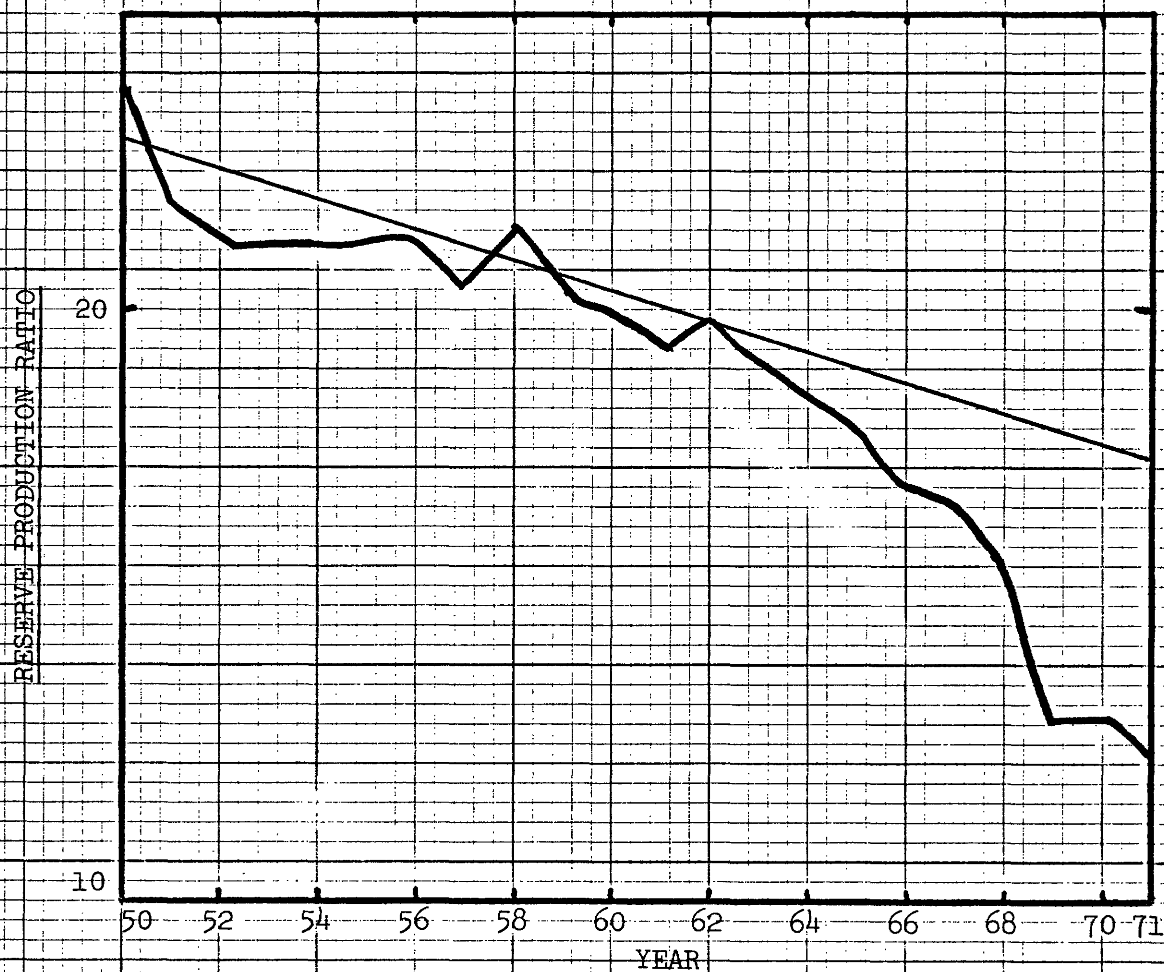

FIG. 4.1: RATIO OF NATURAL GAS RESERVES TO PRODUCTION IN THE UNITED STATES FROM 1950 TO 1971

Source: American Gas Association, "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1971," vol. 26 (Arlington, Va., May 1972).

The policy question we wish to answer is whether or not shortages of natural gas can be ameliorated by suitably increasing the field prices in the future. Closely related to this are the questions posed by "Project Independence": What prices of domestic fuels would be necessary to generate enough additional fossil fuels to satisfy demands in domestic energy markets by 1980? Is the current international oil price set by the oil-producing countries high enough to extract domestically available oil and gas reserves efficiently? Or, does it require use of some tariffs or quotas?

The model developed here of the supply of oil and natural gas reserves is used in conjunction with an existing model of the other sectors of the natural gas industry to address some of these questions.

4.3.1 Regulatory Policy Alternatives for Natural Gas

A large number of alternative proposals have been made under the general heading of "deregulation of field prices" of natural gas. There is hardly a unanimity among experts as to whether deregulation is a good idea and, if so, how and over what time period it should occur. Suggested courses of action have included a complete and instantaneous deregulation at one extreme and a virtual price freeze (except for passing on increases in costs of production) on the other.

Proposals for deregulation are based on the argument that FPC rulings have restricted price increases, even though cost increases have reduced supplies at the same time and demand has increased. Thus, decontrol would allow higher prices which would clear the market of excess demand and would be an inducement to take on increased exploration and, hence, add to reserve supply. Most of the practicable deregulation proposals contain a provision for some national ceiling imposed to avoid adverse inflationary consequences.[1] The White House proposal--outlined in President Nixon's Energy Message of April 1973--falls under this category of gradual deregulation.

At the other extreme are the proposals to put stronger controls on well-head contracts and allow prices on the basis of historical average costs of exploration and development. Future increases in prices would be limited to increases in average costs of production. The draft bills proposed by the staff of the Senate Interior and Commerce Committee are of this type. The argument behind these proposals seems to be that producers have been holding back reserves in anticipation of relaxed price controls--and tighter controls would cause them to see the futility of holding back.

There are many proposals for regulation that lie somewhere between these two categories of proposals. The rulings of the Federal Power Commission in recent years (1970 to 1974) have allowed price increases to follow one such "middle course." They are based on a philosophy of continued regulatory controls of the field prices while allowing price increases somewhat higher than the increase in average costs.

MacAvoy and Pindyck [30] have characterized these three categories of proposals by specific alternatives called "Cost of Service" regulation (most restrictive), "Phased Deregulation" (least restrictive) and "Status Quo" regulation (a middle course such as the current FPC policy).

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[1]The most frequently mentioned ceiling is one that limits the increase on the level of wholesale price of gas by 1980 to 10%.

These three specific alternatives are investigated by inserting the proposed policies into the econometric model developed in this thesis. To examine how the supplies of reserves interact with the other sectors of the natural gas and oil industry, the policy simulations are carried out after combining the model with the MacAvoy-Pindyck [30] model which explains the production supply out of reserves, the pipeline mark-ups and the wholesale demand for natural gas.

4.3.2 Values of Exogeneous Variables

The new contract well-head prices of natural gas are assumed to be increased by 5¢ in each of the years 1973 and 1974. These estimates reflect the decisions of the Federal Power Commission in the last two years. Under "Cost of Service" regulation, price increases on new contracts in the subsequent years are limited to 3¢ per Mcf per annum (in each of the production districts), corresponding to the estimated rate of growth of average total costs per Mcf in the last four years. The "Status Quo" regulation alternative consists of the Federal Power Commission continuing its 1970-1974 policy of allowing price increases of up to 5¢ per Mcf per year. The upper bound of 5¢ price increment is used for the simulation of this alternative. The "Phased Deregulation" alternative seeks to allow price increases that would approximate market-clearing prices toward the end of the decade. Under this policy, it is assumed that a 25¢ per Mcf increase will be allowed in 1975 on new contract prices followed by annual increments of 5¢ per Mcf until 1980. Table 4.9(a) summarizes the U.S. averages of the new

Table 4.9(a): New Contract Prices of Natural Gas at the Well-head Under Alternative Regulatory Policies (in Cents/Mcf.)*

Year	Cost of Service	Status Quo	Phased Deregulation
1972	31.6593	31.6593	31.6593
1973	34.6665	34.6665	34.6665
1974	39.7461	39.7461	39.7461
1975	42.787	44.7769	64.675
1976	45.8663	49.845	69.7266
1977	48.9452	54.9127	74.8014
1978	52.0439	60.0079	79.9566
1979	55.1431	65.1115	85.1464
1980	58.2327	70.2117	90.3358

Table 4.9(b): Well-head Prices of Crude Oil Under Alternative Oil Price Scenarios, $/Barrel (in equivalent 1974 Dollars)

Year	"Low"	"Medium"	"High"
1974	6.50	6.50	6.50
1975	6.25	6.50	6.65
1976	6.00	6.50	6.80
1977	5.75	6.50	6.95
1978	5.50	6.50	7.10
1979	5.25	6.50	7.30
1980	5.00	6.50	7.50

*Averages for the United States.

contract prices under the three alternative regulatory policies.[1]

Well-head oil prices are assumed to stay constant in real terms at the \$6.50/barrel price observed in 1974, i.e., future price increases in oil are expected to exactly match the inflation index. This corresponds to the scenario of "medium" oil prices shown in Table 4.9(b). Based on the Data Resources Quarterly Econometric Model forecast for the period 1972-1980, the G.N.P. per capita is expected to grow at 4.2% in real terms. The rate of inflation is assumed to be 6.5% per annum as forecasted by the Thurow-Ripley Long Term Econometric Model.

It is assumed that the Federal Government will follow a policy of leasing 2 million acres of off-shore lands every year until 1980.[2]

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[1] Prices in the individual production districts are weighted by the respective amounts of production to compute this U.S. average. These figures are therefore obtained as part of the output of the simulation output.

[2] The Department of the Interior is actually considering leasing much larger acreages of off-shore lands every year in an effort to encourage exploration rapidly. A figure of 3 to 10 million acres per year is mentioned in this respect. However, the off-shore drilling activity is limited by the available number of drilling rigs. It is believed on the basis of the current industry capacity and the lag times required to build the rigs that a 2 million acres leasing policy would reflect more accurately the maximum feasible amount of off-shore exploration in the next five or six years.

The demand side of the MacAvoy-Pindyck model requires exogeneous inputs of other economic variables. The most important of them are population growth, which is assumed to remain constant at 1.1 percent per annum, the value added in manufacturing which is assumed to grow at 4.2% per annum and capital additions which are also projected to grow at 4.2% per year.

4.3.3 Results of the Simulation of Alternative Regulatory Policies and Economic Environments: Natural Gas

Tables 4.10 to 4.15 show the forecasts obtained from the simulations of the three alternative regulatory policies. Note that the results of the three policies do not start to deviate from each other until 1976 because the assumed values of exogeneous variables in 1973 and 1974 are identical for the three policies. In addition, there is a one-year lag before exploration and discoveries respond to changes in exogeneous variables.

Let us first consider the impact of the alternative policies on supply of natural gas reserves and production. These are shown in Tables 4.10 to 4.12. The most restrictive regulation represented by "Cost of Service" (Table 4.10) is expected to increase new discoveries rather slowly from 10 trillion cubic feet in 1973 to approximately 15 trillion cubic feet in 1980. Much of the increased exploratory activity responsible for this increase is probably attributable to the relatively high oil prices. Total additions to reserves would also grow slowly, but they are in the range of 20 to 25 trillion cubic feet per year. Production supplied out of the reserves, however, would increase

Table 4.10: Simulated Supply of Natural Gas Reserves and Production Under "Cost of Service" Regulation (using "medium" oil prices)

Year	New Contract Field Price (Continental U.S.) (Cents per Mcf.)	New Discoveries (Continental U.S.) (Trillions of cu.ft.)	Total Additions to Reserves (Continental U.S.) (Trillions of cu.ft.)	Total Reserves (Continental U.S.) (Trillions of cu.ft.)	Supply of Production (Continental U.S.) (Trillions of cu.ft.)	Demands for Production (Continental U.S.) (Trillions of cu.ft.)	Excess Demand for Production (Continental U.S.) (Trillions of cu.ft.)
1972	31.6	4.7	8.8	233.4	23.3	23.4	0.1
1973	34.6	10.1	17.5	228.3	23.7	24.2	0.5
1974	39.7	10.0	19.0	224.0	24.5	26.2	1.6
1975	42.7	12.8	21.6	221.7	25.3	28.7	3.4
1976	45.8	14.2	23.6	220.7	26.1	31.2	5.1
1977	48.9	15.6	25.3	220.8	26.9	33.7	6.7
1978	52.0	16.4	26.5	221.3	27.9	36.1	8.1
1979	55.1	15.7	26.1	220.5	29.0	38.5	9.5
1980	58.2	14.3	24.5	217.2	30.2	41.0	10.8

Table 4.11: Simulated Supply of Natural Gas Reserves and Production Under "Status Quo" Regulation (using "medium" oil prices)

Year	New Contract Field Price (Continental U.S.) (Cents per Mcf.)	New Discoveries (Continental U.S.) (Trillions of cu.ft.)	Total Additions to Reserves (Continental U.S.) (Trillions of cu.ft.)	Total Reserves (Continental U.S.) (Trillions of cu.ft.)	Supply of Production (Continental U.S.) (Trillions of cu.ft.)	Demands for Production (Continental U.S.) (Trillions of cu.ft.)	Excess Demand for Production (Continental U.S.) (Trillions of cu.ft.)
1972	31.6	4.7	8.8	233.4	23.3	23.4	0.1
1973	34.6	10.1	17.5	228.3	23.7	24.3	0.6
1974	39.7	10.0	19.0	224.0	24.5	26.2	1.7
1975	44.7	13.2	22.1	222.0	25.4	28.8	3.3
1976	49.8	15.3	24.7	221.9	26.4	31.2	4.8
1977	54.9	17.6	27.4	223.6	27.3	33.5	6.1
1978	60.0	19.4	29.8	226.7	28.6	35.7	7.1
1979	65.1	19.9	30.7	229.5	30.0	37.8	7.8
1980	70.2	18.8	29.7	230.2	31.5	39.9	8.3

Table 4.12: Simulated Supply of Natural Gas Reserves and Production Under "Phased Deregulation" of Gas (Using "medium" oil prices)

Year	New Contract Field Price (Continental U.S.) (Cents per Mcf.)	New Discoveries (Continental U.S.) (Trillions of cu.ft.)	Total Additions to Reserves (Continental U.S.) (Trillions of cu.ft.)	Total Reserves (Continental U.S.) (Trillions of cu.ft.)	Supply of Production (Continental U.S.) (Trillions of cu.ft.)	Demands for Production (Continental U.S.) (Trillions of cu.ft.)	Excess Demand for Production (Continental U.S.) (Trillions of cu.ft.)
1972	31.6	4.7	8.8	233.4	23.3	23.5	0.1
1973	34.6	10.1	17.5	228.3	23.7	24.3	0.6
1974	39.7	10.0	19.0	224.0	24.5	26.3	1.7
1975	64.6	16.7	25.5	224.1	26.8	28.6	1.8
1976	69.7	21.6	31.2	228.8	28.1	30.5	2.3
1977	74.8	25.3	35.8	237.1	29.2	31.9	2.7
1978	79.9	29.8	41.4	249.5	30.9	33.2	2.2
1979	85.1	29.8	42.8	261.5	32.9	34.2	1.2
1980	90.3	28.9	41.8	270.7	35.0	35.1	0.1

Table 4.13: Simulated Supply of Crude Oil Reserves and Production Under "Phased Deregulation" of Natural Gas and "medium" Oil Prices

Year	New Discoveries	Total Additions to Reserves	Total Year-end Reserves	Supply of Production at R/P = 9*
1972	271.9	1345.2	25293.3	3420.0
1973	339.0	1214.6	24031.3	3260.0
1974	360.1	1264.8	22824.5	3110.0
1975	538.3	1589.2	22285.0	3020.0
1976	488.0	1389.3	21522.1	2910.0
1977	614.1	1708.2	21174.7	2860.0
1978	596.2	1613.0	20772.7	2810.0
1979	547.2	1723.6	20529.5	2780.0
1980	546.9	1655.0	20244.4	2750.0

*A multiplicative factor of 1.22 has been applied to take account of the oil districts within Continental U.S. not included in the model.

Table 4.14: Simulated Supply of Crude Oil Reserves and Production Under "Status Quo" Regulation of Natural Gas and "Medium" Oil Prices (Continental U.S., millions of barrels)

Year	New Discoveries	Total Additions to Reserves	Total Year-end Reserves	Supply of Production at R/P = 9*
1972	271.9	1345.2	25293.3	3430.0
1973	339.1	1214.6	24031.3	3265.0
1974	360.1	1264.8	22924.5	3110.0
1975	538.3	1589.2	22285.0	3020.0
1976	472.4	1373.7	21506.5	2920.0
1977	604.4	1686.5	21139.7	2860.0
1978	619.9	1612.8	20742.9	2810.0
1979	605.0	1765.3	20546.1	2780.0
1980	581.7	1702.7	20307.9	2740.0

*A multiplicative factor of 1.22 has been applied to these figures to account for the oil districts within Continental U.S. not included in the model.

Table 4.15: Simulated Supply of Crude Oil Reserves and Production Under "Cost of Service" Regulation of Natural Gas and "Medium" Oil Prices (Continental U.S., millions of barrels)

Year	New Discoveries	Total Additions to Reserves	Total Year-end Reserves	Supply of Production at R/P = 9*
1972	271.9	1345.2	25293.2	3425.0
1973	339.1	1215.0	24031.3	3170.0
1974	360.1	1264.8	22924.5	3110.0
1975	538.3	1589.2	22284.9	3100.0
1976	470.5	1371.8	21504.5	2910.0
1977	600.6	1681.3	21132.9	2860.0
1978	612.9	1601.5	20725.8	2810.0
1979	593.9	1745.2	20511.4	2780.0
1980	572.8	1678.4	20254.0	2745.0

*A multiplicative factor of 1.22 has been applied to these figures to account for the oil districts not included in the model.

from nearly 24 trillion cubic feet to more than 30 trillion cubic feet by the end of 1980. The increased production comes partly from the existing reserves base as of 1973, thus reducing the total reserves base from 230 to 217 trillion cubic feet and the reserves-to-production ratio from 10 to about 8 by 1980. In spite of consistently producing more natural gas than the total additions to reserves, the production supplied cannot meet the demands. Demands are quite high (41 trillion cubic feet) by the end of 1980 because of a combination of low gas price and high oil price. The sizes of unsatisfied demands would be very substantial, amounting to more than 25% of the total demands by 1980.

The situation would improve slightly if "Status Quo" regulation is used. The total increments to proved reserves are not large enough to match the production supplied in the past few years but they match production towards the end of the simulatio nperiod. The total stock of reserves in 1980 (230 trillion cubic feet) is roughly equal to that at the beginning of the simulation period. However, since production is increasing, the reserves-to-production ratio falls from 10 to less than 8. With the higher wholesale prices of natural gas, the demands for production are less than those in the "Cost of Service" case; but they still exceed the production supply by substantial amounts causing shortages of the order of 8 trillion cubic feet by 1980.

The excess demands would be cut down to nearly zero in case the "Phased Deregulation" policy is adopted, both because the demand is cut down (to about 35 trillion cubic feet in 1980 compared to 40 trillion cubic feet for the "Status Quo" case) and supply out of reserves is increased (to 35 trillion cubic feet in 1980 as against 31.5 trillion in case of "Status Quo" regulation). The shortages in production are eliminated by the end of the seven-year period. The additions to reserves exceed supply of production by the end of the period indicating that shortages in reserves markets also are eliminated.

The response patterns of the additions to natural gas reserves are plotted in Figure 4.3. Notice that the additions to reserves begin to show a decline by 1980 in all the three cases. This may be interpreted as evidence of the depletion of resource base. With a finite resource base and a "sampling without replacement" effect, the returns from further drilling begin to show a significant decline. This, in turn, reduces the incentive to further drilling. Additional price increments would be required at this time if the level of exploratory activity and rate of increase of reserves additions is to be maintained.

The simulation results provide us an opportunity to compute estimates of price elasticities on new discoveries and total reserves additions.[1] For example, to compute the elasticity of new discoveries of

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[1]Since our model has a recursive structure with many non-linear structural equations, elasticities are hard to compute directly from the econometric estimations. For example, a shift in the price of gas has a direct effect on the amount of total exploratory drilling (because of the change in dollar returns expected) as well as an indirect effect through its influence on the quality of reservoirs discovered, i.e., through its influence on the size of discovery and probability of success. In addition, the variance of dollar returns is affected by a price change and, in turn, influences the exploratory wells drilled. The net effect of a price change on the amount of new discoveries is a composite of all these influences. Price elasticities under this structure are therefore far easier to compute from simulation results than from the econometric estimations.

natural gas with respect to price of natural gas, we can observe the percentage difference in some future year between the new discoveries generated by the "Cost of Service" and "Deregulation" alternatives. The required own-price elasticity will then be equal to the ratio of this percentage to the corresponding percentage difference in the prices allowed under the two alternatives. Since the specifications do not constrain the elasticities to be constant, we expect to find the estimates of elasticities varying, depending on the levels of the endogeneous and exogeneous variables. Based on such a computation for the production districts in the Continental United States excluding off-shore Louisiana, the elasticity of new discoveries of natural gas with respect to gas price by the 1978-1980 period was found to be in the range of 0.25 to 0.30.[1] This is considerably smaller than the elasticities reported in earlier studies such as Erickson and Spann [11], Spann and Erickson [38], and Khazzoom [23].[2] The elasticity estimates computed for the latest year of the simulation (1980) tend to be even lower as depletion of these resource bases begins to significantly affect the returns from drilling.

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[1]The value would be higher if the off-shore region is also included, probably because it is still a relatively unexplored area and contains large promise for the future.

[2]In their study published in 1971 [11], Erickson and Spann reported an own-price elasticity of gas discoveries of 0.69. Their later study [38] using more recent data and a regression constrained to obey certain cross-elasticity conditions showed a price elasticity of 3.1.

It should be interesting to observe the corresponding cross-price elasticity also, i.e., elasticity of gas discoveries with respect to oil price. To do this, simulations under the "Status-Quo" and "Phased Deregulation" alternatives are repeated at two other oil price "scenarios," called "low" and "high" oil prices in Table 4.9(b). Under the "low" condition, the price of oil per barrel is assumed to fall linearly from its 1974 level of $6.50 to $5.00 in equivalent 1974 dollars by 1980. Under "high" oil prices, it is assumed to increase (linearly) from $6.50 in 1974 to $7.50 in equivalent 1974 dollars by 1980. The results of these simulations are presented along with those for "medium" oil prices in Tables 4.16 and 4.17. Once again the estimates of cross-elasticities computed from these results vary somewhat depending on which set of policy alternatives is used in computing them. However, all the estimates of cross-elasticity of new discoveries of gas with respect to oil price are negative, and fall in the range -0.15 to -0.25. This empirical finding contradicts a view of the oil and gas discovery process that was often voiced during the discussions on U.S. oil import controls. Under this view, it was claimed that liberalizing the oil import quota system sufficiently to cause the U.S. price of oil to fall would aggravate the shortage of natural gas caused by the ceilings on the well-head price of natural gas.[1] Such an argument presupposes that the

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[1]This view of the oil and gas discovery process contributed to the objections raised in the minority report of the Cabinet Task Force on Oil Import Control. See the Cabinet Task Force on Oil Import Control, The Oil Import Question [7] for a discussion of the oil import problem.

Table 4.16: "Status Quo" Forecasts of Natural Gas Reserves and Production Under Three Oil Price Scenarios*

Year	New Contract Price (Cents/Mcf.)	New Discoveries	Total Additions to Reserves	Total Reserves	Supply of Production
1972	$31.7^{31.7}_{31.7}$	$4.7^{4.7}_{4.7}$	$8.8^{8.8}_{8.8}$	$233.5^{233.5}_{233.5}$	$23.3^{23.3}_{23.3}$
1973	$34.7^{34.7}_{34.7}$	$10.2^{10.2}_{10.2}$	$17.5^{17.5}_{17.5}$	$228.4^{228.4}_{228.4}$	$23.7^{23.7}_{23.7}$
1974	$39.7^{39.7}_{39.7}$	$10.1^{10.1}_{10.1}$	$19.0^{19.0}_{19.0}$	$224.0^{224.0}_{224.0}$	$24.6^{24.6}_{24.6}$
1975	$44.8^{44.8}_{44.8}$	$13.3^{13.1}_{13.5}$	$22.1^{22.0}_{22.3}$	$221.1^{221.9}_{222.3}$	$25.4^{25.4}_{25.4}$
1976	$49.8^{49.8}_{49.8}$	$15.4^{15.1}_{15.7}$	$24.8^{24.6}_{25.1}$	$221.9^{221.6}_{222.5}$	$26.4^{26.4}_{26.4}$
1977	$54.9^{54.9}_{54.9}$	$17.6^{17.4}_{18.0}$	$27.4^{27.2}_{27.8}$	$223.7^{223.1}_{224.6}$	$27.4^{27.4}_{27.4}$
1978	$60.0^{60.0}_{60.0}$	$19.4^{19.0}_{20.0}$	$29.8^{29.4}_{30.4}$	$226.7^{225.8}_{228.2}$	$28.7^{28.6}_{28.7}$
1979	$65.1^{65.1}_{65.1}$	$19.9^{18.5}_{21.1}$	$30.8^{29.4}_{32.0}$	$229.6^{227.3}_{232.2}$	$30.1^{30.0}_{30.1}$
1980	$70.2^{70.2}_{70.2}$	$18.9^{16.9}_{21.6}$	$29.8^{27.5}_{32.7}$	$230.2^{225.8}_{235.5}$	$31.5^{31.4}_{31.7}$

*Superscript and subscript denote highest and lowest alternatives respectively.
All reserves and production in Trillion Cubic Feet.

Table 4.17: "Phased Deregulation" Forecasts of Natural Gas Reserves and Production Under Three Oil Price Scenarios*

Year	New Contract Price (Cents/Mcf.)	New Discoveries	Total Additions to Reserves	Total Reserves	Supply of Production
1972	$31.7^{31.7}_{31.7}$	$4.7^{4.7}_{4.7}$	$8.8^{8.8}_{8.8}$	$233.5^{233.5}_{233.5}$	$23.3^{23.3}_{23.3}$
1973	$34.7^{34.7}_{34.7}$	$10.2^{10.2}_{10.2}$	$17.5^{17.5}_{17.5}$	$228.4^{228.4}_{228.4}$	$23.7^{23.7}_{23.7}$
1974	$39.7^{39.7}_{39.7}$	$10.1^{10.1}_{10.1}$	$19.0^{19.0}_{19.0}$	$224.0^{224.0}_{224.0}$	$24.6^{24.6}_{24.6}$
1975	$64.7^{64.7}_{64.7}$	$16.7^{16.6}_{17.0}$	$25.6^{25.4}_{25.8}$	$224.2^{224.0}_{224.4}$	$26.8^{26.8}_{26.8}$
1976	$69.7^{69.7}_{69.7}$	$21.6^{21.4}_{22.0}$	$31.3^{31.1}_{31.6}$	$228.8^{228.5}_{229.4}$	$28.2^{28.2}_{28.2}$
1977	$74.8^{74.8}_{74.8}$	$25.4^{25.2}_{25.8}$	$35.8^{35.6}_{36.2}$	$237.1^{236.6}_{238.1}$	$29.2^{29.2}_{29.2}$
1978	$80.0^{80.0}_{80.0}$	$29.9^{29.7}_{30.0}$	$41.5^{41.4}_{41.6}$	$249.6^{248.9}_{250.6}$	$31.0^{31.0}_{31.0}$
1979	$85.1^{85.1}_{85.1}$	$29.8^{29.3}_{29.8}$	$42.8^{42.4}_{42.7}$	$261.6^{260.5}_{262.4}$	$33.0^{32.9}_{33.0}$
1980	$90.3^{90.3}_{90.3}$	$28.9^{25.5}_{29.3}$	$41.8^{38.4}_{42.0}$	$270.7^{266.3}_{271.6}$	$35.0^{35.0}_{35.1}$

*Superscript and subscript denote highest and lowest alternatives respectively.
All reserves and production in Trillion Cubic Feet.

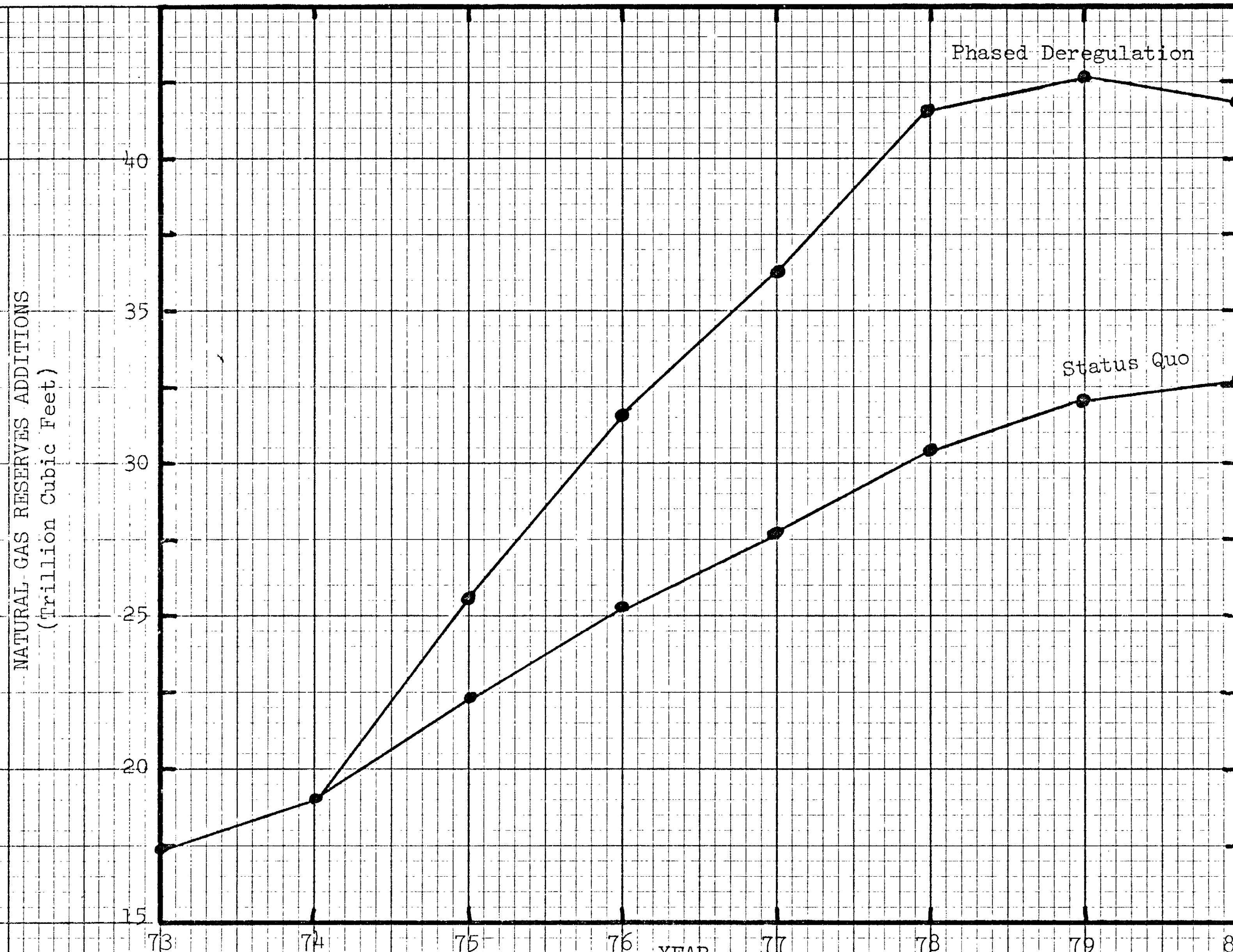

FIG. 4.2: SIMULATED ADDITIONS TO NATURAL GAS RESERVES UNDER ALTERNATIVE REGULATORY POLICIES USING "LOW" OIL PRICES

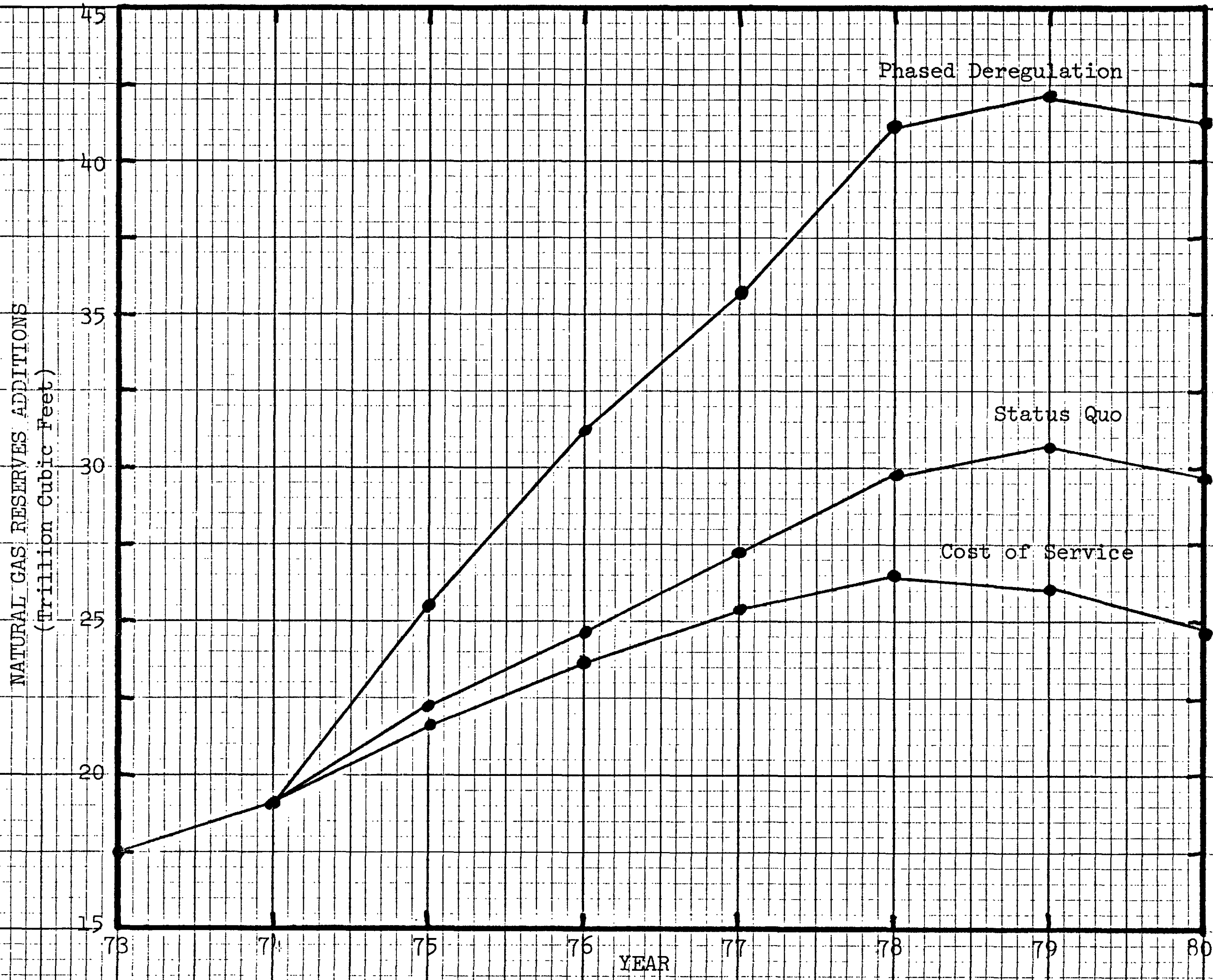

FIG. 4.3: SIMULATED ADDITIONS TO NATURAL GAS RESERVES UNDER ALTERNATIVE REGULATORY PRICES USING "MEDIUM" OIL PRICES

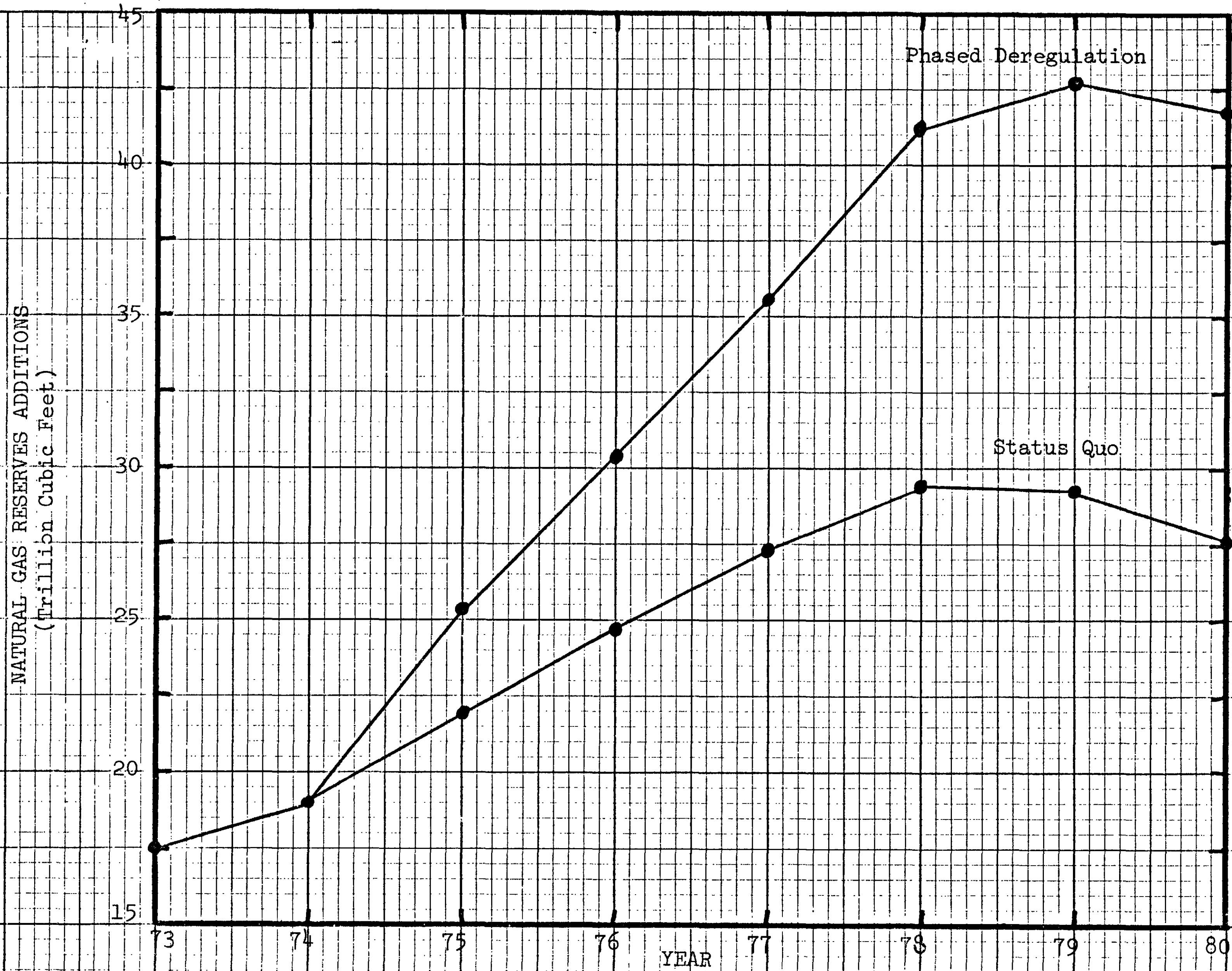

FIG. 4.4: SIMULATED ADDITIONS TO NATURAL GAS RESERVES UNDER ALTERNATIVE REGULATORY POLICIES USING "HIGH" OIL PRICES

cross-elasticity of supply between oil and gas discoveries is positive and dominates any positive cross-elasticity of demand.[1] The small absolute value of the estimated elasticity lends some credence to the Spann-Erickson hypothesis of zero cross-elasticity of supply between oil and gas discoveries.[2,3] The negative cross-elasticity implies that although total exploratory drilling may respond positively to increases in oil price, this effect on new discoveries of natural gas is more than offset

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[1]The possibility of positive supply interdependence was also raised in a submission to the Cabinet Task Force by Richard S. Gonzales in which Gonzales questioned the analysis of Burrows and Domencich presented in U.S. Oil Import Policy [6]. These contentions were based on casual evidence rather than a rigorous empirical study.

[2]Based on a theory of joint costs in oil and gas exploration, Spann and Erickson derive some constraints that must be satisfied by the own-price and cross-price elasticities of oil and gas discoveries. They test their hypothesis of zero cross-elasticity by running regressions under these constraints and concluded that the hypothesis cannot be rejected.

[3]Note also that no constraints such as those incorporated by Spann and Erickson (S-E) are required in estimations of the theoretical model of Chapters II and III. This is because our theoretical formulation model exploratory wells in terms of the size of dollar returns for exploratory wells (rather than as a simple function of prices) and, hence, automatically incorporates the kind of constraints S-E are interested in. Further, note that the constraints in price elasticities derived by S-E hold only under certainty. They must be modified if geological uncertainty is taken into account. Our model in fact automatically incorporates these modified constraints through its theoretical structure, because explorers are assumed to react to dollar returns corrected for risk.

by the directional drilling for oil. In other words, the "substitution" effect of the price change dominates the "scale" effect. Thus it also provides an indirect support to Khazzoom's finding [22] of high directionality.

The own-price and cross-price elasticities of total additions to natural gas reserves also can be similarly computed from the simulation results. These computations revealed an own-price elasticity of approximately 0.8 and a cross-price elasticity (elasticity with respect to oil price) in the range 0.0 to +0.08. This means that when prices of gas are increased, the total additions to gas reserves increase at a faster rate than new discoveries of gas. This is not unreasonable because the information generated from exploratory well drilling and the finding of new reservoirs subsequently paves the way later to extensions and revisions which are also components of reserves additions. It is interesting to note that the cross-elasticity shifted from negative in the case of new discoveries to zero or very slightly positive in the case of total reserves additions. Once again, this means that extensions and revisions of natural gas increase as a result of the increased total exploratory drilling. In fact, they increase enough to compensate completely for the negative cross-elasticity of new discoveries.

Thus, on the whole, even though new discoveries of gas show a decline at higher oil prices, the total additions to natural gas reserves are relatively insensitive to the price of oil. This is clearly evident from the results presented in Tables 4.16 and 4.17. Production supply is also unchanged because it depends only on year-end reserves of gas and the price of gas. Hence, the production and reserves markets would clear (or almost clear) under the "Phased Deregulation" alternative irrespective of whether oil prices are "low," "medium" or "high." The magnitudes of shortages in the case of "Cost of Service" and "Status Quo" regulatory alternatives remain about the same for all three sets of oil prices.

4.3.4 Results of the Simulations of the Supply of Oil Reserves and Production

We can now examine more closely the impact of alternative regulatory policies and oil price levels on the supply of additions to oil reserves and the resulting production. Tables 4.13 to 4.15 show the additions to oil reserves under the assumption of "medium" oil prices and the three regulatory alternatives for natural gas. The sensitivity of the reserves additions to changes in oil price can be judged from the results shown in Tables 4.18 and 4.19. These tables compare the reserves additions for "low," "medium" and "high" oil prices. The own-price and cross-price elasticities of new discoveries and total additions to oil reserves can now be computed in the case of natural gas.

The estimated own-price elasticities of new discoveries and total additions to reserves of oil lie respectively in the ranges 0.25 to 0.35 and 0.10 to 0.20. These may be compared with the lower-price elasticity of 0.87 reported by Spann and Erickson [38] for oil discoveries. The cross-elasticity with respect to price of gas are computed to be -0.10 to -0.25 for new discoveries of oil and 0.0 to -0.06 for total additions to oil reserves. The negative cross-elasticity in

Table 4.18: Forecasted Supply of Oil Reserves and Producticn Under "Status Quo" Regulation of Natural Gas and Three Oil Price Scenarios* (Continental U.S., Millions of Barrels)

Year	New Discoveries	Total Additions to Reserves	Total Year-end Reserves	Supply of Production at R/P = 9**
1972	$271.9^{271.9}_{271.9}$	$1345.2^{1345.2}_{1345.2}$	$25293.3^{25293.3}_{25293.3}$	$3430.0^{3430.0}_{3430.0}$
1973	$339.0^{339.0}_{339.0}$	$1214.6^{1214.6}_{1214.6}$	$24031.3^{24031.3}_{24031.3}$	$3265.0^{3265.0}_{3265.0}$
1974	$360.1^{360.1}_{360.1}$	$1264.8^{1264.8}_{1264.8}$	$22924.5^{22924.5}_{22924.5}$	$3110.0^{3110.0}_{3110.0}$
1975	$538.3^{538.3}_{538.3}$	$1589.2^{1589.2}_{1589.2}$	$22284.9^{22284.9}_{22284.9}$	$3020.0^{3020.0}_{3020.0}$
1976	$472.4^{478.2}_{464.4}$	$1373.7^{1379.5}_{1365.7}$	$21510.6^{21512.2}_{21498.4}$	$2920.0^{2922.0}_{2918.0}$
1977	$604.4^{625.4}_{575.9}$	$1686.5^{1709.0}_{1655.8}$	$21139.7^{21167.1}_{21102.2}$	$2860.0^{2862.0}_{2858.0}$
1978	$619.9^{656.9}_{569.7}$	$1612.8^{1657.8}_{1551.6}$	$20742.9^{20811.4}_{20649.0}$	$2810.0^{2820.0}_{2800.0}$
1979	$605.0^{640.0}_{543.6}$	$1765.3^{1820.5}_{1675.9}$	$20546.1^{20660.1}_{20376.5}$	$2780.0^{2800.0}_{2760.0}$
1980	$581.7^{596.7}_{536.0}$	$1702.7^{1747.4}_{1611.6}$	$20307.9^{20450.6}_{20071.3}$	$2740.0^{2750.0}_{2710.0}$

*Superscript and subscript denote highest and lowest alternatives respectively.
**A multiplicative factor of 1.22 has been applied to these figures to take account of oil districts not included in the model.

Table 4.19: Forecasted Supply of Oil Reserves and Production Under "Phased Deregulation" of Natural Gas and Three Oil Price Scenarios* (Continental U.S., Millions of Barrels)

Year	New Discoveries	Total Additions to Reserves	Total Year-end Reserves	Supply of Production at R/P = 9**
	271.9	1345.2	25293.3	3420.0
1972	271.9	1345.2	25293.3	3420.0
	271.9	1345.2	25293.3	3420.0
	339.0	1214.6	24031.3	3260.0
1973	339.0	1214.6	24031.3	3260.0
	339.0	1214.6	24031.3	3260.0
	360.1	1264.8	22924.5	3110.0
1974	360.1	1264.8	22924.5	3110.0
	360.1	1264.8	22924.5	3110.0
	538.3	1589.2	22285.0	3020.0
1975	538.3	1589.2	22285.0	3020.0
	538.3	1589.2	22285.0	3020.0
	493.5	1394.8	21527.6	2910.0
1976	488.1	1389.3	21522.1	2910.0
	480.5	1381.7	21514.5	2910.0
	634.2	1729.6	21200.9	2880.0
1977	614.2	1708.2	21174.7	2870.0
	587.0	1679.0	21138.9	2865.0
	635.6	1659.9	20842.3	2820.0
1978	596.2	1613.0	20772.9	2810.0
	544.9	1551.1	20680.3	2800.0
	602.8	1800.3	20665.7	2790.0
1979	547.2	1723.6	20529.5	2780.0
	476.3	1624.2	20350.6	2765.0
	583.2	1729.4	20435.6	2765.0
1980	547.0	1655.0	20244.4	2750.0
	453.1	1511.5	19947.2	2710.0

*Superscript and subscript denote highest and lowest alternatives respectively.

**A multiplicative factor of 1.22 has been applied to these figures to take account of oil districts not included in the model.

the case of new discoveries indicates once again that the directional drilling effect dominates the scale effect. However, as in the case of natural gas, this effect is almost entirely compensated by the positive response of extensions and revisions of oil to total exploratory activity, thus yielding a cross-elasticity of total additions to reserves very close to zero. In any event, these results seem to cast considerable doubt on policy arguments resting on the assertion that oil discoveries are highly sensitive to economic factors.

In interpreting the size of supplies of oil reserves and production, two things must be kept in mind. First, some important oil production districts within the Continental United States are not included in the model for reserve additions because of unavailability of some of the required data. To correct for this and get an estimate of the total supply of production in the United States, a multiplicative factor of 1.22 is applied to the figures of oil production appearing in the last columns of Tables 4.13, 4.14, 4.15, 4.18 and 4.19.[1] Secondly, reserves and production from Alaska are not included in the figures reported in Tables 4.9 to 4.19. Alaska is a much more important factor[2] in the case of oil than in the case of natural gas. Under "medium" oil

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[1]The factor 1.22 is obtained as the historical average of the same ratio.

[2]The AGA/API estimates show that more than 10 billion barrels or nearly 27% of the total estimated oil reserves in the U.S.A. lie in Alaska. By comparison, Alaska has only about 12% of the total proved reserves of natural gas in the U.S.A.

prices and "Status Quo" regulation of natural gas, domestic production of oil is expected to go down from its 1972 level of 3.4 billion barrels per year (or ≈ 9.3 million barrels per day) to 2.76 billion barrels per year (or 7.65 million barrels per day) by 1980. Additions to reserves of crude oil would go up by approximately 25% from its 1974 levels, but these would still fall short of the production supplied by as much as 15% (corrected total additions to reserves of oil are expected to be approximately 2.30 billion barrels per year). Because of the low price elasticities, the total additions to reserves and production are not much higher even when "high" oil prices are simulated. The estimated total additions to reserves in the "high" oil price case are about 2.35 billion barrels per year and the corresponding production (assuming a reserves-to-production ratio of 9 to 1) is expected to be 2.9 billion barrels/year (or ≈ 7.8 million barrels per day).[2] These estimates may be compared with the Erickson and Spann estimate [11] of 8.4 million barrels per day and the N.P.C. estimate of 13.6 million barrels per day [36] at real oil prices of $7 per barrel.[1]

The results of the simulations thus indicate that crude oil prices of the order of $7 per barrel (in 1974 dollars) are not enough to generate supplies of oil production that can match the demands. Furthermore, the domestic crude oil reserves market will experience a shortage, with the total additions to reserves substantially below even the already low supply of production.

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[1] See [31] for further discussion of these estimates.

[2] Production estimates from Alaska are not included in this figure.

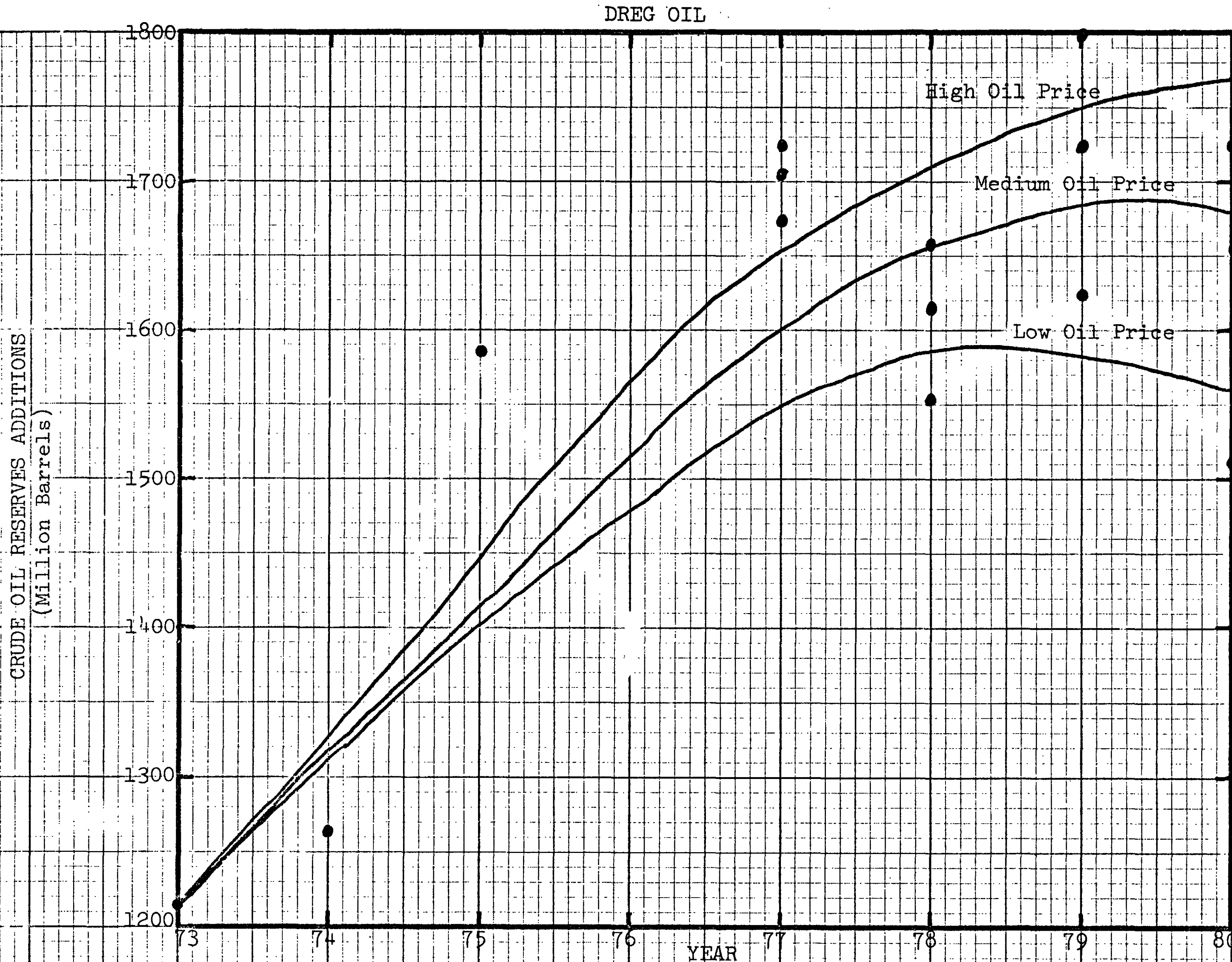

FIG. 4.5: SIMULATED ADDITIONS TO CRUDE OIL RESERVES UNDER ALTERNATIVE OIL PRICE SCENARIOS ASSUMING PHASED DEREGULATION OF NATURAL GAS

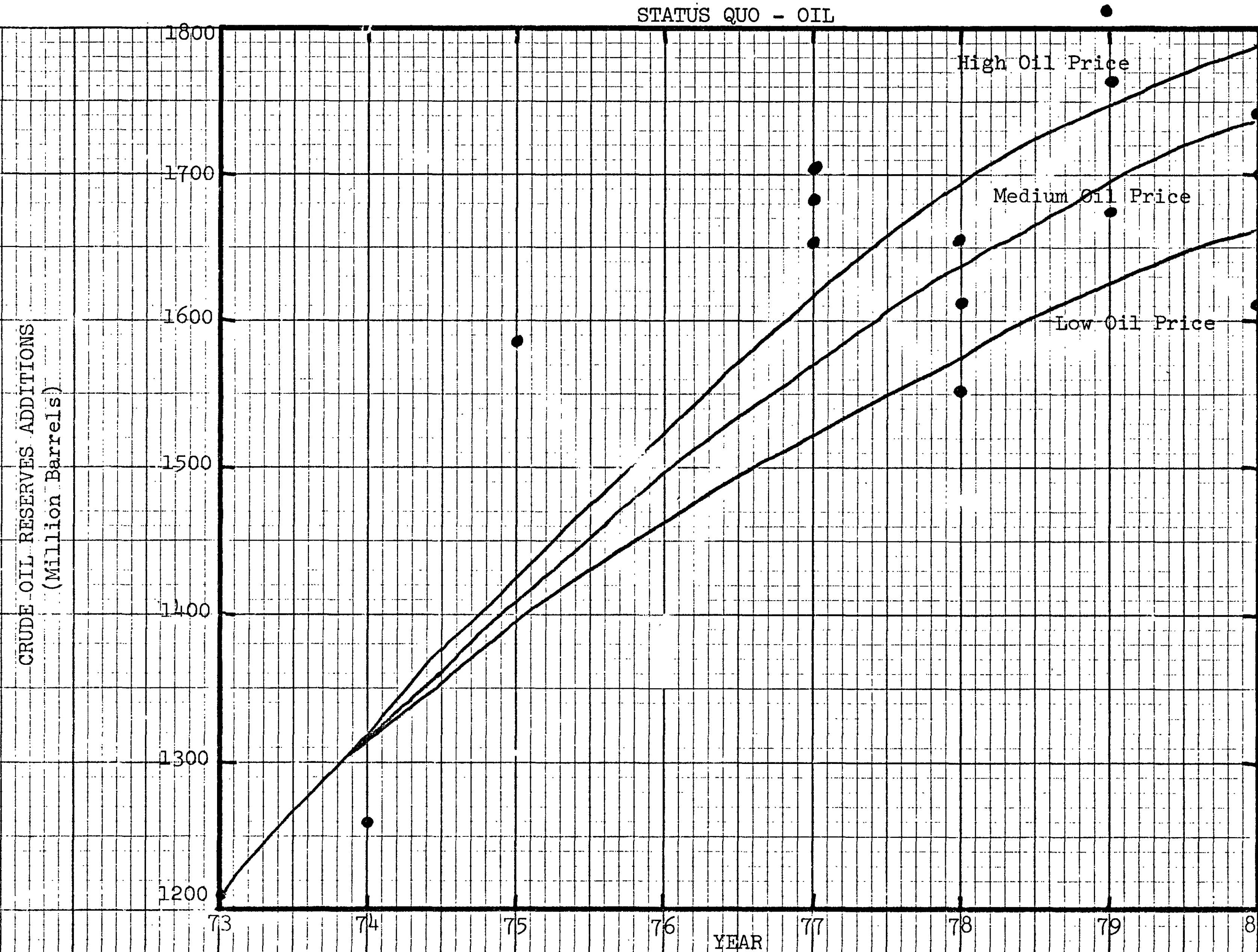

FIG. 4.6: SIMULATED ADDITIONS TO CRUDE OIL RESERVES UNDER ALTERNATIVE OIL PRICE SCENARIOS ASSUMING "STATUS QUO" REGULATION OF NATURAL GAS

The results thus sustain two of the major conclusions of the M.I.T. Energy Policy Study Group [31]. Based on an extensive study of all future energy sources, they have concluded that "...(real) prices of $10.00 to $12.00 per barrel (oil-equivalent) will be necessary to bring forth enough additional supplies of fossil fuels to satisfy demands in domestic energy markets by that time," and also that "the current oil price is high enough to extract present domestic oil and gas reserves with great efficiency. A still higher price would have only a marginal effect on exploration production over the next few years within the United States."

4.3.5 Simulation of Alternative Economic Environments

One might be interested in knowing if the results obtained for different regulatory policies are sensitive to the assumed values of parameters denoting the general economic environment. All the simulations reported in this chapter have therefore been repeated under alternative ("low" and "high") values for exogeneous parameters such as rate of growth of G.N.P. and inflation rate. These results are not presented in detail here, but it may be noted that the simulated values of discoveries, reserves additions and production showed very little sensitivity to changes in these exogeneous parameters.

CHAPTER V

CONCLUSION

It has been demonstrated in this thesis that it is possible to develop an econometric model to explain the oil and gas exploration process which explicitly takes into account the characteristics of the size distribution of reservoirs in nature as well as the physical process of the evolution of a play. The structure of the model is based on the premise that, to the extent possible, the physical process of depletion should be separated from the influence of economic variables. This structure facilitates considerable simplifications in modelling as well as interpretation of the results.

The model breaks some new ground to the extent that it gives explicit consideration to the continuing process of depletion of the resource base in nature and the role of geological uncertainty in governing the amount of exploratory activity, while at the same time taking account of the fact that oil and gas are joint products of exploration and must be treated symmetrically.

Some significant empirical results emerge from the study:

- the geogological process of depletion is a factor to be reckoned with, and causes reductions in both the average sizes of discoveries and probabilities of success as drilling continues within the same area.
- Increases in price incentives affect not only the total exploratory activuty, but the characteristics of the prospects

drilled. On the average, the explorers move towards more extensive drilling as prices go up. The recent increase in the off-shore drilling activity is a demonstration of this tendency.

- Geological uncertainty does have a role to play in determining the individual explorer's decision.
- The results lend some support to the hypothesis of significant "directionality" in the search for oil and natural gas.
- Own-price and cross-price elasticities of discoveries of oil and natural gas are small, but not negligible.

The model has also demonstrated its usefulness for policy analysis in a simulation context. Simulations of the model have been successfully used to examine two currently relevant issues; namely, the regulation of natural gas prices and the sensitivity of domestic oil supplies to price incentives. By simulating alternative regulatory policies currently under consideration for natural gas, we find that the gas shortage <u>can</u> be ameliorated through phased deregulation of well-head prices. The model also shows that the sensitivity of domestic supply of reserves and production of oil to economic incentives is considerably lesser than that suggested in many earlier studies. This means that the price increases required for achieving self-sufficiency in fossil fuel markets in the United States are probably substantially higher than those envisaged so far.

Finally, as far as future improvements in modelling along these lines, two aspects come most immediately to mind. First, an explicit consideration of tax (and other fiscal) differentials across states and over time would enable examination of fiscal policy alternatives more directly than is now possible. Secondly, the role of future expected technical progress could be modelled explicitly. Historically, there is reason to believe that improvements in productivity of drilling rigs, better methods of analyzing geological information, and other technical improvements were approximately offset by cost increases in raw materials and larger depths of drilling required, but this may not be the case in the future and this possibility should be investigated.

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